PUBLIC

Final Environmental Impact Statement
Falls Creek Hydroelectric Project and Land Exchange
Docket No. 11659-002

FINAL ENVIRONMENTAL IMPACT STATEMENT

June 2004
FERC/FEIS – 0167F
NPS D-118A

Glacier Bay National Park and Preserve

Falls Creek Hydroelectric Project (FERC No. 11659) and Land Exchange

Federal Energy Regulatory Commission
Office of Energy Projects
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U.S. Department of the Interior
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FINAL ENVIRONMENTAL IMPACT STATEMENT

FALLS CREEK HYDROELECTRIC PROJECT AND LAND EXCHANGE

FERC Project No. 11659-002
Alaska

Applicant:
Gustavus Electric Company
Gustavus, Alaska

U.S. Federal Energy Regulatory Commission
Office of Energy Projects
Division of Hydropower Licensing
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U.S. Department of the Interior
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June 2004

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF ENERGY PROJECTS

TO THE PARTY ADDRESSED

Attached is the final environmental impact statement (final EIS) for the Falls Creek Hydroelectric Project and Land Exchange (FERC Project No.11659-002). The EIS was prepared in response to the Glacier Bay National Park Boundary Adjustment Act of 1998 and the filing, by Gustavus Electric Company, of a hydroelectric license application with the Commission. The final EIS documents the views of the Federal Energy Regulatory Commission (FERC or Commission) staff and the National Park Service (NPS) on four alternatives regarding the land exchange and licensing of the project.

The final EIS was sent to the U.S. Environmental Protection Agency and made available to the public on or before June 30, 2004. Copies of the final EIS are available for review in the Commission's Public Reference Branch, Room 2A, located at 888 First Street, NE, Washington, DC, 20426. The final EIS also may be viewed on the Internet at http://www.ferc.gov. For assistance, please contact the Commission's online support at FERCOnlineSupport@ferc.gov, or call toll free (866) 208-3676 or (202) 502-8659 (for TTY).

Attachment: Final Environmental Impact Statement

COVER SHEET

a. Title: Falls Creek Hydroelectric Project and Land Exchange, Alaska

b. Subject: Final Environmental Impact Statement

c. Lead Agencies: Federal Energy Regulatory Commission (FERC) and National Park Service (NPS)

d. Abstract: Gustavus Electric Company (GEC) filed an application for an original license for the 800-kilowatt Falls Creek Hydroelectric Project, which would be located on the Kahtaheena River (Falls Creek) near Gustavus in southeastern Alaska.

Provisions to consider a land exchange and siting of a hydroelectric project on lands currently designated as wilderness in Glacier Bay National Park are outlined in the Glacier Bay National Park Boundary Adjustment Act of 1998 (the Act). The Act authorizes FERC to accept and consider a hydroelectric license application from GEC, and, pending an environmental review, the Secretary of Interior could convey the land in Glacier Bay National Park and Preserve (GBNPP) to the state of Alaska for this project. The Act provides for NPS to receive land from the state of Alaska in another park unit and to designate other land in GBNPP as wilderness.

This final environmental impact statement (EIS) considers whether to issue a license for the project, the exchange of federal land with state land, and the removal of land from wilderness designation and the designation of other land as wilderness.

The proposed Falls Creek Hydroelectric Project would consist of a diversion dam, powerhouse and connecting penstock. The project would be operated as run-of-river, where inflows would match outflows downstream of the project. The powerhouse would be constructed at river mile 0.45 just downstream of the Lower Falls. The 60-foot-high Lower Falls, located 0.5 river miles from the river's confluence with Icy Passage, is a permanent barrier to fish migration. Stream habitat in the river reach that would be affected by construction and operation of the proposed project consists of a canyon reach with long, deep bedrock pools, and pools formed by large woody debris. Above the canyon reach, there is an old-growth spruce/hemlock forest typical of areas in southeastern Alaska that

escaped glacial disturbance during Neoglacial advances. The diversion would be located at river mile 2.4.

Key issues associated with licensing this project and implementing the land exchange are the impacts on resident populations of Dolly Varden, impacts on the aesthetic qualities of the Lower Falls, planning public access to maintain existing passive recreational activities, and protection of existing wilderness values of the GBNPP.

If the Commission issues a license for the Falls Creek Hydroelectric Project, construction and operation of the project would require exchange of federal and state lands and designation and de-designation of wilderness lands. Our preferred alternative addresses these actions and is composed of elements from the action alternatives. In regard to the GBNPP and wilderness boundary adjustment, we recommend that the land exchanged to the state of Alaska should be the land described under the Maximum Boundary Alternative with modification to retain approximately 95 acres of land north of the diversion structure and south of The Islands area within GBNPP. This land exchange scenario would result in adjusting the GBNPP boundary and reducing the amount of land in the park by approximately 1,050 acres. With this land exchange scenario, there would be less chance for project-related erosion or landslides or noises from project construction to affect the park than with GEC's Proposed Alternative or the Corridor Alternative.

At this time, NPS has not selected a preferred alternative for the land to be received from the state. In regard to designation of wilderness lands, NPS recommends that both the unnamed island near Blue Mouse Cove and Cenotaph Island, totaling 1,069 acres, be designated as wilderness since this is approximately equal in sum to the wilderness deleted from GBNPP resulting from the land exchange.

If the project is licensed, the preferred FERC project boundary would be the boundary described under GEC's Proposed Alternative with modification to include a 200 foot buffer around all project features, including the powerhouse; the diversion dam and intake structures; the haulback site; and the transmission line, access road, and penstock corridors. The project boundary proposed by GEC, with FERC staff modifications, would constitute the minimum amount of land necessary for the construction and operation of a hydroelectric project, as specified by the Act.

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f. Transmittal: This final EIS prepared by FERC staff and NPS on the hydroelectric license application filed by the Gustavus Electric Company for the Falls Creek Hydroelectric Project (Project No. 11659-002) is being made available to the public on or about June 30, 2004, as required by the National Environmental Policy Act of 1969[1] and the Commission's Regulations Implementing the National Environmental Policy Act (18 CFR Part 380).

[1] National Environmental Policy Act of 1969, as amended (Pub. L. 91-190. 42 U.S.C. 4321-4347, January 1, 1970, as amended by Pub. L. 94-52, July 3, 1975, Pub. L. 94-83, August 9, 1975, and Pub. L. 97-258, §4(b), September 13, 1982).

FOREWORD

The Federal Energy Regulatory Commission (Commission), pursuant to the Federal Power Act (FPA) [2] and the U.S. Department of Energy Organization Act,[3] is authorized to issue licenses for up to 50 years for the construction and operation of non-federal hydroelectric developments subject to its jurisdiction, on the necessary conditions:

> That the project adopted...shall be such as in the judgment of the Commission will be best adapted to a comprehensive plan for improving or developing a waterway or waterways for the use or benefit of interstate or foreign commerce, for the improvement and utilization of water-power development, for the adequate protection and enhancement of fish and wildlife (including related spawning grounds and habitat), and for other beneficial public uses, including irrigation, flood control, water supply, and recreational and other purposes referred to in Section 4(e)...[4]

The Commission may require such other conditions not inconsistent with the FPA as may be found necessary to provide for the various public interests to be served by the projects.[5]

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2 16 U.S.C. §§791(a)–825(r), as amended by the Electric Consumers Protection Act of 1986, Pub. L. 99495 (1986) and the Energy Policy Act of 1992, Pub. L. 102-486 (1992).

3 Pub. L. 95-91, 91 Stat. 556 (1977).

4 16 U.S.C. §803(a).

5 16 U.S.C. §803(g).

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ACRONYMS AND ABBREVIATIONS

ACOE	U.S. Army Corps of Engineers
Act	The Glacier Bay National Park Boundary Adjustment Act of 1998
ADCED	Alaska Department of Community and Economic Development
ADEC	Alaska Department of Environmental Conservation
ADFG	Alaska Department of Fish and Game
ADNR	Alaska Department of Natural Resources
ADOT	Alaska Department of Transportation
ADPOR	Alaska Department of Parks and Outdoor Recreation
ANB	annual net benefits
ANILCA	Alaska National Interest Lands Conservation Act
ATV	all-terrain vehicle
AWUA	available weighted useable area
BIA	Bureau of Indian Affairs
BMP	best management practices
°C	degrees Celsius
CFR	Code of Federal Regulations
cfs	cubic feet per second
CO	carbon monoxide
Commission	Federal Energy Regulatory Commission
dBA	decibels (a-weighted)
EA	environmental assessment
ECM	environmental compliance monitor
EFH	essential fish habitat
EIA	Energy Information Administration
EIS	environmental impact statement
EPA	U.S. Environmental Protection Agency
ESA	Endangered Species Act
ESCP	Erosion and Sediment Control Plan
FERC	Federal Energy Regulatory Commission
FHWA	Federal Highway Administration
FPA	Federal Power Act
FWS	U.S. Fish and Wildlife Service
GBNPP	Glacier Bay National Park and Preserve
GCA	Gustavus Community Association
GEC	Gustavus Electric Company
GLL	Gustavus Land Legacy
GMP	General Management Plan
HDPE	high-density polyethylene
IFIM	Instream Flow Incremental Methodology
Interior	U.S. Department of the Interior
KGNHP	Klondike Gold Rush National Historic Park

km	kilometer
kW	kilowatt
kWh	kilowatt-hours
µ	micron
m	meter
mg/L	milligrams per liter
Ms	surface wave
msl	above mean sea level
NAAQS	national ambient air quality standards
National Register	National Register of Historic Places
NEPA	National Environmental Policy Act
NHPA	National Historic Preservation Act
NMFS	National Marine Fisheries Service
NPS	National Park Service
NRCS	National Resource Conservation Service
NTU	nephelometric turbidity units
O&M	operation and maintenance
OWUA	optimum weighted usable area
PCE	Power Cost Equalization
PDEA	preliminary draft environmental assessment
PME	protection, mitigation, and enhancement
PSD	prevention of significant deterioration
psi	pounds per square inch
RM	river mile
ROD	record of decision
ROS	Recreation Opportunity Spectrum
RSD	relative standard deviation
RTCA	Rivers, Trails, and Conservation Assistance Program
Secretary	Secretary of the Interior
SHPO	State Historic Preservation Officer
SO2	sulfur dioxide
tpy	ton per year
TSP	total suspended particulates
UNESCO	United Nations Educational, Scientific, and Cultural Organization
USDA	U.S. Department of Agriculture
USFS	U.S. Forest Service
USGS	United States Geological Survey
VOC	volatile organic compounds
WARS	Wilderness Attribute Rating System
WSNPP	Wrangell-St. Elias National Park and Preserve
WUA	weighted usable area

EXECUTIVE SUMMARY

This final environmental impact statement (final EIS) evaluates the potential effects on the environment from licensing the proposed 800-kilowatt Falls Creek Hydroelectric Project and land exchange in Glacier Bay National Park and Preserve (GBNPP). The consideration of these actions is authorized under the Glacier Bay National Park Boundary Adjustment Act of 1998 (the Act). On October 23, 2001, Gustavus Electric Company (GEC) filed a license application with the Federal Energy Regulatory Commission (FERC or Commission). The proposed project would be located on the Kahtaheena River (Falls Creek) about 5 miles from the town of Gustavus on lands currently designated as wilderness within GBNPP.

Under the provisions of the Act, FERC and the National Park Service (NPS) have jointly prepared this final EIS to assist both agencies in determining whether the project as proposed by GEC should be licensed and a land exchange between the NPS and state of Alaska should be completed. Before a license can be issued and land exchange completed, the Commission must conduct environmental analyses and, with the concurrence of the Secretary of the U.S. Department of the Interior (Secretary), conclude that the construction and operation of the project on lands in the Kahtaheena River area would not adversely impact the purposes and values of GBNPP as constituted after the exchange of land and would comply with the requirements of the National Historic Preservation Act (NHPA). The Commission also must conclude that construction and operation would be economically feasible and determine, with the concurrence of the Secretary and the state of Alaska, the minimum amount of land necessary to construct and operate the project.

In this final EIS, the potential environmental effects of four alternatives are addressed: (1) not issuing a license for construction and no land exchange (No-action Alternative); (2) issuing a license for construction and operation of the project on 117 acres with 850 acres exchanged with the state of Alaska as proposed by GEC (GEC's Proposed Alternative); (3) issuing a license for a project on 1,145 acres of land exchanged with the state and all exchanged acres in addition to 42 acres on private land included in the FERC project boundary (Maximum Boundary Alternative); and (4) issuing a license for a project on 680 acres of land exchanged with the state and all exchanged acres in addition to 42 acres on private land included in the FERC project boundary (Corridor Alternative). Each action alternative considers an array of environmental protection or mitigation measures for inclusion in any FERC license that may be issued.

Briefly, the principal issues addressed in the final EIS include: (1) erosion and sedimentation control; (2) water quantity and quality; (3) air quality; (4) fisheries, including effects on resident Dolly Varden; (5) vegetation and wetlands; (6) wildlife resources; (7) cultural resources; (8) soundscapes; (9) visual resources; (10) recreation resources; (11) wilderness; (12) park management; (13) land use; and (14) socioeconomics.

Under each action alternative, state of Alaska land having a sufficiently equal value to the amount of land exchanged in each alternative, would be conveyed to the NPS in either Wrangell-St. Elias National Park and Preserve (WSNPP) or Klondike Gold Rush National Historic Park (KGNHP). For compensation for the wilderness acreage deleted from GBNPP and to ensure the transaction maintains, within the National Wilderness Preservation System, approximately the same amount of designated wilderness as currently exists, in priority order the following GBNPP land would be designated as wilderness: (1) the unnamed island near Blue Mouse Cove in Glacier Bay proper, (2) Cenotaph Island in Lituya Bay on the outer coast of GBNPP, and (3) land near Alsek Lake approximately 60 miles southeast of Yakutat, Alaska.

In the draft EIS, FERC staff presented costs for GEC's Proposed Alternative and the action alternatives as well as an economic analysis of the proposed hydroelectric project. In comments on the draft EIS, GEC provided new and revised cost estimates for several measures, and several entities provided alternative economic assumptions for the economic analysis. FERC staff revised its cost estimates and economic analysis to address these comments. As a result, cost figures presented in the final EIS have changed significantly from those presented in the draft EIS.

NO-ACTION ALTERNATIVE

Under the No-action Alternative, the Falls Creek Hydroelectric Project would not be built, lands within GBNPP would not be exchanged with the state of Alaska, and new wilderness areas within GBNPP would not be designated. There would be no new or additional environmental effects associated with this alternative. There would be no project-related effect on the Native allotments or other private and state lands adjacent to the project. The No-action Alternative represents continued reliance on diesel generation and serves as the baseline for comparison in this final EIS. The cost of the No-action Alternative would be $0.

GEC'S PROPOSED ALTERNATIVE

GEC's Proposed Alternative would transfer some 850 acres of wilderness land, currently within GBNPP, to the state of Alaska, with the subsequent transfer of a commensurate amount of state land (based on appraised value) to the NPS for inclusion in either WSNPP or KGNHP. Additionally, approximately 850 acres presently not designated as wilderness in GBNPP would be designated as wilderness. Under this alternative, the GBNPP boundary would be the eastern side of the Kahtaheena River from approximately 0.5 miles north of the diversion dam/intake structure to the powerhouse location.

On the land transferred to the state, GEC would develop a hydroelectric facility on the Kahtaheena River near the town of Gustavus. GEC's Proposed Alternative would affect a stretch of the Kahtaheena River about 2 miles long, from a point about 0.25 miles upstream of the tidewater to a point about 2.2 miles upstream of the tidewater. The entire bypassed reach would be 1.79 miles long. GEC would construct and maintain a new access/service road extending 1.7 miles from the end of the existing road system (Rink Creek Road), at which point it would branch 0.5 miles north to the proposed diversion dam/intake structure and 1.4 miles south to the proposed powerhouse for a total length of 3.6 miles. A 5.0-mile-long transmission line would be buried from the powerhouse, connecting the project to the existing diesel power plant substation at the town of Gustavus.

GEC's Proposed Alternative would include the following protection, mitigation, and enhancement measures: (1) design facilities and provide fish screens and bypass system to minimize effects on anadromous fish and resident Dolly Varden; (2) siting and construction of project facilities to minimize effects on soils (buried pipelines), wetlands, mature forests, and culturally modified trees associated with the Huna Tlingit; (3) construction access and timing to minimize effects on fish and wildlife; (4) an erosion and sediment control plan; (5) a sediment monitoring plan; (6) provision of minimum flows with ramping rate limitations; (7) water quality monitoring during construction; (8) a flow monitoring plan; (9) provision of signage and trail brushing for passive recreation; (10) control of public access along the access road and limiting access to non-motorized recreation; and (11) operate the project in a run-of-river mode.

GEC's Proposed Alternative would affect environmental resources on the project lands and on adjacent GBNPP lands. On the project lands, adverse affects on resources in the area would include an increased potential for landslides, a reduction in flow and increase in summer water temperatures in the bypassed reach, increased turbidity in the Kahtaheena River, reduction in the resident Dolly Varden populations in the bypassed reach, increased air pollution during the construction of the project, the permanent loss of about 9.6 acres of wildlife habitat and 1.15 acres of wetlands, increased noise during construction and operation of the project, diminished aesthetic resources due to a reduction in flow in the entire bypassed reach and over the Lower Falls, loss of solitude or wilderness qualities in the project area, and increased public access to the project area that could result in a diminished recreational experience for those visitors wishing to experience solitude and quiet. On the other hand, this alternative could provide additional land uses on state land that are not currently allowed on GBNPP lands (easier access for viewing the falls, all-terrain vehicle (ATV) use, dog walking, hunting, and trapping) and could provide a positive experience for those visitors.

Under this alternative, the adverse effects associated with landslides, water quantity, water quality, fisheries, wildlife, air quality, noise, and public access would affect the Kahtaheena River, the Native allotment lands, and adjacent GBNPP lands.

Aesthetic resources would be negatively impacted by the reduced flow in the bypassed reach and over the Lower Falls. Visitors within GBNPP along the eastern boundary of the proposed project would, at certain times of year, experience a diminished aesthetic experience when viewing the bypassed reach and the Lower Falls. Social trails might be expected to develop over the term of any license issued as GBNPP visitors curious about project facilities and the Kahtaheena River cross the park boundary. Any effects on wilderness resources on the adjacent GBNPP lands would be short term and localized and would not substantially diminish the purposes and values of this wilderness. The qualitative difference between the wilderness lands removed from the park and those that may be newly designated would not constitute a significant change in the overall quality of the 2.5 million acres of wilderness lands within GBNPP. Additionally, the designation of these new wilderness lands would ensure that there would be no net loss in wilderness land within GBNPP or the National Wilderness System. There would be an adverse impact on park management from an increased need for park staff and law enforcement to monitor and protect park resources on adjacent GBNPP lands.

Project access roads located north of the George allotment and along the eastern boundary of the Mills allotment would be expected to increase the potential for visitors to trespass, and, along with project-related activities, disturb the solitude on the Native allotments and on state and private lands adjacent to the project. There could be a negative effect on Native allotments from the increased recreational opportunities including activities that are not currently allowed on GBNPP lands.

The hydroelectric project, as proposed by GEC, would cost $356,620 annually to operate, have annual power benefits of $266,640, and a net annual benefit of -$89,980 (an annual loss of $89,980). The cost would be about $43/MWh more than the currently available alternative (existing diesel).

To reduce the environmental effects described above, FERC staff recommend that any license issued for the project should include the following measures: (1) a fish facilities evaluation plan; (2) a biotic evaluation plan; (3) a $50,000 escrow account to mitigate for unforeseen effects on fish and wildlife associated with the project; (4) a fuel and hazardous substances spill plan; (5) prohibition of fishing and hunting by construction personnel; (6) a bear-human conflict plan; (7) a road management plan; (8) a flow phone or other means for visitors to check flow rates in the bypassed reach; (9) a public access plan (including signage and trail brushing); (10) a land use and recreation development management plan; (11) a wetlands mitigation plan; and (12) a plan to monitor environmental compliance during construction.

With these additional mitigation and environmental measures, the project would cost $393,890 annually, have annual power benefits of $266,640, and would provide a net annual benefit of -$127,250 (an annual loss of $127,250). The cost would be about $61/MWh more than the currently available alternative.

FERC staff concludes and the NPS concurs that the construction and operation of a hydroelectric project under this alternative would not adversely impact the purposes and values of GBNPP as constituted after the land exchange and that the project would comply with the NHPA.

MAXIMUM BOUNDARY ALTERNATIVE

The Maximum Boundary Alternative (see figure 2-8 in appendix A) would be the same as GEC's Proposed Alternative with the exception that 1,145 acres of land identified in section 3(b) of the Act as potentially available for the development of a hydroelectric project would be transferred to the state of Alaska, and all the transferred land would be within the FERC project boundary and would be subject to the FERC license conditions. Accordingly, the bypassed reach would be included in the FERC project boundary. The project facilities constructed within these lands would be the same as for GEC's Proposed Alternative.

The effects on environmental resources from the construction and operation of the project facilities on project lands, wilderness parcels, and exchange parcels under the Maximum Boundary Alternative would the same as under GEC's Proposed Alternative.

Under this alternative, there would still be adverse effects on the fisheries, wildlife, and air quality resources of GBNPP. However, some effects on adjacent GBNPP lands would be reduced. Lands east of the Kahtaheena River that would be removed from GBNPP under this alternative would serve as a buffer to protect some resources (e.g., wildlife, vegetation, recreation) and reduce or eliminate effects on other resources (soil resources, water quantity and quality, soundscape, public access, and park management) on GBNPP lands. Project access roads located north of the George allotment and along the eastern boundary of the Mills allotment would be expected to increase the potential for visitors to trespass, and, along with project-related activities, disturb the solitude on the Native allotments and on state and private lands adjacent to the project. There could be a negative effect on Native allotments from the increased recreational opportunities including activities that are not currently allowed on GBNPP lands.

Soundscape would be less affected under this alternative because the additional lands along the eastern edge of the Kahtaheena River that would be conveyed to the state of Alaska would provide a sound buffer for the adjoining GBNPP lands. Aesthetic resources on the surrounding GBNPP lands also would be less impacted under this alternative because of this increase in conveyed lands to the state. Under this alternative, GBNPP lands would not extend to the Lower Falls or bypassed reach, and visitors to this area of the park would not be able to view either the bypassed reach or Lower Falls from GBNPP lands. For park management, the ability for GBNPP to manage the public lands along the eastern boundary of the park would be adversely affected in the short term because additional staff would be needed to assess the new land boundaries and determine how they should be managed in the future. Although, over time this effect would diminish and could result in a positive effect on park management as the state of Alaska takes over management of the fisheries resources and recreational opportunities in the conveyed stretch of the Kahtaheena River. There also would be a positive effect on public access and recreational resources for some users because the additional state lands on the eastern side of the Kahtaheena River and west of GBNPP boundary could provide recreational opportunities that are currently not allowed on GBNPP lands (e.g., hunting, trapping, dog walking, ATV use).

The Maximum Boundary Alternative would include GEC's proposed environmental measures and the additional FERC staff recommended environmental measures that would be needed to protect, mitigate, and enhance environmental resources. The estimated project costs of the project and proposed mitigation and environmental measures under the Maximum Boundary Alternative would be the same as under GEC's Proposed Alternative.

FERC staff concludes and the NPS concurs that the construction and operation of a hydroelectric project under this alternative would not adversely impact the purposes and values of GBNPP as constituted after the land exchange and that the project would comply with the NHPA.

CORRIDOR ALTERNATIVE

The Corridor Alternative (see figure 2-9 in appendix A) would be essentially the same as GEC's Proposed Alternative with the exception that the amount of land transferred to the state of Alaska would be reduced. Approximately 680 acres of park land would be transferred to the state, and all of the transferred land would lie within the FERC project boundary. Under this alternative, about 224 acres of GBNPP located to the south of the FERC project boundary between other private lands would be isolated from the remainder of GBNPP. The land transfer would provide a minimum buffer distance of approximately 0.25 miles around all project features (i.e., roads, penstocks, transmission line rights-of-way, borrow pit and disposal sites, diversion site, and powerhouse) except along the eastern boundary, where a 0.25-mile buffer would fall outside the lands identified as potentially available for development of a project in the Act. This alternative includes the bypassed reach in the FERC project boundary. The project facilities constructed within these lands would be the same as for GEC's Proposed Alternative.

The effects on environmental resources from the construction and operation of the project facilities on project lands, wilderness parcels, and exchange parcels under the Corridor Alternative would be the same as under GEC's Proposed Alternative.

Under this alternative, there still would be adverse effects on the fisheries, wildlife, and air quality resources of GBNPP. However, lands east of the Kahtaheena

River that would be removed from GBNPP under this alternative would serve as a buffer and reduce or eliminate effects on GBNPP soil resources and water quantity and quality. Soundscape on the isolated GBNPP land and the northern boundary could be impacted by noise from project construction and operation due to the proximity of these lands to the project facilities and access road. However, the soundscape of GBNPP along the eastern project boundary as compared to GEC's Proposed Alternative could experience a positive benefit because the additional state of Alaska lands would provide a buffer in this area. Under this alternative, there would be less opportunity for new recreational use because less land would be transferred to the state of Alaska. This alternative could adversely affect park management due to the increased demands on park staff to manage the isolated GBNPP land, monitor and protect park resources along the convoluted boundary and isolated GBNPP land, and control access along the boundary of GBNPP.

Under this alternative, as compared to the GEC alternative, aesthetic resources on the surrounding GBNPP would experience a positive benefit due to the conveyance of lands east of the Kahtaheena River to the state of Alaska. GBNPP lands would not extend to the Lower Falls or bypassed reach, and visitors to this area of the park would not be able to view either the bypassed reach or Lower Falls from GBNPP lands. Relative to GEC's Proposed Alternative, there could be a positive effect for those individuals who wish to recreate in solitude and quiet because a greater acreage of land would remain within GBNPP and managed as NPS lands. Project access roads located north of the George allotment and along the eastern boundary of the Mills allotment would be expected to increase the potential for visitors to trespass, and, along with project-related activities, disturb the solitude on the Native allotments and on state and private lands adjacent to the project, but to a lesser extent than GEC's Proposed Alternative as more land would remain in GBNPP.

The Corridor Alternative would include GEC's proposed environmental measures and the additional FERC staff recommended environmental measures that would be needed to protect, mitigate, and enhance environmental resources. The estimated project costs of the project and proposed mitigation and environmental measures under the Corridor Alternative would be the same as under GEC's Proposed Alternative.

FERC staff concludes and the NPS concurs that the construction and operation of a hydroelectric project under the Corridor Alternative would not adversely impact the purposes and values of GBNPP as constituted after the land exchange and that the project would comply with the NHPA.

PREFERRED ALTERNATIVE

If the Commission issues a license for the Falls Creek Hydroelectric Project, construction and operation of the project would require exchange of federal and state lands and designation and de-designation of wilderness lands. Our preferred alternative addresses these actions and is composed of elements from the action alternatives. In regard to the GBNPP and wilderness boundary adjustment, we recommend that the land exchanged to the state of Alaska should be the land described under the Maximum Boundary Alternative with modification to retain approximately 95 acres of land north of the diversion structure and south of The Islands area within GBNPP. This land exchange scenario would result in adjusting the GBNPP boundary and reducing the amount of land in the park by approximately 1,050 acres. With this land exchange scenario, there would be less chance for project-related erosion or landslides or noises from project construction to affect the park than with GEC's Proposed Alternative or the Corridor Alternative.

At this time, NPS has not selected a preferred alternative for the land to be received from the state. In regard to designation of wilderness lands, NPS recommends that both the unnamed island near Blue Mouse Cove and Cenotaph Island, totaling 1,069 acres, be designated as wilderness since this is approximately equal in sum to the wilderness deleted from GBNPP resulting from the land exchange.

If the project is licensed, the preferred FERC project boundary would be the boundary described under GEC's Proposed Alternative with modification to include a 200 foot buffer around all project features, including the powerhouse; the diversion dam and intake structures; the haulback site; and the transmission line, access road, and penstock corridors. The project boundary proposed by GEC, with FERC staff modifications, would constitute the minimum amount of land necessary for the construction and operation of a hydroelectric project, as specified by the Act.

1.0 INTRODUCTION

1.1 PURPOSE OF ACTION AND NEED FOR POWER

1.1.1 Purpose of Action

The Federal Energy Regulatory Commission (FERC) and the National Park Service (NPS) are considering a proposal to construct and operate the Falls Creek Hydroelectric Project (FERC No. 11659-002), exchange of federal and state lands, removal of land from wilderness designation (de-designation), and designation of other land as wilderness. GEC states in its license application that the purpose of the proposed project is to provide hydroelectric power from the Kahtaheena River to electric power users in Gustavus.

The Glacier Bay National Park Boundary Adjustment Act of 1998 (105 Pub. L. 317; 112 Stat. 3002 [1998]) (or the Act) authorizes FERC to accept and consider a hydroelectric license application from the Gustavus Electric Company (GEC) for the construction, operation, and maintenance of the proposed 800-kilowatt (kW) Falls Creek Hydroelectric Project. The proposed project would be located about 5 miles east of Gustavus, Alaska, on land that is currently within Glacier Bay National Park and Preserve [GBNPP] (figures 1-1 and 1-2 in appendix A). Figure 1-3 (appendix A) shows place names in the proposed project area referred to throughout this document. GEC filed its license application with FERC on October 23, 2001 (GEC, 2001a).

The Act authorizes the Secretary of the Interior (Secretary) to exchange designated wilderness land located in GBNPP to the state of Alaska for this project. This exchange is authorized if FERC concludes, with concurrence of the Secretary, that the project can be constructed and operated without adversely impacting the purposes and values of the park, as constituted after the land exchange. The exchange is predicated upon the state conveying to the United States lands for inclusion in the National Park System. To ensure this transaction maintains approximately the same amount of designated wilderness in the National Wilderness Preservation System as currently exists, other land in GBNPP would be designated wilderness upon consummation of the land exchange. The newly designated wilderness land would be administered according to the laws governing national wilderness areas in Alaska.

The Act specifies that FERC and NPS, as joint lead agencies, shall participate in the development of this environmental document. FERC staff and NPS staff have prepared this final environmental impact statement (EIS) in accordance with the National Environmental Policy Act (NEPA) of 1969, and it is consistent with the Council on Environmental Quality’s regulations, found in 40 CFR Part 1500.

1.1.2 Need for Power

Because GEC is an isolated system, we evaluate the need for power locally, rather than on a statewide or regional basis. GEC is an investor-owned utility with approximately 430 customers (residences and businesses) in a service area that extends to all portions of Gustavus. Currently, there are approximately four permanent residences not connected to this system. GBNPP, which is also not connected to the GEC system, has its own diesel-based power installation at Bartlett Cove. GEC has indicated it could interconnect with the NPS system and supply its needs with hydroelectric generation if the Falls Creek Hydroelectric Project is constructed. However, the NPS decision on this matter is separate from this licensing process, and it is not certain that NPS will choose to connect its load to a new hydroelectric project, even if the project is licensed and constructed. If NPS does not connect its system, then GEC's need for increased capacity would be diminished. In comments on the draft EIS, GEC indicated that NPS has not committed to connection with GEC and the corresponding purchase of generation from the proposed project. Therefore, our analysis in chapter 5 of this EIS, *Developmental Analysis*, assumes that GBNPP is not connected to the GEC system and thus GBNPP load, as well as the costs associated with serving GBNPP load, are not included. Section 6.1.1.4 of this final EIS, *Economic Feasibility*, examines both inclusion and exclusion of GBNPP loads and associated costs.

GEC's current generation facilities consist primarily of two primary diesel units (Unit 1 is 250 kW, and Unit 3 is 300 kW) near the Gustavus airport and two standby units (Unit 2 is 100 kW, and Unit 4 is 500 kW). Based on the revised power supply study (GEC, 2001b), GEC operates Unit 1, the most fuel efficient unit, first when possible, operating Unit 3 to add capacity when needed. Unit 4 is utilized for maintenance and backup, and Unit 2 is rarely used, likely due to its age and questions regarding its reliability (300,000 hours, or more than 34 years). Fuel is received approximately six times per year by barge from Seattle; transferred to shore through a steel line at the Gustavus dock; and stored in two, 20,000-gallon tanks in an above-ground tank farm near the dock. From there, it is trucked to two, 1,500-gallon tanks at the generator facility. Fuel transportation, transfer, and storage are managed and monitored under state and federal laws and regulations.

GEC's annual generation has increased at an overall average rate of 8.4 percent per year during the 17-year period from 1985 (437,000 kilowatt-hours [kWh]) to 2003 (1,713,000 kWh), including slight declines in 1995, 1999, 2000, and 2001; maximum annual generation was 1,734,000 kWh in 1998.[6] This overall growth corresponds to an increase in the population of Gustavus from 98 in 1980 to 258 in 1990 and 429 in 2000

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[6] In 1999, the state of Alaska's Power Cost Equalization Program (PCE) reduced its subsidy level from 700 kWh/month to 500 kWh/month, and also reduced the size of the subsidy to residential consumers, which may have indirectly encouraged conservation thereby decreasing subsequent generation needs.

(GEC, 2001b). GEC predicts that generation needs for the area will increase by approximately 46 percent (796,250 kWh) over the next decade, and, approximately 3.9 percent (about 71,520 to 89,020 kWh) annually (GEC, 2001b, appendix D, adjusted for 2002 data).

Assuming that growth in peak demand tracks with projected generation growth, 10 years after hydroelectric project operations would begin (2016), the peak GEC system demand would be about 480 MW with excess capacity remaining available from Units 1 and 3. The required generation projected through 2016 requires units 1 and 3 to operate with a plant factor[7] of about 42 percent in 2007, increasing to about 57 percent in 2016. The projected plant factor through 2016 is reasonable for this type of diesel generator unit. Although current projections show that power and energy for GEC are met through 2016, an increase in the growth rate for GEC's service area, or failure of units 1, 3, or 4, would require adding generator capacity to the GEC system because it cannot obtain energy from outside its system to provide backup generation in case of failure of more than one generating unit. Figure 1-4 shows projected GEC system energy requirements.

The cost of power is expensive in Gustavus relative to the rest of the state, and especially with respect to more urban areas. GEC's 2002 net cost per kWh as a function of sales and corresponding revenues for all sectors was 518 mills/kWh ($0.518/kWh; one mill is one-thousandth of a dollar or one-tenth of a cent), with individual average revenues/kWh for the residential and commercial sectors of 541 mills/kWh and 465 mills/kWh, respectively (EIA, 2004). The final cost to consumers under the residential rate includes a subsidy from the state's PCE program, which is designed to offset high generation and distribution costs (e.g., in rural areas) that would otherwise have to be passed on to consumers in the form of high rates. The Regulatory Commission of Alaska adjusts the rate of subsidy and the range of use over which it applies annually. Since 1999, the rate of subsidy has been approximately two-thirds for the first 500 kW used each month by each residential customer. In other words, the actual cost for residences is approximately one-third of GEC's residential rate for the first 500 kWh each month, beyond which they pay the full rate. Businesses, which are not eligible for PCE, pay the full commercial rate for all usage.

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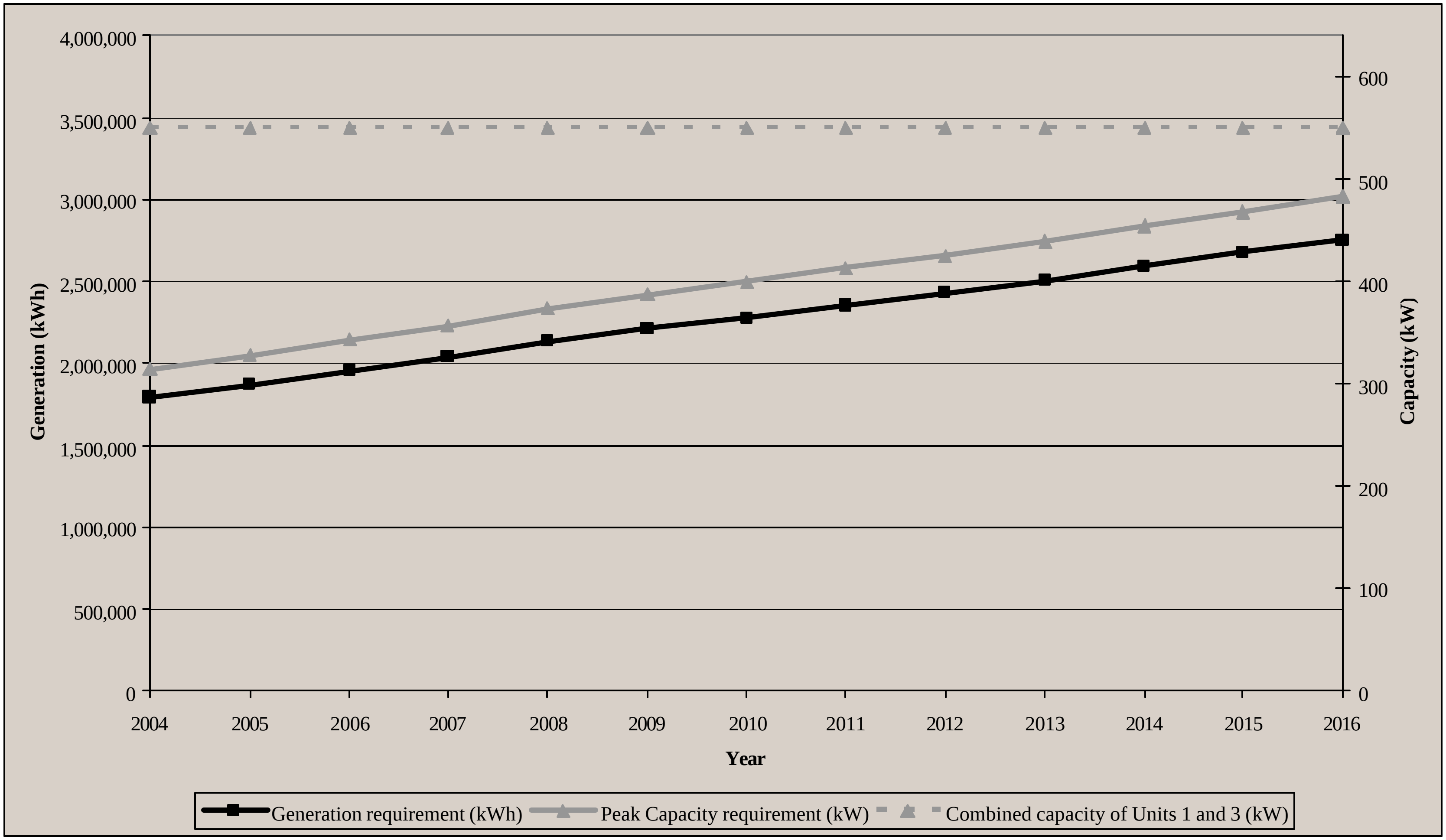
7 Annual generation divided by the total energy available if the generating unit ran at full capacity for the entire year.

Figure 1-4. GEG forecasted generation and capacity requirements. (Source: GEC, 2001b, appendix D, adjusted by preparers for 2002 and 2003 data)



For comparison, the 2002 statewide average revenues/kWh for all sectors were 105 mills/kWh, with individual average revenues/kWh for the residential, commercial, and industrial sectors of 121 mills/kWh, 101 mills/kWh, and 77 mills/kWh, respectively (EIA, 2004). In Anchorage, all customers receive electricity either from Chugach Electric Association or from Anchorage Municipal Light and Power. These utilities' combined 2001 average revenues/kWh for all sectors were 90 mills/kWh ($0.091/kWh), with individual average revenues/kWh for the residential, commercial, and industrial sectors of 107 mills/kWh ($0.108/kWh), 81 mills/kWh ($0.081/kWh), and 77 mills/kWh ($0.078/kWh), respectively. Table 1.1-1 summarizes these data.

Table 1.1-1. Regional 2002 electricity average revenues/kWh, by sector. (Source: Preparers, based on EIA, 2004)

Rates	**GEC**	**Anchorage**[a]	**Statewide**
Residential sector (mills/kWh)	541	107	121
Commercial sector (mills/kWh)	465	81	101
Industrial sector (mills/kWh)		77[b]	77
All sectors (mills/kWh)	518	90	105

[a] Weighted average revenues/kWh for Chugach Electric Association and Anchorage Municipal Light and Power.

[b] Chugach Electric Association only, no data from Anchorage Municipal Light and Power.

Power from the proposed project could potentially provide benefits by: (1) meeting increasing generation requirements or demand that could not reasonably be met with existing capacity in the case of greater than anticipated growth or unit failure, (2) providing generation that would replace a portion or some component of diesel generation and correspondingly reduce air particulate pollution (although present emissions are within ADEC standards), and (3) stabilizing and/or reducing the rate of increase in energy prices.

While increased demand could be met with existing diesel capacity (first year generation cost 127.86 mills/kWh), this would possibly increase associated environmental impacts, such as negative effects on air quality and increased fuel storage and transportation concerns and would require the increased use of GEC's lower efficiency generator units. The proposed project represents another potential means of meeting demand. Although it would not eliminate the environmental problems associated with diesel, since diesel generation would still play a role in supplementing the hydroelectric generation, these concerns would presumably be less than with diesel alone. The presumed reduction of environmental concerns would depend on factors such as the reduction in fuel barges from Seattle and fewer fuel transfers. On the other hand, the hydroelectric generation could introduce a new set of potential environmental effects, which are the subject of the analyses in this final EIS.

Based on analyses presented in chapter 5, *Developmental Analysis*, it is likely that near-term generation from the Falls Creek Hydroelectric Project would actually be as expensive as, or more expensive than, diesel generation. However, hydroelectric generation would likely stabilize energy prices because costs for debt service would be fixed, and there would be no fuel costs for the hydroelectric portion of GEC's generation; there still would be fuel costs for the diesel portion. GEC's forecasts suggest that the overall trend in fuel costs for diesel will be upward. Again, these are only GEC's best estimate of future conditions, with all the uncertainty inherent in any long-term forecast; however, if these forecasts are reasonably accurate, hydroelectric and diesel generation combined would offer energy prices that are lower than diesel alone over the term of a license. The forecasted increases would still affect the diesel portion of GEC's generation, but costs for the hydroelectric portion likely would be more stable and lower.

1.1.3 Alternative Sources of Energy

Other sources of electrical energy besides internal combustion diesel and hydroelectric generation could potentially be used to meet all or a portion of GEC's electrical demand.[8] Potential alternative sources include:

- transmission,
- wind,
- combustion turbines,
- microturbines,
- fuel cells, and
- energy conservation.

GEC also considered a number of alternative sources of energy that were judged to be uneconomic and/or inappropriate, some of which also had the potential for substantial environmental impacts:

- solar - insufficient sunshine;
- nuclear - size of plant and large capital costs, as well as safety concerns;
- geothermal - site-specific, no known sources in area;

8 Throughout this document, "load" or "demand" refers to the power requirements (watts) created by users in GEC's and GBNPP's service area, while "usage" or "generation" refers to the energy, in watt-hours, needed to serve that demand over a specified period of time, usually 1 year. GEC and preparers provided usage in watt-hours, not load in watts.

- batteries - for peak capacity when inexpensive off-peak generation is available or when large load fluctuations occur, which is not the case here;

- coal - large capital costs and need to import coal by barge;

- biomass - large capital costs and need to import fuel by barge; and

- tidal - large capital costs and variation in generation with tidal cycle, as well as likely environmental concerns.

Additionally, it is possible that other streams in the Excursion Inlet area, not in GBNPP, could be developed for hydroelectric generation. However, all potential watersheds there have relatively small drainage areas, are poorly configured for hydroelectric development, and would produce substantially less generation than the proposed Falls Creek Hydroelectric Project. Transmission costs also would be significant.

In the following section, we present a discussion of the six alternative sources listed above.

Transmission (Southeast Alaska Intertie)

Existing transmission lines in the approximate project vicinity include ones connecting the: (1) Skagway and Haines load centers; (2) Juneau load center to the 46,000 kW Snettisham Hydroelectric Project; (3) Petersburg and Wrangell load centers to each other and to the 20,000 kW Tyee Lake Hydroelectric Project; and (4) Ketchikan load center to the 22,500 kW Swan Lake Hydroelectric Project (near Ketchikan). The Southeast Alaska Intertie is a concept developed by the Southeast Conference[9] to develop a more extensive network of power transmission lines and generation facilities including several new hydroelectric projects. Overland and submarine lines would connect most communities in the region, and a preliminary study of potential routes and associated costs was commissioned in 1997. Federal legislation enacted in November 2000 authorized up to $384 million in federal funds to construct the intertie, with 20 percent of the cost to be borne locally. While the Southeast Conference is not itself an appropriate legal entity for building and operating a power generation and transmission system, it currently has a process underway for determining how to create such an entity. Table

[9] The Southeast Conference is a regional, nonprofit corporation meant to advance the collective interests of the people, communities, and businesses in southeastern Alaska. Members include municipalities, Native corporations and village councils, regional and local businesses, civic organizations, and individuals from throughout the region. It is the state-designated Alaska Regional Development Organization, the federally designated Economic Development District, and the federally designated Resource Conservation and Development Council for southeastern Alaska (Southeast Conference website, http://www.seconference.org/).

1.1-2 lists the individual segments of the intertie along with their estimated cost and schedule for construction.

Table 1.1-2. Southeast Alaska Intertie Project proposed costs and timeline. (Source: SC, 2004)

Segment	Estimated Cost (millions)	Estimated Timeline
Juneau - KMCGC - Hoonah	37.1	2007
Kake – Petersburg	23.1	2007
Metlakatla - Ketchikan	6.0	2015-2020
Ketchikan – Prince of Wales	31.7	2020-2025
Kake – Sitka	50.3	2025-2030
Hawk Inlet - Angoon - Sitka	81.2	2020-2025
Hoonah – Gustavus	26.4	After 2030
Juneau – Haines	69.8	After 2030

The Juneau-Hoonah segment of the intertie is now a main focus[10] of the Southeast Conference Intertie efforts. Approximately 80 percent of the segment has been designed, and approximately 11 miles of above-ground transmission line have been installed. The remaining submarine portion of the cable to Admiralty Island could be completed by 2007, contingent upon funding. In the intertie's planned configuration, Hoonah, about 25 miles south of Gustavus, is considered the most logical point at which Gustavus could be connected. A Hoonah-Gustavus segment was not included in the preliminary plan. However, in response to comments from the Gustavus Community Association, this connection was evaluated as part of the overall plan for the intertie.

Using the current estimate of $26.4 million for the cost of connecting Gustavus to Hoonah and assuming that 80 percent federal funding could be obtained, about $5.3 million of local funding would be required. This equates to a transmission cost of approximately 224 mills/kWh of proposed hydroelectric generation averaged over the first 10 years of project operations. Extension of the intertie to Gustavus would improve the reliability of the GEC system, would possibly allow GEC access to lower cost generation, and would possibly allow GEC to sell excess generation. However, the local share of the intertie cost is more than the estimated cost of the Falls Creek Hydroelectric Project, and it does not include the cost of the electricity itself.

[10] In July 2003, federal grants were received that would allow developers to finish planning and begin construction of the Juneau-Hoonah segment (Juneau Empire State News online, July 20, 2003).

Wind

Advantages of wind turbines relative to many conventional energy sources include: (1) no air emissions, (2) no fuel requirements, and (3) operations costs that are relatively shielded from inflationary effects. A recent study for the state of Alaska (Dames and Moore, 1999) investigated construction and operating costs for wind turbines in Naknek and Unalaska. The six units would range in size from 50 to 750 kW with total costs ranging from about 70 to 190 mills/kWh ($0.07 to $0.19/kWh). Because the winds in the Gustavus area are not as high or consistent as in these locations, the per-unit costs incurred by GEC would likely be greater.

One significant disadvantage is that the installed capacity is non-firm: wind generators can only operate between certain minimum and maximum wind speeds and, since wind speed and direction vary considerably on a real-time basis in any given location, generator output would also vary considerably. Even if the total generating capability of the wind turbines were greater than peak power requirements, there would be many times when power output is less than load and a secondary source of power would be needed. Similar to the proposed hydroelectric project, wind turbines would likely require diesel generation operating in parallel.

Other potential disadvantages include: (1) very site-specific energy production; (2) some environmental effects (e.g., disturbance of, and injury or mortality to, migratory birds, noise); and (3) no opportunities for heat recovery (also true of hydroelectric generation). From a cost standpoint, wind turbines have high capital costs per unit output, and their operating lives and long-term maintenance requirements are uncertain.

Combustion Turbines

Data provided by a vendor for a unit in the size range of small application yielded a total cost of about 430 mills/kWh ($0.43/kWh). Combustion turbine unit sizes range from approximately 0.5 MW to hundreds of megawatts, and both gaseous and liquid fuels can be used. Fuel efficiency is poor at low unit loadings, but increases quickly as output is increased. Even at full output, however, combustion turbines use more fuel per unit output than internal combustion generators of similar size. The advantages of combustion turbines over internal combustion generators are lower maintenance costs and lower emissions. Combining these factors, combustion turbines would only be advantageous relative to internal combustion generators in a small application such as this if the unit(s) could be baseloaded and/or if air quality issues are of particular concern.

Microturbines

Based on limited available data, preliminary estimates of total cost of microturbines are about 230 mills/kWh ($0.23/kWh). While combustion turbines have generally been uneconomic and therefore unavailable below about 0.5 MW, new research and manufacturing technology has recently produced smaller units called microturbines that can be economic in some applications. Their advantages include: (1) use of an existing fuel supply system; (2) placement at the load, eliminating the need for improvements to the interconnection or distribution system; and (3) recovery of heat from exhaust gases, making them useful for load centers needing refrigeration or heating. Their major disadvantage at this point is that they are still in the testing phase and have little operating history. They also rely on continued use of fossil fuels with associated air emissions issues, and can have noise issues. Their target market is generally medium to large commercial loads with both electric and heating/refrigeration requirements.

Fuel Cells

Including fuel supply and storage costs, total costs for fuel cells were an estimated 210 mills/kWh ($0.21/kWh). Fuel cells produce electricity using chemical reactions between atmospheric oxygen and clean hydrogen-rich fuels, such as natural gas or propane. Heat and water are the primary byproducts, and very small amounts of hydrocarbons and carbon monoxide are emitted. Significant advantages of fuel cells include: (1) very low exhaust emissions, (2) water and heat byproducts, (3) quiet generation, and (4) no moving parts. Again, a significant disadvantage is that they are still in the demonstration testing phase. They also have high capital costs, and those that are currently in place in Alaska would not be economic without large federal grant subsidies. Further, they require clean hydrogen-rich fuels, and cannot run efficiently on diesel with current technology. Therefore, if GEC were to build and operate a fuel cell system, it would also have to secure a supply of propane and a storage facility.

Energy Conservation

Implementation of energy conservation measures can be driven either by a utility or consumers. Types of energy conservation measures implemented by utilities can include the subsidy of lower wattage appliances, light bulbs, and other forms of electricity usage, as well as incremental or peak/off-peak pricing. Consumer-driven conservation measures can include reduced usage of lighting, electrical heating, or other uses. Utilities are generally interested in conservation to reduce high cost energy purchases or generation, or to allow the delay of infrastructure improvements to increase capacity, while consumer-driven conservation is generally cost based, though some environmental concern is cited as well.

The majority of GEC’s costs are fixed costs associated with distribution, and reductions in energy consumption would not reduce these power costs. Conservation in GEC’s consumer base is driven by the high cost of generation in Gustavus as well as the 500 kWh threshold in the PCE program, as evidenced by the reduction in sales when the PCE threshold and subsidy were reduced. Based on this reduction, consumers are probably already using basic conservation measures. Energy conservation would be beneficial but it cannot replace all or a major portion of diesel generation.

Table 1.1-3 shows a comparison of the projected generation cost/kWh for each alternative energy source.

Table 1.1-3. Projected generation cost/kWh comparison for alternative energy sources. (Source: Preparers)

Electricity Source	Rate
Diesel generation	128 mills/kWh[a]
Transmission	310 mills/kWh
Wind	Greater than 70 to 190 mills/kWh[b]
Combustion turbine	430 mills/kWh
Microturbine	230 mills/kWh
Fuel cell	210 mills/kWh[c]
Conservation	Unknown

a Preparers projected the estimated cost of energy generation using diesel-fueled units based on GEC's projections for future diesel fuel costs as well as projections for annual expenditures for operation of this type of generating unit. This estimated cost value is referenced throughout this final EIS. GEC's cost estimates, which were based on older costing data and updated for this document, were near this value.

b Costs likely to be higher due to speed and inconsistency of winds in project area.

c Technology in demonstration phase, so actual cost unknown.

Because of the remoteness and corresponding challenges to delivering electricity or new fuel sources to the local area, the uncertainty and variability in future fossil fuel prices, the unsuitability of the region for wind power generation, the uncertainty of the actual cost for new generation sources currently in prototype or testing phases, and the limited additional opportunity for the implementation of conservation measures, hydroelectric generation from the Falls Creek Hydroelectric Project appears to be a reasonable means for replacing about 87 percent (from 2007-2016) of GEC's diesel generation with a renewable, non-fuel-dependent method of generation, the cost of which, once constructed, would be relatively insensitive to the effects of inflation.

1.2 GLACIER BAY NATIONAL PARK BOUNDARY ADJUSTMENT ACT OF 1998

The Glacier Bay National Park Boundary Adjustment Act of 1998 (the Act) allows for the conveyance of NPS land in the Kahtaheena River (also known as Falls Creek)[11] area to the state of Alaska along with an adjustment of the GBNPP and wilderness boundary (see appendix B for the full text of the Act). It also authorizes FERC to accept and consider an application from GEC for the right to construct and operate a hydroelectric plant on the land received in exchange from NPS. FERC would retain jurisdiction over any hydroelectric project constructed on this site. This project is exempt

11 Throughout this document, we refer to Falls Creek as the Kahtaheena River.

from the Energy Act of 2000, which allows the state to develop its own licensing program for projects of 5 MW or less.

According to the Act, the boundary adjustment and the construction and operation of the hydroelectric plant are contingent upon each other. In section 3(c)(4), the Act states *"[a] condition of the license to construct and operate any portion of the hydroelectric power project shall be the completion, prior to any commencement of construction, of the land exchange described in this Act*."

In exchange for the Kahtaheena River land, the Act provides, subject to consent by the state of Alaska, for conveyance to the United States of state lands in the Long Lake area, near McCarthy in Wrangell-St. Elias National Park and Preserve (WSNPP), or other lands owned by the state of Alaska. The Act specifies the land would be conveyed to the NPS in the priority shown in figure 1-5 in appendix A. The priority of the land conveyed to the NPS may change from what is shown to reflect the present WSNPP management priorities. In conformance with the Act, any such change would require agreement between the NPS and the state of Alaska. In lieu of the Long Lake lands, the state and the Secretary can consider and determine which other state lands could be exchanged. Acting on this provision, in addition to the Long Lake lands, state lands in Klondike Gold Rush National Historic Park (KGNHP) are considered for exchange (figure 1-6 in appendix A).

The land exchange is subject to the laws applicable to exchanges involving lands managed by the Secretary as part of the National Park System in Alaska and the appropriate process for the exchange of state lands required by state law. This includes an assessment of the potential environmental effects of the proposed land exchange and adjustments to the wilderness boundary. Based on applicable federal and state laws, the Act requires that the conveyed land will have a sufficiently equal appraised value to satisfy these laws, parcels will be subject to clear title and valid existing rights, and environmental contamination will be absent. Further, in section 2(c), the Act specifies:

Any exchange of lands under this Act may occur only if:

1) Following the submission of a complete license application, FERC has conducted economic and environmental analyses under the Federal Power Act (16 U.S.C. 791-828) (notwithstanding provisions of that Act and the Federal regulations that otherwise exempt this project from economic analyses), the National Environmental Policy Act of 1969 (42 U.S.C. 43214370), and the Fish and Wildlife Coordination Act (16 U.S.C. 661-666), that conclude, with the concurrence of the Secretary of the Interior with respect to subparagraphs (A) and (B),. that the construction and operation of a hydroelectric power project on the lands described in section 3(b) [in the Kahtaheena River area] (A)will not adversely impact the purposes and values of Glacier Bay National Park and Preserve

[GBNPP] (as constituted after the consummation of the land exchange authorized by this section); (B) will comply with the requirements of the National Historic Preservation Act (16 U.S.C. 470-470w); and (C) [the project] can be accomplished in an economically feasible manner;

2) FERC held at least one public meeting in Gustavus, Alaska, allowing the citizens of Gustavus to express their views on the proposed project;

3) FERC has determined, with the concurrence of the Secretary and the state of Alaska, the minimum amount of land necessary to construct and operate this hydroelectric power project; and

4) Gustavus Electric Company [GEC] has been granted a license by FERC that requires Gustavus Electric Company to submit an acceptable financing plan to FERC before project construction may commence, and the FERC has approved such plan.

The Act specifies the timing of the exchange. Contingent upon meeting the above conditions, the exchange is to be completed within 6 months after FERC issues a license to GEC. If the Secretary and the state have not agreed on which lands the state of Alaska will convey within 6 months after issuance of the license, Long Lake state lands are to be conveyed, subject to state consent, to the United States within 1 year of issuance of the license. The Act does allow an extension of the above time periods as determined necessary by the Secretary should the processes of state law or federal law delay completion of an exchange.

The specific lands and acreage that may be conveyed in the Kahtaheena River area depend on a combination of the minimum amount of land needed for the project and a land ownership pattern that would be conducive to sound land management. The Act assigns the Secretary and the state joint responsibility to designate the amount and what land is conveyed based on what FERC determines to be the minimum amount of land needed for the project. In sections 2(4) and 3(b)(3), respectively, the Act states:

The lands to be conveyed to the [S]tate of Alaska by the United States under paragraph (1) [Kahtaheena River area] are lands to be designated by the Secretary and the [S]tate of Alaska, consistent with sound land management principles, based on those lands determined by FERC with the concurrence of the Secretary and the [S]tate of Alaska, in accordance with section 3(b), to be the minimum amount of land necessary for the construction and operation of a hydroelectric project.

With the concurrence of the Secretary and the [S]tate of Alaska, the FERC shall determine the minimum amount of lands necessary for construction and operation of such project.

The lands acquired from the state of Alaska, subject to valid existing rights, shall be added to and administered as part of the National Park System. Upon completion of this action, combined with the removal of lands from GBNPP, the Secretary shall adjust, as necessary, the boundaries of the affected National Park System units. The specific boundary between state and federal land will be addressed in any land exchange discussions and negotiations between NPS and the state of Alaska. Boundary lines along natural features, such as a stream or shoreline, can be more easily identifiable than lines based on a rectangular survey. Fine tuning land exchange boundary lines to coincide with natural features, where appropriate and advantageous, would be part of these discussions.

GBNPP land in the Kahtaheena River area is designated wilderness. To maintain approximately the same amount of designated wilderness within the National Wilderness Preservation System, the Act identifies land for wilderness designation as discussed below and shown in figures 1-1 and 1-7 through 1-9 (see appendix A). To conform to the Act, upon consummation of the land exchange, these locations in GBNPP shall be designated as wilderness in the priority listed below:

(A) An unnamed island in Glacier Bay National Park lying southeasterly of Blue Mouse Cove, containing approximately 789 acres (figure 1-7 in appendix A).

(B) Cenotaph Island of Glacier Bay National Park lying in Lituya Bay, containing approximately 280 acres (figure 1-8 in appendix A).

(C) An area of Glacier Bay National Park lying in the Alsek Lake area, containing approximately 2,270 acres (figure 1-9 in appendix A).

The specific boundaries and acreage of these wilderness designations may be reasonably adjusted by the Secretary, consistent with sound land management principles, to approximately equal, in sum, the total wilderness acreage deleted from GBNPP pursuant to the land exchange authorized by the Act. The lands that would be designated as wilderness will be administered according to the laws governing national wilderness areas in Alaska.

In section 3(c), the Act specifies other necessary licensing conditions, including: FERC must approve a finance plan submitted by GEC; NPS waives its right to impose mandatory conditions on potential project lands to be deleted from federal reservation (section 4e) in accordance with the Federal Power Act (FPA); FERC shall not license, relicense, or amend the project without determining, with the Secretary’s concurrence, that the purposes and values of GBNPP would not be adversely impacted (as constituted after the land exchange); any effects on purposes and values identified by the Secretary after the initial licensing shall be mitigated by the licensee; and construction would not commence until completion of the land exchange. The Act does not contain any provisions pertaining to reacquisition of exchanged lands if the project is not constructed. NPS, with the state of Alaska concurring, could use the existing legal authority to do an equal value exchange to reacquire the land in the event the project is not consummated, although the land could not be designated wilderness absent additional Congressional action.

1.3 LICENSING PROCEDURE AND SCOPING PROCESS

By letter dated February 8, 1999, GEC requested approval from FERC to use FERC's alternative licensing procedures. On January 13, 2000, FERC issued a letter order approving GEC's request to follow alternative licensing procedures. In accordance with the FERC Regulations for Licensing Hydroelectric Projects (18 CFR 4.34), this includes a scoping process and preparing a preliminary draft environmental assessment (PDEA) as a substitute for exhibit E of the license application. The PDEA describes GEC's scoping process; includes information about potential resource effects and protection, mitigation, and enhancement proposals; and includes copies of comments received by GEC on the proposed project.

FERC's regulations require applicants to consult with appropriate state and federal environmental agencies, tribal entities, and the public before filing a license application. This consultation is the first step in complying with the Fish and Wildlife Coordination Act, Endangered Species Act (ESA), National Historic Preservation Act (NHPA), and other federal statutes. Pre-filing consultation must be documented in accordance with FERC regulations.

GEC prepared and distributed an Initial Consultation Document on November 25, 1998 (GEC, 1998). GEC received comments from the U.S. Department of the Interior (Interior), Alaska Department of Natural Resources (ADNR), and the Alaska Department of Fish and Game (ADFG). Based on comments, GEC prepared and circulated a Scoping Document 1 on April 19, 1999. GEC held two public meetings to review and comment on the document on May 6 and May 7, 1999. GEC also conducted a site visit on May 6, 1999, and on July 2, 1999, for those who could not participate in the May 6, 1999, site visit. FERC issued a public notice of the scoping meetings and site visit on April 19, 1999. The following entities submitted comment letters on the Scoping Document 1.

Commenting Entity	Date of Letter
National Marine Fisheries Service	May 17, 1999
Glen and Rita Shrank	June 9, 1999
Alaska Department of Fish and Game	June 14, 1999
U.S. Department of the Interior	June 21, 1999
U.S. Department of the Interior	July 6, 1999
Alaska Department of Fish and Game	July 7, 1999
Mike Olney	July 7, 1999
Naomi Sunberg	July 7, 1999
Tom Traibush	July 7, 1999
Mrs. Rosemary Mills Jimboy	July 22, 1999
Sierra Club, Alaska Field Office	August 5, 1999

GEC reviewed all comments received and issued a revised document, Scoping Document 2, on January 22, 2001.

1.4 INTERVENTIONS AND PROTESTS

On October 18, 2001, GEC submitted its license application, including a PDEA, for the Falls Creek Hydroelectric Project. On December 11, 2001, FERC issued a notice accepting GEC's application. This notice set a 60-day period during which interventions could be filed. FERC provides this process for concerned citizens or interest groups to file a protest or an intervention that clearly and specifically expresses their concerns or interests regarding the license application and the proposed project. The following entities filed motions to intervene.

Entity	Date of Letter
Alaska Department of Fish and Game	January 15, 2002
National Marine Fisheries Service	February 5, 2002
Alaska Department of Natural Resources	February 7, 2002
Sierra Club et al.[12]	February 8, 2002
Wilderness Society and Hoonah Indian Association[13]	February 25, 2002
Thomas L. and Patrick G. Mills[13]	August 28, 2002
Sophie and Dianne McKinley[13]	January 6, 2004

The Sierra Club et al. filed a motion to intervene in opposition to the project. Motions filed by the Wilderness Society and Hoonah Indian Association and Thomas and Patrick Mills recommended that FERC deny the application for license and that NPS deny the proposed land exchange.

1.5 AGENCY CONSULTATION

FERC's notice of December 11, 2001, also directed that final comments, recommendations, terms and conditions, and prescriptions concerning the license application and PDEA be filed within 60 days of the date of the notice. The information and analysis from the PDEA has been used, in conjunction with other information, to prepare this final EIS. The following entities responded to the December 11, 2001, request for comments:

Entity	Date of Letter
Alaska Department of Fish and Game	February 1, 2002
U.S. Department of the Interior	February 4, 2002

[12] This motion was filed jointly by the Sierra Club, Trout Unlimited, American Rivers, National Parks Conservation Association, and Glacier Bay's Bear Track Inn.

[13] These interventions were filed past the deadline.

National Marine Fisheries Service February 5, 2002

GEC filed reply comments by letter dated March 21, 2002.

1.6 COMMENTS ON THE DRAFT EIS

NPS and Commission staff sent the draft EIS for the Falls Creek Hydroelectric Project (FERC No. 11659) and Land Exchange to the U.S. Environmental Protection Agency (EPA) on October 31, 2003, and EPA noticed issuance of the draft EIS on November 7, 2003. The notice in the *Federal Register* invited comments on the draft EIS by January 6, 2004. In total, 54 letters, representing 9 agencies and non-governmental organizations and 48 individuals, were filed. Appendix D provides a list of the entities that commented, summaries of the comments, our responses to the comments, and copies of the comment letters. NPS and the Commission also received 436 identical form letters from different senders. The comments included in these letters are referred to as "Park Protection Form" in appendix D.

NPS and Commission staff also conducted four public meetings to solicit comments on the draft EIS. These meetings were held on December 8, 9, 10, and 11, 2003, in Hoonah, Gustavus, Juneau, and Anchorage, respectively. We summarize the comments not contained in written filings in the following section.

Several Native allotees commented on traditional uses of land in the project area and potential effects of the hydroelectric project and land exchange on these traditional lands and Native allotments. Thomas Mills expressed concerns about the effects of the project on his property and the Kahtaheena River. These effects include contamination of his drinking water by oil from equipment, loss of fish in the stream crossed by the proposed access road, increased trespassing and vandalism, and harassment by helicopters. Mr. Mills uses plants on his property for medicinal purposes as part of his cultural heritage. He is concerned that, as a Native, he does not qualify for any fishing rights in Glacier Bay despite fishing there his whole life. Eleanor Mills Moritz stated her concern that she will have her lands taken from her as a result of the project, as she has in the past. As Alaska Natives, she and her family were removed from Excursion Inlet by the U.S. Army. After the U.S. Army left, they did not get their land back; instead it was turned over to the state of Alaska. She is also concerned that the people of Hoonah have to pay more for electricity than the people of Gustavus. Cecelia McKinley spoke on behalf of her mother, Sophia McKinley, the owner of the Charlie and Mary George Allotment. She does not want the project to adversely impact any of their cultural and traditional resources within the surrounding areas, including access routes for subsistence. She is concerned the project will increase access to those lands she and her family use for hunting, fishing, trapping, etc. Additionally, she would like to see the resources protected and stated that Section 810 of the Alaska National Interest Lands Conservation Act (ANILCA) fails to thoroughly analyze the impacts on subsistence uses. Land ownership rights should not be negatively affected by this project in the form of increased access and commercial development. We address these concerns in chapter 4 of the EIS.

Gene Farley testified that he is concerned that the areas of land exchange that would be turned into wilderness areas are currently areas that support commercial fishing. He also states that the proposed area for the project is not the best location because of the existing Native Alaskan allotments and the small amount of water there compared to other areas of the park. Mr. Streveler stated that, within the cumulative impact analysis in the EIS, he would like a discussion of the collateral possibility that the road corridor would inadvertently cause development in the Native allotments. Val Thomas from the Bureau of Indian Affairs requested that the EIS provide more background on the history of use by the Hoonah. We have included more information of the traditional use of land in the project area in chapter 3 of the EIS. We have added descriptions of effects on the Native allotments in chapter 4 of the EIS to address these comments.

A number of people requested more discussion in the EIS concerning how the land would be managed under the action alternatives. Paul Berry, a Gustavus resident, states that this project would spur development in the area, changing the nature of the land forever. Therefore, he requests that lands withdrawn from the park that are not going to be used for this project be managed for recreation and not further development. Judy Brakel and Greg Streveler indicated that they would like the Commission to keep all the land taken out of the wilderness under its oversight and use it just for hydropower. Ms. Brakel states that it would be better for wildlife if any development other than hydropower was prevented. We have revised section 4.15 of the EIS to provide more discussion of land management under each alternative.

A number of people commented on the need for more complete economic assessment of the project. Mr. Berry, Heidi Robichaud, Joan Frankevich, with the National Parks Conservation Association, and Kate Taylor of the Wilderness Society are concerned with the continued reliance on diesel fuel even with the operation of the project, and the lack of a guarantee that the power rates would be lower. Mr. Peder Turner stated that he is concerned if the project is not built there will be a major spill of diesel fuel sometime in the next 50 years. Concerning the economic feasibility of the project, Mr. Turner recommends that federal grant funding be pursued, which would make the project economically viable. Lastly, Mr. Turner would like the project license to allow enough flow downstream to test and use hydrogen fuel cell technology in the future. Ms. Robichaud stated that it is obvious to her the project would require federal funding to be economically feasible. She would like to see very clear graphs and charts showing the different costs associated with the different alternatives. Additionally, Ms. Robichaud is concerned about the possibility of diesel fuel spills. Mr. Berry, TJ Ferrell, and Mr. Howell note that the cost for the underground cable to connect the park to the project is not included in the EIS. We have revised the need for power discussion in section 1.2, the economic analysis in section 6.1.1.4, and the developmental analysis in chapter 5 to address these comments.

1.7 NATIONAL PARK SERVICE BACKGROUND

In this section, we outline major NPS mandates, policies, and plans that are relevant to the Falls Creek Hydroelectric Project and land exchange within GBNPP.

1.7.1 National Park Service Organic Act and Redwood Amendment

The Organic Act of 1916 and the 1978 amendment of the NPS General Authorities Act of 1970 provide the overall mandate for management of the national parks. The Organic Act specifies the core NPS mission, including establishing regulations to protect the environment, such as those being proposed for the current action. The Organic Act states the NPS responsibilities are as follows:

> *The (National Park) service . . . shall promote and regulate the use of the Federal areas known as national parks . . . to conserve the scenery and the natural and historic objects and the wildlife therein and to provide for the enjoyment of the same in such manner and by such means as will leave them unimpaired for the enjoyment of future generations.*

The Organic Act gives NPS a mandate to protect resources of national parks and to make conservation of the environment the leading priority when making management decisions. The Organic Act also states that one of the fundamental purposes of all parks includes the enjoyment of park resources and values. In situations where a conflict exists between NPS efforts to conserve resources and values versus those providing for enjoyment of them, conservation takes precedence.

Congress supplemented and clarified provisions of the Organic Act by the General Authorities Act in 1970 and through enactment of the 1978 "Redwood amendment." Congress wanted to strengthen the ability of the Secretary to protect park resources. The Redwood amendment states:

> *Congress further reaffirms, declares, and directs that the promotion and regulation of the various areas of the National Park System–shall be consistent with and founded in the purpose established by section 1 of this title [the Organic Act provision quoted on page 1], to the common benefit of all the people of the United States. The authorization of activities shall be construed and the protection, management, and administration of these areas shall be conducted in light of the high public value and integrity of the National Park System and shall not be exercised in derogation of the values and purposes for which these various areas have been established, except as may have been or shall be directly and specifically provided by Congress.*

Section 1.4 of NPS management policies (NPS, 2001b), described further in the following section, formally adopts a single interpretation of the key statutory provisions under the Redwood amendment. This single interpretation is necessary to allow as little ambiguity as possible, to ensure consistency in decision making, and to show the courts that decisions made by NPS are logical, reasonable, and thoroughly thought through in accordance with the Organic Act. Section 1.4 of the NPS management policies states that the no-impairment term of the Organic Act and the no-derogation term of the Redwood amendment define a single standard for management of the National Park System and the terms can be used interchangeably (NPS, 2001b).

The clause limiting the exceptions to those "directly and specifically provided for by Congress" has been the subject of much debate as to whether it is to be interpreted broadly to cover all types of activities generally authorized by Congress or limited to only those cases in which Congress has expressly permitted the threatening activity. Several legal scholars and commentators contend that it is to be construed narrowly to apply only to those situations where Congress has explicitly authorized a threatening activity (Mantell and Metzger, 1990). Court decisions have not addressed this issue directly (Mantell and Metzger, 2002).

1.7.2 National Park System Management Policies

NPS management policies (NPS, 2001b) are its basic agency-wide policies. These policies are important factors considered in the effects determinations presented in chapter 4, *Environmental Consequences*, of this final EIS. Adherence to policy is mandatory unless specifically waived or modified by the Secretary, the assistant Secretary, or the NPS Director. Policies are defined for the following categories and are available on the NPS website at http://www.nps.gov/refdesk/mp/:

- land protection,
- natural resource management,
- cultural resource management,
- wilderness preservation and management,
- interpretation and education,
- use of the parks,
- park facilities, and
- commercial visitor services.

With regard to NPS management policies, one of the most important factors in preparing an effects analysis in an EIS is the determination of whether or not an action would result in "impairment" to the park's resources. Impairment as it applies to the lands managed by NPS is derived from the text of the Organic Act's mandate to leave resources "unimpaired for the enjoyment of future generations." Impairment is defined as an effect that, in the professional judgment of the responsible NPS manager, would harm the integrity of park resources or values, including the opportunities that otherwise would be present for the enjoyment of those resources or values. NPS management policies affirm and clarify that NPS may allow certain impacts in National Park System units as long as "park resources and values" are left unimpaired. The management policies define park resources and values as:

- the park's scenery, natural and historic objects, and wildlife, and the processes and conditions that sustain them, including to the extent present in the park: the ecological, biological and physical processes that created the park and continue to act upon it; scenic features; natural visibility, both during the day and night; natural landscapes; natural soundscapes and smells; water and air resources; soils; geological resources; paleontological resources; archeological resources; cultural landscapes; ethnographic resources; historic and prehistoric sites, structures and objects; museum collections; and native plants and animals;

- opportunities to experience enjoyment of the above resources, to the extent that can be done without impairing any of them;

- the park's role in contributing to the national dignity, the high public value and integrity, and the superlative environmental quality of the National Park System, and the benefit and inspiration provided to the American people by the National Park System; and

- any additional attributes encompassed by the specific values and purposes for which it was established (NPS Management Policies 2001, 1.4.6).

NPS management policies (NPS, 2001b) provide the following guidelines for determining what constitutes impairment:

> *The fact that a park use may have an impact does not necessarily mean it will impair park resources or values for the enjoyment of future generations. Impacts may affect park resources or values and still be within the limits of the discretionary authority conferred by the Organic Act. However, negative or adverse environmental impacts are never welcome in national parks, even when they fall far short of causing impairment. For this reason, the Service will not knowingly authorize a park use that would cause negative or adverse impacts unless it has been fully evaluated, appropriate public involvement has been obtained, and a compelling management need is present. In those situations, the*

Service will ensure that any negative or adverse impacts are the minimum necessary, unavoidable, cannot be further mitigated, and do not constitute impairment of park resources and values.

According to NPS policy, an effect could constitute impairment to the extent that it affects a resource or value whose conservation is:

- necessary to fulfill specific purposes identified in the enabling legislation or proclamation of the park;

- key to the natural or cultural integrity of the park or to opportunities for enjoyment of the park; or

- identified as a goal in the park's General Management Plan (GMP) (NPS, 1984) or other relevant NPS planning documents.

Before approving a proposed action, an NPS decision-maker must consider the effects of the proposed action and determine, in writing, that the activity will not lead to an impairment of park resources and values. If there would be an impairment, the action may not be approved without Congressional action. In making a determination of whether there would be impairment, the NPS decision-maker must use his or her professional judgment. The decision-maker must consider any previous legislation, environmental assessment, or EIS required by NEPA; relevant scientific studies and other sources of information; and public comments.

The Wild and Scenic Rivers Act (WSRA, P.L. 90-542, as amended) directs federal agencies to consider potential national wild, scenic, and recreational river areas "in all planning for the use and development of water and related land resources" (WSRA Section 5(d)(1)).

NPS has implemented this mandate in several ways: (1) through Special Directive 90-4, first issued in 1990 and amended in 1995, which instructed park units to assess river resources and identify segments that were potentially eligible for addition to the National Wild and Scenic Rivers System (NWSRS); (2) by creating and maintaining a national inventory of potentially eligible rivers, the Nationwide Rivers Inventory (NRI); and (3) through its Management Policies (MP), which state in part:

Potential national wild and scenic rivers will be considered in planning for the use and development of water and related land resources. The NPS will compile a complete listing of all rivers and river segments in the national park system that it considers eligible for the National Wild and Scenic Rivers System. General management plans (GMP) and other plans potentially affecting river resources will propose no actions that could adversely affect the values that qualify a river for the National Wild And Scenic Rivers System. A determination of eligibility will *not necessarily mean that the NPS will seek designation, which requires legislation. A decision concerning whether or not to seek designation will be made through a GMP, or an amendment to an existing GMP, and the legislative review process." (MP Section 2.3.1.10)*

Parks containing one or more river segments listed in the national rivers inventory maintained by the NPS, or that have characteristics that might make them eligible for the National Wild and Scenic Rivers System, will comply with section 5(d)(1) of the Wild and Scenic Rivers Act, which instructs each federal agency to assess whether those rivers are suitable for inclusion in the system. Such assessments, and any resulting management requirements, may be incorporated into a park's general management plan or other management plan. No management actions may be taken that could adversely affect the values that qualify a river for inclusion in the National Wild and Scenic Rivers System." (MP Section 4.3.4)

1.7.3 Pertinent National Park System Director's Orders

Director's orders are part of the NPS Directives System, as are NPS management policies. Director's orders provide legal references, operating policies, standards, and procedures for particular aspects of park planning. Director's Order 12 (NPS, 2001a) is most relevant because it provides the guidance necessary to prepare an NPS EIS in compliance with NEPA.

Two other director's orders are particularly important to consider. "Director's Order 47, Sound Preservation and Noise Management" (NPS, 2001c) is important because it provides guidance for regulating noise in the park. This director's order articulates NPS policies that require, to the fullest extent practicable, the protection, maintenance, or restoration of the natural soundscape resource in a condition unimpaired by inappropriate or excessive noise sources. "Director's Order 41, Wilderness Preservation and Management" (NPS, 1999a) provides accountability, consistency, and continuity to the NPS wilderness management program, and to otherwise guide NPS-wide efforts in meeting the letter and spirit of the 1964 Wilderness Act. This director's order clarifies, where necessary, specific provisions of the NPS management policies (NPS, 2001b), and establishes specific instructions and requirements concerning the management of all NPS wilderness areas.

1.7.4 National Parks Enabling Legislation

GBNPP

The presidential proclamations of 1925 and 1939 established and expanded Glacier Bay National Monument, and ANILCA of 1980 provides specific statutory requirements for management of GBNPP. These mandates include the following:

- preserving and protecting a great variety of forest consisting of mature areas and bodies of youthful trees which have become established since the retreat of the ice and should be preserved in absolutely natural condition and bare areas, which will become forested during the next century (proclamation);

- preserving and protecting the area's tidewater glaciers and a unique opportunity for scientific study of glaciers and related flora and fauna changes over time, and historic value associated with early explorers and scientists (proclamation);

- preserving lands and waters containing nationally significant natural, scenic, historical, archeological, geological, scientific, wilderness, cultural, recreational and wildlife values (ANILCA);

- preserving the unrivaled scenic and geological values associated with natural landscapes (ANILCA);

- maintaining sound populations of, and habitat for, wildlife species of inestimable value to the citizens (ANILCA);

- preserving the natural, unaltered state of arctic tundra, boreal forest and the coastal rain forest ecosystem (ANILCA);

- preserving wilderness resources and related recreational opportunities within large arctic and subarctic wildlands and on free-flowing rivers (ANILCA);

- preserving historic and archeological sites, rivers, and lands (ANILCA);

- maintaining opportunities for scientific research and undisturbed ecosystems (ANILCA); and

- allowing Glacier Bay National Park to remain " . . . [a] large sanctuary where fish and wildlife may roam free, developing their social structure and evolving over long periods of time as nearly as possible without the changes that extensive human activities would cause." (ANILCA)

KGNHP

Enabling legislation passed on June 30, 1976, created the Klondike Gold Rush National Historical Park "in order to preserve in public ownership for the benefit and inspiration of the people of the United States, historic structures and trails associated with the Klondike Gold Rush of 1898, the Secretary of the Interior is authorized to establish the Klondike Gold Rush National Historical Park, consisting of a Seattle unit, a Chilkoot Trail unit, and a White Pass Trail unit." Additionally, the town of Dyea and the Chilkoot Trail were designated a National Historical Landmark on June 16, 1978. National

Historic Landmarks are nationally significant historic places designated by the Secretary of the Interior because they possess exceptional value or quality in illustrating or interpreting the heritage of the United States.

The 1996 GMP for KGNHP called for the expansion of park management, resource protection, and maintenance needs to meet most of the expected visitor-use increases in the park, while protecting park resources from degradation. The GMP further stated that park facilities would be upgraded with improvements to the visitor and administrative facilities in Skagway and the development of new facilities in Dyea. The 1996 GMP also encouraged the NPS to continue to work with the state of Alaska to provide better access to the Dyea and Chilkoot Trail areas.

WSNPP

Section 201(9) of the ANILCA states that Wrangell-St. Elias National Park and Preserve will be managed for the following purposes, among others:

> *To maintain unimpaired the scenic beauty and quality of high mountain peaks, foothills, glacial systems, lakes and streams, valleys, and coastal landscapes in their natural state; to protect habitat for, and populations of, fish and wildlife including but not limited to caribou, brown/grizzly bears, Dall's sheep, moose, wolves, trumpeter swans and other waterfowl, and marine mammals; to provide continued opportunities, including reasonable access for mountain climbing, mountaineering, and other wilderness recreational activities. Subsistence uses by local residents shall be permitted in the park, where such uses are traditional, in accordance with the provisions of title VIII.*

1.7.5 Park Purposes and Values

Based on the statutory requirements provided in section 1.7.4, the purposes and values of GBNPP are to preserve its accessible tidewater glaciers, superlative scenic grandeur, historic value, and unique opportunities for the study of glaciers and associated plant and animal community succession processes. The GBNPP area is preserved to protect fish and wildlife populations and their habitats; unaltered and undisturbed ecosystems and opportunities for scientific research; wilderness resource values; and related recreational opportunities.

1.7.6 International Biosphere Reserve and World Heritage Site Designations

In 1986, GBNPP was designated as an International Biosphere Reserve by the United Nations Educational, Scientific, and Cultural Organization (UNESCO) under its Man and the Biosphere Program. Biosphere reserves are protected areas that are internationally recognized. They are established to conserve species and natural communities and to discover ways to use environments without degrading them. The program emphasizes research, resource monitoring, and education.

In December 1992, UNESCO also designated GBNPP as a World Heritage Site, a natural site of outstanding universal value to humankind. World Heritage designation recognizes the world's most significant natural and cultural areas. GBNPP is a part of the Kluane/Wrangell-St. Elias/Glacier Bay/Tatshenshini-Alsek World Heritage Site.

1.7.7 Pertinent Park Plans and their Relationship to this Plan

General Management Plan. GBNPP's GMP (NPS, 1984) sets the overall direction for management of natural and cultural resources, visitor use, land protection, and facility development. The following objectives pertain to this proposed project:

1. Protection of park resources: Manage the park and its use in a manner to allow ecological processes to continue unimpaired by visitor use. Protect marine and terrestrial wildlife, vegetation and cultural and ethnic resources from adverse effects. Accomplish this through implementation of sound general management and resource management plans addressing visitor use, along with general development and establish or maintain a balanced relationship between resource preservation and visitor needs.

2. Provision for visitor use: Ensure that patterns of use are consistent with the preservation of ongoing natural processes, which enable visitors to enjoy and understand the natural features and recreational opportunities. Balance forms of access and use to obtain a feeling of ruggedness and wildness of the landscape and the solitude that early inhabitants found.

A separate section of the GBNPP's GMP (NPS, 1984) addresses non-NPS projects with potential effects on the park. The language from this section follows:

> *A proposal has been made to develop a small hydroelectric plant at Falls Creek [Kahtaheena River], just inside the park boundary near Gustavus. The U.S. Army Corps of Engineers has initiated a feasibility study for this project. The study was scheduled for completion in May 1983; however, a final report has not been received. If the project is feasible and desirable to Gustavus residents, Congress may approve such use of the water. A hydroelectric power plant could affect the population growth rate of Gustavus, and it could affect park operations. Potential effects on the park would be separately evaluated before any final decision. The site of the power plant is included in the NPS Gustavus land package being considered for exchange with the state of Alaska for state-owned lands within the boundary of Wrangell-St. Elias National Park and Preserve.*

Wilderness Visitor Use Management Plan. In July 1989, the park adopted a Wilderness Visitor Use Management Plan (NPS, 1989a). The plan establishes wilderness visitor management zones and requirements for access, group size, length of use, and commercial activities.

Glacier Bay Final Environmental Impact Statement, Wilderness Recommendation. A record of decision (ROD) was not issued for this document, and the wilderness recommendation process was not completed. The preferred alternative presented in the final (internal review draft) EIS recommended that Blue Mouse Cove, Cenotaph Island, and the Alsek Lake area be designated as wilderness (NPS, 1988).

Backcountry Management Plan and Environmental Impact Statement. The park backcountry management planning process, which will include an EIS, was initiated in fall 2002. The EIS will present alternatives for managing the park's wilderness and backcountry and will address visitor use of wilderness and non-wilderness waters and land. It will consider use via non-motorized vessels, such as kayaks, some aspects of recreational boating, camper vessel drop-offs, and off-vessel activities. The planning process and the EIS will result in a ROD that will direct the course of backcountry management of the park.

Vessel Quota and Operating Environmental Impact Statement. GBNPP published a draft EIS on vessel quotas and operating requirements in March 2003. A final EIS was issued in October 2003. The EIS describes five alternatives for establishing motorized vessel quotas and associated operating requirements within GBNPP. These alternatives could affect the management of the waters in Blue Mouse Cove adjacent to the unnamed island proposed for designation as wilderness.

1.8 SUMMARY OF ISSUES AND EFFECTS TOPICS ANALYZED

Our environmental analyses are based on the issues and effect topics identified during GEC's prefiling process and issues identified by FERC and NPS staff as requiring consideration for compliance with applicable federal and state laws and policies. In the following section, we identify the issues and effects topics we analyze in chapter 4, *Environmental Consequences*. In section 1.9, we then identify issues and effects topics considered but dismissed from further consideration, along with the reasons for their dismissal.

1.8.1 Effects on Geologic Resources and Soils

- Construction and operation of the project could cause erosion of deep organic soils in the upper watershed.

- Construction of the project could destabilize the steep slopes of the lower portion of the Kahtaheena River.

- Construction of the project could increase levels of sediments in area rivers, streams, and wetlands.

- Construction and operation of the project could interrupt movement of bedload and sediment material through the system.

1.8.2 Effects on Water Quantity and Quality

- Operation of the project could alter the natural flow regime in the Kahtaheena River and adversely affect water quality or other aquatic resources.

- Construction and operation of the project could increase erosion and sedimentation and embeddedness of stream gravel in the Kahtaheena River and in other project-area streams, including Greg, Rink, and Homesteader creeks and the unnamed creek to the east of Homesteader Creek, which would be crossed by the access road.

- Construction and operation of the project could affect water temperature and icing timing and patterns in the Kahtaheena River.

- Construction and operation of the project could increase the potential for the accidental release of fuels, lubricants, or other hazardous materials into project-area waterways.

1.8.3 Effects on Air Quality

- Operation of construction equipment could generate some criteria pollutant emissions.

- Operation of the project could reduce diesel emissions.

- Land clearing, earth-moving, and ground excavation activities could result in short-term fugitive dust emissions during project construction.

1.8.4 Effects on Fisheries

- Increased erosion and sedimentation and embeddedness of stream gravel in the Kahtaheena River and in other project-area streams could reduce the quality and quantity of fisheries habitat.

- Increased potential for the accidental release of fuels, lubricants, or other hazardous materials into project-area waterways could affect fisheries.

- Construction workers could disturb fish populations in the Kahtaheena River and tributaries.

- Operation of the project could entrain resident Dolly Varden char into the water intake at the diversion site.

- Operation of the project could degrade spawning habitat due to sediment loading, bedload transportation, and aggradation/degradation patterns.

- Operation of the project could result in inadequate instream flows for passage, spawning, and egg development.

- Altered icing patterns could affect egg development of fish populations.

- Altered instream flows could create false attraction of anadromous species into the tailrace outlet.

- Operation of the project could result in loss of unique genetic stocks in the resident Dolly Varden char population from loss of habitat in the bypassed reach and the possible loss of genetic diversity in the downstream population of anadromous Dolly Varden char due to reduced upstream recruitment.

- Reduction in Dolly Varden char populations could have a negative effect on area and regional fisheries as well as on the Kahtaheena River ecosystem proper.

1.8.5 Effects on Vegetation and Wetlands

- Construction of the project facilities could disturb or result in the long-term loss of both forest and wetland habitat.

- Project roads and rights-of-way could interrupt or alter existing drainage patterns throughout the area.

- Construction of the project would remove trees and could result in additional disturbance to surrounding forest habitat by increasing the probability of wind throw.

- Increased levels of erosion and sedimentation and/or increased possibility of introducing hazardous materials (oils, lubricants, or other chemicals) into area waterways resulting from project operation could affect wetlands.

1.8.6 Effects on Wildlife

- Habitat loss could affect wildlife populations, including the potential loss of nesting habitat for marbled murrelets in areas of old-growth forest that may be cleared.

- Increased frequency of human/bear confrontations caused by increased access and human presence could degrade habitat and affect area wildlife populations, including effects on black bear spring forage habitat and black bear and other large mammal movement corridors.

- Increased human presence in the area during the construction phase of the project and during project operation could increase use of the area for development, subsistence, or sport hunting or trapping, along with the use of off-road vehicles.

1.8.7 Effects on Cultural Resources

- Project construction and land exchanges could affect ethnographic resources (a subset of cultural resources including archaeology and historic resources) such as traditional cultural properties or cultural landscapes.

1.8.8 Effects on Soundscape/Noise

- Natural sound elements could be diminished as sporadic noise could be noticeable during project construction from drilling, hauling, and excavation of the roads and facilities.

- Localized noise from activities such as excavation, grading, and blasting during the construction period could temporarily affect movement corridors for large mammals.

- Noise disturbance during the breeding season could affect some species of wildlife and terrestrial resources in the project area.

- Flows could be decreased over the Lower Falls of the Kahtaheena River, which could affect natural ambient sound levels.

1.8.9 Effects on Visual Resources (Aesthetics)

- Project facilities (roads, transmission lines, penstock, powerhouse, and diversion structure) could pose a contrast with the natural landscape.

- Flows could be decreased over the Lower Falls of the Kahtaheena River which could affect the visual aesthetic experience of visitors wishing to view this landscape feature.

1.8.10 Effects on Recreation Resources

- Project construction and operation could have effects on local residents and park visitors' ability to experience the expected quiet and natural landscapes associated with the wilderness character of the park.

- The change in land status could result in increased access by recreationists, hunters and trappers, leashed or unleashed domestic dogs, and off-road vehicles.

1.8.11 Effects on Wilderness

- Wilderness values and attributes could be gained or lost, and the relative abundance of these attributes could be altered through the proposed land exchange.

- Wilderness recreation could be gained or lost as a result of the changed land ownership and management designations by this project.

1.8.12 Effects on Park Management

- Removing the project area from NPS wilderness lands (surrounding it on three sides), constructing and operating the hydroelectric generation facilities, and increasing human access and instituting an entirely different land management scheme could lead to increased demands on GBNPP resources to supply rangers for safety and enforcement issues to the proposed project area and to protect park resources on immediately adjacent NPS lands.

- The various land exchange configurations could also influence the complexity of managing the land in the area.

1.8.13 Effects on Land Use Programs and Policies

- The transfer of land to the state of Alaska and the application of state land management policies could allow increased commercial development of the area.

- Policies that allow sport or subsistence hunting and trapping in the area or use of motorized vehicles, including off-road vehicles and snow machines, could affect area resources and land use practices.

- Land ownership and management changes could affect opportunities for economic development of the area, or conversely they could reduce protection of the area from human incursion (park visitors and local residents wishing to experience the wilderness values of the area, and commercial businesses that cater to park visitors seeking a wilderness experience).

1.8.14 Effects on Socioeconomics

- The project could have effects on the local and regional economy, including employment, the value of private properties, businesses, and services such as schools and housing.

- The project could affect the price of power in the community of Gustavus.

- The project could affect the value of private property in the vicinity.

- The project's potential economic viability could be affected by the uncertainties associated with population and load growth, the future cost of diesel fuel, and the effect of required minimum flow releases on the project's ability to generate an adequate amount of power.

1.9 ISSUES CONSIDERED BUT ELIMINATED FROM FURTHER EVALUATION

The following issues were considered but eliminated from further consideration in this final EIS.

1.9.1 Effects on Cultural Resources–Archaeological and Historic Resources

Section 106 of the NHPA, as amended (Pub. L. 89-665; 16 U.S.C. 470), requires that every federal agency "take into account" how each of its undertakings could affect historic properties. Licensing, the land exchange, and designation of wilderness lands would be considered federal undertakings under the NHPA. Historic properties include districts, sites, buildings, structures, traditional cultural properties, and objects that are eligible for inclusion in the National Register of Historic Places.[14]

Transfer of either the Long Lake parcels or the Klondike Gold Rush parcels from the state of Alaska to NPS would enhance NPS opportunities to identify, evaluate, and manage historic properties and traditional cultural properties that might exist on these lands. Additional formal protection would be afforded to the potential traditional cultural properties located on the Cenotaph Island and Alsek Lake parcels through the wilderness designations. No National Register-eligible archaeological resources, historic structures, or traditional cultural properties have been identified within the Falls Creek Hydroelectric Project area on lands that would be de-designated as wilderness. The State Historic Preservation Officer (SHPO) concurred with this finding on July 15, 2003. Therefore, the proposed actions would not affect any historic properties. However, the project area contains a place name (Kahtaheena) that is a component of the greater Glacier Bay cultural landscape; this is further discussed in sections 3.9 and 4.9.

1.9.2 Effects on Endangered Species

Under Section 7 of the ESA, a federal agency is required to consult with the secretaries of Interior and Commerce regarding the presence of ESA-listed species, or

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14 The term "cultural resources" is also used throughout this document to denote properties that have, or have not been, evaluated in terms of their eligibility for inclusion in the National Register. The term cultural resources is defined under NEPA and is used throughout an EA or EIS in a more general sense to denote archaeological and historic resources without necessarily identifying them as historic properties as defined under the NHPA.

critical habitat for these species, within areas potentially affected by a proposed project requiring federal approval.

In a letter dated December 16, 2002, National Marine Fisheries Service (NMFS) indicated that two federally listed ESA species, the threatened Steller sea lion (*Eumetopias jubatus*) and the endangered humpback whale (*Megaptera novaeangliae*), could occur in the project area, although no critical habitat for either species is found in the project area.

The Steller sea lion rookery that is closest to the project area is located at Graves Rocks, 35 to 40 miles away. Steller sea lions may occasionally forage in shallow waters of the intertidal zone near the mouth of the Kahtaheena River, but are not reported to use terrestrial habitats in the vicinity for hauling out to rest.

Humpback whales forage along the shorelines, bays, and fjords of Glacier Bay and Icy Passage, feeding on krill, shrimp, and small fish. A few whales may be present year-round, but most migrate in the fall to warmer waters off the coastlines of the Hawaiian Islands and return to Alaska in the spring, after calving. Humpback whales, which occasionally may be present near the mouth of the Kahtaheena River but move widely throughout the Icy Passage area, would not be expected to be affected by the Falls Creek Hydroelectric Project.

The state-owned parcels proposed for exchange with WSNPP and KGNHP are located inland of the marine environment. Therefore, the exchange of these lands with NPS would not affect federally listed marine mammals or their habitats.

The parcels at Cenotaph Island and the unnamed island near Blue Mouse Cove proposed for wilderness designation are adjacent to the marine environment and are currently managed as if they were classified as wilderness. The designation of these areas as wilderness would not change the management of these areas and therefore would not affect federally listed marine mammals or their habitats. Several parcels at Alsek Lake are also proposed for wilderness designation and are located inland of the marine environment. These parcels are also currently managed as if they were classified as wilderness. The designation of these parcels as wilderness would not change the management of this area and therefore would not affect federally listed marine mammals or their habitats. Harbor seals have been seen, on occasion, as far inland as Alsek Lake; however, in general, marine mammals do not travel this far inland and would not be affected by the change in land status.

Because the development of the Falls Creek Hydroelectric Project, the transfer of state lands to the NPS, and the designation of wilderness areas would not affect federally listed marine mammals identified by Interior and NMFS and no other federally listed species occur in these action areas, endangered species are not discussed further in this document.

1.9.3 Effects on Subsistence Resources

Subsistence is the use of wildland resources for physical, economic, traditional, cultural, and social existence, and it occurs on private, state, and federal lands in Alaska. Specific to this proposal, under ANILCA, the federal lands at the Kahtaheena River in GBNPP and KGNHP, adjacent to the potential exchange lands, are closed to subsistence while the lands at WSNPP, adjacent to the Long Lake land, are open. Subsistence users in southeastern Alaska can use other federal, state, or private lands to harvest resources but not the federal land at the Kahtaheena River or in KGNHP.

Regardless of whether an area is closed to subsistence, Section 810 of ANILCA requires that federal agencies evaluate their proposed land use and the effects on "subsistence hunting and gathering uses and needs, the availability of other lands for the purposes sought to be achieved and other alternatives that would reduce or eliminate the use." Federal agencies are also required to determine the potential for significant restriction of subsistence use. Appendix C, *ANILCA Section 810 (A) Summary Evaluation and Findings*, contains our analysis showing that the proposed action would not result in a significant restriction of federal subsistence uses.

Subsistence users in Gustavus use a variety of resources including deer, goat, small mammals, moose, birds and eggs, vegetation (including berries, wood, and plants) and Dolly Varden char.

The proposed project may increase the use of the area by subsistence users, hunters, and trappers because the land status could change from federal, where subsistence use is closed, to state, where it could be open to subsistence uses. Presently, the Native allotments are used for subsistence. The proposed project could reduce populations of resident Dolly Varden char, a species used for subsistence, which is available to inhabitants or owners of the allotments. It would not be expected to affect other anadromous fish species, wildlife (i.e., black bear, small mammals), wildlife habitat, or vegetation (berries, firewood) that are utilized on a regional basis. The proposed action could make lands transferred to the state available for subsistence use by the Native allotees, but could also increase trespass and disturbance on the Native allotments by other subsistence users. GEC proposes to leave the project access road open to foot traffic. Residents would gain the opportunity to use the lands outside of the project boundary that become controlled by the state. At KGNHP, state land that could be conveyed to the NPS would be in KGNHP and would be closed to subsistence use. If the Long Lake lands would be conveyed to NPS, they would be within WSNPP and open to subsistence use. Because the action would not result in a significant restriction of federal subsistence, we do not discuss subsistence further.

1.9.4 Effects on Marine and Coastal/Shoreline Communities

Marine communities along the shoreline near the mouth of the Kahtaheena River are similar to those found in Glacier Bay, a fjord estuary marine ecosystem. In lower Glacier Bay, waters are relatively shallow and very productive. In addition to about 200 fish species, Glacier Bay supports numerous species of crabs, clams, scallops, shrimp, snails and worms, and a variety of birds and mammals that feed on them. The proposed project lands do not include any marine habitat; however, the waters along the shoreline below mean high tide line are within GBNPP. The project would not affect marine and coastal shoreline communities, and we do not discuss these resources further.

1.9.5 Effects on Minority and Low Income Populations (Executive Order 12898)

According to Executive Order 12898 (February 11, 1994), "[E]ach Federal agency shall conduct its programs, policies, and activities that substantially effect human health or the environment, in a manner that ensures that such programs, policies, and activities do not have the effect of excluding persons (including populations) from participation in, denying persons (including populations) the benefits of, or subjecting persons (including populations) to discrimination under, such programs, policies, and activities, because of their race, color, or national origin." Gustavus, the closest town to the proposed project is a small, isolated coastal town much like the other towns in the study area. The U.S. Census Bureau reports that racial distribution within the Skagway-Hoonah-Angoon census area and the town of Gustavus is similar to that of the state. Therefore, the project would not disproportionately affect minority and low income populations. For this reason, we do not discuss minority and low income populations further.

Transfer of the Long Lake or Klondike Gold Rush parcels to the NPS would continue to protect these lands from development while continuing to offer the lands to the public including minority and low income populations, for recreational use. Designation of the land as wilderness in GBNPP would continue a similar management practice for these lands, which would not affect minority and low income populations because this action would perpetuate the existing conditions.

1.9.6 Effects on Floodplains

Executive Order 11988 directs federal agencies to provide leadership and take action on federal lands to avoid, to the extent possible, the long- and short-term adverse impacts associated with the occupancy and modification of floodplains. Agencies are required to: (1) avoid direct or indirect support of floodplain development whenever there are practicable alternatives; (2) evaluate the potential effects of any proposed action on floodplains; (3) ensure planning programs and budget requests reflect consideration of flood hazards and floodplain management; and (4) prescribe procedures to implement the policies and requirements of the Executive Order.

Floodplains are defined in Executive Order 11988 as lowland and relatively flat areas adjoining inland waters that are subject to a 1 percent or greater chance of flooding in any given year. The Kahtaheena River within the project area is a contained channel incised within the surrounding landform without an established floodplain as defined by Executive Order 11988. There are no floodplains within or immediately adjacent to the areas identified for the development of the proposed project facilities and access roads. Therefore, the development of the project would have no effect on floodplains as defined in Executive Order 11988.

The parcels at Cenotaph Island, the unnamed island near Blue Mouse Cove, and adjacent to Alsek Lake are proposed for wilderness designation. These parcels are currently managed as if they were classified as wilderness. The designation of these areas as wilderness would not change the management of these areas and therefore not affect any floodplains that might exist at these sites.

1.9.7 Effects on Wild and Scenic Rivers

The Wild and Scenic Rivers Act (WSRA, P.L. 90-542, as amended) directs federal agencies to consider potential national wild, scenic, and recreational river areas "in all planning for the use and development of water and related land resources" (WSRA Section 5(d)(1)). The NPS implements this mandate by assessing river resources potentially eligible for addition to the NWSRS and by maintaining a national inventory of potentially eligible rivers. FERC also considers potential wild and scenic rivers in its decisions, having accepted the NRI as a comprehensive plan pursuant to the FPA, as amended by the ECPA of 1988.

During the early 1990s GBNPP inventory, the Kahtaheena River was not identified as a potentially eligible segment; however, it is likely that smaller streams such as the Kahtaheena River were not examined in detail. In GBNPP, the Alsek River was determined to be potentially eligible for addition to the NWSRS and added to the NRI.

As a result of resource information developed under this proceeding, the Kahtaheena River, based on its free-flowing character, ecological status as a glacial refugium, cultural significance, and scenic cascades and waterfalls, has attributes that would potentially make it eligible for addition to the NWSRS. However, before a river can be determined potentially eligible and recommended for designation by Congress, the agency must conduct an eligibility study and make a suitability determination. Suitability depends on subjective factors such as the balance of the public interest in protecting a river in its free-flowing condition versus the interest in developing it for other uses (including hydropower).

Under the Act, if specific conditions are met, Congress directed that a land exchange could take place and a hydroelectric project could be constructed on the Kahtaheena River. With the selection of an action alternative, after completion of the land exchange, the Kahtaheena River would no longer be in GBNPP negating its eligibility as a wild and scenic river under the NWSRS. With the passage of the Act, it appears that Congress has pre-empted the river's wild and scenic eligibility status.

The wilderness designation of several parcels at Alsek Lake would likely enhance the Alsek River's suitability for wild and scenic designation. However, these parcels are already managed as *de facto* wilderness, and thus their addition to the NWPS would not adversely affect the Alsek Lake's eligibility for wild and scenic designation. Therefore, if these lands were designated wilderness, it would not have an effect on potential wild and scenic rivers.

2.0 DESCRIPTIONS OF ALTERNATIVES

2.1 INTRODUCTION

In this chapter, we describe the alternatives analyzed in this final EIS for the Falls Creek Hydroelectric Project and compare the effects associated with each. We also describe the proposed environmental measures as well as measures that, if implemented, would mitigate certain of the adverse effects described in chapter 4, *Environmental Consequences*. We then compare the major components of the alternatives.

We analyze the No-action Alternative and three action alternatives. The action alternatives include GEC's Proposed Alternative and two variations developed, in part, to address issues identified during the applicant's scoping process, and to assist NPS and the Commission in fulfilling the legislative intent of the Act, and their mandated management responsibilities. The temporal scope of our analysis is 50 years, which represents the longest term of any license that may be issued for this project.

The Act set aside for exchange an amount of land that would be enough to encompass the proposed hydroelectric project and also fulfill section 2(a)(4) of the Act by giving the state of Alaska and the Secretary of the Interior latitude to designate the lands to be conveyed based on sound land management principles and on FERC's determination of the minimum amount of land necessary for the construction and operation of a hydroelectric project. We evaluated three action alternatives for the land exchange including the 850 acres alternative proposed by GEC and two other action alternatives developed by NPS and FERC. These three action alternatives provide a range of land exchange options from 680 acres (a corridor boundary) to 1,145 acres (a maximum boundary) and several FERC project boundary configurations. We also evaluate various design, construction, operation, and mitigation measures that are common to each action alternative.

2.2 NO-ACTION ALTERNATIVE

This alternative describes conditions if the project is not granted a license, and the wilderness designations and state-federal land exchanges described in the Act do not take place. This description provides a baseline for comparing and contrasting the effects of the action alternatives. The No-action Alternative assumes the application and enforcement of all existing laws, regulations, approved plans, and policies in effect at this time. It is a viable alternative that may be chosen by the agencies. The No-action Alternative would occur under a variety of scenarios, including, but not limited to, failure to meet each of the conditions described in Section 2(c) of the Act or if the Commission determines that the project would not be in the public interest. The Act is summarized in section 1.2, and a copy of the Act is included in this document as appendix B.

Under the No-action Alternative, there would be no transfer of land between the NPS and the state of Alaska, and no additional wilderness lands within GBNPP would be designated. The construction and operation of the Falls Creek Hydroelectric Project on the Kahtaheena River would not occur.

The town of Gustavus would continue to receive electric power from the existing diesel-generating system until new diesel generation would be added or an alternative source of energy supply would be developed (e.g., through the Southeast Alaska Intertie, fuel cells, turbines, or wind generated power; see discussion in section 1.1.3).

2.3 GEC'S PROPOSED ALTERNATIVE

GEC's proposal would transfer approximately 850 acres of wilderness land, currently within GBNPP, to the state of Alaska, with the subsequent transfer of a commensurate amount of state land (based on appraised value) to the NPS. In accordance with the provisions of the Act, approximately 850 acres presently not designated as wilderness in GBNPP would be designated as wilderness. On the land transferred to the state, GEC would develop a hydroelectric facility on the Kahtaheena River near the town of Gustavus. Figure 2-1 (see appendix A) shows GEC's proposed project, which would affect a stretch of river about 2 miles long, from a point about 0.25 miles upstream of tidewater to a point about 2.2 miles upstream of tidewater. GEC would construct and maintain a new access/service road extending 1.7 miles from the end of the existing road system (Rink Creek Road), at which point it would branch 0.5 miles north to the diversion dam/intake structure and 1.4 miles south to the powerhouse.

2.3.1 Proposed Facilities

GEC's hydroelectric facilities (figure 2-2 in appendix A) would consist of:

- a small (12-foot-high by 150-foot-wide) diversion dam/intake structure at river mile (RM) 2.4 forming a 0.5-acre diversion pool, 670 feet above mean sea level (msl), which would include: (a) a gated section centered over the existing stream channel for releasing required instream flows and for passing high flows and sediment downstream; (b) a concrete wall on the southeast abutment; and (c) a screened intake on the northwest abutment, to direct the diverted flow into the penstock while bypassing fish (figure 2-3 in appendix A);

- a 9,400-foot-long penstock to convey water from the diversion dam/intake structure to a powerhouse, with: (a) a 5,320-foot-long upper section, at low gradient and under low pressure, made of high-density polyethylene (HDPE) pipe varying in diameter from 30 inches (3,150 feet) to 28 inches (2,170 feet); and (b) a 4,080-foot-long lower section, at high-gradient and under high pressure, made of 24-inch-diameter HDPE pipe (2,360 feet) and 20-inch-diameter steel pipe (1,720 feet) (figure 2-4 in appendix A);

- a 35 by 45-foot powerhouse at RM 0.45 made of metal with a concrete foundation, containing: (a) an 1,100 horsepower horizontal axis impulse turbine with a hydraulic capacity of 23 cubic feet per second (cfs) (2 cfs minimum discharge) under 590 feet of gross head; (b) a direct-connected 800-kW generator and flywheel; and (c) a synchronous bypass with a hydraulic capacity of 20 cfs (figure 2-5 in appendix A);

- a 1.79-mile-long bypassed reach;

- a 12-foot by 16-foot substation adjacent to the powerhouse with a pad-mounted 1,000-kilovolt-ampere step-up transformer and disconnect switch;

- 3.6 miles of 14-foot-wide access/service road, consisting of (a) a 1.7-mile-long segment from the end of the existing road system (Rink Creek Road) to a branch point; (b) a 0.5-mile-long segment extending north from the branch point to the diversion dam/intake structure; and (c) a 1.4-mile-long segment extending south from the branch point to the powerhouse (figures 2-1 and 2-2 in appendix A);

- a 5.0-mile-long buried 12.7-kilovolt transmission line connecting the project to the existing diesel power plant substation at the town of Gustavus;

- a tailrace system for conveying discharge from the powerhouse to a plunge pool approximately 800 feet upstream, with: (a) a headbox to collect flow from the turbine and synchronous bypass; (b) a 36-inch-diameter HDPE pipe; and (c) an outlet structure discharging 10 feet above the normal high-water level; and

- appurtenant facilities, such as: (a) hydraulic control valves; (b) a control system for startup, synchronization, and operation; and (c) miscellaneous power, lighting, hoisting, sanitation, heating, and ventilation systems.

2.3.2 Proposed Operation

The proposed diversion dam/intake structure would create a small pond (surface area of about 0.5 acres and a maximum depth of 5 feet), with minimal gross storage and no active storage due to run-of-river[15] operations. GEC proposes to maintain a minimum flow of 7 cfs in the bypassed reach from April through November, and a minimum flow of 5 cfs from December through March; these releases would be made through the gated

[15] Flows downstream of the project would equal inflow to the project at any point in time.

section of the diversion dam/intake structure. GEC proposes to divert flows in excess of these minimum instream requirements by an amount within the operating range of the turbine (i.e., from 2 to 23 cfs) through the penstock to the powerhouse. Flows in excess of the turbine's hydraulic capacity would be released to the bypassed reach through the gated section of the diversion dam/intake structure.

GEC proposes to size the gated portion of the diversion structure to provide a spill capacity equal to or greater than the 100-year frequency flood. It would also provide a means of flushing accumulated sediment from the diversion pond. It would consist of a concrete gate foundation and stilling basin and a 36-foot-long steel gate, which would raise the water 5 feet above the gate foundation (to elevation 665 feet msl). The gate would include two, independently operated panels, which would be raised and lowered by air pressure in large rubber "pillows." The control system would automatically operate the gate to maintain a constant water surface.

GEC proposes to locate the intake adjacent to the west end of the diversion gate and would initially use a modified 20-foot shipping container installed as a flume for diversion of the stream during construction of the gate. The container subsequently would be fitted with a trashrack, fishscreen, instream flow release facility, square-to-circular transition, and butterfly-type shutoff valve. An additional 20-foot shipping container would be stacked over the intake to house the power, control, and monitoring equipment. The intake and control containers would be encapsulated in concrete for protection from the elements. The trashrack would be raked manually when needed, based on continuous monitoring of the head loss across the rack. The fishscreen would consist of two vertical panel screens oriented in a V shape, with the panels aligned 30 degrees to the direction of flow. The panels would have 3/32-inch perforated plate faces in accordance with NMFS criteria for fry-sized salmonids. The apex of the V would be the entrance to the bypass, which would include an upward sloping ramp, an overflow control gate, a downwell, and a 10-inch bypass conduit discharging into the spillway stilling basin. The screens would be cleaned by an automatically controlled motor-operated brush system.

GEC proposes to operate the project in a run-of-river mode with load-following generation, and relative portions of flow diverted to the powerhouse or remaining in the bypassed reach would vary depending on flow available in the river. From May through October, there would generally be enough flow to supply required instream flows to the bypassed reach and to maintain significant generation. During this period, the project would divert flow at a nearly constant rate sufficient to meet expected peak load, with the rate of diversion adjusted weekly. The turbine and the synchronous bypass would be automatically adjusted to provide a constant flow through the powerhouse, with a continuously varying distribution of flow depending on instantaneous load on the generator.

During the remaining 6 months (November through April), there would not be enough flow in excess of the required bypassed reach flows to meet all load requirements. Between 4 and 41 percent of the time during these months, GEC proposes to divert all flow in excess of the minimum instream flow requirements, with the diversion rate adjusted automatically to maintain a constant diversion pond level. Adjustments would be made slowly to limit rate of change in water level downstream of the powerhouse to less than 1 inch/hour. Although the synchronous bypass would still be operable, all diverted flow would pass through the turbine to be used for generation.

During low-flow and/or high-demand periods, project generation would be supplemented by GEC's existing diesel generating facility.

GEC proposes to operate the project automatically, with remote monitoring. There would be no occupied on-site structures, but GEC personnel would make weekly visits for routine maintenance. Routine annual inspection and maintenance tasks requiring the generating unit to be shut down would be conducted during low-flow periods to minimize lost generation.

2.3.3 Proposed Boundary

As proposed by GEC, the FERC project boundary would include a minimum amount of land surrounding the diversion and powerhouse and including narrow corridors for the roads, penstock, and transmission line (approximately 117 acres of exchanged land and existing non-federal lands). Of this total amount within the project boundary, 75 acres would be exchanged land and 42 acres would be land that is currently state and/or private land. The bypassed reach would be outside of the FERC boundary on state land.[16] GEC proposes 850 acres of land would be transferred to the state of Alaska, of which 775 acres would lie outside the FERC project boundary and would be managed by the state of Alaska as wildlife habitat lands under ADNR's Northern Southeast Area Plan (see figure 2-1 in appendix A).[17] Under this designation, development activities would be precluded to protect the natural environment, although the state would reserve the right to approve mineral extraction operations (gravel or rock pits or quarries) to support the hydroelectric project or as needed by the community of Gustavus.

2.3.4 Construction

General. GEC proposes that construction would take place over a 24-month period. Construction of the facilities would be staggered to keep the labor demand within the capacities of the Gustavus labor force and housing opportunities. GEC would restrict

16 Lands within the project boundary would be subject to FERC license conditions governing their use and maintenance.

17 However, these lands would be managed at the state's discretion, and neither GEC, FERC, nor NPS could require the state to manage these lands as GEC proposes.

work to be carried out below the ordinary high-water mark to the period from June 1 through August 7 to minimize effects on fisheries resources. Timber clearing would be restricted to September through April to avoid effects during murrelet and passerine (songbird) nesting periods.

The road construction GEC proposes would require clearing widths of 45 to 81 feet depending on the steepness of the slope. The state of Alaska in comments on the draft EIS indicates that the vegetation clearing limits required for construction of the road are less than the standard land use easement widths (typically 60 or 100 feet) for these types of facilities. The penstock right-of-way, where not adjacent to the road, would require clearing a 30-foot-wide right-of-way. Within these prescribed clearing widths, selected trees not identified as high potential marbled murrelet nesting trees would be removed to further relieve the weight on slopes up- and down-grade from the road. Additional areas cleared of vegetation would include 0.5 acres for a borrow site, located alongside the access road, a 0.7-acres waste disposal site in a forested area south of the strip fen for back-hauled material not used in road construction, and about 1.5 acres in the powerhouse and diversion pool areas.

During construction, GEC proposes to place an environmental compliance monitor (ECM) in the field alongside the construction crew to suggest minor route and construction alterations to optimize tradeoffs between such environmental variables as wetlands, murrelet trees, snags, large woody debris, and animal trails. Additionally, nearby residents and users would be notified of the schedule for machinery operation and blasting to minimize conflict with other uses and values.

GEC proposes to limit vehicular access to that necessary to construct, operate, and maintain the project. A locked gate would be located at the start of the access road to limit access by non- project vehicles. GEC also proposes to seek a lease agreement with ADNR that restricts public access to only that which is necessary to operate the project.

Access Road. GEC proposes that project road construction would follow U.S. Forest Service Region 10 standards and guidelines for single-lane forest roads (see figure 2-6 in appendix A). Where possible, construction of the access road would avoid wetlands and, where not possible, frequent cross drains would be constructed to minimize changes to wetland hydrology.

The access road GEC proposes to construct would start at the end of Rink Creek Road and would generally be aligned to avoid sensitive wildlife habitat near tidewater. The access road would be a single-lane gravel-surfaced road with turnouts, similar to a logging road. This road would generally have a 14-foot drivable surface with a drainage ditch on its uphill side and cross drains at frequent intervals as appropriate to maintain current drainage patterns. The base would be constructed with woody debris and gravel or shot rock; the surface would be shot rock. A locked gate would be located at the start of the road to limit access by non-project vehicles. The grade of the road would generally be less than 6 percent; however, short segments would be steeper. In particular, the 600-foot-long section above the powerhouse would have a grade of nearly 20 percent.

Most of the road would be constructed with a balanced cut-and-fill cross section; however, in unstable or steep areas, the road would be constructed with a full-bench excavation to minimize loading on the downslope. GEC proposes to acquire gravel and shot rock for the initial road construction from existing sources on non-park lands in Gustavus. Additional shot rock would be taken from borrow sites at the base of riser no. 2 (see figures 1-3 and 2-2 in appendix A) and additional pits in the Horseshoe and Old Clearcut vicinities if needed. Side-casting would be avoided along all portions of roads inside The Canyon, and on other steep slopes considered slide-prone. On other road segments, excavated materials would be disposed of in roadbed construction or by side-casting. Because of concern that blasting for the roadbed incision may loosen the bedding planes, with consequent increased potential for slope failure, GEC would limit blasting in The Canyon to small charges and charges would be placed to minimize flying debris.

GEC proposes to use topsoil and vegetation for revegetation and erosion control along roadcuts and sidecast slopes, supplemented by seeding with native grasses as needed. GEC would backhaul all waste material not used in road construction to a 0.7-acre disposal site within the project boundary (see figure 2-2 in appendix A).

Diversion Dam/Intake Structure. GEC proposes to construct the diversion dam/intake structure using a central concrete core wall with rockfill on both sides to provide stability. The core wall would be keyed into the rock foundation, and the outer face of the rockfill would be grouted with concrete to prevent erosion of the fill. This arrangement would minimize the amount of concrete required for the structure and make good use of rockfill that should be available from access road construction and/or on-site quarries (approximately 0.5 acres of land would be cleared at the diversion site). Figure 2-7 in appendix A shows the details of the diversion dam/intake structure.

GEC proposes to construct the diversion dam/intake structure from about March 1 through June to allow temporary diversion of the Kahtaheena River during its lowest flow period. Construction would entail the following steps:

- excavate right abutment (looking downstream) to just above the normal water surface;
- place a cofferdam of large sandbags to isolate the right abutment area;
- place concrete slabs on the right abutment for the sluice and intake container foundations;

- set sluice and temporary diversion containers in place and anchor to bedrock through the foundation shaping concrete;

- place cofferdam of large sandbags across the Kahtaheena River to divert flow through the sluice and temporary diversion containers;

- excavate loose material from beneath the core wall. If rock is fractured or weathered, excavate core trench into rock;

- grout rock beneath core wall if necessary;

- construct reinforced concrete core wall, abutment retaining walls, intake headwall, and intake guide wall;

- place rockfill on both sides of core wall; fill voids in outer 3 feet with concrete to prevent erosion of rockfill during high flows;

- set and anchor intake containers;

- encapsulate sluice and intake containers in concrete;

- place bulkhead at downstream end of sluice container to cause flow to pass through the intake container;

- remove temporary diversion containers;

- place bulkhead in sluiceway bulkhead slots. Install sluice gate and remove downstream bulkhead;

- place bulkhead in intake bulkhead slots. Install transition and butterfly valve; and

- install trashrack, fish screen (if required), handrails, ladders, hatches, valve and gate operators, etc.

Penstock. GEC's proposed 9,400-foot-long pipeline and penstock conduit would include five distinct segments from the intake to the powerhouse (see figure 2-4 in appendix A): two segments would be in the low-gradient section (5,320 feet) starting at the diversion dam/intake structure, and three segments would be in the high-gradient section near the powerhouse (4,080 feet). The penstock would follow the service road route, except where the road grade is inappropriate for the penstock; such as: (a) final approach to the powerhouse, (b) down through the Old Clearcut, and (c) just north of the strip fen.

Low-Gradient Section. GEC proposes to use HDPE for the low-gradient segment of the penstock (segments A - B, first 5,320 feet from diversion dam/intake structure) since it is relatively light in weight, which minimizes shipping and handling costs, and requires little maintenance. The pipe segments would be heat-fused to form watertight joints to minimize leakage.

High-Gradient Section. GEC proposes to use HDPE pipe in most of the high-gradient section (segments C-E from 5,322 feet to the powerhouse). Because the pipe pressure would vary from 60 to 275 pounds per square inch (psi) in normal operation (HDPE could accommodate up to 160 psi) however, GEC proposes to use steel pipe with welded joints for the remainder of this segment. GEC would evaluate the exact transition point for type of pipe, which also would depend on the cost of the pipe materials, when the time comes for ordering the pipe.

Powerhouse. GEC proposes to construct the powerhouse on the toe of a stabilized colluvial[18] lobe located 0.45 miles upstream from the mouth of the Kahtaheena River and 0.21 miles downstream of an approximately 60-foot-high waterfall known as the Lower Falls (see figure 2-2 in appendix A). During construction, GEC would use natural topography and vegetation to screen the powerhouse from the view of visitors to the Lower Falls. As may be required by the site topography, GEC proposes to construct the slab-type reinforced concrete foundation, with column footings and perimeter walls, set on an excavated bench so that the generating unit is set on rock rather than fill. The insulated metal building superstructure of the powerhouse would be designed for appropriate snow, seismic, crane, and wind loads. The building shell would include one 12-foot by 12-foot roll-up door along the axis of the generating unit, and a personnel door directly into the enclosed 15-foot by 16-foot control room. A 14-foot by 20-foot covered loading area would be located adjacent to the powerhouse. A vehicle turnaround pad would be constructed partially on fill and partially incised into the colluvial lobe.

Transmission Line. GEC proposes to construct a 5.0-mile-long transmission line that would connect the power plant to an existing system at the diesel power plant substation. GEC proposes to bury the main power line underground along an undeveloped off-road vehicle trail (2.0 miles) from the southeast tip of the Gustavus runway to the northeast corner of section 9, then along the south boundaries of sections 3 and 4, crossing under Rink Creek, then to Rink Creek Road, then in the access road and service road to the powerhouse.[19] Ruts formed in off-road vehicle trails during transmission line construction would be filled in to avoid any drainage alteration. A

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18 Colluvium is loose and incoherent deposits, usually at the foot of a slope or cliff and brought there chiefly by mass wastage processes such as soil creep, erosion and mass movement.

19 The Commission would require GEC to obtain the utility permits necessary to install the transmission lines and to construct and operate the project.

secondary power line and control cable would be buried in the road from the powerhouse to the intake (3.0 miles) (see figures 2-1 and 2-2 in appendix A).

2.3.5 GEC's Proposed Environmental Measures

GEC proposes the following environmental measures to avoid, reduce, or mitigate potential environmental effects (these measures also would be included in every action alternative):

- Locate the powerhouse and tailrace to minimize effects on anadromous fish and their habitat in the lower Kahtaheena River and to prevent anadromous fish from trying to enter the tailrace (discharge) pipe.

- Conduct all in-water construction activities in the anadromous reach of the river from June 1 through August 7 and upstream of the anadromous reach (i.e., upstream of the Lower Falls) from November 1 through April 30 and June 1 through September 15. No in-water activities would occur in May or from mid-September through the end of October.

- Locate the intake about 300 feet downstream of The Islands area to avoid effects on productive Dolly Varden habitat located in that area.

- Include a synchronous bypass at the powerhouse to allow load-following generation without causing stage fluctuations in the anadromous fish habitat below the tailrace. This would also provide a redundant flow continuation capability to avoid dewatering anadromous fish habitat during a forced outage event.

- Construct road access to the project facilities via upland routes to avoid effects on wildlife habitat in the beach area.

- Bury the pipeline in steep portions of the road cut to protect it from damage due to sliding debris and avoid adding its weight to the vegetative and soil mat.

- Locate roadways and transmission lines to avoid sensitive areas as much as possible.

- Implement an erosion and sediment control plan (ESCP) that limits the potential for erosion by minimizing the area disturbed; using equipment that is proportionally sized for the task at hand; back-hauling materials excavated from the stream canyon and powerhouse area to reduce the possibility of mass wasting; implementing best management practices (BMPs), including use of landscape fabric, sediment fences, and prompt reseeding of disturbed areas; control techniques such as wet suppression (i.e., source watering), wind speed reduction (i.e., wind barriers), cessation of construction activities during periods of high winds, and use of small construction equipment; removing only selected trees not identified as having high potential for marbled murrelet nesting within the clearing widths prescribed by U.S. Forest Service standards and guidelines; avoiding felling trees and snags from May to August during murrelet and passerine nesting season; salvaging topsoil and vegetation during construction and use for revegetation of roadcuts and sidecast slopes (supplementing with native grass seed as necessary to ensure quick ground cover establishment); and monitoring for noxious weeds to limit the establishment and spread of plants such as giant knotweed and reed canary grass.

- Implement a sediment monitoring and management plan, which provides for annual monitoring of bedload transport. Replace any sediment shortfall by manually removing sediments from the impoundment and placing them on a river bar immediately downstream for transport during the next high-water event.

- Install a pneumatically controlled sluice gate on the dam, and lower the gate during high flows, allowing sediments to be carried downstream.

- Operate the project in a run-of-river mode and provide minimum instream flows in the bypassed reach of at least 5 cfs from December through March and 7 cfs from April through November.

- Implement a flow monitoring plan, monitoring streamflows at 15-minute intervals to verify compliance with stream flow and bypass and tailrace ramping requirements.

- Implement a water quality monitoring plan, including daily monitoring from initiation of construction to 60 days following removal of temporary erosion control measures, consistent with agency recommendations to demonstrate adherence to Alaska state water quality standards during construction and operation.

- Implement an adaptive program to monitor fish in the bypassed reach and to monitor potential changes in stream health, and consider remedial actions based on monitoring results.

- Design and construct a fish screen to exclude fry-sized salmonids from the project intake and install a bypass system to provide safe and effective downstream passage past the diversion dam.

- Minimize adverse effects on wetlands by avoiding construction in bogs along the road access route, minimize the risk of wind throw by minimizing clearing widths, and consult with the U.S. Army Corps of Engineers (ACOE) to determine the amount of wetland mitigation that may be needed.

- Minimize the removal of culturally modified trees, which are indicators of past use by Huna Tlingits. Follow acceptable and required protocol for data recovery if trees must be removed.

- In consultation with state of Alaska resource agencies (ADFG and/or ADNR) and private landowners along the road route, develop a plan to control public access on project roads and limit public access and development of the area. Following construction, limit access into the project area to non-motorized public recreation.

- Implement a recreation plan developed in consultation with Gustavus and ADNR for signage and trail brushing.

- Locate the powerhouse structure in a bight in The Canyon 0.21 miles below the Lower Falls and 0.45 miles from the shore, where it would be nearly invisible from nearby vistas. The intake site would also be located in The Canyon, where facilities would only be visible from directly overhead.

- If the project is decommissioned in the future, pursue protection of the lands with the state of Alaska.

In comments filed on the draft EIS, GEC indicated that it is negotiating with the agencies regarding a reduction in the instream flow requirement, possibly to zero. GEC suggested that, if an agreement is reached, the downstream fish bypass included (see section 2.6) in GEC's proposal and Interior's prescription may no longer be necessary. We analyze the effects of no minimum flow requirement in the bypassed reach in this final EIS.

2.4 MAXIMUM BOUNDARY ALTERNATIVE

The Maximum Boundary Alternative (figure 2-8 in appendix A) would be the same as GEC's Proposed Alternative with the exception that:

- the entire 1,145 acres of land identified in section 3(b) of the Act, as potentially available for the development of a hydroelectric project would be transferred to the state; and

- all the transferred land and the additional 42 acres of state and private land would be within the FERC project boundary and would be subject to the FERC license conditions. Accordingly, the bypassed reach would be included in the FERC project boundary. The total acreage within the FERC boundary would be 1,187 acres.

The project facilities constructed within these lands would be the same as for GEC's Proposed Alternative.

2.5 CORRIDOR ALTERNATIVE

The Corridor Alternative (figure 2-9 in appendix A) would be essentially the same as GEC's Proposed Alternative with the exception that the amount of land transferred to the state would be reduced. Approximately 680 acres of park land would be transferred to the state, and all transferred land plus 42 acres of existing state or private land would lie within the FERC project boundary. The total acreage within the FERC boundary would be 722. The land transfer would provide a minimum buffer distance of approximately 0.25 miles around all project features (i.e., roads, penstock, transmission line rights-of-way, borrow pit and disposal sites, diversion site, and powerhouse) except along the eastern boundary, where a 0.25-mile buffer would fall outside the lands identified as potentially available for development of a project in the Act. This alternative includes the bypassed reach in the project boundary.

The project facilities constructed within these lands would be the same as for GEC's Proposed Alternative.

2.6 MANDATORY CONDITIONS

Section 18 of the FPA, 16 U.S.C. §811, states that the Commission shall require construction, maintenance, and operation by a licensee of such fishways as the Secretaries of the Departments of Commerce and Interior may prescribe. NMFS, by letter dated February 5, 2002, filed two conditions under Section 18 of the FPA including:

(1) a requirement that the licensee notify and obtain approval from NMFS for any extensions of time to comply with the provisions of the fishway prescription; and

(2) a limitation of flow alterations (ramping rate[20]) downstream of the tailrace to 1 inch per hour or less, to apply to all operations including startups and

[20] The ramping rate is the established rate at which the water flow is to gradually decrease in the tailrace and increase in the turbine bypass during shutdown (or vice-versa in the case of a start up). The general purpose of establishing rate of flow change is to prevent the stranding of fish downstream from the power plant that may occur as a result of rapidly falling waters as well as to protect the public from sudden increases in streamflow.

shutdowns, and to be based on gaging readings through a control structure or narrow stream reach below the tailrace.

Interior, by letter dated February 4, 2002, filed five conditions under Section 18 of the FPA. These conditions are summarized below.

(1) Install a fish screen and bypass, which meet the most recent NMFS Northwest Region fish-screening criteria, in front of the diversion intake to prevent the entrainment/impingement of fry-sized fishes, with a screen on the intake to prevent Dolly Varden char from accessing the penstock and to allow safe passage to habitat in the bypassed reach. The facilities must be operable through the full range of diverted flows and include an automatically operated cleaning system.

(2) Maintain the fishways to keep them working properly, and to keep fishway areas clear of trash, logs, and other materials that would hinder passage. Anticipated maintenance must be performed prior to a migratory period such that fishways can be tested and inspected and would be operating effectively prior to and during the migratory periods.

(3) Consult with U.S. Fish and Wildlife Service (FWS), NMFS, and ADFG to develop a fishway maintenance and monitoring plan describing anticipated maintenance, schedule, proposed monitoring, and contingencies. The plan must be submitted to FWS for final review and approval and must contain the consultation comments from the agencies, and an explanation of why an agency comment is not included in the plan.

(4) Design and operate the project tailrace to exclude adult fish from entering the pipe transmitting water from the powerhouse to the stream.

(5) Limit flow alterations (ramping rate) downstream of the tailrace to 1 inch per hour or less to apply to all operations including startups and shutdowns, and to be based on gaging read through a control structure or narrow stream reach below the tailrace.

Interior further requests that the Commission reserve authority to modify the fishway prescriptions or prescribe additional construction, operation, maintenance, or evaluation of fishways as deemed necessary, including measures to further evaluate the need for fishways, and to determine, ensure, or improve the effectiveness of such fishways. Interior specifies that this reservation would include authority to prescribe additional fishways for any fish species to be managed, mitigated, protected, or restored in the basin during the term of the license.

2.7 ADDITIONAL MEASURES FOR CONSIDERATION

In addition to GEC's proposed measures, the following measures were recommended by stakeholders or developed by staff preparing this final EIS and are included in every action alternative. Each of the following measures is considered as a possible license article that would be enforced and approved by FERC on lands within the project boundary, and each would be developed and implemented by GEC following license issuance. Any plans would be developed in consultation with appropriate agencies and stakeholders. We consider and analyze the following measures in chapter 4, *Environmental Consequences*, and make our final recommendations in chapter 6, *Conclusions*.

- Locate project access road and transmission lines to minimize the quantity and lengths of easements across private lands. (state of Alaska)
- Develop and implement a fish passage facility evaluation plan to determine the effectiveness of the proposed fish passage facility and allow for modifications, as necessary. (ADFG, FWS, NMFS)
- Develop and implement a biotic evaluation plan to evaluate the effect of instream flow modifications and project construction and operations on fishery resources in the Kahtaheena River. (ADFG, FWS, NMFS)
- Develop and implement a plan for the use of an ECM during construction. (ADFG, FWS, NMFS)
- Require ECM to be an ADFG representative. (ADFG, FWS)
- Provide travel funding for annual ADFG inspections. (ADFG)
- Provide no minimum instream flows to the bypassed reach.[21]
- Provide minimum instream flows of 10 cfs (December 1 through April 30), 25 cfs (May 1 through September 30), 30 cfs (October), and 25 cfs (November) to the bypassed reach. (ADFG)
- Provide minimum instream flows of 10 cfs (December 1 through April 30), 20 cfs (May 1 through September 30), 30 cfs (October), and 25 cfs (November) to the bypassed reach. (FWS, NPS-Rivers, Trails, and Conservation Assistance Program. [NPS-RTCA])

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21 In its March 21, 2002, reply comments to agency terms and conditions, GEC requested that, in addition to its proposed 5 to 7 cfs minimum flow, the effects of no minimum flow also be analyzed.

- Notify agencies of non-compliance event within 12 hours. (ADFG, FWS)

- Allow a ramping rate of not greater than 1 inch per hour.[22] (ADFG, FWS, NMFS)

- Consult with fish and wildlife agencies annually to review study results, monitoring plans, and project operations that affect fish and wildlife and identify courses of action based on results. (ADFG, FWS, NMFS)

- Establish a $50,000 interest-bearing escrow account to mitigate for unforeseen fish, wildlife, and water quality effects associated with project construction and operation. (ADFG, FWS, NMFS)

- Develop and implement a fuel and hazardous substances spill plan. (ADFG, FWS, NMFS)

- Develop and implement an oil and contaminant treatment plan. (ADFG, FWS, NMFS)

- Provide free and unrestricted access to agency representatives with proper identification. (ADFG, FWS, NMFS)

- Prohibit construction personnel from hunting, trapping, fishing, and using all-terrain vehicles (ATVs) on lands off the access roads during construction. (FWS, NPS-RTCA)

- Retain vegetation at project sites to reduce erosion and visual effects. (NPS-RTCA)

- Determine the flow and temperature conditions that cause ice formation in the bypassed reach. (ADFG)

- Develop and implement a bear-human conflict plan for the project. (ADFG, FWS)

- Develop and implement a plan to avoid, minimize, and mitigate effects on wetlands. (ADFG, FWS, NMFS)

- Develop and implement a watershed protection plan. (ADFG, NMFS)

- Develop and implement a road management plan. (ADFG, NMFS)

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22 In its March 21, 2002, reply comments to agency terms and conditions, GEC requested that the state of Washington's allowable ramping rate of 2 inches per hour at night also be considered.

- Develop and implement a public access plan. (ADFG, FWS, NMFS)
- Develop a land use management plan for lands with the FERC project boundary in consultation with state, local, and federal agencies.
- Provide a flow phone or other means, such as flow information on a website, for prospective visitors to check instantaneous flow rates in the bypassed reach prior to visiting the site. (NPS-RTCA)
- Site and design project structures, to the extent possible, to blend in with their natural surroundings. (NPS-RTCA)
- Consult with NPS, Gustavus, and ADNR to develop a comprehensive recreational development plan addressing recreation needs on project lands over the term of the license including public access, recreational facility development, operation and maintenance (O&M), resource protection, signage, and an implementation schedule. (NPS-RTCA)

In comments on the draft EIS, the state of Alaska recommends an alternative road access and transmission route that would minimize the length and quantity of easement that GEC would need to acquire. Based on land parcel maps and the brief description provided in the comment letter, one alternative road route would depart from the north side of Rink Creek Road approximately 1 mile from the end of the existing Rink Creek Road and traverse across an existing (60-foot-wide) state easement along the northern boundary of section 4 and part of section 3. The alternative road route would cross approximately 0.25 miles of private land before entering into the acquired state lands at section 2, and then rejoin GEC's proposed right-of-way. The transmission line would be routed from the project along the alternative road route until the point where the alternative road route intersects with Rink Creek Road. The transmission line would then be routed south across the state of Alaska Mental Health Trust lands in section 4 and part of section 9. The transmission line would cross private land (approximately 0.25 miles) in the southern half of section 9 and align with GEC's proposed transmission line right-of-way immediately southeast of the airport. See figure 2-2 in appendix A.[23]

[23] We prepared a map showing our best estimate of the state's proposed access route. State staff confirmed that the route we describe is close to what they intended, and would eliminate private easement. This alternative road access route would be 1.5 miles longer than GEC's proposed road access route.

2.8 ALTERNATIVES AND ALTERNATIVE COMPONENTS CONSIDERED BUT ELIMINATED FROM DETAILED ANALYSIS

2.8.1 Minimum Corridor Alternative

We considered an alternative that would include 42 acres of private land and transfer the absolute minimum amount of land (75 acres) to the state of Alaska in the form of a narrow corridor along the road, penstock and transmission line right-of-way, and small parcels of land around the powerhouse and diversion sites and in areas of materials extraction for construction. However, we eliminated this alternative because the narrow corridor would fail to provide an adequate buffer between project lands and GBNPP lands. This alternative would not be consistent with sound land management practices because the presence of project roads, traversing wilderness areas but not subject to park management and control and without any buffer lands surrounding them would create a high risk for unauthorized incursions into park land by hunters, recreationists, and others using motorized vehicles.

2.8.2 Corridor Plus Isolated Lands Alternative

This alternative would be the same as the Corridor Alternative included in our analysis except that two partially isolated pieces of land, adjacent to the two private land allotments, totaling 224 acres would be transferred to the state of Alaska and would not be included within the project boundary, and thus would be available for development, as allowed under state land management regulations. Because GEC's proposal includes the unencumbered transfer of these same lands to the state, the effects of this alternative are adequately covered, and a separate analysis of this minor variation in land transfer conditions is not necessary.

2.8.3 Components of Project Alternatives Considered and Dismissed

We considered a number of alternative project components that were ultimately judged not to be reasonable under the circumstances of this project. After this determination, we eliminated the components from detailed study.

Powerhouse Location. One alternative configuration was to locate the powerhouse on the beach between the George and Mills allotments. Although this location would be the most economical in terms of construction costs and would provide the most generation, it was eliminated because of substantial environmental effects. This would divert flow to an adjacent basin and alter streamflow throughout the reach of the Kahtaheena River that supports anadromous fish. Further, the tailrace might attract spawning salmon away from the Kahtaheena River and the location of the access road along the beach would affect shoreline habitat and aesthetics. Another alternative was to place the powerhouse in a shaft excavated from the ridge just west of the Lower Falls, but high costs made it uneconomical. Placement of the powerhouse in its proposed location, but without a tailrace pipeline discharging further upstream, was rejected due to the effects on streamflow in areas used by salmon.

Diversion Structure Location. An alternative configuration was considered that would locate the diversion dam/intake structure immediately upstream of the top of The Canyon. Although this location would have lower construction costs and provide more generation, the impounded water would inundate extensive Dolly Varden habitat in The Islands. We eliminated this configuration because of its substantial environmental effects.

Service Road Locations. A number of configurations were considered to partially or completely remove the service road from The Canyon to minimize environmental effects. One would have involved pumping water up to the lip of The Canyon from an intake structure just below The Islands in lieu of a service road in The Canyon. Another alternative that would remove the service road from The Canyon would have sited the intake just upstream of The Horseshoe and piped water through a drilled tunnel to the strip fen area. A third alternative considered accessing the project by boat at a dock east of the Mills allotment. Other alternatives involved access by aerial trams or a railroad tram. All of these alternatives were considered too costly to be feasible and did not provide a substantial change in environmental effects.

Storage Operation. Storage operation, with construction of an impoundment dam, was also considered. Excess flow in the fall and spring would be stored in a reservoir and used to supplement winter low flows and occasional summer low flows, allowing the project to entirely meet the local need for power. In the near term, the cost of the dam would make the electricity more expensive than that generated by diesel, but this could become economical when loads increase and more energy can be sold. A storage operation would have greater environmental effects including reduced outflow downstream of the project and a greater loss of habitat adjacent to the impoundment.

2.9 COMPARISON OF ALTERNATIVES

The major differences between the three action alternatives are those related to the amount of land transferred from GBNPP to the state and the land use opportunities or constraints put on these lands. Table 2.9-1 summarizes the differences in land ownership and management for the three action alternatives and the No-action Alternative.

GEC's Proposed Alternative would transfer 850 acres of park land currently designated as wilderness to the state of Alaska. Existing wilderness land within the park would be removed from GBNPP, while a commensurate area of existing, non-wilderness park land would be designated as wilderness. Additionally, a commensurate area of state-owned land in another national park would be transferred to federal ownership. Seventy-five acres of these transferred lands, in addition to 42 acres of existing state and private lands, would be within the FERC project boundary (117 total acres) and would be

Table 2.9-1. Comparison of the land ownership effects of the project, by alternative. (Source: Preparers)

	No-action Alternative	GEC's Proposed Alternative	Maximum Boundary Alternative	Corridor Alternative
Total area removed from GBNPP (acres)	0	850	1,145	680
Acres of wilderness removed from GBNPP	0	850	1,145	680
Acres of transferred land not in the project boundary	0	775	0	0
Acres of transferred land within the project boundary	0	75	1,145	680
Acres of existing (non-transferred) state or private land within the project boundary	0	42	42	42
Acres of state land transferred to NPS in other areas	0	850[a]	1,145[a]	680[a]
New acres of land in GBNPP-designated wilderness	0	850[b]	1,145[b]	680[b]

[a] Approximate acreages, final amount of land transferred from the state is to be "consistent with sound land management principles as determined by mutual agreement of the Secretary and the state of Alaska." (the Act) The amount of land conveyed from the state to NPS in compensation for the removal of the Kahtaheena River land is based on an equal value as determined by a real estate appraisal.

[b] Approximate acreages, total area of land to be designated wilderness within the park, and specific wilderness boundaries "may be reasonably adjusted by the Secretary, consistent with sound management principles to approximately equal, in sum, the total acreage deleted…" (the Act).

subject to terms and conditions imposed by the Commission. These terms and conditions could affect non-hydroelectric uses of these 117 acres by the state and private entities. The remaining 775 acres of transferred land would be available for use by the state of Alaska according to its rules and regulations. As GEC proposes, it is likely that state management of these lands would be guided by the applicable ADNR Area Plan for State Lands. The current Northern Southeast Area Plan recommends that, upon transfer of lands to the state, those portions of the transferred land outside of the hydroelectric facility be managed for fish and wildlife habitat. Development activities would be generally precluded to protect the natural environment, although the state would reserve the right to approve mineral extraction activities (quarries, gravel pits), as needed, to support the development of the proposed hydroelectric facility, or for other community development purposes (ADNR, 2002b).

The Maximum Boundary Alternative would transfer more land out of the park and into state ownership. However, all of this land would be within the FERC project boundary and subject to license conditions, thus potentially affecting the state's ability to manage this land for other purposes.

The Corridor Alternative would transfer a smaller amount of land out of the park and to state ownership than the Maximum Boundary Alternative. All of this land would be within the FERC project boundary and subject to license conditions, thus potentially affecting the state's ability to manage this land for other purposes. When compared to the Maximum Boundary Alternative, a smaller area of existing, easily accessible wilderness land within GBNPP would be removed from GBNPP under this alternative, and a correspondingly smaller area of existing, non-wilderness park land would be designated as wilderness. Additionally, a correspondingly smaller area of state-owned land in another national park would be transferred to federal ownership.

Under the No-action Alternative, no land would be removed from GBNPP, and there would be no change in designation of any existing non-wilderness park lands to wilderness. There would not be any effects on the Native allotments. No state-owned lands within other national parks would be transferred to federal ownership.

2.10 PREFERRED ALTERNATIVE

After consideration of comments received on the draft EIS, FERC and NPS have developed a preferred alternative, which is described in section 6.1.2. The preferred alternative is composed of elements from the action alternatives.

3.0 AFFECTED ENVIRONMENT

3.1 INTRODUCTION

In this chapter, we describe the existing physical, biological, and human environment surrounding the construction and operation of the proposed 800-kW Falls Creek Hydroelectric Project on the Kahtaheena River, near the town of Gustavus and the entrance to GBNPP. The wilderness lands proposed for transfer from GBNPP to the state of Alaska (state); state-owned lands proposed for transfer to NPS; and the non-wilderness lands within GBNPP proposed for wilderness designation are also described.

This description of existing conditions in the proposed project area provides the baseline against which we analyze the effects of GEC's proposal and other alternatives (see chapter 4, *Environmental Consequences*). The information presented in this chapter is from GEC's license application (GEC, 2001a) and PDEA (GEC, 2001b), unless otherwise cited.

3.2 LAND DESCRIPTIONS

3.2.1 Kahtaheena River Area (Project Area)

3.2.1.1 Topography. The Kahtaheena River is located in southeastern Alaska near the community of Gustavus (see figure 1-1 in appendix A). Gustavus is located approximately 11 miles to the east of the GBNPP headquarters in Bartlett Cove (see figure 1-2 in appendix A) and serves as the gateway to this area of mountains, glaciers, and fjords noted for its scenic beauty and unique glacial and mountain terrain. The Kahtaheena River system drains an area of approximately 10.7 square miles.

All major project features, with the exception of a short section of transmission line, would be located in the physiographic area known as Excursion Ridge (figure 3-1 in appendix A). The proposed project portion of Excursion Ridge lies within an ecological subsection of southeastern Alaska classified as Inactive Glacial Terrain. The soils, vegetation, and animal life within this class of terrain developed primarily after the retreat of continental ice sheets about 14,000 years ago. The topography is predominantly rolling hills that have been heavily scoured and eroded by ice sheets. Because of their low-lying nature (mostly below 2,000 feet), forests often blanket the entire land surface with little or no interruption by alpine and subalpine communities (Nowacki et al., 2001a).

The proposed project area is in the calcareous argillite sedimentary foothills of the Chilkat Range, composed of noncarbonated rocks that include fine-grained sandstones and mudstones with carbonate areas of limestone and conglomerate. This ecoregion subsection, known as the Salmon River Sediments, is very distinctive compared to the younger surrounding landscapes. The foothills receive only moderate levels of precipitation, but the terraces within the area are poorly drained and capped with deep organics. Wetland complexes are abundant and include an intermixture of scrubby lodgepole pine forests and open bogs and fens. Lush hemlock-spruce forests occupy steeper places. The forests are brushy in the understory, probably due to the fertility of calcareous soils. Streams are less affected by meltwater runoff and more dependent on seasonal precipitation (Nowacki et al., 2001a).

Streams located in karst areas in southeastern Alaska are generally thought to be highly productive systems (Baichtal and Swanston, 1996). The carbonate buffering capacity and carbon input from the limestone bedrock significantly affect system productivity and, thus, the aquatic food chain. Some studies suggest that aquatic habitats in karst landscapes can be 8 to 10 times more productive than adjacent, non-karst dominated systems. Karst systems generally have high biodiversity and exhibit higher growth rates for fish (see sections 3.4 and 3.6 for further discussion).

A portion of the project transmission line would be constructed across an ecological subsection known as Gustavus Flats, which is classified as Active Glacial Terrain. This sprawling outwash plain resulted from huge meltwater discharges during neoglacial retreat, inundating a former tideflat with gravels and sands. Gentle topographic features resulting from low gradient deposition dominate the surface. The underlying well-sorted sands are very nutrient poor, supporting only sparse forests of cottonwood, Sitka spruce, and lodgepole pine amongst brushfields and fens. Although the area receives only moderate levels of precipitation, the mineral soils are inherently wet due to the flat topography, underlying marine silts, and high water table (Nowacki et al., 2001a).

The Kahtaheena River drainage and landform is relatively unique even among other streams in its vicinity due to its steep gradient and numerous associated waterfalls (figure 3-2). The longitudinal profile of the Kahtaheena River indicates an unusually steep gradient along its lower reach. This feature, characterized by two main waterfalls, 60 and 40 to 45 feet high, plus additional smaller falls and a steep canyon reach, sets this stream system apart from other streams in the area. The two falls likely isolate portions of the resident Dolly Varden population within the Kahtaheena River. Among other streams within the immediate area, Homesteader Creek and the East Kahtaheena River exhibit similarly steep profiles along their lower reaches. However, their short (4 miles or less) perennial channels indicate smaller drainages and more limited discharge. In contrast, Rink Creek exhibits an extremely low gradient profile along its lower 9-mile reach. Thus, even streams in the immediate vicinity of the Kahtaheena River lack its distinctive longitudinal profile and scale.

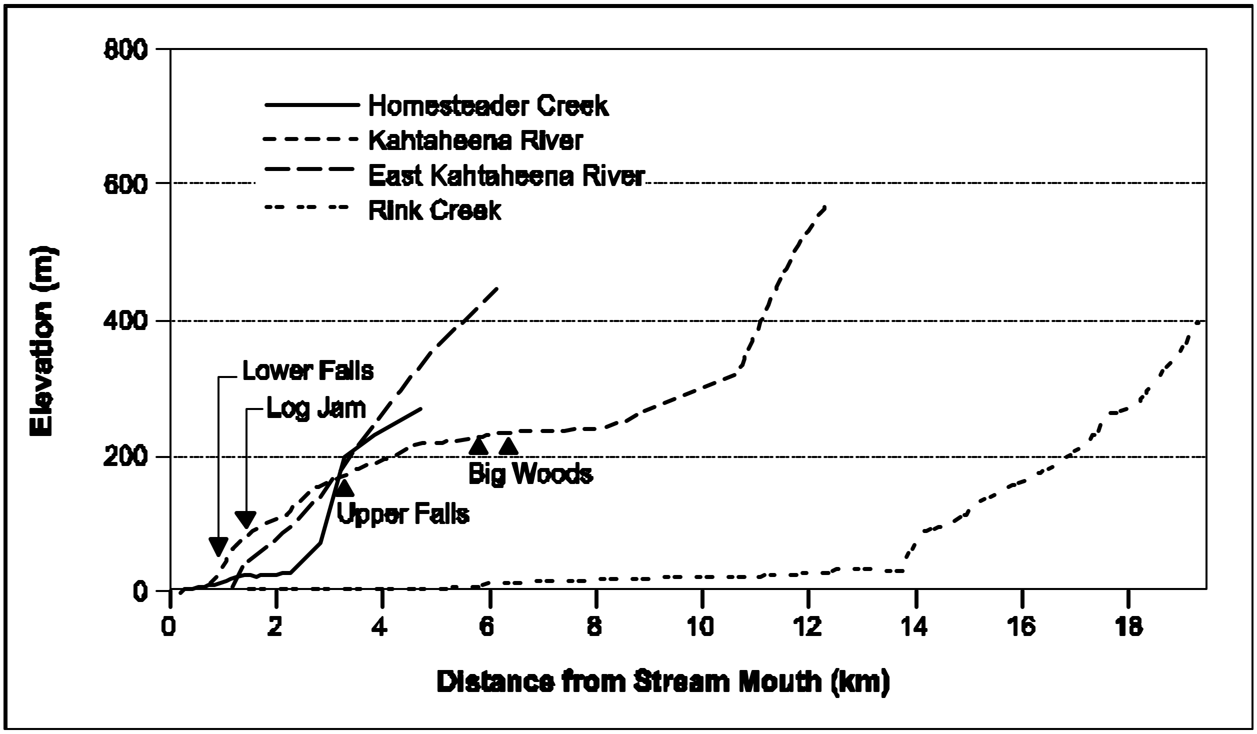

Figure 3-2. Stream longitudinal profiles within the vicinity of the proposed Falls Creek Project Area.

The Kahtaheena River flows mainly over bedrock, meandering through a steep valley and gorge, and under a canopy of moss-laden forest. Elevation in the headwaters is approximately 3,000 feet msl, with an average slope of 5 percent. The proposed project would occupy approximately 2 miles of the lower river, and five sets of falls would be located within the proposed project area, including the Upper Falls, 3 Meter Falls, and Lower Falls. The 40-foot Upper Falls are located near the upper end of a 1.5-mile-long canyon reach and just downstream of the proposed project diversion and intake. Below the Upper Falls, the channel is mainly confined to a narrow chute consisting primarily of cascades descending rapidly in a series of steps. The 3 Meter Falls is located approximately 0.5 miles below the Upper Falls. The 60-foot Lower Falls, approximately 0.5 miles above the river's mouth, is a permanent barrier to fish migration.

The proposed project's diversion and intake structure (RM 2.4) would be constructed at approximately 670 feet msl. The powerhouse (RM 0.45) would be constructed at approximately 75 feet msl. Stream habitat in the river reach that would be affected by construction and operation of the proposed project consists of long, deep bedrock pools and pools formed by large woody debris. Vegetation in the vicinity of the proposed major project features consists generally of communities of upland and wetland forest, shrub, and grasses. Above the canyon reach, there is an old-growth spruce/hemlock forest typical of areas in southeastern Alaska that escaped glacial disturbance during Neoglacial advances. Vegetation in the Gustavus Flats area includes rich meadowland, willow shrubland, spruce/pine/cottonwood parkland of varying ages, and shallow ponds with emergent vegetation.

3.2.1.2 Climate. The Gustavus and Kahtaheena River area climate is predominantly maritime, which is characterized by cool summers and mild winters. Summer temperatures range from 11 degrees Celsius (°C) to 17°C, and winter temperatures generally range from -3°C to 4°C (ADCED, 2002). Annual mean precipitation in Gustavus is 54 inches per year, and annual mean snowfall is approximately 6 feet per year, based on a period of record from 1949 through 2000 (WRCC, 2001). Observed snow depths in the upper Kahtaheena River area are estimated to be well in excess of that due to the higher elevations. The wettest months are September and October, and the driest months are March through June.

3.2.1.3 Study Area. The Glacier Bay National Park Boundary Adjustment Act of 1988 (Act) provides a description of the study area for the proposed Falls Creek Hydroelectric Project. The Kahtaheena River study area contains approximately 1,145 acres that could be transferred to the state by NPS to facilitate the construction of the proposed hydroelectric project. The lands to be transferred to the state, and the lands to be contained within the boundary for the proposed hydroelectric project, would be encompassed within the defined Kahtaheena River study area.

The study area is described as:

A. Township 39 S., Range 59 E., partially surveyed, section 36 (unsurveyed), SE3SW3, S2SW3SW3, NE3SW3, W2W2NW3SE3, and S2SE3NW3, containing approximately 130 acres.

B. Township 40 S., Range 59 E., partially surveyed, section 1 (unsurveyed), NW3, SW3, W2SE3, and SW3SW3NE3, excluding U.S. Survey 944 and Native allotment A-442; section 2 (unsurveyed), fractional, that portion lying above the mean high tide line of Icy Strait, excluding U.S. Survey 944 and U.S. Survey 945; section 11 (unsurveyed), fractional, that portion lying above the mean high tide line of Icy Strait, excluding U.S. Survey 944; section 12 (unsurveyed), fractional, NW3NE3, W2NW3SW3NE3, and those portions of NW3 and SW3 lying above the mean high tide line of Icy Strait, excluding U.S. Survey 944 and Native allotment A-442.

3.2.2 Proposed Land Exchange Parcels

3.2.2.1 Topography

Long Lake

Four distinct parcels of state-owned land within WSNPP, totaling 2,540 acres and referred to as Long Lake, were identified in the Act as potential exchange lands (see figures 1-1 and 1-5 in appendix A). These parcels are approximately 255 miles east of Anchorage in the Chitina River valley, which lies between the Wrangell Mountains to the northwest, St. Elias Mountain range to the east, and Chugach Mountains to the south.

Long Lake lies within an ecoregion identified by Nowacki as Chugach-St. Elias Mountains. The largest collection of icefields and glaciers found on the globe, outside of the polar regions, are located in this rugged ice-clad mountain chain. In the summer, glacial meltwaters form rivulets and plunge down vertical ice shafts to join vast amounts of water flowing along the base of the glaciers. Where the glaciers and icefields have receded, they have formed broad U-shaped valleys, many with sinuous lakes. Alder shrublands and mixed forests grow on these lower slopes and valley floors (Nowacki et al., 2001b).

These proposed exchange parcels are located upstream of the confluence of the Chitina and Copper rivers at an approximate elevation of 1,500 feet msl, forming an intermountain basin with associated rolling uplands. Two basic processes have been primarily responsible for the present configuration of this basin: glaciation and permafrost. Generally, soils in the valley bottoms in this ecoregion are well-drained (NPS, 1986).

Access to Long Lake is provided via a 61-mile-long gravel road from Chitina to the Kennicott River, which is passable during much of the recreational season (May through September). The lake is known to support populations of Dolly Varden, sockeye salmon, coho salmon, grayling, burbot, lake trout, and kokanee salmon. Brown and black bears use the area near Long Lake intensively in the spring, and moose may be encountered anywhere below 4,000 feet throughout this area (NPS, 1986). This ease of access for subsistence activities, coupled with proximity to population and tourist centers, is contributing to a growth in both year-round resident and casual visitor rates in the area.

Klondike Gold Rush

NPS has identified specific parcels or portions of parcels of state-owned lands that lie within the boundary of KGNHP as potentially available for exchange (see figures 1-1 and 1-6 in appendix A). A priority status has been assigned to each of these parcels (see section 3.2.2.3), which together total 1,053 acres.

These KGNHP parcels are located in an Inactive Glacial Terrain ecoregion, between two towering mountain ranges along the U.S.-Canada border. Massive continental ice sheets rounded the mountains and carved deep fjords along bedrock weaknesses, and alpine glaciers poured downslope carving U-shaped valleys. Rounded mountains differ from hills by being higher (>2,000 feet), having alpine and subalpine vegetation zones, and possessing snow cover long into the summer. In mountains, alpine areas are an important source of meltwaters and sediments. Soils mimic the original texture of the bedrock or parent material (often basalt and andesite, as well as volcanic breccia and tuffs, mudstone, and limestone). Landslides often initiate at soil-bedrock contacts on steep slopes. Mountain streams usually have higher bedloads and more power than hill streams (Nowacki et al., 2001a).

The KGNHP parcels generally lie along the Taiya River, northwest of the town of Skagway, which is the northernmost stop on the Alaska Marine Highway. With one exception, each parcel contains a section of the historic Chilkoot Trail. NPS already manages most of the Chilkoot Trail portion of each of these parcels under a 15-year cooperative agreement with the state, as well as campgrounds and other facilities that support recreation use of the Chilkoot Trail (ADNR, 2002a).

Although much of the land in this area is covered with snow and ice most of the year and is extremely rugged, the topography of the proposed exchange parcels is fairly level along the Taiya River. Many of the parcels occupy flat, vegetated portions of the floodplain and adjacent upland areas (ADNR, 2002a). Vegetation and plant communities do not fit clearly into plant associates identified for southeastern Alaska. The area's drier climate and proximity to the interior ecosystem of the Yukon Territory are demonstrated in more drought-tolerant plant communities. At the lower elevations along the river bottom, black cottonwood predominates along with alder, red osier, dogwood, and willow. Outside of the riparian areas, hemlock and spruce forests dominate the valley floor. The Taiya River supports runs of chum, coho and pink salmon, steelhead trout, and Dolly Varden char (NPS, 1996).

3.2.2.2 Climate

Long Lake

The Chugach and St. Elias mountains serve as a barrier to the warm, moisture-laden maritime air from the Gulf of Alaska and the flow of cold continental air from the interior. Long Lake, which is located in this transitional zone between the maritime and continental climate zones, receives only about 10 to 12 inches of rain annually, and about 50 inches of snow. Temperature extremes can range from -50°C to 33°C. At the confluence of the Chitina and Copper rivers, lake and river ice are known to occur as early as August 22 and last as long as June 1 (NPS, 1986).

Klondike Gold Rush

The mountains surrounding the Skagway area and encompassing the proposed exchange lands are covered by deep snow in the winter, but most of the snow melts during the summer, except above the 4,500-foot level, where perennial ice fields can remain (NPS, 1996). The exchange parcels experience mostly a maritime/coastal climate, but the northern portions fall within a transition zone to the drier continental climate. The St. Elias, Fairweather, and Chilkat mountain ranges to the west greatly affect the weather, protecting the area from severe coastal storms and monsoon-like rains.

The area receives about 100 inches of precipitation per year. Clear and dry weather systems regularly push in from the interior, providing warm, sunny weather during the summer and cold, dry weather during the winter. The clash of cold continental and moist maritime air in winter fosters abundant snow cover that persists well into spring (Nowacki et al., 2001a).

3.2.2.3 Study Area

Long Lake

The state lands in the Long Lake area considered eligible for inclusion as exchange parcels are in-holdings within WSNPP. These lands are described as they appear in the Act and are listed by priority as follows:

A. Township 6 S., Range 12 E., partially surveyed, section 5, lots 1, 2, and 3, NE3, S2NW3, and S2, containing 617.68 acres, as shown on the plat of survey accepted June 9, 1922.

B. Township 6 S., Range 11 E., partially surveyed, section 11, lots 1 and 2, NE3, S2NW3, SW3, and N2SE3; section 12; section 14, lots 1 and 2, NW3NW3; containing 1,191.75 acres, as shown on the plat of survey accepted June 9, 1922.

C. Township 6 S., Range 11 E., partially surveyed, section 2, NW3NE3 and NW3, containing 200.00 acres, as shown on the plat of survey accepted June 9, 1922.

D. Township 6 S., Range 12 E., partially surveyed, section 6, lots 1 through 10, E2SW3 and SE3, containing approximately 529.94 acres, as shown on the plat of survey accepted June 9, 1922.

The priority of the land conveyed to NPS may change from what is shown to reflect WSNPP management priorities. The study area will remain the same as listed above.

Klondike Gold Rush

The state identified lands encompassed within the boundary of KGNHP that are suitable for consideration as exchange lands with NPS (ADNR, 2002a). NPS prioritized specific parcels of these state lands, totaling 1,053 acres, for exchange consideration. These parcels, in order of priority, are:

A. Unit S-09; Township 27 S., Range 59 E., section 14, 15, and 22, containing 132.25 acres of lands along the lower Chilkoot Trail in the vicinity of the Kalvik property.

B. Unit S-10; Township 27 S., Range 59 E., section 22, containing 31.58 acres and encompassing a campground and trailhead already operated by NPS.

C. Unit S-11; Township 27 S., Range 59 E., section 22, containing 66.31 acres and encompassing the area in the vicinity of a campground operated by NPS.

D. Unit S-07; Township 26 S., Range 59 E., section 13, 23, 24, 25, 26, 35, 36 and Township 26 S., Range 60 E., section 3, 4, 5, 7-23, 26-35, containing 513.28 acres that encompass Taiya River lands along the Chilkoot Trail and adjacent to Native allotments.

E. Unit S-05; 4 parcels including:

1. Township 26 S., Range 59 E., section 14 (NW3, SE3 and E2, NE3, SW3 to connect with the current Interagency Land Management Agreement boundary to the west and E2, SE3, SE3, NW3 to connect with the current Interagency Land Management Agreement boundary to the west and S2, SW3, NE3), containing 60 acres of lands adjacent to the Canyon City historic site and campground.

2. Township 26 S., Range 59 E., section 12 (N2 of NW3 between the Chilkoot Trail corridor to the SE and the 300-foot contour line to the NE), containing 50 acres that encompass the area to the west of the Chilkoot Trail that includes a concentration of historic/archeological resources.

3. Township 26 S., Range 59 E., section 1 (E2 between the Chilkoot Trail corridor to the SE and the 300-foot contour line to the NE and SE3, SE3, SW3 to the 300-foot contour line), containing 110 acres encompassing the area to the west of the Chilkoot Trail that includes a concentration of historic/archeological resources.

4. Township 26 S., Range 60 E., section 5 (NW3 between the Chilkoot Trail corridor to the SE and the 300-foot contour line to the NE), containing 90 acres that encompass the area to the west of the Chilkoot Trail that includes a concentration of historic/archeological resources.

3.2.3 Wilderness Designation Parcels

3.2.3.1 Topography. The three parcels of non-wilderness lands within GBNPP proposed for wilderness designation are all located within recently deglaciated areas of the Active Glacial Terrain ecoregion. These young, dynamic, and unstable landscapes concentrated in Glacier Bay and along the outer mainland coast experience high rates of erosion and mass wasting. Enormous volumes of meltwaters pouring from the large ice sheets and glaciers, coupled with tectonic uplift and isostatic rebound, produce some of the highest sedimentation rates in the world. As a result, vast glaciofluvial aprons, known as forelands, have formed along the outer coast. Glacial streams run heavy with silt, and their hydrology is linked to the timing of snow and ice melt rather than storm events. Primary vegetation succession is intrinsically linked with soil formation, and unfolds over a much longer period than secondary succession where there are pre-existing plants and soils. Aquatic and fish communities display similar developmental patterns with abundance and diversity dependent on stream habitat complexity and stability (Nowacki et al., 2001a).

Unnamed Island near Blue Mouse Cove

A 789-acre unnamed island that forms the southeastern boundary of Blue Mouse Cove is proposed for designation as wilderness (see figures 1-1 and 1-7 in appendix A). The island is located on the southwestern side of the West Arm of Glacier Bay, approximately 30 miles north of the park headquarters in Bartlett Cove. Blue Mouse Cove and the adjacent unnamed island lie within the Glacier Bay fjord complex that forms a Y-shaped bay up to 15 miles wide and 63 miles long. This bay is the northern terminus of the inside passage from Seattle to Alaska (NPS, 1988).

Blue Mouse Cove and the unnamed island are located in the ecoregion subsection known as the Hugh Miller-Geikie Inlet Mountains. Here, terrestrial surfaces were extensively scoured by repeated neoglacial ice flows (as recently as the mid-1800s) that exposed underlying bedrock composed of a mix of granitic, metasedimentary, and metavolcanic rocks (Nowacki et al., 2001a). Even though smooth surfaces originating from glacial abrasion and water erosion are the least favorable for plant colonization, the unnamed island is populated by Sitka spruce forest (NPS, 1988). The island experiences some seasonal dispersed recreational use but retains an undeveloped and pristine character.

Cenotaph Island

The 280-acre Cenotaph Island lies in the middle of Lituya Bay on the wave-beaten northeastern coast of the Gulf of Alaska and within GBNPP (see figures 1-1 and 1-8 in appendix A). Lituya Bay is a 7-mile-long by 2-mile-wide ice-scoured tidal inlet that lies along the fault line of the Fairweather Mountain Range. The bay and island are within an ecoregion subsection known as the Yakutat-Lituya forelands. The forelands spread seaward from the slopes of the St. Elias and Fairweather mountains, forming a vast coastal plain. The gently sloping area is a complex of unconsolidated glacial, alluvial, and marine deposits that have been uplifted by tectonics and isostatic rebound (Nowacki et al., 2001a). The coastline is predominantly sand and gravel beaches.

This area is riven by the seam between the Pacific and North American plates, and is being rapidly thrust upward by tectonic forces. During the past 150 years, five giant waves have occurred in the bay, denuding Cenotaph Island and the adjacent shoreline up to a height of 492 feet (Mader et al., 1999). An earthquake and landslide in 1958 resulted in a tidal wave that cleared all vegetation from the island except from its highest two peaks (NPS, 1988). Lituya Bay and Cenotaph Island have long served as a haven for seafarers crossing the open Pacific from Cross Sound to Yakutat.

Alsek Lake (Dry Bay)

Approximately 2,270 acres of lands are under consideration for designation as wilderness in the area of Alsek Lake (Dry Bay). Alsek Lake lies along the lower reach of the Alsek River, at the northwestern end of GBNPP, and it is the largest lake within GBNPP (see figures 1-1 and 1-9 in appendix A). As with Cenotaph Island, the Alsek Lake and Dry Bay area lie within the ecoregion subsection known as the Yakutat-Lituya forelands.

The proposed exchange parcels lie along the margins of Alsek Lake. The Alsek River flows from its headwaters in the St. Elias Mountains located in Canada's Yukon Territory through GBNPP to the Pacific Ocean, for a distance of approximately 155 miles. Alsek Lake was formed in the early 1900s by retreating glaciers and continues to grow as the surrounding glaciers retreat. Two glaciers, the Alsek and Grand Plateau, actively calve into the lake and are filling it with icebergs (NPS, 1988).

The Alsek River corridor is the only valley through the coastal mountain range to the Gulf of Alaska for a distance of 120 miles, and it is an important corridor for migratory animals and a major flyway for bird migration (NPS, 1988). The Alsek River system is a major contributor to the commercial fishery in this portion of the Gulf of Alaska, and the fishing community of Dry Bay lies along the glacial outwash plain downstream of Alsek Lake. The lake is also a popular camping spot for rafters navigating the Alsek River.

3.2.3.2 Climate. GBNPP has three climatic zones: the outer coast, along the Gulf of Alaska; upper Glacier Bay, north of a line drawn east-west through Tidal Inlet; and lower Glacier Bay, including the park waters of Cross Sound and Icy Passage (NPS, 1988). The park headquarters in Bartlett Cove is in the lower climatic zone, with average mean summer temperatures of 12°C and average mean winter temperatures of –2°C (WRCC, 2001). Cloudiness and precipitation tend to be the rule during any month, and some form of precipitation occurs on an average of 228 days per year. Annual precipitation is 70 to 80 inches (NPS, 1988). Annual mean snowfall is 115 inches (WRCC, 2001).

Unnamed Island near Blue Mouse Cove

Blue Mouse Cove lies in the area that divides upper and lower Glacier Bay, where the temperature is typically a few degrees colder in summer than at Bartlett Cove. The area receives heavier snowfall in winter than Bartlett Cove (NPS, 1988).

Cenotaph Island

Cenotaph Island, lying along the Gulf of Alaska, experiences milder temperatures and more precipitation, but less snowfall, than either the upper or lower Glacier Bay climatic zones, owing to the influence of the warmer Japanese current. Extended periods of overcast and fog are common and often impede marine navigation. The prevailing winds are southerly and occur during most periods of precipitation. Northerly winds are usually associated with clear weather and are the strongest in winter, frequently reaching gale-force levels (NPS, 1988).

Alsek Lake

Alsek Lake lies at the northern end of the upper Glacier Bay climatic zone. As such, this area receives heavier snowfall in the winter, and it is typically a few degrees colder in the summer than the lower Glacier Bay zone (NPS, 1988).

3.2.3.3 Study Area. These lands are described as they appear in the Act and are listed in priority order.

Unnamed Island near Blue Mouse Cove

The unnamed island in GBNPP, identified as land to be designated wilderness in the Act, is described as lying southeasterly of Blue Mouse Cove in sections 5, 6, 7, and 8, Township 36 S., Range 54 E., shown on United States Geological Survey (USGS) quadrangle Mt. Fairweather (D-2), Alaska. The island contains approximately 789 acres.

Cenotaph Island

Cenotaph Island, situated within GBNPP and identified as land to be designated wilderness in the Act, lies within Lituya Bay in sections 23, 24, 25, and 26, Township 37 S., Range 47 E., shown on USGS quadrangle Mt. Fairweather (C-5), Alaska. The island contains approximately 280 acres.

Alsek Lake

An area lying upstream of Dry Bay, in the vicinity of Alsek Lake, has also been identified by the Act as appropriate for designation as wilderness lands. This area lies in Township 31 S., Range 43 E. and Township 32 S., Range 43 E., and it contains approximately 2,270 acres.

3.3 GEOLOGIC RESOURCES AND SOILS

3.3.1 Kahtaheena River Area (Project Area)

Bedrock beneath Excursion Ridge is composed primarily of bedded late-Silurian/early Devonian calcareous mudstone, moderately folded and, in some places, mildly metamorphosed to slate and phyllite. The most recent major geologic event that shaped the landscape of the area was the last period of glaciation ending approximately 14,000 years ago when all bedrock features were abraded by glacial erosion. In most cases, these features have been stripped of unconsolidated sediment and weathered and decomposed rock (see section 3.2.1.1).

The Kahtaheena River and associated project-area landforms are unique to GBNPP by virtue of landscape age and glacial history. The Kahtaheena River landscape was not glaciated during the recent Neoglacial ice advance (see figure 3-3 in appendix A) in contrast with the majority of landforms and streams within Glacier Bay proper and the Gustavus forelands area, which were largely ice-covered until approximately 250 years ago (Streveler, 1996). Excursion Ridge, the site of much of the Kahtaheena River drainage basin, is geomorphically old (ca. 14,000 years; Mann and Streveler, 1999). Portions of GBNPP's outer coast and Dundas Bay region also were not recently glaciated and are thus comparable in age. However, only one-fifth of the drainages in those areas are comparable in size to the Kahtaheena River.

The location and morphology of watercourses appear to be controlled by the underlying bedrock fold structures and related jointing. The Kahtaheena River follows the axis of an anticline through all of the bypassed reach between the Upper Falls and just upstream of the Log Jam, at which point the river turns across the structural grain and descends abruptly to the anadromous reach. Just downstream of the diversion, the river jogs abruptly across the bedrock's structural grain and then occupies a deep canyon in the canyon and log jam reaches (see figure 1-3 in appendix A). This canyon is eroded along the joint-weakened crest of a bedrock anticline. Before the Anadromous reach, the river turns across the structural grain and descends through another canyon to the Icy Passage.

There is no significant flood plain developed along the upper Kahtaheena River above the Lower Falls. The river is generally bedrock controlled. Small, though biologically significant, accumulations of sediment and coarse woody debris occur at places along upper Kahtaheena River, notably at the Log Jam, near The Islands, and within the Big Woods. Below the Lower Falls, there are much larger deposits of gravel and woody debris in the streambed and the greatest development of a flood plain and accumulations of silt, sand, and gravel that occur in the river delta.

Downstream of the proposed powerhouse site, the Kahtaheena River valley is covered by gravels that accumulated in a series of raised deltas deposited at the end of the last glacial retreat. These deltas have been progressively uplifted by crustal rebound following the removal of the weight of glaciers. A wedge of gravel extends into the intertidal zone, progressively thinning and eventually disappearing at about 14 feet above mean low water. Above the gorge, narrow gravel terraces indicate gradual lowering of local base level as the gorge extended itself upstream (Streveler, 1999). The throughput of gravel to the river's delta is currently sufficient to maintain salmon spawning habitat in the intertidal creek bottom.

Mass wasting, which includes both shallow landslides and soil creep, is an important factor in erosion of the landscape and the transport and supply of soil, rocks, and debris to streams in southeastern Alaska.

Landslides. Landslides are important types of natural disturbances that alter the landscape. Landslide failures tend to occur in the fall during the period of highest rainfall and intense storm events. A regional landslide study using aerial photographs in the Tongass National Forest of Southeast Alaska by Swanston and Marion (1991) inventoried 1,395 landslides larger than 77 cubic meters (m^3) (100 cubic yards [yd^3]) in volume distributed over 41,503 square kilometers (km^2). Out of the inventoried failures, they reported 1,277 (92 percent) in uncut forested areas, 105 (7 percent) were associated with clearcuts, and only 15 (1 percent) were associated with roads. Their study suggests that the occurrence of natural landslides in unmanaged terrain is less than 2 landslides/1,000 km^2 per year. The Swanston and Marion landslide study excluded smaller slope failures (less than 77 m^3 [100 yd^3]) because they could not be consistently identified beneath the forest cover. The study analysis was largely statistical. Refining the estimated number of landslides that could occur within the watershed, estimating the potential of smaller landslides, or estimating landslides based on the underlying geologic unit would require additional detailed investigation, including field reconnaissance.

The Swanston and Marion study also shows that the predominant landslide types are debris avalanche/debris flow type (Varnes, 1978) (87 percent) and debris floods (debris torrents) (13 percent). Debris avalanches/debris flows generally occur in shallow, linear depressions oriented perpendicular to the slope (Swanston and Marion, 1991) where the topography and permeable organic soils tends to result in the convergence of shallow ground water flow. These avalanches and flows travel down the slope along V-notch channels and deposit the entrained material upon reaching gentler gradients at the base of the steeper slopes. Swanston and Marion (1991) indicated that about 85 percent of these failures do not reach perennial streams.

The remaining percent of the landslides were generally debris torrents (debris floods) (Swanston and Marion, 1991). These failures result from rapid failures confined to V-notched gullies and canyons during storms. Although debris torrents occurred less frequently than debris avalanches, they tended to reach low gradient stream sections and caused identifiable changes in channel morphology such as alteration in channel location, destruction of riparian areas, channel aggradation, and movement and redistribution of woody debris (Swanston and Marion, 1991).

The Swanston and Marion (1991) study also shows that 75 percent of the failures occur on slopes steeper than 66 percent, 15 percent of the failures occur on slopes between 48 and 66 percent, and the remaining 10 percent failures occur on lower gradient slopes. Of the failures in lower gradient slopes, Swanston and Marion attributed some of these to failures occurring in areas of undetected higher slope gradients or failures occurring in weaker elevated marine clays and glaciolacustrine deposits.

The slopes along all of the proposed project features (diversion, powerhouse, and roads) fall generally in the lower gradient slope category. Less than 1 percent in the 50 to 72 percent slope category, 11 percent in the 30 to 50 percent slope category, and 88 percent in the lower gradient slope category. The landslide types expected to occur most frequently in the Kahtaheena River watershed are debris avalanches and debris flows.

Soil Creep. Surficial soil creep is another significant geologic process that supplies soil, rocks, and debris to streams, although it is difficult to investigate and studies of its effects are rare. Barr and Swanston (1970) conducted a study in southeastern Alaska in the Maybeso Creek valley near Hollis, Alaska, on Prince of Wales Island. This study indicated that measurable amounts of creep in the upper organic debris and weathered till occurs year round, but movement rates peak in the fall and spring when groundwater levels are highest. The magnitude of creep measured was 0.0064 m/year on a 70 percent slope. In the project area, the steepest slopes are in the canyon reach where slopes exceed 72 percent. Because this area probably has the highest surficial soil creep rate, it probably is a significant source of sediments to the river. Assuming a creep rate of 0.0064 m/year and a thickness of actively creeping soil of 1 m, then soil creep (organics and mixed mineral soils) would supply about 13 m^3/year per kilometer of stream channel with steep valley sides. Therefore, the reach would supply about 20 m^3/year of sediments to the river in the project area under existing conditions.

Several areas of mass movement deposits were observed in unconsolidated glacial material in the Kahtaheena River watershed, primarily in the upper Canyon between Horseshoe and the diversion structure/intake site (Mann, 2000). Figure 3-4 (see appendix A) shows the locations of these active and historic landslides. Mann (2000) identified the following known and potential landslides:

- A rotational slump of unconsolidated glacial deposits on the northwestern side of the Kahtaheena River between the Horseshoe and the river. This landslide covered an area of approximately 200 m^2, occurred 2 to 5 years ago, and consists of surficial deposits of silty gravel and clay-rich, boulder diamicton.[24] The shear plane was along the surface of the underlying sedimentary bedrock.

24 Diamicton refers to a deposit that is usually massive and poorly sorted, containing clasts of many sizes. The clasts range in size from clay to boulders and are of varying compositions. The term

- Four forested landslides of oversteepened unconsolidated glacial sediments along the northwestern bank of the Kahtaheena River between the Horseshoe and the diversion dam/intake site. One of these landslides consists of silty gravel overlying clay- and silt-rich diamicton at creek level.

- Landslide deposits of unconsolidated debris on the bank of the Kahtaheena River along the footslope at the powerhouse site.

- Evidence of repeated mass movements in subsurface materials overlying residual clay-rich gravel parent material at test pit no. 4 (see figure 3-5 in appendix A and table 3.3-1).

Karst Geology. Small-scale karst features, lime-rich springs, and high levels of bicarbonate in Kahtaheena River water all indicate the presence of carbonate minerals in the watershed. Consequently, Kahtaheena River water is highly buffered against acidic input from peats and podzolic[25] soils in the watershed. There are no indications of human effect on water quality parameters in the Kahtaheena River watershed (see section 3.4.2, *Water Quality*). However, slope stability concerns are heightened by the occurrence of carbonate resurgence in The Canyon due to fissure flows and the interbedded nature of the carbonaceous bedrock unit. The evidence of extensive karst development on Excursion Ridge to the northeast supports these concerns.

The Kahtaheena River drainage and its associated landforms were not glaciated during the recent Neoglacial ice advance (see figure 3-3 in appendix A).[26] This drainage is one of only five known coastal carbonate-influenced stream systems remaining ice-free during the Neoglacial within GBNPP. The drainage is significant because of its carbonate geology, and the rock type throughout this area is sedimentary (sandstones) with numerous bands of carbonates. Mann and Streveler (1999) report that sink holes along Excursion Ridge and the water chemistry of the Kahtaheena River indicate considerable carbonate influence. Carbonates weather at a higher rate than other rocks, and streams associated with these deposits typically exhibit high pH, alkalinity, and dissolved solute concentration, which enhances aquatic productivity (Wissmar et al., 1997). Specific aquatic invertebrate species assemblages (e.g., snails, clams, sponges, and amphipods) are often associated with this unique water chemistry.

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diamicton should be used when the origin of a deposit is not known. The term glacial diamicton or till should only be used when the origin of the deposit is known to be glacial.

[25] Podzolization refers to processes by which soils are depleted of alkaline materials, become acid, and develop leached surface layers and lower layers of accumulation. They are formed under moist and cool climatic conditions.

[26] The Neoglacial ice advance is the most recent ice advance in GBNPP. Lieutenant Whidbey of the Vancouver Expedition first mapped the glacier front near the mouth of Glacier Bay in 1794.

Table 3.3-1. Summary of test pit explorations for proposed Falls Creek Hydroelectric Project. (Sources: Mann and Streveler, 1999; Mann, 2000)

Exploration Number	Location Description	Thickness of Surficial Organics (cm)	Depth to Mineral Soil (cm)	Depth to Rock (cm)	Total Depth (cm)	Additional Description from Field Geologist/Soil Scientist
Pit 1 (1999)	SW of Falls Creek Near River	30	30	NR	82	clay-rich gravel, possibly residual soil
Pit 2 (1999)	SW of Falls Creek	85	85	NR	125	woody peat (muck)
Pit 3 (1999)	SW of Falls Creek Northeast of Road	40	40	NR	88	clay-rich gravel, possibly residual soil
Pit 4 (1999)	SW of Falls Creek Near Road Alignment	88	88	NR	115	clay-rich gravel, possibly residual soil, deeper organic layers, slide material
Pit 5 (1999)	SW of Falls Creek and Road	60	60	NR	120	woody peat over unweathered clay-rich gravel, possibly residual soil
Pit 6 (1999)	SW of Falls Creek and Disposal Site	NR	NR	NR	235	woody sledge and peat moss 0 to unknown depth
Pit 7 (1999)	SW of Disposal Site	15	15	NR	75	clay-rich gravel, possibly residual soil
Pit 8 (1999)	SW of Falls Creek SW of Disposal Site	80	80	NR	100	woody peat (muck) over clay-rich gravel, possibly residual soil
Pit 1 (2000)	NW of Road Between Diversion Structure and Upper Falls, Landslide Area	98	98	NR	118	woody peat (muck)
Pit 2 (2000)	Road Alignment Between South Borrow Pit and Powerhouse	18	18	NR	70	
Pit 3 (2000)	Powerhouse Site	200	NR	NR	200	woody peat (muck)
Pit 4 (2000)	SE of South Borrow Pit Site	18	18	NR	62	
Pit 5 (2000)	Near Road Alignment Between Branch and South Borrow Pit	56	56	NR	80	woody peat (muck)

(1) Measurements are approximate and in centimeters (cm).

(2) Logs are supplemented by investigator's description of soils in text of reports (see *Additional Description* column above).

(3) Interbeds of inorganic mineral soils were ignored in determining thickness of surficial organics for Pit 4.

(4) Percentages of textural classes in soils, consistency, depths to groundwater and rock, and engineering properties of soils were not recorded on logs.

(5) NR = Not reported.

Only about 5 percent of Glacier Bay's mapped bedrock geology is known to be comprised of carbonate (see figure 3-3 in appendix A). Less than about one fifth of these areas remained ice-free during the Neoglacial ice advance. Part of the Kahtaheena River drainage and four additional drainages associated with the White Cap Mountain area near Dundas Bay (NPS stream numbers 187, 194, 195, and 196) are the only known coastal areas represented by carbonate landforms within GBNPP[27] that were not recently glaciated.[28] Although it is possible that other small, coastal carbonate-influenced systems remained ice-free during the Neoglacial, their identity, size, and location are currently not known. It is also unknown if the carbonate nature of this system has resulted in habitation of the Kahtaheena River by any unique aquatic invertebrate species because samples collected from the Kahtaheena River during late May in 2000 (Flory, 2001) remain unanalyzed.

Soils. Soil development in southeastern Alaska is influenced by high levels of rainfall, cool maritime temperatures, and moderately low annual soil temperature. Under these conditions, organic material decomposes slowly, resulting in thick surface layers of organic soil. Soils on Excursion Ridge are deep and well-developed. The most prevalent soil-forming processes are organic accumulation at the ground surface and podzolization. Most soils are wetland types, except on the steepest slopes.

Surficial geologic and soils mapping is very limited for the Kahtaheena River watershed, and soil unit mapping was not available from the National Resource Conservation Service (NRCS). Mann and Streveler (1999) and Mann (2000) conducted field investigations in the proposed project area. Thirteen shallow test pits (see figure 3-5 in appendix A) were excavated along a southwestern transect from the Kahtaheena River to just west of Camp Bog, south of the proposed road route descending towards Gustavus, in the vicinity of the proposed powerhouse, and near the access road west of the Kahtaheena River between the powerhouse and diversion dam/intake site (Mann and Streveler, 1999; Mann, 2000). Table 3.3-1 summarizes results of the test pit explorations.

The soils encountered have thick (as much as 6.5 feet) organic surface horizons, are poorly drained, and have fine-grained mineral horizons (Mann and Streveler, 1999; Mann, 2000). Sites with slopes less than 36 percent are more poorly drained with organic

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27 The bedrock geologic formations map for GBNPP (see figure 3-3 in appendix A) is based on work conducted by USGS Geologist Dave Brew (now retired) and others between 1950 and 1977 (Geiselman et al., 1997). Much of this work was conducted on a fairly coarse scale, only part of the park has been mapped, and the scope and accuracy of this work is not known. However, it currently represents the best available information for the park.

28 The maximum extent of the Neoglacial ice advance as depicted was compiled from a wide variety of sources by Elizabeth K. Solomon and Philip N. Hooge (Geiselman et al., 1997). However, relatively more information exists for some areas (i.e., Muir Inlet) than for others. Thus, there may be some inconsistencies associated with this theme. However, this work currently represents the best available information for the park.

horizons 8 to 32 inches thick (Streveler, 1999). The underlying mudstone bedrock weathers readily to poorly drained silt- and clay-rich soils. In combination with the deep, organic accumulations and steeply dipping, thinly bedded bedrock, this makes mass movement a concern for construction on steep slopes, such as for road building.

Soil logs for these explorations are presented in Mann and Streveler (1999) and Mann (2000) and a corresponding classification system is on the NRCS website (http://www.nrcs.usda.gov). The soil classifications qualitatively describe soil horizons and subordinate soil layer distinctions with depth and emphasize organic soil and their transition to mineral soils (NRCS, 2003). The soil horizon found in nine explorations suggests that residual soil and unconsolidated bedrock may be at shallow depth. The depth to rock and groundwater conditions were not reported on the logs. Information on the soil logs are generally not provided in sufficient detail to allow for interpretations of percentages of textural classes in soils (clay, silt, sand, gravel), consistency (density), excavation difficulty, and other engineering-related properties.

Gustavus Flats are composed of primarily sandy glacial outwash sediments related to the most recent advance of ice in Glacier Bay, which culminated about 250 years ago. These sediments were deposited in a former marine embayment that reached the western base of Excursion Ridge. On the Flats, sandy outwash sediments are intermingled with a wedge of glaciomarine silts that were deposited during the glacial maximum as nearby ice depressed the land below sea level. With the melting of the glaciers and removal of the weight, the earth's crust rebounds upwards, thus, raising the land above the sea. Post-glacial uplift is ongoing, progressively baring the silts to colonization by terrestrial plant communities. These silts extend as a huge mudflat 1.5 miles south of the Kahtaheena River’s mouth. Well logs from the general vicinity document the presence of fine-grained marine silt lenses at depths of several meters, which probably are responsible for the generally high-water table (Mann and Streveler, 1999). The proposed power line route is underlain by sand, except along the Rink Creek estuary, where it crosses an area underlain by silt-rich sediments.

The east Glacier Bay-Lynn Canal region, including the study area, shows relatively low seismicity compared with the region further westward. However, larger more distant earthquakes affect the area. Southeastern Alaska and the site are in the Uniform Building Code seismic zone 3.

The nearest seismically active area is the Fairweather-Queen Charlotte Fault system, which extends from the northern end of Vancouver Island to the Gulf of Alaska (AEIC, 2003). This fault system passes within about 60 miles of the site, and it is a large-scale transform fault that is part of the worldwide system of faults bounding the earth’s crustal plates. This fault forms the boundary between the Pacific Oceanic plate and the North American plate. It is similar to the San Andreas Fault and is actively moving about 2 inches per year. The fault generates earthquakes from magnitudes 7 to about magnitude 8. AEIC’s (2003) database of earthquakes lists several significant earthquakes that have occurred in the region. These include the 1927-magnitude Ms 7.1 (Ms = surface wave), 1958 Ms 7.9, and 1972 Ms 7.0. The nearest large earthquake recorded near the site is the 1958 Ms 7.9 (mb 7.4 [mb = body wave magnitude]) Icy Bay earthquake that was centered about 36 miles to the west. This earthquake triggered numerous rockfalls and slides, the largest of which was at Lituya Bay where the side of the mountain slid into the bay (ACOE, 1984).

3.3.2 Proposed Land Exchange Parcels

Long Lake

Although the geology of the Long Lake parcels is not well-documented, the WSNPP GMP outlines general characteristics that can be applied throughout the area. Generally, the geology within the park is extremely diverse (NPS, 1986). Rock formations include those of igneous, sedimentary, and metamorphic origins. Current geological theory suggests that the terranes of the region may have developed at much lower latitude and migrated northward and collided with the North American continent, causing uplift and formation of the massive mountain ranges in the park/preserve (NPS, 1986). Thus, much of the park/preserve is steep rock land, talus, and ice. On the lower slopes, the soils are predominantly loam and either poorly drained with permafrost or deep, well drained gravelly material over bedrock. Soils in valley bottoms are generally well-drained loamy alluvium on top of gravelly and sandy material (NPS, 1986).

Klondike Gold Rush

The landforms in KGNHP have been shaped by continental glaciation that occurred 10,000 years ago followed by recession (Paustian et al., 1994). The current high relief topography is reflected by remnant Alpine glaciers, U-shaped valleys, scoured Alpine summits, colluvial footslopes, and reworked floodplains. Current geologic processes include fluvial erosion, mass wasting, tectonism, and isostatic rebound.

The surficial geology consists of Quaternary glacial ice and colluvial, residual, alluvial, and glaciomarine deposits. Deposits are mostly derived from granitics and have been accumulating and reworked during glacial recession. Colluvial deposits generally occur at the base or footslopes of mountainslopes, residual deposits occur on the mountainslopes, alluvial deposits occur on the alluvial fans and floodplains, and glaciomarine deposits occur at uplifted Dyea estuary. Bedrock geology consists mainly of Late Jurassic and Early Cretaceous granitics, dominated by granodiorites. Bedrock is expressed in rock outcrop areas of the alpine and broken mountainslopes and locally underlain by surficial deposits.

KGNHP lies within the Coast Range batholith of southeastern Alaska. Soils in KGNHP vary considerable depending on whether they form in Alpine areas, mountainslopes, mountain footslopes, or on floodplains. Soils are characterized as undeveloped to very deep, well to poorly drained, and range in organic and mineral material content.

3.3.3 Wilderness Designation Parcels

In general, the bedrock geology of the GBNPP area is complex. The underlying bedrock is composed of terrain moved hundreds of miles from the south along three major, northwest-trending, lateral faults: the Chatham Strait Fault, the Border Ranges Fault, and the Fairweather-Queen Charlotte Fault (NPS, 1984). Widespread folds, metamorphism, and intrusions have complicated the stratigraphic record (NPS, 1984). These northwest-trending faults and fold axes are responsible for generating the region's northwesterly structural grain. USGS has grouped similar lithographic and structural characteristics into five geologic provinces: the Coastal, Fairweather, Geikie, Muir, and Chilkat provinces. The bedrock ranges in age from at least early Paleozoic to middle or late Pleistocene, with evidence of volcanic activity, intrusive rock formations, and faulting (NPS, 1984).

Unnamed Island near Blue Mouse Cove

Detailed information about geology and soils of the unnamed island near Blue Mouse Cove is limited. The island is situated in central Glacier Bay roughly 30 miles north of park headquarters in historically glaciated waters. Based on the retreat of glaciers in Glacier Bay, the island was exposed as recently as 1880 (NPS, 1984). USGS geologic maps indicate the island's bedrock is a biotite composite (Brew, unpublished digital maps).

Cenotaph Island

Cenotaph Island is located in Lituya Bay on the northwestern side of GBNPP on the Gulf of Alaska. Detailed information about geology and soils of Cenotaph Island is limited. General geologic characteristics of the island can be drawn from the surrounding formations as described by the collision of the North American plate with the Pacific plate resulting in many faults, rifts, folds, and tectonic uplift. An earthquake measuring Ms 7.9 occurred in 1958 and caused 39 million cubic yards of rock to plunge into Lituya Bay and generated a surge of water that rose 1,690 feet on the opposite wall of the inlet (ACOE, 1984).

The island has been sculpted by the expansion and recession of glaciers, as well as the erosion and deposition resulting from currents, tides, floods, and storms in the bay.

Alsek Lake

Alsek Lake lies in the northern portion of GBNPP along the Alsek River within the Yakutat-Lituya forelands, which spread seaward from the slopes of the St. Elias and Fairweather mountains, forming the vast coastal plain that encompasses Alsek Lake.

This gently sloping area is a complex of unconsolidated, poorly sorted glacial tills, alluvial, and marine deposits that have been uplifted by tectonics and isostatic rebound. Finer-textured sediments from glacial meltwaters, mixing with larger particles imbedded in icebergs, settled out in the area lakes to form glaciolacustrine deposits. Glacial recession has left behind many deglaciated surfaces and places for mineral soils to form in recently weathered materials.

The young, dynamic, and unstable landscapes in the vicinity of Alsek Lake are far from uniform, reflecting complex glacial processes that include glacier scouring, bedrock differences, subglacial water erosion, and depositional differences. Exposed bedrock, till, moraine, and outwash are common surfaces, and often experience high rates of erosion and mass wasting. Stream channels are active, often adjusting their courses due to debris torrents, channel down cutting, and other geomorphic processes. Enormous volumes of meltwaters pouring from the large ice sheets and glaciers, coupled with tectonic uplift and isostatic rebound, produce some of the highest sedimentation rates in the world. As a result, vast glaciofluvial aprons, known as forelands, have formed along the outer coast.

3.4 WATER QUANTITY AND QUALITY

3.4.1 Kahtaheena River Area (Project Area)

Freshwater resources within the project study area include the Kahtaheena River; a small, unnamed creek immediately west of the Kahtaheena River; Homesteader and Rink creeks farther to the west; and several small ravines draining into sloughs along Gustavus Flats (see figure 1-3 in appendix A).

With a drainage basin of 10.7 square miles (approximately 6,800 acres), as measured at USGS gage No. 15057580, the 8.7-mile-long Kahtaheena River arises at an elevation of about 3,000 feet msl and empties into Icy Passage approximately 11 miles east of the GBNPP entrance. The marine waters at the mouth of the Kahtaheena River are within GBNPP and currently under NPS jurisdiction and management. The average slope of the main channel is 5 percent and, from tidewater to 0.5 miles upstream, the channel has a low to moderate gradient. The Lower Falls marks the upper end of this short, tidewater section of stream. From that point upstream for 1.4 miles, the channel generally has a higher gradient and includes a number of significant falls and steep cascades.

The small, unnamed creek to the immediate west of the Kahtaheena River has a total length of 1.3 miles and drains an area of about 0.8 square miles (approximately 500 acres). Homesteader Creek is a 2.5-mile-long stream draining an area of 2.6 square miles (approximately 1,700 acres). Rink Creek is approximately 5.2 miles long and drains a basin of about 9.3 square miles (5,900 acres).

The Kahtaheena River is one of more than 310 coastal streams and rivers draining the 1,070-mile-long shoreline of GBNPP (Soiseth and Milner, 1993; personal communication from L. Sharman, Coastal Ecologist, GBNPP, with J. Thrall, Meridian Environmental, Anchorage, AK, on May 19, 2003). The majority of these 310 streams (73 percent) are small, having catchment areas less than 2,471 acres. Only 24 percent have catchment areas in the range from 2,471 to 24,710 acres. The Kahtaheena River, with a catchment area of approximately 6,800 acres, falls into the category of streams with basins of more than 2,471 acres.

3.4.1.1 Water Quantity. USGS has monitored flow at two gage sites on the Kahtaheena River. The upper gage (No. 15057580), at an elevation of 560 feet above msl, 1.7 miles upstream of the river's mouth, has a drainage area of 10.1 square miles. The lower gage (No. 15057590) was located at an elevation of 35 feet msl, less than 0.2 miles upstream of the river's mouth, and has a drainage area of 10.7 square miles. Flow data are available for the site near the mouth of the river for October 1998 to September 2001. Data are also available from the site above the Upper Falls for September 1999 through the present. USGS (Meyer et al., 2001, 2002; Bertrand et al., 2000) reports that the quality of the reported daily mean flows is within 15 percent of the actual flow ("fair") for many cases. However, the accuracy of estimated daily values, flows of more than 130 cfs above the Upper Falls, and flows of more than 150 cfs near the mouth have greater errors associated with them and are classified as "poor." Estimated values were relatively common during the low-flow period, particularly at the upper gage (e.g., 49 days in water year 2001). Flows of greater than the limit for "fair" quality data are relatively rare (e.g., 18 days in water year 2001 at the upper gage).

Based on this limited available hydrologic record, average annual discharge from Kahtaheena River is from 50 to 70 cfs (approximately 36,000 to 51,000 acre-feet) at the proposed diversion site (Meyer et al., 2003). High flows occur in May and June during snowmelt and again in the fall when heavy rains are common (table 3.4-1). Low flows commonly occur in the winter months (December through March) as the basin freezes. However, the basin is flashy, and flows vary widely within relatively short periods. The highest peak flow recorded to date was an instantaneous flow of 1,980 cfs on December 27, 1999. The lowest daily mean flow recorded by USGS was 5.5 cfs (March 10, 2000).

ACOE conducted an early investigation of the Kahtaheena River hydroelectric potential (ACOE, 1984). To support this effort, it collected stream flow data from 1982 to 1983; however, it did not report the data collected during this effort in the investigative report. Based on an analysis of the ACOE's measurements, mean monthly flows ranged from 9.6 cfs in March to 180 cfs in August (letter report from D.M. Hoch, Senior Hydrologist, Pertrovich, Nottingham & Drage, Inc., undated included in GEC, 1998). GEC (2001b) reported that the lowest flow measured by the ACOE was 3.5 cfs, which occurred in the winter of 1983. However, it should be noted that the quality of data collected by the ACOE was not indicated in any reports used in this analysis.

Table 3.4-1. Average monthly flow (cfs) measured in the Kahtaheena River. (Sources: Meyer et al., 2001, 2002, 2003; USGS, 2004)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Kahtaheena River near Tidewater (USGS Gage 15057590)[a]												
1998	--	--	--	--	--	--	--	--	--	103	23	25
1999	19	8	19	67	118	113	64	63	118	129	62	133
2000	20	12	25	41	94	115	83	66	105	78	52	40
2001	46	26	23	--	--	--	--	--	--	--	--	--
Kahtaheena River above Upper Falls (USGS Gage 15057580)[b]												
1999	--	--	--	--	--	--	--	--	128	121	55	128
2000	19	11	23	38	91	114	79	62	102	77	50	37
2001	40	23	20	24	58	103	62	27	85	68	23	21
2002	25	19	9	15	107	90	79	132	78	129	99	50
2003	55	23	nr[d]	nr	53	48	33	28	106	47	nr	nr

[a] Elevation 35 feet msl, less than 0.2 miles upstream of the river's mouth, and drainage area of 10.7 square miles. Monitoring was discontinued in early April 2001.

[b] Elevation 560 feet msl, 1.7 miles upstream of the river's mouth, and drainage area of 10.1 square miles. Values for periods after September 2002 are based on provisional data.

[c] Values for 2002 have been revised/updated since the DEIS was issued based on Meyer et al., 2003.

[d] nr = daily mean flow values not reported for several days in the month.

Various parties have modeled flows in the Kahtaheena River to evaluate the economic viability of constructing and operating a hydroelectric project in the basin. The results of several of these studies are compiled along with summaries of measured values reported by USGS in table 3.4-2.

As part of ACOE's (1984) investigation of the hydroelectric potential, it evaluated similarities between the drainage area of 21 USGS stations located in 19 streams in the Gustavus/Juneau area with the Kahtaheena River. Four stations in three streams (Hook Creek, Kadashan River, and Tonalite Creek) were selected to model Kahtaheena River flows. ACOE used the Hook Creek near the Tenakee USGS station, which has a drainage area of 8 square miles and is located approximately 50 miles south of the proposed project area, because it had the longest period of record and its drainage area was similar to the Kahtaheena River. Flows were estimated for the Kahtaheena River Basin by determining the relationship between mean annual flows for numerous gage sites in the region with their respective basin drainage areas and assuming that the percent of flow in each month was the same as for the Hook Creek near the Tenakee gage. These flow records were developed before availability of flow records for the Kahtaheena River, and thus were not calibrated to in-basin observations.

Table 3.4-2. Estimated average monthly flow (cfs) in the Kahtaheena River based on hydrologic analyses. (Sources: See footnotes)

	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sept**	**Oct**	**Nov**	**Dec**
Above the Upper Falls[a]	30	17	37	35	85	102	73	70	91	95	54	70
Near Tidewater[b]	29	15	22	54	106	114	74	64	112	103	46	66
ACOE[c]	24	34	48	55	111	78	35	27	64	130	85	41
HDR[d]	24	39	41	53	34	32	42	49	58	66	55	61
Coupe[e]	20	21	20	31	99	77	50	48	76	102	34	29
Preparers[f]	22	22	20	30	100	77	50	49	75	102	33	28

[a] Based on measurements reported by USGS for gage No. 15057580; period of record September 1999-December 2002. (Sources: USGS, 2000, 2001, 2002; data from B. Bigelow, Chief, USGS, Juneau, AK, to B. Mattax, Senior Aquatic Scientist, Louis Berger Group, Bellevue, WA, November 7, 2002)

[b] Based on measurements reported by USGS for gage No. 15057590; period of record October 1998-March 2001. (Sources: USGS, 2000; 2001; 2002)

[c] Modeled flows (period: 1966-1981) based on flows reported by USGS for Hook Creek Near Tenakee. (Source: ACOE, 1984)

[d] Modeled flows (period: January 1950-November 1964, January 1965-December 1967, January 1985-December 1985, January 1988-December 1991, and January 1998-December 1999) based on HEC-1 model using Gustavus airport precipitation and air temperature records. (Source: HDR, 2000)

[e] GEC modeled flows (period: water years 1968-2000) based on Coupe (2001) flow regressions in Kahtaheena River and the Kadashan River. (Source: GEC, 2001b)

[f] Preparers modeled flows (period: water years 1969-2001 with the exception of water years 1979, 1980, and 1996) based on Coupe (2001) flow regressions in Kahtaheena River and the Kadashan River. (Source: GEC, 2001b)

HDR (2000) modeled mean daily flows in the Kahtaheena River by applying the HEC-1 model developed by ACOE. HEC-1 was designed to simulate a runoff from single storm events; however, it includes several different options for modeling rainfall, losses, unit hydrographs, and stream routing. The model uses simplified approaches to address some processes, such as snowmelt, and to determine base flows, which reduces the accuracy of its predictions in some cases. HDR calibrated and evaluated the HEC-1 model's performance using flow data reported by USGS for September 9, 1998, through December 31, 1999, and precipitation and air temperature data from the Gustavus airport, located about 5 miles from the basin. Following calibration and evaluation of the HEC-1 model, HDR used the 24 years of precipitation and air temperature data from the Gustavus airport to model long-term conditions near the proposed dam site. Comparison of HDR's modeled flows with corresponding USGS reported values indicates that the model did not predict the high degree of variability in flows and did not accurately reflect the degree of seasonal variability (Coupe, 2001). This appears to be due to HEC-1's inability to recognize the difference between rain and snow in the basin, even though the model accounts for the processes of snow accumulation and melt. This limitation is likely exacerbated by the use of near-tidewater weather data from Gustavus airport, while the basin's headwaters are at 3,000 feet and the proposed diversion would be at an elevation of about 665 feet.

Because the HEC-1 modeled flows did not reflect the seasonal variability of USGS reported flows, Coupe (2001) conducted a correlation analysis using USGS recording gage records for the Kadashan River above Hook Creek (USGS No. 15106920) along with the 2-year record that was available for the Kahtaheena River to determine if the Kahtaheena River flow record could be extended in a more reliable manner. Basin flows were normalized as cfs/square mile of basin area to account for differences in drainage areas. Several different methods, including development of a single regression, seasonal regressions, and monthly regressions, were attempted to maximize the reliability of the estimates. The single regression showed relatively poor correlation ($r^2 = 0.65$). In addition, normalized flows were consistently lower in the Kahtaheena River than in the Kadashan River during November to April but were comparable or higher from May through October. Therefore, applying the single regression did not appear to be beneficial. As a result, Coupe’s preferred method to estimate flows for the proposed diversion site was to use two separate seasonal correlations. These seasonal correlations are displayed in figure 3-6, and their regression equations are presented below:

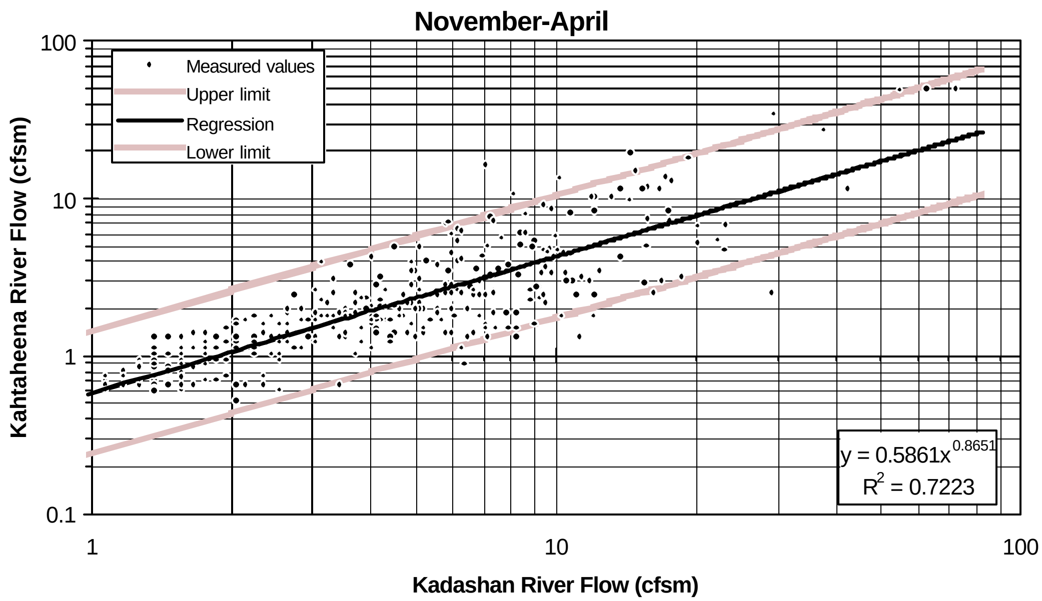
For November through April: $Q_{PD} = 0.5861 * Q_k^{0.8651}$ $R^2=0.72$

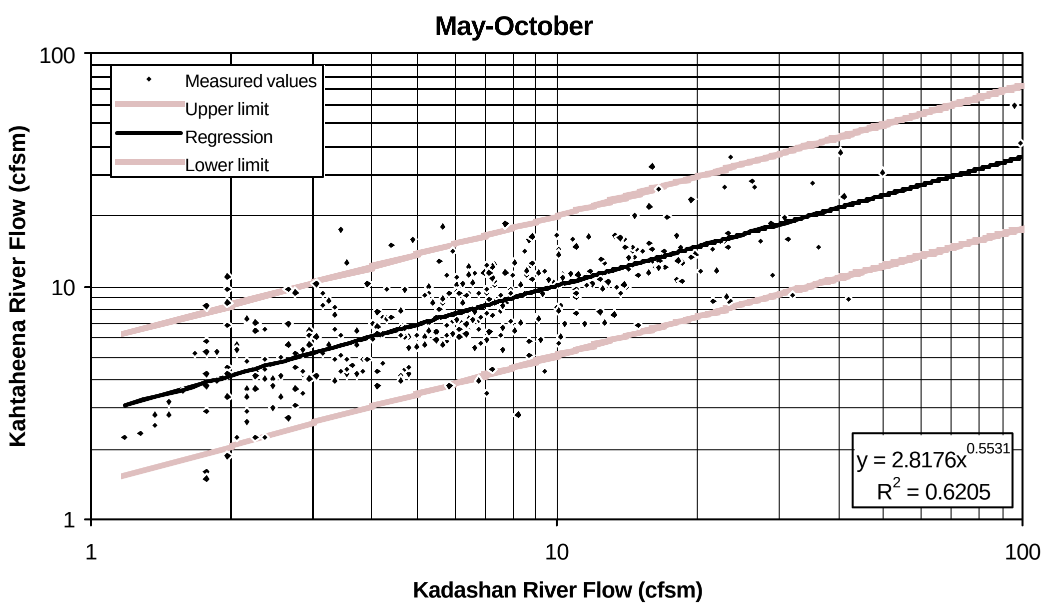
For May through October: $Q_{PD} = 2.8176 * Q_k^{0.5531}$ $R^2=0.62$

where Q_{PD} = Flow in Kahtaheena River in cfs/mi^2
Q_k = Flow in Kadashan River in cfs/mi^2

Coupe (2001) reported estimates of flow for October 1967 through September 2000. Since daily mean flows were not reported for the Kadashan River above Hook Creek gage (USGS No. 15106920) for WY 1979 and 1980, flows for the Kadashan River were first estimated from flows reported for Hook Creek near Tenakee4 (USGS No. 1516960) and regressions of flows at these Hook Creek and Kadashan gages (letter from R. Levitt, President, Gustavus Electric Company, Gustavus, AK, to M. Salas, FERC, Washington, DC, on January 2, 2004). Then flows were estimated for the Kahtaheena River by applying the seasonal regressions developed by Coupe to the reported and estimated Kadashan River flows. To avoid compounding errors in flow estimates introduced by use of regressions, we estimated flows for only the periods when flows were available for the Kadashan River gage. We note Kadashan River flow data for WY 1979, 1980, and 1996 were not available on the internet and have not been filed with the Commission; therefore, we do not include these years in our analysis.

Figure 3-6. Coupe's seasonal regressions with 95 percent confidence intervals of normalized flows (cfs per square mile) used to estimate flows at the proposed diversion dam. (Source: Preparers)





These regressions were developed with limited data and the correlation coefficients were fair at best. Therefore, we used USGS data for 1998 through 2002 to determine if correlations of the data set could provide more accurate estimates of daily mean flows, and to test whether the relationships developed by Coupe (2001) applied to the longer period of record. Results of this analysis had similar correlation coefficients for both seasonal periods, indicating that there would be little benefit in using regressions based on the longer period of record; therefore, we developed a database using Coupe's equations listed above for flow analysis. Using this method, we estimated Kahtaheena River daily mean flows for October 1968 through September 2001, with the exception of periods without flow data reported for the Kadashan River gage (i.e., October 1978 through September 1980 and October 1995 through September 1996). Our flow estimates are very similar to those of Coupe (2001) (see table 3.4-2).

Average monthly biases (modeled - measured) and average monthly relative standard deviations (RSDs) (error/measured value) of daily mean flows were determined to evaluate accuracy of modeled predictions (table 3.4-3). This evaluation indicates that modeled flows generally tend to be high in May and October and low in December, June, and July. Average monthly RSDs are 30 percent or less for the months of January to April, June, July, and November. The highest RSDs were for August and October. The combination of monthly bias and average RSDs indicates that modeled daily flows are most accurate for January to March and least accurate for August and October; however, predictions of overall monthly flows for August and October were relatively accurate.

Table 3.4-3. Accuracy of daily mean flow modeling results for the Kahtaheena River above the Upper Falls; period of record September 1999 through September 2001. (Source: Preparers)

	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sept**	**Oct**	**Nov**	**Dec**
Average observed flow[a]	30	17	37	35	85	102	73	70	91	95	54	70
Bias[b]	–4	–1	+3	–7	+12	–35	–18	+3	–10	+13	–14	–42
Average RSD[c]	21	21	29	26	41	29	30	69	37	51	29	40
% with RSD ≤25	61	67	60	38	55	42	47	34	48	42	53	24
% with RSD ≤50	97	93	84	95	77	97	76	61	78	65	80	68

a Period of record September 1999 – December 2002 (Sources: Meyer et al., 2000, 2001, 2002).
b Bias = modeled - measured.
c RSD = error/measured.

The errors associated with modeled daily mean flows are larger than for USGS reported flows; however, since the measured flow record is relatively short (<4 years), the modeled flows likely better reflect the range of conditions that could occur through a period comparable to a license term (i.e., 30 to 50 years). Therefore, flows derived using Coupe's equations were used for the analyses in this document.

3.4.1.2 Water Quality. NPS lands within the Kahtaheena River drainage basin remain essentially pristine; however, some private lands within the basin have been influenced by human activities related to use of a few foot trails, primarily by visitors to access the Lower Falls; 50.8 acres of previously logged land; and a small cabin and outhouse on private lands in the lower basin. Because of the location, timing, and extent of these activities, Kahtaheena River water quality is likely not noticeably degraded.

Two Native allotments exist in the vicinity of the proposed Project and are used for subsistence. The Mills allotment includes a portion of the Kahtaheena River downstream of the Lower Falls, and the George allotment includes a portion of the lower end of the unnamed creek to the east of Homesteader Creek. These allotments are used for subsistence activities including fishing and gathering along streams and waterways and obtaining drinking water from streams.

Table 3.4-4 shows water quality sampling results on three occasions representing low, mid, and high flows (Streveler, 2000). These results are typical for a relatively undisturbed, coldwater stream in southeastern Alaska. Measurements of total alkalinity (50 to 75 milligrams/liter [mg/L] as $CaCO3$) show the stream has a moderate capacity to limit fluctuations in pH, which ranged from 7.9 to 8.2 standard units. This is expected for a stream basin dominated by carbonate-bearing rocks (limestone) (see section 3.3, for discussion of karst geology). High total nitrogen values recorded in February are attributed to increased influence of peat bog areas under low flows (Streveler, 2000).

Table 3.4-4. Result of water quality sampling in the Kahtaheena River at low, intermediate, and high flows. (Source: Streveler, 2000)

		February 2000 14 cfs		**August 1999 50–70 cfs**		**November 1999 102 cfs**	
Parameter	**Analytical Method**	**Near Proposed Intake**	**Near Proposed Powerhouse**	**Near Proposed Intake**	**Near Proposed Powerhouse**	**Near Proposed Intake**	**Near Proposed Powerhouse**
Hardness (mg/L)	SM B2340B	68	73	64	68	53	53
Turbidity (NTUs)	EPA 180.1	0.37	0.33	1.5	6.1	1.5	6.1
Total dissolved solids (mg/L)	EPA160.1	130	130	75	72	57	82
Total suspended solids (mg/L)	EPA160.2	ND	ND	ND	ND	ND	ND
Nitrates (mg/L)	EPA 300.0	0.166	0.165	ND	ND	0.133	0.142
Phosphorus (mg/L)	EPA 365.2	ND	ND	ND	ND	0.020	0.032

Table 3.4-4. Result of water quality sampling in the Kahtaheena River at low, intermediate, and high flows. (Source: Streveler, 2000)

		February 2000 14 cfs		August 1999 50–70 cfs		November 1999 102 cfs	
Parameter	**Analytical Method**	**Near Proposed Intake**	**Near Proposed Powerhouse**	**Near Proposed Intake**	**Near Proposed Powerhouse**	**Near Proposed Intake**	**Near Proposed Powerhouse**
Grease and oil (μg/ml)	AK 102/103	ND	ND	ND	ND	ND	ND
DO (mg/L)	EPA 360.1	11.9	12.2	10.9	10.3	8.47	8.74
Total nitrogen (mg/L)	EPA 351.3	19.1	34.4	1.4	1.5	ND	ND
Iron (mg/L)	EPA 200.7	ND	ND	0.14	0.19	0.14	0.37
Conductivity (μg/ml)	EPA 120.1	140	150	125	125	105	110
pH	EPA 150.1	8.1	8.2	8.0	8.0	7.9	7.9
Total coliform (FC/100ml)	SM 9222B	4	ND	1.7	1.7	ND	ND
Total alkalinity (mg/L)	EPA 310.1	73	75	64	62	52	51

ND = None detected.
mg/L = milligram per liter
μg/mL = microgram per liter
NTU = nephelometric turbidity units

Table 3.4-5 shows water temperature data from the two USGS gage sites. Temperatures are typical for this stream type and location. Maximum temperatures from 12 to 14EC occur in the summer (June to September), and lows of 0 to 4EC are common during the rest of the year. The stream experiences icing during most of the period from mid-December through early April. For the Kahtaheena River above the Upper Falls, USGS (2003) reported thick layers of ice cover the entire stream during much of the winter (December to March). Although limited information exists on the extent of anchor ice in the river, USGS staff observed anchor ice in the river above the Upper Falls (personal communication from E. Neal, USGS, with C. Soiseth, GBNPP, on December 15, 2000). In late fall, early winter, and early spring, border ice occurs along the channel's edge. Large ice jams have been observed above the upper USGS gage site during spring thaw.

The state of Alaska sets its water quality criteria to protect numerous existing and potential beneficial uses including water supply for domestic, agriculture, aquaculture, and industrial purposes; recreation; and growth and propagation of fish and other aquatic life. Applicable water quality criteria are the most stringent criteria for any of the uses protected. Table 3.4-6 shows a summary of the most stringent numeric water quality criteria applicable to the Kahtaheena River. Limited sampling of Kahtaheena River water quality constituents at low and moderately high flows (see tables 3.4-4 and 3.4-5) indicates these waters conform to state standards.

Table 3.4-5. USGS reported monthly maximum, minimum, and mean water temperatures (°C) for the Kahtaheena River (1998–2000). (Sources: USGS, 2000; 2001; 2002)

		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept
Kahtaheena River Above Upper Falls (USGS Gage 15057580)													
October 1999	Max.	7.5	4.0	-	1.0	-	1.5	-	7.0	9.5	10.5	10.5	9.5
to	Min.	2.0	0.0	-	0.0	-	0.0	-	2.0	3.5	6.5	6.5	4.5
September 2000	Mean	5.5	2.5	-	0.0	-	0.3	-	4.0	6.0	8.4	8.9	7.5
October 2000	Max.	7.5	4.5	3.0	2.5	2.0	2.5	5.0	6.5	9.5	11.5	13.5	9.5
to	Min.	1.0	1.0	0.0	0.0	0.0	0.0	0.0	2.0	3.5	6.5	7.5	6.0
September 2001	Mean	4.6	3.0	0.8	1.4	0.2	0.4	1.5	4.0	5.7	8.2	9.8	7.8
Kahtaheena River Near Gustavus (USGS Gage 15057590)													
October 1998	Max.	8.0	5.0	2.5	0.5	0.5	1.0	4.0	5.5	9.5	12.5	13.5	10.0
to	Min.	2.0	0.0	0.0	0.0	0.0	0.0	0.0	1.5	3.0	6.0	7.0	4.5
September 1999	Mean	5.5	1.3	0.6	0.0	0.1	0.2	1.4	3.5	5.9	9.0	10.1	7.8
October 1999	Max.	7.5	4.0	3.5	1.0	1.0	2.5	5.5	7.5	10.5	11.0	11.0	9.5
to	Min.	2.5	0.0	0.0	0.0	0.0	0.0	0.5	2.5	4.0	7.0	7.0	4.5
September 2000	Mean	5.6	2.8	1.2	0.1	0.4	1.0	2.6	4.7	6.6	8.9	9.2	7.6
October 2000	Max.	8.0	5.0	3.5	3.0	2.5	2.5	-	-	-	-	-	-
to	Min.	1.5	1.5	0.0	0.5	0.0	0.0	-	-	-	-	-	-
September 2001	Mean	5.0	3.5	1.0	1.9	0.4	0.7	-	-	-	-	-	-

Note: Based on hourly measurements with an electronic water temperature recorder, values are reported to within 0.5°C. Continuous measurements were occasionally compared to cross-sectional measurements to ensure that they were representative.

Table 3.4-6. Selected Alaska numeric water quality criteria applicable to the Kahtaheena River. (Source: ADEC, undated)

Parameters	**Criteria**	**Beneficial Use(s)**
Temperature	≤15EC; Following maximum temperatures where applicable: Migration routes: ≤15EC Spawning areas: ≤13EC Rearing areas: ≤15EC Egg and fry incubation: ≤13EC	Domestic water supply; Aquaculture water supply and aquatic life
Dissolved oxygen	>7 mg/L in surface waters used by fish; >5 mg/L in intergravel waters to a depth of 20 cm	Aquatic life
pH	Must be between 6.5 and 8.5; vary ≤0.5 from natural conditions	Aquaculture water supply and aquatic life
Fecal coliform	≤20 FC/100 ml as 30-day-geometric mean; not more than 10% of the samples >40 FC/100 mL	Domestic water supply
Turbidity	≤5 NTU above natural conditions when natural turbidity ≤50 NTU; <10% increase when natural turbidity >50 NTU	Domestic water supply and contact recreation
Total dissolved solids	≤500 mg/L	Domestic water supply
Grease and oil	≤15 *u*g/L as total aqueous hydrocarbons in the water column; ≤10 *u*g/L as total aromatic hydrocarbons in the water column; surface waters and adjoining shorelines must be virtually free from floating oil, film, sheen, or discoloration.	Aquaculture water supply

In the state of Alaska, Alaska Department of Environmental Conservation (ADEC) has the responsibility and authority of protecting water quality, including enforcement of applicable water quality standards and review of the status of the state's water quality. ADEC prepares a list of water quality limited waterbodies that make up the section 303(d) list. Both the 1998 section 303(d) list (ADEC, 1999) and a draft of the 2002 303(d) list (ADEC, 2002) show that the Kahtaheena River has not been identified as water quality limited.

3.4.2 Proposed Land Exchange Parcels

Long Lake is located in the Copper River drainage in south central Alaska. The lake is connected to the Lakina River, a tributary of the Chitina River. The Chitina River is a major tributary of the Copper River, which originates from glacier and snow melt and has an average flow of approximately 20,000 cfs (NPS, 1986). The surface area of Long Lake is approximately 172 acres.

The potential exchange parcels along the Chilkoot Trail are all within the Taiya River drainage, near Skagway. The Taiya River Basin boundary coincides with the international border in Canada, and the river flows for approximately 18 miles in Alaska before emptying into the Taiya Inlet at the northern end of the Lynn Canal. The Taiya River is a glacier meltwater river that normally reaches its maximum discharge in late summer. Mean annual discharge is approximately 1,134 cfs (Paustian et al., 1994). Glacial melt and heavy summer rains lead to rather frequent flooding. The maximum discharge of the Taiya River is estimated at approximately 25,000 cfs (Paustian et al., 1994). Turbidity is generally high in the summer months, due to glacial runoff, and low during the winter. Portions of the river tend to freeze during the winter (NPS, 1996).

3.4.3 Wilderness Designation Parcels

Neither the unnamed island near Blue Mouse Cove or Cenotaph Island has appreciable freshwater resources. According to USGS maps for the area, the unnamed island includes several small lakes with outlets to Glacier Bay.

Alsek Lake is connected to the Alsek River, which originates in the Yukon Territory in Canada and flows for approximately 155 miles in a southerly direction before emptying into the Gulf of Alaska. Limited information pertaining to water quality in the Alsek River (EPD, 1996) suggests that there has been no apparent degradation.

3.5 AIR QUALITY

The U.S. Environmental Protection Agency (EPA) and the state, through the ADEC, regulate air quality in the proposed project area. EPA has established national ambient air quality standards (NAAQS) for criteria pollutants that include particulate matter less than 10 microns (F) in size (PM_{10}), sulfur oxides measured as sulfur dioxide (SO_2), carbon monoxide (CO), ozone (O_3), nitrogen dioxide (NO_2), and lead (Pb).

To identify an area by its air quality, EPA designates all geographic areas in the state as attainment, nonattainment, or unclassifiable. An area is designated attainment for a particular contaminant if its air quality meets the NAAQS for that contaminant. The areas considered in this EIS (including the Kahtaheena River, the proposed land exchange parcels, and the wilderness designation parcels) are located in the Skagway-Hoonah-Angoon census area (see section 3.16, *Socioeconomics*, for more information on this area), which is in attainment for all the criteria pollutants. EPA reports that, in 1999 (the latest year available), the total NO_x, CO, SO_2, PM_{10}, and volatile organic compounds (VOCs) emissions for the entire census area were 1,417; 43,812; 408,825; and 17,851 tons per year (tpy), respectively (from EPA's AirData website, http://www.epa.gov/air/data/).

The areas considered in this EIS also are located in the Southeast Alaska Intrastate Air Quality Control Region and in a Class II area as measured by standards for the prevention of significant deterioration (PSD) of air quality. The PSD Class II designation allows for moderate growth or degradation of air quality within certain limits above baseline air quality standards. Industrial sources proposing construction or modifications, such as GEC's proposed project, must demonstrate that the proposed emissions would not cause significant deterioration of air quality in all areas.

3.6 FISHERIES

3.6.1 Kahtaheena River Area (Project Area)

The Kahtaheena River downstream from the Lower Falls, a large waterfall located 2,379 feet above tidewater, supports populations of pink, chum, and coho salmon; Dolly Varden char; cutthroat trout; and coast range sculpin (Flory, 1999). The Lower Falls consist of two vertical steps, 40 and 60 feet high, which block anadromous fish migration. Resident (non-migratory) Dolly Varden is the only species of fish present above the Lower Falls. A second large (approximately 40 to 45 feet high) waterfall (10 km Falls), 6.2 miles above tidewater and upstream of the proposed project area, is considered the upstream limit of Dolly Varden distribution (see figure 3-7 in appendix A); however, only limited fish sampling has occurred above RM 4.3.

Between the Lower Falls and 10 km Falls, there are several smaller waterfalls and steep cascades. Five separate falls 5 feet or higher exist between RMs 1 and 2. A sixth falls, approximately 6.5 feet high, occurs at RM 6.6, above the proposed project diversion site. These falls and cascades may partially isolate subpopulations of resident char, preventing or inhibiting upstream movement.

In addition to the Kahtaheena River, Rink Creek, Homesteader Creek, an unnamed creek, and several small ravines feeding sloughs on Gustavus Flats lie within the general project area (see figure 1-3 in appendix A). Table 3.6-1 lists the species of fish and the likelihood of their occurrence in these streams (Flory, 2001). Figure 3-8 shows seasonal use of the stream systems by species and life stage.

Table 3.6-1. Species of fish reported from project-area streams.[a] (Source: Flory, 2001)

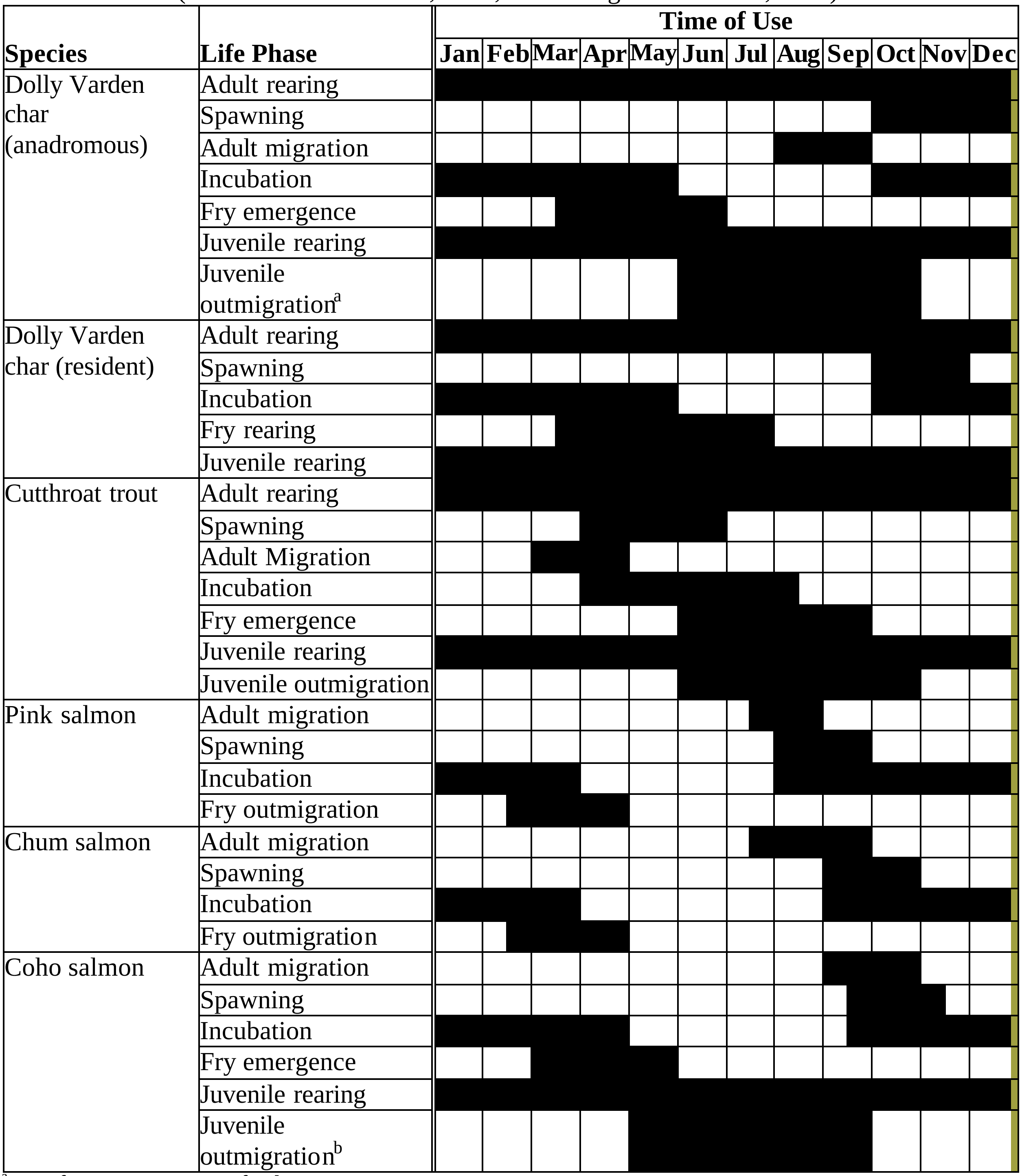
Species	Reach 1	Reach 2 and Above	Homesteader Creek	Rink Creek	Gustavus Flats Sloughs	Unnamed Creek
Dolly Varden char (*Salvelinus malma*)	P	P	P	L	L	I
Cutthroat trout (*Salmo clarki*)	P	A	P	P	I	I
Pink salmon (*Oncorhynchus gorbuscha*)	P	A	P	P	I	L
Chum salmon (*O. keta*)	P	A	P	P	L	L
Coho salmon (*O. kisutch*)	P	A	P	P	P	P
Coast range sculpin (*Cottus aleuticus*)	P	A	P	P	P	P

[a] P = presence confirmed, A = absent, L = annual use likely, I = intermittent use likely.

3.6.2 Aquatic Habitat in the Kahtaheena River

Flory (1999; 2001) divided the lower 4.5 miles of the Kahtaheena River into eight study reaches using the Tongass National Forest channel type classification system (Paustian et al., 1992). Four of these reaches (comprised of several channel types) are located below the proposed diversion site (reaches 1 through 4), and four are located above the proposed diversion (reaches 4 through 8) (see figure 3-7 in appendix A). The following section contains a description of channel types and aquatic habitat in each of these reaches and in a reach located immediately below the 10 km Falls (the upstream reach). Table 3.6-2 summarizes some of the characteristics of the channel types identified in the Kahtaheena River as they pertain to Dolly Varden char usage. Habitat surveys were completed between May 28 and September 29, 1999, and flows during the surveys ranged from 40 to 55 cfs.

Figure 3-8. Life stage periodicities for the fish of the Kahtaheena River and nearby streams. (Source: Streveler et al., 1994; Armstrong and Streveler, 1998).



[a] After 1 to 4 years in fresh water.
[b] After 1 to 3 years in fresh water.

Table 3.6-2. Characteristics of the channel types identified in the Kahtaheena River. (Source: Summarized from Paustian et al., 1992).

Channel Type	Gradient	Hydrologic Function	Available Rearing Habitat	Available spawning Habitat	Use by Dolly Varden char
ES3	Low (0–3%)	Dep.[a]	Moderate	Moderate	Spawn/rear
LC1	Low (<2%)	Dep./Trans.	High	High	Rear
LC2	Mod. (5%)	Trans.[b]	High	High	Rear
MC1	Mod. (1–6 %)	Trans.	Low	Low	Rear (summer)
MC3	Mod. (>4 %)	Trans.	Low	High	Rear
MM1	Mod. (2–6%)	Trans.	High	High	Spawn
FP3	Low (<2%)	Dep.	High	High	Rear

[a] Sediment deposition.

[b] Sediment transport.

3.6.2.1 Reach 1. The lower Kahtaheena River, downstream from the Lower Falls, contains three distinct channel types: a 490-foot-long "narrow large substrate estuarine channel" (ES3); a 1,394-foot-long "moderate gradient contained narrow valley channel" (LC2); and a 984-foot-long section of "moderate gradient deeply incised contained channel" (MC3) (table 3.6-2).

Aquatic habitat was not quantified in the ES3 subreach; however, Flory (1999) noted that it is primarily riffle habitat. The LC2 subreach is also dominated by riffle habitat (72 percent) with substrate consisting of large gravel and cobble. The MC3 subreach contains a mixture of riffle and pool habitat with some cascades. "Good" pink salmon spawning habitat is located in portions of both the LC2 and MC3 subreaches. The Lower Falls, a barrier to anadromous fish migration, is located at the upstream end of the MC3 subreach. Overall, Reach 1 contains 1.50 acres of usable habitat (0.47 acre of pool, 0.92 acre of riffle, 0.04 acre of glide, and 0.07 acre of cascade) (table 3.6-3).

3.6.2.2 Reach 2. Reach 2 of the Kahtaheena River contains 2 distinct channel types: a 755-foot-long LC2 channel that extends upstream from a large log jam located just above the Lower Falls (about 60 feet high), and a 1,244-foot-long MC3 channel located immediately above the LC2 channel (table 3.6-2).

The LC2 subreach contains extensive pool habitat around and beneath the log jam and a mix of pool and riffle habitat with some glide habitat located throughout the remaining section. Nineteen percent of the subreach is pool, and 50 percent is riffle. Fine gravel, overhead shading, and 5- to 6.5-feet-deep pools provide both spawning and overwintering habitat. Flory (1999; 2001) speculated that this subreach contains some of the best habitat available for the resident Dolly Varden char.

Table 3.6-3. Kahtaheena River fisheries study area, available habitat[a] by type and river reach. (Source: Flory, 1999)

Reach	Pool (ac)[b]	Riffle (ac)[c]	Glide (ac^2)	Cascade (ac)[d]	Total (ac)
1	**0. 47** (31 %)	**0.92** (61 %)	**0.04** (3 %)	**0.07** (5 %)	**1.50**
2	**0.15** (11 %)	**0.77** (56%)	**0.25** (18%)	**0.20** (15 %)	**1.37**
3	**0.53** (22 %)	**0.64** (26 %)	**0.02** (1 %)	1**.24** (51 %)	**2.43**
4	**0.18** (7%)	**1.88** (72 %)	**0.14** (5%)	**0.40** (15%)	**2.60**
5	**0.00** (0 %)	**0.13** (14 %)	**0.20** (22 %)	**0.57** (63 %)	**0.90**
6	**0.01** (1 %)	**1.80** (78 %)	**0.50** (22 %)	**0.00** (0 %)	**2.31**
7	**0.09** (7 %)	**0.68** (52 %)	**0.53** (41 %)	**0.00** (0.1 %)	**1.30**
8	**0.00** (<0.01 %)	**0.41** (74 %)	**0.11** (20%)	**0.04** (6 %)	**0.56**
Total	**1.43 (12%)**	**7.23 (57%)**	**1.79 (14%)**	**2. 52 (18%)**	**12.97 (100%)**

[a] Estimate of total available stream habitat is low as Flory's study area did not include a 3,015-foot-long segment between Reach 5 and Reach 6 or habitat above Reach 8.

[b] Combines Flory's shallow and primary pool classifications.

[c] Combines Flory's primary and gentle riffle classifications.

[d] Combines Flory's primary, step, and chute cascade classifications.

Riffles (62 percent) and cascade (30 percent) comprise the majority of the habitat within the MC3 subreach (Flory, 1999). Substrate ranges from cobble to boulder with gravel restricted to small areas behind large boulders or rock outcrops. MC3 channels have low rearing habitat potential for Dolly Varden char, although they have high value as spawning habitat (Paustian et al., 1992). Reach 2 contains 1.37 acres of usable habitat (0.15 acre of pool, 0.77 acre of riffle, 0.25 acre of glide, and 0.20 acre of cascade) (table 3.6-3).

3.6.2.3 Reach 3. Reach 3 is approximately 5,540 feet long. It has an MC3 channel type with a narrow channel and steep gradient (up to 6 percent) (Flory, 1999) (table 3.6-2). Aquatic habitat is a mixture of cascades (51 percent), chutes (9 percent), and deep pools (20 percent). Substrate is mainly bedrock with some gravel accumulating in the pools. Five sets of falls in this reach, all measuring more than 5 feet high, may prevent upstream fish movements, partially isolating subpopulations of resident char. A 1,723-foot-long subreach above the most upstream of these falls provides an area of lower gradient and higher quality habitat, including some large woody debris. Almost no woody debris occurs in the subreaches below the Upper Falls (40 to 45 feet high). Reach 3 contains 2.43 acres of habitat (0.53 acre of pool, 0.64 acre of riffle, 0.02 acre of glide, and 1.24 acres of cascade and chute) (table 3.6-3).

3.6.2.4 Reach 4. Reach 4 of the Kahtaheena River is 3,015 feet long. It has an LC2 channel type with lower canyon walls and lower gradient than Reach 3 (table 3.6-2) (Flory, 1999). Aquatic habitat within this section of river is primarily riffles. Substrate is relatively large (>8 inches in diameter) with some areas of exposed bedrock. At the upper end of the reach, an island and several large woody debris dams provide deep pools and good cover for fish. Flory (1999; 2001) considers this area to contain some of the best habitat available in the river above the Lower Falls. GEC (2001b) classifies this section of reach as narrow, low gradient flood plain channel (FP3). Reach 4 contains 2.60 acres of usable habitat (0.18 acre of pool, 1.88 acres of riffle, 0.14 acre of glide, and 0.40 acre of cascade) (table 3.6-3).

3.6.2.5 Reach 5. Reach 5 is 755 feet long. It has a "narrow shallow contained channel" of moderate gradient (MC1) (table 3.6-2). The sides of the stream channel flatten out, and the gradient is noticeably lower than that observed in reaches 2 through 4. Cascades (60 percent) and glides (22 percent) are the dominant habitat types. There are no pools in this reach. A 6.5-foot-high falls, located near the middle of the reach, likely prevents upstream movement of fish. Substrate is dominated by 8 to 10 inch cobble, and spawning habitat is absent (Flory, 1999; 2000). MC1 channels have low value as spawning and rearing habitat for Dolly Varden char (Paustian et al., 1992). Reach 5 contains 0.90 acre of usable habitat (0.13 acre of riffle, 0.20 acre of glide, and 0.57 acre of cascade) (table 3.6-3).

3.6.2.6 Reach 6. Reach 6 of the Kahtaheena River is 2,536 feet long. It has a "low gradient contained" (LC1) channel type (table 3.6-2) (Flory, 1999). Nearly 80 percent of the aquatic habitat within this reach is low gradient riffle. Pool habitat is restricted to the channel margins of this reach, and substrate is primarily large (9.6 to 16 inch diameter cobble) and unsuitable for Dolly Varden spawning. Reach 6 contains a total of 2.31 acres of usable habitat (0.01 acre of pool, 1.80 acres of riffle, and 0.50 acre of glide) (table 3.6-3).

3.6.2.7 Reach 7. Reach 7 is a 3,015-foot-long "narrow mixed control channel" (MM1) with abundant, large woody debris (table 3.6-2) (Flory, 1999). The channel morphology is complex and consists mainly of a mix of riffles (52 percent), glides (41 percent), and pools (7 percent). Water depths in this reach vary from 0.7 to 6.5 feet, and substrate is predominantly 0.4 to 1.2-inch diameter gravel. Reach 7 contains a total of 1.30 acres of usable habitat (0.09 acre of pool, 0.68 acre of riffle, and 0.53 acre of glide) (table 3.6-3).

3.6.2.8 Reach 8. Reach 8 is a 1,700-foot-long MC1 channel type (table 3.6-2) (Flory, 1999). This reach has less woody debris than does Reach 7, and riffle and glide dominate the habitat. Reach 8 contains 0.56 acre of usable habitat (0.41 acre of riffle, 0.11 acre of glide, and 0.04 acre of cascade) (table 3.6-3).

3.6.2.9 Upstream Reach. Habitat conditions in the Kahtaheena River above Reach 8 are not well documented. Using aerial photography GEC (2001b) estimated that there are an additional 3 acres of useable habitat in the 1.9-mile-long section of river between Flory's study reaches and the 10 km Falls.

Based on limited field observations, Flory (1999; 2000) reported that the habitat above Reach 8 is similar to that found in Reach 7. Riffle and glide habitat predominate, and there is an extensive amount of large woody debris, with debris jams occurring approximately every 65 feet (Flory, 1999). Assuming that habitat type percentages in this area are similar to that reported for Reach 7 (Flory, 1999), an additional 0.21 acre of pool, 1.5 acres of riffle, and 1.23 acres of glide habitat exist in the reach between Reach 8 and the 10 km Falls.

Combining Flory's (1999) measured habitat numbers from table 3.6-3 with this estimate of additional habitat in the upstream area above Reach 8 provides an estimate for the total area of habitat available in the fish-bearing section of the Kahtaheena River of 15.4 acres. Table 3.6-4 shows this total broken down by river section and habitat type.

Table 3.6-4. Estimated total area of habitat in the Kahtaheena River between tidewater and the upper limit of fish-bearing stream (10 km Falls). (Source: Based on Flory, 1999, modified by preparers).

	Pool (acres)	Riffle (acres)	Glide (acres)	Cascade (acres)
Reach 1 (anadromous)	0.5	0.9	0.04	0.1
Reaches 2 to 8	1.0	6.3	1.7	2.0
Upstream area	0.2	1.5	1.2	0
Total	1.7	8.7	2.9	2.1

3.6.3 Fish Populations

3.6.3.1 Coho Salmon. Coho salmon were observed in the Kahtaheena River below the Lower Falls in 1999 and 2000 (Flory, 1999; 2001). According to GEC (2001b), 100 coho salmon were also observed in Reach 1 during an ADFG escapement survey on August 7, 1966. However, Armstrong and Streveler (1998) noted that the 1966 survey was conducted during a time when adult coho salmon would not be expected to occur in the river, and concluded therefore that this record likely is in error.

Flory (1999; 2001) observed spawning coho salmon from September through November. A total of 30 coho salmon were observed in 1999, with a peak of 24 fish reported in mid-October. In 2000, 45 coho salmon were observed, with a peak of 20 fish in late October. During both years, coho salmon were using 4 to 5 inch gravel in the upper section of Reach 1. Flory's estimate of the total spawning run in 2000 was 100 fish. This is in close agreement with the estimate developed by Armstrong and Streveler (1998). They estimated an annual coho spawning run totaling less than 100 fish.

3.6.3.2 Pink Salmon. Escapement counts conducted by ADFG and NPS have documented pink salmon spawning in the lower section of the Kahtaheena River on numerous occasions over the past 35 years (Armstrong and Streveler, 1998; Streveler et al., 1994). As is the case throughout the Icy Passage area, pink salmon in the Kahtaheena River are most abundant during odd year runs. Historical, odd-year, single-day escapement counts, as summarized in Streveler et al. (1994), commonly were in the thousands, with a high of 6,000 fish observed in 1969. Even-year escapement counts were more commonly on the order of 200 to 300 fish with a high of 800 fish reported in 1972.

Pink salmon spawning occurs from July through late September. Flory (1999; 2001) estimated the total spawning population to be approximately 17,000 in 1999 and just over 900 in 2000. Armstrong and Streveler (1998) previously estimated that spawning runs of more than 10,000 pink salmon could "occasionally occur in the Kahtaheena River."

During 1999, spawning by the larger, odd-year run was observed to occur throughout the entire stretch of Reach 1. In 2000, spawning activity of the smaller, even-year population was confined to the lower, intertidal zone, over areas with 3- to 4-inch gravel substrate.

3.6.3.3 Chum Salmon. Historical one-day escapement counts for the Kahtaheena River have noted the presence of chum salmon in at least 10 different years since 1966. Flory (1999; 2001) documented chum salmon spawning in Reach 1 from mid-July through August, estimating total spawning population on the order of 100 fish in 1999 and 700 fish in 2000. In both years, spawning activity was concentrated in the upper portion of the reach, in areas of spawning gravel ranging from 4 to 5 inches in diameter. Armstrong and Streveler (1998) rate the lower reach of the Kahtaheena River as having moderate value for chum spawning and speculate that runs of chum in excess of 2,000 fish "may occasionally occur."

3.6.3.4 Cutthroat Trout. Flory (1999; 2001) documented cutthroat trout presence in Reach 1 of the Kahtaheena River in 1999 and 2000. In 1999, "20 to 30 Dolly and cutthroat" were reported below the Lower Falls (Flory, 1999). In 2000, a total of 57 cutthroat trout were observed during 12 surveys in this same reach (Flory, 2001). Spawning of cutthroat trout was not observed in Reach 1, although juveniles were taken in minnow traps. Flory (2001) suggests that cutthroat likely enter the lower river when salmon are spawning to feed on salmon eggs and migrate to the sea or into other streams when this food source is no longer available. Armstrong and Streveler (1998) rate the lower Kahtaheena River as having “negligible value” as spawning habitat for cutthroat trout.

3.6.3.5 Anadromous Dolly Varden Char. The Kahtaheena River supports two distinct populations of Dolly Varden char. The lower river (Reach 1) supports an anadromous population; a resident population exists above the Lower Falls. A total of 108 anadromous Dolly Varden were observed in Reach 1 during 3 days of snorkel surveys in August and September 2000 (Flory, 2001). The maximum number observed during a single survey was 54 fish on September 1. "Foot surveys" conducted between July 29 and November 4, 2000, documented a total of 243 Dolly Varden in Reach 1. The maximum single-day count was 84 fish in early September (Flory, 2001).

Spawning Dolly Varden char were not observed in Reach 1, although juveniles were captured in this reach in 1999 and 2000. No Dolly Varden char were seen in Reach 1 after September, and no juveniles were trapped during winter months leading Flory (2001) to speculate that they do not spawn in the lower river. Armstrong and Streveler (1998) rate the lower Kahtaheena River as “poor” habitat for anadromous Dolly Varden.

3.6.3.6 Resident Dolly Varden Char. A separate population of resident Dolly Varden char also exists in the Kahtaheena River upstream of the Lower Falls. These fish are reported to be slower growing and smaller than the anadromous population present in the lower river (Flory, 1999; 2001). Leder (2001) compared allele[29] frequencies for resident Dolly Varden char taken from the Kahtaheena River to anadromous populations in the Salmon and Indian rivers and found that the resident population had a lower number of alleles at the loci tested than did the anadromous forms. However, no comparisons were made to anadromous Dolly Varden char from the lower Kahtaheena River.

An estimated 6,500 resident Dolly Varden char occupy the river between the Lower Falls and 10 km Falls (GEC, 2001b). Although, as previously indicated, limited sampling above Reach 8 makes it impossible to determine with certainty the distribution of fish in the upper river. Additional falls in the river above the Lower Falls may partially isolate resident Dolly Varden subpopulations (although upstream fish may be able to move downstream) so up to five separate subpopulations may exist in the river. Five of these isolating falls occur in Reach 3, and one occurs in Reach 5.

Leder (2001) analyzed genetic variation of resident Dolly Varden at the Log Jam and Big Woods sampling locations along the Kahtaheena River and from two nearby anadromous populations (the Salmon River near Gustavus and Indian River near Sitka). Leder (2001) looked at microsatellite markers at five genetic loci. Samples from the

29 An allele is one of two or more alternative forms of a gene occupying the same position (locus) on a chromosome, which result in different gene products and thus different physical appearances and constitutions (phenotypes).

resident Kahtaheena River populations were genetically distinct from the anadromous populations. The genetics of fish sampled at the two locations within the Kahtaheena River also were found to be potentially different. Genetic differences were found at one of the two gene loci tested, but testing was not sufficient to determine conclusively that the population between the Lower and Upper Falls is genetically distinct from the population above the Upper Falls.

The population between the Lower and Upper Falls exhibited a 20 percent allele frequency for allele 232, while the population above the Upper Falls was homozygous at that locus. The absence of this allele in the upper population suggests fish at that site may be reproductively isolated from fish at the lower location. Likely isolating factors would include a 40 to 45 feet high waterfall (the Upper Falls) and the steep stream gradient throughout the canyon reach. Alleles from both resident populations were polymorphic for the Coc3 locus, which also suggests that fish from above the Upper Falls may be genetically distinct from resident fish collected from between the Lower and Upper Falls. However, Leder (2001) indicated that this locus is perhaps too variable for such small sample sizes to draw reliable inferences.

Griswold (2003) examined genetic diversity of Dolly Varden and coastal cutthroat trout among several locations in Prince William Sound, Alaska, using mitochondrial DNA, microsatellite markers, and allozymes. Although genetic variation among Prince William Sound anadromous populations was low (4 percent), Griswold (2003) was able to discern large differences among resident and anadromous populations using microsatellites and allozymes.

Average heterozygosity and mean number of alleles per locus were lower for barrier falls isolated Dolly Varden in Hawkins and Power creeks than for 14 other Prince William Sound sample groups and one Prince of Wales Island group. Waterfall barriers were believed to be the population isolation mechanisms, and alleles were fixed for these two populations based on allozymes and microsatellites. Statistical (cluster) analysis showed that resident populations at Hawkins and Power creeks were consistently different from all other sites. Griswold suggested that waterfall barriers at Power and Hawkins creeks are high enough to significantly reduce the survival rates of fish passing over these barriers, which may limit downstream gene flow. The height of the Upper Falls suggests that the same condition could exist in the Kahtaheena River.

Kahtaheena River Dolly Varden may be the only isolated resident populations of Dolly Varden within GBNPP. However, another recently reported, but yet unverified, population may exist within Stonefly Creek in Wachusett Inlet (personal communication from Dr. A.M. Milner, University of Birmingham, United Kingdom, with C. Soiseth, GBNPP, February 6, 2004). Stonefly Creek (unofficially named) is on the northern shore of Wachusett Inlet approximately 7.5 miles west of its mouth. If these fish are verified as resident Dolly Varden, they would represent the only other known Dolly Varden population isolated by barrier falls in the park. However, in contrast to Kahtaheena River fish, the Stonefly Creek population is likely very young as the drainage was deglaciated less than 40 years ago (Milner et al., 2000).

The Kahtaheena River Dolly Varden population is also one of few known resident populations isolated by waterfalls in northern southeast Alaska. Northern southeast Alaska appears to be "relatively depauperate of isolated stream-resident salmonid populations "(personal communication from K. Hastings, Fisheries Biologist, FWS, with C. Soiseth, May 4, 2004) compared with central southeast Alaska. Hastings wrote that relatively low gradient fish habitat upstream of low elevation waterfalls is more common in the rolling topography of central southeast Alaska, where many (>100) isolated populations of stream-resident salmonids have been identified. The steeper topography of northern southeast Alaska typically precludes low gradient fish habitat above waterfalls; or, if present, the potential habitat is at such a high elevation that fish would never have been able to colonize it from saltwater prior to Holocene uplift.

Hastings also indicates that the Kahtaheena River is one of only three known isolated populations of stream-resident Dolly Varden within a 50 mile radius of Gustavus. Six additional populations have been reported[30] by U.S. Forest Service culvert survey crews but have not been verified.[31] One of these is at the southern end of the Chilkat Peninsula, and the remaining five are on Northeast Chichagof Island. In contrast, within a 50 mile radius of Petersburg (central southeast Alaska), there are 18 isolated populations that are confirmed and an additional eight populations reported that have yet to be verified.

Resident Dolly Varden char in the Kahtaheena River appear to prefer pool habitats and are most numerous in pools associated with large woody debris (Flory, 2001). In 2000, 85 percent of the Dolly Varden char were observed in pool habitats (table 3.6-5).

Table 3.6-5. Summary of snorkel survey data for resident Dolly Varden char, summer 2000. (Source: Flory, 1999; 2001)

Reach Surveyed	Fish in Pools	Fish in Riffles	Total Fish
2	79	6	85
3	29	0	29
4	187	47	234
Totals	295	53	348

30 U.S. Forest Service culvert survey crews reported Dolly Varden at a location that appears to be above a barrier. Neither fish presence nor existence of the barrier has been conclusively established.

31 Sampling bias is prevalent because culvert survey crews only work in roaded areas. However, given that limited information exists for these types of populations and no systematic surveys have yet been conducted, this limited information represents the best currently available information.

As table 3.6-6 shows, minnow trap sampling in the river above the Lower Falls area also indicated that Dolly Varden char prefer areas with pools and woody debris. The sites with the highest catch per unit effort (above 2.0), include the Log Jam in Reach 2, The Islands area in Reach 4, the Big Woods in Reach 7, and the Five Spot above Reach 8. All these sites are characterized by Flory (1999; 2001) as having extensive pool habitat with ample large woody debris.

Table 3.6-6 Minnow trap catch data for resident Dolly Varden char in the Kahtaheena River above the Lower Falls. (Source: Flory, 1999; 2001)

Stream Reach		Date	Number of Traps Fished	Soak Time per Trap (hr)	Total Soak Time (hr)	Total Number of Fish Taken	Catch per Unit Effort
2	Log Jam[a]	8/26/99	13	2.0	26	84	3.2
		8/29/99	8	19.0	152	48	0.3
		11/5/99	13	2.5	32.5	34	1.0
		8/6/00	12	2	24	136	5.7
3	Canyon	7/29/99	12	17.0	204	9	0.0
	Notch[b]	9/27/99	6	1.0	6	9	1.5
	Canyon Notch	8/3/00	12	2	24	30	1.3
	Canyon Notch						
4	Horseshoe[c]	7/28/99	9	23.0	207	17	0.1
	Horseshoe	9/27/99	6	1.0	6	11	1.8
	Islands[d]	8/29/99	8	18.0	144	35	0.2
	Islands	8/30/99	6	23.0	138	25	0.2
	Islands	9/27/99	7	1.0	7	69	9.9
	Islands	11/4/99	5	2.5	12.5	10	0.8
	Horseshoe	8/4/00	12	2	24	24	1.0
	Islands	8/4/00	12	2	24	137	**5.7**
7[a]	Big Woods[e]	6/29/99	7	23.0	161	26	0.2
		6/30/99	6	22.0	132	29	0.2
		7/27/99	9	21.5	193.5	75	0.4
		9/26/99	7	5.0	35	42	1.2
		11/6/99	6	1.5	9	34	3.8
		8/4/00	12	2.0	24	101	4.2
Above 8	Five spot[f]	8/29/99	2	1.0	2	20	10.0
	Five spot	9/26/99	5	1.5	7.5	25	3.3
	Tributary	9/30/99	1	4.0	4	9	2.3
	Finger Woods[g]	9/30/99	5	1.5	7.5	25	3.3

[a] Extensive pool habitat with some fast riffles.
[b] Area of large woody debris with some gravel.
[c] Riffle habitat with small pools.
[d] Mixture of pool and riffles with extensive large woody debris.
[e] Abundant large woody debris with deep pools and good spawning gravel
[f] Good large woody debris and pool habitat.
[g] Habitat not described by Flory (1999; 2001).

Flory (1999) conducted mark recapture sampling in three areas of the river above the Lower Falls in 1999. Sampling results show population estimates of 408 for the Log Jam area of Reach 2, between 323 and 392 for the Islands area of Reach 4, and 963 fish for the Big Woods area of Reach 7 (1,763 fish from parts of 3 of the 8 study reaches).

GEC presents two population estimates for resident Dolly Varden char for the river between the Lower Falls and the 10 km Falls. The first was obtained by application of a modification of Paustian's (1990) method for estimating fish habitat capability based on channel type and average active channel width. This modification uses Flory's (1999) measured habitat areas rather than average active channel width to improve accuracy.

The second estimate is based partially on population density estimates obtained from field surveys (minnow trapping, including trapping for mark and recapture studies and snorkeling surveys) in selected reaches. Where no field data were available, GEC (2001b) adjusted the values calculated by the method of Paustian (1990) using professional judgment and the density values obtained in other reaches where field sampling was conducted. Table 3.6-7 summarizes the results of these analyses.

Table 3.6-7. Population estimates for resident Dolly Varden char in the Kahtaheena River. (Source: GEC, 2001b)

Reach or Subreach	Channel Type	Useable Habitat (ft^2)	Density ($fish/ft^2$)	Capability from Model[a]	GEC Population Estimate
2	LC2[b]	30,795	0.008	246	576[f]
2	MC3[b]	20,150	0.017	343	75[f]
3	MC3[b]	52,194	0.017	887	175[f]
4	LC2[c]	52,345	0.008	419	126[f]
4	FP3[d]	37,200	0.023	856	691[f]
4	LC2	19,633	0.008	157	64[f]
5	LC2	14,294	0.008	114	47[g]
5, 6	LC2	43,055	0.008	344	140[g]
6	LC1	100,642	0.019	1,912	654[g]
7	FP3[d]	56,661	0.023	1,303	1,092[f]
8	FP3[d]	22,723	0.023	523	438[g]
Upstream[e]	FP3[d,e]	129,166	0.023	2971	2,490[g]
Total		578,859		10,075	6,568[g,h]

[a] Useable habitat in square feet multiplied by density.
[b] These reaches lie entirely within the bypassed reach and would be affected by diversion of flow.
[c] This sub-reach is partially within the bypassed reach.
[d] Classified by Flory (1999) as MM1.
[e] From upper end of Reach 8 to the 10 km Falls.
[f] Estimate based on field data obtained within the reach.
[g] Estimate based on adjustment based on data from similar reaches.
[h] Approximately 15% of the total population estimate may reside in the bypassed reach of the river.

The population estimate derived by GEC using its minnow trap, mark and recapture and snorkeling data (ca 6,500 fish) is of the same order of magnitude but lower than that calculated by use of Paustian's methodology (ca 10,000 fish). Because actual field results were used to derive the lower population estimate, it is likely the more accurate of the two. In any case, the order of magnitude agreement between these two independently derived estimates, taken together with Flory's mark and recapture estimate of 1,700 fish from only three areas of the river, suggests that the actual population ranges from 5,000 to 10,000 fish. Additionally, the data collected by Flory suggest that approximately 15 percent of the population resides in the bypassed reach (see footnote h in table 3.6-7). However, because Flory performed limited sampling upstream of the proposed diversion site, population estimates from the upper portion of the Kahtaheena River may be inaccurate. As a result, the bypassed reach portion of the population may actually comprise a greater (or lesser) percentage of the total number of fish within the Kahtaheena River than suggested by Flory's data.

The individual reach estimates given in table 3.6-7 confirm other findings by Flory (1999; 2001) indicating that areas of pools with large woody debris provide the best habitat for the resident char population. High catch rates using minnow traps are reported for the Log Jam immediately above the Lower Falls and The Islands area in Reach 4, designated above as FP3 channel type (Flory, 1999).

Very little information exists concerning spawning and recruitment of resident Dolly Varden in the Kahtaheena River. Flory (1999) reported collecting fish in November and September ranging in length from 14 to 20 cm (5.5 to 7.9 inches) that were either in spawning color, producing milt, or containing eggs. In October 2000, 84 fish, 14 of which were in spawning colors, were collected. These fish, designated as spawners by Flory ranged in length from 13.6 to 19.5 cm (5.4 to 7.7 inches). The smallest of these spawners was judged to be 3 years old, based on otolith analysis[32] (Flory, 2001). The remaining 70 (nonspawner) fish all were between 8 and 13.5 cm (3.1 and 5.3 inches) long. It was Flory's (2001) conclusion that the spawning population ranges in age from 4 to 7 years with occasional 3 and 8 year old fish contributing.

Of five spawners kept for age analysis, three had eggs. Total egg counts from these three fish were 22, 97, and 187 with no apparent relationship between the size of the fish and the number of eggs (Flory, 2001).

32 Otoliths, bony structures formed by biomineralization and sometimes called earstones, are sound receptors and also used by fish for balance and orientation. Because the otolith grows on its outside surface, the history of these relative changes in composition is preserved inside the otolith. Information about fish age and growth can be extracted by looking at changes in these patterns at varying scales.

No spawning was observed nor were any redds reported by Flory (1999; 2001). Two fry were observed in the river in 2000, although the time of observation was not reported. In both cases, they were found in shallow habitat with water depth of 1 to 2 inches and zero velocity.

These data, although limited, are similar to results reported by Blackett (1973) for Dolly Varden sampled on Admiralty Island where the majority of the females matured at age 4 and average fecundity was 66 eggs per female. The early age of maturity and small body size of this population was thought to be an adaptation to existence in a limited environment. Given the limited egg production capabilities of these small fish, reproduction may be a limiting factor in their life history. However, the marginal nature of the small stream habitat in which they exist (limited area of high quality habitat, flashy discharge patterns, and frequent low winter flow conditions) also may be of importance in determining population size.

3.6.4 Proposed Land Exchange Parcels

Long Lake

The Chitina River drainage is approximately 5 million acres. The fisheries resources of the Chitina River contribute substantially to salmonid production in the Copper River system. For example, Chitina chinook salmon comprise as much as 22 percent of the total Copper River adult returns (Wuttig and Evenson, 2001).

Long Lake is a narrow, long lake within the Chitina River drainage. The lake currently provides excellent salmon spawning habitat, including well-aerated clean spawning gravel. Long Lake likely has the largest sockeye adult salmon returns in the Chitina River drainage, with annual adult returns of up to 50,000 salmon. Sockeye salmon in Long Lake also have the longest known annual spawning period, with fish returning in early fall and spawning through the following March. Adult chinook salmon return to the Chitina River beginning in June, with peak returns occurring in August. The primary reason attributed to spawning productivity of Long Lake is the substantial groundwater upwelling through the gravels. The north shore of Long Lake has steep slopes with only minimal shoreline development at this time. The watershed processes that govern the groundwater recharge and the success of the groundwater upwelling along the north shore are relatively fragile processes that could easily be interrupted by impacts from human activities within the watershed surrounding the lake (personal communication from E. Veach, NPS, Anchorage, AK, with M. Daily, Meridian Environmental, Seattle, WA, on May 6, 2003).

Coho salmon are also known to spawn in the vicinity of Long Lake, although no information is available regarding coho use of the area. Other fish that are thought to inhabit Long Lake are steelhead, Dolly Varden, grayling, lake trout, and burbot (NPS, 1986; ADNR, 1986). Steelhead trout in the Copper River drainage represent the northernmost distribution of this species in North America (personal communication from E. Veach, NPS, Anchorage, AK, with M. Daily, Meridian Environmental, Seattle, WA, on May 6, 2003). Similar to other salmonid species living on the edges of their distribution, populations are relatively sparse and unproductive (Flebbe, 1994).

Field review of Long Lake in February 2003 suggests that wildlife were using both live and dead salmon along the open water adjacent to the north shore of the lake where groundwater upwelling occurs (personal communication from E. Veach, NPS, Anchorage, AK, with M. Daily, Meridian Environmental, Seattle, WA, on May 6, 2003).

Klondike Gold Rush

The Taiya River system is known to support populations of chum, coho, and pink salmon; Dolly Varden; and eulachon smelt (NPS, 1986; Paustian et al., 1994).

In early May, the Taiya River generally experiences low turbidity, and steelhead trout enter the system to spawn. The eulachon smelt run usually begins in mid- to late-May. There are two runs of pink salmon in the Taiya River system, the first of which enters the system in late July through early August, while the late run occurs in late August. Chum salmon in the system usually enter freshwater and spawn from late July through the fall (NPS, 1986). Dolly Varden and coho salmon are the primary rearing species observed in the lower Taiya River. Dolly Varden in the system are likely present year-round, with spawning occurring in the fall.

3.6.5 Wilderness Designation Parcels

There are limited freshwater resources on the unnamed island near Blue Mouse Cove and Cenotaph Island. Freshwater fisheries resources would likely be extremely limited or nonexistent on both islands (personal communication from C. Soiseth, Fisheries Biologist, GBNPP, with M. Daily, Meridian Environmental, Seattle, WA, on March 24, 2003).

The Alsek River system is a major contributor of chinook, coho, and sockeye salmon. It is estimated that approximately 95 percent of the chinook salmon, 90 percent of the sockeye salmon, and 75 percent of the coho salmon taken by the commercial fishery in the Deep Bay area of the Gulf of Alaska originates from the Alsek River (Orr, 1993). In addition, there are small populations of pink and chum salmon in the drainage.

3.7 VEGETATION AND WETLANDS

3.7.1 Kahtaheena River Area (Project Area)

The project area lies within the northern portion of the temperate rainforest of southeastern Alaska. Vegetation in the vicinity of the project diversion, powerhouse, and transmission line corridor consists of upland and wetland forest, shrub, and grass communities typical of those found throughout southeastern Alaska.

Review of the license application and associated technical reports indicates plant communities were mapped for the project area on 1:24,000 scale aerial photos and supplemented with field observations to determine mapping boundaries. Each of the vegetation types found in the project area is described below. Table 3.7-1 provides the acreage of each type, as well as its wetland classification.

Table 3.7-1. Proposed project-area plant communities. (Source: Bosworth, 2000, as modified by preparers)

Plant Communities	Wetland Classification	Acres
Rich spruce/hemlock forest	Non-wetland	350
Young spruce forest and logged sites	Non-wetland	134
Poor hemlock/spruce forest	Non-wetland	463
Poor hemlock/spruce forest	Wetland	126
Spruce/pine/cottonwood parkland	Non-wetland	79
Willow shrubland	Wetland	115
Bog	Wetland	96
Fen	Wetland	528
Riparian	Wetland	37
Shallow pond emergent vegetation	Wetland	1
Supratidal meadow	Non-wetland	185
Intertidal sedge meadow	Wetland	63
Total		2,177

3.7.1.1 Rich Spruce/hemlock Forest. Rich spruce/hemlock forest is found primarily on well-drained soils on steep slopes along the Kahtaheena River and west of The Canyon. In the project area, much of this cover type can be described as old-growth forest, based on the high proportion of large-diameter trees; a canopy closure of more than 60 percent; and the abundance of standing snags, stumps, and fallen logs. The overstory forest is dominated by western hemlock with lesser quantities of Sitka spruce. Dominant understory shrubs consist of Alaska blueberry, rusty menziesia, and occasional devil's club. Common understory herbs and forbs include bunchberry dogwood, five leaf bramble, twisted stalk, and shield fern.

3.7.1.2 Young Spruce Forest and Logged Sites. This cover type is a result of timber harvest that occurred in the past in areas that would have been classified as rich spruce/hemlock forest. These areas have naturally regenerated to produce a young forest dominated by Sitka spruce with a substantial composition of western hemlock.

3.7.1.3 Poor Hemlock/Spruce Forest. The poor hemlock/spruce forest is found primarily on the poorly drained soils that are productive enough to support overstory tree growth. These sites are generally found on the hillslope terraces, flat topographic sites, and as a transition between well-drained forest stands and bog and fen plant communities. These less productive forest sites generally contain a more diverse composition of species than the well-drained forested sites. The overstory forest may be dominated by western hemlock with substantial composition of Sitka spruce, mountain hemlock, or shore pine, and occasional Alaska yellow-cedar. Understory shrubs may consist of Alaska blueberry, rusty menziesia, labrador tea, and crowberry. Common understory herbs and forbs include skunk cabbage, bunchberry dogwood, wintergreen, and deer cabbage.

3.7.1.4 Spruce/Pine/Cottonwood Parkland. This is a rich, open community typically comprised of relatively fast-growing trees and shrubs. This community is dominated by Sitka spruce, shore pine, and cottonwood. This plant community is a result of natural colonization on sites that have been subjected to human disturbance, which has improved the soil drainage and exposed mineral soil conditions favorable to seed germination.

3.7.1.5 Bog. Bogs are peat-forming communities that are influenced solely by water falling or infiltrating directly from above the site (e.g., rain, or snowfall and melt) and generally containing a dominant sphagnum moss layer. Bogs in the project area occur in the relatively flat, poorly drained terraces. Bog communities are characterized by the presence of stunted shore pine and mountain hemlock, labrador tea, bog cranberry, dwarf blueberry, and sphagnum mosses.

3.7.1.6 Fen. Fens rely on nutrient and mineral rich surface or subsurface water from outside the boundary of the plant community. The hydrological connection provides these sites with greater nutrients and minerals and results in a more diverse composition of species and greater productivity than found in a bog community. Fens are often found on flat terraces immediately adjacent to well-drained upland sites, or along side estuarine and palustrine streams. Because of the hydrological connection providing mineral rich water, these sites are sensitive to disturbances that disrupt the subsurface hydrology. Fen communities are characterized by the presence of sedges and grasses; shrubs, such as nootka rose; and forbs, such as deer cabbage, alpine meadowrue and twinflower.

3.7.1.7 Willow Shrubland. This community is dominated by Sitka willow or Barclay willow, and may often include a substantial component of Sitka alder. Other shrubs that are commonly present in this plant community include devil's club and elderberry. This plant community often occurs on disturbed sites or in marginal bands along shorelines and watercourses.

3.7.1.8 Shallow Pond with Emergent Vegetation. Documentation associated with the license application does not provide a description of this plant community. Based on the classification system developed by Viereck (1992) for southeast Alaska, this plant community would be considered a wet graminoid herbaceous wetland type. This community type is generally present adjacent to large, open ponds within a larger bog plant community.

3.7.1.9 Riparian. Documentation associated with the license application does not provide a description of riparian plant communities, although the maps show this type mapped along the shoreline of Kahtaheena River, as a subclass to the rich spruce/hemlock forest plant community. The dominant species represented in this community is an overstory of western hemlock and Sitka spruce, and an understory of devil's club, huckleberry, and rusty menziesia.

3.7.1.10 Supratidal Meadow. This plant community is dominated by herbaceous vegetation and is located between the high tide line and the forest edge. Common herbaceous species present in the plant community include fireweed, lupine, cow parsnip, dunegrass, lady fern, and yarrow.

3.7.1.11 Intertidal Meadow. This plant community is located on wet silts below the drier high tide line. Lyngby's sedge is the dominant species.

3.7.2 Proposed Land Exchange Parcels

Vegetation composition for the Long Lake exchange lands is not well documented. The Area Plan for State Lands in the Copper River Basin (ADNR, 1986) indicates that these lands are naturally forested with trees suitable for commercial forest management activities and personal use.

Vegetation composition for the KGNHP exchange lands is not well documented. These lands are located at the end of Lynn Canal, which is the area in a transition zone between the temperate rainforest ecosystem and the interior continental climate pattern. Plant communities in this area do not clearly fit into the plant associations identified for most of southeastern Alaska and the Tongass National Forest, although many of the same species are found here. Common overstory species found in the vicinity include western hemlock and Sitka spruce forest on upland sites, and cottonwood and white birch along the Taiya River. Understory species common to the area include Alaska blueberry, devil's club, rusty menziesia, and lady fern.

3.7.3 Wilderness Designation Parcels

The vegetation composition specific to Cenotaph Island has not been described in the documentation for GBNPP. Based on review of aerial photographs and NPS staff reports, the vegetation is dominated by Sitka spruce, western hemlock, and black cottonwood, with a mix of alders also present (personal communication from M. Kralovec, GBNPP-NPS, with E. McLanahan, Meridian Environmental, Seattle, WA, on April 24, 2003).

At the unnamed island near Blue Mouse Cove and on surrounding shorelines, the dominants consist of Sitka spruce and Sitka alder with an understory of herbaceous plants and mosses (NPS, 1988).

The vegetation composition specific to the Alsek Lake lands has not been described in the documentation for GBNPP, but NPS reports the dominant tree species is Sitka spruce and black cottonwood, with alder and a variety of willow species also occurring (personal communication with J. Capra, NPS, Dry Bay Ranger, on April 24, 2003). A variety of herbaceous species grow in open meadows, including paintbrush, lupine, fireweed, and columbine.

3.8 WILDLIFE

3.8.1 Kahtaheena River Area (Project Area)

The project area provides habitat for a variety of wildlife species that make use of mature spruce/hemlock forest and riparian habitat along Kahtaheena River; forested wetlands, fens and bogs along the proposed access road and transmission line route; and beach meadows and tidal flats along the shoreline.

Since 1991, biologists have conducted a number of studies designed to evaluate potential effects of project construction on wildlife. Study efforts were focused on large mammals and birds. No studies have been conducted to assess project effects on medium-sized mammals, small mammals, or amphibians, but incidental observations of occurrence and habitat use were recorded. Based on a literature review, it is possible that the boreal toad, northwestern salamander, and rough- skinned newt could use open water ponds in fens and forested wetlands that contain permanent water (NPS, 2002). No studies of marine mammals or birds were conducted, since construction would occur over 0.25 miles from the shoreline and would not be expected to affect water quality or fish populations below the project's tailrace, or to cause noise disturbance.

Based on tracking surveys, black bear and moose are the most abundant large mammals in the project area. The surveys also indicate a dense population of martens during some years, and wide use of the project area by porcupines. The project area provides habitat, at least at times, for low numbers of brown bears, wolves, coyotes, deer, river otters, mink, short-tailed weasel, red-squirrel, and red-backed and long-tailed voles.

As part of its pre-licensing studies, GEC conducted calling surveys for northern goshawks. No responses were obtained, but the project area contains suitable habitat and northern goshawks have been observed in the past (Lentfer, 2000). Northern harriers and sharp-shinned hawks were the most commonly observed raptors in the study area. Biologists also documented the presence of bald eagles, red-tailed hawks, osprey, and great horned owls. Peregrine falcons were not observed during the surveys, but have been reported to hunt along the shoreline during waterfowl migration. NPS staff also report observations of short-eared owl and merlin in the project area, in June 2002 and March 2003, respectively (personal communication with A. Banks, GBNPP Outdoor Recreation Planner, on April 28, 2003).

Forested portions of the project area provide habitat for Pacific slope flycatcher, chestnut-backed chickadee, and Steller's jay. American dippers were frequently observed all along the Kahtaheena River. Waterfowl species observed during the surveys include brant, Canada goose, green-winged teal, and mallard. The largest numbers of waterfowl were observed during spring and fall migrations, when several hundred ducks and geese may use the Flats along the shoreline. Gulls were also abundant in nearshore waters and on the tidal flats. Greater yellowlegs nest in muskegs in the project area.

The mouth of Glacier Bay in Icy Passage supports one of the largest concentrations of foraging marbled murrelets within the species' range (DeGange, 1996), and it may be used by birds that are nesting over 75 miles away (Whitworth and Nelson, 2000). GEC conducted surveys to determine if marbled murrelet were nesting or if there was suitable habitat for nesting in the project area. Almost all the forested habitat in the project area can be characterized as suitable for nesting. For this project, biologists classified habitat as fair (potential nest trees spaced greater than 50 feet apart) or good (potential nest trees spaced less than 50 apart). Observations of birds flying through and under the canopy confirmed murrelet nesting on the slope above the powerhouse site. Audio detections of birds circling above the canopy at the two stations along the proposed penstock route are a strong indicator of nesting, but are not considered to confirm it (Lentfer, 2000). In comparison to other parts of Alaska (e.g., Mitkof Island) where over 200 detections have been recorded during dawn survey periods, the 60 detections at Station 3 indicate use of the project area is moderate.

To date, the boreal toad is the only amphibian documented to occur in GBNPP, but five others species are also likely to occur in the vicinity of GBNPP (NPS, 2002) and could occur in the project area. These include the northwestern salamander, long-toed salamander, rough-skinned newt, spotted frog, and wood frog. All of these species breed in aquatic habitats. The boreal toad is most often found in open-area wetlands in coastal forests, but the other five amphibians use a variety of lakes, ponds, and the shallows and slow-moving backwaters of streams. Because of its generally high gradient, most of the Kahtaheena River would not be likely to support breeding.

Areas of glacial refugia in GBNPP have been documented to harbor fauna not found elsewhere in the park. For example, the only record for the Northwestern salamander (*Ambystoma gracile*) in Glacier Bay is reported from a Neoglacial refugium along the outer coast at Graves Harbor. This record represents a range extension for this species. Vertebrate species in inhabiting glacial refugia, although perhaps not representing a separate species, may be genetically unique because of their isolation from adjoining populations and lack of gene flow with adjoining populations, and could serve as important information sources for ecological questions. Because the Kahtaheena River drainage has not been extensively surveyed nor have the species known to occur there been genetically analyzed to any great extent (see Dolly Varden discussion in section 4.6 of this EIS), it is therefore possible that this drainage is inhabited by undiscovered unique fish or amphibian species.

3.8.2 Proposed Land Exchange Parcels

General descriptions of WSNPP indicate that the park supports important populations of black bears, brown bears, moose, and caribou, and one of the largest concentrations of Dall sheep in North America (WSNPP, 1998). Wolves and foxes are also known to be present. There is no specific information about wildlife use of the proposed exchange parcels in the Long Lake area, but NPS maps show habitat for moose, Dall sheep, and furbearers, such as lynx, marten, river otter and marmot. NPS indicates that this is a "unique wildlife area related to food source and use, especially bears."

The Copper River Basin is part of a migration route for a number of waterfowl species, and the park provides nesting habitat for ducks, geese, and trumpeter swans. Bald eagles and golden eagles nest in the park, as well.

Recent amphibian surveys indicate that the boreal toad and woodfrog are the only amphibian species likely to occur in WSNPP (NPS, 2002).

There is no site-specific information about wildlife in KGNHP. Based on its general location and broad-level vegetation cover types, it likely provides habitat for many of the same species as are found in WSNPP. In addition to species identified above, KGNHP is thought to support boreal toads, northwestern salamanders, rough-skinned newts, and long-toed salamanders (NPS, 2002).

3.8.3 Wilderness Designation Parcels

Based on incidental observations, the unnamed island near Blue Mouse Cove and Cenotaph Island provide habitat for black and brown bear, marten, weasel, river otter, and red-backed vole (personal communication with M. Kralovec, GBNPP-NPS, on April 24, 2003). Several other mammals, such as moose, wolf, wolverine, and hoary marmot, have been observed at the unnamed island near Blue Mouse Cove.

Large concentrations of harbor seals use High Miller Inlet, just south of Blue Mouse Cove (Mathews and Pendleton, 2000). Steller sea lions and humpback whales are present from time to time in the vicinity of Cenotaph Island and Blue Mouse Cove (personal communication with M. Kralovec, GBNPP-NPS, on April 24, 2003). Killer whales, harbor porpoises and sea otters are also observed in these waters.

Bird species found at both sites include bald eagle, northern harrier, northwestern crow, common raven, and various songbirds. Peregrine falcons have been observed at Cenotaph Island, as well as white-winged scoter, mew gull, arctic tern, glaucous-winged gull, black-legged kittiwake, tufted puffin, pigeon guillemot, and pelagic cormorant (personal communication with M. Kralovec, GBNPP-NPS, on April 24, 2003).

Marine waters of Blue Mouse Cove also support large numbers of seabirds and waterfowl. Canada geese, surf scoters, mergansers, mew gulls, arctic terns, glaucous-winged gulls, and black oystercatchers are common (NPS, 1988). Incidental observations recorded by NPS staff also include white-winged scoter, Kittlitz's and marbled murrelet, spotted sandpiper, and harlequin duck (personal communication with M. Kralovec, NPS, on April 24, 2003).

The proposed wilderness designation lands at Dry Bay/Alsek Lake are located inland and do not include marine habitat; however, harbor seals use Alsek Lake during the summer. NPS reports observations of many of the same mammals and birds as are found in the vicinity of Cenotaph Island and Blue Mouse Cove. In addition to the species listed above, NPS also has documented the occurrence of glacier bear, mountain goat, lynx, and willow ptarmigan (personal communication from J. Capra, NPS, Dry Bay Ranger, on April 24, 2003).

3.9 CULTURAL RESOURCES

3.9.1 Kahtaheena River Area (Project Area)

Archaeological evidence and oral history place the Tlingit people and their predecessors' occupation of the Glacier Bay region at 9,000 years before the present (Kurtz, 1995). Huna Tlingit oral history is closely tied to Glacier Bay, which the Huna people referred to as the "Huna bread basket." Among the Tlingit, social organization revolves around the membership of every individual in one of two moieties (i.e., either of two basic units that make up a social group): Raven or Eagle in the southern Tlingit territory or Eagle in the northern Tlingit territory. These moieties are matrilineal and exogamous (marrying outside the family, clan, or other social unit). Each moiety comprises multiple clans, and each clan, in turn, comprises lineages or house groups. Five Huna Tlingit matrilineal clans trace their origins to places within GBNPP (NPS, 1997), and consider many places therein as sacred sites. Huna oral accounts describe a village site that existed at Bartlett Cove prior to the most recent glacial advance. One often-told sacred narrative relates how the Huna people fled the readvancing ice sheet to their present village site, Hoonah, on Chichagof Island (Kurtz, 1995). The Huna and neighboring Tlingit groups found abundant food, extensive trade routes, and temperate climates in this region. They built large clan houses embellished with elaborate carvings featuring human, animal, and mythological figures (Kurtz, 1995). These images, which encompass a concept termed *at.oow*, or owned things, are the identifying symbols of clans and often the places they occupied.

At the time of Russian and European explorers in the 18th century, the project area was within the traditional territory of the Huna *kaawu*[33] of the Tlingit Indians (Brakel, 2001). The Tlingit are the most widespread and numerous of the Native Alaskans in the southeast region. Tlingit culture, characteristic of the Northwest Coast culture, included an economy based on fish; settled villages; a sophisticated wood-working industry; highly developed and distinctive art forms; a social organization structured around lineages and clans; and a ritual life focused upon clan symbolism, shamanism, and the attainment of status through potlatching[34] (Yarborough, 1999). At least 20 territorial groups of Tlingits resided in southeastern Alaska in the beginning of the 18th century.

Euroamerican contact in the project vicinity began in 1741 with the arrival of Russian explorer Vitus Bering. The discovery and exploitation of the sea otter by the Russians prompted exploratory expeditions by other nations interested in valuable furs. Captain George Vancouver ventured into the Icy Passage area in 1794. He named many of the topographic features in the area. At the time of Vancouver's expedition, Glacier Bay was completely enclosed by glaciers. By the turn of the century, the glacier had retreated about 40 miles, and by 1916 it had retreated 65 miles from the position observed by Vancouver (Yarborough, 1999).

Euroamerican settlement in the Glacier Bay area was stimulated initially by fur trading and then by the discovery of gold in the 1880s. Other commercial activities focused on timber harvesting, fox farming, fishing, and fish processing, including a saltery at Bartlett's Cove in the late 1890s and the cannery at Dundas Bay which operated until the early 1930s. The first agricultural homesteader arrived at Strawberry Point (now Gustavus) in 1914. The glaciers themselves stimulated scientific and tourist interest in the region. John Muir visited Glacier Bay on four occasions beginning in 1879, and his explorations contributed to increased public knowledge about the bay. Tourist ships first arrived in the harbor in 1883 and visited regularly until the 1899 earthquake created dangerous ice floats which made the harbor inaccessible. Regular cruise ship visitation resumed after the creation of the Glacier Bay National Monument in 1925 (see section 1.7.4) and continues today.

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[33] A *kaawu* (or more commonly *kwaan*) is a local Tlingit group usually associated with a community (e.g., Hoonah, Skagway, and Angoon *kwaan*) and includes members of both moieties and of several clans.

[34] Traditionally, a ceremonial feast with elaborate gifting, oratory, and dancing intended to honor the dead or the new status of a living person.

Following the 1867 treaty which arranged for the United States to "purchase" Alaska from Russia, the United States government allowed settlement to proceed in Tlingit territories without consideration for the status of Native lands. Alarmed at seeing many of their prime lands occupied by outsiders, the Tlingit and Haida Indians, originally through the Alaska Native Brotherhood and later through the Central Council of Tlingit and Haida Indians of Alaska, began in 1935 the legal process to reclaim their traditional lands. Eventually, in 1959 the Court of Claims determined that the Tlingit and Haida Indians had been deprived of most of their traditional lands, totaling over 20 million acres including the Tongass National Forest, Glacier Bay National Monument and the Annette Island Reserve. A monetary settlement for this taking was provided by Congress in 1968, but many Tlingit and Haida Indians do not recognize this act, and still retain strong cultural ties to their aboriginal lands. The project lands lie within the Wooshkeetaan Clan territory of the Huna Tlingit Tribe, and tribal/cultural associations are still active there.

World War II brought considerable change to the region with the construction of an airfield at Gustavus in 1941 and a supply terminal at Excursion Inlet in 1942 with 800 buildings on 600 acres just east of the Monument boundary. The supply terminal and associated buildings were dismantled in 1945, but the airfield remained and enabled NPS to access and develop visitor facilities at Bartlett Cove (NPS, 2003b). In 1955, 14,000 acres of land, including the Gustavus airfield, were removed from the Monument boundary based on nonconforming uses. With the passage of ANILCA in 1980, the Glacier National Monument was redesignated GBNPP. In 1992, GBNPP was included in a joint United States and Canada World Heritage Site encompassing GBNPP, the Kluane National Park, WSNPP, and Tatshenshini-Alsek National Park.

This range of human activity has produced cultural resources that include archaeological sites, historic structures, cultural landscapes, and traditional cultural properties. Archaeological sites–loci of past human activity–and historic structures are the most common and recognizable types of sites present in GBNPP. GEC's cultural resource consultants conducted an archaeological reconnaissance survey of high archaeological sensitivity zones within the area of potential effect. The surveyors selected the high sensitivity zones based on topographic criteria (locations below the 100 foot elevation with slopes of less than 25 percent) combined with existing data on traditional use, known and reported sites, and the location of anadromous fish streams. Based on these criteria, cultural resource surveys were conducted at the powerhouse site and along the western portion of the access road across state of Alaska and GBNPP land to the northwestern corner of USS Surveys 945. These areas correspond to the areas where known sites occur, but do not include the mouth of the Kahtaheena River, the location with the highest archaeological potential, which is within the Mills allotment.

The only cultural remains identified during the reconnaissance survey were 35 culturally modified trees[35] and several cut stumps. The report concludes that individual or small groups of culturally modified trees are not considered significant but their presence in the project area does indicate early historic and possible late prehistoric use. The only reported archaeological site in the project area is an historic period cabin or stable foundation located by the Bureau of Indian Affairs (BIA) archaeologists at the mouth of the Kahtaheena River. This site is located on the 56-acre parcel added to the Mills allotment in 1998, and permission was not obtained to investigate the site. No ground-disturbing activities associated with the construction of the hydroelectric facility would occur within the Mills allotment, however.

Recent research also has recognized all of GBNPP as a cultural landscape, as defined by over 200 traditional Tlingit place names that define the geography of the Huna Tlingit homelands. The name of the Kahtaheena River is derived from the traditional Tlingit name, *Xaat heeni* (fish stream), which is an element of this cultural landscape. Within the context of this cultural landscape, NPS has preliminarily recognized some 15 sites in GBNPP that take on special significance because they are the locations where certain clans have taken their identity, as expressed by at.oow such as crests, stories, songs, and such. These special places fall within a category of National Register sites called traditional cultural properties. Traditional cultural properties are National Register ethnographic sites[36] that are defined as places that gain their importance "because of an association with cultural practices or beliefs of a living community that (a) are rooted in that community's history, and (b) are important in maintaining the continuing cultural identity of the community (National Register Bulletin 38). Although the Kahtaheena River area is important for several individual families who claim it, there are no crests, songs, or stories associated with it which would serve to identify clans or larger social units. Lacking any such associations, the Kahtaheena River is not considered to meet the traditional cultural property criteria. The SHPO concurred with the finding on July 15, 2003. Also, as noted below, a senior allotment holder interviewed by GEC cultural resources consultants indicated that, despite seasonal use by the Huna Tlingit, there are no known sacred areas or burial places on Kahtaheena River area parcels that would be disturbed by construction of the proposed project.

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35 Large spruce, pine, or hemlock trees with triangular, rectangular, or oval shaped scars resulting from the collection of the sweet inner bark that was gathered in the spring and eaten fresh with oil or prepared and preserved for the winter (hemlock only) (Yarlborough, 1999).

36 Ethnographic resources are basic expressions of human culture and the basis for continuity of cultural systems that encompass both the tangible and intangible. They consist of traditional arts, native languages, religious beliefs, special places in the natural world, structures with historical associations, natural materials and subsistence activities, and traditional cultural properties (NPS, 1997).

Native Alaskan Consultation

Since existing lands in the project area are under NPS jurisdiction, and the proposed land exchanges would involve other NPS lands, the GBNPP Superintendent in 1999 formally notified, provided information, and requested the participation of the Hoonah Indian Association, along with other potentially interested Native Alaskan groups including tribal governments and regional native organizations in the proposed Falls Creek Hydroelectric Project and associated land exchanges (Brackel, 2001).[37] At the same time and shortly thereafter through personal introduction by NPS staff, GEC's cultural resource consultants also contacted and interviewed knowledgeable individuals with Hoonah Indian Association and heirs associated with the two Hoonah Tlingit Native allotments in regards to compiling information about cultural resources and the possibilities of any traditional cultural properties that might exist in the project area (Brackel, 2001; Brakel and Yarborough, 2001). In addition to contacts made in Hoonah, NPS staff also contacted allotment holders who do not reside in the area by telephone and informed them of the project and sought their input. A senior allotment holder provided information about his family's connection to the area and a traditional clan leader, acknowledged an official spokesperson for the entire clan, and provided oral history of past events involving the Hoonah Tlingit in the project area. Subsequent to the initial notification and consultation in 1999, and up until the present, the Glacier Bay Superintendent has met semi-annually with the Hoonah Indian Association board and included in those meetings an update of the project and thorough discussion of the issues. In addition, several follow-up meetings with the Wooshkeetaan leader were held to provide updates on the project, and to ensure that all pertinent information had been conveyed.

3.9.2 Proposed Land Exchange Parcels

Long Lake

Available archaeological data suggest that all of the major drainages within and bordering WSNPP and upland areas away from the drainages are culturally sensitive (NPS, 1986), and that prehistoric remains are possible within the Long Lake area (ADNR, 1986). Approximately 90 prehistoric and historic archaeological sites have been identified within the WSNPP boundary (NPS, 1986). There are no records of archaeological surveys conducted on the state-owned parcels with WSNPP that are proposed for the land exchange. However, ADNR notes that prehistoric and historic remains are possible.

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37 Other Native Alaskan groups and associations included Alaska Native Sisterhood, Alaska Native Brotherhood, Hoonah Camp 12, Huna Totem Heritage Foundation, along with three regional groups, Sealaska Corporation, Sealaska Heritage Foundation, and the Central Council on Tlingit and Haida Indian Tribes of Alaska.

Klondike Gold Rush

KGNHP was established in 1976 to preserve and interpret historic sites associated with the Klondike Gold Rush, gold rush era structures, and the historic setting of Skagway and the surrounding area representing the period 1896–1903. KGNHP was listed in the National Register on June 30, 1976. Sixteen miles of the historic Chilkoot Trail pass through the park, and all except one of the potential land exchange parcels include a portion of the trail. The Chilkoot Trail was one of only three glacier-free passages in the northern Lynn Canal that lead over the Coast Mountains to the interior and was one of the main trading routes used by the Tlingit people in prehistoric times (NPS, 1996). The Chilkoot Trail was listed in the National Register on April 14, 1975. The gold rush may have obliterated some, but not all, prehistoric sites.

3.9.3 Wilderness Designation Parcels

Unnamed Island near Blue Mouse Cove

Retreat of glaciers exposed this island in the 1880s. It is unlikely that settlement of the island occurred between the time of its exposure and the creation of the Glacier Bay National Monument in 1925 (personal communication from W. Howell, GBNPP, Alaska, with P. Weslowski, Louis Berger Group, Needham, MA, on January 31, 2003). However, the island would have provided good habitat for seal hunting and may have been a good place to pick soap berries. There is no record of archaeological surveys conducted on this remote and undeveloped island. BIA conducted a cultural resource survey on a nearby island in 1983 but did not identify any archaeological sites. In 1997, NPS identified a historic camp (XMF-081) associated with the international boundary survey of 1907 on the nearby mainland.

Cenotaph Island

At the time of the first European contact with the French explorer La Perouse in 1786, more than 300 Tlingit people occupied several villages within Lituya Bay. Recognized as the place where the Ta<u>k</u>deintaan Clan split from the L'ukna<u>x.</u>adi Clan, Lituya Bay is still of great importance to the both clans. The Ta<u>k</u>deintaan Clan traces its history to a Kittiwake colony on the southern side of Cenotaph Island. The L'ukna<u>x</u>.adi Clan retains strong cultural ties to the bay, and many of the names and stories the clan still retain have their origin here. Lituya Bay is also recognized historically as a home of shamans, which contributes to its significance as a powerful place on the landscape (personal communication from W. Howell, GBNPP, Gustavus, AK, with P. Weslowski, Louis Berger Group, Needham, MA, on February 3, 2003). In the late 1930s, Jim Huscroft, a legendary resident of the outer coast, made his home on Cenotaph Island. Cultural material that may have provided evidence of occupation would likely have been greatly disturbed or carried away by the earthquake-caused tidal waves that have denuded the island periodically over the centuries, most recently in 1958. However, the landforms that are the basis of Tlingit stories remain intact. There is no record of archaeological surveys conducted on Cenotaph Island. Lituya Bay, and in particular Cenotaph Island, is one of 15 potential traditional cultural properties recorded in GBNPP.

Alsek Lake

Dry Bay, or Gunaaxoo, was a place where Tlingits from the coast mingled with Athabaskans from the interior. The Gunaaxoo Kwaan of Tlingits occupied several villages in the Dry Bay area. The Raven moiety L'ukna.xadi Clan originates in Dry Bay at the mouth of the Alsek River (NPS, 1997). As a landscape heavily used by Raven at the time of creation, the Dry Bay area is revered as a homeland and sacred site by several Tlingit clans (personal communication from W. Howell, GBNPP, Gustavus, AK, with P. Weslowski, Louis Berger Group, Needham, MA, on February 3, 2003). However, the wilderness designation parcels are very remote from the tribal village and receive no visitation or traditional use by tribal members (personal communication between GBNPP staff and Yakutat Tlingit Tribe on April 16, 2004). There is no record of archaeological surveys conducted in the Alsek Lake area. Dry Bay is one of 15 potential traditional cultural properties recorded in GBNPP.

3.10 SOUNDSCAPE/NOISE

Natural soundscapes, which are also referred to as natural quiet or the natural ambient sound levels, are the unimpaired sounds of nature. Because natural sounds and tranquility are major resources of many national parks and are highly valued by visitors, NPS is mandated to preserve and restore them within each unit of the National Park System. Natural sounds can be masked or obscured by a variety of human-made sounds and noises. Ambient sounds attributable to human activities in national parks are human-made sounds. Noise is defined as unwanted sound. Sounds derived from human activities can affect both the human and wildlife environments. They can interfere with speech or sleep, cause hearing loss, and create physical or mental stress in humans. For wildlife, noise associated with human activity can cause physiological stress; interfere with breeding, foraging, communication, and escape behaviors; and disrupt movement patterns (Manci et al., 1988).

Sound power is described in terms of a logarithmic ratio designated as the decibel (dBA). Each 10-dBA increase in sound approximates a doubling in loudness, so that 60 dBA is twice as loud as 50 dBA. Noise effects can be determined by evaluating the increase that a new noise source would have on the existing noise levels at a sensitive receptor location, such as a residence, church, school, or park. Currently, GBNPP visitors, wildlife, and residential areas in the town of Gustavus are the main sensitive receptors of noise in the proposed project area.

EPA has developed guidelines to determine when an increase in noise levels would cause an adverse effect. EPA recommends that outdoor day-night average noise level (L_{dn}) values at both urban and rural residences not exceed 55 dBA to protect the public health and welfare with an adequate margin of safety. Although the EPA guideline is not an enforceable regulation, it is a commonly accepted target to prevent significant effects at sensitive receptors.

3.10.1 Kahtaheena River Area (Project Area)

The presence of GBNPP and the two Native American allotments in the proposed project vicinity have protected much of the land from human development and preserves the quiet and solitude found in wild places. Although the proposed project is located approximately 5 miles from Gustavus, the area is relatively untouched except for two small areas on the Native allotment that were logged for timber as recently as 1974. Natural sounds in the proposed project area consist of running creek waters, waterfalls, ocean waves, meteorological events (wind, thunder, precipitation, etc.), and the marine and terrestrial wildlife. Human sound may consist of air traffic to the Gustavus airport, motorized vehicles on Rink Creek Road and eastern Gustavus, and motorized boating near the shore. Typically, aircrafts generate up to 110 dBA measured at 50 feet, clearly audible for 2 miles and more. Motorized vehicles and boats generate up to 70 dBA at 50 feet, audible up to 0.7 miles. Wilderness area ambient daytime sound level can range from 25 to 45 dBA (Parker, 1996), although wilderness ambient levels near the waterfalls are likely far higher than 45 dBA. GEC conducted a study of aesthetic values of the project area. Respondents described the proposed project area as a place to escape the tourist crowds and enjoy quiet solitude. Residents voiced concerns about the proposed project as it related to increased vehicle traffic along Rink Creek Road, increased noise associated with construction and operation of the project, and the numbers of people, dogs, and types of activity that a road to the area would bring (Baker, 2001).

In comments on the draft EIS, GEC suggested that noise from the existing generators and their associated 10 hp cooling fans would continue to operate with their same associated noise levels under the proposed project. This noise is close to the school, post office, community chest, and airport and may affect residences since it can be heard up to 0.5 miles away on quiet days.

3.10.2 Proposed Land Exchange Parcels

Long Lake

The majority of uses of the Long Lake parcels in WSNPP are recreational wildlife viewing and fishing. The parcels are subject to noises associated with recreation here and can include nearby vehicle traffic, human noises, and natural wildlife noises.

Klondike Gold Rush

The majority of sounds within the parcels in KGNHP can be attributed to the human uses of the area, the majority of which is hiking. Other sounds may include natural wildlife or the physical environment. Wilderness area ambient daytime sound level can range from 25 to 47 dBA (Parker, 1996). Parcels located near the road system in Dyea also would be exposed to sound from vehicle traffic, generators, river boating parties, and noises associated with residential development nearby. Also, helicopters that are used for scenic overflights are prevalent in the lower Taiya River Valley during most days in the summer season and likely would be heard from some of the proposed land exchange parcels.

3.10.3 Wilderness Designation Parcels

Unnamed Island near Blue Mouse Cove

The unnamed island near Blue Mouse Cove is one of the only two islands not designated as wilderness within GBNPP. The sounds associated with these lands can be associated with the surrounding recreational uses of GBNPP. The majority of these sounds are motorized watercraft, aircraft, and human recreation sounds from campers, boaters, and kayakers. Other sounds include the natural and physical environment.

Cenotaph Island

Cenotaph Island is the other island not designated as wilderness within GBNPP. The sounds associated with this land can be associated with the surrounding recreational uses of GBNPP. The majority of these sounds are motorized watercraft, aircraft, and human recreation sounds from campers, boaters, and kayakers. Other sounds include the natural and physical environment.

Alsek Lake

The sounds associated with the parcels of Alsek Lake on the Alsek River are related to campers and boaters, along with occasional aircraft activities. Other sounds, such as calving glaciers and moving/capsizing icebergs, are associated with the natural and physical environment.

As mentioned above (see section 3.10.1), typically, aircrafts generate up to 110 dBA measured at 50 feet, clearly audible for 2 miles and more. Motorized vehicles and boats generate up to 70 dBA at 50 feet, audible up to 0.7 miles. Wilderness area ambient daytime sound level can range from 25 to 47 dBA (Parker, 1996).

3.11 VISUAL RESOURCES (AESTHETICS)

3.11.1 Kahtaheena River Area (Project Area)

The visual character of the inside passage of southeastern Alaska, where the proposed project would be located, is dominated by rugged shorelines and mountainous terrain. Numerous beaches, coves, rivers, glaciers, and forested mountains surround the town of Gustavus. Passengers in airplanes leaving the Gustavus airport are afforded views of the entire proposed project area. The visual character of the proposed project area can be divided into two areas: Gustavus Flats and the stair-stepped, forested Excursion Ridge (Baker, 2001).

Gustavus Flats consist of a mosaic of wetlands, meadows, shrublands, and young forests and provide long vistas to surrounding mountains. From the Flats, visitors could view Excursion Ridge, including the project area, and the Icy Passage. Human-made visual elements include Mills cabin at the mouth of the Kahtaheena River and an abandoned fish trap in the upland grasses. Level areas of the Flats are frequented by wildlife and provide excellent viewing opportunities for visitors, especially along the shore.

Excursion Ridge, the area above Gustavus Flats, possesses a different set of aesthetic attributes. The Ridge has both ancient forest and bog vegetation and spectacular views from upper elevation bogs and meadows. Residents surveyed indicate that the presence of difficult to reach and remote places like Excursion Ridge offers additional aesthetic values just through knowing they exist regardless of visitation (Baker, 2001). Survey respondents also complained that vistas are often occluded by dense vegetation, and wildlife is generally less abundant and visible than on the Flats.

The stair-stepped, canyon topography and generally dense vegetation of Excursion Ridge provides opportunity for obscuring the visual and auditory effect of developments (except from aircraft). Clearcuts of two ages in the proposed project area and the associated logging road are the only major signs of human activity on the Ridge. These clearcuts are now sufficiently revegetated to mostly obscure their effects.

Five sets of falls are located along Kahtaheena River in the project area, including, from upstream to downstream, the Upper Falls, 3 Meter Falls, and Lower Falls. The Upper Falls are located at about RM 2 and are 40 feet high. Channel formation below the Upper Falls consists primarily of cascades, often confined to a narrow chute of fast-flowing turbulent water or descending rapidly in a series of steps. Further downstream, there is 3 Meter Falls at RM 1.6. A log jam just upstream of the Lower Falls dominates the stream channel and stretches 50 yards across supporting extensive pool habitat behind it. The Lower Falls, which consists of two vertical steps, 40 and 60 feet high, is located 0.4 miles upstream from the tidewater and is the easiest of the falls in the proposed project area to hike to. Most visits to the Lower Falls are during spring and summer, when the flow over the falls is generally between 2 to 120 cfs. Figure 3-9 depicts the aesthetic quality of flow over the Lower Falls at 70 and 11 cfs. Winter visitation occurs at times when, because of prolonged cold snaps, the river can be walked or skied upon. At that time, flows are generally very low and largely obscured by ice. Travel along the Kahtaheena River banks is difficult as the area is steep and heavily forested.

3.11.2 Proposed Land Exchange Parcels

Long Lake

The Long Lake parcels are located near Long Lake within WSNPP. McCarthy Road runs along the southern shore of the lake, and traffic along the road is visible from the parcels. NPS prepared a corridor plan for the McCarthy Road area as part of an EIS in 1997 (http://www.nps.gov/wrst/mccarthyroad.htm) that identifies Long Lake as an important visual resource, and includes plans for a wayside in this area. The purpose for the wayside, which would be "to protect habitat and views of wildlife associated with Long Lake," speaks to the high value of protecting wildlife use and the inherent value of being able to view the lake. Views surrounding the lake include surrounding houses and an Alaskan homestead. One landowner has an airstrip and a large garden that can be seen from the road (personal communication with D. Sharp, Chief of Resources, WSNPP, on April 20, 2003).

Klondike Gold Rush

There are approximately 1,053 acres identified for exchange with ADNR that are within KGNHP and along the Chilkoot Trail. Scenic resources along the Trail include forests, mountains, streams, expansive views, wildlife (goats, bears, and aquatic birds), glaciers, waterfalls, and historic/archeological artifacts (personal communication with B. Noble, Superintendent, KGNHP, on April 21, 2003).

3.11.3 Wilderness Designation Parcels

Unnamed Island near Blue Mouse Cove

NPS originally proposed and planned a visitor ranger station on this 789 acre island within the west arm of Glacier Bay. The island was glaciated as recently as 1880 (NPS, 1984), and it is only reachable via float plane or boat. The island is in the heart of the main stem of Glacier Bay and has views of the glaciers, mountains, and marine environment. The vegetation on the island consists of Sitka spruce and Sitka alder with an understory of herbaceous plants and mosses. The shoreline is quite rocky and reef-like, limiting mooring sites and contiguous shoreline access. Black and brown bears have been sighted on the island, with waterfowl and sea birds nesting on the southwest side. Six campsites are scattered near the shore.

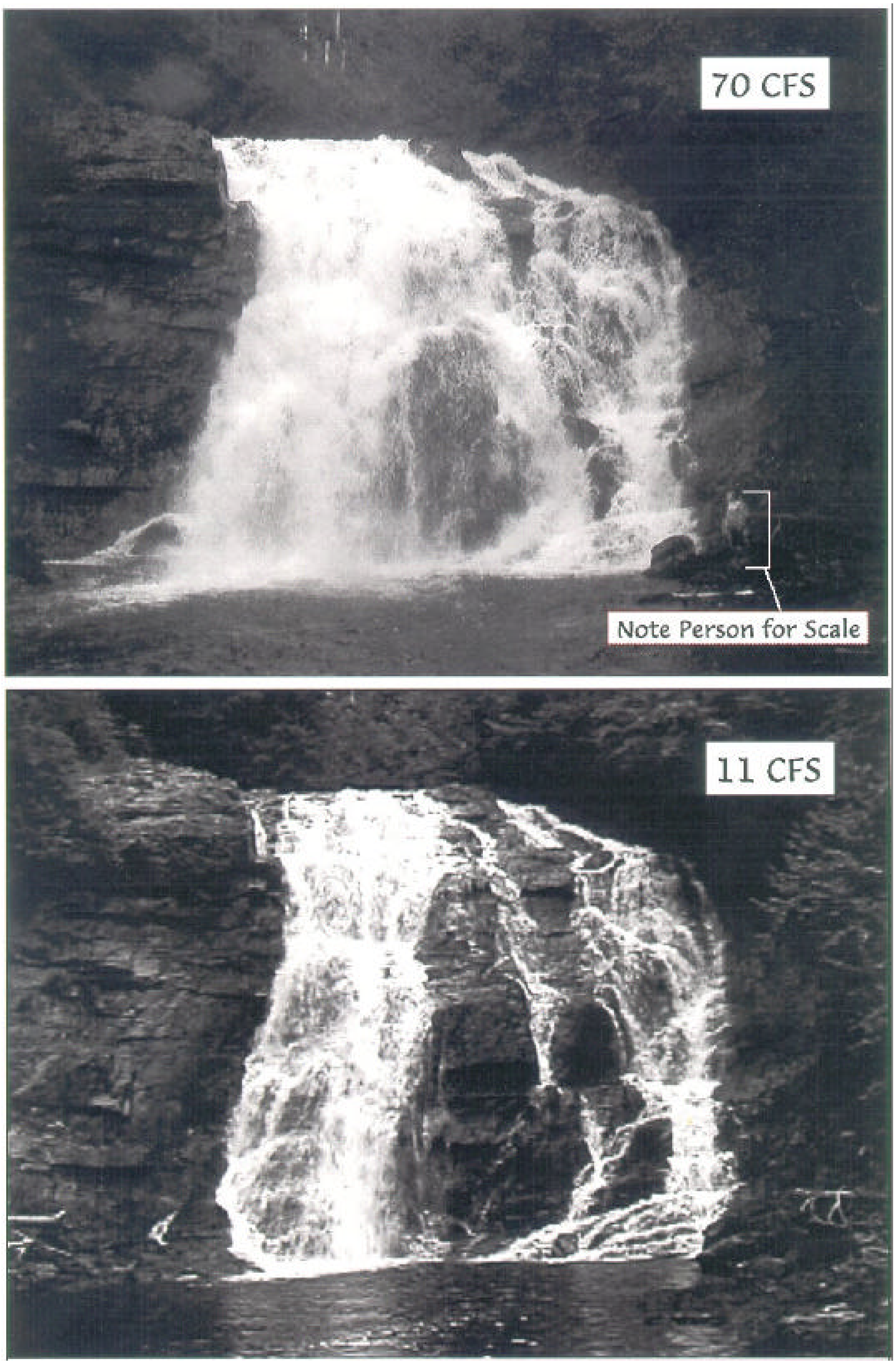

Figure 3-9. Aesthetic quality of flows over the Lower Falls.

Cenotaph Island

This island is located on the west coast of GBNPP in the narrow Lituya Bay. Earthquake-caused tidal waves have denuded the island periodically over the centuries, most recently in 1958 when the island was swept by a large wave that destroyed parts of the forest and any evidence of historical buildings and human settlement. Areas of the island destroyed by the massive wave are now vegetated with young stands of open cottonwood, closed alder, and mixed stands of spruce/cottonwood, while areas protected from the destructive wave are covered in mature forests of spruce, hemlock, shrubs, moss, and rock. The island offers views of surrounding mountain peaks, glaciers, and marine life. No visible structures remain on Cenotaph Island.

Alsek Lake

The parcels of Alsek Lake on the Alsek River are commonly used for overnight camping during river rafting trips down the Tatshenshini-Alsek River. Scenic resources from these parcels include mountains, glaciers, wildlife, the Alsek River, Alsek Lake, and the shoreline of both water bodies. These parcels are not accessible by road. All rafting trips that float the Tatshenshini/Alsek Rivers pass by the parcels at Alsek Lake on their way to the take out at Dry Bay. The Gateway Knob parcel is often used as a camp site for rafting trips where trip participants have unparalleled views of the Alsek and Grand Pacific Glaciers and, when visible, Fairweather Mountain. Although these lands are not designated wilderness, they are managed as such under the GBNPP Wilderness Visitor Use Management Plan. The Alsek River Visitor Use Management Plan provides additional protection of the resources and visitation uses along the Alsek River.

3.12 RECREATION RESOURCES

The inside passage of southeastern Alaska, and the Gustavus area in particular, offer an abundance of recreational opportunities. The northern portion of the inside passage features GBNPP, with more than 3.2 million acres of public land and Tongass National Forest, with nearly 17 million acres. Additional regional recreation opportunities within 150 miles of the proposed project area on federal lands include Admiralty Island National Monument, KGNHP, Endicott River Wilderness, Chuck River Wilderness, Petersburg Creek-Duncan Salt Chuck Wilderness, Stan Price State Wildlife Sanctuary, Tracy Arm-Fords Terror Wilderness Area, and Kootznoowoo National Forest Wilderness (figure 3-10 in appendix A). Additionally, state lands include the Chilkat Bald Eagle Preserve, Chilkat State Park, Totem Bight Historical Park, Haines State Forest and the developing SEA Trail system. GBNPP, however, is the focus of recreationists visiting the Gustavus area and offers backpacking, birding, boating, camping, climbing, fishing, hiking, kayaking, and wildlife viewing. Gustavus is bordered by the park on three sides and Icy Passage on the other. Given the town's proximity to the park, it is recognized as the gateway to GBNPP.

Most recreational facilities within GBNPP are within Bartlett Cove, 10 miles from the town of Gustavus. These include a free walk-in campground with designated sites, a warming shelter with firewood, outhouses, food caches, and 7 miles of maintained trails. Hiking is otherwise limited to glaciated river beds and shorelines because of the steep topography and dense vegetation surrounding the area. The Wilderness Act prohibits the use of mountain bikes within GBNPP on lands designated as wilderness, but mountain biking is available within the Gustavus town limits and within the Tongass National Forest. Because of the nature of the surrounding landscape, the majority of recreation opportunities are water-related and include boating and kayaking through either commercially guided vessels (e.g., cruise ships, tour vessels, or charter vessels), private vessels, or commercial and private kayaks. The coastline surrounding GBNPP and Gustavus contains hundreds of miles of kayaking opportunities. In addition to the specific facilities mentioned, NPS allows primitive camping on all park lands except where specifically prohibited because of safety concerns and wildlife protection.

3.12.1 Visitor Use

Recreational visitor use in the region is concentrated within Tongass National Forest and GBNPP. Concentrations are actually highest in communities visited by large cruise ships, e.g., Juneau and Skagway. Four large ships, carrying up to 3,000 people (passengers and crew) per ship, can visit Skagway several days each week during the summer. Passengers and crew commonly visit areas outside Tongass National Forest for recreational purposes. U.S. Department of Agriculture (USDA) national visitor use monitoring results for the Tongass National Forest show that an estimated 8.2 million people visit the forest each year (USDA, 2002). Visitor use surveys compiled by NPS staff for GBNPP reveal recreational use patterns within the park from 1979 to 2001. The majority of users who visit the park do not stay overnight. Visitor counts in 2001 included more than 336,000 recreation visits aboard cruise ships. Cruise ships typically enter and depart from the park within the same 8 to 12 hour period. Of the visitors that do spend the night within GBNPP, most tend to stay at local lodging or camp in the back country. Visitor use nights (number of visitors multiplied by the number of nights they stayed) in 2001 were primarily composed of stays at the Glacier Bay Lodge (9,410), Glacier Bay National Park Campground (1,272), or in the Glacier Bay back country (7,504). Back-country campers (camping considered anywhere away from developed park facilities at Bartlett Cove) comprise 18 percent of the total overnight stays, and 43 percent of the total camping use in the park.

Backcountry visitors usually experience the backcountry by traveling in sea kayaks or hiking along the shoreline. Visitors usually access the backcountry by departing directly from Bartlett Cove, taking the day tour vessel to specified drop-off locations in the backcountry, or chartering an airplane or vessel. Virtually all backcountry use within the park occurs between May and September, with more than half occurring in July and August (http://www.nps.gov/glba/). NPS notes a 61 percent increase in overall backcountry use (day use and camping) since 1991 (http://www.nps.gov/glba/learn/preserve/projects /visitation/index.htm) with an average of 1900 visitors per year; however, since 1996, backcountry numbers have declined and stabilized at around 1,300 visitors per year. NPS surveys of backcountry distribution were conducted within Glacier Bay proper between 1996 and 1998. These surveys indicated that the entire coastline within Glacier Bay proper, with the exception of those areas closed to protect sensitive resources or where topography precludes access, is used for backcountry campsites. Some of the more heavily used campsites were in areas near tidewater glaciers and kayaker/camper drop-off locations. Based on these results, NPS concludes that most camping occurs within 0.25 miles of the shore (NPS, 1984). Upland camping and hiking opportunities are limited because of the lack of developed trails, steep topography, and dense vegetation.

3.12.1.1 Kahtaheena River Area (Project Area). The proposed project area lies 5 miles east of Gustavus within GBNPP wilderness on the western slope of Excursion Ridge. Rink Creek Road connects the town with this area terminating just east of Rink Creek near the Bear Track Inn. Visitors come to the proposed project area to walk and view wildlife and scenery. Access to the site requires visitors to either walk along the shoreline below the mean high tide line or travel across private property. GEC compiled recreation use estimates for this area using two sources: observations by biologists in the field and a recreation survey.

In 2,836 hours of field work between 1997 and 2001, 34 recreationists were observed within the proposed project study area, all of whom were using the shoreline (table 3.12-1). In 475 hours of observation on the shore between May and September (the summer season), 32 individuals were spotted. Given the dense vegetation in the area, other visitors could have been present but not visible. Because there are no trails or trail heads in the area the majority of recreationists visiting the area probably use the shore and the stream up to the Lower Falls as a trail.

Table 3.12-1. Summary of observer hours and observations of recreationists in the proposed project area. (Source: GEC, 2001b)

	Summer (Observation Hours) (May-Sept)	Summer (Recreationist Sightings)	Winter (Observation Hours) (Oct-April)	Winter (Recreationist Sightings)	TOTALS (Recreationists /Observation Hours)
The Shore	475	32	81	2	34/556
Up to Falls	485	0	108	0	0/593
Uplands	1,403	0	284	0	0/1,687
Totals	2,363	32	473	2	34/2,836

Note: These figures are based on recollections from research staff and the time they spent in the field during non-recreation research.

Assuming the observations occurred evenly across both weekends and weekdays, the data indicate recreational use along the shore of the proposed project area is limited to 32 hikers approximately every 40 recreation days[38] (or 0.8 person per recreation day) in the summer. Projecting over a 150-day summer recreation season would yield approximately 120 people visiting the shore and no visits to the Lower Falls. In comments on the draft EIS, GEC indicated that our estimates were too high, and it provided lower estimates in its comments. We have modified the data consistent with the dates backcountry visits occurred within GBNPP and based on the GBNPP backcountry surveys. Using the population growth rate of Gustavus (4.7 percent, or 1.047 as described in section 3.16, *Socioeconomics*), the number of visitors would increase to 476 people, or roughly 3 people per recreation day, over the next 30 years.

In addition to the field observations, GEC conducted 41 interviews with Gustavus residents, guests at the Bear Track Inn, representatives of environmental organizations, and one land allotment heir. The interviews were qualitative and designed to estimate respondents' view of the aesthetic and wilderness value of the proposed project area. Questions for estimating visitor use of the area included: "Have you been to the area? Where? Why? How often? and Did you see other people or signs of them?"

Overall, respondents indicated that most of their activity was confined to the shore. Twelve of the 41 respondents visited the Lower Falls at some time, five respondents said they had also been to the Upper Falls, and a few ventured to the uplands. Respondents reported visits to the Kahtaheena River from 0 to 40 times in their lifetime and the Lower Falls from 0 to 20 times.

Based on the qualitative nature of the survey, some basic assumptions have been made to quantify the number of visitors to the Lower Falls. Of the 35 residents surveyed, 10 have visited the Lower Falls indicating that only 2 of the original 25 randomly selected residents (or 8 percent) visited the Lower Falls. Assuming these were annual visits, an estimated 34 residents visited the Lower Falls in 2001 (or 8 percent of the 429 people living in Gustavus in 2001). In addition to this estimate, the owner of the Bear Track Inn stated 5 to 10 guests and employees visit the Lower Falls and 20 to 25 guests visit the mouth of the creek each year. Thus, the estimated maximum number of annual visits to the Lower Falls would be 44 (the combined total of the 34 residents plus the 10 guests at the Bear Track Inn). Using the population growth rate of 1.047, the number of visitors would rise to 175 people over the next 30 years. In comments on the draft EIS, GEC indicated that our estimates were too high, and it stated that its estimates provided in the comments on the draft EIS are more accurate. We modified the data because precise estimates do not exist. As such, staff used an appropriate methodology for approximating a conservative estimate of recreational use of the area.

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38 A recreation day is defined between 8 am and 8 pm, or 12 hours. A total of 475 hours of observation divided by 12 hours per recreation day equals 40 recreation days.

As reported by Baker (2001), most residents did not see other people when visiting Gustavus Flats or the lower reaches of the Kahtaheena River. Overall, use estimates between May and September indicate a total of 145 people visited the shoreline, and 44 people visited the Lower Falls in 2001. In comments on the draft EIS, GEC indicated that our estimates were too high. As stated above, we have modified the data to yield a conservative estimate of recreational use of the area.

The Recreation Opportunity Spectrum (ROS), a framework for assessing the recreational opportunities commonly used by the U.S. Forest Service, is useful in characterizing the state of recreation opportunities within the proposed project area. Based on the ROS described by Clark and Stankey in 1980, the Kahtaheena River area is characterized as offering primitive recreational opportunities based on the following criteria: access is difficult, roads do not exist, onsite management does not exist, social interaction is absent, and an interparty contact does not exist.

3.12.1.2 Proposed Land Exchange Parcels

Long Lake

The four Long Lake parcels proposed for land exchange with the state are inholdings within WSNPP near Long Lake on McCarthy Road. Access into the Long Lake area is primarily by overland traffic along the McCarthy Road; however, local residents do use an airstrip on private property. The parcels, currently owned and managed by ADNR, are free of human development and managed for recreation and fish and wildlife habitat. Recreation near the Long Lake parcels includes sightseeing, hiking, and fishing.

McCarthy Road, one of only two improved roadways within WSNPP, lies along the southern shores of Long Lake (LDN, 2000). The Alaska Department of Transportation (ADOT) manages this dirt and gravel roadway. Maintenance of the road is seasonal, from May through October, and the roadway is not plowed during the winter months (LDN, 2000). In 2000, approximately 8,000 visitor vehicle trips occurred on the McCarthy Road, in comparison to approximately 850 trips by residents and employees in the area. Alaska land managers and ADOT estimate that these numbers will increase to approximately 13,800 trips for visitors and 1,096 trips for residents and employees by the year 2025 (LDN, 2000). Most of the land around the McCarthy Road side of Long Lake is privately owned, limiting the public's access to the lake for fishing and other recreational activities (personal communication with D. Sharp, WSNPP, on April 20, 2003). Space for camping is limited to the ADOT right-of-way and only in small recreational vehicles or trucks. WSNPP staff have not estimated the percentage of McCarthy Road traffic that stops at Long Lake. Based on the limited access and parking and the lack of developed facilities in this area, the percentage of vehicle traffic along McCarthy Road that stops at Long Lake is probably low. ADOT and interested public are currently working on plans to improve McCarthy Road, although they have not completed a formal plan.

Klondike Gold Rush

NPS identified approximately 1,053 acres of land along the Chilkoot Trail of the KGNHP as suitable land to exchange with the state in accordance with the proposed project. For ease of analysis, the lands in this area are divided into a southern group and a northern group.

The southern group of parcels contains approximately 230 acres of land that is completely encompassed in the KGNHP. The lands are generally flat and occupy portions of the Taiya River floodplain just north of the town of Skagway. Recreational fishing occurs in the area, but the primary human use is hiking the Chilkoot Trail, which begins within this parcel. There are currently no commercial or residential developments in the southern group of parcels (NPS, 1996; ADNR, 2002a).

The northern group of parcels includes approximately 825 acres of land along the Chilkoot Trail in the upper Taiya River drainage. There are no roads servicing these lands, and human access is limited to hiking. There are historical structures and limited services for hikers along the trail, such as Canyon City and Pleasant Camp. The extent to which recreational fishing occurs in this area is unknown (NPS, 1996; ADNR, 2002a).

Overall, the Chilkoot Trail receives approximately 3,000 overnight hikers per year from May through September. The lower portion of the Chilkoot Trail receives a significantly larger number of day hikers: approximately 11,500 (personal communication with T. Steidel, KGNHP park staff, on April 21, 2003). The Chilkoot Trail is primarily used for backpacking, though the lower part of the trail near Dyea receives a number of other types of commercial recreation interests including river rafting, horseback riding, ranger-led tours, and bicycle tours. These activities service approximately 30,000 day use clients in a season (personal communication with T. Steidel, KGNHP park staff, on April 21, 2003).

3.12.1.3 Wilderness Designation Parcels

Unnamed Island near Blue Mouse Cove

The unnamed island southeast of Blue Mouse Cove is located at the opening of the cove in the west arm of Glacier Bay. The 789-acre island was originally considered for the GBNPP ranger station currently located at Bartlett Cove and thus purposely not developed. NPS records indicate one popular site was visited by 29 groups over the last 4 years (personal communication with A. Banks, Recreation Planner, GBNPP, on April 24, 2003). The island is usually passed by kayakers and motorized water craft entering and leaving Blue Mouse Cove. The near-shore environment of the island is rocky and shallow offering few anchorages for motorized vessels. The island is roughly 0.25 miles from the Blue Mouse Cove floating ranger station operated by NPS, which is open only during peak visitor season.

Cenotaph Island

Cenotaph Island is situated in Lituya Bay on the west coast of GBNPP. The island is one of the three lands besides the unnamed island near Blue Mouse Cove and the parcels at Alsek Lake within GBNPP outside the Bartlett Cove area not designated as wilderness but covered under the GBNPP Wilderness Visitor Use Management Plan. The area is in a remote part of GBNPP and only reachable via a long boat ride or float plane. The majority of use associated with the island is based on its protective location in Lituya Bay, which provides a safe anchorage for vessels traversing the exposed outer coastline of GBNPP. GBNPP estimates recreation use of the island is minimal (personal communication with A. Banks, Recreation Planner, GBNPP, on April 24, 2003).

Alsek Lake

The lands proposed for wilderness designation near Dry Bay are near Alsek Lake on the Alsek River in northern GBNPP. These parcels are one of three parcels within GBNPP besides the unnamed island near Blue Mouse Cove and Cenotaph Island outside the Bartlett Cove area not designated as wilderness lands but covered under the GBNPP Wilderness Visitor Use Management Plan. This area is used primarily for dispersed camping and hiking associated with rafting trips down the Alsek River. Rafting occurs from July 1 through September 10, and human use of the area is limited outside of the boating period. NPS rangers recorded 810 rafts taken out at Alsek Lake in 2002, amounting to 2,470 user nights. Rangers also identified 6 overnight stays not associated with rafting trips and 14 day users. Camping by boaters at Alsek Lake is limited to two consecutive nights. Overall use of the area is limited by permit, which only allows a maximum of one, 15-person party per day to take out at Dry Bay, with commercial trips alternating with private boaters. Not all dates to take out rafts are currently allocated in any given permit season. There are no roads that service this area, and access is generally by airplane, kayak, raft, or jet boats (NPS, 1989b). The area is free of developed structures, and human effect is generally limited.

3.12.2 Public Access and Safety

3.12.2.1 Kahtaheena River Area. The isolation of the town of Gustavus and GBNPP considerably limits public access to the region. Because Gustavus is not connected to other settlements via a highway, access is limited to air or boat travel. Airport facilities in Gustavus consist of a state-owned airport with jet capability (757) and a 6,700-foot-long asphalt runway. Float planes typically land in nearby Bartlett Cove. Air traffic in the Gustavus area is relatively high during peak summer months (ADCED, 2002). From June to September, Gustavus is served by 737 jet service daily. Daily flights from the Gustavus airfield to and from Juneau are routed about 0.5 miles offshore and seldom over the Kahtaheena River area (Baker, 2001; ADCED, 2002). Visitors wishing to visit the town must make arrangements with air travel purveyors or smaller boats/ferry operators with service to Gustavus. Freight arrives to the town of Gustavus and the surrounding area by barge (ADCED, 2002).

The primary roads in Gustavus are a 10-mile-long local road connecting Bartlett Cove with the airport and the Rink Creek Road, which extends approximately 5 miles from Gustavus out to the western edge of the Kahtaheena River study area (ADCED, 2002). Rink Creek Road ends approximately 1.5 miles west of the Kahtaheena River, so there is currently no vehicle access to the study area. Loggers developed access into the Native allotments for logging activities between 1969 and 1973, which resulted in a primitive road linked to the Gustavus road system (Streveler, 1999). This road has since been abandoned and sections are revegetated to the point of being impassable. The Kahtaheena River area is accessed by walking into the area through private lands, landing a boat on the shoreline within NPS-designated lands, walking into the area from NPS lands north of the private lands, walking into the area across state and federal (belonging to the Federal Aviation Administration) lands near the Gustavus airport, or hiking the shore below the mean high tide line. The most common mode of human access to the area is to hike from the end of Rink Creek Road across the tideland flats that extend from the road terminus to the mouth of the Kahtaheena River (Baker, 2001).

The town of Gustavus provides some public services to visitors and residents. The Gustavus Community Association Emergency Response provides rescue services, and the Gustavus Community Clinic provides emergency medical services. The town of Gustavus has a memorandum of understanding with GBNPP for some law enforcement services. The town does not offer any police services.

3.12.2.2 Proposed Land Exchange Parcels. Access into the Long Lake area is limited to overland travel along McCarthy Road. The south shore of Long Lake is visible from McCarthy Road; however, private property in the area severely limits direct access from the road to the lake although it is possible on foot.

Access to the Chilkoot Trail head is possible from the city of Skagway's road network. Access onto ADNR lands within KGNHP is limited to foot traffic and horseback riding as the parcels are upland and difficult to reach. The state is responsible for police, and search and rescue type public safety in the area, which has been delegated to the city of Skagway, along with providing volunteer firefighters in the event such services are required along the Chilkoot Trail. NPS is responsible for initial response and evaluation of risks, hazards, and injuries and transfers leadership to Skagway police once they are available. KGNHP stations full-time employees at the road-accessible areas of the Chilkoot Trail head, and during the summer hiking season an employee is stationed at Sheep Camp on the Chilkoot Trail. GBNPP employees are equipped with radios capable of communication throughout the park and the city of Skagway, as well as back up satellite phones.

3.12.2.3 Wilderness Designation Parcels. Access to the unnamed island near Blue Mouse Cove and Cenotaph Island is limited to watercraft and float planes. In the lower GBNPP, NPS maintains a ranger station at Bartlett Cove and, during the summer months, a floating station in Blue Mouse Cove. Search and rescue operations are the responsibility of GBNPP.

Access to Alsek Lake is usually via float trips down the Alsek River or plane to Alsek Lake. The Yakutat Ranger District is responsible for recreationists' safety within this area of GBNPP and delegates one park ranger with responsibility for Alsek Lake. The ranger is supplied with both a radio and satellite phone.

3.13 WILDERNESS

Understanding the values for which wilderness lands in general and Glacier Bay in particular are designated is essential for evaluating the effects of the proposed action and alternatives. Because wilderness in Glacier Bay is part of the much larger National Wilderness Preservation System, we include a discussion of the implications for the entire system, which serves as the context for the proposed project. Throughout the National Wilderness Preservation System, wilderness lands are valued for their unique recreational, scientific, historic, and inspirational values. Activities that may harm these values within the context of wilderness are subject to administrative and policy scrutiny.

First we discuss the legislative history of wilderness in GBNPP, including the Wilderness Act of 1964 and ANILCA, which are the two primary relevant pieces of legislation. Next, we present an overview of the wilderness within GBNPP and its role in the National Wilderness Preservation System. Finally, we provide the location and an overview of the values inherent in the lands under consideration for ownership and status change in this final EIS, including a detailed description of the lands based on the criteria of capability, availability, and need.

Hendee et al. (1990) describe three central themes related to wilderness values: experiential, or the direct value of a wilderness experience; scientific, or the value of wilderness in providing baseline information; and symbolic/spiritual, the values of wilderness to the nation and the world regardless of visitation. Experiential values are those associated with direct visitation to wilderness areas. Western society is increasingly drawn to the benefits provided by wilderness experiences–closeness to nature and a sense of independence, freedom, solitude, and simplicity–as well as any associated aesthetic and mystical qualities. See section 3.12, *Recreation Resources*, for discussion of experiences associated with backcountry visitation at GBNPP.

Wilderness provides important values for science that eventually may lead to a better understanding of human effects on the earth and its life support systems. Because wilderness areas retain characteristics of undisturbed ecosystems, they represent the best way of evaluating and understanding some major components of human-caused environmental change (Vitousek et al., 2000). The last theme of wilderness described by Hendee et al. considers the symbolic and spiritual values inherent in wilderness that provides us a place outside an increasingly mechanized and fast-paced world. Wilderness symbolizes stability, simplicity, and timelessness, and it provides opportunities to enjoy and appreciate wildness. This last theme does not rely on direct visitation to the wilderness; these values are inherent in the landscape and can provide important social benefits to the public just by knowing wildernesses exist.

Economists classify such values as use and non-use values. Use values occur when the benefits of a resource are directly consumed or used by people, such as backcountry visitors enjoying a trip to the wilderness (see section 3.12, *Recreation Resources*). Non-use values are not associated with actual or direct enjoyment of a resource or area, but are still often very important. Such non-use values can be classified as existence value (just knowing that an area exists is worth something to somebody); bequest value (the value of an area or resource to future generations); or option value (a person wants the option to use the area or resource sometime in the future). The importance of such non-use values is often reflected in public comments on nationally significant resources that are distant from population centers, where the commenter may have little chance of ever visiting the area.

Aplet et al. (2000) describe naturalness and freedom as characteristics of wilderness that, when examined in two-dimensional space on continua, moves from the built environment (cityscapes) to increasingly wild environments (wilderness). Aplet et al. describe characteristics of both naturalness and freedom in a landscape. For freedom, the characteristics are:

1. the degree to which land provides opportunities for solitude;

2. the remoteness of the land from mechanical devices; and

3. the degree to which ecological processes remain uncontrolled by human agency.

The attributes that contribute to the naturalness of the land are:

1. the degree to which it maintains natural composition;

2. the degree to which it remains unaltered by artificial human structure; and

3. the degree to which it is unpolluted.

Although each attribute need not exist at an absolute maximum in wilderness, collectively, they define the qualities of freedom and naturalness and therefore describe the important elements of wilderness that are potentially affected by human action.

Landres et al. (2000) and Cole (1996; 2001), among others, agree that these attributes are the defining elements of wilderness.

3.13.1 The Regulatory Environment

Unlike other components of the affected environment, wilderness is a holistic concept, and the notion of it as a resource is different from that of individual attributes such as wildlife, water, fisheries, soils and scenery. It does not represent a particular biophysical attribute, but rather a sense of naturalness and untrammeled character that occurs within a pristine environment that is largely unaffected by human activity. The Wilderness Act of 1964 (Pub. L. 88-577) defines wilderness as follows:

> *. . . an area of undeveloped Federal land retaining its primeval character and influence, without permanent improvements or human habitation, which is protected and managed so as to preserve its natural conditions and which (1) generally appears to have been affected primarily by the forces of nature, with the imprint of man's work substantially unnoticeable; (2) has outstanding opportunities for solitude or a primitive and unconfined type of recreation; (3) has at least five thousand acres of land or is of sufficient size as to make practicable its preservation and use in an unimpaired condition; and (4) may also contain ecological, geological, or other features of scientific, educational, scenic, or historical value.*

The 1916 Organic Act states that the purpose of the national parks is to "conserve the scenery and the natural and historic objects and the wild life therein and to provide for the enjoyment of the same in such manner and by such means as will leave them unimpaired for the enjoyment of future generations" (16 USC §1). In this case, the resource of wilderness would be left unimpaired for enjoyment of future generations.

Public lands in Alaska designated as wilderness under the provisions of ANILCA differ in some respects from those designated outside of Alaska. Section 1110 of ANILCA permits " . . . the use of snowmachines, motorboats, airplanes, and non-motorized surface methods for traditional activities . . . such use shall be subject to reasonable regulations by the Secretary to protect the natural and other values of the conservation system unit." However, nothing in ANILCA contradicts the basic purposes of wilderness in terms of management. Administration of wilderness in Alaska's national parks is therefore different than administration in non-Alaskan national parks because some activities that are considered incompatible in other locations are allowed to occur in Alaskan wilderness. For example, motorized access is allowed for "traditional activities." The provisions of ANILCA (Section 1110(a)) are:

> *Notwithstanding any other provision of this Act or other law, the Secretary shall permit, on conservation system units . . . the use of snowmachines (during periods of adequate snow cover, or frozen river conditions in the case of wild and scenic*

rivers), motorboats, airplanes, and nonmotorized surface transportation methods for traditional activities (where such activities are permitted by this Act or other law) and for travel to and from villages and homesites. Such use shall be subject to reasonable regulations by the Secretary to protect the natural and other values of the conservation system units . . . and shall not be prohibited unless, after notice and hearing in the vicinity of the affected unit or area, the Secretary finds that such use would be detrimental to the resource values of the unit or area (94 Statute 2371).

3.13.2 Wilderness in GBNPP

Under ANILCA, 2,658,186 acres of GBNPP's total 3,283,168 acres are congressionally designated as part of the National Wilderness Preservation System (table 3.13-1).

Table 3.13-1. Terrestrial designations within GBNPP. (Source: NPS, 2002)

Designation	Acres
Wilderness land	2,610,548
Non-wilderness preserve land	54,811
Non-wilderness land	8,504
Total	2,673,863[a]

[a] Acreage totals in this table differ from those listed in section 701 of ANILCA because of the use of more exact mapping techniques and isostatic rebound.

These wilderness resources include most of the land in GBNPP and five marine wilderness waterways: Adams Inlet, the Beardslee Islands, Dundas Bay, the Hugh Miller/Scidmore complex, and Rendu Inlet. These marine wilderness waterways comprise 47,638 acres (about 8 percent) of the total marine waters in the park.

Much of the designated terrestrial wilderness in the park consists of glaciers and rock outcroppings. Other land cover involves brush and early successional stage forests as lands have become available for plant growth. Old-growth forests relatively accessible to the general public occur in only a few places in designated GBNPP wilderness. One of these places is the Kahtaheena River drainage (see land descriptions of this area in section 3.2.1, *Kahtaheena River Area*).

3.13.3 GBNPP Wilderness in Relation to the National Wilderness Preservation System

Currently, Alaska has 48 congressionally designated wildernesses. With the passage of ANILCA, eight areas were designated as wilderness under NPS management. Those eight wilderness areas, though only about 1.02 percent of the total number of areas in the United States, contain nearly 34 million acres or 13 percent of the total wilderness acreage in all the United States. In Alaska, Glacier Bay wilderness represents nearly 8 percent of the total NPS wilderness and nearly 5 percent of the total acres of wilderness for all agencies that manage wilderness (Wilderness Information Network, 2002).

More important than its size, the Glacier Bay wilderness offers some of the most unique resources and values in the National Wilderness Preservation System. With its calving tidewater glaciers, temperate rainforest, plant diversity, and terrestrial and marine wildlife, the Glacier Bay wilderness is an unparalleled intact ecosystem. In addition, natural processes such as glaciation and isostatic rebound occur in this area in combination with other pristine attributes, such as the interface with marine ecosystems. It is these values that provide Glacier Bay with important wilderness values that the 1916 Organic Act of the NPS mandates to protect in an unimpaired fashion.

Also, Glacier Bay contains the only designated marine wilderness waters in all of Alaska for any federal agency and contains one of only two designated marine wilderness waterways in all of the United States (the other one is the Marjory Stoneman Douglas Wilderness, part of the Everglades National Park in Florida). Thus, activities and policies in this wilderness may have a disproportionate effect on policies elsewhere in the National Wilderness Preservation System.

3.13.4 Parcels of Land with Potential Change in Land Status and Framework to Characterize Affected Lands

The affected environment in terms of wilderness resources for the proposed action and alternatives includes from 680 to 1,145 acres, with GEC's proposal affecting 850 acres in the Kahtaheena River drainage currently designated wilderness; three parcels of land currently designated park land (not wilderness); an unnamed island near the mouth of Blue Mouse Cove; Cenotaph Island in Lituya Bay; and lands at Alsek Lake. The two islands are currently managed as if they are designated wilderness.

To effectively characterize the potentially affected lands, we evaluate their suitability as wilderness in terms of capability, availability, and need. We base our analysis on a modification of the Wilderness Attribute Rating System (WARS) developed by the U.S. Forest Service along with public interest groups in 1977 and used to inventory the wilderness characteristics of roadless areas during the second Roadless Area Review and Evaluation (RARE II) process. WARS measures an area's wilderness quality, largely based on the attributes that are important as components of the legislatively defined notion (in the Wilderness Act) of wilderness, including: natural integrity, apparent naturalness, outstanding opportunity for solitude, and primitive recreation opportunities. It is the only systematic process for evaluating the suitability of lands for wilderness, and we apply this framework to the lands involved.

The capability of a potential wilderness is the degree to which that area contains the basic characteristics (attributes) that make it suitable for wilderness designation without regard to its availability for or need as wilderness. We consider the following attributes:

- Untrammeled - Lack of evidence of human control or manipulation.
- Undeveloped - Lack of evidence of modern human presence, occupation, modification.
- Natural ecological systems are substantially free from effects of modern civilization.
- Opportunities for solitude or primitive and unconfined recreation remoteness, solitude, freedom, risk, challenge.

Determination of availability is conditioned by the value of and need for the wilderness resource compared to the value of and need for other resources. In this analysis, we describe historic land uses and potential conflicts with other uses. We also look at the effect that wilderness designation and management is likely to have due to the public's increased interest in wilderness lands. Availability analysis sets the foundation for understanding the consequences of alternative land designations.

We analyze the need for an area to be designated as wilderness based on the degree to which it contributes to the local and national distribution of wilderness. Important considerations include the amount of wilderness adjacent to the area under consideration, the evidence of public need for keeping the existing wilderness or for additional wilderness (demonstrated through public involvement), and the geographic distribution of landforms and ecosystems that closely match the area. This component allows us to better understand the significance of the potential land de-designation and designation actions.

3.13.4.1 Kahtaheena River Area (Project Area). The Kahtaheena River drainage is bounded by Excursion Ridge to the north and east, Gustavus Flats and the town of Gustavus to the west, and Icy Passage to the South. Kahtaheena River is unique in GBNPP in that it is relatively easily accessible to visitors that wish to hike in terrestrial wilderness and offers a mix of low and high elevation ecosystems, waterfall viewing, and exploration of old-growth spruce and hemlock forests. There are two Native allotments just to the south of the project area and outside the park boundary that have been logged or thinned in the past. Otherwise, the area is completely surrounded by NPS-administered lands and lands designated wilderness.

Within the drainage, the project area encompasses approximately 850 acres. While a crude, non-designated trail does exist to the Kahtaheena River drainage and to the Lower Falls area, it is difficult to find and challenging to follow. Both characteristics increase the value of the drainage as wilderness.

Many mammals and birds call the Kahtaheena River drainage home, and several others are transient visitors. See section 3.8, *Wildlif*e, for further discussion. The aquatic system contains remnant and small populations of Dolly Varden and represents an ecosystem type that is relatively rare within GBNPP (see section 3.6, *Fisheries*).

Capability

The Kahtaheena River drainage is essentially an untrammeled area, with very little evidence of human manipulation or impact. Although some human created trails exist, they are difficult to find and follow because of the growth of vegetation in this ecosystem. The dense vegetation and multi-storied canopy provide excellent opportunities to experience solitude and unconfined recreation. Although the area is relatively close to civilization, within 1.5 miles of the Rink Creek Road and the Bear Track Inn, there is considerable challenge associated with hiking due to the lack of an improved trail, the unevenness of the ground in the area, the difficult walk across tidal flats, the steepness of the terrain, and the occurrence of inclement weather.

Availability

The project area is bounded by demarcated natural features, including Excursion Ridge to the northeast and the smaller ridgelines describing the Kahtaheena River drainage itself (see figure 3-1 in appendix A, which shows this area including Excursion Ridge).

As population increases in the United States, Alaska, and the community of Gustavus, and as visitation to the park increases, this area will become increasingly valuable as wilderness.

Need

GBNPP has more than 2.7 million acres of wilderness (2.6 million of which are land based [see table 3.13-1]). On both a national scale (850 acres of 105 million acres nationwide) and a local park scale, the amount of land under consideration for de-designation as wilderness in the Kahtaheena River drainage is infinitesimally small. When looking at the relative contribution of an old growth spruce/hemlock ecosystem to the entire Glacier Bay ecosystem, the value is low. However, because the Kahtaheena River is one of the very few terrestrial wilderness portions of the park that is relatively accessible to local residents and visitors, it has natural features of high value as attractions (two prominent waterfalls and old growth forest); it therefore is highly valuable as wilderness on the GBNPP scale, although it is not unique in southeastern Alaska. Public use is very low.

Summary

The wilderness qualities (its untrammeled character, lack of evidence of human impact, ecosystem substantially free from effects of modern civilization, and outstanding opportunity for solitude) of the Kahtaheena River drainage are very high because of its place as a relatively scarce ecosystem within GBNPP, ease of access, and abundant wildlife and fish.

3.13.4.2 Unnamed Island near Blue Mouse Cove. This island is approximately 789 acres and lies at the opening of Blue Mouse Cove in the main part of Glacier Bay. It has numerous campsites and offers safe anchorage for motorized vessels off its southeastern shores. The island is situated 0.25 mile from the Blue Mouse Cove floating ranger station.

During the planning phase of wilderness designations to park land as part of ANILCA (1980), this island was singled out as a potential future location for a ranger station, thus eliminating it from consideration as designated wilderness. Currently, the island is managed as if it was wilderness under the park's GMP (NPS, 1984) and includes no roads, structures, or other permanent human-made improvements (see section 3.13.2 for policies). While the island is managed as wilderness, it lies immediately adjacent to major motorized vessel routes in Glacier Bay, including cruise ships and tour boats. Blue Mouse Cove is a popular area for anchoring private vessels. The sounds from these vessels and activity often intrude into campsites and affect the feeling of wilderness. To the immediate north, activity at and adjacent to the floating ranger station often intrudes into the feeling of naturalness, solitude, and remoteness for which this island is currently managed. Section 3.7, *Vegetation and Wetlands*, contains a description of vegetation and land cover of this island.

Capability

This island is free of human-made structures. There is no noticeable evidence of modern human occupation or modification. However, marine mammals, birds, and terrestrial wildlife in the vicinity are rarely out of view of motorized vessels moving through the main bay, traveling into and out of Blue Mouse Cove, or anchored off the southwest shore. The presence of motorized vessels can interfere with wilderness and decrease the sense of naturalness found there for non-motorized and other backcountry visitors. Opportunities for wilderness-dependent recreation and solitude are limited because the island is open to main Glacier Bay and is situated at a point in a narrow part of the bay where many motorized vessels pass. The island is also is near to Blue Mouse Cove, where a floating ranger station is stationed during the tourist season.

The island currently acts as a buffer zone between the main bay, Blue Mouse Cove, and the non-motorized Hugh Miller/Scidmore complex in Glacier Bay proper. Glacier Bay proper and some parts of Blue Mouse Cove are currently open to motorized vessels. Other parts of the cove and the Hugh Miller/Scidmore complex are administratively designated as marine wilderness. This buffer zone provides a shield from the sounds, smells, and potential spills these motorized vessels can produce.

Availability

This island was specifically not chosen for wilderness designation because it was thought to be a good place to build a ranger station if the park decided to move its current location from Bartlett Cove (personal communication from M. Sharp, park pilot, in air over Blue Mouse Cove, with C. Besancon, on August 16, 2002). This plan has since been abandoned.

Blue Mouse Cove currently is the most utilized protected waterway for anchoring boats in all of GBNPP as self reported in the 1997-1999 backcountry visitor survey (NPS, 2000). Of the 1,660 reported anchorages in GBNPP, 330 of them were within Blue Mouse Cove and to the south of the unnamed island. If this island were designated wilderness, there may be potential conflicts for non-motorized (sea kayak) visitors to the island if their expectations include solitude from anchored motorboats offshore from campsites.

Need

The wildlife and plant species found on the island or that inhabit the bay are not unique and are represented elsewhere in GBNPP. Beyond adding to the number of acres of wilderness in GBNPP, designating this island as wilderness would not serve to protect this island beyond the current level of protection because there is little likelihood of future development.

Summary

While the wilderness qualities of the island itself are high, the current intrusion of the sights and sounds of motorized vessels operating nearby limit opportunities to enjoy solitude and escape the impacts from civilization.

3.13.4.3 Cenotaph Island. The French explorer La Perouse named this island "Cenotaph," meaning "empty tomb" after losing 21 of his men to an accident in the dangerous waters surrounding this 280-acre island at the entrance to Lituya Bay. In 1786, he erected a monument on Cenotaph Island to his lost men. Habitation on this island includes cabins, sheds, and the farming of foxes. In 1958, a giant earthquake caused a landslide into Lituya Bay which created a massive tidal wave that swept across the bay destroying the structures on the island, trees up to an elevation of 1,700 feet, and sunk two fishing vessels killing two persons. Currently, the island is managed as if it were wilderness under the park's GMP though it does not hold that formal designation. There are few visual remnants of the destroyed structures.

Lituya Bay can only be reached by a long, and somewhat challenging, motorized boat or float plane trip up the Outer Coast of GBNPP, making it very difficult to access. The potential for further geological catastrophes is relatively high, resulting in some risk to visitors venturing into the bay.

Capability

Cenotaph Island, though it currently contains debris from some past structures destroyed by the earthquake and tidal wave in 1958, appears in its natural state. This is due to the length of time since the tidal wave, and also because the vegetation on the island has covered up signs of human habitation. Lituya Bay is not currently designated a wilderness waterway, nor is it managed for non-motorized use. Motorized vessels enter this protected bay and anchor there overnight, thus not offering a high quality wilderness experience for those visitors seeking solitude away from the sights, sounds, and smells of motorized vessels.

Because of the presence of extreme Gulf of Alaska weather and ocean conditions, the treacherous entry, and a long wait for help in case of emergency, visitors to Lituya Bay and to Cenotaph Island can experience a great deal of risk and challenge.

Availability

From early visits by native indigenous peoples to western explorers, this island has a long history of human visitation and habitation. Several cabins and associated outbuildings as well as past fox farming characterize the rich history of this island. Catastrophic earthquakes and tidal waves have influenced the vegetation of this island. The island shows little remaining evidence of human occupation, and thus now appears to be untrammeled and natural.

Need

Currently the only other islands not designated as wilderness in GBNPP include all of the islands within Alsek Lake and the unnamed island at the mouth of Blue Mouse Cove. There are approximately 2.6 million acres of wilderness adjacent to the island. Public scoping has not shown a public need to protect the resources of this island as designated wilderness. Beyond adding to the number of acres of wilderness in GBNPP, designating this island as wilderness would not serve to protect this island beyond the current level of protection because there is little likelihood of future development.

Summary

Because of the high historical incidence of earthquakes and tidal waves in this area, there is very little chance that the park would build structures on this island. Not enough is known about the vegetation and wildlife to assess the relative scarcity or abundance of similar landscape/vegetation types within GBNPP or the extent to which the values on the island would be a significant addition to the GBNPP wilderness.

3.13.4.4 Alsek Lake Lands. The Alsek Lake Lands encompass about 2,270 acres located in the northwestern part of GBNPP. The potential wilderness designated lands lie immediately adjacent to Alsek Lake, which is created by a large bend and low lying area into which two glaciers calve and the Alsek River flows. The calving glaciers form icebergs that flow down the river and out to sea past campsites on the river bank. The vegetation for this area has not been described. Currently, the area is managed as if it were wilderness.

As noted in section 3.6.2.2, the terrestrial water interface is used during the summer as the last night's stop for people rafting or kayaking the Tatshenshini-Alsek River. Any human impacts observed in this area would most likely be a result of this use. No other evidence of human use or occupancy has been recorded. See section 3.2.1, *Kahtaheena River Area*, for additional description of this area.

Capability

These lands are near Alsek Lake on the Alsek River in northern GBNPP. The lands are pristine and undeveloped with no roads or other human-made structures present. Between July 1 and September 30 (the permitted boating season), the shoreline is often utilized for camping by rafters. No motorized vessels are permitted in Alsek River above Gateway Knob, so there are excellent opportunities for solitude.

Availability

The U.S. Forest Service managed lands in this area immediately prior to ANILCA. These lands were designated as part of GBNPP when ANILCA came into effect, but were not designated as wilderness. Other than the current recreational use occurring on these lands, there are no other direct human uses.

Need

Though not currently designated wilderness, these lands are managed as such under the Wilderness Visitor Use Management Plan. The landforms and species diversity found in this area are not unique and are well represented elsewhere in GBNPP. This area is currently not designated as wilderness, though it is managed as *de facto* wilderness. However, the pristine qualities found in the Gateway Knob area (encompassed by the lands under consideration for wilderness designation) could be under future threat for development due to the easy accessibility and the outstanding vistas.

Summary

The Alsek Lake lands, especially the Gateway Knob area, contain exceptional vistas and pristine landscapes of considerable significance to backcountry visitors. Formalized wilderness designation could prevent future developments from taking place and preserve for future generations the current level of high quality pristine wilderness.

3.14 PARK MANAGEMENT

3.14.1 Kahtaheena River Area (Project Area)

The lands in the Kahtaheena River study area have been designated by Congress as wilderness areas and are managed for low-impact activities, in accordance with the management guidelines for wilderness lands throughout GBNPP. Wilderness lands in the park are meant to provide for public use, understanding, research, and enjoyment, while protecting the natural processes and wilderness character (NPS, 1984). Wilderness areas are managed so that the potential resource effects from visitor use will be negligible and not readily apparent (NPS, 1989a). To accomplish this, camping group sizes are held to a maximum of 12 persons and no group may occupy a campsite for more than 3 consecutive nights (NPS, 2002; 1989a). No permanent shelters, pit toilets, fire grills, bear-proof lockers, or other facilities are allowed in the wilderness areas (NPS, 1989a).

Hunting and trapping are not allowed in GBNPP, but sport fishing is permitted in park streams, including the Kahtaheena River, in accordance with ADFG freshwater fishing regulations (36 CFR 13.21). In the park, certain items may be gathered by hand for personal use or consumption including: unoccupied seashells, all edible berries and fruits, edible mushrooms, and clams or mollusks taken in accordance with ADFG regulations (NPS, 2002).

Transportation within GBNPP is predominantly limited to motorized and non-motorized watercraft. Use of motorized vehicles (i.e., ATVs, snowmobiles) is prohibited, except on approved roads, parking lots, or specifically designated areas (36 CFR 2.18, 43 CFR 36.11). In addition, bicycles may only be used in specifically designated areas (36 CFR 4.30). Landing of helicopters in the wilderness lands of GBNPP is prohibited except in the event of an emergency or with prior approval from the GBNPP superintendent. USGS helicopters have landed periodically in the Kahtaheena River area to check the stream gages when weather and snow accumulation has prevented foot access. This use received prior approval by the GBNPP superintendent under a Special Use Permit.

There are no valid mineral extraction claims within the Kahtaheena River study area and no new claims are allowed within GBNPP (NPS, 1984). Thus, no land use activities associated with mineral extraction occur in the project area and no historical reports were found pertaining to such activities.

GBNPP is managed by NPS personnel. GBNPP employs 50 year-round people and an additional 45 during the summer months (mid-May to mid-September). Demand for personnel is increased during the summer months to account for increased visitation to the park. During the fiscal year 2002, there were 292,604 recreation visits to GBNPP. Emergency law enforcement in Gustavus is currently provided by NPS Law Enforcement personnel through a formal agreement with the state of Alaska, Department of Public Safety. Law enforcement personnel comprise 9 percent of the total GBNPP personnel.

3.14.2 Proposed Land Exchange Parcels

Long Lake

NPS currently has no jurisdiction over the potential exchange lands in the Long Lake area. However, in the GMP for WSNPP (1986), the lands around Long Lake are identified as high priority areas for acquisition. Since the lands are completely encompassed by the park, NPS is interested in ensuring that uses of these lands are consistent with the goals and objectives of WSNPP. The GMP cautions that subdivisions of state and private lands in the area are becoming more common and could increase human occupancy and use of the area, which could lead to increased stress on park infrastructure and natural resources. The plan also states that if NPS acquired these lands, they would be managed in the same manner as adjacent park lands (NPS, 1986).

Klondike Gold Rush

Most of the land proposed for transfer to NPS lies within KGNHP, although NPS does not currently own these lands. Under agreement with the state, NPS manages the lands directly associated with the Chilkoot Trail. NPS manages these lands primarily to protect cultural resources, while providing public access. Limited developments have been provided for use as camping shelters and sanitation services for users of the Chilkoot Trail. Efforts are being made, such as limiting group sizes and helicopter access, to protect the natural and cultural resources against potential adverse impacts from increased tourism.

3.14.3 Wilderness Designation Parcels

Unnamed Island near Blue Mouse Cove and Cenotaph Island

Although these islands are not currently designated as wilderness, they are surrounded by wilderness lands and are managed in the same manner. Therefore, NPS included these two islands in the GBNPP Wilderness Visitor Use Management Plan (1989a).

Alsek Lake

The Alsek River Visitor Use Management Plan (NPS, 1989b) states that the primary management goals for the area are to maintain the pristine nature of the Alsek River for use as a low-impact recreational area. Therefore, a maximum of 72 float trips are authorized on the Alsek River from July 1 through September 10, averaging one trip per day. Only 15 people are allowed in each float group on the river. Campers may spend no more than 3 consecutive days in a campground and camping must be conducted in a manner which minimizes disturbance to the area. No construction of facilities or improvements is permitted along the portion of the Alsek River within the park. However, some facilities (i.e., airstrip, lodges) have been constructed in the preserve along the south shores of the Alsek River near Dry Bay. Furthermore, no motorized vessels are permitted in Alsek River above Gateway Knob.

3.15 LAND USE PROGRAMS AND POLICIES

3.15.1 Existing Use

3.15.1.1 Kahtaheena River Project Area. For this analysis, the Kahtaheena River study area consists of the current NPS lands that would be exchanged, the two private Native allotments, and state lands that would be used for construction of the project access roads and transmission line (see figure 2-1 in appendix A), and private and state lands adjacent to these areas. The majority of the study area, approximately 1,145 acres, lies within GBNPP and would be transferred to the state upon approval of the land exchange. The acres of land exchanged would vary depending upon the alternative chosen. The parcels currently owned by the state that are proposed to be transferred to NPS are not contiguous to GBNPP, but are within or adjacent to WSNPP and KGNHP. Currently, the land managed by NPS in the Kahtaheena River area is preserved for its wilderness character, fish and wildlife habitat, and low-impact recreational use. The area has a natural character in that there has been relatively little human intervention and use.

Historical use of the area began with trapping and subsistence fishing in the vicinity of the Native allotments, although these uses likely extended beyond the boundaries of the allotments (Brakel, 2001). The Mills and George allotments were applied for in 1909 and conveyed in 1922. Under the Alaska Native Allotment Act of 1906, Albert Mills filed for the maximum allowable 160 acres at Kahtaheena River, but in 1922 he was granted only 94.22 acres. The remaining 65.78 acres were added to the allotment in the 1990s after the case was reviewed by the U.S. Bureau of Land Management (Brakel, 2001). The Mills family maintains a small cabin near the mouth of Kahtaheena River on its allotment. The George allotment consists of 104 acres located west of the Mills allotment.

Timber harvest occurred on the two Native allotments in the early 1900s (Brakel, 2001). Additional timber harvest also was conducted in the area between the Mills parcel and the Kahtaheena River between 1910 and 1914 (Bosworth and Streveler, 1999). In 1974, timber harvest was again conducted on the native parcels (GEC, 2001a). Section 3.7, *Vegetation and Wetlands,* identifies 134 acres in the project area (6.2 percent of the project area) classified as either young spruce forest or recently logged.

The first non-native settlement in the region was documented around 1914. Several families arrived in the Gustavus area and settled near the Salmon River where they raised vegetables, beef cattle, and strawberries to sell to nearby canneries during the summer (Brakel, 2001). The Gustavus community slowly grew as more homesteaders arrived. When the Glacier Bay National Monument was expanded in 1939, Gustavus was included within the boundary, although it was later removed in 1955.

One of the primary access points to GBNPP is the airstrip in Gustavus, which was created by the U.S. military during World War II. The airstrip is now owned by the state and is used by commercial aircraft. Float planes are another mode of access to the area from nearby locations, and cruise ships and float barges also frequent Gustavus and Glacier Bay. Additional information on access to GBNPP and the Gustavus area is in the discussion of public access and safety (see section 3.12, *Recreation Resources*).

The majority of the land in Gustavus is privately owned, although there are parcels of state-owned lands. Most land uses in the town are residential and commercial businesses related to tourism, public services, and fishing. Gustavus and the NPS facilities at Bartlett Cove are linked to each other by road. Because there are no other surface access routes, transportation into and out of the Gustavus and Bartlett Cove area is limited to air and water travel. Roaded access to the Kahtaheena River area from Gustavus does not exist, with the closest road terminating at the Bear Track Inn Lodge (see figure 2-2 in appendix A). The primary means of reaching the Kahtaheena River are on foot or by boat.

Lands within the GBNPP boundary proposed for transfer to the state are currently managed for the protection of wilderness values. The existing use of wilderness lands in the Kahtaheena River area consists of low impact recreation hiking. Consistent with wilderness regulations, motorized or developed use of the area is not allowed.

3.15.1.2 Proposed Land Exchange Parcels

In exchange for use of land within GBNPP, NPS has identified several suitable parcels.

Long Lake

The four proposed land exchange parcels are completely encompassed within WSNPP (see figure 1-5 in appendix A). The parcels total approximately 2,500 acres, although the actual area of land exchanged would depend upon negotiations between NPS and the state. ADNR owns and manages the parcels, which are devoid of formal development and primarily used for recreation and fish and wildlife habitat. Long Lake is known to be a high quality spawning and rearing area for sockeye salmon, and steelhead trout are also known to spawn in this area. Recreational fishing for sockeye, grayling, burbot, and lake trout has been documented in this area (NPS, 1986; ADNR, 1986). In addition, the area provides important grizzly bear habitat (ADNR, 1986).

The McCarthy Road traverses through two of the parcels and is adjacent to the other two. There are no residential, commercial, or industrial structures located on the potential exchange lands near Long Lake, although there are residences in the general area, mostly along the McCarthy Road (LDN, 2000; ADNR, 1986).

Klondike Gold Rush

NPS has identified approximately 1,053 acres of land along the Chilkoot Trail of KGNHP for potential exchange with the state. See figure 1-6 in appendix A for the specific locations and acreages associated with these parcels.

A southern group of parcels comprises approximately 230 acres of land that is completely encompassed in KGNHP. The lands are generally flat and occupy portions of the Taiya River floodplain just north of the town of Skagway. The Taiya River is known to provide anadromous fish habitat for chinook, coho, chum, and pink salmon, in addition to Dolly Varden char. Recreational fishing occurs in the area, but the primary human use is recreation associated with the Chilkoot Trail, which begins within this parcel. There are currently no commercial or residential developments in the southern group of parcels (NPS, 1996; ADNR, 2002a).

A northern group of parcels includes approximately 825 acres of land along the Chilkoot Trail in the upper Taiya River drainage. There are no roads servicing these lands, and human access is limited to the Chilkoot Trail. There are historical structures and limited services for hikers along the trail, such as Canyon City and Pleasant Camp. The Taiya River and several of its tributaries in the area are known to provide anadromous fish habitat for coho and pink salmon, in addition to Dolly Varden char. The extent to which recreational fishing occurs in this area is uncertain (NPS, 1996; ADNR, 2002a).

3.15.1.3 Wilderness Designation Parcels

To maintain approximately the same amount of designated wilderness as currently exists within GBNPP, three areas of NPS land that are within GBNPP but not currently designated as wilderness are proposed for wilderness designation.

Unnamed Island near Blue Mouse Cove

The unnamed island near Blue Mouse Cove comprises approximately 789 acres located in Glacier Bay proper. The area is undeveloped and used only for recreational purposes, which include kayaking, hiking, and dispersed camping (NPS, 1988). This island is primarily accessed by boat or float plane, but current human use is thought to be limited.

Cenotaph Island

Cenotaph Island is composed of approximately 280 acres located in Lituya Bay on the northeastern shore of the Gulf of Alaska. The lands surrounding Lituya Bay are already designated as wilderness, although Cenotaph Island is not so designated. The area is primarily used for boating, hiking, and dispersed camping. Access to the island is mostly by boat or float plane, but current human use is thought to be limited (NPS, 1988).

Alsek Lake

The proposed wilderness lands in the Dry Bay area are near Alsek Lake on the Alsek River. This area is used primarily for commercial and non-commercial rafting trips down the Alsek River and dispersed camping and hiking associated with rafting. Rafting only occurs from July 1 through September 10, and human use of the area is limited outside of the boating period. Alsek River is a known producer of anadromous salmonids, particularly chinook, and recreational fishing also occurs in the watershed (NPS, 1989b; Pahlke and Etherton, 2001). There are no roads that service this area, and access is generally by raft, kayak, or airplane (NPS, 1989b). The area is also devoid of developed structures, and human impacts are generally limited.

3.15.2 State of Alaska's Land Use Guiding Policies

3.15.2.1 Kahtaheena River Area (Project Area). The area immediately west of the GBNPP boundary in the Kahtaheena River area consists of a mixture of private and state ownership. The Rink Creek Road provides the only access to landowners in this area. Prior to April 2004, Gustavus was an unincorporated township, and there was no formal government agency that dictated development and land use policy in the area. As of April 2004, Gustavus became an official city within the state of Alaska.

The majority of the private lands along the Rink Creek Road are used for residential development, although the Bear Track Inn, located at the terminus of this road, provides lodging services. This area also contains Alaska Mental Health Trust Authority lands, which are state lands designated for the purpose of generating funds for mental health services. The Gustavus Land Legacy (GLL), a committee of the GCA, has been working with the Alaska Mental Health Trust Authority to develop management policies for the trust lands in the Gustavus Area. The GLL has expressed a desire to either purchase lands or secure easements on key properties to protect beaches, forested areas, meadows, and wetlands (GCA, 1999). Purchase of the lands or conservation easements would help to protect natural resources in the area, while still providing funds for the Mental Health Trust.

Other state land in the area consists of parcels adjacent to the airport. Some of these lands have been designated in the ADNR's Northern Southeast Area Plan[39] as public facilities lands and are to be reserved for infrastructure development that serves state interests (ADNR, 2002a). Other state parcels in the area are designated for undeveloped public recreation and tourism and are to be managed for dispersed recreation and wildlife protection. Development of these parcels is considered inappropriate except as necessary for airport operations (ADNR, 2002a).

3.15.2.2 Proposed Land Exchange Parcels

Long Lake

Management of the state lands at Long Lake is dictated by ADNR's Copper River Basin Area Plan (1986). Since state lands in the Long Lake area are completely encompassed within WSNPP, state policies are geared toward land management that is consistent with the recreational values of the National Park. The state does not plan to develop recreation facilities (i.e., campgrounds) on these lands; however, leases and permits for commercial and noncommercial recreation activities are allowed where consistent with other management goals and objectives.

The state lands immediately adjacent to Long Lake are primarily managed to preserve salmonid spawning areas and for a combination of fish and wildlife habitat and public recreation (ADNR, 1986). ADNR explicitly states that the areas around Long Lake and its outflow stream are precluded from mineral extraction activities, in an effort to preserve fish spawning habitat. To further safeguard salmonid spawning habitat, ADNR does not permit the development of structures along the north shore of Long Lake (ADNR, 1986). ADNR management policies also state that any McCarthy Road maintenance or improvement projects must retain a buffer of trees between the road and the lakeshore to protect water quality from increased runoff and erosion (ADNR, 1986).

Klondike Gold Rush

Much of the state land proposed for exchange is encompassed within the external boundary of KGNHP. Under an agreement with the state, NPS manages lands directly associated with the Chilkoot Trail while the rest of the area is managed by either ADNR or the Alaska Department of Parks and Outdoor Recreation (ADPOR). All of the state lands are managed to ensure compatibility with KGNHP. Emphasis is placed upon protection of wetlands, mountain goat habitat, anadromous fish streams, and the historical resources associated with the Chilkoot Trail (ADNR, 2002a). Development is not allowed on these parcels unless deemed necessary for KGNHP operations. The Northern

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[39] The Northern Southeast Area Plan determines management intent, land-use designations, and management guidelines that apply to all state lands in the planning area and directs how ADNR will manage state uplands, tidelands, and submerged lands within the planning boundary.

Southeast Area Plan states that portions of all of these parcels would be appropriate for exchange with NPS to facilitate KGNHP operations (ADNR, 2002a).

3.16 SOCIOECONOMICS

The regional study area for the socioeconomic analysis of the proposed Falls Creek Hydroelectric Project consists of the 13 towns within the Skagway-Hoonah-Angoon census area of southeastern Alaska.[40] Gustavus, the closest town to the proposed project, is located 5 miles west. Gustavus is a small, isolated coastal town much like the other towns in the study area. Many of these local economies are shrinking because of downturns in commercial fishing, fish processing, and timber markets; however, tourism continues to support some of these economies. The following sections describe the regional and local socioeconomic environment that would be affected by the project.

3.16.1 Population

The Alaska Department of Community and Economic Development (ADCED) reported[41] the population of the Skagway-Hoonah-Angoon census area was 3,164 in 2003. This was a loss of 690 people since 1993, or a 22 percent decrease in the decade (table 3.16-1). In general, southeastern Alaska[42] grew by 4,234 people between 1990 and 2000, or 6.5 percent (U.S. Census Bureau, 2000). Table 3.16-2 shows gender and race characteristics for the Skagway-Hoonah-Angoon census area and the town of Gustavus. Racial distribution within the census area and Gustavus was similar to that of the state. Table 3.16-3 shows age distributions of residents for the census study area and Gustavus. Age distribution within Gustavus is comparable to age distribution of the study area with the greatest portion of the population between 18 and 65. Age distribution is important in small communities as it can affect both supply of labor and level and distribution of income within an area.

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40 The 13 towns within the Skagway-Hoonah-Angoon census area include: Angoon city, Chilkat ANVSA, Cube Cove CDP, Elfin Cove CDP, Game Creek CDP, Gustavus CDP, Hobart Bay CDP, Hoonah city, Klukwan CDP, Pelican city, Skagway city, Tenekee Springs city, and White Stone Logging Camp CDP.

41 ADCED produces residential population estimates for the state of Alaska using Alaska permanent fund dividend data, vital statistics, and survey information as the primary indicators of population change from year to year. ADCED uses the U.S. Census Bureau figures as control numbers to help validate the estimates.

42 The population figures considered for southeastern Alaska include Haines, Juneau, Wrangell-Petersburg, Ketchikan, Prince of Wales, and Sitka.

Table 3.16-1. Skagway-Hoonah-Angoon census area population. (Source: Alaska Department of Labor and Workforce Development, 2004)

1990	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
4,385	3,719	3,854	3,828	3,747	3,823	3,668	3,642	3,541	3,436	3,390	3,243	3,164

Table 3.16-2. Study area gender and race, 2000. Source: U.S. Census Bureau, 2000)

Area	Male	Female	White	American Indian or Alaska Native	Other
Skagway-Hoonah-Angoon census area	1,848 (53.8%)	1,588 (46.2%)	1,998 (58.1%)	1,203 (35%)	269 (7%)
Gustavus	241 (56.2%)	188 (43.8%)	383 (89.3%)	18 (4.2%)	18 (4.2%)

Table 3.16-3. Study area population age distribution, 2000. (Source: U.S. Census Bureau, 2000)

Area	Under Age 18	Age 18-64	Age 65 or Older
Skagway-Hoonah-Angoon census area	920 (26.8%)	2,264 (65.9%)	252 (7.3%)
Gustavus	112 (26.1%)	296 (69%)	21 (4.9%)

The town of Gustavus has a year-round population of 438 according to the ADCED 2003 estimates. The community has experienced population increases of approximately 4.7 percent annually from 1993 to 2003. During the 2000 U.S. Census, there were a reported 345 total housing units in Gustavus, 146 of which were vacant. Approximately 60 of the vacant housing units are used seasonally, primarily during summer months.

Table 3.16-4 shows population history for the town of Gustavus between 1950 and 2000. The town's population increased from 258 residents in 1990 to 429 residents in 2000, and it has more than quadrupled since 1980 (2000 U.S. Census). Between 1993 and 2003, population growth has fluctuated and, though at times it has been negative, it has averaged 4.7 percent a year. The abundance of relatively flat, developable land conditions and proximity to GBNPP have further influenced Gustavus' growth where other communities in the region have seen stagnant, or even negative growth. GEC reports that the single largest component driving energy demand is population growth.

Table 3.16-4. Census population history, Gustavus (2000). (Source: U.S. Census Bureau, 2000)

Census Period	Before 1950	1960	1970	1980	1990	2000
Population	no data	107	64	98	258	429

The population of Gustavus grows considerably in the summer months because of the influx of tourists traveling to GBNPP, the temporary population associated with tourist-based services, and the seasonal influx of people with summer homes (mostly from Juneau). Gustavus' primary employment relates to tourism, government, and fishing. Approximately 30 residents hold commercial fishing permits, although it is not known whether all of these individuals are active in the commercial fishing industry (ADCED, 2002). Commercial fishing currently provides a reasonable proportion of total livelihood for only a handful of families, yet guided sportfishing provides a significant proportion of the total livelihood for more than 20 charter fishing captains (personal communication with L. Sharman, Coastal Ecologist, GBNPP, on April 22, 2003).

3.16.2 Employment

NPS activities may have influenced the population growth rate in the 1990s. Between 1991 and 1998, NPS went through a hiring phase to fill vacant positions and completed an upgrade of park facilities. Both of these actions affected the population growth rate during that time. During the same period, NPS was drafting commercial fishing regulations in GBNPP proper, which took effect in October 1999. These regulations use a phase-out approach, so any impacts the regulations may have had on the commercial fishing industry, and ultimately population growth, are not considered in this population growth rate because they would have occurred outside the scope of population information. However, the potential does exist for a decrease in the future Gustavus population due to restraints put on the commercial fishing industry around Gustavus. The present leveling off of staffing at Glacier Bay National Park will be a factor in the population growth of Gustavus. Up to date population data are not available to make accurate estimates as to the extent of such effects. As such, a growth rate of 4.7 percent (taken from the best available data) provides a conservative estimate for our analysis and discussion.

Table 3.16-5 shows employment figures from the 2000 U.S. Census for the Skagway-Hoonah-Angoon census area and the town of Gustavus. Employment in the census area decreased from 1,815 jobs in 1995 to 1,497 jobs in 1999 (http://www.dced.state.ak.us/cbd/). Sectors employing the largest number of residents in the census area include: agriculture, forestry, fishing and hunting; transportation and warehousing and utilities; educational, health, and social services; and arts, entertainment, recreation, accommodation, and food services. Within Gustavus, the sectors employing the most people include: arts, entertainment, recreation, accommodation and food services; education, health, and social services; government; and construction (table 3.16-5). The Census further characterizes the class type of workers indicating that, within Gustavus, approximately 35 percent are private wage and salary workers and almost 40 percent are government workers (table 3.16-6).

Table 3.16-5. General description of employment trends in Gustavus. (Source: U.S. Census Bureau, 2000)

Total potential work force (age 16+)	348
Total employment	190
Civilian employment	190
Military employment	0
Civilian unemployed (and seeking work)	31
Percent unemployed	14
Adults not in labor force (not seeking work)	31
Percent of all 16+ not working (unemployed + not seeking)	45.5
Private wage and salary workers	66
Self-employed workers (in own not incorporated business)	45
Government workers (city, borough, state, federal)	75
Unpaid family workers	4

Table 3.16-6. Employment by industry for Skagway-Hoonah-Angoon census area and the town of Gustavus. (Source: U.S. Census Bureau, 2000)

Sector	**Jobs in Census Area**[a]	**Jobs in Gustavus**[b]
Agriculture, forestry, fishing, and hunting	213	7
Construction	130	23
Manufacturing	77	7
Wholesale trade	7	-
Retail trade	132	7
Transportation and warehousing, and utilities	207	19
Information	8	2
Finance, insurance, real estate, and rental and leasing	37	2
Professional, scientific, management, administrative	52	10
Educational, health, and social services	271	26
Arts, entertainment, recreation, accommodation, and food services	187	60
Other services	34	10
Public administration	116	17
Total	1,471	190

[a] Out of 1,471 workers, 57.4 percent are private wage and salary workers; 29.2 percent are government workers; 13.1 percent are self-employed workers in own, not incorporated, business; and 0.3 percent are unpaid family workers.

[b] Out of 190 workers, 34.7 percent are private wage and salary workers; 39.5 percent are government workers; 23.7 percent are self-employed workers in own, not incorporated, business; and 2.1 percent are unpaid family workers.

3.16.3 Local Economy and Income Trends

Because of its proximity to GBNPP, much of the Gustavus economy and residents' income is based on tourism (www.dced.state.ak.us/cdb). NPS, recreation and tourism businesses, commercial fishing ventures, and the airport are the main employers in Gustavus and lend a seasonal nature to the community. The U.S. Census Bureau reports that almost 40 percent of working Gustavus residents are employed in government. ADCED recognizes 95 current business licenses in Gustavus, 35 of which are related to recreation or lodging accommodations.

The U.S. Census Bureau (2000) estimated the 2000 median household income in Gustavus as $34,766, which is below the state median of $51,571. The income of two households (1 percent of the total households) was between $100,000 and $199,000, while the income of 27 households (13.2 percent) was less than $10,000. The relationship between the upper and lower income brackets is consistent with census-area income statistics.

3.16.3.1 Influence of GBNPP on the Gustavus Community. NPS first began development at Bartlett Cove in the 1950s. Development accelerated in the early 1960s with construction of a lodge and associated facilities. A major renovation in facilities began in the mid-1990s and continues today. Activities include replacement of the old dock with a new one of equal capacity; the conversion of the gravel road to a wider, surfaced road; removal of mobile homes and the construction of permanent buildings; replacement of the fuel farm with a new facility; and the installation of refuse facilities. These NPS projects have generated local purchases, which have had a positive effect on the local economy, employment, equipment rentals and material. These upgrades have also enabled GBNPP to support higher numbers of visitors in the Gustavus area contributing to the rate of development in the Gustavus area. Overall, the distribution and number of employment opportunities in tourist-related services confirms a strong relationship between the presence of GBNPP and the economy in Gustavus.

3.16.3.2 Native Allotments. Two Native allotments exist in Gustavus Flats abutting the shore near the proposed project. The Alaska Native Allotment Act of 1906 provided an opportunity for Native people to establish ownership of property under U.S. law. The two Native land allotments in the study area were two of the six original allotments that were granted titles before 1971 in what later became GBNPP and Gustavus (Brakel, 2001). The allotments were originally conveyed to Messrs. George and Mills, based on their subsistence value (Brakel, 2001). Portions of both of the Native allotments have been previously logged. The heirs to the Mills property have various aspirations for the land. Those who use the Mills cabin value the property for its remote, undeveloped nature. The George allotment is highly valued by the heirs for the same reasons.

Little, if any information exists as to the subsistence harvest and dependence of the Native allotments by the allotment heirs. Tom Mills Sr., speaking on behalf of the Mills heirs, stated that he uses the property to enjoy the peacefulness and wildlife the allotment offers, and does not hunt there (Brakel, 2001). In general, use of both of the allotments stems from their remote, undeveloped qualities rather than from subsistence harvest.

3.16.3.3 Private Property and Infrastructure. Within the Kahtaheena River study area, there is one commercial facility, the Bear Track Inn, outside the GBNPP boundary. Located at the end of Rink Creek Road, the inn has 14 guest rooms and a restaurant. Additionally, there are 20 to 25 private parcels with residences or summer cabins along or near Rink Creek Road. Currently, these residents pay for the maintenance and general up-keep of this gravel road. The only residential structure near the Kahtaheena River itself is the small, seasonally used cabin on the Mills allotment.

3.16.4 Proposed Land Exchange Parcels and Wilderness Designation Parcels

These lands are remote and undeveloped and do not have a socioeconomic environment practical for evaluation within the scope of this document.

4.0 ENVIRONMENTAL CONSEQUENCES

This chapter contains analysis of the environmental consequences of the No-action Alternative, GEC's Proposed Alternative, the Maximum Boundary Alternative, and the Corridor Alternative, including all proposed and recommended measures (see chapter 2, *Descriptions of Alternatives*, for complete description of measures). Developmental analysis of the proposed and recommended measures is presented in chapter 5, *Developmental Analysis*, and all recommendations are presented in chapter 6, *Conclusions*.

4.1 METHODS FOR EVALUATING ENVIRONMENTAL EFFECTS

In accordance with NEPA, this final EIS evaluates the direct, indirect, and cumulative effects that would occur with implementation of the proposed action and alternatives. Direct effects are the effects on the environment that would result from implementing the action and occur at the same time and place. Indirect effects are the effects on the environment that would result from implementing the action, but may occur later in time, or would be farther removed in distance from the direct effect. Cumulative effects are the effects on the environment that would result from the incremental effect of the action when added to other past, present, and reasonably foreseeable future actions, regardless of what agency or person undertakes such other actions.

Alternatives are evaluated to determine the effects of the construction and operation of the proposed Falls Creek Hydroelectric Project on GBNPP, KGNHP, and WSNPP resources and values. The scope of the analysis is based on issues raised during scoping, identified by resources specialists, and associated with compliance with applicable federal and state laws and policies.

Within each resource section of this chapter, the preparers define evaluation parameters that can be used to evaluate the impacts associated with the actions within each alternative. Most resources have from one to five parameters that are described and evaluated to guide the preparer in an effects determination for the resource. More parameters may be used if the relationship between the actions and the effects on the resource is more complex. A conclusion paragraph for an alternative within each resource section provides a single summary of effects determination for the resource as a result of the actions within the alternative.

4.2 CUMULATIVE EFFECTS SCOPE

According to the Council on Environmental Quality's regulations for implementing NEPA (50 CFR §1508.7), an action may cause cumulative effects on the environment if its effects overlap in space or time with the effects of other past, present, or reasonably foreseeable future actions, regardless of the agency, company, or person undertaking the action. Cumulative effects can result from individually minor but collectively significant actions taking place over a period of time.

The spatial scope of analysis for cumulatively affected resources is defined by the physical, biological, or social boundaries of: (1) the project's effects on a particular resource, and (2) the contributing effects from other non-project-related activities. Because a proposed action may affect resources at different scales, the spatial scope of analysis varies among the resources.

The temporal scope of analysis for cumulative effects includes past, present, and future actions and their effects on each resource. For this analysis, the temporal scope will look approximately 50 years into the future, the maximum duration of any project license that may be issued. The assessment of future actions is limited to actions that are reasonably foreseeable. Existing conditions, not historical conditions, are the baseline for comparison of alternatives. The inclusion of past actions is limited to available information, and it provides a historical context from which the existing conditions have developed.

4.2.1 Cumulative Effects Analysis

Cumulative effects are the incremental impact upon a resource that results from the interaction of two or more individual actions. There are two types of cumulative effects that could occur on this project, and are described in this document: (1) the incremental effect of two different project actions occurring within a proposed alternative, and (2) the incremental effect resulting from the interaction between a project action and a non-project action. Each type of cumulative effect must consider past, present, and reasonably foreseeable future actions (temporal component), and actions that may be separated by distance (spatial component) if there is the potential for incremental effects.

Our cumulative effects analysis is primarily based on information collected by GEC and presented in the license application, PDEA, and supporting technical studies. The available information results in the cumulative effects analysis being most detailed with respect to direct project effects, with broader based non-project actions analyzed more qualitatively.

4.2.1.1 Cumulative Effects Resulting from Project Actions. Two or more project actions that result in direct or indirect effects on the same resource can have a cumulative effect. These cumulative effects are described for each alternative in the environmental consequences sections of this final EIS (sections 4.3 through 4.16).

4.2.1.2 Cumulative Effects among Project and Non-Project Actions. Cumulative effects can also occur when the effects of project-related actions interact with non-project-related actions occurring in the same geographic area. The non-project effects may occur at differing temporal scopes than the project action, such as persisting effects from past actions, or effects that may result from reasonably foreseeable future actions. Non-project actions can include other federal, state, local government, or private industry activities, or management and policy decisions relating to social or resource management.

We present three components for each cumulative effects analysis: (1) identify the non-project action and its associated effect, (2) identify the related project action and its associated effect, and (3) describe the incremental effect resulting from the two actions. Since the location, magnitude, and timing of many non-project actions are known with only a limited degree of certainty, the cumulative effects statements provide a general indication of the direction of the potential cumulative effect:

Non-Project Action/Effect	**+**	**Project Action/Effect**	**=**	**Incremental Cumulative Social, Biological, or Physical Effect**

4.2.2 Non-Project Actions Contributing To Cumulative Effects

The following policies, projects, and actions could potentially contribute to the cumulative effects of the natural and social resources in the Kahtaheena River area. The interaction of these non-project actions with the alternatives evaluated for the proposed project are presented in the environmental consequences sections of each resource area (sections 4.3 through 4.16).

Phase-out of commercial fishing in GBNPP. GBNPP is incrementally phasing out commercial fishing in Glacier Bay proper and has closed all commercial fishing in designated wilderness waters. Commercial fishing in areas within GBNPP and outside of Glacier Bay proper and wilderness water will continue in perpetuity. This management policy would have the effect of shifting commercial fishing to areas outside of Glacier Bay proper and wilderness waters and areas adjacent to the park.

Commercial logging on land in the vicinity of the Kahtaheena River. Forest management activities (e.g., timber harvest and road construction) may occur on federal, state, and private lands adjacent to GBNPP where allowed by current regulations. These activities may result in the conversion of mature forest habitat conditions to early successional stage habitat.

Changes in habitat value and successional development of nearby forested areas that have been previously harvested. Previous forest management activities on private lands in the vicinity of the Kahtaheena River are undergoing successional development from young to mature forest conditions. This successional development provides a changing habitat composition in future years.

Increased commercial recreational guiding and tourism in the general Gustavus area. Long-term growth of commercial recreation and tourism may result in additional pressures on the existing economic and social infrastructure and natural resources in the Gustavus area.

Increased tourism at GBNPP. Increasing tourism at GBNPP may result in an increasing number of tourists staying at lodges and bed and breakfasts in Gustavus.

Incorporation of Gustavus as a second-class city. The incorporation of Gustavus as a second-class city would create a governing board that would have the authority to establish a taxing infrastructure, manage growth and development, and develop a public utility system in Gustavus.

Increased development of National Park facilities and interconnection of the National Park electric grid to the community of Gustavus. Increased development of the facilities and infrastructure at GBNPP may provide a greater incentive to combine some selected social services, including utilities, between Bartlett Cove and Gustavus. The interconnection of the electric utility services between the community of Gustavus and GBNPP facilities at Bartlett Cove, which has been identified as a potential future activity, could provide increased reliability of electrical service for both communities.

General population growth and the corresponding increase in subsistence and recreational hunting in the Gustavus area. Increased long-term population growth in rural areas of southeastern Alaska may result in a corresponding increase in the demand for subsistence resources and recreational hunting in the Gustavus area. The increased demand for subsistence resources may conflict with the access management plan proposed for the project area lands.

Increased development of private land in the Gustavus area. Potential future development of state and private lands adjacent to the proposed project access road could occur. Development of these parcels may provide socioeconomic benefits to the Gustavus community. However, additional development may also result in a loss of vegetation; disturbance of significant resources, species, or habitats; a decrease in water quality due to soil erosion; and change in existing land use.

Glacier Bay National Park Vessel Quotas and Operating Requirements EIS. GBNPP is currently evaluating the impacts of vessel traffic in Glacier Bay proper and Dundas Bay. Decisions regarding vessel management could result in a change in the type or amount of recreational activities and opportunities that will occur in the GBNPP and Gustavus area.

Connection of Gustavus to the Southeast Alaska Electrical Intertie. A proposed electrical intertie connecting many communities of southeastern Alaska could provide these communities with a more reliable energy source.

Establishment of Point Sophia and a cruise ship dock in Hoonah. Point Sophia, which opens to the public in 2004, will be a cultural center for tourism. In addition to the Point Sophia development, the town of Hoonah is also developing a cruise ship docking facility in order to provide cruise ship passengers with access to Point Sophia and Hoonah. Both the Point Sophia development and the cruise ship dock at Hoonah could result in additional visitor recreational use of the Gustavus/Icy Passage area.

Increased commercial and charter fishing in the Icy Passage region. Changes in the commercial and recreational fishing regulations may result in additional impacts on fisheries resources in the Icy Passage region. These changes may interact with the impacts associated with the Falls Creek Hydroelectric Project.

Tongass National Forest Wilderness recommendation EIS. The Tongass National Forest has conducted an evaluation of roadless areas for potential inclusion in the National Wilderness System. A ROD has been published that includes a recommendation that no additional Wilderness areas be created in the Tongass National Forest.

GBNPP Backcountry Management Plan EIS. GBNPP is evaluating the effects of managing backcountry recreational use within the park. This plan will affect how the park manages different backcountry areas, describe what types of use are considered appropriate in specific areas, and determine the desired future condition for all backcountry areas in the park. A decision regarding levels and locations of backcountry use may result in changes in the quantity of recreational impacts within the Glacier Bay and Gustavus area.

4.3 GEOLOGIC RESOURCES AND SOILS

Several evaluation parameters are used to identify and describe potential impacts on the geologic resources and soils of the project area from the proposed action and action alternatives:

1. Geology or soil destabilization
2. Erosion and sedimentation
3. Bedload transport

The analysis of the potential effects of the project on geologic resources and soils includes a discussion of the context of the resources in the project area. The intensity of the impact on resources is generally characterized by quantifying the area of impact for geologic resources that are common to the area; and identifying the presence, absence, or probability of impacts. The duration of the impact is described where necessary to understand the context and intensity of the impact.

4.3.1 No-action Alternative

4.3.1.1 Effects Analysis. Under the No-action Alternative, the proposed project would not be constructed; the land surrounding the proposed project would be retained within the National Wilderness Preservation System for the foreseeable future and would continue to be managed as wilderness in accordance with the GBNPP GMP; and there would be no land exchange. Natural rockfalls, rockslides, and mass wasting due to earthquakes and storms could continue, and the natural occurrence of slides transporting soil into the river channel would continue, primarily as a result of storm events.

Under the No-action Alternative, the unnamed island near Blue Mouse Cove, Cenotaph Island, and the Alsek Lake lands would continue to be managed under the Wilderness Visitor Use Management Plan administered by GBNPP. Under this management plan, development of these parcels is prohibited, so the lands would remain as described in section 3.3.

Management of the proposed land exchange parcels would not change. Therefore, there would be no additional effects on the geologic resources of these lands.

4.3.1.2 Cumulative Effects Analysis. Under the No-action Alternative, there would be no cumulative effects because no project actions would occur in the Kahtaheena River watershed; state-owned parcels adjacent to WSNPP and KGNHP; or the parcels at Cenotaph Island, the unnamed island near Blue Mouse Cove, and Alsek Lake. Therefore, there is no potential for cumulative effects on geologic and soil resources based on the interaction between a project and non-project action.

4.3.1.3 Conclusion. Under the No-action Alternative, there would be no project-related effects. The level of effects on geologic resources and soils anticipated from this alternative would not result in an impairment of GBNPP resources that fulfill specific purposes identified in the enabling legislation or are key to the natural integrity of the park. Under this alternative, GBNPP would continue to operate and manage its lands as outlined in the enabling legislation (see section 1.7.4).

The level of effects on geologic resources and soils anticipated from this alternative would not result in an impairment of WSNPP or KGNHP resources that fulfill specific purposes identified in the enabling legislation, or are key to the natural integrity of these parks. Under this alternative, WSNPP and KGNHP would continue to operate and manage their lands as outlined in their enabling legislation (see section 1.7.4).

4.3.2 GEC's Proposed Alternative

4.3.2.1 Effects of Construction and Operation. Construction of the proposed facilities and access road would disturb the land, which could further destabilize land forms that are only marginally stable. Table 4.3-1 provides estimates of land disturbance for the proposed project facilities.

Table 4.3-1. Estimate of acreage that would be affected by each project feature. (Source: Based on GEC, 2001)

Project Feature	Acres Affected[a]	Permanent Footprint[b]
Access road (1.7 miles long; 14 feet wide)[c,d]	8.5	2.8
Service road (1.9 miles long, 14 feet wide)[c,d]	14.3	3.4
Penstock (1,270 feet, 30 feet wide)[d,e]	0.9	0.9
Borrow pits (2 sites)[f]	1.0	1.0
Disposal site (1 site)[f]	3.4	0.0
Diversion site[g]	0.5	0.5
Powerhouse and substation[c]	1.0	1.0
Total	29.6	9.6

[a] Road acres affected would include entire estimated vegetative clearing width for road construction, which may vary from 41 to 81 feet depending on slopes.

[b] Permanent footprint for roads reflect the area that would remain permanently unvegetated based on a 14-foot-wide road footprint.

[c] GEC, 2001b, table 11.

[d] GEC, 2001b, appendix C (total width cleared would vary from 45 to 81 feet).

[e] GEC, 2001b, exhibit A, table A-1.

[f] GEC, 2001b, exhibit F-1.

[g] Estimate based on GEC, 2001b, exhibit F-3.

GEC's proposed access road alignment was selected from a number of alternatives during scoping. GEC proposes to access project facilities almost exclusively via upland routes. The Canyon contains steep slopes, active and historic landslides have been reported along the west side of the Kahtaheena River and north of the Horseshoe, and there is potential for significant mass movement in this high hazard area (figure 3-4 in appendix A). GEC considered the following alternative project configurations to remove any service road from The Canyon (GEC, 2001b):

1. Pumping the water up to the lip of The Canyon from an intake structure just below The Islands. From there, the road and penstock would follow The Canyon edge to meet the access road at the Strip Fen.

2. Piping the water through a drilled tunnel to the Strip Fen from the intake sited upstream of the Horseshoe.

3. Constructing a 1,700-foot-long road from a boat-accessible 200-foot dock to the powerhouse. A 160-foot-long bridge would be required to span the Kahtaheena River from the bank opposite the powerhouse.

4. Use of aerial trams instead of roads in the project area.

All four alignments were rejected at least in part due to cost. In addition, the alternative with the road to the powerhouse from the Kahtaheena River intertidal delta was rejected because of tide-restricted access, and to keep all project impacts away from the shore zone. GEC's proposed alignment would reduce or avoid effects on geology and soils as compared to the other alignments that were considered. Section 2.3.4, *Construction–Access Road*, contains a detailed description of GEC's proposed access road alignment.

Mass Wasting and Soil Destabilization. GEC proposes erosion control measures to ensure that construction procedures for trenches and buried transmission lines adjacent to existing roadway and log bridge crossings would not destabilize the road, bridge abutments, or stream bed, and to avoid sediment transport into streams. These measures include avoiding alignment through highly organic and peat laden soils, minimizing rock cuts and the need for blasting, avoiding steeply sloping areas, burying the pipeline, revegetating disposal sites, and removing trees unlikely to harbor nesting murrelets. ADFG, FWS, and NMFS recommend agency review and approval of final plans to control erosion, control slope instability, and minimize the quantity of sediment introduced into the Kahtaheena River and other project streams. ADFG and NMFS also recommend that GEC develop and implement a road management plan. The agencies recommend that GEC develop such a plan that would include road maintenance and measures to monitor for and limit the potential for road-related slope erosion over the term of any license.

GEC proposes to start the project access road from the end of the existing access road (Rink Creek Road). The proposed main access road would traverse 1.7 miles of moderate sloped area and then bifurcate with the north branch leading to the diversion dam/intake area and the south branch to the powerhouse. This proposed road/penstock alignment (see figure 3-4 in appendix A) would avoid the most deeply incised and steepest portion of The Canyon below the Upper Falls. Overall, although longer, it would be the best alignment to minimize high slope instability areas and thicker peat and organic soils in lowlands. GEC evaluated other road alignments following the Kahtaheena River between Icy Passage and the powerhouse. These alternatives involved traversing high landslide and erosion hazard areas and the construction of a new bridge crossing the Kahtaheena River. GEC did not adopt these alternatives because of environmental impacts and higher cost over the proposed alignment.

The northern branch of the road would skirt west above the deeply incised canyon and pass southwest through a saddle to the southwestern side of the ridge confining the canyon segment of the river. Two critical road segments would occur along this alignment. The first critical segment would be about a 500-foot segment from the saddle and north towards the diversion dam/intake structure. This segment would be moderately steep (30 to 72 percent slope) and is located immediately above the Kahtaheena River. Because of the steeper slopes (see figure 3-4 in appendix A), this area probably has a higher risk of slope instability and/or higher rate of soil creep occurring with greater risk of soil debris reaching the creek. Regional landslide studies by Swanston and Marion (1991) indicate that the lower quartile (25 percent) of all failures occur in slopes of this range. Water collected along the upslope side would be discharged on the steeper downslope side. Adding to the risk of slope failure would be potential for ground movement (creep and/or settlement) to sever the pipeline. This event could lead to a worst case scenario of sudden release of a large volume of water with rapid earth failure and transport and deposition of soil and rocks into the river. Following a pipeline failure, elevated turbidity in the Kahtaheena River would likely make the water temporarily (several weeks or months) undesirable for the inhabitants or owners of the Mills allotment to use the Kahtaheena River as a primary source of drinking water. This road segment would be adjacent to a proposed borrow pit. Water collected from the disturbed landscape of a pit would also have to discharge away from these steep slopes.

The second critical segment would be along the river. This segment would cross over four identified active and historic landslides (see figure 3-4 in appendix A). The age of the trees on the landslides, however, suggests that there has been no significant movement for more than 200 years. The proposed road crossing historic landslides could result in slope instability, if landslides are reactivated, and potentially could supply sediments to the Kahtaheena River. However, a well-designed road crossing the toe of landslides at this location would provide a buttressing effect, and thus, increase slope stability. For example, increasing drainage, slope protection, and the addition of weight at the toe of the slope could improve the stability.

The upper stretch of the proposed road would follow the river and lie perpendicular to the structural grain of the bedrock. Geologic mapping shows the attitude of the bedrock striking perpendicular to the creek/road alignment with dips 25 to 55 degrees in an upstream direction (Mann and Streveler, 1999). This orientation of the bedrock strike is favorable for rock slope stability and construction because it does not result in bedding plane surfaces dipping out of the excavation slopes. Therefore, a bedrock failure in this segment of road would be unlikely.

The access road would be designed to minimize rock cuts in adverse dipping strata. However, some limited blasting may be required for bedrock excavation. Blasting of bedrock for the roadbed incision could loosen or undercut the bedding planes, thereby increasing the potential for slope failure. GEC proposes to limit blasting to small charges that would be placed to minimize flying debris. This procedure would limit blast damage to the rock. Additional measures that could be utilized to maintain rock slope stability if necessary are localized rock bolting and/or horizontal drainage holes to maintain stability.

The south branch alignment would follow slightly below the crest of the ridge to the powerhouse location. This is the best alignment because it would avoid the steepest slopes that are typically found at mid-section of slopes and the deepest colluvial soils and the thickest peat and organic soils that are typically found along the base of the slopes. Most of the slopes that would be traversed range from 15 to 40 percent. Based on regional landslide occurrence, only about 10 percent of landslides occur on slopes within this range. In addition, a higher alignment would reduce the potential amount of water infiltrating from above the road to the groundwater system. This would reduce the amount of groundwater that may be intercepted and collected in roadside ditches that must be handled to prevent erosion.

The road then would turn southwest and descend the slope steeply to the powerhouse. As the road descends, it would skirt along the margin of a concave steeper terrain area near the Lower Falls. About a 500-foot segment of road would traverse an area that has elements characteristic of higher risk slope areas (steeper slopes of 30 percent and concave geometry which tends to cause convergence of shallow ground water). Consequently, this short segment of the proposed road would have a relatively higher slope instability risk than other portions of the road. In addition, the controlled discharge of water collected in the upslope ditches would be critical to prevent destabilizing the slope. For most of the alignment, the penstock would follow the road, but at the southeastern end, the road/penstock separate and each feature would take a route most favorable for its respective function. The penstock would take a straighter route for efficiency, and the road would follow a less steep route to permit vehicular access. An additional 600 feet of temporary construction road may be required to reach the disposal site.

The state of Alaska, in comments on the draft EIS, recommended an alternative access road to minimize the length and quantity of private easements at the western end of the project boundary. This route (see figure 2-2 in appendix A) would result in a 25 percent increase in access road construction activity. We assume that the land traversed by this alternative would have qualities similar to the upland route of the main access road proposed by GEC. Therefore, the potential construction effects on geology and soils would be similar for both routes, except that the state of Alaska route would cross one additional stream. The erosion and soil control measures proposed by GEC for its main access road also would be used to mitigate any potential effects of the alternative road access route.

Following construction, the disposal site would be regraded and reseeded with native vegetation to reduce the risk of erosion. Water collected along roadside ditches would be handled according to GEC's proposed ESCP to minimize risk of locally saturating and initiating local slope instabilities. Also, within the clearing widths prescribed by the U.S. Forest Service standards and guidelines, selected trees not identified as having high potential for marbled murrelet nesting would be removed to further relieve the weight on slopes upgrade and downgrade from the road. Removing these numerous trees along the road cuts, diversion, penstock, and powerhouse routes and location, however, would cause further soil destabilization and erosion and sedimentation in the area. Finally, burial of the pipeline in steep portions of the road cut would protect it from damage due to sliding debris and would avoid adding its weight to the vegetative and soil mat. These measures would adequately address the potential for soil destabilization during construction of project facilities at this location. Careful attention should be given to the implementation of the ESCP at borrow sites adjacent to high hazard areas for slope failures.

Road Construction Techniques and Effects. To analyze the potential effects of project construction on the geology and soils in the proposed project area, we examined information from the Tongass National Forest. The forest surrounds GBNPP, and it has many similarities to the Kahtaheena River watershed with respect to soil type, bedrock, topography, vegetation, and climate. It also has available data on potential protection and mitigation measures related to construction.

Mass movement (shallow landslides), which is described earlier in section 3.3, has been inventoried by the Tongass National Forest for southeastern Alaska. The landslide inventory for the Tongass National Forest shows that 16 percent of all landslides occur along road alignments (USFS, 2003). Landslide and erosion mitigations are not always 100 percent effective, and case histories demonstrate that unforeseen events may occur even with the use of BMPs (personal communication from C. Soiseth, GBNPP, with G. Strachan, Hydro-Geosciences, Redmond, WA, on August 4, 2003).

In addition to slope instability, there is the potential for erosion of unprotected soils and sedimentation caused by intense rains common in southeastern Alaska. For example, the recent main road project at GBNPP had major erosion and sedimentation problems during construction, even in terrain that is relatively flat compared to the Kahtaheena River watershed. Ditches underlain by unconsolidated glacial outwash sediments adjacent to asphaltic pavement were subjected to significant erosion under heavy precipitation. The project design called for protective covering on slopes and silt fencing, but the contractor had not placed the protective covering in time prior to rainfall, and significant erosion and sedimentation occurred (personal communication from C. Soiseth, GBNPP, with G. Strachan, Hydro-Geosciences, Redmond, WA, on August 4, 2003).

The Tongass National Forest successfully uses road construction techniques for forest land that is similar to the land in the Kahtaheena River watershed. Forest practices in muskeg soil areas use brush mat[43] overlays for surface erosion protection for upland roads. Brush mats are used when peat is less than 5 feet thick; otherwise, geotextiles (geogrids and geofabrics) are used for surface erosion protection, and the road is "floated" into place. The Tongass National Forest typically keeps road grades below 15 percent, and uses a full bench cut when traversing side slopes above 55 percent. Roads are typically partially benched with a portion of the road constructed on side-cast fill composed of excavated materials. Typically, about 25 percent of the excavated material is used for fill, and the remaining 75 percent is removed and disposed of at disposal sites (personal communication from J. Oien, Tongass National Forest, AK, with G. Strachan, Hydro-Geosciences, Redmond, WA, on July 22, 2003). Where the road and road drainage ditches intercept groundwater flow through these organic soils on slopes, the downslope flow of shallow groundwater flow would be disrupted. Frequent cross culverts are used to release and disperse water on the downslope side to prevent concentration and to restore the groundwater flow on the downslope side. Construction would typically proceed from the start to end in the road footprint. All traffic (e.g., haul trucks) would be confined to the road or to temporary construction access to the disposal site. Road surfaces are typically finished with crushed or quarried rock because of long-term settlement that would occur as organics decay beneath the unpaved road.

Leaving portions of the peat and organic soils in place maintains the insulative properties of the near-surface organic soils and prevents icing conditions, reduces the required volume of fill and intensity of earthwork operations, and allows drainage through geotextiles. This road surface permits regrading of the settled areas as needed. This type of road construction used by the Tongass National Forest also has significantly lower construction costs, in contrast to removal of organic soils to firm-bearing soil or rock and related site-preparation earthwork for higher volume paved roads under Federal Highway Administration (FHWA) and state of Alaska standards.

A disadvantage of this type of road construction is the distress that occurs when the organic material decays and causes differential settlement, punch outs, and possibly mass wasting. Groundwater flow patterns can also be affected as organic material degrades, and differential settlement may occur over a long period of time requiring road maintenance as organics in the soil decay. The life of this type of road is generally 30 years. Technologies have been developed that reduce differential settlement and increase lateral stability for forest roads underlain by organic soils, including the use of surface drainage systems, deep foundation systems, geotextiles, and pre-construction-induced consolidation of soils.

GEC proposes to avoid routing the road through highly organic or peat-laden soils. However, because some construction through these areas is largely unavoidable, GEC

[43] A brush mat is an erosion control mat that consists of native plant vegetation, such as brushes and small conifers.

proposes to use special construction techniques in these areas. Primarily, GEC proposes to keep construction vehicles from entering areas of deep organic soils and using geogrids or geofabrics to reinforce any roadbed constructed on organic soils or peat. Preventing construction vehicles from treading on areas of peat and deep organic soils would eliminate the potential for vehicles to become bogged down in the soft soils or disturb areas outside of the footprint of the roadbed. Geogrids and geofabrics would be placed on the soil surface, and the roadbed would be constructed on top of these reinforced surfaces. This technique would leave the peat or organic soils in place, stabilize the subgrade, and minimize disruption of the groundwater hydrology in the subsurface soils (GEC, 2001a).

Surface erosion is a potential problem during road construction, and sediment may be delivered to drainages at road crossings flowing towards the Kahtaheena River. For the proposed project, short-term effects would occur over the 24-month construction schedule, and long-term effects from erosion of road surfaces and slopes would occur during project operation. Sediment transport from road construction activity, short-term effects, would be minimized with erosion control measures (described in the ESCP) and BMPs. Long-term erosion of the road prism and associated slopes would be addressed by post-construction BMPs, including revegetation and road maintenance, and under the road management plan recommended by ADFG and NMFS.

Road construction could induce mass movement near steep slopes, as in the road section between the Upper Falls and diversion dam/intake structure and steeper road sections above the powerhouse. In those areas, there is the possibility of a significant landslide occurrence, which could substantially increase sediment in the Kahtaheena River. A major landslide would increase sediment and turbidity in the Kahtaheena River and temporarily (several weeks or months) degrade the water quality in river segments that cross the Mills allotment and marine waters of GBNPP at the mouth of the river. This potential effect could be minimized by implementation of the procedures in the ESCP, such as establishing a setback distance between road construction operations and the top of steep slopes, avoiding side-casting near the slopes, containing and controlling surface water and subsurface drainage, use of geotechnical instrumentation and piezometers to monitor slope conditions, and protecting the slope with vegetation. BMPs would minimize surface erosion and mass movement.

GEC proposes to locate the diversion dam/intake structure 2.4 miles upstream of the mouth of the Kahtaheena River where the stream is confined by rock abutments and drops several feet in a short distance. The proposed diversion dam/intake structure would consist of a central core wall with rockfill on both sides to provide stability, which would be keyed into the rock foundation, and the outer face of the rockfill would be grouted with concrete to prevent erosion of the fill. Rockfill should be available from access road construction and/or on-site quarries. GEC proposes to found the structure on bedrock. Geologic mapping shows the bedrock bedding planes dip 25 to 55 degrees upstream.

This bedrock bedding orientation is more resistant to sliding and, thus, favorable for a stable foundation.

GEC proposes to locate the powerhouse 0.45 mile upstream from the mouth of the Kahtaheena River. The powerhouse would be constructed on the toe of the stabilized colluvial lobe and use a slab-type reinforced concrete foundation, with column footings and perimeter walls, which would be set on rock rather than fill. The site is underlain by forested colluvial lobes that suggest there has been movement greater than 250 years ago (Mann, 2000). Movement of these colluvial soils may be reactivated with serious consequences of loss of powerhouse and transport of soil and rock debris into the river. Transport of soil and rock into the river downstream of the powerhouse would adversely affect the stretch of river that runs through the Mills allotment, and temporarily (several weeks or months) reduce its suitability as a source of drinking water. Fish habitat in the marine waters of GBNPP at the mouth of the river would also be degraded. Founding the load-bearing structures of the powerhouse either directly on bedrock or through intermediate piles would be preferred over founding structures on colluvial soils. A deep foundation system would provide for a stable structure. The stabilization of the colluvial lobes is critical to prevent reactivation of ground movement. Containing and controlling surface water and subsurface drainage, and the use of geotechnical instrumentation and piezometers to monitor slope conditions, also would help minimize this potential effect.

The pipeline would follow along the road alignment. The hazards to the pipeline would be the same as to the road with the additional hazard of carrying a large volume of water. There is an inherent risk that ground movement may sever the pipeline, thus, releasing a concentrated flow of water that could cause significant erosion, transport, and deposition of soil, rock, and debris to the river. As noted previously, pipeline failure would increase turbidity and temporarily render the water that flows through the Mills allotment unsuitable for drinking. The most likely scenario however would be gradual ground movement that would distort and distress the pipeline that would lead to eventual leakage, and ground movement could probably be detected by periodic visual inspection along the pipeline route. The worst case scenario of rapid large ground movement resulting in sudden failure of the pipeline has a low probability of occurrence. Such complete pipeline failure resulting in uncontrolled release of concentrated flow of water could cause significant mass movement and erosion of soil on the slope below the pipeline and deposition of the debris into the river. The quantity of released water and severity of erosion could be reduced by an automated system that would monitor and alert the operator and/or shut down the system upon detection of loss of expected flow.

GEC proposes that the transmission line would extend 5 miles from the powerhouse to an interconnection with the existing system at the diesel power plant. The transmission line would be buried for its entire length, in or adjacent to the proposed access road to across Homesteader Creek to a point where the project access road turns west to connect to Rink Creek Road. From there, the access road would turn west;

however, the transmission line would continue south approximately 0.25 mile, turn west for approximately 1.1 mile, and then finally turn southwest for about 0.7 mile where it would connect to the existing grid system. The buried transmission line, as GEC proposes, would be sensitive to ground movement greater than several inches. The hazards for the buried transmission lines would be the same as for the access road as discussed above in section 4.3.2. In the event of significant ground movement, power transmission would be lost.

The upland (non-tidally affected) portion of the Gustavus Flats is underlain by well-sorted, medium to fine glacial outwash sand occasionally overlain by a thin, discontinuous veneer of marine silt that is probably responsible for the high water table in the area. Other parts of these lowlands probably contain glacial outwash gravels. Rapid land uplift is occurring at rates of about 0.4 inch per year improving the drainage as the base level is lowered and causing streams to incise through the former tide flats (Streveler, 1995). Although, slopes in the Gustavus Flats area are relatively flat (less than 10 percent), incised stream crossings at Rink and Homesteader creeks along the proposed transmission line route may have distinctly steeper slopes that are at risk of small, localized rotational slumps in the finer grained sediments. Alternating layers of groundwater-saturated glacial outwash sand overlying marine silt on steeper slopes also are landslide-prone.

GEC proposes to acquire gravel and shot rock for the initial road construction from existing sources on non-park lands in Gustavus. Additional shot rock would be taken from borrow sites and additional pits in the Horseshoe and Old Clearcut vicinities, if needed (see figures 1-3 and 2-2 in appendix A). The quantity of fill required for the project can only be roughly estimated at this time because of the wide spacing and shallow depth of explorations in the vicinity of the road alignment. However, GEC proposes several measures that would reduce the amount of fill that the proposed facilities would require. Use of U.S. Forest Service standards for road construction (see previous description) would greatly reduce the quantity of fill required. In addition, in most road sections, brush mat and geotextiles would be floated over organic soils instead of excavating these soft soils, which would reduce the need for fill materials.

GEC proposes to backhaul all road-cut material out of the stream canyon to reduce potential for mass wasting. All excess or unsuitable materials not used in road construction would be hauled to a 0.7-acre disposal (see figure 2-2 in appendix A) site within the project boundary, and the disposal site would be revegetated. Slopes at the proposed disposal area primarily range from 5 to 15 percent, which would be relatively stable. The proposed site is away from surface streams, which reduces the risk of erosion of the capping layer until vegetation becomes reestablished.

GEC proposes to salvage topsoil and vegetation and use it for revegetation and erosion control along road cuts and side-cast slopes, supplemented by seeding with native grasses, as needed. Reuse of excavated materials would decrease the need for hauling excess material to the disposal site and lessen the size of the disposal area required. Revegetation also would prevent erosion and sedimentation, is a good practice, and would be more economical than hauling in more materials.

GEC proposes to use gravel and shot rock for initial road construction. Gravel and sand pit materials are present in the Gustavus area, and shot rock sources are available in the Kahtaheena River watershed. The character of Gustavus area pit glacial outwash materials is well known, but potential hard rock sources for shot rock in the Kahtaheena River area have not been adequately characterized for quantity and quality for road construction.

FHWA (1985) investigated potential construction material sources of sand and gravel for the main GBNPP road, including three pits within and adjacent to GBNPP, as well as other pits in the vicinity of Gustavus. All pits were situated on the glacial outwash lowlands where a shallow water table is present. FHWA found that available local material sources of sand have marginal to poor base aggregate properties and that processing with the addition of binder improves the strength properties of the aggregate as a base material. This is also likely the case with gravel from the same sources. After evaluating alternatives for granular aggregate construction materials locally, aggregate was imported of higher quality for GBNPP road construction by shipping from sources out of the area (personal communication between Steven Anderson, GBNPP Engineer, and Glen Strachan, Hydro Geosciences, Inc., on July 21, 2003). Other sources of hard rock road construction materials would be in the Chilkat Range, Chichagof Island, and Juneau area.

Within the watershed, there are reportedly significant deposits of stream gravel in terraces adjacent to and upstream of the proposed intake site and at an old clearcut area north of the Lower Falls (Mann, 2000). GEC's application identified borrow material site for road construction in the saddle near the junction of the access road to the diversion dam/intake structure and powerhouse. This site would be an excavation required to maintain the hydraulic gradient of the pipeline. Materials from excavation would be used elsewhere for the access road. Stability of soils on these slopes is probably only marginal. Surface water runoff during and following construction may be disrupted, concentrated, or rerouted. If water is discharged on or above this steep slope, it may destabilize the slope and initiate a landslide. Such an event would negatively affect the water quality of the Kahtaheena River and its suitability as a source of drinking water. Groundwater may also intercept at the bottom and side slopes of the road cut. High groundwater within or discharging on side slopes decreases the stability of the slope. The road cut may intersect groundwater aquifers causing groundwater to become surface water with possible concomitant erosion effects at and downstream from these locations.

GEC’s proposed ESCP would establish procedures to prevent significant erosion and mass movement. Careful implementation of the ESCP would be required for borrow pits near steep slopes. In addition, borrow pits and hard rock quarries located on the uphill side of the access road from the Kahtaheena River, in contrast to the downhill side, would have less potential sediment effect on the stream. Borrow pits located adjacent to the road alignment would help to avoid secondary access road construction.

The Tongass National Forest typically uses hard rock from quarries as shot rock for road surfaces. The upper few feet of road fill material used in the Tongass National Forest is mostly 2-inch minus shot rock with fines, capped by 1-inch minus of crushed rock at the road surface (personal communication from J. Oien, Tongass National Forest, AK, with G. Strachan, Hydro-Geosciences, Redmond, WA, on July 22, 2003). Sedimentary rock in the watershed is dominated by calcareous mudstone (Mann, 1999). It is likely that calcareous mudstone underlies most of the Kahtaheena River watershed study area, and it probably supplies sediment to drainages of the Kahtaheena River.

Calcareous mudstone is generally variable in rock quality. Non-metamorphosed mudstone has low durability and low resistance to erosion from water and potentially could degrade to fines, which could affect the Kahtaheena River water quality if it is nearby and downslope. In addition, calcareous mudstone is usually rippable with a backhoe, but some mudstone that is cemented to a higher degree may require blasting. It is unlikely that blasting would be necessary in mudstones in the Kahtaheena River watershed. It would be advisable to use the hardest, most durable, rock material on the road surface and softer, less durable, material lower in the fill section of the road. Although metasedimentary rocks and greywacke sandstone tend to be harder and more durable and resistant to erosion, quantity and access may be limited in the watershed.

In conclusion, potential gravel and shot rock suitable for road construction materials in the watershed are probably available in sufficient quantity, variable in quality, and would likely become more available as a result of road construction. Onsite rock material may not be suitable for use in structural concrete. It is possible that onsite materials would be inadequate, and it would become necessary to obtain rock from outside the immediate project area. Trucking of rock from off site would increase traffic on the proposed road, and degrade pavement and road surfaces resulting in increased maintenance of the road, and increased maintenance of bridges.

Erosion and Sedimentation. Geologic materials with moderate to high relative erodibility would be the most probable sources of sediment available to streams and the Kahtaheena River watershed drainage system. This may include sediments derived from both surficial and bedrock deposits that potentially contribute to streams through surface erosion and mass movement. Surficial deposits most likely to be eroded and released to streams in the watershed are organic soils and peat, colluvium (previously transported soil by mass wastage), and glaciolacustrine and outwash sediments. Bedrock deposits that are most likely to be eroded and released to streams in the watershed are residual soils (weathered from rock) of calcareous mudstone. Calcareous mudstone dominates the sedimentary bedrock for the watershed (Mann, 1999), and for our sediment transport analysis we assume that the watershed bedrock is entirely calcareous mudstone. This is a conservative assumption, but less erodible rock appears to be in very limited supply. Calcareous mudstones tend to produce silts and clays, and clays may produce suspended particles that increase turbidity in water. The most vulnerable points where erosion may occur and release sediment into drainages flowing towards the Kahtaheena River are at road crossings and where mass wastage may occur near steep slopes such as at the Horseshoe.

Estimates for erosion and sediment entrainment from surfaces of gravel road and exposed soil along ditches are uncertain. However, using reasonable assumptions, sediment (turbidity) rates would be as follows:

No-action (baseline)	20 m^3/year[44]
Short-term during construction	175 m^3/year[45]
Long-term post-construction (baseline + roads)	55 m^3/year[46]
Landslide event (typical size)	600 m^3/year (in addition to baseline under no-action or long-term post-construction)[47]

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44 Sediment source supply is assumed to be dominated by soil creep in areas of steep slopes, primarily in The Canyon reach. Assumptions include: soil creep rate of 0.0064 m (based on measured soil creep rate from Prince of Wales Island, Barr and Swanston, 1970); soil thickness of 1 m; and The Canyon Reach, 1.5 km. Therefore, sediment = soil thickness x creep rate x length of reach x two sides of stream = approximately 20 m^3/year.

45 Sediment/turbidity = 0.1% of volume of runoff water from all proposed disturbed areas. Values for the quantity of water runoff and the concentration of entrained sediment are our best estimates. The assumed concentration of sediment is prior to implementation of the ESCP. We assume that water runoff from about half of the disturbed area may go directly to the river, whereas runoff from the other half may be discharged in vegetated areas or “bio-swales” where sediments may be removed before water reaches the river. In addition, the ESCP should further reduce the total amount of sediments from reaching the river by less than 50 percent (Cherry, 2002).

46 Sediment/turbidity = 0.1% of volume of runoff water from areas of proposed roads and powerhouse. Values for the quantity of water runoff and the concentration of entrained sediment are our best estimates. The assumed concentration of sediment is prior to implementation of the ESCP. We assume that water runoff from about half of the disturbed area may go directly to the river, whereas runoff from the other half may be discharged in vegetated areas or bio-swales where sediments may be removed before water reaches the river. In addition, the ESCP should further reduce the total amount of sediments from reaching the river by less than 50 percent (Cherry, 2002).

47 We assumed individual landslides of typical size and that the mixture of the soil/rock deposited in the river would be eroded and transported by the river. Sediment volume = assumed width x thickness x displacement into river = 20 m x 3 m x 10 m = 600 m^3 per landslide event.

Landslides represent infrequent but extreme events that may have significant impact on the sediment supply to streams (see section 3.3). Based on the size of the watershed, the risk of a landslide occurring would be about two landslides during the license period of 50 years. Assuming a typical shallow landslide (20 m wide, 3 m deep) that moves about 10 m, approximately 600 m^3 of soil and debris would be deposited in the river. Also, landslides generally occur during an extreme event, so there may be multiple slides during a single intense storm. The number of landslides that may occur in a future extreme event cannot be predicted. However, an extreme event may initiate three landslides in the watershed (one in the unmanaged terrain outside of the project and two along the access road in previously identified steeper terrain). As a result, about 1,800 m^3 of sediments could be deposited in the river from both project-related and non-project related slope failures.

The amount of borrow material needed to build the roads, the powerhouse, and associated construction would be approximately 43,000 yd^3. The amount of borrow material needed to maintain the roads and project would be 220 yd^3 per year. GEC proposes that this borrow material would come from some of the excavated material. The sites would be adjacent to the proposed road/penstock alignment and would require minimal haul effort and land disturbance to acquire material. GEC proposes that an estimated 30,000 yd^3 of borrow material would come from excavated areas. Borrow areas would be regraded and reseeded with native vegetation to reclaim the site and to prevent erosion. The best time period to re-seed for borrow areas and along the access road would be immediately after the snowmelt and throughout the summer. Enough time must be allowed between seeding and freeze up for the plants to develop a good root system and top growth. The roots and litter would stabilize the soil if the plant dies after freezing (personal communication from M. Kralovec, GBNPP-NPS, on August 5, 2003).

The truck traffic needed to haul the borrow material and the subsequent toll on the constructed road is unknown. Culverts would be needed to collect and direct surface drainage under the constructed road, but the number and sizes and their locations would be developed during final road design. Culverts would be designed to pass the sediment bedload to prevent plugging the pipes. Therefore, they probably would not disrupt the bedload transport of sediment. A bridge would be constructed over Homesteader Creek, and the size and design of the bridge would be determined during the final design.

Construction of the above facilities would extend over 24 months. Clearing and disturbance would result in the potential risk of increased erosion and sediment input into area waterways. GEC developed a draft ESCP (GEC, 2001b, appendix G) in which it proposes to limit the potential for erosion by minimizing the area disturbed; using equipment that is proportionally sized for the task; back-hauling materials excavated from the stream canyon and powerhouse area; and implementing BMPs such as silt fencing, reseeding, covering exposed soil with straw or visqueen, and directing surface runoff away from excavated areas. Earthwork in moisture-sensitive soil would be conducted in dryer summer months.

ADFG, FWS, and NMFS request that GEC consult with and obtain their written approval for the final ESCP. Review and approval by these agencies and others, as appropriate, would ensure that agencies are able to suggest modifications to the ESCP and identify any potential concerns. GEC's proposed construction techniques in the ESCP would minimize effects on the geologic resources and soils in the proposed project area. There could be some effect on soils as a result of proposed road construction and borrow pit development, with somewhat more significant effects possible for the road section and north borrow pit area between the Upper Falls and intake/diversion structure, and for the road at the powerhouse location. Unanticipated, unseasonable storms that may occur during construction also could reduce the effectiveness of construction techniques (as described in the ESCP) that entail a degree of risk (e.g., controlling and containing drainage).

The agency-recommended road management plan would provide measures to address potential slope erosion during project operation related to road crossings of water bodies in the project area. Implementation of a road management plan, including road maintenance and monitoring, could help to prevent any detrimental effects on water quality and fisheries from road-related erosion and sediment transport.

Bedload Transport. Operation of hydroelectric projects can interrupt sediment transport processes, particularly at dam sites and in bypassed reaches. Maintaining sediment transport past the diversion dam would be important to maintain spawning habitat for fish using the Kahtaheena River in the bypassed reach and below the Lower Falls.

GEC proposes several measures and features (described below) to minimize the effects of the project on sediment transport. It proposes to limit flow diversions from the Kahtaheena River to a maximum of 23 cfs and to install a pneumatically operated sluice at the diversion dam. GEC proposes that the intake would include a sediment retention wall to prevent bedload from reaching the trashrack and fish screens and instead direct it to the sluice gate. The facility would include a system for sluicing any sediment that may settle in the intake and a trash boom for directing any floating debris to the sluice gate area. The pneumatic sluice gate would automatically be lowered during high flow events to allow bedload to pass the dam into the bypassed reach. In addition, GEC proposes to compensate for sediment trapped in the impoundment by manually removing sediments and placing them on a river bar immediately downstream of the structure for re-entrainment during the next high water event. The need for these activities would be based on results of annual monitoring of cross-sections in the impoundment as specified in GEC’s proposed sediment monitoring and management plan.

The agencies do not recommend any measures beyond those proposed by GEC related to bedload transport.

Construction and operation of the project could alter sediment transport in the Kahtaheena River and negatively affect water quality of the Kahtaheena River on the Mills allotment and the marine waters of GBNPP at the mouth of the river. We focus our analysis of potential effects on sediment transported along the bottom of a stream by traction (sliding) and saltation (bouncing), which is commonly referred to as bedload. Bedload consists of sand, gravel, cobble, and boulder-sized particles. Bedload transport is a function of particle size and supply of sediments and the power of the stream, which is related to the volume of water, stream velocity, and stream gradient. Bedload transport is important for creating and maintaining habitat for aquatic communities, and it is highly unpredictable (Sear, 2003) and very difficult to measure and quantify. Table 4.3-2 presents some important factors affecting bedload transport in the Kahtaheena River.

Table 4.3-2. Parameters affecting bedload transport in the Kahtaheena River. (Source: Preparers)

	Above Upper Falls Diversion Structure	**Downstream of Upper Falls/ The Canyon**	**Interpretation/Consequence**
Stream gradient	2.7%	5.8%	Stream gradient is twice as steep in the canyon reach as in the upstream reach.
Valley walls/ slopes	20 to 40%	40 to 125%	Valley walls are significantly steeper in The Canyon than in the upstream reach suggesting that the bedrock is harder and more resistant there. Also, the steeper slopes would cause a higher creep rate in the surficial soils and result in greater sediment supply to the stream. Estimate for sediment supply is about 20 m^3/yr.
Peak stream flow	2,000 cfs measured on December 27, 1999; the 100-year flood is estimated at 3,500 cfs (NPS letter, May 14, 2001)		The proposed maximum diversion of 23 cfs would decrease flow through The Canyon by about 1 to 2 percent for major storms.
Effect of diverting flow	Up to 23 cfs reduction in flow below point of diversion		GEC's proposal would slightly reduce the frequency of flows required to flush fine-grained sediments from the bar below the dam.

The stream channel below the Upper Falls is probably capable of transporting larger sized sediment and greater quantities of sediment than the reach above the Upper Falls. In addition, the steeper valley walls suggest that the coarse-grained sediment that would originate from within The Canyon probably is harder and more durable than the sediment that originates from upstream of the reach. Based on the parameters listed above, bedload is likely transported more rapidly through The Canyon than above the Upper Falls. Diversion of 23 cfs for hydroelectric power production would decrease peak flows by 1 to 2 percent. This reduction would not change mass wasting of soils along the valley slopes, which is the source of the sediments to the stream. Typically, most sediment transport occurs during peak flows. With the small reduction at peak flow, there probably would be little effect on transport of sediment through the canyon reach.

An intake structure and its associated impoundment would alter flow patterns to encourage sediments and debris to be routed away from the intake and toward the sluice gate. The proposed facility would include a pneumatic controlled sluice gate that would be automatically lowered to pass sediments during high flows. Although operation of these facilities would avoid accumulation of sediments in front of the intake, some sediments would be deposited within the impoundment due to the slower velocities and reduced stream power. The extent of sediment deposition that would occur within the impoundment is unknown.

GEC provides a description of its proposal for monitoring sediment accumulation and sediment augmentation, if needed, in the sediment monitoring and management plan. GEC proposes to evaluate the extent of sediment accumulation in the impoundment by annually surveying cross-sections for 910 feet upstream of the diversion dam, and comparing the streambed levels to previously monitored conditions. If there is appreciable difference between the bed elevations, GEC would collect bulk sediment samples to determine the grain size distribution of deposited sediments and prepare a report describing monitoring results. GEC proposes to make up for any shortfall in sediment supplied to the bypassed reach by manually removing sediments from the impoundment and placing them on a river bar immediately downstream of the structure for re-entrainment during the next high flow season.

While GEC's proposed actions would reduce the effects that the project would have on bedload transport, manually removing sediments from the impoundment and depositing them on a bar downstream of the dam may actually result in adverse effects on sediment conditions downstream of the dam.

Hydraulic analysis of a transect across the bar below the dam indicates that it takes 150 cfs for surficial flushing and 330 cfs to mobilize gravel on the bar. Based on estimated daily mean flow conditions in the proposed bypassed reach, project operation would result in surficial flushing flows occurring an average of 5 days per year with the project compared to 10 days per year under existing conditions. This reduction in flushing along with the placement of sediments during the low-flow period could result in prolonged periods where fine sediments block the interstices between gravel particles in the bar and other nearby areas. To evaluate the extent of this potential adverse effect and take appropriate action, GEC would need to monitor the conditions of sediments in the reach immediately downstream of the dam, and adapt its management of sediments in the area.

In summary, construction and operation of the proposed project would result in short-term delays (generally less than 1 year) in bedload transport to the proposed bypassed reach. As sediments are transported down the river, some would be temporarily deposited in the impoundment until they are flushed downstream when the pneumatic sluice gate is lowered during high flow events or they are manually removed and placed on a bar downstream of the dam. GEC's proposed management of these sediments would ensure that sediments would be delivered to the reach downstream of the dam within 1 year of when they are deposited in the reservoir. Following their placement on the bar, flows in the bypassed reach would distribute them further downstream; however, the reduced flows in the bypassed reach could lead to fine-grained particles filling the interstices of sediments for prolonged periods. To evaluate the extent of this potential adverse effect and take corrective actions, GEC would have to monitor sediments immediately below the dam and take corrective actions to resolve any problems.

See section 4.6, *Fisheries*, for an analysis of potential effects of disruption of bedload transport on spawning habitat and fisheries.

4.3.2.2 Effects of the GBNPP and Wilderness Boundary Adjustment. Under GEC's Proposed Alternative, the geologic and soils resources of the proposed wilderness designation parcels would not be affected, and the land exchange parcels considered for transfer would come under NPS management and values, which would protect the geologic and soils resources of these parcels.

4.3.2.3 Cumulative Effects Analysis. The occurrence of large storm events may destabilize subsurface geological features in areas completely independent and separated from the proposed project features and result in the initiation of a mass wasting event. This mass wasting event would affect vegetation and wildlife resources and, depending on the location and extent of the event, possibly fisheries and water resources. The combined effect of the natural storm and mass wasting event with the location of the project facilities (e.g., access roads, penstock) may result in the failure of the project facilities; the additional accumulation of soil and debris in the natural event; and a cumulative increase in the effect on vegetation, wildlife, water, and fisheries resources.

There are no project-related actions identified that would result in an impact on geologic resources and soils for the WSNPP and KGNHP transfer parcels. Therefore, no cumulative effects on water resources would occur as a result of the interaction between project actions and non-project actions at these sites.

There are no project-related actions identified that would result in an impact on geologic resources and soils for the proposed wilderness parcels at the unnamed island near Blue Mouse Cove, Cenotaph Island, or Alsek Lake. Therefore, no cumulative effects on water resources would occur as a result of the interaction between project actions and non-project actions at these sites.

Because of the high rate of uplift (0.4 inch/year) in the tidal portion of the Kahtaheena River, this reach could increase in length by several hundred feet or more within a license term (30 to 50 years). Assuming that increased stream length would correspond to increased anadromous fish habitat, over time the numbers of anadromous fish using the Kahtaheena River could increase. Therefore, from a cumulative perspective, the ramifications of any project-related effects on this reach or the fish inhabiting it could be even greater in the future. Project-related increases in sediment input to the stream system would be most pronounced during the first few years of any license term, and these effects likely would decrease over time, suggesting there may be little if any effect on future anadromous fish populations. The proposed project would disrupt bedload transport within the stream system, but this effect would not reduce the amount of available spawning materials in the tidal portion of the river since the effect would be a delay in bedload movement (up to roughly 1 year) and not the elimination or suspension of bedload transport into this area. Over the long term, a 1-year delay in bedload movements would not limit the availability of anadromous fish spawning habitat in the tidal reach.

4.3.2.4 Conclusion. Marginally stable landforms could be destabilized by the proposed project, especially along the two road and pipeline segments that would traverse steep slopes. Some surface erosion from road crossings would occur during construction and the early years of operation with the potential to deliver increased sediment into the Kahtaheena River and its tributaries. Construction and operation of the project would delay bedload transport through the impounded reach and past the dam and would result in more episodic transport (i.e., up to a 1-year delay in bedload movement) than would occur naturally.

Under GEC's proposal, the geology and soils of the Kahtaheena River area could be adversely affected by project construction and operation. Under this alternative, the majority of the developed facilities associated with this action would be constructed in a localized area, and these effects would be contained within the Kahtaheena River drainage below the point of diversion but could affect the surrounding GBNPP lands along the eastern edge of the Kahtaheena River, the Mills allotment, and marine waters at the mouth of the river. GEC proposed and the resource agencies recommended erosion and sediment control measures that would minimize or avoid some of the potential effects. These measures include construction techniques and practices that would avoid unstable soils, limit blasting and tree removal, and control surface runoff and operational measures that would attempt to maintain bedload movement within the Kahtaheena River. Lands within GBNPP would be above the eastern lip of the Kahtaheena River canyon and likely would not be directly affected by construction of the diversion structure or the powerhouse. Decreased flow through the canyon reach would reduce scour and erosion of the east bank of the river but it would not affect the land within GBNPP. A mass wasting event is possible along the east bank of the river, but it would be more likely due to natural events (storms) than project-related effects such as decreased bank erosion.

The purposes and values of GBNPP identified in the enabling legislation include the preservation of geological values associated with natural landscapes (see section 1.7.4). The construction and operation of the proposed project would not adversely impact the purposes and values of GBNPP because the majority of the effects would be contained on either state land or within the FERC project boundary, and any effects on geologic resources within GBNPP would be short-term and localized and would not substantially diminish the geological value of GBNPP. Under GEC's proposal, the geologic resources and soils of the unnamed island near Blue Mouse Cove, Cenotaph Island, and lands at Alsek Lake would not be affected because these lands would remain in GBNPP. Therefore, the anticipated effects on geology and soils under this alternative would not result in an impairment of the GBNPP resources that fulfill the specific purposes identified in the enabling legislation or are key to the natural integrity of the park. GBNPP would continue to operate and manage park lands to preserve nationally significant geological values associated with natural landscapes.

As noted above, the majority of the developed facilities associated with this action would be constructed in a localized area, and these effects would be contained within the Kahtaheena River drainage below the point of diversion. Conveying state land to NPS in either WSNPP or KGNHP would not have any effect on geology and soils at these locations. Therefore, the level of impacts on the geology and soils resources anticipated from this alternative would not result in an impairment of WSNPP or KGNHP resources that fulfill specific purposes identified in the enabling legislation or are key to the natural integrity of these parks. WSNPP or KGNHP would continue to operate and manage their lands as outlined in the enabling legislation (see section 1.7.4).

4.3.3 Maximum Boundary Alternative

Under the Maximum Boundary alternative, the 1,145 acres of land identified in section 3(b) of the Act as potentially available for the development of a hydroelectric project would be transferred to the state of Alaska, and all transferred land would be within the project boundary. The land would be subject to FERC license conditions, potentially restricting its use and development by the state, and the bypassed reach would be included in the FERC project boundary.

4.3.3.1 Effects of Construction and Operation. Protection and mitigation measures relating to geology and soils would be the same under this alternative as under the proposed action. As discussed in section 4.3.2.1, these measures would reduce project effects on soil destabilization, erosion and sedimentation, and interruption of bedload transport.

4.3.3.2 Effects of the GBNPP and Wilderness Boundary Adjustment. Under the Maximum Boundary Alternative, the wilderness designation parcels and the proposed land exchange parcels considered for transfer would not be affected as described in section 4.3.2.1.

4.3.3.3 Cumulative Effects Analysis. The types of cumulative effects that could be expected to occur on geologic resources and soils under this alternative would be the same as those described under GEC's proposal in section 4.3.2.3.

4.3.3.4 Conclusion. Overall, the Maximum Boundary Alternative would have the same effects on geologic resources and soils as the proposed action (section 4.3.2.4), except that the 1,145 acres of NPS land that would be conveyed to the state of Alaska would include the entire bypassed reach and lands to the east of the bypassed reach.

The majority of the developed facilities associated with this action would be constructed in a localized area, and the effects of project construction and operation would be contained within the Kahtaheena River drainage below the point of diversion. Project construction and operation would not affect the surrounding GBNPP lands because the state lands within the maximum project boundary would provide a buffer between the project and the surrounding GBNPP lands. However, increased sedimentation and turbidity in the Kahtaheena River could affect GBNPP at the mouth of the river where it meets the marine waters. These effects would include short-term (i.e., several weeks or months) increases in turbidity of waters within GBNPP in the immediate area of the mouth of the Kahtaheena River. The measures proposed by GEC and recommended by the resource agencies would minimize or avoid the potential negative effects on geology and soils. These measures include construction techniques and practices that would avoid unstable soils, limit blasting and tree removal, and control surface runoff and operational measures that would address the movement of sediments within the Kahtaheena River.

The purposes and values of the GBNPP identified in the enabling legislation include the preservation of geological values associated with natural landscapes (see section 1.7.4). The construction and operation of the proposed project would not adversely impact the purposes and values of GBNPP because the majority of the effects would be contained on either state land or within the FERC project boundary, and any effects on geologic resources within GBNPP would be short-term and localized and would not substantially diminish the geological value of GBNPP. Under GEC's proposal, the geologic resources and soils of the unnamed island near Blue Mouse Cove, Cenotaph Island, and lands at Alsek Lake would not be affected because the effects on geology and soils would only occur in a localized area encompassing the project facilities, and these lands would continue under NPS management. Therefore, the anticipated effects on geology and soils under this alternative would not result in an impairment of GBNPP resources that fulfill specific purposes identified in the enabling legislation or are key to the natural integrity of the park. GBNPP would continue to operate and manage its lands as outlined in the enabling legislation (see section 1.7.4).

Conveying state land to NPS in either WSNPP or KGNHP would not have any effect on geology and soils at these locations. Therefore, the Maximum Boundary Alternative would not result in an impairment of WSNPP or KGNHP lands that fulfill specific purposes identified in the enabling legislation or are key to the natural integrity of these parks. These parks would continue to operate and manage their lands as outlined in the enabling legislation (see section 1.7.4).

4.3.4 Corridor Alternative

Under the Corridor Alternative, approximately 680 acres of park land would be transferred to the state of Alaska, and all transferred land would lie within the FERC project boundary. The land transfer would provide a minimum buffer distance of approximately 0.25 miles around project roads, penstock, transmission line rights-of-way, borrow pit and disposal sites, diversion site, and powerhouse, except along the eastern boundary, where a 0.25-mile buffer would fall outside the lands identified as potentially available for development of a project in the Act. This alternative would include the bypassed reach in the project boundary.

4.3.4.1 Effects of Construction and Operation. Measures relating to geology and soils would be the same under this alternative as under the proposed action. As discussed relative to that alternative (see section 4.3.2.1), these measures would adequately address the potential for soil destabilization, erosion and sedimentation, and interruption of bedload transport.

4.3.4.2 Effects of the GBNPP and Wilderness Boundary Adjustment. Measures relating to and effects on geologic resources and soils of the wilderness designation parcels and the land exchange parcels would be the same under this alternative as under the proposed action, described in section 4.3.2.1. Therefore, there would be no effect on the geologic resources and soils of the wilderness and exchange parcels.

4.3.4.3 Cumulative Effects. The types of cumulative effects that could be expected to occur on geologic resources and soils under this alternative would be the same as those described under GEC's proposal in section 4.3.2.3.

4.3.4.4 Conclusion. Overall, the Corridor Alternative would have the same effects on geologic resources and soils as the proposed action (section 4.3.2.4), except that the 680 acres of NPS land that would be conveyed to the state of Alaska would include the entire bypassed reach and lands to the east of the bypassed reach.

The majority of the developed facilities associated with this action would be constructed in a localized area, and the effects of construction and operation would be contained within the Kahtaheena River drainage below the point of diversion. Project construction and operation would not affect the surrounding GBNPP lands along the eastern edge of the Kahtaheena River because state lands would provide a buffer between the project and the surrounding GBNNP lands. However, increased sedimentation and turbidity in the Kahtaheena River could affect GBNPP at the mouth of the river where it meets the marine waters. These effects would include short-term (i.e., several weeks or months) increases in turbidity of waters within GBNPP in the immediate area of the mouth of the Kahtaheena River. The measures proposed by GEC and recommended by the resource agencies would minimize or avoid the potential negative effects on geology and soils. These measures include construction techniques and practices that would avoid unstable soils, limit blasting and tree removal, and control surface runoff and operational measures that would address the movement of sediments within the Kahtaheena River.

The purposes and values of GBNPP identified in the enabling legislation include the preservation of geological values associated with natural landscapes (see section 1.7.4). The construction and operation of the proposed project would not adversely impact the purposes and values of GBNPP because the majority of the effects would be contained on either state land or within the FERC project boundary, and any effects on geologic resources within GBNPP would be short-term and localized and would not substantially diminish the geological value of GBNPP. Under GEC's proposal, the geology and soil resources of the unnamed island near Blue Mouse Cove, Cenotaph Island, and lands at Alsek Lake would not be affected because they are not located near the project site. These lands would continue under NPS management. Therefore, the anticipated effects on geology and soils under this alternative would not result in an impairment of GBNPP resources that fulfill the specific purposes identified in the enabling legislation or are key to the natural integrity of the park. GBNPP would continue to operate and manage park lands to preserve nationally significant geological values associated with natural landscapes (see section 1.7.4).

Conveying state land to NPS in either WSNPP or KGNHP would not have any effect on geology and soils at these locations. Therefore, any negative effects on the geologic resources and soils anticipated from the Corridor Alternative would not result in an impairment of WSNPP or KGNHP resources that fulfill specific purposes identified in the enabling legislation or are key to the natural integrity of these parks.

4.4 WATER QUANTITY AND QUALITY

In this section, we analyze the effects that the project would have on water quantity and water quality. Three evaluation parameters are used to identify and describe the potential impacts on water quantity:

1. Magnitude of daily mean flows

2. Rate of short-term water level and flow alterations

3. Interruption of subsurface water flow

The analysis of potential effects of the proposed project on water quantity includes a discussion of the spatial and temporal context of surface and subsurface waters in the project area. The intensity of the impact on water quantity is generally characterized by the use of flow duration analyses for the proposed bypassed reach and effects of project operations on the short-term rate of change in both the proposed bypassed reach and the reach downstream of the powerhouse discharge. The duration of the impact is described where necessary to understand the context and intensity of the impact.

Four evaluation parameters have been developed to identify and describe the potential impacts on water quality:

1. Sediment supply as a surrogate for turbidity

2. Potential risk of landslides

3. Maximum summertime water temperatures

4. Potential risk of hazardous materials spills

The analysis of potential effects of the proposed project on water quality includes a discussion of the context of water quality in the project area. The intensity of the potential effects on water quality is characterized by quantifying maximum summertime water temperatures and the level of risks associated with elevating turbidity and potentially hazardous materials. The duration of the effects is described where necessary to understand the context and intensity.

In addition, we discuss the physical characteristics associated with icing. However, we do not present our analysis of effects on icing in this section since the associated concern is primarily the potential for impacts on aquatic resources. Instead, we present our analysis of icing in section 4.6, *Fisheries*.

4.4.1 No-action Alternative

4.4.1.1 Effects Analysis. Under the No-action Alternative, the proposed project would not be constructed; the land surrounding the proposed project would be retained within the National Wilderness Preservation System for the foreseeable future and would continue to be managed as wilderness in accordance with the GBNPP GMP; and there would be no land exchange. The project would not be constructed or operated under the No-action Alternative; therefore, the Kahtaheena River's flow regime would not change. Based on modeling of flows for a 30-year period, average monthly flow for the proposed diversion site would range from 20 cfs in March to a little more than 100 cfs in October (see table 3.4-2). During winter (December through March), daily mean flows of less than 15, 10, and 5 cfs would continue to occur 50, 33, and 8 percent of the time, respectively.

Because the project would not be constructed and the flow regime would remain unchanged, Kahtaheena River water temperatures and icing conditions would not be changed from existing conditions. Based on measurements reported by the USGS (2000; 2001; and 2002), Kahtaheena River water temperatures would continue to generally range between 0 and 13EC. The river would continue to be completely covered by ice and/or snow during much of the winter (December through March). Based on the limited understanding of specific conditions that result in anchor ice in the Kahtaheena River, anchor ice would likely form at the onset of ice formation in the river during December. It would also form occasionally throughout the winter during cold periods immediately following warmer periods that cause the ice cover to melt.

Under the No-action Alternative, no project would be constructed, and there would be no associated effect on turbidity levels of area waterways. There would be a continued risk of landslides supplying substantial quantities of sediments to area waterways, and subsequently increasing turbidity. Although landslides would occur infrequently, they would result in prolonged turbid conditions in the receiving water and downstream, and could occasionally reduce the suitability of water from the Kahtaheena River for drinking by the Mills allotees.

There would be no major changes in hazardous material storage and use in the Kahtaheena River Basin; however, diesel fuel would continue to be transferred, stored, and used at the generation facilities in Gustavus to produce electricity at current levels (i.e., there would be no reduction in diesel use). Therefore, the risk of accidental spills associated with these facilities would continue to occur, particularly during transfer of fuel, and would remain unchanged unless demand increases. If demand increases were to result in increased barge and transfer activity, the risk of spills likely would increase in proportion to the increase in these activities.

4.4.1.2 Cumulative Effects Analysis. Under the No-action Alternative, there would be no cumulative effects because there are no project actions that would occur in the Kahtaheena River watershed; state-owned parcels adjacent to WSNPP and KGNHP; and the parcels at Cenotaph Island, the unnamed island near Blue Mouse Cove, and Alsek Lake. Therefore, there is no potential for cumulative effects on water resources based on the interaction between a project and non-project action.

4.4.1.3 Conclusion. Under the No-action Alternative, there would be no effect on water quantity and quality in the Kahtaheena River area, on the potential land exchange parcels, or on the wilderness parcels. Implementation of the No-action Alternative would not result in impairment of GBNPP resources that fulfill specific purposes as identified in the enabling legislation or are key to the natural integrity of the park. Under this alternative, GBNPP would continue to operate and manage its lands as outlined in the enabling legislation (see section 1.7.4). There would be no effect on water resources in the Native allotments under this alternative.

The level of effects on water resources anticipated from this alternative would not result in an impairment of WSNPP or KGNHP resources that fulfill specific purposes as identified in the enabling legislation, or are key to the natural integrity of these parks. Under this alternative, WSNPP and KGNHP would continue to operate and manage their lands as outlined in their enabling legislation (see section 1.7.4).

4.4.2 GEC's Proposed Alternative

4.4.2.1 Effects of Construction and Operation. Construction and operation of the proposed project could affect water quantity and water quality in the project area by:

- alteration of the natural flow regime in the proposed 1.79-mile-long bypassed reach, between the diversion structure downstream to the base of the Lower Falls;
- alteration of the natural flow regime in the reach accessible to anadromous fish, between the base of the Lower Falls and the river's terminus;
- construction activities that could increase the likelihood of mass movement as localized erosion and sedimentation, which could subsequently adversely affect water quality by elevating turbidity;
- alteration of natural stream temperature regimes and icing in the Kahtaheena River due to impoundment behind the diversion structure or diversion of flow into the project penstock with associated reductions in flow in the bypassed reach;
- introduction of hydrocarbons (e.g., fuel, lubricants) or other chemical contaminants into area streams through spills or minor leakage from

construction machinery and project vehicles or through uncontained spills at the project powerhouse; and

- reduction in need to produce power at diesel-generating facilities in Gustavus would reduce the risk of spills related to transporting and transferring fuel.

4.4.2.1.1 Water Quantity

Alteration of Flow Regime. Diversion of from 2 to 23 cfs of flow in the proposed bypassed reach could affect stream depth, velocity, temperature, and substrate. During winter, the effects of reduced instream flow also could result in an increase in icing and the freezing of some stream gravels.

GEC proposes to return powerhouse discharge to the base of the Lower Falls, which would avoid diverting water around the Mills allotment and the section of river accessible to anadromous fishes. GEC also proposes to operate the project in run-of-river mode, which would limit its ability to shift seasonal runoff patterns. In addition, GEC proposes to install a synchronous bypass at the powerhouse to allow load-following generation without causing stage fluctuations in the reach accessible to anadromous fish. These factors would result in a flow regime that is very similar to the natural flow regime in the river downstream of the Lower Falls, including the portion of the river that passes through the Mills allotment.

In this section, we analyze the effects of GEC-proposed and agency-recommended flows (table 4.4-1) along with a no minimum flow scenario on the existing flow regime within the river reach that would be bypassed, and the effects of the proposed synchronous bypass on flows in the Kahtaheena River below the powerhouse discharge. Effects of the flow regimes on water temperature and icing are discussed later in this section, and effects on fisheries resources are presented in section 4.6, *Fisheries*.

GEC proposes a minimum flow release of 5 cfs during December through March and 7 cfs for the remainder of the year (see table 4.4-1), stating that 5 cfs is significantly greater than the lowest flow ever measured (3.5 cfs by ACOE) or modeled (2.5 cfs) in the Kahtaheena River. GEC states that its proposed flows would “provide a reasonable probability of survival of the small group of potentially affected Dolly Varden.”

ADFG, NMFS, and FWS recommend higher minimum flow releases to protect aquatic habitat in the proposed bypassed reach. Citing uncertainties associated with the instream flow analyses done for the project, they also request that operational flows, water quality, and populations of resident char be monitored after project construction so that the effects of flow reduction can be better quantified. Depending upon the results of post-operational monitoring, they request modification of minimum flow requirements, as appropriate. These agencies recommend monitoring for a minimum of 5 years following project start-up.

Table 4.4-1. Proposed and recommended minimum flows for habitat maintenance in the bypassed reach of the Kahtaheena River.

Month	GEC (cfs)	ADFG (cfs)	FWS (cfs)
January	5	10	10
February	5	10	10
March	5	10	10
April	7	10	10
May	7	25	20
June	7	25	20
July	7	25	20
August	7	25	20
September	7	25	20
October	7	30	30
November	7	25	25
December	5	10	10

The agencies' recommended minimum flows of 10 cfs through the entire bypassed reach in the winter months would require the release of substantially more water for habitat maintenance than proposed by GEC. They state that, while flows have fallen below 5 cfs in the past, there is a fundamental difference between the effects of these naturally occurring, occasional low-flow events and the detrimental effects of a more prolonged period of low flow that would occur under GEC's proposal. They suggest that, over the long term, low flows in the winter can change the thermal budget of the river and result in increased icing and hard freezes that have a detrimental effect on fish (see section 4.6, *Fisheries*).

ADFG recommends minimum flows of 25 cfs over most of the remainder of the year and 30 cfs during October. FWS also recommends 30 cfs in October, but 20 cfs rather than 25 cfs for the remainder of the year with the exception of November. FWS recommends 25 cfs in November. ADFG states that 25 cfs would be necessary during May through September to adequately protect adult, juvenile, and fry rearing stages; 30 cfs would be necessary in October to provide adequate spawning habitat; and 25 cfs would be necessary in November to protect spawning and adult, juvenile, and fry rearing. ADFG compares the frequency that natural flows would exceed its recommended flows for several months and uses these comparisons to indicate that its recommended flows should not conflict with the economic viability of the project.

We evaluated the flow regimes using a 30-year period of record (Water Years 1969-2001, with the exception of 1979, 1980, and 1996). This evaluation was based on modeled daily mean flows for natural conditions (no action) using the regression equations that Coupe (2001) derived (see section 3.4.1, *Water Quantity*). We also modeled flows assuming the maximum allowable diversion would occur under each of four minimum flow scenarios: GEC's proposal, FWS and ADFG recommendations, and a no minimum flow scenario. For each alternative flow, we assume that the project would:

1. release all water through the bypassed reach when natural discharge is at or below the recommended minimum;

2. divert any excess flows that are 2 cfs or more above the required minimum release through the powerhouse, up to a maximum power diversion of 23 cfs;[48] and

3. release all additional available water (i.e., flows greater than the minimum flow plus 23 cfs) through the bypassed reach.

By conducting percent exceedance analyses, we compared differences in modeled flows. Accuracy of measured flows and the proportion of the variability in flows explained by Coupe's seasonal regressions are less than desired (see section 3.4.1.1), which limits our ability to accurately estimate flows in the Kahtaheena River. However, the following analysis provides a reasonable evaluation of differences that would likely occur between the scenarios evaluated since they are all based on the same set of base (unregulated) flows. We present tables and figures to evaluate the differences between the flow regimes likely to occur under the different operating scenarios with the no-action (natural) flow regime. Table 4.4-2 provides a summary of these analyses.

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[48] This assumption results in the lowest allowable flows in the bypassed reach during modeled operations. GEC indicates that the actual diversion would depend on the expected peak load and would occasionally be less than the maximum allowable diversion.

Table 4.4-2. Estimated flows[a] (cfs) released into the upper end of the bypassed reach that would be equaled or exceeded 0, 25, 50, 75, and 100 percent of the time under alternative conditions. (Page 1 of 2) (Source: Preparers)

	Time Period													
No Action[b]														
Exceedance	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Annual	Dec-Mar	Apr-Nov
0%	361	242	269	258	196	142	130	232	166	188	209	300	361	269	361
25%	127	42	34	28	26	25	40	114	97	60	56	94	73	28	88
50%	92	25	19	14	13	15	26	95	74	46	41	62	40	15	55
75%	69	15	10	8	8	8	18	81	54	35	31	44	19	8	34
100%	27	5	3	2	3	4	6	50	24	15	16	18	2	2	5
Range	334	237	266	256	193	138	124	182	142	173	193	282	359	267	356
Proposed by GEC															
Exceedance	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Annual	Dec-Mar	Apr-Nov
0%	338	218	246	235	173	118	106	209	143	165	186	277	338	246	338
25%	104	19	11	7	6	6	17	91	74	37	33	71	50	7	65
50%	69	7	5	5	5	5	7	72	51	23	18	39	17	5	32
75%	46	7	5	5	5	5	7	58	31	12	8	20	7	5	11
100%	7	5	3	2	3	4	6	27	7	7	7	7	2	2	5
Range	331	213	243	233	170	114	100	182	136	158	179	270	336	244	333
FWS Recommendation															
Exceedance	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Annual	Dec-Mar	Apr-Nov
0%	338	218	246	235	173	118	106	209	143	165	186	277	338	246	338
25%	104	25	12	11	11	10	17	91	74	37	33	71	50	11	65
50%	69	25	10	10	10	10	10	72	51	23	20	39	20	10	32
75%	46	15	10	8	8	8	10	58	31	20	20	20	10	8	20
100%	27	5	3	2	3	4	6	27	20	15	16.	18	2	2	5
Range	311	213	243	233	170	114	100	182	123	150	170	259	336	244	333

Table 4.4-2. Estimated flows[a] (cfs) released into the upper end of the bypassed reach that would be equaled or exceeded 0, 25, 50, 75, and 100 percent of the time under alternative conditions. (Page 2 of 2) (Source: Preparers)

	Time Period														
ADFG Recommendation															
Exceedance	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Annual	Dec-Mar	Apr-Nov
0%	338	218	246	235	173	118	106	209	143	165	186	277	338	246	338
25%	104	25	12	11	11	10	17	91	74	37	33	71	50	11	65
50%	69	25	10	10	10	10	10	72	51	25	25	39	25	10	32
75%	46	15	10	8	8	8	10	58	31	25	25	25	10	8	25
100%	27	5	3	2	3	4	6	27	24	15	16	18	2	2	5
Range	311	213	243	233	170	114	100	182	119	150	170	259	336	244	333
No Minimum Flow Scenario															
Exceedance	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Annual	Dec-Mar	Apr-Nov
0%	338	218	246	235	173	118	106	209	143	165	186	277	338	246	338
25%	104	19	11	5	3	2	17	91	74	37	33	71	50	5	65
50%	69	2	0	0	0	0	3	72	51	23	18	39	17	0	32
75%	46	0	0	0	0	0	0	58	31	12	8	20	0	0	11
100%	4	0	0	0	0	0	0	27	1	0	0	0	0	0	0
Range	334	218	246	235	173	118	106	182	142	165	186	277	338	246	338

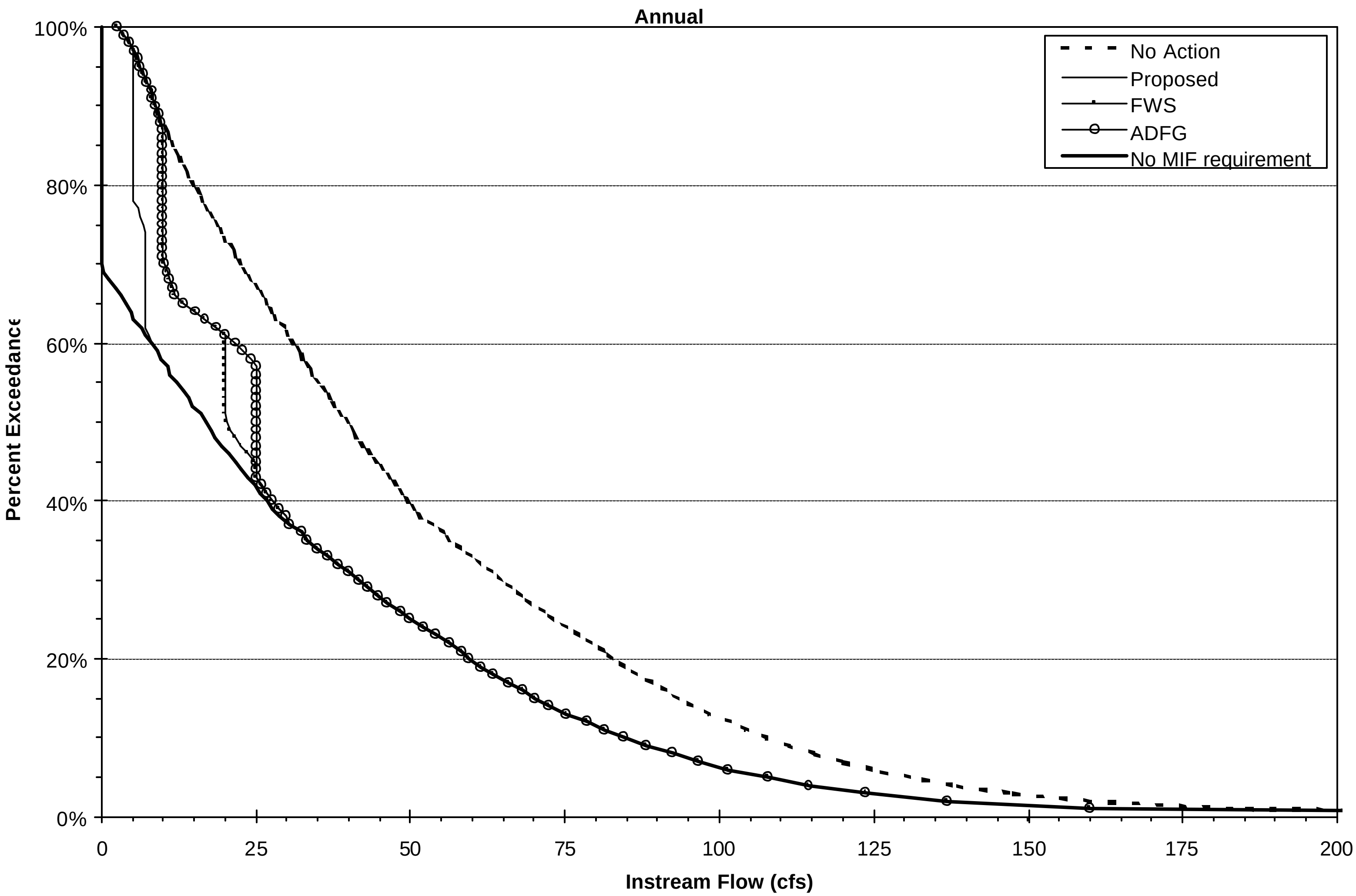
Figure 4-1 presents percent exceedance curves for GEC's proposal, the two agency-recommended minimum flows, the no minimum flow scenario, and the No-action Alternative for the entire year. Figure 4-2 presents the same information for the winter (December through March), and figure 4-3 provides a plot of the monthly 80 percent exceedances for the entire year for each alternative compared to natural flow (no action).

Under any minimum instream flow evaluated, the flows in the proposed bypassed reach would be highly dependent on natural conditions. The project would not be capable of augmenting flows during low-flow periods, since there would be virtually no storage capacity above the diversion dam. In addition, natural flows frequently exceed the proposed minimums and the maximum hydraulic capacity of 23 cfs. During these periods, more than the specified minimum flow would be released into the upper end of the bypassed reach. Whenever the natural flow would exceed 30 cfs, the flow released into the bypassed reach would be the same regardless of which evaluated flow regime was followed (figure 4-1). The reduction in flow would be at its maximum (23 cfs) when the natural flow is 30 cfs or more. The main differences in the flow regimes that would occur in the bypassed reach under the proposed, recommended, and no minimum flow scenarios would be associated with flows of 10 cfs or less.

During the low-flow period (December through March), natural flows would frequently drop below each of the recommended minimum flows. Construction and operation of the project as GEC proposes or the agencies recommend would not alter the frequency or timing of extremely low flows (< 5 cfs); they would continue to occur approximately 8 percent of the time (figure 4-2). Although flows of less than 5 cfs in the bypassed reach would typically not be altered, operating the project under GEC's proposal would substantially increase the frequency of flows between 5 and 10 cfs. For example, operating the project as GEC proposes would increase the occurrence of flows of less than 10 cfs by nearly 50 percent (i.e., increase from 33 percent of the time to 80 percent of the time).

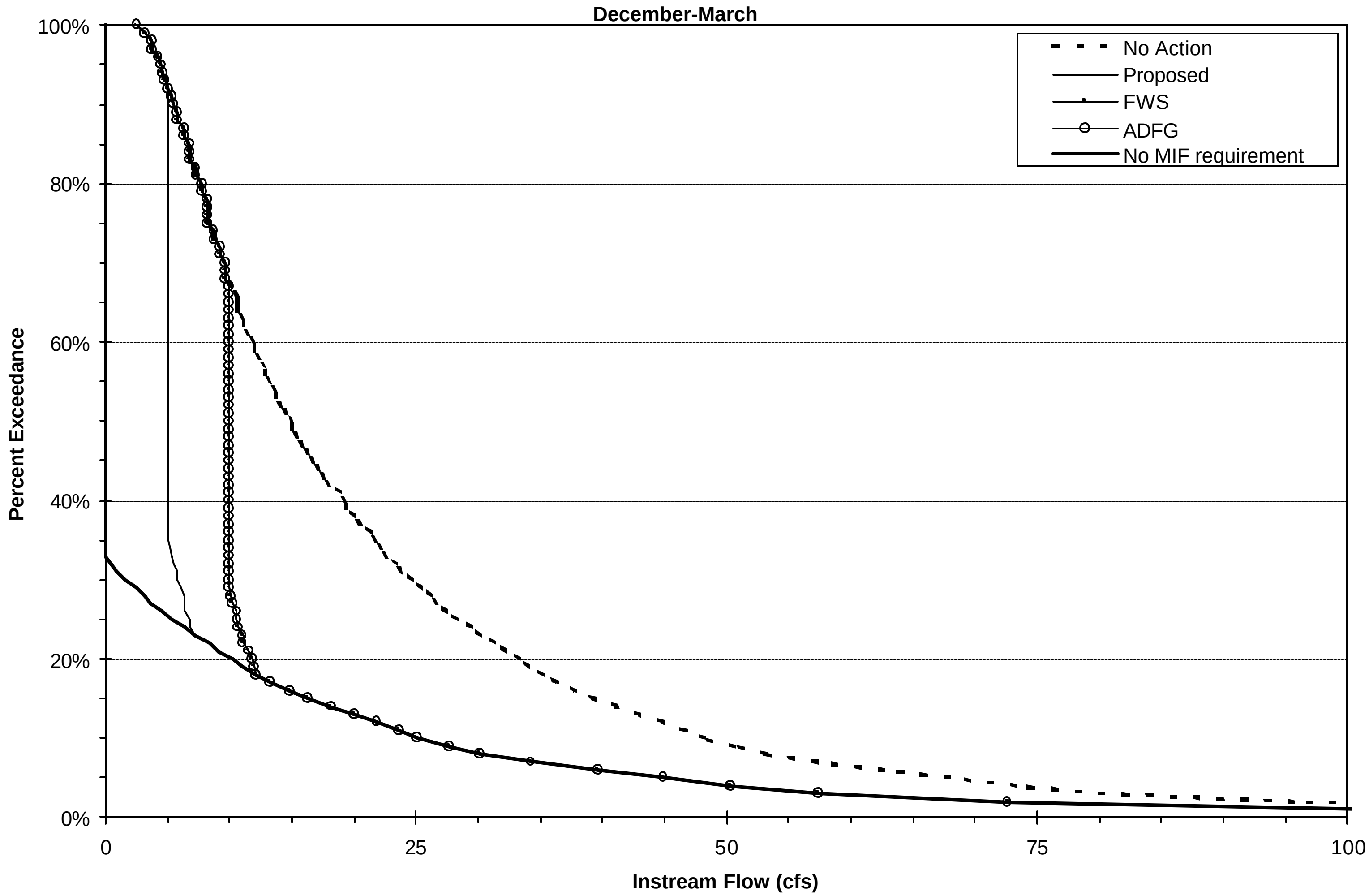
Both ADFG and FWS recommendations would provide winter flows closer to existing conditions than would GEC's proposal or under the no minimum flow scenario, although natural, low-flow conditions in the winter would preclude the maintenance of 10 cfs for about one third of the time (figure 4-2). Winter flows of less than 10 cfs would occur 33 percent of the time under no action or the agencies' recommendations; whereas, they would occur 80 percent of the time under GEC's proposal and a no minimum flow scenario. Operating the project to maximize power production and consequently not releasing water into the bypassed reach when unregulated flows are 23 cfs or less (i.e., no minimum flow) would increase the frequency of flows lower than 5 cfs to 75 percent of the time and flows of less than 10 cfs to 80 percent of the time during the low-flow period (figure 4-2).

Figure 4-1. Annual percent exceedance of modeled daily mean flows at the upstream end of the bypassed reach under alternative flow scenarios. (Source: Preparers)



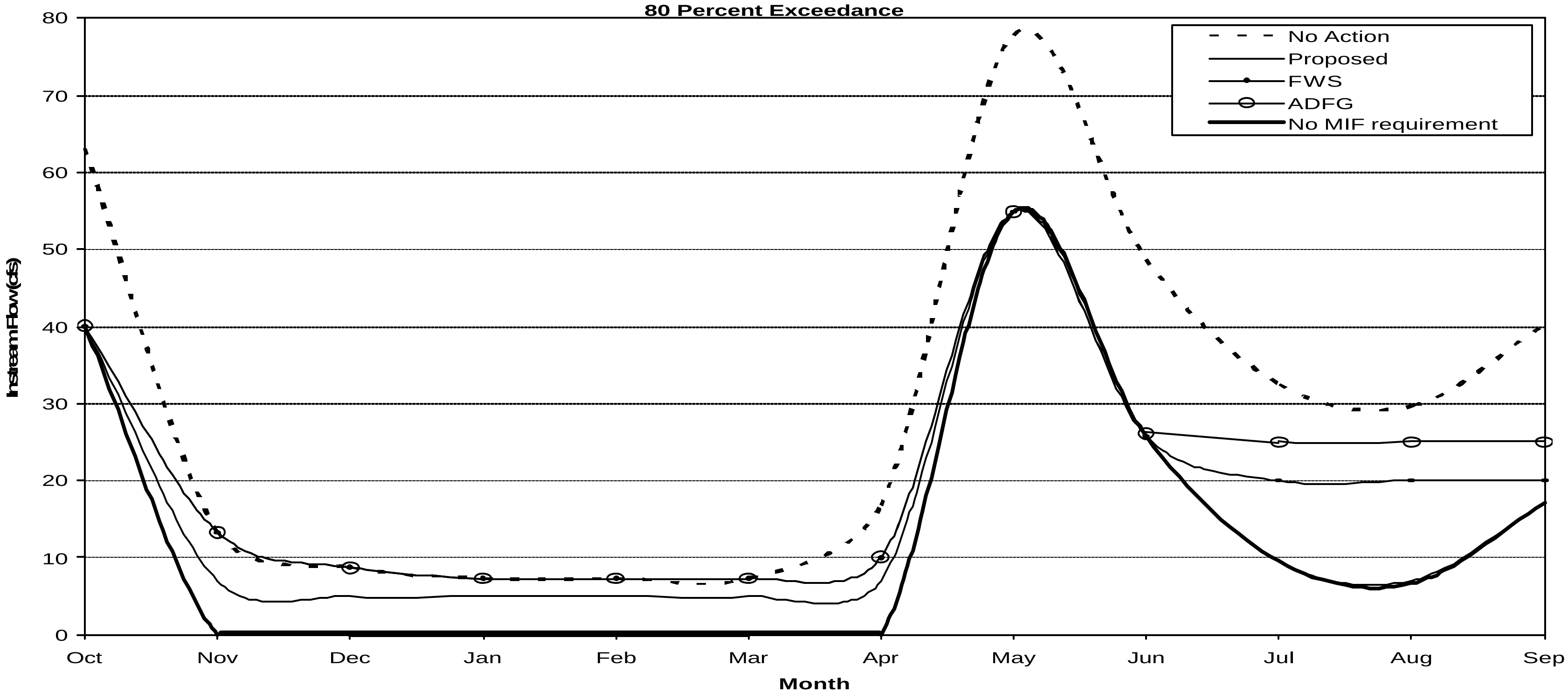
Note: See section 3.4.1.1 for a description of the uncertainty associated with modeled daily mean flows.

Figure 4-2. Percent exceedance of December-March modeled daily mean flows at the upstream end of the bypassed reach under alternative flow scenarios. (Source: Preparers)



Notes: FWS and ADFG values are the same.
See section 3.4.1.1 for a description of the uncertainty associated with modeled daily mean flows.

Figure 4-3. Plot of monthly 80 percent exceedances of modeled daily mean flows at the upstream end of the bypassed reach under alternative flow scenarios. (Source: Preparers)



Notes: FWS and ADFG values are the same from October to June.

See section 3.4.1.1 for a description of the uncertainty associated with modeled daily mean flows.

Low flows during extremely cold periods could result in ice accumulation between the diversion dam and the powerhouse, and consequently reduce the flow within the bypassed reach. We are unable to predict the extent of ice accumulation that would occur under the various flow regimes; however, we would expect icing of accreted flows under a no minimum flow scenario to be substantial and reduce or even eliminate the volume of accreted flows within the bypassed reach, especially towards the downstream end of the bypassed reach. We would expect ice accumulation and any corresponding reduction in flows to occur less frequently under GEC's proposed wintertime flows of 5 cfs than under a no minimum flow scenario. Ice accumulation and reduced flows could occur under the ADFG/FWS recommended wintertime flow of 10 cfs; however, because of the increased thaw bulb of these higher flows, ice accumulation would likely occur less frequently under agency flows than with either no required flow or GEC proposed flows.

Our analysis of the differences in concurrent daily mean flows reported for the two Kahtaheena River gages indicates that accretion increases the flow in the bypassed reach by an average of 8 percent. Generally, the largest percent increases occur during the months of November through March when accretion increases the flow by 11 percent (approximately 2 to 5 cfs) on average. The smallest percent increases occur during the months of June and May when accretion increases the flow by 3 percent or less (approximately 1 to 3 cfs) on average. These estimates of accretion should be applied cautiously, due to the accuracy of the reported flows on which they are based (see section 3.4.1.1). Two tributaries downstream from the diversion (Greg Creek and a small, unnamed creek that joins the Kahtaheena River about 820 feet downstream of 3 Meter Falls in Reach 3) likely contribute much of the accretion to the reach. During extreme cold periods, these tributaries may experience considerable icing, which could reduce their inflows to the bypassed reach. However, GEC noted that it observed Greg Creek flowing during the lowest flow event in the winter of 2001 (letter from R. Levitt, President, Gustavus Electric Company, Gustavus, AK, to M. Salas, FERC, Washington, DC, on January 2, 2004). Based on this observation, along with the fact that the creek drains deep peat soils, GEC infers that Greg Creek seldom if ever has no flow. The USGS Water Resources Data report (Meyer et al., 2001) indicates that water discharge records are reported as fair to poor for Gage No. 15057580 (Kahtaheena River above Upper Falls near Gustavus) and poor for Gage No. 15057590 (Kahtaheena River near Gustavus; also known as the lower gage site). Fair records mean that about 95 percent of daily discharges within 15 percent of the true value. Poor records do not meet these criteria. The poor accuracy of many of these discharge measurements suggests that our accretion estimates may not reflect true accretion within the reach (Meyer et al., 2001).

During much of the high flow months (May, June, and October), there would be less difference in flow between the four different operational scenarios because natural flow is often greater than the combined maximum hydraulic capacity of the project and the proposed/recommended minimum instream flow releases (figure 4-3). Our analysis indicates that flows would be the same for all four operational regimes approximately 90 percent of the time in May and October and 80 percent of the time in June.

In addition to the proposed project operations, excavation and clearing of vegetation associated with road and pipeline construction and maintenance could also result in flow alterations by influencing subsurface flow patterns and timing. After construction, there would be somewhat less subsurface water storage capability and connectivity, particularly along the roadway that would be routed through The Canyon to access the powerhouse site. This modification along with precipitation on the roadway would necessitate an appropriate water drainage system for all project roadways (see section 4.3, *Geologic Resources and Soils*).

Subsurface water would likely extrude along the upslope side of the roadway through The Canyon and would be routed past the roadway through culverts. This loss of subsurface water could result in somewhat lower accretion to the bypassed reach during low-flow periods, particularly during the winter, although these effects would likely be minor. There is not sufficient information available to accurately model the effects of excavation and clearing on subsurface and surface flows in the basin; therefore, we did not include these in modeling flows for the bypassed reach.

Load-following operations can substantially increase the potential for large changes in flow and stage over relatively short periods of a few minutes to a few hours depending on specific project operations. To minimize effects of load-following operations on flow and stage levels in the Kahtaheena River, GEC (2001a) proposes the following:

1. Divert flow at a nearly constant rate for prolonged periods. During May through October, the diversion would typically be equivalent to the expected peak load. During other periods, divert all flow in excess of the instream flow requirement.

2. Approximately weekly adjustments to the diversion rate would be made in a manner that limits the rate of water level changes downstream of the powerhouse discharge to 1 inch per hour.

3. A synchronous bypass consisting of a branch off the power conduit upstream of the turbine shutoff valve, a 14-inch butterfly type guard valve, and a 14-inch sleeve valve would be used for routing a portion of the diverted flow around the turbine during off-peak periods.

GEC notes that, since the turbine jet deflectors would provide flow continuation, the synchronous bypass would provide a redundant system of providing flow continuation under load-following operations (letter from D. Levitt, GEC, Gustavus, AK, to D. Boergers, Secretary, FERC, Washington, DC, on March 21, 2002); however, sole use of the turbine jet deflectors would limit the ability to operate the project in load-following mode while maintaining a constant flow diversion. GEC indicates that it made this proposal because agencies have recently requested such redundant flow continuation systems for other hydroelectric projects in the area; however, it reserves the right to modify the proposed synchronous bypass if it is not required by the agencies.

ADFG, FWS, and NMFS recommend a limit on the ramping rate (stage change) of 1 inch per hour. The agencies have not indicated whether they want redundant flow continuation systems for the proposed project.

Operation of the project as GEC proposes and the agencies recommend would typically maintain flow and water levels in the reach below the Lower Falls (including through the Mills allotment) near their natural levels throughout the year. However, adjustment of the flow diversion would alter flows and water levels in both the proposed bypassed reach and the reach below the Lower Falls when natural flows exceed the flow needed to produce enough energy to meet the demand for power. These adjustments would generally be made approximately weekly and be limited to changes of 1 inch per hour in the reach below the Lower Falls, and coinciding fluctuations in the bypassed reach. The reach below the Lower Falls would also experience ramping rates of up to 1 inch per hour related to the changes in the demand for power. Under GEC's current proposal, the turbine needle valve and synchronous bypass would provide redundancy for ensuring that this ramping rate is met during load-following operations and project outages. Installation of a synchronous bypass valve also would provide a means of maintaining flow releases to the reach below the Lower Falls during long-term planned and unplanned outages. If the synchronous bypass was not installed and the turbine needle valve failed to operate properly, then a ramping rate of more than 1 inch per hour could occur.

In summary, the primary effect of the proposed project on surface water quantity would be reduction of flows in the bypassed reach of the Kahtaheena River caused by the diversion of 2 to 23 cfs for operation of the project. Construction and operation of the project would affect frequency, magnitude, and duration of water quantity in the bypassed reach depending on which flow requirements were implemented. Flow reductions in the bypassed reach would be largest under GEC's proposal and smallest under ADFG's recommendation. Operating the project with no minimum flow requirement would result in substantially lower flows in the bypassed reach during low-flow periods. During these times, flows in the bypassed reach would frequently consist only of accreted flows from tributaries and groundwater sources. During extremely cold periods, accreted flows may freeze solid and thereby result in no flow within the bypassed reach.

Project operations would typically limit water level changes to 1 inch per hour (in comparison to natural fluctuations) in the Kahtaheena River downstream of the Lower Falls. Adjustment of the flow diversion also would result in altered flow and water level conditions throughout the proposed bypassed reach. These changes would typically occur over a few hours on a weekly or smaller interval for the entire term of any license.

In addition, excavation and clearing of vegetation along roadway and pipeline corridors would result in some interruption of the natural flow of subsurface water. Within The Canyon, subsurface water would likely extrude along the upslope side of the corridors and would need to be routed to the downslope side of the corridor in an appropriate manner. The disturbance of existing subsurface flow patterns could affect accretion to the bypassed reach, although there likely would be little effect on surface waters.

The construction and operation of the project would alter surface flow downstream of the proposed diversion, and subsurface flow patterns along roads in The Canyon. The impacts on the surface flow regime within the 1.79-mile-long proposed bypassed reach would be dependent on which of the proposed or recommended flow regimes is implemented. Operating the project under GEC's proposal would adversely affect the surface flow regime. In contrast, operating the project under a no minimum flow scenario would result in greater impacts on the surface flow regime. Road construction in The Canyon also would affect subsurface flow patterns.

4.4.2.1.2 Water Quality

Alteration of Turbidity Conditions. Construction and operation of the project is expected to increase the likelihood of localized erosion and mass movement, which could subsequently have an adverse effect on water quality.

GEC proposes to limit the potential for erosion and subsequent sediment supply to surface waters by minimizing the area disturbed during construction of the project; constructing roadways, pipelines, and transmission lines in less sensitive (flatter) areas as much as possible; routing linear features such as roadways and pipelines along each other where practical; and implementing appropriate BMPs. GEC has developed a draft ESCP that specifies greater detail associated with many of these proposals. GEC would finalize the ESCP before initiating construction activities.

ADFG, FWS, and NMFS request that GEC consult with them and obtain their approval of the final ESCP. Further, ADFG, FWS, and NMFS recommend that GEC employ an ECM to ensure compliance with environmental measures during project construction. ADFG, FWS, and NMFS also request that GEC consult with and obtain their written approval for a fuel and hazardous substances spill plan to help prevent and minimize any impacts associated with the handling of hazardous substances during project construction and operation. They also recommend an oil and other contaminant treatment plan for the treatment and removal of any condensate and leakage from turbines and other equipment in the powerhouse. ADFG, FWS, and NMFS also recommend that GEC monitor the effectiveness of erosion control measures through daily water quality sampling from the initiation of construction until 60 days following the removal of temporary erosion control structures.

In comments on the draft EIS, the state of Alaska indicated a concern about relying on acquiring easements for GEC's proposed route for roads and transmission lines. The state of Alaska recommends an alternative route that would minimize the quantity and length of easements needed across private land.

Project construction could increase turbidity in area streams through three primary pathways: (1) increasing sediment supply from surface erosion and landslides, (2) in-water construction activities, and (3) severing a project pipeline.

Since the geology of most of the basin is dominated by calcareous mudstone, which tends to easily produce silts and clays, increased sediment supply to waterways in the area would result in increased turbidity. The largest effects on turbidity in the streams would likely be related to rainfall events during the construction period and extremely intense rainfall events that result in mass movement of sideslopes. By effectively implementing appropriate BMPs, effects on turbidity could be limited; however, some adverse effects would still occur because of the steep terrain, with unconsolidated soils and high rates of precipitation. We anticipate that construction activities and/or mass movement of sideslopes could result in short-term turbidity increases of greater than 5 NTU, which is the applicable state water quality criterion when natural conditions are 50 NTU or less.

As discussed in section 4.3.2, *Erosion and Sedimentation*, GEC's proposed measures are expected to limit the project's potential to increase erosion and mass movement; however, erosion would still be increased by construction of the project. This would particularly be the case in areas near roadway crossings over creeks and in areas where the roadway alignment is near streams. Based on the best available information, we estimate that surface erosion would increase the rate of sediment supply to area waterways from about 20 m^3/year under existing conditions to about 350 m^3/year during the construction period.

The state of Alaska's recommended road corridor alignment would be about 1.5 miles longer than GEC's proposal and have one additional stream crossing than GEC's proposal (see figure 2-2 in appendix A). However, it would not be within proximity of any streams for substantial distances. GEC's proposal, on the contrary would be within proximity of Rink Creek for 0.3 miles. The overall effects of the state of Alaska's recommended road alignment on stream turbidity would be similar but somewhat less than GEC's proposal. The primary difference between these road alignments would be the routing within proximity to streams, which could result in erosion in these areas throughout the period of a new license. Under the state of Alaska's recommendation, there would be less erosion from the roadway reaching Rink Creek, and turbidity in Rink Creek would be lower during high runoff events. In contrast, construction of the additional stream crossing would likely result in a short-term localized increase in turbidity during and potentially immediately following construction.

Landslides generally occur infrequently, but can supply substantial amounts of sediment in a single event. Although construction of roads, pipelines, and transmission lines would likely increase the frequency of landslides supplying sediment to area waterways, a statistical analysis of the area disturbed indicates that there would be little change in the frequency of landslides of greater than 77 m^3 (see section 4.3.2, *Erosion and Sedimentation*). Based on results of a regional evaluation of landslides greater than 77 m^3 (Swanston and Marion, 1991), we estimate that about 2 landslides would occur during a 50-year license period. Assuming that these events are typical shallow landslides, each would supply on the order of about 600 m^3 of soil and debris to the creek. Since landslides occur during extreme events, multiple slides may occur during a single intense storm.

Smaller landslides occur more frequently; however, adequate information for estimating these levels was not available to the authors of this report. It is likely that construction of the roadway would increase the risk of small landslides downslope of the road cut through The Canyon.

In summary, the rate of surface erosion and landslides would be increased by construction and operation of the project and would subsequently increase turbidity in the Kahtaheena River and other streams in the area. The largest increases in turbidity would be associated with major runoff events and during construction of the project. Specific areas affected by increases in turbidity would be dependent upon the road alignment used. We conclude that the overall adverse effects on stream turbidity would be somewhat less under the state of Alaska's recommended alignment primarily because the road would not be within proximity of streams for any substantial distances.

GEC would need to conduct some in-water construction to develop the project. GEC could limit the extent of in-water construction activities, but it would be impossible to totally avoid working in the stream while constructing some project features such as the diversion dam, bridge over Homesteader Creek, and culverts for several small tributaries, including Rink Creek, Homesteader Creek, Greg Creek, and the unnamed creek downstream of Homesteader Creek. In-water construction activities substantially increase the potential to adversely affect water quality by increasing turbidity. These risks could be limited, although not completely avoided, by adequately implementing appropriate BMPs. Appropriate BMPs could include limiting the timing of in-water activities to low-flow periods when practical, using coffer dams or other means of limiting the interflow of turbid water from the area being disturbed to the rest of the stream. Implementation of a water quality sampling program would allow GEC to monitor the effectiveness of the proposed ESCP and BMPs on limiting increase in turbidity in the Kahtaheena River.

Severing of the project pipeline could have devastating effects on the Kahtaheena River's water quality and could reduce the suitability of the water as a source of drinking water for the Mills allotees. Therefore, all reasonable efforts to reduce the likelihood of such an event should be implemented. GEC has limited the potential for the pipeline to be severed by proposing to bury the pipeline throughout much of its length and routing it in relatively stable areas (see section 4.3.2.1); however, there are two critical portions of the power conduit where ground movement could sever the pipeline. The critical areas are where the conduits and road traverses directly above a steep-sloped (72 percent) area near Horseshoe, and a pipeline segment near the powerhouse. Severing of the pipeline in either of these areas could cause a release of up to 23 cfs of water, and result in severe erosion and/or trigger a landslide that would very likely reach the river. An event of this nature would elevate turbidity to extremely high levels and would persist until after release of water from the pipeline was cut off. Following any severing of the pipeline, the river would experience elevated turbidities during runoff events until the area disturbed by the event becomes restabilized. As indicated above, elevated turbidity could reduce the suitability of the Kahtaheena River as a primary source of drinking water for the Mills allotees.

GEC's proposal to bury much of the pipeline and route it in areas of limited risk of landslides would limit the potential for earth movement to result in severing the pipeline. The potential risk of severing the pipeline could be further limited by ensuring that water does not accumulate upslope of either the road or pipeline and that runoff in upslope areas is routed in such a manner so as to avoid further increasing the risk of landslides in the area. It also would be valuable to ensure that the project could be remotely operated to enable terminating diversion of water into the pipeline so that the amount of time that water is released at the severed point would be short. These measures would reduce the risk of a pipeline failure, thereby reducing the probability of a project-related landslide and increased erosion that could increase stream turbidity downstream of the event, including the segment of the river that serves the Mills allotees.

Alteration of Stream Temperature Dynamics. GEC's proposal may affect water temperatures throughout the year. Impoundment of the Kahtaheena River would increase the surface area and reduce velocities resulting in increased interaction with the surrounding environment. Reduction of stream flow could diminish a stream's ability to buffer temperatures, and thereby cause larger changes (both increases and decreases) in water temperatures. It is also possible, although less likely, for water temperatures to be altered in conduits used to transport water from the diversion site to the powerhouse.

As described above in our discussion of water quantity, the agencies recommend higher minimum instream flows than GEC proposes. One of their primary concerns is the protection of Dolly Varden and their eggs during the winter when icing could adversely affect their survival and development. We discuss the effects of the minimum instream flow proposals and recommendations on Dolly Varden in section 4.6.2.1 under *Fisheries*.

The proposed diversion dam would widen the river somewhat in the river reach immediately upstream of the dam. The dam would result in an impoundment with a surface area of approximately 0.5 acres in comparison with 0.25 acres under existing conditions (GEC, 2001a). The impoundment's capacity would be less than 109,000 ft^3 of water, based on the maximum depth of 5 feet reported by GEC (2001a), and would not provide any usable storage since the project would be operated in run-of-river mode. Based on comparison of daily mean and maximum temperatures reported for the two Kahtaheena River USGS gages, the largest temperature changes between the two gages occurs during the months of July and August (see table 3.4-5); therefore, we would expect the impoundment to result in the largest increases in temperatures during this period. Based on the median of modeled daily mean flows for July and August, water would typically reside in the impoundment for less than 45 minutes compared to less than 20 minutes without the impoundment. At the lowest daily mean flow modeled for July and August (i.e., 15 cfs), the gross exchange rate for water in the impoundment would be about 2 hours. The impoundment's rapid exchange rate, small surface area, and minimal removal of riparian vegetation along the impoundment would result in little effect on water temperatures.

Operation of the project would reduce flows in a 1.79-mile-long bypassed reach of the Kahtaheena River. These flow reductions would be most likely to cause warming during the months of July and August and cooling, which could increase icing, during the winter months (December through March). Empirical estimates of the thermal effects of diverting water out of the river are currently unavailable.

The potential for increasing summer water temperatures in the bypassed reach was determined by estimating the heat load currently contributed to the river and applying that heat load to the proposed and recommended minimum instream flows. We use the following assumptions:

- Temperature increases of 0.5EC in July and August 2000 represent typical summer heat loading through the proposed bypassed reach (see table 3.4-5).

- Temperature increases measured in July and August 2000 were associated with a flow of approximately 55 cfs, which is the median daily mean flow for the period.

- Temperature increases occur at a constant rate between the two USGS gages.

- Inflow to the bypassed reach is negligible. Based on daily mean flows reported by USGS for July and August 2000, accretion between the two gages ranged from -5 to 14 cfs, with a median of 4 cfs. This level of accretion is negligible when one considers the accuracy (i.e., within 15 percent) of most data reported for the two gages.

- Convection and evaporation would not appreciably change from existing conditions.

- Thermal loading would remain the same under existing, proposed, and recommended flow regimes.

A conservative approach to selecting assumptions was used so that estimates would be the maximum increases expected. Since temperature increases at a much slower rate as it approaches the equilibrium temperature (Theurer et al., 1984), estimates of warming for the lowest flows evaluated (GEC's proposed minimum instream flow of 7 cfs during warm periods) are expected to be very conservative. Evaluation of modeled flows indicates that high natural flows occur approximately 40 percent of the time. Under high flows, the same flow and water temperature would occur in the bypassed reach regardless of which flow scenario was implemented.

Application of the above assumptions indicates increases of 4EC for the proposed 7 cfs, and 1EC for FWS's recommended 20 cfs and ADFG's recommended 25 cfs. Based on these computations, maximum water temperatures for July and August 2000 would have been less than 14EC under 7 cfs, and less than 12EC under 20 to 25 cfs minimum instream flows. Somewhat warmer temperatures would likely occur during summers that are drier and warmer than 2000. Based on water temperature records for the Kahtaheena River, temperatures would rarely if ever exceed 15ºC with 7 cfs flowing through the bypassed reach, and 14ºC with 20 cfs or more flowing into the bypassed reach. Under a no minimum flow scenario, flow through the bypassed reach would likely be intermittent, at least in some sections, and water temperatures would be highly influenced by the temperature of source water to the bypassed reach and connectivity of surface water through the reach. Water temperatures at many locations in the reach likely would be warmer than under a 7 cfs release and much warmer in sunny stagnant areas.

There is potential for water temperature to change in the power conduit based on the rate of water exchange. The proposed power conduit would be a pipeline and penstock system that is 9,400 feet long and buried for more than one-third of its length. As proposed, the power conduit would vary between 20 and 30 inches in diameter and consist of 7,680 feet of high-density polyethylene and 1,720 feet of steel pipe (see section 2.34 for description of these facilities). Conservative estimates of exchange rates for water in the conduit were computed by assuming the maximum diameter of the system (i.e., 30 inches) for its entire length. At the minimum powerhouse flow of 2 cfs, the rate of water exchange in the system would be more than 2 times per hour. Increasing the flow in the conduit to 10 cfs would result in an exchange rate of about 12 times per hour (once every 5 minutes). Based on these relatively high exchange rates, and considering that most of the pipe would be plastic and insulated via burial, any change in temperature of water in the power conduit would be negligible.

Observations reported by USGS (2001) and Flory (2001) indicate that the Kahtaheena River remains near 0EC and is completely iced over during much of the winter. Evaluation of the potential for project operations to exacerbate these conditions is based on flows that would occur in the proposed bypassed reach, substrates in the reach, and hydraulic conditions measured under ice cover in mid-February 2000.

During cold periods, ice and/or snow on the stream's surface act as insulators to ambient air temperatures and contain the thermal energy in the water. Border ice usually forms along stream margins due to lower flow velocities near stream banks and faster cooling of the ground than water (Majewski and Kolerski, 2001). Without snow and/or ice covering a stream, anchor ice is more likely to form. Anchor ice commonly occurs in southeastern Alaska streams during much of the winter, particularly during cold periods immediately following warm periods (personal communication from B. Bigelow, Chief, USGS, Juneau, AK, with B. Mattax, Senior Aquatic Scientist, Louis Berger Group, Bellevue, WA, on May 9, 2003). USGS summaries of streamflow measurements for the Kahtaheena River gage above the Upper Falls (USGS, 2003) indicate that ice cover is common during December through March and that border ice sometimes occurs during December and April. Although the streamflow measurement summary does not indicate the extent of anchor ice, USGS staff reported observing anchor ice in the river above the Upper Falls. Ed Neal of USGS (personal communication from E. Neal, USGS, with C. Soiseth, GBNPP, on December 15, 2000) reported that, on December 12, 2000, the river was beginning to ice up and there was "plenty of anchor ice" above the Upper Falls. The flow at this time was 20 cfs and had ranged from about 20 to 30 cfs within the 3 previous days (USGS, 2002).

Lyons (2001) notes the interaction of energy contained in stream water with the energy contained in the area around the stream channel, which is commonly referred to as the thaw bulb. Streambeds and floodplains with substantial quantities of gravel-sized and smaller sediments enable surface water and groundwater to interact with one another and increase the thermal buffering capacity of a stream system by forming and maintaining a thaw bulb. Creation of a thaw bulb can reduce the likelihood of anchor ice formation. Throughout most of the proposed bypassed reach, the Kahtaheena River has a limited floodplain and a noticeable lack of substantial quantities of small-sized sediments, which substantially limits the potential for formation of a thaw bulb throughout most of the proposed bypassed reach. However, it may be possible for a small thaw bulb to form in the fine-grained sediments near the proposed diversion site or in other localized areas.

Diverting water from the river would reduce the river's thermal buffering capacity by reducing the mass of water that would need to change its temperature to compensate for energy losses and gains (Poole and Berman, 2003). In some streams the reduction of wintertime flows would also be expected to reduce the size and buffering capacity of the thaw bulb, although that is not the case for the proposed bypassed reach since the current size of the thaw bulb is expected to be quite small.

The modeled flow availability indicates that each of the minimum instream flow scenarios would substantially reduce the flow in the bypassed reach during the months of December through March (see figure 4-2). Each flow scenario evaluated would have flows of less than 20 cfs (which is the flow that occurred when USGS observed the river beginning to ice up and the formation of anchor ice in December 2000) 87 percent of the time, in comparison to 62 percent of the time under existing conditions. Daily mean flows of less than 10 cfs would occur 32 percent of the time under existing conditions and agencies' recommendations, but would occur 80 percent of the time under GEC's proposal and the no minimum flow scenario. The frequency of extremely low flows (<5 cfs) would continue to occur 8 percent of the time under both GEC's proposed and the agencies' recommended operations; whereas, they would occur 74 percent of the time under a no minimum flow scenario. Operating the project with no minimum flow would result in wintertime flows of less than 1 cfs 70 percent of the time.

It is not possible to accurately predict the occurrence of icing under the alternative flow regimes given the limited information describing conditions that lead to icing; however, it is reasonable to assume that icing would likely be exacerbated from reducing wintertime flows to levels of less than 20 cfs. Sustained long-term low flows during winter would increase the rate of border ice formation and subsequently complete ice cover of the stream. Substantially reducing wintertime flows in the bypassed reach could lead to a portion of the water accumulating as ice in the bypassed reach. This would reduce the actual flow in the reach and further limit or reduce available winter habitat for Dolly Varden in the bypassed reach. Extended periods of extremely low flow that would occur under a no minimum flow requirement would result in isolated pockets of water that would freeze completely during cold periods; hard freezes would occur annually. GEC's proposed operations are expected to result in longer more extensive icing periods than existing conditions, although icing would likely be much less extensive than under a no minimum flow requirement. Implementation of the agencies' recommended operations would also probably result in increased icing in the proposed bypassed reach, although the higher minimum instream flows would provide greater protection against freezing than GEC's proposal.

There is a limited understanding of the flow and air temperatures that lead to particular icing conditions in the Kahtaheena River. Further protection against icing could be provided by monitoring conditions that lead to icing and adjusting wintertime flows based on the information obtained. We discuss the effects of icing on fish habitat in section 4.6, *Fisheries*.

In summary, the primary effect of operating the project would be increased summer temperatures caused by reducing flows in the Kahtaheena River. Temperature increases in the power conduit between the diversion dam and powerhouse and in the impoundment would be negligible.

Based on an analysis of water temperatures measured in July and August 2000, project-related temperature increases (compared to existing conditions) would be no more than 4EC under a flow release of 7 cfs, and no more than 1EC under flow releases of 20 to 25 cfs. See section 4.6, *Fisheries*, for discussion of temperature effects on fish spawning, incubation, and rearing.

Operation of the project under GEC's proposal or the agencies' recommended regimes would result in water temperatures very similar to existing conditions in the reach below the Lower Falls since all the water diverted for power generation would be returned to the pool immediately below the falls. The temperature of water diverted from the river would remain nearly unchanged as it is routed from the proposed diversion dam down to the outlet at the Lower Falls; whereas, this water currently experiences minor temperature increases as it flows through the 1.79-mile-long reach. Mixing of this water discharged at the Lower Falls (which could be up to 23 cfs) with water flowing through the proposed bypassed reach would virtually eliminate the effects of increased warming in the bypassed reach on thermal conditions downstream of the Lower Falls.

Based on review of the available information, it is very likely that sustained lower flows resulting from operating the project under a no minimum flow scenario, GEC's proposal, and the agencies' recommendations would increase the formation of ice over the stream's surface and anchor ice in the bypassed reach. Icing conditions would be most extreme under the no minimum flow scenario. Implementation of GEC's proposal would provide more protection over icing, although implementation of the agencies' recommendation would provide considerably more protection than GEC's proposal. The effects of minimum instream flows on aquatic habitat are analyzed in section 4.6, *Fisheries*.

Monitoring Flow, Water Temperature, and Icing. ADFG, FWS, and NMFS request that GEC consult with them and receive their approval on a final plan to monitor instream flows. They request that the plan include using a gage that meets or exceeds USGS standards to monitor flows in the project-affected reaches of the Kahtaheena River and to measure stage changes and river water levels. They request that the plan be provided to them at least 60 days before the scheduled date to begin activities related to the plan, and that they have a review period of at least 30 days.

ADFG, FWS, and NMFS also recommend that GEC continuously monitor instream flows prior to construction, during construction, and for the remainder of the license term, and that GEC provide the data and summary reports in electronic and paper (if requested) formats. They request that summary reports be prepared each month for the first year of operation, and annually in the following years. ADFG and FWS also request that GEC notify them within 12 hours from the beginning of any non-compliance event.

GEC concurs with the agencies' requests for development of a monitoring plan, monitoring of flows in project-affected reaches, and notifying them in non-compliance events (letter from D. Levitt, GEC, Gustavus, AK, to D. Boergers, Secretary, FERC, Washington, DC, on March 21, 2002). However, GEC has concerns about using the term "continuous," since that would technically require an infinite number of measurements. GEC suggests wording be switched to specify an interval, and provides an example of "not more than 15 minutes."

To protect water resources in the project area, any license issued for the project should set flow requirements for both construction and post-construction. It would be necessary to implement a streamflow monitoring plan developed prior to construction of the project to verify compliance with any flow and ramping rate measures included in a license. The plan could be developed in consultation with FWS, NMFS, ADFG, and ADEC, and include the location of all flow gages (both new and existing), the party responsible for maintaining the gages, procedures for ensuring that the gages are calibrated, and proposed reporting procedures.

FWS and ADFG request that GEC determine the flow and temperature conditions that cause ice formation in the bypassed reach to evaluate the effect of low winter flows on fish populations. There is limited information describing what specific conditions lead to icing and the effects that icing under a reduced flow regime would have on char populations. Implementation of a monitoring plan, with particular focus on anchor ice, hard-freezes, and their effects on char populations would provide information necessary to ensure that anchor ice and hard-freezes are not forming and resulting in substantial detrimental effects on char populations. Adjustments to flows should be made if detrimental effects are evident. See section 4.6, *Fisheries*, for discussion of monitoring of fish populations.

Hazardous Materials. Construction of the proposed project would require the use of an assortment of heavy equipment (i.e., bulldozers, dump trucks, and various tractors). This equipment would require fuel (diesel and gasoline), motor oil, hydraulic fluid, and other lubricants. The contractor may wish to store fuels and other hydrocarbons on site and may elect to perform some routine maintenance in the general project area. Onsite fuel storage facilities for a project of this type commonly are in the range of several hundred to one thousand or more gallons of fuel, along with lesser amounts of motor oil, hydraulic fluid, and lubricants. The presence of these materials creates a risk of accidental release of hydrocarbons, with the potential for contamination of area waterways.

The recommended fuel and hazardous substances spill plan and oil and other contaminant treatment plan would require that fuel and other hydrocarbons be stored in areas away from waterways and that appropriate primary and secondary containment be provided for all fuel and hydrocarbons stored on site, to reduce the likelihood of accidental releases directly or indirectly contaminating drainage ways or streams. These plans also would include provisions for emergency response and notification procedures and availability, on site, of equipment to contain spills.

There still would be some risk for accidental introduction of hydrocarbons into the area streams and rivers. Occasional small releases (10 gallons or less), due to minor drips or leaks from equipment operating in or near streams, are likely to occur at some time during project construction. If small spills occur in a manner that results in their direct or indirect entrance into water, there could be some adverse effects on water quality, which could result in adverse effects on aquatic communities. These small spills could also limit the suitability of the Kahtaheena River and the unnamed creek in the George allotment as drinking water sources.

Larger releases, due to accidental spill from fuel storage containers or rupture and release of fuel from the fuel tanks on construction equipment, is less likely. Secondary containment facilities associated with fuel storage containers would further reduce the likelihood that a release would contaminate waterways. However, if such releases occur and the material is released directly into project area waterways, the effects on water quality would be serious and would likely be detectable in the entire section of waterway downstream of the event, with measurable residual effects lasting for several weeks to months after the event. If it occurred in or near the waterway, a spill of this magnitude would likely degrade the Kahtaheena River's water quality to a level that it is not appropriate for use as a source for drinking water for an extended period of time. Depending on the size of release, there may be effects on the marine waters of GBNPP.

The effect that spills would have on water quality would be reduced by implementing an appropriate plan for handling hazardous substances. Spills would probably result in limited adverse effects on water quality during construction. However, there is a remote possibility that a large spill could occur and result in a significant adverse effect on water quality, including suitability as drinking water, during construction.

Following construction of the project, project vehicles and maintenance equipment would operate in the project area. The level of use of these vehicles would be substantially reduced in comparison to the construction period, and vehicles would tend to be used much less frequently in areas near waterways. Use of vehicles in the project area would necessitate storage and use of fuel, lubricants, hydraulic fluids, and other hydrocarbons used in the O&M of the project, which would present a risk for release of hydrocarbons into area waterways for the life of the project. In addition to measures discussed above for project construction, the agencies also request that condensate and leakage from turbines and other equipment in the powerhouse be treated to remove oil and other contaminants before being discharged. These activities could be included in a single plan addressing the handling of fuels and hazardous substances.

It is likely that the project would cause occasional, small releases of hydrocarbons. However, most, if not all, such releases would be small and would occur in areas that do not result in the introduction of hydrocarbons into area waterways. Following construction, five hydroelectric projects owned and operated by the state of Alaska had an average of about one spill per project every 5 years (personal communication from S. Sieczkowski, Operations Manager, The Four Dam Pool Power Agency, with J. Thrall, Senior Fisheries Biologist, Meridian Environmental, Anchorage, AK, on February, 6, 2003). With one exception, these spills were small (5 gallons or less), on land, and a thorough cleanup was conducted immediately so little hydrocarbon contamination of ground and surface water would have occurred. Implementation of a plan for handling fuels and hazardous substances would likely require training of operators in emergency response and reporting procedures and use of secondary containment for all hydrocarbons stored on site and would reduce the level of risk for spills. Implementation of the protection measures described would typically limit operational effects.

To the extent that operation of the proposed project would reduce the use of diesel fuel at existing diesel generation facilities in Gustavus, there would be a slight reduction in the risk of accidental spills at these other sites. Although these other generation facilities may not reduce the amount of fuel stored on site, they would reduce the rate of consumption and thus would reduce their frequency of refueling. Since transporting and transferring fuel are the times of increased risk for spill, there would be some reduction in the probability of a spill.

4.4.2.2 Effects of the GBNPP and Wilderness Boundary Adjustment. Transfer of the proposed lands from GBNPP to the state of Alaska would result in the water resource being managed to produce energy and protect fish and wildlife habitat (ADNR, 2002a). The transfer of lands adjoining 4.3 miles of the middle and lower Kahtaheena River and development of a hydroelectric project would have the greatest effects on the water resources of the Kahtaheena River, as described above.

Transferring these lands from GBNPP to state ownership would result in de-designation of the lands from wilderness status, which could reduce the level of protection that lands adjoining the lowermost 4.3 miles of the Kahtaheena River and its tributaries would experience. The transferred and de-designated lands would no longer be managed as wilderness, and rock pits and quarries could be developed on these lands. If such development occurs, water quality would likely degrade somewhat with the amount of degradation determined by the extent of development and effectiveness of BMPs implemented. Such development and corresponding effects on water quality could adversely affect the Native allotees' use of water for drinking and other purposes.

Wilderness designation of the unnamed island near Blue Mouse Cove, Cenotaph Island, and the land at Alsek Lake near Dry Bay would not affect water quantity and water quality resources because GBNPP already essentially manages these lands as wilderness. GBNPP management includes prohibiting construction or operations that might diminish water quantity or degrade water quality in water bodies in these parcels.

Conveying the Long Lake parcels to NPS would result in the parcels being managed by WSNPP. Since lands adjacent to Long Lake and its outflow stream are currently protected from mineral extraction activities, the effects on water quantity and water quality would be negligible. Similarly, conveying lands adjacent to KGNHP would not have measurable effects on water resources, because they are already managed to ensure compatibility with uses associated with KGNHP, including protection of anadromous fish streams.

4.4.2.3 Cumulative Effects Analysis. The state of Alaska maintains the right to develop mineral resources on state-owned lands. The state may potentially conduct mineral development in the future on its lands to provide material for road maintenance in the Gustavus area, or for other purposes. The continued use of these quarry sites could result in erosion and the transport of sediment to the Kahtaheena River, increasing the river's turbidity and reducing its suitability as a source of drinking water to the Mills allotees. The construction of the project facilities and roads, and the ongoing use of the project roads for operations and maintenance activities, would result in the production of sediment that may be transported to the Kahtaheena River and increase the turbidity of the river. The combined effects of potential future mineral development by the state of Alaska and the ongoing use of project roads may produce a cumulative adverse effect on water quality as a result of erosion and sediment transport to the Kahtaheena River.

The expected growth in the population of Gustavus, or an increase in residential or commercial demand for power, could result in the need for additional diesel generation to supplement hydroelectric power. Increased diesel generation would require the ongoing transportation of fuels and the associated risks of fuel spills that could adversely affect water quality. The development of the Falls Creek Hydroelectric Project would reduce the demand for diesel generated power compared to existing conditions. This reduction in the need for diesel generation may result in decreased risk of fuel spills associated with the transportation, transfer, and storage of fuel and the potential effects on water quality. A reduced potential for spills would reduce the risk of contaminating plant and animal organisms in the nearby marine environment. The combined effect of the growth in electrical demand in the community of Gustavus and the development of the Falls Creek Hydroelectric Project may produce a cumulative decrease in the risk of fuel spills that could affect water quality as a result of offsetting factors that influence the demand for diesel generation.

The potential establishment of an electrical intertie connection between Gustavus and adjacent communities in southeastern Alaska could replace or supplement diesel and hydropower generation. A reduction in the need for diesel generation would reduce the transportation, transfer, and storage of fuels and the associated risk of fuel spills that could adversely affect water quality. The development of the Falls Creek Hydroelectric Project would reduce the demand for diesel-generated power compared to existing conditions. This reduction in the need for diesel generation may result in decreased risk of fuel spills associated with the transportation, transfer, and storage of fuel and the potential effects on water quality. As a result of decreased demand for diesel-generated power, establishment of an electrical intertie connection with Gustavus and the development of the Falls Creek Hydroelectric Project may produce a cumulative decrease in the risk of fuel spills that could adversely affect water quality.

There are no project-related actions identified that would result in an impact on water resources for the WSNPP and KGNHP transfer parcels. Therefore, no cumulative effects on water resources would occur as a result of the interaction between project actions and non-project actions at these sites.

There are no project-related actions identified that would result in an impact on water resources for the proposed wilderness parcels at the unnamed island near Blue Mouse Cove, Cenotaph Island, or Alsek Lake. Therefore, no cumulative effects on water resources would occur as a result of the interaction between project actions and non-project actions at these sites.

4.4.2.4 Conclusion. Operating the project as proposed by GEC or recommended by the agencies would reduce the magnitude of daily mean flows in the bypassed reach of the Kahtaheena River. Under GEC's proposal, wintertime flows in the bypassed reach would be less than 5 cfs 8 percent of the time and less than 10 cfs 80 percent of the time. Under ADFG's recommendations, wintertime flows in the bypassed reach also would be less than 5 cfs 8 percent of the time, but less than 10 cfs only 33 percent of the time. Under no minimum flow requirement, wintertime flows released into the bypassed reach would be 0 cfs 68 percent of the time, less than 5 cfs 75 percent of the time, and less than 10 cfs 80 percent of the time. There would be negligible adverse effects on the magnitude of daily mean flows in the Kahtaheena River below the Lower Falls because the project would be operated in run-of-river mode where inflow to the project above the diversion would equal outflow downstream of the project.

Operation of the project would alter the rate of short-term water level and discharge in the Kahtaheena River between the proposed diversion dam and the terminus of the river. GEC would typically operate the project so that load-following operations and alterations in the amount of flow diverted into the pipeline would cause the water level below the Lower Falls to vary by no more than 1 inch per hour. Following changes in the amount of flow diverted into the pipeline, water levels and flows also would change in the proposed bypassed reach at a similar rate.

Clearing of vegetation and soils along the roadway and pipeline corridors would interrupt subsurface water flow patterns. Subsurface water would likely extrude, and would need to be routed to the downslope side of the roadway, particularly in The Canyon. This interruption in natural processes could affect the timing and slightly reduce rate of accretion of flow to the bypassed reach and the magnitude of surface flows.

The construction and operation of the proposed project would result in reductions to the frequency, magnitude, and duration of flows and rate of short-term water level and discharge alterations throughout approximately one-third of the Kahtaheena River, and interruption of subsurface flow patterns. These impacts would persist over the life of the project. Operating the project under either of the agencies' recommendations would result in smaller, but still noticeable, changes to the frequency, magnitude, and duration of flows and rate of short-term water level and flow alterations throughout much of the Kahtaheena River, and similar interruption of subsurface flow patterns. Operating the project to maximize power production with no minimum flow requirement would result in no minimum flow being released into the 1.79-mile-long bypassed reach for about 30 percent of the time over the entire season for the life of the project.

Construction of the roadway, pipeline, and transmission lines would require disturbing corridors of lands, and construction of some project facilities would require in-water construction activities. Construction and maintenance of corridors for project facilities would increase the risk of eroding surface sediments into area waterways and could increase turbidity in the Kahtaheena River. Under the GEC-proposed road alignment, there also would be an increased risk of eroding surface sediments into Rink Creek. Under the state of Alaska’s recommended road alignment, the adverse effects on turbidity in Rink Creek would be less. However, there would likely be a short-term increase in turbidity during construction and possibly immediately following construction at the additional stream crossing associated with the state’s proposed alignment. GEC proposes to reduce project effects by implementing an ESCP.

The project also would increase the risk of small landslides due to a pipeline rupture, particularly in The Canyon. Although the likelihood of such events would be small, they would result in a significant short-term increase in the level of stream turbidity and could temporarily reduce the suitability of the river as a source of drinking water for the Mills allotees. Over the long term, the material entering the stream from small landslides would be expected to be transported through the system.

Diverting water from the Kahtaheena River would increase summertime water temperatures below the diversion dam. The level of effect would be dependent upon the flow allowed to continue through the proposed bypassed reach. Predicted estimates of maximum summertime temperatures for 2000 are 14EC for 7 cfs (GEC) and 12EC for 20 cfs (FWS) and 25 cfs (ADFG). Under a no minimum flow requirement, maximum summertime water temperatures would be higher than under GEC's proposal and likely higher than the applicable state criterion of 15EC in some portions of the bypassed reach.

Construction and operation of the project would necessitate the storage, use, and disposal of potentially hazardous materials. Even with implementation of the BMPs and fuel and hazardous substances spill plan, the construction and operation of the project could result in periodic small releases of hydrocarbons into local waterways resulting in short-term adverse effects on water quality of local streams and their suitability as a source of drinking water for the Mills allotees. There also would be a remote possibility that a larger spill could substantially degrade the Kahtaheena River's water quality and its suitability as a source of drinking water by the Mills allotees for days or months.

In regard to icing, there would be a small reduction in the thaw bulb under GEC's proposed and the agencies' recommended flows, but under the no minimum flow scenario the associated reduction in the thaw bulb likely would increase the occurrence of anchor and border ice.

The project likely would reduce the operation of the diesel-generation facilities in Gustavus, which could subsequently reduce the need for transporting fuels from Seattle to Gustavus and transferring diesel fuel from barges to diesel-generation facilities in Gustavus. If this occurs, the potential beneficial effects on water quality in the marine environment would be primarily dependent on the extent of reduction in need for transporting and transferring diesel fuel.

Under GEC's proposal, construction and operation of the project would primarily affect water quantity and quality in a localized area in the Kahtaheena River drainage and could affect the adjacent GBNPP lands that abut the river near the diversion dam and below the powerhouse and short-term effects on GBNPP marine waters due to increased turbidity or fuel or oil spills. The purposes and values of GBNPP identified in the enabling legislation include the preservation of waters containing nationally significant natural values. The construction and operation of the proposed project would not adversely impact the purposes and values of GBNPP because the majority of adverse effects on water quality would be contained within the project boundary and/or on state lands. Any effects on water quality within GBNPP would be short-term (weeks or months) and localized (in the marine waters at the mouth of the Kahtaheena River) and would not substantially diminish the nationally significant values of the waters of GBNPP. Under GEC's proposal, the water resources associated with the unnamed island near Blue Mouse Cove, Cenotaph Island, and lands at Alsek Lake would not be adversely affected because they are not located near the project area. The anticipated effects on water resources from this alternative would not result in an impairment of GBNPP resources that fulfill the specific purposes identified in the enabling legislation or are key to the natural integrity of the park. Under this alternative, GBNPP would continue to operate and manage its lands as outlined in the enabling legislation (see section 1.7.4).

Conveying state lands to NPS in either WSNPP or KGNHP would not have any effect on water resources at these locations. Therefore, the level of impacts on the water resources anticipated from this alternative would not result in an impairment of WSNPP or KGNHP resources that fulfill specific purposes identified in the enabling legislation or are key to the natural integrity of these parks. This level of effect would not impair the ability of these parks to operate and manage their lands as outlined in the enabling legislation (see section 1.7.4).

4.4.3 Maximum Boundary Alternative

Under the Maximum Boundary alternative, the 1,145 acres of land identified in section 3(b) of the Act as potentially available for the development of a hydroelectric project would be transferred to the state of Alaska, and all transferred land would be within the project boundary. The land would be subject to the FERC license conditions, restricting its use and development by the state, and the bypassed reach would be included in the FERC project boundary.

4.4.3.1 Effects of Construction and Operation. The effects that constructing and operating the project under the Maximum Boundary Alternative would have on water quantity and water quality are the same as would occur under GEC's proposal. These effects are described in section 4.4.2.

4.4.3.2 Effects of the GBNPP and Wilderness Boundary Adjustment. Effects of land transfers, de-designation, and designation of wilderness areas on water quantity and quality would be the same as under GEC’s proposal.

Transfer of the proposed lands from GBNPP to the state of Alaska would result in water resources being managed to produce energy and protect fish and wildlife habitat (ADNR, 2002a). The transfer of lands adjoining 4.3 miles of the middle and lower Kahtaheena River and development of a hydroelectric project would have the greatest effects on the water resources of the river, as described above.

Transferring these lands from GBNPP to state ownership would result in de-designation of the lands from wilderness status, which could reduce the level of protection that lands adjoining the lowermost 4.3 miles of the Kahtaheena River and its tributaries would experience. The transferred and de-designated lands would no longer be managed as wilderness, and rock pits and quarries could be developed on these lands. If such development occurs, water quality would likely degrade somewhat with the amount of degradation determined by the extent of development and effectiveness of BMPs implemented. Such development and corresponding effects on water quality could adversely affect the Native allotees’ use of water for drinking and other purposes.

Wilderness designation of the unnamed island near Blue Mouse Cove, Cenotaph Island, and the land at Alsek Lake near Dry Bay would not affect water quantity and water quality resources because GBNPP already essentially manages these lands as wilderness.

Exchanging the Long Lake parcels to the NPS would result in the parcels being managed by WSNPP. Since lands adjacent to Long Lake and its outflow stream are currently protected from mineral extraction activities, effects on water quantity and water quality from adding these lands to WSNPP would be negligible. Similarly, exchanging lands adjacent to KGNHP would not have any measurable effects on water resources, since they are already managed to ensure compatibility with uses associated with KGNHP, including protection of anadromous fish streams.

4.4.3.3 Cumulative Effects Analysis. The types of cumulative effects that could be expected to occur on water resources under this alternative would be the same as those described under GEC's proposal in section 4.4.2.3.

4.4.3.4 Conclusion. The Maximum Boundary Alternative would provide essentially the same effects on water quantity and quality as GEC's proposal (see section 4.4.2).

Under the Maximum Boundary Alternative, construction and operation of the project would primarily affect water quantity and quality in a localized area in the Kahtaheena River drainage and would not affect the adjacent GBNPP lands because project lands would provide a buffer between the project and surrounding GBNPP lands. However, there could be short-term effects on GBNPP marine waters due to increased turbidity or fuel or oil spills. The water quantity and water quality effects associated with the unnamed island near Blue Mouse Cove, Cenotaph Island, and lands at Alsek Lake would be negligible because they are not near the project area, and they would remain under NPS management. The purposes and values of GBNPP identified in the enabling legislation include the preservation of waters containing nationally significant natural values. The construction and operation of the proposed project would not adversely impact the purposes and values of GBNPP because the majority of adverse effects on water quality would be contained within the project boundary and/or on state lands. Any effects on water quality within GBNPP would be short-term (weeks or months) and localized (in the marine waters at the mouth of the Kahtaheena River) and would not substantially diminish the nationally significant values of the waters of GBNPP. The anticipated effects on water resources from this alternative would not result in an impairment of GBNPP resources that fulfill the specific purposes identified in the enabling legislation or are key to the natural integrity of the park. Under this alternative, GBNPP would continue to operate and manage its lands as outlined in the enabling legislation (see section 1.7.4).

Conveying state lands to NPS in either WSNPP or KGNHP would not have any effect on water resources at these locations. Therefore, the level of impacts on the water resources anticipated from this alternative would not result in an impairment of WSNPP or KGNHP resources that fulfill specific purposes identified in the enabling legislation or are key to the natural integrity of these parks. This level of effect would not impair the ability of these parks to operate and manage their lands as outlined in the enabling legislation (see section 1.7.4).

4.4.4 Corridor Alternative

Under the Corridor Alternative, approximately 680 acres of park land would be transferred to the state of Alaska, and all transferred land would lie within the FERC project boundary. The land transfer would provide a minimum buffer distance of approximately 0.25 miles around project roads, penstock, transmission line rights-of-way, borrow pit and disposal sites, diversion site, and powerhouse, except along the eastern boundary, where a 0.25-mile buffer would fall outside the lands identified as potentially available for development of a project in the Act. This alternative includes the bypassed reach in the project boundary.

4.4.4.1 Effects of Construction and Operation. The effects of constructing and operating the project under the Corridor Alternative on water quantity and water quality would be the same as would occur under GEC's proposal. These effects are described in section 4.3.2.

4.4.4.2 Effects of the GBNPP and Wilderness Boundary Adjustment. Effects of land transfers, de-designation, and designation of wilderness areas on water quantity and quality would be the same as under GEC's proposal.

Transfer of the proposed lands from GBNPP to the state of Alaska would result in the water resources of the Kahtaheena River being managed to produce energy and protect fish and wildlife habitat (ADNR, 2002a). The transfer of lands adjoining 4.3 miles of the middle and lower Kahtaheena River and development of a hydroelectric project would have the greatest effects on the water resources of the river, as described above.

Transferring these lands from GBNPP to state ownership would result in de-designation of the lands from wilderness status, which could reduce the level of protection that lands adjoining the lowermost 4.3 miles of the Kahtaheena River and its tributaries would experience. The transferred and de-designated lands would no longer be managed as wilderness, and rock pits and quarries could be developed on these lands. If such development occurs, water quality would likely degrade somewhat with the amount of degradation determined by the extent of development and effectiveness of BMPs implemented. Such development and corresponding effects on water quality could adversely affect the Native allotees' use of water for drinking and other purposes.

Wilderness designation of the unnamed island near Blue Mouse Cove, Cenotaph Island, and the land at Alsek Lake near Dry Bay would not affect water quantity and water quality resources because GBNPP already essentially manages these lands as wilderness.

Exchanging the Long Lake parcels to NPS would result in the parcels being managed by WSNPP. Since lands adjacent to Long Lake and its outflow stream are currently protected from mineral extraction activities, effects on water quantity and water quality resources of adding these lands to WSNPP would be negligible. Similarly, exchanging lands adjacent to KGNHP would not have measurable effects on water resources, since they are already managed to ensure compatibility with uses associated with KGNHP, including protection of anadromous fish streams.

4.4.4.3 Cumulative Effects Analysis. The types of cumulative effects that could be expected to occur on water resources under this alternative would be the same as those described under GEC's proposal in section 4.4.2.3.

4.4.4.4 Conclusion. The Corridor Alternative would result in essentially the same effects on water quantity and quality as GEC's proposal.

Under the Corridor Alternative, construction and operation of the project would primarily affect water quantity and quality in a localized area in the Kahtaheena River drainage and would not affect the adjacent GBNPP lands because project lands would provide a buffer between the project and surrounding GBNPP lands. However, there could be short-term effects on GBNPP marine waters due to increased turbidity or fuel or oil spills. The water quantity and water quality effects associated with the unnamed island near Blue Mouse Cove, Cenotaph Island, and lands at Alsek Lake would be negligible, because they are not located near the proposed project site, and these lands would remain under NPS management. The purposes and values of GBNPP identified in the enabling legislation include the preservation of waters containing nationally significant natural values. The construction and operation of the proposed project would not adversely impact the purposes and values of GBNPP because the majority of adverse effects on water quality would be contained within the project boundary and/or on state lands. Any effects on water quality within GBNPP would be short-term (weeks or months) and localized (in the marine waters at the mouth of the Kahtaheena River) and would not substantially diminish the nationally significant values of the waters of GBNPP. The anticipated effects on water resources from this alternative would not result in an impairment of GBNPP resources that fulfill the specific purposes identified in the enabling legislation or are key to the natural integrity of the park. Under this alternative, GBNPP would continue to operate and manage its lands as outlined in the enabling legislation (see section 1.7.4).

Conveying state lands to NPS in either WSNPP or KGNHP would not have any effect on water resources at these locations. Therefore, the level of impacts on the water resources anticipated from this alternative would not result in an impairment of WSNPP or KGNHP resources that fulfill specific purposes identified in the enabling legislation or are key to the natural integrity of these parks. This level of effect would not impair the ability of these parks to operate and manage their lands as outlined in the enabling legislation (see section 1.7.4).

4.5 AIR QUALITY

Several evaluation parameters are used to identify and describe the potential impacts on the air quality resources of the project area:

1 Criteria pollutant emissions

2. Dust emissions during construction

3. Attainment status

The analysis of the potential effects of the project on air quality resources includes a discussion of the context of the air quality resources in the project area. The intensity of the impact on air quality resources is generally characterized by quantifying the emissions of criteria pollutants and analyzing the existing ambient levels of these pollutants. The duration of the impact is described where necessary to understand the context and intensity of the impact.

4.5.1 No-action Alternative

4.5.1.1 Effects Analysis. Under the No-action Alternative, the proposed project would not be constructed; the land surrounding the proposed project would be retained within the National Wilderness Preservation System for the foreseeable future and would continue to be managed as wilderness in accordance with the GBNPP GMP; and there would be no land exchange. Under this alternative, the main sources of air pollutant emission in the project area would be related to the operations of the existing GEC and NPS diesel generators, including the generators, the diesel storage tanks, and the access and service road traffic. VOC emissions from the storage tanks are very low due to the almost non-volatility of diesel. In fact, using the TANKS 4.09 model[49] (EPA, 2000), the estimated total VOC emission rate from the storage tanks is 0.001 tpy (see section 3.5 for comparison). This is a minuscule fraction of the total VOC emission of the census area reported in section 3.5 to be 17,851 tpy under which the area has a pristine attainment status. Therefore, the storage tank emissions do not affect the quality of air in the project area, and this rate of emission would continue under the No-action Alternative.

The roads to the storage tanks are only occasionally used for O&M of the generators and for diesel fuel transportation to the storage tanks. Although there are no direct data to calculate mobile emissions, based on proposed operations and the short length and nature of the roads to the tanks, mobile emissions of VOC, CO, and PM_{10} would be very low compared to diesel generator emissions. Generator operations, on the

[49] TANKS 4.09 is a Windows-based computer software program that estimates VOC and hazardous air pollutant (HAP) emissions from fixed- and floating-roof storage tanks. TANKS is based on the emission estimation procedures from chapter 7 of AP-42 (EPA, 1995).

other hand, emit all the criteria pollutants at much higher rates. Using emission factors from AP-42 (EPA, 1995)[50] and the average 2007-2016 predicted generation (see table 5.3-1), we estimated total emissions of NO_x, CO, SO_2, PM_{10}, and VOC (table 4.5-1). Using the annual estimates presented in table 4.5-1 and the 1999 EPA air pollution data, we estimate annual GEC emission rates for NO_x, CO, SO_2, PM_{10}, and VOC as 2.47, 0.02, 4.28, 0.05, and 0.05 percent, respectively, of total annual emissions for the census area.

VOC emissions from the storage and transfer of diesel fuel to operate the diesel generators are extremely small due to the very low volatility of diesel fuel. For example, VOC emissions from the diesel fuel storage tanks as calculated by EPA's TANKS model are estimated to be 0.005 tons/year. This compares to an estimated 6.75 tons/year of VOC emissions from the operation of the diesel generators at current generation rates.

Emissions from the generators would be localized in the vicinity of the generators and would not affect the proposed hydro project area. Under the No-action Alternative, these emissions would increase slightly over the years as diesel generation increases to serve increased power demand.

The air quality of the Kahtaheena River area and the proposed land exchange parcels and wilderness designation lands would not be affected because air quality would still be protected under NPS wilderness visitor use policy and management, which supports the preservation of air quality.

4.5.1.2 Cumulative Effects. Under the No-action Alternative, there would be no project-related actions in the Kahtaheena River area, the state lands near WSNPP and KGNHP, the unnamed island near Blue Mouse Cove, Cenotaph Island, or Alsek Lake. Therefore, no project actions could interact with non-project actions expected to occur in these areas in the foreseeable future with the potential to produce a cumulative effect on air quality resources. Cumulative effects would be unchanged. Diesel generation by GEC and NPS would continue with no new emissions except for increased demand.

4.5.1.3 Conclusion. Under the No-action Alternative, the air quality in the vicinity of the proposed project would remain at its current and pristine attainment level (see section 3.5) with a slight increase over the years due to projected increase in generator power demand. Overall, effects on the air quality resources anticipated from this alternative would not constitute an impairment of the purposes and values of GBNPP associated with air quality, as identified in the enabling legislation; or are key to the natural integrity of the park. Under this alternative, GBNPP would continue to operate and manage its lands as outlined in the enabling legislation (see section 1.7.4).

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50 AP-42 provides EPA's recommended air pollutant emission factors for both criteria and toxic emissions. AP-42, Volume I ,addresses hundreds of stationary, point, and area sources.

Table 4.5-1. Estimated criteria pollutant emissions based on projected average generation over the period 2007-2016 assuming that all power is generated by the diesel generators. (Source: Based on EPA, 1995, by preparers)

	GEC Emissions (tpy)												
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Annual**
Pollutant													
NO_X	4.39	4.19	3.64	3.78	3.93	4.38	4.48	4.79	4.33	3.68	4.28	3.93	49.79
CO	0.95	0.90	0.79	0.81	0.85	0.94	0.96	1.03	0.93	0.79	0.92	0.85	10.73
SO_2	0.29	0.28	0.24	0.25	0.26	0.29	0.30	0.32	0.29	0.24	0.28	0.26	3.29
PM_{10}	0.31	0.30	0.26	0.27	0.28	0.31	0.32	0.34	0.31	0.26	0.30	0.28	3.53
VOC	0.36	0.34	0.29	0.31	0.32	0.35	0.36	0.39	0.35	0.30	0.35	0.32	4.03

The level of effects on air quality anticipated from this alternative would not result in an impairment of WSNPP or KGNHP resources that fulfill specific purposes as identified in the enabling legislation, or are key to the natural integrity of these parks. Under this alternative, WSNPP and KGNHP would continue to operate and manage their lands as outlined in their enabling legislation (see section 1.7.4).

4.5.2 GEC's Proposed Alternative

4.5.2.1 Effects of Construction and Operation. The primary effects on the air quality resources would be those associated with the construction and operation of the hydroelectric project. The development of a road, penstock, tailrace, intake facilities, powerhouse, and other hydroelectric production and transmission structures would generate sporadic emissions, primarily from vehicles and during refueling, in the 24-month construction phase of the project that might affect the air quality in the proposed project vicinity. The operation of the hydroelectric generating facility would generate no air emissions, and the GEC back-up diesel generators and the NPS diesel generators would continue to be the main sources of pollutant emissions in the area and would emit at lower rates.

Project Construction. Construction would temporarily disturb about 29.6 acres of lands. The operation of construction equipment would sporadically emit some criteria pollutants (NO_x, CO, SO_2, PM_{10}, and VOC) during the construction phase of the project. Short-term fugitive dust emissions would be generated due primarily to land clearing, earth-moving, and ground excavation activities. The amount of total suspended particulates (TSP) could be grossly estimated over the area of land disturbed and the total months of construction using the emission factor 1.2 tons/acre/month of activity (AP-42, section 13.2.3). Assuming that 50 percent of the approximately 30-acre site is disturbed by construction activity for a period of 4 months at the beginning of construction, approximately 71 tons of uncontrolled TSP emissions would be generated (table 4.5-2).

This TSP emission could be less because GEC proposes to use control techniques such as wet suppression (source watering), wind speed reduction (wind barriers), ceasing construction activities during periods of high winds, and use of small construction equipment. GEC also would preclude all non-project vehicle use along the access road reducing the disturbances to the air quality resources in the area caused by vehicular traffic. Section 13.2.4 of AP-42 indicates that wet suppression control techniques can reduce particulate emissions by as much as 90 percent. Assuming that source watering is used exclusively, the total TSP emissions would be 7.1 tons during the initial year of construction which represents less than 0.1 percent of the entire census area yearly PM_{10} emissions and would not deteriorate the air quality of the proposed project area.

Despite proposed use of mitigation techniques, construction activity would have a negative effect on the air quality resources in the vicinity of the project area. The impacts would be sporadic (during construction time only), for a period of 24 months.

Table 4.5-2. Estimated criteria pollutant emissions from GEC's diesel generators based on projected average generation over the period 2007-2016 assuming development of the hydroelectric project with the flow regime proposed by GEC and GBNPP continues to generate its own power. NPS emissions are not included in this table. (Source: Based on EPA, 1995, by preparers)

	GEC Emissions (tpy)													
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Annual**	**Reduction***
Pollutant														
NO_X	1.81	1.70	1.09	0.20	0.00	0.00	0.00	0.00	0.00	0.00	0.72	0.95	6.47	87%
CO	0.39	0.37	0.23	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.16	0.21	1.39	87%
SO_2	0.12	0.11	0.07	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.06	0.43	87%
PM_{10}	0.13	0.12	0.08	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.07	0.46	87%
VOC	0.15	0.14	0.09	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.08	0.52	87%
Percent Reduction	59%	59%	70%	95%	100%	100%	100%	100%	100%	100%	83%	76	* Relative to no action	

Project Operations. No air emissions would be generated by the operation of the Falls Creek Hydroelectric Project. The operation of the diesel generator systems would remain the main sources of air pollution. The emissions from the operations of the GEC diesel generators were estimated using emission factors obtained from AP-42 (EPA, 1995) and the 2007 diesel power generations (see table 5.3-1). Table 4.5-2 presents the estimated total emissions of NO_x, CO, SO_2, PM_{10}, and VOC. As shown, GEC's proposed action would have a positive effect on the area air quality because it would significantly reduce annual air emissions by 87 percent as compared to the No-action Alternative. The hydroelectric power plant would completely replace the diesel generators from May through October, and no emissions would be generated. Emissions would be reduced by 73 percent in the months of November through April where low flow and/or high demand require the use of back-up diesel generators to meet energy requirements in excess of the hydroelectric project's capacity. These high percent reduction figures would be a benefit to air quality for the duration of the license term. The low emissions would be localized to the vicinity of the generators, and no negative air quality impact would be noticeable.

Region-wide, the proposed action would be a benefit to air quality in a region that is already in pristine attainment condition. Although, as generation requirements in GEC's service area increase over time and cannot be completely met by hydroelectric generation due to the project's capacity limitation, emissions would increase as a result of increased diesel generation. However, these emissions would remain significantly below levels that would occur under the no-action alternative where all demand would likely be met by diesel generation. Although there are no data to perform mobile emission calculations, very low mobile emissions of VOC, NO_x, and PM_{10} would be expected to be generated from the 3.6-mile, gravel-surfaced access road because travel would be limited to the routine maintenance visits only during project operation.

Under GEC's proposed action, the construction phase would have small, localized effects on the air quality resources during the 24-month period. Visitors would have to be on the construction site to be affected by pollutant emissions. The location of the project area and the dense forest cover would be a barrier to the transport of some pollutants further downwind. Dust and airborne pollutants from construction along the access road, penstock, and powerhouse site could affect the northern portion of the George allotment and eastern edge of the Mills allotment, which are adjacent to these construction areas. During operation of the proposed project, pollutant emissions would decrease in the town of Gustavus, assuming a constant level of demand. Emissions from the NPS generators may increase slightly with increasing demand. Consequently, the development of the proposed project would negatively affect air quality resources during the construction phase and would improve air quality thereafter. Under the state of Alaska's alternative access route, the amount of land disturbed by construction would increase by about 25 percent and result in a corresponding 25 percent increase in mobile emissions.

4.5.2.2 Effects of the GBNPP and Wilderness Boundary Adjustment. The transfer of lands of the middle and lower Kahtaheena River out of GBNPP and development of a hydroelectric project on this section of river would have no substantial effects on air quality resources associated with the area. The effects would be the same as described in section 4.5.1, resulting in a limited adverse impact on air quality resources during the construction phase and reduced emissions thereafter.

Proposed Land Exchange Parcels. The exchange of the Long Lake parcels to NPS would bring these parcels under the management of WSNPP. Exchange of the parcels adjacent to KGNHP to NPS would bring these parcels under the management and values of KGNHP. Both of these groups of land are currently owned by the state of Alaska and managed to protect their scenic and wildlife values. Therefore, the exchange of these parcels would have no effect on the air quality resources of these parcels.

Wilderness Designation Parcels. The designation of the unnamed island near Blue Mouse Cove, Cenotaph Island, and the land at Alsek Lake near Dry Bay would not affect air quality resources because, for all practical purposes, GBNPP currently manages these lands as wilderness and there would be no changes in emissions in these areas.

4.5.2.3 Cumulative Effects Analysis. Potential changes to the number of large vessels permitted to operate within Glacier Bay may result in increases or decreases in the total quantity of criteria pollutants. The long-term operation of the proposed project would reduce the emissions of criteria pollutants as a result of electrical power generation for the community of Gustavus. Combined, these actions may produce either a cumulative increase or decrease in the total quantity of criteria pollutants emitted in the general Glacier Bay and Gustavus area, depending on the change in the number of vessels operating in Glacier Bay.

The construction of the Falls Creek Hydroelectric Project would increase the fugitive dust emissions in the watershed during the construction period, while long-term operation of the hydroelectric project would result in a reduction in emissions of criteria pollutants. The absence of non-project-related actions with the potential to interact with project-related actions eliminates the possibility of producing a cumulative effect on air quality.

There are no non-project-related actions identified that would result in an impact on air quality in the state lands near WSNPP and KGNHP, the unnamed island near Blue Mouse Cove, Cenotaph Island, or Alsek Lake.

4.5.2.4 Conclusion. Under GEC's proposal, construction of the project facilities could generate about 71 tons of uncontrolled TSP emissions during the 24-month construction period. GEC proposes to control the emission of TSPs during construction using wet suppression techniques that could reduce emissions to less than 0.1 percent of the PM_{10} emissions for the entire census area. The effects would be localized to the construction sites and portions of the George and Mills allotments adjacent to the construction sites in the project area. During project operation, pollutant emissions could decrease in the town of Gustavus in direct proportion to the replacement of hydropower for diesel generation.

Under GEC's proposal, construction activity could affect the air quality on adjacent GBNPP lands on the eastern side of the Kahtaheena River near the diversion dam and below the powerhouse construction sites, but the effects would be limited to the 24-month construction period. The air quality resources of the unnamed island near Blue Mouse Cove, Cenotaph Island, and the lands at Alsek Lake would not be affected because they are not in the vicinity of the proposed construction. The purposes and values of GBNPP identified in the enabling legislation include the preservation of wilderness resources in their natural state. Effects on air quality within GBNPP would be localized to areas adjacent to the project area and would not diminish the natural state in GBNPP. Therefore, project-related effects on air quality would not adversely impact the purposes and values of GBNPP. The anticipated effects on air resources would not result in an impairment of GBNPP resources that fulfill the specific purposes identified in the enabling legislation or are key to the natural integrity of the park. Under this alternative, GBNPP would continue to operate and manage its lands as outlined in the enabling legislation (see section 1.7.4).

Construction and operation of the proposed project would have no effect on the air quality resources of the Long Lake parcels within WSNPP and the parcels in neighboring KGNHP over the long term, these parcels would become protected under NPS policy and management that supports the preservation of the air quality resources. The anticipated short-term impacts on the air quality resources anticipated from the proposed action would not result in an impairment of WSNPP or KGNHP resources that fulfill the specific purposes and values or are key to the natural integrity of the parks.

4.5.3 Maximum Boundary Alternative

4.5.3.1 Effects of Construction and Operation. Under the Maximum Boundary Alternative, about 1,145 acres of GBNPP designated wilderness would be exchanged with the state of Alaska, and all of this area would be included in the project boundary. Project construction and operation under this alternative would be the same as under GEC’s proposal. The effects on air quality from the proposed project associated with this alternative would be similar to those described for the proposed action in section 4.5.2.

4.5.3.2 Effects of the GBNPP and Wilderness Boundary Adjustment. The Maximum Boundary Alternative would affect the amount of land exchanged as well as the amount of land designated as wilderness. Exchange of the parcels at Long Lake and/or the exchange of the Klondike parcels to NPS would not affect the air quality resources of these lands because the state of Alaska, for all practical purposes, currently manages both these lands in a manner compatible with NPS goals outlined in the WSNPP and KGNHP management plans.

Designating all or parts of the lands, including the unnamed island near Blue Mouse Cove, Cenotaph Island, and the lands at Alsek Lake, as wilderness would have negligible effects on air quality resources. For all practical purposes, these lands are currently managed as if they were wilderness lands under the GBNPP Wilderness Management Plan.

4.5.3.3 Cumulative Effects Analysis. The types of cumulative effects that could be expected to occur on air quality under this alternative would be the same as those described under GEC's proposal in section 4.5.2.3.

4.5.3.4 Conclusion. Because the Maximum Boundary Alternative only considers a change in the project boundary, the effects on the air quality of the project area and vicinity would be the same as those described above in section 4.5.2, except that the 1,145 acres that would be conveyed to the state of Alaska would include the entire bypassed reach and the lands to the east of the bypassed reach.

Under the Maximum Boundary Alternative, construction activity could affect the air quality on adjacent GBNPP lands on the eastern side of the Kahtaheena River near the diversion dam and powerhouse sites where the adjacent GBNPP lands would be within several hundred feet of construction activity, but the effects would be limited to the 24-month construction period. The purposes and values of GBNPP identified in the enabling legislation include the preservation of wilderness resources in their natural state. Effects on air quality within GBNPP would be localized to areas adjacent to the project area and would not diminish the natural state in GBNPP. Therefore, project-related effects on air quality would not adversely impact the purposes and values of GBNPP. The air quality resources of the unnamed island near Blue Mouse Cove, Cenotaph Island, and the lands at Alsek Lake would not be affected because they are not in the vicinity of the proposed construction, and they would remain in GBNPP. The anticipated effects on air resources would not result in an impairment of GBNPP resources that fulfill the specific purposes identified in the enabling legislation or are key to the natural integrity of the park. Under this alternative, GBNPP would continue to operate and manage its lands as outlined in the enabling legislation (see section 1.7.4).

Conveying state lands to NPS for either the WSNPP or KGNHP would not have any effect on the air quality resources at these locations and would not result in an impairment of WSNPP or KGNHP resources that fulfill specific purposes identified in the enabling legislation, or are key to the natural integrity of these parks.

4.5.4 Corridor Alternative

4.5.4.1 Effects of Construction and Operation. Under the Corridor Alternative, 680 acres of land would be encompassed within the project boundary, which would include a larger amount of land designated for the project. Project construction and operation under this alternative would be the same as under GEC's proposal. The effects on the air quality of the proposed project associated with this alternative would be similar to those described for the proposed action in section 4.5.2.

4.5.4.2 Effects of the GBNPP and Wilderness Boundary Adjustment. The Corridor Alternative would reduce the amount of lands exchanged. Exchange of either the Long Lake parcels or the Klondike parcels would not affect the air quality resources of the lands exchanged because the state of Alaska currently manages these lands in a manner compatible with NPS goals. The exchange of one or both of these lands would bring them under either WSNPP or KGNHP management practices. The practical effect would be negligible because of the current management.

The Corridor Alternative would affect the amount of lands designated wilderness at either the unnamed island near Blue Mouse Cove, Cenotaph Island, or the lands at Alsek Lake. These lands are currently not designated as wilderness; however, for all practical purposes, they are managed as such as mentioned in the GBNPP Wilderness Management Plan. Regardless of which lands become admitted under the wilderness designation, all the lands would continue to be managed as such. The practical effect would be negligible because the current management would be similar.

4.5.4.3 Cumulative Effects Analysis. The types of cumulative effects that could be expected to occur on air quality under this alternative would be the same as those described under GEC's proposal in section 4.5.2.3.

4.5.4.4 Conclusion. Because the Corridor Alternative only considers a change in the project boundary, the effects on the air quality of the project area and vicinity would be the same as those described above in section 4.5.2, except that the 680 acres that would be conveyed to the state of Alaska would include the entire bypassed reach and the lands to the east of the bypassed reach.

Under the Corridor Alternative, construction activity could affect the air quality on adjacent GBNPP lands on the eastern side of the Kahtaheena River near the diversion dam site where the adjacent GBNPP lands would be within several hundred feet of construction activity, but the effects would be limited to the 24-month construction period. The purposes and values of GBNPP identified in the enabling legislation include the preservation of wilderness resources in their natural state. Effects on air quality within GBNPP would be localized to areas adjacent to the project area and would not diminish the natural state in GBNPP. Therefore, project-related effects on air quality would not adversely impact the purposes and values of GBNPP. The air quality resources of the unnamed island near Blue Mouse Cove, Cenotaph Island, and the lands at Alsek Lake would not be affected because they are not in the vicinity of the proposed construction. They would be protected under NPS management that supports the preservation of air quality resources. The anticipated effects on air resources under this alternative would not result in an impairment of GBNPP resources that fulfill the specific purposes identified in the enabling legislation (see section 1.7.4).

Conveying state lands to NPS for either WSNPP or KGNHP would not have any effect on the air quality resources at these locations and would not result in an impairment of WSNPP or KGNHP resources that fulfill specific purposes identified in the enabling legislation, or are key to the natural integrity of these parks.

4.6 FISHERIES

In this section, we analyze the effects of the proposed project on fisheries resources in the Kahtaheena River. First, we describe the effects of the proposed project on fish habitat quality and quantity, and then we describe the effects of these habitat changes on fish population size and distribution. The following evaluation parameters are used to describe the level of impacts on fish populations:

1. Changes in water quality due to the physical disturbance of the drainage basin related to project construction and operation.
2. Changes in habitat quality and quantity due to flow diversion for power production.
3. Changes in habitat quality due to the presence of project structures in the stream.

This section includes a discussion of the spatial distribution of fish within the system as well as the temporal context of project-induced water quality and flow alterations. The intensity of the impacts is characterized by comparison of existing water quality and flow conditions within the proposed bypassed reach to predicted construction phase and post-operational conditions in both the proposed bypassed reach and the reach downstream of the powerhouse discharge. The duration of the impact is described where necessary to understand the context and intensity of the impact.

4.6.1 No-action Alternative

4.6.1.1 Effects Analysis. Under the No-action Alternative, the proposed project would not be constructed; the land surrounding the proposed project would be retained within the National Wilderness Preservation System for the foreseeable future and would continue to be managed as wilderness in accordance with the GBNPP GMP; and there would be no land exchange. Under this alternative, fisheries and other aquatic communities in the Kahtaheena River would be unaffected by the proposed development activities and would remain relatively undisturbed.

Because all proposed wilderness designation parcels are currently managed as *de facto* wilderness, only recreational fishing is allowed within GBNPP wilderness freshwater stream systems, and no measurable impacts on fisheries or other aquatic resources would be expected under this alternative.

Parcels in the Long Lake area and KGNHP would not be transferred from state to NPS ownership. Thus, lands surrounding Long Lake and its outlet would continue to be managed by the state of Alaska in accordance with the Copper River Basin Plan. The plan precludes development along the north shore of the lake near prime sockeye salmon spawning habitat, and development would not be permitted in parcels proposed for exchange. Therefore, fisheries resources would be largely unaffected by development activities and would be expected to be unaffected by the No-action Alternative.

NPS already manages the lands proposed for exchange along the Chilkoot Trail under agreement with the state of Alaska. NPS management policies mandate the protection of fish and wildlife habitat in the area. Thus, the No-action Alternative would not change the management of these lands, and there would be no adverse effects on fisheries resources of the Taiya River system.

4.6.1.2 Cumulative Effects Analysis. Under the No-action Alternative, there would be no cumulative effects because no project actions would occur in the Kahtaheena River watershed, state-owned parcels adjacent to WSNPP and KGNHP, or the parcels at Cenotaph Island, the unnamed island near Blue Mouse Cove, and Alsek Lake. Therefore, there is no potential for cumulative effects on fisheries resources based on the interaction between project and non-project actions.

4.6.1.3 Conclusion. Under the No-action Alternative, the proposed project would not be constructed, and there would be no land exchange or changes in wilderness designations. In addition, there would be no changes to stream flows, aquatic habitat, or water quality. As a result, there would be no effect on aquatic resources. The No-action Alternative would not result in impairment of GBNPP resources that fulfill specific purposes of maintaining aquatic ecosystems in their natural state and protecting habitat for, and populations of, fish and wildlife, as identified in the enabling legislation or are key to the natural integrity of the park. Under this alternative, GBNPP would continue to operate and manage its lands as outlined in the enabling legislation (see section 1.7.4).

The level of effects on fishery resources anticipated from this alternative would not result in an impairment of WSNPP or KGNHP resources that fulfill specific purposes of maintaining ecosystems in their natural state and protecting habitat for, and populations of, fish and wildlife, as identified in the enabling legislation, or are key to the natural integrity of these parks. Under this alternative, WSNPP and KGNHP would continue to operate and manage their lands as outlined in their enabling legislation (see section 1.7.4).

4.6.2 GEC's Proposed Alternative

4.6.2.1 Effects of Construction and Operation

Project Construction. Project construction may affect the fish and aquatic organisms in the Kahtaheena River as a result of erosion and sedimentation related to ground disturbance; by accidental release of hydrocarbons into area drainages; or by increased human activity, including unauthorized fishing by project workforce members.

Erosion and Sedimentation

Construction activities associated with GEC's proposal could increase the likelihood of mass movement and localized erosion, which could subsequently increase suspended sediment levels in the lower Kahtaheena River. The deleterious effects of increased suspended sediments on fish and other aquatic biota are well recognized. Common effects in salmonid streams include mechanical injury to gills; stress or suffocation of eggs or fry due to oxygen reduction associated with sediment settling in gravel interstices; and reduced feeding success (Bjornn and Reiser, 1991). Increased suspended sediments can also reduce the production and survival of aquatic invertebrates, affecting the primary food source of stream resident salmonids.

Movement of sediment into streams due to surface erosion is directly related to the amount of bare compacted soil exposed to rainfall and runoff. Hence, road construction, vegetation removal, landslides, ditches, and other ground-disturbing events can contribute large quantities of sediments to stream channels (Chamberlin et al., 1991). The quality of management planning and its associated protection measures strongly influence sediment production and its potential to affect aquatic habitat and fish populations.

GEC proposes a number of actions to limit the proposed project's effects on erosion rates in the Kahtaheena River Basin. Construction would be limited to a 24-month period; blasting in The Canyon would be limited to small charges to minimize flying debris; road construction would follow U.S. Forest Service Region 10 standards and guidelines and employ full bench road cuts and complete removal of spoil; and side casting would be avoided along all portions of roads inside The Canyon and on other steep slopes considered slide prone. GEC would also construct roadways and transmission lines in less sensitive (flatter) areas. As discussed in section 4.3, these and other measures are included in GEC's draft ESCP (GEC, 2001b, appendix G).

In addition to those measures included in the ESCP, ADFG, FWS, and NMFS recommend conducting all in-water construction activities in the anadromous reach of the river from June 1 through August 7 (to avoid the May high flow period and to reduce the risk of introducing sediment into salmonid spawning areas). Resource agencies also recommend that GEC conduct all in-water construction activities in the river above the Lower Falls from November 1 through April 30 and from June 1 through September 15. No in-water activities would be allowed in May or from mid-September through the end of October. These construction windows would reduce the likelihood of excessive erosion associated with large storm events and heavy precipitation.

ADFG, FWS, and NMFS recommend that GEC use an ECM to ensure compliance with environmental measures during construction, conduct water quality sampling to evaluate the effectiveness of erosion and sediment control measures, and implement a road management plan. We discuss the road management plan in our discussion of geologic resources and soils in section 4.3.2.1.

Finally, these same agencies recommend that GEC establish a $50,000 interest-bearing escrow account to mitigate for unforeseen fish, wildlife, and water quality effects associated with project construction and operation.

Under GEC's proposal, it is likely that fish would be subject to occasional increases in turbidity (total suspended solids) in several project reaches. Increases would likely occur in the river near the diversion structure, near the road leading from the diversion structure, in the vicinity of the powerhouse and its access road, and near the road crossings at Greg and Homesteader creeks. Erosion rates would be greatest during periods of high runoff.

Under existing conditions (no action), an estimated 20 m^3 of sediment enter the Kahtaheena River per year (see section 4.3.2). Short-term construction effects would result in an estimated 8-fold increase in erosion over existing conditions (175 m^3/year). This estimate is based on GEC's proposed alternative and assumes the road and transmission line alignment presented in section 3.3.1. The state of Alaska in comments on the draft EIS has suggested an alternative route for the section of road leading from the end of the existing road system (Rink Creek Road) to the branch point near the Kahtaheena River (see figure 2-2 in appendix A). This alternative road alignment would be approximately 3.2 miles long, as opposed to GEC's proposed alignment that would be 1.7 miles long. This increased length of new road would result in an increase in disturbance of an additional 7.5 acres of currently undisturbed land during construction and an increase in the area of permanently disturbed land following completion of construction of approximately 2.5 acres. This amounts to an approximate increase in the total amount of construction and post-construction land disturbance of 25 percent. The increased amount of land disturbance would likely increase turbidity above levels resulting from GEC's proposed alignment and/or cause turbidity increases in streams not affected by the GEC alignment. While sediment input into the Kahtaheena River would increase substantially under either of the proposed road alignment scenarios during project construction, fish and other aquatic biota would be able to tolerate relatively short-term increases in sediment concentrations.

Newcombe and MacDonald (1991) and Newcombe and Jensen (1998) review the literature on the effects of suspended sediment on fish and benthic organisms and provide a general dose-response model to assist fisheries biologists and habitat managers in addressing local sediment problems. In general, the severity of the effects is related both to the concentration and to the duration of exposure. Fish are often only moderately affected by short-term exposure to extremely high sediment concentrations. Waters (1995), in a review of the literature on sediment effects on salmonids, cites several cases of fish surviving short-term exposure to sediment concentrations of 500 to 1,000 mg/L. In many cases, fish exposed to high levels of sediment simply move to other areas to avoid the deleterious effects (Waters, 1995; Servizi and Martens, 1992).

Fish may be more severely affected, however, by low to moderate sediment concentrations over prolonged periods. Larkin et al. (1998) report on the application of Jensen's (1996) Severity of Effects scale to salmonids in several disturbed watersheds in British Columbia. They conclude that exposure to mean suspended sediment concentrations ranging from 25 to 72 mg/L over a 3-month period could result in sub-lethal and paralethal effects on the fish including reduction in feeding success, poor condition, reduced growth rate, reduced hatching, and reduced fish density. Under GEC's proposal, the effects of suspended sediment on aquatic habitat and fish populations due to construction activities would be minimal and relatively short in duration. Although some sediment would likely enter the stream during construction, evidence suggests that salmonids are well adapted to short-term increases in turbidity as such conditions are frequently experienced in natural settings as a result of storms, landslides, or other natural events (Redding 1987). It is chronic exposure to increased turbidity that has been found to be the most damaging to salmonid populations (The Watershed Company, 2000). Furthermore, studies have found that when habitat space is not limiting, salmonids will move to avoid localized areas of increased turbidity, thereby alleviating the potential for long term adverse physiological impacts (Bisson and Bilby, 1982). During project construction, it is highly unlikely that aquatic biota in the Kahtaheena River would be exposed to sediment concentrations exceeding 150 mg/l. Short-term exposure (< 2 weeks) to sediment concentrations in this range would have little effect on existing fish populations. Mortality would be unlikely for adult and juvenile salmonids located both above and below the Lower Falls; however, fish that remain in the project-affected reaches could experience some poor feeding success and reduced growth over the short term.

As discussed in section 4.3.2, portions of the proposed project area contain steep slopes with active and historic landslides. Although GEC's proposed erosion control measures as described in the ESCP are designed to minimize project-related landslide risk, construction of the proposed project and access road could further destabilize landforms that are only marginally stable. Destabilization in high hazard areas could reactivate or create new landslides contributing large amounts of sediment to the Kahtaheena River and its tidal area. While the number and size of landslides that may occur in the future (if any) cannot be predicted, large or multiple landslides could have a substantial impact on the sediment supply to the river, adversely affecting fish populations residing both above and below the Lower Falls. Potential impacts on the fishery resource would be directly related to the magnitude of the landslide or landslides. Impacts on existing populations, associated with a landslide (600 m^3/year), could result in the loss of several year classes, but because natural landslides are a common event in southeastern Alaska, we would expect the fish populations to persist under these conditions.

Increased sediment delivery to the stream channel during construction also could increase stream embeddedness, leading to reduced production of benthic macroinvertebrates and reduced egg and alevin survival. These impacts would be short in duration, and, without future disturbances (i.e., numerous massive landslides), bedload movement during normal high flows would likely reduce the amount of fines in the stream channel.

In the upper river, construction timing restrictions recommended by the resource agencies would help to limit the probability of erosion during months of high precipitation and runoff. In the lower river, construction-timing restrictions would minimize the risk of erosion during the high flow month of May as well during the salmonid spawning and incubation period (see table 3.6-2). From June through August, most of the use is by fry, adult, and juvenile salmonids. Adult and juvenile salmonids that are mobile and able to seek out shelter from sources of sediment often tolerate elevated sediment levels over short periods of time.

Additional measures proposed by GEC would limit the amount of erosion that would occur during construction, and thus reduce the potential for large-scale sediment delivery to the stream. The agencies recommended ECM would ensure compliance with environmental measures during construction, and the resource agency's recommended escrow account would provide a source of funds to implement additional erosion control measures should unforeseen problems occur, providing additional protection against construction-related effects of sediment on fish, wildlife, and water quality.

Introduction of Hazardous Materials into Project Area Waterways

As discussed in section 4.4, *Water Quantity and Quality,* construction of the proposed project facilities would require the use of heavy equipment and other construction machinery. This equipment would require fuel, motor oil, hydraulic fluid, and other lubricants. The presence of these hazardous materials in the project area creates a risk of accidental release of hydrocarbons and other toxic substances, with the potential for contamination of the Kahtaheena River and its associated waterways. Hazardous materials entering these waterways could adversely affect aquatic biota and severely reduce the quality and quantity of existing aquatic habitat (if concentrations in the waterway exceed the lethal tolerance limit of a species or if exposures result in indirect effects such as stress, disease, or increased susceptibility to predators).

GEC does not propose any measures to address the handling of toxic substances during project construction.

To prevent fuel and/or hazardous substance spills and minimize any potential impacts associated with the handling of hazardous substances during project construction, ADFG, FWS, and NMFS recommend that GEC consult with the resource agencies and obtain their written approval on a fuel and hazardous substances spill plan. The plan would include contingencies with appropriate measures for containment and clean up in the event of hazardous substance spills. The plan would also include provisions to employ a qualified ECM during construction to ensure compliance with environmental measures included in the plan.

As discussed in section 4.4, small fuel spills (on the order of 5 gallons or less due to minor drips or leaks from equipment operating in or near streams) are the most likely spill events to occur during project construction. Such minor releases, when they occur on soil away from waterways where the contaminated soil can be removed before the hydrocarbons have had a chance to migrate into area waterways, would have no measurable effect on aquatic organisms. If small spills occur in an area that results in their direct entrance into water, they would likely have localized short-term adverse effects on fish and other aquatic organisms. Larger spills from fuel storage containers or construction equipment are less likely. However, if gasoline or diesel fuel were released directly into project-area waterways, the effects on aquatic organisms would be immediate and include both fish and benthic invertebrate mortality. These effects would occur over the entire section of waterway downstream of the event. While spilled fuels would be rapidly carried out of the system and/or would evaporate, measurable residual effects could last for several years resulting in ongoing adverse impacts on aquatic biota (i.e., stress, disease, or increased susceptibility to predators). The duration of these impacts would depend on the size and location of the spill, and on the toxicity of the hazardous substance. Major spill events could appreciably reduce the size of anadromous fish populations in the lower Kahtaheena River and render the surviving population of questionable value as a food source. This could also negatively affect individuals who may eat these fish including sport anglers and the two Native allotment owners.

Similar effects could occur in the marine waters of GBNPP near the mouth of the Kahtaheena River should measurable amounts of the spilled material be carried through the river into the marine environment.

Implementation of the agency-recommended fuel and hazardous substances spill plan would reduce the likelihood of spills during project construction and provide appropriate measures for containment and clean up in the event of hazardous substance spills. Compliance monitoring using qualified personnel would also ensure that any spills are documented and addressed in an appropriate manner. Including a measure in the fuel and hazardous substances spill plan that would limit fuel storage and refueling to an approved containment area located no closer than 1,000 feet from any project area waterway would further reduce the risk to aquatic resources. In the event of a spill, implementation of these measures would reduce the effects on aquatic resources.

Effects of Project Workforce

Unless controlled, project workforce fishing could affect fish populations and habitat quality in the Kahtaheena River, below the Lower Falls. In particular, allowing the workforce to fish in the proposed project area could have significant adverse effects on fish populations.

GEC does not propose any measures to address the effects of the project workforce on existing fish populations.

FWS has recommended that hunting, trapping and fishing by the construction workforce be prohibited to protect existing aquatic and terrestrial resources. GEC does not disagree with this recommendation but indicated that it is a matter for the state of Alaska to decide.

The presence of a relatively large number of people on site for an extended period of time could result in excessive fishing pressure and overexploitation of the fisheries resources. Coho salmon and cutthroat trout, both species of choice for anglers, are present in low numbers in the Kahtaheena River and would be susceptible to overfishing. In addition, fishing activities would likely be concentrated in specific areas along the anadromous reach of the river and both the stream bank and stream bottom would be exposed to physical damage (compaction, disturbance of protective vegetation) with resultant loss of habitat value. Uncontrolled overfishing by the construction workforce could reduce the size of the anadromous fish populations in the lower river and reduce the opportunity for utilization of this resource by sport anglers and the Native allotment owners. In addition, the presence of a large number of project workers in the lower Kahtaheena River would increase the likelihood of trespass or damage to the Native allotment in this area.

Prohibiting hunting, trapping and fishing within the project boundary, as recommended by the FWS, would largely eliminate the potential effects of the project workforce on fisheries resources. Enforcement of this policy could be incorporated into the license conditions for the project and included as a part of the ECM's duties (see previous discussion).

Project Operations. Operation of the proposed project could affect the fisheries resources and aquatic communities of the project area through:

- erosion and introduction of sediment into area streams along project roads and penstock and transmission line rights-of-way;

- introduction of hydrocarbons (fuel, lubricants) or other hazardous chemical contaminants into area streams through spills or minor leakage from project vehicles operating along access roads or through uncontained spills at the project powerhouse;

- alteration of stream sediment dynamics by trapping materials behind the diversion structure;

- alteration of the natural discharge regime in the 1.79-mile-long bypassed reach, between the diversion structure downstream to the base of the Lower Falls;

- alteration of natural stream temperature regimes in the Kahtaheena River due to impoundment behind the diversion structure or reductions in bypassed reach flow; and

- entrainment of fish or eggs into the project power diversion system.

Erosion and Sediment Transport

As discussed in sections 4.3 and 4.4, implementation of the ESCP, as proposed by GEC (GEC, 2001b, appendix G), would include a number of erosion control measures that would reduce sediment input to a level that is above pre-project levels within a period of 2 to 5 years. However, exposed soils on project roadways, bridge abutments, transmission line and penstock corridors, and areas surrounding the diversion structure and powerhouse, combined with the need to perform periodic maintenance (grading and weeding) in some of these areas, may result in chronic but low level increases in sediment as well as occasional, more pronounced short-term increases in erosion rates with resultant adverse effects on water quality. As discussed in section 4.3.2, sediment input to the Kahtaheena River following project construction would approach an estimated 55 m^3/year (compared to 20 m^3/year under existing conditions). Most of this sediment would result from unpaved roads and unstabilized side slopes. This estimate is based on GEC's proposed road alignment. As discussed in section 4.6.2.1, an alternative road alignment, recommended by the state of Alaska, would result in an additional 2.5 acres of permanent road footprint, an increase of about 25 percent in the total post-construction project footprint. This increase in the area of unvegetated road surface would result in an increase in the amount of sediment input into the Kahtaheena River, as well as into Homesteader Creek.

Unpaved roads are sources of erosion and sediment for as long as they are actively maintained and are in use (Reid, 1981). Erosion of fine sediment from the road surface and occasional erosion and wasting from unstabilized side slopes can result in increased levels of sediment over those found in un-roaded basins (Reid, 1981). In large part, the erosion of sediments from unpaved road surfaces is a function of the intensity of use of the road and of the density of roads within the basin (miles of road per square mile). For the proposed project, the level of use would be low (one or two vehicles per day much of the time), and the ratio of road to drainage basin would be quite low (0.16 of road per square mile of basin area) so that erosion and sediment production should be correspondingly low. Cederholm and Salo (1979) found that the relative amount of road surface within logged basins is strongly correlated with the buildup of sediments in streams. They report that sediment buildup was detectible in areas where road densities were 1.5 miles or more of road per square mile of basin. This is nine times higher than the ratio cited above for the Kahtaheena River. Thus, the projected 55 m^3 /year increase in sediment contribution rates over existing conditions would not be expected to adversely affect fish populations in the project area.

In conclusion, implementation of GEC's proposed ESCP, combined with good maintenance practices and continued control of the level of use, would result in minor to non-detectible effects on fish and benthic invertebrates after construction. However, the potential for small increases in sediment input into area waterways would exist for the life of the project (50 years or more, depending on future license renewals).

Introduction of Hazardous Materials into Project Area Waterways

Small fuel spills due to drips or leaks from equipment operating in or near waterways could introduce hydrocarbons in area waterways (see discussion in section 4.4.2.1, *Water Quality*). Spills of this magnitude could affect aquatic organisms and can be dealt with by removing the contaminated soil from the area, for offsite remediation. In such cases, the effects on fish and other aquatic resources of the area would be non-detectible.

Larger releases due to spill from fuel storage containers or rupture and release of fuel from the fuel tanks on maintenance equipment are less likely (see section 4.3, *Geologic Resources and Soils*). However, if such releases occur, the effects on aquatic organisms would be serious. The effects of such a spill event would be as previously described, including a reduction in both the number of salmonids in the lower Kahtaheena River and their suitability as a sport or food fish resource.

Implementation of the agency-recommended fuel and hazardous substances spill plan would reduce the likelihood of spills during project operation and provide appropriate measures for containment and clean up in the event of hazardous substance spills. In the event of a spill, implementation of these measures would minimize or avoid effects on aquatic resources. Including a measure in the fuel and hazardous substances spill plan that would limit fuel storage and refueling to an approved containment area located no closer than 1,000 feet from any project area waterway would further reduce the risk to aquatic resources.

Alteration of Stream Sediment Dynamics

Operation of hydroelectric projects can interrupt sediment transport processes, particularly at dam sites and in bypassed reaches. Maintaining sediment transport past the diversion dam would be important to maintain spawning habitat in the bypassed reach and the river below the Lower Falls. Both the continued downstream supply of substrate materials suitable for spawning and the movement of fines out of the gravel are important to maintenance of spawning and incubation habitat. As discussed in section 4.3, lowering the pneumatically controlled sluice gate during high flow events to allow sediment to pass the diversion structure and periodically removing material from the diversion pool and placing it in the stream bed below the diversion dam would allow some sediment transport past the diversion dam. The pneumatic gate and diversion structure would alter the natural quantity, quality, and timing of sediment transport through the bypassed reach. As detailed in section 4.3, the measures proposed by GEC reduce the potential for disruption of bedload transport to short-term occurrences. Because the project's maximum hydraulic capacity is small in relation to peak flood flows (23 cfs versus a peak discharge of 1,980 cfs recorded in December of 1999) and much of the river below the diversion is steep and functionally sediment transport oriented (see also table 3.6-3), flushing sediment downstream and avoiding a build up of fines in the downstream gravel should be achievable. Thus, it should be possible to maintain adequate spawning and incubation substrate in the downstream river reaches with minimal effects from the diversion structure on sediment transport.

Alteration of Flow Regime

The major effects on aquatic and fisheries resources from operation of the proposed project would be those associated with the reduction of flow in the bypassed reach. This approximately 1.7-mile-long section of the Kahtaheena River would experience flow reductions of 2 to 23 cfs as water is diverted from the stream channel and routed through the project penstock and powerhouse, to be returned to the river at a point just below the Lower Falls.

Because GEC proposes to return powerhouse discharge to the base of the Lower Falls, and provide flow continuation, there should be no measurable effects on the natural flow regime or habitat in the anadromous section of river.

As discussed in section 4.4, GEC proposes a minimum bypassed reach flow regime of 5 cfs in winter and 7 cfs in the summer. ADFG and FWS recommend that the proposed project be required to supply higher minimum flow releases to protect the habitat values in the bypassed reach (see table 4.4-1 in section 4.4, *Water Quantity and Quality*, for GEC proposed and agency recommended flows). Although GEC has proposed a minimum flow release, it also recommends that this EIS examine the consequences of providing no minimum flow release during project operations.

Reduction of flow in the bypassed reach would affect the total wetted area of the stream, stream depth, velocity, temperature and substrate, effectively reducing the total amount of useable habitat for resident Dolly Varden in this section of river, as well as habitat for other aquatic organisms (benthos). These habitat effects would be the greatest during periods of low flow (winter) and possibly during the late summer when the combination of low flow and warm water temperatures could cause thermal stress. During the winter, the effects of reduced instream flow also could include an increase in icing and the freezing of some stream gravels.

Habitat Effects. Resident Dolly Varden char populations in the Kahtaheena River above the Lower Falls would be subject to the effects of flow diversion. From 2 to 23 cfs would be diverted from a 1.79-mile-long section of the river. This represents approximately 20 percent of the entire length of the Kahtaheena River, 28 percent of the 6.2-mile-long section that supports fish populations, and 32 percent of the 5.7-mile-long section of river that supports resident Dolly Varden char. Reduced flows in the bypassed reach would reduce the wetted perimeter, depth, current velocity, and the rate of exchange of water through pools and stream bed gravel. These changes have the potential to affect water temperature, winter icing conditions, and sediment transport mechanisms.

Type and Area of Habitat Affected

Flory (2001) and GEC (2001b) have estimated that there is a total of about 14 acres of stream habitat in the section of the river thought to support resident Dolly Varden, from the top of the Lower Falls upstream to the 10 km Falls. This includes some 1.2 acres of pool, 7.8 acres of riffle, 2.9 acres of glide, and 2.1 acres of cascade. Diversion of flows for power would occur only in that portion of river between the Lower Falls and the site of the proposed diversion structure. As shown in table 4.6-1, this diversion would affect about 4.5 acres of habitat.

Table 4.6-1. Area of habitat (acres) in the bypassed reach of the Kahtaheena River. (Source: Preparers).

Reach	Pool	Riffle	Glide	Chute/Cascade
2	0.15	0.77	0.25	0.2
3	0.53	0.64	0.02	1.2
4[a]	0.02	0.52	0.07	0.06
Total	0.70	1.93	0.34	1.46

[a] Includes only areas from lower end of reach to upper end of proposed intake diversion pool.

Fifty-eight percent of the available pool habitat in the section of river supporting resident Dolly Varden would be affected by flow diversion, as would 25 percent of the riffle habitat, 12 percent of the glide habitat, and 70 percent of the chute/cascade habitat. The effect on pool habitat may be partially ameliorated by the creation of an approximately 0.5-acre pool upstream of the diversion structure. This additional pool habitat would be of limited or no value to fish occupying the bypassed reach of river, including the population in the productive log jam area just above the Lower Falls. Waterfalls and steep cascades essentially isolate fish in the log jam area from the upper river, and fish from the diversion pool (and the river upstream of the project) may be available as a recruitment source to the bypassed reach if they are carried (or actively move) downstream. However, the movement rates or the ability of individual fish to survive passage over the Upper Falls is not known. Lastly, additional pool habitat provided by the diversion structure would be of value for sustaining Dolly Varden population in the river above the project.

Estimated Number of Fish in the Affected Area

Less than one-sixth of the resident Dolly Varden populations is estimated to occur in the bypassed reach. GEC (2001b) estimated that the total population of resident Dolly Varden in the Kahtaheena River is on the order of 6,500 fish (see table 3.6-7). Based on these estimates, 952 fish (15 percent) reside in the bypassed reach and would be directly affected by the proposed project's altered flow regime (table 4.6-2). While this population estimate is based on very limited sampling (both spatially and temporally) and must be viewed with caution, mark and recapture studies carried out by Flory (1999) in two sections of river in or near the bypassed reach resulted in an estimate of between 731 and 800 fish from these two locations alone. Thus, a total population of 950 fish in the

Table 4.6-2. Estimated Dolly Varden char populations by reach and sub-reach in the Kahtaheena River in and above the bypassed reach of the river. (Source: Preparers)

Reach or Sub-reach	Channel Type	Bypassed Reach	Population Estimate	Population Totals by Effect Area
2 Log Jam	LC2	Yes	576	bypassed reach
2 Log Jam	MC3	Yes	75	952
3 Canyon	MC3	Yes	175	
4 Lower	LC2	Yes	126	
4 Islands	FP3	No	691	above bypassed reach
4 Upper	LC2	No	64	5,616
5	LC2	No	47	
Between 5 and 6	LC2	No	140	
6	LC1	No	654	
7	FP3	No	1092	
8	FP3	No	438	
Above 8	FP3	No	2490	

entire bypassed reach appears reasonable. However, the actual number of fish in various reaches of the river could vary considerably both seasonally and annually.

Effects of Diversion on Stream Habitat Characteristics

Weighted useable area (WUA)/discharge relationships for both the anadromous fish using the river below the Lower Falls and the resident Dolly Varden char populations using the river above the Lower Falls were developed using the FWS' Instream Flow Incremental Methodology (IFIM) (R2 Consultants, 2000). This methodology evaluates physical habitat conditions, including depth, velocity, and substrate, under a range of stream flows and compares these conditions to the life history and habitat requirements of the fish species being examined to determine the effect of various flow regimes on available fish habitat. The resulting WUA values represent habitat value weighted by species and life stage.

Because the proposed project would be run-of-river, returning all powerhouse discharge to the base of the Lower Falls, the flow regime in the lower river (Reach 1) would not be altered from existing conditions. Accordingly, GEC (2001a; 2001 b) did not present an instream flow analyses for the section of river downstream of the Lower Falls.

WUA discharge relationships were developed for the river above the Lower Falls. Table 4.6-3 and figure 4-4 summarize the relationships of WUA to minimum flows for resident Dolly Varden spawning; and fry, juvenile, and adult Dolly Varden rearing based on combined results from the transects that were evaluated in the river above the Lower Falls. However, only two areas were analyzed in this portion of the river. Three transects were evaluated in Reach 2 and two transects were evaluated in Reach 4 (Flory's Log Jam and Islands areas). As discussed in more detail below, this relatively small number of transects makes the reliability of this analysis questionable.

As shown in table 4.6-3, flows providing 80 percent or more of the maximum available weighted useable area (AWUA) for spawning are predicted to occur over a relatively wide range (between 21 and 154 cfs). Flows providing 80 percent or more of the AWUA for fry rearing occur over a lower range (2 to 29 cfs), and flows providing 80 percent of the AWUA for juvenile and adult rearing occur between 10 to 40 cfs. Flows predicted to provide less than 50 percent of the AWUA are as follows:

1. Spawning <6 cfs
2. Fry rearing < 2 or > 90 cfs
3. Juvenile rearing < 4 cfs or > 80 cfs
4. Adult rearing < 4 cfs or > 89 cfs

Table 4.6-3. WUA, by discharge, for resident Dolly Varden char, as percent of maximum available habitat, for reaches 2 and 4, combined. (Source: GEC, 2001b)

Discharge (cfs)	Spawning; % Maximum Habitat	Fry; % Maximum Habitat	Juveniles; % Maximum Habitat	Adults; % Maximum Habitat
2	16.2	80.7	38.5	38.2
4	36.4	92.0	52.3	51.9
6	48.5	96.2	63.1	63.2
8	57.4	97.8	73.6	73.6
10	62.9	98.3	81.1	80.8
12	68.7	100.0	89.0	89.2
14	71.7	98.2	93.3	93.3
16	74.6	96.5	96.4	96.3
18	76.8	94.0	97.1	97.4
20	79.6	92.2	99.9	99.8
22	81.8	89.8	100.0	100.0
24	83.2	86.7	99.6	99.5
26	84.4	83.9	98.6	98.6
28	85.5	81.4	97.5	97.8
30	86.8	79.2	96.7	96.9
35	90.3	74.2	91.3	91.6
40	92.8	70.3	82.7	82.7
45	94.7	67.1	74.0	73.7
50	96.9	64.4	67.9	67.7
55	98.4	61.8	62.9	63.3
60	99.0	60.0	59.8	61.1
70	99.6	54.9	55.2	58.2
80	100.0	49.2	50.4	54.4
90	99.4	44.8	46.0	50.6
100	98.8	41.2	42.7	47.9
120	94.7	35.3	38.0	44.6
140	85.2	31.0	34.8	42.0
160	77.7	28.6	32.1	39.4
180	71.6	27.1	30.0	37.3
200	64.9	25.8	28.6	35.7

Figure 4-4. WUA, by discharge, for resident Dolly Varden char in the Kahtaheena River. (Source: GEC, 2001b).

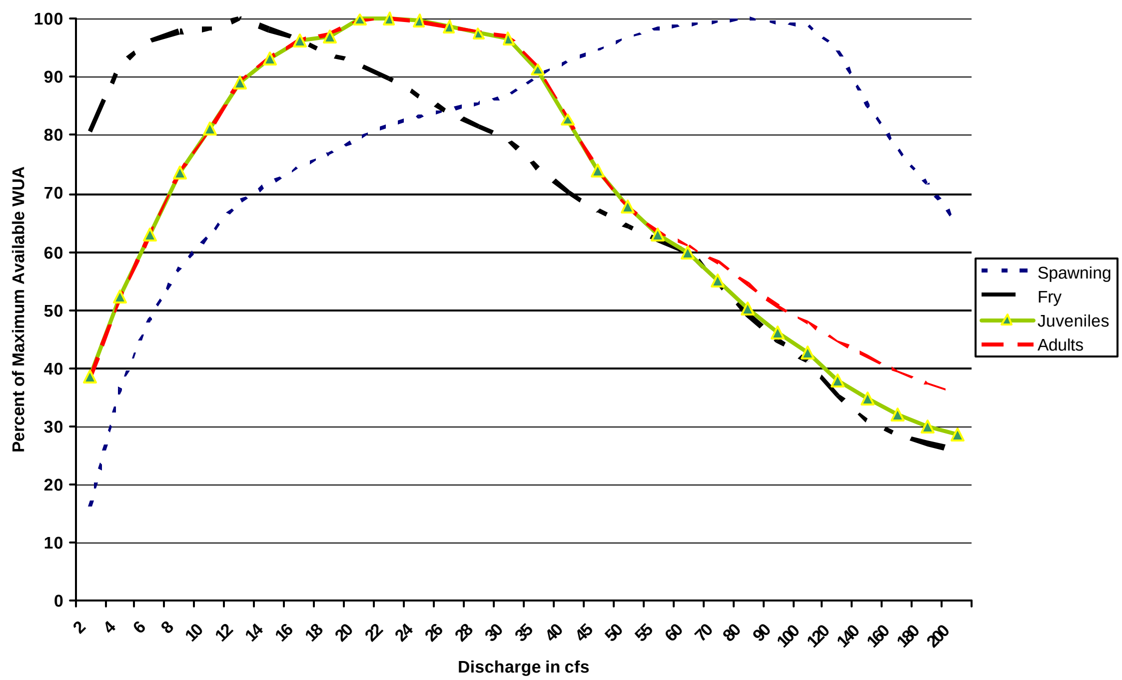


Table 4.6-4 summarizes the effects of flow diversion on calculated WUAs for GEC's proposed and the agency recommended minimum flow regimes, compared to the No-action Alternative. This table presents the availability of flows predicted to provide at least 80 percent of the optimum weighted usable area (WUA) and flows that would provide 50 percent or less of the WUA under the various flow regimes.

As table 4.6-4 shows, diversion of water for power production would result in:

1. a noticeable reduction in the percent of time that acceptable flow conditions exist for spawning and for juvenile and adult rearing under both GEC's proposed regime and the no minimum flow scenario when compared to existing conditions, but little difference between existing conditions and FWS- and ADFG-recommended regimes.

2. a noticeable improvement in the percent of time that acceptable flows for fry rearing occur for all but the minimum flow scenario when compared to existing conditions. This apparent improvement is related to the reduction of frequency of high flows above the acceptable range for fry rearing, due to withdrawal of water for power production.

Table 4.6-4. Percent of time various flow regimes are predicted to provide acceptable and low levels of WUA in the bypassed reach of the Kahtaheena River.

	Percent Time Flows Provide 80% or More of WUA	Percent Time Flows Provide 50% or Less of WUA
Spawning (Oct - Nov)		
No-action	72	1
ADFG	76	1
FWS	76	1
GEC 5/7 cfs	56	1
No minimum flow	56	29
Fry (mid-Mar - July)		
No-action	24	21
ADFG	51	9
FWS	51	9
GEC 5/7 cfs	51	9
No minimum flow	31	29
Juvenile Rearing (All year)		
No-action	43	23
ADFG	59	13
FWS	59	13
GEC 5/7 cfs	29	13
No minimum flow	29	46
Adult Rearing (All year)		
No-action	43	18
ADFG	59	10
FWS	59	10
GEC 5/7 cfs	29	10
No minimum flow	29	44

3. a slight improvement in adult and juvenile rearing conditions under the FWS and ADFG regimes, again related to the reduction in the frequency of high flows by withdrawal of water for power production, but a significant decrease in habitat conditions for adults and juveniles under GEC's proposed regime and no minimum flow.

Overall these results indicate that the habitat conditions would be fairly well protected under either of the agency's recommended minimum flow regimes. Excluding fry rearing, GEC's proposed flow regime would result in a substantial degradation of existing habitat quality, and more so under a no minimum flow scenario. These results must be interpreted with caution, however. As noted, a lack of a sufficient number of transects to adequately characterize the entire bypassed reach; inability to obtain hydraulic calibration data at flows less than 22 cfs (thus reducing the model's reliability at extrapolating to flows in the 5 to 10 cfs range); use of existing Habitat Suitability Curves rather than development of site-specific information; and the failure to include substrate and cover code ratings in all life stages except spawning limit the reliability of the analysis. Finally, IFIM studies do not adequately account for the effects of ice. Thus, winter application of the WUAs obtained for this project may be unreliable. In particular, the lack of model calibration using data collected at or near the lower range of flows proposed for winter minima is a potential concern. Milhouse et al. (1989) suggest extrapolation ranges for PHABSIM simulations of 0.4 times the lowest calibration flow. Thus, for this analysis, accuracy and reliability are compromised below 9 cfs, and model results extrapolated below 8.8 cfs may be less reliable.

In particular, the increased frequency of low-flow conditions in the bypassed reach, particularly in winter, is likely the most important habitat effect of the project for the resident Dolly Varden. Tables 4.6-5 and 4.6-6 summarize the frequency of occurrence of low-flow conditions, both on the various life stages and during the critical winter period, when the fish would be subjected to the most stress.

As demonstrated by the following tables, all of the proposed or recommended flow regimes would subject the resident char to substantially increased periods of low flow, especially in the winter, as compared to the No-action Alternative.

Decreased winter flows reduce the total area and the quality of habitat available to overwintering fish. Wetted perimeter, total stream area, water depth, and rate of water circulation all decrease as flows are reduced. Extended periods of very low flow, particularly those in the 0 to 5 cfs range, would have a number of additional, more serious negative habitat effects including the dewatering and freezing of redds; partial or complete dewatering of winter refuge areas (pools); and reduction in the size, depth and rate of water circulation in many remaining refuge areas. As discussed in section 4.4.2 reduced winter flows would also exacerbate icing conditions, including increases in border ice formation and the frequency of occurrence of anchor ice. In addition, under reduced flow conditions, ice cover would likely persist for longer periods than it does under existing conditions. These ice effects would degrade winter habitat conditions for the resident char. In addition, substantially reducing wintertime flows in the bypassed reach could lead to a portion of the water accumulating as ice. This would further reduce flow and exacerbate the adverse effects of icing on the resident Dolly Varden char residing in the bypassed reach. In the case of the no minimum flow scenario, these icing effects could result in the elimination of all or most of the fish in the bypassed reach. Under the proposed 5 cfs minimum release, ice effects could substantially reduce flows and fish habitat in the lower bypassed reach.

The FWS- and ADFG-recommended regimes would not change the frequency of flows less than 10 cfs, but the frequency of flows at 10 cfs would be increased by 17

Table 4.6-5. Percent of time Dolly Varden char in the bypassed reach would be subjected to low and no flow conditions, by life stage.

	10 cfs or less (%)	5 cfs or less (%)	Less than 5 cfs (%)	Less than 1 cfs (%)
Spawning (Oct - Nov)				
No-action	6	0	0	0
ADFG	6	0	0	0
FWS	6	0	0	0
GEC 5/7 cfs	32	0	0	0
No minimum flow	32	27	27	23
Fry (mid-Mar - July)				
No-action	4	1	1	0
ADFG	22	1	1	0
FWS	22	1	1	0
GEC 5/7 cfs	29	8	1	0
No minimum flow	29	23	23	19
Juvenile Rearing (All year)				
No-action	12	3	3	0
ADFG	29	3	3	0
FWS	29	3	3	0
GEC 5/7 cfs	42	22	3	0
No minimum flow	42	36	36	32
Adult Rearing (All year)				
No-action	12	3	3	0
ADFG	29	3	3	0
FWS	29	3	3	0
GEC 5/7 cfs	42	22	3	0
No minimum flow	42	36	36	32

Table 4.6-6. Percent of time winter (Dec - Mar) flows would be at or below specified levels under alternative flow regimes.

	10 cfs or less (%)	5 cfs or less (%)	Less than 5 cfs (%)	Less than 1 cfs (%)
No-action	32	8	8	0
ADFG	71	8	8	0
FWS	71	8	8	0
GEC	80	65	8	0
No minimum flow	80	75	75	69

percent. Increasing the frequency of 10 cfs flows would reduce fish habitat relative to higher natural flows; however, maintaining a minimum 10 cfs flow through the winter may reduce possible icing effects on Dolly Varden.

Although very little information is available describing ice conditions in the Kahtaheena River, hydraulic conditions were measured in reaches 2 and 4 in mid-February 2000 (personal communication from M. Gagner, R2 Resource Consultants, Redmond, WA, with C. Soiseth, Fisheries Biologist, GBNPP, and others, on August 17, 2001). These measurements indicate that, at a flow of 10 cfs, habitat conditions would be suitable for adult and juvenile Dolly Varden, suggesting that a winter minimum flow release of 10 cfs stream conditions would be suitable, for survival. Thus the agencies proposed winter minimum of 10 cfs would likely provide a level of protection to the Dolly Varden that would allow survival of reasonable numbers of fish.

Flows of 5 cfs, which would occur frequently under GEC's proposed minimum flow regime, would likely still provide some habitat suitable for survival, but the amount and quality almost certainly would be measurably reduced over that available at the higher flows provided under the agencies' 10 cfs recommendation. Many pools, especially the larger pools would remain; however, they would have reduced areas, depths, and circulation rates. Smaller pools would be more likely to be partially or completely dewatered. Ice effects, including increased frequency of anchor ice formation and hard freezing of areas of the stream would be more common. Thus, while some portion of the population would survive under the proposed 5 cfs winter minimum, it is likely that the total number of fish would be significantly reduced.

Under extremely low-flow conditions, as expected with the no minimum flow scenario, significant portions of the bypassed reach would either be completely dewatered or frozen and the amount of available overwintering habitat would be severely restricted, as only the largest and deepest pools would be expected to provide conditions conducive to survival. As discussed in section 4.4, during the winter, some water would remain in the larger pools and input from two small tributaries located downstream from the diversion might provide some flow below the diversion point. However, during periods of cold, dry weather, common in late winter, these smaller tributaries would likely completely freeze and not contribute any appreciable flow. This would result in extensive dewatering of the entire bypassed reach of river.

Such frequent and prolonged periods of very low to no flow in the winter under the no minimum flow scenario would likely result in the loss of nearly all the resident Dolly Varden in the bypassed reach. Small resident Dolly Varden are known for their ability to adapt to marginal habitats (personal communication from W. Dolezal, ADFG Biologist, Anchorage, AK, with J. Thrall, Meridian Environmental, Anchorage, AK, on January 13, 2003; R. Harding, ADFG biologist, Juneau, AK, with J. Thrall, Meridian Environmental, Anchorage, AK, on January 30, 2003); however, it is highly unlikely that appreciable numbers of these fish would survive repeated and prolonged dewatering and freezing of the stream channel.

Alteration of Stream Temperature Dynamics

As detailed in section 4.4, *Water Quantity and Quality*, neither the impoundment of water upstream of the small diversion structure nor the routing of water through the project penstock would have a measurable effect on stream temperatures downstream of the Lower Falls. However, the reductions in flow due to removal of water from the river for the production of power would measurably affect water temperature in the proposed bypassed reach, particularly in the low-flow, late-summer (July through August) time period, when adult and juvenile Dolly Varden are rearing in the river. Under GEC's 7-cfs minimum flow, summer flows would drop to 7 cfs about 13 percent of the time in July and 22 percent of the time in August (expected minimum flows under existing conditions are 15 cfs for July and 16 cfs for August).

As discussed in section 4.4.2, at a flow of 7 cfs (GEC's proposed summer release), late-summer water temperatures could increase by as much as 4°C over existing conditions to about 14°C and generally result in temperatures of less than 15°C. This is slightly below the adult and juvenile rearing criterion, but above the criterion for incubating eggs and sac fry (see table 3.4-6 for temperature criteria; however, fry would not occur during late summer in the bypassed reach. Weber-Scannell (1992) gives the range of optimum temperatures reported for Arctic char (*S. alpinus*) and Dolly Varden as between 3 and 16°C. Thus, occasional late summer increases to 15°C or slightly more would have negligible adverse effects on the fish in the bypassed reach.

Under ADFG's recommended late summer minimum release of 25 cfs and under the FWS 20-cfs minimum release, maximum temperatures would be less than 12ºC. However, our analysis indicates that there would be some risk of slightly exceeding 14°C with a flow release of 20 to 25 cfs during dry warm conditions. This is well within the range of optimum temperatures reported by Weber-Scannell (1992) for Dolly Varden.

Under the no minimum flow scenario, temperatures in the bypassed reach would be increased substantially, particularly in sunny, stagnant areas (small pools). The extent of increase would be a function of the size and exposure of the isolated pools remaining in the stream, the length of time flow remains at or near zero cfs and the weather. However, if no flow conditions occur over a period of consecutive days when the weather is warm and sunny, water temperatures could substantially exceed both the 13°C egg and sac fry incubation and 15°C adult and juvenile rearing criteria. Houston (1982) reports that incipient lethal temperatures for Arctic char and brook trout (*S. fontanalis*) range from 20°C (for larval char) to about 22°C for juveniles and adults. It is reasonable to assume that during periods of no flow lasting several days, water temperatures could reach these levels in small isolated pools. Such temperature increases would likely be lethal to fish trapped in these pools. Temperatures in larger pools or areas receiving some inflow from tributaries would experience lesser increases in temperature but even these areas could experience temperatures that would heavily stress the fish. Flows would be expected to drop to 0 cfs on 3 percent of the days in July and 6 percent of the days in August.

As discussed in section 4.4.1, *Water Quality*, low winter flows would probably reduce or eliminate the thaw bulb in any areas of the stream where a small thaw bulb might occur. This would occur under any of the proposed minimum flow regimes but would be less under the FWS and ADFG-recommended 10 cfs and more pronounced under the GEC proposed minimum and the no minimum flow scenario. For the no minimum flow scenario, it is likely that the reduction in the thaw bulb would result in a measurable increase in the frequency of both border and anchor ice in the bypassed reach, with associated negative effects on overwintering adults and juveniles (reduction in total area of available habitat) as well as on incubating eggs and sac fry (desiccation or freezing of redds).

Entrainment, Impingement, and False Attraction of Fish

GEC proposes to design and install a fish screen and bypass system at the diversion capable of excluding Dolly Varden char from the penstock and allowing fish free movement downstream into the bypassed reach of river. The proposed screen would consist of two vertical panel screens oriented in a V-shape, with the panels aligned at a 30-degree angle to the direction of flow. The panels would have 3/32-inch perforated plate faces. The entrance to the bypass would be at the apex of the V. The bypass would consist of an upward sloping ramp, leading to a downwell 10-inch bypass pipe discharging to the spillway stilling basin below the diversion. The panels would be cleaned with an automatically controlled motor-operated brush system.

GEC also proposes to design an outflow structure at the base of the Lower Falls that would preclude the entry of fish. The tailrace discharge system would consist of a headbox to collect flow from the turbine, a 36-inch-diameter pipe to carry turbine flows to the base of the Lower Falls, and an outlet set to discharge 10 feet above normal high water level.

Hydroelectric projects may entrain adult and juvenile fish into water diversions, resulting in their death or injury. Eggs, larvae, and juvenile fish can be impinged on to diversion system screens. Adult fish also can be attracted to powerhouse discharge flows, potentially subjecting them to mechanical injury (if they are able to enter the draft tube area) or impeding their movements to appropriate spawning areas, imposing additional energy requirements, and increasing stress, thereby reducing reproductive fitness. Finally, dams or diversion structures can isolate subpopulations of fish by preventing their free upstream and downstream movement.

ADFG and FWS recommend design and installation of a fish screen and bypass system at the diversion intake to prevent entrainment of Dolly Varden and to allow fish to navigate past the diversion and into the bypassed reach of river. These systems would function over the entire range of flows anticipated and would include automated cleaning systems. They also recommend that the return flow system designed to release powerhouse discharge at the base of the Lower Falls be designed to protect anadromous fish in the lower river.

Both the fish screen and bypass system for the diversion and the tailrace outlet system proposed by GEC have been reviewed by the resource agencies and a number of modifications made to incorporate their concerns. ADFG has made additional suggestions concerning the geometry of the bypass well, the bypass pipe transition, and the bypass pipe entrance design. ADFG and FWS recommend that the final design of these systems, to be completed upon licensing, be submitted for final agency and FERC review, and post-operational monitoring of these systems required to ensure that they function as intended.

With an appropriately designed and maintained system, entrainment of fish into the penstock and impingement on the bypass screens should be largely avoided, although some loss of fry and juvenile fish would likely occur. The proposed bypass system, in combination with the pneumatically controlled sluice gate, would allow movement of fish downstream past the diversion works and into the bypassed reach of river. Thus the diversion would not preclude fish from upstream portions of the river from moving downstream into the bypassed reach, contributing to the maintenance of this portion of the population. These downstream moving fish would also be available to the river below the Lower Falls as they move, or are carried downstream by high flow events, thereby sustaining the potential for genetic flow from upstream to downstream Dolly Varden populations. Implementation of a fish passage effectiveness plan would ensure that the fish screen and bypass system function as intended and are effective in moving fish around the project.

Finally the proposed outlet structure at the base of the Lower Falls should successfully prevent problems with anadromous fish attempting to move towards turbine discharge flows. Fish moving up to the base of the Lower Falls would encounter the same hydraulic conditions below the powerhouse outlet pipe as exist below the falls (water falling from a distance above the surface and plunging to depth). Thus, tailrace outlet flows should not trigger any change in behavior in spawning fish nor have effects on their reproductive success (injury due to jumping or delay in spawning). Because the outlet would be located 10 feet above the normal high water surface of the river there would be no chance of fish entering the 36-inch diameter outlet pipe.

Biotic Evaluation Plan

Maintaining healthy fish populations in streams requires adequate streamflow (i.e., water depth, water velocity, and habitat space); sufficient spawning habitat (spawning gravel); sufficient rearing habitat; appropriate food sources at different life stages; and proper environmental conditions (particularly water temperature, DO, and turbidity) (Bjornn and Reiser, 1991). Implementation of the proposed project would include a number of measures that would alter aquatic habitat conditions in the project-affected reaches of the Kahtaheena River. These altered habitat conditions could affect the distribution and abundance of resident and anadromous Dolly Varden; pink, chum, and coho salmon; cutthroat trout; and coast range sculpin. Fish population monitoring is often conducted to determine if project-related environmental measures, like those GEC proposes and the agencies recommend, provide the desired level of protection for target fish species, and aid in the development of responsive management strategies. Monitoring is typically based on the presence or absence of particular species, numbers of particular species, or on community parameters (such as productivity, density, and diversity), and is usually conducted over multiple years.

GEC proposes an adaptive management program to monitor fish in the bypassed reach and to consider remedial actions if there are concerns about their survival. The program includes char population monitoring and an evaluation of anchor ice formation.

FWS and ADFG recommend that GEC develop and implement a biotic evaluation plan designed to monitor the effects of project construction and operation on fishery resources. The plan would include: (1) monitoring of pre-project resident Dolly Varden populations until the project becomes operational; (2) monitoring of project effects on resident Dolly Varden for 5 years after commencement of project operations, and subsequently thereafter if instantaneous instream flow regimes are modified; (3) determination of flow and temperature conditions that cause ice formation in the bypassed reach; and (4) monitoring of adult salmon escapement in the anadromous reach (Reach 1). NMFS also recommends a biotic monitoring plan that focuses on adult escapement in the anadromous reach.

It is appropriate to monitor the effects of the proposed project on the distribution and abundance of existing fish populations in the Kahtaheena River. An evaluation of flow and temperature conditions leading to ice formation in the bypassed reach also would eliminate some of the uncertainty about the adequacy of the instream flow releases. However, there are many factors, in addition to project construction and operation, that could affect the distribution and abundance of fish in the affected stream reaches. These include, but are not limited to, abnormally high flow events, extreme summer temperatures, debris avalanches, biotic interactions (i.e., competition and predation), angler or commercial harvest, food availability, and disease. Even in relatively undisturbed watersheds, the abundance of salmonids can vary dramatically from year to year (House, 1995). Therefore, any fish monitoring plan for the proposed project should be designed as much as possible to allow project operational effects to be identified and distinguished from non-project-related effects. This is important because, to amend a project license to modify the minimum flow releases (or recommend other measures), there should be evidence that project operations are causing an adverse effect on the monitored fish population.

Development of a biotic monitoring plan would be appropriate to examine pre-project (baseline) conditions and to evaluate general trends in fish abundance over a minimum of 5 years. If after the fifth year of post-project monitoring, a negative trend in fish abundance is detected, new instream flows or other mitigation measures could be considered, in consultation with resource agencies. A biotic monitoring plan should be developed in consultation with FWS, NMFS, and ADFG to ensure it measures appropriate parameters. The plan could specify the frequency of monitoring, the species to be monitored, the locations of monitoring reaches, and the indices that would be used to document compliance or noncompliance with agency management objectives, as well as the rationale for selecting each variable. A draft plan could be distributed to the consulted agencies who would be allowed at least 60 days to comment on the plan. The final plan could incorporate agency recommendations or explain why they were not incorporated into the plan, and include a detailed description of the agencies' ecological resource objectives for fish populations in the project area. Following the monitoring specified in the Commission-approved plan, GEC could develop a report, in consultation with FWS, NMFS, and ADFG, and file it with the Commission, documenting the results of the fish monitoring and any recommended flow release modifications or follow-up actions. This report could serve as a basis to consider potential license amendments that pertain to fish populations in project-affected waters, as appropriate.

Summary of Project Operational Effects on Anadromous Fish. The anadromous fish utilizing the lower river would be subjected to occasional short-tem increases in sediment levels during construction and very low increases over the life of the project. In addition, the potential would exist for exposure to oil or fuel spills. In the case of a major spill directly into the river, fish populations would be severely impacted with measurable residual effects (reduced reproductive success, increased predation, etc.) persisting over a period of several years.

The anadromous fish would not be measurably affected by any change in the flow regime or by water quality or water temperature changes. The water diverted for power production would be returned to the river at the base of the Lower Falls with no measurable alteration in flow or water quality conditions.

Summary of Project Operational Effects on Resident Dolly Varden. As detailed above, the major effects of the proposed project would be changes in habitat due to the diversion of flows from:

- approximately one third of the length of the river supporting resident Dolly Varden char;

- 58 percent of the available pool habitat, 25 percent of the available riffle habitat, 12 percent of the glide habitat, and 70 percent of the chute/cascade habitat in the area supporting resident char; and

- a section of river estimated to support about 15 percent of the total population of resident char (950 fish out of a total population estimated at 6,500 fish).

These effects would result in the loss of some or nearly all the fish in the bypassed reach, depending on the flow release regime selected for the project. Low flow in winter likely would be the major factor contributing to this loss.

As is common for many species of fish, a critical period for resident Dolly Varden is during winter, under low-flow conditions. However, given the widespread distribution of this species in small streams with marginal habitat, they probably are able to survive under winter conditions of reduced flow, as long as there are refuge areas that provide adequate conditions for overwintering. It is known that pools appear to be particularly important to isolated, resident Dolly Varden found in small streams with apparently marginal habitat conditions in southeastern Alaska (personal communication from K. Hastings, FWS biologist, Juneau, AK, with J. Thrall, Meridian Environmental, Anchorage, AK, on February 11, 2003). Pool habitat is preferred by Dolly Varden inhabiting the Kahtaheena River (Flory, 1999; 2001).

A population of resident char in Pyramid Creek near Unalaska, for example, exists in a stream system with two small water supply impoundments. Despite heavy diversion of water, this population persists within the stream (Locher Interests Ltd., 1998). Resident Dolly Varden char have survived for over 17 years following impoundment in the Swan Lake Hydroelectric Project, constructed on the Falls Creek, near Ketchikan (Kelly, 1998). This population has survived despite the reservoir's inundation of a majority of the spawning habitat on tributaries to the preproject natural lake (R.W. Beck, 1987).

The available information is not sufficient to quantitatively predict the extent of population decline in this section of river due to reductions in flow caused by diversion of water for power production with any degree of certainty. However, any reduction in flow, particularly over the winter, is likely to result in a measurable reduction in population numbers in the bypassed reach. The adoption of the 5-cfs winter/7-cfs summer regime would result in a more pronounced decline in the number of fish surviving in the bypassed reach than would be the case under either of the two agency-recommended regimes. While adoption of the no minimum flow regime would very likely result in the complete loss of fish below the diversion structure (although occasional individuals from the area upstream of the diversion may be carried down into the bypassed reach where they could survive for a limited time).

Under either of the agencies' regimes, or under GEC's 5-cfs winter/7-cfs summer regimes, this level of loss would likely occur over a period of years due in large part to the effects of repeated exposure to significantly extended low-flow periods in winter.

However, both ADFG's and FWS' recommended regimes would provide significantly more protection of the habitat over the winter than would GEC's 5-cfs winter regime. Under the agencies' recommended winter regime, the frequency of low-flow conditions (<10 cfs) would be the same as under the No-action Alternative (natural conditions). However, flows in the range of 10 to 15 cfs would occur more frequently under the agencies' recommended flows than under existing conditions (about 53 percent of the time). Thus, even with this higher flow requirement, there likely would be some decline in the total population of fish residing in the bypassed reach.

Under GEC's 5-cfs winter/7-cfs summer regime, flows of 5 cfs would occur, on average, 58 percent of the time while flows less than 5 cfs would occur 8 percent of the time. Flows less than 4 cfs but greater than 2 cfs would occur, on average, some 6 percent of the time under this flow regime. The reduction in both the amount and quality of available habitat over winter under this regime would both inflict increased mortality on the fish inhabiting the bypassed reach and would reduce the fitness of fish surviving the winter. This would reduce reproductive fitness of a population that may be limited by low egg production and recruitment (see section 3.6 for a discussion of Dolly Varden egg production).

A no minimum flow scenario would, in all probability, eliminate essentially all the fish using the bypassed reach, to the point that it would no longer support a viable, self-sustaining population. Severe conditions during winter (periodic complete dewatering of major portions of the stream and hard freeze ups) would make it difficult for more than a few fish to survive. Maintenance of some semblance of a population may be aided to some extent by movement of fish downstream from the river above the diversion structure.

As previously discussed in this section, ADFG and FWS have recommended, and GEC proposes installation of, a fish screen and bypass system at the diversion to prevent Dolly Varden from being entrained into the penstock while allowing them to freely move downstream. The bypass portion of this system is intended to allow Dolly Varden produced in the river above the diversion to continue to serve as a source of recruitment into downstream sections of the river. However, GEC has indicated that, under a no minimum flow scenario, a bypass system would be unnecessary.

Without minimum flows and a bypass system, Dolly Varden would be unable to access the bypassed reach when natural flows are at or below 23 cfs (the hydraulic capacity of the turbines) or above 2 cfs (the minimum requirement for operation of the turbine). Flows in the range of 3 to 23 cfs occur about 30 percent of the time, most commonly in the winter. Without a bypass system, but with screening to prevent entrainment into the penstock, fish would have little or no access to the river below the diversion during the winter months as all the water would be diverted for power production. However, for the remaining 70 percent of the time, there would be some flow past the diversion works. Particularly at higher flows, such as those experienced in late summer and fall, fish would be able to move past the diversion works and access the bypassed reach. Some of these fish would move or be carried into the lower, anadromous section of river. However, fish that remain in the bypassed reach of river above the Lower Falls would be subject to the same severe winter conditions as described above, and their survival rate would likely be limited. Thus, under a no minimum flow scenario, a few fish would continue to be recruited into the bypassed reach from upstream habitats and would be found in the bypassed reach, albeit sporadically.

The presence of a significant area of stream above the project diversion that supports Dolly Varden could result in some replenishment of Dolly Varden in the bypassed reach under all the proposed regimes. This upstream section of the river would not be affected by the proposed flow diversion. The upstream component of the resident char population would be available to contribute. However, it is likely that the number of fish carried downstream would be insufficient to maintain the population numbers in the lower bypassed reach at levels approaching pre-project conditions, and this portion of the population would be reduced in numbers under each of the flow alternatives. With no minimum flow, the entire population in the bypassed reach could be extirpated. To the extent that the bypassed reach population is genetically distinct from resident Dolly Varden in the river above the diversion structure, this would result in a reduction in the genetic diversity of the resident char in the river. Additionally, the transfer of lands from the park could affect the remaining genetic diversity within the park by removing the fish inhabiting the lower river, which may be distinct from fish in the upper portions of the river (Leder, 2001).

During a meeting held on January 30, 2004, ADFG suggested that interbreeding between resident and anadromous Dolly Varden may be important for maintaining the genetic integrity of the anadromous population. It is possible that resident char move downstream into the river below the Lower Falls and interbreed with the anadromous population. Whether the possible reduction or loss of the bypassed reach population would have any effect on the anadromous population is unknown. However, since some resident Dolly Varden would likely access the lower river during high flows that would occur under any minimum flow scenario, there may be no significant effect on interbreeding with the anadromous population of their genetics.

4.6.2.2 Effects of the GBNPP and Wilderness Boundary Adjustment

Kahtaheena River Area (Project Area). Implementation of GEC's proposal would result in the transfer of 850 acres of park land to state ownership. This land encompasses the lower 4.3 miles of the Kahtaheena River, including all the anadromous portion of the river that currently lies within GBNPP and the 4.2-mile-long section, from the Lower Falls upstream to the northern limit of the proposed land exchange boundary, which supports resident Dolly Varden char. Removal of these sections of the river from the wilderness area of the park and transfer of the management responsibilities of the middle and lower basin would reduce the level of protection currently afforded to this watershed including protection of the fisheries resources.

Of the transferred land, GEC proposes that 75 acres would be within the FERC project boundary, while the remaining 775 acres would be owned and managed by the state. The project roads would lie within the FERC project boundary and thus would be subject to controlled use, as mandated by FERC or implemented by GEC. GEC proposes to control public access on the project roads, effectively limiting public access and development of the area within the project boundary. In regard to management of the remaining lands, the state has recently adopted a revised Northern Southeast Area Plan (ADNR, 2002a) that specifies management of the lands within the transfer area for fish and wildlife, with the exception that mineral extraction (quarry or gravel extraction) in support of the proposed hydroelectric project or for other community development projects would be allowed. Development and use of additional quarries could increase the risk of elevated rates of erosion and sedimentation in the basin. However, such effects on fisheries resources would be slight.

Exchange of the lands surrounding the middle and lower Kahtaheena River out of GBNPP would remove a portion of potentially unique watershed from the park and lands that represent the habitat and landform types that are uncommon within GBNPP. The removal of these lands represents a potential loss of ecosystem diversity from GBNPP. Soiseth and Milner (1993) estimate that more than 310 streams drain the 1,070-mile-long shoreline of the park. Sorted by catchment size, these streams can be grouped into four categories (table 4.6-7). Most (73 percent) are small, with drainage basins of 3.9 square miles or less.

Table 4.6-7. Streams draining GBNPP shoreline. (Source: Soiseth and Milner, 1993)

Catchment Size (square miles)	**Number of Streams**
<0.39	31 (10 %)
>0.39 to 3.9	195 (63 %)
>3.9 to 39	75 (24 %)
>39 to 390	8 (3 %)

The Kahtaheena River is one of 75 streams having basins in the 3.9 to 39 square miles size category and one of the 27 percent of streams to have a catchment basin larger than 3.9 square miles (Soiseth and Milner, 1993). In addition, it exhibits other characteristics that are identified with streams likely to support salmonid populations, including a gradient of 15 percent or less in the first 0.31 miles or more above stream mouth and clear (non-glacial) water (Soiseth and Milner, 1993). The Kahtaheena River also is unusual within GBNPP as it is not a recently de-glaciated basin. It lies within the Salmon River Sediments ecological subunit (Nowacki et al., 2001a). These calcareous argillite sedimentary foothills, although heavily scoured during the last great glacial period were left untouched by neoglacial ice re-advances, making the basin quite distinct as compared to younger, neighboring landscapes. The calcareous soils of the Kahtaheena River Basin likely contribute to the river's high fertility, as compared to other watersheds in the park, and may well contribute to the high numbers of pink salmon produced in the lower river (personal communication from G. Streveler, Biologist, Icy Strait Environmental Services, Gustavus, AK, with J. Thrall, Meridian Environmental, Anchorage, AK, on May 8, 2003).

The Kahtaheena River is one of 43 streams within the park known to support Dolly Varden char (personal communication from C. Soiseth, Fisheries Biologist, GBNPP, with J. Thrall, Meridian Environmental, Anchorage, AK, on November 6, 2002) and the only stream in the park known to support resident Dolly Varden. Since there has been no systematic sampling for such resident populations in the park, it is not known for certain whether this represents a unique resource in the park. However, it is not considered likely that other such resident populations exist in park stream systems (personal communication from C. Soiseth, Fisheries Biologist, GBNPP, with J. Thrall, Meridian Environmental, Anchorage, AK, on May 7, 2003). GBNPP staff conclude that removal of a portion of the Kahtaheena River from GBNPP could incrementally reduce the genetic diversity of Dolly Varden char within the park. Additionally, GBNPP staff believe that unknown species of taxonomic and geo-biological significance may be present within the lands or waters to be transferred.

As discussed in section 3.6, populations of physically isolated, resident Dolly Varden are known to exist in a number of other streams throughout southeastern Alaska. Although the exact number of such populations is unknown, it is thought to be in the hundreds (personal communication from K. Hastings, FWS, Juneau, AK, with J. Thrall, Meridian Environmental, Anchorage, AK, on February 11, 2003). Thus, this population of fish cannot be considered unique from a regional or statewide perspective.

Given the recent de-glaciation of much of GBNPP and the very young age of most of the stream systems, it is likely that few if any other streams of similar age, geomorphology, and water chemistry exist within the park and would have been available for establishment of such resident populations. Thus, the Kahtaheena River population may well be at or near the geographic limit of resident char in northern southeastern

Alaska (personal communication from K. Hastings, FWS, Juneau, AK, with J. Thrall, Meridian Environmental, Anchorage, AK, on February 11, 2003). If it is the only stream system within the park boundaries supporting resident Dolly Varden, it would represent a unique resource.

Implementation of GEC's proposal would remove the middle and lower river from GBNPP. This would include all of the anadromous section of river that currently lies within the park boundary and that portion of the river supporting resident Dolly Varden, from the Lower Falls upstream some 4.2 miles to the proposed land exchange boundary. About 3.1 miles of the upper river would remain within the park and under park wilderness protection, including some 1.5 miles of the river below the 10 km Falls that is thought by Flory (1999; 2001) to support some unknown portion of the resident char population.

A major portion of this river system would be removed from GBNPP. However, a portion of the resource would remain within GBNPP; be afforded the level of protection mandated for wilderness areas; and be available for the use of park personnel, the scientific community, and the public to partially repopulate the river if operation of the proposed project were to result in complete or near complete loss of fish in the bypassed reach of river.

In addition to the loss of this portion of river from the park, the land immediately adjacent to the river and east of the exchange lands, from the Lower Falls upstream, would remain under park ownership. The project access road and diversion structure would be located along the canyon lip and relatively close to the west bank of the river from Greg Creek upstream to the proposed location of the diversion structure. The project boundary west of the Kahtaheena River would be along the eastern canyon rim and would create a relatively narrow buffer between park land and project lands, which could present administrative challenges to parties attempting to minimize effects on the park. Project-induced habitat changes or inadvertent incursions into park land during construction along this section of river could have significant effects on adjacent park land. A mass wasting event related to construction of the diversion structure on the eastern bank of the Kahtaheena River (there would not be any road construction on the eastern bank) would likely have measurable direct effects on lands administered by the park.

Proposed Land Exchange Parcels. The exchange parcels near Long Lake would be managed in accordance with the WSNPP GMP. No development activities would be permitted on these lands, and they would be managed predominantly for the protection of fish and wildlife habitat. These management policies would provide a minor increase in protection of these areas, as recreational use would be more strictly governed. However, fisheries resources would still be managed in accordance with regulations, and no measurable effect on fisheries resources would be expected under GEC's proposal.

NPS already manages the exchange parcels along the Chilkoot Trail. Therefore, the effects on fisheries resources would be the same as described in section 4.6.1.3 for the No-action Alternative.

Wilderness Designation Parcels. These lands are currently managed as *de facto* wilderness; therefore, no impacts on fisheries or other aquatic resources would be expected as a result of their designation as wilderness.

4.6.2.3 Cumulative Effects Analysis. Potential increases in commercial and recreational guiding and tourism in the Kahtaheena River area could occur as a result of estimated future population growth in Gustavus, or as a result of increased tourism at GBNPP increasing road access into the Kahtaheena River. The increased recreational activity may result in increased fishing pressure on anadromous salmonids in the Kahtaheena River below the Lower Falls. It is possible that increased recreational activity and access could increase fishing pressure on resident Dolly Varden in the Kahtaheena River and result in a corresponding decrease in abundance. However, the small size of the resident Dolly Varden in the river and the availability of other species in the general area make this unlikely. The reduction in flows in the bypassed reach of the Kahtaheena River following development of the proposed project would decrease the total quantity of fish habitat available and may reduce resident fish populations. The combined effects of the potential increased fishing pressure and the reduction of available habitat in the bypassed reach of the Kahtaheena River may produce a cumulative decrease in the long-term population of resident fish in the Kahtaheena River.

The state maintains the right to develop mineral resources on state-owned lands. The state may potentially conduct mineral development in the future on its land to provide material for road maintenance in the Gustavus area, or for other purposes. The continued use of these quarry sites may result in the production of erosion and the transport of sediment to the Kahtaheena River, decreasing productive fish habitat. The construction of the project facilities and roads, and the ongoing use of the project roads for operations and maintenance activities, would result in the production of sediment that may be transported to the Kahtaheena River and decrease the amount of productive fish habitat. The combined effects of potential future mineral development by the state and the ongoing use of project roads may produce a cumulative adverse effect on productive fish habitat as a result of erosion and sediment transport to the Kahtaheena River.

Potential increases in subsistence and recreational fishing in the Kahtaheena River area could occur as a result of estimated future population growth in Gustavus. Increased fishing pressure would result in reductions of the existing fish populations. The development of an access road to the proposed project would provide improved access for subsistence and recreational anglers to areas previously accessible only by cross-country hiking. The combined effects of increased subsistence and recreational fishing and the improved access to areas with previously limited access, may produce a cumulative increase in the subsistence and recreational fishing use of the Kahtaheena River and a corresponding decrease in fish populations.

There are no project-related actions identified that would result in an impact on fisheries resources for the WSNPP and KGNHP transfer parcels. Therefore, no cumulative effects on fisheries resources would occur as a result of the interaction between project actions and non-project actions.

There are no project-related actions identified that would result in an impact on fisheries resources for the proposed wilderness parcels at the unnamed island near Blue Mouse Cove, Cenotaph Island, or Alsek Lake. Therefore, no cumulative effects on fisheries resources would occur as a result of the interaction between project actions and non-project actions at these sites.

4.6.2.4 Conclusion. Proposed and recommended mitigation measures would reduce erosion; however, during construction and operation there would still be some increases in turbidity, especially in areas near the site of the proposed diversion dam and the powerhouse. Increased turbidity could result in fish moving out of these areas or perhaps remaining and experiencing poor feeding success and reduced growth. Additionally, there may be some increases in sediment delivery to the stream.

Normal erosion associated with project construction would be expected to deliver mostly fine material to the stream. This increased level of fines could increase stream embeddedness slightly, reducing benthic production and salmon reproduction. However, potential impacts would be short term, as these fines would likely be flushed from the system during normal high flow events. Increased delivery of coarse material would be less likely to result from normal erosion but could occur as the result of a mass wasting event. The initial effect of such a major event would be the loss of both benthos and fish through burial under a mixture of fine and coarse material. The extent of such an effect would depend on both the size of the event and its proximity to high quality, downstream habitat. A large landslide, delivering substantial quantities of sediment to the stream, could result in the loss of one or more year classes of salmonids. Over time, and mainly during high flow events, the coarse sediment would be carried downstream and could provide a source of gravel for downstream spawning areas. This added gravel source could have some beneficial effect in the river below the Lower Falls where glacial rebound is causing the stream to downcut into clays, reducing the amount of pink salmon spawning habitat (Mann and Streveler, 1999).

If substantial quantities of hazardous substances enter the waterway, there could be direct mortality of aquatic organisms and residual effects for several years; however, implementation of a fuel and hazardous substances spill plan would greatly reduce or eliminate the likelihood of this type of event.

During construction, fishing or hunting by the project workforce in the project area could result in overexploitation of these resources; however, prohibiting these activities could prevent this possible adverse effect.

Reduced flows in the bypassed reach could reduce the available fish habitat and the number of non-migratory Dolly Varden char in the river above the Lower Falls as far upstream as the proposed diversion site. Under the no minimum flow scenario, these losses would be near 100 percent in the bypassed reach. Under GEC's proposal (5 cfs winter/7 cfs summer regime), some Dolly Varden habitat would be maintained, and Dolly Varden would likely persist within the bypassed reach; however, the numbers of Dolly Varden in this area would be greatly reduced, most likely due to reduced reproductive success and overwinter survival. Under the flow regimes proposed by ADFG and FWS, most of the available habitat would be maintained, and losses of Dolly Varden would be much less than under the no minimum flow or GEC's proposed flows.

Predicted temperature increases of 0 to 3°C could occur under GEC's proposed or the agencies' recommended flow regimes; however, they would have negligible effects on the existing fish populations. Under the no minimum flow scenario, temperatures within the bypassed reach would increase significantly, particularly in sunny stagnant pools. In regard to icing, there would be a small reduction in the thaw bulb under GEC's proposed or the agencies' recommended flows, but under the no minimum flow scenario the associated reduction in the thaw bulb would likely increase the occurrence of anchor and border ice which could negatively affect overwintering adults and juveniles or incubating eggs or sac fry.

Fish screens and bypass systems proposed by GEC and recommended by the agencies would reduce entrainment and impingement of fish and eggs at the proposed diversion site. Returning the powerhouse discharge to the base of the Lower Falls would protect anadromous fish habitat in the lower reach. Locating the discharge pipe 10 feet above the water surface would reduce the possibility that fish attracted to this discharge could be harmed by jumping at or trying to enter the tailrace pipe.

Construction and operation of the proposed project could result in a loss of the existing aquatic system in the bypassed reach and could affect fisheries resources of the surrounding GBNPP lands. The Kahtaheena River has a number of characteristics that make it ecologically distinct from most, if not all, of the other stream systems in the park, and it may be the only stream in the park with a population of resident Dolly Varden. However, a portion of the stream (3.1 stream miles in the upper basin), including a 1.5-mile-long segment that likely would continue to support a viable resident Dolly Varden population, would remain within GBNPP. The parcels that would be designated as wilderness under GEC's proposal are currently managed as *de facto* wilderness; therefore, no impacts on fisheries or other aquatic resources would be expected as a result of their designation as wilderness. In the enabling legislation for GBNPP, the purposes and values of GBNPP are identified as preservation of waters containing nationally significant natural wildlife values and allowing GBNPP to remain a large sanctuary where fish and wildlife may roam free.

Although there would be negative effects on fisheries resources under GEC's proposal, all of these effects would occur entirely outside of GBNPP, from the point of diversion to areas downstream. It is possible that fish moving downstream from within GBNPP would enter the project area and be harmed by construction or operation of the project as described in section 4.6.2.1. However, we would not anticipate these effects to significantly decrease in the numbers of Dolly Varden inhabiting the upper portions of the watershed that would remain within GNBPP. Additionally, these effects would not affect the ability of fish and wildlife to roam free within GBNPP or diminish the nationally significant natural wildlife values of GBNPP. Therefore, while there may be some adverse effects on some fish migrating from GBNPP lands into the project area, these effects would not constitute an adverse impact on the purposes and values of GBNPP.

Under GEC's proposal, the water resources associated with the unnamed island near Blue Mouse Cove, Cenotaph Island, and lands at Alsek Lake would not be adversely affected because they are not located near the project area. The anticipated effects on fisheries would not result in an impairment of GBNPP resources that fulfill the specific purposes identified in the enabling legislation or are key to the natural integrity of the park. Under this alternative, GBNPP would continue to operate and manage its lands as outlined in the enabling legislation (see section 1.7.4).

Conveying state land to NPS for either WSNPP or KGNHP would not have any effect on fisheries resources at these locations. The effects on aquatic resources anticipated from this alternative would not result in an impairment of WSNPP or KGNHP resources that fulfill specific purposes of maintaining quality of lakes and streams and coastal landscapes in their natural state and protecting habitat for, and populations of, fish and wildlife, as identified in the enabling legislation; or are key to the natural integrity of these parks.

4.6.3 Maximum Boundary Alternative

4.6.3.1 Effects of Construction and Operation. Under this alternative, the effects of construction and operation on fisheries resources would be the same as described above in section 4.6.2.1 for the proposed action.

4.6.3.2 Effects of the GBNPP and Wilderness Boundary Adjustment. A larger area of land in the Kahtaheena River Basin would be transferred from GBNPP to state ownership under this alternative (1,145 acres compared to 850 acres). An additional 295 acres would be transferred to the state under this alternative, including an additional 0.3 miles of the Kahtaheena River and 0.15 miles of the lower Black River. Aquatic resources within these sections of these rivers would be lost from GBNPP, and they would likely receive less protection than if they remained within GBNPP.

The potential effects on fisheries resources of the proposed wilderness designations under the Maximum Boundary Alternative would be the same as described for the proposed action.

The potential effects on fisheries resources of the proposed land exchange for lands transferred from state ownership to the park would be the same as for GEC's proposal, with the exception that the park would likely receive a larger amount of acreage which may contain a larger amount of fisheries resources.

4.6.3.3 Cumulative Effects Analysis. The types of cumulative effects that could be expected to occur on fisheries resources under this alternative are the same as those described under GEC's Proposed Alternative in section 4.6.2.3.

4.6.3.4 Conclusion. Under this alternative, construction and operation of the proposed project would have the same effects on fisheries resources as described for the proposed action in section 4.6.2.4. The parcels that would be designated as wilderness under this alternative are currently managed as *de facto* wilderness; therefore, no impacts on fisheries or other aquatic resources would be expected as a result of their designation as wilderness. In the enabling legislation for GBNPP, the purposes and values of GBNPP are identified as preservation of waters containing nationally significant natural wildlife values and allowing GBNPP to remain a large sanctuary where fish and wildlife may roam free. All of the effects on fisheries resources would occur entirely outside of GBNPP; however, some fish from within GBNPP could move downstream into the project area and be harmed by construction or operation of the project. These effects would not limit the ability of fish and wildlife to roam free within GBNPP or diminish the nationally significant natural wildlife values of GBNPP. Therefore, adverse effects on fish in the project area would not constitute an adverse impact on the purposes and values of GBNPP. Under this alternative, the water resources associated with the unnamed island near Blue Mouse Cove, Cenotaph Island, and lands at Alsek Lake would not be adversely affected because they are not located near the project area. The anticipated effects on fisheries would not result in an impairment of GBNPP resources that fulfill the specific purposes identified in the enabling legislation or are key to the natural integrity of the park. Under this alternative, GBNPP would continue to operate and manage its lands as outlined in the enabling legislation (see section 1.7.4).

Conveying state land to NPS for either WSNPP or KGNHP would not have any effect on fisheries resources at these locations. The level of effects on aquatic resources anticipated from this alternative would not result in an impairment of WSNPP or KGNHP resources that fulfill specific purposes of maintaining quality of lakes and streams and coastal landscapes in their natural state and protecting habitat for, and populations of, fish and wildlife, as identified in the enabling legislation; or are key to the natural integrity of these parks.

4.6.4 Corridor Alternative

4.6.4.1 Effects of Construction and Operation. Under this alternative, the effects of construction and operation on fisheries resources would be the same as described above in section 4.6.2.1 for the proposed action.

4.6.4.2 Effects of the GBNPP and Wilderness Boundary Adjustment. This alternative would transfer less land from park ownership to the state than the proposed action. Under this alternative, only 680 acres of land would be transferred out of the park. Thus the park would retain approximately 200 acres of additional land within the park when compared to the proposed action, including an additional 560 linear feet of the upper Kahtaheena River. This additional stream section of the river contains resident Dolly Varden. In addition, about 0.4 miles of the small, unnamed stream to the west of the Kahtaheena River (west of the George allotment and northeast of the FERC boundary) would be retained within the park under this alternative. Aquatic resources inhabiting the 560 foot section of the Kahtaheena River and the unnamed stream would continue to be managed by NPS and would receive greater protection than resources on lands that would be removed from GBNPP.

The potential effects of the proposed wilderness designations would be the same as described in section 4.6.2.2 for the proposed action.

The potential effects of the proposed land exchange would be the same as described in section 4.6.2.1 for the proposed action, with the exception that NPS would likely receive a lesser amount of state land in the exchange for the lands removed from GBNPP.

4.6.4.3 Cumulative Effects Analysis. The types of cumulative effects that could be expected to occur on fisheries resources under this alternative are the same as those described under GEC's Proposed Alternative in section 4.6.2.3.

4.6.4.4 Conclusion. Under this alternative, construction and operation of the proposed project would have the same effects on fisheries resources as described for the proposed action in section 4.6.2.4. In comparison to GEC’s proposal, the Corridor Alternative would provide slightly increased protection for aquatic resources because approximately 0.3 miles of the upper Kahtaheena River would remain in the park under NPS management. In addition, the boundary to the east of the upper river would be larger and provide an additional buffer between the project area and park wilderness land. In the enabling legislation for GBNPP, the purposes and values of GBNPP are identified as preservation of waters containing nationally significant natural wildlife values and allowing GBNPP to remain a large sanctuary where fish and wildlife may roam free. All of the effects on fisheries resources would occur entirely outside of GBNPP; however, some fish from within GBNPP could move downstream into the project area and be harmed by project construction or operation. These effects would not limit the ability of fish and wildlife to roam free within GBNPP or diminish the nationally significant natural wildlife values of GBNPP. Therefore, adverse effects on fish in the project area would not constitute an adverse impact on the purposes and values of GBNPP. Under this alternative, the fisheries resources associated with the unnamed island near Blue Mouse Cove, Cenotaph Island, and lands at Alsek Lake would not be adversely affected because they are not located near the project area. The anticipated effects on fisheries would not result in an impairment of GBNPP resources that fulfill the specific purposes identified in the enabling legislation or are key to the natural integrity of the park. Under this alternative, GBNPP would continue to operate and manage its lands as outlined in the enabling legislation (see section 1.7.4).

Conveying state land to NPS for either WSNPP or KGNHP would not have any effect on fisheries resources at these locations. The level of effects on aquatic resources anticipated from this alternative would not result in an impairment of WSNPP or KGNHP resources that fulfill specific purposes of maintaining quality of lakes and streams and coastal landscapes in their natural state and protecting habitat for, and populations of, fish and wildlife, as identified in the enabling legislation; or are key to the natural integrity of these parks.

4.7 VEGETATION AND WETLANDS

Several evaluation parameters are used to identify and describe the potential impacts on the vegetation and wetland resources of the project area. These parameters include:

1. Vegetation type
2. Vegetation area
3. Wetland type
4. Wetland area
5. Wetland hydrology
6. Noxious weed populations

The assessment of the potential effects of the project on vegetation and wetland resources includes a discussion of the context of the vegetation resources in the project area. The intensity of the impact on vegetation resources is generally characterized by quantifying the area of impact for vegetation types that are common to the area; and identifying the presence, absence, or probability of impacts for rare or unique vegetation types. The duration of the impact is described where necessary to understand the context and intensity of the impact.

4.7.1 No-action Alternative

4.7.1.1 Effects Analysis. Under the No-action Alternative, lands and vegetation resources within the project area would continue to be managed by the existing land owners and land management policies. There would be no changes in vegetation or wetlands as a result of the ongoing production and distribution of electrical power by GEC. Plant assemblages of bogs, fens, and other wetland types identified in the project area would remain undisturbed. Vegetation and wetlands on GBNPP lands adjacent to the project area would not be affected by the No-action Alternative.

Under the No-action Alternative, there would be no change in NPS management of vegetation or wetlands at Cenotaph Island, Blue Mouse Cove, or the Dry Bay area.

Under the No-action Alternative, there would be no actions that would result in the disturbance to plants and wetlands in the state parcels proposed for exchange with WSNPP and KGNHP.

4.7.1.2 Cumulative Effects Analysis. Under the No-action Alternative, there would be no cumulative effects because no project actions would occur in the Kahtaheena River watershed; state-owned parcels adjacent to WSNPP and KGNHP; and the parcels at Cenotaph Island, the unnamed island at Blue Mouse Cove, and Alsek Lake. Therefore, there is no potential for cumulative effects on vegetation and wetland resources based on the interaction between a project and a non-project action.

4.7.1.3 Conclusion. Under the No-action Alternative, there would be no effect on vegetation and wetlands in the Kahtaheena River area, on the potential land exchange parcels, or on the wilderness parcels. Implementation of the No-action Alternative would not result in impairment of GBNPP resources that fulfill specific purposes as identified in the enabling legislation or are key to the natural integrity of the park. Under this alternative, GBNPP would continue to operate and manage its lands as outlined in the enabling legislation (see section 1.7.4).

The level of effects on vegetation and wetlands anticipated from this alternative would not result in an impairment of WSNPP or KGNHP resources that fulfill specific purposes as identified in the enabling legislation, or are key to the natural integrity of these parks. Under this alternative, WSNPP and KGNHP would continue to operate and manage their lands as outlined in their enabling legislation (see section 1.7.4).

4.7.2 GEC's Proposed Alternative

Participants in scoping identified two issues related to the effects of the project on vegetation. These include disturbance of upland vegetation and alterations of wetland character or hydrology. The introduction and spread of noxious weeds and weedy invasive plants may also be a concern, since weeds tend to be rapid colonizers of disturbed soils.

4.7.2.1 Effects of Construction and Operation. Construction of the project would directly affect 28.4 acres of uplands and 1.15 acres of wetlands. Effects on vegetation and wetlands would be confined to the project site, and the vegetation and wetlands on the Native allotments and adjacent GBNPP land would remain in their present condition excluding the possibility that introduced noxious weeds could spread from the project area into the allotments or into GBNPP. The total acreage of vegetation that would be permanently removed by the project is fairly small (about 9.6 acres), since most of the penstock and all of the transmission line would be buried, and the disposal site and portions of the road right-of-way would be revegetated following construction. Table 4.3-1 (see section 4.3, *Geologic Resources and Soils*) shows the estimated acreage that would be affected by each project feature.

Uplands. Project construction would affect 28.4 acres (about 2 percent) of the 1,211 acres of uplands contained in the project area. Several upland sites along the proposed penstock route have been identified as potentially sensitive, because clearing vegetation on steep and unstable slopes could increase the risk of slope failure and wind throw. GEC proposes to construct roads using U.S. Forest Service construction standards and techniques to minimize the potential for road failure on all slopes (see section 4.3, *Geologic Resources and Soils*). The potential for wind throw along the road right-of-way cannot be quantified, and no mitigation measures are proposed to prevent this potential project effect. As a result, an indirect effect of the project may be the loss of additional spruce or hemlock trees in the future, as well as trees cleared intentionally during construction. The state of Alaska, in comments on the draft EIS, proposed an alternative access route that would be about 1.5 miles longer (see figure 2-2 in appendix A) and would disturb an additional 7.5 acres of currently undisturbed land during construction and would permanently affect an additional 2.5 acres. Under the state's proposed road access the amount of land disturbed by construction and operation of the project would increase by about 25 percent, roughly less than 1 percent of upland vegetation in the project area. Additional loss of spruce or hemlock would also occur but in a smaller amount than upland vegetation losses.

Wetlands. Wetlands account for about 44 percent (966 acres) of the vegetation types in the total 2,177-acre Kahtaheena River watershed. Construction would affect 1.15 acres (less than 0.1 percent) of these wetlands. Road construction would disturb wetland vegetation and soils over an area about 0.65 acres in size, and convert about 0.16 acres permanently to road surface. Waste disposal would affect about 0.5 acres of forested wetland. Assuming a similar percentage of wetlands are affected in the additional 7.5 acres that would be disturbed under the state's alternative road access, this route would likely affect about 2 acres of wetlands for the total project. Under any of these alternatives, ATV use or horse riding could adversely affect wetlands if these uses are permitted on the lands removed from GBNPP.

GEC proposes to design the access and service road alignments to avoid wetlands, where possible.

ADFG, FWS, and NMFS recommend that GEC develop and implement a wetland mitigation plan to mitigate for the loss of any wetlands through the restoration, creation, mitigation, or preservation of nearby wetlands as compensation for unavoidable damage resulting from project construction. FWS further recommends that GEC avoid and minimize impacts on wetlands in the project area.

As GEC proposes, the roads would avoid bogs and shallow ponds, but would cross about 500 feet of wetlands. Wetlands that would be directly affected by project construction include willow shrubland, poor hemlock/spruce forest, and fen vegetation types. Where the road would cross wetlands, GEC proposes to construct ditching up-slope of the road, and culverts under the road to maintain the existing hydrologic connections. Culverts would also be installed at five points where the road would cross intermittent streams or drainage ways. Given the limited linear feet of wetlands that would be affected and the measures proposed to avoid changes to existing hydrologic connections, effects of road construction on wetlands would be limited.

Disposal of waste (including slash and excavated materials) to a depth of about 10 feet at the haulback site would bury existing wetland vegetation and soils, impair wetland functions, and permanently alter 0.5 acre of wetland. GEC believes that this site would rapidly revegetate into a shrubland, which would eventually convert into a well-drained luxuriant forest.

GEC also proposes as mitigation for the disturbance of 1.15 acres of wetland to restore the hydrological connection of wetlands bordering the Dude Creek Critical Habitat Area. ADFG has indicated that the Prouty ditch that is proposed to be back-filled flows into the Good River and may be providing rearing habitat for coho salmon, but it has not recommended alternative mitigation measures. GEC proposes to consult with ACOE to determine the amount and type of wetland mitigation that may be needed, and the agencies have recommended development of a wetland mitigation plan. Implementation of a wetland mitigation plan developed in consultation with ADFG, FWS, NMFS, and ACOE would provide a process for addressing the need to mitigate for the loss of wetlands.

Noxious Weeds. Both construction activity and long-term management of the road could affect native plant communities in the project area. Construction equipment, ATVs, and even dogs and pedestrians can serve as vectors for the introduction and spread of noxious weeds and non-native plant species.

GEC would reduce the risk of introducing non-native plant species and noxious weeds to the project area by using certified weed-free seed mixes for revegetation of disturbed soils, and to provide immediate cover from erosion. The agencies make no recommendations regarding the control of non-native plant species in the project area. Some inadvertent introduction of non-native plant species is expected to result from construction of new roads and could spread into adjacent areas.

4.7.2.2 Effects of the GBNPP and Wilderness Boundary Adjustment. Under GEC's proposal, 850 acres of vegetation and wetlands would be removed from GBNPP. However, the vegetation (primarily mature spruce/hemlock forest) and wetlands in the Kahtaheena River area are common and represent only a small portion of this type of vegetation within the GBNPP. The proposed action would not affect vegetation or wetlands on lands proposed for wilderness designation at Cenotaph Island, the unnamed island near Blue Mouse Cove, or Alsek Lake. Because these lands are currently managed as *de facto* wilderness, the formal designation of these areas as wilderness would represent a change in administrative designation but not a change from current management direction.

The Long Lake exchange parcels are currently managed by ADNR to emphasize protection of fish and wildlife resources. The transfer of these lands to NPS would provide similar management and would continue to provide protection to vegetation and wetland resources.

NPS currently manages the proposed exchange lands bordering KGNHP according to the provisions of a management agreement with the state. Upon completion of the exchange, NPS would continue to manage these parcels for fish, wildlife, and cultural resources, also providing protection of vegetation and wetland resources.

4.7.2.3 Cumulative Effects Analysis. The establishment of roads, residential and commercial development, the airport, and other infrastructure in the vicinity of Gustavus has resulted in a decrease of naturally vegetated uplands and wetlands in the Gustavus area. The development of the proposed project would result in a loss of upland and wetland vegetation from construction of the access road and riparian vegetation at the diversion and powerhouse sites. The combined effect of the historical development in the vicinity of Gustavus, and the development of the hydroelectric project, would result in a cumulative increase in the loss of upland and wetland vegetation in the general Gustavus area.

There are no project-related actions identified that would result in an impact on vegetation and wetland resources for the WSNPP and KGNHP transfer parcels. Therefore, no cumulative effects on vegetation and wetland resources would occur as a result of the interaction between project action and non-project actions at these sites.

There are no project-related actions identified that would result in an impact on vegetation and wetland resources for the proposed wilderness parcels at the unnamed island near Blue Mouse Cove, Cenotaph Island, or Alsek Lake. Therefore, no cumulative effects on vegetation and wetland resources would occur as a result of the interaction between project actions and non-project actions at these sites.

4.7.2.4 Conclusion. Construction of the proposed project would result in a permanent loss of about 9.6 acres of upland vegetation; however, these plant community types (rich spruce/hemlock forest, poor spruce/hemlock forest, logged-over areas) are not unique within the region.

Construction of the proposed project would disturb 1.15 acres of wetlands including 0.65 acres due to road construction and 0.5 acres due to waste disposal. The impacts on wetlands would persist over the life of the project. The changes to the wetland communities would be localized to the immediate impact area and would affect wetland types that are common to the region. The proposed project would not affect wetland communities on the two Native allotments on adjacent GBNPP land.

Construction and operation of the proposed project would result in a measurable change in the distribution and composition of plant communities in the Kahtaheena River watershed that are common to the region, as measured by the area and types of vegetation communities affected. The proposed project would not affect the distribution and composition of vegetation on adjacent GBNPP land. The impacts on vegetation communities would persist over the life of the project. Mitigation measures would be implemented to prevent the introduction and spread of noxious weeds to the project area.

The purposes and values of GBNPP identified in the enabling legislation include the preservation of the natural forest ecosystems that have developed following glacial retreat. The construction and operation of the proposed project would not adversely impact the purposes and values of GBNPP because the majority of the effects would occur on either state land or within the FERC project boundary. Any effects on vegetation and wetland resources within GBNPP would be short-term and localized, and would not substantially diminish the value of the forest ecosystem within GBNPP. Under GEC's proposal, the vegetation and wetland resources of the unnamed island near Blue Mouse Cove, Cenotaph Island, and lands at Alsek Lake would not be affected because these lands would remain in GBNPP. Therefore, any anticipated effects on vegetation and wetlands under this alternative would not result in an impairment of the GBNPP resources that fulfill the specific purposes identified in the enabling legislation, or are key to the natural integrity of the park. GBNPP would continue to operate and manage park lands to preserve nationally significant vegetation and wetland values associated with natural landscapes.

Conveying state land to NPS for either WSNPP or KGNHP would not have any effect on vegetation and wetlands at these locations. For this reason there would be no impairment of WSNPP or KGNHP vegetation resources that fulfill specific purposes identified in the enabling legislation (see section 1.7.4), or that are key to the natural integrity of these parks.

4.7.3 Maximum Boundary Alternative

4.7.3.1 Effects of Construction and Operation. Implementation of this alternative would have the same effects on vegetation and wetland resources during construction and operation as those of GEC’s proposal on lands in the Kahtaheena River area and adjacent GBNPP lands. Under the Maximum Boundary Alternative, however, GEC would be responsible for long-term management of about 1,145 acres in the project area, instead of 117 acres. The long-term management of the 1,145-acre project area by GEC under FERC direction may provide greater protection to vegetation and wetland resources than would otherwise be provided under management by the state upon implementation of GEC's proposal. Under this alternative, GEC would implement the same protection and mitigation measures as those described under GEC's proposal (section 4.7.2) but to a greater amount of land. Agency-recommended measures would also be the same as described under GEC's proposal.

4.7.3.2 Effects of the GBNPP and Wilderness Boundary Adjustment. The effects of the Maximum Boundary Alternative on the vegetation and wetland resources of lands proposed for wilderness designation at the unnamed island near Blue Mouse Cove, Cenotaph Island, and Alsek Lake would be the same as those described under GEC’s proposed alternative.

The Maximum Boundary Alternative would result in a larger acreage of land exchanged between the state and NPS within WSNPP or KGNHP than GEC’s proposed alternative. The effects of the land exchange on the vegetation and wetland resources would be the same as those described under GEC's proposed alternative.

4.7.3.3 Cumulative Effects Analysis. The types of cumulative effects that could be expected to occur on vegetation and wetland resources under this alternative are the same as those described under GEC’s Proposed Alternative in section 4.7.2.3.

4.7.3.4 Conclusion. Under the Maximum Boundary Alternative, the effects of the construction and operation of the proposed project on vegetation and wetlands would be the same as described under GEC's proposal (see 4.7.2.4), except that 1,145 acres, including the entire bypassed reach and lands to the east of the Kahtaheena River, would be conveyed to the state.

The purposes and values of GBNPP identified in the enabling legislation include the preservation of the natural forest ecosystems that have developed following glacial retreat. The construction and operation of the proposed project would not adversely impact the purposes and values of GBNPP because the majority of the effects would occur on either state land or within the FERC project boundary. Any effects on vegetation and wetland resources within GBNPP would be short-term and localized, and would not substantially diminish the value of the forest ecosystem within GBNPP. Under the Maximum Boundary Alternative, the vegetation and wetland resources of the unnamed island near Blue Mouse Cove, Cenotaph Island, and lands at Alsek Lake would not be affected because these lands would remain in GBNPP. Therefore, any anticipated effects on vegetation and wetlands under this alternative would not result in an impairment of the GBNPP resources that fulfill the specific purposes identified in the enabling legislation, or are key to the natural integrity of the park. GBNPP would continue to operate and manage park lands to preserve nationally significant vegetation and wetland values associated with natural landscapes.

Conveying state land to NPS for either WSNPP or KGNHP would not have any effect on vegetation and wetlands at these locations. For this reason there would be no impairment of WSNPP or KGNHP vegetation resources that fulfill specific purposes identified in the enabling legislation (see section 1.7.4), or that are key to the natural integrity of these parks.

4.7.4 Corridor Alternative

4.7.4.1 Effects of Construction and Operation. Implementation of this alternative would have the same effects on vegetation and wetland resources during construction and operation as those of GEC's proposed action on lands in the Kahtaheena River area and adjacent GBNPP lands. GEC's management of the approximately 680 acres that would be included within the project boundary under this alternative would be the same as described for the 1,145 acres that would be included within the project boundary under the Maximum Boundary Alternative. Under this alternative, GEC would implement the same protection and mitigation measures as those described under GEC's Proposed Alternative (see section 4.7.2) but on a greater amount of land. Agency-recommended measures would also be the same as described under GEC's proposed alternative. Under the Corridor Alternative, less land would be transferred out of GBNPP and, therefore, there would be less impact on vegetation and wetlands.

4.7.4.2 Effects of the GBNPP and Wilderness Boundary Adjustment. The effects of the Corridor Alternative on the vegetation and wetland resources of lands proposed for wilderness designation at the unnamed island near Blue Mouse Cove, Cenotaph Island, and Alsek Lake would be the same as those described under GEC's proposed alternative.

The Corridor Alternative would result in a smaller acreage land exchange between the state and NPS within WSNPP and KGNHP than GEC's proposal but would result in more acreage within the project boundary. The effects of the land exchange on the vegetation and wetland resources would be the same as those described under GEC's proposed alternative.

4.7.4.3 Cumulative Effects Analysis. The types of cumulative effects that could be expected to occur on vegetation and wetland resources under this alternative are the same as those described under GEC's Proposed Alternative in section 4.7.2.3.

4.7.4.4 Conclusion. Under the Corridor Alternative, the effects of the construction and operation of the proposed project on vegetation and wetlands would be the same as described under GEC's proposal (see section 4.7.2.4) and the Maximum Boundary Alternative (see section 4.7.3.4), except that only 680 acres including the entire bypassed reach and lands to the east of the Kahtaheena River would be conveyed to the state.

The purposes and values of GBNPP identified in the enabling legislation include the preservation of the natural forest ecosystems that have developed following glacial retreat. The construction and operation of the proposed project would not adversely impact the purposes and values of GBNPP because the majority of the effects would occur on either state land or within the FERC project boundary. Any effects on vegetation and wetland resources within GBNPP would be short-term and localized, and would not substantially diminish the value of the forest ecosystem within GBNPP. Under the Corridor Alternative, the vegetation and wetland resources of the unnamed island near Blue Mouse Cove, Cenotaph Island, and lands at Alsek Lake would not be affected because these lands would remain in GBNPP. Therefore, any anticipated effects on vegetation and wetlands under this alternative would not result in an impairment of the GBNPP resources that fulfill the specific purposes identified in the enabling legislation, or are key to the natural integrity of the park. GBNPP would continue to operate and manage park lands to preserve nationally significant vegetation and wetland values associated with natural landscapes.

Conveying state land to NPS for either WSNPP or KGNHP would not have any effect on vegetation and wetlands at these locations. For this reason there would be no impairment of WSNPP or KGNHP vegetation resources that fulfill specific purposes identified in the enabling legislation (see section 1.7.4), or that are key to the natural integrity of these parks.

4.8 WILDLIFE

Several evaluation parameters are used to identify and describe the impacts on the wildlife resources of the project area. These parameters include:

1. Habitat types

2. Habitat quantities

3. Distribution of habitat

4. Habitat quality

5. Disturbance

All of the evaluation parameters identified for wildlife resources are used to provide an indication of the potential changes in populations of wildlife species using the area within, or surrounding, the proposed project area. Since the wildlife populations cannot be efficiently and accurately estimated to determine the effects of implementing the proposed project, we use these evaluation parameters as a proxy index to indicate the expected change in species populations that may occur. Some evaluation parameters can be directly measured (e.g., habitat types and quantities), while others are themselves a proxy index and can only be evaluated in a qualitative manner.

The effects of the project on wildlife resources include a discussion of the context of the wildlife resources in the project area. The intensity of the impact on wildlife resources is generally characterized by quantifying the area of impact for habitat types that are common to the area; and identifying the presence, absence, or probability of impacts for important habitat types. The duration of the impact is described where necessary to understand the context and intensity of the impact.

4.8.1 No-action Alternative

4.8.1.1 Effects Analysis. Under the No-action Alternative, there would be no change in wildlife habitat or populations in the Kahtaheena River watershed and adjacent GBNPP land, other than any changes that might occur as a result of natural events or ongoing NPS management.

Under the No-action Alternative the state lands adjacent to WSNPP and KGNHP would not be transferred to NPS and management of these lands would retain the existing protections for wildlife.

Under the No-action Alternative, there would be no change in NPS management of Cenotaph Island, Blue Mouse Cove, or the Alsek Lake area.

4.8.1.2 Cumulative Effects Analysis. Under the No-action Alternative, there would be no cumulative effects because there are no project actions that would occur in the Kahtaheena River watershed, state owned parcels adjacent to WSNPP and KGNHP, and the parcels at Cenotaph Island, the unnamed island at Blue Mouse Cove, and Alsek Lake. Therefore, there is no potential for cumulative effects on wildlife resources based on the interaction between a project and a non-project action.

4.8.1.3 Conclusion. Under the No-action Alternative, there would be no effect on wildlife in the Kahtaheena River area, on the potential land exchange parcels, or on the wilderness parcels. Implementation of the No-action Alternative would not result in impairment of GBNPP resources that fulfill specific purposes as identified in the enabling legislation or are key to the natural integrity of the park. Under this alternative, GBNPP would continue to operate and manage its lands as outlined in the enabling legislation (see section 1.7.4).

The level of effects on wildlife anticipated from this alternative would not result in an impairment of WSNPP or KGNHP resources that fulfill specific purposes as identified in the enabling legislation, or are key to the natural integrity of these parks. Under this alternative, WSNPP and KGNHP would continue to operate and manage their lands as outlined in their enabling legislation (see section 1.7.4).

4.8.2 GEC's Proposed Alternative

4.8.2.1 Effects of Construction and Operation. Potential effects of the project on wildlife include habitat loss and alteration; blocking or fragmentation of wildlife movement corridors; disturbance of nesting raptors or marbled murrelets during construction; and higher levels of recreation disturbance resulting from improved human access into the area over the long term. There also could be an increase in the number of uncontrolled dogs in the project area as a result of increased access.

Construction and operation of the project could have effects on mammals or birds that use fish or riparian resources. Reduced instream flows may cause changes in riparian habitat or in the forage base for wildlife species that prey on fish, amphibians, or aquatic macroinvertebrates.

Under this alternative, GEC would manage 117 acres of land within the FERC boundary, and ADNR would manage approximately 775 acres of land that is now managed by GBNPP. The state of Alaska maintains the right to develop mineral resources on state-owned lands. The state could conduct mineral development in the future on its land to provide material for road maintenance in the Gustavus area, or for other purposes, which could result in the disturbance of wildlife species. In addition to retaining mineral extraction rights, it is assumed that the state would manage this land for wildlife and recreation and would allow sport and subsistence hunting, trapping, and fishing. Helicopter landings, ATV use, and horses could occur on the land that are currently not allowed. These activities may displace animals from preferred habitats to areas that are already occupied and place additional stress on them. GEC would manage land within the FERC boundary according to the terms of the license, which could be conditioned to discourage public access and protect wildlife.

Habitat Loss or Alteration. Project construction would require the disturbance and removal of 28.4 acres of upland vegetation. Much of this upland vegetation consists of spruce/hemlock forest. This forest type is common throughout the coastal rain forest in southeastern Alaska adjacent to GBNPP, and the loss of this acreage would represent a small portion of this forest type in the Kahtaheena River watershed and adjacent areas. GEC's surveys indicate that stands along the access road, penstock route, and at the powerhouse site represent good quality habitat for marbled murrelets and include trees that are likely used for nesting, as indicated by audio and visual detections of birds during the breeding season (Lentfer and Streveler, 1999a; Lentfer, 2000). GEC proposes to avoid felling any trees between May and August to protect nesting birds, such as marbled murrelets. These stands also provide potential nesting or denning habitat for raptors, wolf, black bear, marten, mink, and river otter; however, no actual nest or den sites have been currently documented.

Project construction would remove or alter about 1.15 acres of wetland habitat. Wetlands account for about 44 percent of the vegetation types in the total 2,177-acre Kahtaheena River watershed. Construction would affect less than 0.1 percent of these wetlands. The agencies and GEC agree to the preparation of a wetland mitigation plan and to coordinate with ACOE in the identification of appropriate mitigation for the loss of these wetlands.

The alternative project access route recommended by the state of Alaska would result in the loss of an additional 7.5 acres of vegetation that is currently providing habitat for native wildlife species. Approximately 2.5 acres of this area would be permanently converted to a developed road, and the remaining area would revegetate to native plant communities over the long term.

Blocking or Fragmentation of Wildlife Movement Corridors. Noise and activity during the 24-month construction phase could temporarily affect movement corridors for large mammals. The license application includes maps of two high-use animal trails near the junction of the access road with the penstock route, and several high-use trails at the powerhouse site. Maps of trails along the Kahtaheena River indicate low use along the west side and moderate use along the east side of the river between the powerhouse site and the Upper Falls. Although they highlighted areas of intense use, the tracking studies indicate that black bears and moose are not restricted to the trails, but also disperse cross-country between beach meadows near the mouth of the Kahtaheena River and the Excursion Ridge uplands and muskegs, and could temporarily use alternate routes during construction.

To minimize disturbance to animal movement, GEC proposes to access construction sites via upland routes, rather than more sensitive beach fringe habitats (with the exception of the transmission line crossing at Rink Creek). Biologists conducting the tracking studies found that black bears use the beach meadows throughout their active season. Use was most intensive during the spring and summer. In late summer, bears also were observed to forage in fens and forested habitats along Excursion Ridge where blueberries were abundant, and to forage along the Kahtaheena River during the salmon runs in June, July, August, and September. Brown bears, in lower numbers, also were observed to forage along the Kahtaheena River during the summer and early fall.

There is strong evidence that heavily used forest roads displace numerous wildlife species (Gaines et al., 2003; Gucinski et al., 2001), but the same species, including moose, bear, deer, and wolves, often travel on roads that are used infrequently, rather than avoiding them (Brody and Pelton, 1989; Thurber et al., 1994; Claar et al., in Joslin and Youmans). The project access and service road rights-of-way would be a maximum of 14 feet wide, and after construction is completed, vehicle traffic for maintenance would be infrequent. With a narrow configuration and low levels of traffic, the project would not be likely to cause any long-term blocks to animal movement or fragmentation of movement corridors in the project area.

Disturbance and displacement of wildlife during construction of project roads and facilities would be temporary and local. Project roads and facilities would not create a barrier to wildlife movement in GBNPP or other nearby lands.

The disturbance of habitat and activities associated with the construction and operation of the hydroelectric project would affect the movement of wildlife in areas immediately adjacent to the area of disturbance, although would have no effect on the movement of wildlife in GBNPP and other lands adjacent to the project area.

Noise Disturbance. Noise may disturb wildlife foraging, breeding, and movement patterns, and increase physiological stress (Manci et al., 1988). The effects of noise disturbance on wildlife would vary from species to species, and would also depend on factors such as topography, vegetative screening, timing, frequency, and the type of activity and equipment in use. The types of activities and the levels of noise that would occur during construction and operation of the hydroelectric project are described in section 4.10, *Soundscape/Noise*. Noise from activities such as excavation and grading would be localized in small areas during the construction period, but may be audible from a distance up to 1 mile. The noise generated from activities such as hauling of construction materials, spoil disposal, and blasting would disturb wildlife over larger areas, possibly audible up to 2 miles from the project site. Noise disturbance during the breeding season could adversely affect marbled murrelets in mature spruce/hemlock forest, and common mergansers, kingfishers, and dippers nesting along the banks of the Kahtaheena River. Construction could also cause disturbance to river otters, mink, or marten. Outside the breeding season, most birds and mammals would avoid construction sites, but would likely remain in the proposed project area.

Operation of the proposed hydroelectric facility would produce a constant low level noise from the generator located inside the powerhouse building. Since the generator is located within a building structure, it would not likely be heard from a distance of more than 100 feet. The location of the powerhouse is immediately adjacent to the Kahtaheena River and the Lower Falls, which creates a natural constant background noise. The effects of project operation on wildlife in the immediate area would be negligible due to the low volume of noise generated and the adjacent natural background noise levels.

The generation of high decibel, short duration, and infrequent noises (e.g., blasting) associated with the construction of the proposed hydroelectric project would affect wildlife in GBNPP and other lands adjacent to the project area. All other noises generated during the construction and operation of the proposed hydroelectric project would not affect wildlife in GBNPP, although they would affect wildlife in the project area and other lands immediately adjacent to the project area.

Disturbance of Nesting Raptors or Marbled Murrelets. As mentioned above, marbled murrelets are thought to nest in mature spruce/hemlock forest in the project area. Nesting by raptors is also possible, although no nest sites have been documented. Potential habitat for these species would be reduced by about 29.6 acres. Approximately 9.6 acres would be a permanent loss of habitat, and the remaining area would revegetate to native plant communities over the long term. This forest type is common throughout the coastal rain forest in southeastern Alaska adjacent to GBNPP, and the loss of this acreage would represent a small portion of this forest type in the Kahtaheena River watershed and adjacent areas. To minimize disturbance and potential loss of productivity, GEC proposes to avoid felling potential murrelet or raptor nest trees during the breeding season. The active raptor nesting season is generally March 1 to September, while the active nesting season for murrelets is May 1 to August 15 (FS, 1997).

The loss or disturbance of forest types potentially supporting raptor or murrelet nests within the project area would not affect the raptors and murrelets in GBNPP and other lands adjacent to the project area.

Improved Access. The license application indicates that current use of the project area for activities such as hiking and wildlife viewing occurs primarily on Gustavus Flats, but hikers do use informal trails along the Kahtaheena River to visit both the Lower and Upper Falls. The population of Gustavus is growing by 4.7 percent annually, and it is likely that the demand for recreation activities in the project area, such as hiking and wildlife viewing, will also increase. Although GEC does not propose any specific recreation facilities or improvements, NPS-RTCA, ADFG, and NMFS recommend that GEC develop a recreation plan for the project area.

Following construction, GEC proposes to limit access into the project area to non-motorized recreation by gating the access road and posting signs indicating no motorized access. Non-motorized recreation would include foot- and bicycle-based activities that create nominal levels of noise that could disturb wildlife. The presence of visitors on foot or bicycle would have a lower immediate potential of disturbing wildlife for most species, but a recent literature review (Gaines et al., 2002) suggests that non-motorized recreation activities may cause higher levels of disturbance to some species, such as those with small home ranges or limited mobility, than motorized recreation. Recreation activities may alter behavior, vigor, or productivity of individual animals as they respond to disturbance (Joslin and Youmans, 1999). These changes may in turn alter the abundance, distribution, or demographic structure of populations, in turn altering species interactions and species composition (Knight and Cole, 1995, *in* Knight and Gutzwiller, eds., 1995). In addition to affecting wildlife within the project area, noise and human activity could also affect wildlife on adjacent lands remaining within GBNPP by displacing animals into habitats that might already be occupied.

Other effects associated with increased recreation include harassment, injuries, and mortalities of wildlife species caused by dogs, and the attraction of black bears and brown bears to improperly stored food or garbage. Bears that habituate to food and garbage attractants may be at risk, since bears involved in human-bear conflicts are typically removed or killed. FWS and ADFG recommend GEC consult with the agencies in developing a bear-human conflict plan. Implementation of a bear-human conflict plan would help to avoid human-bear conflicts and would prepare construction workers and plant operations for handling human-bear conflicts.

In addition to improving access for hikers and bicyclists, road construction would increase accessibility of the area to recreational and subsistence hunting and trapping. Because of the limited roaded access to the forest areas surrounding the community of Gustavus, additional roaded access to the forest would be used for recreation and subsistence activities. Although hunting and trapping could be prohibited within any FERC project boundary, increased access into the state lands along both sides of the new access road would likely increase legal hunting and trapping pressure and increase the risk of poaching on adjacent GBNPP lands. In particular, FWS is concerned that hunting and trapping would increase the risk of harm to bald eagles (e.g., injury or mortality in leg-hold traps, shooting). FWS also recommends that hunting, trapping, and fishing in the project area by construction personnel during construction of the project be prohibited.

Other activities that currently are not allowed on NPS lands that could occur on lands transferred to the state of Alaska include helicopter landing, ATV use, horseback riding, skeet shooting, etc. All of these activities have the potential to adversely affect wildlife by placing additional stress on them and dispersing animals from preferred habitats to areas that are already occupied by existing populations.

The overall effects of increased pedestrian and bicycle access for recreation would depend to a great extent on management. For example, if access is infrequent or involves a few individuals at a time, effects would be minor, but large numbers of people making frequent trips could increase adverse impacts. Illegal access (e.g., ATVs, poaching, target practice) to the project area may contribute further to adverse impacts. In addition to GEC's proposal to close the road to motorized vehicles except for construction and operation, NPS-RTCA, ADFG, and NMFS recommend GEC develop and implement a road management plan, a public access plan, and a recreation plan to address potential resource conflicts. GEC concurs with the agencies recommendation to develop these plans.

Changes in Fish or Riparian Resources. GEC's license application noted the presence of several wildlife species in habitats along the Kahtaheena River that rely to some extent on aquatic resources for food. These include river otter, mink, common merganser, belted kingfisher, and American dipper. Construction and operation of the project is expected to reduce the abundance of Dolly Varden in the bypassed reach, which contains about 15 percent of the entire Dolly Varden population in the Kahtaheena River, but would not affect Dolly Varden populations above the diversion dam, or the abundance of other fish species in the lower Kahtaheena River. A reduction of about 15 percent of the total resident Dolly Varden population, as discussed in section 4.6, *Fisheries*, suggests that piscivorous birds and mammals could be displaced from the bypassed reach over the life of the project. However, most observations of kingfishers, and all observations of bald eagles and osprey, were recorded near the mouth of the river or above the adjacent tidal flats, an area where fish populations would not be affected by the proposed project (Lentfer and Streveler, 1999a). Surveyors noted that one pair of mergansers may nest along the river above the Lower Falls. The estimated reduction in fish populations or change in riparian habitat would not affect this species.

No mink sign was observed above the falls, and river otter tracks were observed above the Lower Falls on only one occasion (Lentfer and Streveler, 1999b). Few bear scats were found to contain fish, even in the anadromous reach of the Kahtaheena River. However, because fish bones are often completely absorbed by the animal and do not pass through the digestive tract, it is difficult to determine the diet of a piscivorous mammal from their scat. It is likely that bears and other land mammals are feeding on fish, especially in the anadromous stretch when pink, chum, and coho salmon return to the Kahtaheena River to spawn and die.

GEC provided no information about the effects of reduced flows in the bypassed reach on aquatic macroinvertebrates. Based on the 20 percent reduction in instream habitat that would result from GEC's proposed flows, however, potential habitat for species such as mayflies and stoneflies would also be reduced. There likely would be associated adverse impacts on American dippers, which feed primarily on mayflies and stoneflies.

The changes in fish and riparian habitat within the project area would not affect the wildlife populations dependent on these habitats in GBNPP and other lands adjacent to the project area.

4.8.2.2 Effects of the GBNPP and Wilderness Boundary Adjustment. Under GEC's proposal, 850 acres of upland vegetation and wetlands that support wildlife would be removed from GBNPP. These habitats are common in the region. The proposed Long Lake exchange parcels would be transferred from state to NPS ownership and would be incorporated into WSNPP. ADNR currently manages these lands to emphasize protection of fish and wildlife resources. NPS management of these lands would provide similar protection to wildlife resources.

The proposed KGNHP exchange parcels are currently managed by NPS according to the provisions of a management agreement with the state. Upon completion of the exchange, NPS would continue to manage these parcels for fish, wildlife, and cultural resources.

GEC's proposal would not affect wildlife resources in the areas proposed for wilderness designation, since NPS proposes to continue current management direction.

4.8.2.3 Cumulative Effects Analysis. The potential increase in development of residential housing, commercial facilities, or logging in and around the community of Gustavus in response to general population and economic growth would result in a decrease in habitat availability for wildlife species. The development of the proposed hydroelectric project would reduce available wildlife habitat in the future by approximately 29.6 acres. The combined effect of increased development in the vicinity of Gustavus, and the development of the hydroelectric project, would result in a cumulative reduction of wildlife habitat in the general Gustavus area.

The potential future increase in population in the Gustavus area would result in greater use of the surrounding natural environment for recreation and subsistence activities. The development of the proposed hydroelectric project, and roads accessing the project, would provide increased non-motorized access to natural areas that could be used by the local population. The combined effect of increased population in the Gustavus area and improved access to natural areas surrounding the community would result in a cumulative increase in disturbance to wildlife species and a potential reduction in wildlife populations.

The construction and operation of the proposed project would result in the generation of noise and other activities that may disturb existing wildlife behavioral patterns and habitat use. The combined effects of potential future mineral development by the state and the construction and operation of the proposed project may produce an ongoing cumulative increase in the frequency of disturbance to wildlife behavioral patterns and habitat use.

There are no project-related actions identified that would result in an impact on wildlife resources for the WSNPP and KGNHP transfer parcels. Therefore, no cumulative effects on wildlife resources would occur as a result of the interaction between project actions and non-project actions at these sites.

There are no project-related actions identified that would result in an impact on wildlife resources for the proposed wilderness parcels at the unnamed island near Blue Mouse Cove, Cenotaph Island, and Alsek Lake. Therefore, no cumulative effects on wildlife resources would occur as a result of the interaction between project actions and non-project actions at these sites.

4.8.2.4 Conclusion. Under GEC's proposal, construction of the project would temporarily disturb 29.6 acres, permanently replace about 9.6 acres of existing wildlife habitat to a developed land use, and alter habitat characteristics over an area of about 20 acres. Although the effects on wildlife would persist for the life of the project, the amount of acreage disturbed represents a small proportion of habitat available in the area. The proposed land exchange and operation of the project would increase human access to the area and could influence the behavior of some wildlife species in the watershed over a long period of time. Direct mortality to wildlife could occur if hunting and/or trapping are allowed on the exchanged lands. These impacts could result in a negative effect on the wildlife resources in the area.

The construction and operation of the proposed project would result in a small change to wildlife habitat or populations within the watershed, which could affect the overall composition and distribution of wildlife on the adjacent GBNPP land. The operation of the project could also result in the long-term disturbance of wildlife species which could influence wildlife habitat use and movements within the watershed and possibly on adjacent GBNPP land.

The purposes and values of GBNPP identified in the enabling legislation include the preservation of populations of wildlife species and habitat for those species. The construction and operation of the proposed project would not adversely impact the purposes and values of GBNPP because the majority of the effects would occur on either state land or within the FERC project boundary. Any effects on wildlife species and their habitat within GBNPP would be short-term and localized, and would not substantially diminish the value of the wildlife populations and habitat within GBNPP. Under GEC's proposal, the wildlife species and habitat resources of the unnamed island near Blue Mouse Cove, Cenotaph Island, and lands at Alsek Lake would not be affected because these lands would remain in GBNPP. Therefore, any anticipated effects on wildlife and their habitats under this alternative would not result in an impairment of the GBNPP resources that fulfill the specific purposes identified in the enabling legislation, or are key to the natural integrity of the park. GBNPP would continue to operate and manage park lands to preserve populations of wildlife species and their habitats associated with natural landscapes.

Conveying state land to NPS for either WSNPP or KGNHP would not have any effect on wildlife at these locations. Because there would be no effects on wildlife, there would be no impairment of WSNPP or KGNHP resources that fulfill the specific purposes as identified in the parks' enabling legislation (see section 1.7.4), or that are key to the natural integrity of the parks.

4.8.3 Maximum Boundary Alternative

4.8.3.1 Effects of Construction and Operation. Implementation of the Maximum Boundary Alternative would have the same effects on wildlife in the

Kahtaheena River area and adjacent GBNPP land during the construction period as GEC's proposal. GEC would implement the same protection and mitigation measures described in section 4.8.2.1; however, because of the larger project boundary, a greater area would be affected. Agency mitigation measures also would be the same as described under GEC's proposal.

Long-term effects from the operation of the project on wildlife would be similar to GEC's proposal. Under the Maximum Boundary Alternative, GEC would be responsible for management of about 1,145 acres in the project area according to the terms of any FERC license conditions. For this analysis, it is assumed that license conditions would restrict the types and amounts of recreation activity allowed in the 1,145-acre project area, prohibiting dogs, hunting, trapping, and other activities that would have the potential to cause wildlife disturbance or harassment, as well as motorized vehicles. With the exception of developed project features, management would be similar to current NPS management and would be more protective than state management.

4.8.3.2 Effects of the GBNPP and Wilderness Boundary Adjustment. Under the Maximum Boundary Alternative, more acreage would be exchanged than under GEC's proposal, which would increase the acreage transferred from the state to the WSNPP and KGNHP. The effects on wildlife resources of the transfer parcels would be the same as those of GEC's proposal.

The effects of the Maximum Boundary Alternative on wildlife resources of the proposed wilderness designation parcels at the unnamed island near Blue Mouse Cove, Cenotaph Island, and Alsek Lake would be the same as those under the proposed action.

4.8.3.3 Cumulative Effects Analysis. The types of cumulative effects that could be expected to occur on wildlife resources under this alternative are the same as those described under GEC's Proposed Alternative in section 4.8.2.3.

4.8.3.4 Conclusion. The Maximum Boundary Alternative could provide greater protection for wildlife resources within the FERC boundary and on adjacent GBNPP lands than the proposed action, because FERC's license conditions could limit the amount and type of human use that occurs in the area to protect and maintain the project facilities. Wildlife resources on the lands that are exchanged but outside of the FERC boundary would be managed by the state of Alaska. These resources may not receive the same protection because the state of Alaska's management of fish and wildlife resources may differ from FERC or NPS. This higher level of protection would include 1,145 acres instead of the 117 acres that would be included within the FERC boundary under GEC's Proposed Alternative.

Under this alternative, the construction and operation of the proposed hydroelectric project would result in a small change to wildlife habitat or populations within the watershed, and possibly on adjacent GBNPP land. The operation of the project could result in the long-term disturbance of wildlife species, influencing their habitat use and movements within the watershed, and possibly on adjacent GBNPP land.

The purposes and values of GBNPP identified in the enabling legislation include the preservation of populations of wildlife species and habitat for those species. The construction and operation of the proposed project would not adversely impact the purposes and values of GBNPP because the majority of the effects would occur on either state land or within the FERC project boundary. Any effects on wildlife species and their habitat within GBNPP would be short-term and localized, and would not substantially diminish the value of the wildlife populations and habitat within GBNPP. Under the Maximum Boundary Alternative, the wildlife species and habitat resources of the unnamed island near Blue Mouse Cove, Cenotaph Island, and lands at Alsek Lake would not be affected because these lands would remain in GBNPP. Therefore, any anticipated effects on wildlife and their habitats under this alternative would not result in an impairment of the GBNPP resources that fulfill the specific purposes identified in the enabling legislation, or are key to the natural integrity of the park. GBNPP would continue to operate and manage park lands to preserve populations of wildlife species and their habitats associated with natural landscapes.

Conveying state land to NPS for either WSNPP or KGNHP would not have any effect on wildlife at these locations. Because there would be no effects on wildlife, there would be no impairment of WSNPP or KGNHP resources that fulfill the specific purposes as identified in the parks' enabling legislation (see section 1.7.4), or that are key to the natural integrity of the parks.

4.8.4 Corridor Alternative

4.8.4.1 Effects of Construction and Operation. During construction of the project, the effects of the Corridor Alternative on wildlife resources of the Kahtaheena River and adjacent GBNPP lands would be the same as those that would occur under the proposed action. GEC's management of the approximately 680 acres that would be included within the project boundary under this alternative would be the same as described for the 1,145 acres that would be included within the project boundary under the Maximum Boundary Alternative. GEC would implement the same protection and mitigation measures described for the proposed action in section 4.8.2.1; however, because of the larger project boundary, a greater area would be affected. Agency mitigation measures would also be the same as described under GEC's proposal.

4.8.4.2 Effects of the GBNPP and Wilderness Boundary Adjustment. Under this alternative, less acreage (680 acres) of state land would be transferred to NPS ownership within WSNPP or KGNHP, compared to GEC's proposal. The effects of the exchange on wildlife resources would be similar to those of the proposed action.

The effects of the Corridor Alternative on wildlife resources of the proposed wilderness designation parcels at the unnamed island near Blue Mouse Cove, Cenotaph Island, and Alsek Lake would be the same as those under the proposed action.

4.8.4.3 Cumulative Effects Analysis. The types of cumulative effects that could be expected to occur on wildlife resources under this alternative are the same as those described under GEC's Proposed Alternative in section 4.8.2.3.

4.8.4.4 Conclusion. Under the Corridor Alternative, the anticipated effects on wildlife resources within the project boundary would be the same as described for GEC's proposal (see section 4.8.2.4) and the Maximum Boundary Alternative (see section 4.8.3.4), with the exception that only 680 acres, including the entire bypassed reach and lands to the east of the Kahtaheena River, would be conveyed to the state of Alaska. The Corridor Alternative could afford more protection for the wildlife resources within the FERC boundary and on adjacent GBNPP lands than the proposed action, because less land would be transferred to the state of Alaska, and all lands transferred would be subject to FERC's license conditions. As a condition of the license, FERC could limit the amount and type of human use that occurs in the area to protect and maintain the project facilities. The Corridor Alternative would extend these conditions to 680 acres instead of the 117 acres included within the FERC boundary under the proposed action.

The construction and operation of the proposed project could result in a small change to wildlife habitat or populations within the watershed, and possibly on adjacent GBNPP land. The operation of the project could result in the long-term disturbance of wildlife species and influence their habitat use and movements within the watershed and on the adjacent GBNPP land.

The purposes and values of GBNPP identified in the enabling legislation include the preservation of populations of wildlife species and habitat for those species. The construction and operation of the proposed project would not adversely impact the purposes and values of GBNPP because the majority of the effects would occur on either state land or within the FERC project boundary. Any effects on wildlife species and their habitat within GBNPP would be short-term and localized, and would not substantially diminish the value of the wildlife populations and habitat within GBNPP. Under the Corridor Alternative, the wildlife species and habitat resources of the unnamed island near Blue Mouse Cove, Cenotaph Island, and lands at Alsek Lake would not be affected because these lands would remain in GBNPP. Therefore, any anticipated effects on wildlife and their habitats under this alternative would not result in an impairment of the GBNPP resources that fulfill the specific purposes identified in the enabling legislation, or are key to the natural integrity of the park. GBNPP would continue to operate and manage park lands to preserve populations of wildlife species and their habitats associated with natural landscapes.

A smaller acreage of exchange lands in WSNPP or KGNHP would result in fewer benefits to long-term protection of wildlife resources under the Corridor Alternative than under GEC's proposal. The effects of the changes in wilderness designation under the Corridor Alternative would be the same as those under GEC's proposal. Conveying state land to NPS for either WSNPP or KGNHP would not have any effect on wildlife at these locations. Because there would be no effects on wildlife, there would be no impairment of WSNPP or KGNHP resources that fulfill the specific purposes as identified in the parks' enabling legislation (see section 1.7.4), or that are key to the natural integrity of the parks.

4.9 CULTURAL RESOURCES

There are several evaluation parameters that identify and describe the potential effects on the cultural resources of the project area from the proposed action and action alternatives. These parameters include effects on:

1. Huna Tlingit cultural landscape within GBNPP

2. Traditional cultural properties within GBNPP that contribute to the Huna cultural landscape

The assessment of the potential effects of the project on cultural resources includes a discussion of the context of the resources in the project area. The intensity of the impact on resources is generally characterized by quantifying the area of impact for resources that are common to the area and identifying the presence, absence, or probability of impacts. Duration of the impact is described where necessary to understand the context and intensity of the impact.

4.9.1 No-action Alternative

4.9.1.1 Effects Analysis. Under the No-action Alternative, the proposed project would not be constructed; the land surrounding the proposed project would be retained within the National Wilderness Preservation System for the foreseeable future and would continue to be managed as wilderness in accordance with the GBNPP GMP; and there would be no land exchange. Project-related access roads would not be constructed, and therefore, no cultural resources would be disturbed as a result of project-related construction and there would be no project-related changes to the Huna Tlingit cultural landscape around the Kahtaheena River. The No-action Alternative would have no effect on cultural resources because there would be no project-related change to the cultural resources described in section 3.9.

Under the No-action Alternative, the unnamed island near Blue Mouse Cove, Cenotaph Island, and the Alsek Lake parcels would not be designated as wilderness lands. However, these lands would continue to be managed in accordance with current

NPS policies for cultural resources management in GBNPP, and there would be no change to cultural resources. Therefore, this alternative would have no effect on potential wilderness parcels and landforms of Cenotaph Island that are the basis of Huna Tlingit stories, or on the landscape of Dry Bay and Alsek Lake revered as a homeland and sacred site by several Tlingit clans, both potential traditional cultural properties.

Under the No-action Alternative, the land exchange would not occur, and the parcels at Long Lake and in KGNHP would remain in state ownership. These lands would continue to be managed in accordance with current state land use policies, and the state would continue to coordinate management of cultural resources on these lands with WSNPP and KGNHP. Therefore, the No-action Alternative would have no effect on any archaeological sites that might exist on the Long Lake parcels or on the Chilkoot Trail and associated historic sites in the KGNHP.

4.9.1.2 Cumulative Effects Analysis. Under the No-action Alternative, there would be no cumulative effects because there would be no project actions that would occur in the Kahtaheena River watershed, state-owned parcels adjacent to WSNPP and KGNHP, and the parcels at Cenotaph Island, the unnamed island near Blue Mouse Cove, and Alsek Lake. Therefore, there is no potential for cumulative effects on cultural resources based on the interaction between a project and a non-project action.

4.9.1.3 Conclusion. Under the No-action Alternative, there would be no effects on cultural resources. Cultural resources in the project area would not be disturbed because no project-related construction or ground-disturbance would occur. The effects on cultural resources anticipated from this alternative would not result in an impairment of GBNPP resources that fulfill specific purposes of preserving lands and waters containing significant historical or archaeological, or cultural values, as identified in the enabling legislation or are key to the natural integrity of the park. Under this alternative, GBNPP would continue to operate and manage its lands as outlined in the enabling legislation (see section 1.7.4).

The effects on cultural resources anticipated from this alternative would not result in an impairment of WSNPP or KGNHP resources that fulfill specific purposes to allow traditional uses or preserve the historic structures and trails associated with the Klondike Gold Rush of 1898, as identified in the enabling legislation, or are key to the natural integrity of these parks. Under this alternative, WSNPP and KGNHP would continue to operate and manage their lands as outlined in their enabling legislation (section 1.7.4).

4.9.2 GEC's Proposed Alternative

4.9.2.1 Effects of Construction and Operation. The primary effects of the proposed action on cultural resources would be those associated with the permanent removal of a few cultural resources (culturally modified trees) located in the vicinity of the proposed powerhouse. GEC's proposal to minimize the removal of cultural modified trees through adjustments to the access road alignment reflects a concern for cultural sensitivities of the Huna Tlingit. GEC would notify the Hoonah Indian Association prior to the removal of culturally modified trees to allow data recovery. Under GEC's proposed action, the state of Alaska would manage the 775 acres of land surrounding the project as wildlife habitat, although the state also would reserve the right to permit mineral extraction activities. Management of lands for wildlife purposes would not likely result in the removal of cultural resources. GEC's proposal would affect cultural resources in a localized area at the powerhouse and adjacent to the Mills allotment, and it would involve resources that are common to the cultural landscape for which the data have been recorded. Therefore, the effects on cultural resources in the project area would be negligible.

4.9.2.2 Effects of the GBNPP and Wilderness Boundary Adjustment. Under GEC's proposed action, lands on which cultural resources are located would be removed from GBNPP. Removal of these lands would reduce the number of cultural resources within GBNPP. However, the effect would be negligible because only a few cultural resources (35 culturally modified trees) were identified in the project area, and they are common to the Huna Tlingit cultural landscape.

Under GEC's proposed action, the designation of the unnamed island near Blue Mouse Cove would have no effect on cultural resources because none have been identified and none are likely to exist on the island (NPS, 1984). Designation of the Alsek Lake parcels would have negligible effects on cultural resources over the term of any license because the GBNPP staff would continue to evaluate these parcels as part of their on-going efforts to record the traditional cultural properties in GBNPP. As noted in section 3.9, the Dry Bay area, including Alsek Lake, is revered as a homeland and sacred site by several Tlingit clans as a landscape heavily used by Raven at the time of creation. Designation as wilderness would not affect on-going efforts to evaluate and protect traditional cultural properties.

Designation of Cenotaph Island would have negligible effects on cultural resources because there would be little change in the on-going efforts to research, evaluate, and protect the traditional cultural properties identified by GBNPP on this island to date, including the basic landforms of the island. As noted in section 3.9, these parcels, and the potential traditional cultural properties associated with the Huna Tlingit, would enjoy a higher level of protection under the wilderness designation even though they are currently managed similar to nearby wilderness areas.

Under GEC's alternative, the exchange of the Long Lake parcels to NPS would bring these parcels under the management practices of NPS and could result in inventory and evaluation of potential archaeological and historic sites on these parcels under GBNPP's cultural resources management program. Exchange of the KGNHP parcels to NPS would bring these parcels, which include portions of the Chilkoot Trail, under the management practices of NPS and could also result in the inventory and evaluation of potential sites. The practical effect of the transfer would be negligible because the state of Alaska currently coordinates with NPS on management of these parcels.

4.9.2.3 Cumulative Effects Analysis. The potential inventory and the development of a cultural resources management and interpretive plan for the parcels adjacent to WSNPP and KGNHP could be conducted in the future as part of a resource management program for these lands. The transfer of the state-owned parcels to NPS would provide additional cultural resource management opportunities for WSNPP and KGNHP. The combined effects of the development of a cultural resources inventory and management plan with the transfer of these lands to NPS would provide a cumulative beneficial effect of providing more opportunities for increasing the understanding of cultural resources in this portion of southeastern Alaska.

The potential loss of cultural resources associated with the Huna Tlingit cultural landscape occurs as a result of past, present, and future timber harvesting and other forest management practices conducted on the Tongass National Forest. The construction of the Falls Creek Hydroelectric Project could result in a loss of several cultural resources (culturally modified trees) in the vicinity of the proposed powerhouse site. The combined effects of forest management activities on the Tongass National Forest and the development of the Falls Creek Hydroelectric Project would result in the cumulative loss of cultural resources in this portion of southeastern Alaska.

No cumulative effects are identified for the parcels at Cenotaph Island, the unnamed island near Blue Mouse Cove, and Alsek Lake. The proposed project would not change the current management of these parcels, and no other non-project actions are identified that would affect cultural resources at these sites.

4.9.2.4 Conclusion. Project construction would disturb a small number of cultural resources common to GBNPP and the Huna Tlingit cultural landscape. The state of Alaska would manage the lands surrounding the project as wildlife habitat and would not likely disturb cultural resources for wildlife management purposes.

The purposes and values of GBNPP identified in the enabling legislation include the preservation of lands and waters containing nationally significant historical and archaeological values. The construction and operation of the proposed project would not adversely impact the purposes and values of GBNPP because all project-related effects on cultural resources would occur within the project boundary or on state or private lands. Designation of the unnamed island southeast of Blue Mouse Cove would not affect the ability of GBNPP to protect and preserve cultural resources because none are known to exist on the island. The Alsek Lake or Cenotaph Island parcels, which are in Lituya Bay and Dry Bay, are currently managed as wilderness areas and are under consideration as traditional cultural properties associated with the Huna Tlingit cultural landscape. The anticipated effects on cultural resources on these designated parcels under this alternative would not result in an impairment of GBNPP resources that fulfill specific purposes of preserving lands and waters containing significant historical or archaeological, or cultural values, as identified in the enabling legislation, or are key to the natural integrity of the park. The anticipated effects under this alternative would not impair the ability of GBNPP to continue to operate and manage its lands as outlined in its enabling legislation (see section 1.7.4).

Effects on cultural resources resulting from the potential land exchanges would be negligible because the land exchanges would not involve any ground-disturbance or construction activities. However, conveying either the Long Lake parcels or the Klondike Gold Rush parcels from the state of Alaska to NPS could enhance opportunities to identify, evaluate, and manage historic properties that exist on these lands through inclusion in existing cultural resource management programs. Effects on any archaeological sites that exist on the Long Lake parcels in the WSNPP and on portions of the Chilkoot Trail and associated historic sites on parcels in KGNHP would be negligible and beneficial. The anticipated effects on cultural resources from the land exchanges under this alternative would not result in an impairment of WSNPP or KGNHP resources that fulfill specific purposes to allow traditional uses or preserve the historic structures and trails associated with the Klondike Gold Rush of 1898, identified in the enabling legislation, or are key to the natural integrity of these parks. The anticipated effects under this alternative would not impair the ability of WSNPP and KGNHP to continue to operate and manage their lands as outlined in their enabling legislation (see section 1.7.4).

4.9.3 Maximum Boundary Alternative

4.9.3.1 Effects of Construction and Operation. Under the Maximum Boundary Alternative, the effects of GEC's proposed action on cultural resources adjacent to GBNPP would be the same as described under GEC's proposed action.

4.9.3.2 Effects of the GBNPP and Wilderness Boundary Adjustment. Under the Maximum Boundary Alternative, lands on which cultural resources are located would be removed from GBNPP. Removal of these lands would reduce the number of cultural resources within GBNPP. However, the effect would be negligible because only a few cultural resources (35 culturally modified trees) were identified in the project area, and they are common to the Huna Tlingit cultural landscape.

Under the Maximum Boundary Alternative, the exchange of the Long Lake parcels to WSNPP would bring these parcels under the management practices of WSNPP and could result in inventory and evaluation of potential sites on these parcels under the WSNPP cultural resources management program. The effects on cultural resources would be negligible because the state and NPS already coordinate on the management of these parcels.

Exchange of the Klondike Gold Rush parcels to NPS would bring these parcels under the management practices of NPS and also could result in the inventory and evaluation of potential sites on these parcels. The practical effect of the exchange would be negligible because the state of Alaska currently coordinates with NPS on the management of these parcels.

Under the Maximum Boundary Alternative, the designation of the unnamed island near Blue Mouse Cove would have no effect on cultural resources because none have been identified and none are likely to exist. Designation of the Alsek Lake parcels and Cenotaph Island would have negligible effects on cultural resources because GBNPP staff would continue to evaluate these parcels as part of their on-going efforts to record the traditional cultural properties in GBNPP. As noted in section 3.9, the Dry Bay area, including Alsek Lake, is revered as a homeland and sacred site by several Tlingit clans as a landscape heavily used by Raven at the time of creation. Designation as wilderness would not affect on-going efforts to evaluate and protect traditional cultural properties.

4.9.3.3 Cumulative Effects Analysis. Under the Maximum Boundary Alternative, there would be a beneficial cumulative effect on cultural resources because WSNPP and/or KGNHP would be able to include the historic properties, including portions of the Chilkoot Trail, and potential traditional cultural properties, including landforms and special places, located on the land exchange parcels in cultural resource management programs of these two parks. GBNPP already includes the wilderness designation parcels in its cultural resource management programs, so no cumulative effects would be associated with these parcels.

4.9.3.4 Conclusion. Under the Maximum Boundary Alternative, the effects of construction and operation of the project would be the same as described under GEC's proposal (see section 4.9.2.4), except that 1,145 acres would be conveyed to the state, and all of the conveyed acreage would be included within the FERC boundary.

The purposes and values of GBNPP identified in the enabling legislation include the preservation of lands and waters containing nationally significant historical and archaeological values. The construction and operation of the proposed project would not adversely impact the purposes and values of GBNPP because all project-related effects on cultural resources would occur within the project boundary or on state or private lands. Under the Maximum Boundary Alternative, designation of the unnamed island near Blue Mouse Cove would have no effect on cultural resources because none have been identified on this island. Designation of the Alsek Lake or Cenotaph Island parcels would be expected to slightly benefit cultural resources because wilderness designation offers the highest level of protection within NPS. Neither designation would result in an impairment of GBNPP resources that fulfill specific purposes of preserving lands and waters containing significant historical or archaeological, or cultural values, as identified in the enabling legislation, or are key to the natural integrity of the park. The anticipated effects under this alternative would not impair the ability of GBNPP to continue to operate and manage its lands as outlined in its enabling legislation (see section 1.7.4).

Conveying either the Long Lake parcels or the Klondike Gold Rush parcels from the state of Alaska to NPS would enhance opportunities to identify, evaluate, and manage any archaeological sites that may exist on the Long Lake parcels and the portions of the Chilkoot Trail and associated historic properties that exist on the KGNHP parcels. Conveyance of these lands would not result in an impairment of WSNPP or KGNHP resources that fulfill specific purposes to allow traditional uses or preserve the historic structures and trails associated with the Klondike Gold Rush of 1898, identified in the enabling legislation, or are key to the natural integrity of these parks. The anticipated effects under this alternative would not impair the ability of WSNPP and KGNHP to continue to operate and manage their lands as outlined in their enabling legislation (see section 1.7.4).

4.9.4 Corridor Alternative

4.9.4.1 Effects of Construction and Operation. Under the Corridor Alternative, the effects of GEC's proposed action on cultural resources adjacent to GBNPP would be the same as described under GEC's proposed action.

4.9.4.2 Effects of the GBNPP and Wilderness Boundary Adjustment. Under the Corridor Alternative, lands on which cultural resources are located would be removed from GBNPP. Removal of these lands would reduce the number of cultural resources within GBNPP. However, the effect would be negligible because only a few cultural resources (35 culturally modified trees) were identified in the project area, and they are common to the Huna Tlingit cultural landscape.

Under the Corridor Alternative, the designation of the unnamed island near Blue Mouse Cove would have no effect on cultural resources because none have been identified and none are likely to exist. Designation of the Alsek Lake parcels and Cenotaph Island would have negligible effects on cultural resources because GBNPP staff would continue to evaluate these parcels as part of their on-going efforts to record the traditional cultural properties in GBNPP. As noted in section 3.9, the Dry Bay area, including Alsek Lake, is revered as a homeland and sacred site by several Tlingit clans as a landscape heavily used by Raven at the time of creation. Designation as wilderness would not affect on-going efforts to evaluate and protect traditional cultural properties.

Under the Corridor Alternative, the effects of the exchange of the Long Lake parcels to WSNPP would be the same as described under GEC's proposed action. The effects on cultural resources would be negligible because the state and NPS already coordinate on the management of cultural resources on these parcels.

Exchange of the Klondike Gold Rush parcels to NPS would bring these parcels under the management practices of NPS and also could result in the inventory and evaluation of potential sites on these parcels. The practical effect of the exchange would be negligible because the state of Alaska currently coordinates with NPS on the management of these parcels.

4.9.4.3 Cumulative Effects Analysis. Under the Corridor Alternative, there would be a beneficial cumulative effect on cultural resources because WSNPP or KGNHP would be able to include the historic properties and ethnographic resources on the exchange parcels in cultural resource management programs of these two parks. GBNPP already includes the wilderness designation parcels in its cultural resource management programs so no cumulative effects would be associated with these parcels.

4.9.4.4 Conclusion. Under the Corridor Alternative, the effects of the construction and operation of the project on cultural resources would be the same as described under GEC's proposal (see section 4.9.2.4) and the Maximum Boundary Alternative (see section 4.9.3.4), except that only 680 acres would be conveyed to the state, all of which would be included in the FERC project boundary.

The purposes and values of GBNPP identified in the enabling legislation include the preservation of lands and waters containing nationally significant historical and archaeological values. The construction and operation of the proposed project would not adversely impact the purposes and values of GBNPP lands because all project-related effects on cultural resources would occur within the project boundary or on state or private lands. Under the Corridor Alternative, designation of the unnamed island near Blue Mouse Cove would have no effect on cultural resources because none have been identified on this island. Designation of the Alsek Lake or Cenotaph Island parcels would be expected to slightly benefit the potential traditional cultural properties in Lituya Bay and Dry Bay because designated wilderness offers the highest level of protection within NPS. Neither designation would result in an impairment of GBNPP resources that fulfill specific purposes of preserving lands and waters containing significant historical or archaeological, or cultural values, as identified in the enabling legislation, or that are key to the natural integrity of these parks. The anticipated effects on cultural resources under this alternative would not impair the ability of GBNPP to continue to operate and manage its lands as outlined in its enabling legislation (see section 1.7.4).

Under the Corridor Alternative, conveying either the Long Lake parcels or the Klondike Gold Rush parcels from the state of Alaska to NPS would enhance opportunities to identify, evaluate, and manage any archaeological sites that exist on the Long Lake parcels in WSNPP and the portions of the Chilkoot Trail and associated historic sites on parcels in KGNHP. Conveyance of these lands would not result in an impairment of WSNPP and/or KGNHP resources that fulfill specific purposes to allow traditional uses or preserve the historic structures and trails associated with the Klondike Gold Rush of 1898 identified in the enabling legislation, or are that key to the natural integrity of these parks. The anticipated effects on cultural resources under this alternative would not impair the ability of WSNPP and KGNHP to continue to operate and manage their lands as outlined in their enabling legislation (see section 1.7.4).

4.10 SOUNDSCAPE/NOISE

Several evaluation parameters are relevant to identify and describe the potential impacts on soundscapes in the project area:

1. Audibility (i.e., whether a sound can be heard at all within the natural soundscape)

2. Sound level (i.e., amount of sound energy or loudness of the sound)

3. Time factors (i.e., duration, frequency of occurrence, and timing)

The assessment of the potential effects of the project on soundscapes includes a discussion of the context of soundscapes in the project area. The intensity of the impact on soundscapes is generally characterized by quantifying the sound level and its audibility through the use of typical data. The duration of the impact is described where necessary to understand the context and intensity of the impact.

4.10.1 No-action Alternative

4.10.1.1 Effects Analysis. Under the No-action Alternative, the proposed project would not be constructed; the land surrounding the proposed project would be retained within the National Wilderness Preservation System for the foreseeable future and would continue to be managed as wilderness in accordance with the GBNPP GMP; and there would be no land exchange. Under the No-action Alternative, the main sources of human-made sound in the project area would be related to the operations of the Gustavus airport, vehicle traffic on Rink Creek Road and in eastern Gustavus, and the operation of motorized boating near the shore. Currently, the existing ambient noise level in the project area is low, typically 25 to 45 dBA (see section 3.10) and would remain the same under the No-action Alternative.

Soundscape resources of the Kahtaheena River area and the proposed wilderness designation lands would bear no effects because they would still be protected under NPS wilderness visitor use policy and management that supports the preservation of soundscape resources in the state of Alaska.

4.10.1.2 Cumulative Effects Analysis. Under the No-action Alternative, there would be no project-related actions proposed in the Kahtaheena River watershed, the state lands near the WSNPP and KGNHP, the unnamed island near Blue Mouse Cove, Cenotaph Island, and Alsek Lake. Therefore, there is no potential for cumulative effects on soundscape resources based on interaction between a project and a non-project action.

4.10.1.3 Conclusion. Under the No-action Alternative, noise levels in the vicinity of the proposed project area would remain at their current low levels (see section 3.10). Overall, the effects on soundscape resources anticipated from this alternative would not result in an impairment of GBNPP resources that fulfill specific purposes identified in the enabling legislation or are key to the natural integrity of the park. Under this alternative, GBNPP would continue to operate and manage its lands as outlined in the enabling legislation to among other mandates, allow the park to remain a large wildlife sanctuary without the changes that extensive human activities would cause (see section 1.7.4).

The effects on soundscape resources anticipated from this alternative would not result in an impairment of WSNPP or KGNHP resources that fulfill specific purposes identified in the enabling legislation, or are key to the natural integrity of these parks. Under this alternative, WSNPP and KGNHP would continue to operate and manage their lands as outlined in their enabling legislation (see section 1.7.4).

4.10.2 GEC's Proposed Alternative

4.10.2.1 Effects of Construction and Operation. The primary effects on soundscapes from the proposed action would be those associated with the construction and operation of the hydroelectric generation facility. The development of a road, penstock, tailrace, intake facilities, powerhouse, and other hydroelectric production and transmission structures would generate sporadic human-made sound during the 24-month construction phase of the project that might affect the natural quiet in the vicinity of the project area. The operation of the hydroelectric generating facility would generate low-level human-made sounds. The development of the Falls Creek Hydroelectric Project would require the establishment of rock quarries along the access road to provide material for construction and project development. Furthermore, if the state decides to develop mineral resources in the exchange lands, noise would be generated from these mining operations.

Project Construction. During construction of the roads and facilities, the natural sound would be diminished along Rink Creek Road as vehicle and construction noise emanate from the area. The acoustic disturbances of the construction would exist for 24 months and would be buffered by the surrounding vegetation. Sound disturbances created during construction of the access road and project facilities would be most disruptive to residents and businesses of eastern Gustavus to the west of the project area, to Native allotment lands, and to any visitors and wildlife in adjacent GBNPP lands east of the Kahtaheena River. Sporadic noise would be noticeable during the construction from drilling, hauling, and excavation, and road traffic. Most activities would be expected to regularly exceed the EPA 55 dBA noise guideline in the direct vicinity of the project area. Typically, bulldozers, trucks, and other construction vehicles and generators generate up to 85 dBA measured at 50 feet, which would be audible for 1 mile or more. Chain saws or logging trucks would generate up to 110 dBA at 50 feet, which would be audible for 1 mile or more. Surface blasting, trucks with inadequate mufflers, and truck back up alarms would generate more than 120 dBA and could be audible for up to 2 miles. The EPA's 55-dBA noise guideline could be exceeded by 30 dBA to 55 dBA intermittently at least 8 hours a day for 5 days a week during the 24-month construction period. Ambient noise levels, which are typically 25 to 45 dBA (see section 3.10), also would be exceeded with the same frequency.

These human-made sounds could be mitigated. GEC proposes to use small construction equipment and would also preclude all nonproject vehicle use along the access road reducing the disturbances by vehicle traffic to soundscapes in the area. GEC does not propose to use helicopters to access the project facilities during project construction.

Despite proposed use of mitigation techniques, construction activity would have a negative effect on the soundscape in the vicinity of the project area. The impacts would be sporadic (during construction time only), yet they would last for 24 months. The proposed mitigation techniques, such as use of small construction vehicles and prohibiting non-project vehicles on the access road, would minimize the negative effects on soundscape resources.

Project Operations. The diversion of 2 to 23 cfs of stream flows would reduce the sounds associated with water falling over the waterfalls. The generator would produce a constant, low frequency drone that would occur 24 hours a day for the duration of the hydroelectric power generation activities. However, because it is housed in a building, it would not likely be heard from a distance of more than 100 feet. The sounds associated with the powerhouse and facilities only would be audible to visitors to the immediate area and would not be greater than those of the nearby Lower Falls or the Gustavus airport. The public could possibly still hear the Lower Falls at 30 cfs. However, with reduced flows by 23 cfs, it is likely that ambient sound levels would concurrently be reduced, and there would be a greater potential to hear the generator located nearby and human activity in the immediate and surrounding area. Wildlife and visitors in the project area could hear these sounds. However, because of the distance between the source of the sound (the generator) and the receptors in the park and in Gustavus (5 miles or more), visitors, residents, and wildlife (see section 4.8, *Wildlife*, for more analysis of effects on wildlife) likely would be unaware of the sounds produced by the project under normal operating conditions. Other noise sources that are not associated with the proposed project but may occur in the project area are ATVs and helicopters. The operation of the proposed project would not have a significant effect on soundscape resources of the area.

As a result of a reduction in operation of the diesel generators located near the Gustavus airport, there would be a corresponding reduction in noise in the immediate vicinity of these units.

4.10.2.2 Effects of the GBNPP and Wilderness Boundary Adjustment

Effects of Removal and Loss of the Land from GBNPP. The removal of the middle and lower Kahtaheena River from GBNPP would reduce the amount of natural, water-related soundscape available within GBNPP. There would be negative effects on soundscape resources in adjacent GBNPP lands during the 24-month construction period. However, during operation of the project effects would be negligible.

Proposed Land Exchange Parcels. The exchange of the Long Lake parcels to NPS would bring these parcels under the management of WSNPP. Exchange of the parcels adjacent to KGNHP to NPS would bring these parcels under the management and values of KGNHP. All of these parcels are currently owned by the state of Alaska and managed to protect their scenic and wildlife values including soundscape. Therefore, although the exchange of these parcels would have a negligible effect on soundscape resources in the short term, the exchange may provide increased, long-term protection of soundscape in these areas.

Under the land exchange conditions, the state would reserve the right to approve mineral extraction operations to the lands transferred to them even though they would be managed as wildlife habitat. This action would have a negative effect on wildlife. Similar to the construction phase of the project (see section 4.10.2.1), activities such as blasting, hauling, and truck traffic would have negative effects on soundscape because they would generate high decibels of noise that could be audible at distances of more than 2 miles.

Wilderness Designation Parcels. The designation of the unnamed island near Blue Mouse Cove, Cenotaph Island, and the land at Alsek Lake near Dry Bay would not affect soundscape resources because GBNPP currently manages these lands as *de facto* wilderness. The effects on soundscape resources of designating these lands as wilderness would be negligible.

4.10.2.3 Cumulative Effects Analysis. Potential increases in recreational guiding and tourism, or subsistence and recreational hunting, could occur as a result of estimated future population growth in Gustavus, or as a result of increased tourism at GBNPP. The increased activity could result in a greater frequency of occurrence of unwanted sounds in backcountry areas. The continuous operation of the proposed project generation facilities and the occasional maintenance vehicle traffic along the access road would increase the human-made sounds and noises in adjacent natural areas. The combined effects of the potential increases in noise from recreation or hunting activities and the increased noise levels from project-related human-caused activities may produce a cumulative increase in the frequency of occurrence of observed noise levels in the backcountry areas adjacent to the project.

There are no project-related actions identified that would result in an impact on soundscapes for the WSNPP and KGNHP transfer parcels. Therefore, no cumulative effects on soundscape resources would occur as a result of the interaction between project actions and non-project actions at these sites.

There are no project-related actions identified that would result in an impact on soundscapes for the proposed wilderness parcels at the unnamed island near Blue Mouse Cove, Cenotaph Island, or Alsek Lake. Therefore, no cumulative effects on soundscape resources would occur as a result of the interaction between project actions and non-project actions at these sites.

4.10.2.4 Conclusion. Under GEC's proposal, construction of the project would increase noise levels intermittently and negatively affect the soundscape resources of the Kahtaheena River area. Operation of the project would increase low-noise in the immediate vicinity of the powerhouse and would decrease natural, water-related sounds in the Kahtaheena River. The primary effects of the construction and operation of the proposed project on soundscape resources would be experienced by residents west of the project area and visitors and wildlife on the adjacent GBNPP lands east of the Kahtaheena River near the diversion dam and downstream of the powerhouse. Other noise sources that are not associated with the proposed project but may occur in the project area are ATVs and helicopters.

The purposes and values of GBNPP identified in the enabling legislation include allowing GBNPP to remain a large sanctuary without the changes that extensive human activities would cause. The construction and operation of the proposed project would not adversely impact the purposes and values of GBNPP because the majority of the effects would occur on either state land or within the FERC project boundary. Any effects on soundscape resources within GBNPP would be localized to the immediate project area and would not substantially diminish the purposes and values of GBNPP as a sanctuary. Under GEC's proposal, the soundscape resources of the unnamed island near Blue Mouse Cove, Cenotaph Island, and lands at Alsek Lake would not be affected because these lands would remain in GBNPP.

Overall, the level of effects on soundscape resources would not result in impairment of GBNPP resources that fulfill the specific purposes identified in the enabling legislation (see section 1.7.4), or which are key to the natural integrity of the park.

Conveying soundscape resources of the Long Lake parcels within WSNPP and the parcels neighboring KGNHP to NPS would result in negligible effects because they are removed from the project area, and they would be protected under NPS policy and management that supports the preservation of soundscape resources. Because the effects would be negligible, there would be no impairment of WSNPP or KGNHP soundscape resources that fulfill specific purposes identified in the enabling legislation (see section 1.7.4), or are key to the natural integrity of these parks.

4.10.3 Maximum Boundary Alternative

4.10.3.1 Effects of Construction and Operation. Under this alternative, the effects of constructing and operating the project on soundscape resources of the project area and its vicinities would be the same as those described above in section 4.10.2. Furthermore, the GBNPP boundary would be further away from the sound source. Therefore, there would be less potential for noise to be heard on GBNPP land where the majority of visitation occurs. Other noise sources that are not associated with the proposed project but may occur in the project area are ATVs and helicopters.

4.10.3.2 Effects of the GBNPP and Wilderness Boundary Adjustment. The Maximum Boundary Alternative would affect the amount of land exchanged as well as the amount of land designated as wilderness. The removal of the middle and lower Kahtaheena River from GBNPP would reduce the amount of natural water-related soundscape available within GBNPP. The effects on soundscape resources in adjacent GBNPP lands would be the same as under GEC's proposal with adverse effects during the 24-month construction period and negligible effects during the operation of the project.

Exchange of the parcels at Long Lake and/or the exchange of the Klondike parcels to NPS would not affect the soundscape resources of these lands because the state of Alaska, for all practical purposes, currently manages both these lands in a manner compatible with NPS goals outlined in the WSNPP and KGNHP management plans.

Designating all or parts of the lands, including the unnamed island near Blue Mouse Cove, Cenotaph Island, and the lands at Alsek Lake, as wilderness would have negligible effects on soundscape resources. For all practical purposes, these lands are currently managed as if they were wilderness lands under the GBNPP Wilderness Management Plan.

4.10.3.3 Cumulative Effects Analysis. The types of cumulative effects that could be expected to occur on soundscape resources under this alternative are the same as those described under GEC's Proposed Alternative in section 4.10.2.3.

4.10.3.4 Conclusion. Under the Maximum Boundary Alternative, the effects of the construction and operation of the project would be the same as described under GEC's proposal (see section 4.10.2.1), except that 1,145 acres including the entire bypassed reach and lands to the west of the river would be conveyed to the state of Alaska and would be included in the FERC project boundary. The additional lands conveyed to the state would provide a buffer between the project and the eastern boundary of the GBNPP, and eastern boundary of the GBNPP would be farther away from the sound source. Other noise sources that are not associated with the proposed project but may occur in the project area are ATVs and helicopters.

The purposes and values of GBNPP identified in the enabling legislation include allowing GBNPP to remain a large sanctuary without the changes that extensive human activities would cause. The construction and operation of the proposed project would not adversely impact the purposes and values of GBNPP because the majority of the effects would occur on either state land or within the FERC project boundary. Any effects on soundscape resources within GBNPP would be localized to the immediate project area and would not substantially diminish the purposes and values of GBNPP as a sanctuary. Under the Maximum Boundary Alternative, the soundscape resources of the unnamed island near Blue Mouse Cove, Cenotaph Island, and lands at Alsek Lake would not be affected because these lands would remain in GBNPP.

Overall, the level of effects on soundscape resources would not result in impairment of GBNPP resources that fulfill the specific purposes identified in the enabling legislation (see section 1.7.4), or which are key to the natural integrity of the park.

Conveying soundscape resources of the Long Lake parcels within WSNPP and the parcels neighboring KGNHP to NPS would result in negligible effects because they are removed from the project area, and they would be protected under NPS policy and management that supports the preservation of soundscape resources. Because the effects would be negligible, there would be no impairment of WSNPP or KGNHP soundscape resources that fulfill specific purposes identified in the enabling legislation (see section 1.7.4), or are key to the natural integrity of these parks.

4.10.4 Corridor Alternative

4.10.4.1 Effects of Construction and Operation. The effects of constructing and operating the hydroelectric power generation system on soundscape resources associated with this alternative would be similar to those described in section 4.10.2. Other noise sources that are not associated with the proposed project but may occur in the project area are ATVs and helicopters. However, because the Corridor Alternative results in less land being transferred to the state, there would be less land available for ATV use and helicopter landings resulting in a corresponding decrease in effects on soundscape. Similar to the Maximum Boundary Alternative, because there would not be state-owned land that could be developed for mineral extraction, the impacts associated with these activities (see section 4.10.2.2) would not exist under this alternative.

4.10.4.2 Effects of the GBNPP and Wilderness Boundary Adjustment. The removal of the middle and lower Kahtaheena River from GBNPP would reduce the amount of natural water-related soundscape available within GBNPP. The effects on soundscape resources in adjacent GBNPP lands would be the same as under GEC's proposal with adverse effects during the 24-month construction period and during the operation of the project.

The Corridor Alternative would also reduce the amount of lands exchanged. Exchange of either the Long Lake parcels or the Klondike parcels would not affect soundscape resources of the lands exchanged because the state of Alaska currently manages these lands in a manner compatible with NPS goals. The exchange of one or both of these lands would bring them under either WSNPP or KGNHP management practices. The practical effect would be negligible because management practices would remain similar.

The Corridor Alternative would affect the amount of lands designated as wilderness at either the unnamed island near Blue Mouse Cove, Cenotaph Island, or the lands at Alsek Lake. These lands are currently not designated as wilderness; however, for all practical purposes, they are managed as such as mentioned in the GBNPP Wilderness Management Plan. Regardless of which lands become admitted under the wilderness designation, all the lands would continue to be managed as such. The practical effect on the soundscape resources under the Corridor Alternative would be negligible.

4.10.4.3 Cumulative Effects Analysis. The types of cumulative effects that could be expected to occur on soundscape resources under this alternative are the same as those described under GEC's Proposed Alternative in section 4.10.2.3.

4.10.4.4 Conclusion. Under the Corridor Alternative, the anticipated effects would be the same as described under GEC's proposal (see section 4.10.2.1), except that only 680 acres including the entire bypassed reach and lands to the west of the river would be conveyed to the state and included in the FERC project boundary. The additional lands conveyed to the state between the bypassed reach and the GBNPP boundary would provide a buffer between the project and the boundary of GBNPP. As a result, the boundary of GBNPP would be farther away from the sound source. Other noise sources that are not associated with the proposed project but may occur in the project area are ATVs and helicopters.

The purposes and values of GBNPP identified in the enabling legislation include allowing GBNPP to remain a large sanctuary without the changes that extensive human activities would cause. The construction and operation of the proposed project would not adversely impact the purposes and values of GBNPP because the majority of the effects would occur on either state land or within the FERC project boundary. Any effects on soundscape resources within GBNPP would be localized to the immediate project area and would not substantially diminish the purposes and values of GBNPP as a sanctuary. Under the Corridor Alternative, the soundscape resources of the unnamed island near Blue Mouse Cove, Cenotaph Island, and lands at Alsek Lake would not be affected because these lands would remain in GBNPP.

Overall, the level of effects on soundscape resources would not result in impairment of GBNPP resources that fulfill the specific purposes identified in the enabling legislation (see section 1.7.4), or which are key to the natural integrity of the park.

Conveying soundscape resources of the Long Lake parcels within WSNPP and the parcels neighboring KGNHP to NPS would result in negligible effects because they are removed from the project area, and they would be protected under NPS policy and management that supports the preservation of soundscape resources. Because the effects would be negligible, there would be no impairment of WSNPP or KGNHP soundscape resources that fulfill specific purposes identified in the enabling legislation (see section 1.7.4), or are key to the natural integrity of these parks.

4.11 VISUAL RESOURCES (AESTHETICS)

Several evaluation parameters are used to identify and describe the impacts on the visual aesthetics of the project area. These parameters include:

1. Views from specific viewpoints
2. Vegetation/land disturbance
3. Flows
4. Recreation viewers

The discussion of the potential effects of the project on aesthetics includes the context of the aesthetic resources in the project area. The intensity of the impact on aesthetic resources is generally characterized by quantifying the area of impact, the changes in flows in the Kahtaheena River, and the potential number of recreationists affected. The duration of the impact is described where necessary to understand the context and intensity of the impact.

4.11.1 No-action Alternative

4.11.1.1 Effects Analysis. Under the No-action Alternative, the proposed project would not be constructed, the land surrounding the proposed project would be retained within GBNPP, and there would be no land exchange. Under the No-action Alternative, the proposed project area would remain visually intact as described in section 3.11. Under this alternative, there would be no effect on visual resources.

Under the No-action Alternative, the lands surrounding the Kahtaheena River area would not be exchanged with the state of Alaska, and GBNPP wilderness land would not be removed. All lands proposed for exchange under the proposed action would continue to be managed as wilderness under GBNPP wilderness visitor use policy and management. Because there would be no change in NPS management and policy, the overall effect of this action on visual resources would be none.

ADNR would continue to manage the Long Lake parcels consistent with its Copper River Basin Area Plan, which protects the lands around the lake from development or mineral extraction and prohibits development along the north side of the lake. Under the No-action Alternative, the management of these lands by ADNR for the protection of fish and wildlife habitat would continue. There would be no effects on the visual resources of the parcels surrounding Long Lake under this alternative.

The lands at KGNHP would not be affected because, although they are owned by the state, they are currently managed by NPS to ensure compatibility with uses associated with KGNHP, with emphasis placed upon protection of wetlands, mountain goat habitat, anadromous fish streams, and the historical resources associated with the Chilkoot Trail. Accordingly, the parcels within KGNHP would experience no effects under the No-action Alternative.

Under the No-action Alternative, the visual resources of the unnamed island near Blue Mouse Cove, Cenotaph Island, and Alsek Lake would be unaffected, and they would continue to be managed by GBNPP as *de facto* wilderness. There would be no effects on the visual resources of these lands under the No-action Alternative.

4.11.1.2 Cumulative Effects Analysis. Under the No-action Alternative, revegetation of the previously logged areas and road corridor would continue, and the natural regrowth would enhance the visual elements of the forest over time by obscuring prior land disturbances and returning these areas to more natural states.

There would be no cumulative effects on visual resources of state-owned parcels adjacent to WSNPP and KGNHP; or the parcels at Cenotaph Island, the unnamed island near Blue Mouse Cove, and Alsek Lake because no project actions would occur. Therefore, there is no potential for negative cumulative effects on visual resources based on the interaction between a project and a non-project action.

4.11.1.3 Conclusion. Under the No-action Alternative, the proposed project area would continue to exist in its current visual state, and the level of effects on visual resources anticipated from this alternative would not result in an impairment of GBNPP resources that fulfill specific purposes as identified in the enabling legislation or are key to the natural integrity of the park. Under this alternative, GBNPP would continue to operate and manage its lands as outlined in the enabling legislation (see section 1.7.4).

The effects on visual resources anticipated from this alternative would not result in an impairment of WSNPP or KGNHP resources that fulfill specific purposes as identified in the enabling legislation, or are key to the natural integrity of these parks. Under this alternative, WSNPP and KGNHP would continue to operate and manage their lands as outlined in their enabling legislation (see section 1.7.4).

4.11.2 GEC's Proposed Alternative

4.11.2.1 Effects of Construction and Operation. The effects on visual aesthetic resources would be those associated with the construction and operation of the hydroelectric generation facilities. Constructing a road, penstock, tailrace, intake facilities, powerhouse, and other hydroelectric production and transmission structures would introduce new human-made visual elements into an almost pristine wilderness area. In addition to the presence of new structures, the diversion of from 2 to 23 cfs of water from the river would reduce the volume of flow in the bypassed reach and over the Lower Falls, diminishing the aesthetic attraction of the falls to recreationists in the area. Additionally, if the state pursues mineral extraction possibilities within the exchanged lands, operations would further diminish the visual resources of the area. To mitigate these effects, participants in scoping make four recommendations with implications on aesthetic resources: NPS-RTCA and GEC recommend minimum flows, and NPS-RTCA recommends landscape and facility design practices to blend the natural setting. The state of Alaska, in comments on the draft EIS, recommends an alternative route to access the proposed project that would minimize the quantity and length of easements that would need to be obtained, and NPS-RTCA recommends a flow conveyance device to inform the public on the status of current flows.

Project Construction. GEC proposes that the powerhouse structure be sited in a bight in the Kahtaheena River 0.21 miles below the Lower Falls and 0.45 miles from the shore. GEC also proposes to limit all non-project vehicle use along the access road which would reduce the disturbances to the aesthetic resources in the area caused by vehicle and pedestrian traffic. Because the proposed project would be in a relatively undisturbed area, NPS-RTCA's recommendations to retain vegetation where possible and site and design facilities to blend with the natural setting are appropriate measures to mitigate the development.

Siting the powerhouse in the location proposed by GEC would make it nearly invisible from nearby vistas or from the river including GBNPP and Native allotments. The intake site would also be located where facilities would be visible only to persons very close (100 to 200 feet) to the structures or directly overhead from the air.

The presence of a cleared and maintained access road would contrast with the current wilderness setting in the proposed project area. Because of the density of the surrounding forest, individuals viewing the area from Gustavus Flats or the adjacent GBNPP lands would not be able to see the proposed service road routes and facilities, except for the segment of the access road extending from the end of Rink Creek Road. Overall, construction would directly affect about 29.6 acres of lands, of which about 20 acres would be temporarily disturbed and replanted following construction. The roads

(3.6 miles long and 14 feet wide) and facilities would permanently replace an estimated 9.6 acres of vegetation. The state of Alaska (ADNR) recommends an alternative route that would require approximately 1.5 more miles of road construction permanently disturbing 2.5 acres more than GEC's proposal. Under this recommendation, the transmission lines would be routed along the proposed road, then head in a southern direction across the Mental Health Trust lands eventually aligning with the transmission line right-of-way proposed by GEC southeast of the airport. As such, the effects resulting from ADNR's recommended alternative route would not be as visible to people on the beach, from within GBNPP or the Native allotments. Of the two Native allotments, the northern boundary of the George allotment would be within a few hundred feet to the access road, however due to the dense vegetation, visible evidence associated with the road would be extremely rare if at all. Construction of the access road and facilities would compromise the auditory environment associated with the parcels, however construction activities are expected to last two years. Under the state of Alaska's recommended road alignment the access road would be located further north from the allotment boundaries resulting in even less of an effect on the aesthetic resources of these parcels. Constructing the road and transmission lines would cause visible scars, especially where there is sidecasting of waste materials along the roads and where trees are felled.

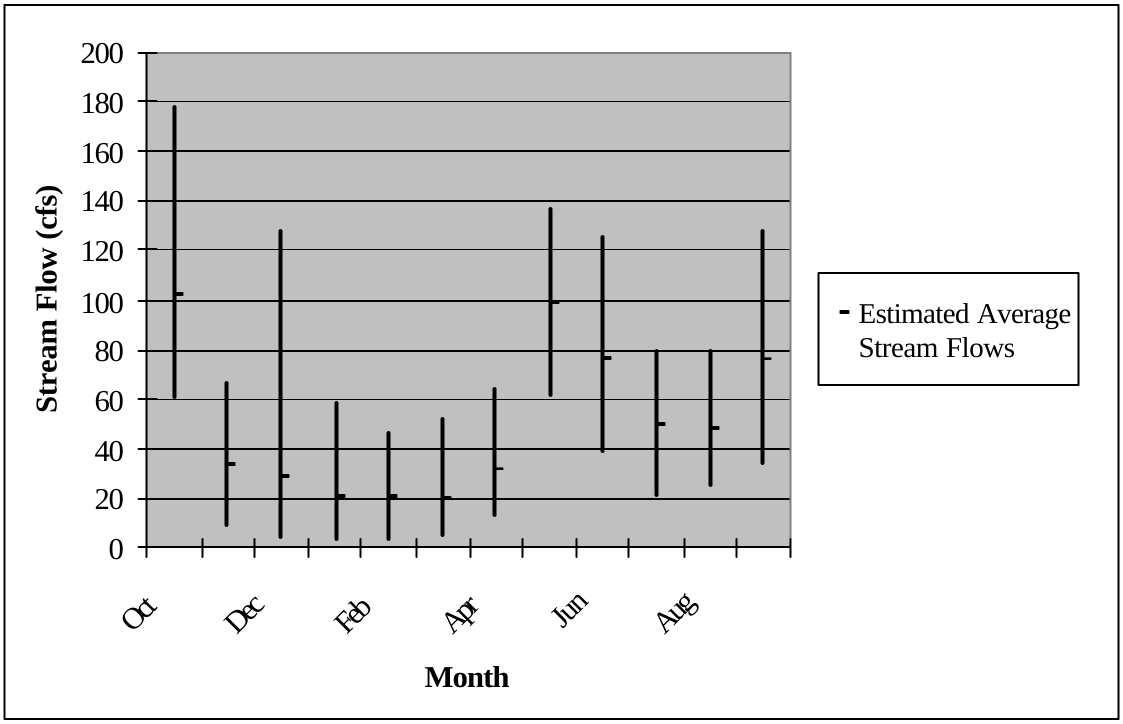
Visitors to areas of GBNPP adjacent to the project area would not be able to see any project structures with the exception of parts of the access road as described above. These facilities would last throughout the term of a license (30 to 50 years) and be located in clusters of development all within a 5-mile radius. Visitors within GBNPP along the eastern boundary of the proposed project would, at certain times of the year, experience a diminished aesthetic experience when viewing the bypassed reach and the Lower Falls. Social trails might be expected to develop over a 50 year period as GBNPP visitors curious about project facilities and the Kahtaheena River cross the park boundary.

Project Operations. The proposed project would reduce flow by 2 to 23 cfs in the bypassed reach and over the Lower Falls. The estimated average available flow in the Kahtaheena River varies from below 20 cfs in February to over 100 cfs in September-October. Figure 4-5 shows the estimated average stream flows at the proposed diversion structure for the last 32 years and is assumed to represent flows over the Lower Falls.[51] The reduced flow regime would be most noticeable at the Lower Falls because this is one of the prime destinations of hikers into the proposed project area. Effects on the flows would not occur below this point because flows in the lower 0.4 miles of the river would remain the same as under current conditions because the project would operate on a run-

51 To make this determination, GEC estimated the average stream flows for the Kahtaheena River based upon hydrographic information by correlating the actual gaged flows on the Kahtaheena River with those on the nearby and similar Kadashan River near Tenakee Springs.

of-river mode where inflow upstream of the diversion would equal outflow downstream of the project. The Mills allotment is adjacent to and contains a portion of the lower Kahtaheena River, however since water used for hydroelectric generation would be returned to the river below the Lower Falls, the aesthetic resources associated with enjoyment of water in the river would not be compromised by the proposed project.

Figure 4-5. Estimated average streamflows at the proposed diversion structure. (Source: Preparers)



NPS-RTCA recommends that the project be required to meet certain minimum flows to mitigate the aesthetic resources damaged in the bypassed reach. NPS-RTCA's minimum flows would have the same magnitude and timing as those recommended by FWS to protect the habitat values in the bypassed reach discussed in section 4.4, *Water Quantity and Quality* (see table 4.4-2). The minimum flows recommended by NPS-RTCA would maintain between 10 and 30 cfs in the bypassed reach throughout the year.

Table 4.11-1 shows the reduced flow (as a percentage reduction below the average flows) for the river under GEC's proposed and NPS-RTCA's recommended flows. Differences in flow between the median flows and the proposed minimum instream flows would be smallest in May and October (a 24 percent reduction) and greatest in April (a 68 percent reduction). Between May and October, visitors to the Lower Falls would experience flows up to approximately 50 percent less than median flows under both GEC and NPS-RTCA flow regimes. However, between November and April, flows over the Lower Falls would be higher under the NPS-RTCA's recommended flows compared to GEC's proposed flows (table 4.11-2).

Table 4.11-1. Estimated flows for the Kahtaheena River representative of the Lower Falls compared to the flows from GEC's proposed flow regime, NPS-RTCA recommended flow regime, and estimated number of recreationists affected by change in flows. (Source: Preparers)

Month	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**July**	**Aug**	**Sep**
Monthly average (cfs)	102	34	29	20	21	20	31	99	77	50	48	76
Average flows over the Lower Falls under GEC's proposed (cfs)	79	11	6	5	5	5	8	76	54	27	22	53
Percent below average	23	68	79	75	75	75	74	23	30	46	54	30
Average flows over the Lower Falls under NPS-RTCA flows (cfs)	79	25	10	10	10	10	10	76	54	27	22	53
Percent below average	23	26	65	50	50	50	68	23	30	46	54	30
Estimated visitors in year 30[a]	1	1	1	1	1	1	1	34	34	34	34	34

[a] The estimated number of recreationists in the table does not account for construction of the road.

Table 4.11-2. Estimated median monthly flows (cfs) for the Kahtaheena River at the Lower Falls under flow regimes proposed by GEC, recommended by ADFG and DOI, and no minimum flow requirements.[a] (Source: Preparers).

	Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**
No Action	97	28	21	15	15	17	28	97	75	49	46	65
NPS-RTCA recommended	74	28	12	12	12	12	12	74	52	26	24	42
Percent reduction	24%	0%	43%	20%	20%	29%	57%	24%	31%	47%	48%	35%
GEC proposed	74	10	7	7	7	7	9	74	52	26	23	42
Percent reduction	24%	64%	67%	53%	53%	59%	68%	24%	31%	47%	50%	35%
No minimum flow requirement	74	5	2	2	1	2	5	74	52	26	23	42
Percent reduction	24%	82%	90%	87%	93%	88%	82%	24%	31%	47%	50%	35%
Estimated visitors in year 30[b]				5						170		

[a] Based on daily mean flows estimated for the gage above the Upper Falls developed by applying seasonal regressions reported by Coupe (2001), and adjusted by the monthly average percent accretion between the two Kahtaheena River gages based on concurrent reported daily mean flows.

[b] The estimated number of recreationists in the table does not account for construction of the road.

The following analysis addresses the intersection between the visually appealing nature of waterfalls and the number of people who view them. The focal point rests on the magnitude of the change in flow over the falls from project operations with the number of visitors observing those flows. The effects of water withdrawals would be most significant during times when recreationists venture to the river to enjoy the aesthetic beauty of the Lower Falls. Based on GEC estimates, survey respondent information, and estimates (see section 4.12, *Recreation Resources*), more than 95 percent of visitors to the Lower Falls go between May and September (the recreation season). The recreation season coincides with some of the highest monthly average flows within the river. As such, 30 years from now, approximately 170 people during the recreation season would view flows over the Lower Falls that would be compromised because of the proposed project (see section 4.12.2.1). Given the construction of a road in the area, the amount of foot traffic in the area, the proximity of the Bear Track Inn, and the natural attraction of a waterfall at the end of a maintained road, many more people can be expected to visit the Lower Falls, and visitation likely will increase. On a monthly basis, recreationists would experience a 23 percent reduction from average flows in May, a 30 percent reduction in June, a 46 percent reduction in July, a 54 percent reduction in August, and a 30 percent reduction in September (see table 4.11-1).

The estimated reductions in flows are based on GEC diverting 23 cfs out of the river during average flows in the river. Under below average flow conditions during naturally dry periods, water withdrawals would be dictated by the proposed minimum instream flow requirements. Because most recreation visits occur between May and September, analysis of low-flow conditions focuses on the recreation season; however, the off-season likely would also increase.

Flows that are exceeded 80 percent of the time (low flows) range from 89 cfs in May to 35 cfs in August (table 4.11-3). At these flows, visitors to the Lower Falls in May would observe flows around 66 cfs (89 cfs natural low flow minus the 23 cfs diverted through the powerhouse). Under the NPS-RTCA minimum flow regime, visitors to the falls would experience flows at or above 20 cfs between July and August, while under GEC's minimum flow regime, visitors to the Lower Falls during the same period would experience flows between 12 and 17 cfs because of the lower flow recommendation. See figure 3-9 (section 3.11) for a photograph of flows over the Lower Falls at 11 cfs. Thus, during low-flow periods, visitors would be afforded between 4 and 8 cfs (8 and 23 percent, respectively) more flow under the NPS-RTCA recommended flows than under GEC's proposed flows.

Table 4.11-3. Estimated flows over the Lower Falls under low-flow conditions, GEC's proposed flow regime, and NPS-RTCA recommended flow regime. (Source: Preparers)

	May	June	July	August	September
Flows exceeded 80 percent of the time (low flows) (cfs)	89	54	40	35	59
Flows under GEC's proposed flow regime (cfs)	66	31	17	12	36
Percent below low flows	74	57	42	34	61
Flows under NPS-RTCA flow regime (cfs)	66	31	20	20	36
Percent below low flows	74	57	50	57	61

NPS-RTCA also recommends that GEC provide a means for prospective visitors to check instantaneous flow rates in the bypassed reach. Incorporating NPS's recommendation to install electronic flow conveyance information devices (flow phone, web page, etc.) so the public could check flow rates prior to visiting would provide visitors a means to check when flows may be sufficient to enjoy larger waterfalls.

NPS-RTCA further recommends the development of a public access/recreation plan. Formal recreation facilities within the proposed boundary, if recommended by the plan, could further diminish the aesthetic qualities observed by recreationists seeking a natural setting, increasing the magnitude of effects of the project on other resources such as aesthetics (see section 4.11, *Visual Resources*).

Under GEC's proposed action, the presence of the road and project structures and the diversion of stream flows would conflict with the existing natural forest and stream flows. With the exception of the access road, this alternative would have small, localized effects on the aesthetic resources. Visitors would have to be in close range (estimated 100 feet or less) with an unobstructed view to see the structures. Based on the location of the structures and the dense forest cover, it is unlikely that persons overhead could see the project facilities save for the access road. The structures associated with hydroelectric generation (road, pump house, diversion pipeline) and the reduced instream flows associated with facility operation would exist for the duration of the license (from 30 to 50 years) or longer. Based on the expected time frame, these structures would negatively affect the aesthetic resources and the concentration of facilities in localized areas.

4.11.2.2 Effects of the GBNPP and Wilderness Boundary Adjustment

Effects of Removal and Loss of the Land from GBNPP. The transfer of lands of the middle and lower Kahtaheena River out of GBNPP would have the greatest significance to aesthetic resources associated with the waterfalls within the stream reaches. The project would remove 4.3 miles of stream from GBNPP. The Kahtaheena

River is one of 75 streams having basins in the 3.9 to 39 square miles size category of streams draining the coastline of GBNPP (Soiseth and Milner, 1993). In addition, the hike to the stream exhibits certain characteristics that recreationists enjoy when hiking in the area, including mixed habitat types of flat grasslands, beach shoreline, and the steep forested area, home to some of Excursion Ridge's few, if not only, significant waterfalls. Excursion Ridge is steep and heavily forested, which makes the area extremely inaccessible. Because of this lack of access, NPS has very little documentation of the streams and stream characteristics in this area and, it is unknown how unique the waterfalls of the Kahtaheena River are to this portion of GBNPP (personal communication from M. Kralovec, GBNPP-NPS, with J. Splenda, Louis Berger Group, on April 29, 2003). What is unique, however, is the proximity and relative ease of access residents are afforded to the Lower Falls from the town of Gustavus.

Construction of GEC's proposed project would remove the middle and lower sections of the Kahtaheena River from GBNPP, including four waterfalls that currently lie within the park boundary. Although the removal of four waterfalls and 4.3 miles of river section from GBNPP would pose a significant contrast to the existing visual landscape, and would be observable over a long period, thus resulting in a negative effect, the effect would be localized, and, it is uncertain what similarly unique aesthetic features (waterfalls) would remain. Regardless, a substantial portion of the stream including the 10 km Falls would remain within the park and would be afforded the level of protection mandated for wilderness areas.

Proposed Land Exchange Parcels. The exchange of the Long Lake parcels to NPS would bring these parcels under the management of WSNPP. Exchange of the parcels adjacent to KGNHP to NPS would bring these parcels under the management and values of KGNHP. Both of these groups of lands are currently owned by the state of Alaska and managed to protect their scenic and wildlife values. Therefore, the exchange of these parcels would have a negligible effect on the aesthetic resources of these parcels by ensuring the long term protection of these resources.

Wilderness Designation Parcels. The designation of the unnamed island near Blue Mouse Cove, Cenotaph Island, and the land at Alsek Lake near Dry Bay would not affect aesthetic resources because, for all practical purposes, GBNPP currently manages these lands as wilderness. The effect of designating these lands as wilderness would be negligible.

4.11.2.3 Cumulative Effects Analysis. Potential logging of lands adjacent to GBNPP and within Native allotments would result in an effect on the viewshed of the Kahtaheena River watershed. The development of the Falls Creek Hydroelectric Project would result in the clearing of some forested areas at the location of the powerhouse, access road, penstock, and transmission line. The combined effects of the potential logging of lands in the Kahtaheena viewshed and forest clearing as a result of the development of the project would produce a cumulative increase in the total amount of native forest vegetation that is cleared in areas adjacent to the Kahtaheena River.

Potential increases in recreational guiding and tourism could occur as a result of estimated future population growth in Gustavus, or as a result of increased tourism at GBNPP. The increased activity could result in a greater number of recreation visitors observing the Lower Falls of the Kahtaheena River. The appreciation of the falls is valued on an individual or group basis at the moment of viewing something, and does not increase or decrease in value depending on the overall number of people that visit the falls. The continuous operation of the Falls Creek Hydroelectric Project would reduce the quantity of streamflow in segments of the Kahtaheena River and over the Lower Falls, reducing its visual appearance to observers. The combined effects of the potential increases in recreational users in the Kahtaheena River area and the decreased visual appearance of the Lower Falls would result in a cumulative decrease in the appreciation of the visual appearance of the Kahtaheena River.

Potential increases in the commercial and residential development in the Gustavus area could occur as a result of estimated future population growth in Gustavus. This development would further reduce the natural visual appearance of the landscape within and near the community of Gustavus. The development of the Falls Creek Hydroelectric Project (powerhouse, access road, etc.) would decrease the natural appearance of areas adjacent to Gustavus. The combined effects of increased development within and adjacent to the community of Gustavus and the development of the Falls Creek Hydroelectric Project would result in a cumulative decrease in the natural appearance of the landscape in the vicinity of Gustavus.

The state maintains the right to develop mineral resources on state-owned lands. The state may potentially conduct mineral development in the future on its land to provide material for road maintenance in the Gustavus area, or for other purposes. This activity would reduce the natural visual appearance of the Kahtaheena River watershed. The combined effects of potential future mineral development by the state and the establishment of rock quarries for project construction may produce an ongoing cumulative decrease in the natural visual appearance of the landscape in areas adjacent to the proposed project.

There are no project-related actions identified that would result in an impact on visual resources for the WSNPP and KGNHP transfer parcels. Therefore, no cumulative effects on visual resources would occur as a result of the interaction between project actions and non-project actions at these sites.

There are no project-related actions identified that would result in an impact on visual resources for the proposed wilderness parcels at the unnamed island near Blue Mouse Cove, Cenotaph Island, or Alsek Lake. Therefore, no cumulative effects on visual resources would occur as a result of the interaction between project actions and non-project actions at these sites.

4.11.2.4 Conclusion. Under GEC's proposal, the visual resources of the Kahtaheena River area would be negatively affected by project construction and operation. The majority of the facilities associated with this action would pose a significant contrast with the surrounding environment and would be detected over a long period of time but these facilities would be visible only from a very short distance away. The primary effects of the construction and operation of the proposed project on visual resources would be at the locations of project facilities and at the northern end of the George allotment and southeastern portion of the Mills allotment in the Kahtaheena River. The project would reduce flow over the Lower Falls on the Kahtaheena River and negatively affect the aesthetic resources in that area. Reduced flow over the Lower Falls would be visible to individuals in the immediate area or from the air. With the exception of the access road, the facilities and the resulting flows in the river would not be visible from the adjacent GBNPP lands. Accordingly, construction and operation of the project would not affect the visual resources of GBNPP.

The purposes and values of GBNPP identified in the enabling legislation include allowing the preservation of lands and waters containing nationally significant scenic values and unrivaled scenic values associated with natural landscapes. The construction and operation of the proposed project would not adversely impact the purposes and values of GBNPP because all effects on visual resources would occur on either state land or within the FERC project boundary. There would be no effects on aesthetic resources within GBNPP. Under GEC’s proposal, the aesthetics resources of the unnamed island near Blue Mouse Cove, Cenotaph Island, and lands at Alsek Lake would not be affected because these lands would remain in GBNPP. GBNPP would continue to operate and manage park lands to preserve the aesthetic values associated with natural landscapes.

Overall the level of effects on the aesthetic resources would not result in an impairment of GBNPP resources that fulfill the specific purposes identified in the enabling legislation to “preserve the unrivaled scenic and geological values associated with natural landscapes” or are key to the natural integrity of the park.

Under GEC’s Proposed Alternative, the aesthetic resources of the Long Lake parcels within WSNPP and the parcels neighboring KGNHP would not be negatively affected because they would receive enhanced protection under NPS policy and management which supports the preservation of the aesthetic resources through the protection of all park resources. Because there would be no adverse effects, there would be no impairment of WSNPP or KGNHP resources that fulfill specific purposes identified in the enabling legislation or are key to the natural integrity of these parks.

4.11.3 Maximum Boundary Alternative

4.11.3.1 Effects of Construction and Operation. Under the Maximum Boundary Alternative, about 1,145 acres of GBNPP designated wilderness would be exchanged with the state of Alaska, and all of this area would be included in the project boundary. All else being equal, the effects on the visual resources would be equal to those mentioned above in section 4.11.2; however, ultimately the effects on the aesthetic resources of GBNPP would depend on the management policy within the project boundary. Effects include the construction of human-made structures in an almost pristine environment, and the operation of such facilities which includes altering the flow regime in the Kahtaheena River. In addition, the state reserves its rights to mineral extraction. All proposals for development or access, including mineral extraction, would be subject to FERC review. Thus the additional level of management makes this alternative slightly more protective of aesthetic resources than the proposed alternative. The effects from this alternative would be expected to last between 30 to 50 years (the term of the license) or longer for areas subject to large amounts of landscape alteration.

4.11.3.2 Effects of the GBNPP and Wilderness Boundary Adjustment. The removal of approximately 1,145 acres from GBNPP would have the greatest effect on the aesthetic resources associated with the waterfalls within this reach. The magnitude of the effects under this alternative would be the same as under GEC's Proposed Alternative because construction and operation of the facilities, with the exception of the access road, would still be contained within the river corridor.

The Maximum Boundary Alternative would affect the amount of land exchanged as well as the amount of land designated wilderness. Exchange of the parcels at Long Lake and/or the exchange of the Klondike parcels to NPS would not affect the aesthetic resources of these lands because the state of Alaska, for all practical purposes, currently manages both these lands in a manner compatible with NPS goals outlined in the WSNPP and KGNHP management plans set to protect their scenic and wildlife values.

Designating all or parts of the lands, including the unnamed island near Blue Mouse Cove, Cenotaph Island, and the lands at Alsek Lake, as wilderness would have negligible effects on the aesthetic resources. For all practical purposes, these lands are currently managed as if they were wilderness lands under the GBNPP Wilderness Management Plan.

4.11.3.3 Cumulative Effects Analysis. The types of cumulative effects that could be expected to occur on visual resources under this alternative would be the same as those described under GEC's proposal in section 4.11.2.3.

4.11.3.4 Conclusion. Because the Maximum Boundary Alternative only considers a change in the project boundary, the effects on the aesthetic environment of the Kahtaheena River and adjacent area would be similar to those described above in section 4.11.2. The primary effects of the construction and operation of the proposed project on visual resources would be at the locations of project facilities and in the Kahtaheena River. With the exception of the access road, the facilities and the resulting flows in the river would not be visible from the adjacent GBNPP lands. Accordingly, construction and operation would not affect the visual resources of GBNPP. Overall, management within the project boundary would be slightly more restrictive protecting the aesthetic resources at a higher level than would likely occur under GEC's proposal.

The purposes and values of GBNPP identified in the enabling legislation include allowing the preservation of lands and waters containing nationally significant scenic values and unrivaled scenic values associated with natural landscapes. The construction and operation of the proposed project would not adversely impact the purposes and values of GBNPP because all effects on visual resources would occur on either state land or within the FERC project boundary. There would be no effects on aesthetic resources within GBNPP. Under GEC's proposal, the aesthetics resources of the unnamed island near Blue Mouse Cove, Cenotaph Island, and lands at Alsek Lake would not be affected because these lands would remain in GBNPP. GBNPP would continue to operate and manage park lands to preserve the aesthetic values associated with natural landscapes.

Overall the level of effects on the aesthetic resources would not result in an impairment of GBNPP resources that fulfill the specific purposes identified in the enabling legislation to "preserve the unrivaled scenic and geological values associated with natural landscapes" or are key to the natural integrity of the park.

Under GEC's proposal, the aesthetic resources of the Long Lake parcels within WSNPP and the parcels neighboring KGNHP would not be negatively affected because they would receive enhanced protection under NPS policy and management which supports the preservation of the aesthetic resources through the protection of all park resources. Because there would be no adverse effects, there would be no impairment of WSNPP or KGNHP resources that fulfill specific purposes identified in the enabling legislation or are key to the natural integrity of these parks.

4.11.4 Corridor Alternative

4.11.4.1 Effects of Construction and Operation. The effects of the Corridor Alternative on the aesthetic resources in the Kahtaheena River and adjacent area would be similar to those described for GEC's proposal (section 4.11.2). In this case, 680 acres of land would be encompassed within the project boundary, which would include a larger amount of land designated for the project. Project construction and operation under this alternative would be the same as under GEC's proposal. Effects include the construction of human-made structures in an almost pristine environment, and the operation of such facilities which includes altering the flow regime in the Kahtaheena River. The adjacent GBNPP lands would continue to be managed by GBNPP as wilderness, and lands within the project boundary would be managed under the FERC hydroelectric license. Effects from this alternative would be expected to last 30 to 50 years or longer in areas where large disturbances to forests and hillslopes would be created for project developments.

4.11.4.2 Effects of the GBNPP and Wilderness Boundary Adjustment. The removal of 680 acres from GBNPP would have the greatest effects along the river corridor as described under the Proposed Alternative (see section 4.11.2). The effects from this alternative would be expected to last 30 to 50 years or longer.

The Corridor Alternative would reduce the amount of lands exchanged. Exchange of either the Long Lake parcels or the Klondike parcels would not affect the aesthetic resources of the lands exchanged because the state of Alaska currently manages these lands in a manner compatible with NPS goals. The exchange of one or both of these lands would bring them under either WSNPP or KGNHP management practices. The practical effect would be negligible because of the current management.

The Corridor Alternative would affect the amount of lands designated wilderness at either the unnamed island near Blue Mouse Cove, Cenotaph Island, or the lands at Alsek Lake. These lands are currently not designated as wilderness; however, for all practical purposes, they are managed as such as mentioned in the GBNPP Wilderness Management Plan. Regardless of which lands become admitted under the wilderness designation, all the lands would continue to be managed as such. The practical effect would be negligible because the current management would be similar.

4.11.4.3 Cumulative Effects Analysis. The types of cumulative effects that could be expected to occur on visual resources under this alternative would be the same as those described under GEC's proposal in section 4.11.2.3.

4.11.4.4 Conclusion. Under the Corridor Alternative, the effects of the construction and operation of the project on the aesthetic environment would be similar to those described for the previous action alternatives. However, because less land would be transferred from the state to NPS, federal protection at Long Lake and KGNHP would be reduced compared to the proposed action and the Maximum Boundary Alternative. The primary effects of the construction and operation of the proposed project on visual resources would be at the locations of project facilities and in the Kahtaheena River. With the exception of the access road, the facilities and the resulting flows in the river would not be visible from the adjacent GBNPP lands. Accordingly, construction and operation of the project would not affect the visual resources of GBNPP.

The purposes and values of GBNPP identified in the enabling legislation include allowing the preservation of lands and waters containing nationally significant scenic values and unrivaled scenic values associated with natural landscapes. The construction and operation of the proposed project would not adversely impact the purposes and values of GBNPP because all effects on visual resources would occur on either state land or within the FERC project boundary. There would be no effects on aesthetic resources within GBNPP. Under GEC's proposal, the aesthetics resources of the unnamed island near Blue Mouse Cove, Cenotaph Island, and lands at Alsek Lake would not be affected because these lands would remain in GBNPP. GBNPP would continue to operate and manage park lands to preserve the aesthetic values associated with natural landscapes.

Overall the level of effects on the aesthetic resources would not result in an impairment of GBNPP resources that fulfill the specific purposes identified in the enabling legislation to "preserve the unrivaled scenic and geological values associated with natural landscapes" or are key to the natural integrity of the park.

Under GEC's proposal, the aesthetic resources of the Long Lake parcels within WSNPP and the parcels neighboring KGNHP would not be negatively affected because they would receive enhanced protection under NPS policy and management which supports the preservation of the aesthetic resources through the protection of all park resources. Because there would be no adverse effects, there would be no impairment of WSNPP or KGNHP resources that fulfill specific purposes identified in the enabling legislation or are key to the natural integrity of these parks.

4.12 RECREATION RESOURCES

Several evaluation parameters are used to identify and describe the potential impacts on the recreation resources of the project area:

1. Recreation uses
2. Diversity of recreation opportunity
3. Visitor safety

The assessment of the potential effects of the project on recreation resources includes a discussion of the context of the recreation resources in the project area. The intensity of the impact on recreation resources is generally characterized by quantifying the area of impact, identifying the available experiences, identifying the diversity of recreation opportunities and identifying the potential for changes in visitor safety. The duration of the impact is described where necessary to understand the context and intensity of the impact.

4.12.1 No-action Alternative

4.12.1.1 Effects Analysis. Under the No-action Alternative, the proposed project would not be constructed; the land surrounding the proposed project would be retained within the National Wilderness Preservation System for the foreseeable future and would continue to be managed as wilderness in accordance with the GBNPP GMP; and there would be no land exchange. Under the No-action Alternative, recreation conditions would remain as described in section 3.12. Recreation opportunities would remain as hiking, recreational fishing, birdwatching, bear viewing, berry picking, and occasional cross-country skiing, with the majority of activity along the shore and some visitors seeking out the Lower Falls. Under the ROS framework (see section 3.12), the site would continue to be considered primitive. Based on the guidelines, this alternative would not affect the recreational resources of the project area.

Under the No-action Alternative, GBNPP would not exchange lands with the state of Alaska. The lands surrounding Long Lake would continue to be managed by the state of Alaska in accordance with the Copper River Basin Plan. The management plan precludes any development along the north shore of the lake where prime sockeye spawning habitat is located. Furthermore, development would not be permitted on the parcels proposed for exchange. Therefore, recreation resources would remain unaffected by this alternative and would remain in their current state. The state-owned lands within KGNHP would continue to be managed by NPS under an agreement with the state and would not experience any effects from the No-action Alternative.

Under the No-action Alternative, NPS would continue to manage the unnamed island near Blue Mouse Cove, Cenotaph Island, and parcels near the Alsek River as *de facto* wilderness. These lands would not experience any effects from this alternative.

4.12.1.2 Cumulative Effects Analysis. Under the No-action Alternative, there would be no actions proposed in the Kahtaheena River watershed, the state lands near the WSNPP and KGNHP, the unnamed island near Blue Mouse Cove, Cenotaph Island, or Alsek Lake that would potentially interact with non-project actions expected to occur in these areas in the foreseeable future with the potential to produce a cumulative effect.

4.12.1.3 Conclusion. Under the No-action Alternative, there would be no effect on recreation resources in the Kahtaheena River area, on the potential land exchange parcels, or on the wilderness parcels. Implementation of the No-action Alternative would not result in impairment of GBNPP resources that fulfill specific purposes as identified in the enabling legislation or are key to the natural integrity of the park. Under this alternative, GBNPP would continue to operate and manage its lands as outlined in the enabling legislation (see section 1.7.4).

The effects on recreation resources anticipated from this alternative would not result in an impairment of WSNPP or KGNHP resources that fulfill specific purposes as identified in the enabling legislation, or are key to the natural integrity of these parks. Under this alternative, WSNPP and KGNHP would continue to operate and manage their lands as outlined in their enabling legislation (see section 1.7.4).

4.12.2 GEC's Proposed Alternative

4.12.2.1 Effects of Construction and Operation. Under its proposed action, GEC would manage the lands within the project boundary (117 acres) in a similar manner to surrounding state lands for the protection of water resources, fish, and wildlife habitat. Construction of the access road would cause the primary effects on recreation resources by increasing public access into the proposed project area and neighboring lands.

The remaining 775 acres, undisturbed by construction activities, would be managed by the state of Alaska. The state proposes to manage its lands to protect water resources, fish, and wildlife habitat as described in the Northern Southeast Area Plan. The state also reserves the right to develop these areas for mineral extraction and rock quarry facilities. Increased recreational use on the state lands facilitated by the access road, however, could conflict with the state's objectives to protect these resources within the Northern Southeast Area Plan (ADNR 2002a; 2002b). In addition, the state land classification would also allow the use of motorized vehicles, including 4-wheel ATVs.

Construction of 3.6 miles of access and service roads in the upper Kahtaheena River area would create the potential for increased access beyond the terminus of Rink Creek Road. This access along with the removal of lands from GBNPP would likely result in recreational activities on these lands that are currently not allowed within GBNPP, including hiking, people walking their dogs, mountain biking (road only), cross-country skiing, helicopters, and off road vehicles, and it would increase the access to adjacent state and NPS lands. Such access would benefit recreationists by allowing people to reach areas within GBNPP that were previously difficult to reach and by means previously illegal under GBNPP policies and objectives; however, due to the dense forest and steep topography recreation opportunities away from the access road would remain limited to cross-country hiking. Such access could also diminish the experiences of those seeking a "true" park experience. However, individuals seeking a "true" park experience could access remaining lands within GBNPP rather than state lands within the project boundary. Under this alternative, 3.6 miles of roadway would be available to mountain bikers in an area where it is currently prohibited. The state of Alaska's alternative access road alignment would contribute an additional 1.5 miles of roadway compared to GEC's proposal.

On average, 144 people visit the shoreline in the project area, and 44 people visit the Lower Falls each year (Baker, 2001, as modified by preparers). Without the project, growth estimates predict that 175 people would visit the Lower Falls 30 years from now (using the Gustavus population residential growth rate between 1991-1998 of 4.7; see section 3.16, *Socioeconomics*). This projected increase in growth does not include increases due to tourism growth. It is likely that tourism in the area would continue to increase over the next 30 to 50 years. Some of these tourists also may visit the project area. Consequently, estimates of visitation in this section may underestimate the future visitation to the area. Construction of the access road is likely to somewhat increase the number of people visiting this area. Factors considered include current uses and patterns, the proximity to Gustavus and the distance from Bartlett Cove.

GEC does not propose to increase recreation opportunities actively or mitigate primary effects of the project on recreation resources within the proposed project boundary. Typical uses along the road would include occasional hikers, mountain biking, cross-country skiing, and a weekly vehicle trip made by maintenance workers to the facilities. Construction of project facilities, specifically the road, would increase access within the area, changing the ROS status from primitive to semi-primitive/semi-modern based on the following factors: the gravel access road, isolated onsite modifications, primarily natural appearance, and infrequent to occasional interparty contacts.

Noticeable changes in diversity of uses and visitor experience would occur. The access road would allow more visitors to reach the upland environment along the Kahtaheena River and make the Lower Falls more accessible. Improved access would be perceived as a negative effect to some people because this would allow more forms of recreation (e.g. mountain biking) and the potential for increased numbers of recreationists using the area. Conversely, improved access would be seen as a positive effect to others for these same reasons. In a study by Baker (2001), survey respondents expressed concerns that the construction of the project and access road would increase recreational use of nearly pristine environments, thereby diminishing the quality of the recreation experience, thus the overall effects are determined to be negative. There would be no effect on regional recreation resources or patterns; thus the effects on recreational resources would exist over the life of the project.

Construction and operation of the Falls Creek Hydroelectric Project and changes in recreational use in the project area may adversely affect the Native allotments. Currently, visitors wishing to hike to the Lower Falls must trespass across the southeastern portion of the Mills allotment to reach the Kahtaheena River before following the river up to the falls. Construction of the access road would reduce the difficulty in accessing the Kahtaheena River above the Lower Falls increasing the number of visitors to the area each year. Visitor's curiosity with project facilities and the surrounding area could result in the development of informal trails connecting areas such as the service road and penstock with the Lower Falls potentially spilling onto the Mills allotment. Trespassing could become more frequent across both allotments should visitors undertake a "loop" trail from the end of Rink Creek Road along the access road to the penstock down the Kahtaheena River and out to the beach and back to the end of Rink Creek Road. Vandalism of the allotments would be expected to increase as a result of the increased number of people trespassing across the allotments. Native allotees would be highly affected by this imposition on their lands and the potential effects on their use of this land.

Public Access and Recreation Development

ADFG and NMFS recommend that GEC develop and implement a recreational enhancement plan to address the potential for increased recreational demand in the Kahtaheena River area. NPS-RTCA recommends that GEC develop a comprehensive recreational development plan addressing recreation needs on project lands over the term of the license. ADFG and NMFS also recommend that GEC develop a public access plan to address public vehicle access in the project area. In response to agency comments, GEC proposes to implement a recreation plan developed in consultation with the town of Gustavus and ADNR, focused on public access, signage, and trail brushing.

A plan would engage the community and agencies in efforts toward a single goal. Development of a public access and recreational development plan would engage Gustavus area residents and subsistence users as well as resource agencies in a process that could facilitate consensus on public access and recreational use in the project area. Such a plan could address: (1) kinds of public access for recreational purposes that should be allowed (or discouraged such as vehicular access, ATVs, hunting, etc.); (2) kinds of experiences the area would be managed for (semi-primitive road; developed, etc.); (3) kinds of facilities, if any, necessary to accommodate this access; and (4) responsibilities for implementing, maintaining, and managing the recreational use plan. Examples of mitigations that might be considered are signs; a parking area by the gate, if the road is gated; and improved trails from the access road to the falls viewpoint.

A public access and recreational development plan that recognizes the potential conflicts between motorized and non-motorized trail uses (snowmobiling versus cross-country skiing), and that establishes the types of activities appropriate for the lands within the project boundary (e.g., dogs on leash, no motorized vehicles, no mountain biking) could help mitigate the effects of the proposed project on current recreation resources by limiting the development of unnecessary recreational facilities and regulating the types of recreation considered acceptable in the area. One plan that addresses public access would satisfy all interested parties assuming the plan is developed in a manner that facilitates public participation of Gustavus residents and includes NPS-RTCA and GBNPP staff.

Public Safety

The proposed access road and facilities would provide access to an area that has not been easily accessible to most visitors and residents, potentially decreasing visitor safety relative to human-wildlife interactions and human-project (structural) features. The road corridor would create a higher potential for human-bear interactions compromising recreationists safety. The development of project facilities could invite recreationists to investigate or vandalize the structures, thereby slightly increasing their risk of injury. GBNPP staff might need to shift some resources for monitoring and enforcement in park lands adjacent to this area to minimize the impact of access and support public safety in the vicinity. Currently there are no police services in Gustavus, so emergency law enforcement function is provided by NPS law enforcement personnel through a formal agreement with the state of Alaska, Department of Public Safety. Currently, there is no plan for the state to increase its law enforcement presence in Gustavus in the near future. NPS protection rangers would only respond to emergencies and would not routinely patrol the land that would be transferred to the state of Alaska as it would no longer be under federal jurisdiction. The development of a flow rate conveyance system could alleviate potential hazards associated with increased numbers of recreationists hiking the lower stream reaches during high flows. GEC does not make any specific proposal for collecting or conveying stream flow data to the public. Development of a recording and transmitting device (flow phone or website) to convey instantaneous flow rates, as NPS-RTCA recommends, however, would benefit recreationists planning visits to the area by providing a means to check flows in the reach (which range from below 5 cfs to more than 100 cfs) prior to recreating there. The method for providing flow rate information should be addressed in any public use and recreation plan developed for the project.

4.12.2.2 Effects of the GBNPP and Wilderness Boundary Adjustment

Effects of Removal and Loss of Land from GBNPP. The exchange of lands from the lower Kahtaheena River area out of GBNPP to the state of Alaska would have the greatest effect on the aesthetic resources sought after by recreationists visiting the area. The proposed action would remove 4.3 miles of stream, 4 waterfalls, and 850 acres from GBNPP. The waterfalls and stream reach would be managed under the license and subject to regulated low-flow regimes. The Excursion Ridge area is extremely steep and densely vegetated making hiking into the upland areas difficult. This lack of access into the area has prevented GBNPP from documenting the resources in this area however, so the level of uniqueness offered by the recreational resources of the Kahtaheena River area is unknown.

Although the removal of the stream reach and waterfalls from GBNPP could be considered a loss of the scenic features that attract visitors, a considerable amount of forested hiking opportunities and streams would continue to exist within GBNPP, including the 10 km Falls, which lies above the proposed project boundary (see figure 3-7 in appendix A). Overall, this boundary adjustment could have a negative effect on recreationists who wish to recreate in pristine, difficult to access areas because people would be able to participate in activities that GBNPP policies prohibited in the area (walk dogs and use off-road motorized vehicles). However, this boundary adjustment could have a positive effect for individuals wanting to recreate in the area by hunting, trapping, walking dogs, horseback riding, and riding ATVs.

Proposed Land Exchange Parcels. The lands at Long Lake are owned and managed by ADNR for fish, wildlife, and recreation, while neighboring private lands have experienced some development. Under NPS stewardship, the ADNR parcels would be administered under WSNPP policies consistent with park recreation values. Based on the current recreational uses of the parcels (fishing and wildlife viewing), the proposed action would have negligible effects on the recreation resources of the Long Lake area by transferring ownership and management to NPS.

Based on the existing recreational use of the lands (hiking) within KGNHP, the exchange would not adversely affect the opportunities currently available in the Klondike Gold Rush Area. The lands would become part of KGNHP and continue to be managed in a manner consistent with current guidance. The Chilkoot Trail would not experience any change in visitor experience or diversity of opportunities. Thus, the proposed land exchange under this alternative would have negligible effects on KGNHP lands.

The proposed action would result in negligible effects on the recreational resources of both the Long Lake parcels and the KGNHP parcels.

Wilderness Designation Parcels. Under the proposed action, the unnamed island near Blue Mouse Cove could receive a formal wilderness designation. Because the island is currently managed as *de facto* wilderness, formal designation would not affect the current recreational resources. Motorized vessels would continue to pass within visible distance of the island, and camping would continue to be managed according to wilderness objectives. The designation of this island as wilderness would have a negligible effect on the recreation resources of this island.

Under the proposed action, Cenotaph Island could receive a formal wilderness designation. Because the island is currently managed as *de facto* wilderness, formal designation would not change the recreational resources. Motorized vessels would continue to pass within visible distance of the island, use its harbors for anchorage, and camping parties would continue to be subject to the GBNPP Wilderness Visitor Use Management Plan. Designation would have a negligible effect on the current recreational use of the island.

Under the proposed action, a portion of 2,270 acres at Alsek Lake near Dry Bay could be recognized as wilderness. Because this land is currently managed as *de facto* wilderness, formal designation would have a negligible effect on the current recreational use of the lands.

Under GEC's proposal, the recreational resources of the unnamed island near Blue Mouse Cove, Cenotaph Island, and the Alsek Lake parcels would experience negligible effects because the lands would continue to be managed under the GBNPP Wilderness Visitor Use Management Plan and subject to wilderness management.

4.12.2.3 Cumulative Effects Analysis. Potential increases in commercial and recreational guiding and tourism in the Kahtaheena River area could occur as a result of estimated future population growth in Gustavus, or as a result of increased tourism at GBNPP. The development of a road to the Falls Creek Hydroelectric Project would provide improved access for recreational users to areas previously accessible only by cross-country hiking. The combined effects of increased commercial and recreational tourism and the improved access to areas with previously limited access may produce a cumulative increase in the recreational use of the Kahtaheena River watershed and adjacent GBNPP lands.

Future population growth in Gustavus could potentially increase subsistence and recreational hunting in the Kahtaheena River area. The development of a road to the project would provide improved access for subsistence and recreational hunters to areas previously accessible only by cross-country hiking. The combined effects of increased subsistence and recreational hunting and the improved access to areas with previously limited access may produce a cumulative increase in the subsistence and recreational hunting use of the Kahtaheena River watershed.

The McCarthy Road corridor is projected to undergo substantial growth in recreational and residential use over the next 25 years (LDN, 2000). The potential improvement of McCarthy Road and the development of a formal viewing area near the Long Lake parcels may increase recreational visitation along the corridor as access is improved (LDN, 2002). The transfer of the Long Lake parcels to the WSNPP would not create an action that would contribute to a change in the recreational usage of the McCarthy Road corridor. The combined actions of increased recreational use in the McCarthy Road corridor and the transfer of the Long Lake parcels to the WSNPP would not produce a cumulative effect on recreational resources.

There are no non-project actions identified in the foreseeable future for the KGNHP area that would interact with the proposed action of transferring parcels from the state to KGNHP and contribute to a cumulative effect on recreational resources.

There are no non-project actions identified in the foreseeable future on the parcels proposed for wilderness designation that would interact with the proposed action of designating these areas for wilderness and contribute to a cumulative effect on recreational resources.

4.12.2.4 Conclusion. Under GEC's proposal, construction and operation of the proposed project would increase public access into the project areas and neighboring lands. Developed facilities associated with this action would be constructed in a localized area and only be visible from a short distance away but would exist over the term of any license. This could result in a positive and negative effect on the recreational resources in the area from project construction and operation. Lands under the state of Alaska management could provide recreational opportunities that currently are not available, such as the use of ATVs, bicycles, horses, helicopter flights, and hunting and trapping. This would result in a positive effect for those recreational opportunities. At the same time, some visitor opportunities to recreate without the presence of motorized vehicles or hunting and trapping activities could be negatively affected by these activities.

Recreational resources on the surrounding NPS lands would not be affected by the proposed project as management of those resources would not change.

The purposes and values of GBNPP identified in the enabling legislation include allowing the preservation of lands and waters containing nationally significant recreational values and related recreational opportunities. The construction and operation of the proposed project would not adversely impact the purposes and values of GBNPP because all effects on recreational resources would occur on either state land or within the FERC project boundary. There would be no effects on recreational resources within GBNPP. GBNPP would continue to operate and manage park lands to preserve the recreational values associated with natural landscapes.

Under GEC's proposal, the recreational resources of the unnamed island near Blue Mouse Cove, Cenotaph Island, and the lands at Alsek Lake would experience negligible effects because they are already managed as *de facto* wilderness under the GBNPP Wilderness Visitor Use Management Plan.

Overall, the level of impacts on recreation would not result in impairment of GBNPP resources that fulfill the specific purposes as identified in the enabling legislation (see section 1.7.4), or that are key to the natural integrity of the park.

Conveyance to NPS of either WSNPP parcels or the KGNHP parcels would result in negligible effects on the recreational resources of these areas. Because these effects would be negligible, there would be no impairment of the resources that fulfill specific purposes of WSNPP or KGNHP as identified in the parks' enabling legislation (see section 1.7.4), or are key to the natural integrity of these parks. The anticipated effects under this alternative would not impair the ability of WSNPP and KGNHP to continue to operate and manage their lands as outlined in their enabling legislation (see section 1.7.4).

4.12.3 Maximum Boundary Alternative

4.12.3.1 Effects of Construction and Operation. Under this alternative, approximately 1,145 acres of NPS land would be transferred to the state of Alaska; however, all these lands would be within the FERC project boundary and subject to FERC jurisdiction. Although the state of Alaska reserves mineral extraction rights to the lands transferred to the state, and this type of land use could be allowed within the hydroelectric license (see section 4.15, *Land Use Programs and Policies*, for more discussion of mineral extraction rights), all proposals would need to be reviewed by FERC. In addition, the state land classification would also allow the use of motorized vehicles, including 4-wheel ATVs. This could result in the creation of trails and expand the terrain available to recreationists. Again, all uses within the project boundary would be subject to further review and regulation under the project license issued by FERC.

Effects associated with the construction and operation of the hydroelectric project would be the same as those described for the proposed action in section 4.12.2. The recreational resources of the adjacent park lands would be affected under this alternative as described in section 4.12.2.

4.12.3.2 Effects of the GBNPP and Wilderness Boundary Adjustment

Effects of Removal and Loss of the Land from GBNPP. Because the only change is related to the size of the project boundary, for all practical purposes effects of the removal of 1,145 acres from GBNPP on recreational resources would be the same as those described for the proposed action in section 4.12.2.

Proposed Land Exchange Parcels. The protection of recreational resources of the parcels at Long Lake in WSNPP and the parcels near KGNHP would be similar to that described in section 4.12.2. However, under this alternative, more land would be transferred to NPS thus incorporating more land into the recreational resources of WSNPP and KGNHP than under the proposed action.

Wilderness Designation Parcels. The recreational resources of the unnamed island near Blue Mouse Cove, Cenotaph Island, and the parcels at Alsek Lake would experience negligible effects for the same reasons as described for the proposed action in section 4.12.2.

4.12.3.3 Cumulative Effects Analysis. The types of cumulative effects that could be expected to occur on recreation resources under this alternative are the same as those described under GEC's proposal in section 4.12.2.3.

4.12.3.4 Conclusion. Under the Maximum Boundary Alternative, the effects of the construction and operation of the proposed project on the recreational resources of the Kahtaheena River area would be the same as described under GEC's proposal (see section 4.12.4.2, except that all of the 1,145 acres of NPS land that would be conveyed to the state of Alaska would be included in the FERC project boundary and managed in accordance with license conditions. The public access and recreation plan and the land management plan (see section 4.16) could restrict recreational use, including the use of motorized vehicles, hunting, horses, etc., to protect fish and wildlife resources.

The purposes and values of GBNPP identified in the enabling legislation include allowing the preservation of lands and waters containing nationally significant recreational values and related recreational opportunities. The construction and operation of the proposed project would not adversely impact the purposes and values of GBNPP because all effects on recreational resources would occur on either state land or within the FERC project boundary. There would be no effects on recreational resources within GBNPP. GBNPP would continue to operate and manage park lands to preserve the recreational values associated with natural landscapes.

Under Maximum Boundary Alternative, the recreational resources of the unnamed island near Blue Mouse Cove, Cenotaph Island, and the lands at Alsek Lake would experience negligible effects because they are already managed as *de facto* wilderness under the GBNPP Wilderness Visitor Use Management Plan.

Overall, the level of impacts on recreation would not result in impairment of GBNPP resources that fulfill the specific purposes as identified in the enabling legislation (see section 1.7.4), or that are key to the natural integrity of the park.

Conveyance to NPS of either WSNPP parcels or the KGNHP parcels would result in negligible effects on the recreational resources of these areas. Because these effects would be negligible, there would be no impairment of the resources that fulfill specific purposes of WSNPP or KGNHP as identified in the parks' enabling legislation (see section 1.7.4), or are key to the natural integrity of these parks.

4.12.4 Corridor Alternative

4.12.4.1 Effects of Construction and Operation. Under this alternative, approximately 680 acres of land would be transferred to the state of Alaska, and all of these lands would be included within the FERC project boundary. The effects on recreational resources associated with the construction and operation of this alternative would be similar to those described in section 4.12.3. Motorized vehicles and mineral extraction uses reserved by the state would be subject to FERC approval under the terms of the license prior to initiating these types of uses.

The impacts on the recreational resources of the Kahtaheena River area would be the same as described for GEC's Proposed Alternative in section 4.12.2.

4.12.4.2 Effects of the GBNPP and Wilderness Boundary Adjustment. Effects from the removal of 680 acres from GBNPP on recreational resources would be similar to those described for the proposed action in section 4.12.2. However, because less land would be transferred out of GBNPP, there would be less opportunity for certain recreational activities such as use of ATVs, hunting, trapping, dog walking, horse riding, and helicopter flights.

The effects on recreational resources of the lands proposed to be exchanged under this alternative would be negligible for the same reasons as described in section 4.12.2; however, should this alternative be pursued, less land would be transferred between the state of Alaska and NPS than under GEC's proposal.

The lands identified for wilderness designation would also experience negligible effects on recreational resources similar to those described in section 4.12.2.

4.12.4.3 Cumulative Effects Analysis. The types of cumulative effects that could be expected to occur on recreational resources under this alternative would be the same as those described under GEC's proposal in section 4.12.2.3.

4.12.4.4 Conclusion. Under the Corridor Alternative, the effects of the construction and operation of the proposed project on the recreational resources of the Kahtaheena River area would be the same as described under GEC's proposal (see section 4.12.4.2) except that all of the 680 acres of NPS land that would be conveyed to the state of Alaska would be included in the FERC project boundary and managed in accordance with license conditions. The public access and recreation plan and the land management plan (see section 4.16) could restrict recreational use, including the use of motorized vehicles, hunting, horses, etc., to protect fish and wildlife resources.

The purposes and values of GBNPP identified in the enabling legislation include allowing the preservation of lands and waters containing nationally significant recreational values and related recreational opportunities. The construction and operation of the proposed project would not adversely impact the purposes and values of GBNPP because all effects on recreational resources would occur on either state land or within the FERC project boundary. There would be no effects on recreational resources within GBNPP. GBNPP would continue to operate and manage park lands to preserve the recreational values associated with natural landscapes.

Under the Corridor Alternative, the recreational resources of the unnamed island near Blue Mouse Cove, Cenotaph Island, and the lands at Alsek Lake would experience negligible effects because they are already managed as *de facto* wilderness under the GBNPP Wilderness Visitor Use Management Plan.

Overall, the level of impacts on recreation would not result in impairment of GBNPP resources that fulfill the specific purposes as identified in the enabling legislation (see section 1.7.4), or that are key to the natural integrity of the park.

Conveyance to NPS of either WSNPP parcels or the KGNHP parcels would result in negligible effects on the recreational resources of these areas. Because these effects would be negligible, there would be no impairment of the resources that fulfill specific purposes of WSNPP or KGNHP as identified in the parks' enabling legislation (see section 1.7.4), or are key to the natural integrity of these parks.

4.13 WILDERNESS

Several evaluation parameters are used to identify and describe the potential impacts from the proposed actions on the wilderness resources of the project area. These parameters include:

1. Wilderness acres

2. Developed acres

3. Degree of naturalness and opportunities for solitude (Capability)

4. Suitability of area to be managed as wilderness (Availability)

5. Ability of resources to contribute to the local and national distribution of wilderness (Need)

The analysis of potential effects of the project on wilderness resources includes a discussion of the context of the resources in the project area. The intensity of the impact on wilderness is generally characterized by the amount of wilderness and developed acreage, the degree of naturalness, identifying the opportunities for solitude, examining the ability of lands to be managed as wilderness including coexistence with adjacent land management, and the ability of the resources in the wilderness area to contribute to the local and national distribution of wilderness. The duration of the impact is described where necessary to understand the context and intensity of the impact.

4.13.1 No-action Alternative

4.13.1.1 Effects Analysis. Under the No-action Alternative, current land designations and management policy for wilderness in the Kahtaheena River area as described in the GMP for the park would remain. The project would not be constructed, and the current distribution of land uses and opportunities for solitude would be preserved. The wilderness area would not be de-designated, and it would be retained within the National Wilderness Preservation System and would continue to be managed as wilderness in accordance with the GMP. There would be no irreversible or irretrievable commitment of resources to alternative and incompatible land uses. The intent of NPS is to manage Cenotaph Island, the unnamed island near Blue Mouse Cove, and the Alsek Lake lands as if they were wilderness in perpetuity. Nevertheless, there is a very slight possibility that the management policy for these lands might change, allowing for a loss of wilderness values.

Under this alternative, there would not be any changes to national park units, the current management direction for Cenotaph Island, the unnamed island near Blue Mouse Cove, or the Alsek Lake lands or designated wilderness boundaries in Alaska. As a result, there would be no impacts on wilderness.

4.13.1.2 Cumulative Effects Analysis. Under the No-action Alternative, there would be not be any negative or positive cumulative effects because there are no project actions that would occur in the Kahtaheena River watershed, state-owned parcels adjacent to WSNPP and KGNHP, and the parcels at Cenotaph Island, the unnamed island near Blue Mouse Cove, and Alsek Lake. Therefore, there is no potential for cumulative effects on wilderness resources based on the interaction between a project and a non-project action.

4.13.1.3 Conclusion. The No-action Alternative would provide the greatest possible protection for wilderness values and resources within GBNPP. It would retain the untrammeled and natural environment of the Kahtaheena River area as well as opportunities to experience solitude and to enjoy an aquatic and terrestrial ecosystem not frequently accessible to wilderness visitors. The No-action Alternative would not lead to impairment of wilderness character at GBNPP because the wilderness resources would still fulfill the purposes set out by the Wilderness Act, GBNPP's enabling legislation, and ANILCA.

The effects on wilderness resources anticipated from this alternative would not result in an impairment of WSNPP or KGNHP resources that fulfill specific purposes of maintaining unimpaired scenic beauty and quality of high mountain peaks, foothills, glacial systems, lakes and streams, valleys, and coastal landscapes in their natural state, as identified in the enabling legislation; or are key to the natural integrity of these parks. Under this alternative, WSNPP and KGNHP would continue to operate and manage their lands (including the added parcels) as outlined in their enabling legislation.

4.13.2 GEC's Proposed Alternative

4.13.2.1 Effects of Construction and Operation. Construction and operation of the proposed project would have no direct impact on wilderness because the project facilities would be built and operated upon land that is no longer wilderness. However, there could be several indirect impacts.

Given that 117 acres within the proposed project boundary and the 775 acres of state management land would be directly accessible from the community of Gustavus by the proposed access road, there could be pressures for development, including roads in the project area. The access road could be used by motorized and non-motorized recreationists, depending upon how it is managed, thus potentially increasing use in the area and adjacent areas (including private lands and Native allotments) remaining designated as wilderness. This increased use may lead to a loss of solitude for wilderness visitors and the possibility of incompatible uses that may encroach on wilderness (e.g., mountain biking) and a depreciation of value of privately held lands that border the project area. These private lands and Native allotments may lose some of their wilderness value because natural conditions could be diminished, and some opportunities for solitude may be lost as a result of the increased noise from road building, motor vehicle travel, and project operations. There are also potential impacts on another important wilderness value: natural conditions. While the sections of the Kahtaheena River that would be affected by GEC's proposal are not unique to southeastern Alaska, they may be some of the few river reaches within the park to support a resident population of non-anadromous Dolly Varden.

Indirect impacts from construction of the hydroelectric project would affect the park wilderness because of potential loss of solitude in the surrounding area from the use of road building equipment and chainsaws (see section 4.10, *Soundscape*). This impact, however, would only occur during the construction period.

4.13.2.2 Effects of the GBNPP and Wilderness Boundary Adjustment. The proposed project would affect wilderness resources differently than other resources and values within GBNPP. First, wilderness is a holistic concept and land designation. It represents the sum of the biophysical and social values identified on land designated as wilderness. Second, because the project involves de-designating one area designated as wilderness and designating others as wilderness, this action in itself leads to potentially environmentally significant actions. Thus, we analyze the effects of the proposed action on wilderness resources according to three logical components. First, we consider the effects of de-designating between 680 and 1,145 acres (see table 2.9-1) of lands within GBNPP currently designated as wilderness (common to all the alternatives except for the No-action Alternative). Second, we analyze the effect of designating new lands as wilderness; and third, we consider the effects of creating several different, formal FERC-designated project boundaries. These project boundaries would have different effects on nearby lands that would remain as wilderness.

The purposes, values, and characteristics of the wilderness contained within Glacier Bay as defined in the Wilderness Act of 1964 and managed under ANILCA would be affected by the proposed actions. Because wilderness is a distinct park resource, separate from visitor experience, the proposed action's effects on other aspects of visitor experience within the wilderness of Glacier Bay are considered in section 4.12, *Recreation Resources*. The analysis is based on the impacts on the values for the areas involved that were described in section 3.13, *Wilderness*.

GEC's proposal would transfer to the state of Alaska about 850 acres in the Kahtaheena River area, of which 75 acres (along with 42 acres of private land) would be directly identified for the FERC project boundary. Under this alternative, roads, facilities, a diversion dam, and penstock would be constructed in areas formerly designated as wilderness.

The 775 acres not included in the FERC project boundary, while managed by the state of Alaska as Water Resource and Wildlife Habitat lands under ADNR's Northern Southeast Area Plan, would be subject to possible future development, because this land designation is administrative, not legislative. In addition, because mineral extraction rights would be retained by the state of Alaska, the road could be used for the development of rock quarries/gravel pits that would potentially have associated loud noises (see section 4.10.1 for additional information about noises associated with road building). These loud noises would affect adjacent wilderness by eroding the potential for visitors to experience solitude. While much of this use would occur on the 775 acres administered by the state of Alaska, surrounding wilderness lands could be subject to increased use and effects by recreationists. Natural conditions associated with wilderness are typified by the lack of human presence. Because the increased presence of humans could bring litter, the construction of user trails, and a disruption of wildlife, these natural conditions would be diminished. Adjacent GBNPP lands currently designated as wilderness may lose some of their natural conditions, although the character of the land would remain.

GBNPP is under several mandates to conserve and protect wilderness resources. First, there is a mandate from the Organic Act of 1916 that calls for the conservation and protection of the resources found there, later strengthened and clarified through the Redwood Amendment in 1978 (see section 1.7, *National Park Service Background*, for a thorough review of these mandates). Second, there is a mandate from the presidential proclamations of 1925 and 1939 (see section 1.7.4, *National Parks Enabling Legislation*) that established and expanded GBNPP and specifically called for preserving and protecting of, "a great variety of forest consisting of mature areas, and bodies of youthful trees …[etc.]" The old growth, "mature areas" mentioned in this proclamation are relatively rare throughout GBNPP but are found within the wilderness in the Kahtaheena River area. Third, ANILCA gave authority to NPS to manage lands in Alaska under the National Wilderness Preservation System and at the same time designated more than 2.6 million acres of wilderness in GBNPP. ANILCA called for the preservation of wilderness resources, scenic values, the natural and unaltered state of forests, and maintaining undisturbed ecosystems. ANILCA places most of the terrestrial and marine areas in GBNPP within the jurisdiction of the Wilderness Act of 1964 that also calls for resources to be left, "unimpaired for future generations." The Wilderness Act adds an additional level of protection on top of GBNPP's status as a national park. It was specifically intended to be a difficult designation to change; requiring an act of Congress for boundary adjustments and de-designations.

Boundary adjustments in wilderness are rare, but not unprecedented. Reasons for federal agency wilderness boundary adjustments include consolidating ownership of land for management purposes and to allow for subsistence activities not generally consistent with wilderness management (Anaktuvuk Pass in Gates of the Arctic National Park). These actions, however, are substantively different from de-designating wilderness lands for commercial activities that lead to trammeling land and adversely affecting natural conditions. Prohibition of commercial activities in wilderness is one of the main tenets the writers of the Wilderness Act identified, as follows:

> *In order to assure that an increasing population, accompanied by expanding settlement and growing mechanization, does not occupy and modify all areas within the United States and its possessions, leaving no lands designated for preservation and protection in their natural condition, it is hereby declared to be the policy of the Congress to secure for the American people of present and future generations the benefits of an enduring resource of wilderness.*

De-designating lands in the Kahtaheena River watershed, currently wilderness, and conveying them to the state of Alaska would have a significant adverse effect on GBNPP wilderness values and resources. Protection of lands with exceptional wilderness characteristics, for which GBNPP was established to protect, would be lost.

Designating Non-Wilderness Lands

The effects of designation of certain areas as wilderness must be understood within the context of the congressional action. First, Congress indicated that designation of wilderness would occur in an order of priority: the unnamed island near Blue Mouse Cove, Cenotaph Island, and the Alsek Lake lands. Second, Congress indicated that an area approximately equal in sum to that de-designated would be designated wilderness. This action is conditioned by the requirement that the specific boundaries and acreage of these wilderness designations may be reasonably adjusted by the Secretary of the Interior consistent with sound land management principles.

This analysis considers that designating only portions of the first two priority lands as wilderness would not be consistent with sound land management principles. Thus, this direction from Congress makes understanding the consequences of de-designating and designating lands for wilderness somewhat complex. Table 4.13-1 indicates the various acreages involved under the No-action Alternative and under an alternative that would de-designate and designate lands for wilderness.

The management direction in the current GMP also is important in understanding the acreage consequences of designation and de-designation. Table 4.13-1 shows that, since the Alsek Lake lands include substantially more acres of land than the acres of land necessary for the project and were identified by Congress as third in priority, these lands would not realistically be considered for wilderness designation. Sound land management dictates that it would not make sense to mix wilderness and non-wilderness designations on a small island, and because the total acres of land for the two islands add up to be about equal (1,069 acres) to the amount of land proposed for de-designation, the most likely scenario for action would be the designation of the two islands as wilderness, not the Alsek Lake lands. However, since it is impossible to predict what lands and how many acres would be designated wilderness by the Secretary, it is impossible to establish specific total acreages for lands designated or managed under the proposed action or any alternatives. At most, there would probably be about 1,364 acres designated and managed as wilderness under GEC's proposal. About 2,214 acres would be designated and managed as wilderness under the No-action Alternative, 1,069 under the Maximum Boundary Alternative, and 1,534 under the Corridor Alternative (see table 2.9-1).

Table 4.13-1. Quantitative estimates of lands designated as wilderness and managed as wilderness under each of the proposed alternatives. (Source: Preparers)

Area	No Action Designated and Managed as Wilderness (acres)	GEC's Proposal Designated and Managed as Wilderness (acres)	Maximum Boundary Alternative Designated and Managed as Wilderness (acres)	Corridor Alternative Designated and Managed as Wilderness (acres)
Kahtaheena River	1,145	295	0	465
Unnamed Island near Blue Mouse Cove	789[a]	789	789	789
Cenotaph Island	280[a]	280	280	280
Alsek Lake (Dry Bay)	0	0	0	0
Total	2,214	1,364	1,069	1,534

[a] Currently managed *de facto* as wilderness.

Although the amount of acreage involved in the proposed action is important (see table 4.13-1), the values contained within the areas affected by the proposed action are equally important. Under the assumptions identified above, there would be no significant net increase in land congressionally designated as wilderness within GBNPP under the proposed land designation and de-designating action. However, under the proposed action, there would be fewer acres *managed* as wilderness under NPS policy even though lands would be designated wilderness by Congress. In addition, the proposed action would lead to a loss of protection and control by GBNPP for an aquatic ecosystem and vegetation system that is relatively uncommon within GBNPP, as this land would be exchanged with the state. Current GBNPP management direction states that the lands to be designated as wilderness under the proposed action are currently managed as if they were wilderness. Revisions to the General Management Plan (GMP) in the future could potentially change the manner in which these lands are managed.

In terms of the capability criterion, the net effect of designating two islands as wilderness and de-designating another area from wilderness would create the following results. First, Blue Mouse Cove is an area where current visitor use patterns impinge on opportunities for solitude. Second, this action would remove from wilderness status sections of the Kahtaheena River, which contain exceptional opportunities for solitude in an area that is highly natural.

In terms of availability, the proposed action would de-designate and remove from management as wilderness 850 acres that have no current conflicts with other land uses. It would potentially add about 1,069 acres of islands and/or about 2,200 acres in the Alsek Lake area, which are intruded upon by nearby recreational and administrative activity and motorized use, but only if the Secretary decides to designate this third priority area.

In terms of need, the proposed action would eliminate protection of a riparian and terrestrial ecosystem not abundant in the GBNPP wilderness and potentially add two areas (The Islands), which are currently managed as wilderness, which contain relatively common terrestrial ecosystems within GBNPP.

De-designating the Kahtaheena River area as wilderness and designating the unnamed island near Blue Mouse Cove, Cenotaph Island in Lituya Bay, and the Alsek Lake lands would result in a loss of lands managed as wilderness in GBNPP (see table 4.13-1).

Proposed Land Exchange Parcels

The land exchange parcels would not be affected by wilderness designation or de-designation in GBNPP. The areas to be added would not be designated as wilderness.

4.13.2.3 Cumulative Effects Analysis. Potential increases in recreational activities, tourism, or subsistence could occur as a result of estimated future population growth in Gustavus, or as a result of increased tourism at GBNPP. The increased activity could result in a greater frequency of occurrence of unwanted sounds in backcountry areas. The continuous operation of the proposed project, and the occasional maintenance vehicle traffic along the access road, would contribute to a cumulative effect on the soundscape in adjacent natural areas. These combined effects would, therefore, contribute to a cumulative loss of solitude for wilderness visitors in GBNPP wilderness areas adjacent to the project.

The state maintains the right to develop mineral resources on state-owned lands. The state may potentially conduct mineral development in the future on its land to provide material for road maintenance in the Gustavus area, or for other purposes. The development of the project would require the establishment of rock quarries along the access road to provide material for construction and project development. The combined effects of potential future mineral development by the state of Alaska and the establishment of rock quarries for project construction may produce a cumulative loss of solitude for wilderness visitors in GBNPP wilderness areas and unknown environmental effects adjacent to the Falls Creek Hydroelectric Project.

Increased demand for power in the community of Gustavus, or the desire to further reduce the dependency of Gustavus or GBNPP on diesel generation for power production, may result in a greater emphasis to evaluate other streams within GBNPP wilderness areas for the potential development of hydroelectric power. The development of additional hydroelectric power sources within GBNPP would require Congressional approval to change existing wilderness area boundaries, or establish an exemption of allowable uses. The re-designation of a portion of the GBNPP wilderness area for the establishment of the project represents a change from past Congressional actions regarding changes to wilderness boundaries to allow for private development.

4.13.2.4 Conclusion. Under GEC's proposal, the construction and operation of the proposed project would result in a loss of solitude in the surrounding area including the Native allotments as a result of the use of road building equipment and chainsaws (see section 4.10, *Soundscape/Noise*). This impact would occur during the construction period. The noise and dust associated with the construction of the project also could affect adjacent GBNPP lands; however, these effects would be short term.

The purposes and values of GBNPP identified in the enabling legislation and presidential proclamations include preservation of wilderness and old-growth, mature forests. The construction and operation of the proposed project would not adversely impact the purposes and values of GBNPP as constituted after the land exchange because the majority of effects would occur within the project boundary or on state land. Any effects on wilderness within GBNPP would be short-term and localized and would not substantially diminish the purposes and values of GBNPP wilderness. An area of approximately 1,069 acres, some of which constitutes old growth and mature forest, would be removed from the park. Under this alternative, wilderness values of the unnamed island near Blue Mouse Cove, Centotaph Island, and lands at Alsek Lake would not be affected because those lands are currently managed as wilderness and depending on the amount of land exchanged it would be designated wilderness.

The effects of the de-designation and designation would lead to a net loss of area managed as if it were wilderness, even though the designations would lead to approximately equal amount of designated wilderness (see table 4.13-1). The designation of lands on the unnamed island near Blue Mouse Cove, Cenotaph Island, and the Alsek Lake lands would not mitigate the loss of the Kahtaheena River area wilderness lands because there would be an overall loss of lands managed as wilderness in the park, and the lands designated as wilderness would not contain similar qualities as those lost.

Overall, although there would be a loss of 850 acres of unique designated wilderness and a decrease in the value of 1,069 acres of wilderness, more than 2.5 million acres of designated wilderness would remain in existence and would continue to fulfill the purposes of the park as established by the Wilderness Act, GBNPP's enabling legislation (see section 1.7.4), and ANILCA. Therefore, there would be no impairment of GBNPP resources that fulfill the specific purposes identified in the enabling legislation (see section 1.7.4), or which are key to the natural integrity of the park.

Conveyance of either the Long Lake parcels or the Klondike Gold Rush parcels from the state of Alaska to NPS would not affect the wilderness resources of these two parks because neither parcel is designated as wilderness, and the parcels are not located wilderness areas. Because there would be no adverse effects, there would be no impairment of the resources that fulfill specific purposes of WSNPP or KGNHP as identified in the parks' enabling legislation (see section 1.7.4), or are key to the natural integrity of these parks.

4.13.3 Maximum Boundary Alternative

4.13.3.1 Effects of Construction and Operation. Effects of the Maximum Boundary Alternative would be similar to GEC's proposal (section 4.13.2). Direct impacts would be inconsequential because the area of development would no longer be wilderness. Indirect impacts from the construction and operation of the hydroelectric project would have a minimal effect on the park wilderness due to the potential loss of solitude in the surrounding area as a result of the use of road building equipment and chainsaws. This impact would last for a short-term basis only.

Fewer effects on natural conditions from land management on the remaining lands would be expected because of more certain long range control of these lands. However, uncertainties in how the access road would be managed may still lead to increases in recreational use on nearby wilderness lands, potentially reducing natural conditions.

4.13.3.2 Effects of the GBNPP and Wilderness Boundary Adjustment. Effects of this alternative would be similar to GEC's proposal. De-designating the Kahtaheena River area as wilderness and designating the unnamed island near Blue Mouse Cove, Cenotaph Island in Lituya Bay, and the Alsek Lake lands would result in a loss of about 1,145 acres managed as wilderness in GBNPP. In addition, the lands designated as wilderness would not have the same high quality wilderness characteristics as those lost.

4.13.3.3 Cumulative Effects Analysis. The types of cumulative effects that could be expected to occur on wilderness resources under this alternative are the same as those described under GEC's Proposed Alternative in section 4.13.2.3.

4.13.3.4 Conclusion. Under the Maximum Boundary Alternative, the effects of project would be the same as described in the conclusion for GEC's Proposed Alternative (section 4.13.2.4), except that the 1,145 areas that would be conveyed to the state of Alaska would include the entire bypassed reach and lands to the east of the river, and all the land would be included in the FERC project boundary. Therefore, the effects could be somewhat less in intensity though because of greater control of land uses on exchanged lands that would be included as part of the formal project boundary.

The purposes and values of GBNPP identified in the enabling legislation and presidential proclamations include preservation of wilderness and old-growth, mature forests. The construction and operation of the proposed project would not adversely impact the purposes and values of GBNPP as constituted after the land exchange because the majority of effects would occur within the project boundary or on state land. Any effects on wilderness within GBNPP would be short-term and localized and would not substantially diminish the purposes and values of GBNPP wilderness. An area of approximately 1,069 acres, some of which constitutes old growth and mature forest, would be removed from the park. Under this alternative, wilderness values of the unnamed island near Blue Mouse Cove, Cenotaph Island, and lands at Alsek Lake would not be affected because those lands are currently managed as wilderness and depending on the amount of land exchanged it would be designated wilderness.

Overall, although there would be a loss of 1,145 acres of unique designated wilderness and a decrease in the value of 1,069 acres of wilderness, more than 2.5 million acres of designated wilderness would remain in existence and would continue to fulfill the purposes of the park as established by the Wilderness Act, GBNPP's enabling legislation (see section 1.7.4), and ANILCA. Therefore, there would be no impairment of GBNPP resources that fulfill the specific purposes identified in the enabling legislation (see section 1.7.4), or which are key to the natural integrity of the park.

Conveyance of either the Long Lake parcels or the Klondike Gold Rush parcels from the state of Alaska to NPS would not affect the wilderness resources of these two parks because neither parcel is designated as wilderness and the parcels are not located wilderness areas. Because there would be no adverse effects, there would be no impairment of the resources that fulfill specific purposes of WSNPP or KGNHP as identified in the parks' enabling legislation (see section 1.7.4), or are key to the natural integrity of these parks.

4.13.4 Corridor Alternative

4.13.4.1 Effects of Construction and Operation. The effects of the Corridor Alternative on wilderness values in the Kahtaheena River area would be similar to the effects of GEC's proposal (see section 4.13.2). Direct impacts would be inconsequential because the area of development would no longer be wilderness. Indirect impacts from the construction and operation of the hydroelectric project would have a minimal effect on the park wilderness due to the potential loss of solitude in the surrounding area as a result of use of road building equipment and chainsaws. Because the wilderness boundary would be closer to project operation, there would be the greatest potential under this alternative for noise intrusion. This impact would last for a short-term basis only.

Fewer effects on natural conditions from land management on the remaining lands would be expected because of more certain long range control of these lands. However, uncertainties in how the access road would be managed may still lead to increases in recreational use on nearby wilderness lands, potentially reducing natural conditions.

4.13.4.2 Effects of the GBNPP and Wilderness Boundary Adjustment. Effects of this alternative would be similar to the Proposed Alternative. De-designating the Kahtaheena River area as wilderness and designating the unnamed island near Blue Mouse Cove, Cenotaph Island in Lituya Bay, and the Alsek Lake lands would result in a loss of about 680 acres managed as wilderness in GBNPP. In addition, the lands designated as wilderness would not have the same level of high quality wilderness characteristics as those lost.

4.13.4.3 Cumulative Effects Analysis. The types of cumulative effects that could be expected to occur on wilderness resources under this alternative are the same as those described under GEC's Proposed Alternative in section 4.13.2.3.

4.13.4.4 Conclusion. Under the Corridor Alternative, the effects on wilderness resources would be the same as described in the conclusion for GEC's Proposed Alternative (section 4.13.2.4), except that the 680 acres that would be conveyed to the state of Alaska would include the entire bypassed reach and lands to the east of the river, and all the conveyed lands would be within the FERC project boundary. Therefore, the effects could be somewhat less in intensity though because of greater control of land uses on exchanged lands that would be included as part of the formal project boundary.

The purposes and values of GBNPP identified in the enabling legislation and presidential proclamations include preservation of wilderness and old-growth, mature forests. The construction and operation of the proposed project would not adversely impact the purposes and values of GBNPP as constituted after the land exchange because the majority of effects would occur within the project boundary or on state land. Any effects on wilderness within GBNPP would be short-term and localized and would not substantially diminish the purposes and values of GBNPP wilderness. An area of approximately 1,069 acres, some of which constitutes old growth and mature forest, would be removed from the park. Under GEC’s proposal, wilderness values of the unnamed island near Blue Mouse Cove, Cenotaph Island, and lands at Alsek Lake would not be affected because those lands are currently managed as wilderness and depending on the amount of land exchanged it would be designated wilderness.

Overall, although there would be a loss of 680 acres of unique designated wilderness and a decrease in the value of 1,069 acres of wilderness, more than 2.5 million acres of designated wilderness would remain in existence and would continue to fulfill the purposes of the park as established by the Wilderness Act, GBNPP’s enabling legislation (see section 1.7.4), and ANILCA. Therefore, there would be no impairment of GBNPP resources that fulfill the specific purposes identified in the enabling legislation (see section 1.7.4), or that are key to the natural integrity of the park.

Conveyance of either the Long Lake parcels or the Klondike Gold Rush parcels from the state of Alaska to NPS would not affect the wilderness resources of these two parks because neither parcel is designated as wilderness, and the parcels are not located wilderness areas. Because there would be no adverse effects, there would be no impairment of the resources that fulfill specific purposes of WSNPP or KGNHP as identified in the parks' enabling legislation (see section 1.7.4), or are key to the natural integrity of these parks.

4.14 PARK MANAGEMENT

Several evaluation parameters are used to identify and describe the potential effects on park management in the project area:

1. Personnel numbers
2. Demand for park personnel
3. Law enforcement patrols
4. Acres of land managed
5. Jurisdiction of resource management area
6. Consistency of management within park boundary
7. Management conflicts with adjacent lands

The assessment of potential effects of the proposed project on park management includes a discussion of the context of park management in the area to provide an indication of the scale. The intensity of the effects on park management are generally characterized by quantifying the amount of land that is transferred into or out of the park's jurisdiction and the resulting changes in the personnel levels and demand, area of land managed, and compatibility with adjacent parcel management and the overall management plan of the park.

4.14.1 No-action Alternative

4.14.1.1 Effects Analysis. Under the No-action Alternative, the proposed project would not be constructed; the land surrounding the proposed project would be retained within the National Wilderness Preservation System for the foreseeable future and would continue to be managed as wilderness in accordance with the GBNPP GMP; and there would be no land exchange.

The lands at the unnamed island near Blue Mouse Cove, Cenotaph Island, and the Alsek Lake parcels would not be designated as wilderness and would continue to be managed in accordance with current NPS policies relating to these areas. Therefore, no changes to park management would occur on these lands under the No-action Alternative.

Likewise, parcels in the WSNPP Long Lake area and near KGNHP would remain under state of Alaska ownership. Therefore, these lands would continue to be managed as they currently are and there would be no effects on park management under this alternative.

4.14.1.2 Cumulative Effects Analysis. Under the No-action Alternative, no changes in park management policies or development would occur. Therefore, there is no potential for cumulative effects on park management resources based on the interaction between a project and a non-project action.

4.14.1.3 Conclusion. The No-action Alternative would have no effects on park management since current policies and operations would remain in place. Likewise, under this alternative, there would not be any benefits associated with NPS management of the transfer or wilderness designation lands.

4.14.2 GEC's Proposed Alternative

4.14.2.1 Effects of Construction and Operation. Under this alternative, approximately 850 acres would be transferred to the state, but the FERC project boundary would be the minimum amount of land (117 acres) required for construction and operation surrounding the diversion, powerhouse, and the roads. These lands would be subject to FERC license conditions that could restrict pedestrian and vehicular access along with other activities to protect the watershed and project facilities. The remaining exchanged lands (733 acres) would not be subject to FERC jurisdiction and would be managed by the state of Alaska. Effects on park management could result from introducing new activities on state lands, increased access to the adjacent GBNPP lands, removing portions of the Kahtaheena River from GBNPP, and an increase in the number of entities with whom the GBNPP would need to coordinate.

The state of Alaska could allow hunting, trapping, motorized access, dogs, mining, timber harvest, and borrow pits, activities that are currently not allowed on GBNPP lands. Depending on the activity authorized, the land exchange would result in a limited adverse effect on park management because of the additional staff and time needed to manage the effects of activities on adjacent GBNPP lands. Activities that take place on the state lands along the western edge of the river could easily carry over to park lands along the eastern edge through direct (e.g., dogs crossing the river, people shooting guns across the river, increased trailing on park lands due to illegal hunting or trapping activities associated with the river channel) or indirect (e.g., increased sedimentation in the stream bed from borrow pits, timber harvest, or roads on state lands and effects on the visitor experience from motorized activities on state lands) contact. All of these activities could require additional staff time to monitor the effects, enforce park regulations, and negotiate with the various land owners. These adverse effects would be minimized if the state and NPS management goals are similar.

The change in land ownership would result in additional access to GBNPP lands from state lands. This could lead to increased visitation to areas that currently experience very little visitation. This in turn, would require park managers to increase the amount of resource protection and monitoring on these lands. Additional park staff would be needed to enforce park regulations such as no hunting or trapping and to monitor fish and wildlife populations, visitor use, soundscape, air quality, and human/bear conflicts. Additional park staff and the infrastructure to support this staff would require an increase in park funding to cover the costs of new staff or would require NPS to relocate existing staff from other areas. Over time, park staff would adjust to the change in ownership and increased visitation making the effect on park management more intense in the short term, but less over the long term.

Under this alternative, the eastern boundary of the exchanged land would be the Kahtaheena River. Due to the surrounding terrain, it is likely that the majority of the visitor activity would occur along the lower reaches of the river. NPS would no longer have full jurisdiction over the entire Kahtaheena River, but would share management of the lower reaches of the river with the state of Alaska. The loss of jurisdiction over the lower reaches of the Kahtaheena River would adversely affect NPS management of fish populations, water quality, and other water issues in the Kahtaheena drainage. The projected increase in visitation at the Lower Falls coupled with the shared jurisdiction between the state and NPS would have an adverse effect on park management since the river would remain the jurisdictional boundary over the long term. Additional visitors and coordination with the state to manage the river corridor would require additional staff and resources to ensure that the management of the park's resources remains consistent with their management plans and that the visitor experience of the park is unaffected.

Under this alternative, there would be four different jurisdictional authorities and likely land use patterns for the life of the license; NPS authority on the GBNPP lands, FERC jurisdiction within the project boundary, state of Alaska authority on all the exchanged lands, and private ownership authority on the private lands within and surrounding the exchanged land. This alternative would likely require additional park staff and time to coordinate the management of the GBNPP lands with the state of Alaska and FERC; however, overall effects would be limited because the new boundaries would be a very small portion of the overall GBNPP boundary.

4.14.2.2 Effects of the GBNPP and Wilderness Boundary Adjustment. Under this alternative, the reconfiguration of park boundaries in the WSNPP and KGNHP, by the addition of approximately 850 acres, could adversely affect park management at these parks. This effect would primarily be during the short-term transition period and would result from increased coordination with the state and the adjacent landowners. There would be additional park staff time necessary or personnel assigned to this project during the transition period. Over the long term, transfer of the Long Lake lands to NPS (see figure 1-5 in appendix A) would eliminate a few parcels of private land within WSNPP, thus eliminating some management conflicts in this area. The transfer would ensure that no development would occur and facilitate management of that park as a whole. This land would be assimilated into WSNPP and, depending on the management scheme, it may or may not require additional staffing. The potential exchange lands in the KGNHP (see figure 1-6 in appendix A) that would be transferred from state to NPS ownership are currently managed by NPS under an agreement with the state. These lands are managed primarily for recreational use that is similar to the adjacent NPS lands. Thus, NPS designations would add acreage to the park, though, under the present management scheme, it is not expected to require additional staffing. The exchange would ensure that the exchange lands are maintained consistent with NPS management plan and policies in perpetuity, thus facilitating park management of the transferred lands in the KGNHP over the long term.

Under GEC's proposal, 850 acres of land that are currently designated as wilderness under the NPS Wilderness and National Wilderness System would be de-designated as wilderness and transferred to the state of Alaska. This de-designation could result in a positive effect on park management because of the reduced acreage and staff time necessary to manage the wilderness lands in the Excursion Ridge area. Presently, there is private land with several different owners bordering GBNPP and, under this alternative, only state land would abut the GBNPP boundary. To compensate for the de-designation of wilderness lands in the Kahtaheena River area, an approximately equal amount of land within GBNPP, not currently designated as wilderness, would be designated as such under the National Wilderness System. Potential lands for wilderness designation include an unnamed island near Blue Mouse Cove, Cenotaph Island, and Alsek Lake Lands as shown in figures 1-7 through 1-9 in appendix A. Additional staff time may be needed to manage these lands under the National Wilderness Act and accordingly could result in an adverse effect on park management. This effect is expected to be negligible because the NPS currently manages the proposed lands as *de facto* wilderness areas.

4.14.2.3 Cumulative Effects Analysis. GBNPP staff is currently in the process of developing several management plans (e.g., vessels management plan, Backcountry Management Plan/GMP) that, depending on the final decisions, could require more staff, or additional staff time, to manage the proposed actions, resources, and mitigation identified in these plans. The change in GBNPP boundaries, area under management, and administrative changes to existing land designations, would require additional staff time and resources to properly manage these areas. The combined effects of increased staffing requirements as a result of the implementation of management plans for other resources or areas of the park and the need for additional staff time to manage the changed area and boundaries of GBNPP may produce a cumulative negative effect in the ability of GBNPP staff to properly manage the resources in GBNPP.

4.14.2.4 Conclusion. Project operations, as well as increased visitation and recreation, resulting from GEC's proposal could result in a negative effect on NPS management of the adjacent GBNPP by increasing the need for park staff and law enforcement patrols in lands adjacent to the project area. As a result, additional funding may be required to support new staff, or existing staff may be diverted from other areas of the park. The construction of the project also would limit the ability of NPS to manage the Kahtaheena River as a whole since the river would become the boundary and may lead to management conflicts with the adjacent state lands.

The proposed wilderness designation areas (unnamed island near Blue Mouse Cove, Cenotaph Island, and the Alsek Lake parcels) and the potential exchange lands (either Long Lake within WSNPP or land near KGNHP) would be mitigation for the transfer of wilderness lands outside of GBNPP in the proposed project area. The removal of lands in the Kahtaheena River area and addition of lands in the Long Lake area or KGNHP would have a positive effect on the lands transferred to NPS due to additional protection. However, the transfer would have an overall adverse effect on park management by changing the configuration of the park boundary, which would require NPS to assess the new lands and determine how they should be managed into the future. The transfer of wilderness lands outside of the project area would result in a positive effect on park management in the immediate project area due to the reduction in lands that would need to be managed under the National Wilderness System. Designation of *de facto* wilderness areas as mitigation would have a positive effect on park management because it would not change current management practices and would ensure their protection in perpetuity.

The construction and operation of the proposed project would result in a measurable change in park management as measured by the change in acreage and reconfiguration of the park boundary, which would likely require additional personnel and law enforcement. The effects on park management would persist over the long term; however, they would be more intense in the short-term transitional period until park staff could adjust to the new boundaries and staff levels. Likewise, the amount of land affected would be very small in comparison to the total acreage of GBNPP.

4.14.3 Maximum Boundary Alternative

4.14.3.1 Effects of Construction and Operation. Under this alternative, the FERC project boundary would include all the lands exchanged (approximately 1,145 acres). These lands would be subject to FERC license conditions that could restrict pedestrian and vehicular access along with other activities to protect the watershed and facilities. These additional restrictions could limit the type and amount of authorized activities that take place on the land, and would lessen the effect of this alternative on park management as compared to GEC's proposal, under which some acreage would be transferred to the state without encumbrance. If hunting, trapping, firearms, dogs, and motorized access are permitted on the exchange lands, additional park staff could be required to monitor and manage the effect of these activities on the GBNPP lands.

Depending on the type of activities authorized within the FERC boundary, additional access to GBNPP lands from state lands could lead to increased visitation to areas that currently experience very little visitation. This in turn, could require park managers to increase the amount of resource protection and monitoring on these lands. Additional park staff would be needed to enforce park regulations such as no hunting or trapping and monitor fish and wildlife populations, visitor use, soundscape, air quality, and human/bear conflicts. Additional park staff and the infrastructure to support this staff would require an increase in park funding to cover the costs of new staff or would require NPS to relocate existing staff from other areas. Over time, park staff would adjust to the change in ownership and increased visitation making the effect on park management more intense in the short term.

Under this alternative, the exchanged land would include the entire 1,145 acres of land identified in section 3(b) of the Act, including lands along the eastern side of the Kahtaheena River. This boundary delineation would result in reduced acreage under NPS jurisdiction, which would positively affect park management. Because the exchanged lands would include both sides of the Kahtaheena River, visitor use of the river would be under the state of Alaska jurisdiction. Due to the surrounding terrain, it is likely that a majority of the visitor activity would focus along the Lower Falls area. This, in turn, could result in less staff time needed for resource enforcement and monitoring on the GBNPP lands, since most visitation would not be on park lands. However, the new boundary could result in some adverse effects on park management due to the additional staff and staff time required to manage and protect the resources along the new park boundary on the adjacent GBNPP lands, though not as intense as under GEC's proposal, where the Kahtaheena River is the boundary.

Following the land exchange, NPS would no longer have jurisdiction over the lower reaches of the Kahtaheena River, but only about 50 percent of the total river length. The lower reaches would be under state jurisdiction and would be affected by project operations due to reduced instream flow. The loss of jurisdiction over the lower reaches of the Kahtaheena River would result in an adverse effect on park management of fish populations, water quality, and other water issues in the Kahtaheena drainage since NPS would no longer manage the river in its entirety.

Under this alternative, there would be three different jurisdictional authorities and land use patterns for the life of the license; NPS authority on the adjacent GBNP lands, FERC license conditions within the FERC boundary (on state of Alaska land), and private ownership on the lands within and surrounding the exchanged land. Additional park staff and/or time could be required to coordinate with the various jurisdictional authorities mentioned above on managing the adjacent GBNPP lands resulting in adverse effects on park management. However, there would be fewer jurisdictional boundaries than under GEC's proposal where the FERC boundary differs from the state of Alaska boundary. As a result, there would be fewer effects on park management.

4.14.3.2 Effects of the GBNPP and Wilderness Boundary Adjustment. Under the Maximum Boundary Alternative, 1,145 acres of land that are currently designated as wilderness under the NPS Wilderness and National Wilderness System would be de-designated and transferred to the state of Alaska as opposed to the 850 acres under GEC's proposal. The effects of this alternative on park management for both the GBNPP transfer lands and the wilderness boundary adjustment lands would be the same as those described in section 4.14.2.2, with the exception of the amount of acreage. Under this alternative, more land would be de-designated as wilderness in the project area, thus NPS would have fewer lands to manage and possibly more *de facto* wilderness in the unnamed island near Blue Mouse Cove, Cenotaph Island, and Alsek Lake lands would be designated as wilderness under the National Wilderness Act and protected in perpetuity, both resulting in positive effects on park management.

Under this alternative, more land would be transferred to NPS jurisdiction in Long Lake or KGNHP resulting in the reconfiguration of park boundaries in the WSNPP and KGNHP, which would affect park management at these parks due to the need for additional park staff time or personnel to manage the additional acreage and new boundary reconfiguration. However, as under GEC's proposal, effects would likely be short term, as park staff adjusts its management from lands around the Kahtaheena River to the newly transferred lands that are already managed consistent with NPS policies on adjacent lands.

4.14.3.3 Cumulative Effects Analysis. The types of cumulative effects that could be expected to occur on park management under this alternative are the same as those described under GEC's proposal in section 4.14.2.3.

4.14.3.4 Conclusion. Like GEC's proposal, project construction under the Maximum Boundary Alternative would have a negative adverse effect on park management due to increased visitation on neighboring project lands and the reconfiguration of park boundaries following the land transfer. The construction and operation of the proposed project would result in a measurable change in park management as measured by the change in acreage and reconfiguration of the park boundary, which would likely require additional personnel and law enforcement. This reconfiguration of the park boundary would adversely affect park management, especially in the short term, because park staff would need to assess the new lands and boundaries to determine how they should be managed into the future, which may require additional personnel. However, the amount of land affected would be very small in comparison to the total acreage of GBNPP.

Under the Maximum Boundary Alternative, effects on park management from the land transfer and wilderness designation areas would be the same as under GEC's proposal except 1,145 acres versus 850 acres would be affected. The removal of lands in the Kahtaheena River area and addition of lands in the Long Lake area or KGNHP would have a positive effect on the lands conveyed to NPS due to additional protection. There would be an overall adverse effect on park management due to the reconfiguration of the park boundary, which would require NPS to assess the new lands and determine how they should be managed into the future. The transfer of wilderness lands outside of the project area would have a positive effect on park management in the immediate project area, due to the reduction in lands that would need to be managed under the National Wilderness System. Designation of *de facto* wilderness areas as mitigation would have a positive effect on park management because future management would be similar to current management and would ensure their protection in perpetuity.

The construction and operation of the proposed project would result in a measurable change in park management as measured by the change in acreage and reconfiguration of the park boundary, which would likely require additional personnel and law enforcement. Although the effects on park management would persist over the long term, they would be more intense in the short-term transitional period until park staff could adjust to new boundaries. Additionally, the amount of land affected would be very small in comparison to the total acreage of GBNPP.

4.14.4 Corridor Alternative

4.14.4.1 Effects of Construction and Operation. Under this alternative, the FERC project boundary and exchanged lands would be restricted to a minimum buffer of approximately 0.25 mile around all project features including the access road, borrow pits, intake site, penstock, and powerhouse. These lands would be subject to FERC license conditions that could restrict pedestrian and vehicular access along with other activities to protect the watershed and hydroelectric facilities. These additional restrictions could limit the type and amount of authorized activities that take place on the land for the term of the license. This alternative would result in a narrower corridor of exchange lands and leave approximately 224 acres (a 67-acre parcel to the west of the Native allotments and a 157-acre parcel between the two allotments) of GBNPP land entirely surrounded by either state (includes FERC project boundary) and private land (see figure 2-9 in appendix A). Correspondingly, there would be a greater increase in the amount of linear NPS boundary when compared to the other alternatives. This could result in a corresponding greater adverse effect on park management over the other alternatives to manage issues along the jurisdictional boundaries. If hunting, trapping, firearms, dogs, and motorized access are not discouraged within the FERC boundary, additional park staff would likely be required to monitor and manage the effect of these activities on GBNPP lands. Additionally, the configuration of the project boundary following land transfer leaves two parcels of isolated NPS land that would likely require additional personnel and law enforcement along the boundaries to coordinate management strategies with adjacent parcels under separate jurisdiction and to maintain park values and resources. The additional jurisdictional boundaries coupled with the isolated NPS lands would have an adverse effect on park management.

Additional access to the GBNPP lands from state lands could lead to increased visitation to areas that currently experience very little visitation. This in turn, may require park managers to increase the amount of resource protection and monitoring on these lands. Additional park staff would be needed to enforce park regulations such as no hunting or trapping and monitor fish and wildlife populations, visitor use, soundscape, air quality, and human/bear conflicts along a greater and more convoluted boundary than the other alternatives. Additional park staff and the infrastructure to support this staff would require an increase in park funding to cover the costs of new staff or would require NPS to relocate existing staff from other areas. Over time, park staff would adjust to the change in ownership and increased visitation making the effect on park management more intense in the short term.

Under this alternative, the eastern boundary of the exchanged land would include some lands along the eastern side of the Kahtaheena River, though not as much as under the Maximum Boundary Alternative. This eastern boundary delineation would be closer to the river and include less acreage than under the Maximum Boundary Alternative and could affect park management because of the additional staff and staff time required to manage and protect the resources on GBNPP lands. Like the Maximum Boundary Alternative, the exchanged lands would include both sides of the lower Kahtaheena River, where due to the terrain it is likely that a majority of the visitor activity would focus. As a result, the river corridor, where most of the additional activities and management resources would be required, would be under the state of Alaska jurisdiction. However, some additional staff time would be required to manage any activities in the river corridor that spill over onto park lands. The effects on park management would be greater than under the Maximum Boundary Alternative because the boundary is closer to the river, but would not be as noticeable as under GEC's proposal, where the Kahtaheena River is the boundary.

Following the land exchange, NPS would no longer have jurisdiction over the lower reaches of the Kahtaheena River, but only about 50 percent of the total river length. The lower reaches would be under state jurisdiction and would be affected by project operations due to reduced instream flow. The loss of jurisdiction over the lower reaches of the Kahtaheena River would result in an adverse effect on park management of fish populations, water quality, and other water issues in the Kahtaheena drainage since NPS would no longer manage the river in its entirety.

Under this alternative, there would be three different jurisdictional authorities and land use patterns for the life of the license; NPS authority on GBNPP lands, FERC license conditions within the FERC boundary and on state of Alaska land, and private ownership authority on the private lands within and surrounding the exchanged land. Additional park staff and/or time could be required to coordinate with the various jurisdictional authorities mentioned above on managing GBNPP lands, resulting in an adverse effect on park management depending on jurisdictional management differences. The increase in jurisdictional boundary between the FERC project boundary and NPS lands also would likely increase the amount of time NPS staff spend coordinating with the various land owners on managing and protecting the resources under this alternative.

4.14.4.2 Effects of the GBNPP and Wilderness Boundary Adjustment. Under the Corridor Alternative, 680 acres of land that are currently designated as wilderness under the NPS Wilderness and National Wilderness System would be de-designated and transferred to the state of Alaska as opposed to the 850 acres under GEC's proposal and 1,145 acres under the Maximum Boundary Alternative. The effects of this alternative on park management for both the GBNPP transfer lands and the wilderness boundary adjustment lands would be the same as those described in section 4.14.2.2, with the exception of acreage. Under this alternative, less land would be de-designated as wilderness in the project area. This could result in a smaller decrease in park staff time necessary to manage this wilderness to the National Wilderness Act standards as compared to GEC's proposal and the Maximum Boundary Alternative. Accordingly, there could be a lesser positive effect on park management than the other alternatives. Due to a decreased amount of acreage that would be designated as wilderness under the National Wilderness Act and protected in perpetuity on the unnamed island near Blue Mouse Cove, Cenotaph Island, and Alsek Lake lands, less staff time would be needed, resulting in a positive effect on park management.

Under this alternative, less land would be transferred to NPS jurisdiction at Long Lake in WSNPP or KGNHP resulting in the reconfiguration of park boundaries in the WSNPP and KGNHP. It is expected that the effect on park management in these parks, due to the need for additional park staff time or personnel to manage the additional acreage and boundary reconfiguration, would be similar to the other alternatives. For the NPS lands in the Kahtaheena River area, as under GEC's proposal, effects would likely be short term as park staff adjusts its management from lands around Kahtaheena River to the newly transferred lands that are already managed consistent with NPS policies on adjacent lands.

4.14.4.3 Cumulative Effects Analysis. The types of cumulative effects that could be expected to occur on park management under this alternative are the same as those described under GEC's Proposed Alternative in section 4.14.2.3.

4.14.4.4 Conclusion. Under the Corridor Alternative, increased visitation to the project area could lead to an increased need for law enforcement patrols on the lands surrounding park lands. This, in turn, could divert park staff from other areas of the park. This would result from the greater amount of interface between the state of Alaska land (includes FERC project boundary) and the NPS land. The acreage involved in the land transfer is the smallest amount under this alternative; however, the new project corridor would be narrower and leave isolated pockets of NPS land, thus the effects on boundary management issues would be more intense. Under this alternative, the state of Alaska land surrounded by NPS land and the isolation of approximately 224 acres of NPS land could lead to an increase in management issues along the jurisdictional boundaries, which could affect park management depending on jurisdictional differences. Ultimately, the Corridor Alternative could result in an increased adverse effect on park management as compared to GEC's proposal due to the increased acreage and reconfiguration of the park boundary. The effects on park management would persist over the long term; however, they would be more intense in the short-term transitional period until park staff could adjust to new boundaries, and the amount of land affected is very small in comparison to the total acreage of GBNPP.

The Corridor Alternative would reduce the negative effects on park management of wilderness in the Kahtaheena River area, since fewer lands would be de-designated.

Likewise, the addition of lands in the Long Lake area or KGNHP would have a similar adverse effect on park management as the other two alternatives. The difference in exchanged acreage when compared to the total acreage under NPS jurisdiction is negligible. However, the resulting land transfer would change the configuration of the park boundary, which would require NPS to assess the new lands and determine how they should be managed into the future. This would likely require additional personnel and law enforcement to be directed to protecting and managing the NPS lands in the Kahtaheena River area.

4.15 LAND USE PROGRAMS AND POLICIES

Several evaluation parameters are used to identify and describe the potential impacts on land uses:

1. Land ownership acreages
2. Land use management policies
3. Intensity of human use/disturbance
4. Compatibility with existing land uses

The assessment of the potential effects of the project on land use includes a discussion of the context of land uses in the project area. The intensity of the impact on land use is generally characterized by quantifying the area of lands to be exchanged; qualitatively discussing the compatibility of actions on land management policies and existing land uses; and qualitatively discussing the intensity of human use and disturbance associated with project actions. The duration of the impact is described where necessary to understand the context and intensity of the impact.

4.15.1 No-action Alternative

4.15.1.1 Effects Analysis. Under the No-action Alternative, the proposed project would not be constructed. There would be no land exchange, and the land surrounding the proposed project would be retained within the National Wilderness Preservation System for the foreseeable future. It would continue to be managed as wilderness in accordance with the GBNPP GMP. The potential exchange lands in the Kahtaheena River area would remain within GBNPP and would be managed under existing land use policies. Similarly, state and private lands in the proposed project area would continue to be managed under current land use policies.

The state of Alaska parcels in the Long Lake area, and those near KGNHP, would not be transferred from state of Alaska to NPS ownership. Thus, no effects on current land uses would occur under this alternative. These lands would continue to be managed in accordance with current state land use policies.

The unnamed island near Blue Mouse Cove, Cenotaph Island, and the Alsek Lake parcels would not be designated as wilderness and would continue to be managed in accordance with current NPS land use policies relating to these areas. Therefore, no changes in land use would occur under the No-action Alternative.

4.15.1.2 Cumulative Effects Analysis. No new development or changes to land management policies would be associated with this alternative; therefore, no cumulative effects have been identified in relation to the NPS Kahtaheena River lands or the proposed wilderness designation lands. They would continue to be managed under GBNPP land use policies.

The current state of Alaska land management policies would remain in place for the Long Lake lands, targeting protection of fish and wildlife habitat. The proposed improvement and expansion of the McCarthy Road could increase growth and human development along the corridor as access is enhanced (LDN, 2002). The current state management policies for the lands along Long Lake do not limit the number of people or visitor trips to the area. Therefore, increased growth and use of the McCarthy Road corridor could increase recreational pressure and use, thereby cumulatively affecting the fish and wildlife resources. Potential cumulative effects of increased human development in the Long Lake area may range from negligible to adverse depending upon the types of developments permitted by the state in the area and how much the uses differ from adjacent park management.

4.15.1.3 Conclusion. Under the No-action Alternative, there would be no effect on land management policies or existing land uses in the Kahtaheena River area, on the potential land exchange parcels, or on the wilderness parcels. Implementation of the No-action Alternative would not impair GBNPP resources that fulfill specific purposes as identified in the enabling legislation or are key to the natural integrity of the park.

Because an exchange of lands would not be pursued, the effects on land use management policies or existing uses of these parcels would be unchanged and would not impair WSNPP or KGNHP resources that fulfill specific purposes as identified in the enabling legislation, or are key to the natural integrity of these parks. Under this alternative, WSNPP and KGNHP would continue to operate and manage their lands as outlined in their enabling legislation (see section 1.7.4).

4.15.2 GEC's Proposed Alternative

The primary land use actions that would occur under this alternative include:

1. the de-designation of 850 acres of land in the Kahtaheena River area currently classified as wilderness;

2. the transfer of 850 acres of land in the Kahtaheena River area from GBNPP to the state of Alaska;

3. the transfer of land in the Long Lake and KGNHP areas from the state of Alaska to NPS; and

4. the designation as wilderness of three parcels in GBNPP (unnamed island near Blue Mouse Cove, Cenotaph Island, and Alsek Lake parcels).

Secondary actions that would occur as a result of implementing the primary actions identified above include:

1. a change in land use management policies for individual parcels included in the transfer of land between NPS and the state of Alaska;

2. the construction, operation, and maintenance of the hydroelectric project and associated infrastructure; and

3. development of a land use management plan and a public use and access management plan for project land.

As a result of implementing the primary and secondary actions, additional actions may occur that are associated with, or indirectly linked to, the actions described above. These are actions that may occur, or increase in occurrence, with the land exchange and the development of the project, and could increase effects on resources as a result of the development of the project. These associated actions may include:

1. motorized recreation use of the project road and adjacent land;

2. recreation and subsistence hunting, trapping, and fishing on project land and adjacent areas;

3. the extraction of mineral resources on state land;

4. the development of state, private, or Native allotment parcels adjacent to project land;

5. the disruption or contamination of water used for domestic purposes;

6. helicopter flights over project land, or landings on state land;

7. the disturbance of wildlife by recreation users and dogs on project land; and

8. trespass and theft from Native allotment land.

Proposed Land Use Designations of NPS Land Transferred to the State. The state of Alaska developed the Northern Southeast Area Plan for the management of its lands in this region. This plan identifies the land use designations that would be applied to the 850 acres of NPS land acquired by the state. In addition, ADFG filed a letter with FERC (August 9, 2002), in which it describes the land use designations proposed for the lands acquired by the state in the project area. Management of these lands would be consistent with the objectives and guidelines for habitat and water land use designations described in the Northern Southeast Area Plan.

The water resources designation would apply to all of the state lands required for the development of the hydroelectric facility (approximately 75 acres), while the remaining lands would be managed for fish and wildlife habitat. The management intent of the habitat designation is to protect fish and wildlife species where alteration of the habitat or human disturbance could result in a permanent loss of a population or sustained yield of a species. On the habitat lands, development activities would be precluded. The state has also reserved the right to approve mineral extraction activities (i.e., rock pits or quarries) as needed to support the hydroelectric facility or community development. The Northern Southeast Area Plan states that the Gustavus community would be consulted prior to ADNR authorization of any development activities in the exchange area (ADNR, 2002b).

State land may be used for other purposes described in the Northern Southeast Area Plan. The most common use of state lands is for non-commercial recreation activities. The generally allowed uses listed below are subject to the requirement that the activity must minimize disturbance of fish, wildlife, vegetation, and soil resources. Other uses that may be compatible with the habitat and water designations for this land include:

1. travel by foot, horse, or bicycle;

2. use of recreational all terrain vehicles;

3. landing of helicopters;

4. hunting, fishing, or trapping;

5. harvesting native plants and vegetation for personal use (excluding trees); and

6. setting up and using a camp for personal recreational use.

There is no guarantee that the state lands would be managed in perpetuity according to these land use designations, because the state may change them in the future should it be necessary to revise the Northern Southeast Area Plan.

Land Use Authorities and Responsibilities of Participating Entities. A portion of the NPS land in the Kahtaheena River area transferred to the state of Alaska would be within the project boundary defined by FERC (approximately 75 acres), with the remainder of the land outside of the project boundary (approximately 775 acres). The state of Alaska, FERC, and GEC each would participate in determining the management guidelines for portions of the transferred land, depending on their regulatory authorities and requirements.

State of Alaska

The state of Alaska would retain sole ownership of all lands transferred from NPS to the state in the Kahtaheena River area. State ownership would include both surface and subsurface rights for these parcels. Water and habitat land use designations would be assigned to this area as described above. These lands would be included with the group of other state lands managed in the Gustavus area.

FERC

The FERC project boundary would encompass approximately 117 acres consisting of a corridor along the road and transmission line right-of-way, the intake, powerhouse, borrow pits, and disposal sites (see figure 2-1 in appendix A). State lands inside the project boundary would be subject to the management guidelines prescribed by FERC. FERC may establish land use conditions that may complement the proposed state land use designations; determine that additional measures are required to protect resources; or require GEC to develop a land use management plan to address the concerns of agencies, the local community, and Native allotment owners.

A standard condition for licenses issued by FERC includes the requirement that the project owner have control over access to the project facilities. This control can be established through either direct land ownership or easement rights granted by the property owner. The state of Alaska would grant an easement to GEC for the use of the land within the FERC project boundary, including the access road.

Other license conditions could include the development of a public use and access plan and other measures to protect the environmental resources. These measures would be developed by GEC in coordination with agency and local community representatives, including Native allotment holders.

GEC

GEC is responsible for implementing license conditions established for the project by FERC. These license conditions would pertain only to the area within the FERC project boundary, and not to adjacent state lands acquired from NPS. The potential measures described above may require GEC to develop access and land management plans in consultation with agency and local community representatives, including Native allotment holders. These plans would identify allowable uses of project land. Issues such as motorized use of roads, future extraction of gravel from project borrow pits, and hunting and trapping could be addressed.

Wilderness Watch, in comments on the draft EIS, recommends the establishment of a non-developmental easement along the access road right-of-way to provide permanent protection to the natural resources of this area. If a license is issued for this project, we expect that development along the new access road and within the project boundary would be addressed during consultation and preparation of any required public access plans and land use management plans.

4.15.2.1 Effects of Construction and Operation. Under GEC's proposal, approximately 850 acres of NPS lands would be transferred to the state of Alaska for the development of the proposed project. Only about 75 acres of this land would be included in the FERC boundary and managed by GEC. The remaining 775 acres would be outside of the FERC boundary and managed by the state. The project lands would be used for the construction of the diversion, penstock, powerhouse, access road, borrow pit, and disposal site. Construction activities would be managed to disturb the minimum amount of land needed to build and operate the project, while all other lands within the FERC boundary would remain undisturbed. Construction and operation of project facilities would alter the undeveloped character of the site.

Development of the hydroelectric project would be consistent with the land use management policies contained in the Northern Southeast Area Plan (ADNR, 2002a; 2002b). Although the state of Alaska would not have jurisdiction over the lands within the FERC boundary, it would have the opportunity to participate in the development of the land use management plan and other required measures and thus ensure that the plan would be consistent with the State priorities for the Kahtaheena River area. In addition to the project facilities described above, GEC would bury the transmission line along the proposed access road from the powerhouse to the end of Rink Creek Road. The buried line would then traverse southwest across undeveloped state and private land to an existing substation on the south side of the airport.

An easement would need to be obtained from private landowners and the state of Alaska Mental Health Trust for the transmission line south of Rink Creek Road. If GEC cannot obtain an easement across private land, then other solutions for obtaining control or ownership of the land may be pursued. The area adjacent to the airport is already highly developed, and burial of the transmission line would have a negligible effect on existing land uses. The parcel east of the airport and north towards the end of Rink Creek Road is managed for undeveloped public recreation and tourism (ADNR, 2002a). The transmission line would be buried along an existing, undeveloped off-road vehicle trail that is already partially cleared. The line would not impede recreational use of these lands. Short-term disturbance of these parcels would occur during initial installation of the line.

The state of Alaska is concerned about the need to acquire easements across private land to access the acquired state lands and the project facilities. The current state easement on Rink Creek Road terminates approximately 0.75 miles before the end of the road. The state has proposed an alternative route to access the hydroelectric project that minimizes the easements needed from private landowners. The alternative route departs from the north side of the Rink Creek Road approximately 1 mile before its end and traverses an existing 60-foot-wide state easement along the northern boundary of section 4 and part of section 3. This alternative route crosses approximately 0.25 miles of private land before entering the acquired state lands at section 2, and then rejoining the right-of-way proposed by GEC. The transmission line would be routed from the project along the alternative road route to its intersection with Rink Creek Road. The transmission line would then extend across undeveloped Alaska Mental Health Trust land, cross private land (approx. 0.25 miles), and align with the transmission line right-of-way proposed by GEC immediately southeast of the airport.

This 2.25-mile-long alternate route would reduce the length of easements across private land from approximately 2.5 miles to approximately 0.5 miles. Although this route would be longer, it would primarily traverse state lands and would be compatible with the existing use designations. The transmission line right-of-way south of Rink Creek Road would cross Alaska Mental Health Trust land for most of its length. These lands are not included in the state's management plan, and therefore compatibility can not be determined. GEC would need to obtain easements from the Alaska Mental Health Trust for the placement of the transmission line along this alternative route.

It is possible for the land exchange to occur and, for unforeseen reasons, the Falls Creek Hydroelectric Project not to be constructed. The actions involving wilderness designations and the land exchange are independent of the development of the hydroelectric facility, but are required to be completed before construction of the project. If the change in wilderness designations and the exchange of land between the state and NPS occurs without the development of the hydroelectric project, the effects on land use resources would be the same as those identified and described in this section (4.15).

Effects of Changes in Land Ownership and Management Policies

Project Area Land

Following construction of project facilities, GEC proposes to manage lands within the FERC boundary to limit human disturbance and protect fish and wildlife habitat. A land use management plan could help guide future management of project land. GEC could develop this plan in collaboration with federal, state, and local representatives, including Native allotment owners. Issues such as mineral extraction and other development could be addressed. The objectives of the plan would be to identify appropriate land uses. The cost for developing the land use plan has been included in the environmental measures detailed in section 5.3, *Cost of Environmental Protection, Mitigation, and Enhancement Measures*.

As described in section 4.12, *Recreation Resources*, GEC proposes to develop a public use and access plan in addition to the land use plan to determine the appropriate level of public recreation use and access to the project area. This plan would be developed by GEC in collaboration with federal, state, and local representatives, including Native allotment owners. Issues such as unrestricted or gated access to project roads, motorized use of project roads for recreation, and types of recreation uses permitted on project land would be addressed.

The development of recreation facilities in the project area would be incompatible with the state's habitat land use designation, and is not currently proposed for the project area.

GEC is currently proposing to restrict motorized vehicle use within the project area, although allowing non-motorized recreation. Pedestrian and bicyclists would likely be permitted to use the project roads, which would increase human use over existing conditions. With improved access, recreational use of these lands would be expected to increase, yet the intensity of impact on fish and wildlife habitat from bicycle and pedestrian uses would be less than if motorized vehicle access were permitted. However, such uses and potential disturbance could reduce fish and wildlife quality of the area in comparison to existing conditions. In addition, domestic dogs could enter the project area. Dogs are currently restricted from NPS land to protect wildlife resources. Thus, pedestrian, bicycle, and dog use in the project area would likely produce a minor effect on existing land use in the area.

If the public use and access plan developed by GEC and agency representatives determines that motorized use (e.g., automobiles, ATVs) of the project roads is allowed and is determined to be compatible with the management of the hydroelectric project, human disturbance in the project area could increase substantially. This type of use would not be compatible with the state's proposed habitat land use designation, or with existing land use policies. Thus, if vehicular access were permitted, there would be an adverse impact on land use in the project area.

The proposed hydroelectric facility would not be directly adjacent to the new GBNPP boundary, and the proposed project would not affect NPS' ability to implement the land use management policies of the park.

State Acquired Land

The 775 acres of state land outside of the FERC boundary would not be directly disturbed by the project, and would be under the sole jurisdiction and management of the state of Alaska. The state proposes to designate these lands as fish and wildlife habitat and water resource uses as described above. The state has also reserved the right to permit mineral extraction on all its land (including those within the FERC project boundary), which is evaluated in the discussion of cumulative effects (see section 4.15.2.3). The objectives of managing for fish and wildlife values is meant to preserve the natural character of the state lands, although the creation of access roads associated with the project would likely increase human use in the Kahtaheena River area. Such increased use would be inconsistent with the fish and wildlife habitat land use management policies for these lands.

Native Allotments

Access roads for the development of the hydroelectric project would be constructed in proximity to northern boundary of the George allotment and the eastern boundary of the Mills allotment. The location of these roads would provide an opportunity for increased disturbance on allotment lands by project personnel or recreation users. Allotment landowners have recorded increased disturbance on their land since project studies were initiated. These effects range from trespassing and disturbance of vegetation to theft and destruction of personal property. The potential to introduce additional disturbance to allotment lands would be incompatible with the traditional Tlingit values of the land, including subsistence and cultural/spiritual values.

The project access road would be located in proximity to the Native allotments and would provide easier access to this land. This is undesirable to the George allotment owners and most of the Mills allotment owners. While it would provide development opportunities, some find this incompatible with their values.

4.15.2.2 Effects of the GBNPP and Wilderness Boundary Adjustment. Under GEC's proposed action, approximately 850 acres of GBNPP would be removed from the existing park boundary and transferred to state ownership. The land immediately to the north and the east of the transferred land would be retained within the National Wilderness Preservation System and would continue to be managed as wilderness. The specific recreation, fish, and wildlife habitat values that would be removed from the park with the land exchange are discussed in those resource sections (see sections 4.12, 4.6, and 4.8, respectively). GBNPP is designated as a World Heritage Site (1992) and a Biosphere Reserve (1986). The transfer of 850 acres from GBNPP to the state would not change the World Heritage Site and Biosphere Reserve status of the remaining park land. The effects of the changes in the boundary of GBNPP and the wilderness area as a result of the transfer of this land to the state of Alaska are described above in section 4.15.2.1.

Approximately equal acreage (850 acres) of park lands not currently designated as wilderness would be so designated under this alternative. NPS currently manages all three of the potential wilderness designation lands (the unnamed island near Blue Mouse Cove, Cenotaph Island, and the Alsek Lake parcels) as *de facto* wilderness areas, affording them the same amount of protection. Therefore, designation of these lands as wilderness would not have an effect on land management, although it would ensure the preservation of wilderness values in perpetuity. Approximately 850 acres of land in the Long Lake area could be transferred from state to NPS ownership under this alternative. These lands would be incorporated into WSNPP. In accordance with the provisions of the GMP for the park, these lands would be managed in the same manner as adjacent park lands, with an emphasis on protecting fish and wildlife resources around Long Lake. No new developed structures would be permitted on these lands, nor would mineral extraction be allowed.

In general, land use management policies for the Long Lake area after the exchange would be similar to those currently implemented by ADNR, as described in section 3.15. NPS management would provide increased, long-term protection of the Long Lake area by precluding future human development of the exchanged lands. Such land use management would be compatible with existing land uses and applicable plans and policies.

Approximately 850 acres of land either in or near the borders of KGNHP could also be transferred to NPS ownership with implementation of this alternative. Since NPS already manages the portions of these lands along the Chilkoot Trail under agreement with the state, land use management policies would not be expected to change substantially upon completion of the land exchange. These lands would still be managed for the protection of fish and wildlife habitat, and cultural resources associated with the Chilkoot Trail. The transfer would ensure long-term NPS management of these lands and preservation of the area for the purposes of KGNHP. The management guidelines for this land under NPS ownership would be compatible with existing land uses and consistent with existing land use plans and policies.

4.15.2.3 Cumulative Effects Analysis. Trends have shown that the population of the Gustavus area is growing by approximately 4.7 percent annually, placing increased recreational demand on adjacent resources. Additional recreational demand may occur with increased cruise ship dockings in Hoonah, which may provide recreational tourism services to GBNPP and the Gustavus area. The development of roaded access for the construction and operation of the hydroelectric project would provide additional opportunities for recreational access and use of the Kahtaheena River area. The combined effect of the increased recreation demand in the Gustavus and Hoonah areas, and the improved roaded access to the Kahtaheena River area, would likely result in a cumulative increase in the recreational use of the Kahtaheena River area.

The state of Alaska has reserved the option to permit mineral extraction on the lands exchanged to the state, although no plans for such activities currently exist. The construction of the hydroelectric project also would require the development of rock quarries to provide mineral aggregate for the construction of roads and other facilities associated with the project. The potential development or expansion of rock quarries on state lands, in addition to the rock quarries to be developed for construction of the hydroelectric project, would likely result in a cumulative adverse effect on existing and proposed land uses and would not be compatible with the fish and wildlife habitat land use designation proposed for the state land. There are no other actions identified that would interact with the effects of the proposed action designating the unnamed island near Blue Mouse Cove, Cenotaph Island, and Alsek Lake as wilderness. We recognize the importance and use of the Alsek Lake area by the Yakutat Tlingit Tribe and the possible direct effects of the change in land use designation of this land. These lands are already managed as *de facto* wilderness; therefore, no cumulative effects would be expected to occur.

The proposed improvement and expansion of the McCarthy Road has the potential to increase human development and recreational use along the McCarthy Road corridor (personal communication from D. Sharp, NPS, to M. Daily, Meridian Environmental, on May 13, 2003). The exchange of the Long Lake parcels to NPS would increase the amount of resource protection on these lands and preserve them for fish and wildlife habitat uses. NPS land management policies may aid in offsetting the potential cumulative effects resulting from increased human development and recreational demand associated with the McCarthy Road expansion.

Recreational use of the Chilkoot Trail in KGNHP is increasing annually (NPS, 1996). Mineral extraction activities also occur in the KGNHP vicinity. Increased recreational use combined with mineral extraction activities on state managed lands could combine to exacerbate human use and disturbance in the area. The exchange of the Chilkoot Trail parcels to NPS could increase the level of resource protection, which may offset the potential adverse cumulative effects associated with increased recreational use and mineral extraction.

4.15.2.4 Conclusion. Under GEC's proposal, approximately 75 acres of the total 850 acres to be transferred from NPS to state ownership would be within the FERC project boundary and used for project facilities, access roads, and other related facilities. Development of a land use plan would define appropriate uses within the project boundary.

The remaining 775 acres transferred to the state of Alaska outside of the FERC boundary would be managed by the state for fish and wildlife habitat. Because of the potential for uses such as hunting and trapping, bicycling, dog walking, and motorized vehicles, human disturbance on these lands would increase in comparison to existing conditions. Future mineral extraction activities that are not related to the development of the hydroelectric project would increase over existing conditions.

The designation of wilderness lands at Cenotaph Island, the unnamed island near Blue Mouse Cove, or Alsek Lake also would not affect land management policies, existing uses, or current levels of human disturbance.

The potential transfer of state lands at Long Lake or KGNHP would not produce a substantial change in land uses in these areas. If transferred to NPS ownership, land management policies would focus on fish and wildlife habitat preservation and would be consistent with existing land uses and levels of human use.

4.15.3 Maximum Boundary Alternative

The maximum boundary alternative includes two changes from the actions described in GEC's proposed alternative. The maximum boundary alternative includes NPS land immediately east of the Kahtaheena River within the area proposed to be transferred to the state of Alaska (see figure 2-8 in appendix A). This alternative also includes all NPS land transferred to the state within the FERC-designated project boundary. These changes result in more land being exchanged between NPS and the state, and FERC having administrative and regulatory authority over all state lands acquired from the NPS within the Kahtaheena River area.

4.15.3.1 Effects of Construction and Operation. Under this alternative, 1,145 acres would be transferred from NPS to state ownership, all of which would be included within the FERC project boundary. The project facilities would be constructed on approximately 1,187 acres of state and/or private land, and GEC's land use management plan would be applicable to all of the lands conveyed from NPS to the state as well as non-exchange project lands. As with GEC's proposed action, public use of the project access roads would be restricted by a public use and access management plan. These management plans would be developed by GEC in collaboration with federal, state, and local entities, including Native allotment owners. The potential effects of increased human access to the area due to project roads would be the same as described in section 4.15.2.3.

Effects of Changes in Land Ownership and Management Policies

All future potential uses of state land acquired from NPS in the Kahtaheena River area would be within the FERC project boundary and managed by GEC in accordance with a land use plan and a public access and management plan, if a license is issued. As described in section 4.15.2.2, FERC would maintain administrative authority for all 1,187 acres within the project boundary. Additional information on the plan is contained in section 6.1.1.

In addition, recreation uses in the project area would be identified by the public access and management plan developed by GEC in consultation with federal and state resource agencies and local entities. For this analysis, we assume the plan would be designed to minimize wildlife disturbance through measures such as prohibiting domestic dogs and use of ATVs. ADNR would likely participate in drafting both the land use plan and the public access and recreation development plan and could recommend that permissible land uses in the project area be consistent with the state's fish and wildlife land use designation for the area. However, if determined to be necessary, FERC could impose more strict land use regulations than would be applied under the state fish and wildlife habitat land use designation. For example, FERC could sustain current use prohibitions in the Kahtaheena River area (e.g., non-subsistence hunting and trapping, and walking domestic dogs) within the project boundary, but these uses would be allowed on state land outside of the project boundary.

The Maximum Boundary Alternative would not alter the manner in which lands along the transmission line would be managed; therefore, the land use effects would be the same as those described in section 4.15.2.3.

The project facilities would not be directly adjacent to the new GBNPP boundary, and the proposed project would not affect NPS' ability to manage the park.

Project Area Land

The effects on project area lands would be the same as described for GEC's Proposed Alternative in section 4.15.2.4, although the area encompassed within the project area is larger and includes all lands transferred from NPS to the state in the Kahtaheena River area.

State Acquired Land

Although more land would be acquired by the state (1,145 acres instead of 850 acres), 1,145 acres of exchange land would be located within the project boundary instead of 75 acres. The state could provide input to FERC-required management plans, but otherwise would have no regulatory jurisdiction.

Native Allotments

The effects on Native allotments from project development would be similar to those described for the GEC proposed alternative in section 4.15.2.4. Because all of the state land would be within the project boundary and therefore within FERC's jurisdiction, it is possible that land use and public access restrictions would reduce the overall effects on Native allotments. A larger project boundary would protect public access and recreational use of state land adjacent to the Native allotments than might occur under direct state management of this land.

4.15.3.2 Effects of the GBNPP and Wilderness Boundary Adjustment. Under the Maximum Boundary Alternative, approximately 1,145 acres of GBNPP would be removed from the existing park boundary. This land supports recreation, fish and wildlife habitat, uses that are assessed in sections 4.12, 4.6, and 4.8, respectively. From a land use perspective, the removal of these lands from GBNPP would not affect NPS land management policies for remaining lands after consummation of the exchange.

NPS currently manages all three of the potential wilderness designation lands (unnamed island near Blue Mouse Cove, Cenotaph Island, and the Alsek Lake parcels) as *de facto* wilderness areas, affording them similar protection as designated wilderness. Therefore, formal designation of these lands as wilderness would have no effect on existing and proposed future land uses, although this action would ensure the preservation of wilderness values on this land in perpetuity.

The increased acreage associated with the land exchange (1,145 acres) under this alternative would increase the amount of land transferred to NPS within WSNPP or KGNHP in comparison to GEC's proposed alternative. However, the actual effects of this alternative on land uses in these areas would be the same as those described in section 4.15.2.5.

4.15.3.3 Cumulative Effects Analysis. The potential cumulative effects associated with increased human access to the project area would be the same as those described in section 4.15.2.3. The potential for increased human development on the lands exchanged from NPS would be reduced under this alternative, if such provisions are included in the land use plan.

There are no other actions identified that would interact with the effects of this alternative designating the unnamed island near Blue Mouse Cove, Cenotaph Island, and Alsek Lake as wilderness. These lands are already managed as *de facto* wilderness; therefore, no cumulative effects would occur.

The potential cumulative effects associated with the exchange of lands near Long Lake or in the KGNHP area to NPS would be the same as those discussed in section 4.15.2.6.

4.15.3.4 Conclusion. Under the Maximum Boundary Alternative, 42 acres of existing state and/or private land and all of the 1,145 acres of land to be transferred from NPS to the state of Alaska would be within the FERC project boundary and managed in accordance with the project license conditions. Development of a land use plan and a public use and access management plan would define appropriate uses within the project boundary and could include that these lands be managed to limit additional human disturbance for the protection of fish and wildlife habitat.

The proposed project would not affect NPS' ability to implement the land management policies of the park after consummation of the 1,145-acre land exchange. The designation of wilderness lands at Cenotaph Island, the unnamed island near Blue Mouse Cove, or Alsek Lake also would have no effect on NPS' implementation of its land use management policies.

The potential transfer of state lands at Long Lake or KGNHP would not produce a substantial change in land uses in these areas. If transferred to NPS ownership, land management policies would focus on fish and wildlife habitat preservation and would be consistent with existing land uses and levels of human use.

4.15.4 Corridor Alternative

The Corridor Alternative includes two changes from the actions described in GEC's proposed action. The Corridor Alternative includes only the transfer of NPS land within a corridor around project facilities and access roads to the state of Alaska (see figure 2-9 in appendix A). Similar to the Maximum Boundary Alternative, all land acquired by the state from NPS would be included within the FERC-designated project boundary. This alternative includes some land east of the Kahtaheena River, similar to the area identified in the Maximum Corridor Alternative. The corridor arrangement of land would result in the isolation of two non-contiguous parcels of NPS land located south of the project access road.

4.15.4.1 Effects of Construction and Operation. Under this alternative, 42 acres of existing state and/or private land and all of the 680 acres of land transferred from NPS to state ownership would be included within the FERC project boundary, and subject to GEC's land use plan. The management plan would be developed by GEC in collaboration with federal, state, and local agencies. Construction and operation of the project facilities would be the same as described in the other action alternatives. The potential effects of increased human access to the area within the FERC boundary would be the same as described in section 4.15.2.3 and 4.15.3.1.

The potential land use effects associated with burial of the transmission line would be the same as those described in section 4.15.2.3.

Effects of Changes in Land Ownership and Management Policies. The land to the north and south of the project corridor, aside from the Native allotments, would remain within GBNPP. This would result in two isolated parcels south of the project corridor that are non-contiguous with the remainder of GBNPP. These lands would continue to be managed as wilderness areas and would be protected from increased human development. The isolation of these two parcels from the general GBNPP land would affect the quality of the land as wilderness (see section 4.14, *Wilderness*) and increase the complexity of maintaining wilderness conditions.

Project Area Land

The effects on the project area land would be the same as described for the GEC proposed alternative in section 4.15.2.4, although the area of state land encompassed within the project area is larger (680 acres instead of 75 acres) and includes all lands transferred from NPS to the state in the Kahtaheena River area.

State Acquired Land

The effects on the state acquired land would be similar to those described for the GEC proposed alternative in section 4.15.2.4. Because all of the state land would be within the project boundary, and therefore within FERC's jurisdiction, the state would have input on management plans, but no other direct regulatory authority.

Native Allotments

The effects on Native allotments would be similar to those described for the Maximum Boundary Alternative in section 4.15.2.4. Since two NPS parcels would be isolated immediately adjacent and between the two Native allotments, it is possible that the wilderness designation of these parcels may buffer some of the adverse effects associated with the development of the hydroelectric project. However, the location of the project access road and the FERC project boundary relative to the Native allotments would likely adversely affect the Native allotments as a result of project and recreational use. The corridor project boundary would potentially protect public access and recreational use of the state land than would otherwise be available under GEC's proposed alternative.

GBNPP Land

The Corridor Alternative would result in the greatest adverse effect on GBNPP land among the development alternatives. This alternative isolates two NPS parcels between the project access road, the Native allotments, and other state and private landholdings. The isolation of these two parcels would likely result in the loss of the natural characteristics that enabled their classification a wilderness quality.

4.15.4.2 Effects of the GBNPP and Wilderness Boundary Adjustment. Under the Corridor Alternative, approximately 680 acres of GBNPP would be removed from the existing park boundary. This land provides recreation, and fish and wildlife habitat, uses that are discussed in those resource sections (see sections 4.12, 4.6, and 4.8, respectively).

From a land use perspective, the removal of a corridor of land around the proposed hydroelectric project facilities from GBNPP would have no effect on the management of the remaining NPS land in the Kahtaheena River area after consummation of the land exchange. As described in section 4.15.4.1, the isolation of two parcels from the remainder of GBNPP could result in a loss of natural characteristics for this land. However, the change in wilderness area and GBNPP boundary would not change the World Heritage Site and Biosphere Reserve status of the remaining park land.

NPS currently manages all three of the potential wilderness designation lands (Cenotaph Island, unnamed island near Blue Mouse Cove, and the Alsek Lake parcels) as *de facto* wilderness areas, affording them the same level of protection as designated wilderness areas. Therefore, designation of these lands as wilderness would not affect land use management, although this action would ensure the preservation of wilderness values in perpetuity. The decreased acreage associated with the land exchange under this alternative (680 acres) could decrease the number of acres transferred to NPS within WSNPP and KGNHP, in comparison to GEC's Proposed Alternative (850 acres exchanged). However, the actual effects of this alternative on land uses in these areas would be the same as those described in section 4.15.2.1.

4.15.4.3 Cumulative Effects Analysis. The potential cumulative effects associated with increased human access to the area would be the same as those described in section 4.15.2.3. All of the lands would either be managed under the land use plan developed by GEC and administered by FERC, or continue to be managed by NPS, thereby minimizing the potential for increased human development in the study area.

There are no other actions identified that would interact with the effects of the proposed action designating the unnamed island near Blue Mouse Cove, Cenotaph Island, and Alsek Lake as wilderness. These lands are already managed as *de facto* wilderness; therefore, no cumulative effects would be expected to occur.

The potential cumulative effects associated with the exchange of lands near Long Lake or in the KGNHP area to NPS would be the same as those discussed in section 4.15.2.3.

4.15.4.4 Conclusion. Under the Corridor Alternative, all of the 680 acres of land to be transferred from NPS to state ownership would be within the FERC project boundary and managed in accordance with the project license conditions. Development of a land use plan would define appropriate uses within the project boundary. The land use plan could include guidelines that would limit additional human disturbance and protect fish and wildlife habitat. Under this alternative, all of the land transferred from NPS to the state would be within the FERC project boundary, and actions such as hunting and trapping or mineral extraction could be prohibited under a land use plan.

The proposed project would not affect NPS' ability to implement the land use management policies of the park after consummation of the 680-acre land exchange. The exchange would isolate approximately 150-acres of NPS land south of the project corridor, which could affect the quality of these parcels as wilderness. The designation of wilderness lands at Cenotaph Island, the unnamed island near Blue Mouse Cove, or Alsek Lake would not affect land use management policies; although the designation of parcels at Alsek Lake may affect existing use of the area by the Yakutat Tlingit Tribe.

The potential transfer of state lands at Long Lake or KGNHP would not produce a substantial change in land uses in these areas. If transferred to NPS ownership, land management policies may focus on fish and wildlife habitat preservation and would be consistent with existing land uses and levels of human use.

4.16 SOCIOECONOMICS

Several evaluation parameters were used to identify and describe the potential impacts on the socioeconomic resources of the project area:

1. Employment
2. Population growth, immigration, and emigration
3. Energy rates
4. Private property values

The assessment of the potential effects of the project on socioeconomics includes a discussion of the context of the socioeconomic resources in the proposed project area. The intensity of the impact on socioeconomic resources is generally characterized by quantifying the area of impact, the changes in employment and economic activity, and the potential changes in energy rates. The duration of the impact is described where necessary to understand the context and intensity of the impact.

4.16.1 No-action Alternative

4.16.1.1 Effects Analysis. Under the No-action Alternative, the project would not be built; the land surrounding the proposed project would be retained within the National Wilderness Preservation System for the foreseeable future and would continue to be managed as wilderness in accordance with the GBNPP GMP; and environmental and economic conditions in the Kahtaheena River area would be those expected if GEC continued to rely on diesel power generation. Currently, GEC has enough capacity in its diesel generators to meet foreseeable demands. Based on existing capacity and demand, GEC would continue to be able to meet foreseeable demands under the No-action Alternative. Effects on the local employment and economy, population, and property values would fluctuate in a manner consistent with pre-project conditions (see section 3.16). Additionally, the installed capacity of GEC's current generators could be considered a restriction to long-term growth and a cumulative effect on Gustavus under this alternative. The socioeconomic environment of Gustavus would face little or no noticeable change in economic activity or employment under the No-action Alternative.

Under the No-action Alternative, the lands at WSNPP and KGNHP would continue to be managed in a manner compatible with the neighboring national parks. This action would not change the economic environment or employment patterns associated with these parcels so there would be a negligible effect on the socioeconomic resources of these lands.

For all practical purposes, the lands identified for wilderness designation would continue to be managed as wilderness under the No-action Alternative. The effects of this action on the socioeconomic resources of these lands would be negligible.

4.16.1.2 Cumulative Effects Analysis. Without the proposed project, if installed capacity remains the same with the current price structure, economic development could be slowed because of higher, volatile energy prices.

4.16.1.3 Conclusion. The socioeconomic environment of Gustavus would experience negligible negative effects under the No-action Alternative from continued reliance on diesel generators to supply electricity. Not building the project would perpetuate baseline conditions, including the transportation and storage of diesel fuel, the limits on generation capacity, and variable energy costs. The overall impact on the socioeconomic resources under the No-action Alternative would be negligible.

4.16.2 GEC's Proposed Alternative

4.16.2.1 Effects of Construction and Operation. This section addresses the effects on the socioeconomic environment of Gustavus and the larger region under GEC's proposal. GEC would construct a hydroelectric facility on the Kahtaheena River to supply energy to the town of Gustavus and, pending further negotiations, GBNPP. Existing diesel generators would be used to supplement electricity during times of peak demand or low flow. Socioeconomic aspects that could be affected by the construction of this project include: (1) area employment and population growth, (2) the local economy and electric rates, (3) value of private properties, (4) and generation of electricity at GBNPP.

Population, Employment, and Income Trends. Under GEC's proposal, no local business establishments would be displaced. GEC proposes to maximize local hire and purchase from local vendors (Snow, 1999). Construction of the penstock (6 employees for 3 months), the intake (6 employees for 1 month), the powerhouse (6 employees for 3 months), and the transmission lines (3 employees for 2 months) would occur over a 24-month construction period (Snow, 1999). GEC estimates that 15 construction workers would be needed at any given time during project construction, and efforts would be made to fill as many of these positions as possible from the local labor force. GEC estimates that roughly half the required workers would be brought in from out of town temporarily to fill specialty positions such as pipe welders and road and powerhouse builders. Workers are not expected to permanently relocate to Gustavus based on the short duration and seasonal nature of these construction jobs.

All employees associated with the construction of the proposed project who must temporarily relocate to Gustavus should be able to find lodging within the capacity of local rental units, bed and breakfasts, and inns. The personnel who currently operate the diesel generation facility would be trained to operate the hydroelectric plant, which would result in no long-term changes in employment (GEC, 2001). Under GEC's proposal, direct effects of the project would include a short-term increase in local employment of 7 to 8 workers. GEC stated it would attempt to purchase material from local vendors, and support local rental units, which would result in minor effects on the socioeconomic environment for 24 months during project construction. The effects on employment would be short-term as employment would rise during project construction then decline to pre-project levels once the project is fully operational. These short-term effects would result in a minimal effect on the employment in Gustavus.

Under GEC's proposed alternative, in the short term, the population of Gustavus would continue to grow at historical rates (4.7 percent), while the long-term picture is less clear. A major influence on the population of Gustavus includes the future price of electricity in Gustavus in relation to surrounding communities, which could either attract or deter businesses and residents. Changes in population would be based on decisions related to the cost of electricity from hydroelectric power in Gustavus versus the cost of electricity from diesel plants, the future of the intertie proposal (see discussion in section 1.1.3), and the price of installing individual diesel generators at interested businesses. For this analysis, we estimated that the price of electricity post-project would be stable but higher than current prices and the intertie would not become a reality through the first half of the proposed license. Under these assumptions, population growth would be expected to grow at historical rates until electricity rates in the surrounding communities solidified, at which point business and people would settle into a stable business environment. Population growth beyond this would be highly speculative given the unknown fate of the intertie (and corresponding price of electricity) over the 30 to 50 year potential license time frame.

Electricity Production and Rates. GEC estimates that, on average, hydroelectric generation would run 98 percent of the time throughout the year over the first 10 years of project operations, while diesel would be relied upon to supplement electricity an average of 22 percent of the time during the first 10 years of project operation. Based on GEC's forecasted energy production schedule of hydroelectric power during the spring and summer months, and a combination of hydroelectric and diesel during times when flows in the Kahtaheena River cannot meet the demand, the amount of diesel fuel consumption would be reduced as discussed above. For a more detailed discussion on how well the seasonal availability of hydropower matches seasonal demand under current and future growth conditions, see chapter 5, *Developmental Analysis*, and the economic analysis section in chapter 6, *Recommendations and Conclusions*.

Because hydroelectric generation would alleviate most of the dependency on diesel fuel (and its variable price), GEC expects the cost to produce electricity would be less volatile than in the past (GEC, 2001). The majority of costs in a hydroelectric project are tied into financing the project while operations and maintenance are typically a small component of the total annual project costs. Fuel costs drive the majority of costs in a diesel plant and are highly susceptible to inflation and it is reasonable to expect them to increase into the future. Thus, electricity prices would be more stable than the current prices; however, approximately a quarter of the annual electricity would still be subject to price variability of diesel fuel. Based on the developmental analysis in chapter 5, the estimated cost to meet the average total generation requirements over the first 10 years of project operations (2,397,090 kWh) under GEC's proposal would be $ 0.147/kWh (assuming 2,361,010 kWh of hydro generation at $0.147/kWh and 36,090 kWh of diesel generation at $0.128/kWh), compared to the price of producing the same amount of electricity using diesel at $ 0.128/kWh.[52] Given the long time frame, market volatility and historic prices, GEC's estimates are reasonable that the cost of diesel is expected to rise over the next 30 years to levels that would make the hydroelectric facility a cheaper alternative because the cost to produce electricity is relatively fixed except for annual operations and maintenance costs.

The state of Alaska's Power Cost Equalization program is assumed to continue to support residents up to the first 500 kWh of electricity used each month. The beneficial effects on the cost of electricity under the proposed action would continue throughout the term of the project.

Influence of GBNPP on Gustavus Community. Under the proposed alternative, GEC could negotiate with NPS to connect Bartlett Cove to GEC's electrical grid. Under this alternative, GBNPP's reliance on diesel fuel for electricity would be reduced if Bartlett Cove were to connect to the GEC electrical grid. GBNPP still would be required to store some diesel fuel in its fuel farm to maintain back-up generators. However, this action would possibly result in GBNPP purchasing electricity from GEC at a higher rate than the current cost of $0.128/kWh using diesel generation. A higher cost per kWh paid by GBNPP for electricity could result in reduced employment due to budget shortfalls from increased utility costs. If NPS does not purchase electricity from GEC, GBNPP would continue to operate its electrical generation facilities as described in section 3.16.

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52 The cost to produce electricity is not the cost consumers pay. For a more detailed discussion, see chapter 5, *Developmental Analysis*.

Native Allotments. Under the proposed action, the Native allotments would be surrounded by state lands potentially leading to development of the parcels. Under the proposed action, the values of the allotments could decrease based on the loss of adjacent wilderness designation or could increase based on their proximity to a road that connects to Gustavus. Currently, GEC does not propose to connect any private parcels, including the Native allotments, to the access road, nor do the owners propose to sell the allotments.

Private Property and Infrastructure. Construction of the project would begin at the terminus of Rink Creek Road and continue to the intake and tailrace structures on the Kahtaheena River. During the 24-month construction period, additional traffic would be generated on the Gustavus road system (Snow, 1999). This would be especially problematic on the Wilson/Rink Creek Road from which the project's road system continues, because this gravel road is maintained at residents' expense and is often in bad condition (Snow, 1999). GEC has not made any proposals to mitigate the wear and tear on local roads during construction activities associated with this project. The overall impact of this would result in exacerbated damage (most likely potholes) to the road by heavy construction vehicles during the 24-month construction period, shifting to little noticeable wear and tear from the weekly maintenance trip during project operation. The effects of these impacts would be noticed during construction and until the roads are repaired. GEC employment estimates for the project are sufficient to account for road repair. Once construction is completed, the traffic along Rink Creek Road would resume to pre-project levels with the addition of weekly trips by GEC staff to the site for routine maintenance at the project. Traffic associated with recreational use of the project area may increase moderately during the summer recreation season along Rink Creek Road due to improved access to the project area. During project operation, because only 1 extra vehicle trip per week is scheduled post construction in addition to the daily summer traffic associated with the Bear Track Inn, the overall increase in road maintenance would be very little and would result in a negligible effect on area employment and the local economy.

The conversion of land designations from "wilderness" status to state of Alaska "resource protection" status and subsequent construction and operation of the proposed project may affect the monetary value of adjacent lands. In general, the value of the land is higher on land that abuts protected areas where there is a relatively high expectation that the land status will not change compared to other land that borders upon less certain land designations, especially commercial land. Consequently, the value of land is determined by many other variables including location, environmental constraints, and access. The proposed project is likely to increase access to private lands, increasing land values and opportunities for development, especially on the existing Native allotments presently within park boundaries, although most allotment holders have stated that they would not sell. Thus, the project could accelerate the development of private lands east of Gustavus into private residences or lodges, adding to the human utilization of lands and waters that were formerly undeveloped. This area within the limits of Gustavus is relatively flat; however, vehicle access is limited to Rink Creek Road. Development of these lands within the foreseeable future is unknown given that population growth over the last 10 years has fluctuated and increased slightly. Effects on the private lands surrounding the proposed project area include potential increases in private residential development spurred by access. This development, however speculative at this time, could add short-term construction jobs and increase local spending if growth is greater than what the local market currently maintains. The construction of the access road would erase the “end of the road” character of the Rink Creek neighborhood, with particular effect on the Bear Track Inn.

Under the proposed action, the Bear Track Inn and other residents along Rink Creek Road would be subject to the sight and sound of additional vehicle traffic from construction of the access road and project facilities and during weekly maintenance vehicle trips after the project is operating. Residents along Rink Creek Road would be impacted by the dust from and sight and sound of heavy equipment traveling along the road. Because of the Rink Creek Road base (e.g., clay and fine sands), there are currently periods when Rink Creek Road is passable to only 4-wheel drive vehicles. Additional, heavy equipment use of Rink Creek Road could result in increased wear and tear on the road and result in periods when the road would be impassable. Rink Creek Road is not a state-maintained road and as a result, maintenance of the road (e.g., grading) is the responsibility of the individuals who reside along the road. Increased heavy equipment use of Rink Creek Road could add an additional financial burden to those residents who would need to increase road maintenance to maintain it for private vehicle access.

The construction of the project is scheduled in phases, with timber-clearing activities occurring between September and April. This may mitigate some impact from the sight and sound of additional vehicle traffic because this time period would correspond with the time when residents spend a large portion of their time inside their houses and the Bear Track Inn is closed. However, road and facilities construction would continue after April. The guests, owners, and employees of the Bear Track Inn would be the least affected from the sight and sound of project construction during this time period because the Bear Track Inn is approximately 600 feet off Rink Creek Road. However, guest ability to experience quiet and solitude may be reduced slightly by the sight and sound of construction and maintenance equipment.

The development and presence of borrow pits within the project area may lead to continued use of the sites as a quarry for crushed rock needs in Gustavus resulting in increased traffic on Rink Creek Road. It is currently uncertain as to whether the borrow pits would be accessible to the public or not, and we will not know until the Commission, Interior, and the state decide on access issues. As such, the level of effect the presence of the borrow pits would impose on either the demand for crushed rock or the wear and tear on the access road, if any, is uncertain. Should the borrow pits supply rock for uses outside the project area, this would result in an increase in construction-type traffic along

Rink Creek Road associated with the transport of rock. Effects from such an increase would be similar to wear and tear during the construction of the proposed project.

4.16.2.2 Effects of the GBNPP and Wilderness Boundary Adjustment. The lands proposed for exchange in WSNPP and KGNHP are currently managed to prohibit development. Thus, the exchange would have a negligible effect on the socioeconomic resources associated with these parcels.

For all practical purposes, the lands within GBNPP determined to receive the wilderness designations are already managed as wilderness. Therefore, a change in formal designation would have a negligible effect on the socioeconomic resources associated with these parcels.

4.16.2.3 Cumulative Effects Analysis. The potential expansion or renovation of administrative facilities at GBNPP could provide increased employment and income opportunities for residents in the community of Gustavus. The construction of the Falls Creek Hydroelectric Project would provide additional employment and income opportunities for Gustavus residents. The combined effect of the potential expansion or renovation of facilities at GBNPP and the construction of the Falls Creek Hydroelectric Project would produce a cumulative increase in employment and income opportunities for Gustavus residents.

The potential increase in the number of tourist-lodging facilities at Bartlett Cove or in Gustavus, or the potential increase in the total number of cruise ship passengers, could increase the maximum number of tourists visiting the Gustavus area, resulting in an increase in money spent in the community. The construction of the Falls Creek Hydroelectric Project would provide additional employment and income opportunities for residents of Gustavus. The combined effect of increased tourism to GBNPP and Gustavus and the construction of the Falls Creek Hydroelectric Project would produce a cumulative increase and diversification in employment and income opportunities for Gustavus residents.

The potential establishment of an electrical intertie connection between Gustavus and adjacent communities in southeastern Alaska may increase the price of power to consumers as a result of high construction costs, although long-term prices may stabilize. The construction of the Falls Creek Hydroelectric Project may increase the price of power to residents and businesses in Gustavus, although it could possibly stabilize prices over the long term. The cumulative effect of the establishment of an electrical intertie and the development of the proposed project may increase power prices to consumers, although these prices may remain stable over the long term.

There are no project-related actions identified that would result in an impact on socioeconomic resources for the WSNPP and KGNHP transfer parcels. Therefore, no cumulative effects on socioeconomic resources would occur as a result of the interaction between project actions and non-project actions at these sites.

There are no project-related actions identified that would result in an impact on socioeconomic resources for the proposed wilderness parcels at the unnamed island near Blue Mouse Cove, Cenotaph Island, or Alsek Lake. Therefore, no cumulative effects on socioeconomic resources would occur as a result of the interaction between project actions and non-project actions at these sites.

4.16.2.4 Conclusion. Based on the above analysis, GEC's proposed project would have positive and negative effects on the socioeconomic resources of the region and within the town of Gustavus. Positive effects would include short-term increases in local employment and local purchases from project-related spending, and electricity prices that are more stable (due to less dependence on fluctuating diesel prices) or increase at a slower rate over the long term. Negative effects under this alternative would include potentially higher electricity prices in the short term (e.g., the first several years of project operations).

The socioeconomic environment of the lands identified in WSNPP and KGNHP and in GBNPP to receive a wilderness designation would not be affected in a positive or negative manner.

4.16.3 Maximum Boundary Alternative

4.16.3.1 Effects of Construction and Operation. Under the Maximum Boundary Alternative, the effects on the socioeconomic environment would be the same as the ones described above in section 4.16.2.1.

4.16.3.2 Effects of the GBNPP and Wilderness Boundary Adjustment. Based on current uses and land classifications, there would not be any effects on the socioeconomic resources of the lands to be exchanged at WSNPP or KGNHP or the lands identified to receive wilderness designations as described above in section 4.2.16.2.

4.16.3.3 Cumulative Effects Analysis. The types of cumulative effects that could be expected to occur on socioeconomic resources under this alternative would be the same as those described under GEC's proposal in section 4.16.2.3.

4.16.3.4 Conclusion. Under the Maximum Boundary Alternative, effects on the socioeconomic environment of Gustavus would the same as those described in section 4.16.2.4. Effects on the socioeconomic environment of the Long Lake and KGNHP parcels and the lands identified for wilderness designations would be the same as those described in section 4.16.2.4.

4.16.4 Corridor Alternative

4.16.4.1 Effects of Construction and Operation. Under the Corridor Alternative, approximately 680 acres of land would be transferred to the state, all of these lands would be included within the FERC project boundary, and GEC would construct an 800-kW hydroelectric facility on the Kahtaheena River. The effects on the socioeconomic resources associated with this alternative would be the same as those discussed for GEC's proposal in section 4.16.2.1.

4.16.4.2 Effects of the GBNPP and Wilderness Boundary Adjustment. The effects on the socioeconomic resources of the exchange parcels and wilderness designation lands associated with this alternative would be the same as those described for GEC's proposal in section 4.16.2.2.

4.16.4.3 Cumulative Effects Analysis. The types of cumulative effects that could be expected to occur on socioeconomic resources under this alternative would be the same as those described under GEC's proposal in section 4.16.2.3.

4.16.4.4 Conclusion. The effects of the Corridor Alternative on the socioeconomic resources of Gustavus and lands associated with the proposed project would be the same as those described in section 4.16.2.4.

4.17 RELATIONSHIP BETWEEN LOCAL SHORT-TERM USES OF THE ENVIRONMENT AND THE MAINTENANCE AND ENHANCEMENT OF LONG-TERM PRODUCTIVITY

In this section, we address the question of whether the proposed action would be providing short-term benefits at the cost of future generation. The proposed project would provide electrical power generation for the duration of any license that would be granted for the project. There also would be an option for relicensing at the end of this term. The project's potential effect on long-term productivity would involve the conversion of about 680 to 1,145 acres of undeveloped wilderness and certain vegetative habitats to a developed industrial use. The conversion would diminish habitat values within the project area over the long term. In exchange for the lands on which the project would be built, the state of Alaska would transfer parcels currently located within WSNPP and KGNHP to NPS. In addition, other lands currently within GBNPP would be designated as wilderness lands.

4.18 IRREVERSIBLE/IRRETRIEVABLE COMMITMENTS OF RESOURCES

Irreversible effects are those that cannot be reversed except in the extreme long term. Irreversible and irretrievable commitments of resources within the proposed project area would be as follows:

- From 680 to 1,145 acres of land would be removed from GBNPP.

- Land use in the project area (i.e., 722 to 1,187 acres) would be altered and committed to energy production and energy transmission.

- Of this acreage, about 9.6 acres of mature forest would be permanently lost as a result of construction of project facilities, and its value to wildlife would be lost.

- Visual impacts of the project structures and road/transmission line routes would be irreversible.

4.19 UNAVOIDABLE ADVERSE EFFECTS

Based on the analysis in chapter 4, there would be no unavoidable adverse effects under the No-action Alternative. GEC's Proposed Alternative (and additional measures that would be needed to protect or mitigate effects on environmental resources) would result in several unavoidable adverse effects on water resources, air quality, fisheries, vegetation and wildlife, visual resources, recreation, and wilderness values.

Construction and operation of the project would result in an unavoidable disruption to the short-term timing of bedload transport and a long-term reduction in the bedload transport during low-flow periods. Project construction also would cause short-term increases in sedimentation where construction occurs in proximity to water bodies.

There would be a long-term reduction in flows in the bypassed reach, including the Lower Falls, and its impact on aesthetics and aquatic resources other than fish (e.g., birds, invertebrates) during the winter months, although extreme low-flow conditions (< 5 cfs) would continue to occur with or without the project. However, the naturally occurring winter low flows do not happen as frequently or persist as long as the winter low flows that would result from the project. The reduction of flows in the bypassed reach would cause a slight increase of temperatures during the summer months.

Construction of the project also would cause sporadic emissions of dust that would adversely affect air quality in the immediate project are for short periods of time during the 24-month construction period.

Project construction and operation would result in the permanent diversion of 2 to 23 cfs of flow from the Kahtaheena River bypassed reach and would increase the frequency of low-flow conditions in the winter months. Diversions of flow would reduce the number of resident Dolly Varden char over the long term in the bypassed reach.

Project construction would result in the initial loss of 29.6 acres of vegetative cover, including 23.5 acres of mature forest, 1.15 acres of wetland, and 4.9 acres of other vegetative types, and the permanent loss of about 8 acres of vegetative cover. The temporary loss could extend from several years for ground cover to several decades or longer for mature forests.

Construction of the project also would require a short-term increase in traffic that would cause a minor unavoidable adverse effect on soundscapes and passive recreation in the immediate project vicinity and new permanent human-made features that would contrast with existing visual elements.

5.0 DEVELOPMENTAL ANALYSIS[53]

In this section, we assess the developmental benefits of the project and quantify the individual and cumulative effects of various proposed and recommended environmental measures on project economics. This information assists the Commission in assessing whether the project would be best adapted to a comprehensive plan for improving or developing the waterway for beneficial uses, while providing for the adequate protection, mitigation, and enhancement of environmental resources.

As articulated in Mead Corporation, Publishing Paper Division (72 FERC '61,027), the Commission's approach to evaluating the overall economics of a hydroelectric project uses current costs to compare the costs of the project and likely alternative power. We consider the power benefit of the project to be equal to the current cost of the alternative source of power that would be used in the absence of the project. We use a 30-year period of analysis with no forecasts of potential future inflation, escalation, or deflation to convert all costs to a levelized annual value. The levelized annual value is a convenient metric for comparing a cost to a resulting benefit, whether the benefit is measured in dollar-value or non-dollar-value terms.

We compute the net benefit of a hydropower project by subtracting the total cost of the project, including the cost of required environmental measures from the value (benefit) of the project power. If the cost of the project is less than the power benefit, the project has a positive net benefit. The net benefit of a project is negative if the project cost is more than the current cost of the alternative. Since project economics is only one of many public interest factors considered by the Commission, a finding of negative net economic benefits based on the Commission’s current cost method of analysis does not preclude the issuance of a license. If the Commission issues a license for a project with negative net benefits based on the Commission’s method of analysis, it is up to the licensee to make the business decision of whether or not to accept the license and build, or continue to operate the project based on its own financial analysis and business requirements.

For the Falls Creek Hydroelectric Project, the Act states that the proposed land exchange required to construct the project cannot occur until the Commission determines that construction and operation of the project can be accomplished in an economically feasible manner. Chapter 6, *Conclusions,* presents additional information and analysis on the economics of the project.

For the Falls Creek Hydroelectric Project, we consider three alternatives: (1) the proposed project; (2) the proposed project with staff-recommended modifications; and (3) the No-action Alternative. For an existing hydroelectric project, the Commission uses the

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53 This is a standard section for FERC NEPA documents that does not necessarily reflect the methods or conclusions of NPS/Interior staff on project economics.

No-action Alternative, where the project would continue to operate as it is currently operated with no new environmental measures, as a baseline for comparison of both the environmental and economic effects of the action alternatives. Since the Falls Creek project is not yet built, the No-action Alternative would be no hydroelectric project development and GEC's continued use of diesel generation to meet the needs of its customers.

In the draft EIS, FERC staff presented costs for GEC's Proposed Alternative and the action alternatives as well as an economic analysis of the proposed hydroelectric project. In comments on the draft EIS, GEC provided new and revised cost estimates for several measures. FERC staff revised its cost estimates to address these comments. As a result, cost figures presented in the final EIS have changed significantly from those presented in the draft EIS.

5.1 PROPOSED PROJECT ALTERNATIVE

Project Description

The proposed project would be located on the Kahtaheena River approximately 5 miles east of Gustavus, Alaska. The project would include a diversion dam and intake located 2.4 stream miles above the mouth of the Kahtaheena River, a 9,400-foot-long pipeline and penstock, and a powerhouse containing one 800-kW generating unit capable of operating with flows of from 2 to 23 cfs. Power from the project would be transmitted by a proposed 5.0-mile-long transmission line to an existing substation serving the existing diesel power plant in Gustavus.

In the draft EIS, we based our economic analysis on two potential electricity load scenarios: one with both GEC and GBNPP load being served by the project and one with just GEC load. GBNPP has not committed to purchasing power and energy from GEC. Therefore, for the final EIS, this analysis excludes GBNPP load and costs associated with serving that load.

The project would have no reservoir storage and would be operated run-of-river with the unregulated flows from the Kahtaheena River. Stream flows from May through October nearly always would be high enough to supply the total electricity needs of GEC plus the minimum flow GEC proposes to maintain in the stream downstream of the diversion. During this period, GEC would set the amount of diversion flow on an approximately weekly basis to operate the project at a nearly constant stream flow diversion rate sufficient to meet the expected peak electricity load for the following time period. Diverted flow in excess of that needed to match the continuously varying loads, would be routed through a synchronous bypass at the power plant and returned via the project's tailrace pipeline to the Kahtaheena River.

During the remaining 6 months of the year (November through April), there frequently would be less flow in the stream than necessary to meet all load. During those periods, the proposed project would divert all of the stream flow in excess of the proposed minimum instream flow requirement of 5 cfs, through the entire bypassed reach, from December through March and 7 cfs April through November.

Projected Generation

Under GEC's Proposed Alternative, it estimates the 800-kW hydroelectric project would generate an annual average of 2,085,460 kWh. We have independently confirmed the reasonableness of this value in the analysis presented here from our own energy modeling based on monthly flow values. The annual generation reflects an average for the anticipated first 10 years of operation (2007-2016), and is based on adjustment of load data provided by GEC (2001b, appendix D, updated to reflect more recent data) and on FERC staff's hydrologic-operational model.

Table 5.1-1 and figure 5-1 show the historic and staff's projected future electricity generation to serve GEC. The projected required generation to serve GEC is based on the growth rates used for the middle estimates in GEC's Power Requirements Study (GEC, 2001b, appendix F) and historic data.

Month-by-month patterns of usage within a given year, based on section 3 of the PDEA (GEC, 2001b), were used to model what portion of load each month could be met with hydroelectric generation and what portion would require supplemental diesel generation. The model also takes account of any required minimum instream releases in computing the amount of water available for generation.

Table 5.1-2 shows the resulting hydropower generation for each of the first 10 years of operation with GEC's minimum instream flow releases.

Projected Cost

GEC estimates project construction costs in its license application; we escalated these costs at 3.0 percent using actual inflation data to the base year of our analysis, yielding $4,508,000 and $31,830 (2003$), respectively (GEC, 2001b). Appendix E contains the details of the development of construction cost values. GEC's proposed project includes the environmental protection and mitigation measures listed in table 5.3-3. GEC estimates that the capital cost of its proposed measures represents about half of the total construction cost.

Table 5.1-1. Historic and projected future usage for the GEC service area. (Source: Preparers)

Year	GEC Energy Usage (kWh)
Actual	
1993	1,188,000
1994	1,457,000
1995	1,414,000
1996	1,625,000
1997	1,677,000
1998	1,734,000
1999	1,713,000
2000	1,694,000
2001	1,603,000
2002	1,638,900
2003	1,713,000
Projected	
2004	1,790,720
2005	1,870,840
2006	1,953,860
2007	2,039,840
2008	2,128,860
2009	2,208,990
2010	2,280,510
2011	2,354,340
2012	2,430,560
2013	2,509,250
2014	2,589,800
2015	2,672,230
2016	2,756,550
Average 2007-2016	2,397,090

Figure 5-1. Historic and projected future generation to serve the GEC service area. (Source: GEC and preparers)

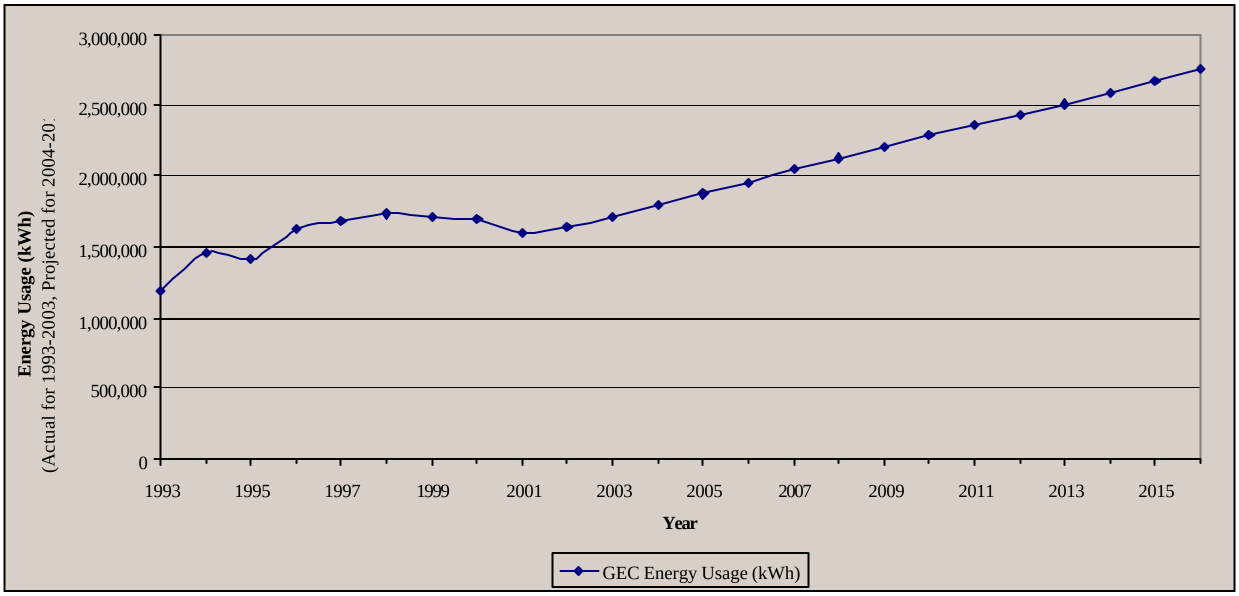

Table 5.1-2. Staff's projected hydropower generation for first 10 years of operation assuming GEC's proposed minimum instream flows. (Source: Preparers)

Year	Staff's Projected Hydropower Generation (kWh/year)
2007	1,791,330
2008	1,863,960
2009	1,930,600
2010	1,990,220
2011	2,050,860
2012	2,114,190
2013	2,177,870
2014	2,244,930
2015	2,311,250
2016	2,379,370
Average (2007-2016)	2,085,460

Power Value

Electricity generated by the hydropower project would replace diesel generation, which is currently the only source of power available to GEC. We use GEC's cost of diesel generation and the current cost of diesel fuel to represent the value of the proposed project generation. We use a power value of 127.86 mills/kWh, which is based on a fuel to energy efficiency of 13 kWh per gallon and a current fuel cost of $1.51 per gallon in 2003.[54] Diesel generator operating costs include a variable O&M component based on 5 mills/kWh in 2001, escalated to 2003 at 3.0 percent annually. Periodic engine overhaul costs 6 mills/kWh in 2001, escalated to 2003 at 3.0 percent annually (GEC, 2001b).

Economic Assumptions

Table 5.1-3 lists the economic parameters we used to compute the levelized annual cost and benefit of the licensing decision alternatives and the individual environmental protection and mitigation measures considered in this final EIS.

Table 5.1-3. Assumptions for economic analysis of the Falls Creek Hydroelectric Project. (Sources: See source column and footnotes)

Parameter	Value	Source
Dollar value	2003	FERC
Term of analysis	30 years	FERC
Term of financing	30 years	GEC
Interest rate	5.48 percent	GEC
Discount rate	8 percent	FERC
Construction cost[a]	$4,508,000	GEC/FERC
Annual O&M cost[b]	$31,830	GEC/FERC
Installed capacity	800 kW	GEC
Annual generation, no minimum flow (kWh)[c]	2,397,090	GEC/FERC
Energy value (including capacity)[d]	127.86 mills/kWh	FERC/GEC
Bond/debt ratio	1.00	GEC
Cumulative federal and state income tax rate	34 percent	FERC
Local property tax rate	0 percent	GEC
Insurance rate	0.25 percent of initial net investment	FERC
Escalation rate after 2003	0 percent	FERC

[a] Based on GEC's proposed project cost escalated to 2003 using the implicit price deflator; see appendix E for calculation details (GEC, 2001b).
[b] Based on GEC's estimate of $30,000 per year (2001$) escalated to 2003 at 3.0 percent annually (GEC, 2001b).
[c] Based on staff's projected average annual generation over the first 10 years of project operation (2007-2016).
[d] Based on the estimated current cost of existing diesel generation (GEC, 2001b).

[54] Fuel cost based on $1.41 per gallon in 2001, escalated to 2003 at 3.5 percent annually.

Economic Cost and Benefit of the Proposed Project Alternative

Under the proposed project alternative, the Falls Creek Hydroelectric Project would generate an annual average of 2,085,460 kWh of electricity based on projected generation over the first 10 years of operation. We estimate the annual project cost to produce that power would be $356,620 (about 171 mills/kWh). Based on current diesel fuel costs and use of existing diesel generators, we estimate the value of this amount of power would be $266,640 (about 128 mills/kWh). Subtracting the cost of production from the value of the power produced, we find that the proposed project would have a negative net power benefit of -$89,980 (about -43 mills/kWh).

5.2 PROPOSED PROJECT WITH STAFF-RECOMMENDED MODIFICATIONS

Project Description

The preliminary staff-recommended licensing alternative would consist of GEC's proposed project plus the following additions and modifications:

- Prepare and implement a road management plan
- Prepare a sediment monitoring and management plan
- Prepare and implement a plan for environmental monitoring during construction
- Fund an escrow account for fish, wildlife and water quality enhancement
- Prepare and implement a fuel and hazardous substance spill plan
- Prepare an oil and other contaminant treatment plan
- Prepare and implement a flow monitoring plan
- Prepare a fish passage facility evaluation plan
- Prepare a biotic evaluation plan
- Prepare a wetland mitigation plan
- Conduct annual consultation with wildlife agencies
- Prepare a bear-human conflict plan
- Provide real time flow information to the public

- Site and design structures to blend with surroundings
- Prepare a land use management plan
- Prepare a public access and recreation development plan

The above measures would increase the capital cost of the project by $135,000 and the annual O&M cost by $27,660 for a total levelized cost increase of $37,270 compared to the cost of the proposed project alternative.

Economic Cost and Benefit of the Preliminary Staff-recommended Licensing Alternative

Under the staff-recommended licensing alternative, the Falls Creek Hydroelectric Project would generate an annual average of 2,085,460 kWh of electricity based on projected generation over the first 10 years of operation. We estimate the annual project cost to produce that power would be $393,890 (about 189 mills/kWh). Based on current diesel fuel costs and use of existing diesel generators, we estimate the value of this amount of power would be $266,640 (about 128 mills/kWh). Subtracting the cost of production from the value of the power produced, we find that the Falls Creek Hydroelectric Project would have a negative net power benefit of -$127,250 (about -61 mills/kWh).

5.3 COST OF ENVIRONMENTAL PROTECTION, MITIGATION, AND ENHANCEMENT MEASURES

Minimum Flows

Table 5.3-1 shows the staff-estimated month-by-month generation mix between hydropower generation and diesel generation under the minimum flow regime considered in this final EIS. The total annual generation is the average projected for the first 10 years of project operation (2007-2016) based on typical flows and forecasted usage. Table 5.3-2 shows the change in annual mix under each regime over the 10 years in response to forecasted usage increases. In both tables, totals are based on adjustment of GEC's forecasts, and relative portions of generation are based on our hydrologic-operational model.

With no minimum instream flow in the bypassed reach, the project would be expected to generate an average of 2,300,050 kWh annually over the 10-year period as shown in tables 5.3-1 and 5.3-2, yielding an annual power benefit of $294,080 (about 128 mills/kWh). Based on the construction and O&M costs assumed in this analysis, which are independent of instream flows, and excluding the cost of environmental measures proposed by GEC or staff besides the annual cost of those measures GEC considers part of its baseline proposal in its license application, the cost of producing this energy would

Table 5.3-1. Average (2007-2016) month-by-month mix of hydroelectric and diesel generation under various instream flow regimes. (Source: Preparers)

	Total Usage (kWh)	**No Minimum Flow**[a] **Hydro (kWh)**	**No Minimum Flow**[a] **Diesel (kWh)**	**No Minimum Flow**[a] **Percentage Hydro Generation**	**GEC**[b] **Hydro (kWh)**	**GEC**[b] **Diesel (kWh)**	**GEC**[b] **Percentage Hydro Generation**
Jan	211,310	168,460	42,850	79.7%	124,170	87,140	58.8%
Feb	201,740	163,550	38,180	81.1%	119,720	82,020	59.3%
Mar	175,400	166,330	9,070	94.8%	122,900	52,500	70.1%
Apr	182,000	182,000	0	100.0%	172,570	9,430	94.8%
May	189,190	189,190	0	100.0%	189,190	0	100.0%
Jun	210,740	210,740	0	100.0%	210,740	0	100.0%
Jul	215,530	215,530	0	100.0%	215,530	0	100.0%
Aug	230,500	230,500	0	100.0%	230,500	0	100.0%
Sep	208,350	208,350	0	100.0%	208,350	0	100.0%
Oct	177,220	177,220	0	100.0%	177,220	0	100.0%
Nov	205,940	205,940	0	100.0%	171,300	34,640	83.2%
Dec	189,170	182,230	6,940	96.3%	143,280	45,900	75.7%
Ann	2,397,090	2,300,050	97,050	96.0%	2,085,460	311,640	87.0%

	Total Usage (kWh)	**ADFG**[c] **Hydro (kWh)**	**ADFG**[c] **Diesel (kWh)**	**ADFG**[c] **Percentage Hydro Generation**	**FWS and NPS**[d] **Hydro (kWh)**	**FWS and NPS**[d] **Diesel (kWh)**	**FWS and NPS**[d] **Percentage Hydro Generation**
Jan	211,310	92,390	118,930	43.7%	92,390	118,930	43.7%
Feb	201,740	88,160	113,580	43.7%	88,160	113,580	43.7%
Mar	175,400	89,460	85,940	51.0%	89,460	85,940	51.0%
Apr	182,000	154,260	27,740	84.8%	154,260	27,740	84.8%
May	189,190	189,190	0	100.0%	189,190	0	100.0%
Jun	210,740	206,930	3,820	98.2%	210,740	0	100.0%
Jul	215,530	166,580	48,950	77.3%	190,220	25,310	88.3%
Aug	230,500	157,060	73,440	68.1%	188,220	42,270	81.7%
Sep	208,350	190,970	17,380	91.7%	203,350	4,990	97.6%
Oct	177,220	177,000	210	99.9%	177,000	210	99.9%
Nov	205,940	82,570	123,370	40.1%	82,570	123,370	40.1%
Dec	189,170	113,250	75,920	59.9%	113,250	75,920	59.9%
Ann	2,397,090	1,707,820	689,270	71.2%	1,778,830	618,260	74.2%

[a] Although no entity is proposing a complete absence of instream flows, GEC requested that an evaluation of generation under such a scenario be included.

[b] GEC proposes instream minimum flows of 5 cfs January through March, 7 cfs April through November, and 5 cfs in December.

[c] ADFG recommends instream minimum flows of 10 cfs January through April, 25 cfs May through September, 30 cfs in October, 25 cfs in November, and 10 cfs in December.

[d] FWS and NPS-RTCA recommend instream minimum flows of 10 cfs January through April, 20 cfs May through September, 30 cfs in October, 25 cfs in November, and 10 cfs in December

Table 5.3-2. Annual mix of hydroelectric and diesel generation under various instream flow regimes. (Source: Preparers)

	Total Usage (kWh)	No Minimum Flow[a] Hydro (kWh)	Diesel (kWh)	Percentage Hydro Generation	GEC[b] Hydro (kWh)	Diesel (kWh)	Percentage Hydro Generation
2007	2,039,840	1,970,130	69,710	96.6%	1,791,330	248,510	87.8%
2008	2,128,860	2,052,680	76,180	96.4%	1,863,960	264,900	87.6%
2009	2,208,990	2,126,780	82,210	96.3%	1,930,600	278,390	87.4%
2010	2,280,510	2,193,460	87,050	96.2%	1,990,220	290,290	87.3%
2011	2,354,340	2,262,100	92,240	96.1%	2,050,860	303,480	87.1%
2012	2,430,560	2,331,540	99,020	95.9%	2,114,190	316,370	87.0%
2013	2,509,250	2,403,330	105,920	95.8%	2,177,870	331,380	86.8%
2014	2,589,800	2,478,420	111,380	95.7%	2,244,930	344,870	86.7%
2015	2,672,230	2,552,460	119,770	95.5%	2,311,250	360,980	86.5%
2016	2,756,550	2,629,560	126,990	95.4%	2,379,370	377,180	86.3%
Avg	2,397,090	2,300,050	97,050	96.0%	2,085,460	311,640	87.0%

	Total Usage (kWh)	ADFG[c] Hydro (kWh)	Diesel (kWh)	Percentage Hydro Generation	FWS and NPS[d] Hydro (kWh)	Diesel (kWh)	Percentage Hydro Generation
2007	2,039,840	1,478,890	560,950	72.5%	1,537,380	502,460	75.4%
2008	2,128,860	1,535,620	593,240	72.1%	1,596,670	532,190	75.0%
2009	2,208,990	1,587,890	621,100	71.9%	1,651,810	557,180	74.8%
2010	2,280,510	1,634,770	645,740	71.7%	1,701,230	579,280	74.6%
2011	2,354,340	1,681,740	672,610	71.4%	1,750,970	603,370	74.4%
2012	2,430,560	1,731,360	699,200	71.2%	1,803,340	627,220	74.2%
2013	2,509,250	1,779,930	729,320	70.9%	1,855,020	654,230	73.9%
2014	2,589,800	1,832,580	757,220	70.8%	1,910,550	679,250	73.8%
2015	2,672,230	1,882,290	789,930	70.4%	1,963,580	708,640	73.5%
2016	2,756,550	1,933,120	823,430	70.1%	2,017,760	738,780	73.2%
Avg	2,397,090	1,707,820	689,270	71.2%	1,778,830	618,260	74.2%

[a] Although no entity is proposing a complete absence of instream flows, it was requested that an evaluation of generation under such a scenario be included.

[b] GEC proposes instream minimum flows of 5 cfs January through March, 7 cfs April through November, and 5 cfs in December.

[c] ADFG recommends instream minimum flows of 10 cfs January through April, 25 cfs May through September, 30 cfs in October, 25 cfs in November, and 10 cfs in December.

[d] FWS and NPS-RTCA recommend instream minimum flows of 10 cfs January through April, 20 cfs May through September, 30 cfs in October, 25 cfs in November, and 10 cfs in December.

be $352,740 annually (about 153 mills/kWh), which is about $58,660, or about 26 mills/kWh, higher than the cost of currently available alternative generation. Table 5.3-3 shows the costs of the various flow regimes relative to this baseline based on the modeled annual hydroelectric generation for each regime.

The cost shown in table 5.3-3 for the instream flow regime recommended by ADFG (10/25/30 cfs) represents an average annual generation value of 1,707,820 kWh with a corresponding reduction in annual generation of 592,230 kWh relative to the baseline of no minimum flow, and the cost of the minimum flow recommended by FWS and NPS-RTCA (10/20/25/30 cfs) represents an average annual generation value of 1,778,830 with a corresponding reduction in annual generation of 521,220 kWh relative to the baseline of no minimum flow. All annual hydroelectric generation figures presented here are averages for the expected first 10 years of project operation (2007-2016), based on staff's hydrologic-operational model.

Table 5.3-3. Summary of costs of proposed and recommended measures for the proposed project. (Source: GEC and preparers)

Environmental Measures	Recommending Entity	Capital and one-time costs (2003$)	Annual costs including O&M (2003$)	Total annualized cost (2003$)
1. Provide minimum instream flows in bypassed reach (5/7 cfs)[a]	GEC, staff	0	0	27,440
2. Provide minimum instream flows in bypassed reach (10/25/30 cfs)[b]	ADFG	0	0	75,720
3. Provide minimum instream flows in bypassed reach (10/20/25/30 cfs)[c]	FWS, NPS-RTCA	0	0	66,640
4. Free and unrestricted agency access	ADFG, FWS, NMFS	0	0	0
5. Erosion and sediment control plan[f]	GEC, ADFG, FWS, NMFS, staff	8,000	0	570
6. Sediment monitoring and management plan[e]	GEC, ADFG, NMFS, staff	8,000	0	570
7. Watershed protection plan[f]	ADFG, NMFS	8,000	0	570
8. Road management plan[f]	ADFG, NMFS,	10,000	5,000	5,710

Table 5.3-3. Summary of costs of proposed and recommended measures for the proposed project. (Source: GEC and preparers)

Environmental Measures	Recommending Entity	Capital and one-time costs (2003$)	Annual costs including O&M (2003$)	Total annualized cost (2003$)
	staff			
9. Plan for environmental compliance monitoring during construction[g]	ADFG, FWS, NMFS, staff	40,000	0	2,850
10. Construction timing restrictions (anadromous/non-anadromous)	GEC, ADFG, FWS, NMFS, staff	0	0	0
11. Escrow account for fish, wildlife and water quality enhancement[f]	ADFG, FWS, NMFS, staff	50,000	0	3,560
12. Fuel and hazardous substance spill plan[g]	ADFG, FWS, NMFS, staff	2,000	0	140
13. Oil and other contaminant treatment plan[f]	ADFG, FWS, NMFS, staff	8,000	0	570
14. Run-of-river operation with limit on stage change of 1 inch per hour	GEC, ADFG, FWS, NMFS, staff	0	0	0
15. Flow monitoring plan (recording of flows at no more than 15-minute intervals)[e,g]	GEC	10,000	0	710
16. Flow monitoring plan (continuous gaging; data monthly/annually)[f]	ADFG, FWS, NMFS, staff	10,000	160	870
17. Water quality (daily) monitoring during construction[f]	GEC, ADFG, FWS, NMFS, staff	13,480	0	960
18. Notify agencies within 12 hours of a non-compliance event	ADFG, FWS	0	0	0
19. Fish passage facility evaluation plan[f]	ADFG, FWS, NMFS, staff	0	5,000	5,000

Table 5.3-3. Summary of costs of proposed and recommended measures for the proposed project. (Source: GEC and preparers)

Environmental Measures	Recommending Entity	Capital and one-time costs (2003$)	Annual costs including O&M (2003$)	Total annualized cost (2003$)
20. Fisheries monitoring plan[f]	GEC	10,000	0	710
21. Biotic evaluation plan[f]	ADFG, FWS, NMFS, staff	0	15,000	15,000
22. Biotic monitoring plan[f]	NMFS	0	5,000	5,000
23. Prohibit hunting/trapping /fishing by construction personnel	FWS, staff	0	0	0
24. Annual consultation with wildlife agencies[g]	ADFG, FWS, NMFS, staff	0	500	500
25. Avoid tree removal from May through September	GEC, staff	0	0	0
26. Bear-human conflict plan[f]	ADFG, FWS, staff	2,000	1,000	1,140
27. Wetland mitigation plan[g]	ADFG, FWS, NMFS, staff	25,000	0	1,780
28. Seek state land use lease that would restrict vehicular access	GEC, staff	0	0	0
29. Public access plan[f]	ADFG, FWS, NMFS	8,000	0	570
30. Recreation enhancement/ management plan[e,f]	GEC, ADFG, NMFS, NPS-RTCA	5,000	0	360
31. Public access and recreation development plan[f]	Staff	5,000	0	360
32. Provide real time flow information to public[f]	NPS-RTCA, staff	0	1,000	1,000
33. Site and design structures to blend with surroundings	NPS-RTCA, staff	0	0	0
34. Land Use Management Plan[f]	Staff	8,000	0	570

Table 5.3-3. Summary of costs of proposed and recommended measures for the proposed project. (Source: GEC and preparers)

Environmental Measures	Recommending Entity	Capital and one-time costs (2003$)	Annual costs including O&M (2003$)	Total annualized cost (2003$)
35. Monitor noxious weeds	GEC, Staff	0	0	0
Total, GEC's Proposal		54,480	0	31,320
Total, Staff Alternative		189,480	27,660	68,590

[a] Total annualized cost represents a reduction in generation of 214,590 kWh relative to the no minimum flow scenario.
[b] Total annualized cost represents a reduction in generation of 592,230 kWh relative to the no minimum flow scenario.
[c] Total annualized cost represents a reduction in generation of 521,220 kWh relative to the no minimum flow scenario.
[d] Part of proposed operations; no additional cost.
[e] Annual cost only part of proposed operations.
[f] Capital and annual costs estimated by staff.
[g] Cost estimate from GEC.

Other Environmental Protection and Mitigation Measures

Table 5.3-3 summarizes the cost, recommending entity, and levelized annual cost of all the environmental protection and mitigation measures considered in this final EIS. We discuss our reasons for recommending, or not recommending, these measures in the section 6.1.1.1, *Comprehensive Development*. A more detailed description of each measure can be found in the resource analysis in chapter 4 of this final EIS.

5.3.1 No-action Alternative

Under the No-action Alternative, the proposed project would not be built, the proposed and/or recommended mitigative measures would not be necessary, and the existing environment would not change. GEC would continue to rely entirely on diesel generation to meet its customers' needs.

5.3.2 Comparison of Alternatives

Table 5.3-4 summarizes the annual benefits, costs, and net benefits of GEC's proposal and FERC staff's recommended alternative (GEC's proposal with additional recommended measures), with the No-action Alternative as a (zero) baseline for comparison.

Table 5.3-4. Summary of annual benefits, costs, and net benefits of alternatives for the proposed project. (Source: Staff)

	GEC's Proposed Alternative	**FERC Staff's Recommended Alternative**
Installed capacity (kW)	800	800
Annual generation (kWh)	2,085,460	2,085,460
Annual power benefit ($)	266,640	266,640
(mills/kWh)	127.86	127.86
Annual cost ($)	356,620	393,890
(mills/kWh)	171.00	188.87
Annual net benefit ($)	-89,980	-127,250
(mills/kWh)	-43.15	-61.02

The above analysis indicates that energy from the project as proposed would cost more than diesel generation at current cost levels. However, these results are based on a current year approach which does not account for the escalation of diesel fuel and other costs in later years. GEC’s own analyses also showed that the net annual benefit of the project when compared to diesel generation increased significantly in later years of project operation. However, this analysis does not examine the impact of the fluctuation of assumptions used in this analysis, and such fluctuation could significantly impact the economics of this project. Chapter 6, *Conclusions*, contains a discussion and analysis of factors that could affect the overall economic feasibility of the project.

6.0 CONCLUSIONS

6.1 RECOMMENDATIONS AND CONCLUSIONS

Under the Act, any exchange of lands for the construction of the proposed Falls Creek Hydroelectric Project may occur only if the Commission concludes, with the concurrence of the Secretary of the Interior, that the construction and operation of a hydroelectric project: (1) would not adversely impact the purposes and values of GBNPP (as constituted after the land exchange), and (2) would comply with the requirements of NHPA. The Commission also must determine that the project can be constructed and operated in an economically feasible manner. In addition, the Commission also must determine, with the concurrence of the Secretary of the Interior and the state of Alaska, the minimum amount of land necessary to construct and operate the proposed project.

In the following section, FERC staff provide recommendations addressing the Commission's various responsibilities under the FPA and the Act. In addition to the requirements listed above, staff include recommendations for license requirements in the event that a license is issued for the project.

NPS addresses FERC staff’s determination of compliance with the NHPA and the potential for adverse impacts on the purposes and values of GBNPP in the following section.

6.1.1 FERC Staff Recommendations and Conclusions

6.1.1.1 Comprehensive Development. Section 4(e) of the FPA provides that, in issuing licenses for non-federal projects, FERC “shall give equal consideration to the purposes of energy conservation; the protection, mitigation of damage to, and enhancement of fish and wildlife (including related spawning grounds and habitat); the protection of recreational opportunities; and the preservation of other aspects of environmental quality.” Furthermore, Section 10(a)(1) of the FPA provides that licensed projects:

> *will be best adapted to a comprehensive plan for improving or developing a waterway or waterways for the use or benefit of interstate or foreign commerce, for the improvement and utilization of water power development [for adequate protection, mitigation, and enhancement of fish and wildlife (including related spawning grounds and habitat], and recreation [and other purposes referred to in Section 4(e) of the FPA]*.

This section presents FERC staff’s rationale in balancing developmental and non-developmental values of the proposed hydroelectric project and FERC staff’s recommendations for the plan best adapted to comprehensive development of the proposed hydroelectric project. The balancing analysis considers the comparative environmental effects of the alternatives (chapter 4); their economic viability (chapter 5); and their consistency with relevant agency recommendations, comprehensive plans, laws, and policies (sections 6.2, 6.3, 6.4, and 6.5). Based on FERC staff's review and evaluation of GEC's Proposed Alternative, the Maximum Boundary Alternative, and the Corridor Alternative, FERC staff recommend that, if a license is issued, it contain GEC's proposed environmental measures (see section 2.3.5, *GEC's Proposed Environmental Measures* and listed below), and additional or modified measures adopted from section 2.7, *Additional Measures for Consideration*. Where GEC proposes a measure, but it has been modified, we include it in the second list below.

FERC staff recommend including the following environmental measures proposed by GEC in any license issued for this project.

- Locate the powerhouse and the tailrace to minimize effects on anadromous fish and their habitat in the lower Kahtaheena River and to prevent anadromous fish from trying to enter the tailrace (discharge) pipe.

- Conduct all in-water construction activities in the anadromous reach of the river from June 1 through August 7 and upstream of the anadromous reach (upstream of the Lower Falls) from November 1 through April 30 and June 1 through September 15. No in-water activities would occur in May or from mid-September through the end of October.

- Locate the intake about 300 feet downstream of The Islands area to avoid effects on productive Dolly Varden habitat located in that area.

- Include a synchronous bypass at the powerhouse to allow load-following generation without causing stage fluctuations in the anadromous fish habitat below the tailrace. This would also provide a redundant flow continuation capability to avoid dewatering anadromous fish habitat during a forced outage event.

- Construct road access to the project facilities via upland routes to avoid effects on wildlife habitat in the beach area.

- Bury the pipeline in steep portions of the road cut to protect it from damage due to sliding debris and avoid adding its weight to the vegetative and soil mat.

- Locate roadways and transmission lines to avoid sensitive areas as much as possible.

- Implement an ESCP that limits the potential for erosion by minimizing the area disturbed; using equipment that is proportionally sized for the task at hand; back-hauling materials excavated from the stream canyon and powerhouse area to reduce the possibility of mass wasting; implementing BMPs, including use of landscape fabric, sediment fences, and prompt reseeding of disturbed areas; control techniques such as wet suppression (i.e., source watering), wind speed reduction (i.e., wind barriers), cessation of construction activities during periods of high winds, and use of small construction equipment; removing only selected trees not identified as having high potential for marbled murrelet nesting within the clearing widths prescribed by U.S. Forest Service standards and guidelines; avoiding felling trees and snags from May to August during murrelet and passerine nesting season; salvaging topsoil and vegetation during construction and use for revegetation of roadcuts and sidecast slopes (supplementing with native grass seed as necessary to ensure quick ground cover establishment); and monitor noxious weeds to limit the establishment and spread of plants such as giant knotweed and reed canary grass.

- Implement a sediment monitoring and management plan, which provides for annual monitoring of bedload transport. Replace any sediment shortfall by manually removing sediments from the impoundment and placing them on a river bar immediately downstream for transport during the next high-water event.

- Install a pneumatically controlled sluice gate on the dam, and lower the gate during high flows, allowing sediments to be carried downstream.

- Operate the project in a run-of-river mode, and provide minimum instream flows in the entire bypassed reach of at least 5 cfs from December through March and 7 cfs from April through November.

- Implement a water quality monitoring plan, consistent with agency recommendations, including daily monitoring from the initiation of construction to 60 days following removal of erosion control measures to evaluate the effectiveness of the measures and to demonstrate adherence to Alaska State water quality standards during construction and operation.

- Design and construct a fish screen to exclude fry-sized salmonids from the project intake, and install a bypass system to provide safe and effective downstream passage past the diversion.

- Minimize adverse effects on wetlands by avoiding construction in bogs along the road access route, minimize the risk of wind throw by minimizing clearing widths, and consult with ACOE to determine the amount of wetland mitigation that may be needed.

- Minimize the removal of culturally modified trees, which are indicators of past use by Huna Tlingits. Follow NPS protocol for data recovery if trees must be removed.

- In consultation with the state of Alaska resource agencies (ADNR/ADFG) and private landowners along the road route, develop a plan to control public access, effectively limiting public access and development of the area. Following construction, limit access into the project area to non-motorized public recreation.

- Locate the powerhouse structure in a bight in The Canyon 0.21 miles below the Lower Falls and 0.45 miles from the shore, where it would be nearly invisible from nearby vistas. The intake site would also be located in The Canyon, where facilities would only be visible from directly overhead.

- Actively pursue protection of the lands with the state of Alaska if the project is decommissioned in the future.

In addition to GEC's proposed measures listed above, FERC staff recommend that the following additional or modified measures be included in any license issued for this project (state and federal agencies that recommend a particular measure are listed in parentheses after the measure):

- Develop and implement a fish passage facility evaluation plan to determine the effectiveness of the proposed fish passage facility and allow for modifications as necessary. (ADFG, FWS, NMFS)

- Develop and implement a biotic evaluation plan to evaluate the effects of instream flow modifications and project construction and operations on fishery resources in the Kahtaheena River, including monitoring Dolly Varden char populations, evaluating ice formation, and conducting adult salmon escapement counts, over 5 years and adjust minimum flows if warranted. (ADFG, FWS, NMFS)

- Develop and implement a plan for the use of an ECM during construction. (ADFG, FWS, NMFS)

- Notify agencies of non-compliance events within 12 hours as part of the flow monitoring plan. (ADFG, FWS)

- Allow a ramping rate of no greater than 1 inch per hour in the bypassed reach and downstream of the project. (ADFG, FWS, NMFS)

- Implement a flow monitoring plan, monitoring streamflows at 15-minute intervals, from a gaging station at the powerhouse, to verify compliance with license conditions related to streamflows and ramping. (ADFG)

- Consult with fish and wildlife agencies annually to review study results, monitoring plans, and project operations that affect fish and wildlife, and identify courses of action based on results. (ADFG, FWS, NMFS)

- Establish a $50,000 interest-bearing escrow account to mitigate for unforeseen fish, wildlife, and water quality effects associated with project construction and operation. (ADFG, FWS, NMFS)

- Develop and implement a fuel and hazardous substances spill plan that, among other things, addresses oil and other contaminants. (ADFG, FWS, NMFS)

- Provide free and unrestricted access to agency representatives with proper identification. (ADFG, FWS, NMFS)

- Develop and implement a plan to discourage hunting, trapping, fishing, and use of ATVs on lands off the access road in the project area by construction personnel during construction. (FWS, NPS-RTCA)

- Develop and implement a bear-human conflict plan for the project. (ADFG, FWS)

- Develop and implement a plan to avoid, minimize, and mitigate effects on wetlands. (ADFG, FWS, NMFS)

- Develop and implement a road management plan. (ADFG, NMFS)

- Develop and implement a public access and recreation development plan. (ADFG, FWS, NMFS, NPS-RTCA), and include provisions for signage and trail brushing.

- In consultation with state, local, and federal agencies, develop a land use management plan for lands with the FERC project boundary.

- Provide a flow phone or other means, such as flow information on a website, for prospective visitors to check instantaneous flow rates in the bypassed reach prior to visiting the site. (NPS-RTCA)

- Site and design project structures, to the extent possible, to blend in with their natural surroundings. (NPS-RTCA)

Some of these measures would reduce the net benefit of the project as proposed by GEC. Others involve consolidation of several components for cost-effective implementation. We discuss in the following section the rationale for these measures and provide comparative costs that are levelized annual values that include both upfront capital costs and O&M costs over 30 years.

Minimum Flows

Operation of the Falls Creek Hydroelectric Project would reduce flows in the bypassed reach. Our analysis suggests that the primary resources that could be adversely affected by these reduced flows would be resident Dolly Varden and aesthetics. In this final EIS, we have evaluated the effects of four bypassed reach flow regimes including: no minimum flow, a 5 to 7 cfs minimum flow proposed by GEC, a 10-25-30-25 cfs minimum flow recommended by ADFG, and a 10-20-30-25 cfs minimum flow recommended by FWS and NPS-RTCA

In regard to fisheries resources, our analysis suggests that, under the no minimum flow scenario, frequent prolonged periods of dewatering the bypassed reach would eliminate the existing bypassed reach sub-population of the Kahtaheena River Dolly Varden, and fish would only occasionally and temporarily occur in the bypassed reach, likely drifting down from upstream areas. Under each of the other minimum flows, the bypassed reach sub-population would likely persist; however, GEC's proposed minimum flows would significantly reduce the available habitat and likely reduce the numbers of Dolly Varden inhabiting the bypassed reach. The higher agency-recommended minimum flows would provide more habitat and would likely sustain a greater portion of the current bypassed reach sub-population.

The Kahtaheena River resident Dolly Varden population provides little value in regard to subsistence, sport, or commercial fishing. Rather, the value of maintaining and protecting this population is based on its uniqueness to GBNPP and its potential genetic uniqueness in regard to other resident Dolly Varden within Alaska. Under each of the land exchange alternatives, a portion of the Kahtaheena River upstream of the proposed diversion site would remain within GBNPP and the portion of the Kahtaheena River Dolly Varden population within this reach would remain as a valued resource of the park. However, if the land exchange occurs and the Falls Creek Hydroelectric Project is constructed, the bypassed reach sub-population of Dolly Varden would no longer be part of GBNPP and, regardless of the flow regime selected for project operation, this sub-population would no longer be an asset of GBNPP.

The genetic uniqueness of the Kahtaheena River Dolly Varden population was assessed during preparation of the license application (Leder; 2001). The study concluded that the Kahtaheena River resident Dolly Varden displayed a lack of genetic diversity suggesting that the population probably arose from a few individuals and may have been severely bottlenecked.[55] The Kahtaheena River resident Dolly Varden is reproductively isolated by the Lower Falls, which is a barrier to upstream migration. It is likely that no Dolly Varden from other populations, resident or anadromous, have been able to interbreed with fish upstream of the Lower Falls for hundreds of generations. The genetic diversity of the original founder group was likely low compared to the widely distributed and wide ranging anadromous population from which it separated. Post-isolation selection pressures could have further reduced the overall genetic diversity of this population, as it adapted to the upper Kahtaheena River ecosystem (i.e., wide-ranging flows and temperatures, relatively oligotrophic conditions, lack of competition or predation from other fish). Numerous other resident populations of Dolly Varden exist in southeastern Alaska and have successfully adapted to survival in similar steam systems. Most, if not all these populations likely underwent a similar sequence of isolation and selection, resulting in similar populations having lower genetic diversity than that seen in the much larger anadromous population.

Regardless of the operation of the project, a portion of the Kahtaheena River Dolly Varden population upstream of the proposed diversion site would persist, relatively undisturbed. Thus, the availability of this population for scientific study by park personnel or other interested researchers would be maintained. Under the no minimum flow scenario, the bypassed reach sub-population would be essentially lost. Each of the proposed minimum flows would maintain the bypassed reach sub-population; however, under GEC's proposed flows, available habitat would be reduced, and the number of fish would likely be reduced as well. The higher agency-recommended minimum flows would maintain more existing habitat and likely a greater portion of the existing population.

The project could adversely affect stream aesthetics, especially at the Lower Falls since it would reduce streamflows in the bypassed reach by 2 to 23 cfs. Limited visitor information suggests that less than 10 individuals visit the stream per month from May through September. Visitation would be even less during other times of the year. With no minimum flow, the bypassed reach would be dry on occasion, and the aesthetic value of the stream, especially the Lower Falls, would be greatly diminished. Under GEC's proposed and the agencies' recommended flow regimes, there would be little difference in the flows passing over the Lower Falls during May, June, and September, primarily because streamflows generally exceed the project capacity and the minimum flows during this time. During July and August, when natural streamflows would be lower and visitation may be at its peak, flows over the Lower Falls would be higher under the agencies' recommended minimum flows than GEC's flows. Our analysis suggests that during this time of year, GEC's proposed minimum flows would reduce flows over the lower falls by approximately 4 to 8 cfs on average, potentially resulting in a decrease in

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55 Bottleneck refers to a short-term but significant reduction in population size followed by an increase in population size.

the aesthetic enjoyment of the Lower Falls for some visitors. However, to avoid visiting the stream during periods when aesthetics may be affected by low flows, visitors could monitor streamflows by using the flow phone (or other means to notify the public) that we are recommending and plan trips to ensure that they visit the stream only during periods of desired aesthetic flows.

In this final EIS, FERC staff do not make a recommendation whether or not to issue a license for the Falls Creek Hydroelectric Project. However, if the Commission elects to issue a license for this project, it would also require completion of other significant actions including the exchange of federal and state lands and designation/de-designation of wilderness areas. If these efforts are undertaken, a primary benefit would be to provide 800 kW of additional generation to the Gustavus area at a more stable or inflation-resistant cost compared to diesel-fueled generation. While the higher flows would potentially protect Dolly Varden and stream aesthetics better than GEC’s proposed flows, these higher flows would reduce annual generation by about 377,640 kWh, or about 18 percent, under the ADFG recommendation, and about 306,630 kWh, or about 15 percent, under the FWS/NPS-RTCA recommendation versus generation under GEC’s proposed flow regime. This lost generation corresponds to a reduction in net annual benefits of about $48,280 and $39,200, respectively, versus the preliminary staff-recommended alternative including GEC’s proposed flow regime. We do not believe the benefit of the higher flows would be worth the annual cost or the reduction in total generation; therefore, we are recommending that any license issued for the project include a requirement for GEC's proposed minimum flows of 5 and 7 cfs. GEC's proposed minimum flows would provide adequate protection of the resident Dolly Varden population and aesthetic resources without severely reducing the generation benefit of the project.

Flow Monitoring Plan

It is necessary to accurately document minimum instream flows and ramping rates to monitor compliance with license conditions. To ensure that license conditions designed to mitigate effects on fisheries populations are implemented, ADFG, FWS, and NMFS recommend that GEC consult with them and receive their approval on a final plan to monitor instream flow and ramping rates. As part of the plan, they recommend that GEC continuously record instream flows from the initiation of construction through the term of any license. GEC agrees that a flow monitoring plan is necessary, but suggests recording of instream flows at specified intervals of no more than 15 minutes.

In section 4.4.2.1.1, *Water Quantity,* we conclude that monitoring instream flows is necessary to document compliance with the minimum instream flows and ramping rate limits specified in the conditions of any license issued for the project and would be required under any action alternatives. We make no conclusion on the need to continuously record instream flows relative to the benefit on water quality or fisheries. However, we agree with the agencies that continuous monitoring of instream flows can be accomplished at very little additional cost. We recommend that the frequency of recording flows be at least 15 minutes and that any further refinement of recording intervals be addressed in the flow monitoring plan. Therefore, we recommend that GEC develop a monitoring plan in consultation with ADFG, FWS, and NMFS and file the plan with the Commission for approval at least 6 months prior to the initiation of project construction. The plan should include the location of all flow and stage measuring gages (both new and existing), the entity responsible for maintaining the gages, procedures for ensuring that the gages are calibrated, and procedures for reporting monitoring results to the agencies. We estimate our recommended flow monitoring plan with continuous monitoring would cost $870 annually, which would be only $160 more than the estimated cost of GEC's proposed flow monitoring plan. The cost of developing and implementing a flow monitoring plan would be justified to ensure compliance with flow and ramping requirements.

Road Management Plan

GEC's proposed road alignment for access and service roads would cross several ravines that provide habitat to anadromous fish. ADFG and NMFS recommend that GEC develop and implement a road management plan with measures to minimize the potential for the obstruction of fish movement and contribution of sediment to fish spawning and rearing habitat in streams that would be crossed by the proposed access and service roads. GEC's ESCP includes measures to minimize the potential for erosion and sedimentation. In section 4.3.2.1, we conclude that implementation of a road management plan, including road maintenance and monitoring, could help to prevent any detrimental effects on water quality and fisheries from road-related erosion and sediment transport. This measure would be recommended for all action alternatives. We estimate an annual cost of $5,710 for this plan and road maintenance implemented under this plan. Development and implementation of a road management plan would be justified because it would provide for maintenance of access and service roads and would minimize the potential for erosion and sedimentation to enter streams within the general project area.

Fuel and Hazardous Substances Spill Plan

GEC does not propose any measures to address the handling of fuel and hazardous substances during project construction and operation. ADFG, FWS, and NMFS recommend that GEC consult with them and obtain written approval of both a fuel and hazardous substances spill plan and an oil and other contaminants treatment plan. GEC includes provisions for the handling of fuel and hazardous substances in its ESCP. We conclude in section 4.4.2.1.2, *Water Quality*, that there would be some risk for small accidental spills from fuel handling and that occasional, minor releases of hydrocarbons could occur on the site or in the powerhouse. In section 4.4.2.1, we conclude that hazardous substances entering the waterways could adversely affect aquatic biota and severely reduce the quality and quantity of existing aquatic habitat, especially if concentrations exceed the lethal tolerance limit of a species. We conclude that a plan for handling fuels and hazardous substances and the treatment and removal of oil or other contaminants would reduce the risk of spills and improve containment of any spills that might occur. Therefore, we agree with the agencies that GEC should develop and implement a fuel and hazardous substances spill plan that also addresses the treatment and removal of oils and other contaminants in consultation with ADFG, FWS, and NFS. We estimate that the plan would cost $710 annually. This plan would be recommended under all action alternatives because all action alternatives would include project construction and operation. The cost of developing and implementing our recommended plan would be justified by the benefit to be derived from reducing the potential for spills and the resulting effects that release of hydrocarbons could have on fisheries resources.

Biotic Evaluation Plan

The alteration of the flow regime during and after project construction would affect fisheries. GEC proposes to implement an adaptive program to monitor fish in the bypassed reach and to consider remedial actions based on the monitoring results. ADFG and FWS recommend that GEC implement a biotic evaluation plan that would include: (1) monitoring of pre-project resident char (Dolly Varden) populations until the project becomes operational; (2) monitoring project effects on resident char populations for 5 years after commencement of project operations, and thereafter if minimum instream flow increases are warranted; (3) evaluating flow and temperature conditions that cause ice formation in the bypassed reach; (4) conducting adult escapement counts in the anadromous reach; and (5) developing schedules for providing monitoring results to the agencies, consulting with the agencies, and implementing the biotic monitoring programs. NMFS also recommends a biotic monitoring plan to evaluate the effects of instream flow modifications and project construction and operation on fisheries resources in the Kahtaheena River, but only specifies that the plan include adult salmon escapement counts in the anadromous reach. GEC disagrees with the need to conduct escapement counts and states that the proposed run-of-river operation, synchronous bypass system, and pipeline to return flow to the head of the anadromous reach are designed to avoid impacts on fisheries.

In sections 4.4.2.1.1, *Water Quantity*, and 4.6.2.1, *Fisheries*, we conclude that it would be appropriate to examine pre-project (baseline) conditions and to evaluate general trends in fish abundance over a minimum of 5 years. If after the fifth year of post-project monitoring, a negative trend in fish abundance is detected, new instream flows or other measures could be considered, in consultation with resource agencies. The Commission would not recommend the adjustment of the initial recommended streamflows and other initial conditions unless there are clearly demonstrated project-related adverse effects on fish populations.

In sections 4.4.2.1.1, *Water Quantity*, and 4.6.2.1, *Fisheries*, we conclude that the sustained lower flows that would result from operating the project under any of the proposed minimum instream flow recommendations would increase the formation of ice over the stream's surface and anchor ice in the bypassed reach. Evaluating flow and temperature conditions that cause ice formation in the bypassed reach would provide information necessary to ensure that anchor ice and hard-freezes are not forming and are not resulting in substantial detrimental effects on char populations and to make adjustments to instream flows if such effects are evident.

In section 4.6.2.1, *Fisheries*, we conclude that it is appropriate to monitor the effects of the proposed project on the distribution and abundance of existing fish populations in the Kahtaheena River because the proposed project would include a number of measures that would alter the aquatic habitat conditions in the bypassed reach. Changes in the flow regime and sediment transport that could result from landslides could alter the aquatic habitat in the Kahtaheena River. Altered habitat conditions would affect the distribution of resident Dolly Varden, as well as pink, chum, and coho salmon, cutthroat trout and coat range sculpin. Therefore, we agree with the agencies that monitoring of pre-project resident Dolly Varden populations and adult salmon escapement counts in the anadromous reach would be necessary components of any fish monitoring plan.

In section 4.4.2.1.1, *Water Quantity*, we also conclude that a plan should specify the frequency of monitoring, the species to be monitored, the locations of monitoring reaches, and the indices that would be used to document compliance or noncompliance with agency management objectives, as well as the rationale for selecting each variable.

Because the biotic evaluation plan would address the alteration of flows in the Kahtaheena River, the plan would be necessary under all action alternatives. We estimate an annual cost of $15,000 for this plan. Developing and implementing a biotic evaluation plan would be justified by the benefit to fisheries resources from assessing potential adverse effects from project operations and taking remedial actions.

Fish Passage Facility and Evaluation Plan

Construction of a diversion in the Kahtaheena River would affect upstream and downstream movement of Dolly Varden char. To address the impact on fish movement, GEC proposes to design and install a fish screen and bypass system at the diversion capable of excluding Dolly Varden char from the penstock and capable of allowing fish free movement downstream into the bypassed reach. FWS, ADFG, and NMFS have reviewed and agreed with GEC's proposed plans for fish passage facilities except for a few minor changes that GEC would include in its final fish passage design. FWS, ADFG, and NMFS also recommend a plan to evaluate the effectiveness of fish passage facilities, including adult fish exclusion at the tailrace and juvenile screening at the diversion intake. We conclude, in section 4.6.2.1, that the proposed design would be effective in allowing downstream passage and in preventing fish from entering the project tailrace pipeline. We agree with the agencies that development and implementation of a fish passage evaluation plan would ensure that the fish passage facilities function as intended and that they are effective in moving fish around the diversion. The fish passage evaluation plan would be recommended under action alternatives because it would include the design and installation of fish passage facilities. We estimate an annual cost of $5,000 for this plan. Developing and implementing the fish passage evaluation plan would be justified based on the benefit to fisheries by ensuring that the fish passage facilities are effective.

Wetlands Mitigation Plan

GEC's proposed road alignment would avoid bogs and shallow ponds and would cross 500 feet of wetlands; however, a proposed disposal site would permanently change the wetland functions of 0.5 acre of wetland vegetation. GEC proposes to address the loss of an estimated 1.15 acres of wetlands through mitigation on lands bordering the Dude Creek Critical Habitat Area. ADFG, FWS, and NMFS recommend that GEC develop and implement a wetlands mitigation plan. ADFG further states that the area proposed by GEC for wetland mitigation may provide rearing habitat for coho salmon. In response, GEC proposed to consult with ACOE to determine the amount and type of wetland mitigation that might be needed. In section 4.7.2.4, we conclude that GEC's proposed project would have a moderate effect on wetlands. GEC would be required by ACOE to address the loss of wetlands. A wetlands mitigation plan developed in consultation with ADFG, FWS, NMFS, and ACOE, could provide a process to determine the need and method for addressing the loss of wetlands. This plan would be recommended under all action alternatives. We estimate that the annual cost would be $1,780. Developing and implementing a wetlands mitigation plan would ensure no net-loss of wetlands by the project.

Plan to Discourage Fishing, Hunting, and Trapping during Construction

GEC does not propose any measures to address the effects of the project workforce on existing fish and wildlife populations. FWS and NPS-RTCA recommend that hunting, trapping, and fishing by the construction workforce be prohibited to protect existing aquatic and terrestrial resources. In section 4.4.2.1, we conclude that coho salmon and cutthroat trout, the likely species of choice for anglers, would be susceptible to overfishing because of their low numbers, and concentrated fishing below the Lower Falls could result in physical damage to the streambank, including compaction and disturbance of vegetation, with a potential loss of habitat value. In section 4.7.2.1, we indicate that hunting and trapping could increase the risk of harm to bald eagles. Therefore, we agree with FWS and NPS-RTCA that fishing, hunting, and trapping by the construction workforce on lands within the project boundary could be detrimental to the fisheries and wildlife resources. If lands are removed from GBNPP for the proposed project, they would become state lands and subject to state laws regulating fishing, hunting, and trapping. While fishing, hunting, and trapping may be allowed on these lands under state ownership, GEC could be required by the Commission to develop and implement a plan that would discourage the project workforce from fishing, hunting, and trapping within the project boundary during construction. Under such a plan, GEC could notify the construction workforce that, because of possible adverse environmental effects, fishing, hunting, and trapping are discouraged within the project area during construction. GEC could also post signage along the access road entering the project area and along the Kahtaheena River below the Lower Falls, discouraging these activities by the project workforce. Under GEC's proposal, the plan would only apply to the 117 acres that would be within the project boundary, not the remaining 775 acres of land that would be outside of the project boundary. Under both the Maximum Boundary Alternative and the Corridor Alternative, such a plan would apply to all of the lands that are transferred out of GBNPP because all of the lands would be within the FERC project boundary. We estimate that there would be no additional cost involved in implementing this policy at the construction site under any action alternative.

Bear-Human Conflict Plan

Project construction and the improved access to the project area would increase the incidences of human-bear conflict. FWS and ADFG recommend that GEC develop a bear-human conflict plan in consultation with the resource agencies. GEC concurs with the need for this plan. We conclude, in section 4.8.2.2, that while project construction and operation would not block movement corridors for bears, it would improve human access to the project area and increase the opportunities for human-bear conflicts. A plan that would include instructions for project operating practices that minimize possible conflicts with bears; avoiding areas often used by bears, if possible; and keeping construction sites and refuse areas clean of substances that would attract bears, as proposed by FWS and ADFG, would protect construction workers and visitors to the areas, and limit the number of bears that might need to be removed or destroyed. This plan would be recommended under all of the action alternatives because all of the alternatives include project construction and operation. We estimate that the annual cost of our recommended bear-human conflict plan would be $1,140. The cost of developing and implementing the plan would be justified by the improved safety for both humans and bears during construction and operation of the project.

Escrow Account for Fish, Wildlife, and Water Quality

GEC proposes an adaptive management program for monitoring fish in the bypassed reach and to consider remedial actions should the monitoring results show that the persistence of fish populations would be adversely affected. GEC also agrees that any required minimum flows would be re-evaluated after 5 years and adjusted if they are adversely affecting fish populations. ADFG, FWS, and NMFS recommend that GEC establish a $50,000 interest-bearing escrow account to mitigate for impacts on fish, wildlife, and water quality associated with project construction and operation. An escrow account would provide the necessary funding to address any remedial actions or adjustment to flows after 5 years of project operations. We conclude, in section 4.6.2.1, that the agency-recommended escrow account would likely mitigate for any unforeseen fish, wildlife, and water quality effects resulting from project construction or operations, including the effects of erosion and sedimentation in project-area streams. The measure would be recommended under all action alternatives. The annual cost of a $50,000 escrow account would be $3,560. Establishment of an escrow account would be justified based on the potential need to take remedial actions to address effects of project construction and operation on water quality and fisheries in the Kahtaheena River.

Environmental Compliance Monitor

The potential for slope erosion, sediment transport into streams, and hazardous substance spills exists at the proposed construction site. To address these concerns and minimize the potential effects of such events, ADFG, FWS, and NMFS recommend that GEC's final ESCP and fuel and hazardous substance spill plan include: (1) a provision for an ECM to ensure compliance with the environmental measures specified in any license during construction of the project with authority to (a) ensure strict compliance with the provisions of the license; (b) cease work and change orders in the field, as necessary; (c) and make pertinent and necessary field notes on monitoring compliance by the licensee; (2) the position description including duties and responsibilities; and (3) provision to hold meetings between the licensee and agencies annually to: (a) review and evaluate results of all monitoring activities and reports; (b) make necessary adjustments of project monitoring to meet resource needs; (c) and decide on continuation of monitoring. ADFG and FWS recommend that the ECM be an on-site representative of ADFG who is qualified to issue or modify Alaska Title 16 Fish Habitat Permits and that GEC provide funding to ADFG to conduct an annual inspection of the project. In section 4.4.2.1, we conclude that compliance monitoring using qualified personnel would also ensure that any spills are documented and addressed in an appropriate manner. In section 4.6.2.1, we conclude that a qualified ECM could ensure compliance with environmental measures designed to protect the fisheries streams affected by project construction. We also conclude, in section 4.12.2.1, that implementation of our recommended measure to prohibit fishing (see discussion below) within the project boundary should be included as part of the ECM's duties. However, we do not agree with ADFG that the ECM needs to be an ADFG employee who can issue or modify permits because that is the responsibility of the state of Alaska. We also disagree with ADFG that GEC should fund it to annually inspect the project, because FERC regularly inspects projects as part of its compliance monitoring responsibility. We recommend that GEC employ an ECM with the responsibilities to monitor compliance with license conditions during construction. We estimate an annual cost of $2,850. The cost of providing an ECM would be justified by the benefits to water quality, fisheries, and visual resources from minimizing the potential for accidents that might adversely affect these resources.

Public Access and Recreation Development Plan

Improved access would attract more recreational use to the project area. ADFG and NMFS recommend that GEC develop and implement a recreation enhancement plan to address the potential for increased recreation demand that would result from improved access to the Kahtaheena River area. NPS-RTCA recommends a more comprehensive recreation development plan. In response to the agency recommendations, GEC proposes to develop a recreation plan in consultation with the town of Gustavus, ADNR, and other appropriate agencies. As part of the plan, GEC would construct and maintain 6 to 12 signs and clear (brush) and maintain about 100 yards of trails to enable viewing of the Upper and Lower Falls on the Kahtaheena River.

ADFG and NMFS also recommend that GEC develop and implement a public access plan to address concerns about public vehicular use. The agencies state that vehicular access would require more rigorous road design and maintenance standards and could increase non-point sources of pollution to the Kahtaheena River and other stream crossings. Increased recreation demand could result in a provision in the public access and recreation development plan that would allow motorized vehicles to use the access road and service roads.

In section 4.12.2.2, we conclude that a single public access and recreation development plan would be a reasonable approach to facilitate consensus among the town of Gustavus and resource agencies on the extent of public use and recreation development in the project area. The recommended plan would be applicable to all action alternatives because in all the alternatives the majority of the increased recreation demand would focus on the access and service roads and areas in the immediate vicinity of the Kahtaheena River. However, the scope of the plan could be greater under the Maximum Boundary or Corridor alternatives because more land would be included in the FERC project boundary. We estimate the annual additional cost for a combined public access and recreation development plan would be $570. The cost of developing and implementing the plan would be justified by the benefits that would result to the visual resources and utilization of recreation and fisheries resources of the project area.

Land Use Management Plan

As previously discussed, improved access and changes in land use management resulting from the land exchange and subsequent hydroelectric development could result in various changes to land uses in the Kahtaheena River area. Therefore, to ensure that land uses would be consistent with the intent of GEC and the stakeholders, we recommend development of a land use management plan for lands within the FERC project boundary. The land use management plan could be developed in concert with the public access and recreation development plan.

The land use management plan could reference the public access and recreation development plan for such issues as appropriate recreation uses and restrictions within the FERC boundary (i.e., hunting, trapping, domestic dog use) and modes of access (i.e., bicycles, ATVs) that would be permitted or restricted within the FERC boundary.

The land use management plan could also address such issues as mineral extraction and restrictions on human development (i.e., recreation facilities, additional roadways) in the project area. The management policies and regulations would be determined by GEC in collaboration with applicable local, state, and federal agencies. The stakeholders involved in developing the land use management plan would likely include GEC, ADNR, ADFG, NPS, and the town of Gustavus.

The land use management plan would only apply to lands within the FERC boundary because the state of Alaska would have sole jurisdiction over exchanged lands outside of the boundary. Therefore, the scope of the land use management plan and acreages of land covered under the plan would vary by alternative. We estimate the annual additional cost of the land use management plan would be $570. The cost of developing and implementing the plan would be justified by the benefits of reducing potential land use inconsistencies and ensuring compatibility with the land use goals and policies of GEC and the local, state, and federal agencies with interests in the Kahtaheena River area.

Flow Information

Project construction and operation under all action alternatives would attract more visitors to the Upper and Lower falls areas of the Kahtaheena River and could increase public safety concerns of visitors hiking the lower stream reaches during high flow periods. GEC does not propose any measures to provide flow information to visitors. To maximize the public enjoyment of higher natural flow events, NPS-RTCA recommends that GEC provide a means for prospective visitors to check instantaneous flow rates in the bypassed reach prior to visiting the site. We conclude, in section 4.12.2, that because flows in the bypassed reach can vary from 5 to 100 cfs in a year, providing flow information via a flow phone or website would benefit people planning to visit the area. Therefore, we recommend that a method for providing flow information be addressed in our recommended public access and recreation development plan. We estimate that the annual cost of providing flow information to the public would be $1,000. The additional cost of providing flow information would be justified as both a safety measure for the increased use of the lower reach during high flow periods and as a measure that would enhance the visitor experience to the Kahtaheena River area.

6.1.1.2 Effects on Purposes and Values of GBNPP. The Act states that the exchange of lands may occur only if the Commission determines, with the concurrence of the Secretary, that the construction and operation of the hydroelectric project will not adversely impact the purposes and values of GBNPP (as constituted after the consummation of the land exchange).

In this final NEPA document, we analyze the effects of no action, GEC's proposed action to construct and operate the hydroelectric project, and two action alternatives that include GEC's proposed action with different project boundaries. In each resource section, we make findings about the level of effect that each action alternative would have on 16 types of environmental resources. In this section, we summarize our conclusions about the effects of the construction and operation of the project on the purposes and values of GBNPP. Table 6.1-1 identifies the specific purposes and values of GBNPP for each resource area analyzed and indicates whether the effects would adversely impact the purposes and values, referencing the resource section that contains the complete analysis.

FERC staff analyzed the effects of the three alternatives considered in this EIS and conclude that, under any of these alternatives, the construction and operation of the Falls Creek Hydroelectric Project would not adversely impact the purposes and values of GBNPP (as constituted after the land exchange).

NPS has reviewed the FERC staff determination and concurs that the construction and operation of the Falls Creek Hydroelectric Project described in the action alternatives would not adversely impact the purposes and values of GBNPP (as constituted after the land exchange).

6.1.1.3 Compliance with the National Historic Preservation Act. The Act states that the exchange of lands may occur only if the Commission determines, with the concurrence of the Secretary, that the construction and operation of the hydroelectric project would comply with the requirements of the NHPA.

FERC staff reviewed the cultural resources study reports provided by GEC, consulted with NPS, and determined that no historic properties (properties listed or eligible for listing in the National Register) exist in the project's area of potential effect. Therefore, FERC staff conclude that under each action alternative (i.e., licensing alternative) considered in this EIS, construction and operation of the Falls Creek Hydroelectric Project would comply with the requirements of the NHPA.

NPS has reviewed the FERC staff determination and concur that the construction and operation of the Falls Creek Hydroelectric Project would comply with the requirements of the NHPA.

Table 6.1-1. GBNPP purposes and values for each resource.

Resources	GBNPP Purposes and Values[a]	Section Reference	Conclusions
Geologic Resources and Soils	*preserving the unrivaled ... geological values associated with natural landscapes (ANILCA);* *preserving lands and waters containing nationally significant…, geological,… values (ANILCA);*	4.3.2.2 4.3.2.4	None of the alternatives would adversely impact these purposes and values of GBNPP.
Water Quantity	*preserving lands and waters containing nationally significant natural, ... values (ANILCA);*	4.4.2.2 4.4.2.4	None of the alternatives would adversely impact these purposes and values of GBNPP
Water Quality	*preserving lands and waters containing nationally significant natural, ... values (ANILCA);*	4.4.2.2 4.4.2.4	None of the alternatives would adversely impact these purposes and values of GBNPP
Air Quality	*preserving wilderness resources (ANILCA);*	4.5.2.2 4.5.2.4	None of the alternatives would adversely impact these purposes and values of GBNPP

Table 6.1-1. GBNPP purposes and values for each resource.

Resources	GBNPP Purposes and Values[a]	Section Reference	Conclusions
Fisheries	*allowing Glacier Bay National Park to remain " ... [a] large sanctuary where fish ... may roam free, developing their social structure and evolving over long periods of time as nearly as possible without the changes that extensive human activities would cause." (ANILCA)*	4.6.2.2 4.6.2.4	None of the alternatives would adversely impact these purposes and values of GBNPP
Vegetation and Wetlands	*preserving and protecting a great variety of forest consisting of mature areas and bodies of youthful trees which have become established since the retreat of the ice and should be preserved in absolutely natural condition and bare areas, which will become forested during the next century (proclamation);* *preserving the natural, unaltered state of arctic tundra, boreal forest and the coastal rain forest ecosystem (ANILCA);*	4.7.2.2 4.7.2.4	None of the alternatives would adversely impact these purposes and values of GBNPP

Table 6.1-1. GBNPP purposes and values for each resource.

Resources	GBNPP Purposes and Values[a]	Section Reference	Conclusions
Wildlife	*maintaining sound populations of, and habitat for, wildlife species of inestimable value to the citizens (ANILCA);* *allowing Glacier Bay National Park to remain " ... [a] large sanctuary where ... wildlife may roam free, developing their social structure and evolving over long periods of time as nearly as possible without the changes that extensive human activities would cause." (ANILCA)* *preserving lands and waters containing nationally significant ... wildlife values (ANILCA);*	4.8.2.2 4.8.2.4	None of the alternatives would adversely impact these purposes and values of GBNPP
Cultural Resources	*preserving lands and waters containing nationally significant ..., historical, archeological, ... values (ANILCA);*	1.8.1	None of the alternatives would adversely impact these purposes and values of GBNPP.

Table 6.1-1. GBNPP purposes and values for each resource.

Resources	GBNPP Purposes and Values[a]	Section Reference	Conclusions
	preserving lands and waters containing nationally significant ..., cultural, ... values (ANILCA);	4.9.2.2 4.9.2.4	None of the alternatives would adversely impact these purposes and values of GBNPP
Soundscape/Noise	*allowing Glacier Bay National Park to remain " ... [a] large sanctuary ... without the changes that extensive human activities would cause." (ANILCA)*	4.10.2.2 4.10.2.4	None of the alternatives would adversely impact these purposes and values of GBNPP
Visual Resources and Aesthetics	*preserving lands and waters containing nationally significant ..., scenic, ... values (ANILCA);preserving the unrivaled scenic ... values associated with natural landscapes (ANILCA);*	4.11.2.2 4.11.2.4	None of the alternatives would adversely impact these purposes and values of GBNPP.

Table 6.1-1. GBNPP purposes and values for each resource.

Resources	GBNPP Purposes and Values[a]	Section Reference	Conclusions
Recreation	*preserving lands and waters containing nationally significant ..., recreational ... values (ANILCA);* *preserving ... related recreational opportunities (ANILCA);*	4.12.2.2 4.12.2.4	None of the alternatives would adversely impact these purposes and values of GBNPP
Wilderness	*preserving wilderness resources ... (ANILCA);* *preserving lands and waters containing nationally significant ..., wilderness, ... values (ANILCA);*	4.13.2.2 4.13.2.4	None of the alternatives would adversely impact these purposes and values of GBNPP

[a] GBNPP purposes and values are fully described in section 1.7.4, *National Parks Enabling Legislation*.

6.1.1.4 Economic Feasibility. The Commission, following guidelines articulated in Mead Corporation, Publishing Paper Division (72 FERC &61,027, July 13, 1995), employs an analysis that uses current costs to compare the costs of the project and likely alternative power with no forecasts concerning potential future inflation, escalation, or deflation beyond the license issuance date. Chapter 5, *Developmental Analysis*, of this final EIS presents this analysis, which provides a general estimate of the potential power benefit, the costs of the project, and reasonable alternatives to the project power.

The Act, however, states that the exchange of lands may occur only if the Commission determines that the construction and operation of the hydroelectric project can be accomplished in an economically feasible manner. The Act provides no specific language or information to define economic feasibility, and the Commission's developmental analysis presents a specific, limited viewpoint of economic feasibility. Therefore, in the following section, we provide a broader economic analysis of the Falls Creek Hydroelectric Project.

6.1.1.4.1 Stakeholder Comments and Analyses

In response to the publication of the draft EIS, one individual, the applicant, and two organizations submitted economic analyses of the proposed project. Appendix E contains a discussion of this analyses which we summarize here.

Cutter Analysis. Eric Cutter (Cutter) filed a report on December 16, 2003, prepared by 100th Meridian for the Sierra Club entitled *Economic Analysis of the Proposed Gustavus Electric Falls Creek Hydro Project and Potential Alternatives*. This report does not provide a complete analysis of the economics of the proposed project, but it does examine certain related variables:

- electric demand and load growth;
- required generation versus sales;
- construction and operating costs;
- financing and rates;
- project firm capacity; and
- GEC rates versus rates in similar communities.

Cutter also discusses overall generation costs throughout his report when justifying the impact of the above-mentioned variables, although he does not submit a complete analysis or calculation methodology.

Cutter states that the above-mentioned variables show that proposed project costs are much higher than those for diesel generation from generating units currently operated by GEC, and, therefore, development of the project is not worth the associated impacts.

GEC Analysis. GEC filed comments on the draft EIS on January 2, 2004. GEC submitted comments on:

- project completion date;
- insurance, property tax, and income tax rates;
- term of analysis;
- financing terms, including interest rates, grant availability, and term of analysis;
- GBNPP interconnection costs;
- projected generation under minimum flow scenarios; and
- fuel-specific and general inflation values.

GEC performed a cost-benefit analysis to summarize its conclusions, which result in a benefit-cost ratio for the proposed project of 1.14 including GBNPP loads and 1.06 excluding park loads.

AIDEA Analysis. On January 6, 2004, the Alaska Industrial Development and Export Authority/Alaska Energy Authority (AIDEA) submitted an analysis prepared by the Financial Engineering Company. AIDEA's comments focus on draft EIS chapter 5 in the following areas:

- discount and inflation rates;
- additional capacity requirements;
- project operating costs;
- the GEC/GBNPP interconnection; and
- a discussion of the draft EIS analysis, as well as AIDEA's own analysis.

AIDEA concludes that, based on its analysis of project economics including use of its values for the variables discussed above, the project would realize a cumulative net benefit of about $2,500,000 over a 30-year period.

NHI Analysis. On January 6, 2004, the National Heritage Institute (NHI) submitted a report prepared by 100th Meridian entitled *Comments on the Economic Analysis in the Draft Environmental Impact Statement for the Falls Creek Hydroelectric Project (P-11659).* NHI commented on both chapters 5 and 6 covering the following issues:

- the potential for and timing behind the decision to interconnect to serve GBNPP load;
- the need to account for additional environmental enhancement costs to address Section 3(C)(3) of the Act;

- the absence of costs including depreciation, return on rate base, recovery of taxes, and GBNPP transmission line construction;
- load growth in the GEC service area;
- the need for additional capacity in the GEC service area;
- financing costs related to project construction;
- a skew created by the current cost methodology in the developmental analysis;
- income taxes related to project operation; and
- an assessment of GEC's final rates to consumers, including an analysis of generation versus sales.

NHI concludes that the cost of generation to ratepayers would be between $290 and $310/MWh if park load were excluded and between $350 and $440/MWh if park load were connected and the cost of transmission to connect the park was $2.250 million. These values are higher than the $130/MWh cost of diesel generation from generating units currently operated by GEC.

6.1.1.4.2 Independent Commission Analysis

To perform our independent analysis of the economics of the proposed hydroelectric project, we determined the cost of hydroelectric generation versus diesel generation from existing generating units. The cost of hydroelectric generation was computed based on standard utility rate-making practices, and the analysis included the assessment of cost escalation throughout the period of analysis. Appendix E gives the details regarding the methodology used in this analysis.

We examined several variables as part of our analysis:

- GEC system load growth, defined here as growth in the generation needed to serve the GEC system.

- General cost escalation, defined here as the overall rate of cost inflation.

- Diesel fuel cost escalation, defined here as the rate of inflation of the cost of diesel fuel over and above the general cost escalation.

- Equipment overhaul and replacement costs associated with diesel generation, defined here as the cost associated with overall and replacement of diesel-generating equipment currently servicing GEC system load.

- Grant availability, defined here as the amount of money available to GEC to defray project construction costs.

- Interest rate on debt, defined here as the overall cost of borrowing funds for project construction.

To examine the effect of a range of values for these variables on project economics, we developed the following five scenarios covering a range of assumed values for each variable: Low, Low-middle, Middle, High-middle, and High. We define the value for each variable under each scenario in appendix E. A general description of the values used for each variable under each scenario is provided below.

- Low estimate: the lowest reasonably expected value, assuming a change in market/economic conditions, that would decrease the value of the project versus the middle estimate.

- Low-middle estimate: a value that is possible under current market/economic conditions and would decrease the value of the project versus the middle estimate.

- Middle estimate: our opinion of the most likely value for a particular variable.

- High-middle estimate: a value that is possible under current market/economic conditions and would increase the value of the project versus the middle estimate.

- High estimate: the highest reasonably expected value, assuming a change in market/economic conditions, that would increase the value of the project versus the middle estimate.

We then compute and compare the following economic parameters of each scenario over a 30-year period:

- Present value of annual net benefit: the sum of the annual difference between the cost of generation from the proposed project versus the cost of diesel generation from generating units currently operated by GEC, discounted at the cost of debt.

- First year of positive annual net benefit: the year where the cost of diesel generation from generating units currently operated by GEC exceeds the cost of generation from the proposed project.

- Year of positive cumulative net benefit: the year where the discounted sum of the annual net benefit becomes positive.

As part of this economic analysis, we have attempted to address all reasonably foreseeable economic conditions, as analyzed in appendix E, that would be directly associated with the economics of the hydroelectric project. In order to conduct an economic analysis of the proposed hydroelectric project, it is necessary to estimate the amount of load that could be served by the project; this is an important aspect of our analysis. Based on our public record, future load could include current Gustavus customers plus some population-related load growth within Gustavus as well as interconnection to GBNPP. Therefore, we have evaluated five scenarios of possible load growth within Gustavus without interconnection to GBNPP and the same five scenarios with interconnection to GBNPP.

Comments on the draft EIS suggested that, in addition to evaluating the effect of including GBNPP load on the economics of the construction and operation of the proposed project, we should assess the potential cost of constructing a transmission line to connect GEC to GBNPP. We were also asked to account for line losses along any new transmission line that would be constructed to interconnect GEC and GBNPP and to treat the possible abandonment of the existing NPS diesel generation equipment as a stranded cost. Lastly, we were asked to assess how interconnection of GEC and GBNPP would affect the price of electricity for GBNPP.

All of these factors would be important economic considerations for any analysis of the costs, benefits, or practicality of GBNPP interconnecting with GEC; however, we have made no attempt in this document to assess whether GBNPP should interconnect with GEC or not. Such an analysis is beyond the scope of this proceeding. As specified in the Act, the Commission must determine if "the construction and operation of a hydroelectric power project … can be accomplished in an economically feasible manner." As indicated above, our analysis of the economics of the proposed hydroelectric project attempts to address all reasonably foreseeable economic conditions (i.e., possible future Gustavus and GBNPP load, diesel fuel costs, interest rates on debt, etc.) that would be directly associated with the hydroelectric project. Possible transmission line costs, transmission line losses, stranded NPS costs, and GBNPP electricity rates, hereafter referred to as interconnection costs, are beyond the scope of any analysis of the economics of the hydroelectric project, and we do not include them in our analysis.

Our economic analysis only addresses the economics of construction and operation of the hydroelectric project. We do not provide all of the economic and environmental analysis to support a decision on interconnection of GBNPP to GEC.

Results. Tables 6.1-2 and 6.1-3 show the summary measures of financial performance under each scenario with and without GBNPP load. Figures 6-1 and 6-2 show the annual net benefit for each scenario with and without GBNPP load, and figures 6-3 and 6-4 show the cumulative net benefit of each scenario with and without GBNPP load. Appendix E details the calculations associated with each estimate.

Table 6.1-2. Summary of financial performance measures, GBNPP load excluded. (Source: Preparers)

	Low Estimate	Low-Middle Estimate	Middle Estimate	High-Middle Estimate	High Estimate
Net present value	-$4,266,000	-$2,928,000	$1,521,000	$2,281,000	$4,786,000
Year annual net benefit realized	N/A[a]	2036	2016	2015	2010
Year cumulative net benefit realized	N/A[b]	N/A[b]	2025	2022	2013

[a] Diesel costs did not exceed the cost of hydropower during the 30 year period of analysis.

[b] The discounted sum of the annual net benefit was not positive during the 30 year period of analysis.

Table 6.1-3. Summary of financial performance measures, GBNPP load included. (Source: Preparers)[a]

	Low Estimate	Low-Middle Estimate	Middle Estimate	High-Middle Estimate	High Estimate
Net present value	-$2,876,000	-$1,621,000	$3,057,000	$3,927,000	$6,650,000
Year annual net benefit realized	N/A[b]	2032	2009	2008	2007
Year cumulative net benefit realized	N/A[c]	N/A[c]	2011	2009	2007

[a] The economic analysis only addresses the economics of the hydroelectric project. None of the costs of the interconnection of GBNPP to GEC are included in these estimates.

[b] Diesel costs did not exceed the cost of hydropower during the 30 year period of analysis.

[c] The discounted sum of the annual net benefit was not positive during the 30 year period of analysis.

Figure 6-1. Annual net benefit, GBNPP load excluded. (Source: Preparers)

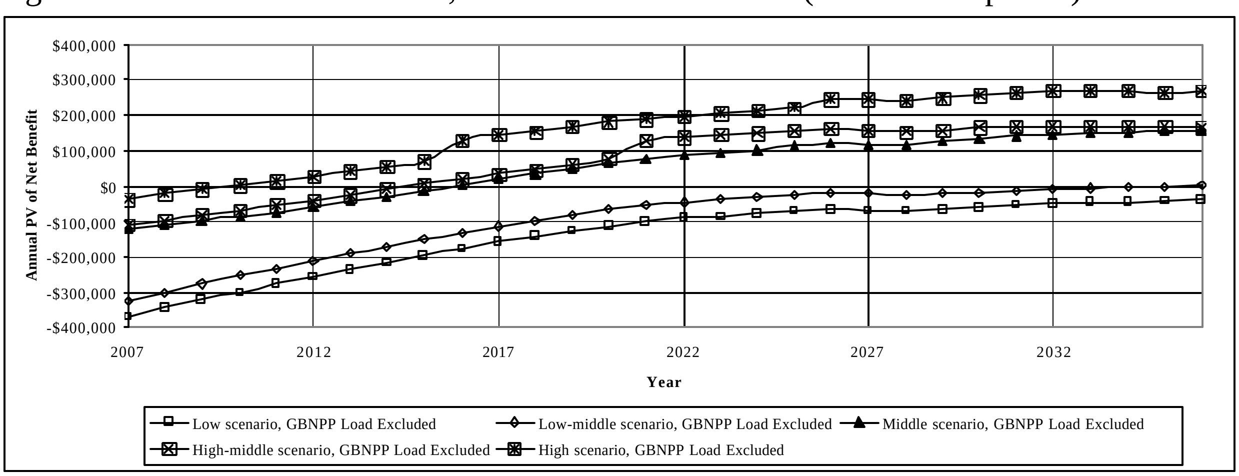
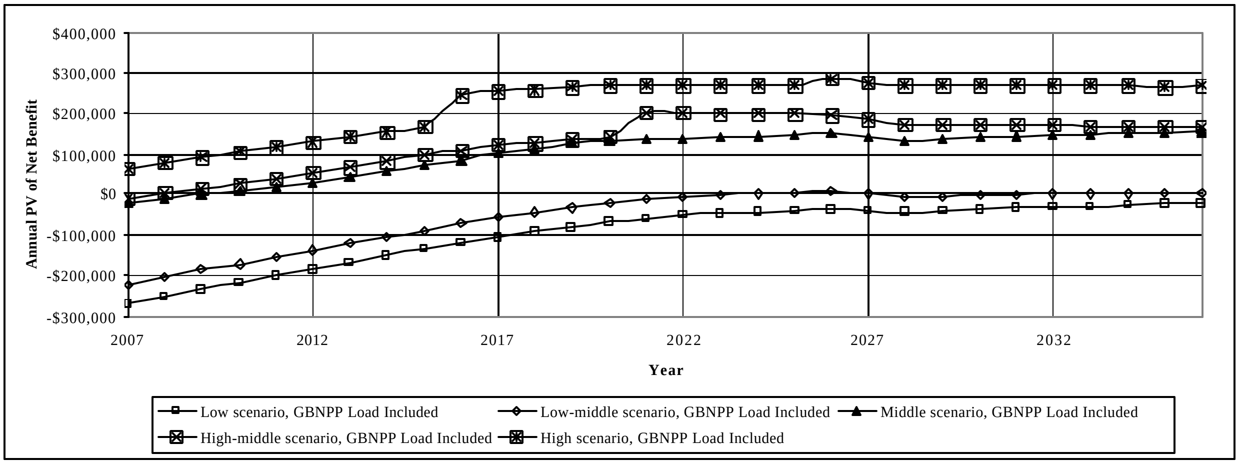


Figure 6-2. Annual net benefit, GBNPP load included. (Source: Preparers)[a]



[a] The economic analysis only addresses the economics of the hydroelectric project. None of the costs of the interconnection of GBNPP to GEC are included in these estimates.

Figure 6-3. Cumulative net benefit, GBNPP load excluded. (Source: Preparers)

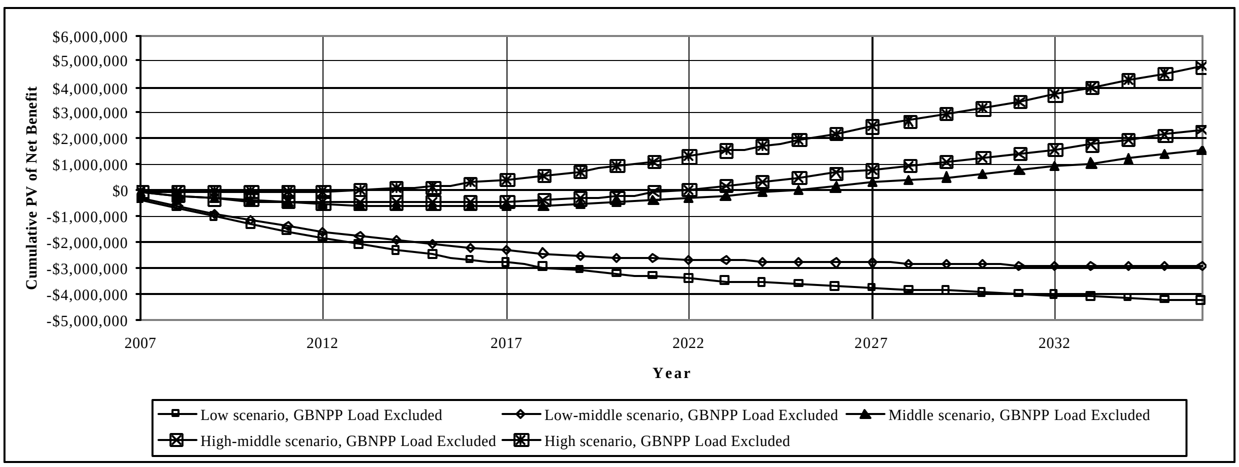
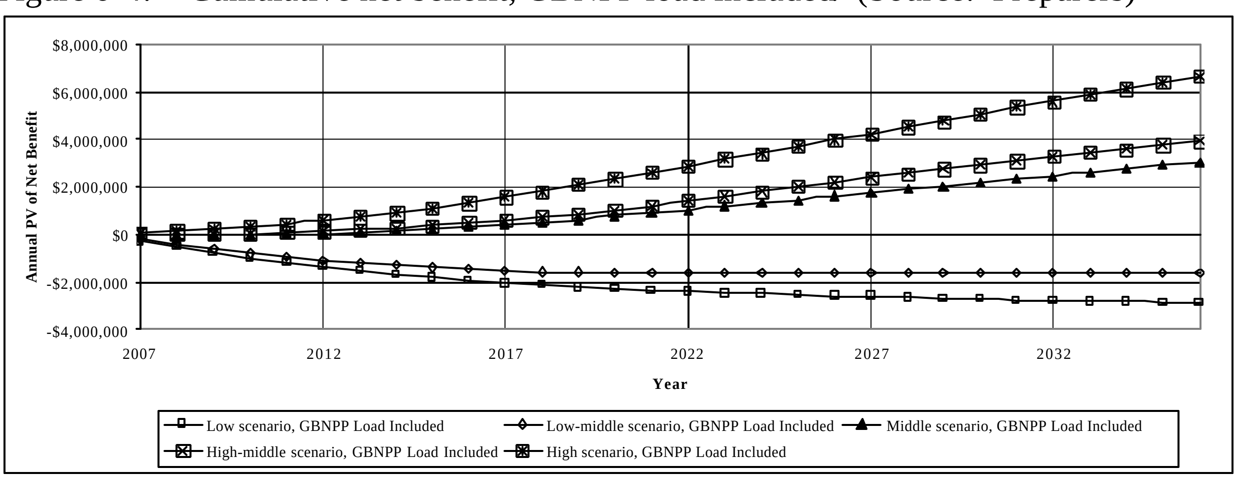


Figure 6-4. Cumulative net benefit, GBNPP load included. (Source: Preparers)[a]



[a] The economic analysis only addresses the economics of the hydroelectric project. None of the costs of the interconnection of GBNPP to GEC are included in these estimates.

As an examination of the sensitivity of each variable, table 6.1-4 presents the net present value as a function of each variable with all other variables held at the middle estimate value and with GBNPP load excluded.

Table 6.1-4. Effect of variation of individual variables on net present value. (Source: Preparers.)

Value	Net present value for each projection				
	Low Estimate	**Middle-Low Estimate**	**Middle Estimate**	**Middle-High Estimate**	**High Estimate**
Load growth	-$1,120,000	$937,000	$1,521,000	$1,578,000	$1,610,000
General cost escalation	$630,000	$698,000	$1,521,000	$1,369,000	$1,754,000
Diesel fuel cost escalation	$606,000	$1,021,000	$1,521,000	$1,476,000	$1,974,000
Other diesel generation costs	$1,197,000	$1,333,000	$1,521,000	$2,087,000	$2,332,000
Grant availability	$233,000	$233,000	$1,521,000	$1,521,000	$2,611,000
Interest rate on debt	-$690,000	-$273,000	$1,521,000	$1,808,000	$1,884,000

Discussion. The middle scenario, which uses the most likely value for each variable, shows that:

- Hydroelectric generation would be 58 percent more expensive than diesel generation in the first year of project operations.
- Hydroelectric generation would begin to cost less than diesel generation after the tenth year of project operations (2016), after which time hydroelectric generation would be less expensive than diesel generation.
- The project would realize a positive cumulative net benefit in the nineteenth year of project operations (2025).
- The net benefit of the proposed project would increase every year throughout the period of analysis.

- The cost per kilowatt-hour for hydroelectric generation would decline from the start of project operations through the 20th year of operations (2026), after which hydroelectric generation costs would increase slightly on an annual basis due to the payment of deferred taxes.

As previously stated, interconnection costs are not included in the economic analysis of the proposed hydroelectric project; however, our analysis does consider the economics of construction and operation of the proposed hydroelectric project with and without GBNPP load. Our results show that the cumulative net present value would be positive for the middle, middle-high, and high scenarios, whether GBNPP load is excluded or included.

With or without GBNPP load, the proposed project would yield a positive annual net benefit in four of the five scenarios; however, the low-middle scenario without GBNPP load did not yield a positive annual net benefit until 2036 (the last year of the analysis). Only the low estimate failed to yield a positive annual net benefit at any time during the period of analysis, with or without GBNPP load. Under three of the scenarios with the proposed project providing GBNPP load, the annual net benefit would be positive the first 3 years of the analysis.

In regard to cumulative net benefits, the proposed project would yield a positive benefit in three of the five scenarios, with or without GBNPP load. Under both the low and low middle scenarios, the proposed project fails to reach a positive cumulative net benefit at any time during the analysis, with or without GBNPP load. The middle, high-middle, and high scenarios without GBNPP load yield positive cumulative net benefits after 18, 15 and 6 years, respectively. With GBNPP load, the middle, high-middle, and high scenarios yield positive cumulative net benefits after 4, 2 and in the first year of analysis, respectively.

The middle scenario results in a positive net present value of about $1,521,000 when GBNPP load is excluded and $3,057,000 when GBNPP load is included.[56] Load growth and interest rate on debt have the greatest potential for decreasing the net present value of the project. Based on the sensitivity analysis, if GBNPP does not interconnect with GEC and load growth is slow, the net present value of the project would be greatly reduced below the middle scenario estimate and could become negative. Additionally, if the interest rate on debt is higher than the value we used for the middle scenario estimate, the net present value of the project could decrease significantly or become negative. The sensitivity analysis also indicates that load growth, grants, and other diesel generation costs have the greatest potential for increasing the net present value of the project. These factors would have the greatest potential to cause the net present value of the project to be significantly greater than the middle scenario.

[56] Estimates for scenarios that include GBNPP load do not include interconnection costs.

6.1.1.5 Boundary Determination. Section 4(e) of the FPA[57] authorizes the Commission to "issue licenses ... for the purpose of constructing, operating, and maintaining dams, water conduits, reservoirs, powerhouses, transmission lines, or other project works necessary for the development, transportation, and utilization of power ...." The FPA defines project works to include all water conduits and dams that are part of the unit of power development; all storage, diverting, or forebay reservoirs directly connected therewith; and all ditches, dams, and reservoirs that are necessary or appropriate in the maintenance and operation of the development unit.[58] In issuing licenses, the Commission must also include lands and land management regimes it determines are necessary for other, non-power beneficial public uses required by Section 10(a)(1) of the FPA.[59]

The Act states that the exchange of lands may occur only if the Commission determines, with the concurrence of the Secretary and the state of Alaska, the minimum amount of land necessary to construct and operate the hydroelectric project. The Act also states that the federal lands to be conveyed to the state of Alaska should be consistent with sound land management practices.

All lands removed from GBNPP would be conveyed to the state of Alaska; however, the lands contained within the project boundary would also be subject to FERC jurisdiction. During scoping, commenters indicated they were concerned about future use of the lands removed from GBNPP. These concerns focused on the potential for future development, mineral extraction, and/or motorized recreational use of the lands removed from GBNPP.

In this final EIS, we evaluate three action alternatives to assess how establishment of a project boundary could affect the potential future use of lands removed from GBNPP. We summarize the effects of these alternatives below.

Under GEC's Proposed Alternative, 850 acres of land currently within GBNPP would be conveyed to the state of Alaska. The FERC project boundary would include 117 acres of this land (75 acres of exchanged land and 42 acres of existing state and/or private land), and the Commission would have no jurisdiction over the remaining 775 acres of exchanged land. The FERC project boundary would encompass all the project facilities, including transmission lines, access roads, and the bypassed reach. Under this alternative, the Commission could include provisions to protect fish and wildlife within the 117 acres within the project boundary. To establish appropriate uses for lands within the project boundary, FERC staff recommend that the Commission require GEC to develop a land use management plan in consultation with the appropriate entities.

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57 16 U.S.C. §797(e).

58 FPA Section 3(11), 16 U.S.C. § 796(11).

59 Georgia Power Company, 32 FERC ¶ 61,237 at pp. 61,560-61 (1985).

Activities that could affect the conservation or protection of fish and wildlife within the project boundary (such as non-hydropower development, mineral extraction, and motorized recreational use) would be addressed under the plan. Because the remaining 775 acres of land would be outside the FERC project boundary, the plan would not apply to these lands.

Under the Maximum Boundary Alternative, the FERC project boundary would total 1,187 acres and consist of the 1,145 acres of exchanged land and 42 acres of existing state and/or private land. Under this alternative, the Commission would have the authority to require GEC to manage all of these lands consistent with the land use management plan and other measures recommended by FERC staff. None of the lands removed from GBNPP would be outside of the FERC project boundary.

Under the Corridor Alternative, the FERC project boundary would total 722 acres and consist of 680 acres of exchanged land and 42 acres of existing state and/or private land. The same set of circumstances described above for the Maximum Boundary Alternative would apply, except less land would be involved.

In comments on the draft EIS, the state of Alaska indicated that it would prefer that the Commission limit the extent of the FERC project boundary to minimize the encumbrances and conditions that may be placed on lands transferred to the state.

The FERC staff recommendation for a FERC project boundary, as well as the reasoning for this recommendation, is presented as part of the description of the preferred alternative in the following section.

6.1.2 PREFERRED ACTION ALTERNATIVE

If the Commission elects to issue a license for the Falls Creek Hydroelectric Project, construction and operation of the project would require completion of other actions including the exchange of federal and state lands and designation and de-designation of wilderness lands. In the following section, we describe our preferred alternative for each of these separate actions. Figure 6-5 (appendix A) shows the boundaries of this preferred action alternative.

6.1.2.1 GBNPP and Wilderness Boundary Adjustment. If the project is licensed, we recommend that the land exchanged to the state of Alaska should be the scenario described under the Maximum Boundary Alternative with one minor modification (described below). This land exchange scenario would result in adjusting the GBNPP boundary and reducing the amount of land in the park by approximately 1,050 acres. This amount of land would be slightly less (i.e., about 95 acres) than the total amount of land identified in the Act as potentially available for exchange from GBNPP.

Our analysis in chapter 4 indicates that the effects of construction and operation of the proposed hydroelectric project on environmental resources in the proposed project area would be the same under each land exchange and GBNPP boundary adjustment scenario. Differences among the possible land exchange and boundary adjustment scenarios result from possible effects on the remaining GBNPP lands, which we summarize below.

Under the land exchange scenario described under the Maximum Boundary Alternative (see figure 2-8 in appendix A), the park boundary would generally be further east from the proposed hydroelectric project than under GEC's proposal. Additional land between the bypassed reach, facilities, and roads would reduce the possibility of project-related effects, such as erosion or construction noise, from adversely affecting lands or resources within the park boundary. Under the GEC proposal, the GBNPP boundary would be along the eastern canyon rim of the Kahtaheena River (see figure 2-1 in appendix A). There would be a possibility that construction of the diversion dam could stimulate erosion or a landslide on the eastern bank of the Kahtaheena River canyon that could ultimately affect lands on the canyon rim; under GEC's proposal, these potential effects could occur within GBNPP. Because GBNPP would be further east and away from the canyon rim under the Maximum Boundary Alternative, there would be less chance for project-related erosion or landslides to affect the park. Additionally, because the GBNPP boundary would generally be further east under the Maximum Boundary Alternative than under GEC's proposal, there would be less potential for noise from construction activities to be heard within that portion of GBNPP.

The land exchange described under the Corridor Alternative would create two areas of GBNPP land that would no longer be contiguous with the rest of GBNPP. These lands would be to the south of the lands exchanged to the state with one parcel between the two Native allotments and the other parcel between the easternmost Native allotment and private/state land outside of the present park boundary (see figure 2-9 in appendix A). The isolation of NPS lands, especially designated wilderness lands, among private and state land is not consistent with sound land management principles. This alternative would adversely affect park management due to the increased demands on park staff to manage the isolated GBNPP land, monitor and protect park resources along the convoluted boundary and isolated GBNPP land, and control access along the GBNPP boundary. It would also create unnecessary administrative and management burdens between the state, NPS, and private land and Native allotments owners.

Additionally, under the Corridor Alternative, there would be slightly less land to serve as a buffer between the proposed project and the GBNPP boundary than under the Maximum Boundary Alternative (see figure 2-9 in appendix A). The amount of land east of the bypassed reach would be similar to the amount described under the Maximum Boundary Alternative and would be adequate to buffer most effects on GBNPP soil resources and soundscape. However, soundscape and wilderness attributes on the two isolated parcels of GBNPP land and the GBNPP land north of the corridor could be affected by noise and activity from project construction and operation due to the proximity of these lands to the project facilities and access road. When compared to the Corridor Alternative, the land exchange described under the Maximum Boundary Alternative would be more consistent with sound land management principles by not creating two isolated GBNPP parcels, and it would provide a greater buffer for project effects on the two isolated parcels and GBNPP lands to the north of the proposed project.

Our recommended modification of the Maximum Boundary Alternative (mentioned above) would consist of retaining, in GBNPP, 95 acres of land north of the diversion structure and south of The Islands area shown in figure 2-8 in appendix A. This modification would increase the amount of the upper watershed retained in GBNPP and include a portion of the Kahtaheena River downstream of the confluence with Black Creek that is considered valuable habitat for the upstream component of the resident Dolly Varden population. Most of the stream habitat upstream of the Upper Falls would remain within GBNPP, and NPS would have management and protection authority over most of the habitat believed to be important to the upstream component of the resident Dolly Varden population. Our analysis in chapter 4 indicates that these lands would not be affected by the proposed project and that implementation of any mitigation measures on these lands would be unnecessary. Lastly, because these lands are not needed for construction and operation of the proposed project, retaining them within the boundary of GBNPP would have no effect on the ability of GEC to develop the project.

Based on our analysis presented in chapter 4 and the discussion above, our preference for the wilderness de-designation and exchange of land from GBNPP to the state would be the Maximum Boundary Alternative with the one minor modification described above.

6.1.2.2 Conveyance of State Land to NPS. The final EIS considers the possibility of conveying state lands in either the Long Lake area near McCarthy in WSNPP or along Chilkoot Trail in KGNHP to the NPS. Under the preferred alternative, approximately 1,050 acres of GBNPP land would be exchanged to the state. The amount of land to be conveyed to NPS, according to the Act, would have sufficiently equal value (appraised) to satisfy federal and state law.

The NPS has not selected a preferred alternative for the land to be received from the state. The Act specifies that, if the Secretary and the state have not agreed on which lands the state of Alaska will convey within 6 months after issuance of the license, Long Lake lands are to be conveyed, subject to state consent, to the NPS within 1 year of issuance of the license. The Act does allow an extension of the above time periods as determined necessary by the Secretary should the processes of state law or federal law delay completion of an exchange.

6.1.2.3 Wilderness Boundary Adjustment. To maintain approximately the same amount of designated wilderness within the National Wilderness Preservation System that currently exists, under the preferred alternative approximately 1,050 acres of land in GBNPP would need to be designated wilderness. According to the Act, upon consummation of the land exchange land, in priority order, an unnamed island southeasterly of Blue Mouse Cove (789 acres), Cenotaph Island (280 acres), or Alsek Lake area (approximately 2,270 acres) shall be designated as wilderness.

The Act allows the Secretary to reasonably adjust the specific boundaries and acreage of these wilderness designations, consistent with sound land management principles, to be approximately equal, in sum, to the total wilderness acreage deleted. Given the criteria of the Act, both the unnamed island near Blue Mouse Cove and Cenotaph Island, totaling 1,069 acres, would be designated as wilderness because this is approximately equal in sum to the wilderness deleted from GBNPP.

6.1.2.4 The FERC Project Boundary. If the project is licensed, our preference for the FERC project boundary would be the boundary described under GEC's Proposed Alternative with modification (described below). The GEC proposed project boundary would encompass 117 acres of land including the powerhouse; the diversion dam and intake structures; the haulback site; and the transmission line, access road, and penstock corridors.

Our analysis in chapter 4 indicates that the effects of construction and operation of the proposed hydroelectric project on environmental resources would be the same under each of the FERC-designated project boundary scenarios that we evaluated. Differences among the project boundary scenarios result from differences in the possible management of the lands that would be transferred to the state of Alaska versus how these lands would be managed if kept within the project boundary.

The FERC project boundaries described under the Maximum Boundary and Corridor alternatives would encompass significantly greater amounts of land than with GEC's proposed FERC project boundary. Under each of these scenarios, lands within the FERC project boundary would be owned and managed by the state of Alaska, but they would also be subject to the terms and conditions of the FERC license. Specifically, if a license was issued to GEC and required development and implementation of a land use management plan, this plan would likely apply to all the lands within the FERC project boundary. Several commenters on the draft EIS indicated that certain undesirable land uses and/or activities should be restricted on the lands removed from GBNPP. These commenters recommended that all the lands removed from GBNPP should be included in the FERC project boundary and that FERC should require GEC to implement measures to restrict or discourage these undesirable actions, such as ATV use or private development of the state-owned land. Conversely, in comments on the draft EIS, the state indicated that it would prefer that the extent of the FERC project boundary be minimized. The state of Alaska indicated that limiting the extent of the FERC project boundary would allow it to manage the remaining lands removed from GBNPP without possible conflicts or encumbrances imposed by measures required in the FERC project license.

We believe that the project boundary proposed by GEC, with modifications proposed by FERC staff (described below) would constitute the minimum amount of land necessary for the construction and operation of a hydroelectric project, as specified by the Act.

In regard to modification of GEC's proposed project boundary, FERC staff recommend expanding the boundary proposed by GEC to include a 200 foot buffer around all project features. GEC's proposed project boundary would generally include a 30 to 50 foot buffer around project features. While this buffer would provide some ability to implement measures mitigating project-related effects, it is possible that some effects, such as surface erosion, would extend to areas beyond the 30 to 50 foot buffer. While a 200 foot buffer would not guarantee that all project-related effects would be contained within the project boundary, it would decrease the likelihood of unmitigated effects occurring on non-project lands. Therefore, we recommend that the project boundary be expanded beyond what GEC proposed to include a 200 foot buffer zone around all project features.

6.1.2.5 Recommended Measures for any Hydropower License. In section 6.1.1.1, *Comprehensive Development*, FERC staff list the measures they recommend for inclusion in any license, if one is issued.

6.2 FISH AND WILDLIFE AGENCY RECOMMENDATIONS

Under the provisions of the FPA, each hydroelectric license issued by the Commission would include conditions based on recommendations provided by federal and state fish and wildlife agencies for the protection, mitigation of damage to, and enhancement of fish and wildlife resources that would be affected by the project.

Section 10(j) of the FPA states that whenever the Commission finds that any fish and wildlife agency recommendation is inconsistent with the purposes and requirements of the FPA or other applicable law, the Commission and the agency shall attempt to resolve any such inconsistency, giving due weight to the recommendations, expertise, and statutory responsibilities of such agency.

Table 6.2-1 lists the federal and state fish and wildlife agency recommendations subject to Section 10(j), and indicates whether or not recommendations are adopted under the recommended alternative. Recommendations that FERC considers outside of the scope of Section 10(j) have been considered under Section 10(a) of the FPA and are addressed in the specific resources sections of this document (see chapter 4).

FERC staff made a preliminary determination that one recommendation by FWS, one recommendation by NMFS, and two recommendations by ADFG may be inconsistent with the purpose and requirements of the FPA or other applicable law. Two of the recommendations that we found to be inconsistent with the purposes and requirements of the FPA concerned minimum flows, and two concerned the need for a watershed protection plan. We notified each agency of our preliminary determinations in letters issued on November 12, 2003. In a letter filed with the Commission on December 23, 2003, ADFG indicated that the staff-recommended post-construction and operational plans would be adequate to address watershed issues in the Falls Creek basin and that a separate watershed protection plan would not be necessary. NMFS did not file a response.

In the draft EIS, we did not recommend adopting FWS's recommendation to provide interim seasonal minimum flows of 10 cfs in December through April, 20 cfs in May through September, 30 cfs in October, and 25 cfs in November, or inflow, whichever is less, to be finalized after 5 years of flow data are available and the hydrologic model and instream flow analyses are updated. ADFG made a similar recommendation, with the exception that flows in December would be 10 cfs and in May through September would be 25 cfs. The primary resources that could be adversely affected by reduced flows into the bypassed reach would be resident Dolly Varden and aesthetics. In section 4.6, *Fisheries*, we concluded that no minimum flow would eliminate the existing Dolly Varden population within the bypassed reach. Under the minimum flows proposed by GEC and recommended by agencies, the bypassed reach sub-population likely would persist; however, the minimum flows recommended by ADFG and FWS would provide more habitat and likely would sustain a greater portion of the current bypassed reach sub-population than GEC's proposed flows. Also, regardless of the flow in the bypassed reach, a portion of the Dolly Varden population in the Kahtaheena River would persist upstream of the proposed diversion site.

We concluded in section 4.11.2, *Visual Resources (Aesthetics)* that during July and August, when natural streamflows would be lower and visitation may be at its peak, flows over the Lower Falls would be higher under the agency-recommended minimum flows than under GEC's proposed minimum flows. However, as we discussed in section 6.1.1.1, the agencies' recommended flows would reduce generation by 23 to 26 percent and would cost $75,720 (ADFG) and $66,640 (FWS) annually, compared to 9.3 percent and $27,440 for GEC's proposed flows. Therefore, FERC staff found that FWS' and ADFG's recommendation may be inconsistent with the comprehensive planning standard of Section 10(a) and the equal consideration provision of Section 4(e) of the FPA.

In response to our preliminary determinations, ADFG and FWS filed letters on December 23, 2003, requesting a meeting to discuss their recommended minimum flows. FERC conducted a teleconference on January 30, 2004, in which representatives of ADFG, FWS, NMFS, GEC, and NPS participated. The agencies raised concerns about icing and the loss of potentially unique genetics due to the possible extirpation of the bypassed reach population of Dolly Varden. Participants in the meeting did not come to any agreement on minimum flows for the proposed project. No significant new information or effects were identified during the meeting; therefore, our recommendation regarding minimum flows in the bypassed reach is unchanged. However, as a result of the meeting, we have incorporated additional discussion about ice formation and effects on Dolly Varden genetics into this final EIS.

During the meeting, GEC indicated that it is continuing to talk to the agencies about minimum flows and that some sort of agreement may be reached in the future. No agreement had been filed with the Commission prior to issuance of this document.

Table 6.2-1. Fish and wildlife agency 10(j) recommendations.

Recommendation	Agency	Within the scope of 10(j)?	Annual Cost	Recommend Adopting?
1. Downstream fish screen and bypass facility	ADFG, NMFS[a]	Yes	$8,520[b]	Yes
2. Construct tailrace barrier	ADFG, NMFS	Yes	$23,800[b]	Yes
3. Fish passage facility evaluation plan	ADFG, FWS, NMFS	Yes	$5,000	Yes
4. Ramping rate not greater than 1 inch per hour	ADFG	Yes	$0	Yes. Recommended as part of flow monitoring plan.
5. Continuous stream gaging; provide data monthly in year one, annually thereafter	ADFG, FWS, NMFS	Yes	$870	Yes
6. 12-hour notice of non-compliance stream flow event	ADFG, FWS	Yes	$0	Yes. Recommended as part of flow monitoring plan.
7. Interim minimum instream flow regime; final flows established 5 years post-license	ADFG, FWS[c,d]	Yes	$48,280[d] (ADFG) $39,200[d] (FWS)	No. Lower minimum flows would provide adequate protection of fisheries at much less cost.
8. Run-of-river operation	ADFG	Yes	$0[b]	Yes

Table 6.2-1. Fish and wildlife agency 10(j) recommendations.

Recommendation	Agency	Within the scope of 10(j)?	Annual Cost	Recommend Adopting?
9. Biotic evaluation plan	ADFG, FWS, NMFS	Yes	$15,000	Yes
10. Biotic monitoring plan	NMFS	Yes	$5,000	Yes, as part of the biotic evaluation plan (item 9) which includes escapement counts of adult salmon in anadromous reaches.
11. Water quality sampling daily for turbidity from start of construction to 60 days after removal of temporary erosion control structures.	ADFG, FWS, NMFS	Yes	$960	Yes
12. Bear-human conflict plan	ADFG, FWS	Yes	$1,140	Yes
13. Sediment/large wood management plan	ADFG, NMFS	Yes	$570	Yes, as part of GEC's proposed sediment monitoring and management plan.
14. Road management plan	ADFG, NMFS	Yes	$5,710	Yes

Table 6.2-1. Fish and wildlife agency 10(j) recommendations.

Recommendation	Agency	Within the scope of 10(j)?	Annual Cost	Recommend Adopting?
15. Watershed protection plan	ADFG, NMFS	Yes	$570	No. Other recommended plans (i.e., public access and recreation development plan, land use management plan, road management, ESCP, sediment and large wood management) would adequately address this measure, and the agencies no longer support the need for this measure.
16. Wetland mitigation plan	ADFG, FWS, NMFS	Yes	$1,780	Yes
17. Public access plan	ADFG, FWS, NMFS	No; not a specific measure to protect fish and wildlife	$570	Yes. Recommended as part of a public access and recreation development plan that would address recreational enhancements, if needed, and public safety.
18. Recreation enhancement plan	ADFG, NMFS	No, not a specific measure to protect fish and wildlife	e	Yes. Recommended as part of a public access and recreation development plan that would include signage, brushing trails, and flow information.

Table 6.2-1. Fish and wildlife agency 10(j) recommendations.

Recommendation	Agency	Within the scope of 10(j)?	Annual Cost	Recommend Adopting?
19. Prohibit hunting, trapping and fishing by construction personnel	FWS	Yes	$0	Yes. Recommend GEC develop a plan to discourage fishing, hunting, and trapping by construction personnel.
20. Establish $50,000 escrow account for fish, wildlife and water quality enhancement	ADFG, FWS, NMFS	No; not a specific measure to protect fish and wildlife	$3,560	Yes
21. Annual consultation with agencies	ADFG, FWS, NMFS	No; not a specific measure to protect fish and wildlife	$0	Yes
22. On-site ECM during construction	ADFG, FWS, NMFS	Yes	$2,850	Yes
23. Require that the ECM be an on-site representative of ADFG who is qualified to issue or modify Alaska Title 16 Fish Habitat Permits	ADFG, FWS	No; not a specific measure to protect fish and wildlife	$0	No. Issuance and modifications of Alaska Title 16 Fish Habitat Permits is the responsibility of the state of Alaska.
24. Provide travel funding for an ADFG representative to inspect the project annually	ADFG	No; not a specific measure to protect fish and wildlife	$2,000	No. FERC regularly inspects licensed projects as part of its compliance monitoring responsibilities.

Table 6.2-1. Fish and wildlife agency 10(j) recommendations.

Recommendation	Agency	Within the scope of 10(j)?	Annual Cost	Recommend Adopting?
25. Construction timing restrictions in anadromous and non-anadromous reaches	ADFG, FWS, NMFS	Yes	$0	Yes
26. Erosion and sediment control plan	ADFG, FWS, NMFS	Yes	$570	Yes
27. Fuel and hazardous substances spill plan	ADFG, FWS, NMFS	Yes	$140	Yes
28. Free and unrestricted agency access	ADFG, FWS, NMFS	No, not a specific measure to protect fish and wildlife	$0	No. Access would be provided to state and federal resource management agency personnel in the performance of their official duties with adequate notification to licensee.
29. Oil and contaminant treatment plan	ADFG, FWS, NMFS	Yes	$570	Yes. Recommended inclusion of this item in fuel and hazardous substances plan in Item 27.

[a] Measures filed by NMFS under both Section 18 and 10(j). Similar measures are filed by FWS under Section 18 only.

[b] Included in GEC's proposal; therefore, there is no additional cost associated with this agency recommendation.

[c] Recommended flows vary by 5 cfs during the period May 1 through September 30 between the two agencies.

[d] Above cost of GEC's proposed flow regime.

[e] Cost included with recommendation No. 17.

6.3 CONSISTENCY WITH COMPREHENSIVE PLANS

Section 10(a)(2)(A) of the FPA requires that FERC consider the extent to which a hydroelectric project would be consistent with comprehensive plans for improving, developing, or conserving waterways affected by the project (16 U.S.C. § 803(a)(2)(A)). The following section evaluates the consistency of the Falls Creek Hydroelectric Project with the comprehensive plans that manage the lands within or adjacent to the proposed project area. Other resource plans that appear relevant but have not been included on FERC's list of recognized comprehensive plans are also addressed.

6.3.1 FERC Recognized Plans Relevant to the Falls Creek Hydroelectric Project

There are 29 plans identified in FERC's February 2004 list of comprehensive plans for the state of Alaska. Most are related to specific regions in the state. Only two plans are pertinent to the proposed project area or potential exchange lands.

1. Catalog of Waters Important for Spawning, Rearing, or Migration of Anadromous Fishes. 1998. Alaska Department of Fish and Game. Juneau, Alaska. And: Atlas to the Catalog of Waters Important for Spawning, Rearing, or Migration of Anadromous Fishes. 1998. Alaska Department of Fish and Game. Juneau, Alaska.

Alaska state statute 16.05.870 requires that ADFG identify the rivers, lakes, and streams or segments thereof that are important for the spawning, rearing, or migration of anadromous fish. The statute also requires that any entity proposing to use, divert, obstruct, pollute, change the flow of, construct in, or operate a vehicle in these specified water bodies must first obtain written approval from ADFG.

The “Catalog of Waters Important for Spawning, Rearing, or Migration of Anadromous Fishes” recognizes Falls Creek as Kahtaheena River (catalog stream number 114-23-10220). The accompanying Atlas and draft 2002 Atlas updates illustrate that the lower reach of the Kahtaheena River (below the Lower Falls) is utilized by coho (rearing) and pink (spawning) salmon in addition to cutthroat (rearing) and Dolly Varden (present) trout. Prior to any flow regime alterations or construction in the lower Kahtaheena River, written approval would need to be required from ADFG.

Under each project alternative, the flow regime in the anadromous reach of Kahtaheena River would not be altered, and construction would not occur in the lower reach. Therefore, each alternative would be consistent with the Catalog and Atlas.

2. Alaska’s Outdoor Legacy: Statewide Comprehensive Outdoor Recreation Plan (SCORP) 1997-2002. 1999. Alaska Department of Natural Resources. Juneau, Alaska.

This plan was prepared in accordance with the provisions of the federal Land and Water Conservation Fund Act of 1965. The SCORP is designed to assess the supply and demand for outdoor recreation and include implementing strategies for meeting the state's recreation needs through 2002.

The SCORP explains that Alaskan residents place a high value on outdoor recreation opportunities. The SCORP suggests that there is general satisfaction with existing recreation opportunities, but it also illustrates that there is support for expansion in some areas (table 6.3-1).

Table 6.3-1. Support for facility improvements and developments. (Source: SCORP, 1999)

Type of Recreation Development	**Percent Support**
Disabled accessible facilities	86
Public use cabins	79
Tent campgrounds	77
Trailheads along roads	76
Roadside toilets	74
Non-motorized trails	74
Road upgrade (park roads)	71
Picnic areas	68
New parks	67
RV dump stations	64
Boat launches	63
Recreation programs	61
Water/toilets in campgrounds	59
Off-road-vehicle trails	56
RV campgrounds	52
Visitor centers	49
Tourist resort facilities	41

In addition to the public preference information, the SCORP also states that, in southeastern Alaska, the top 10 recreation facility needs are: campgrounds and community parks; trails; recreational courts/fields; boat ramps and restrooms; upgrades of existing facilities; swim areas; winter sports areas; harbors; recreation complexes; and target ranges.

The SCORP describes potential methods for funding the recreation improvements needed in the state. Such strategies include federal grants, cooperative agreements, private developments, tourist dollars, and other methods.

The No-action Alternative would make no changes to existing recreation facilities and generally would be consistent with the SCORP. The other project alternatives propose no additional recreation facilities, but would provide increased recreational access to the Kahtaheena River area, which would be consistent with some of the objectives identified in the SCORP.

6.3.2 Other Relevant Resource Plans

In addition to the comprehensive plans from FERC's list, the following resource plans have been identified as potentially pertinent to the proposed project licensing.

1. Glacier Bay National Park and Preserve General Management Plan. 1984. Department of the Interior, National Park Service.

The General Management Plan for GBNPP discusses the natural resource, cultural resource, land protection, use and development goals for lands within the park. It also discusses potential boundary adjustments and wilderness designations for park lands. The majority of the park has been designated as wilderness, including the proposed project lands. These lands are managed in accordance with ANILCA, federal Wilderness Act, and NPS wilderness management policies.

Land uses in Glacier Bay National Preserve include temporary fish campsites and cabins for the continued exercise of valid commercial fishing rights and privileges, including the use of public lands for cabins, motorized vehicles, and aircraft landings on existing airstrips in the preserve. However, such uses must still be compatible with the preservation of fish and wildlife habitat. No additional developments are proposed by the management plan.

The No-action Alternative would have no effect on the manner in which NPS manages land in GBNPP and would be consistent with this plan. The proposed project would be constructed on lands removed from GBNPP, but adjacent to the park boundary. Our analysis suggests that construction and operation of the project would have no effect on the planned uses of GBNPP as constituted after the land exchange. Therefore, construction and operation of the proposed project would be consistent with this plan.

2. Wilderness Visitor Use Management Plan, Glacier Bay National Park and Preserve. 1989. Department of Interior National Park Service.

This later addendum to the 1984 General Management Plan specifically addresses visitor use of the designated wilderness areas, which comprise the majority of lands within GBNPP. The objectives of the plan are to:

a. Allow ecological processes to continue unimpaired by visitor use activities and patterns.
b. Preserve opportunities for outstanding aquatic and terrestrial wilderness experiences.
c. Protect specific sensitive species of wildlife and vegetation from adverse effects of visitor use.
d. Provide opportunities for visitors to gain a greater understanding of the park resources and values to help heighten the enjoyment of their visit.

e. Minimize the effects that motorized uses such as aircraft and motor boats may have on wilderness values and experiences.
f. Develop a greater understanding through research of those issues that are important to the other objectives mentioned above.
g. Monitor and evaluate the effects of the management program to provide information for modifications.
h. Make adjustments/modifications in the management program as needed based on monitoring and research information and public review and comment.

The No-action Alternative would have no effect on the manner in which NPS manages land in GBNPP and would be consistent with this plan. The proposed project would be constructed on wilderness lands removed from GBNPP, but adjacent to the park boundary. The proposed project would be constructed on lands removed from GBNPP, but adjacent to the park boundary. Our analysis indicates that this action would not affect the planned uses of GBNPP, as constituted after the land exchange. Therefore, construction and operation of the proposed project would be consistent with this plan.

3. Alsek River Visitor Use Management Plan, Glacier Bay National Park and Preserve. 1989. Department of Interior, National Park Service.

This later addendum to the 1984 General Management Plan specifically addresses visitor use in the Alsek River area. The Alsek River offers an uncommonly pristine experience, free for the most part of evidence of humans and their works. The plan recognizes that the wilderness experience in the area is sensitive to the number of people that use it. Policies and procedures guide management of visitor use of the portion of the Alsek River watershed within GBNPP. The objective is to manage recreation use of the Alsek River consistent with the overall objectives of the park, preserve, and designated wilderness. This plan establishes limitations pertaining to such things as number of float trips, numbers of people in a camping group, nights that can be spent at a campsite, use of motorized watercraft, and other issues relating to the preservation of the wilderness character of this area.

The No-action Alternative would have no effect on the manner in which NPS manages land in GBNPP and would be consistent with this plan. The proposed project would be constructed on lands removed from GBNPP, but adjacent to the park boundary. Our analysis indicates that this action would not affect the planned uses of GBNPP as constituted after the land exchange. Therefore, construction and operation of the proposed project would be consistent with this plan.

4. Northern Southeast Area Plan. 2002. Alaska Department of Natural Resources Division of Mining, Land, and Water.

The purpose of the plan is to establish a balanced combination of land for public and private purposes in an area that includes Gustavus and the potential exchange lands near KGNHP. Submerged lands (oceanic), uplands, and non-tidal waters are also included. According to the Alaska Constitution, state lands are to be managed for multiple uses. The Northern Southeast Area Plan explicitly details which uses are permissible in the planning area.

The proposed project area is identified in the plan, which states that, if conveyed to the state, the parcel is to be managed for water resources and fish and wildlife habitat. This designation specifically allows for development of a hydroelectric facility providing that the rest of the lands in the area remain undeveloped for the protection of fish and wildlife habitat.

The plan also states that the potential exchange parcels near KGNHP are to be managed in a manner consistent with NPS goals and objectives. Furthermore, the plan states that these lands are appropriate for transfer to NPS for management under KGNHP.

Under the No-action Alternative, the Kahtaheena River lands would remain within GBNPP and would not be under the authority of this plan. The plan provides for construction and operation of the proposed project; therefore, the project would be consistent with this plan.

6.4 RELATIONSHIP TO LAWS AND POLICIES

6.4.1 Water Quality Certification

ADEC has waived water quality certification for Commission-licensed hydroelectric projects in Alaska (letter from M. Brown, Commissioner, ADEC, Juneau, Alaska, on August 2, 1999); therefore, compliance with this act is not required for the alternatives evaluated in this final EIS.

6.4.2 Endangered Species Act

Section 7(a)(2) of the Endangered Species Act (ESA) (16 U.S.C.1531 et seq.) requires federal agencies to ensure that their actions are not likely to jeopardize the continued existence of federally listed threatened and endangered species, or result in the destruction or adverse modification of designated critical habitat. The following federally listed threatened or endangered species could occur in waters near the project area: humpback whale (*Megaptera novaeangliae*) and Steller sea lion (*Eumetopias jubatus*).

None of the proposed action alternatives would affect these species listed under ESA.

6.4.3 Magnuson-Stevens Act

The Magnuson-Stevens Fishery Conservation and Management Act (P.L. 104-297) is the governing authority for all fishery management activities that occur in federal waters within the 200 nautical mile limit of the United States. It addresses all sustainable fisheries through a regional management approach. The North Pacific Fishery Management Council is responsible for designating essential fish habitat (EFH) in the project region and for collecting, analyzing and reviewing annual data to define harvest levels for the subsequent year. EFH includes those waters and substrate needed by fish for spawning, feeding or growth to maturity (as defined in 50 CFR 600.10).

NMFS indicates, by letter dated February 5, 2002, that the proposed project would adversely affect areas designated as essential fish habitat for Pacific salmon in the Fishery Management Plan for the Alaska Salmon Fisheries. NMFS indicates that harm to EFH involves possible degradation or destruction of the stream and stream bed due to altered flow, sedimentation, erosion, and introduction of toxics. NMFS' recommendations filed pursuant to Section 10(j) of the FPA are also NMFS' EFH conservation recommendations. Our analysis and conclusions regarding these measures are presented in section 6.2.

6.4.4 Coastal Zone Management Act

Congress passed the Coastal Zone Management Act in 1972 to promote the orderly development and protection of the country's coastal resources. It establishes a voluntary partnership between the federal government and states to develop individual state programs to manage coastal resources. The Alaska Coastal Management Program (ACMP) implements legislation passed by the state of Alaska in 1977 and formalizes the state's management partnership with the federal government. A network of governmental and public interests is incorporated into the ACMP process, ensuring that all aspects of a project are considered during the state's review and approval process. A finding of consistency must be obtained before permits can be issued for project development.

GEC submitted a coastal project questionnaire and certification statement for consistency determination to the Alaska Division of Governmental Coordination on September 25, 1997. The state of Alaska has not yet completed its coastal zone management review. This review will be conducted by the ADNR, Office of Project Management and Permitting, after all resource agency authorization applications and supporting documents have been received, per 15 CFR 930.50 - 930.66 and 6 AAC50.425.

6.4.5 National Historic Preservation Act

Relicensing is considered an undertaking within Section 106 of the NHPA, as amended (Pub. L. 89-665; 16 U.S.C. 470). Section 106 requires that every federal agency "take into account" how each of its undertakings could affect historic properties. Historic properties include districts, sites, buildings, structures, traditional cultural properties, and objects that are eligible for inclusion in the National Register. As the lead federal agency for issuing a license, FERC is responsible for insuring that the licensee will take all the steps necessary to "evaluate alternatives or modifications" that could "avoid, minimize, or mitigate any adverse effects on historic properties" for the term of the project license. FERC must also consult with the SHPO, as well as with other land management agencies where the project may have an effect, and with Indian tribes who may have cultural affiliations with properties affected by the project. The overall review process involving Section 106 is administered by the Advisory Council on Historic Preservation, an independent federal agency, whose regulations implementing Section 106 (36 CFR Part 800) provide guidelines to planners and federal agencies for carrying out the intent of the Section 106 process. A principal purpose of these regulations is to provide a framework for resolving any conflict that might exist between historic preservation objectives and a proposed development project.

GEC's investigations of archaeological, historical, and traditional cultural properties revealed no properties eligible for inclusion on the National Register. NPS has conducted studies of potential traditional properties and has not identified any traditional cultural properties in the project area. Therefore, FERC staff conclude that each of the action alternatives would comply with the requirements of the NHPA.

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APPENDIX A
PROJECT LOCATION
AND FACILITIES FIGURES
ARE NON-INTERNET PUBLIC

APPENDIX B

GLACIER BAY NATIONAL PARK BOUNDARYADJUSTMENT ACT OF 1998

PUBLIC LAW 105-317
OCTOBER 30, 1998

Public Law 105-317
105th Congress

An Act to provide for an exchange of lands located near Gustavus, Alaska, and for other purposes.

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,

SECTION 1. SHORT TITLE.

This Act may be cited as the »Glacier Bay National Park Boundary Adjustment Act of 1998.=

SEC. 2. LAND EXCHANGE AND WILDERNESS DESIGNATION.

(a) IN GENERAL.—(1) Subject to conditions set forth in subsection (c), if the State of Alaska, in a manner consistent with this Act, offers to transfer to the United States the lands identified in paragraph (2) in exchange for the lands identified in paragraph (4), selected from the area described in section 3(b)(1), the Secretary of the Interior (in this Act referred to as the »Secretary=) shall complete such exchange no later than 6 months after the issuance of a license to Gustavus Electric Company by the Federal Energy Regulatory Commission (in this Act referred to as »FERC=), in accordance with this Act. This land exchange shall be subject to the laws applicable to exchanges involving lands managed by the Secretary as part of the National Park System in Alaska and the appropriate process for the exchange of State lands required by State law.

(2) The lands to be conveyed to the United States by the State of Alaska shall be determined by mutual agreement of the Secretary and the State of Alaska. Lands that will be considered for conveyance to the United States pursuant to the process required by State law are lands owned by the State of Alaska in the Long Lake area within Wrangell-St. Elias National Park and Preserve, or other lands owned by the State of Alaska.

(3) If the Secretary and the State of Alaska have not agreed on which lands the State of Alaska will convey by a date not later than 6 months after a license is issued pursuant to this Act, the United States shall accept, within 1 year after a license is issued, title to land having a sufficiently equal value to satisfy State and Federal law, subject to clear title and valid existing rights, and absence of environmental contamination, and as provided by the laws applicable to exchanges involving lands managed by the Secretary as part of the National Park System in Alaska and the appropriate process for the exchange of State lands required by State law. Such land shall be accepted by the United States, subject to the other provisions of this Act, from among the following State lands in the priority listed:

COPPER RIVER MERIDIAN

(A) T.6 S., R. 12 E., partially surveyed, Sec. 5, lots 1, 2, and 3, NE¼, S½NW¼, and S½. Containing 617.68 acres, as shown on the plat of survey accepted June 9, 1922.

(B) T.6 S., R. 11 E., partially surveyed, Sec. 11, lots 1 and 2, NE¼, S½NW¼, SW¼, and N½SE¼; Sec. 12; Sec.14, lots 1 and 2, NW¼NW¼. Containing 1,191.75 acres, as shown on the plat of survey accepted June 9, 1922.

(C) T.6 S., R. 11 E., partially surveyed, Sec. 2, NW¼NE¼and NW¼. Containing 200.00 acres, as shown on the plat of survey accepted June 9, 1922.

(D) T.6 S., R. 12 E., partially surveyed, Sec. 6. lots 1 through 10, E½SW¼ and SE¼. Containing approximately 529.94 acres, as shown on the plat of survey accepted June 9, 1922.

(4) The lands to be conveyed to the State of Alaska by the United States under paragraph (1) are lands to be designated by the Secretary and the State of Alaska, consistent with sound land management principles, based on those lands determined by FERC with the concurrence of the Secretary and the State of Alaska, in accordance with section 3(b), to be the minimum amount of land necessary for the construction and operation of a hydroelectric project.

(5) The time periods set forth for the completion of the land exchanges described in this Act may be extended as necessary by the Secretary should the processes of State law or Federal law delay completion of an exchange.

(6) For purposes of this Act, the term »land= means lands, waters, and interests therein.

(b) WILDERNESS.—(1) To ensure that this transaction maintains, within the National Wilderness Preservation System, approximately the same amount of area of designated wilderness as currently exists, the following lands in Alaska shall be designated as wilderness in the priority listed, upon consummation of the land exchange authorized by this Act and shall be administered according to the laws governing national wilderness areas in Alaska:

(A) An unnamed island in Glacier Bay National Park lying southeasterly of Blue Mouse Cove in sections 5, 6, 7, and 8, T. 36 S., R. 54 E., CRM, and shown on United States Geological Survey quadrangle Mt. Fairweather (D-2), Alaska, containing approximately 789 acres.

(B) Cenotaph Island of Glacier Bay National Park lying within Lituya Bay in sections 23, 24, 25, and 26, T. 37 S., R. 47 E., CRM, and shown on United States Geological Survey quadrangle Mt. Fairweather (C-5), Alaska, containing approximately 280 acres.

(C) An area of Glacier Bay National Park lying in T. 31. S., R. 43 E and T. 32 S., R. 43 E., CRM, that is not currently designated wilderness, containing approximately 2,270 acres.

(2) The specific boundaries and acreage of these wilderness designations may be reasonably adjusted by the Secretary, consistent with sound land management principles, to approximately equal, in sum, the total wilderness acreage deleted from Glacier Bay National Park and Preserve pursuant to the land exchange authorized by this Act.

(c) CONDITIONS.—Any exchange of lands under this Act may occur only if—(1)

following the submission of a complete license application, FERC has conducted economic and environmental analyses under the Federal Power Act (16 U.S.C. 791-828) (notwithstanding provisions of that Act and the Federal regulations that otherwise exempt this project from economic analyses), the National Environmental Policy Act of 1969 (42 U.S.C. 4321-4370), and the Fish and Wildlife Coordination Act (16 U.S.C. 661-666), that conclude, with the concurrence of the Secretary of the Interior with respect to subparagraphs (A) and (B), that the construction and operation of a hydroelectric power project on the lands described in section 3(b)—

(A) will not adversely impact the purposes and values of Glacier Bay National Park and Preserve (as constituted after the consummation of the land exchange authorized by this section);

(B) will comply with the requirements of the National Historic Preservation Act (16 U.S.C. 470-470w); and

(C) can be accomplished in an economically feasible manner;

(2) FERC held at least one public meeting in Gustavus, Alaska, allowing the citizens of Gustavus to express their views on the proposed project;

(3) FERC has determined, with the concurrence of the Secretary and the State of Alaska, the minimum amount of land necessary to construct and operate this hydroelectric power project; and

(4) Gustavus Electric Company has been granted a license by FERC that requires Gustavus Electric Company to submit an acceptable financing plan to FERC before project construction may commence, and the FERC has approved such plan.

SEC. 3. ROLE OF FERC.

(a) LICENSE APPLICATION.—(1) The FERC licensing process shall apply to any application submitted by Gustavus Electric Company to the FERC for the right to construct and operate a hydropower project on the lands described in subsection(b).

(2) FERC is authorized to accept and consider an application filed by Gustavus Electric Company for the construction and operation of a hydropower plant to be located on lands within the area described in subsection (b), notwithstanding section 3(2) of the Federal Power Act (16 U.S.C. 796(2)). Such application must be submitted within 3 years after the date of the enactment of this Act.

(3) FERC will retain jurisdiction over any hydropower project constructed on this site.

(b) ANALYSES.—(1) The lands referred to in subsection (a) of this section are lands in the State of Alaska described as follows:

COPPER RIVER MERIDIAN

Township 39 South, Range 59 East, partially surveyed, Section 36 (unsurveyed), SE¼SW¼, S½SW¼SW¼, NE¼SW¼, W½W½NW¼SE¼, and S½SE¼NW¼. Containing approximately 130 acres.

Township 40 South, Range 59 East, partially surveyed, Section 1 (unsurveyed), NW¼, SW¼, W½SE¼, and SW¼SW¼NE¼, excluding U.S. Survey 944 and Native allotment A-442; Section 2 (unsurveyed), fractional, that portion lying above the mean high tide line of Icy Passage, excluding U.S. Survey 944 and U.S. Survey 945; Section 11 (unsurveyed), fractional, that portion lying above the mean high tide line of Icy Passage, excluding U.S. Survey 944; Section 12 (unsurveyed), fractional, NW¼NE¼, W½NW¼SW¼NE¼, and those portions of NW¼ and SW¼ lying above the mean high tide line of Icy Passage, excluding U.S. Survey 944 and Native allotment A-442. Containing approximately 1,015 acres.

(2) Additional lands and acreage will be included as needed in the study area described in paragraph (1) to account for accretion to these lands from natural forces.

(3) With the concurrence of the Secretary and the State of Alaska, the FERC shall determine the minimum amount of lands necessary for construction and operation of such project.

(4) The National Park Service shall participate as a joint lead agency in the development of any environmental document under the National Environmental Policy Act of 1969 in the licensing of such project. Such environmental document shall consider both the impacts resulting from licensing and any land exchange necessary to authorize such project.

(c) ISSUANCE OF LICENSE.—(1) A condition of the license to construct and operate any portion of the hydroelectric power project shall be FERC=s approval, prior to any commencement of construction, of a finance plan submitted by Gustavus Electric Company.

(2) The National Park Service, as the existing supervisor of potential project lands ultimately to be deleted from the Federal reservation in accordance with this Act, waives its right to impose mandatory conditions on such project lands pursuant to section 4(e) of the Federal Power Act (16 U.S.C. 797(e)).

(3) FERC shall not license or relicense the project, or amend the project license unless it determines, with the Secretary=s concurrence, that the project will not adversely impact the purposes and values of Glacier Bay National Park and Preserve (as constituted after the consummation of the land exchange authorized by this Act). Additionally, a condition of the license, or any succeeding license, to construct and operate any portion of the hydroelectric power project shall require the licensee to mitigate any adverse effects of the project on the purposes and values of Glacier Bay National Park and Preserve identified by the Secretary after the initial licensing.

(4) A condition of the license to construct and operate any portion of the hydroelectric power project shall be the completion, prior to any commencement of construction, of the land exchange described in this Act.

SEC. 4. ROLE OF SECRETARY OF THE INTERIOR.

(a) SPECIAL USE PERMIT.—Notwithstanding the provisions of the Wilderness Act (16 U.S.C. 1133-1136), the Secretary shall issue a special use permit to Gustavus Electric Company to allow the completion of the analyses referred to in section 3. The Secretary shall impose conditions in the permit as needed to protect the purposes and values of Glacier Bay National Park and Preserve.

(b) PARK SYSTEM.—The lands acquired from the State of Alaska under this Act shall be added to and administered as part of the National Park System, subject to valid existing rights. Upon completion of the exchange of lands under this Act, the Secretary shall adjust, as necessary, the boundaries of the affected National Park System units to include the lands acquired from the State of Alaska; and adjust the boundary of Glacier Bay National Park and Preserve to exclude the lands transferred to the State of Alaska under this Act. Any such adjustment to the boundaries of National Park System units resulting from this Act shall not be charged against any acreage limitations under section 103(b) of Public Law 96-487.

(c) WILDERNESS AREA BOUNDARIES.—The Secretary shall make any necessary modifications or adjustments of boundaries of wilderness areas as a result of the additions and deletions caused by the land exchange referenced in section 2. Any such adjustment to the boundaries of National Park System units shall not be considered in applying any acreage limitations under section 103(b) of Public Law 96-487.

(d) CONCURRENCE OF THE SECRETARY.—Whenever in this Act the concurrence of the Secretary is required, it shall not be unlawfully withheld or unreasonably delayed.

SEC. 5. APPLICABLE LAW.

The authorities and jurisdiction provided in this Act shall continue in effect until such time as this Act is expressly modified or repealed by Congress.

Approved October 30, 1998.

LEGISLATIVE HISTORYCH.R. 3903 (S. 2109):
HOUSE REPORTS: No. 105-706, Pt. 1 (Comm. on Resources).
SENATE REPORTS: No. 105-306 accompanying S. 2109 (Comm. on Energy and Natural Resources).
CONGRESSIONAL RECORD, Vol. 144 (1998):
Sept. 15, considered and passed House.
Oct. 2, considered and passed Senate.
Oct. 8, Senate vitiated passage; reconsidered and passed, amended.
Oct. 10, House concurred in Senate amendments.

APPENDIX C

ANILCA SECTION 810(A)
SUMMARY OF EVALUATIONS AND FINDINGS

I. Introduction

This evaluation and finding was prepared to comply with Title VIII, section 810 of the Alaska National Interest Lands Conservation Act (ANILCA). The Glacier Bay National Park Boundary Adjustment Act of 1998 (P.L. 105-317) (The Act) contains provisions allowing for an exchange of designated wilderness land in Glacier Bay National Park and Preserve lands to the State of Alaska for the construction and operation of a hydroelectric plant. The ANILCA Section 810 analysis evaluates the potential restrictions to subsistence activities that could result from the construction and operation of a hydroelectric facility on Falls Creek (also known as the Kahtaheena River) and the exchange of NPS lands within Glacier Bay National Park, Wrangell-St. Elias National Park and Preserve, and Klondike Gold Rush National Historical Park. The proposed actions would be administered in accordance with ANILCA Section 1302, Land Acquisition Authority, and the laws governing national wilderness areas in Alaska. ANILCA Section 1302 authorizes the exchange of lands within the boundaries of NPS areas.

II. The Evaluation Process

Section 810(a) of ANILCA states:

> "In determining whether to withdraw, reserve, lease, or otherwise permit the use, occupancy, or disposition of public lands . . . the head of the Federal agency . . . over such lands . . . shall evaluate the effect of such use, occupancy, or disposition on subsistence uses and needs, the availability of other lands for the purposes sought to be achieved, and other alternatives which would reduce or eliminate the use, occupancy, or disposition of public lands needed for]-subsistence purposes. No such withdrawal, reservation, lease, permit, or other use, occupancy or disposition of such lands which would significantly restrict subsistence uses shall be affected until the head of such Federal agency:
>
> 1. gives notice to the appropriate State agency and the appropriate local committees and regional councils established pursuant to section 805;
>
> 2. gives notice of, and holds, a hearing in the vicinity of the area involved; and
>
> 3. determines that (A) such a significant restriction of subsistence uses is necessary, consistent with sound management principles for the utilization of the public lands, (B) the proposed activity would involve the minimal amount of public lands necessary to accomplish the purposes of such use, occupancy, or other disposition, and (C) reasonable steps would be taken to minimize adverse impacts upon subsistence uses and resources resulting from such actions."

Title II of ANILCA created the following new units and additions to existing units of the national park system in Alaska.

Wrangell-St. Elias National Park, containing approximately eight million one hundred and forty-seven thousand acres of public lands, and Wrangell-St. Elias National Preserve, containing approximately four million one hundred and seventeen thousand acres of public lands, were created by ANILCA, section 201(9), for the following purposes:

> "The park and preserve shall be managed for the following purposes, among others: To maintain unimpaired the scenic beauty and quality of high mountain peaks, foothills, glacial systems, lakes, and streams, valleys, and coastal landscapes in their natural state; to protect habitat for, and populations of, fish and wildlife including but not limited to caribou, brown/grizzly bears, Dall sheep, moose, wolves, trumpeter swans and other waterfowl, and marine mammals; and to provide continued opportunities including reasonable access for mountain climbing, mountaineering, and other wilderness recreational activities. Subsistence uses by local residents shall be permitted in the park, where such uses are traditional, in accordance with the provisions of Title VIII."

ADDITIONS TO EXISTING AREAS

Glacier Bay National Monument was expanded by the addition of an area containing approximately five hundred and twenty-three thousand acres of federal land. Approximately fifty-seven thousand acres of additional public land was established as Glacier Bay National Preserve. The monument was re-designated as "Glacier Bay National Park." The monument addition and preserve was created by ANILCA, section 202(1), for the following purposes:

> "To protect a segment of the Alsek River, fish and wildlife habitats and migration routes and a portion of the Fairweather Range including the northwest slope of Mount Fairweather. Lands, waters, and interests therein within the boundary of the park and preserve which were within the boundary of any national forest are hereby excluded from such national forest and the boundary of such national forest is hereby revised accordingly."

> "To protect habitats for, and populations of, fish and wildlife including, but not limited to, high concentrations of brown/grizzly bears and their denning areas; to maintain unimpaired the water habitat for significant salmon populations; and to protect scenic, geological, cultural and recreational features."

ANILCA and National Park Service regulations do not authorize subsistence use on federal lands within Klondike Gold Rush National Historical Park.

III. Proposed Action on Federal Lands

The Act allows the potential for an exchange of lands within Glacier Bay National Park, with either lands in the Long Lake area of Wrangell-St. Elias National Preserve (WSNPP) near McCarthy, Alaska, or lands along the Chilkoot Trail in Klondike Gold Rush National Historical Park (KGNHP) to facilitate the potential development a hydroelectric facility on Falls Creek (also known as Kahtaheena River). The exchange involves the de-designation of wilderness land at Falls Creek and the designation of an approximately equal amount in GBNPP; in priority order, either at Blue Mouse Cove, Cenotaph Island or Alsek Lake. The maximum amount of land proposed for exchange is 1145 acres which would be satisfied by the designation of wilderness at Blue Mouse Cove and Cenotaph Island. The Act authorizes the Secretary of the Interior to adjust wilderness boundaries and acreage consistent with sound land management practices.

Proposed actions considered in the Environmental Impact Statement include:

<u>Alternative 1</u>: Under the No-action Alternative the project is not granted a license, and the wilderness designations and state-federal land exchanges described in the Act do not take place.

<u>Alternative 2</u>: Under Gustavus Electric Company (GEC) Proposed Action Alternative NPS would transfer some 850 acres of wilderness land, currently within GBNPP, to the state of Alaska, with the subsequent transfer of a commensurate amount of state land either in WSNPP or KGNHP to NPS. Within the land transferred to the state, GEC would develop a hydroelectric facility on the Kahtaheena River near the town of Gustavus.

<u>Alternative 3</u>: The Maximum Boundary Alternative would be the same as the GEC Proposed Action Alternative except that the entire 1,145 acres of land identified in section 3(b) of the Act, as potentially available for the development of a hydroelectric project, would be transferred to the state, and all the transferred land would be within the project boundary and would be subject to the Federal Energy Regulatory Commission (FERC) license conditions, restricting its use and development by the state of Alaska. Accordingly, the section of the Kahtaheena River that is below the diversion point and above the location where the water is return to the river would be included in the FERC project boundary. State land either in WSNPP or KGNHP would be transferred NPS.

Alternative 4: The Corridor Alternative would be essentially the same as GEC's Proposed Action Alternative except that the amount of land transferred to the state would be reduced. Approximately 680 acres of park land would be transferred to the state, and all transferred land would lie within the FERC project boundary. The land transfer would provide a minimum buffer distance of approximately 0.25 mile around all project features (i.e., roads, penstock, transmission line rights-of-way, borrow pit and disposal sites, diversion site, and powerhouse) except along the eastern boundary, where a 0.25-mile buffer would fall outside the lands identified as potentially available for development of a project in the Act. State land either in WSNPP or KGNHP would be transferred NPS.

IV. Affected Environment

Subsistence uses, as defined by ANILCA, Section 810, means 'The customary and traditional use by rural Alaska residents of wild, renewable resources for direct personal or family consumption as food, shelter, fuel, clothing, tools, or transportation; for the making and selling of handicraft articles out of non-edible byproducts of fish and wildlife resources taken for personal or family consumption; for barter, or sharing for personal or family consumption; and for customary trade." Subsistence activities include hunting, fishing, trapping, and collecting berries, edible plants, and wood or other materials.

ANILCA and National Park Service regulations authorize subsistence use of resources in all Alaska national parks, monuments and preserves with the exception of Glacier Bay National Park, Klondike Gold Rush National Historical Park, Katmai National Park, Kenai Fjords National Park, "old" Mount McKinley National Park, and Sitka National Historical Park (Codified in 36 CFR part 13, Subparts A, B, and C). ANILCA provides a preference for local rural residents over other consumptive users should a shortage of subsistence resources occur and allocation of harvest becomes necessary.

A summary of the affected environment pertinent to local subsistence uses for each NPS unit within the study area is presented in the following section.

Glacier Bay National Park and Preserve

Important subsistence use areas within the region include Icy Strait, Excursion Inlet, Lynn Canal, Tongass National Forest, and Glacier Bay National Preserve. Glacier Bay National Park lands are closed to subsistence uses. ANILCA, however, authorized subsistence uses on adjacent federal public lands.

Most of the rural communities of southeastern Alaska rely on renewable natural resources for at least a portion of their subsistence needs. About one-third of the rural communities of the region take at least half of their meat and fish by hunting and fishing (Holleman and Kruse, 1992).

Residents of such communities as Gustavus (429), Hoonah (860), Elfin Cove (32), Pelican (163), Excursion Inlet (10), Sitka (8,835) and Yakutat (680) engage in subsistence uses near the boundaries of Glacier Bay National Park. (*Population figures are 2000 estimates from the U.S. Census Bureau.*) Community resource gathering activities include such things as hunting, fishing, digging for clams, catching shellfish, gathering firewood, and collecting food items from berries to herring eggs. Historical resource utilization patterns, such as fish camps or communal deer hunts, are linked to traditional social and subsistence use patterns. Sharing of resource occurs between communities, as well as within communities throughout the region.

Some of the major resources used for subsistence in these communities are bears (black and brown), deer, goat, moose, furbearers, spruce grouse, ptarmigan, waterfowl, marine mammals, salmon, trout, halibut, crab, clams, berries and other edible plants (such as wild celery, ferns, and kelp), alder, spruce, and other wood resources (Kruse and Muth, 1990).

Klondike Gold Rush National Historical Park

Federal lands within Klondike Gold Rush National Historical Park are closed to subsistence uses. Other federal lands adjoining the park in the Tongass National Forest are open for subsistence uses as allowed under federal regulations. Regional subsistence activities that occur include hunting, fishing, trapping, berry picking, and plant gathering. Black bear, moose, fish, furbearers, small mammals, berries, other edible plants, and wood constitute the major subsistence resources used by local residents in region.

Wrangell-St. Elias National Park and Preserve

Subsistence uses by local rural residents are allowed in Wrangell-St. Elias National Park and Preserve which, together, constitute approximately 13.2 million acres. "Based on 2000 US Census data compiled by the Alaska Department of Community and Economic Development, the National Park Service estimates that approximately 6,000 individuals are eligible to engage in subsistence activities in the park and preserve."

Most subsistence hunting within WSNPP occurs off of the Nabesna, McCarthy, and Kotsina roads and on the Malaspina Forelands. The Copper and Chitina rivers also provide access via watercraft. The upper Chitina River, upper Chisana River, Nabesna River, and the Copper River drainages contain significant populations of salmon, caribou, moose, Dall sheep, and bear.

Subsistence users in the Long Lake area within WNSPP utilize the area off of the McCarthy Road. Subsistence users of Long Lake fish for trout, grayling, and burbot. Long Lake provides the only opportunity in the area to find such a quantity, and variety of fish. Hunting in the area is for moose, grouse, rabbit, and bear. Gathering activities include opportunities to collect high and low bush cranberries, as well as currants. Subsistence users trap a variety of animals, including, wolf, coyote, wolverine, lynx, marten, mink, and occasionally beaver.

V. Subsistence Uses and Needs Evaluation

Potential Impacts on Subsistence Users

To determine the potential impacts on existing subsistence activities for the preferred action as outlined in the EIS, three evaluation criteria were analyzed relative to existing subsistence resources:

- the potential to reduce important subsistence fish and wildlife populations by (a) reductions in number, (b) redistribution of subsistence resources, or (c) habitat losses;
- what effect the action might have on subsistence fisherman or hunter access;
- the potential for the action to increase fisherman or hunter competition for subsistence resources.

Construction and operation of hydroelectric facility

Under the no action alternative, the proposed hydroelectric facility would not be constructed and there would be no effects on subsistence activities.

Under Alternatives 2, 3, and 4, the proposed action in relation to the construction and operation of the hydroelectric facility would be the same for each alternative. The impacts on subsistence activities are described below.

1. The potential to reduce populations

(a) Reduction in Numbers:

The construction and operation of the proposed hydroelectric facility has the potential to impact the fisheries resources of the Kahtaheena River. Important species for subsistence include Dolly Varden Char. Currently, all of the land that would be within the project boundary for the hydroelectric facility is not open to subsistence use. Other species, i.e. black bear, small mammals, berries, wood, etc., that are utilized on a regional basis are not expected to experience a reduction in numbers. The proposed project is located in the vicinity of Tongass National Forest, the location of a high amount of subsistence use. As outlined in the EIS, the reduction in Dolly Varden Char is expected to be minor.

(b) Redistribution of Resources:

The construction and operation of the proposed hydroelectric facility has the potential to impact the fisheries resources of the Kahtaheena River. Important species for subsistence include Dolly Varden Char. Currently, all of the land that would be within the project boundary for the hydroelectric facility is not open to subsistence use. Other species, i.e. black bear, small mammals, berries, wood, etc., that are utilized on a regional basis are not expected to experience redistribution. As outlined in the EIS, any redistribution in Dolly Varden Char is expected to be minor.

(c) Habitat Loss:

The construction and operation of the proposed hydroelectric facility has the potential to impact the fisheries resources of the Kahtaheena River. Important species for subsistence include Dolly Varden Char. Currently, all of the land that would be within the project boundary for the hydroelectric facility is not open to subsistence use. Other species, i.e. black bear, small mammals, berries, wood, etc., that are utilized on a regional basis are not expected to experience a loss of habitat. As outlined in the EIS, the habitat loss for Dolly Varden Char is expected to be minor.

2. Restriction of Access

The construction and operation of the proposed hydroelectric facility has the potential to impact access to the Kahtaheena River. Currently, all of the land that would be within the project boundary for the hydroelectric facility is not open to subsistence use. GEC has proposed allowing access to the area via the access road. This change in availability of lands will not restrict access for subsistence use.

3. Increase in Competition

The construction and operation of the proposed hydroelectric facility has the potential to impact access to the Kahtaheena River. Currently, all of the land that would be within the project boundary for the hydroelectric facility is not open to subsistence use. GEC has proposed allowing access to the area via the access road. This change in availability of lands will not restrict access for subsistence use or other recreational users. Because the area has not been open to subsistence use, the proposed action is not expected to result in an increase in competition for subsistence resources. The continued implementation of provisions of ANILCA Title VIII should ensure a subsistence priority on federal lands within the region.

Exchange of lands

Glacier Bay National Park and Preserve

As stated in the enabling legislation for GBNPP, the lands at Falls Creek, Blue Mouse Cove and Cenotaph Island are not open to subsistence uses. Since subsistence uses are not authorized in these areas, there is no effect on any of the resources outlined above.

For lands in GBNPP at Alsek Lake, Alternative1 would not incur an exchange of lands and would, therefore, have no effect on subsistence use in the area. For each of the Alternatives 2, 3, and 4, there is the potential to change the designation of between 680 and 1,145 acres of land to wilderness. The impacts of this potential change in land designation are addressed below.

1. The potential to reduce populations

(a) Reduction in Numbers:
A change in the designation of the area would have little to no effect on how the area is managed. Since the management of the area would not change, the proposed action is not expected to cause the displacement of species that are utilized for subsistence.

(b) Redistribution of Resources:
A change in the designation of the area would have little to no effect on how the area is managed. Since the management of the area would not change, the proposed action is not expected to cause the redistribution of species that are utilized for subsistence.

(c) Habitat Loss:
A change in the designation of the area would have little to no effect on how the area is managed. Since the management of the area would not change, the proposed action is not expected to cause any habitat loss.

2. Restriction of Access

A change in the designation of the area would have little to no effect on how the area is managed. Since the management of the area would not change, the proposed action is not expected to change access to the area.

3. Increase in Competition

A change in the designation of the area would have little to no effect on how the area is managed. Since the management of the area would not change, the proposed action is not expected to result in an increase in competition for subsistence resource on lands that are only open to eligible subsistence users. The continued implementation of provisions of ANILCA Title VIII should ensure a subsistence priority on federal lands within the region.

<u>Wrangell-St. Elias National Park</u>

For lands in WSNPP, Alternative1 would not incur an exchange of lands and would, therefore, have no effect on subsistence use in the area. For each of the Alternatives 2, 3, and 4, there is the potential to change the designation of between 680 and 1,145 acres of land to wilderness. The impacts of this potential change in land designation are addressed below.

1. The potential to reduce populations

(a) Reduction in Numbers:
A change in the designation of the area would have little to no effect on how the area is managed. Since the management of the area would not change, the proposed action is not expected to cause the displacement of species that are utilized for subsistence.

(b) Redistribution of Resources:
A change in the designation of the area would have little to no effect on how the area is managed. Since the management of the area would not change, the proposed action is not expected to cause the redistribution of species that are utilized for subsistence.

(c) Habitat Loss:
A change in the designation of the area would have little to no effect on how the area is managed. Since the management of the area would not change, the proposed action is not expected to cause any habitat loss.

2. Restriction of Access

A change in the designation of the area would have little to no effect on how the area is managed. Since the management of the area would not change, the proposed action is not expected to change access to the area.

3. Increase in Competition

A change in the designation of the area would have little to no effect on how the area is managed. Since the management of the area would not change, the proposed action is not expected to result in an increase in competition for subsistence resource on lands that are only open to eligible subsistence users. The continued implementation of provisions of ANILCA Title VIII should ensure a subsistence priority on federal lands within the region.

Klondike Gold Rush National Historic Park

As stated in the enabling legislation for KGNHP the lands to be designated wilderness are not open to subsistence uses. Since subsistence uses are not authorized in these areas, there is no effect on any of the resources outlined above.

VI. Availability of Other Lands

There are no other lands that have been identified. The land exchange parcels were identified as a part of the Glacier Bay National Park Boundary Adjustment Act of 1998.

VII. Findings

This analysis concludes that the proposed action would not result in a significant restriction of subsistence uses.

APPENDIX D

RESPONSES TO COMMENTS ON THE FALLS CREEK HYDROELECTRIC PROJECT AND LAND EXCHANGE DRAFT ENVIRONMENTAL IMPACT STATEMENT

APPENDIX D
RESPONSES TO COMMENTS ON THE
FALLS CREEK HYDROELECTRIC PROJECT
AND LAND EXCHANGE
DRAFT ENVIRONMENTAL IMPACT STATEMENT

The Federal Energy Regulatory Commission (Commission or FERC) and the National Park Service (NPS) issued a draft environmental impact statement (EIS) for the relicensing of the Falls Creek Hydroelectric Project (FERC No. 11659-002) on October 30, 2003. The Commission and NPS requested comments pertaining to the draft EIS be filed by January 6, 2004. The following entities filed comments:

Commenting Entity	Acronym	Filing Date of Letter
Jenny Pursell	Pursell	November 17, 2003
Melanie Heacox	Heacox	November 24, 2003
Kenneth Marchbanks	Marchbanks	December 12, 2003
Eric Cutter	Cutter	December 16, 2003
Sam Hanlon, Sr.	Hanlon	December 18, 2003
Allison Banks	Banks	December 18, 2003
Wanda Culp	Culp	December 19, 2003
Ruth Niswander	Niswander	December 23, 2003
Dave Westman	Westman	December 23, 2003
Robert B. Robertson	Robertson	December 23, 2003
Lawrence E. Wilkinson, P.E.	Wilkinson	December 23, 2003
Lisa Mayo	Mayo	December 23, 2003
Patricia Jones	Jones	December 30, 2003
Richard Spotts	Spotts	December 30, 2003
Chad Schoen	Schoen	December 30, 2003
John Spezia	Spezia	December 30, 2003
Gustavus Electric Company	GEC	January 2, 2004
Jim Edelson	Edelson	January 2, 2004
Laurel Clark	Clark	January 2, 2004
Jed Davis	Davis	January 2, 2004
Clifford E. Anderson	Anderson	January 2, 2004
Professor and Mrs. Glen Schrank	Schrank	January 5, 2004

Commenting Entity	Acronym	Filing Date of Letter
State of Alaska ANILCA Implementation Program	AAIP	January 6, 2004
State of Alaska Department of Fish and Game	ADFG	January 6, 2004
Alaska Industrial Development and Export Authority	AIDEA	January 6, 2004
Natural Heritage Institute (Sierra Club et. al.)	NHI	January 6, 2004
Hoonah Indian Association	Hoonah	January 6, 2004
Chad Soiseth	Soiseth	January 6, 2004
Wayne Howell	Howell	January 6, 2004
Craig H. Wilson	Wilson	January 6, 2004
Individuals	Park Protection Form	January 6, 2004
Michael E. Bialas	Bialas	January 6, 2004
Robert Markeloff	Markeloff	January 8, 2004
Edward Cahill	Cahill	January 13, 2004
Robert Cherry	Cherry	January 13, 2004
Don Duke	Duke	January 13, 2004
Wilderness Watch	Wilderness	January 13, 2004
Jim and Denise Healy	Healy	January 13, 2004
Karen Jettmar	Jettmar	January 13, 2004
Bruce Kruger	Krugerb	January 13, 2004
William L. Kruger	Krugerw	January 13, 2004
Priscilla Mooney	Mooney	January 13, 2004
Gary Owen	Owen	January 2, 2004
David Pisaneschi	Pisaneschi	January 13, 2004
Sam Rice	Rice	January 13, 2004
Joe Vanderzandez	Vanderzandez	January 13, 2004
United States Environmental Protection Agency	EPA	January 13, 2004
John Swanson	Swanson	January 14, 2004
Robert E. Howe	Howe	January 15, 2004
William Patrick Lee, Sr.	Lee	January 15, 2004

Commenting Entity	Acronym	Filing Date of Letter
Friends of Glacier Bay	Friends	January 20, 2004
Donald D. and Martha V. Romero	Romero	January 21, 2004
Jeanie Farrell	Farrell	January 26, 2004
Tara Walker	Walker	February 9, 2004

NPS and the Commission received 436 identical form letters from different senders. The comments included in these letters are referred to as "Park Protection form letter" in this appendix.

In this appendix, we summarize the comments received, provide responses to those comments, and indicate where any change to the EIS occurs. We have not included in the table comments that reflect opinions with no supporting documentation, comments that do not address information in the draft EIS, comments that agree with or restate the information presented in the draft EIS, or comments that deal with minor correction and editorial revisions. Copies of the comments letters and the Park Protection form letter are included in appendix D.

	Comment	Response/Revision to the EIS
	General	
001	Portions of Rink Creek Road and the access road extending through section 3 cross private land with no state of Alaska easement. The state of Alaska would need to obtain legal access in the form of a limited state holding across section 3 from Rink Creek Road to the Access Road in section 2. This easement only needs to provide road access for the hydro project and to the state for inspection and maintenance and other uses authorized by the DNR and allowed within the FERC license restrictions. (AAIP)	Should a license be issued, the licensee would be required to obtain rights necessary for the construction and operation of the project. We have addressed your comment in section 4.15.2 of the final EIS.
002	The final EIS should address an alternative access route from Rink Creek Road through the existing 60 foot public access and utility easement of ASLS 790151 and ASLS 790152 to reduce the length of easement granted to the state from 2.25 miles to 0.25 miles. The transmission line could then be routed through the Mental Health Trust Land in section 4 to the airport, alleviating the congestion at the existing end of Rink Creek Road. (AAIP)	We have added a discussion of the access route that you have proposed (as we understand it) to sections 2.7 and chapter 4.0 of the EIS.
003	The state of Alaska requests minimizing the FERC project boundary to the smallest area needed (Alternative 2) to minimize the encumbrances and conditions on the state-acquired land. The state is unclear what the process is to arrive at the FERC license plans and what latitude the state of Alaska would have to manage the lands if they are a part	The Act indicates that the land exchange (and subsequent construction and operation of the project) cannot occur unless FERC concludes, with concurrence from the Secretary of DOI and the state of Alaska, the minimum amount of land necessary for the construction and operation of the project (Section 3 [b][3]). We have evaluated several different project boundary

	Comment	Response/Revision to the EIS
	of the FERC project boundary. (AAIP)	configurations in the EIS. This information will assist the Commission, DOI, and the state in selecting the appropriate project boundary if the project is licensed.
004	Clarify the procedures used to develop and implement the land use management plans before the license order is granted. Specifically, what would the state's involvement be in the development, implementation, oversight, and enforcement of post-licensing plans related to land use? Will GEC pay for time and resources needed for enforcement and management? Is this factored into the economic analysis? (AAIP)	As described in section 4.15.2.2, and section 6.1.1 of the final EIS, we are recommending that, should a license be issued, GEC be required to develop a land use management plan in consultation with appropriate state, federal, and private entities. This plan would only apply to the land within the FERC boundary. The state of Alaska would have sole jurisdiction over exchanged land outside of the FERC boundary. Since this plan would rely heavily on the provisions of the public access and recreation development plan, a reasonable approach would be to develop this plan simultaneously with the creation of the access and recreation plan. The costs for developing and implementing the land use management plan have been included in the cost of environmental measures detailed in section 5.3.
005	This action to place a portion of the buried transmission line across state airport property is subject to utility permits and transmission line burial would be stipulated. (AAIP)	The Commission would require a licensee to obtain the utility permits necessary to construct and operate the project should any license be issued for the project. We have added language to section 2.3.4 of the final EIS to address your comment.
006	A 6 month deadline for the land exchange is unrealistically optimistic. To meet the requirements of the Glacier Bay National Park Boundary Adjustment Act of 1998, it may be required to begin appraisals and surveys prior to issuance of a FERC license. The time lag between the issuance of the final EIS and the license may provide the time necessary. (AAIP)	The Act states that the Secretary of the Interior shall complete the land exchange no later than 6 months after the issuance of a license (Sec 2(a) (1) of the Act). However, as stated in section 1.2 of the final EIS (page 1-13 of the draft EIS), the Act also provides that the Secretary may extend this time period should the process of state or federal law delay completion of the exchange (Sec.2(a)(4) of the Act).
007	NHI requests that, pursuant to 40 CFR § 1502.14(e) and 40 CFR § 1502.9(c), the Commission and NPS publish a supplemental draft EIS that evaluates non-hydropower alternatives to the proposed action. NHI recommends that the supplemental draft EIS evaluate alternatives identified	Our discussion of these alternative energy sources is in section 1.1.3 of the EIS. We find no need to prepare a supplemental draft EIS.

	Comment	Response/Revision to the EIS
	in the November 5, 2003, report by 100th Meridian, "Economic Analysis of the Proposed Gustavus Electric Falls Creek Hydro Project and Potential Alternatives" and the January 6, 2004 report, "Comments on the Economic Analysis in the Draft Environmental Impact Statement for the Falls Creek Hydroelectric Project". These reports identify tidal energy, fuel cells, the Southeast Intertie, and energy conservation as potential alternatives to the proposed action. NHI also requests the opportunity to provide further comment on any supplemental draft EIS that is prepared. (NHI, Davis)	
008	Pursuant to 18 CFR § 385.1301 et seq., the Commission and NPS should undertake a joint hearing with RCA regarding the rates that GEC would charge to cover the project costs. (NHI)	GEC, as a certificated utility in Alaska, is regulated by the Regulatory Commission of Alaska (RCA) in regard to rate-making. The RCA would therefore be responsible for confirming rates charged by GEC if this project is developed.
009	Contact manufacturers of alternative renewable technologies, including Verdant Power, to discuss feasibility at sites in or near Gustavus. (NHI)	The Commission's regulations require a license applicant to consider alternative sources of energy. In its application, GEC filed information in response to this requirement. We discuss alternate energy sources in section 1.1.3 of the final EIS.
010	Direct GEC to file a water quality certification request with DEC to complete its application. (NHI)	As noted in section 6.4.1 of the draft EIS, ADEC has waived water quality certification for Commission-licensed hydroelectric projects in the state of Alaska. In a notice issued on December 11, 2001, the Commission accepted the application for license filed on October 23, 2000, for filing.
011	Respond to all comments by providing the letters with the corresponding responses adjacent to the comments. NHI requests a response to its comment letter; its exhibits, including Exhibit 6, which states the individual comments of the Sierra Club, Alaska Chapter, Juneau Group; and the incorporated Economic Analysis. (NHI)	We summarized the comments provided by the NHI and the comments of Sierra Club that are attached to the NHI filing and provide responses to the comments in this table. We reviewed the report prepared by Eric Cutter and based our revisions in section 6.1.1.4 of the final EIS on information presented in the report and in other comment letters. Copies of all comment letters are included in the final EIS.

	Comment	Response/Revision to the EIS
012	FERC staff concludes that GEC's proposal and two variations on it would not adversely impact the purposes and values of the GBNPP as constituted after the land exchange. However, the conclusion of the NPS staff on this key issue is missing, an omission that is particularly troubling because the NPS is the agency best qualified to evaluate the likely effects of the project on park values and resources. (NHI)	The Act states that, before issuing a license, the Commission must conclude, with concurrence from the Secretary of the Interior, that the project does not adversely affect the purposes and values of GBNPP, as constituted after the land exchange. The FERC staff's preliminary determination is presented in section 6.1.1.5 of the final EIS. A formal determination by the Commission would be presented in any license issued for the project, and the concurrence by the Secretary of the Interior would be included in its Record of Decision for this proceeding.
013	Congress's two basic questions have gone unanswered in the draft EIS. A complete answer to park impacts requires both FERC and the Secretary to respond, but only FERC has responded. And FERC staff has not provided its conclusion on economic feasibility. These omissions undercut the credibility and utility of the draft EIS, and they indicate a failure on the part of FERC and NPS staff to fully comply with the requirements of the Act. (NHI)	Under the Act, any exchange of lands for the construction of the proposed Falls Creek Hydroelectric Project may occur only if the Commission concludes, with the concurrence of the Secretary of the Interior, that the construction and operation of a hydroelectric project: (1) would not adversely impact the purposes and values of GBNPP (as constituted after the land exchange), and (2) would comply with the requirements of NHPA. The Commission also must determine that the project can be constructed and operated in an economically feasible manner. In addition, the Commission also must determine, with the concurrence of the Secretary of the Interior and the state of Alaska, the minimum amount of land necessary to construct and operate the proposed project. The EIS addresses the agencies' responsibilities under NEPA. The agencies' responsibilities under the Act will be addressed in an order by FERC and a record of decision by NPS/DOI.
014	EPA is concerned that the information contained in operation, mitigation, and monitoring plans that will be developed after license issuance is necessary to define the effects from the proposed project and/or identify mitigation measures. This information should be reflected in the EIS. EPA recommends that FERC and NPS ensure that all necessary analyses/studies are completed and	At this time, there are multiple project boundary, project operations, and project designs under consideration by FERC staff and NPS in this EIS. The license order, if issued, would establish the specific requirements upon which the plans would be based. Requiring development of these plans after the license is issued is fully consistent with the approach used by the Commission for other project proposals. All post-licensing

	Comment	Response/Revision to the EIS
	included in the EIS so that effects and appropriate mitigation approaches are defined and disclosed to the public in the EIS before decisions are made, as directed by NEPA regulations. (EPA)	plans would be subject to agency and public review prior to Commission approval. In spite of the lack of specifics regarding these plans, we have attempted to account for the anticipated effects of these measures in the EIS.
015	The draft EIS indicates that the existing diesel generators would continue to be used to supplement power generated by the proposed project, but EPA was unable to locate information in the draft EIS that indicates why diesel generation would be necessary with operation of the hydroelectric project and if so, under what situations operation of the diesel generators would be necessary. This information should be included in the final EIS, particularly because the proposed project would apparently not eliminate the need for or use of the existing diesel generating system. (EPA)	As discussed in section 2.3.2 and 5.3 of the final EIS, diesel generation would be required when flows are insufficient to produce generation adequate to meet the demand of GEC's customer base, typically during low flow.
016	This project could set a precedent for exchanging National Park lands to other entities. The exchange of National Park lands to facilitate the use of a natural resource is not acceptable. (Pursell, Heacox, Banks, Spotts, Friends, Swanson, Cherry, Park Protection Form). This type of land exchange is in direct opposition to the Organic Act and the Redwood Amendment which ensure the preservation and protection of National Park lands for their wilderness values. (Pursell)	The precedent of exchanging land park lands to the state for a hydroelectric project is not a proper consideration of this EIS. Whatever precedent that may exist, was set by Congress when it enacted the Glacier Bay Boundary Adjustment Act of 1998. Neither FERC nor NPS have the legal authority to decide to make other lands available for hydropower projects; therefore, this action does not set a precedent for NPS or FERC to take such action in the future. Such future action would require congressional action, and the issue of whether Congress should exercise such authority is beyond the scope of this EIS.
017	Removal of the proposed land from the park would allow a private corporation to make money off of the Wooskeetaan land. The Wooskeetaan clan has never relinquished their traditional ownership of this land, and the NPS has honored their traditional connection to their homeland. By removing this land from GBNP and allowing it to be developed for private purposes, this project will remove a	We have revised section 3.9.1 of the final EIS to address your concern. The exchange lands within GBNPP as defined by the Act are federal lands managed by NPS. The proposed actions described in section 2.2 and analyzed in chapter 4 of the final EIS relate to the exchange of federal and state lands based on the Glacier Bay National Park Boundary Adjustment Act of 1998.

	Comment	Response/Revision to the EIS
	part of the Wooskeetaan clan heritage, and their ties to their homeland will be diminished. (Hanlon)	
018	There is no legislative guarantee that lands transferred to the state of Alaska will remain in the good condition they are now and the impacts of future development by the state have not been anticipated or mitigated. Possible activities and developments on neighboring land could impact Gustavus residents. If the entire project area came under FERC project oversight there would at least be some added ability to protect the integrity of the area. (Banks, Schoen, Clark, Wilderness)	In a filing dated August 9, 2002, the state of Alaska described the land use designations proposed for the lands acquired by the state in the project area. These lands would be managed consistent with the management objectives and guidelines for habitat (Ha) and water (W) land use designations described in the Northern Southeast Area Plan. The state has also indicated the lands not directly disturbed by the project would be managed for fish, recreation and wildlife uses. A land use management plan or a recreation and public access management plan for lands within the FERC project boundary would be developed in consultation with the appropriate agencies and we would expect them to be consistent with the objectives of the Northern Southeast Area Plan. Future developments on state land that are reasonably foreseeable to occur are identified in section 4.2 of the final EIS and evaluated in the cumulative effects sections under each resource area.
019	What is the current standing of GEC and Gustavus Dray with the EPA and the Regulatory Commission of Alaska (RCA)? Is GEC responsive to EPA and RCA concerns/questions? Does FERC have any policy or standard concerning an applicant's standing with EPA and RCA? (Davis)	Under this proceeding, NPS and FERC are responsible for addressing the environmental effects of the land exchange, wilderness designations, and licensing of the proposed hydropower project. Should a license be issued for the proposed hydroelectric project, license articles would require development of plans in consultation with interested entities, which may include EPA and RCA. However, as part of this analysis we do not address GEC's standing with EPA or RCA beyond the proposed hydropower project. We suggest you contact these agencies directly with your comments regarding GEC's non-hydropower-related activities.
020	Heavy equipment may damage the "wilderness" value of privately held lands along the access route (Schrank)	We have revised section 4.13.2.1 of the final EIS to address your concern.
	Summary	

	Comment	Response/Revision to the EIS
021	Page xxviii, line 16-17, it is incorrect to state that "[t]here would be no environmental effects associated with this alternative." The sentence should either be deleted or rephrased along the lines of "With this alternative, the current environmental effects associated with diesel generation would continue." (GEC)	We have revised the Executive Summary of the final EIS to address your comment.
022	Page xxix, line 31, the phrase "and adjacent GBNPP lands" should be deleted. The effects listed would only occur on project lands, not on adjacent GBNPP lands. (GEC)	No change has been made to this text in the final EIS. Our analysis indicates that the effects of project construction and operation on these resources would extend to lands adjacent to the project area and within GBNPP. For instance, in section 4.10.2 in the final EIS, we conclude that there would be a negative effect on the soundscape of adjacent GBNPP lands during the 24-month construction period.
023	Page xxix, lines 33-35. GEC believes practically no GBNPP visitors will leave the park from the eastern boundary and travel into the project lands, as there are no trails in this area. Delete or modify the sentence to indicate the number of visitors expected to suffer this negative impact. (GEC)	We acknowledge that there are no trails in any of the project areas, yet visitors do hike up the creek bed and could follow animal trails. Social trails could develop over the term of any licensee as GBNPP visitors curious about project facilities and the Kahtaheena River cross the park boundary. The intent of this section is to draw attention to the concern that the potential project's facilities and impacts on flows in the Kahtaheena River could be visible from portions of GBNPP. We have revised the *Executive Summary* and section 4.11.2.1in the final EIS to clarify our intent.
024	Project area acreage amounts should be different by the amount of private or state land outside the Glacier Bay park boundary, but within the project area. Clarify how the figure of 117 acres in the Proposed Alternative was derived. (AAIP)	The acreage noted in the action alternatives described in chapter 2 of the draft EIS included only the lands that would be exchanged between GBNPP and the state of Alaska. According to Exhibit G of the license application, approximately 42 acres of private land along the transmission line southwest of the GBNPP boundary would be included in each action alternative. Under GEC's proposed action, approximately 75 acres of exchange lands would be included in the project boundary for a total of 117 acres. The 117 acres is derived from GEC's Exhibit

	Comment	Response/Revision to the EIS
		G-1, which states that 117.37 acres are included within the proposed project boundary. These lands include 75.39 acres of exchange lands and 41.98 acres of private lands along the transmission line route southwest of GBNPP. We rounded this figure to 117 acres in the final EIS. We have revised the text in chapter 2 of the final EIS and in table 2.9-1 to include the private lands that would be included in each action alternative. We have also modified figures 2-1, 2-8, and 2-9 to show the GBNPP boundary in relation to the proposed development.
025	There is an inconsistency on page xxix regarding the use and access of motorized recreation. It is suggested that specific references to ATVs be deleted from this section, deferring ATV use to the Land Use Management Plan. (AAIP)	We have revised section 4.15.2 to clarify that ATV use is a potential use of the project area lands either inside or outside of the FERC project boundary. GEC could use ATV's to access the project facilities.
026	On page xxviii, line 29 and 2-2 lines 15-23, a 12-foot-high, 150-foot-wide structure is described as a "diversion/intake structure." Such a structure is obviously a dam that includes an intake structure, as shown in Figure 2-6. Why is this feature not described as "dam with diversion/intake structure"? (NHI)	We have revised the text in the Executive Summary and other sections of the final EIS to clarify that the diversion structure is a dam.
027	On page xxix, lines 13-24, the adverse effects listed would destroy the value of a visit for those interested in a true park experience. In addition to the solitude and quiet, a true park experience includes aesthetic appreciation, wilderness appreciation, an opportunity to view wildlife not hunted or trapped, and enjoyment and challenge of traversing pristine and often rugged landscapes. If the project was constructed and hundreds of acres dropped out of the Glacier Bay Wilderness, most persons seeking at real national park experience would avoid visiting the project area. (NHI)	In chapter 4 of the draft EIS, we assessed project effects on project lands as constituted after the land exchange, as directed by the Act. Therefore, we assess effects on lands that would be conveyed to the state and not park lands, as mentioned in your comment. We agree that the hydro development on these lands might discourage some people from visiting the area.
028	On page xxix, lines 24-27, when describing GEC's	In section 4.12.2.1 of the final EIS, we indicate that removal of

	Comment	Response/Revision to the EIS
	alternative, the final EIS should also acknowledge that visitors seeking a true park experience could have a negative experience when encountering persons engaged in additional recreational opportunities such as hunting, fishing, and ATV use. GEC comments that the examples should be deleted or replaced by more positive examples such as easier access for viewing the falls. (GEC,NHI)	lands from GBNPP would likely result in recreational activities on these lands that are currently not allowed within GBNPP and may diminish the experience of those seeking a "true" park experience. However, we would expect that individuals seeking a "true" park experience would access remaining lands within GBNPP rather than state lands within the project boundary. We have added the activity that you suggested; however, we have not deleted the other activities since these are recreational activities that could occur within the project boundary. The perception of these activities as positive or negative would vary from individual to individual; therefore, it would be inappropriate to assume that these are negative examples of recreational activities that could occur within the project area. Lastly, should the project be licensed, we recommend that recreational activities permitted within the FERC project boundary would be determined in consultation with the appropriate agencies through development of a public access and recreation development plan.
029	On page xxix, 35-38, wilderness resources would be diminished but not for the reason cited. Wilderness resources would be lost outright due to the hundreds of acres of designated wilderness that would be cut out of the park under the three action alternatives. Park wilderness adjoining the deleted acreage would be diminished if activities allowed on the former park land intentionally or unintentionally spilled over into the adjoining park. (NHI)	Under each of the action alternatives, wilderness land would be de-designated in the proposed project area; however, other land in GBNPP would be designated as wilderness. Our analysis suggests that none of the possible lands under consideration for wilderness designation would contain the same qualities as the lands that would be removed from the park. In section 4.13.2.1, we discuss the possible effects on the adjacent wilderness lands within the park from activities occurring on the proposed project lands and conclude that indirect effects on wilderness may include the loss of solitude for wilderness visitors and incompatible uses that may encroach on wilderness. We have revised the *Executive Summary* and other sections of the final EIS to address your comment.
030	On page xxix, lines 38-40, are a classic *non sequitur*. A	We have revised the Executive Summary to clarify that

	Comment	Response/Revision to the EIS
	reduction of wilderness resources would result from the transfer of hundreds of acres of park wilderness into state ownership for hydropower development and other uses not allowed on park lands. This deletion cannot be compensated for by the mere presence of wilderness elsewhere in the park. (NHI)	wilderness values of GBNPP land adjacent to the project would be diminished but that the overall quality of the 2.5 million acres of wilderness would not significantly change.
031	On page xxxi, lines 15-18, it is wishful thinking that the state would take over active management. The land within the Falls Creek project area that the state would own would be isolated and unsuitable as a management unit. The state would be unlikely to expend funds to manage it, even if it could afford to. The state faces years of severe budget shortfalls, with existing programs eliminated or cut back and employees laid off. (NHI)	We have revised the text in sections 4.15.2.1 and 4.15.3.1 to indicate your concern regarding the state's ability to manage these lands.
032	On page xxxi, lines 24-26, it is not desirable to try enhancing pristine, unimpaired resources that need no enhancement. Protection for these resources could be maintained at the current high level—the highest level available under federal law—by selecting the No-action Alternative. (NHI)	We have deleted the word enhance from these lines in the *Executive Summary*.
033	Page xxxi, lines 26-28, state that estimated costs of the project and proposed mitigation and environmental measures would be the same under the Maximum Boundary Alternative as under GEC's alternative. Costs on page xxx, lines 1-4, and 16-19, show that the Maximum Boundary Alternative would cost significantly more than GEC's alternative. (NHI)	The costs cited in page xxx of the draft EIS compare the cost of GEC's proposed action to GEC's proposed action with the preliminary FERC staff additional recommended measures. There is no difference in the effect of the boundary and land exchange alternatives on the cost of the project. The Maximum Boundary and Corridor alternatives discussed in this section differ only in regard to the project boundary and the amount of lands that would be transferred. GEC's proposed generation and environmental mitigation measures and FERC staff additional recommended mitigation measures are the same for all action alternatives.
	Introduction	

	Comment	Response/Revision to the EIS
034	Section 1.1.1 (page 1-1) states that the purpose of the action is construction, operation, and maintenance of the 800-kilowatt hydropower project. However, NEPA requires the EIS to state the "*underlying* purpose and need to which the agency is responding…" 40 CFR § 1502.13. What GEC electricity system needs is the project intended to meet? (NHI)	We have revised section 1.1.1 of the final EIS to indicate the underlying purpose and need of GEC's proposal.
035	Section 1.1.2 (page 1-2) appears to assume that the purpose of the action is to meet future electricity demand in GEC's service territory in excess of the 1,050-kW capacity of the existing diesel generation, to replace the diesel generation (page 1-5) to the extent that the project generation may meet existing demand, or (page 1-5) to stabilize or reduce the rates charged to GEC's customers. NHI agrees that these are project purposes but states that the application is not intended to enhance the environmental quality of the GBNPP. (NHI)	We have revised section 1.1.2 of the final EIS to more clearly portray the potential environmental effects of reducing diesel generation and to indicate that this would be an indirect effect of the proposed action.
036	Section 1.1.2 of the draft EIS does not clearly present projected electrical loads on the GEC system and their relationship to the proposed hydroelectric project. Loads are projected to increase from roughly 1.7 million kWh in 2002 to roughly 2.8 million kWh in 2016. Page 1-2 indicates the current generation facilities consist of 4 diesel generators with a combined capacity of 1,150 kW and that currently 2 of the 4 units (representing 600kW of generating capacity) are generally not used. The draft EIS presents current diesel capacity as estimated at 2.4 kWh annually, which assumes the operation of the two primary generating units (1 and 3) at 50 percent of their maximum theoretical annual output. Figure 1-4 of the draft EIS suggests that operation of the 2 primary units at roughly 60% of their annual rated capacity would meet projected	We have revised section 1.1.2 of the final EIS to address your comments. Section 1.1.2 discusses the need for power in terms of the benefits provided by the proposed project, which do include increased overall capacity to serve GEC's current and future load, but also highlights other factors including reduced cost variability and a reduction in issues related to electrical generation using diesel fuel. We also have revised the economic feasibility analysis in section 6.1.1.4 of the final EIS to reflect new information contained in comments provided on the draft EIS.

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	power demand. This potential change in operation, when combined with increased utilization of the other generating units (2 and 4) suggests that current installed generating capacity is more than sufficient to meet expected demand for Gustavus well into the future. Because the proposed project would irreversibly and irretrievably commit natural resources, it is critically important for the final EIS to present a clear and direct connection between the projected need for power and why the proposed project is required to meet that need, including an analysis showing that projected demand cannot be met using the current diesel-fired generating facility. (EPA, Park Protection Form) The draft EIS assumes that GEC would use its two primary diesel units at a capacity factor of 50% on page 1-2. Given that assumption and the related assumption that demand growth would track the 1985-2002 period, it concludes (page 1-2) that GEC's capacity would not meet demand in 2012 and later. The draft EIS does not explain why the other diesel units, which have a 600-kW capacity, would be unavailable to meet such demand growth, or why a 50% capacity factor is the best that these units would achieve. (NHI)	
037	Page 1-1, lines 4-16, note that the Glacier Bay National Park Boundary Adjustment Act of 1998 "…authorizes FERC to accept and consider a hydroelectric license application" from GEC. The final EIS should acknowledge that the Act was necessary because Congress, in enacting the FPA, does not allow the Commission to accept license applications for new hydropower projects within national parks. (NHI- Sierra)	This aspect of this proceeding would be addressed in any order acting on the license application and any record of decision.

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038	Page 1-2, line 8. As presently configured, the NPS would have to purchase electricity from hydroelectric generation for the project to be economically competitive with diesel in the short term. Since the NPS decision on using hydroelectric power will not be made until after any project license is issued, and economic viability must be demonstrated before a license can be issued, economic viability must be demonstrated without NPS connected to hydropower. This can be done using grants, down sizing the project to carry only the Gustavus not the park load, or by other means. Work will continue on this matter over the next several months and the results communicated to FERC. (GEC)	Our economic analysis addresses the proposed project with and without serving NPS load. Additionally, we have attempted to incorporate and consider any reasonably foreseeable grants or discounted loans. Significant changes in the proposed project design, such as reducing the project capacity, would require an amendment of the license application if it occurred before a license is issued. If it occurred after a license is issued, it would require an amendment of the license.
039	Page 1-2, line 9. GEC's generation for 2003 was 1,713,000 kWh, a 4.5% increase. It should be noted that all kWh figures used in the draft EIS were for kWh generated and not kWh sold. The economics section of these comments uses kWh sold. We do not have the NPS kWh generation figures for December, but the Park is on track to use approximately 1,000,000 kWh for the second straight year. This should probably be the NPS baseline usage should FERC choose to include a scenario with the Park using hydropower. The NPS just completed a large new maintenance facility. The old maintenance facility will be converted to office space. In addition, the existing office building will be enlarged. These changes will add load to the NPS system. (GEC)	Based on the generation, sales, and load loss information provided in comments on the draft EIS, we have updated section 1.1.2 of the final EIS and have differentiated between kWh generated and kWh sold throughout the final EIS.
040	Page 1-4 starting on line 1. GEC provides corrected costs per kilowatt hour. (GEC)	We have revised the text in section 1.1.2 of the final EIS to include the new costs per kilowatt hour provided by GEC.
041	Page 1-5, line 14. Insert the sentence: "In addition, the project would result in considerably lowered carbon emissions from Gustavus power generation." (GEC)	We state in section 1.1.2 of the final EIS that providing generation from the proposed project would replace a portion of diesel generation and correspondingly reduce air particulate

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		pollution. The amounts are quantified in our discussion of the effects on air quality in section 4.5.2 in the final EIS. An additional sentence in not necessary to make this point.
042	Page 1-5. EPA was unable to locate analyses in the draft EIS that reflect the future air quality impacts and effects related to future fuel storage and transportation with the continued use of diesel generators to meet power demand. As these effects would be associated with implementing the No-action Alternative, the final EIS should assess and present them. (EPA)	We have added the information you requested to section 4.5.1.1 of the final EIS. These effects would apply to all alternatives not just the no action alternative.
043	Page 1-7, footnote 8. In regard to the Juneau-Hoonah segment of the Southeast Intertie, there currently are only federal grants for a feasibility study and no construction funding has been authorized.(GEC)	We have revised the footnote to indicate that the $2.5 million federal grant would allow developers to finish the planning and begin construction, as indicated in the July 20, 2003, article in the Juneau Empire State News.
044	On page 1-12, lines 4-6, the draft EIS states that FERC would retain authority and it is exempt from the Energy Act of 2000. Does this mean that at no time in the future the state of Alaska could be given management over the hydro issues? (AAIP)	Section 3(a)(3) of the Glacier Bay National Park Boundary Adjustment Act of 1998 states "FERC will retain jurisdiction over any hydropower project constructed on this site."
045	Page 1-12, lines 8-12. AAIP agrees that the construction and operation of the project is contingent upon the boundary adjustment happening first, however Section 3(c)(4) does not seem to indicate that the boundary adjustment is contingent upon construction and operation of the hydro facility. To address this concern, it is suggested that a condition of the FERC license should be a posting of a performance guarantee prior to the occurrence of the land exchange to provide certainty of construction once the exchange occurs. (AAIP)	We have added a discussion of your concern and recommendation to section 1.2 of the final EIS. The Act does not contain any provisions pertaining to reacquisition of exchanged lands if the project is not actually constructed. The NPS, with the State concurring, could use the existing legal authority to do an equal value exchange to reacquire the land in the event the project is not consummated, though the land could not be designated wilderness absent additional Congressional action.
046	On pages 1-20 lines 4-7, 1-21 lines 6-33, 1-22 lines 35-37, and 1-23 lines 1-4, among the specific purposes identified for national conservation system units in the ANILCA are	We agree that the description of the purposes and values of GBNPP is incomplete. We have revised the text in section 1.6.4 to include the purpose to preserve historic and archaeological

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	"to protect and preserve…rivers' and "to preserve wilderness resource values and related recreational opportunities…on freeflowing (sic) rivers." (ANILCA Sec. 101(b)). This purpose does not appear in the draft EIS' otherwise complete list of ANILCA purposes and mandates. The omission was probably an oversight. Unfortunately, it means that the project's effects on the Kahtaheena River as a free-flowing river were not analyzed in the draft EIS. The final EIS should include an analysis of the effects the project would have on the free-flowing quality of Falls Creek and its associated wilderness values and related recreational opportunities, then determine whether or not the project is consistent with the intent of Congress in ANILCA and NPS policy. (NHI)	sites, rivers, and land, and to clarify that the purpose to preserve wilderness values and recreational opportunities extends to large arctic and subarctic wildlands and on free-flowing rivers. We analyzed the effects of the proposed project on the free-flowing segments of the Kahtaheena River in the draft and final EIS in terms of geology and soils, water quality, water quantity, fisheries, wildlife, soundscape, wilderness, recreation, and aesthetics.
047	Page 1-25, line 9. Insert the bullet: "Offsite mitigation could reduce sediment associated with the poorly installed Rink Creek bridge and Homesteader Creek culvert." (GEC)	We are not aware of any proposed "off-site" mitigation measures that would reduce sediment associated with the Rink Road and Homesteader Creek culverts.
048	On page 1-31 line 28 and page 1-32 lines 11-12, in referring to an exchange of Falls Creek project lands for state lands at Long Lake in WSNPP, the final EIS should state that the NPS would be trading national park wilderness acreage (Falls Creek) for land that would become national preserve non-wilderness. How would this trade constitute an equal value exchange, as required by the Act? (NHI, Wilderness)	The Act specifies, as described in section 1.2, that state lands within WSNPP are to be exchanged for federal lands within GBNPP and that lands already within GBNPP at Alsek Lake, Cenotaph Island, and Blue Mouse Cove would be designated wilderness in exchange for the de-designation of lands within GBNPP. The Act specifies that the land exchange is subject to the laws applicable to lands managed by the Secretary and to the laws required by the state of Alaska for a land exchange. These laws require that the land conveyed will have a sufficiently equal appraised value. Regarding wilderness designations, the Act allows for the wilderness designations to be approximately equal in sum to the total wilderness acreage deleted from GBNPP.
049	There are over 30 Native Allotments in Glacier Bay held	Alaska Native allotments are held in restricted status, rather than

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	"in trust" by the Secretary of the Interior. That should mean any proposals that affect any one of those restricted properties would bring into play "Trust Responsibility." Without recognition of that responsibility by Interior, this proposal has no integrity. The proposed project would cross over two Native Allotments. Where are the landowners in this issue? (Culp, Friends, Markeloff, Bialas, Jettmar, Wilson)	"in trust," and, in this regard, the U.S. Department of the Interior acknowledges a trust responsibility in regard to the two approved Native allotments adjacent to or near the project area. No part of the project would occur on Native allotment land, and potential impacts on the allotments have been identified and discussed in chapter 4 of the final EIS. In response to comments, we have expanded our discussion of potential effect to Native allotment lands in the final EIS. The Bureau of Indian Affairs has been informed of the project so that it can fulfill its responsibilities to advise and assist the owners of the two potentially affected Native allotments.
050	The Huna Tlingit oppose this project because the location has cultural significance to their people and it is held in trust by the NPS. (Culp, Hoonah)	Section 3.9.1 of the final EIS acknowledges that lands in the project vicinity have cultural significance to the Huna Tlingit. Project lands would be protected by and managed in accordance with applicable laws protecting cultural resources. Specifically, section 2(c) (B) of the Glacier Bay Boundary Adjustment Act of 1998 conditions the occurrence of the land exchange on a finding that the construction and operation of the project will comply with the requirements of the National Historic Preservation Act.
051	The population growth rate is overestimated because the NPS growth accounted for much of the past increase and the growth is nearly complete. Figure 5-1 shows the NPS power usage remaining flat through 2016, however, load is estimated to grow 60 percent in the same span of time. What do EIS preparers know about future growth that is unknown to NPS planners and residents? (Davis, Lee, Wilson)	We have used the best available data for estimating population growth rates. The information presented in the draft EIS was extracted from the GEC license application and U.S. Census information, specifically the average growth rate between 1993 and 2003. In addition to population growth, future energy needs are expected to increase due to an increase in usage within Gustavus itself. Based on additional information received subsequent to distribution of the draft EIS, we have reassessed the growth in energy usage by GEC's customer base and revised chapter 5 and section 6.1.1.4 of the final EIS accordingly.
052	The population growth rate is overestimated because the commercial fishing industry has disappeared, the NPS is	We used the best available data when estimating the population growth rate in Gustavus. Section 3.16.1 of the final EIS

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	no longer growing, and tourism is slowing. (Lee)	addresses the population of Gustavus in a historical context and notes that the population has changed quite considerably since U.S. Census data were recorded in the 1960s (see table 3.16-4). We have added a discussion of the NPS growth and commercial fishing regulations and how they might affect population growth to section 3.16.2 of the final EIS.
	Description of Alternatives	
053	Page 2-13, line 12: GEC is in the process of negotiating a settlement with the agencies regarding a reduction in the instream flow requirement to zero. If that effort is successful, as GEC believes it will be, then the downstream fish bypass included in Interior's prescription will no longer be required. (GEC)	We have added language to the final EIS to indicate that GEC is pursuing negotiations with the state and federal fish and wildlife agencies to eliminate the minimum flow requirement and modify the downstream fish bypass measures.
054	On page 2-5, lines 30-32, the right of way easement width should be clarified. The text only suggests the width needed for clearing not the actual land use authorization. Standard widths for road easements are typically 60 or 100 feet. (AAIP)	We have revised section 2.3.4 of the final EIS to address your comment.
055	The draft EIS does not analyze any action alternative involving renewable technologies other than this project. This narrow scope of analysis does not comply with the NEPA duty of the Commission or the NPS. (NHI, Niswander, Westman, Spotts, Schoen, Spezia, Edelson, Clark, Pisaneschi, Schrank, Friends, Bialas, Jettmar, and Park Protection Form). In addition, after finding that renewable technologies other than hydropower are more costly today than diesel generation (pp. 1-5 to 1-11), the draft EIS does not examine alternative future scenarios that may enhance the feasibility of these technologies, despite the fact that the draft EIS examines future scenarios when the project was found to be uneconomic. This treatment stacks the deck against such alternatives. If no-action is a	In section 1.1.3 of the draft and final EIS, we analyze several alternative means for generating electricity, including renewable technologies and conservation. We find this level of analysis appropriate for an EIS on the action before FERC and NPS.

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	static baseline, then the final EIS should treat non-hydropower alternatives as action alternatives. These alternatives are identified in reports by NHI's economic consultant, 100th Meridian, "Economic Analysis of the Proposed Gustavus Electric Falls Creek Hydro Project and Potential Alternatives" (November 5, 2003) and "Comments on the Economic Analysis in the Draft Environmental Impact Statement for the Falls Creek Hydroelectric Project" (January 6, 2004). (NHI, Wilson)	
056	On page 2-6, lines 13-16, GEC proposes a lease agreement with ADNR that limits vehicles on the access road to those necessary to construct, operate, and maintain the project. Does the ADNR Northern Southeast Area Plan include a provision for restricting access road use as proposed by GEC? Would there be a provision prohibiting snowmobiles and all-terrain vehicles on the project lands the state would acquire? (NHI)	The ADNR Northern Southeast Area Plan includes a provision for limiting access in the Management Guidelines for Public Access. The guidelines state that "Access to state lands may be curtailed at certain times to protect public safety, allow special uses, and prevent harm to the environment, fish and wildlife." In section 4.12.2 of the final EIS, we conclude that implementation of a public access and recreation development plan, developed in consultation with state and federal agencies, would identify uses that should be limited or restricted on the exchanged lands.
057	Why is the SE Alaska Intertie not considered a better choice for providing power to Gustavus than the proposed hydroelectric project? (Culp)	We discuss the Southeast Alaska Intertie in section 1.1.3 of the draft and final EIS. Connection of the GEC system to the SE Alaska Intertie project is under consideration but not proposed for development before 2030.
058	Explain in detail in the final EIS how the number of acres for exchange was determined, based on the project's limited need. (Wilderness)	We have revised the introduction of Chapter 2 of the final EIS to address your comment. We also evaluate various design, construction, operation, and mitigation scenarios in Chapter 2.
059	Draw the boundary of the exchange along geographic contour lines rather than straight lines to create a geographically identifiable and manageable boundary. (Wilderness)	We have revised section 1.2 of the final EIS to address your comment.
060	Include provisions under each development alternative that would mandate that a permanent non-development	If a license is issued for this project, we expect that development along the new access road and within the project boundary

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	easement along the new road be one of the stipulations for completing the land exchange with the state. (Wilderness)	would be addressed during consultation and preparation of any required public access plans and land use management plans.
	Affected Environment	
	Land Descriptions	
061	Page 3-8, line 34. Delete "densely populated by Sitka spruce forest"; replace with "dominated by alder/willow thicket with emergent cottonwood and spruce." (GEC)	The statement the comment references is based on the description of the vegetation conditions provided in a 1988 NPS NEPA document, which states "The vegetation covering the unnamed island adjacent to Blue Mouse Cove consists of Sitka spruce and Sitka alder with an understory of herbaceous plants and mosses."
	Geologic Resources and Soils	
062	Page 3-11, paragraph beginning line 20. Misstates the geologic context (see Mann & Streveler, 1999, p2, last paragraph). You will note therein that Falls Creek follows the axis of an anticline through all of the bypassed reach between the Upper Falls and just upstream of the Log Jam, at which point the river turns across the structural grain and descends abruptly to the anadromous reach. (GEC)	We have revised the text in section 3.3.1 of the final EIS to clarify the geologic context.
	Water Quantity and Quality	
063	Page 3-19, line 35. The river empties into Icy Strait, not Glacier Bay. (GEC)	We have revised the text in section 3.4.1 to clarify that the Kahtaheena River empties into Icy Passage and that the marine waters at the mouth of the Kahtaheena River are within GBNPP and currently under NPS jurisdiction and management.
064	Page 3-24, lines 1-9. The draft EIS is correct in stating that no description was provided by GEC of the method used to estimate Kahtaheena River flows during periods when there are no records of Kadashan River flows at USGS No. 15106920. For WY79-80, the missing Kadashan River flows were first estimated by a correlation with another USGS gage in the Kadashan River basin (Hook Creek near Tenakee, USGS No. 1516960, 8.00 sq. mi. drainage area). The correlations are quite good, as	We have revised the final EIS to clarify how GEC estimated Kahtaheena River flows for periods when flows were not reported for the Kadashan River above Hook Creek gage (i.e., WY 1979 and 1980).

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	expected from similar sized streams in the same basin. For WY96, there is data for USGS No. 15106920, although it is not available online. (GEC)	
065	A descendant of one of the Native allotment owners paid the State of Alaska a $500 fee for the claim of water rights on his family's property in 1996. Why is this water right claim not recognized by the proposal? Why hasn't the federal government sought to resolve the water rights question on native allotment land? (Culp)	Neither FERC nor NPS oversee the administration or adjudication of water rights within the state of Alaska. Private water rights issues are administered by the state of Alaska and are not within the scope of this document. We recommend that you inquire with the state of Alaska regarding the status of this claim.
066	The stream flow and precipitation data used in the draft EIS have a large margin for error resulting in the possibility that stream flows are less than predicted and less energy could be generated by the proposed project. (Lee)	We used the best available data to evaluate the effect of the proposed project on flows. In section 3.4.1.1 of the final EIS, we discuss the accuracy of the daily mean flow data for the Kahtaheena River gages, regression coefficients for seasonal regressions developed by Coupe, and average monthly bias of estimates of flows for the Upper Falls. Although the error margins for daily mean flows are relatively large in some cases, we conclude that our estimates of flow are sufficient to assess long-term patterns and estimate energy production.
	Fisheries Resources	
067	Page 3-41, Table 3.6-7. GEC recommends that this table be structured to: (1) indicate which of the reaches comprise the bypassed reaches, and (2) give a subtotal of fishes in these reaches for comparison to the overall totals. (GEC)	We have revised table 3.6-7 in section 3.6 of the final EIS to address this comment.
	Vegetation and Wetlands	
068	Page 3-46, line 1. Delete reference to cedar. The only cedars occur at elevations above the project area. (GEC)	In section 3.7.1, we describe the existing conditions of the vegetation resources in all the areas identified in the proposed action and action alternatives. Therefore, this section must cover an area that includes the potential FERC project boundary as well as the potential land exchange area and the wilderness designation areas. Cedar is documented to occur within the Poor Hemlock/Spruce Forest vegetation type in the area within the

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		potential land exchange boundary.
069	Page 3-46, paragraphs beginning at line 4 and 26 should indicate that these vegetation types are found only in the Gustavus flats portion of the project area. (GEC)	The descriptions of the vegetation communities in section 3.7.1 of the draft and final EIS do not specifically describe where each individual plant community types occur, as it would be difficult to describe their size and spatial arrangement in text. The text in section 3.7.1 describes the vegetation communities in the potential FERC project boundary as well as the potential land exchange area and the wilderness designation areas
	Wildlife	
070	Page 50, line 14. Change "red-backed" to "long-tailed." The former vole is not known to occur here in Glacier Bay. (GEC)	An NPS checklist of mammals known to be present in GBNPP includes the red-backed vole. This species was also identified as present on the unnamed island near Blue Mouse Cove and Cenotaph Island by NPS personnel (personal communication from M. Kralovec, GBNPP-NPS, with E. McLanahan, Meridian Environmental, Seattle, WA, on April 24, 2003)
	Cultural Resources	
071	Page 3-55, last paragraph. Should be mentioned that for many years ending in the late 1930's, Jim Huscroft, a legendary resident of the outer coast, made his home on Cenotaph Island. See D Bohn, "Glacier Bay, the land and the silence" for extended discussion of Huscroft and a photo of his Cenotaph Island home. (GEC).	The property associated with this individual has not been identified as a Historic Property; however we have added information about this property to our description of the history of Cenotaph Island in section 3.9 of the final EIS.
	Soundscape/Noise	
072	Page 3-57, line 5. Both allotments, which are a visually dominant part of the project area vicinity, have been extensively clearcut, and should not be characterized as "relatively untouched." (GEC)	We have revised the text in section 3.10.1 to indicate that although the proposed project is located approximately 5 miles from Gustavus, the area is relatively untouched with the exception of two small sections that were logged for timber during 1974.
073	Page 3-57, lines 8-9. The usual approach to the Gustavus airport is about ½ miles offshore of the project area, and pilots seldom fly directly over the project area. (GEC)	We have revised the text in section 3.10.1 of the final EIS to reflect your information on typical flight routes into the Gustavus airport.
	Visual Resources (Aesthetics)	

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074	Page 3-58, line 34. Should be mentioned that no portion of the project would be visible from that perspective. (GEC)	We state in section 3.11 that from the Flats, visitors could view the project area. This is an accurate statement. We do not analyze in section 3.11 the potential effects of the proposed project or from which vantage points the proposed project facilities would be visible. This analysis is presented in section 4.11 of the final EIS.
075	Page 3-61, line 26. See comment regarding page 3-8. This island was deglaciated about 150 years ago, and has no mature forest on it, and no cedar at all. (GEC)	A 1988 NPS NEPA document states that the vegetation covering the unnamed island adjacent to Blue Mouse Cove consists of Sitka spruce and Sitka alder with an understory of herbaceous plants and mosses.
076	Page 3-61, line35-36. Strike "willow and scrub-shrubs" and substitute "cotton wood and young spruce." (GEC)	Aerial photo classification of the land cover on Cenotaph Island indicates that early successional vegetation types (indicating areas destroyed by recent tidal waves) include open cottonwood, closed alder, and mixed stands of spruce / cottonwood.
	Recreation Resources	
077	Page 3-63, line 37-39. This statement is true in a gross sense, but we have never seen evidence of camper use on the project area coastline. (GEC).	We have revised the text to indicate that backcountry camping surveys were conducted within Glacier Bay proper.
078	Page 3-64, line 25-26. Almost all visitor use occurs during late May-late August, for about 90 days. 90 x .8 gives a more realistic estimate of 72 visits. Use this figure in lieu of 120 in the several places it is employed in the EIS. (GEC)	We have modified the data to be consistent with the dates backcountry visits occurred within GBNPP as stated by the GBNPP backcountry surveys. We address your comment in section 3.12.1.1 of the final EIS.
079	Page 3-65, line 18. It is incorrect to assume that these were annual visits to Lower Falls. This information is based on Baker's (2001) data, which lead to a reasonable estimate that about 8 percent of Gustavus residents have visited the Falls Creek area at some time. Based on the GEC field team's observing no visits to the falls during the 485 hours of observation in the summers of 1997-2000, the estimated 34 annual resident visits to the Lower Falls is a considerable overestimate. We suspect the average	We have modified the data because precise estimates do not exist. As such, staff found it an appropriate methodology to approximate a conservative estimate of recreational use of the area. We address your comment in section 3.12.1.1 of the final EIS.

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	number is closer to 10 (not 34). (GEC)	
080	Page 3-65, line 28-29. We again feel that these figures are too high, by about a factor of two, based on this reasoning: Shoreline visits: First, as stated under 3-64, above, a reasonable estimate for visits to the shore would be about 72 (not 145). This estimate is based on observations by GEC's field team of all visits, and thus the Bear Track Inn estimates should not be added. Lower Falls: As stated just above, a reasonable estimate for resident visits to the Lower Falls would be 10. Adding the upper end of Bear Track Inn visitor estimate gives 10 + 10 = ~20 (not 44). (GEC)	As stated above, we have modified the data to yield a conservative estimate of recreational use of the area. We address your comment in section 3.12.1.1 of the final EIS.
	Wilderness	
081	Page 3-73, line 11-12. This sentence regarding old-growth forests is grossly inaccurate. There are many thousands of acres of old-growth forest and associated mature habitats outside Neoglacial Ice limits inside the entire periphery of the park wilderness. The most extensive of these include: outer coast foothills and fjordlands from Deception Hills to Cape Spencer, thence along the north shore of Icy Passage to Dundas Bay; and from the Excursion Ridge northward to the slopes of the Beartrack range and eastward to and including the Excursion river valley and associated slopes. (GEC)	There are many thousands of acres of old-growth forest in GBNPP. However, only a small percentage is readily accessible to the public. We have revised the text in section 3.13 to state that old-growth forests relatively accessible to the general public occur only in a few places within GBNPP wilderness areas.
082	Page 3-73, line 25. GEC agrees that GBNPP contains unique resources, but the Falls Creek area is one of the least unique portions of the park. Its vegetation, fauna and geomorphology are very similar to large stretches of northern SE Alaska. (GEC)	The sentence in the text section 3.13.3 of the draft and final EIS is made in reference to the National Wilderness Preservation system and describes the unique character of portions of GBNPP that are designated wilderness. The sentence is not made in reference to either the Kahtaheena River area or southeastern Alaska.
083	Page 3-75, line 20. Throughout the document, the Native allotments are down-played, despite the fact that they are	We have revised sections 3.4.2, 3.10.1, 3.13.4.1, 3.15.1.1, and 3.16.3.2 to clarify that both of the Native allotments have been

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	large, centrally located, and contain the lion's share of the critical biotic values of the Falls Creek area. Not only have these parcels been logged in the past, but the high likelihood of their being developed in the future, hydro project or no hydro project, considerably reduces the long-term probability of high wilderness value being maintained in the project area vicinity. (GEC)	logged in the past; the George allotment (12.2 acres) in 1974 and the Mills allotment (38.6 acres) also in 1974. We also have identified and summarized potential effects on the Native allotments in each resource section.
084	Page 3-75, line 33. This paragraph again overstates the wilderness character of the Falls Creek area. It has been extensively clear cut, there is a frequently used cabin at the creek mouth, and old logging trail follows the entire shore, debris from the old logging camp is still evident, and again we must stress the potential for further diminution of wilderness character on the extensive private lands. (GEC).	The sentence in the text refers to the existing wilderness and the project area, as indicated in the titles for sections 3.13 and 3.13.4.1. The text statement is not inclusive of Native allotments located to the south and west of the proposed project area. Our assessment of vegetation conditions did not lead to a conclusion that the drainage in the proposed project area within designated Wilderness had been "extensively clear cut" as GEC asserts. The cabin at the mouth of the river is no longer frequently used because sediment deposition and uplift have made it more difficult to access this cabin from the water with a boat. Boat access to the cabin is now restricted to only certain tide heights.
085	Page 3-76, line 25. This summary paragraph overstates the untrammeled character of the area and its biotic uniqueness both within the park and in the adjacent national forest. (GEC)	The summary statement in section 3.13.4.1 of the draft and final EIS accurately states that the Kahtaheena River drainage within GBNPP Wilderness may be described as essentially untrammeled in character, there is very little evidence of human impact (what exists within the wilderness in this drainage involves a few informal trails), is substantially free from the effects of modern civilization, and provides an outstanding opportunity for solitude.
086	Page 3-78, line 11. This summary of the Blue Mouse Cove exchange parcel understates its values. This island is essentially untouched; there are no structures on it; it is used very little by people but frequented by a large array of wildlife; it is subject to boat and plane traffic related to the	The unnamed island is essentially untouched, there are no structures on it, and it may contain or be visited by a wide range of wildlife. Our summary statement in section 3.13.4.2 of the draft and final EIS states as such, but with the proviso that, because of its location with respect to the ranger station and

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	Blue Mouse anchorage, but no more so than the Falls Creek area, which lies near the plane approach to Gustavus airport and near the Icy Passage marine transportation route. Designating it as wilderness plugs a "doughnut hole" in a very large stretch of wilderness, broken only by one Native allotment that NPS is hoping to acquire. (GEC)	vessel travel routes, there is a greater chance that opportunities for solitude would be adversely affected by noise, and that there may be a reduced chance the island would escape impacts from modern civilization. Because of the difficulty of access, stream noise, and density of vegetation, the proposed project area sustains fewer of these potential impacts in its current condition. There is one small island in the Hugh Miller Inlet Wilderness complex that is currently wilderness and NPS lands but is under consideration for conveyance to native allotment lands. At the moment, this has not taken place and the island is still under the jurisdiction of the NPS and part of the National Wilderness System.
087	Page 3-79, line 25. Cenotaph Island and vicinity is one of the best-known areas of the park. The survey (Streveler et al., 1980, Lituya Bay Environmental Survey, NPS, 346p) shows that the island's biotic values are considerable, including: a large bird colony, a representative sample of recovering giant wave altered vegetation. In addition, it has high historical value, being the former home of Jim Huscroft and the site of the LaPerouse expedition's claim of the area in the name of the French crown. (GEC)	Cenotaph Island has historical and biological values, and we include information about the general characteristics of the island in the affected environment discussions in the final EIS. However, the Streveler report which focuses on Lituya Bay is not comprehensive enough to determine if the biological values of Cenotaph Island are different enough from conditions elsewhere in the GBNPP. As a result it would be difficult to assess the value of this island to the existing wilderness in GBNPP based on this study alone.
	Land Use Programs and Policies	
088	Page 3-83, line 26. The extent of that logging is for the most part certain, and is mapped by Bosworth and Streveler (1999). The principal logging area lies outside the Native allotments in what is presently park land, and was linked to the shore by a skid road through the Mills allotment, along which there may have been some minor logging obscured by the much more extensive logging on that allotment in the 1960s. (GEC)	Bosworth and Streveler (1999) provide a map showing vegetative coverage but not in relation to the boundaries of the Native allotments or logging area outside of the Native allotments. The areas logged in the early 1900s are not distinctly mapped in existing reports, and are only generally described in text of the report. However, we would agree that historic records could show the extent of the logging and we have revised section 3.15.1 of the final EIS accordingly.
	Socioeconomics	
089	Page 3-89, line 5. GEC would not characterize a 4.7%	We have revised this section of the final EIS to address your

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	annual growth rate as moderate. This is one of the highest growth rates in Alaska, being similar to that of the railbelt. (GEC)	comment.
090	Page 3-89, Table 3.16-4. It is misleading to show Gustavus population before 1950 as zero; just say "no data." (GEC)	We have revised this section of the final EIS to address your comment.
	Environmental Consequences	
091	The draft EIS does not articulate a rational standard to determine whether a given impact complies with Section 3(c)(3) of the Boundary Adjustment Act. The draft EIS suggests that an adverse impact complies as long as most of the 2.5 million acres of GBNPP wilderness lands would be unaffected by the footprint of this project and associated land exchange. This implies that an adverse impact on GBNPP purposes or values would occur only if it involves a unique resource recognized in the organic statutes for the GBNPP or the NPS's implementing rules. Additionally, the draft EIS makes, and NHI supports, factual findings that the project would cause adverse impacts on the post-exchange GBNPP lands, including the riparian lands on the eastern bank of the bypassed reach. These factual findings compel the legal conclusion that the license would not comply with Section 3(c)(3) of the Boundary Adjustment Act as applied to post-exchange GBNPP lands that would be directly or indirectly affected by this project. (NHI)	Section 2 (c) states that an exchange of lands shall occur only if the Commission and the Secretary conclude that construction and operation of a hydroelectric power project on the lands specified in Section 3 (b) will not adversely impact the purposes and values of GBNPP as constituted following the land exchange. Section 3 (b) (3) states that issuance of a license is subject to the same condition. Adequate standards have been articulated in the draft EIS and they are described as the purposes and values of the unit as set by Glacier Bay National Park and Preserve enabling legislation (section 1.7.4). The "purposes and values" of the GBNPP are broadly stated; therefore we looked to the project's effects on the purposes and values of GBNPP as a whole. The possible effects on these purposes and values have been identified in the discussion of Environmental Consequences (chapter 4). In section 6, FERC concludes and NPS concurs, that the impacts on specific, local resources identified in the final EIS would not adversely affect the purposes and values of GBNPP.
	Cumulative Effects Scope	
092	Future residential or other development on private lands in the project area was left out of the cumulative effects analysis. Development on these lands would interrupt many important wildlife migration/access routes. These lands are owned in fee simple, guaranteed reasonable	Section 4.2.2 identifies non-project actions that may result in cumulative effects when interacting with project actions. This section identifies the incorporation of Gustavus as a second class city (potential growth and development of the city), and general population growth (as related to subsistence and recreational

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	access across park holdings, and not presently high on the park priority list for acquisition, so are therefore very likely to be developed. This likelihood is increased if access for the hydro project eventually links the allotments to the Gustavus road system. (GEC)	hunting pressure) as two actions with the potential to create a cumulative impact. We have included a new action specifically identifying potential future development of state, private, or Native allotments adjacent to the proposed access road for the project area in the list of potential actions for cumulative effects consideration.
093	Erosion of the wilderness preservation system is a cumulative impact. (Friends)	Implementation of the land exchange and boundary adjustment would result in no net loss of wilderness from the National Wilderness System. Additionally the possible future removal of land from the national wilderness system is highly speculative and not reasonably foreseeable; therefore, we do not address this action as part of our cumulative effects analysis.
	Geologic Resources and Soils	
094	Page 4-16, lines 31-37. If GEC has to bring in road construction materials from outside the project area, as the NPS did in building its new road to Bartlett Cove, what would be the estimated increased cost of the project? Did FERC staff estimate the increased road construction costs in its analysis of economic feasibility of the project? (NHI)	GEC indicated in the license application that all necessary road construction materials could be obtained from the proposed project site. However, GEC's incorporation of a 15 percent contingency in its construction cost estimate (as described in sections 5.1 and 6.1.1.4 of the draft and final EIS) would address additional costs in the event that materials for road construction would be needed from outside the project area.
095	Page 4-14, lines 8-10 states that the transmission line would be buried in or adjacent to the existing Rink Creek Road. This is not so. The transmission line would cross Rink Creek Road at the start of the access road and then cross the Gustavus forelands as described in the preferred alternative and shown in figure 2-1 of the draft EIS. The only time the transmission line would be in Rink Creek Road would be to cross it. At no time would it run parallel to it. (GEC)	We have revised the text in section 4.3.2.1 of the final EIS to address this comment.
096	Page 4-15, lines 37-39 imply that the proposed borrow pit in the Horseshoe is located on a slope greater than 72%. Borrow from the Horseshoe area will be taken because a	We have revised the text in section 4.3.2.1 to clarify the slope at the location of the proposed borrow pit.

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	cut is required through the Horseshoe Ridge for the Penstock to maintain a 0.33% slope through the area. Material from this cut will then be used as borrow material for road construction. The area of this cut is not adjacent steep terrain. Its hydrology and geomorphology would not be conducive to decreasing slope stability. (GEC)	
097	Page 4-16, lines 31-37 state that it is likely GEC would have to import rock or gravel construction materials. Based on previous road construction, much of the material needed is available at Falls Creek. Logging road builders from Hoonah came to look at the Falls Creek area and said the rock is very suitable for road building purposes required for the project. It is not known whether the mudstone is suitable for structural concrete, or whether a source of higher quality rock is available in the project area. Even if neither is true, there would only be 3 or 4 dump truck loads of gravel from Gustavus required to be trucked in. (GEC)	We have revised the text in section 4.3.2.1 of the final EIS to address your comment.
098	Pages 4-17, lines 16-22; 4-43 line 7; 4-73 line 9; page 4-47 line 31, 4-77. The figures of 350 m 3/year and 1210 m3/year are referenced by footnotes number 36 and 37 respectively. The footnotes state that "this estimate is high…" by approximately double. It is suggested to use the more probable figures of 175 m 3/year and 55 m 3/year, or at least list the sediment runoff as a range, e.g., 55-110 m 3/year. It is not stated in the document whether measures described in an ESCP were considered when the above sediment volume was calculated. Further, it is not described how the 0.1% of volume of runoff water was derived.	We have revised the text to clarify that these are our best estimates of erosion prior to implementation of an ESCP. Furthermore, we have revised the related footnotes to better indicate how these estimates were made.

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	Also, if 350 m3/year is 0.1% of the total runoff of disturbed areas and 110 m3/year is 0.1% of the total runoff of the permanent footprint, the total precipitation in the area would be 112 inches per year. The figures should be adjusted for 59 inches of precipitation per year. This is the total precipitation at the Gustavus Airport plus the 11% documented increase in precipitation in the Falls Creek area. (GEC)	
099	Page 4-17, line 4-5. Remove the word "lacustrine" in both places. Lacustrine has to do with lake sediments; these do not occur in the project area (see Mann & Streveler, 1999). (GEC)	We have deleted the reference to organic soils and peat in the watershed as lacustrine materials. However, glaciolacustrine sediments may have been deposited in the project area when water levels were higher during past periods of glaciation. We have revised the erosion and sedimentation discussion in section 4.3.2.1 of the final EIS to be consistent with this information.
100	Page 4-21, Table 4.3-2. The word "slightly" should be placed before "reduce" in "Interpretation/Consequence." This would be more harmonious with the conclusion in line 12 that there probably would be little effect on sediment transport. (GEC).	We have revised table 4.3-2 and the text in section 4.3.2 to address your comment.
101	Page 4-22, line 20. Apropos of the above comment, the words "would disrupt" are too strong and should be replaced with the words "may affect." (GEC)	We have revised the text to clarify that construction and operation of the project would result in short-term delays (generally less than 1 year) of bedload transport to the bypassed reach.
102	Page 4-23, line 40. The word "negatively" is too strong in light of conclusions drawn in 4-21, line 12 and 4-23, lines 26-34. (GEC)	We have revised the text in section 4.3.2.4 of the final EIS to indicate that the project would slow bedload transport consistent with our discussion of cumulative effects in section 4.3.2.3.
103	Page 4-24, line 9-10. This statement is based on the misapprehension that the proposed GEC boundary lies along the bank of the creek rather than the eastern lip of the canyon. Thus the canyon would lie outside the park. GEC does agree that remaining park, tidelands, and waters	We have revised the text in section 4.3.2.4 of the final EIS to clarify potential impact above the creek on the eastern side of the canyon.

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	at the mouth of the creek could be affected. (GEC)	
104	Page 4-8 of the draft EIS states that GEC evaluated other access road options and did not pursue them for environmental and cost reasons. The draft EIS provides no indication that FERC and NPS have independently evaluated the options for accessing the proposed project and the associated environmental effects. The final EIS should be revised to reflect that the FERC and NPS have independently assessed reasonable access options for the project. If additional reasonable alternatives for accessing the project are identified, include and evaluate in the final EIS. (EPA)	We have independently reviewed alternative access road locations for the project in response to comments received on the draft EIS. An alternative road alignment was identified by the state of Alaska that would minimize the quantity and length of easements that would need to be granted to the state across private land. Additional discussion is included in section 2.7 and 4.0 of the final EIS describing this alternative road alignment and its potential effects on other resources.
105	The proposed rock quarry for construction will be an attraction to the community, driving the local demand for crushed rock from that quarry up, and leading to a continued increase in traffic on Rink Creek Road. (Wilson)	We have revised the final EIS to describe the possible effects on Rink Road if the borrow pits are used as a source for crushed rock for other activities in Gustavus.
	Water Quality and Quantity	
106	Page 4-31, Section 4.4.2.1.1. So far, GEC has been unable to successfully negotiate with the appropriate agencies on instream flow requirements (IFR) necessary to maintain the Dolly Varden population in the bypassed reach. At present, GEC is preparing some possible offsite mitigation measures and costs to present to the agencies for consideration. GEC hopes to have a mitigation plan and IRF agreed to by all parties within 4 months, and to submit this to FERC. At present, the agencies have not agreed to offsite mitigation or a reduced IFR. The 5/7 cfs IRF in GEC's preferred alternative in the PDEA was derived from economics. It was the minimum IFR required to generate electricity at a cost no higher than diesel. Since then, FERC recommended adding additional environmental	No agreement regarding minimum flows has been filed with the Commission and neither you nor the agencies have filed anything to indicate that you are formally revising your proposal or recommendations regarding minimum flows. We have added the information regarding project economics and minimum flows to our economic analyses in chapter 6.

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	measures, increasing the project cost. In addition, project revenues were based on generated kWh, and not kWh sold, resulting in a reduction of projected revenues. This has resulted in the 5/7 IFR alternative no longer being able to produce power at a cost less than diesel. Since agencies contend that the 5/7 cfs IFR will not maintain the Dolly Varden, the no minimum flow alternative could have the same effect on these resident fish. Going to a no minimum flow requirement would produce enough additional revenue to satisfy the additional FERC requested measures, compensate for reduced revenue projection, and provide for a fund to finance agreed on offsite mitigation measures. (GEC)	
107	Page 4-33, lines 3-7. Recognize that the described operation is the "worst-case scenario" in that it diverts up to 23 cfs whenever available. The actual diversion will depend on the expected peak load, and will usually be less than 23 cfs, even if 23 cfs or more is available for diversion. (GEC)	In section 4.4.2.1.1 of the draft EIS, we describe the assumptions used in our evaluation of flow regimes. These included assuming that 23 cfs would be diverted whenever estimated daily mean flows exceed the required minimum instream flow by 2 cfs or more. As you indicate, this represents worst-case conditions (i.e., the lowest flows in the bypassed reach), since GEC would not necessarily divert this much water, particularly if the peak demand did not necessitate it. We have revised this section in the final EIS to clarify this point.
108	Page 4-39, lines 22-27. GEC has compared the concurrent gage records of the two gages on the Kahtaheena River, and finds that the inflow to the bypassed reach from tributaries will average about 3.0 cfs, or about 6 percent of the Kahtaheena River flow. During the lowest flow event during winter 2001, GEC observed that Greg Creek, the major tributary to the bypassed reach, was still running, and infer that this stream, which drains deep peats, seldom or never goes dry. (GEC)	We have expanded our discussion of accretion in the Kahtaheena River including reference to GEC's observations of Greg Creek flowing during low-flow period in the winter of 2001.

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109	Page 4-40, lines 29-31. The statement that "sole use of the turbine jet deflectors would limit the ability to operate the project in load-following mode while maintaining a constant flow diversion" is incorrect. If the synchronous bypass is not provided, the turbine jet deflectors will be fully capable of providing both load-following capability and a constant flow diversion; the only loss would be redundancy. (GEC)	We have revised section 4.4.2.1.1 of the final EIS to indicate that the turbine jet deflectors would be fully capable of providing both load-following capability and a constant flow diversion.
110	Page 4-41, lines 12-14. The statement that "if the synchronous bypass were not required and the turbine jet deflectors failed to operate properly then a ramping rate of substantially more than 1 inch per hour could occur" is incorrect. Under those conditions, the ramping rate will be controlled by the turbine needle valves, which will be set to adjust slowly, both to limit the rate of change in the anadromous reach and to protect the power conduit from hydraulic surges. (GEC)	We have revised section 4.4.2.1.1 of the final EIS to clarify the risk of not requiring a synchronous bypass.
111	Page 4-41, lines 20-22. The statement that "operating the project under a no minimum flow requirement would result in a significant adverse effect on surface water quantity" is unsupported, and should be removed or modified. (GEC)	Our analysis indicates that during low flow periods, flows in the bypassed reach would be substantially lower under a no minimum flow requirement than either GEC's proposed or agency recommended minimum instream flows. Under a no flow scenario, flows in the bypassed reach would frequently consist only of accreted flows from tributaries and groundwater sources. We have revised section 4.4.2.1.1 of the final EIS to clarify this point.
112	Page 4-41, line 35 through Page 4-42, line 3. This paragraph seems entirely redundant, and should be removed. (GEC)	We have retained this text since it summarizes the effects described in section 4.4.2.1.1 of the draft and final EIS.
113	Page 4-47, lines 26-28. The statement that "streambeds consisting of small-sized sediments enhance the formation and maintenance of a thaw bulb, since they enable water from the stream to flow into and through the streambed	We have revised the text in section 4.4.2.1.2 of the final EIS to clarify the effects of small-sized sediments on thaw bulbs.

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	and the area immediately below the streambed" seems incorrect. Large-sized sediments seem more likely than small-sized sediments to enhance thaw bulb formation for the reason given. (GEC)	
114	Page 4-50, lines 22-25. The lengthy list of equipment should be deleted. It is sufficient to say an assortment of heavy equipment will be used. (GEC)	We have revised the text in this section to provide only a few examples of the types of heavy equipment.
115	Page 4-54, line 32. Flows would be affected in just the bypassed reaches, which comprise about 2 miles or about 1/3 of the 6.5 mile fish-inhabited portion of Falls Creek. Change "much" to "about 1/3" as a more accurate characterization. (GEC)	We have revised the text in section 4.4.2.4 of the final EIS to better define the river segment that would be affected by flow alteration as you suggest in your comment.
116	Table 4.4-1 should include NPS-Rivers, Trails, and Conservation Assistance Program's recommended flows for aesthetic resources described under section 4.11. (ADFG)	Table 4.4-1 presents proposed and recommended minimum flows for fish habitat maintenance. NPS recommendations for aesthetic flows are considered in section 4.11 of the final EIS.
117	The development will negatively impact the water, fish, and wildlife that depend on the stream for their survival. The stream and the life that depend on it are currently in pristine condition, just as the Wooshkeetaan Clan ancestors left them and this project will disturb that delicate balance, regardless of how carefully it is built. (Hanlon)	Our conclusions regarding the effects of the project on water, fish, and wildlife in the proposed project area are summarized in section 4.4, 4.6, and 4.8. We have added descriptions of the effects to Native allotments to these sections to address your comment.
	Air Quality	
118	Page 4-63, lines 12-25. The analysis described in this paragraph grossly overestimates the particulate emissions. First of all, the amount of disturbed land that will produce particulate emissions is less than 29.6 acres, since only a small section of the project will be worked on at any one time, and much of the disturbed land will only be disturbed to the extent that trees will be removed. Second, ground-disturbing construction activity will occur only for a small portion of the 24-month construction period, particularly	Based on information provided in the license application and your comment we have revised section 4.5.2.1 of the final EIS to assume that only 50 percent of the acreage would be disturbed by construction activity for about 4 months. We have recalculated the total TSP emission estimate based on these new assumptions.

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	during the road building period. Third, the area's climate is moist, which naturally limits particulate emissions. (GEC)	
119	Page 4-65, lines 3-9. The reference to table 2.3-1 should be corrected, probably to table 5.3-1. However, it is not clear how the emissions reductions are calculated. If they are based on a simple multiplication factor, then the reductions should be proportional to the reduction in diesel generation. Table 5.3-1 indicates that, for GEC's proposed alternative, the reduction should be 92% instead of 85%. (GEC)	We have corrected the table reference to table 5.3-1. We also have revised the text in section 4.5.2.1 to explain how we calculated the reduction in emissions to address your comment.
120	Page 4-65, lines 32-34. The statement that "the development of the proposed project would negatively affect air quality resources during the construction phase and could slightly improve air quality thereafter" is biased and unbalanced. It should be modified by replacing "could slightly" with "would."(GEC)	We have revised this discussion in section 4.5.2.1 of the final EIS to address your comment.
	Fisheries Resources	
121	Page 4-93, line 29. "Kahtaheena River" should be replaced with "Falls Creek." The Swan Lake project is on a different Falls Creek than GEC's proposed project. (GEC, AAIP)	We have revised the summary of project operation in section 4.6.2.1 to indicate that the Swan Lake Hydroelectric Project is located on Falls Creek.
122	Page 4-96, line 20. It is true that, given incomplete survey data, Falls Creek is the only stream in the park known to maintain resident Dolly Varden. It is also true that the project has <u>no</u> potential to eliminate this population, nor can the project's effects ramify into the 86% of the population residing upstream of the intake site. It is further true that dozens of resident Dolly Varden populations are known to exist elsewhere in SE Alaska. (GEC)	In section 4.6.2.1 of the final EIS, we indicate that the Kahtaheena River is the only stream in GBNPP <u>known</u> to maintain resident Dolly Varden. In sections 3.6.3.6 and 4.6.2.1, we indicate that resident Dolly Varden are known to occur in several other streams in Southeast Alaska. In section 4.6.2.4, we conclude that under a no minimum flow scenario, losses of resident Dolly Varden could be near 100 percent <u>in the bypassed reach</u>, not the entire stream.
123	Page 4-97, line 21, Page 4-173, lines 30-31, Page 4-174,	Figure 2-1 shows GEC's proposed boundary would be along the

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	line 12. This is based on a misapprehension of GEC's proposed boundary, which lies along the canyon lip rather that at creekside. (GEC)	eastern lip of the canyon. We have revised the text in section 4.6.2.2 of the final EIS to indicate that under the GEC proposal there would be a narrow buffer between project lands and adjacent GBNPP lands. We have revised section 4.14.2.1 to correct the description of the eastern boundary; however, the effects on Park lands described in this section remain unchanged.
124	Page 4-98, line 5. GEC strongly doubts that 4 inch long char will ever be a big draw to local fishermen provided with the opportunity to catch salmon and halibut. (GEC)	We have revised the text in section 4.6.2.3 of the final EIS to address your comment.
125	Page 4-99, line 6**.** Increased coarse sediment delivery to the delta would likely be a very positive outcome. At present, glacial rebound is resulting in a tendency for the creek mouth to downcut into clays, with a consequent potential loss of pink salmon spawning habitat (see Mann & Streveler, 1999), and increased sediment input would counteract that. (GEC)	We have revised section 4.3.2 of the final EIS to address your comment.
126	Page 4-102, lines 29-30. It is hard to understand this conclusion, especially given the argument developed elsewhere in the document that state management constitutes a reduction in protection. (GEC)	We have revised the text in section 4.6.4.4 to clarify our conclusion.
127	Dolly Varden char population estimates should be used with caution, because they were conducted for only small areas at one point in time. (ADFG)	The limitations of the population numbers are discussed in section 4.6.2.1 of the final EIS. This discussion recognizes the need to view the population estimates with caution. However, the data upon which the estimates are based represent the best and only information available regarding population size and provide a reasonable order of magnitude estimate of Dolly Varden numbers in Falls Creek. None of our conclusions regarding effects of the various alternatives nor the various protection, mitigation, or enhancement measures was based solely on these population estimates.
128	PHABSIM model is unreliable at the extrapolation limits	Concerns about the application of the PHABSIM model are

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	used by FERC/NPS. Request clarification for using these limits. (ADFG)	discussed in detail in section 4.6.2.1 of the draft and final EIS. While there are legitimate concerns about how this model was applied, taken in combination with the information collected on the available habitat areas and distribution of fish in the bypassed reach it provides an additional means for quantifying the effects of reduced flows on fish habitat in the bypassed reach.
129	Facilities excluding fish from the penstock and providing fish passage downstream into the bypassed reach are proposed. However, the alternative of no instream flow is not evaluated in section 4.6.2.1 of the draft EIS. If no instream flow is provided, facilities must be properly designed to prevent impacts on fish. (ADFG)	We have revised section 4.6.2.1 to discuss the effects of no minimum flow and downstream movements of Dolly Varden.
130	Page 6-6 through 6-8. ADFG disagrees with the method for making instream flow recommendations used in the draft EIS. The draft EIS bases their instream flow recommendations on the upstream persistence of Dolly Varden populations and the continued availability of Dolly Varden for scientific study. ADFG is mandated to protect and manage fish and wildlife resources on the sustained yield principle and persistence and availability for study are not adequate criteria for sustained yield. Instead, it is suggested that evaluations should be based on the sustained yield principle. (ADFG)	We assume that by sustained yield, you are suggesting that the resident Dolly Varden population should remain at its current level of abundance. While no net loss would be a desirable outcome for any of the resources that could be affected by this proposal, it is generally not achievable when trying to balance all possible benefits and impacts of a proposal for new development. As we explain in section 6.1.1.1 of the draft and final EIS, the benefit of the higher flows recommended by the agencies for protection of resident Dolly Varden is not worth the costs in terms of reduced generation. Further, we explain in section 6.2 of the final EIS that staff assesses the agencies' recommended higher flows to be inconsistent with the comprehensive planning standard of Section 10(a) of the Federal Power Act. We have concluded that reduced abundance of the resident Dolly Varden population in the bypassed reach due to lower minimum flows would be acceptable when considered in combination with the possible benefits of the higher project generation and reduced diesel generation.
131	Description of the length of the bypassed reach needs to be	We have revised the final EIS so that the length of the bypassed

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	reconciled throughout the document. (ADFG)	reach is described as 1.79 miles consistently throughout the document.
132	Show Table 4.6-3 as a multiple line graph so that the changes in “weighted useable area” (WUA) percents per unit of change in discharge can be observed from the curve gradients. Such a graph, unlike a table, would use a constant unit interval on the discharge axis, or at least indicate any change in discharge interval values. (AAIP)	We have added new figure 4-4 to the final EIS to address your comment.
133	Tables 4.6-5 and 4.6-6 could be read to imply that the frequency of flows of *less than* 5 cfs would increase under the GEC proposed flow regime as compared to the No-action Alternative. Less misleading column headings should be used. (AAIP)	We have revised tables 4.6-5 and 4.6-6 to clarify the frequency of flows less than 5 cfs.
134	On page 4-86, lines 5-11, the paragraphs misleadingly imply increased percentages of time of flows less than 5 cfs under all of the proposed or recommended flow regimes. Lines 10 and 11, which explicitly refer to flows “in the 0 to 5 cfs range,” imply that this range of flows would increase in percentage of time in the winter, although the only increase in this range would be at its upper extreme, except under the no minimum flow scenario. (AAIP)	We have revised tables 4.6-5 and 4.6-6 to clarify the frequency of occurrence of flows less than 5 cfs.
135	On page 4-87, lines 7-11, the first sentence in the paragraph is incorrect. Under the FWS and ADFG-recommended scenarios, diversions could not occur at stream flows of less than 10 cfs; therefore, the percentage of time of these lesser flows would not increase over the No-action Alternative. The last sentence of this paragraph is literally true, but misleadingly implies that a 10 cfs winter minimum flow is required to prevent increases in percentage of time for flows in the 0 to 5 cfs range. (AAIP)	Implementation of the FWS and ADFG-recommended flow regimes would not change the frequency of flows of less than 10 cfs; however, the frequency of 10-cfs flows would be increased under the agency recommended regimes. We have modified the discussion of the effects of diversion of stream habitat characteristics in section 4.6.2.1 of the final EIS to clarify this issue.

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136	The sentence on page 4-94, lines 18-20, is misleading because the percentage increase of time this range of flows would be experienced is true only for its upper extreme of 5 cfs, not for lesser flows of <5 cfs. (AAIP)	We have revised tables 4.6-5 and 4.6-6 to clarify this.
137	The magnitude of effect on resident Dolly Varden and other species is very similar to a naturally occurring event such as land slip, drought, or change in watershed runoff. (Banks)	While the magnitude of effects may be similar to natural events, when viewed as one time events, the frequency and duration of project related events would likely be higher and there would likely be more pronounced long-term population effects.
	Wildlife	
138	Page 4-114, line 6. Change "the year" to "their active season."(GEC)	We have corrected the text in section 4.8.2 to recognize that black bear use of the beach meadows occurs throughout their active season, and not throughout the entire year.
139	Page 4-115, line 28. There is no trail along the creek to the Upper Falls. The falls may be reached by trails requiring considerable local knowledge to find, and a difficult traverse along the canyon wall. (GEC)	The text used the term "informal trail" to indicate that there are no developed or improved trails along the Kahtaheena River, but that hikers may use informal trails or game trails to traverse the area.
140	Page 4-118, lines 29-30**.** GEC agrees with this statement, but believes it should be tempered with the likelihood that such impacts will probably occur with or without the project. See comment 4-2 for elaboration. (GEC)	The cumulative effects statement assumes that a disturbance effect on wildlife would occur as a result of population growth in the area alone. The primary function of this sentence is to disclose the potential interaction of effects (the cumulative effect) between the potential non-project and project actions.
141	The wetlands running parallel to the forests between Rink and Falls creeks are a significant feeding area for black bears in the spring and early summer. Roads, more human presence, and impacts from the infrastructure of the project will have measurable effects on the wildlife that use this area. (Pursell, Spotts, Friends, Wilson)	Project effects on vegetation and bears are evaluated under sections 4.7 and 4.8, respectively. Project studies identified and described locations and times of habitat use by bears in the project area and surrounding habitats. This information was used to evaluate project impacts on bears using these habitats. This information is summarized in the discussion about blocking or fragmentation of wildlife corridor movement in section 4.8.2.1 of the final EIS.
	Soundscape/Noise	
142	Section 4.10 Soundscape/Noise (Page 4-133): This section does not evaluate the reduction in noise from the existing	We have revised the discussion of the effects of project operation on soundscape in sections 3 and 4 of the final EIS.

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	diesel powerplant in Gustavus that would occur with the project operation. That beneficial effect should be documented to the same degree as the noise created by the project construction and operation. Under no action, existing generators and their associated 10 H.P. cooling fans would continue to operate with their same associated noise levels. This noise is close to the school, post office, community chest, and airport. It affects many residences, as it can be heard up to ½ mile away on quiet days. Using Falls Creek hydropower, noise from the diesel system would be silenced most of the time, and reduced the remainder of the time. (GEC)	
143	Helicopter flights to and from Bear Track Inn have been previously voted down by residents. Would residents be assured that there would be no helicopter usage in the development, construction, operation, and maintenance of such a facility? (Farrell)	GEC has indicated that it has no plans to utilize helicopters during the construction, operation, and/or maintenance of the hydroelectric facility.
	Visual Resources	
144	Page 4-143, Table 4.11-1**.** Based on the GEC field team's seeing no visits to the falls during 485 hours of observation during the summers of 1997-2000, the estimate of 34 annual resident visits to the Lower Falls is a considerable overestimate. GEC can offer no firm number, but suspects the average resident visits per year is 10 (not 34). Thus, using 34 in the table is misleading. Given that no firm figure exists, we recommend deleting this line in the table. (GEC)	Table 4.11-1 estimates 34 recreation visitors per month in year 30, not 34 annual resident visits. We have revised the table to make it more clear. We have revised section 4.11.2.1 of the final EIS to refer the reader to section 4.12.2.1 for the derivation of the number of visitors per month.
145	Table 4.11-1, Page 4-143**:** GEC provides values for the zero instream flow proposal pursued by GEC and modifies the values slightly for the other two instream flow regimes by (1) using average daily flows rather than average monthly flows, and (2) by factoring in inflow between the	The cost of the instream flow proposed by GEC in its license application is the value against which we compare the alternative flow proposals to assess the economics of the proposed project. We revised the text and table 4.11-1 to clarify that the stream flows are calculated using daily mean flows

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	diversion and the lower falls (estimated to be 6% of the flow at the diversion). Note that the reductions shown in the revised table provided by GEC are based on the assumption that the project will divert as much flow as possible, up to 23 cfs. In reality, the diversions will usually be less than the 23 cfs maximum because the load will be less than the 800 kW maximum.(GEC)	rather than monthly flows and to match the discussion in the water resources section 4.2. The table also incorporates the accretion of flows below the bypass structure, which results in more accurate estimates. Staff's hydrologic modeling is used with GEC's generation projections to determine generation availability versus GEC system load requirements.
146	Table 4.11-2, Page 4-144**:** GEC provides values for the zero instream flow proposal pursued by GEC and modifies the values slightly for the other two instream flow regimes by (1) using average daily flows rather than average monthly flows, and (2) by factoring in inflow between the diversion and the lower falls (estimated to be 6% of the flow at the diversion). Note that natural flows exceeded 80% of the time are significantly different than those shown in Table 4.11-2, which are inconsistent with Table 4.4.2 of the draft EIS. (GEC)	We have revised the table and corresponding text to use the average daily flows rather than the monthly flows and factors in the accretion below the diversion structure. These numbers also reflect the analysis presented in the water resources section 4.2 in the final EIS.
147	Page 4-146, lines 20-23: The last sentence of this paragraph is false. Although each individual viewer may have a lesser appreciation of the visual appearance, the increased visitation as the result of improved access will likely result in a cumulative increase in appreciation. (GEC)	There is a delicate balance between existing users' values and the increase in users due to improved access. We have revised the text to clarify that "the appreciation of the falls is valued on an individual or group basis at the moment of viewing something, and does not increase or decrease in value depending on the overall number of people that visit the falls."
148	The magnificence of the Lower Falls of Falls Creek must be emphasized. It would be a crime to harness Falls Creek for this hydroelectric project. To do so will diminish the awesome character of the water falls of Falls Creek. (Pursell)	We provide a description of the aesthetic values of the Lower Falls in section 3.11.1 of the final EIS and address the potential effects on the aesthetic resources of the Kahtaheena River area that could stem from the proposed project in section 4.11.2 of the final EIS.
	Recreation	
149	Page 4-153, line 13. As noted in comments on 3-64 and 3-65, more realistic estimates are 72 and 10 visits, respectively. (GEC)	We have modified the data to be consistent with the dates backcountry visits occurred within GBNPP as stated by the GBNPP backcountry surveys. We address your comment in

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		section 3.12.1.1 of the final EIS.
	Wilderness	
150	Section 4.13.2.2 starting on page 4-163. The paragraph starting line 25, page 4-165 states that the land exchange "would have considerable negative effect on GNPP wilderness values and resources." Is “considerable” quantified as the personal bias of the section’s author? To say that these lands have "exceptional wilderness value" is very different than what other researchers say. Certainly, Interior officials and members of the U.S. Congress in 1998 would disagree. They felt that if this project met the condition of a FERC license, that the land exchange would be an improvement to National Park System and wilderness boundaries. While many NPS employees oppose taking land out of wilderness for any reason as demonstrated at the Gustavus public hearings, this is not the wishes of the people of the U.S.A. as voiced by elected representatives in Washington DC. The document’s conclusions are misleading. There is parity on a larger scale than GBNPP. Great thought was put into which lands the NPS wanted to exchange in the legislation, and for others to second guess these selections at a later date is probably personal bias. The paragraph starting on line 27, page 167 contains the same bias. GEC researchers intimate with all subject lands maintain the exact opposite of the opinion expressed in the draft EIS. This entire section could just as easily and more justifiably express the opinion that the de-designation of wilderness lands and the designation of non wilderness lands would have considerable positive effect on GBNPP wilderness values and resources. (GEC)	We have revised the text to state that the land exchange would have an overall negative impact on GBNPP wilderness values and resources. This overall negative impact may be somewhat offset by the designation of other parcels as wilderness within GBNPP. However, because the value of wilderness can vary from location to location based on the uniqueness of the resources, the compensation for wilderness lost in one area with replacement in another should not be considered as equal.

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151	Table 4.13-1 (page 4-166) is very misleading. It treats the island near Blue Mouse Cove, Cenotaph Island, and Alsek Lake as wilderness, when in fact they are **not** wilderness. It is managed as *de facto* wilderness now, but this could change at any time in the future, and a concessionaire could build a lodge there at the very least. The title of this table should change to show that it is designated and *de facto* wilderness, similar to what it is in the column headings. Also, there should be another table showing the same information, but not treating *de facto* wilderness as though it was presently wilderness. This new table would have the same number in the "TOTAL" column, and would be provide a true picture of the alternatives. The legislation mandated parity in the exchange, and it should be shown. This entire section on Wilderness refers to lands managed as wilderness. It should be emphasized that these lands are presently managed as wilderness. Some discussion should be given to the possibility that they would not be managed as wilderness in the future if the No-action Alternative is selected. (GEC)	As indicated in section 4.13. 2.2, the lands proposed to be designated as wilderness are already managed as such under the current GBNPP general management plan, which indicates that these lands will remain undeveloped. Table 4.13-1 indicates which lands are currently designated as wilderness, and which lands managed as *de facto* wilderness under each of the four alternatives. We agree that the change in the title of the table would be more accurate. We have revised the text in section 4.13 of the final EIS to reflect the possibility of a change in the General Management Plan for GBNPP in future years, which could change the way these lands are managed.
	Park Management	
152	Page 4-176, line 1 to 4-179, line 22. The argument in these pages is hard to accept. It seems that, by considerably simplifying the park boundary and separating native allotments from park lands, NPS management would be considerably simplified under both alternatives. In addition, by setting the boundary along the canyon lip which is a natural barrier to human travel, the GEC alternative further simplifies management. Since no analysis is given to future management difficulties from development on the allotments, these two sections come, overall, to a more negative view of future management	Evaluation parameters developed by FERC and NPS staff to identify and describe the potential effects on park management in the project include (as listed in section 4.14 of the draft EIS): personnel numbers, demand for park personnel, law enforcement patrols, acres of land managed, jurisdiction of resource management area, consistency of management within park boundary, and management conflicts with adjacent lands. Based on these parameters, we conclude that effects on park management would be more intense under the corridor alternative than the proposed GEC boundary alternative and the maximum boundary alternative.

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	under either the GEC or maximum boundary alternative than would seem warranted. (GEC)	
	Socioeconomics	
153	On page 4-197, line 20-22, the draft EIS states that, once construction is completed, traffic along Rink Creek Road would resume to pre-project levels with the addition of weekly trips by GEC staff. AAIP requests that the projected increase in traffic related to recreation be recognized in this context. (AAIP)	We revised the text in section 4.16.2.1 to recognize that, once construction would be completed, Rink Creek Road could experience a small amount of recreational use related traffic associated with the presence of the proposed access road.
	Irreversible/Irretrievable Commitments of Resources	
154	Section 4.18 on page 4-201 mentions irreversible effects of the project. The first bullet is true, but incomplete. One effect is removal of land from GBNPP. It is suggested that another irreversible effect would be the addition of land to either KGNHP or to WSNPP. The second bullet item does not make sense. Please clarify. This item would be covered by the other 3 bullet items. Please explain the removal from the Excursion Ridge/Kahtaheena River area. In the third bullet item, the reference to the transmission line should be removed, since the transmission line will be buried and therefore have no visual impact. (GEC)	We have revised the text in section 4.18 of the final EIS to indicate that the exchange of state lands within KGNHP and WSNPP also would be irreversible. We have revised the second bullet to clarify that it relates to use of the lands, not the exchange of the lands. While the transmission line would be buried, the access road that parallels the transmission line route would have a visual impact. Therefore, we have revised the fourth bullet to indicate that visual impacts of the project structures and road/transmission line routes would be irreversible.
	Developmental Analysis	
155	The on-line date of 2007 projected by GEC in its application and PDEA, and subsequently used by FERC in the draft EIS, now appears in doubt due to the time required to issue the draft EIS and the anticipated process for issuing the license and completing the land exchange. A later on-line date would actually make the project economics more favorable because of (1) the expected increase in Gustavus loads over time, and (2) the escalation of diesel fuel prices. Nevertheless, GEC is reluctant to abandon hope of a 2007 on-line date, and recommends it	We used the start date of 2007 as projected by GEC in the license application in our assessment of the economics of the proposed project.

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	be retained for the final EIS. (GEC)	
156	FERC has estimated insurance costs as 0.25% of the investment cost. That percentage is reasonable, however FERC failed to deduct from the calculated amount of $11,090 the amount already included by GEC in the operation and maintenance costs ($5,000 in 2001$, $5,300 in 2003$, see Table A-3 of the Application for License for a breakdown of the estimated operation and maintenance costs). (GEC)	We note that the O&M cost of $35,000 in the license application includes insurance; however, the $30,000 O&M in the PDEA, which was our basis for the values used in the draft and final EIS appears to have excluded the insurance value, so a deduction appears unnecessary.
157	FERC has estimated property taxes as 3% of the investment cost. The project will be located on either state land or private land (AIDEA). Gustavus is unincorporated and therefore not capable of assessing property taxes. The state does not assess property taxes. For that portion of the project on state land, GEC expects to enter into a long-term lease, for which there may be a payment. However, since the state land will be used for generation and transmission of energy for the public good, GEC expects that any lease payment will be nominal. GEC is negotiating with the owner of the small piece of private land regarding compensation, however, and amount has not been determined. GEC included an amount for lease payments in its estimate of operation and maintenance costs ($5,000 in 2001$, $5,300 in 2003$, see Table A-3 of the Application for License for a breakdown of estimated O&M costs), and believes that amount is sufficient. (GEC)	We have adjusted our values accordingly in chapter 5 and section 6.1.1.4 of the final EIS to reflect no property tax payments.
158	FERC has estimated federal income taxes based on a tax computation that is not reproducible from the information in the draft EIS or in the subsequent responses to GEC's requests. Regardless, GEC expects to fund all of the construction by either grants or long-term low interest loans. Since there will be no equity financing, the project	We have adjusted our values in chapter 5 and section 6.1.1.4 of the final EIS to assume the project is funded 100 percent with debt.

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	will not result in additional federal income tax payment by GEC since income taxes result only from returns on the equity part of the financing. (GEC)	
159	FERC has conducted the analysis for a term of 30 years. That may be appropriate for relicensing existing projects, where license terms are typically 30 years. However, original licenses are issued for 50 year terms, and therefore it is appropriate for the economic evaluation to extend for 48 years (the 50 year term of the license less 2 years for construction). This does not involve any greater degree of uncertainty, and it more fairly evaluates the long-term benefits of hydropower. (GEC)	The Commission's methodology for the determination of net annual benefit in section 5, *Developmental Analysis*, of the draft and final EIS uses a term of 30 years for the period of analysis even though the license term could be longer. The topic of economic evaluation is addressed in section 6.1.1.4.
160	GEC has been earmarked for a grant in the amount of $1,083,685 from the Denali Commission to assist in defraying the construction cost of the project. FERC's analysis should reduce the estimated construction cost by that amount. (GEC) AEA found the project to be economically feasible if NPS electrical loads were included and allocated $1,083,685 in grant funds to the project subject to further assessment and verification of NPS load. (AIDEA)	We note that the Denali Commission has awarded this grant based on a determination of positive net benefit due to the inclusion of NPS loads. Since, at this time, the NPS load is not part of GEC's load, we assume in our developmental analysis (chapter 5) that this grant will not be received. However, in the economic feasibility discussion in section 6.1.1.4, we examined the economics of the project with and without the grant and NPS load as five separate scenarios.
161	GEC has been earmarked for a loan in the amount of $1,000,000 from AIDEA, with an interest rate of 5.43% and a term of 30 years. In addition, GEC will qualify for a loan from the Rural Utility Service, which currently has programs with interest rates of about 5.5% and terms of 30 years. For the final EIS, it will be appropriate to assume the balance of the financing will be by a loan with an interest rate of 5.5% and a term of 30 years, which are much more favorable conditions than assumed by FERC (8.0%, 20 years). A final financing plan consisting of	Because nothing in the record appears to indicate that these loans are tied to inclusion of NPS load or other conditions, we assume that these loans would be available (for some of our modeled scenarios) and adjust the cost of debt accordingly. However, we use a discount rate as allowed by the RCA rather than as a function of the cost of capital.

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	grants and loans will take at least 6 months to develop. (GEC)	
162	FERC estimated costs for the mitigation measures proposed by GEC amounting to $54,480 in capital costs and $7,000 in annual costs. GEC estimated $10,000 in annual costs (2001$) for environmental monitoring costs (see Table A-3 of the Application for License for a breakdown of the estimated operation and maintenance costs), somewhat more than estimated by FERC. Therefore, FERC should not have added the $7,000 on as an additional annual cost. GEC did not explicitly estimate mitigation capital costs; however, they are included in the contingency allowance (see Table A-2 of the Application for License). Since the measures were proposed by GEC, FERC should assume that their costs are also included in GEC's estimated costs, and FERC should not add them onto the construction cost. GEC is in the process of negotiating a settlement with the agencies on a reduction in the instream flow requirement to zero. If that effort is successful, as GEC believes it will be, then GEC would expect to provide off-site mitigation to compensate for the impacts on resources in the bypassed reach. GEC expects the amount of off-site mitigation to be about $50,000. (GEC)	We have adjusted annual cost values accordingly. Since, at this time, there are no finalized off-site mitigation measures, the developmental analysis only examines the project with proposed minimum flows and no off-site mitigation costs.
163	FERC has recommended mitigation measures in addition to those proposed by GEC. The total additional capital cost is estimated to be $315,160, and the additional annual cost is estimated to be $27,000. GEC recognizes that additional mitigation will be required by the license; however, some of the estimated costs are not reasonable. GEC provided estimated costs for FERC-recommended mitigation measures.(GEC)	We have reviewed your cost estimates and have revised chapter 5 to include your cost estimates, except we maintained the escrow fund capital cost of full $50,000 and the annual cost for the biotic evaluation plan.

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164	FERC has evaluated the cost and benefits of the project if GBNPP does not interconnect. If GBNPP decides not to interconnect, then GEC will need to resize the project so it is appropriate only for the Gustavus load. The following major changes would occur: • Generating unit capacity would be decreased to 600 kW. • Penstock diameter would be decreased for the revised flow rate of 17 cfs (30" pipe would decrease to 26," 28" pipe would decrease to 24," 24" pipe would decrease to 21," and 20" pipe would decrease to 18") GEC estimates that these modifications would decrease the capital cost to $3,860,000 (2001 cost level). GEC is reluctant to design and build the project at this reduced size because it feels the NPS would not choose to burn fossil fuels if hydropower were in place and available. However, if it is necessary to downsize the project to obtain the license, GEC would do so. (GEC)	The draft and final EISs are based on the project as proposed in the license application. A change in project features as described here would likely require amendment of the license application. We continue to assess the project as proposed in the current application for license.
165	FERC's estimate of revenue is based on displacement of diesel generation rather than the actual load (i.e., sales). GEC's generation is actually substantially greater than the load because of line losses in its widespread system and forced-air cooling of the diesel generators. GEC provided generation and sales for the last 10 years. Note that there is a pronounced tendency for the sales/generation ratio to increase with generation. Since generation is expected to increase with time, it is appropriate to expect a higher ratio in the future. For its analysis, GEC has assumed that future sales will be 87.5% of the generation. (GEC)	The Commission staff's economic analysis in the final EIS includes no estimate of GEC "revenues" from the sale of project power. Our economic analyses are based on production costs compared to the cost of diesel generation, which we believe is the most likely alternative to project generation and, therefore, a reasonable proxy for the "value" of the project power. The power value we use for our analysis may be much different than "revenues" GEC derives from the sale of power to its customers at retail prices.
166	Discussions in the 1st and 3rd paragraphs of page 5-1 should be clarified to explain a possible contradiction. The	We have adjusted the text in these paragraphs in chapter 5 of the final EIS to distinguish between the developmental analysis and

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	first paragraph states "…that the proposed land exchange required to construct the Fall Creek Hydroelectric Project cannot occur until the Commission determines that construction and operation of the project can be accomplished in an economically feasible manner." However, the third paragraph states "If the Commission issues a license for a project with negative net benefits based on the Commission's method of analysis, it is up to the licensee to make the business decision of whether or not to accept the license and build, or continue to operate the project based on its own financial analysis and business requirements."(ADFB)	economic feasibility sections.
167	In table 5.3-2, footnote "e" is not referenced in the table. Clarification is needed because the instream flows recommended in footnote "e" do not match the instream flows recommended on page 6-3. (ADFG)	Footnote e should not have been included in the text, and we have removed it from the final EIS.
168	The economic analysis should incorporate land use fees associated with state and non-state lands. These costs as well as the costs associated with the Mental Health Trust Lands and private landowners should be included in the economic analysis. (AAIP)	In the license application, GEC supplied an estimate for the use of lands, and we have incorporated these costs into sections 5.1 and 6.1.1.4 of the final EIS developmental analysis and economic feasibility sections.
169	There is no urgent need for additional generation resources in the near future. GEC's peak loads are around 315 kW. The two primary diesel generators (Units 1 & 3) have a combined capacity of 550 kW, there is a 500-kW backup generator (Unit 4), and a 100-kW generator that is seldom used (Unit 2). Under mid range growth scenarios, GEC's peak capacity will not approach 540 kW until 2014. (Cutter)	We based our assessment of the need for power on the relationship of proposed project to existing and future demand for power. As discussed in section 1.1.2 of the draft and final EIS, the proposed project is designed to take the place of the majority of GEC's diesel-fired generation, at least in the near-term. The draft and final EISs discuss the need for power in terms of the benefits provided by the proposed project, which do include increased overall capacity to serve GEC's current and future load, but also highlight other factors including reduced cost variability and a reduction in issues related to electrical generation using diesel fuel.

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170	The draft EIS indicates annual *generation* of 1,638 MWh in 2002, while documents provided by the Regulatory Commission of Alaska indicate annual *sales* of 1,404 MWh in 2002, nearly 15 percent lower. Account for this difference in calculating power costs to the community of Gustavus. (Cutter)	Based on the generation, sales, and load loss information provided in comments on the draft EIS, we have revised section 1.1.2 of the final EIS to differentiate between kWh generated and kWh sold and have updated load values.
171	The project application assumes that GEC can serve NPS load at Bartlett Cove and the project is not economically feasible if the NPS load is not included. However neither the application nor the draft EIS include any costs for building the 9-mile underground transmission line from Gustavus to Bartlett Cove. (AIDEA, Banks, Soiseth, Lee). Cutter states that a contractor told NPS that the total cost for laying the underground cable would be $4.5 million; AIDEA estimates the cost at $500,000. (Cutter, Wilson); GEC estimates the cost at $600,000 (2003 cost level). Note that GEC has installed 80 miles of underground cable in the Gustavus area in the last 20 years, and knows the costs better than anyone. (GEC)	Our analysis of the economics of the proposed hydroelectric project attempts to address reasonably foreseeable economic conditions that would directly affect the economics of the hydroelectric project. This includes various scenarios of future load that may be served by the project, including serving GBNPP load. However, a complete analysis of the economics of connecting the GBNPP to GEC, including the cost to construct a transmission line to GBNPP, is beyond the scope of this proceeding and we have not included these costs as part of our economic analysis of the hydroelectric project.
172	The exact cost of the interconnection to Bartlett Cove cannot be determined at present, because it is unknown how the NPS would want to build the line. GEC feels that public comments estimating a cost of $4.5 million are grossly inflated. At that cost, the project could not include the park, and the analysis would proceed without the park connection. Including the cost of the interconnection to the Park as part of the project cost would require the Gustavus ratepayers to pay a portion of its cost, which GEC opposes. Without NPS commitment and participation in connecting to hydropower, the analysis must proceed without park connection. If, at a later date, the NPS would choose to entertain the idea of connection	Our analysis of the economics of the proposed hydroelectric project attempts to address reasonably foreseeable economic conditions that would directly affect the economics of the hydroelectric project. This includes various scenarios of future load that may be served by the project, including serving GBNPP load. However, a complete analysis of the economics of connecting the GBNPP to GEC, including the cost to construct a transmission line to GBNPP, is beyond the scope of this proceeding and we have not included these costs as part of our economic analysis of the hydroelectric project.

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	go to hydropower, discussions could start at that time. (GEC)	
173	No inflation is used in the projection of the 30-year cost stream yet it uses nominal discount and amortization rates. Since the project is capital intensive and the alternative cost of power is not, the use of too high a discount rate will bias the analysis toward the alternative source of power. FERC acknowledges that inflation should be included in the analysis, however reference is made to section 6 and the base case remains as is. Since the base case is referenced elsewhere in the report, it would be better to have that case reflective of technically correct assumptions. Many cases run in section 6 are without inflation. It is assumed that the discount rates used in these cases are 8.0 percent, which would be an erroneous rate to use. (AIDEA)	The assessment of economic feasibility in section 6.1.14 of the final EIS examines general and component-specific inflation, thus, the use of nominal rates in that section is warranted. The methodology used in chapter 5, *Developmental Analysis*, uses nominal rates and cost escalation due to inflation is not included.
174	The value of power used in FERC's analysis is based simply on the variable cost of diesel generation; future additions or replacements to the generating plant are not considered. If the project is not built, GEC and NPS would need to add new generation to provide adequate generating capacity. New capacity would not be required if the project is built. Therefore, the power value should include provisions for capital costs of diesel units added throughout the study period. (AIDEA)	The current value of power does include O&M on diesel generating equipment. Since there are times of the year when hydroelectric generation would not be available due to insufficient flows, it is likely that additional diesel capacity would be required whether or not the hydroelectric project was built if GEC demand so warranted. Thus, new diesel generation costs are equivalent whether or not the project is built. We revised our projections of generation and demand and reveal that additional generating units would need to be added to GEC's system to meet load requirements and have adjusted our analysis as warranted.
175	With the construction of the project, GEC may be able to obtain lower insurance premiums on existing diesel resources; this should be reflected in the analysis. (AIDEA)	Without specific cost data on the record related to these potential reductions, we cannot adequately assess whether GEC can obtain lower insurance premium rates.
176	The payment of federal income taxes is not a cost directly	We adjusted our values in chapter 5 to assume the project is

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	associated with the project operations, and the amount paid by GEC is a bit more complex than simply applying a factor to the net book value of the project. GEC will also pay federal taxes without the project, and therefore, it is best left out of the analysis. (AIDEA)	funded 100 percent with debt, and thus not subject to income taxes on equity.
177	FERC's analysis is very limited in scope and, in some instances, is using the wrong discount rates in calculating annualized project costs. Explanations of assumptions throughout the economic analysis of the draft EIS are somewhat vague. It is therefore difficult to replicate FERC's work and to determine which assumptions should be challenged. (AIDEA)	We have revised our analyses in chapter 5 and section 6.1.1.4 of the final EIS based on comments on the draft EIS. The analyses include lists of assumptions and the source for these assumptions.
178	Generation and revenues based on approved rates for service would be partly a function of the customers' demand. Pages 5-2 to 5-5 overestimate the future demand by assuming it will match historic growth. Growth since 1997 has been less than half the average since 1985 due to several factors. While pp 6-30 to 6-31 include alternative growth scenarios, they do not state actual probabilities of occurrence. Amendments to these scenarios must reflect such probabilities. (NHI, Wilson)	While we cannot assign special probabilities to the likelihood of future growth scenarios, our discussion of load growth in section 6.1.1.4 includes an analysis of the variables that influence load growth. Our analysis incorporates the comments and data provided by you and others subsequent to issuance of the draft EIS.
179	The draft EIS does not assign any probability of the occurrence of NPS interconnecting with GEC. It does not explain why NPS would strand its capital investment in its own diesel generation if the project would be substantially more expensive than that existing capacity. (NHI)	Our analysis of the economics of the proposed hydroelectric project attempts to address reasonably foreseeable economic conditions that would directly affect the economics of the hydroelectric project. This includes various scenarios of future load that may be served by the project, including serving GBNPP load. However, a complete analysis of the economics of connecting the GBNPP to GEC, including possible stranded costs associated with NPS' diesel generators, is beyond the scope of this proceeding and we have not included these costs as part of our economic analysis of the hydroelectric project.
180	The draft EIS does not analyze or explain why or whether	GEC, as a certificated utility in Alaska, is regulated by the RCA

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	the Regulatory Commission of Alaska (RCA) would approve the rates necessary to recover capital and other costs of the project, particularly if those rates would be substantially higher than otherwise occur under the No-action Alternative. NHI estimates that, even in a hypothetical situation where 20% of the capital cost is paid through an unknown grant, the total cost that GEC would seek to recover in rates would be $.21 - $.52/kWh by contrast to the $.17 - $.20 cost/kWh of the existing diesel generation. (NHI)	in regard to rate-making. The RCA, not FERC, would therefore be responsible for confirming rates charged by GEC if this project is developed.
181	Section 3(c)(3) of the Boundary Adjustment Act requires that any license would be conditioned to require additional measures if the NPS, based on post-licensing monitoring, determines them to be necessary to protect GBNPP purpose and values. The Commission and NPS should include a scenario whereby the costs of environmental measures increases in the future. (NHI)	We have no basis for quantifying such future measures at this time in our developmental analysis in chapter 5. In the Comprehensive Development section of the final EIS, we discuss known or anticipated mitigation measures and associated costs for the Falls Creek Project.
182	Chapter 5 appears to omit certain financing and other costs from the economic analysis, such as depreciation, return on rate base (a full cost-benefit analysis must include the impact the increase in rate base will have on rates, in the form of the return the utility is allowed to earn on that rate base), recovery of tax payments (the RCA must increase the total return to the utility, which in turn increases income tax, to the point, that when income taxes are taken out, the appropriate return is left for the utility), and the construction of any transmission line to GBNPP in the event that NPS agrees to the interconnection. (NHI)	Chapter 5 of the final EIS describes the method and lists the variables included in the economic analysis presented. The analysis uses depreciation of capital investment in the computation of federal taxes, which are included in the project cost. Section 6.1.1.4 is a broader analysis of economics that attempts to address all reasonably foreseeable economic conditions that would directly affect the economics of the hydroelectric project. This includes various scenarios of future load that may be served by the project, including serving GBNPP load. However, a complete analysis of the economics of connecting the GBNPP to GEC, including the cost to construct a transmission line to GBNPP, is beyond the scope of this proceeding and we have not included these costs as part of our economic analysis of the hydroelectric project.
183	The developmental analysis improperly omits any	The developmental analysis addresses costs and benefits directly

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	quantification of the costs on third parties, including the repair or replacement of the privately maintained Rink Creek Road as a result of construction traffic; damages that may result from increased ease of public access and thus risk of trespass on native allotments; damages that may be imposed on local tourism businesses such as Bear Track Inn as a result of construction and other project impacts; or the NPS's effective loss of its investment in its diesel generation if it interconnects with GEC. (NHI, Friends, Park Protection Form)	associated with the construction and operation of the proposed project, and it does not address indirect potential project effects. The direct cost of Rink Creek Road improvements is included as part of the project construction cost in the developmental analysis, while the other indirect costs mentioned in this comment are addressed in revisions to section 4.16, *Socioeconomics*. A complete analysis of the economics of connecting the GBNPP to GEC, including possible stranded costs associated with NPS' diesel generators, is beyond the scope of this proceeding and we have not included these costs as part of our economic analysis of the hydroelectric project.
184	The information presented in Section 5 of the draft EIS is inconsistent with information presented elsewhere in the draft EIS. Page 5-1 indicates that the developmental analysis considers 3 alternatives: the proposed project, the proposed project with staff-recommended modifications, and the No-action Alternative. An alternative consisting of the proposed project with staff-recommended modifications has not been identified nor evaluated in the draft EIS until this section. This section should be revised to reflect analyses of the alternatives being evaluated throughout the final EIS, as required by NEPA regulations. (EPA)	We have revised chapter 5 in the final EIS to clarify that the Corridor and Maximum Boundary alternatives vary only in the extent of land that is exchanged and include the same set of environmental measures as GEC's proposed action. Separate economic analysis of these two alternatives would yield the same costs.
185	Page 5-8 discusses a "staff-recommended licensing alternative" which appears to conflict with the statement on page 6-1 that "neither FERC nor NPS has identified a preferred alternative." This inconsistency should be resolved and analyses should be developed and presented consistent with that resolution. (EPA)	We have revised the text in section 5.2 to clarify that we are providing updated cost information for measures that FERC staff would consider appropriate should the Commission license the project.
186	Please provide a clear statement about what is included in this project, including a breakdown of all the project components with corresponding cost estimates including	The cost of project components is broken out in the license application and was summarized in the draft EIS. Based on information on the record, including that supplied in comments

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	options. The cost estimate for each component should be calculated by an independent engineering/consulting firm familiar with South East Alaska conditions and National Electric Code requirements for these types of projects. Please do not calculate any kWh usage from the NPS in any of your graphs/figures unless you also show a corresponding cost to get the power to the park. The total distance from the existing GEC power house to the park power house is 9 miles. A t least 4.4 miles from the park boundary to the park power house will need to be buried cable. (Davis, Soiseth)	on the draft EIS, we have performed our own independent analysis of project economics. Our results are presented in chapter 5 and section 6.1.14 of the final EIS. Our analysis of the economics of the proposed hydroelectric project attempts to address reasonably foreseeable economic conditions that would directly affect the economics of the hydroelectric project. This includes various scenarios of future load that may be served by the project, including serving GBNPP load. However, a complete analysis of the economics of connecting the GBNPP to GEC, including the cost to construct a transmission line to GBNPP, is beyond the scope of this proceeding and we have not included these costs as part of our economic analysis of the hydroelectric project.
187	Please provide simple graphs that show corresponding kWh cost against a project funding scenario that goes from 0% to 100% use of public funds to pay for the project. Please provide graphs that show the project with and without NPS kWh usage/cost. (Davis)	Based on information provided in comments on the draft EIS, we have revised our economic analysis in section 6.1.1.4 to address the several possible funding scenarios, including the use of public funds. None of these funding scenarios include a large percent of public funding and we have therefore not included a scenario that assumes a large percentage of public funding in our analysis.
188	GEC told the community that distribution price as opposed to generation price is $0.32 per kWh. GEC's total price per kWh is $0.52. That makes GEC's price for generating power $.20 per kWh. How/why is the distribution cost so much different than most diesel powered electric utilities in the Gustavus area and what does this mean about long-term costs of power in the community. (Davis)	GEC has indicated that distribution costs are related to the low density of consumers and the costs of constructing the underground portion of the distribution system. The justification for GEC's retail rates is beyond the scope of this EIS and comments regarding GEC's retail rates, including the distribution costs, should be directed at GEC and RCA.
189	According to the Army Corps of Engineers (ACOE) Letter Report on Small Scale Hydropower for Gustavus, Alaska (June 1984) the cost of diesel fuel has only risen 3 cents in 20 years. Please verify this and explain why. Discuss relationship between Gustavus Dray (fuel supplier) and	Diesel fuel cost varies on a year to year basis as a function of many variables, and thus examination of cost between two single points is not as valid as analysis of the overall trend in prices over a period of time. Our updated analysis of economic feasibility in section 6.1.14 of the final EIS examines the

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	GEC. (Davis)	variability in diesel fuel cost trends in the past and into the future. It is beyond the scope of this EIS to discuss the business relationship between GEC and the Gustavus Dray.
190	The 1984 ACOE estimated cost for a hydroelectric project on Falls Creek was $7,958,000. Why is this cost nearly twice as much as the estimated cost for the proposed project? Please discuss the record of cost overruns for these types of projects. (Davis, Soiseth, Howell).	We have added a discussion of the ACOE cost estimate to section 6.1.1.4 of the final EIS in our discussion of project construction costs.
191	The cost of the project does not reflect the costs of maintaining the Rink Creek Road or bridge rebuild. It is not fair to expect the residents to be burdened with these costs or impacts of using this road. (Soiseth, Howell, Lee, Wilson, Farrell). If this permit is granted, and the project lands are transferred from Federal to State ownership, the responsibility for maintaining the road should be transferred to the State of Alaska. (Howell)	The Rink Creek bridge and part of Rink Creek Road are located on private land. GEC would need to obtain permanent access to the project site as part of a license condition. Options for project access could include the purchase of land, an easement agreement with the existing landowners, or through condemnation proceedings. Any of these options would likely result in GEC assuming responsibility for a proportionate share, or possibly all of the cost of maintaining the road and bridge features. GEC has indicated during public meetings that they would repair any roadway damage associated with project construction.
192	The draft EIS did not address the cost to GEC for use, lease, or purchase of NPS equipment. (Lee)	Our analysis of the economics of the proposed hydroelectric project attempts to address reasonably foreseeable economic conditions that would directly affect the economics of the hydroelectric project. This includes various scenarios of future load that may be served by the project, including serving GBNPP load. However, a complete analysis of the economics of connecting the GBNPP to GEC, including possible financial costs or benefits associated with NPS' diesel generators, is beyond the scope of this proceeding and we have not included these costs as part of our economic analysis of the hydroelectric project.
193	The economic analysis is missing costs for Rink Creek Road construction and improvements, O&M costs for both	The construction costs provided by GEC include a cost for the construction of roads and a bridge. We include O&M costs for

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	a hydroelectric plant and diesel generator backup, and increased insurance costs from increased infrastructure. (Wilson, Farrell)	diesel generation back-up as part of the power value as discussed in chapter 5. We have revised chapter 5 to include insurance costs.
	Conclusions	
194	The method of calculation does not account for a difference between the general inflation rate and escalation rate of the price of diesel fuel. If a difference in escalation rates can be demonstrated, then FERC's analysis should consider the difference. (GEC)	In the final EIS, we do not attempt to predict a single future rate of inflation for fuel costs, instead we have assessed a number of fuel cost inflation rates in an attempt to encompass a range of possible future fuel cost scenarios. We have added a discussion of general and diesel specific inflation rates to section 6.1.1.4 of the final EIS.
195	Page 6-29. The decrease in electrical energy use starting in 1999 is primarily as a result of the elimination or reduction in the PCE program. It is expected that as hydropower goes online and rates can start a gradual decline, the usage will increase as a result, generating further decline in rates. Commercial customers who are generating their own electricity have said they will use hydropower when it goes online. For these reasons, GEC feels that its load growth will meet or exceed its projections. (GEC).	We note that GEC has submitted varying statements for the trend of generation costs for the proposed project. The January 2002 revised power supply notes that the cost of hydroelectric generation versus diesel generation would initially increase, then would decrease over time and become less expensive than diesel generation at some point in the future. However, the analysis submitted in conjunction with GEC's comments on the draft EIS shows that the cost of hydroelectric generation would be the same or less than existing diesel generation, although comment text discussing the draft EIS introduction notes that NPS interconnection is required for the cost of hydroelectric generation to be competitive with the cost of existing diesel generation. We performed an independent analysis of the annual cost of generation in section 6.1.1.4 of the final EIS. Although no explicit projections regarding load growth as a function of the cost of generation are made in the final EIS, overall load growth trends are discussed in section 6.1.1.4.
196	Page 6-2, lines 30-34. As noted in 4.4.2.1.1, GEC proposed a synchronous bypass because the agencies had recently requested redundant flow continuation systems on other projects, and GEC reserves the right to eliminate the	The synchronous bypass was included as part of GEC's proposed project in its application for license. At this time, no revisions to this application have been made that would eliminate this feature; therefore, we have included it as part of evaluation of

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	synchronous bypass if redundant flow continuation is not required. The impulse turbine jet deflectors and needle valves will allow adequate load following and flow continuation capability. (GEC)	project effects and costs.
197	Page 6-3, lines 29-34: We are in the process of negotiating a settlement with the agencies regarding a reduction in the instream flow requirement to zero. If that effort is successful, as we believe it will be, then GEC would expect to provide off-site mitigation to compensate for the impacts on resources in the bypassed reach and the biotic monitoring plan will only need to address the anadromous reach. The amount of off-site mitigation would be about $50,000. Furthermore, there will no longer be a need to reevaluate instream flows after 5 years. (GEC)	The 5/7 cfs minimum flow proposed by GEC in its application for license is considered part of the proposed project. We use the no minimum flow proposal as the basis for the comparison with other recommended flows in our assessment of the economics. We also evaluated the effects of a no minimum flow requirement on the environment. Any agreements that would change the proposed project should be filed with the Secretary of the Commission and served on all parties.
198	FERC's estimate of the project generation is based on an operation simulation model that uses average monthly flows as input. GEC has used average daily flows in its simulation model, which is believed to be more accurate. GEC provided project generation numbers.(GEC)	We independently derived our own generation estimates using average monthly flows and used these estimates to validate GEC's generation estimates and to provide a basis for estimating generation under the minimum flow scenarios. We consider GEC's proposed generation values reasonable and have used them throughout the final EIS.
199	Evaluation of diesel fuel costs should be based on assumed differences between the inflation rate of diesel fuel costs and general inflation. The figure below shows the fuel prices paid by GEC for the last 10 years. Although fuel price has varied dramatically during that period, there is nevertheless an upward trend averaging about 3.2% per year. In contrast, general inflation over that same time frame has been about 2.5% per year (based on the Consumer Price Index published by the Bureau of Labor Statistics). Considering that diesel is a fossil fuel becoming scarcer and more difficult to obtain, we conclude that diesel fuel prices will continue to escalate	In the final EIS we consider the effect fuel cost escalation could have on project economics and discuss factors that could affect future fuel costs, including the ones you raise.

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	faster than general inflation, and the difference will likely accelerate during the life of the project. We analyzed the project benefits over the operating term of the license if diesel fuel costs increase more than general inflation by two amounts, 0.5% and 1.0%. Equivalent 2003 fuels costs and diesel production costs are as follows: • 0.0% inflation difference.....$1.51/gal.................... • 0.5% inflation difference.....$1.70/gal.................... • 1.0% inflation difference.....$1.93/gal.................... The results of these varying diesel fuel prices are summarized in Table C-6 of GEC's comment letter for the same eight cases considered in our comments on Chapter 5. (GEC)	
200	Even though the economic analyses show the project to be feasible over the long term, the cost of power with the hydro project could still be higher than with diesel generation in the first few years of operation, particularly if GBNPP refuses to interconnect. To avoid that circumstance, we are actively pursuing other grant funding opportunities. Table C-7 of our comment letter indicates the impact on economic feasibility if the current grant amount is doubled. (GEC)	As part of our economic analysis in section 6.1.1.4, we have considered scenarios where outside funding may be obtained for this project. Any additional information regarding grants or other funding sources should be filed with the Secretary of the Commission and served on all parties.
201	Page 6-29, Table 6.1-2: The middle column shows a 2003 diesel fuel cost of $1.41/gallon, which is actually the 2001 diesel fuel cost. The value should be changed to $1.51/gallon. The power value shown in the table for that column ($380,380) is in fact based on $1.51/gallon. (GEC)	In section 6.1.1.4 of the final EIS, we have substantially revised the analysis presented in the draft EIS, including using current fuel cost information.
202	The economic analysis prepared by 100th Meridian for the Sierra Club concludes that the costs for the project are likely to be higher than indicated in the application or draft EIS, and much higher than the alternative of diesel generation. (Cutter)	We discuss the economic analysis provided by the Sierra Club in the final EIS and this information is part of the record.

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203	We reevaluated the project economics using FERC's method of analysis with the modified assumptions stated above. Table C-5 in GEC's comment letter presents the analyses for eight sets of assumptions. As can be seen, of the eight cases evaluated, all but one show a positive economic benefit, and the one that doesn't is only slightly negative (a benefit-cost ratio of 0.999). This is a sufficient indication of economic feasibility to meet the conditions of the Act. (GEC) AEA contractor Financial Engineering Company conducted a financial analysis in consideration of whether to provide loan financing to the project. The analysis concluded that the project was economically feasible only with NPS loads and an annual load growth of 2%. Capital cost reduction from the AEA grant was projected to cause the project to show annual benefits in its early years if NPS loads are included and there is overall load growth. The revised analysis by Financial Engineering Company finds that the project shows net benefits of approximately $2.5 million over a 30-year period. The analysis assumes the Commission's mid-range growth scenario with NPS loads included and a higher project cost to account for the additional line extension cost. The analysis includes inflation of 3% that was apparently omitted from the draft EIS analysis; no property taxes since they do not exist and are not being considered; and, diesel generator replacement costs under the no-action case. The analysis does not include federal taxes, which would be paid in both the hydro and no-action cases. AEA finds the project to be economically feasible under these assumptions and	We have added the new information you have provided into section 6.1.1.4 of the final EIS.

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	recommends the Commission include these comments in revising its economic analysis. (AIDEA)	
204	In chapter 6, FERC investigates the benefits in a single outlying year. The only function this analysis serves is to determine whether the annual project costs are less than or greater than the alternative costs. Given the relatively fixed nature of project costs, the benefits in outlying years can be quite significant. (AIDEA)	One benefit of hydropower that we identify in section 1.1.2 (the Need for Power) of the draft and final EIS is the relative stability of future costs relative to fossil fuel based generation.
205	The project application included a load growth projection even higher than the high case presented later in the Power Requirements Study by HDR Alaska. Since the application was filed, loads have declined. There are many reasons loads may grow more slowly in the future. (Cutter, Schoen, Wilson, Park Protection Form)	Our economic feasibility analysis examines a range of alternative load growth scenarios which we summarize in section 6.1.1.4 of the final EIS.
206	The draft EIS (page 6-1) does not include a preferred alternative or a recommendation whether the license application should be approved. This omission is inconsistent with the plain requirement of NEPA that a draft EIS include a preferred alternative. *See* 40 CFR § 1502.14(e). (NHI)	40 CFR § 1502.14(e) states that the EIS shall "[i]dentify the agency's preferred alternative or alternatives, if one or more exists,…". At the time we issued the draft EIS, a preferred alternative did not exist. We have included a preferred alternative in the final EIS.
207	The draft EIS finds that the project would have a positive economic value only under one scenario, where the cost of diesel fuel doubles (pp. 6-29 to 6-33) and apparently where NPS agrees to the interconnection. The draft EIS does not estimate the probability of this scenario. (NHI)	We have revised section 6.1.1.4 of the final EIS and we attempt to define the likelihood of each scenario we evaluated; however, the likelihood that GBNPP would interconnect to GEC is unknown.
208	Section 2(c)(1)(C) of the Boundary Adjustment Act permits license issuance, including land exchange, only if the Commission with the NPS's concurrence determines that the project "can be accomplished in an economically feasible manner." This standard means more than a possibility that under a hypothetical scenario would be economically feasible. Section 2(c)(4) of the Boundary	The economic analysis in the final EIS is intended to provide a basis for a decision on the economic feasibility of the project. The Act indicates that, if the project is licensed, GEC would need to file a financing plan for Commission approval. The exact terms of financing, including the amount of any grant assistance, would be known at that time. Please note that the Act does not require NPS concurrence with the Commission's

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	Adjustment Act requires that, after license issuance, construction will begin only if the Commission approves an "acceptable financing plan" in a subsequent proceeding. NHI understands the two sections read together to mean that GEC must show in this licensing proceeding, and the Commission and NPS must also find, that the project is reasonably likely to secure financing. However, the application does not state, and the draft EIS does not analyze, the potential forms of financing the $4.3 million capital cost of constructing this project. (NHI, Friends)	finding on economic feasibility or approval of a financing plan.
209	Section 2(c)(C) of the Boundary Adjustment Act requires that the Commission and NPS find this project is economically feasible, and otherwise, to deny the license application. The project meets that standard in only one of the many scenarios that the draft EIS analyzes; that scenario has an unknown probability of occurrence. In the draft EIS supplement that NHI suggests, the Commission and NPS should include an action scenario whereby the license is denied now (or the application is withdrawn) subject to refiling if future conditions warrant. Section 5 of the Boundary Adjustment Act permits such refiling without competition. (NHI, Spotts)	Based on the comments on the draft EIS, we have substantially revised the economic analysis in chapters 5 and 6 of the final EIS. This information will be available for the Commission's consideration in determining the economic feasibility of the project. The No-action Alternative contained in the draft and final EIS represents the scenario where the project would not be constructed, either by Commission license denial or any other reason. The possibility of the applicant filing a future license in such an eventuality, and the conditions with respect to economic feasibility at that time, are too speculative to warrant consideration in this proceeding. Lastly, Section 2(c)(1) of the Act indicates that the FERC conclusions require the "concurrence of the Secretary of Interior with respect to subparagraphs (A) and (B)." Economic feasibility is addressed in subparagraph (C) of this section and does not require concurrence of the Secretary of the Interior.
210	The draft EIS lists applicable comprehensive plans in Chapter 6; however, it does not analyze consistency with management requirements stated in those plans. Most notably, it does not analyze consistency with water quality standards, including temperature and turbidity. That duty devolves to the Commission and NPS because the Alaska	Section 6.4.1 identifies the blanket water quality certification waiver. Although state criteria may not be enforced through this regulatory mechanism, we identified relevant state water quality criteria (table 3.4-6) and analyzed the consistency of the proposed project with these criteria. We have added our conclusions to section 4.4.2.1.2 relative to meeting water quality

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	Department of Conservation, on August 2, 1999, issued a blanket waiver of water quality certification for all hydropower projects as a result of its budgetary constraints. (NHI)	standards.
211	The draft EIS does not include a FERC staff conclusion on economic feasibility, even a preliminary one, despite the staff's finding that the proposed project would lose several hundred thousand dollars annually for several years following its construction. (NHI)	Based on the comments on the draft EIS, we have substantially revised the economic analysis in chapters 5 and 6 of the final EIS. This information will be available for the Commission's consideration in determining the economic feasibility of the project. FERC staff have made no conclusions regarding economic feasibility in this final EIS.
212	If the Maximum Boundary Alternative is chosen, it is recommended that the public be allowed to participate in the process of drawing up permit stipulations so that community concerns are incorporated into the management regime. (Howell)	The pre-application consultation process for the Falls Creek Project, and additional public participation during the NEPA analysis, has been an entirely public process and provided the public with numerous opportunities to provide input regarding licensing conditions and mitigation measures for the proposed project. Additionally, through consultation with the applicant, appropriate agencies representing public interests could participate in development of any mitigation or monitoring plans, including any required land use management plans, that would be required if the project is licensed.
	Project Location and Utility Figures	
213	Separately illustrate state and private land ownership in figures 2-1, 2-8, and 2-9. Label township/range/sections and differentiate between national park lands, other private land, and tide and submerged lands on the figures. (AAIP)	We have revised these figures to show GBNPP boundaries and state and private lands.

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FEDERAL ENERGY REGULATORY COMMISSION

To: Federal Energy Regulatory Commission
Re: Falls Creek Hydroelectric Project #11659-002

November 17, 2003

Dear Ms. Magalie Salas,

I am writing to you to apprise you of my strong opposition to the Falls Creek Hydroelectric Project, # 11659-002. The alternative that I elect is NO-Action. The reasons for my opposition to this project are many. First and foremost I believe that this project could set a precedent for exchanging National Park lands to other entities, in this case it would be to the state of Alaska. The exchange of National Park lands to facilitate the use of a natural resource on that land is not acceptable. This type of land exchange is in direct opposition to the Organic Act and the Redwood Amendment which ensure the preservation and protection of National Park lands for their wilderness values.

In addition to this reason I also am very concerned about soil erosion which this project will create along Falls Creek. This erosion will occur because of road building and other hydroelectric related infra-structure that will be built close to or on the creek itself.

In addition to the soil erosion and sedimentation occurring in the creek, I am concerned about the impact that this will have on the Dolly Varden char that spawn in and use the creek for egg laying nurseries.

I am also concerned of how the project will affect wildlife in the area. The wetlands running parallel to the forests between Rink and Falls creeks are a significant feeding area for black bears in the spring and early summer. Moose, bears, and wolves from Glacier Bay National Park use natural corridors from the National Park to the Falls Creek area to travel within. I am concerned that roads, more human presence, and impacts from the infra-structure of the hydroelectric project will have measurable affects on the wildlife that use this area.

I have personally had the pleasure of hiking in the Falls Creek area which afforded me a memorable wilderness quality experience. The rich diversity of ecosystems, consisting of sitka spruce and hemlock forests, scrubby lodgepole pine forests, open bogs and fens, and wetlands provide habitat for wildlife and fish.

As a last point I must emphasize the magnificence of the Lower Falls of Falls Creek. It would be a crime to harness Falls Creek for this hydroelectric project. To do so will diminish the awesome character of the water falls of Falls Creek.

It is my opinion that 'the purpose of need' for the town of Gustavus to use Falls Creek for electricity generation does not warrant the negative impacts that this project will have on Falls Creek itself as well as the surrounding wilderness quality lands.

Sincerely,

Jenny Pursell

Jenny Pursell

Jenny Pursell
P.O. Box 33578
Juneau, Alaska, 99803

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November 17, 2003

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FEDERAL ENERGY REGULATORY COMMISSION

Magalie R. Salas, Secretary
Federal Energy Regulatory Commission
8888 1st Street NE
Washington, D.C. 20426

Dear Ms. Salas:

I am writing in response to the draft environmental impact assessment for the "Falls Creek Hydroelectric Project and Land Exchange (FERC #11659)" that was released by the U.S. Federal Energy Regulatory Commission (Office of Energy Projects) and Glacier Bay National Park in October 2003. In short, I stand in opposition to the hydro-project.

At first glance, it would seem that someone concerned about the environment (as I am) would quickly choose hydro over diesel. It's energy efficient and clean and more ecologically sound than the burning of fossil fuels. But unfortunately, in this case, the argument is not that simple and straightforward.

The in-stream flow data indicates that there simply isn't enough water on a year-around basis to generate enough power to replace diesel, So even if this project were built, diesel fuel would still need to be shipped into Gustavus, off-loaded, and burned, albeit at a much lower volume than at present. While it seems a pressing economic argument can always be found to remove lands from Wilderness status (oil in the Arctic National Wildlife Refuge), or logging roads into public lands (as in the Tongass National Forest), this project does not have a compelling financial argument either. The Gustavus Electric Company has been forthcoming that it is doubtful the kilowatt per hour price will go down. So it comes down to an ecological argument. Should land for the hydro project (about 1,000 acres) be removed from Wilderness in Glacier Bay National Park, and given to the State of Alaska? No. This project must be weighed against the loss of habitat for bears, murrelets, marten and other wildlife, and stream habitat for salmon and Dolly Varden, and finally the loss of existing Wilderness and all the intangibles that go with it. Would this set a dangerous precedent for the removal of lands (and Wilderness) from other national parks and refuges in Alaska? It could. While people in Alaska talk about impounding Falls Creek water in Glacier Bay National Park, parks in the Lower 48 are tearing down their dams. Are we out of touch? Or are they? We are.

Please leave Falls Creek alone. Let the last remaining wilderness areas in the world stay wild and let's wait out the other energy possibilities on the horizon: wind, solar, fuel cells, and tidal impoundments, such as those in Chile and France.

Thank you for the opportunity to comment. The original idea was a good one, but now that the research results are in and the ramifications pondered, I can not support the Falls Creek Hydroelectric Project and ask that you choose the No Action alternative.

Sincerely,

Melanie Heacox

Melanie Heacox
P.O. Box 359
Gustavus, AK 99826

Glacier Bay Country Inn

P.O. Box 5
Gustavus, AK 99826

December 12, 2003

Magalie R. Salas, Sec.
FERC
888 First St. NE.
Washington, D.C. 20426

Dear Madam Secretary:

Thank you for the opportunity to comment on the proposed Falls Creek Hydroelectric Project (docket P-11659-002). Please excuse any grammatical incorrectness, I am not a highly educated man as many are in this area. As a person who resides year around in Gustavus, Alaska and as co – owner of Gustavus Electric Company's (GEC) larger, maybe even largest consumer of electricity (the Glacier Bay Country Inn), I wish to make the following comments:

1. I first wish to comment on the environmental issues that concern residents and all citizens alike. As a provider of wildlife tours, saltwater sport fishing, freshwater fishing, and Glacier Bay National Park concessions, our company is also very concerned about the environment. Our business depends on the pristine environment we here enjoy. If the project were to proceed as planned with National Park Service (NPS), State of Alaska, REC, and FERC construction guidelines in place, of course no environmental damage will be allowed to occur. Yes, the environment will be impacted, but for the greater good of all. Considering the poor condition of the Gustavus fuel – oil transfer facility and the funds for replacement not available for many years to come, it would seem that this project when successfully completed will minimize the very likely risk of a serious fuel spill in the Icy Strait/Glacier Bay area in the near future. To harness the clean energy of one of the many very seldom visited creeks would pale in comparison to the tragedy of killing thousands of fish, sea birds, and marine mammals with several thousand gallons of fuel – oil.

2. Cost of energy. As a large commercial user, our company is fortunate in the fact that it receives a special rate as do the other few large energy consumers here in town, we however do not benefit from cost equalization as do private residences. Even with the discounted rate, our 14-room facility still spends an average of $12,000 - $14,000 annually for electricity with the bulk of the costs incurred during the months of May – September. As many conservation practices are in place (including electronically –ballasted florescent lighting) as can be when catering to a public not accustom to expensive electricity. Our company has considered alternative means of energy (a private diesel powered generation facility) and has determined that "dropping off of the grid" will effectively make the GEC load go down and offer GEC an incentive to increase rates for everyone else. We endeavor to be good citizens, but economics, foreign and domestic, will dictate our status as one of GEC's largest consumers. The successful completion the Falls Creek Hydroelectric Project is the only solution to the long-term needs of the community.

Sincerely,

Kenneth Marchbanks

FC/KM

Eric Cutter
28 Durham Rd.
San Anselmo, CA 94960

December 16, 2003

Magalie R. Salas, Secretary
Federal Energy Regulatory Commission
8888 1st Street NE
Washington, D.C. 20426

RE: Gustavus Electric Proposed Falls Creek Hydroelectric Project and Land Exchange (P-11659-002)

Dear Ms. Salas:

I am writing in response to the Draft Environmental Impact Statement for the Falls Creek Hydroelectric Project and Land Exchange (P-11659) issued by FERC and the National Park Service in October 2003.

Attached please find an economic analysis of the proposed Falls Creek Hydroelectric Project and potential alternatives that I authored. Also attached is a spreadsheet provided by the Reguatory Commission of Alaska with historical sales for Gustavus Electric. The analysis finds the costs for the Falls Creek project are likely to be higher that indicated in the project application or the Draft EIS, and much higher than the alternative of diesel generation. While the goal of reducing Gustavus's reliance on diesel generation is laudable, the proposed hydroelectric project is an extremely expensive and risky means of achieving this goal.

A few points to which I would like to draw the attention of the FERC staff are:

- There is no urgent need for additional generation resources in the near future. Gustavus Electric's peak loads are around 315 kW. The two primary diesel generators (Units 1 & 3) have a combined capacity of 550 kW. In addition Gustavus has a 500 kW backup generator (Unit 4) and a 100 kW generator that is seldom used (Unit 2). Under mid range load growth scenarios Gustavus Electric's peak capacity will not approach 550 kW until 2014.

- The project economics are extremely sensitive to load growth projections. The project application included a load growth projection even higher than the high case presented later in the Power Requirements Study by HDR Alaska. Since the application was filed loads have declined. As shown in the attached report, under more likely load growth scenarios, power costs will start as high as $0.33/kWh. Note that the Draft EIS indicates annual *generation* of 1,638 MWh in 2002, while documents provided by the Regulatory Commission of Alaska indicate annual *sales* of 1,404 MWh in 2002, nearly 15 percent lower. It is critical that FERC account for this difference in calculating power costs to the community of Gustavus. Furthermore, there are many reasons load may grow more slowly in the future, for example nearly half of the $15 million funding for the Power Cost Equalization Program came from an unreliable one time source for this fiscal year. The PCE credits for Gustavus residents may be significantly reduced in the future, particularly Alaska state budget challenges persist.

- The project application assumes that Gustavus Electric can serve Park Service load at Bartlett Cove, and indeed the project is clearly uneconomic under all scenarios if park service load is not included. However neither the project application nor the Draft EIS include any costs for building the 9 mile underground transmission line from Gustavus to Bartlett Cove. The Park Service contacted a contractor who does work in Southeast Alaska and was told that cost for laying underground cable should be figured at $500K per mile, for a total cost of $4.5 million, as much as the hydroelectric project itself.

For these and many other reasons contained in the attached report, I urge FERC not to approve the project at this time and allow Gustavus time to consider alternatives. Gustavus has at least five years in which the community can safely pursue promising alternatives, such as tidal energy and fuel cells. As described in the report, these technologies stand a good chance of providing economic and environmentally sound energy in the near future and will have little or no adverse or irreversible impact in Glacier Bay National Park.

Sincerely,

Eric Cutter

ECONOMIC ANALYSIS OF THE PROPOSED

GUSTAVUS ELECTRIC
FALLS CREEK HYDRO PROJECT

AND POTENTIAL ALTERNATIVES

Eric Cutter
David Deputy

November 5, 2003

Prepared for
The Sierra Club

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CONTENTS

I. Executive Summary

This report presents an analysis of viable economic alternatives to the 800 kW run of the river Falls Creek Hydro Project (FERC Project No. 11659) proposed by Gustavus Electric Company. We conclude that the Preliminary Draft Environmental Assessment and the Draft Project Application are extremely optimistic in estimating the generating costs of the Falls Creek Project and that the project is likely to increase rather than decrease existing rates. Similarly, the Federal Energy Regulatory Commission (FERC) and the National Park Service (NPS) just issued the October 2003 Draft Environmental Impact Statement (Draft EIS) for the Falls Creek Project, which found negative economic benefits under eight of nine scenarios evaluated. We therefore believe the project has failed to meet specific standards in the applicable legislation (see below) that require that the project can be completed in an economically feasible manner.

There is no pressing need for the project, as existing resources can easily meet the electric demand in Gustavus for many years. We are sympathetic to the desire to decrease Gustavus's reliance on diesel fuel, given its volatile prices and air emissions. However, the Falls Creek project is an extremely expensive and risky means of achieving this goal. On the other hand, promising alternative technologies have the potential to provide both economic and environmental benefits in the near future without irreversibly impacting a site inside a national park. We therefore suggest that the best option is to give these alternative technologies several years to improve and develop before making a substantial and irreversible commitment to Falls Creek.

Gustavus Electric estimates a total project cost of $5.1 million, with annual costs of approximately $600,000 or $0.15/kWh. The proposed site is located on the Kahtaheena River, also known as Falls Creek, within the boundary of Glacier Bay National Park and the Glacier Bay Wilderness Area. The Glacier Bay Boundary Adjustment Act of 1998 authorizes a land exchange to allow for development of a hydro project within Glacier Bay National Park in the event the project is licensed by FERC. The act specifically requires that the project be economically feasible and that FERC approve the project's financial plan. Several parties, including the Sierra Club, the sponsor of this report, oppose the project due to its location within a national park, as well as environmental, aesthetic and economic concerns.

The estimates of load growth and generating costs made by Gustavus Electric are unreasonably optimistic and fail to consider a full range of possible scenarios. We estimate initial generating costs in the rage $0.30/kWh as opposed to Gustavus Electric's estimates of $0.15, which does not compare favorably to the alternative of diesel generation at costs of $0.17-$0.20/kWh (including capital recovery). This is primarily due to two assumptions; that load will grow at a slower rate than forecast by Gustavus Electric and that it is unlikely that the National Park Service (NPS) will choose to be served by Gustavus Electric. Furthermore, the project will dramatically increase the size of Gustavus Electric, raising capital assets from under $1 million to over $5 million. Without state or federal funding (for which no specific sources have yet been identified), this will increase Gustavus Electric's rate base and add $0.05/kWh, and possibly much more, to electric rates. Other factors, such as higher minimum instream flow requirements and higher financing costs also have the potential to increase the rate impacts of the Falls Creek Project.

The October 2003 Draft EIS estimates average power costs of around $0.21/kWh over the first 10 years of the project, and that is if park service load is included. Under a range of load growth scenarios, the Draft EIS finds that the cost of Falls Creek power is, on average, $0.09 - $0.11/kWh higher than the alternative of diesel generation over the first 10 years of the project (or $0.13-$0.17/kWh higher without park service load). Only under a scenario of high load growth, high diesel fuel cost increases, and including park service load did the Draft EIS find positive economic benefits (and then of only $23,000 per year or $0.006/kWh, beginning in 2016). Under the most likely scenarios, the project will not show economic benefits until after 2018 or later.

Both this paper and the Draft EIS analysis find that the Falls Creek project fails to pass the test of economic viability required for approval by the Glacier Bay Boundary Adjustment Act. Given the lack of urgent need for power and the questionable economics of the Falls Creek Project, there is a good argument for deferring the Falls Creek project for several years to evaluate potential alternatives that are showing promise. Demonstration projects for tidal technologies in Alaska and British Columbia as well as other parts of the US are currently in advanced stages of implementation and several manufacturers argue they can generate electricity under $0.10/kWh. Fuel cells are installed at over 650 sites worldwide and manufactures are investing heavily to develop commercially viable units. These technologies show promising potential to provide economic *and* environmentally sensitive generation for Gustavus without irreversibly compromising a site inside a national park. Interconnection via submarine cable to the Hoonah leg of the proposed Southeast Intertie also presents a potential alternative, though only with sufficient federal and state funding. Independent of the above alternatives, energy efficiency initiatives implemented in other rural Southeast Alaska towns could reduce Gustavus's energy consumption by as much as 30 percent, further deferring the need for investment in new generating resources.

Figure 1 below provides an overview of alternatives described above. The numbers represent approximate cost estimates made by a number of manufacturers and researchers for the technologies. Costs for tidal energy and fuel cells are expected to decline significantly in the near future, though costs for Gustavus are likely to be somewhat higher than elsewhere due to the relatively small load and remote location.

Figure 1

Summary of Economic Alternatives

Source	$/kW	$/kWh	Comments
Falls Creek Hydro	$5,163	~$0.30	Proven existing technology. May be little or no firm capacity in low flow Summer months.
Tidal Energy	$1,400-$3,000	$0.06-$0.15	Several demonstrations in development. Promising, but not commercially proven. Cost may be higher for the small scale development, required in Gustavus.
Fuel Cell	$4,500.	~$0.16.	Over 650 installed world wide. Some technological and cost issues must be overcome for widespread commercial use. Large propane reformers needed for use in Gustavus are in development, but not yet available.
Southeast Intertie	$23,000	~$0.30 + purchased power costs	Existing technology, extremely high capital investment. Some federal funds promised, but additional state funds needed.
Energy Efficiency	$2,000	N/A	Proven existing technology implemented in other SE Alaska towns. State funds may become available.

Gustavus Electric already charges rates that are 20 to 50 percent higher than comparable utilities in Southeast Alaska. Gustavus Electric's reported non-fuel power costs are over 50 percent higher than the costs of the next highest utility. The Regulatory Commission of Alaska (RCA) recently opened a rate case for Gustavus Electric (Docket U-03-17) and Gustavus Electric still has not filed updated financial information that was due to the RCA in July 2003. FERC does not normally examine retail electric rates as part of its licensing process. However, the Glacier Bay National Park Boundary Adjustment Act requires Gustavus Electric to submit an acceptable financing plan to FERC before initiating construction and retail rates are an integral part of the financing of any utility project. FERC should therefore require a full analysis of the rates that Gustavus Electric will have to charge its customers to pay for the project and assess the impact of those rates on the community already burdened by high energy costs.

In conclusion, Falls Creek would commit $5 million to a project of dubious need or economic benefit with little or no firm capacity in low flow summer months. Falls Creek would irreversibly impact a site within a national park and preclude investment in alternative sources of generation for decades to come. Instead, we suggest that Gustavus invest in energy efficiency, which will further defer the need for new generation. With or without investment in efficiency, Gustavus has at least five years in which the community can safely pursue promising alternatives, such as tidal energy and fuel cells. These technologies stand a good chance of providing economic and environmentally sound energy in the near future and will have little or no adverse or irreversible impact in Glacier Bay National Park.

II. Falls Creek Project Economics

A. **Applicable Legislation**

Conclusion: The Glacier Bay National Park Boundary Adjustment Act contains specific requirements over and above other applicable legislation for Gustavus Electric to show that the Falls Creek Project can be completed in an economically feasible manner. Both this analysis and the October 2003 Draft EIS show that this burden has not been met.

This section highlights legislation that is particularly relevant to economic issues that must be considered by FERC in considering the Falls Creek Hydro Project. The Glacier Bay National Park Boundary Adjustment Act of 1998 contains additional requirements more stringent that those in the Federal Power Act and National Environmental Policy Act normally considered by FERC.

The Federal Power Act, Section 10 (a) 2 (C) states that FERC shall consider:

"*…the electricity consumption efficiency improvement program of the applicant, including its plans, performance and capabilities for encouraging or assisting its customers to conserve electricity cost-effectively*, taking into account the published policies, restrictions and requirements of relevant State regulatory authorities applicable to such applicant." (Emphasis added)

The Federal Power Act, Section 15 (a) 2 states that FERC shall consider:

(C) The plans and abilities of the applicant to operate and maintain the project in a manner most likely to *provide efficient and reliable electric service*.
(D) *The need of the applicant over the short and long term for the electricity generated by the project or projects to serve its customers*, including, among other relevant considerations, *the reasonable costs and reasonable availability of alternative sources of power, taking into consideration conservation* and other relevant factors and taking into consideration the effect on the provider (including its customers) of the alternative source of power, the effect on the applicant's operating and load characteristics, the effect on communities served or to be served by the project…"
(E) The existing and planned transmission services of the applicant, *taking into consideration system reliability, costs and other applicable economic and technical factors*.
(F) *Whether the plans of the applicant will be achieved, to the greatest extent possible, in a cost effective manner*." (Emphasis added)

The above statues clearly require Gustavus Electric to show the proposed Falls Creek Hydro Project provides generation that is required by the community in Gustavus and provides that generation in a reasonable and cost effective manner. The statues also clearly require FERC to consider alternative sources of power, including conservation, Gustavus Electric's arguments for not including conservation as an alternative notwithstanding.

The National Environmental Policy Act, as implemented in US Code, Title 42, Chapter 55, Section 4332, Paragraph 2 (C) states, All agencies of the Federal Government shall include in every recommendation or report on proposals for legislation and other major Federal actions significantly affecting the quality of the human environment, a detailed statement by the responsible official on

(iv) the relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity and
(v) any irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented.

The Falls Creek Hydro Project would irreversibly commit both natural and economic resources significant to the community of Gustavus. The project would commit Gustavus to expensive hydro generation to the exclusion of more environmental and economic alternatives that may be available in the near future. The National Environmental Policy Act clearly requires an environmental and economic assessment that weights the benefits of the proposed project against current and potential future alternative options for serving the power needs of Gustavus.

In addition, the Glacier Bay National Park Boundary Adjustment Act of 1998, Section 2 (c) states:

"(c) CONDITIONS- Any exchange of lands under this Act may occur only if--
(1) following the submission of a complete license application, FERC has *conducted economic and environmental analyses under the Federal Power Act* (16 U.S.C. 791-828) (notwithstanding provisions of that Act and the Federal regulations that otherwise exempt this project from economic analyses), the National Environmental Policy Act of 1969 (42 U.S.C. 4321-4370), and the Fish and Wildlife Coordination Act (16 U.S.C. 661-666), that conclude, with the concurrence of the Secretary of the Interior with respect to subparagraphs (A) and (B), that the construction and operation of a hydroelectric power project on the lands described in section 3(b)--
(A) *will not adversely impact the purposes and values of Glacier Bay National Park and Preserve* (as constituted after the consummation of the land exchange authorized by this section);
(B) will comply with the requirements of the National Historic Preservation Act (16 U.S.C. 470-470w); and
(C) *can be accomplished in an economically feasible manner*;
(2) FERC held at least one public meeting in Gustavus, Alaska, allowing the citizens of Gustavus to express their views on the proposed project;
(3) FERC has determined, with the concurrence of the Secretary and the State of Alaska, the minimum amount of land necessary to construct and operate this hydroelectric power project; and
(4) Gustavus Electric Company has been granted a license by FERC that *requires Gustavus Electric Company to submit an acceptable financing plan to FERC before project construction may commence*, and the FERC has approved such plan."
(Emphasis added)

The Glacier Bay National Park Boundary Adjustment Act further emphasizes that an economic and environment analysis is required. In addition, the Glacier Bay National Park Boundary Adjustment Act specifically requires that the project can be accomplished in an economically feasible manner. Furthermore, the above statues specifically require Gustavus Electric to submit a financing plan for review by FERC. Both of these requirements place an increased burden on Gustavus Electric to show, and on FERC to find with some degree of certainty and specificity, how the project will be financed and how the project will provide economic benefits to the community of Gustavus.

In the following sections we will show not only that this burden has not been met, but that the project is likely to have negative economic benefits. Even appendices to Gustavus Electric's Preliminary Draft Environmental Assessment (Draft EA) state "the cumulative benefits are negative due to the high capital costs of the project".[1] The report indicates that for the project to provide savings by year five of its operation, the project costs would have to be lowered from the current $5 million estimate by 42 percent, to $3.4 million. The same Appendices also show that the load growth projections provided by Gustavus are unreasonably high and that there is no need for additional generation in the near future. We also show that it is highly likely that the Falls Creek Hydro Project will significantly increase rather than reduce electric rates in Gustavus, which are already 20-50 percent higher than comparable utilities in Southeast Alaska.

B. Gustavus Electric Demand and Load Growth

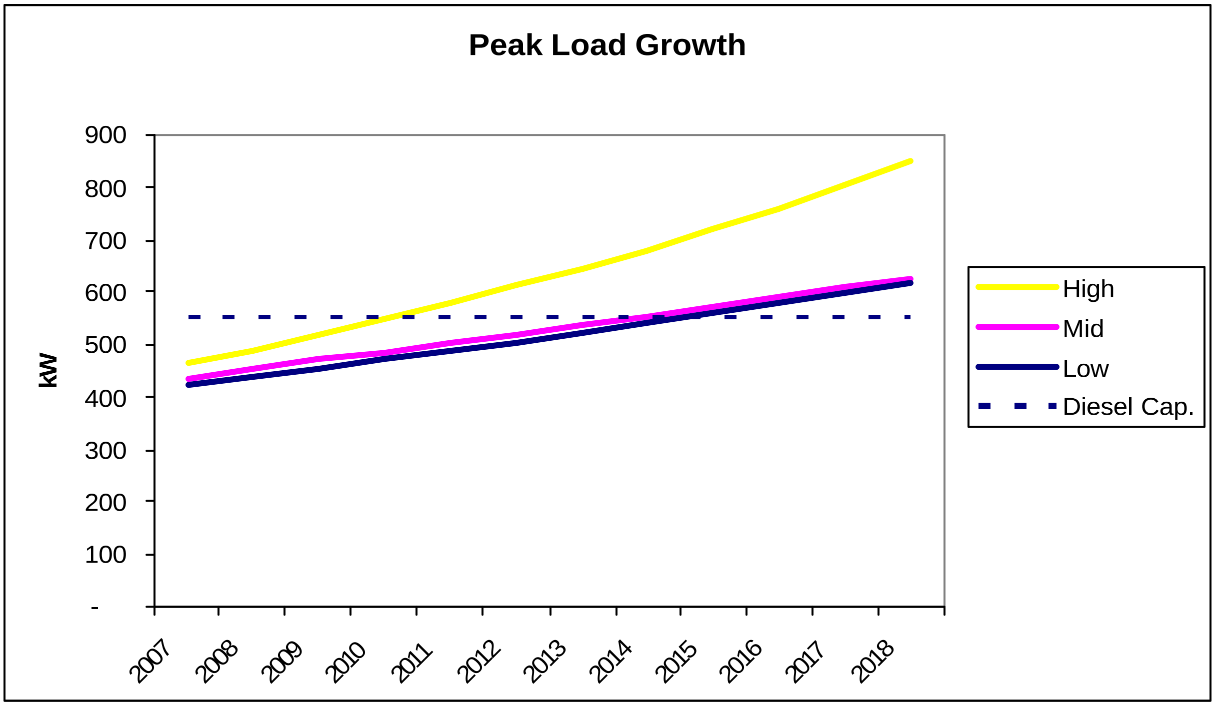
Conclusion: because the generation of the Falls Creek Project will be limited not by the project's capacity, but electric demand in Gustavus (and possibly Glacier Bay National Park) the project economics are extremely sensitive to load growth projections (The October 2003 Draft EIS also emphasizes this point). The Project Application considers only the most optimistic load growth scenario. There are several reasons load growth is likely to be lower than projected by Gustavus Electric and even the October 2003 Draft EIS, which would dramatically increase projected generating costs.

The Draft EA states that "GEC is expected to have adequate capacity throughout the study period with only the existing resources" (p. 23). The Power Requirements Study in Appendix B of the Draft EA presents a low, middle and high case for load growth forecasts. The high case assumes an average annual load growth of 5.72 percent, compared to 3.71 and 3.84 for the low and middle cases. We assume, as does in the Power Requirements Study, that Gustavus Electric's peak load of 350 kW grows at the same rate as annual loads. Under the high load growth scenario, peak loads will not surpass the combined capacity of Gustavus Electric's two primary diesel generators (Units 1 and 3 at 550 kW) until 2011 (Figure 2). Under the low and middle cases the cross over point does not occur until 2014. Furthermore, in addition to the two primary units considered here, Gustavus Electric has an additional 500 kW diesel generator (Unit 4) that is currently used when the primary units are off-line for maintenance and a 100 kW diesel generator (Unit 2) that is seldom used.

A hydro facility would reduce the price volatility and air emissions associated with diesel generation, but at an extremely high cost. Given that there is no pressing need for additional generating capacity, Gustavus Electric must show that the Falls Creek Hydro project will provide economic and environmental benefits as compared to existing and potential future technology that could be implemented before 2014. We do not believe Gustavus Electric has made a sufficient showing in this regard.

[1] Appendix B to EA, Page VI-I, Summary and Conclusions

Figure 2



The forecast of annual electric loads provided in the Draft EA now appear to be unrealistically high. That document shows an electric load of 1,694 MWh in 2000 and projects a load of 2,670 MWh in 2007, an annual increase of 6.72 percent. In fact, loads have actually declined since the report was published in May 2001. Since 1997 the annual load has never increased more than 2.78 percent and annual loads actually decreased between 1999 and 2001 (Figure 3). Since 2001, utilities through out the US have revised their load forecasts downward to reflect reduced economic activity. US Department of energy forecasts load growth of less that 1.1 percent for the next two years (Short-Term Energy Outlook -- August 2003, Energy Information Administration).

Interestingly, the 2,670 MWh figure for Gustavus loads in 2007 in the Preliminary Draft EA is even higher than the high case of 2,390 MWh from the Power Requirements Study presented later in Appendix B of the Preliminary Draft EA. The high case assumes an average annual load growth of 5.72 percent, compared to 3.71 and 3.84 for the low and middle cases.

Figure 3

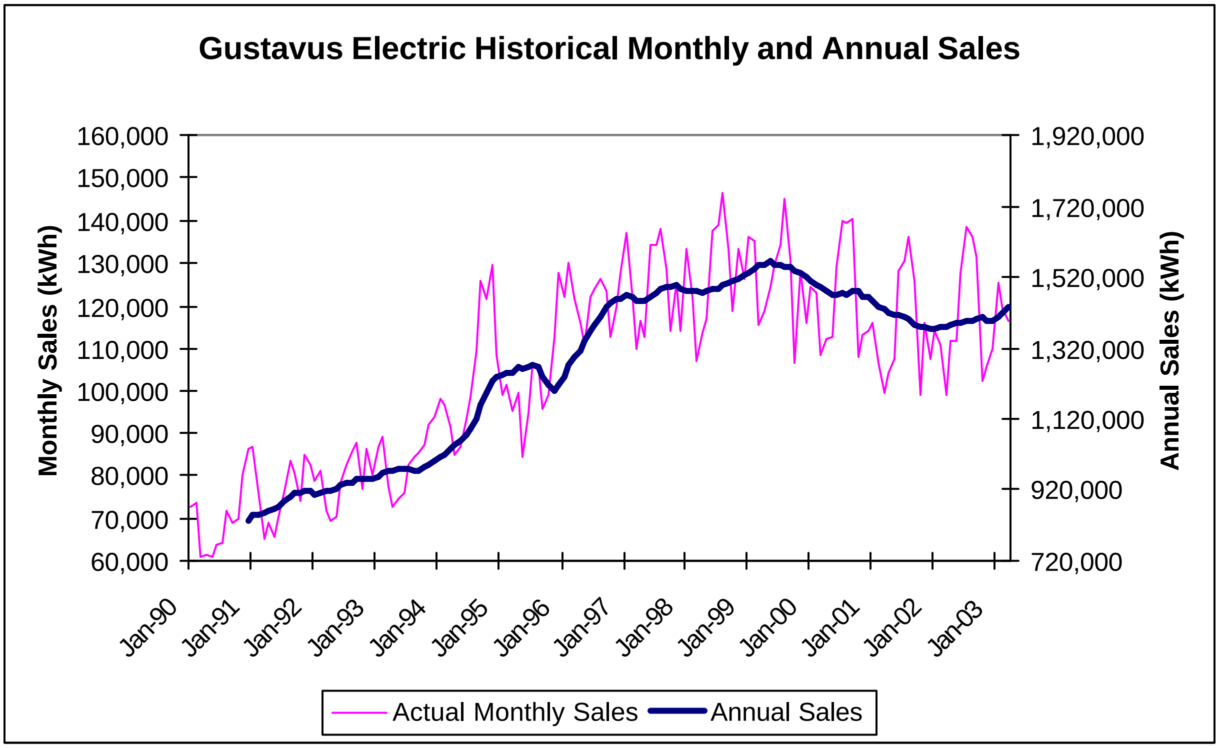
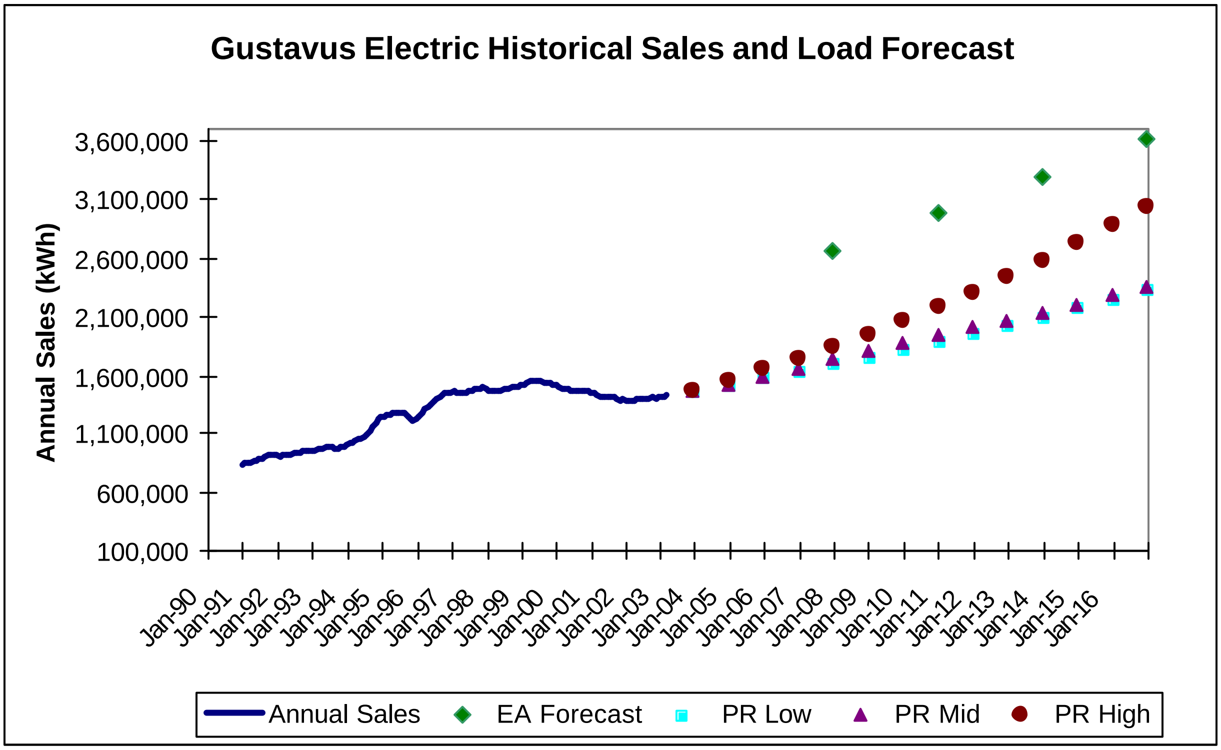


Figure 4 shows the projected load growth beginning with actual 2002 sales of 1,400 MWh and using the percent load growth from the Power Requirements Study in the Draft EA, Appendix B. As the figure shows, even the high case projects substantially lower loads that those presented in the body of the Draft EA. Because the useful generation of Falls Creek project will be limited by loads in Gustavus, the rates of load growth assumed in the study significantly impact the economics of the proposed project, as shown in the next section.

Figure 4



EA Forecast: from Preliminary Draft Environmental Assessment
PR Forecasts: based 2002 actual kWh sales and on load growth percentages from Power Requirements Study, Preliminary Draft Environmental Assessment, Appendix B

The Draft EA also argues that the tourism industry Gustavus will protect the town from the decline in economic activity on other Southeast Alaska towns as a result of declining lumber and fish processing in the area. However, travel and tourism has decreased since 2001 in Alaska as it has throughout the US as a result of a slow economy and heightened security concerns. According to the Alaska Department of Community and Economic Development, vacation and pleasure travel in Alaska actually decreased in 2002 (Alaska Department of Community and Economic Development, 2003).

The October 2003 Draft EIS also makes assumptions about load growth that may be too high. The Draft EIS notes that load has grown an average of 8.1 percent from 1985 to 2002. However, 1985 coincides with the implementation of the Power Cost Equalization Credit, which significantly reduced electric rates seen by customers in Gustavus. The Draft EIS assumes load growth of 4 percent for the next decade. Since 1990 load growth has averaged 4.1 percent, including several significant jumps in 1992, 1994 and 1996. However, since 1997 load has not increased by more than 3 percent and actually decreased in several years. Since 1997 the Power Cost Equalization Credit for commercial customers has been discontinued and portions of Glacier Bay National Park have been closed to commercial fishing. Also the rate of population and load growth tends to decline as small towns get larger as Gustavus has. Gustavus's population grew from 98 in 1980 to 258 in 1990 (a 163 percent increase) and to 429 in 2000 (66 percent increase). Finally the Draft EIS assumes annual generation of 1,638 MWh in 2002, while documents provided by the Regulatory Commission of Alaska indicate annual sales of 1,404 MWh in 2002, nearly 15 percent lower.

Gustavus Electric argues that when hydro projects have been completed in other areas of Alaska, electric demand increased significantly. However, there are several reasons this may not occur in Gustavus. In most cases hydro is cheaper than the existing resources, leading to an immediate reduction in electric rates, which in turn spurs increased demand. In the case of Gustavus, because the Falls Creek Project is relatively expensive and generation is limited by the demand for electricity, not the project's capacity, the Falls Creek project will not lower rates *unless* demand increases. Consumers would have to increase electric usage on the promise that rates will decrease in the future as a result. Furthermore, generation from the Falls Creek project would not be eligible for Power Cost Equalization Credits, as is the current diesel generation. This would lead to a reduction in the total Power Cost Equalization credit seen by customers. Some customers may be willing to use more electricity because it is from a cleaner source that diesel, but there is certainly some limit to the additional cost these customers would be willing to incur. Studies have indicated many customers are willing to pay a few cents more per kWh for green power, but both this study and the October 2003 Draft EIS suggest costs for the Falls Creek Project are likely to be $0.09-$0.15/kWh (or 50-80 percent) higher, if not more, than diesel.

C. Falls Creek Construction and Operating Costs

Conclusion: The generation costs proposed by Gustavus Electric are based on extremely optimistic assumption. More realistic assumptions show that the Falls Creek Hydro Project is likely to generate electricity at costs significantly higher than that of existing or new diesel generation.

The Preliminary Draft Environmental Assessment forecasts costs of $0.089/kWh for the Falls Creek Project (Section IV – Generating Alternatives Overview). The Draft Project Application projects costs of $0.15/kWh in the first year (Section 3.2 Annual Costs). However this projection assumes an extremely high based upon total generation and utilization of 5.5MWh and include Park Service load.

The actual project generation will be limited primarily by the demand for electricity in Gustavus, making the cost of power extremely sensitive to load growth projections.[2] The load for Gustavus alone is estimated in the Draft EA at 2,670 MWh in 2007, growing to 3,610 in 2017.[3] Given that the Falls Creek project will provide power only when water flows allow, we assumed a best case 82 percent of the Gustavus load could be served by the Falls Creek Project.[4] Given proposed minimum instream flow requirements, the Draft EIS assumes the Falls Creek Project can serve 78-80 percent of Gustavus's load, while Gustavus Electric assumed a level over 90 percent. Without park service load (see below), the amount of energy useable in this scenario is 2,270 in 2007, with an average of 2,670 and a cost per kilowatt-hour of 18.4 cents over the first 10 years of the project. This is higher than the power costs of $0.17/kWh reported in Section 3.2 of the Draft Project Application for existing diesel generation in Gustavus and not much less than the costs of around $0.20/kWh reported by the park service (see Diesel Technology Section below).

However, as explained in the previous section, actual loads are likely to be far less than projected by the Draft EA in May 2001. Figure 5 shows the projected load growth using the percentage load

[2] Appendix B to EA, Page IV-9
[3] EA, Page A-9, Table A-4
[4] 2007 ratio from EA, Page A-9, Table A-4

growth figures from the Power Requirements Study, beginning with actual 2002 generation of 1,400 MWh. Again, we assume that at most 82 percent of Gustavus's load can be served by the Falls Creek Project. Using these figures it does not appear that the Falls Creek Hydro Project will be economic until 2018 under low or mid range growth projections.

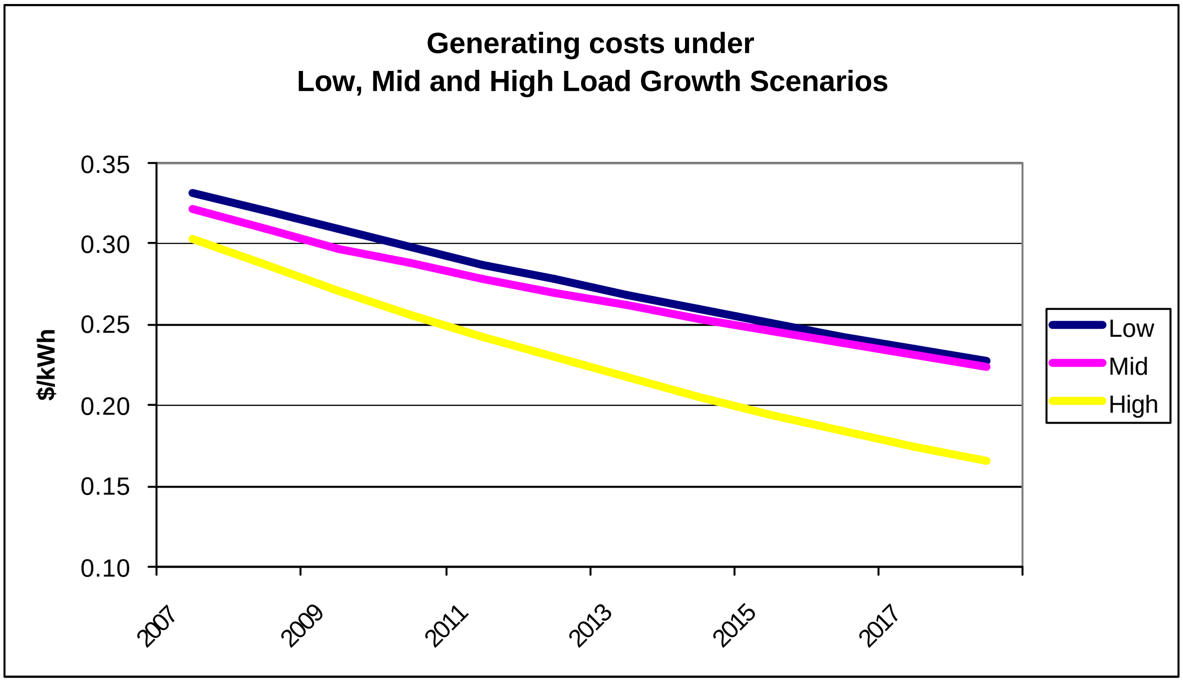
Figure 5

Projected Gustavus Load Growth

2002 Load (MWh)	1,400
Percent served by Falls Creek	82%
Annual Operating Costs	$460,000

	Projected Load Growth			Projected Load			$/kWh		
	Low	Mid	High	Low	Mid	High	Low	Mid	High
2000	4.23%	4.66%	5.90%						
2001	4.16%	4.62%	5.88%						
2002	4.09%	4.58%	5.85%						
2003	4.01%	4.55%	5.82%	1,456	1,464	1,482			
2004	3.94%	4.51%	5.79%	1,514	1,530	1,567			
2005	3.87%	4.47%	5.76%	1,572	1,598	1,658			
2006	3.80%	4.44%	5.74%	1,632	1,669	1,753			
2007	3.73%	4.40%	5.71%	1,693	1,743	1,853	0.33	0.32	0.30
2008	3.66%	4.36%	5.68%	1,755	1,819	1,958	0.32	0.31	0.29
2009	3.63%	3.76%	5.68%	1,818	1,887	2,069	0.31	0.30	0.27
2010	3.61%	3.24%	5.69%	1,884	1,948	2,187	0.30	0.29	0.26
2011	3.58%	3.24%	5.69%	1,952	2,011	2,312	0.29	0.28	0.24
2012	3.56%	3.24%	5.69%	2,021	2,076	2,443	0.28	0.27	0.23
2013	3.54%	3.24%	5.69%	2,093	2,144	2,582	0.27	0.26	0.22
2014	3.50%	3.21%	5.67%	2,166	2,212	2,728	0.26	0.25	0.21
2015	3.46%	3.18%	5.65%	2,241	2,283	2,883	0.25	0.25	0.19
2016	3.41%	3.16%	5.63%	2,317	2,355	3,045	0.24	0.24	0.18
2017	3.37%	3.13%	5.61%	2,395	2,429	3,216	0.23	0.23	0.17
2018	3.33%	3.10%	5.58%	2,475	2,504	3,395	0.23	0.22	0.17

Figure 6



Gustavus Electric proposes that the Falls Creek Project could also serve the Park Service load. However, it is misleading to include such an assumption in the Draft EA without also including the additional costs associated with serving the Park Service. The Draft EA makes no estimate of the cost of building the transmission line between Gustavus and Park Service Headquarters. More importantly, in discussion with Park Service personnel, they indicated that they recently made significant capital investments in their diesel generation system, which is capable of serving their needs for some time. The total cost was estimated at $0.20/kWh, with $0.08/kWh of this representing capital and operating expenses. If the system were idled due to interconnection with Gustavus, the capital cost of the system would be unrecoverable. Therefore, any economic evaluation that includes the Park Service load should address this cost of stranded capital.

D. Financing and Rate Calculations

Conclusion: Absent state for federal funding, for which there is no specifically identified source, the cost of financing the Falls Creek Project is likely to be higher than the 7 percent assumed in the project application. Again, absent government funding, the $5 million project will also substantially increase Gustavus Electric's rate base (currently under $1 million), increasing rates by $0.05/kWh and possibly much more.

Utilities typically finance the construction of capital assets such as generating plants and transmission lines with a combination of debt and equity. The utility pays interest for debt such as bonds or bank loans, which typically provides 40-60 percent of the investment in a new project. The remaining portion is financed with equity, capital provided by the owners or shareholders of the utility in return for which the owners or shareholders expect a return on their investment. Debt is less risky and therefore less costly than equity financing, but the cost of debt rises with the proportion of the investment that is financed with debt. Projects may be financed with as much as

80 percent debt or even more, but the more debt and less equity invested in a project, the greater the risk of default, and banks and bond holders will require a higher interest rate to compensate for the higher risk. This is comparable to a home loan; the lower the down payment (or equity) invested by the buyer, the higher the interest rate charged by the bank for the home loan. Companies will generally try to find the balance of debt and equity that minimizes their overall cost of financing the project.

The Draft Project Application assumes that the project is 100 percent debt financed at an interest rate of 7 percent. The Draft EIS recently issued by the FERC and the NPS assumes an interest rate of 8 percent. However, absent grants or low interest loans, this would appear to be a low cost of capital for project such as Falls Creek, which is quite large for a relatively small utility such as Gustavus Electric. Furthermore, such low interest rates are predicated on the assumption that the lender is quite confident in the economic feasibility of the project. Thirty year bonds for large investment grade companies currently have yields of 6-7 percent and large companies with lower ratings must pay 8 percent or more. Smaller companies, companies financing projects considered more risky by lenders and companies financing new projects with a high percentage of debt usually must pay higher rates. To achieve a lower cost of debt, Gustavus Electric must secure grants or low interest loans, or invest its own equity in the project. However, any portion of the project that is financed with equity by the owners of Gustavus Electric will require even higher rates of return, typically in the 10-15 percent range for electric utilities (see discussion of authorized rate of return in next paragraph). If Gustavus Electric is successful in securing federal or state funding for all or a significant portion of the project, the cost of financing could be significantly reduced. However, absent clear evidence that such funding is available, it is reasonable to assume that the cost of financing the Falls Creek will be higher than 7 percent. A 2 percent increase in the cost of capital results in a $0.03/kWh increase in power costs in 2007 assuming a load of 2,670 MWh. However, as explained above, we believe the 2,670 MWh load projection to be unreasonably optimistic; at lower loads the increase in power costs would be closer to $0.05/kWh.

Investments made by the utility contribute to the utility's rate base; the capital investment for which the utility earns an authorized rate of return approved by a regulatory commission. This return is designed to provide an adequate incentive for utilities to make the capital investments necessary to provide sufficient and reliable generation, while protecting consumers from unreasonably high rates that an unregulated monopoly might otherwise charge. Authorized rates of return can vary considerably, but are typically in the range of 9-15 percent.

The Falls Creek Hydro Project will profoundly impact the rate base that is used to calculate the authorized return allowed for Gustavus Electric. Any equity investments made by Gustavus Electric will go directly towards the rate base, as described above. As Gustavus Electric repays the principle of any debt, that will increase Gustavus Electric's ownership or equity in the project and therefore increase the utility's rate base.

The Falls Creek Project has already had a substantial impact on Gustavus Electric's balance sheet, which showed fixed assets of $670,534 in 2000 and $1,000,677 in 2002. As shown in Figure 7, this 50 percent increase is due primarily to expenditures related to the Falls Creek Hydro Project. Because the total cost of the project ($5 million) is quite large in comparison to Gustavus Electric's existing assets ($1 million), absent state or federal funding, the project would significantly increase the utility's rate base and therefore its electric rates.

Figure 7

Gustavus Electric Fixed Assets

	2000	2001	2002	Change
Office Equipment	$42,917	$48,941	$49,968	$7,051
Misc. Intangible Plant	88	88	88	-
Hydro Electric Plant	240,111	584,864	708,266	468,155
Misc. Equipment	9,630	11,639	13,695	4,065
Fuel Tanks	1,930	1,930	1,930	-
Generators	218,763	220,092	237,789	19,026
Buildings - Structures	168,324	168,324	168,624	300-
Accessory Electrical Equipment	214,088	241,088	241,088	27,000
Station & Substation	13,339	13,339	13,339	-
Overhead Lines	34,599	61,599	61,599	27,000
Underground	361,957	361,957	361,957	-
Transformers	225,964	225,964	225,964	-
Services	145,999	145,999	145,999	-
Meters	57,637	57,637	57,637	-
Transportation Equipment	50,870	50,870	62,801	11,931-
Power Operated Equipment	67,071	67,071	74,114	7,043-
Accumulated Depreciation	(1,236,755)	(1,328,272)	(1,424,382)	(187,627)
Total Fixed Assets	$670,534	$933,132	$1,000,677	$330,143

In 1989, the Regulatory Commission of Alaska (RCA) found that a 6.5 percent return on a rate base of $325,000 (or $21,101) was reasonable. This amounted to approximately $0.03/kWh with annual generation of 644,302 kWh in 1989. Even if only 30 percent of the construction cost is eventually included in rate base, a 6.5 percent return would amount to approximately $80,000 (as stated above, returns above 10 percent are commonly found reasonable). Again this would increase rates by approximately $0.03/kWh at loads of 2,670 MWh and $0.05/kWh at lower demand levels.

We are sensitive to the desire to utilize hydro generation to reduce Gustavus's dependence on often volatile diesel prices and to reduce the air emissions associated with diesel generation. If, as we find, the Falls Creek Hydro Project is not likely to produce electricity at rates lower than existing facilities, that removes one of Gustavus Electric's primary arguments supporting the project; that it will reduce generating costs. The Final EA should present a much more realistic picture of the generating cost of the Falls Creek Project and include generating costs under a range of likely scenarios, not just the most optimistic.

E. <u>Falls Creek Hydro Project Firm Capacity</u>

Conclusion: As a run-of-the-river hydro plant, the Falls Creek Project generation may be severely limited by available stream flow and minimum instream flow requirements, particularly in the summer months. When considering alternatives, it is important to remember that the Falls Creek project will not provide firm capacity year round, and will be supplemented by diesel generation.

In is important to point out that generation from the Falls Creek Project will not be available throughout the year and in some months may be quite limited. This is an important consideration when comparing the Falls Creek Project to alternatives. One of the disadvantages of alternative generating technologies when compared to more established technologies is that technologies like solar, wind and tidal are less “firm” and more intermittent in nature. However this is not necessarily the case when considering alternatives to Falls Creek. The Falls Creek Hydro Project is a run-of-the-river project that will generate only when sufficient flow is available in the river. Gustavus has proposed that the Falls Creek Project will be a load following project, that is follow the electricity demand in Gustavus. However, state agencies have pointed out that it is often not possible for a run-of-the-river project to follow load over the course of the day without some storage capacity, which is not proposed for Falls Creek. Furthermore, some agencies are proposing minimum instream flow requirements that may prevent the operation of the Falls Creek altogether in low flow months. These agencies have also questioned the methods used to estimate the available flows in the Kahtaheena River and suggested further study. All these issues suggest that the generation from the Falls Creek Hydro Project will be intermittent in nature during some portion of the year and require supplemental diesel generation. Acknowledging the intermittent nature of the generation from the Falls Creek Hydro Project makes alternatives that are also intermittent in nature, such as tidal, more competitive in comparison.

F. Gustavus Electric Rates

Conclusion: Gustavus Electric charges rates higher than comparable towns in Southeast Alaska. While there may be good reasons for this, a recently initiated rate case may shed more light on the issue. Furthermore, because rates are an integral part of financing this project, and FERC is required to approve an acceptable financing plan, FERC must carefully consider the rate impacts of this project.

Gustavus Electric Inc. charges some of the highest rates for electricity in Southeast Alaska. Gustavus charges rates that are 20 to 50 percent higher than other suppliers of electricity to rural towns in Southeast Alaska relying solely on diesel generation (Figure 8). Non-fuel power costs listed in Power Cost Equalization calculations provided by the Regulatory Commission of Alaska are over 50 percent higher than the next highest utility.

Figure 8

Comparison of Gustavus Electric Bills, Revenues and Costs with other Southeast Alaska utilities relying solely on diesel generation

	500 kWh Bill (1)	Revenue ¢/kWh (2)		Non-Fuel Power Cost (3)	Fuel Cost (4)		Annual MWh (5)
		Res.	Com.	¢/kWh	$/Gal	¢/kWh	
Gustavus Electric Inc	**$248**	**49.8**	**42.1**	**35.4**	**1.49**	**13.3**	**1,466**
Whale Pass(APC)	*193*	*29.1*		*17.6*	*1.30*	*9.9*	
Naukati Bay(APC)	*166*	*28.2*		*17.6*	*1.30*	*9.0*	*1,156*
Coffman Cove(APC)	*152*	*28.5*		*17.6*	*1.30*	*9.3*	
Tlingit & Haida Region El Auth	183	36.5	26.5	22.5	1.16	10.0	13,008
Tenakee Springs City of	*159*	*31.8*	*31.8*	*17.3*	*1.53*	*15.6*	*393*
Yakutat Power Inc	130	26.0	20.5	13.8	1.13	8.2	7,491
Elfin Cove City of	*71*	*14.1*	*5.0*	*9.6*	*1.73*	*15.8*	*349*

(1) Electric: Sample of Monthly Residential Rates, Regulatory Commission of Alaska Feb. 28, 2003
(2) U.S. Department of Energy, Energy Information Administration, Form EIA-861, 2000 data.
(Revenue for Alaska Power Company (APC) from Regulatory Commission of Alaska PCE Calculations
(3) Power Cost Equalization (PCE) Spreadsheets provided by the Regulatory Commission of Alaska, July 2003
(4) Cost of Power Adjustment (COPA) Spreadsheets provided by the Regulatory Commission of Alaska, July 2003
(5) Energy Information Administration, Form EIA-861 Annual Electric Utility Report, 2001 and
Power Cost Equalization (PCE) Spreadsheets provided by the Regulatory Commission of Alaska, July 2003
APC sales aggregated for North Prince of Whales Island (Whale Pass, Naukati Bay, Coffman Cove)

Gustavus Electric is a privately owned utility and is therefore regulated by the Regulatory Commission of Alaska (RCA). The most recent breakdown of non-fuel costs that the RCA was able to provide is from a 1989 rate case (Docket U-86-74, Order 2). Price of Wales Island is served by the Alaska Power Company (APC), also a regulated utility. While towns in North Prince of Wales Island rely solely on diesel generation, hydro power supplies a portion of the loads in South Prince of Wales Island. Detailed non-fuel power cost data specific to the towns in North Prince of Wales Island was not available. The remaining utilities in Southeast Alaska that rely solely on diesel generation are cooperative or publicly owned, and therefore not regulated by the RCA. However, non-regulated utilities provide updated non-fuel cost information each year in order to receive Power Cost Equalization funds. Regulated utilities such as Gustavus Electric are not required to provide updated cost data each year for Power Cost Equalization credits. The RCA did, however, provide a 2001 income statement for Gustavus Electric from which we were able to estimate most of the detailed non-fuel power costs (except for parts and supplies, which was not listed separately).

Figure 9 shows a non-fuel power cost for Gustavus Electric from 1989 that is slightly lower, on a cents per kWh basis, than the non-fuel power cost from the 2003 Power Cost Equalization calculation shown in Table 1. Still Gustavus Electric's non-fuel power cost is over 40 percent higher than the next highest utility. Figure 10 shows that in each category for non-fuel power costs (except Parts and Supplies in 1989 which was zero for Gustavus, and O & M in 2001); Gustavus Electric is at or near the top of the list on a cents per kWh basis.

Figure 9

Comparison of Gustavus Electric Total Non-Fuel Power Costs with Other Southeast Alaska Utilities Relying Solely on Diesel Generation

Non-Fuel Costs	Year Reviewed	kWh Sales	Total Non-Fuel Costs	(¢/kWh)
Gustavus Electric Inc (1)	**1989**	**518,962**	**$167,386**	**32.3**
Gustavus Electric Inc (2)	**2001**	**1,603,200**		
Tlingit & Haida Region El Auth	*2002*	*11,384,288*	*2,558,540*	*22.5*
Tenakee Springs City of	2002	382,159	66,139	17.3
Yakutat Power Inc	*2002*	*7,614,569*	*988,531*	*13.0*
Elfin Cove City of	2002	348,849	33,593	9.6

(1) Regulatory Commission of Alaska, Docket U-86-74, Order 2 (for Gustavus Electric as a regulated utility)
(2) Gustavus Electric Profit and Lost Statement, 2001, provided by Regulatory Commission of Alaska
Otherwise Power Cost Equalization (PCE) Spreadsheets provided by the Regulatory Commission of Alaska, July 2003 (for all other utilities, which are unregulated)

Figure 10

Detailed Comparison of Gustavus Electric Non-Fuel Power Costs with Other Southeast Alaska Utilities Relying Solely on Diesel Generation

Non-Fuel Costs	Labor	Parts & Supplies	O & M	G & A	Dep.	Int. Exp	Other
Gustavus Electric 1986	**$54,527**	**$0**	**$21,013**	**$30,267**	**$40,174**	**$21,405**	**$0**
Gustavus Electric 2001	**205,054**		**14,270**	**90,676**	**91,513**	**28,723**	
Tlingit & Haida Region El Auth	*531,252*	*37,953*	*221,099*	*762,858*	*563,342*	*361,950*	*80,086*
Tenakee Springs City of	35,207	10,462	2,088	6,463	11,919	-	-
Yakutat Power Inc	*443,440*	*41,677*	*73,781*	*202,643*	*184,488*	*82,502*	*(40,000)*
Elfin Cove City of	16,342	2,213	8,712	226	5,473	-	627

Non Fuel Costs (¢/kWh)	Labor	Parts & Supplies	O & M	G & A	Dep.	Int. Exp	Other
Gustavus Electric 1986	**10.5**	**0.0**	**4.0**	**5.8**	**7.7**	**4.1**	**0.0**
Gustavus Electric 2001	**12.8**		**0.9**	**5.7**	**5.7**	**1.8**	**0.0**
Tlingit & Haida Region El Auth	*4.7*	*0.3*	*1.9*	*6.7*	*4.9*	*3.2*	*0.7*
Tenakee Springs City of	9.2	2.7	0.5	1.7	3.1	0.0	0.0
Yakutat Power Inc	*5.8*	*0.5*	*1.0*	*2.7*	*2.4*	*1.1*	*-0.5*
Elfin Cove City of	4.7	0.6	2.5	0.1	1.6	0.0	0.2

One of the arguments for hydro power is that it generally provides cheaper power than fossil fuel based alternatives. However, in this case, we expect that the Falls Creek Hydro Project will increase rather than decrease Gustavus Electric's already high rates (see above).

Gustavus Electric argues that there are two main reasons its rates are higher than the other utilities in this comparison. The first is that all the other utilities received significant state funding for their generation and distribution systems, which Gustavus Electric did not. The second is that Gustavus is much less centralized than other small towns, requiring many more miles of distribution lines. Furthermore, much of Gustavus Electric's distribution system in underground, which is less prone to outages, but much more expensive as compared to overhead lines

The Regulatory Commission of Alaska has indicated that an examination of rates for Gustavus Electric Company is underway (Docket U-03-17), which could shed some light on the reasons for Gustavus Electric's relatively high rates. Gustavus was required to file information supporting revised rates by July 1, 2003 (as required by 3ACC 48.275(a)). Gustavus Electric has not submitted the required filing and on August 29, 2003, Gustavus Electric filed a motion for an order extending time for filing. Before granting Gustavus Electric a permit to develop the only site suitable to provide Gustavus with conventional hydro power, FERC should receive a thorough justification of the utility's high rates relative to other utilities in the area as part of the required economic analysis and financial plan.

III. Promising Alternative Sources of Electric Generation

A. Tidal

Conclusion: Given the strong currents in the area, tidal energy is a promising but not yet proven resource. Several demonstration projects of a variety of technologies are underway in the US and Canada and several manufacturers promise costs under $0.10/kWh. Though they may soon, tidal technologies have not yet proven themselves in a commercial setting.

Tidal flows are significant in the Gustavus area, with four tides of up to 20 feet per day. Standard navigation charts indicated maximum tidal currents in the Icy Strait of between 5 and 8 knots.

For purposes of exploring the tidal energy potential of the Gustavus area, we reviewed relevant research and contacted leading companies. The companies we contacted were based upon: 1) the respondents to the Canadian province of British Columbia's recent request for proposals (RFP) for renewable energy including tidal and wave and 2) the city of San Francisco's recent work on tidal flow generators in the Golden Gate, 3) our review of UK tidal energy projects.

Of the four companies contacted, three responded to our request, UEK, Tidal Electric and Hydro Venturi. Of these, Tidal Electric's Peter Ullman was very familiar with the Gustavus area and has had conversations with Gustavus Electric's President, Dick Levitt and spent some time with the head of the Glacier National Park. He mentioned that he also has spoken with the Sierra Club regarding the tidal potential of the area. His comments indicated that excellent tidal resources exist in the area and he believed that they could be economically developed. However, he felt that it was not worth spending a lot of time on the feasibility issues without a local partner, principally Gustavus Electric.

Hydro Venturi's Joseph Neil also responded that the potential of the area was significant and that they are putting a strategic focus on BC and Alaska projects. He indicated that the best way to move forward would be to find a local partner with which to form a joint venture to explore the opportunity further.

1. Tidal Energy Costs

Detailed assessments of the tidal flows around Gustavus are not available. Therefore, our general discussions below are based upon work done in British Columbia[5]. The best tidal resource identified in British Columbia is Discovery Strait.

In an October 2002 report, Triton Consultants, Ltd. calculated that using current technology, a tidal farm consisting of 800 one-megawatt turbines at this location could produce power for 30 years at 8 cents per kilowatt-hour. Triton also estimated the cost of a smaller 43 Megawatt installation at Race Passage at a cost of 18 cents per kilowatt-hour. The difference is principally due to the economies of scale accruing to a large facility. Gustavus's power needs would be served by a much smaller and therefore more costly implementation than either of the above scenarios. However, other technologies described below promise lower costs at smaller sizes as well (See below).

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[5] See "Green Energy Study for British Columbia, Phase II: Mainland, Tidal Current Energy", for BC Hydro by Triton Consultants, October 24, 2002

Future costs of tidal technologies are expected to drop. Specifically, the Triton report indicates that within a few years cost of between 5 and 7 cents per kilowatt-hour may be achievable for large tidal farms. This estimate is based upon the fact that tidal technologies have and will continue to mature rapidly over the next few years. The technology and costs for converting tidal energy to grid ready electricity can also present challenges, particularly for small projects. While several tidal technologies are being test deployed, there are currently no commercial tidal energy production facilities in operation. Given the above, we view the tidal energy as an option to be monitored and explored further as the technologies mature, rather than a current opportunity.

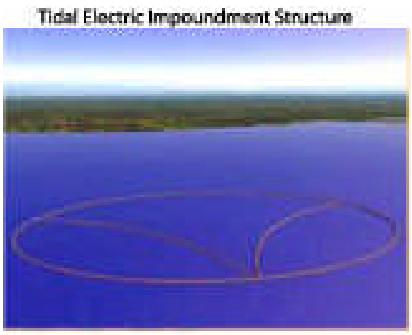
2. Tidal Technologies

UEK of Annapolis Maryland manufactures turbines that are designed to deliver 90 kW in a 5 knot current. Discussions with Philippe Vauthier of UEK indicated that they are installing 3 ten ft. diameter units for a total of 270 kW on the Yukon River in Eagle, AK. Installed costs are estimated at $1,400/kW. The installation includes protective fish screens.

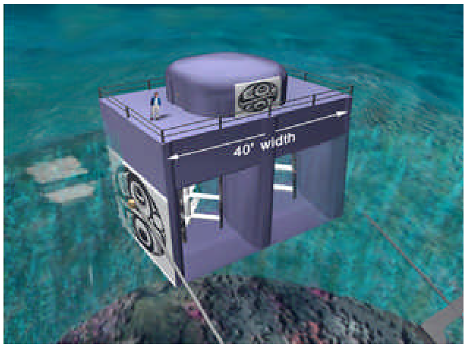
Marine Current Technologies of London utilizes a single monopole to mount dual 300kW turbines. These turbines can be raised to the surface for maintenance and include innovative variable pitch blades. The company has received UK government support and is developing a prototype installation in South West England. The turbines require large areas of relatively shallow water with little navigation or submerged debris – potentially a problem around Gustavus.

Hydro Venturi Device

Hydro Venturi of London manufactures a turbine generator with no moving parts. The technology relies upon the Bernoulli principal to compress air, which is then piped to shore to run an on-shore generator. Since there are no moving parts, Hydro Venturi claims the device is more environmentally benign, reliable and economic than other turbine generators. San Francisco recently approved $2 million to study the use of this technology in San Francisco Bay and Hydro Venturi believes the project could be operation within 15 months.



Tidal Electric offers a unique construction technique, rather than a turbine technology. They utilize an offshore impoundment structure rather than the more typical tidal barrage system. Standard low head turbines are utilized for power production and undersea cables carry the power to shore. Tidal Electric claims that the impoundment structure is a more environmentally benign and economically advantageous means of utilizing tidal resources than barrage systems.



Blue Energy is developing a prototype 250 kW power system for small to mid-sized communities. The unit will be viable in ocean currents of 2 knots or greater, and a depth of at least 30 feet. Blue Energy expects to a capital cost of $1,200 per kW for large-scale facilities and $3,000 for small and midrange systems.

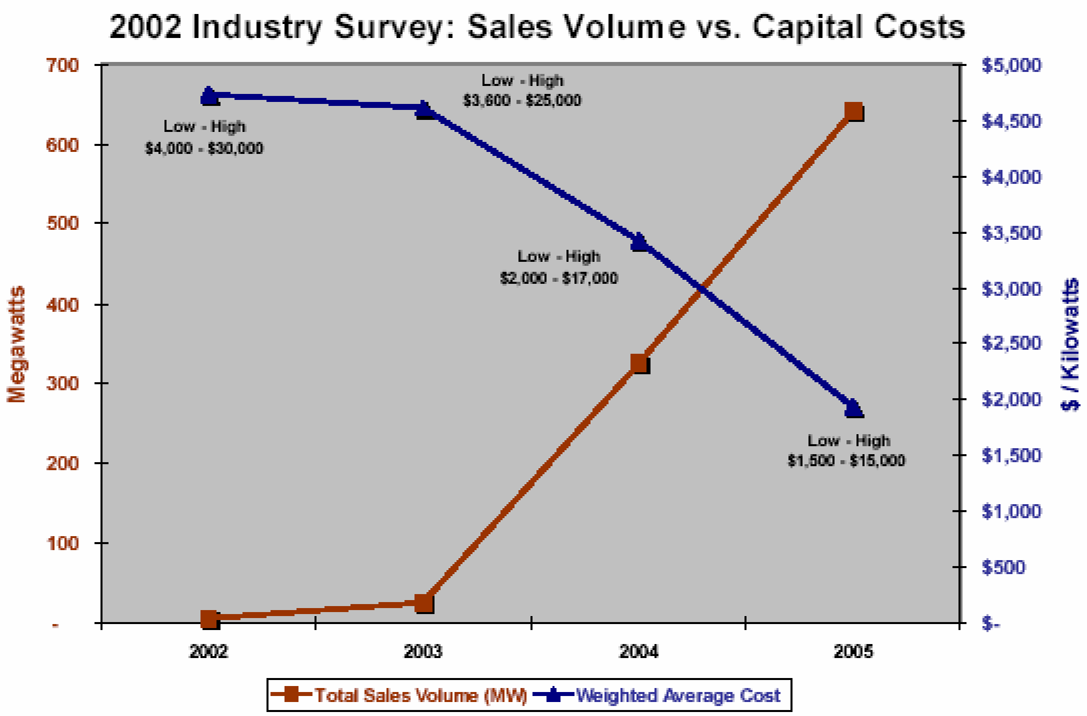
B. Fuel Cells

Conclusion: It is possible, but not certain, that fuel cells will become an economic as well as environmental option for electrical generation in Gustavus in the near future. Fuel cell technology is progressing rapidly and costs are declining, but currently available commercial products of the appropriate size are relatively expensive and are not configured to utilize fuels available in Gustavus (propane or diesel).

Fuel cells provide the highest efficiency in the conversion of fuel to electricity, often reaching 50 percent or more. In addition, fuel cells also provide much lower emissions than internal combustion engines, although this is somewhat dependent upon the fuel type and pre-processing used. Heat produced by a fuel cell can be easily captured and utilized for water and space heating, often resulting in efficiency above 80 percent. Fuel cells have moved out of the laboratory and into the real world; over 650 large stationary fuel cell system (>10 kW) have been installed world wide (Fuel Cell Today 2003).

Fuel cells are currently expensive compared to existing generating technologies. Studies cite average costs around $4,500/kW, though costs vary widely among different sizes, technologies and applications (Fuel Cell Today 2003, California Stationary Fuel Cell Collaborative 2002). To be competitive with existing technologies, fuel cell manufactures expect that costs must drop closer to $1,500/kW.

Figure 11



(California Stationary Fuel Cell Collaborative, 2002)

Many manufacturers and researchers believe that fuel cells are moving from field testing to commercial viability quite rapidly and that technological advances and increased production levels (with declining per unit costs) will lead to economically competitive models in less than five years. Figure 11 presents the results of a 2002 survey of fuel cell manufactures, showing their expectations of increased sales and declining costs in 2004 and 2005.

While the industry and many researchers present an optimistic picture, some researchers argue for more caution. Demonstration projects and field tests have not been universally encouraging; the 2.5 kW fuel cell installed in Yellowstone National Park was removed after only five years after becoming unreliable. Problems with stack degradation, durability and fuel impurities continue to pose challenges, with no clear path to solutions say some researchers.

Bear in mind that much of what your read about fuel cells in the general media concerns automobiles and that the challenges facing fuel cells for transportation are much more formidable than those for stationary applications. While researchers estimate that fuel cell cars are at least ten years and probably even further away (Despite Detroit and Washington's declarations to the contrary), stationary fuel cells will achieve commercial viability much sooner.

The ongoing fuel cost must be incorporated into the cost estimates for fuel cells. Currently Gustavus has diesel and propane delivered via a barge to an offloading area on the Salmon River. The diesel is used for the existing electrical production as well as for resident space heating. The propane is primarily used for cooking.

Fuel cells run on hydrogen. Hydrogen is either provided directly from a source such as electrolysis or is stripped from a fossil fuel such as natural gas or propane through a hydrogen reformer device.

Hydrogen reformers strip the carbon and other elements from the hydrocarbon fossil fuel. In this process they generate waste, in the form of carbon dioxide and carbon monoxide. The vast majority of reformers are designed to utilize natural gas. While not nearly as popular, some reformers are available for propane and work is underway on diesel reformers. Gustavus has no natural gas infrastructure. Therefore, propane represents the only currently available option for a fuel cell, although diesel fuel may be useable in the near future.

A limited number of propane-powered fuel cells have been utilized in test as well as commercial installations. For example, Yosemite Park installed a 2.5 kW propane fuel cell manufactured by Plug Power Corporation at one of its park entrance kiosks. The fuel cell provides electricity as well as heat for the kiosk.

Nearly all installed propane powered fuel cells are small (<10 kW). The limitation on the size of installed propane fuel cells appears to relate to two issues; 1) the technically difficult problem of building a propane powered hydrogen reformer and 2) lack of market demand for the larger solutions where natural gas dominates.

The Propane Education Council is the main entity funding and tracking the development of propane fuel cells. Currently it has solicitation for a detailed study of propane fuel cell installations and results out for bid. Upon completion of this study, a realistic timeframe and review of the prospects for a propane fuel cell system in Gustavus should become clearer.

1. Fuel Cell Technology Review

This section presents a brief review of the fuel cell technologies that may be appropriate for use in Gustavus in the near future.

Proton Exchange Membrane (PEMFC): Smaller, easier to manufacture and operate at lower temperatures, but more sensitive to fuel impurities. PEMFC's are the primary candidates for automobiles. Stack and cell endurance have presented some problems, resulting in shorter than expected useful lifetimes.

Phosphoric Acid Fuel Cell (PAFC): Most mature of fuel cell technologies, large stationary PAFC's up to 250 kW are commercially available and installed at over 200 sites around the world. PAFC's can tolerate more impure fuel than other types of fuel cells and are highly efficient when used for cogeneration, but are larger and generate lower current and power relative to other technologies. In addition PAFC's require expensive platinum as a catalyst.

Solid Oxide Fuel Cell (SOFC): A promising technology for large, high power applications. Larger, more difficult to manufacture and operate at higher temperatures (up to 1,000° C). Demonstration units have produced up to 220 kW and several companies have designs close to commercialization.

Molten Carbonate Fuel Cell (MCFC): also highly efficient and operate at high temperatures (1,200° C). 10 kW to 2 MW demonstration models have operated on several different types of fuel, including propane. High temperatures, however, enhance corrosion and the breakdown of cell components.

2. Fuel Cell Manufacturers

This section briefly describes the state of some fuel cell manufactures producing models that may be appropriate for Gustavus.

United Technology Company (UTC) has sold over 250 200kW PAFC's (Model PC25) at costs around $4,500/kW. Most run on natural gas, but many use methane from biomass, and at least one, in Guangzhou, China, uses propane. The lifetime of the units has only reached five years however, typical of PAFCs. UTC is now focusing on its 150 kW PEM models, which, while somewhat less efficient, are also less costly. UTC also has large SOFC models in long term development.

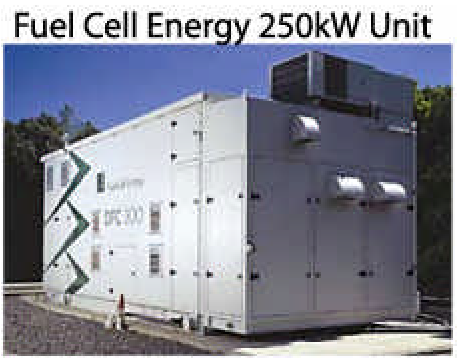
Fuel Cell Energy: has commercialized a 250 kW MCFC and shipped over 25 units in 2003 (see cost example below).

Fuel Cell Technologies, H Power and Avista Labs have each installed small (5 kW) fuel cells running on propane in commercial settings, including Yosemite, Yellowstone, Kehoe Bay and Department of Defense sites. (Fuel Cells 2000, 2002)

Plug Power recently formed a joint venture with GE in order to sell, install and service the Plug Power fuel cell running on natural gas or propane. When available, the initial products targeted are sized in the several kilowatt range and are intended for use by individual households and small businesses. The venture has stated an intention to build larger commercial scale fuel cell systems.

3. Case Study for Gustavus

We contacted Fuel Cell Energy regarding their 250kW MCFC (model DCF 300A) which utilizes natural gas. Based upon the specifications and our discussions with the firm the unit would consume 7,260 BTU per kWh produced (commonly referred to as "heat rate"). At $0.95 per gallon[6], the propane fuel will cost 8.3cents per kWh. Assuming a cost of $4,500/kWh ($1,125,000) the added capital cost of the project is likely to equate to 8.0 cents per kWh, for a total cost of 16.3 cents per kWh[7].



In addition to this 16.3-cent cost, we estimate the marginal cost of moving from a natural gas based reformer to a propane reformer to be 1 to 2 cents. This figure is provided as an estimate as we could not locate a commercially available propane reformer system of the appropriate scale.

[6] See Preliminary Draft Environmental Assessment, Sub Appendix A, Base Case Assumptions
[7] Using manufacturers assumptions regarding availability, maintenance cost, stack degradation and replacement and financing term, interest rate and developer's 15% margin

The final cost of the fuel cell system, at 20.4 cents is competitive with either the existing diesel generation or the proposed Falls Creek Hydro project. This cost does not include any federal or state rebates that may be available.

4. Hydrogen Future

A future option for reducing the cost of a fuel cell at Gustavus may come from wind farms currently being planned in the Prince Rupert, BC area. Several developers have proposed developing significant onshore of offshore wind resources in the range of several hundred megawatts each. Assuming that some of these developers are successful in building out these projects, it is likely that at certain times excess electricity will be available due to transmission constraints. It may be possible for a business to be developed that would generate hydrogen with the excess electricity, transport and sell it to rural communities for use in fuel cell applications. More information on companies proposing to develop wind farms in the Northern BC area can be obtained from BC Land and Water.

C. Southeast Alaska Intertie (Submarine Cable)

Conclusion: Despite significant capital requirements, there continues to be strong interested pursuing the proposed Southeast Intertie, which presents a possible alternative to the Falls Creek Project.

A preliminary draft report on connecting Gustavus to Hoonah via a submarine cable as part of the proposed Southeast Alaska Intertie was completed in July 2003 and should be available publicly in the Fall of 2003. Estimated construction costs for the Hoonah Gustavus leg are $23 million, with an annual operating cost of around $500,000 (including O&M, A&G and contingency funds, but no recovery of capital costs). These costs include a connection to Glacier Bay National Park, but not Excursion Inlet. Federal legislation, which has approved, but not yet funded, the Southeast Intertie, requires 20 percent matching contribution. It is anticipated that at least a portion of the matching funds would be contributed by the State of Alaska.

The economics of such a project present a formidable challenge. However there continues to be significant interest in linking rural towns in Southeast Alaska to hydro facilities via submarine cables in order to utilize excess capacity and reduce diesel generation.

D. Energy Efficiency

Conclusion: low cost savings of 20-30 percent are possible and could be used in combination with or to defer capital investment in new facilities, resulting in net savings for Gustavus.

Gustavus has a population of 421 permanent residents, with nearly double that population during the summer tourist season. The town consists of 345 housing units 146 of which are vacant some portion of the year (2000 census).

Peak loads of approximately 300 kW occur both in the winter, for lighting and heating loads, and in the summer, during the tourist season. Peak loads typically occur in the evening around dinnertime. (Preliminary Draft Environmental Assessment, Appendix A HDR Study of Generating Alternatives). 2002 annual generation was 1,400 MWh.

The Draft EA states that conservation was not considered as an alternative because "GEC is expected to have adequate capacity throughout the study period with only the existing resources. Therefore, load management and energy conservation could provide savings to the consumer but would increase GEC's per-unit cost of energy." (p. 23). This assertion sidesteps many strong arguments for supporting efficiency programs, programs that are routinely implemented by utilities throughout the US despite the fact that they reduce energy sales and increase the capital cost per kWh that must be recovered. In the case of Gustavus, increased energy efficiency will reduce the total PCE subsidy ($0.2235/kWh) paid by the AEA. A 20 percent reduction in annual energy consumption would reduce the PCE subsidy by approximately $62,000 each year (based on 1,400 MWh used in 2002). Utilities commonly use efficiency programs to defer investments in new facilities, delaying capital expenditures that would increase rates even more. With a weighted cost of capital of 10 percent and an inflation rate of 3 percent, deferring a capital investment of $4.1 million for five years results in a net savings of $1.1 million.

The Alaska Energy Authority (AEA) and Rural Alaskans Conserve Energy (RACE) and Rebuild America have performed several studies and energy audits for small rural Alaskan towns, including, Kake, Craig and Tanakee Springs. The Alaska Energy Authority sponsored energy audits for the Gustavus community buildings and the Gustavus School that were performed by Heat Loss Analysis in June 2001. In the library, fire hall and school energy efficient lighting in the form of florescent T8 lamps with electronic ballasts were already in place. However, the study found that older lights in the community building and the clinic could be replaced with more efficient fixtures. A combination of measures resulted in calculated savings of over 4,000 kWh per year for these two buildings. These findings, as well as the success of efficiency measures taken in other Southeast Alaska towns suggest that an energy savings of 20-30 percent is certainly possible in Gustavus. While efficiency cannot eliminate the need for new generation, it can defer capital investment and result in net savings, the arguments made by Gustavus Energy notwithstanding.

1. Tenakee Springs

In the Summer of 2002, the Alaska Energy Authority led an energy efficiency retrofit effort in Tenakee Springs, a small town located on the east side of Chichagof Island in Southeast Alaska. Most of the structures in the village were built in the early 1900s and have been well maintained, but many were in need of new lighting and thermal upgrades. Figure 12 shows the measures implemented in Tenakee Springs and the resulting savings.

Light Bulbs Arrive at Tenakee Springs

Figure 12

Energy Efficiency Measures Implemented in Tenakee Springs and Resulting Savings

Location	No.	Item	Cost	Annual Savings	Simple Payback (years)	Savings (kW)	Savings (kWh)
Commercial							
Mercantile	10	Light Fixtures	$260	$204	1.3	0.49	815
Post Office	6	Light Fixtures	316	125	2.5	0.3	499
School	166	Light Fixtures	18,062	1,573	11.5	4.58	6,290
Clinic	6	Light Fixtures	811	128	6.3	0.66	512
Community Hall	50	Light Fixtures	2,630	1,456	1.8	2.5	4,160
Residential							
26 Residences	85	Light Fixtures	6,150	2,964	2.1	4.8	8,469
	12	Refrigerators	6,228	2,313	2.7	2.4	9,250
Total			$34,457	$8,763	3.9	16	29,996

Improvements were made in 26 homes, or approximately one quarter of the residences in Tenakee Springs. Overall the efficiency measures resulted in an annual savings of nearly 30,000 kWh and $8,763. This was achieved primarily though replacing lights with more efficient fluorescent fixtures. In addition, 12 older refrigerators were also replaced. The average simple payback period was less than four years and in most cases less than three years. These payback periods were calculated with electric rates of $0.25/kWh (After PCE) which are similar to Gustavus Electric rates after the PCE of $0.28/kWh.

2. Efficiency Measures

In residential homes, installing energy efficient compact fluorescent light bulbs (CFL's) is typically the most practical and economic option for reducing electricity use. CFL's are 75 percent more efficient than incandescent bulbs and last ten times as long. Technological advances have long since overcome initial complaints associated with compact florescent lights (such as flicker, delayed start up and noise). A wide range of CFL's are now available that are dimmable, silent, without flicker and without start up delays. CFL's can also produce higher quality light as compared to incandescent bulbs.

Installing three CFL's in just one quarter of Gustavus's approximately 200 full-time and 150 part-time dwellings would save approximately 23,000 kWh per year. Because peak generation occurs during the evening hours, when most of these lights are likely to be in use, peak demand could be reduced by up to 20 kW. This would reduce PCE payments by over $5,000 per year and save $3,000 in fuel costs (of about $0.13/kWh). The total savings to the residential customer from CFL's would pay for their installation in approximately two years.

As described above, it is also likely that more efficient lighting could be installed in several commercial and municipal buildings that have not already installed fluorescent T8 lights with electronic ballasts. Timers, motion sensors and photo-electric sensors can also significantly reduce lighting demand. In addition replacing emergency and exit lighting with LED signs also saves about 300 kW per year per fixture. The 2001 audit found that two of the five buildings examined could benefit from these types of measures, with savings of over 4,000 kWh per year. If similar savings could be found in the fifteen or so commercial and community facilities that were not included in the study, energy demand could be reduced by 12,000 kWh per year.

In Tenakee Springs, refrigerators were replaced in 12 of the 90 households (13 percent) at a total cost of $6,200, resulting in a savings of 9,251 kWh. The new refrigerators cost approximately $500 a piece, depending on size, and saved on average 771 kWh per year. A similar effort in Gustavus would replace 45 refrigerators, cost around $23,000 and save over 34,000 kWh a year.

Water heaters might present additional potential savings. Most, if not all of the water heaters in Gustavus use oil. In addition to being more efficient given the high price of electricity, oil water heaters are far more economical. However, to the extent any homes have electric water heaters, replacing them with oil water heaters would save approximately 4,500 kWh per year per heater.

IV. Other Generation Technologies Considered

A. Wind

Conclusion: Wind does not represent an economically viable option due to lack of sufficient wind in the area as well as its tendency to be intermittent on a seasonal basis.

Background: Large wind turbines (1.5 megawatt and above) are now cost competitive with least cost fossil fuel generation in areas with consistent strong winds (6-10 meters per second). In the best sites, large wind turbines can generate power at 3.5 cents or below. Since wind power is a cube of wind speed, turbine output and the generated cost of energy is dramatically impacted by wind speed.

The Alaska Energy Authority and the Alaska Industrial Development and Export Authority funded an analysis titled "Initiatives Aimed at Improving Rural Energy Efficiency and Reliability" in December of 2002. This report included an analysis of wind power in rural villages and rank ordered the top 31 communities most likely to be able to cost effectively capitalize on their wind resource. Gustavus was not included in this list.

Our review of these analyses was supplemented by conversations with the owner of the Bear Track Inn in Gustavus, Mike Olmey, who referred us to a Lee Baker, also a Gustavus resident. Lee has installed and operated windmills in the area for over ten years. Our discussions with Mike and Lee confirm the conclusions reached in the HDR analysis regarding low wind speed in Gustavus. Specifically, Gustavus is in a low plain with no nearby hills upon which turbines could be mounted to catch higher-level winds. Lee also mentioned that the wind in the area is intermittent on a yearly basis; that is some years there is wind and some years there is not. His conclusion was that upper level weather patterns, of global long-term nature, led to this intermittent wind pattern.

B. Biomass

Conclusion: While a sufficient quantity of wood waste exists just across the Icy Strait, wood waste is not a viable option for electrical production due to future availability concerns, shipping and handling costs as well as a lack of proven small-scale biomass to electricity conversion devices.

Background: Wood wastes from lumber operations represent a substantial waste to energy conversion opportunity for Southeast Alaska. Lumber operations generally dispose of wood waste through burning with no associated energy production. Technologies exist to convert these feedstocks through:

- Gasification and utilization of the gas in an engine or turbine to turn a generator and make electricity,
- Direct combustion for powering a steam boiler and associated turbine/genset,
- Direct combustion in conjunction with a hot-air engine, generally a Stirling cycle.

In order to determine the viability of utilizing wood waste, we reviewed the availability, cost and usability of area feedstock. Using these assumptions, we further analyzed the feasibility and costs across the three energy conversion options above.

Log Sort Yard Residue

The report "Southeast Alaska Biomass-to-Ethanol Project Feedstock Supply Plan", by TSS Consultants, June 20, 2000, identified Whitestone Southeast Logging in Hoohan, Alaska, just across the Icy Strait from Gustavus as having excess lumber yard waste that is currently being disposed of by burning. The estimate was for 3,125 bone dry tons (BDT) of sawdust and bark and 1,000 BDT of slabs, butt and long ends available each year.

We contacted Whitestone Southeast Logging to check on the current status of their operations and spoke with Dave Owens, manager. Dave indicated that the logging operations are still in place, but that the future is uncertain. They are mostly taking logs now from private lands rather than from their historic source, the Tongass National Forest. When discussing the potential to use the wood waste from the operations for energy production in Gustavus, Dave expressed the following concerns:

1. Gustavus does not have a good port to the Icy Strait. The coast is a long beach with no place for a port where the wood could be unloaded. Currently, goods are shipped up the Salmon River into town via barges of various sizes. The barge captain Whitestone Logging uses received complaints in the past from Gustavus residents regarding an incident where the barge ran aground. This was using a large barge of the type necessary to haul wood waste. The captain has indicated that he refuses to take the large barge back up river and into town.

2. The cost of handling small pieces of wood waste would be very high. There are currently no facilities for chipping, drying, transporting or storing the materials at either Whitestone or Gustavus. An example of a barge loading facility of the type needed, from the Viking mill at Klawok, AK, is pictured above.

3. Environmental considerations. Dave recommended I review the history of the co-gen steam plant at a sawmill in Haines. He indicated that the wood fired facility was shut down due to environmental concerns and that a wood fired solution was unlikely to be acceptable for Gustavus. We called the town of Haines and confirmed that the power is now supplied by hydro and that no wood fired electricity is generated. We were not able to confirm the reason for the plant being shut down.

We note that Dave Owens also indicated that he has worked on the Falls Creek Hydro project and believes that it is the best solution for the energy needs of Gustavus.

Assuming the transport and handling issues could be resolved in a cost effective manner, options for such small-scale energy conversion do exist, but they are not yet widely proven or cost effective at this time. A brief review of these options is presented below:

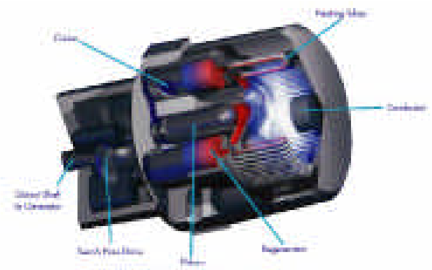
1. Bio-gasification

Community Power Corporation had developed a bio-gasification technology that consumes 1.5 kg of wood waste per kilowatt-hour of electricity produced. Gustavus consumes approximately 2,000 MWh of electricity per year. Using this device, approximately 3300 bone dry tons of wood would be required. Whitestone logging is noted to have approximately 3,125 bone dry tons (BDT) of sawdust and bark and 1,000 BDT of slabs, butt and long ends available each year.

2. Direct Combustion with Steam Turbine

Our analysis of the available products for direct combustion of wood waste, generally through fluidized bed combustors indicated that no technologies are available in the sub 5-megawatt range. OSHA rules require a full time operator when high-pressure steam is utilized. Therefore, the economics of steam turbine generation dictate that a certain economy of scale must be reached before the project is economically viable.

3. Direct Combustion with Hot Air Engine



STM 4-Piston Stirling Engine

Hot air engines work on a similar principal as the classic James Watt steam engine; only they use low-pressure air as the expansion fluid rather than steam, and therefore do not require an operator. The most notable of the hot air engine designs are the Stirling and Ericsson engines. Matched to a biomass furnace providing sufficient heat output, a hot air engine mated to a generator could provide significant electrical generation. Currently several manufacturers of Stirling engines are nearing commercial availability. The most notable of these is STM Power, owned by Detroit Edison. A single STM power module provides 55kw of power and consumes 0.5 kg of wood waste per kWh of electricity produced[8].

C. <u>Biodiesel/Fish Oil</u>

Conclusion: Not an economically viable option due to the distance between feedstock supplies and Gustavus.

Background: Conventional diesel engines, such at the ones employed by Gustavus Electric, can generally utilize high quality biodiesel with little or minor modification. In addition, work has been done to successfully utilize fish oil in a blend with conventional diesel. Should a stable source of biodiesel or fish oil be available or be developed in the region, the existing diesel generation units might be capable of utilizing the fuel, potentially mitigating fuel price risk, as well as reducing particulate emissions. 100th Meridian undertook research to identify the availability of biodiesel, biodiesel feedstocks or fish oil within the region. Biodiesel is generally made from high fat waste

[8] Assuming 160 therms per BDT wood and 12,000 BTU per kwh

products such as animal renderings, from high oil content agricultural crops such as soybeans or from frying oil recycled from restaurants.

We contacted the Alaska Energy Authority, spoke with local residents and contacted a variety of commercial entities regarding feedstock availability. Our findings indicate that the agricultural, animal rendering and restaurant based feedstocks necessary for biodiesel production do not exist in the region in quantities sufficient to build a cost effective production facility. Specifically, no high oil content agricultural crops are grown in the region and no slaughterhouses are nearby.

With respect to fish oil, we were provided with a report entitled "Demonstrating the use of Fish Oil as a Fuel in a Large Stationary Diesel Engine", *J.A. Steigers*, 2002. This report analyzed the potential for burning fish oil directly, without conversion of the oil into biodiesel. The fish oil is a byproduct of Pollack processing both at on-shore facilities and in floating processing centers.

Dutch Harbor Unisea Processing Facility

The report and our conversations with its author, John Steigers at Steigers Corporation indicates that fish oil was burned in a variety of blends with conventional diesel in Fairbanks Morse 3160 and 3960 horsepower two stroke diesel engines. Steigers Corporation is currently undertaking similar research utilizing 4 stroke diesel engines, the type utilized currently by Gustavus Electric. The results of the report conclude that with some engine modification, fish oil in a blend up to 50 percent with #2 diesel, could be burned directly in these engines. Emissions results indicated a decrease in particulate emission of up to 60 percent, decrease in sulphur dioxide of up to 78 percent and decrease in carbon dioxide of up to 33 percent. An increase in nitrous oxide of up to 8 percent was also observed. The report concluded that the emissions reductions were essentially offset by the nitrious oxide emissions and emissions benefits should be viewed in the context of the local relative to the emissions component.

Most fish processing facilities internally utilize the waste fish oil for boiler fuel. This leaves no excess fish oil available. However, large facilities in the Aleutian chain such as two in a thirty-five mile radius of Dutch Harbor have excess fish oil that they sell to the market for a variety of uses including export. The primary feedstock identified by the report was the UniSea processing facility on Amaknak Island. Another processing facility approximately thirty miles away was also presented as having excess fish oil. A third in Kodiak Alaska was also mentioned as a potential feedstock supplier. The Dutch Harbor community is approximately 1000 miles from Gustavus and Kodiak over 500 miles. These distances are far too large to allow for cost efficient transport of the fuel to Gustavus. We were unable to locate fish processing facilities nearer to Gustavus that have excess fish oil.

Floating fish processing facilities ("mother ships") also have the potential of generating large amounts of fish oil as they currently do not extract nearly as much oil from fish processing as do land based processors. John Steiger's opinion was that the economics of additional fish oil generation did not make sense for these floating facilities and that absent some regulatory impetus, their potential as a fish oil supply source was limited.

D. Higher Efficiency Diesels

Conclusion: Installing a higher efficiency diesel engine and potentially configuring it to load follow may be a means of reducing cost and fuel consumption, but a detailed operational analysis is required before a definitive conclusion can be drawn.

Gustavus Electric operates 4 diesel generation units. Currently, Gustavus units are dispatched as needed. Once dispatched, the machines are run unattended and at a constant speed. The most efficient of these units is dispatched first. It is a 250 kW Cummings diesel with approximately 45,000 hours on it and produces 13.75 KWh per gallon of fuel under full load, equal to just over 10 cents per Kilowatt hour[9]. Other older less efficient (12 kWh/g and below) units are dispatched on top of this first unit on an as needed basis.

To evaluate the impact of newer, more efficient diesel engines, we relied upon the Rural Alaska Energy Plan: Draft Diesel Efficiency Plan, prepared for the Alaska Energy Authority, December 2002. The report noted that fuel cost is up to 85 percent of generation cost in a diesel system, and therefore savings of as little as 5 percent may justify the cost of upgrades. Two types of retrofits/upgrades of potential applicability were highlighted in the report. The first is switchgear & controls to allow the generators to load follow. The second was replacing the gensets with newer, more efficient technology.

Evaluation of the benefits of switchgear & controls requires analysis of the impact on maintenance and reliability, which is outside the scope of this report. It is noted that while an industry average savings of 5 percent was standard, each situation varies and in many cases these upgrades were not cost justified based upon the savings. Therefore, without a detailed study, a proper analysis cannot be conducted. It is noted in the report that often the best time to install load following technology is in conjunction with a genset upgrade.

The report went on to identify two gensets that provide high efficiency, with one operating across a relatively similar load profiles as in Gustavus (Detroit Diesel Series 60).

[9] Using $1.41/gallon diesel

Figure 13

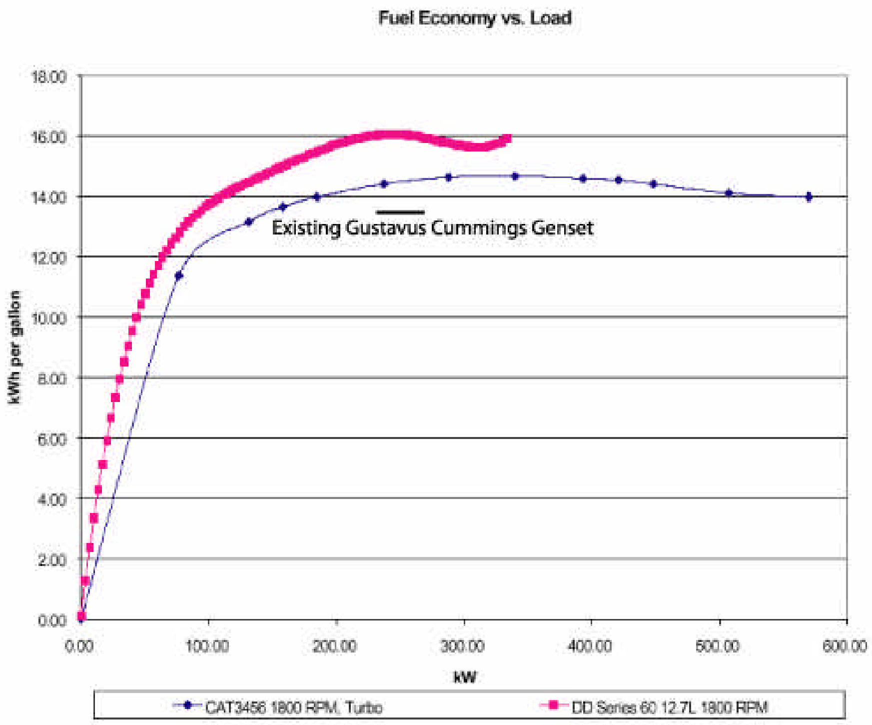
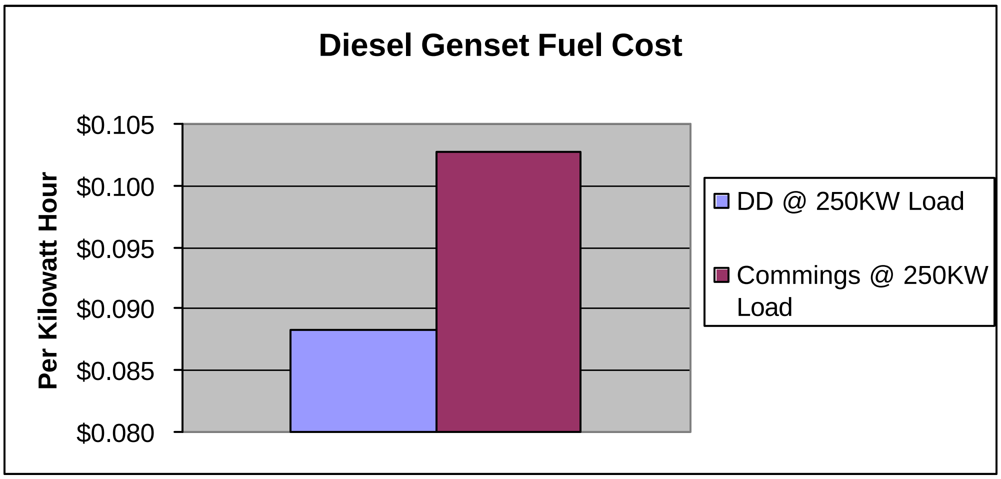


Figure 13 illustrates the KWh per gallon of the Detroit Diesel (DD) machine, a larger Caterpillar machine and the 13.75KWh output of the existing Gustavus Cummings machine. The DD machine's highest efficiency is 16 KWh per gallon and at the Gustavus minimum base load (~150KW) it achieves well over 14 KWh per gallon. In order to calculate potential fuel saving from this new genset, we assume the DD machine is run unattended at a constant 250KW output, the same as the existing Cummings genset. At this output, the DD machine generates 16KWh per gallon, well above the 13.75 KWh per gallon noted in the Project Draft EA for the existing Cummings engine.

Figure 14



This represents a 16.3 percent increase in efficiency and shifts the cost of fuel from 10.3 cents to 8.8 cents per KWh using $1.41/g diesel. Assuming a 95 percent availability factor for both machines and equal maintenance costs over time, the move to the DD machine would save $30,000 per year in fuel which could be applied to amortization of the capital investment.

Additional factors that may further reduce fuel consumption and generation cost include:

1. Consideration of the broader power range of the DD machine, whereby it can offset dispatch of the even less efficient existing Gustavus machines in the 250KW to 350KW range. Currently machines with efficiency below 12KWh per gallon are dispatched when load requires additional generation.

2. The addition of load following technology in conjunction with the genset upgrade whereby the DD machine would adjust its output to match the load requirements and thereby reduce fuel consumption.

In summary, it appears that technology exists that would, at a minimum, reduce Gustavus' diesel fuel consumption by 16 percent. Whether this savings is sufficient to warrant replacement of the existing technology and whether additional load following technology might be appropriate, will require access and analysis of detailed data relating to the operation and cost of Gustavus' existing gensets.

Further Note: We reviewed with Jed Davis of the Glacier Bay National Park Service the recent installation of new generators to serve its load. He noted that the fuel cost per kWh produced was averaging in the 12 cent range and that cost per KWh when capital costs are included was around 20 cents.

E. <u>Micro Hydro</u>

Conclusion: Small and Micro-hydro technologies may be appropriate for individual households, but do not appear viable as a larger generation resource for the town of Gustavus.

1 kW Reaction Turbine

The Good and Salmon Rivers flow through the town of Gustavus but have relatively low gradients. While there are high volume/low head hydro technologies, they do not appear to be viable for these rivers, as both the flows and the gradients are too low. In river turbine/propeller technologies have been proposed for larger rivers, including a proposed project on the Yukon River near Eagle (UEK technologies). Smaller designs (1 kW or less) are available and may be suitable for individual homes near the Good and Salmon Rivers. Propeller designs are, however, the least efficient of the small and micro-hydro technologies. Smaller (1 kW) reaction turbines (designed for high volume/low head) require at least two and generally five or more feet of drop, which in the case of the Good and Salmon rivers, would require lengthy diversion structures.

V. Conclusion

We are sympathetic to the desire to reduce Gustavus's reliance on diesel generation. However, the proposed Falls Creek Hydroelectric Project is not a sound or economically viable means of doing so. The project will irreversibly alter a unique resource inside a national park and commit Gustavus to high cost generation that will limit its ability to benefit from technological advances in other promising technologies in the future. The project will generate power at costs higher, not lower, than existing diesel generation and increase, rather than reduce Gustavus Electric's rates. The specific burden that the Glacier Bay Boundary Adjustment Act places upon this project to prove economic viability and sound financing has not been met.

Energy efficiency has been proven as an effective means of reducing energy demand in other Southeast Alaska communities and can defer the need for new investment in capital intensive generating resources. While Gustavus Electric expressed concern that conservation will only increase electric rates, utilities throughout the US have implemented efficiency programs with benefits for both the consumer and the utility. The community may want to initiate discussions with the Regulatory Commission of Alaska and the Alaska Energy Authority regarding how efficiency programs could be implemented and funded in Gustavus.

Fuel cells, tidal generation and the Southeast Intertie are all potential alternatives that may become economically feasible well before electric demand in Gustavus nears or exceeds existing generating capacity. While the future of these technologies is far from certain, significant investments and advances are being made and many are optimistic. Given the lack of urgent need for new generation in Gustavus and the poor economics of the proposed Falls Creek project, it would be prudent for Gustavus to allow several years for these alternatives to develop before committing significant capital to the Falls Creek Project.

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U.S. Department of Energy, Energy Information Administration, 2001. Form EIA-861, 2001 data.

Calculation of GECI Fuel Costs Exceeding $.20/gal Markup

(A) DATE	(B) Actual Fuel Consumption (Gal.)	(C) Actual Fuel Expense ($)	(D) Actual Fuel Expense ($/Gal.)	(E) Actual Monthly Sales (kWh)	Monthly Generated (kWh)	(F) Annual Sales (kWh)	(G) Applicable Efficiency Standard (kWh/Gal.)	(H) Actual Monthly Efficiency (kWh/Gal.)	Monthly Efficiency new method (kWh/Gal.)	(I) Actual Yearly Efficiency (kWh/Gal.)	(J) Imputed Fuel Consumption (Gal.)	(K) Imputed Monthly Efficiency (kWh/Gal.)	(L) Imputed Annual Efficiency (kWh/Gal.)	(M) Imputed Fuel Cost Excluding AFF/INT Adjustment ($)	(N) Does Actual Consumption = Imputed? (YES/NO)	(O) Efficiency - Related Disallowed Fuel Costs ($)	(P) AFF/INT - Related Disallowed Fuel Costs ($)	(Q) Surcharge Assessed ($/kWh)	(R) Beginning Balance Balancing Account ($)
Jan-00	9,950	$12,039.50	$1.21	72,660				7.30											
Jan-00	10,777	$13,040.00	$1.21	73,765				6.84											
Mar-90	8,303	$10,046.63	$1.21	60,852				7.33											
Apr-90	8,897	$10,765.37	$1.21	61,365				6.90											
May-90	8,944	$10,822.24	$1.21	60,829				6.80											
Jun-90	10,025	$12,130.25	$1.21	63,873				6.37											
Jul-90	10,160	$12,293.60	$1.21	64,014				6.30											
Aug-90	10,748	$13,005.08	$1.21	71,705				6.67											
Sep-90	11,302	$13,675.42	$1.21	68,753				6.08											
Oct-90	9,672	$13,153.92	$1.36	69,659			8.00	7.20											
Nov-90	11,268	$17,916.12	$1.59	80,275			8.00	7.12		6.79									
Dec-90	11,870	$18,873.30	$1.59	86,097		833,847	8.00	7.25		6.84									
Jan-91	11,827	$18,804.93	$1.59	86,845		848,032	8.00	7.34		6.85	10,856	8.00		$17,261	NO			$0.04750	$0.00
Feb-91	10,230	$13,196.70	$1.29	75,918		850,185	8.00	7.42		6.90	9,490	8.00		$12,242	NO			($0.00980)	($811.14)
Mar-91	8,301	$9,878.19	$1.19	65,105		854,438	8.00	7.84		6.93	8,138	8.00		$9,684	NO			($0.00980)	($17.14)
Apr-91	7,493	$8,916.67	$1.19	68,829		861,902	8.00	9.19		7.07	7,493	9.19		$8,917	YES			($0.00980)	($151.11)
May-91	7,357	$8,754.83	$1.19	65,452		866,525	8.00	8.90		7.21	7,357	8.90		$8,755	YES			($0.05790)	($1,613.59)
Jun-91	9,356	$10,198.04	$1.09	70,460		873,112	8.00	7.53		7.30	8,808	8.00		$9,601	NO	$597		($0.05790)	$419.08
Jul-91	10,049	$10,953.41	$1.09	76,437		885,535	8.00	7.61		7.41	9,555	8.00		$10,415	NO	$538		($0.05790)	$2,783.72
Aug-91	10,256	$12,204.64	$1.19	83,222		897,052	8.00	8.11		7.54	10,256	8.11		$12,205	YES	#N/A		($0.05790)	$5,348.42
Sep-91	9,560	$10,898.40	$1.14	80,484		908,783	8.00	8.42		7.75	9,560	8.42		$10,898	YES	#N/A		($0.05790)	$9,006.97
Oct-91	7,863	$8,963.82	$1.14	74,169		913,293	9.00	9.43		7.91	7,863	9.43		$8,964	YES	#N/A		($0.05790)	$11,639.00
Nov-91	9,129	$10,224.48	$1.12	84,945		917,963	9.00	9.30		8.10	9,129	9.30		$10,224	YES	#N/A		($0.05790)	$12,985.38
Dec-91	8,200	$9,184.00	$1.12	82,362		914,228	9.00	10.04		8.34	8,200	10.04	8.63	$9,184	YES	#N/A		($0.05790)	$14,485.70
Jan-92	7,951	$8,905.12	$1.12	78,503		905,886	9.00	9.87		8.57	7,951	9.87	8.80	$8,905	YES	#N/A		($0.00780)	$15,211.46
Feb-92	8,278	$9,271.36	$1.12	81,093		911,061	9.00	9.80		8.78	8,278	9.80	8.96	$9,271	YES	#N/A		($0.00780)	$12,120.78
Mar-92	7,268	$8,140.16	$1.12	71,867		917,823	9.00	9.89		8.93	7,268	9.89	9.01	$8,140	YES	#N/A		($0.00780)	$9,000.31
Apr-92	7,445	$8,189.50	$1.10	69,312		918,306	9.00	9.31		8.94	7,445	9.31	9.04	$8,190	YES	#N/A		($0.00780)	$6,158.87
May-92	7,432	$8,175.20	$1.10	70,513		923,367	9.00	9.49		8.98	7,432	9.49	9.18	$8,175	YES	#N/A		($0.00780)	$3,757.50
Jun-92	8,405	$9,161.45	$1.09	78,457		931,364	9.00	9.33		9.15	8,405	9.33	9.31	$9,161	YES	#N/A		($0.00920)	$1,158.50
Jul-92	9,117	$10,028.70	$1.10	82,616		937,543	9.00	9.06		9.29	9,117	9.06	9.42	$10,029	YES	#N/A		($0.00920)	($1,558.69)
Aug-92	9,487	$10,435.70	$1.10	85,759		940,080	9.00	9.04		9.39	9,487	9.04	9.49	$10,436	YES	#N/A		($0.00920)	($4,037.63)
Sep-92	9,063	$9,969.30	$1.10	87,704		947,300	9.00	9.68		9.51	9,063	9.68	9.51	$9,969	YES	#N/A		($0.00920)	($6,585.64)
Oct-92	7,842	$8,626.20	$1.10	76,661		949,792	9.00	9.78		9.53	7,842	9.78	9.56	$8,626	YES	#N/A		($0.00920)	($9,894.77)
Nov-92	8,161	$8,977.10	$1.10	86,063		950,910	9.00	10.55		9.64	8,161	10.55	9.60	$8,977	YES	#N/A		($0.00920)	($12,875.48)
Dec-92	8,159	$8,974.90	$1.10	80,275		948,823	9.00	9.84		9.62	8,159	9.84	9.60	$8,975	YES	#N/A		($0.00920)	($16,928.70)
Jan-93	8,747	$9,621.70	$1.10	86,596		956,916	9.00	9.90		9.63	8,747	9.90	9.61	$9,622	YES	#N/A		($0.00920)	($20,107.17)
Feb-93	8,415	$9,256.50	$1.10	88,910		964,733	9.00	10.57		9.69	8,415	10.57	9.68	$9,257	YES	#N/A		($0.00920)	($23,595.49)
Mar-93	7,023	$7,725.30	$1.10	77,395		970,261	9.00	11.02		9.77	7,023	11.02	9.81	$7,725	YES	#N/A		($0.00920)	($28,799.52)
Apr-93	6,886	$7,574.60	$1.10	72,846		973,795	9.00	10.58		9.86	6,886	10.58	9.89	$7,575	YES	#N/A		($0.08030)	($33,792.49)
May-93	7,223	$8,017.53	$1.11	74,636		977,918	9.00	10.33		9.93	7,223	10.33	9.98	$8,018	YES	#N/A		($0.08030)	($33,066.95)
Jun-93	7,457	$8,351.84	$1.12	76,007		975,468	9.00	10.19		10.00	7,457	10.19	10.09	$8,352	YES	#N/A		($0.08030)	($32,042.68)
Jul-93	9,489	$10,627.68	$1.12	82,660		975,512	9.00	8.71		9.96	9,489	8.71	10.06	$10,628	YES	#N/A		($0.08030)	($30,794.32)
Aug-93	8,500	$9,350.00	$1.10	84,249		974,002	9.00	9.91		10.04	8,500	9.91	10.08	$9,350	YES	#N/A		($0.08030)	($27,803.72)
Sep-93	8,678	$9,632.58	$1.11	85,406		971,704	9.00	9.84		10.06	8,678	9.84	10.09	$9,633	YES	#N/A		($0.08030)	($26,218.53)
Oct-93	8,081	$8,889.10	$1.10	86,994		982,037	10.00	10.77		10.14	8,081	10.77	10.11	$8,889	YES	#N/A		($0.08030)	($24,443.42)
Nov-93	8,406	$9,246.60	$1.10	91,745		987,719	10.00	10.91		10.18	8,406	10.91	10.21	$9,247	YES	#N/A		($0.08030)	($23,539.81)
Dec-93	8,641	$9,505.10	$1.10	93,417		1,000,861	11.00	10.81		10.26	8,492	11.00	10.31	$9,342	NO	$163		($0.08030)	($22,659.68)
Jan-94	8,876	$9,763.60	$1.10	97,742		1,012,007	11.00	11.01		10.36	8,876	11.01	10.36	$9,764	YES	#N/A		($0.08030)	($21,819.30)
Feb-94	9,132	$10,045.20	$1.10	96,660		1,019,757	11.00	10.58		10.36	8,787	11.00	10.37	$9,666	NO	$379		($0.08030)	($20,903.61)
Mar-94	7,698	$8,467.80	$1.10	91,089		1,033,451	11.00	11.83		10.43	7,698	11.83	10.48	$8,468	YES	#N/A		($0.07620)	($19,999.82)
Apr-94	7,608	$8,368.80	$1.10	84,974		1,045,579	11.00	11.17		10.48	7,608	11.17	10.55	$8,369	YES	#N/A		($0.07620)	($20,219.84)
May-94	8,514	$9,365.40	$1.10	86,844		1,057,787	11.00	10.20		10.46	7,895	11.00	10.61	$8,684	NO	$681		($0.07620)	($20,022.82)
Jun-94	8,802	$9,682.20	$1.10	93,354		1,075,134	11.00	10.61		10.50	8,487	11.00	10.85	$9,336	NO	$346		($0.08310)	($19,668.30)
Jul-94	9,826	$10,808.60	$1.10	98,317		1,090,791	11.00	10.01		10.61	8,938	11.00	10.95	$9,832	NO	$977		($0.08310)	($18,567.59)
Aug-94	10,990	$12,089.00	$1.10	109,752		1,116,294	11.00	9.99		10.61	9,977	11.00	11.06	$10,975	NO	$1,114		($0.08310)	($17,355.44)
Sep-94	12,260	$13,486.00	$1.10	125,676		1,156,564	11.00	10.25		10.63	11,425	11.00	11.07	$12,568	NO	$918		($0.08310)	($15,886.05)
Oct-94	12,125	$13,337.00	$1.10	121,616		1,191,186	11.00	10.03		10.55	11,056	11.00	11.08	$12,161	NO	$1,176		($0.08310)	($14,058.38)
Nov-94	11,049	$12,153.00	$1.10	129,510		1,228,951	11.00	11.72		10.64	11,049	11.72	11.15	$12,153	YES	#N/A		($0.08310)	($11,835.09)
Dec-94	10,467	$11,513.70	$1.10	108,509		1,244,043	11.00	10.37		10.60	10,467	10.37	11.09	$11,514	YES	#N/A		($0.08310)	($9,718.81)
Jan-95	9,976	$10,973.60	$1.10	98,818		1,245,119	11.00	9.91		10.51	8,983	11.00	11.09	$9,881	NO	$1,093		($0.08310)	($6,614.71)
Feb-95	8,802	$9,682.20	$1.10	101,600		1,250,059	11.00	11.54		10.58	8,802	11.54	11.07	$9,682	YES	#N/A		($0.08310)	($4,391.93)
Mar-95	7,896	$8,685.60	$1.10	94,935		1,253,905	11.00	12.02		10.60	7,896	12.02	11.14	$8,686	YES	#N/A		($0.08310)	($2,583.97)
Apr-95	8,575	$9,432.50	$1.10	99,416		1,268,347	11.00	11.59		10.63	8,575	11.59	11.18	$9,433	YES	#N/A		($0.08310)	($1,255.87)
May-95	7,188	$7,906.80	$1.10	84,319		1,265,822	11.00	11.73		10.73	7,188	11.73	11.24	$7,907	YES	#N/A		($0.07320)	$472.60
Jun-95	9,524	$10,476.40	$1.10	94,587		1,267,055	11.00	9.93		10.68	9,524	9.93	11.14	$10,476	YES	#N/A	$666.68	($0.07320)	$1,009.75
Jul-95	10,340	$11,374.00	$1.10	106,329		1,275,067	11.00	10.28		10.70	10,340	10.28	11.06	$11,374	YES	#N/A	$723.80	($0.07710)	$2,551.84
Aug-95	10,590	$11,649.00	$1.10	105,755		1,271,070	11.00	9.99		10.70	10,247	10.32	11.00	$11,272	NO	$377	$204.94	($0.05540)	$4,237.00
Sep-95	9,637	$10,600.70	$1.10	95,738		1,241,132	11.00	9.93		10.68	8,703	11.00	11.00	$9,573	NO	$1,028	$87.03	($0.05540)	$3,220.89
Oct-95	8,558	$9,413.80	$1.10	98,667		1,218,183	11.00	11.53		10.82	8,558	11.53	11.04	$9,414	YES	#N/A	$85.58	($0.05220)	$2,634.74
Nov-95	10,154	$11,169.40	$1.10	112,986		1,201,659	11.00	11.13		10.76	10,154	11.13	10.98	$11,169	YES	#N/A	$101.54	($0.05220)	$1,267.58
Dec-95	11,420	$12,562.00	$1.10	127,656		1,220,806	11.00	11.18		10.84	11,420	11.18	11.06	$12,562	YES	#N/A	$114.20	($0.05220)	$86.91
Jan-96	10,227	$11,249.70	$1.10	122,307		1,244,295	11.00	11.96		11.02	10,227	11.96	11.15	$11,250	YES	#N/A	$102.27	($0.05220)	($1,303.65)
Feb-96	10,750	$11,825.00	$1.10	130,318		1,273,013	11.00	12.12		11.08	10,750	12.12	11.21	$11,825	YES	#N/A	$161.25	($0.05220)	($3,414.49)
Mar-96	10,284	$11,312.40	$1.10	121,572		1,299,650	11.00	11.82		11.08	10,284	11.82	11.21	$11,312	YES	#N/A	$154.26	($0.05220)	($5,877.14)
Apr-96	8,895	$10,051.35	$1.13	115,877		1,316,111	11.00	13.03		11.19	8,895	13.03	11.32	$10,051	YES	#N/A	$400.28	($0.06900)	($7,897.34)

Calculation of GECI Fuel Costs Exceeding $.20/gal Markup

DATE	Actual Fuel Consumption (Gal.)	Actual Fuel Expense ($)	Actual Fuel Expense ($/Gal.)	Actual Monthly Sales (kWh)	Monthly Generated (kWh)	Annual Sales (kWh)	Applicable Efficiency Standard (kWh/Gal.)	Actual Monthly Efficiency (kWh/Gal.)	Monthly Efficiency new method (kWh/Gal.)	Actual Yearly Efficiency (kWh/Gal.)	Imputed Fuel Consumption (Gal.)	Imputed Monthly Efficiency (kWh/Gal.)	Imputed Annual Efficiency (kWh/Gal.)	Imputed Fuel Cost Excluding AFF/INT Adjustment ($)	Does Actual Consumption = Imputed? (YES/NO)	Efficiency - Related Disallowed Fuel Costs ($)	AFF/INT - Related Disallowed Fuel Costs ($)	Surcharge Assessed ($/kWh)	Beginning Balance Balancing Account ($)
May-96	9,356	$12,185.88	$1.30	110,915		1,342,707	11.00	11.85		11.21	9,356	11.85	11.33	$12,186	YES	#N/A	$280.68	($0.06900)	($8,861.11)
Jun-96	10,909	$14,072.61	$1.29	122,343		1,370,463	11.00	11.21		11.31	10,909	11.21	11.44	$14,073	YES	#N/A	$218.18	($0.06900)	($7,115.65)
Jul-96	11,763	$14,939.01	$1.27	123,848		1,387,982	11.00	10.53		11.33	11,763	10.53	11.45	$14,939	YES	#N/A	$0.00	($0.06900)	($4,467.16)
Aug-96	11,789	$14,854.14	$1.26	126,468		1,408,695	11.00	10.73		11.38	11,789	10.73	11.47	$14,854	YES	#N/A	$2,122.02	($0.06900)	($872.65)
Sep-96	11,238	$14,159.88	$1.26	123,709		1,436,666	11.00	11.01		11.46	11,238	11.01	11.46	$14,160	YES	#N/A	$955.23	($0.06900)	$274.62
Oct-96	9,961	$11,654.37	$1.17	112,856		1,450,855	11.00	11.33		11.45	9,961	11.33	11.45	$11,654	YES	#N/A	$0.00	($0.06900)	$2,147.31
Nov-96	11,436	$13,265.76	$1.16	119,919		1,457,788	11.00	10.49		11.39	11,436	10.49	11.39	$13,266	YES	#N/A	$0.00	($0.06900)	$3,463.38
Dec-96	11,905	$13,809.80	$1.16	127,773		1,457,905	11.00	10.73		11.34	11,905	10.73	11.34	$13,810	YES	#N/A	$178.58	($0.03880)	$5,744.79
Jan-97	12,239	$14,564.41	$1.19	136,996		1,472,594	11.00	11.19		11.28	12,239	11.19	11.28	$14,564	YES	#N/A	$550.76	($0.03880)	$3,813.80
Feb-97	10,704	$12,630.72	$1.18	122,172		1,464,448	11.00	11.41		11.22	10,704	11.41	11.22	$12,631	YES	#N/A	$0.00	($0.03880)	$1,140.49
Mar-97	10,066	$11,676.56	$1.16	109,881		1,452,757	11.00	10.92		11.15	10,066	10.92	11.15	$11,677	YES	#N/A		($0.03880)	($1,109.31)
Apr-97	9,623	$11,162.68	$1.16	116,670		1,453,550	11.00	12.12		11.10	9,623	12.12	11.10	$11,163	YES	#N/A	$0.00	($0.03880)	($2,816.26)
May-97	10,178	$11,806.48	$1.16	112,880		1,455,515	11.00	11.09		11.04	10,178	11.09	11.04	$11,806	YES	#N/A	$0.00	($0.05670)	($5,863.46)
Jun-97	12,277	$13,504.70	$1.10	134,509		1,467,681	11.00	10.96		11.02	12,277	10.96	11.02	$13,505	YES	#N/A	$0.00	($0.05670)	($5,786.17)
Jul-97	13,170	$14,487.00	$1.10	134,307		1,478,140	11.00	10.20		10.98	12,960	10.36	11.00	$14,256	NO	$231	$0.00	($0.05670)	($6,256.51)
Aug-97	13,926	$15,318.60	$1.10	137,841		1,489,513	11.00	9.90		10.89	12,823	10.75	11.00	$14,105	NO	$1,214	$0.00	($0.05670)	($5,955.30)
Sep-97	11,774	$14,482.02	$1.23	128,646		1,494,450	11.00	10.93		10.89	11,695	11.00	11.00	$14,385	NO	$97	$0.00	($0.05670)	($6,171.72)
Oct-97	10,333	$11,882.95	$1.15	114,037		1,495,631	11.00	11.04		10.87	10,333	11.04	10.98	$11,883	YES	#N/A	$0.00	($0.05670)	($5,153.49)
Nov-97	11,354	$12,602.94	$1.11	125,422		1,501,134	11.00	11.05		10.91	11,354	11.05	11.03	$12,603	YES	#N/A	$0.00	($0.05670)	($5,118.59)
Dec-97	11,409	$13,006.26	$1.14	113,998		1,487,359	11.00	9.99		10.85	10,962	10.40	11.00	$12,497	NO	$509	$0.00	($0.05670)	($5,547.16)
Jan-98	12,996	$14,426.56	$1.11	133,545		1,483,908	11.00	10.28		10.77	12,140	11.00	10.98	$13,476	NO	$951	$0.00	($0.05670)	($4,894.48)
Feb-98	10,365	$11,505.15	$1.11	122,039		1,483,775	11.00	11.77		10.79	10,365	11.77	11.01	$11,505	YES	#N/A	$0.00	($0.05670)	($5,293.47)
Mar-98	9,983	$11,081.13	$1.11	107,211		1,481,105	11.00	10.74		10.78	9,936	10.79	11.00	$11,029	NO	$52	$0.00	($0.05670)	($6,467.86)
Apr-98	10,950	$11,826.00	$1.08	113,804		1,478,239	11.00	10.39		10.66	10,346	11.00	10.92	$11,174	NO	$652	$0.00	($0.05670)	($6,578.00)
May-98	10,475	$11,313.00	$1.08	117,204		1,482,563	11.00	11.19		10.67	10,475	11.19	10.93	$11,313	YES	#N/A	$0.00	($0.05670)	($7,228.31)
Jun-98	13,066	$14,111.28	$1.08	137,692		1,485,746	11.00	10.54		10.63	12,517	11.00	10.93	$13,518	NO	$593	$0.00	($0.05670)	($8,092.85)
Jul-98	12,960	$12,960.00	$1.00	139,010		1,490,449	11.00	10.73		10.68	12,637	11.00	10.99	$12,637	NO	$323	$0.00	($0.05670)	($8,880.71)
Aug-98	14,175	$15,025.50	$1.06	146,305		1,498,913	11.00	10.32		10.72	13,505	10.83	11.00	$14,315	NO	$711	$0.00	($0.05670)	($10,686.84)
Sep-98	10,909	$11,454.45	$1.05	133,336		1,503,603	11.00	12.22		10.82	10,909	12.22	11.10	$11,454	YES	#N/A	$0.00	($0.05670)	($11,573.35)
Oct-98	9,015	$9,465.75	$1.05	118,889		1,508,455	11.00	13.19		10.96	9,015	13.19	11.24	$9,466	YES	#N/A	$0.00	($0.05670)	($13,973.20)
Nov-98	11,178	$10,954.44	$0.98	133,462		1,516,495	11.00	11.94		11.03	11,178	11.94	11.32	$10,954	YES	#N/A	$0.00	($0.05670)	($16,860.19)
Dec-98	9,288	$9,102.24	$0.98	126,219		1,528,716	11.00	13.59		11.29	9,288	13.59	11.55	$9,102	YES	#N/A	$0.00	($0.05670)	($19,772.90)
Jan-99	13,991	$13,711.18	$0.98	136,075		1,531,246	11.00	9.73		11.23	13,991	9.73	11.41	$13,711	YES	#N/A	$0.00	($0.05670)	($23,785.28)
Feb-99	12,750	$12,240.00	$0.96	135,361		1,544,568	11.00	10.62		11.13	12,750	10.62	11.31	$12,240	YES	#N/A	$0.00	($0.05670)	($24,212.83)
Mar-99	10,137	$9,731.52	$0.96	115,588		1,552,945	11.00	11.40		11.18	10,137	11.40	11.36	$9,732	YES	#N/A	$0.00	($0.05670)	($26,036.86)
Apr-99	11,075	$10,632.00	$0.96	118,840		1,557,981	11.00	10.73		11.21	11,075	10.73	11.33	$10,632	YES	#N/A	$0.00	($0.05670)	($28,314.02)
May-99	12,935	$12,935.00	$1.00	124,615		1,565,392	11.00	9.63		11.06	12,935	9.63	11.19	$12,935	YES	#N/A	$0.00	($0.05670)	($30,029.79)
Jun-99	12,206	$12,816.30	$1.05	129,693		1,557,393	11.00	10.63		11.08	12,206	10.63	11.15	$12,816	YES	#N/A	$0.00	($0.05670)	($30,042.12)
Jul-99	12,774	$14,051.40	$1.10	134,471		1,552,854	11.00	10.53		11.06	12,774	10.53	11.11	$14,051	YES	#N/A	$0.00	($0.05670)	($30,701.53)
Aug-99	13,035	$14,338.50	$1.10	145,208		1,551,757	11.00	11.14		11.14	13,035	11.14	11.14	$14,339	YES	#N/A	$0.00	($0.05670)	($30,622.02)
Sep-99	12,742	$15,035.56	$1.18	130,705		1,549,126	11.00	10.26		10.98	12,446	10.50	11.00	$14,686	NO	$350	$0.00	($0.05670)	($31,369.73)
Oct-99	10,065	$12,178.65	$1.21	106,902		1,537,139	11.00	10.62		10.81	9,718	11.00	10.86	$11,759	NO	$420	$0.00	($0.05670)	($30,263.75)
Nov-99	11,555	$13,981.55	$1.21	128,336		1,532,013	11.00	11.11		10.75	11,555	11.11	10.80	$13,982	YES	#N/A	$0.00	($0.05670)	($29,611.41)
Dec-99	10,797	$13,064.37	$1.21	116,144		1,521,938	11.00	10.76		10.56	10,559	11.00	10.63	$12,776	NO	$288	$0.00	($0.05670)	($28,963.76)
Jan-00	10,769	$14,968.91	$1.39	124,391		1,510,254	11.00	11.55		10.72	10,769	11.55	10.79	$14,969	YES	#N/A	$0.00	($0.05670)	($28,255.39)
Feb-00	10,729	$15,127.89	$1.41	123,024		1,497,917	11.00	11.47		10.79	10,729	11.47	10.86	$15,128	YES	#N/A	$0.00	($0.08320)	($26,210.42)
Mar-00	10,488	$15,627.12	$1.49	108,710		1,491,039	11.00	10.37		10.71	9,883	11.00	10.83	$14,726	YES	#N/A	$0.00	($0.08320)	($20,604.83)
Apr-00	9,160	$13,648.40	$1.49	112,318		1,484,517	11.00	12.26		10.82	9,160	12.26	10.93	$13,648	YES	#N/A	$0.00	($0.08320)	($14,293.16)
May-00	11,023	$16,424.27	$1.49	112,829		1,472,731	11.00	10.24		10.88	11,023	10.24	11.00	$16,424	YES	#N/A	$0.00	($0.08320)	($9,338.30)
Jun-00	12,006	$16,928.46	$1.41	128,983		1,472,021	11.00	10.74		10.89	12,006	10.74	11.01	$16,928	YES	#N/A	$0.00	($0.08320)	($1,646.93)
Jul-00	12,859	$18,131.19	$1.41	139,873		1,477,423	11.00	10.88		10.93	12,859	10.88	11.05	$18,131	YES	#N/A	$0.00	($0.08320)	$5,297.46
Aug-00	12,112	$17,562.40	$1.45	139,482		1,471,697	11.00	11.52		10.96	12,112	11.52	11.08	$17,562	YES	#N/A	$0.00	($0.08320)	$12,601.89
Sept-00	12,458	$18,562.42	$1.49	140,241		1,481,233	11.00	11.26		11.05	12,458	11.26	11.15	$18,562	YES	#N/A	$0.00	($0.08320)	$19,367.80
Oct-00	9,936	$14,804.64	$1.49	108,318		1,482,649	11.00	10.90		11.07	9,936	10.90	11.14	$14,805	YES	#N/A	$0.00	($0.08320)	$27,074.85
Nov-00	10,413	$15,515.37	$1.49	113,078		1,467,391	11.00	10.86		11.05	10,413	10.86	11.12	$15,515		$0	$0.00	($0.08320)	$33,495.91
Dec-00	10,339	$15,405.11	$1.49	114,302		1,465,549	11.00	11.06		11.08	10,339	11.06	11.13	$15,405		$0	$0.00	($0.08320)	$40,258.99
Jan-01	10,746	$16,011.54	$1.49	115,892		1,457,050	11.00	10.78		11.02	10,746	10.78	11.07	$16,012		$0	$0.00	$0.03490	$46,816.92
Feb-01	9,389	$13,989.61	$1.49	106,532		1,440,558	11.00	11.35		11.00	9,389	11.35	11.05	$13,990		$0	$0.00	$0.03490	$40,172.29
Mar-01	9,126	$13,597.74	$1.49	99,248		1,431,096	11.00	10.88		11.05	9,126	10.88	11.05	$13,598		$0	$0.00	$0.03490	$33,335.32
Apr-01	9,289	$13,469.05	$1.45	104,356		1,423,134	11.00	11.23		10.97	9,289	11.23	10.97	$13,469		$0	$0.00	$0.03490	$27,530.57
May-01	10,382	$14,638.62	$1.41	107,505		1,417,810	11.00	10.35		10.99	10,219	10.52	11.00	$14,409		$230	$0.00	$0.03490	$20,597.54
Jun-01	12,606	$17,774.46	$1.41	128,382		1,417,209	11.00	10.18		10.93	11,951	10.74	11.00	$16,851		$923	$0.00	$0.03490	$13,989.62
Jul-01	12,480	$17,596.80	$1.41	130,576		1,407,912	11.00	10.46		10.89	12,014	10.87	11.00	$16,940		$657	$0.00	($0.02110)	$5,742.09
Aug-01	12,702	$17,909.82	$1.41	136,094		1,404,524	11.00	10.71		10.82	12,372	11.00	10.95	$17,445		$465	$0.00	($0.02110)	$4,466.24
Sep-01	10,836	$15,278.76	$1.41	125,662		1,389,945	11.00	11.60		10.84	10,836	11.60	10.98	$15,279	YES	#N/A	$0.00	($0.02110)	$2,925.82
Oct-01	9,742	$13,736.22	$1.41	98,877		1,380,504	11.00	10.15		10.78	8,989	11.00	10.98	$12,674		$1,062	$0.00	($0.02970)	$675.29
Nov-01	10,349	$13,971.15	$1.35	116,056		1,383,482	11.00	11.21		10.81	10,349	11.21	11.01	$13,971		$0	$0.00	($0.02970)	$405.94
Dec-01	11,274	$15,219.90	$1.35	107,784		1,376,964	11.00	9.56		10.68	9,899	10.89	11.00	$13,364		$1,856	$0.00	($0.02970)	($815.20)
Jan-02	9,930	$12,809.70	$1.29	114,034		1,375,106	11.00	11.48		10.73	9,930	11.48	11.06	$12,810		$0	$0.00	($0.03720)	($1,560.01)
Feb-02	10,082	$13,005.78	$1.29	111,051		1,379,625	11.00	11.01		10.71	10,082	11.01	11.03	$13,006		$0	$0.00	($0.03720)	($2,821.95)
Mar-02	9,285	$11,977.65	$1.29	98,915		1,379,292	11.00	10.65		10.70	9,285	10.65	11.02	$11,978		$0	$0.00	($0.03720)	($3,519.85)

Calculation of GECI Fuel Costs Exceeding $.20/gal Markup

(A) DATE	(S) Costs Added ($)	(T) Adjustments ($)	(U) Base Rate Revenue ($)	(V) Surcharge Revenue ($)	Ending Balance Balancing Account ($)	Estimated Fuel (Gal.)	Estimated Cost ($/Gal.)	Estimated Sales (kWh)	Estimated Efficiency (kWh/Gal.)	Surcharge (COPA) ($/kWh)
Jan-00										
Jan-00										
Mar-90										
Apr-90										
May-90										
Jun-90										
Jul-90										
Aug-90										
Sep-90										
Oct-90										
Nov-90										
Dec-90					$0.00					
Jan-91	$17,261.00		$13,947.00	$4,125.14	($811.14)	19385	$25,007.00	160450	8.28	($0.0098)
Feb-91	$12,242.00		$12,192.00	($744.00)	($17.14)					
Mar-91	$9,684.00		$10,456.00	($638.03)	($151.11)	17739	$21,109.00	204000	11.50	($0.0579)
Apr-91	$8,917.00		$11,054.00	($674.52)	($1,613.59)					
May-91	$8,755.00		$10,512.00	($3,789.67)	$419.08					
Jun-91	$9,601.00		$11,316.00	($4,079.63)	$2,783.72					
Jul-91	$10,415.00		$12,276.00	($4,425.70)	$5,348.42					
Aug-91	$12,205.00		$13,365.00	($4,818.55)	$9,006.97					
Sep-91	$10,898.00		$12,926.00	($4,660.02)	$11,639.00					
Oct-91	$8,964.00		$11,912.00	($4,294.39)	$12,985.38					
Nov-91	$10,224.00		$13,642.00	($4,918.32)	$14,485.70	34380	$36,786.00	343000	9.98	($0.0111)
Dec-91	$9,184.00		$13,227.00	($4,768.76)	$15,211.46					
Jan-92	$8,905.00		$12,608.00	($612.32)	$12,120.78					
Feb-92	$9,271.00		$13,024.00	($632.53)	$9,000.31					
Mar-92	$8,140.00		$11,542.00	($560.56)	$6,158.87					
Apr-92	$8,190.00		$11,132.00	($540.63)	$3,757.50					
May-92	$8,175.00		$11,324.00	($550.00)	$1,158.50					
Jun-92	$9,161.00		$12,600.00	($721.80)	($1,558.69)					
Jul-92	$10,029.00		$13,268.00	($760.07)	($4,037.63)					
Aug-92	$10,436.00		$13,773.00	($788.98)	($6,585.64)					
Sep-92	$9,969.00		$14,085.00	($806.88)	($9,894.77)					
Oct-92	$8,626.00		$12,312.00	($705.28)	($12,875.48)					
Nov-92	$8,977.00		$13,822.00	($791.78)	($16,928.70)					
Dec-92	$8,975.00		$12,892.00	($738.53)	($20,107.17)					
Jan-93	$9,622.00		$13,907.00	($796.68)	($23,595.49)					
Feb-93	$9,257.00	($1,000.00)	$14,279.00	($817.97)	($28,799.52)					
Mar-93	$7,725.00	($1,000.00)	$12,430.00	($712.03)	($33,792.49)	105360	$115,896.00	1022000	9.70	($0.0803)
Apr-93	$7,575.00	($1,000.00)	$11,699.00	($5,849.53)	($33,066.95)					
May-93	$8,018.00	($1,000.00)	$11,987.00	($5,993.27)	($32,042.68)					
Jun-93	$8,352.00	($1,000.00)	$12,207.00	($6,103.36)	($30,794.32)					
Jul-93	$10,628.00	($1,000.00)	$13,275.00	($6,637.60)	($27,803.72)					
Aug-93	$9,350.00	($1,000.00)	$13,530.00	($6,765.19)	($26,218.53)					
Sep-93	$9,633.00	($1,000.00)	$13,716.00	($6,858.10)	($24,443.42)					
Oct-93	$8,889.00	($1,000.00)	$13,971.00	($6,985.62)	($23,539.81)					
Nov-93	$9,247.00	($1,000.00)	$14,734.00	($7,367.12)	($22,659.68)	87600	$96,360.00	876000	10.00	($0.0765)
Dec-93	$9,342.00	($1,000.00)	$15,003.00	($7,501.39)	($21,819.30)					
Jan-94	$9,764.00	($1,000.00)	$15,697.00	($7,848.68)	($20,903.61)					
Feb-94	$9,666.00	($1,000.00)	$15,524.00	($7,761.80)	($19,999.82)					
Mar-94	$8,468.00	($1,000.00)	$14,629.00	($6,940.98)	($20,219.84)					
Apr-94	$8,369.00	($1,000.00)	$13,647.00	($6,475.02)	($20,022.82)					
May-94	$8,684.00	($1,000.00)	$13,947.00	($6,617.51)	($19,668.30)	79636	$87,600.00	876000	11.00	($0.0831)
Jun-94	$9,336.00	($1,000.00)	$14,993.00	($7,757.72)	($18,567.59)					
Jul-94	$9,832.00	($1,000.00)	$15,790.00	($8,170.14)	($17,355.44)					
Aug-94	$10,975.00	($1,000.00)	$17,626.00	($9,120.39)	($15,886.05)					
Sep-94	$12,568.00	($1,000.00)	$20,184.00	($10,443.68)	($14,058.38)					
Oct-94	$12,161.00	($512.00)	$19,532.00	($10,106.29)	($11,835.09)					
Nov-94	$12,153.00	$0.00	$20,799.00	($10,762.28)	($9,718.81)					
Dec-94	$11,514.00	$0.00	$17,427.00	($9,017.10)	($6,614.71)					
Jan-95	$9,881.00	$0.00	$15,870.00	($8,211.78)	($4,391.93)					
Feb-95	$9,682.00	$0.00	$16,317.00	($8,442.96)	($2,583.97)	51808	$56,999.80	570000	11.00	($0.0651)
Mar-95	$8,686.00	$0.00	$15,247.00	($7,889.10)	($1,255.87)					
Apr-95	$9,433.00	$0.00	$15,966.00	($8,261.47)	$472.60					
May-95	$7,907.00	$0.00	$13,542.00	($6,172.15)	$1,009.75					
Jun-95	$9,809.32	$0.00	$15,191.00	($6,923.77)	$2,551.84					
Jul-95	$10,650.20	($87.00)	$17,076.00	($8,197.97)	$4,237.00					
Aug-95	$11,067.06	($958.00)	$16,984.00	($5,858.83)	$3,220.89	52175	$57,393.00	573927	11.00	($0.0550)
Sep-95	$9,485.97		$15,376.00	($5,303.89)	$2,634.74					
Oct-95	$9,328.42		$15,846.00	($5,150.42)	$1,267.58					
Nov-95	$11,067.46		$18,146.00	($5,897.87)	$86.91					
Dec-95	$12,447.80		$20,502.00	($6,663.64)	($1,303.65)					
Jan-96	$11,147.73		$19,643.00	($6,384.43)	($3,414.49)					
Feb-96	$11,663.75		$20,929.00	($6,802.60)	($5,877.14)					
Mar-96	$11,157.74		$19,524.00	($6,346.06)	($7,897.34)	59446	$65,390.60	653911	11.00	($0.0727)
Apr-96	$9,650.73		$18,610.00	($7,995.51)	($8,861.11)					

Calculation of GECI Fuel Costs Exceeding $.20/gal Markup

DATE	Costs Added ($)	Adjustments ($)	Base Rate Revenue ($)	Surcharge Revenue ($)	Ending Balance Balancing Account ($)	Estimated Fuel (Gal.)	Estimated Cost ($/Gal.)	Estimated Sales (kWh)	Estimated Efficiency (kWh/Gal.)	Surcharge (COPA) ($/kWh)
May-96	$11,905.32		$17,813.00	($7,653.14)	($7,115.65)					
Jun-96	$13,854.82		$19,648.00	($8,441.67)	($4,467.16)					
Jul-96	$14,939.00		$19,890.00	($8,545.51)	($872.65)					
Aug-96	$12,731.98		$20,311.00	($8,726.29)	$274.62					
Sep-96	$13,204.77		$19,868.00	($8,535.92)	$2,147.31	75970	$95,722.00	856000	11.27	($0.0463)
Oct-96	$11,654.00		$18,125.00	($7,787.06)	$3,463.38					
Nov-96	$13,266.00		$19,259.00	($8,274.41)	$5,744.79					
Dec-96	$13,631.43		$20,520.00	($4,957.59)	$3,813.80					
Jan-97	$14,013.25		$22,002.00	($5,315.44)	$1,140.49	93360	$108,298.00	1053106	11	($0.0567)
Feb-97	$12,631.00	($0.08)	$19,621.00	($4,740.27)	($1,109.31)					
Mar-97	$11,677.00	($0.33)	$17,647.00	($4,263.38)	($2,816.26)					
Apr-97	$11,163.00		$18,737.00	($4,526.80)	($5,863.46)					
May-97	$11,806.00		$18,129.00	($6,400.30)	($5,786.17)					
Jun-97	$13,505.00		$21,602.00	($7,626.66)	($6,256.51)					
Jul-97	$14,256.00		$21,570.00	($7,615.21)	($5,955.30)					
Aug-97	$14,105.00		$22,137.00	($7,815.58)	($6,171.72)					
Sep-97	$14,385.00		$20,661.00	($7,294.23)	($5,153.49)					
Oct-97	$11,883.00		$18,314.00	($6,465.90)	($5,118.59)					
Nov-97	$12,603.00		$20,143.00	($7,111.43)	($5,547.16)					
Dec-97	$12,497.00		$18,308.00	($6,463.69)	($4,894.48)					
Jan-98	$13,476.00		$21,447.00	($7,572.00)	($5,293.47)					
Feb-98	$11,505.00		$19,599.00	($6,919.61)	($6,467.86)					
Mar-98	$11,029.00		$17,218.00	($6,078.86)	($6,578.00)					
Apr-98	$11,174.00		$18,277.00	($6,452.69)	($7,228.31)					
May-98	$11,313.00		$18,823.00	($6,645.47)	($8,092.85)					
Jun-98	$13,518.00		$22,113.00	($7,807.14)	($8,880.71)					
Jul-98	$12,637.00		$22,325.00	($7,881.87)	($10,686.84)					
Aug-98	$14,315.00		$23,497.00	($8,295.49)	($11,573.35)					
Sep-98	$11,454.00		$21,414.00	($7,560.15)	($13,973.20)					
Oct-98	$9,466.00		$19,094.00	($6,741.01)	($16,860.19)					
Nov-98	$10,954.00		$21,434.00	($7,567.30)	($19,772.90)					
Dec-98	$9,102.00		$20,271.00	($7,156.62)	($23,785.28)					
Jan-99	$13,711.00		$21,854.00	($7,715.45)	($24,212.83)					
Feb-99	$12,240.00		$21,739.00	($7,674.97)	($26,036.86)					
Mar-99	$9,732.00		$18,563.00	($6,553.84)	($28,314.02)					
Apr-99	$10,632.00		$19,086.00	($6,738.23)	($30,029.79)					
May-99	$12,935.00		$20,013.00	($7,065.67)	($30,042.12)					
Jun-99	$12,816.00		$20,829.00	($7,353.59)	($30,701.53)					
Jul-99	$14,051.00		$21,596.00	($7,624.51)	($30,622.02)					
Aug-99	$14,339.00		$23,320.00	($8,233.29)	($31,369.73)					
Sep-99	$14,686.00		$20,991.00	($7,410.97)	($30,263.75)					
Oct-99	$11,759.00		$17,168.00	($6,061.34)	($29,611.41)					
Nov-99	$13,982.00		$20,611.00	($7,276.65)	($28,963.76)					
Dec-99	$12,776.00		$18,653.00	($6,585.36)	($28,255.39)		$72,600.00	760,000	11	($0.1023)
Jan-00	$14,969.00		$19,977.00	($7,052.97)	($26,210.42)					
Feb-00	$15,128.00		$19,758.00	($10,235.60)	($20,604.83)					
Mar-00	$14,726.00		$17,459.00	($9,044.67)	($14,293.16)					
Apr-00	$13,648.00		$18,038.00	($9,344.86)	($9,338.30)					
May-00	$16,424.00		$18,120.00	($9,387.37)	($1,646.93)					
Jun-00	$16,928.00		$20,715.00	($10,731.39)	$5,297.46					
Jul-00	$18,131.00		$22,464.00	($11,637.43)	$12,601.89					
Aug-00	$17,562.00		$22,401.00	($11,604.90)	$19,367.80					
Sept-00	$18,562.00		$22,523.00	($11,668.05)	$27,074.85					
Oct-00	$14,805.00		$17,396.00	($9,012.06)	$33,495.91					
Nov-00	$15,515.00		$18,160.00	($9,408.09)	$40,258.99					
Dec-00	$15,405.00		$18,357.00	($9,509.93)	$46,816.92					
Jan-01	$16,012.00		$18,612.00	$4,044.63	$40,172.29					
Feb-01	$13,990.00		$17,109.00	$3,717.97	$33,335.32					
Mar-01	$13,598.00		$15,939.00	$3,463.76	$27,530.57					
Apr-01	$13,469.00		$16,760.00	$3,642.02	$20,597.54					
May-01	$14,409.00		$17,265.00	$3,751.92	$13,989.62					
Jun-01	$16,851.00		$20,618.00	$4,480.53	$5,742.09	37,429	$1.41	419,596	11.21	($0.0211)
Jul-01	$16,940.00		$20,971.00	($2,755.15)	$4,466.24					
Aug-01	$17,445.00		$21,857.00	($2,871.58)	$2,925.82					
Sep-01	$15,279.00		$20,181.00	($2,651.47)	$675.29	30,688	$1.41	335,698	10.94	($0.0297)
Oct-01	$12,674.00		$15,880.00	($2,936.65)	$405.94					
Nov-01	$13,971.00		$18,639.00	($3,446.86)	($815.20)					
Dec-01	$13,364.00		$17,310.00	($3,201.18)	($1,560.01)	29,261	$1.41	321,672	10.99	($0.0372)
Jan-02	$12,810.00		$18,314.00	($4,242.06)	($2,821.95)					
Feb-02	$13,006.00		$17,835.00	($4,131.10)	($3,519.85)					
Mar-02	$11,978.00		$15,886.00	($3,679.64)	($3,748.21)	32,277	$1.41	340,243	10.54	($0.0379)

Calculation of GECI Fuel Costs Exceeding $.20/gal Markup

(A)	(B)	(C)	(D)	(J)	(M)	(N)	(O)		
DATE	ACTUAL FUEL CONSMPTN (GAL)	ACTUAL FUEL EXPENSE ($)	ACTUAL FUEL EXPENSE ($/GAL)	IMPUTED FUEL CNSMPTN (GAL)	IMPUTED FUEL COST ($)	DOES ACTUAL CONSUMPT = IMPUTD (YES/NO)	EFFCNCY DISALLWD FUEL COSTS ($)	PURCHASES BY DRAY	MARKUP
Jan 95	9,976	10,973.60	1.10	8,983	9,881	NO	1,093		
Feb 95	8,802	9,682.20	1.10	8,802	9,682	YES	#N/A		
Mar 95	7,896	8,685.60	1.10	7,896	8,686	YES	#N/A		
Apr 95	8,575	9,432.50	1.10	8,575	9,433	YES	#N/A		
May 95	7,188	7,906.80	1.10	7,188	7,907	YES	#N/A	5/2 - 22216 @ .83	
Jun 95	9,524	10,476.40	1.10	9,524	10,476	YES	#N/A		1.10-0.83=.27
Jul 95	10,340	11,374.00	1.10	10,340	11,374	YES	#N/A	7/5 - 30259 @.83 -y	1.10-0.83=.27
Aug 95	10,590	11,649.00	1.10	10,247	11,272	NO	377	8/13 - 30008 @ .88 - y	1.10 - .88=.22
Sep 95	9,637	10,600.70	1.10	8,703	9,573	NO	1,028	9/24 45255 @ .89 - y	1.10 - .89 =.21
Oct 95	8,558	9,413.80	1.10	8,558	9,414	YES	#N/A		1.10 - .89 =.21
Nov 95	10,154	11,169.40	1.10	10,154	11,169	YES	#N/A		1.10 - .89 =.21
Dec 95	11,420	12,562.00	1.10	11,420	12,562	YES	#N/A		1.10 - .89 =.21
Jan 96	10,227	11,249.70	1.10	10,227	11,250	YES	#N/A		1.10 - .89 =.21
Feb 96	10,750	11,825.00	1.10	10,750	11,825	YES	#N/A	2/6 - 12481 @.885 - y	1.1 - .885 =.215
Mar 96	10,284	11,312.40	1.10	10,284	11,312	YES	#N/A	3/8 15238 gal @ $.885	1.10-.885=.215
Apr 96	8,895	10,051.35	1.13	8,895	10,051	YES	#N/A		1.13-.885=.245
May 96	9,356	12,185.88	1.30	9,356	12,186	YES	#N/A	5/4 35208 @ $1.07	1.3-1.07=.23
Jun 96	10,909	14,072.61	1.29	10,909	14,073	YES	#N/A		1.29-1.07=.22
Jul 96	11,763	14,939.01	1.27	11,763	14,939	YES	#N/A		1.27-1.07=.20
Aug 96	11,789	14,854.14	1.26	11,789	14,854	YES	#N/A	7/22 75122 @$.88	1.26-.88=.38
Sep 96	11,238	14,159.88	1.26	11,238	14,160	YES	#N/A	8/26 20044 @ .975	1.26-..975=.285
Oct 96	9,961	11,654.37	1.17	9,961	11,654	YES	#N/A		1.17-.975=.195
Nov 96	11,436	13,265.76	1.16	1,143	13,266	YES	#N/A	10/26 10000 @$1.005	1.16-1.005=.155
Dec 96	11,905	13,809.80	1.16	11,905	13,810	YES	#N/A	12/2 21683 @ .945	1.16-.945=.215
Jan 97	12,239	14,564.41	1.19	12,239	14,564	YES	#N/A		1.19-.945=.245
Feb 97									
Mar 97									
Apr 97									
May 97									
Jun 97									
Jul 97									
Aug 97									

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Calculation of GECI Fuel Costs Exceeding $.20/gal Markup

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Calculation of GECI Fuel Costs Exceeding $.20/gal Markup

DISALLOWED MARKUP ($/KWH)	AFF INTRST DISALLOWED FUEL EXP ($)	
0.07	666.68	
0.07	723.80	
0.02	204.94	
0.01	87.03	
0.01	85.58	
0.01	101.54	
0.01	114.20	
0.01	102.27	
0.015	161.25	
0.015	154.26	
0.045	400.28	
0.03	280.68	
0.02	218.18	
0	0.00	
0.18	2122.02	3175.415
0.085	955.23	
0	0.00	
0	0.00	
0.015	178.58	
0.045	550.76	
TOTAL:	7107.27	

Calculation of GECI Fuel Costs Exceeding $.20/gal Markup

ORIGINAL

December 17, 2003

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2004 JAN 15 P 2:11

FEDERAL ENERGY
REGULATORY COMMISSION

Magalie R. Salas, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Reference Project Number 11659-002 (Falls Creek Hydroelectric Project)

Dear Secretary Salas:

When I first learned of the Falls Creek Hydroelectric Project, I agreed with the general feeling in our community that it was the answer to several environmental and quality of life issues at Gustavus by eliminating diesel generation, providing a higher quality service, and lowering consumer rates for power. Currently, the diesel generators in use by Gustavus Electric Company (GEC) are old, inefficient and result in air quality concerns within the community. The prices paid by Gustavus residents for electrical power are exorbitant and the service they receive is poor. There are frequent power fluctuations resulting in brown outs, outages, surges and damage to the users' appliances and electronics. In a recent incident, residents suffered losses in the thousands of dollars when appliances and electronics were destroyed by unregulated power surges in the GEC system. Because of the high cost of electrical power generated by GEC, there are families who cannot afford to connect to power (even with the state subsidy) and others who must severely limit their use to bare essentials which do not include the "amenities" that most American families take for granted, such as television, washing machine, computer, other electronics or adequate lighting. However, after learning more about the project and having access to the DEIS, I no longer believe those expectations will be met.

The DEIS and public comments made by one of the GEC corporate owners, Mr. Levitt, now clearly show that there will be periods when the stream flows in Falls Creek will not be sufficient to provide adequate power and diesel generation will be required to make up the deficit. The DEIS estimates on stream flow are based on questionable data leading to the probability that much more diesel generation will be required than is currently presented in the DEIS.

The USGS metering devices used to determine the stream flows have a margin of error of somewhere between 5% - 15%. It appears from USGS reports that the metering used for this project was rated as "fair" which translates into a 15% margin of error. Furthermore, Hook Creek (the stream used for modeling since there was not enough data on Falls Creek flows) is located 70 miles to the south. Anyone in Southeast Alaska understands that there are often major differences in precipitation and snow pack within much less distance than that. Even the precipitation data used is from the Gustavus airport and although the distance is only a few miles (5 miles or so), those figures are questionable for the Falls Creek drainages (elevation, terrain and weather patterns). If the stream flows are less than predicted in the DEIS, then Gustavus will be even more reliant on diesel generation than the DEIS indicates.

The DEIS and public comments made by Mr. Levitt (GEC) also indicate that there will be no major reduction in the cost to the consumer, certainly not in within the first 10 years of the project, or longer. In fact, the cost per kWh may ***increase***. Any suggested savings from less dependency on diesel generation are less certain with the questionable stream flow data and modeling used as more diesel generation may be required than is predicted by GEC, plus Mr. Levitt stated more than a year ago in a public meeting that rates could go up as GEC would have to recoup the cost of the project and amortization of equipment.

It creates a great deal of concern that the DEIS does not provide an analysis of the rates GEC will have to charge and the impacts on the community. It is my understanding that the power generated by the hydroelectric project would not qualify for Power Cost Equalization (state subsidy for private users) so that even if GEC's rates remained at the current cost per kWh, the individual consumer would see an increase in his/her out-of-pocket cost for power. The final EIS should provide a range of rates based on more than one set of conditions and an analysis of each.

The DEIS also fails to show that this project will be "economically feasible" which is one of the criteria for approving the project for licensing.

There are numerous deficiencies in the economic feasibility section of the DEIS, but two clear examples are the failure to address the cost of connecting the National Park Service facilities at Bartlett Cove and to provide a realistic cost for constructing a road in the project site along with the analysis of how they would impact the cost of the project and GEC rates.

Anyone who is familiar with the proposed road corridor will recognize that the cost GEC has estimated for road construction is notably inadequate. The estimated cost does not begin to cover the many site-specific difficulties and costly obstacles to constructing a road that will be serviceable for more than the first year. It will not cover the costs of construction through the wetlands, peat bogs, steep grades, soil types, erosion, etc. for a road that only meets the standard for forest/timber roads in Southeast Alaska, even if the road is closed to public use and only receives a minimum of traffic. Annual or perhaps seasonal maintenance of the proposed road if it is not built to an adequate standard and adequately stabilized would remain very costly, which undoubtedly would be passed along to the consumers through future rate increases.

The National Park Service has stated that it cannot and will not accept salvaged materials (a purported practice used by GEC) for a tie-in to GEC. The cable will of necessity be new (previously unused) and of sufficient capacity and quality as to meet the park's power needs and run from the GEC plant in Gustavus to the Park Service plant at Bartlett Cove to hook into the park's power grid. Apparently the park has made informal inquiries into costs of laying power cable in Southeast Alaska and the figures they are citing run approximately a half million dollars ($500,000) per mile. It is nine miles from GEC's plant in Gustavus to the Park Service plant at Bartlett Cove, an estimated cost of $4.5 million. Although Mr. Levitt has been overheard saying that he can install the cable for less, I have been assured by the park that GEC will be required to meet strict standards for all of the work performed and materials used.

The DEIS also did not address the cost to GEC for use, lease or purchase of the park's equipment, i.e. power grid, meters, switching system, or generators. These are costs that should be addressed in the final EIS and included in the range of rates to be analyzed in an alternative or scenario in which the Park Service would hook up to GEC for their power requirements.

The assumptions in the DEIS pertaining to the expected growth of Gustavus and the demand for electrical power appear to be exaggerated. Future projections cannot be based on past growth because of changes that have occurred or are imminent.

The commercial fishing industry has almost disappeared locally with the restriction and eventual phase out of commercial fishing in Glacier Bay. Large or medium scale commercial processing is no longer a viable business.

The Park Service is the biggest employer in the area. The fact that it has been building up its operations for several years has had a major impact on the growth of Gustavus, but park managers have stated in public meetings and upon being questioned that they are not able to continue adding to their work force based on the park's budget/funding and long-term planning for the park. The park has admitted that some vacant positions will not filled now and could be permanently eliminated because of budget shortfalls.

Travel statistics from the park show a steady decline in independent travelers since about 1995 which translates into less demand for tourist facilities/services in Gustavus and fewer employees needed in the tourism industry.

Unless a new industry locates in Gustavus or there is a major change in tourism patterns (fewer cruise ship and tour boat passengers and more independent travelers), I seriously question the projected growth in population.

Without a ***substantial*** decrease in rates to all consumers, it is highly doubtful that consumption will increase, especially if non-commercial consumers will not be eligible for state subsidies on the power generated by the hydroelectric project.

The final EIS should contain realistic projections for growth in both population and demand for power.

In summary, at the beginning of this phase of the project (1998) it was generally accepted within Gustavus that a hydro project would provide "cleaner" power by eliminating diesel generation and the cost per kWh would be reduced substantially. However, neither objective will be met by the proposed Falls Creek Hydroelectric Project. The DEIS did not adequately address the "economically feasible" requirement of the Glacier Bay National Park Boundary Adjustment Act and the deficiencies should be corrected in the final EIS and be given adequate consideration by the Commission when reaching a decision.

Thank you for the opportunity to comment on this project.

William Patrick Lee, Sr.
P.O. Box 283
Gustavus, Alaska 99826

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2003 DEC 18 P 12:43
FEDERAL ENERGY REGULATORY COMMISSION

December 9, 2003

Sam Hanlon Sr.
P.O. 91
Hoonah, Alaska 99826

Ms. Magalie R. Salas
Secretary, Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426
Project No: 11659-002
To Whom It May Concern:

My name is Sam Hanlon, Sr. My Tlingit name is Stoo Wux Ilth Ghei. I am the traditional leader of the Wooshkeetaan clan, within whose territory the proposed project will occur. What is now called Falls Creek, but traditionally is called Tleixaneisheen (Fish Creek) was used by my grandfather, Lou Hansen, as a place to catch and smoke fish.

I am opposed to this hydroelectric project because of its potential for environmental impacts. Foremost, I am concerned that the development will negatively impact the water, fish and wildlife that depend on the stream for their survival. My ancestors have learned to live with and respect these natural resources for generations, and I see this project as a threat to the continued well being of that place. The stream and the life that depend on it are currently in pristine condition, just as our ancestors left them to us, and this project will disturb that delicate balance, regardless of how carefully it is built. The place will never be the same, and something timeless will be lost.

I am also opposed to a private, for-profit corporation being able to make money off of Wooskeetaan land. Our heritage is there, and this project will not respect that fact. Our clan has never relinquished our traditional ownership of this land, and the National Park Service has honored our traditional connection to our homeland. We feel a part of Glacier Bay just as our ancestors were, and that bond remains strong. By removing this land from Glacier Bay National Park and allowing it to be developed for private purposes, this project will remove a part of our heritage, and our ties to our homeland will be diminished.

As Chief of the Wooshkeetaan Clan, I say no to this project. I support the No Action alternative.

Samuel Hanlon Sr

Sam Hanlon, Sr.

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2003 DEC 18 P 12:47

FEDERAL ENERGY
REGULATORY COMMISSION

Allison Banks
PO Box 237
Gustavus, AK
99826
10 December 03

Magalie R. Salas
Secretary, Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Dear Ms. Salas:

Please accept this letter as a comment on the Fall Creek Hydroelectric Project and Land Exchange, Project 11659-002.

I am a resident of Gustavus, AK and a customer of GEC. When reviewing this proposal like many people here I found myself facing a dilemma. I desire electricity from a clean renewable energy source. I also desire to protect the intrinsic values of Glacier Bay National Park's designated wilderness. Basically I want it all.

The project planning team needs quantitative, substantive comments on the EIS draft. Unfortunately this letter does not contain new information or suggestions for improving the document, so you will probably need to place it in the "other comments" pile.

After trying to solve the dilemma for myself, here's what I came up with and wish to pass along to you for consideration.

*I do not particularly care if my electricity bill stays the same, goes up or down as a result of the project. I try to conserve energy and feel all should do this regardless of where they live, how their power is generated, or the price per kilowatt. It is part of the price for living in a remote area. You either accept it or leave. Frankly, if power rates resulting from the Falls Creek project are high it may be a good thing, as it will force residents to be as efficient as possible which is sustainable in itself.

*I do not object to hydroelectric power if the project does not cause irreparable damage to a water source and the wildlife that depends upon it. This project seems to have taken appropriate protective measures and I can accept the alteration to the Kahtaheena River system it would cause. I feel the magnitude of effect on resident Dolly Varden and other species is very similar to a naturally occurring event such as land slip, drought, or change in the watershed runoff pattern.

*Lack of information on cost to connect the National Park Service facilities at Bartlett Cove to the power system is a big concern. It may break the financial back of this project. Without knowing if Glacier Bay NP can even realistically become a GEC customer I feel the economic feasibility of the project is in serious doubt.

*The future of lands transferred to the State of Alaska is also in serious doubt. There is no legislative guarantee that these lands will remain in the good condition they are now, and the impacts of future development by the state have not been anticipated or mitigated. The concerns of the 2 inholder families arc well founded. Gustavus residents may take their neighboring land conditions for granted, but if quarrying, logging, parcel leases, sales for private developments (with a brand new road, power, and a potential new city government to boot), unmanaged recreation, trapping and hunting occur here it will have a direct effect on these same residents. Quarrying hard rock is the likely use as there is always a need for building and road material in Gustavus. I do not believe the state will be overly concerned about Gustavus' views on what will be appropriate uses for these parcels. If the entire project area came under FERC hydroelectric project oversight there would at least be some added ability to protect the integrity of the area.

*I do not like to see any designated wilderness area whittled away for the convenience of private industry or one small community even if I benefit. You will hear a lot of comments about this so I am not going to go into detail. I am completely opposed to the removal of any land from wilderness regardless of size, net loss or gain, swaps, or original motivation for doing it.

*I would like to see Gustavus lose its appetite for diesel fuel. Even if we can't rely on hydropower completely it is still a good thing to reduce our fuel use. Diesel is dirty, toxic to air, water, land, wildlife and human alike. Transporting it is hazardous. Accidents happen given enough time and volume. It is a finite resource and we should be weaning ourselves off it no matter how rosy the oil industry tries to make the future sound. Generators are noisy too. Hard to imagine Gustavus without the background roar of a diesel fired powerplant, but I hope I live to see it.

There are bad and good sides to the Falls Creek project. However, after trying to consider all sides I cannot support this project. The concern that outweighs all others is the precedent it creates.

Conservation ethics always suggest we "think globally and act locally". Well, I am doing just that. I am registering my protest against this project not because it causes a significant local effect, but because it makes many future local effects possible. It will become global. This "small" removal from wilderness is the tip of the proverbial iceberg. The lands offered in exchange are not suffering from particular problems that becoming wilderness would solve. The Islands in GBNPP are defacto wilderness already and are not at risk for development. It doesn't matter how many acres there were before or will be left after. The exchange is not equal. Lands transferred to the state lose a legislative protection. Granted, Congress can decide to remove a designation, but it is much harder to justify or carry out and demands public participation on a national scale. This state cannot guarantee such oversight and usually doesn't care to.

How many small remote utilities or resource businesses are just waiting for the final decision on this project? If resource dependent industries of the USA realize they can convince Congress to pare down wilderness designations to make their businesses more profitable or feasible will FERC and Congress be flooded with pleas to carve bits off National Parks, National Forests, National Monuments, Recreation Areas, Grasslands, Wild and Scenic Rivers, Wildlife Refuges, etc?

I believe so. Small as FERC Project 11659 seems it can cause a significant threat to the Wilderness Preservation System as a whole. This is abhorrent at any price.

Thank you for listening.

Sincerely,

Allison H. Banks

Wanda Culp, Chookenshaa
Descendant from Glacier Bay
P.O. Box 51
Hoonah, Alaska 99829

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FERC REGULATORY COMMISSION
04 DEC 19 PM 3:14

December 10, 2003

National Park Service, Alaska Region & FERC
U.S. Department of the Interior
240 W. 5th Avenue, Room 114
Anchorage, Alaska 99501

Magalie R. Salas, Secy.
888 First St. NE.
Wash, DC 20426

RE: Dick Levitt's Gustavus Hydroelectric Plan
FERC No. 11659-002

Dear Sir/Madam:

Glacier Bay is an integral part of the Huna Tlingit, we used and occupied that Place since the beginning of memory. It is a sacred place to us and is still considered today as our homeland.

The proposed hydroelectric plant would cross over two Native Allotments. Where are the landowners in this issue? Have they had to stand-alone against the proponents of this plan? I think they have.

There are over 30 Native Allotments in Glacier Bay. That is land held "In Trust" by the Secretary of the Interior. That means that the Department of Interior holds the responsibility to protect those "restricted lands" for the "landowners". Ideally, that should mean that any proposals that affect any one of those restricted properties would bring into play the "Trust Responsibility." Without recognition of that responsibility by the Department of Interior, this proposal has no integrity.

A descendant of one of the Native allotment owners has paid the State of Alaska their $500 fee required for the claim of water rights on his family's property. This was in 1996. At that time it was determined that Falls Creek is not large enough to accommodate a hydroelectric plant, the returning salmon, and the needs of the landowners. Why is this water right claim not recognized in this proposal???

In addition, this proposal affects restricted land that has *prior* water rights even to the State of Alaska due to prior use and claim of the allotment itself. I understand that the issue of water rights on Native allotments in Alaska is not resolved, as it had to be in the Lower 48 on reservations. Why hasn't the federal government sought to resolve the water rights question on allotment land – unless the plan is to continue taking without soundness of moral principle and character?

The Huna Tlingit were not included in *any* of the planning of the NPS' taking of our traditional use area throughout the years from 1925 to the designation of "wilderness lands and waters" that ultimately lead to the 1996 federal regulations that have banned our presence out of that Place while almost doubling the number of tour ships into those "pristine" waters. Realizing this previous statement is a mouthful; it basically means that we are not welcome in our own home. No matter how friendly the Glacier Bay NPS staff is to us now, those regulations are still on the books – recent books at that.

How can the NPS justify eliminating Glacier Bay's indigenous people out of their homeland while entertaining the notion of a proposal that negatively puts itself into the purpose of your Park? I say, be very careful about making "an exception" for *anyone* before resolving the Huna Tlingit issue of being banned out of sacred land.

There are other alternatives on the horizon for hydroelectric projects that are more advanced than this proposal and that is the S.E. Intertie. Gustavus is in the plan as well. Why is this not in the mix of possibilities here? Villages up north are experimenting with windmills as an alternative energy source. If Gustavus wants to "go green", then do it with integrity and forethought. Consider all possibilities and all who are affected for, if nothing else, we are your neighbors.

Thank you for your time, I appreciate this opportunity to be heard.

Wanda Culp, Chookensha
Descendant from Glacier Bay
P.O. Box 51, Hoonah, AK 99829

Dec. 15, 2003

Secretary Magalie R. Salas
Fed. Energy Regulatory Com.
888 First St., N.E.
Washington, D.C. 20426

FILED
OFFICE OF THE SECRETARY
2003 DEC 23 P 2:41
FEDERAL ENERGY REGULATORY COMMISSION

Dear Secretary Salas:

I strongly object to the Falls Creek Hydroelectric Project and Land Exchange (Project No. 11659-002). It is irresponsible to propose this unnecessary project for a World Heritage park, which would suffer much damage to its wilderness, fish and wildlife, and visitor enjoyment as a result! I recommend that FERC and NPS reject the project and consider an alternative (not in the DEIS): upgraded diesel power combined with energy efficiency and conservation measures.

Please do not damage beautiful Glacier Bay!

Sincerely,
Ruth Niswander
622 Barbera Pl.
Davis, Ca. 95616

Dave Westman
827 Broadway St.
Suite 310
Oakland, CA 94607

ORIGINAL

FILED
OFFICE OF THE
SECRETARY
2003 DEC 23 P 2:31
FEDERAL ENERGY
REGULATORY COMMISSION

Magalie R. Salas, Secretary
Federal Energy Regulatory Commission
888 1st Street, NE
Washington, DC 20426

Dear Secretary,

I object to Project No. 11659-002, the Falls Creek Hydroelectric project and Land Exchange. I object to this unnecessary project would inflict on the park, its wilderness, fish & wildlife, aesthetics, visitor's enjoyment & the interests of Native allotment owners

I do not think that a world heritage site, such as this, one of the most pristine wildlife & wilderness parks in the world, and a benchmark against which other Nat'l parks & natural areas are measured.

I recommend that FERC & the NPS reject the project in favor of an alternative not mentioned in the DEIS: upgrade diesel power with Biodiesel power & increase solar, wind & conservation energy method

Thank you for your time
I look forward ~~th~~ to hearing back from yo

ORIGINAL

Robert B. Robinson
4424 Teel Court
Juneau, Alaska 99801
(907) 789-2700

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SECRETARY

2003 DEC 23 P 2:43

FEDERAL ENERGY
REGULATORY COMMISSION

Magalie R. Salas
Federal Energy Regulatory Commission
888 First Street, N. E.
Washington, D. C. 20426

ATTN: Falls Creek Hydroelectric Project and Land Exchange, FERC 11659-002

December 15, 2003

Dear Ms. Salas:
I feel the small scale hydroelectric plant for Gustavus is a good idea and should be developed if at all possible. Small scale hydroelectric is a very useful concept in this state where many communities are remote, and hydroelectric resources are plentiful.

The land exchange and plant development for Gustavus have several points in their favor, including ready availability, reasonable costs, and environmental benefits compared to diesel power. The land exchange is well justified if the exchange is required for the best hydroelectric site. Gustavus is a good example of a town where small scale hydroelectric would be very beneficial.

I hope the Energy Regulatory Commission is able to expedite the hydroelectric plant construction for Gustavus.

Sincerely,

Bob Robinson

Bob Robinson

ORIGINAL

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OFFICE OF THE SECRETARY
2003 DEC 23 P 1:54
FEDERAL ENERGY REGULATORY COMMISSION

Lawrence E. Wilkinson, P.E.
Box 19192 Thorne Bay, Alaska 99919
PrinceWalesIsland@HotMail.Com

December 16, 2003

Magalie R Salas, Secretary
Federal Energy Regulatory Commission
888 First Street NE
Washington D.C. 20426

Subject: Falls Creek Hydroelectric Project and Land Exchange, FERC No. 11659-002

Dear Ms. Salas:

Please count me as a Southeast Alaska resident in favor of the proposed Falls Creek Hydroelectric Project and Land Exchange, FERC No. 11659-002. My reasons are listed below and represent those of a growing number of Americans that feel that some petroleum resources should be saved for future generations.

1) Anywhere a hydroelectric resource exists in Southeast Alaska that can satisfy an existing load we should give it an economic assessment to be determine if it is economically viable. I believe that Gustavus Electric Co. has done that for the subject site.
2) If the site happens to be inside a National Park or wilderness area then every effort should be made to realign the boundaries of the park. In my view, National Parks should not always grow, they should mature- that means to be negotiable.
3) The presence of old growth timber and aquatic plants in the proposed watershed should be no more of a deterrent than a new-fallen snow. What we need in Southeast Alaska is not more old trees and plants to coddle but instead a reduction in our dependence on diesel oil for electrical generation.

Future generations will hold us accountable for opportunities missed when the oil spigot runs dry. Opportunities like Falls Creek Hydroelectric plant are one example.

Most sincerely,

Lawrence E. Wilkinson

ORIGINAL

December 16, 2003

Magalie R. Salas, Secretary
Federal Energy Regulatory Commission
888 First St. NE
Washington, DC 20426

P-11659

Dear Secretary Salas:

I am writing in regards to the Falls Creek Hydroelectric Project and Land Exchange in Glacier Bay National Park. I have visited Glacier Bay and the area that will likely be impacted by this project, and I believe strongly that this project is not in the best interest of Alaskans or American citizens.

Based on the information I have read, including the economic analysis by the Alaska Conservation Foundation's resource economist, I believe that the economic gains for this project have been overstated. I also believe that given the lack of urgent need for the power and the magnitude of the impact of this project on wilderness, wildlife, and people, that it would be best if the plan was deferred for several years to evaluate all the alternatives and allow better technologies to develop.

I urge you to delay this badly conceived and money-driven project until a better arrangement can be crafted.

Thank you for your time,

Lisa Mayo

Lisa Mayo
12602 Grey Eagle Ct #43
Germantown, MD 20874

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2003 DEC 23 P 1:56
FEDERAL ENERGY
REGULATORY COMMISSION

ORIGINAL

Patricia Jones
690 Market Street, #320
San Francisco, CA 94104

P-11659

FILED
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SECRETARY

2003 DEC 30 A 9:16

FEDERAL ENERGY
REGULATORY COMMISSION

December 19, 2003

Magalie R. Salas, Secretary
Federal Energy Regulatory Commission
888 First Street, NE, Washington, DC 20426

Dear Secretary Salas:

I'm aghast at the plans for the Falls Creek Hydroelectric Project and Land Exchange in Glacier National Bay Wilderness! One really has to wonder if we don't have the wolves in Washington guarding our 'publicly-owned' sheep across the country??

One really does not know where to begin to explain why this is such a BAD IDEA in this pristine Wild Heritage Park! How about the damage to:

- The Park's wilderness qualities;
- The fish and wildlife;
- Old growth forests;
- Natural beauty; and
- The economy from those who go to Alaska to enjoy UNSPOILED areas

We here on the West coast think that the whole administration on the East Coast wants to destroy what's left of our natural resources and make it all look like I-95, the New Jersey Turnpike, etc.

Please REJECT this HORRIBLE proposal!

As Edward Abbey said, "God bless this country- now, let's save some of it!"

Cheers, Thank You!

Patricia Jones

DEC. 23, 2003

ORIGINAL

DEAR FERC SECRETARY SALAS:

PLEASE ACCEPT THIS LETTER WITH MY COMMENTS ON THE JOINT FERC AND NPS DRAFT ENVIRONMENTAL IMPACT STATEMENT (DEIS) ON THE PROPOSED REGULATORY CREEK HYDROELECTRIC PROJECT AND LAND EXCHANGE (FERC PROJECT NO. 11659-002).

I OPPOSE THIS PROPOSED PROJECT BECAUSE:

1.) THE DEIS COST-BENEFIT ANALYSIS ALONG WITH THE ANALYSIS CONDUCTED BY RESOURCE ECONOMISTS ERIC CUTTER AND DAVID DEPUTY DEMONSTRATES THAT THE PROJECT IS NOT ECONOMICALLY VIABLE OR FEASIBLE AND THEREFORE CANNOT BE AUTHORIZED PURSUANT TO THE GLACIER BAY NATIONAL PARK BOUNDARY ADJUSTMENT ACT OF 1998;

2.) THE PROPOSED PROJECT WOULD CAUSE UNNECESSARY HARM TO RESIDENT DOLLY VARDEN TROUT IN THE CREEK BELOW THE DAM/INTAKE BECAUSE THE RECOMMENDATIONS FOR HIGHER FLOW REQUIREMENTS BY STATE AND FEDERAL FISH AND WILDLIFE AGENCIES WOULD NOT BE IMPLEMENTED;

3.) THE PROPOSED EXCHANGE OR SUBSTITUTE NPS LANDS WOULD NOT BE EQUIVALENT IN EITHER ECOLOGICAL VALUE OR MANAGEMENT INTEGRITY;

4.) THE PROPOSED TRANSFER OF EXISTING NPS LAND TO THE STATE WOULD OPEN A HIGHLY IMPORTANT AND SENSITIVE ECOLOGICAL AREA TO A WIDE RANGE OF INCOMPATIBLE, HARMFUL, AND INTENSIVE USES AND DEVELOPMENTS;

5.) THE DEIS FAILS TO CONSIDER THE REASONABLE ALTERNATIVE OF DEFERRING THE DAM FOR SEVERAL YEARS TO EVALUATE WHETHER A COMBINATION OF ENERGY CONSERVATION, EFFICIENCIES, UPGRADED DIESEL, AND PERHAPS TIDAL POWER COULD MEET THE PROJECTED ENERGY NEEDS; AND

6.) IT WOULD BE FUNDAMENTALLY WRONG AND ESTABLISH A DANGEROUS PRECEDENT TO SACRIFICE AN ECOLOGICALLY IMPORTANT AREA WITHIN A NATIONAL PARK WILDERNESS FOR A DEVELOPMENT WITH NO COMPELLING NEED, AN UNFAVORABLE COST-BENEFIT RATIO, AND WHERE A REASONABLE, LESS DAMAGING ALTERNATIVE IS AVAILABLE.

I URGE FERC TO DENY THIS PROJECT APPLICATION FOR THE PRECEDING REASONS.

THANK YOU VERY MUCH FOR YOUR CONSIDERATION.

SINCERELY,

[illegible] [redacted]

December 20, 2003
1404 Carroll Street
Durham, NC 27707

ORIGINAL

Magalie R. Salas, Secretary
Federal Energy Regulartory Commission
888 First Street NE
Washington DC 20426

Public Comment: FERC Project No. 11659-002, Falls Creek Hydoelectric Project and Land Exchange.

FILED
OFFICE OF THE SECRETARY
2003 DEC 30 A 10:55
FEDERAL ENERGY REGULATORY COMMISSION

Dear Madames and Sirs,

I write during the public comment period on FERC Project No. 11659-002 Falls Creek Hydorelectric Project and Land Exchange.

As one who has visited Glacier Bay National Park I am offended by this crude attempt by special interests to grab valuable federal lands and to offer the American taxpayer less valuable lands in return. This is not in the public interest, but benefits at best a small number of people at the cost of all citizens of the United States, who treasure their national parks.

The proposed project fails to make economic sense. The proposal that Gustavus Electric Company would sell energy to Glacier Bay National Park is especially unfortunate. The Park already produces energy at a lower cost than Gustavus Electric Company charges its customers. It would certainly not be in the interest of the public for Glacier Bay National Park to purchase power generated by Gustavus. The estimates of Gustavus Electric Company of load growth appear overly optimistic to economic experts. Please pay attention to the Cutter/Deputy report, Economic Analysis of the Proposed Falls Creek Hydro Project and Potential Alternatives.

The project would rob the American people of valuable wilderness in the Falls Creek watershed of the National Park. This land would be turned over to the State of Alaska, which will undoubtedly manage it in a way which does not protect wildlife and is determinental to its current wilderness qualities. (Allowing hunting, trapping, snowmobiles, perhaps timber sales...) The proposal calls for damaging road construction through old growth forest. The proposed dam and associated structures would adversely affect fish populations. The proposal to replace this actual wilderness by designating other parts of Glacier Bay National Park as wilderness, even though these other areas do not possess similar high quality wilderness characteristics is cynical.

There is no urgent need for this project. There are alternatives which make more economic sense and are better for the environment. Increasing energy efficiency in rural Southeast Alaska towns could decrease the demand for energy significantly. Furthermore, demonstration projects for tidal energy generation show promise for providing economic and environmentally satisfactory alternatives.

During my lifetime I have seen a great many wonderful natural areas ruined by individuals who did not understand their value and saw only the potential for private profit and public expense. If the proposed hydroelectric project in the Falls Creek Watershed goes through, we will have yet another example of this. Don't let it happen.

Sincerely yours,

Chad Schoen

Dec 20, 2003

Mr. John Spezia
P.O. Box 2255
Steamboat Spring, CO 80477

Ms Salas,

ORIGINAL

I am writing in regard to the proposed Fall Creek Hydroelectric Project + Land exchange (Proj. # 11659-002) in Glacier Bay NP.

I have spent a great deal of time sailing, kayaking, skiing, climbing + fishing in Glacier Bay as well as other Parts of the Panhandle of Alaska + Glacier is the most spectacular and unique area I have experienced.

Since GBNP is unique, a World Heritage Park, a wilderness national Park, a wildlife habitat of special note I believe that this project should be rejected.

Instead the Park, Gustavus and surrounding energy needs should be met by

1- upgrading + reducing diesel power pollution
2- Develop energy efficient + conservation for the power use.
3- Look into alternatives for power sources, possibly tides, solar (yes!!!) even in GBNP and waves.

Sincerely, John Spezia

Comments of Gustavus Electric Company
on the
Draft Environmental Impact Statement
(FERC/DEIS – 0167D, NPS D-118)
Falls Creek Hydroelectric Project (FERC No. 11659-002) and Land Exchange

EXECUTIVE SUMMARY

Page xxviii, line 16-17. It is incorrect to state that "[t]here would be no environmental effects associated with this alternative". The sentence should either be deleted or rephrased along the lines of "With this alternative, the current environmental effects associated with diesel generation would continue".

Page xxix, line 24-27. The purpose of this sentence is to indicate that there could be some positive recreational effects associated with the project. However, many people would regard the examples given in this sentence as negative impacts, particularly ATV use which GEC does not want to allow. The examples should be deleted or replaced by more positive examples, such as easier access for viewing the falls.

Page xxix, line 31. The phrase "and adjacent GBNPP lands" should be deleted. The effects listed would occur only on project lands, not on adjacent GBNPP lands.

Page xxix, lines 33-35. GEC believes practically no GBNPP visitors will leave the park from the eastern boundary and travel into the project lands, as there are no trails in this area. The sentence should be deleted or modified to indicate the number of visitors expected to suffer this negative impact.

SECTION 1.0 INTRODUCTION

Page 1-2, line 8: As presently configured, the NPS would have to purchase electricity from hydroelectric generation in order for the Falls Creek Hydroelectric Project to be economically competitive with diesel in the short term. Since the NPS decision on using hydroelectric power will not be made until after a project license is issued, and economic viability must be demonstrated before a license can be issued, it is necessary to demonstrate economic viability without the NPS connected to hydropower. This can be done using grants, down sizing the project to carry only the Gustavus load and not the Park, or by using other means. Work will continue on this matter over the next several months and the results communicated to FERC.

Page 1-2, line 9: GEC's generation for 2003 was 1,713,000 kWh, a 4 ½% increase. It should be noted that all kWh figures used in the DEIS were for kWh generated and not kWh sold. The economics section of these comments use kWh sold. We do not have the NPS kWh generation figures for December, but the Park is on track to use approximately 1,000,000 kWh for the second straight year. This should probably be the NPS baseline usage should FERC choose to include a scenario with the Park using hydropower. The NPS just completed a large new maintenance facility. The old maintenance facility will be converted to office space. In addition, the existing office building will be enlarged. These changes will add load to the NPS system.

Page 1-4 starting on line 1: GEC's cost per kWh of electricity shown in this section is in error. The per kWh cost should be:

	2000	2001	2002	2003
Rate 1:	$.4982	$.5272	$.4771	$.4540
Rate 2:	$.4205	$.3872	$.3471	$.3240

Rate 1 includes residential, small commercial and government.
Rate 2 includes large commercial.
In 2002, residential was 58.1% of all sales.
Government was 14.5% of all sales.
Small Commercial was 11.9% of all sales.
Large Commercial was 15.5% of all sales.
*Enclosed is a downloaded sheet showing GEC rate among some other utilities for 2002.

Page 1-7, footnote 8. There are federal grants so far only for feasibility study of the Juneau-Hoonah segment of the intertie. No construction funding has yet been authorized.

Page 1-5, line 14. Insert the sentence: "In addition, the project would result in considerably lowered carbon emissions from Gustavus power generation".

Page 1-25, line 9. Insert the bullet: "Offsite mitigation could reduce sediment associated with the poorly installed Rink Creek bridge and Homesteader Creek culvert."

SECTION 2.0 DESCRIPTION OF ALTERNATIVES

Page 2-13, line 12: GEC is in the process of negotiating a settlement with the agencies regarding a reduction in the instream flow requirement to zero. If that effort is successful, as GEC believes it will be, then the bypass included in Interior's prescription will no longer be required.

SECTION 3.0 AFFECTED ENVIRONMENT

Page 3-1, line 33. Delete word "noncarbonated".

Page 3-8, line 34. Delete "densely populated by Sitka spruce forest"; replace with "dominated by alder/willow thicket with emergent cottonwood and spruce".

Page 3-11, line 16: insert the word "ending" before the word "approximately".

Page 3-11, paragraph beginning line 20 misstates the geologic context (see Mann & Streveler, 1999, p2, last paragraph). You will note therein that Falls Creek follows the axis of an anticline through all of the bypass reach between the Upper Falls and just upstream of the Log Jam, at which point the river turns across the structural grain and descends abruptly to the anadromous reach.

Page 3-19, line 35. The river empties into Icy Strait, not Glacier Bay.

Page 3-24, lines 1-9: The DEIS is correct in stating that no description was provided by GEC of the method used to estimate Kahtaheena River flows during periods when there are no records of Kadashan River flows at USGS No. 15106920. For WY 79-80, the missing Kadashan River flows were first estimated by a correlation with another USGS gage in the Kadashan River basin (Hook Creek near Tenakee, USGS No. 15106960, 8.00 sq. mi. drainage area). The correlations are quite good, as would be expected from similar sized streams in the same basin. For WY96, there is published data for USGS No. 15106920, although that data is not available online.

Page 3-30, line 36. delete the word "above" and insert " upstream of".

Page 3-41, Table 3.6-7. We recommend that this table be structured to 1) indicate which of the reaches comprise the bypassed reaches, and 2) give a subtotal of fishes in these reaches for comparison to the overall totals.

Page 3-46, line 1. Delete reference to cedar. The only cedars occur at elevations above the project area.

Page 3-46, paragraphs beginning at line 4 and 26. Should indicate that these vegetation types are found only in the Gustavus flats portion of the project area.

Page 3-46, paragraph beginning at line 31. This vegetation type is in fact described by Bosworth and Streveler (1999, p. 8, first paragraph) as part of the bog community.

Page 3-50, line 14. Change "red-backed" to "long-tailed". The former vole is not known to occur in this portion of Glacier Bay.

Page 3-55, last paragraph. Should be mentioned that for many years ending in the late 1930's, Jim Huscroft, a legendary resident of the outer coast, made his home on Cenotaph Island. See D Bohn, "Glacier Bay, the land and the silence" for an extended discussion of Huscroft and a photo of his Cenotaph Island home.

Page 3-57, line 5. Both allotments, which are a visually dominant part of the project area vicinity, have been extensively clearcut, and should not be characterized as "relatively untouched".

Page 3-57, lines 8-9. The usual approach to the Gustavus airport is about ½ mile offshore of the project area, and pilots seldom fly directly over the project area.

Page 3-58, line 34. Should be mentioned that no portion of the project would be visible from this perspective.

Page 3-61, line 26. See comment regarding page 3-8. This island was deglaciated about 150 years ago, and has no mature forest on it, and no cedar at all.

Page 3-61, line 35-36. Strike "willow and scrub-shrubs" and substitute " cotton wood and young spruce".

Page 3-63, line 37-39. This statement is true in a gross sense, but we have never seen evidence of camper use on the project area coastline.

Page 3-64, line 25-26. Almost all visitor use occurs during late May-late August, about 90 days. 90 x .8 gives a more realistic estimate of 72 visits. This figure should be used in lieu of 120 in the several places it is employed in the EIS.

Page 3-65, line 18. It is not correct to assume that these were annual visits to the Lower Falls. This information is based on Baker's (2001) data, which lead to a reasonable estimate that about 8% of Gustavus residents have visited the Falls Creek area <u>sometime in their lives.</u> Based on the GEC field team's seeing no visits to the falls during 485 hours of observation during the summers of 1997-2000, we believe that the estimate of 34 annual resident visits to the Lower Falls to be a considerable overestimate. We can offer no firm number, but suspect the average resident visits per year is closer to 10 (not 34).

Page 3-65, line 28-29. We again feel that these figures are too high, by about a factor of two. Our reasoning is as follows:

> <u>Shoreline visits</u> First of all, as stated under 3-64, above, a reasonable estimate for visits to the shore would be about 72 (not 145). This estimate is based on observations by the GEC field team of all visits, and thus the Bear Track Inn estimates should not be added to this.
>
> <u>Lower Falls</u> As stated just above, a reasonable estimate for resident visits to the Lower Falls would be about 10. Adding the upper end of Bear Track Inn visitor estimate to these numbers gives 10+10 =~ 20 (not 44).

Page 3-73, line 11-12. This sentence regarding old-growth forests is grossly inaccurate. There are many thousands of acres of old-growth forest and associated mature habitats outside Neoglacial Ice limits inside the entire periphery of the park wilderness. The most extensive of these include: outer coast foothills and fjordlands from Deception Hills to Cape Spencer, thence along the north shore of Icy Strait to Dundas Bay; and from the Excursion Ridge northward to the slopes of the Beartrack range and eastward to and including the Excursion river valley & associated slopes.

Page 3-73, line 25. We agree that GLBA contains unique resources, but the Falls Creek area is one of the least unique portions of the park. Its vegetation, fauna and geomorphology are very similar to large stretches of northern SE Alaska.

Page 3-75, line 20. Throughout the document, the native allotments are down-played, despite the fact that they are large, centrally located, and contain the lion's share of the critical biotic values of the Falls Creek area. Not only have these parcels been logged in the past, but the high likelihood of their being developed in the future, hydro project or no hydro project, considerably reduces the long-term probability of high wilderness value being maintained in the project area vicinity.

Page 3-75, line 33. This paragraph again overstates the wilderness character of the Falls Creek area. It has been extensively clearcut, there is a frequently used cabin at the creek mouth, an old logging trail follows the entire shore, debris from the old logging camp is still evident, and again we must stress the potential for further dimunition of wilderness character on the extensive private lands.

Page 3-76, line 25. This summary paragraph overstates the untrammeled character of the area and its biotic uniqueness both within the park and in the adjacent national forest.

Page 3-78, Line 11. Having just passed a section in the EIS where the wilderness values of the Falls Creek area are in our view over-stated, this summary of the Bluemouse Cove exchange parcel now under-states its values. This island is essentially untouched; there are no structures on it; it is very little used by people but frequented by a large array of wildlife; it is subject to boat and plane traffic related to the Bluemouse anchorage, but no more so than the Falls Creek area, which lies near the plane approach to Gustavus airport and near the Icy Passage marine transportation route. And designating it as wilderness plugs a "doughnut hole" in a very large stretch of wilderness, broken only by one native allotment that NPS is hoping to acquire.

Page 3-79, line 25. At variance with this statement, the geology, vegetation and wildlife of Cenotaph Island and vicinity were subjected to an intensive survey (Streveler et al., 1980, Lituya Bay Environmental Survey, NPS, 346p.). It is one of the best-known areas of the park. What that survey shows is that the island's biotic values are considerable, including: a large bird colony, a representative sample of recovering giant wave altered vegetation. In addition, it has high historical value, being the former home of Jim Huscroft and the site of the LaPerouse expedition's claim of the area in the name of the French crown.

Page 3-83, line 26. The extent of that logging is for the most part certain, and is mapped by Bosworth and Streveler (1999). The principal logging area lies outside the allotments in what is presently park land, and was linked to the shore by a skid road through the Mills allotment, along which there may have been some minor logging obscured by the much more extensive logging on that allotment in the '60's.

Page 3-89, line 5. We would not characterize a 4.7% annual growth rate as moderate! This is one of the highest growth rates in Alaska, being similar to that of the railbelt.

Page 3-89, Table 3.16-4. It is misleading to show Gustavus population before 1950 as zero; better just to say "no data".

SECTION 4.0 ENVIRONMENTAL CONSEQUENCES

Page 4-2. The cumulative effects analysis leaves out a very important subject: Future residential or other development on private lands in the project area vicinity. As explained in detail in the Applicant-prepared DEIS, these lands contain a large share of the important biotic values of the Falls Creek area. Their development would essentially erase access of bears to the best spring habitat in the Gustavus area; would interrupt a major wildlife thoroughfare along the shore; and would probably interfere seriously with the ongoing major waterfowl use during migration. These lands are owned in fee simple; guaranteed reasonable access across park holdings; and not presently high on the park priority list for acquisition. Thus they are very likely to be developed in the future. This likelihood would be further increased if access for the hydro project eventually links the allotments to the Gustavus road system.

Page 4-14, lines 8-10 state that the transmission line would be buried in or adjacent to the existing Rink Creek Road. This is not so. The transmission line would cross Rink Creek Road at the start of the access road and then cross the Gustavus forelands as described in the preferred alternative and shown in figure 2-1 of the DEIS. The only time the transmission line would be in Rink Creek Road would be to cross it. At no time would it run parallel to it.

Page 4-15, lines 37-39 imply that the proposed borrow pit in the Horseshoe is located on a slope greater than 72 percent. Borrow from the Horseshoe area will be taken because a cut is required through the Horseshoe Ridge in order for the Penstock to maintain a 0.33% slope through the area. Material from this cut will then be used as borrow material for road construction. The area where this cut will be is not adjacent steep terrain. Its hydrology and geomorphology would not be conducive to decreasing slope stability.

Page 4-16, lines 31-37 state that it is likely that GEC would have to import rock or gravel construction materials. Logging roads build by the U.S. Forest Service in the Homeshore area and by Sealaska Corp and Huna Totem Corp. in the Hoonah area use much the same type of material as available at Falls Creek. The quality of this rock is highly suitable for its purpose, which is short term intense usage, followed by periodic usage thereafter. Logging road builders from Hoonah came to look at the Falls Creek area and said the rock is very suitable for road building purposes required for the project.

It is not known whether the mudstone is suitable for structural concrete, or whether a source of higher quality rock is available in the project area. Even if neither is true, there would only be 3 or 4 dump truck loads of gravel from Gustavus required to be trucked in.

Page 4-17, lines 16-22 refer to volumes of sediment estimated to reach the river. The figures of 350 m 3/year and 110 m 3/year are referenced by footnotes number 36 and 37 respectively. These footnotes state that "This estimate is high…" by approximately double. It is suggested to use the more probable figures of 175 m3/year and 55 m 3/year, or at least list the sediment runoff as a range, eg. 55-110 m3/year.

It is not stated in the document whether measures described in an ESCP were taken into consideration when the above sediment volume was calculated. Further, it is not described how the 0.1% of volume of runoff water was derived.

Also, if 350 m3/year is 0.1% of the total runoff of disturbed areas and 110 m 3/year is 0.1% of the total runoff of the permanent footprint, the total precipitation in the area would be 112 inches per year. It is suggested that the figures be adjusted for 59" of precipitation per year. This is the total precipitation at the Gustavus Airport plus the 11% documented increase in precipitation in the Falls Creek area.

The above estimated sediment runoff figures are also referenced on page 4-43 line 7, page 4-73 line 9 and page 47 line 31. This could result in minor changes to the Erosion and Sediment Transport on page 4-77.

Page 4-17, line 4-5. Remove the word “lacustrine” in both places. Lacustrine has to do with lake sediments; these do not occur in the project area (see Mann & Streveler, 1999).

Page 4-20, Table 4.3-2. 58% should read 5.8%.

Page 4-21, Table 4.3-2. The word “slightly” should be placed before “reduce” in “Interpretation/Consequence”. This would be more harmonious with the conclusion stated in line 12 that there probably would be little effect on sediment transport.

Page 4-22, line 20. Appropos of the above comment, the words“ would disrupt” are too strong and should be replaced with the words “may affect”.

Page 4-23, line 40. Again on the above subject, the word “negatively” is too strong in light of conclusions drawn in 4-21, line 12 and 423, lines 26-34.

Page 4-24, line 9-10. This statement is based on the misapprehension that the proposed GEC boundary lies along the bank of the creek rather than the eastern lip of the canyon. Thus the canyon would lie outside the park. We do agree that remaining park, tidelands, & waters at the mouth of the creek could be affected.

Page 4-31, Section 4.4.2.1.1: Prior to submitting its PDEA, GEC was negotiating with the appropriate resource agencies regarding instream flow requirements (IFR) necessary to maintain the Dolly Varden population in the by pass reach. When it became necessary to prepare the PDEA for submittal with its license application prior to the Legislative mandated deadline, GEC told the agencies that it was going to use the 5/7 cubic feet per second (cfs) alternative in the PDEA. GEC told the agencies the reasons were economic, and that money was better spent on environmental mitigation measure that GEC proposed to do. GEC and the agencies agreed that the negotiations were not completed, and that they would resume after the license application was submitted.

The IFR negotiations continued after the license submittal, and it soon became obvious that no agreement could be reached between GEC and the agencies. With the agencies firm in their opinion of the necessary IFR requirements for the Dolly Varden, GEC said it could not build the project because of the resulting reduction of revenue. Unless the agencies agreed that there was some scenario that the project could be built without guaranteeing that the resident Dolly Varden population in the by pass reach could be saved, the project would have to be abandoned. To that effect, GEC and the agencies continued discussions to see what could be done to allow the project to be viable. The possibility of onsite mitigation of Dolly Varden, or other fish habitat was discussed, and it was agreed there was no suitable possibilities. The possibility of GEC providing offsite mitigation of fish habitat in the Gustavus area was then discussed. At the present time, GEC is preparing some possible mitigation measures, along with their costs, to present to the agencies. GEC hopes to have a mitigation plan and IFR agreed to by all parties within 4 months. We will submit this agreement to FERC. At present, the agencies have not agreed to offsite mitigation or a reduced IFR. The 5/7 cfs IFR in GEC's preferred alternative in the PDEA was derived from economics. It was the minimum IFR required to generate electricity at a cost no higher than diesel. Since then, FERC recommended that additional environmental measures be added, increasing the cost of the project. In addition, project revenues were based on generated kWh, and not kWh sold, resulting in a reduction of projected revenues. This has resulted in the 5/7 IFR alternative no longer being able to produce power at a cost less than diesel.

Since the agencies contend that the 5/7 cfs IFR will not maintain the Dolly Varden, then the no minimums flow alternative could have the same effect on these resident fish. Going to the no minimum flow requirement would produce enough additional revenue to satisfy the additional FERC requested measures, compensate for the reduced revenue projection, and provide for a fund to finance any agreed upon offsite mitigation measures.

Page 4-33, lines 3-7: It should be recognized that the described operation is the “worst-case scenario” in that it diverts up to 23 cfs whenever available. The actual diversion will depend on the expected peak load, and will usually be less than 23 cfs, even if 23 cfs or more is available for diversion.

Page 4-39, lines 22-27: GEC has compared the concurrent gage records of the two gages on the Kahtaheena River, and finds that the inflow to the bypassed reach from tributaries will average about 3.0 cfs, or about 6% of the Kahtaheena River flow. During the lowest flow event during winter 2001, we observed that Greg Creek, the major tributary to the bypassed reach, was still running, and infer that this stream, which drains deep peats, seldom or never goes dry.

Page 4-40, lines 29-31: The statement that “sole use of the turbine jet deflectors would limit the ability to operate the project in load-following mode while maintaining a constant flow diversion” is incorrect. If the synchronous bypass is not provided, the turbine jet deflectors will be fully capable of providing both load-following capability and a constant flow diversion; the only loss would be redundancy.

Page 4-41, lines 12-14: The statement that “if the synchronous bypass were not required and the turbine jet deflectors failed to operate properly then a ramping rate of substantially more than 1 inch per hour could occur” is incorrect. Under those conditions, the ramping rate will be controlled by the turbine needle valves, which will be set to adjust slowly, both to limit the rate of change in the anadromous reach and to protect the power conduit from hydraulic surges.

Page 4-41, lines 16: The phrase “Kahtaheena River flows” should be replaced by “flows in the bypassed reach of the Kahtaheena River”.

Page 4-41, line 18: The phrase “in the bypassed reach” should be inserted between “quantity” and “depending”.

Page 4-41, lines 20-22: The statement that "operating the project under a no minimum flow requirement would result in a significant adverse effect on surface water quantity" is unsupported, and should be removed or modified.

Page 4-41, line 29: The word "moderate" should be replaced with "minor" to coincide with the analysis.

Page 4-41, line 35 through Page 4-42, line 3: This paragraph seems entirely redundant, and should be removed.

Page 4-47, lines 26-28: The statement that "streambeds consisting of small -sized sediments enhance the formation and maintenance of a thaw bulb, since they enable water from the stream to flow into and through the streambed and the area immediately below the streambed" seems incorrect. Large-sized sediments would seem more likely than small-sized sediments to enhance thaw bulb formation for the reason given.

Page 4-50, lines 22-25: The lengthy list of equipment should be deleted. It is sufficient to say an assortment of heavy equipment will be used.

Page 4-54, line 32. Flows would be affected in just the bypassed reaches, which comprise about 2 miles or about 1/3 of the 6.5 mile fish-inhabited portion of Falls Creek. We ask that you change "much" to "about 1/3", as a more accurate characterization.

Page 4-61, lines 27-29. Not only would it not constitute an impairment, the project would certainly constitute an enhancement of the purposes and values of the park associated with air quality, due principally to the long-term reduction of greenhous gas emissions and various other pollutants.

Page 4-63, lines 12-25: The analysis described in this paragraph grossly overestimates the particulate emissions. First of all, the amount of disturbed land that will produce particulate emissions is less than 29.6 acres, since only a small section of the project will be worked on at any one time, and much of the disturbed land will only be disturbed to the extent that trees will be removed. Second, ground-disturbing construction activity will occur only for a small portion of the 24-month construction period, particularly during the road building period. Third, the area's climate is moist, which naturally limits particulate emissions.

Page 4-65, lines 3-9: The reference to table 2.3-1 should be corrected, probably to table 5.3-1. However, it is not clear how the emissions reductions are calculated. If they are based on a simple multiplication factor, then the reductions should be proportional to the reduction in diesel generation. Table 5.3-1 indicates that for GEC's proposed alternative, the reduction should be 92% instead of 85%.

Page 4-65, lines 32-34: The statement that "the development of the proposed project would negatively affect air quality resources during the construction phase and could slightly improve air quality thereafter" is biased and unbalanced. It should be modified by replacing "could slightly" with "would".

Page 4-93, line 29: "Kahtaheena River" should be replaced with "Falls Creek". The Swan Lake project is located on a different Falls Creek than GEC's proposed project.

Page 4-96, line 20. It is true that, given incomplete survey data, Falls Creek is the only stream in the park known to maintain resident Dolly Varden. It is also true that the project has <u>no</u> potential to eliminate this population, nor can the project's effects ramify into the 86% of the population residing upstream of the intake site. It is further true that dozens of resident Dolly Varden populations are known to exist elsewhere in SE Alaska.

Page 4-97, line 21. This is based on a mis-apprehension of GEC's proposed boundary, which lies along the canyon lip rather that at creekside.

Page 4-98, line 5. We strongly doubt that 4 inch long char will ever be a big draw to local fishermen provided with the opportunity to catch salmon and halibut.

Page 4-99, line 6. Increased coarse sediment delivery to the delta would likely be a very positive outcome. At present, glacial rebound is resulting in a tendency for the creek mouth to downcut into clays, with a consequent potential loss of pink salmon spawning habitat (see Mann & Streveler, 1999), and increased sediment input would counteract that.

Page 4-102, lines 29-30. It is hard to understand this conclusion, especially given the argument developed elsewhere in the document that state management constitutes a reduction in protection.

Page 4-114, line 6. Change "the year" to "their active season".

Page 4-115, line 28. There is no trail along the creek to the Upper Falls. The falls may be reached by trails requiring considerable local knowledge to find, and a difficult traverse along the canyon wall.

Page 4-118, lines 29-30. We agree with this statement, but believe it should be tempered with the likelihood that such impacts will probably occur with or without the project. See comment 4-2 for elaboration.

Section 4.10 Soundscape/Noise (Page 4-133): This section does not evaluate the reduction in noise from the existing diesel powerplant in Gustavus that would occur with the project operation. That beneficial effect should be documented to the same degree as the noise created by the project construction and operation. Under the no action alternative, the existing generators and their associated 10 H.P. cooling fans would continue to operate with their same associated noise levels. This noise is close to the school, Post Office, Community Chest and Airport. It affects many residences, as it can be heard up to ½ mile away on quiet days. Using Falls Creek Hydropower, the noise from the diesel system would be silenced most of the time, and reduced the remainder of the time.

Page 4-143, Table 4.11-1. Based on the GEC field team's seeing no visits to the falls during 485 hours of observation during the summers of 1997-2000, we believe that the estimate of 34 annual resident visits to the Lower Falls to be a considerable overestimate. We can offer no firm number, but suspect the average resident visits per year is closer to 10 (not 34). Thus, using 34 in the last line of the table is misleading. Given that no firm figure exists, we recommend that this line in the table be deleted.

Table 4.11-1, Page 4-143: The following table augments Table 4.11-1 by showing values for the zero instream flow proposal being pursued by GEC. It also modifies the values slightly for the other two instream flow regimes by 1) using average daily flows rather than average monthly flows, and 2) by factoring in inflow between the diversion and the lower falls (estimated to be 6% of the flow at the diversion).

Month	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Average natural flow, cfs	108	36	31	22	22	21	33	105	81	53	51	81
Regulated flows with zero instream flow proposal												
Average flow, cfs	85	17	14	8	8	6	13	82	58	30	28	58
% below average	21	53	53	63	64	70	61	22	28	44	45	28
Regulated flows with 5/7 instream flow proposal												
Average flow, cfs	85	21	18	12	12	10	16	82	58	30	29	58
% below average	21	42	42	46	47	52	51	22	28	42	42	28
Regulated flows with NPS-RTCA instream flow proposal												
Average flow, cfs	87	28	21	14	14	13	18	82	59	34	35	60
% below average	20	20	33	33	35	38	46	22	27	35	32	25

It should also be noted that the reductions shown in the above table are based on the assumption that the project will divert as much flow as possible, up to 23 cfs. In reality, the diversions will usually be less than the 23 cfs maximum because the load will be less than the 800 kW maximum.

Table 4.11-2, Page 4-144: The following table augments Table 4.11-2 by showing values for the zero instream flow proposal being pursued by GEC. It also modifies the values slightly for the other two instream flow regimes by 1) using average daily flows rather than average monthly flows, and 2) by factoring in inflow between the diversion and the lower falls (estimated to be 6% of the flow at the diversion). Also, note that the natural flows exceeded 80% of the time are significantly different than those shown in Table 4.11-2 of the DEIS, which are inconsistent with Table 4.4.2 of the DEIS.

Month	May	June	July	August	Sept.
Natural flows exceeded 80% of the time (cfs)	81	50	34	29	42
Regulated flows with zero instream flow proposal					
80% exceedence flow (cfs)	58	27	11	6	19
Percent of natural flow	72	54	32	22	45
Regulated flows with 5/7 instream flow proposal					
80% exceedence flow (cfs)	58	27	11	9	19
Percent of natural flow	72	54	32	30	45
Regulated flows with NPS-RTCA instream flow proposal					
80% exceedence flow (cfs)	58	27	22	22	22
Percent of natural flow	72	54	64	74	53

Page 4-146, lines 20-23: GEC believes the last sentence of this paragraph to be false. Although each individual viewer may have a lesser appreciation of the visual appearance, the increase in visitation as the result of improved access will likely result in a cumulative increase in appreciation.

Page 4-153, line 13. As explained under comments related to 3-64 and 3-65, a more realistic estimate is 72 and 10 visits, respectively.

Section 4.13.2.2 starting on page 4-163 describes the effects of the GBNPP and Wilderness Boundary Adjustment. There is much discussion on congressional mandates regarding wilderness, the National Park System and GBNPP on page 164. One congressional mandate not discussed is the Glacier Bay National Park Boundary Adjustment Act of 1998. The paragraph starting line 25, page 4-165 states that the land exchange "would have considerable negative effect on GNPP wilderness values and resources." How is "considerable" quantified? Is it the personal bias of the author of this section? To say that these lands have "exceptional wilderness value" is very different than what other researchers would say. Certainly, Department of Interior officials and members of the U.S. Congress in 1998 would disagree with these conclusions. They felt that if this project met the condition of a FERC license, that the land exchange would be an improvement to National Park System and wilderness boundaries. While it was evident that many NPS employees oppose the taking of land out of wilderness for any reason as demonstrated at the Gustavus public hearings, that is not the wishes of the people of the U.S.A. as voiced by their elected representatives in Washington D.C. The document is making foregone conclusions, but they are misleading. There is parity on a larger scale than GBNPP.

Please reference the attached two newspaper articles from 1995 and 1996 regarding the legislation for this project. The original legislation included the State owned Dude Creek Critical Habitat Area in Gustavus in the land exchange. This would have kept the amount of land in GBNPP the same. However, it was the desire of the NPS that the state lands exchanged be in another park. Note the quotes by George Frampton, Assistant Secretary of the Interior, in the articles. The land exchange was even taken out of the Park Omnibus bill in 1996 so that the NPS would have time to select the best land they could for the exchange. This meant the legislation had to pass as a standalone bill subject to veto in 1998. At the time, it was felt that this legislation would improve NPS land in Alaska. Great thought was put into which lands the NPS wanted to exchange in the legislation, and for others to second guess these selections at a later date is probably personal bias.

The paragraph starting on line 27, page 167 contains the same bias. GEC has researchers intimate with all the subject lands and maintain that the exact opposite is true from the opinion expressed in the DEIS.

This entire section could just as easily and more justifiably expressed the opinion that the de-designation of wilderness lands and the designation of non wilderness lands would have considerable positive effect on GBNPP wilderness values and resources.

Table 4.13-1 (page 4-166) is very misleading. It treats the island near Blue Mouse Cove, Cenotaph Island and Alsek Lake as wilderness, when in fact it is **NOT** wilderness. It is managed as de facto wilderness now, but this could change at any time in the future, and a concessionaire could build a lodge there at the very least. The title of this table should change to show that it is designated and de facto wilderness, similar to what it is in the column headings. Also, there should be another Table showing the same information, but not treating de facto wilderness as though it was presently wilderness. This new table would have the same number in the "TOTAL" column, and would be much more useful to a person trying to get a true picture of the alternatives. The legislation mandated parity in the exchange and it should be shown.

This entire section (Section 13 Wilderness) refers to lands MANAGED as wilderness. It should be emphasized that these lands are PRESENTLY MANAGED AS WILDERNESS. Some discussion should be given to the possibility that they would not be managed as wilderness in the future if the no action alternative is selected.

Page 4-173, lines 30-31. This is based on a misapprehension of GEC's boundary proposal. See comment under 4-97.

Page 4-174, line 12. This is based on a misapprehension of GEC's boundary proposal. See comment under 4-97.

Page 4-176, line 1 to 4-179, line 22. The argument constructed in these pages is hard to accept. It seems that by considerably simplifying the bark boundary, and by separating the native allotments from park lands, that NPS management would be considerably simplified under both alternatives. In addition, by setting the boundary along the canyon lip which is a natural barrier to human travel, the GEC alternative further simplifies management. Since no analysis is given to future management difficulties due to development on the allotments, these two sections come, overall, to a more negative view of future management under either the GEC or maximum boundary alternative than would seem warranted.

Section 4.18 on page 4-201 mentions irreversible effects of the project. The first bullet is true, but incomplete. One effect is removal of land from GBNPP. It is suggested that another irreversible effect would be the addition of land to either KGNHP or to WSNPP.

The second bullet item does not make sense. Please clarify it. This item would be covered by the other 3 bullet items. Please explain the removal from the Excursion Ridge/Kahtaheena River area.

In the third bullet item, the reference to the transmission line should be removed, since the transmission line will be buried and therefore have no visual impact.

SECTION 5.0 DEVELOPMENTAL ANALYSIS

In the developmental analysis, FERC has applied its "standard" method of analyzing the economics that it first applied in 1995 (Project 2506-002,Mead Corporation, Publishing Paper Division). In Mead and the Falls Creek DEIS, FERC indicates that it may license a project even if its standard method of analysis indicates the project would have a negative net economic benefit. FERC has been able to use its standard method of analysis because it also assigns to the developer the business decision as to whether or not to proceed. For the Falls Creek Project, the Act does not allow FERC to assign that decision solely to the developer - - it requires FERC to determine if the project "can be accomplished in an economically feasible manner". Since FERC must analyze the economics of the Falls Creek project, it must conduct an analysis that is appropriate and specific to the Falls Creek project. Finally, we note that in Mead Corporation, FERC makes clear that it is not a definitive method (*"We recognize that there may be other, equally valid approaches that we could employ. We remain open to new ideas on this subject, and to suggestions on further improvements in our analysis."*).

It is important to note that the legislation specifies two conditions regarding the project economics: 1) that FERC must determine that the project "can be accomplished in an economically feasible manner", and 2) the FERC license must include a requirement for GEC to submit an acceptable financing plan. GEC understands these two requirements to be essentially two levels of economic analysis. The first level, as required for issuance of a license, is to be based on one or more sets of reasonable assumptions, since exact values for many evaluation parameters cannot be determined at this juncture. The second level, as required for authorization for the start of construction, is to be based on firm values, such as grant and loan authorizations and construction contractor's bids. Because it is a two-level evaluation, GEC believes that if FERC's analysis for the FEIS demonstrates economic feasibility for one or more sets of reasonable assumptions, that is sufficient for issuance of a license.

FERC has chosen to evaluate project economics both with and without interconnection of the GBNPP load. Given GBNPP's inability or reluctance to commit to interconnection at this time, we recognize that FERC must evaluate both conditions. However, it is GEC's intent to obtain additional grants and low-interest funding such that the cost of power will be less than diesel generation, even in the first year of operation and without the GBNPP load. If that goal can be achieved, GEC believes GBNPP will connect to the GEC grid and purchase hydropower at some later date.

There are two general types of deficiencies with the economic analysis presented in Section 5.0 of the DEIS: 1) flawed methods of calculation, and 2) invalid assumptions. Our only complaint regarding the method of calculation is that it does not account for a difference between the general inflation rate and escalation rate of the price of diesel fuel. We recognize that a primary reason why FERC developed its standard method of analysis was to avoid the arguments associated with fuel escalation rates. Nevertheless, it seriously diminishes the very real benefits of hydropower, and if a difference in escalation rates can be demonstrated, then FERC's analysis should consider the difference, despite the inconvenience.

Regarding the invalid assumptions, we recognize that FERC has used its "standard" assumptions, with the expectation that more project-specific values will be submitted by GEC and others. To that end, we have summarized below our recommendations for more appropriate values for assumptions used in the developmental analysis.

1. Project completion date: The on-line date of 2007 projected by GEC in its application and PDEA, and subsequently used by FERC in the DEIS, now appears in doubt due to the time required to issue the DEIS and the anticipated process for issuing the license and completing the land exchange. A later on-line date would actually make the project economics more favorable because of 1) the expected increase in Gustavus loads over time, and 2) the escalation of diesel fuel prices. Nevertheless, GEC is reluctant to abandon hope of a 2007 on-line date, and recommends it be retained for the FEIS.

2. Insurance: FERC has estimated insurance costs as 0.25% of the investment cost. That percentage is reasonable, however FERC failed to deduct from the calculated amount of $11,090 the amount already included by GEC in the operation and maintenance costs ($5,000 in 2001$, $5,300 in 2003$, see Table A-3 of the Application for License for a breakdown of the estimated operation and maintenance costs).

3. Property taxes: FERC has estimated property taxes as 3% of the investment cost. The project will be located on either State land or private land. Gustavus is unincorporated and therefore not capable of assessing property taxes. The State does not assess property taxes. For that portion of the project on State land, GEC expects to enter into a long-term lease, for which there may be a payment. However, since the State land will be used for generation and transmission of energy for the public good, GEC expects that any lease payment will be nominal. GEC is negotiating with the owner of the small piece of private land regarding compensation, however, and amount has not been determined. GEC included an amount for lease payments in its estimate of operation and maintenance costs ($5,000 in 2001$, $5,300 in 2003$, see Table A-3 of the Application for License for a breakdown of the estimated operation and maintenance costs), and believes that amount is sufficient.

4. Income taxes: FERC has estimated Federal income taxes based on a tax computation that is not reproducible from the information in the DEIS or in the subsequent responses to GEC's requests. Regardless, GEC expects to fund all of the construction by either grants or long-term low interest loans. Since there will be no equity financing, the project will not result in additional Federal income tax payment by GEC since income taxes result only from returns on the equity portion of the financing.

5. Term of analysis: FERC has conducted the analysis for a term of 30 years. That may be appropriate for relicensing of existing projects, where the license terms are typically 30

years. However, original licenses are issued for 50 year terms, and therefore it is appropriate for the economic evaluation to extend for 48 years (the 50 year term of the license less 2 years for construction). This does not involve any greater degree of uncertainty, and it more fairly evaluates the long-term benefits of hydropower.

6. AIDEA grant: GEC has been earmarked for a grant in the amount of $1,083,685 from the Denali Commission to assist in defraying the construction cost of the project. FERC's analysis should reduce the estimated construction cost by that amount.

7. Loans: GEC has been earmarked for a loan in the amount of $1,000,000 from AIDEA, with an interest rate of 5.43% and a term of 30 years. In addition, GEC will qualify for a loan from the Rural Utility Service, which currently has programs with interest rates of about 5.5% and terms of 30 years. For the FEIS, it will be appropriate to assume the balance of the financing will be by a loan with an interest rate of 5.5% and a term of 30 years, which are much more favorable conditions than assumed by FERC (8.0%, 20 years). A final financing plan consisting of grants and loans will take at least 6 months to develop. We will keep FERC advised.

8. GEC mitigation costs: FERC estimated costs for the mitigation measures proposed by GEC amounting to $54,480 in capital costs and $7,000 in annual costs. The individual amounts are as follows:

Table C-1

Mitigation measure	Capital cost	Annual cost
ESCP	$8,000	0
Sediment monitoring plan	$8,000	0
Water quality monitoring plan	$13,480	0
Fisheries monitoring plan	$10,000	$1,000
Recreation plan	$5,000	$1,000
Flow monitoring plan	$10,000	$5,000
Total	$54,480	$7,000

GEC estimated $10,000 in annual costs (2001$) for environmental monitoring costs (see Table A-3 of the Application for License for a breakdown of the estimated operation and maintenance costs), somewhat more than estimated by FERC. Therefore, FERC should not have added the $7,000 on as an additional annual cost. GEC did not explicitly estimate mitigation capital costs, however, they are included in the contingency allowance (see Table A-2 of the Application for License). Since the measures were proposed by GEC, FERC should assume that their costs are also included in GEC's estimated costs, and FERC should not add them onto the construction cost.

GEC is in the process of negotiating a settlement with the agencies regarding a reduction in the instream flow requirement to zero. If that effort is successful, as GEC believes it will be, then GEC would expect to provide off-site mitigation to compensate for the impacts to resources in the bypassed reach. GEC expects the amount of off-site mitigation to be about $50,000.

9. FERC-recommended mitigation costs: FERC has recommended mitigation measures in addition to those proposed by GEC. The total additional capital cost is estimated to be $315,160, and the additional annual cost is estimated to be $27,000. GEC recognizes that additional mitigation will be required by the license, however, some of the estimated costs are not reasonable, as described below. Table C-2 below summarizes the estimated costs of the FERC-recommended mitigation measures.
    - Fish passage evaluation plan - - GEC is in the process of negotiating a settlement with the agencies regarding a reduction in the instream flow requirement to zero. If that effort is successful, as GEC believes it will be, then the annual cost will be significantly less than $5,000 since there will no longer be bypass facilities at the intake. In that case, an annual cost of $3,000 is estimated to be sufficient for operation and maintenance of the intake screen and tailrace outfall.
    - Biotic evaluation plan - - GEC is in the process of negotiating a settlement with the agencies regarding a reduction in the instream flow requirement to zero. If that effort is successful, as GEC believes it will be, then the annual cost will be significantly less than $15,000 since it will only need to address the anadromous reach. Furthermore, GEC is confident that the mitigation measures it proposed for the anadromous reach will be effective in minimizing impacts to the anadromous fishery, and therefore believes it reasonable to assume that the annual cost (say $10,000) should only occur for the first five years of operation.
    - Environmental compliance monitor - - the capital cost of this plan ($139,160) appears to be sufficient to provide full-time monitoring over the two year construction period. However, the ECM will only be required during ground-disturbing activities, particularly those near the stream. Furthermore, the construction is not planned to be continuous for two years, as there will be curtailments during the winter. GEC intends to hire a Gustavus resident to provide the ECM service on an as-needed basis, and expects the cost to be approximately $40,000.
    - Annual consultation with agencies - - the agency recommendations for this plan allow for deferring the annual consultation meetings if not warranted. GEC believes that meetings will be required annually for the first few years, and then will be less frequent as the project operation becomes routine. Therefore, GEG suggests an annual cost of $500 is more appropriate than the $1000 assumed by FERC.
    - Escrow account for fish, wildlife, and water quality - - the escrow fund is to pay for mitigation of unforeseen impacts during construction and possible adjustment of instream flows after 5 years of project operations. GEC is in the process of negotiating a settlement with the agencies regarding a reduction in the instream flow requirement to zero. If that effort is successful, as GEC believes it will be, then there will be no need to reevaluate and adjust instream flows after 5 years, as the zero instream flow settlement will assume that the char in the bypassed reach are expendable. Furthermore, by including the full amount of the escrow account ($50,000) as a capital cost, FERC has tacitly assumed that there will be substantial unforeseen impacts. GEC believes that for the economic analysis, the cost of the escrow account should not be based on the worst-case scenario, and a lesser amount, say $25,000, would be more reasonable. Also, the agency recommendations for the escrow account allow for return of the escrowed funds to GEC if not used.

- Fuel and hazardous substances spill plan - - GEC will prepare this plan from existing plans for other projects. It will cost a minor amount to prepare, say $2,000.
- Bear safety plan - - FERC has estimated a capital cost of $2,000 and an annual cost of $1,000 for this plan. The capital cost estimate is fine, as GEC will prepare this plan from existing plans for other projects. GEC does not see the need for an additional annual cost.
- Wetlands mitigation plan - - FERC has estimated a capital cost of $100,000 for mitigation of impacts to 1.15 acres of wetland. The DEIS does not indicate the basis for the estimate, but to GEC it appears very high. Obviously, the exact amount cannot be determined until the plan is developed, but GEC suggests that $25,000 is a more appropriate estimate.

Table C-2

	FERC Estimate in DEIS		GEC Estimate	
Mitigation measure	Capital cost	Annual cost	Capital cost	Annual cost
Fish passage plan	0	5,000	0	5,000 / 3,000 (1)
Biotic evaluation plan	0	15,000	0	15,000 / 10,000 (2)
Less GEC fish monitoring plan (3)	-10,000	-1,000	-10,000	-1,000
Road management plan	10,000	5,000	10,000	5,000
ECM	139,160	0	40,000	0
Notify within 12 hours	0	0	0	0
Ramping rate	0	0	0	0
Annual consultation	0	1,000	0	500
Escrow fund	50,000	0	25,000	0
Fuel/hazardous plan	8,000	0	2,000	0
Agency access	0	0	0	0
Prohibit hunting	0	0	0	0
Bear safety plan	2,000	1,000	2,000	0
Wetlands mitigation plan	100,000	0	25,000	0
Public access plan	8,000	0	8,000	0
Land use mgmt plan	8,000	0	8,000	0
Flow phone	0	1,000	0	1,000
Design to blend	0	0	0	0

(1) Lesser amount if instream flows reduced to 0.
(2) Lesser amount if instream flows reduced to 0; for first 5 years of operation only.
(3) Estimated cost of fish monitoring plan included in GEC mitigation measures.

10. The analyses do not include the cost to interconnect to GBNPP for those cases where it is assumed GEC supplies power to GBNPP. GEC estimates this cost to be $600,000 (2003 cost level). Note that GEC has installed 80 miles of underground cable in the Gustavus area in the last 20 years, and knows better than anyone what the cost will be.

11. FERC has evaluated the cost and benefits of the project if GBNPP does not interconnect. If GBNPP decides not to interconnect, then GEC will need to resize the project so it is appropriate only for the Gustavus load. The following major changes would occur:

- The generating unit capacity would be decreased to 600 kW.
- The penstock diameter would be decreased for the revised flow rate of 17 cfs (30" pipe would decrease to 26", 28" pipe would decrease to 24", 24" pipe would decrease to 21", and 20" pipe would decrease to 18")

GEC estimates that these modifications would decrease the capital cost to $3,860,000 (2001 cost level). GEC is reluctant to design and build the project at this reduced size because it feels the NPS would not choose to burn fossil fuels if hydropower were in place and available. However, if it is necessary to downsize the project in order to obtain the license, GEC would do so.

12. Hydroelectric generation: FERC's estimate of the project generation is based on a operation simulation model that uses average monthly flows as input. GEC has used average daily flows in its simulation model, which is believed to be more accurate. The differences are shown below:

Table C-3

	With GBNPP Load			Without GBNPP Load		
		Hydro Generation			Hydro Generation	
Year	Load	5/7 IFR	0 IFR	Load	5/7 IFR	0 IFR
2007	2,880,540	2,517,850	2,786,510	2,039,840	1,791,330	1,970,130
2008	2,969,560	2,589,840	2,866,050	2,128,860	1,863,960	2,052,680
2009	3,049,690	2,655,050	2,940,300	2,208,990	1,930,600	2,126,780
2010	3,121,210	2,712,430	3,002,810	2,280,510	1,990,220	2,193,460
2011	3,195,040	2,772,160	3,069,510	2,354,340	2,050,860	2,262,100
2012	3,271,260	2,832,630	3,137,620	2,430,560	2,114,190	2,331,540
2013	3,349,950	2,896,410	3,208,670	2,509,250	2,177,870	2,403,330
2014	3,430,500	2,959,120	3,278,740	2,589,800	2,244,930	2,478,420
2015	3,512,930	3,025,030	3,351,360	2,672,230	2,311,250	2,552,460
2016	3,597,250	3,091,230	3,424,980	2,756,550	2,379,370	2,629,560
Average	3,237,790	2,805,180	3,106,660	2,397,090	2,085,460	2,300,050

13. Load vs. generation: FERC's estimate of revenue is based on displacement of diesel generation rather than the actual load (i.e., sales). GEC's generation is actually substantially greater than the load because of line losses in its widespread system and forced-air cooling of the diesel generators. The following table shows GEC's generation and sales for the last 10 years. Note that there is a pronounced tendency for the sales/generation ratio to increase with generation. Since generation is expected to increase with time, it is appropriate to expect a higher ratio in the future. For its analysis, GEC has assumed that future sales will be 87.5% of the generation.

Table C-4

Year	Generation	Sales	Ratio
1993	1,188,000	996,353	83.9%
1994	1,457,000	1,251,012	85.9%
1995	1,414,000	1,212,643	85.8%
1996	1,625,000	1,457,905	89.7%
1997	1,677,000	1,487,299	88.7%
1998	1,734,000	1,528,716	88.2%
1999	1,713,000	1,520,788	88.8%
2000	1,694,000	1,466,089	86.5%
2001	1,603,000	1,376,964	85.9%
2002	1,638,900	1,400,096	85.4%
Average			87.0%

GEC has reevaluated the project economics using FERC's method of analysis with the modified assumptions stated above. Table C-5 below presents the analyses for eight sets of assumptions, corresponding to the following:

- With and without the cost of additional mitigation measures proposed by FERC
- With and without serving the GBNPP load
- With the 5/7 cfs instream flow regime proposed by GEC in its application, and without an instream flow requirement.

As can be seen, of the eight cases evaluated, all but one show a positive economic benefit, and the one which doesn't is only slightly negative (a benefit-cost ratio of 0.999). GEC considers this to be a sufficient indication of economic feasibility to meet the conditions of the Act.

TABLE C-5 SUMMARY OF ECONOMIC ANALYSES

CASE	1	2	3	4	5	6	7	8
Mitigation Cost	GEC	GEC	GEC	GEC	FERC	FERC	FERC	FERC
Include Park Load?	Yes	Yes	No	No	Yes	Yes	No	No
Instream Flow	5/7	0	5/7	0	5/7	0	5/7	0
2001 Estimated construction cost	$ 4,130,000	$ 4,130,000	$ 3,860,000	$ 3,860,000	$ 4,130,000	$ 4,130,000	$ 3,860,000	$ 3,860,000
Escalation (3% for two years)	$ 251,520	$ 251,520	$ 235,070	$ 235,070	$ 251,520	$ 251,520	$ 235,070	$ 235,070
Park interconnection cost	$ 600,000	$ 600,000	$ -	$ -	$ 600,000	$ 600,000	$ -	$ -
Mitigation capital cost	$ -	$ 50,000	$ -	$ 50,000	$ 120,000	$ 170,000	$ 120,000	$ 170,000
2003 Estimated construction cost	$ 4,981,520	$ 5,031,520	$ 4,095,070	$ 4,145,070	$ 5,101,520	$ 5,151,520	$ 4,215,070	$ 4,265,070
Less grant	$ 1,083,685	$ 1,083,685	$ 1,083,685	$ 1,083,685	$ 1,083,685	$ 1,083,685	$ 1,083,685	$ 1,083,685
Loan amount	$ 3,897,830	$ 3,947,830	$ 3,011,380	$ 3,061,380	$ 4,017,830	$ 4,067,830	$ 3,131,380	$ 3,181,380
Loan interest rate	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%
Loan term, years	30	30	30	30	30	30	30	30
Annual debt service	$ 268,190	$ 271,630	$ 207,200	$ 210,640	$ 276,450	$ 279,890	$ 215,460	$ 218,900
Life-of-project operating costs								
Land lease fees	$ 5,300	$ 5,300	$ 5,300	$ 5,300	$ 5,300	$ 5,300	$ 5,300	$ 5,300
Parts and supplies	$ 5,300	$ 5,300	$ 5,300	$ 5,300	$ 5,300	$ 5,300	$ 5,300	$ 5,300
Insurance	$ 12,450	$ 12,580	$ 10,240	$ 10,360	$ 12,750	$ 12,880	$ 10,540	$ 10,660
Environmental mitigation	$ 5,300	$ 5,300	$ 5,300	$ 5,300	$ 11,500	$ 9,500	$ 11,500	$ 9,500
Interim replacements	$ 10,610	$ 10,610	$ 10,610	$ 10,610	$ 10,610	$ 10,610	$ 10,610	$ 10,610
Total life-of-project operating costs	$ 38,960	$ 39,090	$ 36,750	$ 36,870	$ 45,460	$ 43,590	$ 43,250	$ 41,370
5-year mitigation costs								
Biotic monitoring plan	$ 5,300	$ 5,300	$ 5,300	$ 5,300	$ 15,000	$ 10,000	$ 15,000	$ 10,000
Discount rate	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%
Equivalent 2003 annual cost	$ 272,460	$ 275,560	$ 217,450	$ 220,550	$ 288,570	$ 288,410	$ 233,570	$ 233,400
Estimated displaced diesel generation, kWh	2,805,180	3,106,660	2,085,460	2,300,050	2,805,180	3,106,660	2,085,460	2,300,050
Estimated displaced load, kWh	2,454,530	2,718,320	1,824,780	2,012,540	2,454,530	2,718,320	1,824,780	2,012,540
Equivalent 2003 annual benefit	$ 313,830	$ 347,560	$ 233,310	$ 257,320	$ 313,830	$ 347,560	$ 233,310	$ 257,320
Net annual benefit	$ 41,370	$ 72,000	$ 15,860	$ 36,770	$ 25,260	$ 59,150	$ (260)	$ 23,920
Benefit-cost ratio	1.15	1.26	1.07	1.17	1.09	1.21	1.00	1.10

SECTION 6.0 CONCLUSIONS

Page 6-29 Load Growth: In 1999, the State of Alaska's Power Cost Equalization (PCE) program which subsidized the high cost of electricity in Rural Alaska was changed to eliminate commercial and government customers and reduce the subsidy to residential customers. As a result, some commercial customers resorted to generating their own electricity instead of buying from the GEC grid. Other commercial customers instituted conservation methods to reduce their electrical usage, primarily by converting from electric to propane appliances.

The PCE program reduced its subsidy to residences from 700 kWh/m to 500 kWh/mo. Residences who previously exceeded the 500kWh/mo found ways to conserve in order to keep their usage with the subsidy limits. Converting to propane was also a large conservation method. In addition, the amount of the PCE subsidy within the 500 kWh/m limit was also reduced, encouraging residences to conserve even further.

This in the primary reason for the decrease in electrical energy use starting in 1999. It is expected that as hydropower goes on line and rates can start a gradual decline, that usage will increase as a result, generating a further decline in the rates. It has been shown in other communities that have gone from fossil fuel electric generation to green alternative energy, that usage increases. When a propane range, clothes dryer, water heater, etc. breaks down and needs replacing, customers will buy an electric model to replace it. This gradually encourages the cycle of increased usage and lower rates.

GEC plans to institute time of day metering to encourage off peak electrical usage at night when loads are historically low. Heating of hot water for use during the day, for instance, could occur in the middle of the night. In a run-of-river hydro project, river water that is not used at the moment for hydropower generation cannot be stored and used later.

Commercial customers, who are generating their own electricity, including the grocery store, have said they will use hydropower when it goes on line. For these reasons, GEC feels that its load growth will meet or exceed its projections.

Page 6-2, lines 30-34: As noted in 4.4.2.1.1, GEC proposed a synchronous bypass because the agencies had recently requested redundant flow continuation systems on other projects, and GEC reserves the right to eliminate the synchronous bypass if redundant flow continuation is not required. The impulse turbine jet deflectors and needle valves will allow adequate load following and flow continuation capability.
Page 6-3, lines 29-31: GEC is in the process of negotiating a settlement with the agencies regarding a reduction in the instream flow requirement to zero. If that effort is successful, as GEC believes it will be, then GEC would expect to provide off-site mitigation to compensate for the impacts to resources in the bypassed reach. GEC expects the amount of off-site mitigation to be about $50,000.
Page 6-4, lines 29-34: GEC is in the process of negotiating a settlement with the agencies regarding a reduction in the instream flow requirement to zero. If that effort is successful, as GEC believes it will be, then the biotic monitoring plan will only need to address the

anadromous reach. Furthermore, there will no longer be a need to reevaluate instream flows after 5 years.

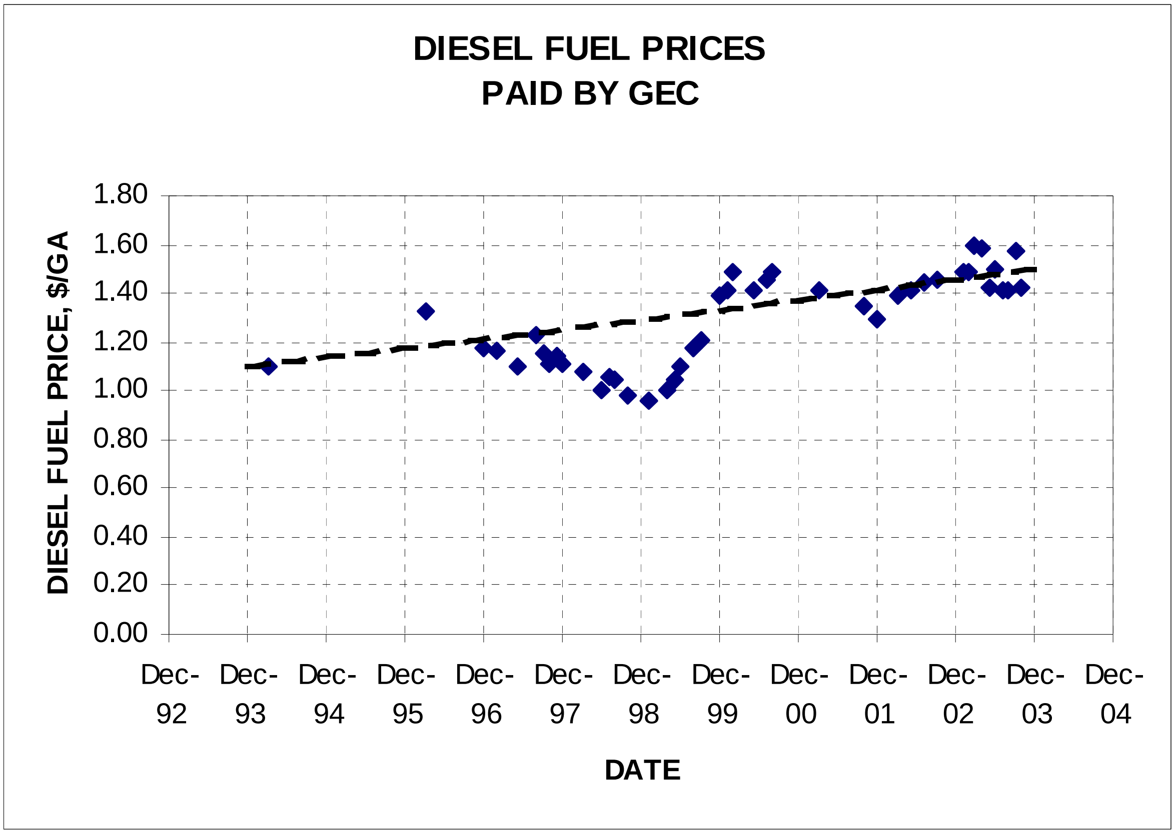
Section 6.1.1.4 Economic Feasibility: The DEIS presents the results of GEC's economic sensitivity analyses that were included in the PDEA. It is clear that FERC will not use those analyses as the basis for determining economic feasibility, rather, it will use its own supplemental analyses. Therefore, in the interest of clarity, GEC recommends that the presentation of its economic sensitivity analyses be deleted for the FEIS. GEC also suggests that FERC's supplemental analyses should be modified or expanded, as described below:

1. Assumptions regarding construction costs, mitigation costs, financing conditions, insurance costs, property taxes, income taxes, generation, sales, instream flows, and analysis term should be modified as described in our comments on Section 5 Developmental Analysis.

2. The evaluation of diesel fuel costs should be based on assumed differences between the inflation rate of diesel fuel costs and general inflation. The figure below shows the fuel prices paid by GEC for the last 10 years. Although the price of fuel has varied dramatically during that period, there is nevertheless an upward trend averaging about 3.2% per year. In contrast, general inflation over that same time frame has been about 2.5% per year (based on the Consumer Price Index published by the Bureau of Labor Statistics). Considering that diesel is a fossil fuel that is becoming scarcer and more difficult to obtain, GEC believes the price of diesel fuel will continue to escalate faster than general inflation, and the difference will likely accelerate during the life of the project. GEC has analyzed the project benefits over the operating term of the license if diesel fuel costs increase more than general inflation by two amounts, 0.5% and 1.0%. Equivalent 2003 fuels costs and diesel production costs are as follows:

    - 0.0% inflation difference ....$1.51/gal........12.8¢/kWh
    - 0.5% inflation difference ....$1.70/gal........14.3¢/kWh
    - 1.0% inflation difference ....$1.93/gal........16.0¢/kWh

    The results of these varying diesel fuel prices are summarized in Table C-6 for the same eight cases considered in our comments on Section 5.



3. Even though the economic analyses show the project to be feasible over the long term, the cost of power with the hydro project could still be higher than with diesel generation in the first few years of operation, particularly if GBNPP refuses to interconnect. To avoid that circumstance, GEC is actively pursuing other grant funding opportunities. Table C-7 indicates the impact on economic feasibility if the current grant amount is doubled.

4. As noted in our comments on Section 5, it appears that the assumed on-line date of 2007 is in jeopardy. Table C-8 indicates the impact on economic feasibility if the first year of operation is 2009 rather than 2007. The positive impact results from continuing load growth.

Page 6-29, Table 6.1-2: The middle column shows a 2003 diesel fuel cost of $1.41/gallon, which is actually the 2001 diesel fuel cost. The value should be changed to $1.51/gallon. The power value shown in the table for that column ($380,380) is in fact based on $1.51/gallon.

TABLE C-6
SUMMARY OF ECONOMIC ANALYSES FOR VARYING DIESEL FUEL COSTS

CASE	1	2	3	4	5	6	7	8
Mitigation Cost	GEC	GEC	GEC	GEC	FERC	FERC	FERC	FERC
Include Park Load?	Yes	Yes	No	No	Yes	Yes	No	No
Instream Flow	5/7	0	5/7	0	5/7	0	5/7	0
Equivalent 2003 annual cost	$ 272,460	$ 275,560	$ 217,450	$ 220,550	$ 288,570	$ 288,410	$ 233,570	$ 233,400
Estimated displaced load, kWh	2,454,530	2,718,320	1,824,780	2,012,540	2,454,530	2,718,320	1,824,780	2,012,540
0.0% difference in fuel escalation (2003 diesel fuel cost = $1.51/gal)								
Equivalent 2003 annual benefit	$ 313,830	$ 347,560	$ 233,310	$ 257,320	$ 313,830	$ 347,560	$ 233,310	$ 257,320
Net annual benefit	$ 41,370	$ 72,000	$ 15,860	$ 36,770	$ 25,260	$ 59,150	$ (260)	$ 23,920
Benefit-cost ratio	1.15	1.26	1.07	1.17	1.09	1.21	1.00	1.10
0.5% difference in fuel escalation (2003 diesel fuel cost = $1.70/gal)								
Equivalent 2003 annual benefit	$ 350,060	$ 387,680	$ 260,240	$ 287,020	$ 350,060	$ 387,680	$ 260,240	$ 287,020
Net annual benefit	$ 77,600	$ 112,120	$ 42,790	$ 66,470	$ 61,490	$ 99,270	$ 26,670	$ 53,620
Benefit-cost ratio	1.28	1.41	1.20	1.30	1.21	1.34	1.11	1.23
1.0% difference in fuel escalation (2003 diesel fuel cost = $1.93/gal)								
Equivalent 2003 annual benefit	$ 392,390	$ 434,560	$ 291,710	$ 321,730	$ 392,390	$ 434,560	$ 291,710	$ 321,730
Net annual benefit	$ 119,930	$ 159,000	$ 74,260	$ 101,180	$ 103,820	$ 146,150	$ 58,140	$ 88,330
Benefit-cost ratio	1.44	1.58	1.34	1.46	1.36	1.51	1.25	1.38

TABLE C-7
SUMMARY OF ECONOMIC ANALYSES FOR GRANT AMOUNTS

CASE	1	2	3	4	5	6	7	8
Mitigation Cost	GEC	GEC	GEC	GEC	FERC	FERC	FERC	FERC
Include Park Load?	Yes	Yes	No	No	Yes	Yes	No	No
Instream Flow	5/7	0	5/7	0	5/7	0	5/7	0
With existing grant amount ($1,083,685)								
Equivalent 2003 annual cost	$ 272,460	$ 275,560	$ 217,450	$ 220,550	$ 288,570	$ 288,410	$ 233,570	$ 233,400
Equivalent 2003 annual benefit	$ 313,830	$ 347,560	$ 233,310	$ 257,320	$ 313,830	$ 347,560	$ 233,310	$ 257,320
Net annual benefit	$ 41,370	$ 72,000	$ 15,860	$ 36,770	$ 25,260	$ 59,150	$ (260)	$ 23,920
Benefit-cost ratio	1.15	1.26	1.07	1.17	1.09	1.21	1.00	1.10
With doubled grant amount ($2,167,370)								
Equivalent 2003 annual cost	$ 207,920	$ 211,020	$ 152,910	$ 156,010	$ 224,020	$ 223,870	$ 169,020	$ 168,850
Equivalent 2003 annual benefit	$ 313,830	$ 347,560	$ 233,310	$ 257,320	$ 313,830	$ 347,560	$ 233,310	$ 257,320
Net annual benefit	$ 105,910	$ 136,540	$ 80,400	$ 101,310	$ 89,810	$ 123,690	$ 64,290	$ 88,470
Benefit-cost ratio	1.51	1.65	1.53	1.65	1.40	1.55	1.38	1.52

TABLE C-8
SUMMARY OF ECONOMIC ANALYSES WITH DELAYED CONSTRUCTION

CASE	1	2	3	4	5	6	7	8
Mitigation Cost	GEC	GEC	GEC	GEC	FERC	FERC	FERC	FERC
Include Park Load?	Yes	Yes	No	No	Yes	Yes	No	No
Instream Flow	5/7	0	5/7	0	5/7	0	5/7	0
With 2007 first year of operation								
Equivalent 2003 annual cost	$ 272,460	$ 275,560	$ 217,450	$ 220,550	$ 288,570	$ 288,410	$ 233,570	$ 233,400
Estimated displaced diesel generation, kWh	2,805,180	3,106,660	2,085,460	2,300,050	2,805,180	3,106,660	2,085,460	2,300,050
Estimated displaced load, kWh	2,454,530	2,718,320	1,824,780	2,012,540	2,454,530	2,718,320	1,824,780	2,012,540
Equivalent 2003 annual benefit	$ 313,830	$ 347,560	$ 233,310	$ 257,320	$ 313,830	$ 347,560	$ 233,310	$ 257,320
Net annual benefit	$ 41,370	$ 72,000	$ 15,860	$ 36,770	$ 25,260	$ 59,150	$ (260)	$ 23,920
Benefit-cost ratio	1.15	1.26	1.07	1.17	1.09	1.21	1.00	1.10
With 2009 first year of operation								
Equivalent 2003 annual cost	$ 272,460	$ 275,560	$ 217,450	$ 220,550	$ 288,570	$ 288,410	$ 233,570	$ 233,400
Estimated displaced diesel generation, kWh	2,933,450	3,249,520	2,217,150	2,447,460	2,933,450	3,249,520	2,217,150	2,447,460
Estimated displaced load, kWh	2,566,770	2,843,330	1,940,010	2,141,530	2,566,770	2,843,330	1,940,010	2,141,530
Equivalent 2003 annual benefit	$ 328,180	$ 363,540	$ 248,040	$ 273,810	$ 328,180	$ 363,540	$ 248,040	$ 273,810
Net annual benefit	$ 55,720	$ 87,980	$ 30,590	$ 53,260	$ 39,610	$ 75,130	$ 14,470	$ 40,410
Benefit-cost ratio	1.20	1.32	1.14	1.24	1.14	1.26	1.06	1.17

Additional Comments Regarding GBNPP Interconnection: It has long been hoped (and assumed) that at some point, the NPS would continue to negotiate the possibility of connecting to the Gustavus power grid should the Falls Creek Hydroelectric Project go on line. However, the NPS has continually stated that it will not even discuss the possibility of connecting to Falls Creek Hydroelectric Project or to the Gustavus Grid, because it would be a conflict of interest since they are co-leads in the preparation of the NEPA document. Prior to the passage of the Glacier Bay National Park Boundary Adjustment Act of 1998, GEC was negotiating with NPS engineering personnel in Denver, Co. regarding the possibility of connecting NPS facilities at Bartlett Cove to the GEC electrical grid. As negotiations left off, the rate for electrical service to the NPS would have consisted of 3 parts:

1) Generation cost; whether diesel, hydro or a combination of both. This would be the cost to generate the electricity and send it to the electrical distribution system. It would include the cost of fuel, generator maintenance, operation and overhaul, operation, and maintenance of other generation plants such as controls, buildings, switch gear, substation, etc. These would also be the capital recovery on investment of all physical assets. This rate would probably be the same rate as paid by the Gustavus ratepayers.
2) Distribution Cost within Gustavus:

   This would be the cost of the main distribution feeder along the main road to the park, from the generation building near the airport to the park boundary. Gustavus ratepayers and the NPS would use this line. Costs of capitalization, operation and maintenance of this line would be shared by the NPS and Gustavus ratepayers in proportion to their respective usage's.
3) Distribution Cost Within the Park Boundary:

   This cost would be entirely born by the NPS. GEC and the NPS were discussing three alternatives for this interconnect line, which does not exist at the present time.

   A) GEC would sell wholesale power to the NPS at the park boundary, and the NPS would be responsible for everything past that point.
   B) GEC would build the interconnect line and maintain it. GEC would sell wholesale power to the NPS at Bartlett Cove and the NPS would distribute the electricity at Bartlett Cove using its existing distribution system.
   C) GEC would build the interconnect line and take over responsibility of the NPS Bartlett Cove distribution system. GEC would then read the meters at the individual consumption site and bill the NPS for retail power.

Each of these three options would have its own rate, and would be a function of who financed the interconnect line. Any proposal agreed upon would have its rate approved by the public utilities commission. GEC has no idea if the NPS is still interested in connecting to its grid or which alternative it would prefer if it did. Discussions are not expected to continue until a license determination is made.

These options and summary of negotiations are described in the <u>NPS Evaluation Report</u> of 2-22-96, memo dated 2-22-96, which is attached. <u>The NPS Evaluation Report</u> is not attached but may be obtained from the NPS.

Note that in our revised economic analyses, we have included the $600,000 cost of the interconnection to Bartlett Cove as part of the capital cost of the project in the scenarios that include the Park load. The exact cost of this line cannot be determined at present, because it is unknown how the NPS would want to build the line. Public comments included an estimate of $4.5 million to build this line, which we consider to be grossly inflated. At that cost, the project could not include the park, and the analysis would proceed without the park connection. Including the cost of the interconnection to the Park as part of the project cost would require the Gustavus ratepayers to pay a portion of its cost. GEC opposes this scenario. Without NPS commitment and participation in connecting to hydropower, the analysis must proceed without park connection. If, at a later date, the NPS would choose to entertain the idea of connecting to hydropower, discussions could start at that time.

Additional comments regarding the project development history. Some residents of Hoonah requested information on the history of this Hydroelectric Project in Glacier Bay National Park. There is written record of interest in Falls Creek as a hydropower source going back to the 1930's.

In 1976, the US Senate passed a resolution on October 1, 1976 which directed the U.S. Corps of Engineers to investigate the feasibility of hydropower for Gustavus and Bartlett Cove.

In 1982, Acres American, under contract with the Alaska Power Authority, issued its study of Gustavus energy requirements and sources.

In 1982, the National Park Service proposed an exchange of State lands near McCarthy for park service lands adjacent to Gustavus. This parcel was 7 square miles and included the lower 4 mile section of Falls Creek for its hydroelectric potential. A memorandum of understanding for the exchange of these lands was signed by then Secretary of the Interior James Watt at then Governor of Alaska Jay Hammond. The exchange was never finalized because an unrelated court decision stated that congressionally designated wilderness cannot be de-designated by executive order, but only by congress.

At that time, neither the NPS nor the State of Alaska was interested in building or operating the hydroelectric facility. They therefore, choose not to go to congress, but would support GEC in its endeavors to obtain the required federal legislation, since GEC was the only party willing to build and operate the facility.

However, with changes in the positions of the superintendent of GBNPP and the Alaska Regional Director, this support became conditional. The NPS wanted GEC to perform all the studies required to obtain a FERC license before it would support the legislation in Congress. GEC was unwilling to spend the money for these studies in the absence of any assurance of congressional approval, which would be subject to the political whims prevailing at the time.

In 1984, the Corps of Engineers issued their report investigating the feasibility of hydropower development for Bartlett Cove and Gustavus in response to U.S. Senate resolution 10/01/76.

In 1995, legislation was introduced in Congress to remove lands from GBNPP. Later in 1995, the legislation was modified to include a land exchange with the State or land in the Dude Creek Alaska State Critical Habitat Area. The NPS then wanted different land parcel in the exchange and other conditions in the legislation. The GBNPP land exchange was then taken out of the

Park Omnibus Bill of 1996 so the NPS concerns could be addressed. The bill was reintroduced in Congress as a stand alone bill and passed both houses of Congress unanimously and was signed by President Clinton in 1998.

Attached are two Juneau Empire articles from November 1995 and April 1996 which report some of the proceedings.

* For record, GEC is an investor owned Public Utility regulated by the Regulatory Commission of Alaska.

*In 1984, the NPS issued its General Management Plan. The plan included reference to the Falls Creek land exchange for a hydroelectric project (pg 65).

NOTE ON ATTACHMENTS: Several aattachments are refered to in the body of these comments. They will be sent, along with a hard copy of this filing, to the Commission by U.S. Postal Service.

COMMENT ON FALLS CREEK HYDROELECTRIC PROJECT
JANUARY 2, 2004

I object to this proposed project. It is both dangerous to the environment and unnecessary to meet energy needs.

The Glacier Bay and Gustavus area is a World Heritage Site. It is one of the few incomparable areas on Earth that merit this recognition for its scenic, natural, wildlife, and recreational attributes. The proposed project is entirely INCOMPATIBLE with these unique and special attributes.

I am employed full-time in instituting standards for buildings that easily obtain savings at least 30% beyond standard building design. Buildings that have not been built to these advanced 'green'building standars can cost-effecitvely obtain these energy savings.

I recommend that the FERC and the NPS reject this project to prevent its environmental degradation and that the Park immediately seek to study and implement energy saving actions.

Sincerely

Jim Edelson

ORIGINAL

Magalie R. Salas., Secretary
Federal Energy Regulatory Commission
888 First Street, NE, Washington DC 20426

Dec 26, 2003

Dear Ms. Salas:

I understand that you are now accepting public comments on FERC Project No. 11659-002, Falls Creek Hydroelectric Project and Land Exchange. I am writing today to express my opposition to the project.

I was *shocked* and *amazed* to learn that the Gustavus Electric Company is making plans to build a hydroelectric project within Glacier Bay National Park's Wilderness – one of our nations most superb and pristine natural areas and of great natural and cultural importance to all Americans.

Shocked – because the transfer of this irreplaceable wilderness land to state control will likely mean – in addition to the direct environmental impact of the hydro project itself – that the state will open this special and sensitive area to a wide variety of destructive uses, including snowmobiles/ATVs, timber sales, rock quarries, and mineral extraction. Since this land is contiguous to park land – such uses will impact and degrade the surrounding ecosystem as well.

Amazed – because the project is to go-ahead despite DEIS cost-benefit analyses that show that the project is both unnecessary and economically unsound. Economically unsound – even when the most optimistic assumptions are used.

The Falls Creek Hydroelectric Project fails to meet the basic standard of need and economic viability. AND there are other alternatives – including upgrading the existing diesel power generation, employing energy efficiency and conservation measures and applying new technologies like tidal generation.

Do not permit this shortsighted and foolhardy project go forward – please be responsible to the American public and to future generations.

Laurel Clark
690 S. York Street
Denver, CO
80209

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2004 JAN -2 P 2:50
FEDERAL ENERGY
REGULATORY COMMISSION

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FALLS CREEK HYDROELECTRIC PROJECT
DRAFT ENVIRONMENTAL IMPACT STATEMENT (DEIS)
COMMENTS

2004 JAN -2 P 2:17

FEDERAL ENERGY
REGULATORY COMMISSION

Magalie R. Salas
Secretary
Federal Energy Regulatory Commission
888 First Street
Washington, D.C. 20426

Reference Project No. 11659-002

Dear Ms Salas,

As a full time resident, property owner and electricity consumer in the community of Gustavus, I have several concerns about the lack of economic feasibility information in this DEIS. I personally also have serious concerns about how these types of projects are often conceived and how in the final analysis it is public funds that will have to be used to make it "viable". Ginny Fay put it very well in her report titled "A History of Alaska's Mega Projects". In her report she noted some common themes in failed Alaska energy projects. Some of them seem to ring true to the project proposed in this DEIS. They are:

- The disregard for economic feasibility and the belief that an infrastructure project is "economic development;"
- A belief that if subsidized enough, a project will become viable;
- Rather than relying on markets to determine economic feasibility, these projects reflect the "vision" of a small number of "visionaries;"
- Significant influence by parties with vested interests in a projects planning and development, thus the lack of an arm's length economic viability test.

Because of the lack of good economic information in this DEIS I am asking FERC to provide a second DEIS so that our community has an opportunity to adequately evaluate this projects economics. It is important to note that at a regular meeting of our community association on December 11, 2003 that the nearly 40 community members present overwhelmingly voted against a proposal to provide project conditions to FERC that would, if met, signify that our community was in favor of the project. Please understand that many of us in this community are very uneasy about this project for many reasons and the lack of good economic analysis is not helping the situation.

I have the following eight questions for your consideration:

Question #1:

On page 1-2, lines 17 through 24, the DEIS discusses and then predicts growth rate for power needs in our community and apparently bases those needs on past increases in our population over time. The DEIS shows this growth rate in the table pictured in Figure 1-4 on page 1-3. The increase power need the DEIS predicts is 4% per year starting in 2003 and carrying on until 2016. Using this logic, our community would then also have grown by approximately 17 souls this past year and will do approximately the same every year for the next 13 years.

The National Park Service is the largest employer in our community, probably directly effecting the existence of half the population here and indirectly effecting another 25-30%. The park has grown considerably in it's operations and numbers of employees since 1980 under the guidance of it's General Management Plan and the subsequent Development Concept Plan (both of these plans are in our community library). These plans and the growth they directed, are very near complete. Not much, if any, growth of facilities or numbers of employees is planned by the National Park Service from this point forward. The DEIS seems to acknowledge some of this reality in Figure 5-1 on page 5-4. That Figure shows the National Park Service future power usage remaining flat through 2016. But, incredibly it seems, the DEIS shows that our community will have solid growth in it's power requirement over the next 13 years to the tune of 60% greater than what was needed in 2002! What does this DEIS know about future growth in our community that is unknown to National Park Service planners and, apparently, many of us who live here? Can you please discuss?

Question #2:

At various public meetings, at various times over the last two months, our community has been told by GEC (Mr. Dick Levitt); that this project will not go forward, even if granted a license by FERC, unless the National Park Service agrees to purchase it's power from GEC; the opposite, that National Park Service power use is not needed to make this a good project; that GEC will find private investment monies to pay for this project; the opposite, that public funds will pay for this project; that as part of this project GEC will upgrade and continuously maintain rink creek road and bridge; and many other off the cuff remarks about what this project is (or isn't).

Hopefully in a second draft, but at least in the final EIS, can FERC please sort through all the facts/fiction and provide a clear statement about what is included in this project? Optional additions to the basic project should be labeled as such with corresponding costs. I would like to see a simple breakdown of all this projects components with a corresponding estimate of cost posted next to each component (including options). The components should be quantitative. The cost estimate for each component should be calculated by an independent engineering/consulting firm, familiar with South East Alaska conditions and National Electrical Code requirements for these types of projects. PLEASE DO NOT CALCULATE ANY kWh USAGE FROM THE NATIONAL PARK SERVICE IN ANY OF YOUR GRAPHS/FIGURES UNLESS YOU ALSO SHOW A CORRESPONDING COST TO GET THE POWER TO THE PARK! The distance from the existing GEC power house in Gustavus to the park boundary is 4.6 miles. The distance from the park boundary to the park power house is 4.4 miles. Total distance from the existing GEC power house to the park power house is 9 miles. At least the 4.4 miles from the park boundary to the park power house will need to be buried cable.

Question #3:

Hopefully in a second draft, but at least in the final EIS, can FERC please provide simple graphs that show corresponding kWh cost against a project funding scenario that goes from 0% to 100% use of public funds to pay for the project? Please provide graphs that show the project with and without National Park Service kWh usage/cost.

Question #4:

Unlike many diesel powered electric utilities, the majority of GEC's price per kWh to consumers does not seem to stem from diesel fuel costs which are part of power generation costs. GEC (Dick Levitt) has told our community his "distribution price" as opposed to his "generation price" for the current power system in our community is $0.32 per kWh. GEC's total price (distribution plus generation) per kWh is $0.52. That makes GEC's price for generating power $0.20 per kWh. Can FERC discuss how/why the disribution cost is so much different than most diesel powered electric utilities in our area and what it means about long term costs of power in our community?

Question #5:

Much of this project is scheduled to occur on fairly pristine lands that have been under a very high standard of protection for some time now. Hopefully in a second draft, but at least in the final EIS, can FERC please discuss the current standing that GEC and the Gustavus Dray (another local Dick Levitt holding) have with the Environmental Protection Agency (EPA)? Is GEC responsive to EPA concerns/questions? Does FERC have any policy or standard concerning an applicants standing with EPA?

Question #6:

Our community, through our Gustavus Community Association (GCA), has asked the State chartered Regulatory Commission of Alaska (RCA) to look into the rate structure that GEC uses to calculate the fee it charges for power in our community. Our community has received some answers back from RCA but the issue has not been resolved to my knowledge. Hopefully in a second draft, but at least in the final EIS, can FERC please discuss the current standing that GEC has with RCA? Is GEC responsive to RCA concerns/questions? Does FERC have any policy or standard concerning an applicants standing with a State regulatory commission?

Question #7:

Looking over the U. S. Army Corps of Engineers (ACOE) Letter Report on Small Scale Hydropower For Gustavus, Alaska, dated June 1984, I note that the total price of diesel fuel delivered to Gustavus in June of 1983 was $1.36 per gallon. I also note that the total price of diesel fuel delivered to Gustavus in September of 2003 was $1.39 per gallon. Can FERC please verify this information and if true, explain why the total price of diesel fuel delivered to Gustavus has only gone up by 3 cents over the last 20 years? This information would at least be noteworthy when attempting to look ahead to the next 20 years of diesel fuel costs. Please understand that "delivered to Gustavus" cost is not necessarily the price the Gustavus Dray sells fuel to GEC for. It would be good to discuss the relationship between

the Gustavus Dray and GEC. This relationship plays a dynamic role in diesel fuel costs and thus the price per kWh for Gustavus power consumers.

Question #8:

Also in the 1984 ACOE report I note that a similar hydroelectric project at Falls Creek was estimated to cost $7,958,000. which is nearly twice as much as GEC is estimating their cost to be, 20 years later. Given the track record of cost overruns in these types of projects, can FERC please explain why there is such a difference in the estimated cost of these similar projects? Can FERC please discuss the record of cost overruns for these types of projects?

Thank you for considering my comments.

Sincerely,

Jed Davis

Jed Davis
P.O. Box 73
Gustavus, AK 99826

ORIGINAL

December 24, 2003

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2004 JAN -2 P 2:52

FEDERAL ENERGY
REGULATORY COMMISSION

Magalie R. Salas, Secretary
Federal Energy Regulatory Commission
888 First Street NE
Washington, DC 20426

Re: FERC Project No. 11659-002

Dear Ms. Salas,

I am extremely alarmed to learn about the proposed hydroelectric power project in Glacier Bay National Park and worse yet, in a wilderness area of the Park. Glacier Bay is one of the crown jewels of the world's most beautiful natural places and, not surprisingly, one of the most sought-after tourist destinations (I being one of them). Also, building a hydroelectric project in a wilderness area undercuts the whole purpose of wilderness area designations. Please use your considerable influence to veto this project. We owe it to future generations to save these truly priceless areas of the planet.

Sincerely,

Clifford E. Anderson

Clifford E. Anderson
1408 La Sierra Dr.
Sacramento, CA 95864

ORIGINAL

2 Jan 04

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2004 JAN -5 A 9:11

FEDERAL ENERGY
REGULATORY COMMISSION

Magalie R. Salas, Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C.
20426

RE: P-11659-002

Sirs:

This letter concerns the Alaska Falls Creek Hydroelectric Project and Land Exchange (Project # 11659-002). As citizens we have three things to say.

1). A comparison of this Hydro Proposal with a hypothetical similar proposal would be helpful. Let's imagine that an enterprising businessman somehow managed to get a law passed by the U.S. Congress that allowed him to build a road into Yellowstone National Park to one of its 300 (or so) waterfalls, dam it up, install a hydro-generator, build power lines to the outside, and sell the electricity for his personal profit. Since he is smart enough to get this law passed in the first place, he knows that damming up Yellowstone Falls would not work out ... public outcry would not let it happen. So he goes for one of the remote falls. Could he pull it off? It's unlikely ... public outcry would eventually stop it. But that is precisely what is happening in Glacier Bay National Park ... except the falls (Falls Creek) are remote enough that the general public is unaware of what is happening. Our national parks are national treasures, they belong to all citizens, and most certainly should not be destroyed by businessmen for personal profit.

2). Gustavus is an ideal location for a fuel cell power plant. One hundred years from now, give or take, everything in the world will be run by fuel cells. All technical people see this coming. Fuel cell technology is now at about the same stage of development as were computers in the 1950s. Hundreds of scientific papers appear in the journals each year and many companies are now manufacturing fuel cells for different applications. Fuel cells use a "front end reformer" to convert the supplied fuel into hydrogen and waste gases, and then use the hydrogen to make electrical current. Since there are no moving parts in these devices, they are extremely reliable, extremely efficient, and the chemistry is such that no pollutants are emitted. A power company in Anchorage has installed some "first generation " fuel cell units, manufactured by FCI Corp. Siemans-Westinghouse has under construction a manufacturing plant near Pittsburgh that will start turning out "second generation" units by the fall of 2004. These units are modular and so can be easily expanded to fit the need of a growing town like Gustavus. The S-W units are designed to accept natural gas as the fuel. Gustavus has no natural gas, but this is not a serious problem because there are a number of companies, e.g. Plug Power Inc., that specialize in making "front end reformers" that accept propane as fuel.

Additionally, the Gustavus Electric Company is located only several hundred yards from the town school, the town library, the U.S. Post Office, and the airport. Thus it would make good financial sense for GEC to sell the waste heat from a fuel cell installation to these buildings. This would increase the GEC profit by a substantial amount.

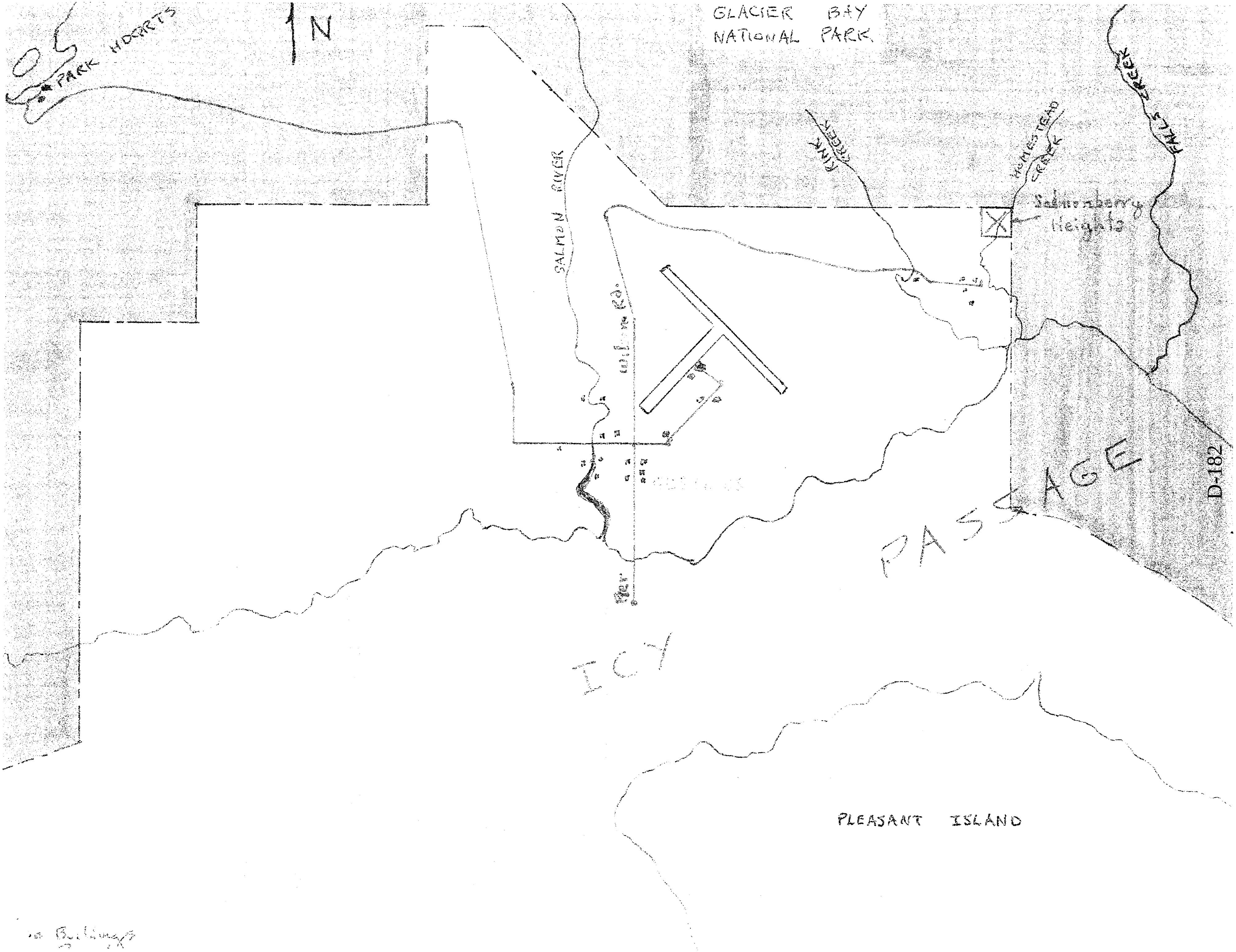
3). We own a unique 40 acre property in Gustavus. We call it Salmonberry Heights. Its location is shown on the enclosed map.

As seen on the map, this property shares two of its boundaries with the National Park. A beautiful stream that comes out of the Park flows diagonally through the property. The property has several springs on it, and a pristine grassy meadow with abundant blueberry growth. Bear, moose, martin and other local wild life are frequent visitors to the meadow. At present this meadow is accessible only by an ATV trail. Many people in the world dream of having a "wilderness" cabin in a place like this. Conversations with realtors in Los Angeles and Chicago who specialize in wilderness properties indicate that this 40 acres is worth several million dollars. The GEC plan includes the construction of a heavy equipment road alongside or near this parcel. Such a road, and the heavy equipment moving along it, would completely destroy the wilderness value of this parcel. If this should happen, we shall file a law suit against GEC in an effort to collect damages.

Sincerely,

Professor and Mrs. Glen Schrank
25202 Butler Rd. P.O. Box 253
Junction City, OR 97448 Gustavus, AK 99826

glens@darkwing.uoregon.edu


N
PARK HQRTS
GLACIER BAY
NATIONAL PARK
SALMON RIVER
RINK CREEK
HOMESTEAD CREEK
FALLS CREEK
Salmonberry
Heights
Pier
ICY PASSAGE
PLEASANT ISLAND
Buildings

STATE OF ALASKA

OFFICE OF THE GOVERNOR
ANILCA IMPLEMENTATION PROGRAM

FRANK H. MURKOWSKI
GOVERNOR

550 W. 7TH AVENUE, SUITE 1660
ANCHORAGE, ALASKA 99501
PH: (907) 269-7477 / FAX: (907) 269-3981
Sally_Gibert@gov.state.ak.us

January 6, 2004

Magalie R. Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Dear Secretary Salas:

The State of Alaska has reviewed the draft environmental impact statement (DEIS) for the Falls Creek Hydroelectric Project and Land Exchange (FERC Project No.11659-002). This letter represents the consolidated views of the State of Alaska resource and transportation agencies. The Alaska Energy Authority is commenting separately on the economic aspects of this project; and the Alaska Department of Fish and Game is submitting separate comments pursuant to Section 10(j) of the Federal Power Act –16 USC 803(j).

The Federal Energy Regulatory Commission should also be aware that the State of Alaska has not yet conducted its coastal zone management review. This review will be conducted by the Alaska Department of Natural Resources, Office of Project Management & Permitting, after all resource agency authorization applications and supporting documents have been received, per 15 CFR 930.50 - 930.66 and 6 AAC 50.425.

Specific Issues

Acreage determinations – The DEIS provides for the following acreage amounts:

	Alternatives	Land Trade Area	FERC Project Area
1.	No Action Alternative	0 acres	0 acres
2.	Proposed Alternative	850 acres	117 acres
3.	Maximum Boundary Alternative	1145 acres	1145 acres
4.	Corridor Alternative	680 acres	680 acres

However, because the project area includes private or state land (specifically the transmission line and a portion of the access road) outside of the Glacier Bay park boundary, the land trade area and the project area should be different by that amount. This needs to be corrected for both alternative 3 & 4 and possibly for alternative 2.

We request the DEIS clarify how the figure of 117 acres in the Proposed Alternative is derived, e.g., the dimensions of the easement, the haul back site, the powerhouse site, and the diversion structure site.

Ownership – The western portion of the project area (sections 3, 9 and 10) crosses both private & state land as indicated in Figures 2-1, 2-8, & 2-9. It would be helpful to separately illustrate state and private ownership in these figures. The state ownership in this area involves multiple jurisdictions. The Mental Health Trust Land Office manages the NE ¼ of Section 9 (as well as portions of Section 4); the rest of Section 9 is within the boundary of the Gustavus Airport and is managed by the Department of Transportation and Public Facilities. In addition it would be helpful to label the township/range/sections and differentiate between national park lands, other private land, and tide and submerged lands (land below mean high water) which all appear in white in the figures.

Access across Private Land – The portion of Rink Creek Road and the access road extending through section 3 crosses private land; the State of Alaska does not hold an easement across these parcels. In conjunction with the land exchange, the State of Alaska will need to obtain legal access across section 3 from Rink Creek Road to the Access Road in Section 2. This should be granted as a limited state holding (easement) from the private land owner(s) to the State of Alaska. This limited state holding does not necessarily have to be generally open to the public; minimally the easement needs to provide access for the hydro project, and to the State for inspection and maintenance and other uses authorized by the Department of Natural Resources (DNR) and allowed within the FERC license restrictions.

Alternative route for Access Road & Transmission Line – We request the EIS additionally address an alternative access route from Rink Creek Road through the existing 60 foot public access and utility easement of ASLS 790151 & ASLS 790152. This alternate route would reduce the length of easement granted to the State from private land owner(s) from approximately 2 ¼ miles to a mere ¼ mile. The transmission line could then be routed through the Mental Health Trust Land in section 4 to the Airport. This route would also alleviate the congestion at the existing end of Rink Creek Road near Bear Track Inn; however, we recognize it would increase the road construction needs and may not be as desirable due to the geography. At any rate, we recommend analyzing this route, especially if access across private land is going to be an issue.

FERC Project Area Size – The State requests minimizing the FERC project boundary to the smallest area needed for the project as reflected in Alternative 2. Alternative 3 and 4 equate the FERC project boundary with the entire land exchange area and makes all land in the exchange subject to FERC license conditions. All of the state acquired land would then be encumbered with the restrictions and conditions of the FERC license including a public access & recreation development plan, and a land use management plan, amongst others. It is unclear what the process would be to arrive at these plans and what latitude the State of Alaska would have to manage these acquired lands into the future if the exchanged lands were entirely within the FERC project area and subject to the licensing conditions.

A larger project boundary would have other affects as well. First, the FERC license would in effect restrict the title to the land and this would have the probable affect of reducing the appraised value of the land, in turn reducing the amount of land transferred from the State of Alaska to the National Park Service. Second, it would make the most sense for DNR's land use authorization(s), issued to Gustavus Electric Company, to encompass the same area as the FERC project boundary. This means the larger the FERC project area the larger the DNR authorization. DNR bases its land use fees on either the appraised value of the land or a per acre basis depending on the type of the land use authorization; the larger the project area the larger the land use fee.

Further, the State prefers the land ownership and exchange approach contained in the Gustavus Electric Company (GEC) proposed alternative. The maximum boundary alternative requires DNR to acquire more land than is necessary in our view for a park 'buffer' area. In addition, the corridor alternative creates blocks of isolated lands which can be challenging to manage and could potentially cause future management issues between DNR and NPS.

Land Use Fees and other costs – The economic analysis should incorporate land use fees associated with state and non-state lands. For land owned by the State and managed by DNR's Division of Mining, Land & Water, the land use fees for a lease or a private, exclusive use easement are based on the appraised fair market rental value; and a private, non-exclusive use easement costs $100 per acre (minimum $200). Other costs include material sales, performance guarantees, and survey and appraisal costs. These costs plus the costs associated with the Mental Health Trust Lands and private land owners should be included in the economic analysis.

Land Use Management Plans – We request the procedures used to develop and implement the Land Use Management Plans be clarified before a decision is made. For example, will the plans be a part of the FERC license or will they be conditioned by reference? As the underlying fee owner-to-be, how will the State be involved in these planning actions? Will the management responsibility be shared with FERC & GEC, and how will they be implemented and enforced? It appears as if GEC is the lead on these planning processes but how will the planning process be mediated? Will the process be public? Can the planning decision be appealed, and if so, to whom?

If the State of Alaska agrees to exchange this land with planning encumbrances to develop recreation, access, and land use management plans, will GEC pay for some or all of the additional time and resources needed for follow up? Have these costs been included in the economic analysis?

Use of Airport Property – The Alaska Department of Transportation and Public Facilities (DOT&PF) has no objection to the project's use of state property at the Gustavus Airport as long as the proposed transmission line is buried across airport property – See Figure 2-2 on page A-10. Please be aware that the project is subject to utility permits from the DOT&PF for airport property use and transmission line burial will be stipulated.

Exchange timeline – A six month deadline for the exchange to occur is unrealistically optimistic given the need to appraise and survey lands. When authorizing land uses that require appraisals and surveys, DNR usually provides 18-24 months for conduct and review before an authorization is issued. In our experience, land exchanges can be even more cumbersome. Therefore to meet the requirements under the Glacier Bay National Park Boundary Adjustment Act of 1998 it may be required to begin appraisals and surveys prior to issuance of the FERC License. The time lag between the Final EIS/Record of Decision and issuance of the FERC License may address this concern by providing the time necessary to negotiate and process the various planning requirements, such as the Land Use Management Plan.

Page-Specific Comments

xxix, lines 10-11 & 24-26. The top paragraph says that GEC proposes to limit access to non-motorized recreation. The next paragraph says that additional recreational opportunities such as ATV's could provide a positive experience for visitors. If non-motorized recreation is proposed in the preferred alternative, how could a motorized vehicle such as an ATV be used? We suggest deleting specific references to ATVs from this section and thus deferring ATV use to the subsequent Land Use Management Plan.

xxxii, line 10. Missing word: …would <u>be</u> the…

1-12, line 4-6. This states that FERC would retain authority and it is exempt from the Energy Act of 2000. Does this mean that at no time in the future the State of Alaska could be given management over the Hydro license?

1-12, line 9. The reference to "Section 3(b)(4)," should be corrected to read "Section 3(c)(4)."

1-12, line 8-12. Section 3(c)(4) indicates that a condition of the FERC license is that the land exchange needs to be completed prior to construction and operation, but it doesn't say that if it is never constructed the land exchange would revert back. DEIS statements that the boundary adjustment and the construction & operation are <u>contingent upon each other may inadvertently imply that</u> the exchange would be reversed if the FERC License is issued and then construction and operation did not come to fruition. We agree that the construction and operation is contingent upon the boundary adjustment happening first; however, 3(c)(4) does not seem to indicate that the boundary adjustment is contingent upon construction and operation of the hydro facility. To address this concern, perhaps a condition of the FERC license should be a posting of a performance guarantee prior to the occurrence of the land exchange to provide for certainty of construction once the exchange occurs.

2-5, line 30-32. The right of way easement width should be classified. The text only suggests the width needed for clearing not the actual land use authorization. Standard widths for road easements are typically 60 or 100 feet.

4-82, 83, Table 4.6-3. It would be helpful to also show this table as a multiple line graph, so that the changes in "weighted useable area" (WUA) %s per unit of change in discharge can be observed from the curve gradients. Such a graph (unlike the table) would use a constant unit interval on the discharge axis, or at least indicate any change in discharge interval values (2 cfs, 5 cfs, 10 cfs, 20 cfs).

4-85, 86, Tables 4.6-5 and 4.6-6. These tables could be read to imply that the frequency of flows of less than 5 cfs would increase under the GEC proposed flow regime as compared to the No-action scenario. The percentages under the columns headed "% Time Flow is 5 cfs or less" apparently include the percentage of time the flow would be exactly 5 cfs, which would increase because of the required bypass flow. However, since the GEC proposed flow regime would require an minimum instream flow of 5 cfs, increased frequencies of lesser flows would not be expected. This should be noted, or less misleading column headings used.

4-86, lines 5-11. These paragraphs misleadingly imply increased percentages of time of flows of less than 5 cfs under all of the proposed or recommended flow regimes. Lines 10 and 11, which explicitly refer to flows "in the 0 to 5 cfs range" imply that this range of flows would increase in percentage of time in the winter, although the only increase in this range would be at its upper extreme, except under the no minimum flow scenario.

4-87, lines 7-11. The first sentence in this paragraph is not correct, since under the U.S. Fish and Wildlife Service and ADF&G-recommended scenarios, diversions could not occur at stream flows of less than 10 cfs; therefore, the percentage of time of these lesser flows would not increase over the No-action scenario. The last sentence in this paragraph is literally true, but misleadingly implies that a 10 cfs winter minimum is required to prevent increases in percentage of time for flows in the 0-5 cfs range. Actually, under the 10 cfs winter minimum, flows in the entire range of 0-9.99 cfs, not just the 0-5 cfs range, would not increase in percentage of time.

4-93, line 29. The Swan Lake project near Ketchikan is constructed on Falls Creek, not on the Kahtaheena River.

4-94, lines 18-20. This sentence is misleading in that the percentage increase of time this range of flows would be experienced is true only for its upper extreme of 5 cfs, not for lesser flows of 0<5 cfs.

4-197, line 20-22. The DEIS states that once construction is completed, traffic along Rink Creek Road would resume to pre-project levels with the addition of weekly trips by GEC staff. We request that the projected increase in traffic related to recreation be recognized in this context.

Thank you for the opportunity to provide these comments. If you have any questions, please fell free to contact this office.

Sincerely,

/ss/

Sally Gibert
State ANILCA Coordinator

cc: Tomi Lee, Superintendent, Glacier Bay National Park and Preserve

STATE OF ALASKA

FRANK H. MURKOWSKI, GOVERNOR

DEPARTMENT OF FISH AND GAME

DIVISION OF SPORT FISH

Research and Technical Services
333 Raspberry Road
Anchorage, AK 99518-1599
Phone: (907) 267-2369
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January 6, 2004

Honorable Magalie R. Salas, Secretary
Office of the Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Dear Secretary Salas:

Re: Falls Creek Hydroelectric Project and Land Exchange, FERC No. 11659-002
Recommendations and Comments on the Draft Environmental Impact Statement

Thank you for providing the Alaska Department of Fish and Game (ADF&G) the opportunity to comment on the October 2003 draft environmental impact statement (DEIS), developed jointly by the Federal Energy Regulatory Commission (FERC) and the National Park Service (NPS). We are providing these recommendations and comments regarding fish and wildlife resources pursuant to Section 10(j) of the Federal Power Act.

In addition to ADF&G's comments in this letter, I have attached correspondence from the Alaska Department of Natural Resources' Office of Habitat Management and Permitting (OHMP). OHMP issues fish habitat permits for the State of Alaska pursuant to AS 41.14.870 and AS 41.14.840. The January 5, 2004 attachment addresses this project. Questions regarding the state fish habitat permit should be directed to Moira Ingle (907) 465-4275.

ADF&G General Comments

Most issues presented in our August 9, 2002[1], letter responding to FERC's Notice of Intent to Prepare Environmental Impact Statement are addressed in the DEIS. However, several outstanding issues require further attention, as follows:

3.6.3.6 Resident Dolly Varden Char – (pages 3-38 thru 3-43) We suggest that resident Dolly Varden char population estimates (and values derived from these estimates to assign population numbers to unsampled reaches) be used with caution in the analysis of effects of project alternatives on fish. Habitat in the proposed bypass reach was inventoried very thoroughly and the type and area of habitat affected may be evaluated with confidence. However, population

[1] Letter from Clayton Hawkes, ADF&G to Secretary Salas, FERC dated August 9, 2002.

estimates were conducted for only small areas at one point in time. Numbers of fish in sampled and unsampled reaches can only be guessed at to within an order of magnitude of precision. This is not adequate for drawing conclusions regarding the numbers of affected fish.

4.6.2.1 Effects of Construction and Operation – Habitat Effects – *Effects of Diversion on Stream Habitat Characteristics* - (pages 4-82 thru 4-88)

The shortcomings of the PHABSIM study (calibration flows, number of transects, habitat suitability criteria) described in the DEIS (page 4-85, lines 14-22) and in our February 1, 2002 letter[1], limit the reliability of the PHABSIM model. We do not believe FERC/NPS gave enough consideration in their review to these factors. In our February 1, 2002 correspondence to FERC[2], we commented that incorrect predictions can occur from: exceeding the accuracy and resolution of input variables, violating model assumptions, or predicting results outside the appropriate simulation range based on hydraulic calibration results.

Based on calibration results and Gustavus Electric Company's (GEC) measured calibration flows of approximately 22 cfs and 45 cfs, U.S. Fish and Wildlife Service (USFWS) and ADF&G commented that PHABSIM would normally only be able to accurately simulate a range of flows between 10 and 100 cfs (USFWS letter dated January 22, 2001[3] and ADF&G by letters dated May 11, 2001[4] and February 1, 2002[1]). In addition, the developers[5] of PHABSIM have stated very clearly in their training sessions that PHABSIM should not be extrapolated beyond the limitations of the model based on review of the calibration data.

Based on numerous papers and reviews of the PHABSIM methodology, we are unaware of any new techniques for using PHABSIM results outside the above referenced and recommended extrapolation limits. Therefore we cannot understand the technical basis for FERC/NPS's use of PHABSIM results outside the referenced extrapolation limit. We therefore request clarification from FERC/NPS for using simulation results outside this range. If use beyond the standard range limitation cannot be justified or was inadvertent by FERC/NPS, we recommend FERC/NPS convene a meeting with PHABSIM technical experts (including fish and wildlife agency experts) with expertise in application and limitations of PHABSIM modeling and analyses. Assuming this is necessary, we recommend this technical panel be requested to agree upon an acceptable flow analysis in as timely a manner as possible to minimize any potential delays in the licensing process for the applicant. We also recommend the applicant be kept informed of our technical concern regarding the validity of the use, analyses, and conclusions related to the FERC/NPS PHABSIM study.

Entrainment, Impingement, and False Attraction of Fish – (pages 4-89 thru 4-91) Facilities for excluding fish from the penstock and providing fish passage downstream into the bypassed reach

[2] Letter from Clayton Hawkes, ADF&G to Secretary Boergers, FERC dated February 1, 2002.
[3] Letter from Steve Brockmann, USFWS to Bruce Greenwood, NPS dated January 22, 2001 (we believe it was mistakenly dated 2001 and should have been dated 2002.
[4] Letter from Clayton Hawkes, ADF&G to Dick Levitt, GEC dated May 11, 2001. Note: the lower limit of 12 cfs described in the May 11, 2001 letter was later reduced to 10 cfs based on further review.
[5] U.S Geological Survey, Biological Resources Division, Midcontinent Ecological Science Center, Fort Collins, Colorado.

are proposed. However, the alternative of no instream flow requirement in the bypassed reach is not evaluated in this section. If no instream flow is provided, facilities must be properly designed to prevent impacts to fish (e.g. allowing fish that enter the intake forebay to avoid impingement and be able to navigate upstream out of the forebay area) (Intake Plan, page A-15).

6.1.1.1 Comprehensive Development - Minimum Flows – (pages 6-6 thru 6-8) FERC staff base their recommendations for instream flows in the proposed bypassed reach on the premise that, although resident Dolly Varden in the bypassed reach would be reduced under GEC's proposed flows (and "essentially lost" under the no flow scenario), the portion of the population unaffected by the project and persisting upstream of the diversion would allow the population of Dolly Varden to persist and therefore be available for scientific study by park personnel and other interested researchers. ADF&G fisheries managers are mandated to protect and manage Alaska's fish and wildlife resources on the sustained yield principle. Persistence and availability for study are not adequate criteria on this basis. We therefore disagree with the use in the DEIS of these criteria as adequately addressing the effect of the proposed project on the resident Dolly Varden in Falls Creek. We suggest, instead, that proposed project alternatives be evaluated based on the sustained yield principle.

ADF&G Specific Comments

Page 4-30, Table 4.4-1. The table should also include NPS-Rivers, Trails, and Conservation Assistance Program's proposed flows for aesthetic resources described under section 4.11 (pages 4-142 to 4-145)

Page 4-79, Line 24. Description of the length of the bypassed reach needs to be reconciled throughout the document (e.g. page 4-80, line 11 describes bypass length as 1.8-mile, etc.).

Page 5-1, 1st and 3rd paragraphs. Discussions in these two paragraphs should be clarified in order to explain a potential contradiction. The first paragraph states "…that the proposed land exchange required to construct the Fall Creek Hydroelectric Project cannot occur until the Commission determines that construction and operation of the project can be accomplished in an economically feasible manner." However, the third paragraph states "If the Commission issues a license for a project with negative net benefits based on the Commission's method of analysis, it is up to the licensee to make the business decision of whether or not to accept the license and build, or continue to operate the project based on its own financial analysis and business requirements."

Page 5-11, Table 5.3-2, footnote "e". This footnote is not referenced anywhere in Table 5.3-2 and further clarification is needed. The footnote states that "FERC staff recommends instream flows of 8 cfs January through March, 15 cfs April through September, 20 cfs in October, 15 cfs in November, and 8 cfs in December" whereas, on page 6-3 (lines 29-31) FERC recommends to "Operate the project in a run-of-river mode, and provide minimum instream flows in the bypassed reach of at least 5 cfs from December through March and 7 cfs from April to November." Clarification is needed on which alternative is the FERC staff recommendation.

Please contact me at 907-267-2148, or Kevin Brownlee at 907-465-4276, if you have any questions.

Sincerely,

Joe Klein
Statewide Instream Flow Coordinator

cc:
K. Hepler, ADF&G/SF HQ-Juneau *
R. Bentz, ADF&G/SF HQ-Juneau *
C. Estes, ADF&G/SF/RTS-Anchorage *
R. Holmes, ADF&G/SF-Juneau *
W. Regelin, ADF&G HQ-Juneau *
D. Larsen, ADF&G/WC-Douglas *
A. McGregor, ADF&G/CF-Juneau *
M. Turek, ADF&G/Subsistence-Juneau *
T. Cunning, ADF&G/CO-Anchorage *
R. Willis, ADF&G/WC-Anchorage *
D. Vincent-Lang, ADF&G/SF HQ-Anchorage *
B. Clark, ADF&G/SF/RTS-Anchorage *
B. Glynn, ADF&G/SF-Juneau *
N. Barten, ADF&G/WC-Juneau *
J. Klein, ADF&G/SF/RTS-Anchorage *
K. Monagle, ADF&G/CF-Juneau *
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T. Davis, ADF&G/HQ-Juneau *
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S. Gibert, ADNR-Anchorage
J. Dunker, ADNR-Juneau *
R. Enriquez, USFWS-Juneau *
L. Shaw, NMFS-Juneau *
C. Soiseth, NPS-Gustavus *
C. Thomas, B. Greenwood, N. Deschu, NPS-Anchorage *
B. Easton, FERC Washington, D.C.
R. Levitt, GEC-Gustavus
D. Belton, Hoonah Indian Association
B. Lindekugel, SEACC-Juneau *
J. Konigsberg, TU-Anchorage *

* e-mail

MEMORANDUM

Department of Natural Resources

STATE OF ALASKA

Office of Habitat Management
and Permitting

TO:	Joe Klein ADF&G Division of Sport Fish	DATE:	January 5, 2004
		TELEPHONE:	465-4275
FROM:	Moira Ingle Area Manager DNR Office of Habitat Management & Permitting	SUBJECT:	Falls Creek DEIS FERC No. 11659

The Office of Habitat Management and Permitting (OHMP) has reviewed the Draft Environmental Impact Statement (DEIS) for the Falls Creek Hydroelectric Project (FERC No. 11659) and Land Exchange. We offer the following comments for incorporation into ADF&G's comments to FERC. We expect to have additional comments for the Alaska Coastal Management Plan review of this project, which will occur at a later time.

Regardless of the alternative selected, the project as proposed would affect fish populations and fish passage in the Kahtaheena River, also known as Falls Creek. Falls Creek has been specified pursuant to AS 41.14.870 as anadromous stream number 114-23-10220, and is catalogued as important for the spawning, rearing and migration of pink salmon. As outlined in the DEIS, coho and chum salmon, as well as both anadromous and resident populations of Dolly Varden char, also have been documented to occur in the stream. Construction and operation of the Falls Creek Hydroelectric Project will require a Fish Habitat permit from OHMP pursuant to AS 41.14.870 and 41.14.840. The permit will probably include a stipulation limiting blasting overpressures because of the proposed blasting associated with road building in "The Canyon" section. Fish Habitat permits also may be required for culverts crossing any anadromous or resident fish-bearing streams along the access road.

According to the DEIS, effects of the project on anadromous fish are expected to be limited primarily to additional inputs of sediment during construction and minor increases during operation, which are proposed to be minimized through implementation of construction BMPs and an Erosion and Sediment Control Plan. OHMP appreciates the measures agreed to by the applicant, such as end-hauling and other measures to reduce the potential for mass wasting and slides in possibly unstable areas.

Regardless of the instream flow requirements imposed as part of the FERC license, the reach supporting anadromous fish is not expected to be measurably affected by any change in the flow regime or by water quality or temperature changes. The water diverted for power production would be returned to the river at the base of the Lower Falls, which is the upper extent of the anadromous reach.

The main effects of the project would be on resident Dolly Varden char in the reach of the stream bypassed by the power project. Diversion of flow for power production would cause habitat changes in approximately one-third of the Dolly Varden habitat in the river, including 58 percent of the available pools, which is habitat preferred by Dolly Varden. The DEIS estimates that this section of river supports approximately 15 percent of the total resident population of Dolly Varden (950 fish of a total population of 6,500 fish). Depending on the instream flow regime selected for the project, diversion of flows would probably result in the loss of at least some and possibly all of the fish in the bypass reach. The principal cause of this loss would be inadequate flows in winter.

OHMP supports the recommendation of ADF&G regarding an instream flow regime for Falls Creek. The ADF&G recommended regime would maintain a minimum flow of at least 10 cfs throughout the winter months. This level is slightly below the lowest measured flow of 12 cfs, and would likely maintain adequate water in the reach to provide for overwintering habitat. The DEIS discusses populations of Dolly Varden elsewhere in Southeast Alaska and other regions of Alaska that exist in small streams with marginal habitat. These populations appear to survive under winter conditions of reduced flow, "as long as there are refuge areas that provide adequate conditions for overwintering" (page 4-93). The DEIS also makes the case, however, that much of the bypass reach consists of a series of cascades and chutes, many of which may be a barrier to upstream passage. It appears that Dolly Varden are concentrated in the lower portion of the reach, in the "Logjam" area, and thus would probably not be able to move to other refuge areas during periods of sustained low flows, such as proposed by the applicant (a 5-cfs winter regime).

The applicant has also requested analysis of a "no minimum flow" alternative, primarily for economic reasons. The DEIS states that this flow regime would have a high probability of eliminating all the fish using the bypass reach, to the point that the reach would no longer support a viable, self-sustaining population. The DEIS points out that the reach upstream from the diversion point would not be affected by the project, and would continue to serve as a "source" population for the bypass reach.

This scenario should be examined in detail in the Final EIS as well as in the Fish Passage Effectiveness Plan proposed by ADF&G and the U.S. Fish and Wildlife Service. Because of our statutory obligation to address fish passage issues, OHMP requests that our office be included in agency reviews of this document when it is prepared. The applicant currently proposes to construct a screen and bypass facility at the diversion point that would allow downstream passage of fish through the bypass reach, to continue to contribute genetically to downstream populations. A bypass design would likely be acceptable if there is adequate flow in the bypass reach to support fish as they move downstream. If the no-minimum-flow option is selected, however, it may not be desirable to allow fish to move downstream if the remaining habitat is inadequate to support them. OHMP requests that this scenario be analyzed in the FEIS, including an assessment of the costs associated with construction of a bypass reach versus a structure to block downstream passage of fish.

OHMP also requests that we be involved in discussions concerning mitigation for blockage of fish passage and impacts to the Dolly Varden population associated with the project, particularly if either the 5/7 cfs or the no-minimum-flow regime is selected.

Thank you for the opportunity to comment. If you have any questions, please call me at 465-4275.

Sincerely,

Moira Ingle
Area Manager

Cc: Al Ott, OHMP, Fairbanks*
Kerry Howard, OHMP, Juneau*
Kevin Brownlee, ADF&G, Douglas*
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January 5, 2004

Mr. Peter Crimp
Alaska Industrial Development and Export Authority
813 West Northern Lights Blvd.
Anchorage, Alaska 99503

Dear Peter:

Pursuant to your request, I have reviewed the Draft Environmental Impact Statement ("DEIS") issued by the Federal Energy Regulatory Commission ("FERC") regarding the proposed Falls Creek Hydroelectric Project ("Falls Creek" or the "Project"). The following provides a summary of this review.

DRAFT ENVIRONMENTAL IMPACT STATEMENT

The DEIS issued by FERC provides a very limited analysis of the Project which can be misleading and lead to erroneous conclusions. Furthermore, there are certain flaws in the analysis that lead to an underestimation of Project benefits.

The economic analysis contained in Section 5 of the DEIS is based on a comparison of the annualized Project costs with the initial year displaced costs. Project costs are based on the sum of 1) amortization of project costs using an 8 percent amortization rate, 2) operating and maintenance costs, 3) property taxes, 4) insurance, and 5) federal taxes paid by Gustavus Electric Company ("GEC"). No inflation is used in the projection of the 30-year cost stream. The annualized Project costs are then calculated by determining the annuity that has the same present value as the projected cost stream. The discount factor for both the annuity and present value of annual costs is set at the cost of capital, 8 percent.

The value of power that the annualized Project cost is compared to is simply the variable cost of diesel generation. This is equal to the sum of fuel (based on 13 kilowatt-hours/gallon), provisions for operations and maintenance, and provisions for overhauls. No inflation is assumed. Energy usage is assumed to be the average of a multi-year period, and therefore, the value of power does not change over time.

Discount Rate/Inflation. The analysis described above does not include any inflationary effects yet it uses nominal discount and amortization rates. This implicitly assumes that the real discount rate (the difference between inflation and the assumed rate) is 8 percent, whereas a rate in the 3 – 4 percent range would be more realistic. Since the Project is capital intensive and the alternative cost of power is not, the use of too high of discount rate will bias the analysis toward the alternative source of power.

FERC's base case was re-run using a 3.5 percent real discount and amortization rate. This correction alone increases the net Project benefits increase from -$242,300 to approximately -$130,000.

Although the use of a real discount rate and amortization rate will better approximate the projected benefits, a better method would be to include the effects of inflation for the cost streams that will be affected. The amortization and discount rates should be commensurate with the assumed inflation rate, and the 8.0 percent used by FERC may be too high given current economic and market conditions.

The base case was re-run using a 3.0 percent inflation rate, a 7.0 percent amortization rate, and a discount rate of 8.0 percent. The use of a discount rate higher than the amortization rate reflects the possibility of a small amount of Project costs being financed by GEC equity. In this case, the net benefits of the Project increase from -$242,300 in the DEIS to approximately -$95,000. A discount rate equal to 7.0 percent results in net Project benefits of approximately -$75,000.

FERC acknowledges that inflation should be included in the analysis since the majority of the costs associated with the Project are fixed and not subject to inflation whereas the alternative diesel costs are highly influenced by inflation. However, reference is made to Section 6 and the base case remains as is. Since the base case is referenced in other areas of the report, it would be better to have that case reflective of technically correct assumptions. It is also noted that many of the cases run in Section 6 are without inflation. It is assumed that the discount rates used in these cases are 8.0 percent, which would be an erroneous rate to use.

<u>Diesel Additions</u>. The value of power used throughout FERC's analysis is based simply on the variable cost of diesel generation. Those costs include fuel, provisions for operations and maintenance, and provisions for overhauls. Future additions or replacements to generating plant are not considered. This assumes that GEC's and the National Park's generating plant would be the same with and without the Project, an unlikely scenario.

If the Project is not built, GEC and the Park will need to add new generation to provide adequate generating capacity as loads increase. Even without load growth, new generation would be added at some time in the future to replace units that are retired.

A much different diesel resource configuration will be associated with the Project. New capacity will not be required to meet load growth, and there should be adequate reserves for quite some time. Retirements will not be as much of a factor either since less operating hours will be placed on the units.

The value of power should, therefore, include provisions for the capital costs of diesel units added throughout the study period. A reasonable estimate for the size of generator at GEC would be $150,000 - $200,000 every fifteen years.

Project Operating Costs. The FERC analysis includes provisions for Project operating costs, property taxes, insurance, and federal taxes. Specific reviews of the amounts assumed were not conducted, but the following general items are noted:

- With the construction of the Project, GEC may be able to obtain lower insurance premiums on the existing diesel resources, and this should be reflected in the analysis.
- The payment of federal income taxes is not a cost directly associated with the operations of the Project, and the amount paid by GEC is a bit more complex than simply applying a factor to the net book value of the Project. GEC will also pay federal taxes without the Project, and therefore, it is best left out of the analysis.
- GEC was contacted, and staff explained that there would be no property taxes. Therefore, the $133,080 annual property tax expense assumed by FERC should be elminated.

GEC/Park Interconnection. In order for the Park to use Project power, an interconnection between the GEC and Park systems must be constructed. The length of this interconnection is approximately five miles, and the cost must be considered in the analysis. A reasonable number to use for overhead line construction is approximately $100,000 per mile, or $500,000.

Outlying Year Analysis. In Section 6, FERC investigates the benefits in a single outlying year – 2016. The only function this analysis serves is to determine whether the annual Project costs are less than or greater than the alternative costs. Given the relatively fixed nature of the Project costs, the benefits in outlying years can be quite significant.

Summary. In general, FERC's analysis is very limited in scope and, in some instances, uses the wrong discount rates in calculating the annualized Project costs. Explanations of assumptions used throughout the economic analysis of the DEIS are somewhat vague. It is therefore difficult to replicate their work and to determine which assumptions should be challenged.

For point of reference, an alternative case was run with the following assumptions.

- Capital costs:
  - Project - $4,436,000
  - Interconnection between GEC and Park - $500,000
  - Diesel replacement - $165,000 (2003$) every 15 years
- Annual operating costs of Project equal to:
  - Operations and maintenance - $31,830 (2003$)
  - Insurance - $11,090 (2003$)

- Diesel costs:
  - Fuel efficiency – 13 kWh/gallon
  - Fuel cost - $1.51/gallon (2003$)
  - Variable O&M – 5.51 mils/kWh (2003$)
  - Overhauls – 6.62 mils/kWh (2003$)
- Power requirements – 2,800,000 kWh in 2007 increasing to 3,600,000 in 2016 and constant thereafter. This approximates FERC's mid-range growth scenario with the Park loads included.
- Economic Factors:
  - Amortization period (Hydro) – 30 years
  - Amortization period (Diesel) – 15 years
  - Amortization rate – 7.0 percent
  - Inflation rate – 2.5 percent (applies to all costs above except capital costs of Project)
  - Discount rate – 7.0 percent
  - Study Period – 30 operating years

Economic analyses typically include the capital cost of future additions in the years the expenditures are made without amortization of debt. In this case, however, debt amortization is included in the analysis to incorporate the full effect of diesel replacements over the 30-year study period. Since GEC is economically regulated by the Regulatory Commission of Alaska, its rates will be based on interest on debt and depreciation of capital assets – slightly different from the principal and interest of debt amortization assumed herein.

Based on these assumptions, the present value of costs over a 30-year period are as follows with details provided in Attachment 1.

Diesel	$8,553,384
Project	6,097,602
Project Benefits	$2,455,782

The assumptions described above result in the Project showing a net benefit over the 30-year study period. It is noted that the Project life is expected to be at least 50 years, and inclusion of future benefits, albeit relatively small in net present value terms, would increase the net present value.

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If you have any questions or desire further analysis, please do not hesitate to call or contact me.

Very truly yours,

THE FINANCIAL ENGINEERING COMPANY

Mike Hubbard

MICHAEL D. HUBBARD

Attachment 1

Page 1 of 4

Cost of Capital	7.00%	
Diesel		
Replacement	$165,000	
Repl Interval	15	years
First Year	2007	
Fuel Efficiency	13.00	kWh/gal
Fuel Price	$1.51	
Diesel O&M	5.51	mils/kWh
Diesel Overhauls	6.62	mils/kWh
Hydro		
Project Cost	4,381,520	
Interconnection	500,000	
FERC Betterments	54,480	
Total	4,936,000	
Amortization Period	30	years
Project O&M	$31,830	
Project Insurance	$11,090	

Attachment 1

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
	1	2	3	4	5	6	7	8	9	10
Project Power										
GEC										
Park										
Energy	2,800,000	2,879,289	2,960,822	3,044,665	3,130,882	3,219,540	3,310,709	3,404,460	3,500,865	3,600,000
Without Project										
Capital Additions	182,129	-	-	-	-	-	-	-	-	-
Amortization of Addn's	$ 19,997	$ 19,997	$ 19,997	$ 19,997	$ 19,997	$ 19,997	$ 19,997	$ 19,997	$ 19,997	$ 19,997
Fuel	358,994	378,389	398,831	420,378	443,089	467,027	492,259	518,853	546,884	576,430
O&M	17,037	17,958	18,928	19,951	21,028	22,164	23,362	24,624	25,954	27,357
Overhauls	20,445	21,549	22,714	23,941	25,234	26,597	28,034	29,549	31,145	32,828
Total	$ 416,473	$ 437,893	$ 460,470	$ 484,266	$ 509,349	$ 535,786	$ 563,652	$ 593,023	$ 623,981	$ 656,611
Present Value at 7.0%	8,553,384									
With Project										
Capital Additions	4,936,000	-	-	-	-	-	-	-	-	-
Amortization of Addn's	$ 397,774	$ 397,774	$ 397,774	$ 397,774	$ 397,774	$ 397,774	$ 397,774	$ 397,774	$ 397,774	$ 397,774
O&M	35,134	36,013	36,913	37,836	38,782	39,751	40,745	41,764	42,808	43,878
Insurance	12,241	12,547	12,861	13,183	13,512	13,850	14,196	14,551	14,915	15,288
Total	$ 445,150	$ 446,335	$ 447,549	$ 448,793	$ 450,068	$ 451,376	$ 452,716	$ 454,089	$ 455,497	$ 456,940
Present Value at 7.0%	6,097,602									
Project Benefits (30-year)										
Nominal Dollars	$ (28,677)	$ (8,442)	$ 12,921	$ 35,473	$ 59,280	$ 84,410	$ 110,936	$ 138,933	$ 168,483	$ 199,671
Discounted to 2007 at:										
0% (Nominal Dollars)	$ 8,471,393									
Inflation (2.5%)	$ 5,257,800									
Discount Rate (7%)	$ 2,455,781									

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
	11	12	13	14	15	16	17	18	19	20
Project Power										
GEC										
Park										
Energy	3,600,000	3,600,000	3,600,000	3,600,000	3,600,000	3,600,000	3,600,000	3,600,000	3,600,000	3,600,000
Without Project										
Capital Additions	-	-	-	-	-	263,777	-	-	-	-
Amortization of Addn's	$ 19,997	$ 19,997	$ 19,997	$ 19,997	$ 19,997	$ 28,961	$ 28,961	$ 28,961	$ 28,961	$ 28,961
Fuel	590,840	605,611	620,752	636,271	652,177	668,482	685,194	702,324	719,882	737,879
O&M	28,040	28,741	29,460	30,197	30,951	31,725	32,518	33,331	34,165	35,019
Overhauls	33,649	34,490	35,352	36,236	37,142	38,070	39,022	39,998	40,998	42,022
Total	$ 672,526	$ 688,839	$ 705,561	$ 722,700	$ 740,267	$ 767,239	$ 785,695	$ 804,614	$ 824,005	$ 843,881
With Project										
Capital Additions	-	-	-	-	-	-	-	-	-	-
Amortization of Addn's	$ 397,774	$ 397,774	$ 397,774	$ 397,774	$ 397,774	$ 397,774	$ 397,774	$ 397,774	$ 397,774	$ 397,774
O&M	44,975	46,099	47,252	48,433	49,644	50,885	52,157	53,461	54,798	56,168
Insurance	15,670	16,062	16,463	16,875	17,297	17,729	18,172	18,627	19,092	19,570
Total	$ 458,419	$ 459,935	$ 461,489	$ 463,082	$ 464,715	$ 466,389	$ 468,104	$ 469,862	$ 471,664	$ 473,512
Project Benefits (30-year)										
Nominal Dollars	$ 214,107	$ 228,904	$ 244,071	$ 259,617	$ 275,552	$ 300,850	$ 317,592	$ 334,752	$ 352,341	$ 370,370

Attachment 1

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
	21	22	23	24	25	26	27	28	29	30
Project Power										
GEC										
Park										
Energy	3,600,000	3,600,000	3,600,000	3,600,000	3,600,000	3,600,000	3,600,000	3,600,000	3,600,000	3,600,000
Without Project										
Capital Additions	-	-	-	-	-	-	-	-	-	-
Amortization of Addn's	$ 28,961	$ 28,961	$ 28,961	$ 28,961	$ 28,961	$ 28,961	$ 28,961	$ 28,961	$ 28,961	$ 28,961
Fuel	756,326	775,234	794,615	814,480	834,842	855,713	877,106	899,034	921,509	944,547
O&M	35,894	36,792	37,711	38,654	39,620	40,611	41,626	42,667	43,734	44,827
Overhauls	43,073	44,150	45,254	46,385	47,545	48,733	49,951	51,200	52,480	53,792
Total	$ 864,254	$ 885,137	$ 906,541	$ 928,480	$ 950,968	$ 974,019	$ 997,645	$ 1,021,862	$ 1,046,685	$ 1,072,128
With Project										
Capital Additions	-	-	-	-	-	-	-	-	-	-
Amortization of Addn's	$ 397,774	$ 397,774	$ 397,774	$ 397,774	$ 397,774	$ 397,774	$ 397,774	$ 397,774	$ 397,774	$ 397,774
O&M	57,572	59,011	60,486	61,998	63,548	65,137	66,766	68,435	70,146	71,899
Insurance	20,059	20,560	21,074	21,601	22,141	22,695	23,262	23,844	24,440	25,051
Total	$ 475,405	$ 477,346	$ 479,335	$ 481,374	$ 483,464	$ 485,606	$ 487,802	$ 490,053	$ 492,360	$ 494,724
Project Benefits:										
Nominal Dollars	$ 388,849	$ 407,791	$ 427,206	$ 447,106	$ 467,504	$ 488,412	$ 509,843	$ 531,809	$ 554,325	$ 577,403

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January 6, 2004

Magalie R. Salas, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Gustavus Electric Company, Falls Creek Hydroelectric Project (P-11659-002)

Dear Secretary Salas:

Intervenors Sierra Club, Trout Unlimited, American Rivers, National Parks Conservation Association, Glacier Bay's Bear Track Inn, The Wilderness Society, Hoonah Indian Association, Thomas L. Mills, Sr., and Patrick G. Mills, and Intervenor-Movants Sophie McKinley and Dianne McKinley, respectfully file these comments on the Draft Environmental Impact Statement: Falls Creek Hydroelectric Project and Land Exchange (October 2003) (DEIS).

COMMENTS

Gustavus Electric Company (GEC) seeks the extraordinary privilege of constructing and operating the Falls Creek Hydroelectric Project in the Glacier Bay National Park and Preserve (GBNPP). No such project now operates in a National Park in Alaska, and Congress has granted a comparable privilege on only one or two occasions in other States. Notwithstanding Federal Power Act (FPA) section 3(c), 16 U.S.C. § 796(2), which prohibits the licensing of a hydropower project in a National Park, the Glacier Bay Boundary Adjustment Act of 1998 authorizes the Commission and the National Park Service (NPS) to consider and grant GEC's license application, and to effect the exchange of park lands which the project would occupy, respectively, if certain conditions are met.

We commend OEP and NPS for their generally thorough and fair analysis of the environmental and economic impacts of the Action Alternatives set forth in the DEIS. Our comments address significant errors or omissions, including the failures to reach any ultimate conclusion whether the project complies with the conditions of the Boundary Adjustment Act, or to make any recommendation for approval or disapproval (p. 6-1). We organize our comments roughly according to the chapter outline.

Purpose for Action (Chapter I)

Chapter 1.1.1 states (p. 1-1) the purpose of the action as construction, operation, and maintenance of the 800-kilowatt (kw) hydropower project. This merely restates the character of the application: namely, GEC has applied to build this project rather than some other form of generation capacity. However, the National Environmental Policy Act (NEPA) requires that the EIS should state the "*underlying* purpose and need to which the agency is responding…." 40 CFR § 1502.13 (emphasis added). In other words, what are the needs of GEC's electricity system which this project is intended to meet?

Chapter 1.1.2 apparently assumes (p. 1-2) that the purpose of the action is to meet future electricity demand in GEC's service territory in excess of the 1,050-kw capacity of the existing diesel generation, or stated differently, to replace the diesel generation (p. 1-5) to the extent that the project generation may meet existing demand. It suggests (p. 1-5) that a related need is stabilizing or reducing the rates charged to GEC's customers. We agree that these are project purposes. Plainly, the application is not intended to enhance the environmental quality of the GBNPP.

Chapter 1 (p. 1-2) states that the application assumes that NPS will interconnect with GEC and replace GBNPP's existing diesel generation. It acknowledges (id.) that the NPS has not made any such commitment, and that its decision is "separate from this licensing decision." We agree that providing supplemental or replacement capacity to the NPS is not a purpose of this proceeding.

We respond to the analysis of electricity demand versus existing generation capacity (pp. 1-2 – 1-5) in our comments on Chapter 5.

Alternatives (Chapter 2)

Chapter 2 presents a No-Action Alternative, which is disapproval of the application, and three Action Alternatives, which are approval of the application with varying amounts of land exchange. The No-Action Alternative is presented (p. 2-1) merely as the "baseline" for analysis of the Action Alternatives. The DEIS does not analyze any Action Alternative involving renewable technologies other than this project. This narrow scope of analysis does not comply with the NEPA duty of the Commission or the NPS. That law requires that an EIS include "all reasonable alternatives" (40 CFR § 1502.14(a)), including those "not within the jurisdiction of the lead agency" (id., (c)). It also requires non-discriminatory treatment of the jurisdictional and non-jurisdictional Action Alternatives. The lead agency must "devote substantial treatment to each alternative considered in detail so that reviewers may evaluate their comparative merits" (id., (b)).

More specifically, after finding that the project is uneconomic under Mead Paper today, the DEIS examines multiple future scenarios (such as a NPS commitment to purchase from GEC, or a doubling of diesel fuel prices) which may overcome that infeasibility in the future. *Compare* pp. 5-6 – 5-7 (Mead Paper analysis of current conditions) with p. 6-27 – 6-34 (future scenarios). By contrast, after finding that renewable technologies other than hydropower are more costly today than diesel generation (*see* pp. 1-5 – 1-11), the DEIS does not examine alternative future scenarios which may enhance the feasibility of retrofitting or replacing the diesel generation with such alternatives. This treatment stacks the deck against such alternatives. If the No-Action Alternative is a static baseline, then the EIS should treat non-hydropower alternatives as Action Alternatives. Such alternatives are identified in reports by our economic consultant, 100th Meridian, "Economic Analysis of the Proposed Gustavus Electric Falls Creek Hydro Project and Potential Alternatives" (November 5, 2003) (hereafter, "Economic Analysis"), which was previously filed with the Commission and is incorporated herein by reference; and "Comments on the Economic Analysis in the Draft Environmental Impact Statement for the Falls Creek Hydroelectric Project" (January 6, 2004) (Exhibit 1). We note that Verdant Power, which has a preliminary permit (P-12178) to develop a hydrokinetic turbine in the East River of New York City, proposes an investigation of such technology (which does not dam or divert water) in this immediate area, including tidal waters. *See* Exhibit 1, Attachment A.

For the same reasons, the DEIS is deficient in its omission of conservation measures which GEC may implement to meet its demand. Although FPA sections 10(a)(2)(C) and 15(a)(2)(D) require consideration of such measures to evaluate project need, the DEIS does not include such measures as part of the No-Action Alternative or as an Action Alternative.

Affected Environment (Chapter 3)

We have no comments.

Environmental Consequences (Chapter 4)

We have no comments on the technical analysis of environmental impacts, although we again commend OEP and NPS for the thoroughness and fairness of that analysis. We agree (pp. 4-201 – 4-202, *passim*) that the project, under any Action Alternative, would result in irretrievable commitments of natural resources and in unavoidable adverse impacts on environmental quality. Our comments focus on the legal significance of those impacts under the Boundary Adjustment Act.

Section 3(c)(3) of that law provides that the Commission may issue the license only if it determines, with NPS' concurrence, that the project "will not adversely impact the purposes and values of Glacier Bay National Park and Preserve (as constituted after the consummation of the land exchange authorized by this Act)." Unlike FPA Part I and NEPA, which generally permit approval subject to feasible mitigation of adverse impacts, this law prohibits such impacts on the purpose and values of the GBNPP.

The DEIS does not articulate a rational standard to determine whether a given adverse impact complies with Section 3(c)(3). The DEIS opines that an adverse impact complies as long as most of the 2.5 million acres of GBNPP wilderness lands would be unaffected by the footprint of this project and associated land exchange, totaling 650 to 1,150 acres under the several Action Alternatives. *See*, e.g., pp. xxix, 4-169 (wilderness value); 4-24, 4-56 (water quality); 4-145 – 4-147 (aesthetic value of waterfalls); and 4-155 (recreation). Obviously, this 800-kw project on a single stream does not change the overall character of 2.5 million acres that would remain protected in the GBNPP. This amounts to a standard that an adverse impact on GBNPP purposes or values will be deemed to occur only if it involves a unique resource recognized in the organic statutes for the GBNPP or the NPS' implementing rules. Under that treatment, the Boundary Adjustment Act is effectively a restatement of FPA Part I or NEPA, which, while permitting adverse impacts to non-unique resources, frown on such impacts to a unique resource.

Such a standard is inconsistent with the plain meaning of Section 3(c)(3), which prohibits *any* adverse impact to the GBNPP purposes and values of post-exchange GBNPP lands. The prohibition is not limited to a unique resource, although Falls Creek is unique as the only known resident Dolly Varden fishery within the GBNPP (p. 4-96). The prohibition is not limited to impairment, since the organic laws for the GBNPP define "impairment" as being something more than the "impact" which Section 3(c)(3) addresses (*see* p. 1-19). Instead, the prohibition is just what it says: a mandate to the Commission to disapprove the license application if the preferred alternative would have *any* adverse impact on GBNPP purposes and values. These include "preserving the unaltered state of …the coastal rain forest ecosystem…," maintaining a "sanctuary where fish and wildlife may roam free, developing their social structure and evolving over long periods of time as nearly as possible without the changes that extensive human activities would cause" (pp. 1-21 – 1-22), and preserving a "feeling of ruggedness and wildness of the landscape and the solitude that early inhabitants found" (p. 1-23).

The DEIS makes, and we support, factual findings that the project would cause adverse impacts to the post-exchange GBNPP lands, including the riparian lands on the eastern bank of the bypass reach. Direct impacts on GBNPP lands would include: a 17-fold increase in baseline turbidity in the bypass reach during construction and a 5.5-fold increase during operation (p. 4-17); a substantially increased frequency of low flow (p. 4-54); a corresponding thermal impact in summer and winter (p. 4-48); and, due to thermal impact and sedimentation, a substantial reduction in the habitat for various resident fish, including Dolly Varden (pp. 4-48, 4-77, 4-85, 4-93). Indirect impacts on post-exchange GBNPP lands would include: poaching from the new State lands on the west bank (p. 4-116) and increased burdens on NPS staff and budget to prevent such poaching and otherwise address the management consequences of the new boundaries (pp. 1-28, 4-174 – 4-174). See also Declarations of Sophie McKinley (Exhibit 2), Thomas Mills Sr. (Exhibit 3), Jack Hession (Exhibit 4), and Mike Olney (Exhibit 5). These factual findings compel the legal conclusion that license would not comply with Section 3(c)(3) of the Boundary Adjustment Act as applied to the post-exchange GBNPP lands that would be directly or indirectly affected by this project.

Developmental Analysis (Chapter 5)

Section 2(c)(1)(C) of the Boundary Adjustment Act permits license issuance, including land exchange, only if the Commission with the NPS' concurrence determines that the project "can be accomplished in an economically feasible manner." This standard plainly means something more than a mere possibility that, under some hypothetical scenario, the project might be feasible. After all, the project would be located in a National Park, and the privilege to pursue this application does not change that fact. Further, Section 2(c)(4) requires that, after license issuance, construction will begin only if the Commission approves an "acceptable financing plan" in a subsequent proceeding. We understand Section 2(c)(1)(C), read together with Section 2(c)(4), to mean that GEC must show in this licensing proceeding, and the Commission and NPS must also find, that the project is reasonably likely to secure a commercial loan, equity investment, or some other form of financing that the post-licensing plan will subsequently state in the form of commitments. However, the application does not state, and the DEIS does not analyze, the potential forms of financing the $4.3 million capital cost of constructing this project.

The project would supply customers in the GEC's service area only. Interconnection to other utilities does not exist. Accordingly, the generation and thus revenues based on approved rates for service would be partly a function of these customers' demand. Chapter 5 (p. 5-2 - 5-5) estimates future demand through 2016 by assuming that it will match historic growth from 1985 to 2002. This assumed equivalency overstates likely future demand. Growth since 1997 has been less than half the average since 1985; funding for the Power Cost Equalization Credit, which stimulates growth, is uncertain; and other factors, including the regional slow-down of recreational travel, may also affect such growth. *See* Exhibit 1, pp. 3-5. While Chapter 6 includes alternative growth scenarios (pp. 6-30 – 6-31), it does not state actual probabilities of occurrence. We recommend amendments to these scenarios to reflect such probabilities. *See* Exhibit 1, pp. 3-5.

The DEIS includes a demand scenario (p. 5-7) where NPS interconnects with GEC and uses this project rather than its own diesel generation. Since it acknowledges that NPS will make that decision in a separate proceeding, this scenario is speculative. The DEIS does not assign any probability to its occurrence. It does not explain why NPS would strand its capital investment in its own diesel generation if the project would be substantially more expensive than that existing capacity. *See* Economic Analysis, pp. 12-13.

Generation revenues would be a function of several factors, including availability of flow for diversion (after compliance with minimum flow schedule), customers' demand, and rates permitted by the Regulatory Commission of Alaska (RCA) under State law. The DEIS does not analyze why or whether the RCA would approve the rates necessary to recover capital and other costs of the project, particularly if these rates would be substantially higher than otherwise occur under the No-Action Alternative where GEC continues to rely on its existing diesel generation. *See* Exhibit 5, ¶ 4-5. We estimate that, even in a hypothetical scenario where 20% of the capital cost is paid through an unknown grant, the total cost which GEC would seek to recover in rates would be \$.21 - \$.52/kwh (Exhibit 1, pp. 16-19), by contrast to the \$.17- \$.20 cost/kwh of the existing diesel generation (Economic Analysis, p. 2).

The DEIS (p. 1-2) assumes that GEC will use its two primary diesel units, which have a 550-kw capacity, at a capacity factor of 50%. Given that assumption, and the related assumption that demand growth would track the 1985-2002 period, it concludes (p. 1-2) that GEC's capacity would not meet demand in 2012 and later. The DEIS does not explain why the other diesel units, which have a 600-kw capacity, would be unavailable to meet such demand growth; or why a 50% capacity factor is the best that these units would achieve. *See* Exhibit 1, pp. 5-6.

We turn now to the capital and other project costs. The DEIS (pp. 5-9 <u>et seq</u>.) assumes that the cost of environmental measures is fixed once the license issues. Indeed, that assumption is a critical basis for concluding (pp. 6-8, 6-28) that the project is not subject to the inflation in fuel cost that may affect the existing diesel generation. However, Section 3(c)(3) of the Boundary Adjustment Act requires that any license will be conditioned to require additional measures if the NPS, based on post-licensing monitoring, determines them to be necessary to protect GBNPP purposes and values. Accordingly, the Commission and NPS should include a scenario whereby the costs of environmental measures increases in the future.

Chapter 5 appears to omit certain financing and other costs from the economic analysis. These include depreciation (Exhibit 1, p. 13), return on rate base (id.), recovery of tax payments (id.), and the construction of any transmission line to GBNPP in the event that the NPS agrees to the interconnection (id., pp. 10-11).

Chapter 5 concludes (p. 5-6) that the project would have a negative economic value in the first ten years of operation. We agree, although the negatives are substantially underestimated as discussed above. Indeed, the DEIS finds that the project would have a positive economic value only under one scenario, where the cost of diesel fuel doubles (pp. 6-29, 6-33) and apparently where NPS agrees to the interconnection. The DEIS does not estimate the probability of this scenario.

Section 2(c)(C) of the Boundary Adjustment Act requires more than Mead Paper, which permits the license applicant to undertake a project that is economically infeasible according to the Commission's developmental analysis (e.g., by subsidizing the project via other generation assets). By contrast, this section requires the Commission and NPS to find that this project is economically feasible, and otherwise, to deny the license application. The project meets that standard in only one of the many scenarios which the DEIS analyzes; and that scenario has an unknown probability of occurrence. In the DEIS supplement that we request below, the Commission and NPS should include an Action Scenario whereby the license is denied now (or the application is withdrawn) subject to refiling if future conditions warrant. *See* Exhibit 1, pp. 7-9. Section 5 of the Boundary Adjustment Act permits such refiling without risk of competition.

Conclusions (Chapter 6)

The DEIS (p. 6-1) does not include a preferred alternative or a recommendation whether the license application should be approved. This omission is inconsistent with the plain requirement of NEPA that a DEIS include a preferred alternative. *See* 40 CFR § 1502.14(e).

Chapter 6 includes a developmental analysis that largely duplicates Chapter 5's economic analysis of the project. Our comments above apply equally here. However, the developmental analysis improperly omits any quantification of the costs on third parties, including the repair or replacement of the privately maintained Rink Creek Road as a result of construction traffic (p. 4-198; Exhibit 5, ¶ 8); damages that may result from increased ease of public access and thus risk of trespass on native allotments (*see* Exhibit 2, ¶ 6 and Exhibit 3, ¶ 7-8); damages that may be imposed on local tourism businesses such as Bear Track Inn as a result of construction and other project impacts (Exhibit 5, ¶ 7-8); or the NPS' effective loss of its investment in its diesel generation if it interconnects with GEC.

A license may issue here only if the project is "best adapted to a comprehensive plan" for Falls Creek under FPA section 10(a)(1). While listing (pp. 6-41 et seq.) applicable comprehensive plans, Chapter 6 does not analyze consistency with the specific management requirements stated in those plans. Notably, it does not analyze consistency with water quality standards, including temperature and turbidity. *See* id., p. 6-45. That duty devolves to the Commission and NPS, because the Alaska Department of Conservation (DEC), on August 2, 1999, issued a blanket waiver of water quality certification for all hydropower projects as a result of its budgetary constraints.[1]

REQUESTED RELIEF

We request that the Commission and NPS undertake the following further procedures after the close of the public comment period:

1. pursuant to 40 CFR § 1502.14(e) and 40 CFR § 1502.9(c), publish a supplement to the DEIS which (A) includes the Action Alternatives discussed above and (B) states a preferred alternative; and then permit further comment on that supplement;

2. pursuant to 18 CFR § 385.1301 et seq., undertake a joint hearing with ARC regarding the rates that GEC would charge to cover the project costs;

3. contact manufacturers of alternative renewable technologies, including Verdant Power, to discuss feasibility at sites in or near Gustavus;

4. direct GEC to file a water quality certification request with DEC in order to complete its application; and

5. respond to all comments in the format where the response is in the right column opposite the individual comment. We request such a response to this comment letter; its exhibits, including Exhibit 6, which states the individual comments of the Sierra Club, Alaska Chapter, Juneau Group; and the incorporated Economic Analysis.

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[1] We intend to challenge that blanket waiver as inconsistent with DEC's duty as a delegate of U.S. Environmental Protection Agency under Clean Water Act section 303(e) and other sections. In the meanwhile, under FPA section 9(b) and implementing rules, GEC has a duty to include in its application "satisfactory evidence" of compliance with State laws, including submittal of a water quality certification request to DEC. Under CWA section 401(a), DEC has a duty to determine whether the blanket waiver applies to this project.

Thank you for considering these comments.

Respectfully submitted,

____

Richard Roos-Collins
Julie Gantenbein
NATURAL HERITAGE INSTITUTE

Attorneys for SIERRA CLUB, TROUT UNLIMITED, AMERICAN RIVERS, NATIONAL PARKS CONSERVATION ASSOCIATION, GLACIER BAY'S BEAR TRACK INN, THE WILDERNESS SOCIETY, HOONAH INDIAN ASSOCIATION, THOMAS L. MILLS, SR., PATRICK G. MILLS, SOPHIE MCKINLEY and DIANNE MCKINLEY

DECLARATION OF SERVICE

Gustavus Electric Company,
Falls Creek Hydroelectric Project (P-11659-002)

I, Katherine Ridolfi, declare that I today served the attached letter to Secretary Salas stating comments on the DEIS, by first-class mail to each person on the official service list maintained by the Secretary in this proceeding.

Dated: January 6, 2004

By:

____
Katherine Ridolfi
NATURAL HERITAGE INSTITUTE

Exhibit 1

COMMENTS ON THE ECONOMIC ANALYSIS
IN THE
DRAFT ENVIRONMENTAL IMPACT STATEMENT
FOR THE
FALLS CREEK HYDROELECTRIC PROJECT (P-11659)

Eric Cutter

January 6, 2004

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1) *Introduction*

This document presents the comments of Eric Cutter of 100th Meridian on the October 2003 *Draft Environmental Impact Statement for the Glacier bay National Park and Preserve: Falls Creek Hydroelectric Project and Land Exchange (P-11659)* (Draft EIS). These comments relate specifically to the economic analysis presented in the Draft EIS and gives specific suggestions on how that analysis should be improved. This review focuses on Chapters 1, 2, 5 and 6 and presents comments in the order in which the issues are presented in the Draft EIS.

The major conclusions in these comments are that the Draft EIS:

- Should include a lower low growth scenario of 2.0%, with a probability that more closely resembles that of the high growth scenario, which currently appears highly unlikely;
- Overstates the need for and benefits of new hydroelectric generation;
- Should provide a more meaningful comparison of the costs and benefits of reducing diesel generation;
- Inappropriately dismisses tidal energy and fuel cells as potential alternatives;
- Should include a Deferred-action Alternative;
- Appropriately assumes higher financing costs than the Draft Project Application;
- Fails to include the costs of building a transmission line to Glacier Bay National Park;
- Significantly underestimates the project costs when compared to a No-action Alternative by failing to include inflation and interest for funds use during construction;
- Appropriately includes income tax as an annual expense;
- Fails to consider the significant impacts the project will have on retail electric rates, an essential factor in assessing the project's economic viability, and
- Should include a determination of economic viability for the project.

This review concludes with a revised economic analysis incorporating several of the above comments. This analysis finds that the total cost of power to the ratepayers of Gustavus for the Falls Creek Project will, at a minimum, exceed $0.21/kWh and could exceed $0.40/kWh if the cost of the transmission line to Glacier Bay National Park is at the high end of current estimates. If less than optimal assumptions are made for any one of three key factors, load growth, financing costs, and transmission line costs, any one of which could change after the project is approved, power costs increase to $0.25, $0.29 and $0.34/kWh respectively, double or more than the cost of diesel generation (at $0.13 in the Draft EIS).

There is no urgent need for new generating resources and power costs for the Falls Creek Project exceed diesel under even the most optimistic scenarios. Reducing consumption of diesel fuel is a desirable goal, but does not relieve this project from the burden of a positive cost/benefit analysis. Furthermore, it is likely that economic and environmentally sound alternatives will become available for Gustavus long before there is a need for additional power. Given these circumstances, it is difficult to understand how FERC could find that the project is, by any definition, economically viable as required for approval under federal legislation. The No-action Alternative is clearly the best option for Gustavus at this time.

2) The Draft EIS overstates the range of projected load growth for Gustavus. (Chapter 1.1.2 and 6.1.1.4)

The Draft EIS notes that the economics of the Falls Creek Project are extremely sensitive to load growth projections. There are several reasons load may grow more slowly than estimated by FERC in the Draft EIS.

The Draft EIS notes that load has grown an average of 8.1 percent from 1985 to 2002. However, 1985 coincides with the implementation of the Power Cost Equalization Credit, which significantly reduced electric rates seen by customers in Gustavus. The Draft EIS assumes load growth of just over 4 percent for the next decade. Since 1990 load growth has averaged 4.1 percent, including several significant jumps in 1992, 1994 and 1996. However, since 1997 load has not increased by more than 3 percent and actually decreased in several years. In 1997 the Power Cost Equalization Credit for commercial customers was discontinued and portions of Glacier Bay National Park have since been closed to commercial fishing. Future funding for the PCE credit is uncertain. Nearly half of the $15 million funding for the Power Cost Equalization Program came from an unreliable one time source for this fiscal year (phone conversation with Alaska Energy Authority). The PCE credits for Gustavus residents may be significantly reduced in the future, particularly if Alaska state budget challenges persist. The addition of the Falls Creek Hydro project may also reduce the PCE credits calculated by the RCA. Electric systems with all diesel generation are subject to a less stringent efficiency standard in the PCE calculations than systems that also have non-diesel generation.

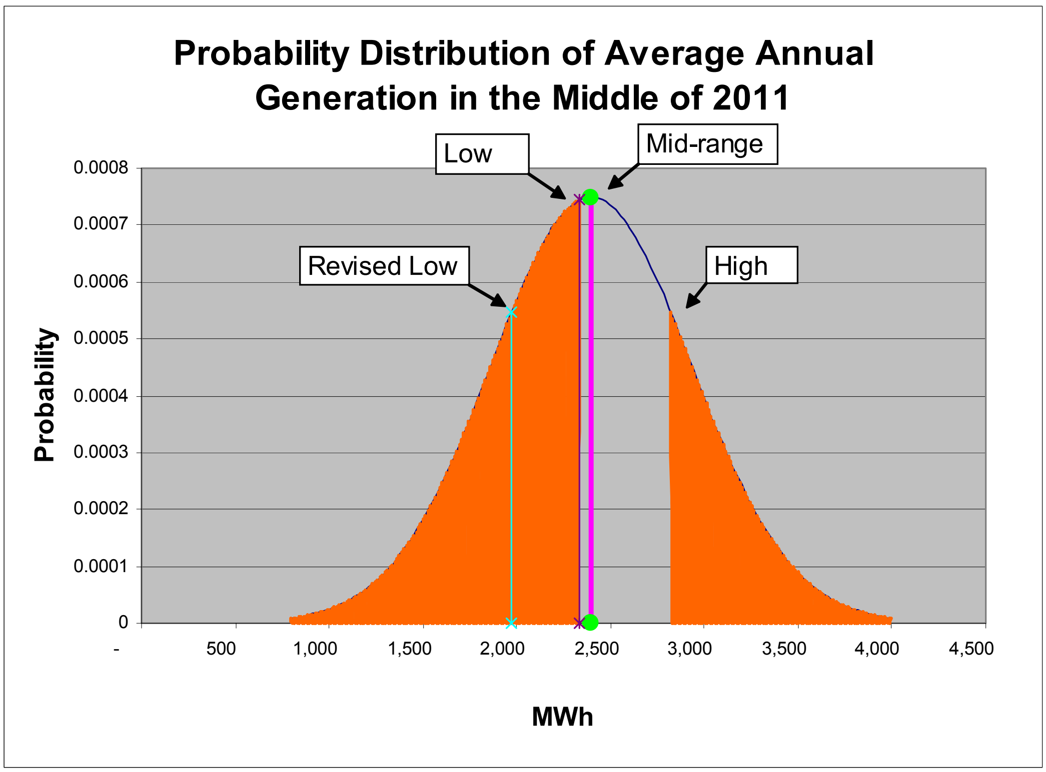
Furthermore, growth rates for communities and organizations tend to decline as their size increases. It is much easier for a town of 100 to double its population that it is for a city of 1,000. This trend can be seen in the rate of population growth for Gustavus. Gustavus's population grew from 98 in 1980 to 258 in 1990, a 163% increase (or 10% per year). Population grew to 429 in 2000, a larger number in absolute terms, but only a 66% increase in relative terms (or 5% per year).

Gustavus Electric argues that hydroelectric generation will encourage load growth as it has in other communities. However, the economic situation of the Falls Creek Project is fundamentally different from other hydroelectric projects. In most cases new hydroelectric power decreases overall rates, which results in an increase in overall demand. In this case, the Falls Creek generation is limited by the demand for power, not the project's capacity, and the presence of new hydropower will not decrease rates and will most likely increase them. Customers as individuals would have to use more electricity on the promise that increasing overall load will reduce prices *in the future* for the benefit of the community as a whole. Such a supposition is counter to several basic tenets of economic theory. Some customers may chose to cease self-generation or increase their use of electricity regardless of cost because they feel better about hydropower as compared to diesel, but we cannot expect all or even most of the ratepayers in Gustavus behave this way. It is certainly not prudent to invest over $5 million on a project based on an economic analysis that depends in large part on all or most of the community to display such counter-intuitive behavior. Furthermore, an expectation of such a self reinforcing spiral can work both ways, if costs end up higher than expected, higher rates will drive more people to reduce their use of electricity, further increasing rates.

Another important point is that the low load growth scenario in the Draft EIS is quite close to the mid-range growth scenario. Given the possibility for load to grow much slower than 4% a year and the sensitivity of the project's economics to load growth projections, it would be more appropriate to include a low growth scenario with a probability of occurring similar to that of the high growth scenario. Figure 1 displays this point graphically. The standard deviation of the growth rates over the last ten years is around 9%. For the sake of argument, and statistical simplicity, let's assume that the "best" estimate of the expected growth rate is the mid-range growth scenario, or just over 4%. This means that of the possible scenarios, 50% will lie above the mid-growth scenario of 2,397,000 kWh and 50% will lie below. With this assumption, the probability that load growth will exceed the high growth scenario, which is 419,000 kWh higher than the mid-range growth scenario, is approximately 22%[1]. This probability is represented by the shaded area on the right hand side of the graph. On the other hand, the probability that load growth will be lower than the low growth scenario, which is only 63,000 kWh below the mid-range growth scenario, is approximately 45%. This probability is represented by the larger shaded area on the left hand side of the graph.

In order to achieve a similar level of probability, the low growth scenario would have to be 419,000 kWh below the mid-range growth scenario, which is an average annual generation of approximately 1,978,000 kWh or a growth rate of around 2.0%. This revised low scenario is represented by the thin line on the left side of the graph. The shaded area to the left of this line is equivalent to the shaded area to the right of the high scenario, representing an equal probability of being exceeded.

Figure 1



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[1] The standard deviation of the annual generation growth rates over the last ten years is 9%. Assuming, for the sake of argument and simplicity, that the best estimate for the annual growth rate is 4%, yields an average annual generation (in the middle of year 2011 of 2,346,000 kWh as in the Draft EIS. The standard error of a load estimate in 2011 is 509,000 kWh. The high growth scenario is 419,000 kWh higher than the mid-range growth scenario, which yields a t ratio of 0.945, with an associated exceedence probability of 22%. The low growth scenario is 63,000 kWh lower than the mid-range growth scenario, with a t ratio of 0.12 and an exceedence probability of 45%. In order for the exceedence probability of the low growth scenario to equal that of the high growth scenario (again assuming that the mid growth scenario is the best estimate), it would have to be 419,000 kWh lower that the mid-range growth scenario or 1,978,000 kWh, which would be an annual growth rate of 2.0%.

If FERC is going to consider a high growth scenario that appears quite unlikely given recent trends, then FERC should adjust the low growth scenario downwards to an equivalent level of probability; a growth rate of 2.0%. The mid-range growth scenario would then actually represent a more of a middle ground bounded by equally probable low and high growth scenarios.

3) The Draft EIS overstates the need for and the benefits of power produced by the Falls Creek Hydroelectric Project (Chapter 1.1.2)

The Draft EIS does not make a convincing case for the need for new generating resources and fails to consider the economic and other benefits of deferring construction of the Falls Creek Project. The Draft EIS identifies four generating units, two primary units with a combined capacity of 550 kW and two units that are used less often with a combined capacity of 600 kW. The Draft EIS then goes on to state that the GEC forecasts show future power requirements surpassing the capacity of the two primary units at a 50% capacity factor around 2012. Diesel generating units are generally capable of operating at much higher capacity factors over the course of a year and the Draft EIS provides no information supporting 50% as an appropriate capacity factor to use when assessing the need for new generation. Resource planning and cost studies usually assume capacity factors of at least 65% and if not higher. Furthermore, such studies generally assume that a plant is part of a larger resource mix and that the capacity factor is limited by economics or load, not the physical capability of a particular unit. Clearly such assumptions are not appropriate for Gustavus, for which diesel generation is the only existing resource. Gustavus Electric has provided no information suggesting that the two primary diesel units are nearing the end of their useful lives or need to operate at lower capacity factors.

If Gustavus were relying only on the two primary diesel generators, it might be appropriate to make conservative assumptions regarding capacity factor is assessing the need for additional generating resources. However, this is not the case. The two additional units, while less efficient, provide ample reserve capacity of 600 kW. Utilities often rely on older, less efficient units to help meet system loads during periods of peak demand or maintenance. Even though they are less efficient and more costly to operate, if used infrequently, it is more cost effective to occasionally rely on such units instead of investing in new generating resources.

Appendix B of the Preliminary Draft Environmental Assessment contains an assessment of power requirements performed by HDR Alaska for Gustavus Electric. That study was far more extensive than the analysis presented in the Draft EIS; it included assessments of monthly and hourly generation requirements and a dispatch analysis. The assessment by HDR Alaska concludes that

> "GEC's existing units provide sufficient capacity throughout the study period (*1999-2018*) and no new generation would be required to maintain adequate reserves. Production is primarily from Units 1 and 3, and load growth increases the number of hours that the two units are operated in parallel. Eventually, loads are projected to exceed to combined capacity of the two units, and Unit 4 is dispatched during peak periods." (Preliminary Draft EA, Appendix B, p. III-2)

A far more extensive analysis than that presented in the Draft EIS, and one which was performed by an engineering firm hired by the project proponent, finds that there is no need for new generating resources until after 2018. It is therefore misleading for the Draft EIS, including only the two primary units and assuming an arbitrarily low capacity factor of 50%, to imply that new generating resources may be required as early as 2012. Increasing the hours that Units 1, 3 and in particular the less efficient Unit 4 are run will likely increase O & M and fuel costs somewhat, but probably not so much as to significantly increase rates. The Draft EIS should clearly state there is no need for new power and that the project must be justified by a cost benefit analysis showing net benefits compared to existing resources.

4) The Draft EIS should provide a more meaningful comparison of the benefits and costs of reducing diesel generation. (Chapters 1.1.2, 1.1.3 and 5)

Reducing reliance on diesel generation, and its associated air emissions, risk of fuel spills and volatile prices, is often cited as a benefit of the Falls Creek Project. The Draft EIS, however, fails to present the benefits of reducing reliance on diesel generation in a way that can be meaningfully compared with the costs of the Falls Creek Project.

At least two the cited benefits of reducing diesel consumption could be quantified in a fairly straightforward manner. Reducing price volatility is one benefit cited in the Draft EIS. However, Gustavus Electric could mitigate the price volatility through hedging with futures or other financial derivatives. The cost of hedging fuel commodity prices varies, but a good estimate is around 5% of the fuel cost. The cost of hedging for a relatively small utility like Gustavus Electric would likely be somewhat higher. Still this compared quite favorably to the power cost estimates for the Falls Creek project, which are 15% or more higher than diesel.

Reducing the risk of a diesel spill by reducing the number of trips required by the barge that delivers diesel to Gustavus is also a benefit cited by the Draft EIS. At the very least FERC could present an estimate of how much the Falls Creek Project would reduce that risk, for example would it reduce the trips required by the barge from six to four or six to two. FERC could further and make an approximate estimate of the cost of such a spill to the economy and environment of Gustavus and calculate an expected value of the reduced spill risk.

To the extent the Draft EIS cites reduced diesel consumption as a benefit of the Falls Creek Project, it should also quantify to the extent possible the value of that benefit. In addition, the Draft EIS should make clear the cost to the community or an average electric ratepayer, in terms of higher electric rates or bills, to realize that benefit.

5) The Draft EIS inappropriately dismisses tidal energy as a potential alternative (Chapter 1.1.3)

The Draft EIS finds that tidal energy does not merit further consideration due to large capital costs, variation in generation and likely environmental concerns (p. 1-6). By these criteria, the Falls Creek Project should also not be considered. The capital required for the Falls Creek project is substantial, in excess of $5,000 kW, higher than capital cost estimates for tidal energy or fuel cells. The generation of the Falls Creek Project will vary with stream flow and will not be available at all during certain periods, particularly if higher minimum instream flows are required or if stream flow predictions prove inaccurate. The record already shows that the Falls Creek project has raised significant environmental concerns. It is not at all clear the environmental concerns raised by a tidal energy project would be any more substantial than those raised for the Falls Creek Project, particularly if a tidal energy project could potentially be located outside existing park boundaries. The *Economic Analysis of the Falls Creek Hydro Project and Potential Alternatives (Economic Analysis)* performed by 100th Meridian and previously submitted to FERC describes several tidal technologies that are in active demonstration projects with projected costs lower than the Falls Creek Project. The Falls Creek Project will preclude future investments in tidal energy, which should be considered as an opportunity cost (Section 8).

Appendix A contains a letter from Verdant Power, an experienced developer of tidal energy projects. A preliminary analysis shows that potential tidal sites exist in the Gustavus Area with capital costs of $2,500 to $3,000 per kW (excluding transmission), as compared to over $5,000 per kW for Falls Creek. Tidal power costs are expected to be in the $0.07-0.09/kWh range. Several tidal technologies, with unit sizes of 250 kW, could me more scalable than the Falls Creek Project, requiring a smaller initial investment for a plant of 500 kW instead of 800 kW. Verdant Power also indicated that on site investigations usually reveal several good sites that do not show up in preliminary, desk-top studies.

6) The Draft EIS inappropriately dismisses fuel cells as a potential alternative (Chapter 1.1.3)

The Draft EIS states that fuel cells "have high capital costs, and those that are currently in place in Alaska would not be economic without large federal grant subsidies" (p. 1-11). Again, the Falls Creek project has capital costs higher than fuel cells on an absolute or $/kW basis (See *Economic Analysis).* The Falls Creek Project is also clearly not economic even *with* large state and federal subsidies. Current fuel cell technologies cannot run on diesel, but large propane delivery systems and fuel cells than can run on diesel are in development. The Falls Creek Project will preclude future investments in fuel cells, which should be considered as an opportunity cost (Section 8).

7) The Draft EIS inappropriately prejudices its analysis of the Falls Creek Project in Chapter 1.1.3

The Draft EIS states that "hydroelectric generation from the Falls Creek Hydroelectric Project appears to be a reasonable means for replacing some of the existing diesel generation and helping to meet the current and future need for power in the Gustavus Area" (p. 1-11). It is unclear how the Draft EIS can fail to make a determination of economic viability as required by legislation, find that the project has negative net benefits under almost every scenario, yet state in the introductory chapter that it is "reasonable". The term "reasonable" has specific implications with regards to utility investments and the term should not be used lightly, particularly without economic justification. Many of the criteria used to dismiss alternatives as not viable (high capital costs, variable generation) apply equally well to the Falls Creek Project. This sentence should not be included unless it is supported by specific findings in the Draft EIS.

8) The Draft EIS should consider a Deferred-action Alternative that properly accounts for the benefits of deferring a large capital investment and allowing potentially economic and environmentally sound alternatives than can be located outside existing park boundaries. (Chapter 2)

Gustavus Electric has presented the choice to Gustavus as this hydroelectric project or diesel forever. FERC's analysis in the Draft EIS presents a similar choice by comparing the project only to a No-action Alternative. Instead the Draft EIS should include a Deferred-action Alternative that accounts for the substantial economic benefit of deferring a significant capital investment as well as the opportunity cost of developing the Falls Creek Project to the exclusion of potential future alternatives.

Utilities frequently balance the costs of extending the lives of older, more expensive generating resources with the cost of investing in newer more efficient resources. On of the benefits includes in such an analysis is the economic benefit of deferring the capital investment in new generating resources. Utilities generally assume a discount rate or cost of capital that is much higher than inflation. This discount rate reflects the cost to the utility of raising capital to invest in new projects, usually 10% or higher. The Draft EIS assumes the cost of capital for the Falls Creek Project is 8%. Assuming a project cost of $5 million in 2007 and $5.8 million in 2012 (escalated at 3% annually), the net present value benefit of deferring the project for five years (from 2007 to 2012) is just over $1 million (at a discount rate of 8%). This analysis involves the use of inflation and a discount rate, which, as explained in Chapter 5 of the Draft EIS, FERC does not normally include in its current cost comparisons of alternatives. However, as explained in Section 12 below comparison of current costs may be appropriate for evaluating alternatives, but including factors such as inflation and discount rates is essential for an analysis of economic viability, particularly when comparing a proposed project to a No-action or Deferred-action Alternative.

Deferring the project will also improve the economics of the Falls Creek Project in particular, even as it allows time for alternatives to develop. The primary factors the project proponent relies upon to argue that the project will be economic are load growth and escalating diesel fuel costs and then only by considering the most optimistic. Deferring the project will allow time for both of these factors to increase. A Deferred-action Alternative should assess how a delayed start date will improve the project's economics. If it makes sense to defer the project, how long of a deferral would be optimal; if a delay of a year or two improves the project's economics, does five or ten years improve it even more.

As noted in the previous section, the power requirements study submitted by Gustavus Electric suggests that the project can be deferred with no adverse impact to system reliability. However, to the extent there are concerns about meeting future load growth with existing resources, the Draft EIS should explicitly consider the costs and benefits if using conservation and efficiency measures to reduce load and further defer the need for new generating resources. The *Economic Analysis* contains an analysis of the potential benefits of conservation measures such as those implemented at Tenakee Springs in Southeast Alaska. The Federal Power Act, in Sections 10 (a) 2 (C) and 15 (a) 2, requires FERC to consider the potential impact of conservation measures in evaluating proposed projects. Energy efficiency may raise rates, but can potentially lower overall electric bills.

The Draft EIS should also consider the opportunity costs of the Falls Creek Project. In economic terms, any decision to spend or invest money involved an opportunity cost; that is the cost or value of the other potential uses for that money. Fundamentally, comparing a proposed project such as Falls Creek to potential alternatives is an evaluation of opportunity costs; an attempt to measure the benefits of the project against the benefits of other potential uses for the land, capital and labor invested in a project. Using a discount rate to discount future cash flows is another means of accounting for opportunity cost; the money used to construct a hydroelectric project could also earn a rate of return through alternative investments. In most cases the opportunity cost of an investment can be quantified and evaluated using these and other methods.

Non-monetary opportunity costs are not so easily measured and quantified. Nevertheless, it is FERC's practice to include both monetary and non-monetary costs and benefits in its analysis of proposed projects. The Draft EIS includes several intangible or unquantified benefits in its comparison of alternatives, such as reducing reliance on diesel generation and increased access to and use of currently undeveloped land. Precluding investment in future alternatives is an intangible but significant cost of the Falls Creek Project that should be considered in the Draft EIS.

At first blush, it may appear we are asking FERC to gaze into a crystal ball, but that is not the case. There are several circumstances unique to this project than make a considered evaluation of potential future alternates particularly pertinent. Committing $5 million to the Falls Creek Project effectively precludes investments in alternatives that may become viable in the near future. It appears clear that the Falls Creek project will not decrease, and may significantly increase electric rates. The small community of Gustavus, even with park service load, could not support an investment in new technology for decades to come. If state or federal agencies support the Falls Creek Project, it is unlikely that they will provide additional funds for new generating resources for Gustavus in the near future. Furthermore, unlike diesel, nearly all of the costs for this project are fixed; they must be paid whether or not the project runs. Thus these costs could not be reduced by the development of a new resource, which would essentially strand the investment in the Falls Creek Project. Although some of the alternative energy sources rely on fossil fuels (as does Falls Creek to some extent), they would not have to be located on a stream or in a pristine area within the current boundaries a national park. Many of the alternatives could be developed with a much smaller and less impactful footprint or could be located in an already developed area. Finally, Gustavus Electric has the highest rates of any Southeast Alaska utility, which dramatically increases the potential for alternative technologies to show economic benefits.

Neither are the potential alternatives as yet unheard of or particularly advanced technologies. The *Economic Analysis of* shows that there is good reason to believe that tidal energy or fuel cells will become economic for Gustavus in the near future. Even if the probability that these alternatives will become viable for Gustavus is assumed to be only 50 or 25%, precluding their development is still an opportunity cost with a quantifiable expected value that should included in the Draft EIS.

Finally, the potential for these alternative technologies to receive state or federal funds is at least as good, if not greater, than that for the Falls Creek Project. The potential sources of funding identified by Gustavus Electric, the Southeast Conference, the Denali Commission and Alaska Industrial Development and Export Authority & Alaska Energy Authority (AIDEA/AEA). have supported a wide range of projects, including several alternative energy projects for rural Alaskan communities. There is every reason to believe that any funds made available for the Falls Creek Project would also be available for alternative technologies.

If reduced diesel consumption merits consideration as an intangible benefit of the Falls Creek Project, then certainly the benefits deferring the project to allow development of potential alternatives not located within the current park boundaries should be given equal weight. This is particularly true given that the project can be deferred without adversely impacting system reliability or significantly increasing operational costs.

9) The Draft EIS appropriately assumes higher financing costs than those presented by Gustavus Electric (Chapters 5.1)

The Draft EIS assumes project financing costs of 8%. This is appropriately higher than the financing cost of 7% included in the Preliminary Project Application and should be considered a minimum cost of capital for the project. In response to figures presented by the Draft EIS and questions raised in the public hearings, Gustavus Electric has suggested that grants and low interest loans to fund the project could be obtained through the Southeast Conference, the Denali Commission and/or the AIDEA/AEA. Unless Gustavus Electric can document the availability of funds or low interest loans contingent on the project's approval, FERC must assume that the project will be financed at market rates, as it has in the Draft EIS.

There are several criteria used by banks and credit rating agencies to evaluate utility investments that suggest, absent alternative financing, the cost to finance the Falls Creek Project could be higher than usual for new utility investments. These criteria include:[2]

- Availability of diverse supply sources;
- Favorable fuel supply arrangements coupled with cost containment strategies;
- Widespread transmission access;
- Production costs that are competitive;
- The size of proposed projects relative to the utility;
- The ability of income levels and usage patters to support existing rates and potential rate increases;
- The ratio of the utility's free cash flow and cash reserves to the minimum financing requirements for the current and future investments;
- Projections of rates that will continue to display a competitive advantage, preserve the revenue stream associated with native load and help attract new load.

Gustavus Electric is a relatively small, isolated utility with high electric rates proposing a substantial investment in a single project with, at best, marginal economics. The above criteria suggest that any lender will consider this project a risky investment and would ask to be compensated for that risk with higher interest rates.

10) If the Draft EIS assumes public subsidization is available for the Falls Creek Project, it should assume that similar financing is available for alternatives as well. (Chapters 5 and 6)

Comparing a highly subsidized hydro project to cost estimates for diesel, tidal or fuel cell generation that assume market based financing costs is clearly an apples to oranges comparison. As explained in the above in Sections 8-10, there is no reason to believe that the grants or low interest loans available for the Falls Creek Project would not also be available for alternatives, even diesel. In fact, many of the available subsidies listed on the AIDEA and AEA websites are specific to alternative technologies. Cost estimates presented in the Draft EIS for alternatives such as diesel, tidal and fuel cell generation assume no public financing when comparing those costs to Falls Creek. If FERC performs analyses for the Falls Creek Project that include public subsidization through grants and low interest loans, it cannot dismiss out of hand alternatives whose costs could also be dramatically lowered with subsidization, as it does in the Draft EIS.

11) The Draft EIS fails to include the costs of building a transmission line to Glacier Bay National Park in its estimates of project costs. (Chapter 5.1)

There is a wide variation in the cost estimates (with no documentation) presented for a transmission line to connect Glacier Bay National Park in Bartlett Cove to the Gustavus Electric system. Park

[2] See Public Finance Criteria: Electric Utility Ratings, Standard & Poor's, November 12, 2002; Project & Infrastructure Finance Review, Standard & Poor's, October 2002; Public Power Rating Guidelines – Overview, Fitch Ratings, June 2003.

regulations require that the line be underground, which is more expensive than overhead transmission lines. The park service informally contacted a contractor familiar with work in Southeast Alaska and was told that cost for laying underground cable should be figured at $500K per mile. At nine miles of cable from Gustavus Electric Company power plant to the park's power plant it would require an additional $4.5 million for installation. If power loss and voltage problems were corrected in Gustavus Electric Company's existing system, there would be approximately four and a half miles of cable from the park's power plant to the closest point where it could be connected to existing cable, at a cost of $2.25 million. These estimates are significantly higher than the $600,000 cost estimated by Gustavus Electric. The Gustavus Electric estimate is based on the company's experience laying underground lines in the town of Gustavus; however it is not clear that this estimate is consistent with the additional requirements placed on transmission lines within a national park.

Clearly a more conclusive estimate of the cost to build this transmission line (with documentation that can be critically examined by interveners) must be made before FERC can appropriately evaluate the power costs and economic feasibility of this project. This burden rests squarely on the project applicant.

12) The current cost methodology of the developmental analysis in Draft EIS significantly underestimates the project cost when compared to a no action alternative. (Chapters 5.0 and 5.1)

Chapter 5.0 of the Draft EIS describes the approach used by FERC in the developmental analysis. In particular it states:

> "We use a 30-year period of analysis with no forecasts of potential future inflation, escalation, or deflation to convert all costs to a levelized annual value. The levelized annual value is a convenient metric for comparing a cost to a resulting benefit, whether the benefit is measured in dollar-value or non-dollar terms."

First a minor point; FERC's use of the term "levelized annual value" in this context is misleading. In economic terms, the calculation of a levelized cost for a stream of payments or revenues incurred over several periods inherently involves the assumption of a discount rate. If FERC is assuming no inflation or escalation (i.e. no discount rate), it would be more accurate to use the term "average annual value", which appears later in Section 5.

FERC's approach of using current costs to compare the costs of a project and likely alternatives is appealing in that it avoids the inherently controversial and inaccurate art of forecasting factors such as fuel prices, inflation and interest rates 30 years into the future. This method can be appropriate for considering alternatives with relatively similar capital requirements, construction lead times and start dates and recommending the best one.

This method is not, however, appropriate for determining whether it makes sense to invest in a proposed project in the first place; that is whether it is economically viable investment, a determination FERC is required to make in this case. In particular, failing to consider inflation and interest for funds used during construction significantly understates the costs of the proposed project, *particularly as compared to a No-action Alternative*.

Including these factors is essential for making an accurate economic comparison to a No-action Alternative. Furthermore, they could be included without adding significant controversy or uncertainty to the analysis. Indeed, the project proponent, in whose interest it would be to exclude these factors so as to minimize the project costs, included both an escalation rate (3% for three years from 2001 to 2004 for a total of $380,000) and interest for funds used during construction (7% loan rate and 3 year construction period from 2004 to 2007 for a total of $520,000) in the Draft Project Application.

Generally agreed upon measures are available for both inflation and interest rates, which will not change significantly during the periods in question: from 2001 to 2003 and 2003 to 2007 respectively. The December 2003 McGraw Hill Engineering News Record Construction Cost Index was 3.3% for the previous year. Certainly it is more accurate to assume this or a similar rate of inflation for the period from 2001 to 2004 based on this or another appropriate index than it is to assume a rate of 0%. This would not raise the concerns or controversy involved in forecasting inflation for a 30 study year period.

Similarly, it should be a straightforward matter for FERC to make some assumption regarding the cost of funds used during construction. Generally accepted accounting and regulatory principles allow utilities to capitalize the cost of funds used during construction (allowance for funds used during construction or AFDUC).[3] AIDEA quoted an interest rate of about 5% for the low interest loan it may make available for the project. Absent documentation that such low interest loans are available for the project, it is more appropriate to assume the rate of 8% listed in Table 5.1.3 of the Draft EIS. Certainly it would be more accurate for FERC to assume a rate in the range of 5-8% than it would be to assume that funds could be borrowed at a rate of 0% for the three year construction period. Again this does not involve the uncertainty inherent in forecasting interest rates for 30 years.

It is also important to note that the Draft EIS makes inappropriate and misleading comparisons when using current cost estimates *without* escalation to perform sensitivity analyses regarding load growth and diesel fuel costs *with* escalation. In particular, the Draft EIS makes a range of assumptions regarding how load and the cost if diesel fuel will increase in the future (Tables 6.1-3 thru 6.1-6). If FERC staff is comfortable considering a range of escalation rates for diesel fuel prices and load growth, it should also include similar factors, such as inflation and interest, in assessing the project's costs.

13) The Draft EIS appropriately includes income tax as an annual project cost. (Chapter 5.1)

The Draft EIS includes income tax as an annual operating cost of the Falls Creek Project. Gustavus Electric has raised questions as to whether taxes should be included in the annual operating costs. However Gustavus Electric has made no showing that it is not subject to Federal income tax or that the Falls Creek Project will not increase the utility's tax liability. The Gustavus Electric Annual Report for 2001 includes line items for State and Federal Income tax of $9,315 and $34,693 respectively. It is therefore appropriate for FERC to include income tax as an annual cost for the project. Taxes should include both the state income tax of 9.4% and the federal income tax of 34%.

[3] See Berk, Joel, *Public Utility Finance & Accounting: A Reader*, Financial Accounting Institute, 1989

14) The Draft EIS fails to consider the significant impact the Falls Creek Project will have on retail electric rates, a critical factor in assessing the economic viability of the project. (Chapters 5 and 6)

The Project Application, Preliminary Draft EA and the Draft EIS all focus their analysis on the project's cost of generation. This is appropriate for a project that is relatively small compared to the existing size of the utility and for which the project proponent bears the risk of economic viability. In most cases a single hydro project will not materially affect the retail electric rates of the utility proposing the project. However, in this case there is a specific requirement that FERC find the project is economically viable. Furthermore, because the Falls Creek Project is several times the size of the existing utility, it will have a substantial impact on retail rates. The cost of the Falls Creek project will be borne entirely by the ratepayers in the relatively small, isolated community of Gustavus. Therefore an assessment of the project's impact on already high retail rates is an essential component of a determination of economic viability.

Furthermore, making some allowance for the vastly different capital requirements when comparing the costs of hydro and diesel is essential. The No-action Alternative involves no capital investment and a new 800 kW diesel plant would require a capital investment of under $1 million as compared to a cost of $5 million for the Falls Creek Project. Hydro projects would be expected to have higher capital and lower operating costs compared to diesel and total annual costs might appear to be similar. However, utilities earn a rate of return on invested capital, but not on operating costs, which are simply passed through to ratepayers. Thus is not accurate to compare the costs of the Falls Creek Project to the cost of existing or new diesel without also considering the vastly different capital requirements and corresponding rate impacts of each alternative.

In setting rates, the Regulatory Commission of Alaska establishes a revenue requirement for Gustavus Electric that includes all the appropriate and allowable costs incurred by the utility to generate and distribute electricity. This revenue requirement includes several items that are not accounted for in the Draft EIS analysis of the projects power cost. In addition to the normal operating expenses, the revenue requirement generally includes depreciation, return on rate base, and taxes. In addition, the figures for Gustavus Electric's *sales*, which will be used to calculate rates, are 15% lower than those for *generation*.

a) Depreciation

Depreciation is an expense that is included in retail rates. This accounts for how the facility is essentially used up slowly over time to produce electricity. Given the significant capital cost of the Falls Creek Project, accounting for the cost of depreciation is important for an accurate economic analysis. This is particularly true when the primary alternatives to which the project is being compared are a No-action Alternative with zero capital costs and new diesel generation, which has a much lower capital cost. Assuming a useful life of 50 years, annual depreciation will total just over $100,000 per year, adding about $0.04/kWh to electric rates. This cost is not accounted for in the Draft EIS.

b) Return on Rate Base

A highly capital intensive project like a hydroelectric facility will have a much larger impact on Gustavus Electric's rate base than existing or new diesel generation. The Falls Creek Project will increase Gustavus Electric's fixed assets from under $1 million to over $5 million. A full cost-benefit analysis must include the impact this increase in rate base will have on rates, in the form of the return the utility is allowed to earn on that rate base. The portion of the project funded with grants or contributed capital would not count towards the utilities rate base. The remaining portion funded with debt or equity will be included in the rate base. Gustavus Electric will then be allowed to earn an authorized rate of return on that rate base, weighted appropriately for the debt/equity ratio used to finance the project. It appears that Gustavus Electric intends to finance the project entirely with state grants and debt, so initially there will be no equity in the project. The interest rate on the loans will determine the rate of return authorized for the debt financed portion of the rate base (AIDEA has indicated it may offer a $1 million grant and $1 million loan at a rate close to 5%). However, as Gustavus Electric pays down the principal on the loan, the equity portion of the project will increase and the debt portion will decrease. The authorized rate of returns on equity for investor owned utilities such as Gustavus Electric are typically in the neighborhood of 13% (The authorized rate of return for Alaska Electric Light and Power is 13%. For Black Bear Hydro, a subsidiary of Alaska Power Company, the authorized rate of return is 14.75%). The Regulatory Commission of Alaska initiated a rate case earlier this year that will establish a new rate of return for Gustavus Electric. Assuming the project is 80% debt financed the return on equity over the first 10 years of the project will increase from 0 to $90,000, averaging $48,000 per year. This will add as much as $0.04/kWh to rates in year 10, or $0.02/kWh on average for the first 10 years of the project.

c) Taxes

Because the return on equity earned by a utility will be taxed as income, the Regulatory Commission of Alaska must account for taxes in setting rates. Furthermore, the RCA will establish the total revenue requirement so that after operating expenses, including taxes, are subtracted, the net income results in the appropriate rate of return on equity for the utility. Restating this another way, if the RCA simply allowed a utility to earn authorize rate of return, the utility would then pay income tax on that return, resulting in an under-recovery of allowable costs. Therefore the RCA must increase the total return to the utility (which in turn increases income tax) to the point, that when income taxes are taken out, the appropriate return is left for the utility. The return should be multiplied by 1/(1-tax rate) and then taxes should be calculated on the increased return. If it has not already, FERC's calculation of the tax impacts of the project should include this factor. The Alaska corporate income taxes rate for companies earning over $90,000 is 9.4%. The Federal corporate tax rate is 34% (from which state taxes can be deducted). Taxes on the return on equity will average $32,000 over the first 10 years, adding about $0.01/kWh to rates.

d) Sales v. Generation

Rates of course are calculated based on the amount of electricity actually sold to customers, not what is generated. The Draft EIS assumes annual *generation* of 1,638 MWh in 2002, while documents provided by the Regulatory Commission of Alaska indicate annual *sales* of 1,400 MWh in 2002, nearly 15% lower. The difference between the generation listed in the Preliminary Draft EA and the sales in documents provided by the Regulatory Commission of Alaska is similar in 2000 and 2001 as well. This difference is usually line loss and lost and unaccounted for energy, though there may be other factors particular to Gustavus Electric accounting for this difference as well. Ultimately, for determining the revenue requirement the costs for the project will be divided by sales to customers rather than generation. Because sales are 15% lower than generation, the impact on rates will be about $0.03/kWh higher than the project costs calculated using annual generation.

Appendix C contains a financial analysis excerpt from the Project Application for the Otter Creek Hydro Project (P-11588), proposed by the Alaska Power & Telephone Company. The interest rate used in this analysis was 6.0%, not much higher than the low interest loans being applied for by Gustavus Electric. As in the case of the Falls Creek Project, the sponsor is an investor-owned utility and the project financing included no equity. Nevertheless, you can see that the economic analysis for the Otter Creek Hydro Project includes a column for depreciation, return on equity (as the principle on the debt is paid off), and taxes. It is also apparent that the power costs are based on sales not generation. It is also interesting to note that while the project costs, at $6.9 million are similar to Falls Creek, the plant capacity is 12 MW versus 800 kW. Even though this project assumes annual generation *over four times* that of the Falls Creek project (12,000 MWh v 3,000 MWh), the power costs estimates range from $0.10 - $0.08/kWh, only 25% less than the cost of diesel. This puts in perspective the challenge the Falls Creek Project faces, with similar costs and only 1/4th of the generation, in producing power competitive with diesel.

15) Precedent for FERC Determination of Economic Viability (Chapter 6)

The Draft EIS fails to make a conclusion regarding one the key provisions of the Glacier Bay National Park Boundary Adjustment; that the project is economically viable. In the Draft EIS and at the public hearings, FERC staff indicated a reluctance to form conclusions regarding economically feasibility, explaining that it is not a usual determination required of a hydro project. However, the act clearly states that a land exchange can occur only if "FERC has conducted economic and environmental analyses… that conclude… that the construction and operation of a hydroelectric power project… can be accomplished in an economically feasible manner." Thus, the land exchange cannot occur *unless* the analyses in the Final EIS conclude that the project is economically feasible. It is difficult to understand how the Final EIS could make this conclusion given the negative annual net benefits shown in Chapter 6.

The concept of economic feasibility is not a new concept to FERC. One of the goals stated in FERC's Annual Report 2000 is " to optimize hydropower benefits by improving the environmental performance of hydropower projects while preserving hydropower as an **economically viable** energy source" (p. 23). In the natural gas industry, FERC has made determinations of economic viability for years. Prior to the adoption of the current "let the market decide" policy, FERC routinely made determinations of the need for and economic viability of new interstate natural gas pipeline projects in granting certificates of public convenience and necessity. Even in the current era, in which FERC lets pipelines assume the market risk for new projects, FERC is responsible for determinations of economic viability for pipeline expansions. Below are excerpts from the Statement of Policy on Certification of New Interstate Natural Gas Pipeline Facilities (Docket No. PL99-3-00, 88 FERC ¶ 61,227) emphasizing the requirement of financial viability.

> "The threshold requirement in establishing the public convenience and necessity for existing pipelines proposing an expansion project is that **the pipeline must be prepared to financially support the project without relying on subsidization** from existing customers."
>
> "Existing pipelines should not have to compete against new entrants into their markets whose projects receive a financial subsidy, and neither pipeline's captive customers should have to shoulder the costs of unused capacity that results from competing **projects that are not financially viable**. This is the only condition that uniformly serves to avoid adverse effects on all of the relevant interests and therefore **should be a test for all proposed expansion projects** by existing pipelines. It will the be the predicate for the rest of the evaluation of a new project by an existing pipeline."

> "**A requirement that the new project must be financially viable** without subsidies does not eliminate the possibility that in some instances the project costs should be rolled into the rates of existing customers."

FERC makes similar determinations when considering new electric transmission facilities. Given FERC's longstanding experience in assessing and comparing the economics of project alternatives, it difficult to understand how the requirement for a determination of economic viability puts FERC staff in an unfamiliar position.

16) Economic Feasibility (Chapters 5 and 6)

The Glacier bay National Park Boundary Adjustment Act of 1998 places a clear burden on the project applicant to show and FERC to find that the project is necessary and can be constructed and operated in a cost efficient and economically feasible manner.

The Draft EIS and the Project Application and the Preliminary Draft Environmental Assessment, which are quoted extensively in the Draft EIS fail in this regard in several respects.

In order to make the project appear economic, the Preliminary Draft EA assumes an extremely optimistic level of load growth and that Glacier Bay National Park will be served by Gustavus Electric. The load growth scenario presented is higher than the high case contained in the Power Requirements Study performed by HDR Alaska, Inc. in Appendix B. The Preliminary Draft EA fails to consider power costs under a range of more likely load growth scenarios.

Absent clear economic benefits, the Draft EIS and the applicant's documents also show no compelling reason that the project must be constructed by 2007. The Power Requirements Study cited above finds no need for new generating resources before 2018. The goal of reducing reliance on diesel generation, while laudable, does not remove the project from the burden of showing net benefits. Gustavus Electric presents the choice as this hydro project or diesel forever, which ignores the potential for alternatives to develop in the next 10 years well before new generating capacity is needed.

The Draft EIS does analyze the project's power costs under a range of load growth and diesel fuel cost scenarios (Tables 6.1-4 and 6.1-6) and finds negative net benefits under all but the most optimistic scenario. The Draft EIS also does not include any cost estimates for connecting Glacier Bay National Park to Gustavus Electric, even though it includes the park load in assessing the project's power cost.

Gustavus Electric has claimed that property tax and federal income tax should not be included in annual operating expenses. However, these alternatives have been presented after the publication of the Draft EIS and with little or no documentation, making it difficult for FERC or interveners to critically examine or comment on these measures. Similarly if FERC is to assume that the project will serve Glacier Bay National Park, the EIS must have at least a preliminary assessment with which to estimate the costs of the transmission line to serve the park (see below). Finally, the public and interveners deserve clearer explanations of the tax implications of this project.

17) Revised Economic Analysis

This section presents a revised economic analysis based on the above comments. The assumptions for the analysis are shown in Figure 1. The analysis assumes (for the sake of argument, as no documentation has yet been provided), that the Falls Creek Project receives a grant from AIDEA of just over $1 million. AIDEA also provides a low interest loan of $1 million at 5%. The remaining capital costs are debt financed with low interest loans from as yet undetermined sources at 6%. The project is assumed to have a useful life of 50 years for purposes of depreciation. Return on equity is set by the RCA at 13%. The federal and state tax rates are 34% and 9.4% respectively. Finally inflation is assumed to be 3%.

Figure 2: Assumptions

Assumptions	Amount	Interest	Term
Initial Equity Investment	-		
Market Cost of Capital		8.00%	30
AIDEA Grant	1,083,685	-	-
AIDEA loan	1,000,000	5.00%	30
Other Low Interest Loans		6.00%	30
Useful Life (years)	50		
Return on Equity	13.0%		
Federal Tax	34.0%		
State Tax	9.4%		
Inflation	3.0%		

The results of the analysis are shown in Figure 3. The first column represents a case of no park load and 100% debt financing at market rates (8% as in the Draft EIS). The second column shows a Gustavus only case with subsidization, which is still higher than the remaining scenarios, which include Gustavus Load. The third column shows a case with park service load and transmission line costs of $600,000, as estimated by Gustavus Electric. The fourth column shows how costs might be reduced with as yet unsecured public subsidization shown in Figure 1. Even in this most optimistic case power costs are much higher than diesel. The fifth column and sixth column show a case with a mid-range estimate of transmission line costs, with and without subsidization. The seventh column is the high transmission line cost case, with subsidization.

Going down the rows in the table, line 1 includes the 2001 capital cost from the Draft Project Application (also used in the Draft EIS). Lines 2 add escalation of construction costs to 2003, as was done in the Draft Project Application but not in the Draft EIS (see Section 12). Line 3 adds interest for funds used during construction, also included in the Draft Project application, but not in the Draft EIS (see Section 12). Line 4 adds the cost of the project enhancements from Table 5.3-3 of the Draft EIS. Line 6 adds varying estimates of the cost for the transmission line to Glacier Bay National Park, ranging from $600,000 to $4,500,000 (see Section 10).

Annual debt service is shown in line 8. Line 9 includes O&M and insurance from the Draft EIS and the Annual Cost Breakdown provided by FERC in a November 18, 2003 letter to Dick Levitt. Line 10 includes federal and state income tax on the return on equity (Line 16) (see Section 12). Note this is slightly different than the calculation performed by FERC in the Draft EIS. Line 11 includes the annual cost of project enhancements from Table 5.3-3 of the Draft EIS. Lines 13-15 divide the total annual costs (Line 12) by the low, medium and high forecasts of load growth for the year 2007.

Figure 3: Revised Economic Analysis

(Note: Some figures do not add up exactly to the total due to rounding)

				Gustavus Only	Gustavus Only & Subsidization	Low Transmission Costs	Low Transmission Costs & Subsidization	Mid Transmission Costs & Subsidization	Mid Transmission Costs	High Transmission Line Costs & Subsidization	Incremental $/kWh (Low Trans.)
	Project Cost										
1)	Capital Cost			$ 4,130,000	$ 4,130,000	$ 4,130,000	$ 4,130,000	$ 4,130,000	$ 4,130,000	$ 4,130,000	
2)	Escalation			380,000	380,000	380,000	380,000	380,000	380,000	380,000	
3)	Interest during construction			520,000	520,000	520,000	520,000	520,000	520,000	520,000	
4)	Project Enhancements			54,480	54,480	54,480	54,480	54,480	54,480	54,480	
5)	Total Project Cost			5,084,480	5,084,480	5,084,480	5,084,480	5,084,480	5,084,480	5,084,480	
6)	NPS Transmission Line			-	-	600,000	600,000	2,250,000	2,250,000	4,500,000	
7)	Total Capital Cost			$ 5,084,480	$ 5,084,480	$ 5,684,480	$ 5,684,480	$ 7,334,480	$ 7,334,480	$ 9,584,480	
	Annual Costs										
8)	Annual Debt Service			$ 451,641	$ 369,382	$ 504,938	$ 326,645	$ 524,609	$ 651,503	$ 688,069	$ 0.17
9)	O&M (incl. Insurance)			42,920	42,920	42,920	42,920	42,920	42,920	42,920	0.01
10)	Tax (10 year Avg.)			23,674	31,865	26,468	29,798	47,011	34,151	61,112	0.01
11)	Project Enhancements			7,000	7,000	7,000	7,000	7,000	7,000	7,000	0.00
12)	Total			$ 525,236	$ 451,167	$ 581,326	$ 406,363	$ 621,540	$ 735,574	$ 799,101	$ 0.20
	Annual Gen. (kWh)	w/o Park	w/park								
13)	Low	2,516,280	2,516,280	$ 0.21	$ 0.18	$ 0.23	$ 0.16	$ 0.25	$ 0.29	$ 0.32	
14)	**Mid**	**2,361,010**	**2,975,030**	**0.22**	**0.19**	**0.20**	**0.14**	**0.21**	**0.25**	**0.27**	
15)	High	2,672,000	3,174,100	0.20	0.17	0.18	0.13	0.20	0.23	0.25	
	Rate Impacts (10 year Avg.)										
16)	Return on Equity			$ 35,211	$ 47,394	$ 39,366	$ 44,319	$ 69,920	$ 50,793	$ 90,893	$ 0.02
17)	Depreciation			101,691	101,691	113,691	92,017	166,691	146,691	211,691	0.04
18)	Total Rate Impacts			$ 136,902	$ 149,085	$ 153,057	$ 136,336	$ 236,611	$ 197,484	$ 302,584	$ 0.06
19)	**Annual Costs to Ratepayers**			$ 662,137	$ 600,252	$ 734,383	$ 542,699	$ 858,150	$ 933,057	$ 1,101,685	
	Annual Sales (kWh)	w/ Park	w/o Park								
20)	Low	2,138,838	2,138,838	$ 0.31	$ 0.28	$ 0.34	$ 0.25	$ 0.40	$ 0.44	$ 0.52	
21)	**Mid**	**2,006,859**	**2,528,776**	**0.33**	**0.30**	**0.29**	**0.21**	**0.34**	**0.37**	**0.44**	$ 0.04
22)	High	2,271,200	2,697,985	0.29	0.26	0.27	0.20	0.32	0.35	0.41	

The next lines add the rate impacts not included in the Draft EIS, including return on equity and depreciation (see Section 13). Line 19 shows the total annual revenue requirement that will be bourn by ratepayers. Lines 20-22 divides those costs by annual sales, as reported to the RCA, rather than annual generation (which is 15% higher) (see Section 14 d.)

The last column of Figure 3 shows the approximate incremental impact on the $/kWh power costs, based on the Low Case. This is to give the reader an approximate idea of the impact each item has on the final cost of power. Note that the $0.03 in Line 21 is the incremental impact of dividing costs by lower sales figure rather than generation. The incremental impact of depreciation and return on equity is significantly higher for the higher transmission line cost cases.

This analysis does not include property tax. The cases with subsidization assume lower financing costs that those included in the Draft EIS. Therefore the costs shown for the low transmission line cost with subsidization are lower than those presented in the Draft EIS. In fact, ignoring rate impacts, with these assumptions, the project may appear sufficiently close to the alternative of diesel (at $0.13/kWh) to be considered economically viable. However, as explained in the comments above, this would be an inaccurate and incomplete analysis. By including the rate impacts and dividing costs by sales instead of generation, it is clear that the project is not economic compared to diesel.

Even in the best case scenario, including the rate impacts brings the total cost to the ratepayer for the project to $0.21/kWh, a full 61% higher than the No-action alternative of diesel generation. Prudent planners hope for the best, but prepare for the worst and have reasonable expectations somewhere in the middle. Scaling back on any one of a few key assumptions by assuming either that; 1) load growth is lower, 2) financing costs are higher or 3) transmission line costs are higher, raises the power cost to $0.25, $0.29 and $0.34/kWh respectively, double or more than the cost of diesel. It is important to remember that a*nyone or all of these assumptions could change dramatically after the project is approved by FERC.* The high transmission cost case is clearly uneconomic under any scenario, with costs in excess of $0.40/kWh even with subsidization.

18) Conclusion

There is no urgent need for new generating resources and power costs for the Falls Creek Project exceed diesel under even the most optimistic scenarios. Reducing consumption of diesel fuel is a desirable goal, but does not relieve this project from the burden of a positive cost/benefit analysis. Furthermore, it is likely that economic and environmentally sound alternatives will become available for Gustavus long before there is a need for additional power. Given these circumstances FERC should find that the project is not, by any definition, economically viable. I urge FERC to select the No-action Alternative best option for Gustavus at this time.

19) References

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Engineering News Record, Construction Cost Index, December 2003, http://enr.construction.com/features/conEco/costIndexes/mostRecentIndexes.asp

Federal Energy Regulatory Commission & The National Park Service, *Draft Environmental Impact Statement for the Glacier bay National Park and Preserve: Falls Creek Hydroelectric Project and Land Exchange (P-11659),* October 2003

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Standard & Poor's, *Project & Infrastructure Finance Review*, October 2002

Appendix A

VERDANT POWER

4640 13th Street, North
Arlington, VA 22207-2102
Phone: 703-528-6445
Fax: 703-812-8157

Mr. Eric Cutter
100th Meridian
28 Durham Road
San Anselmo, CA 94960

January 4, 2004

Re: Possible Tidal Energy Sites – Gustavus, Alaska

Dear Mr. Cutter:

Having recently drafted the chapter on Instream Energy Generation Technology for the Electric Power Research Institute's 2004 Technical Assessment Guide (TAG), we have become familiar with over 38 various types of hydro kinetic energy conversion devices. And, as a systems integrator, we have experience in assessing resources such as for TVA and developing tidal energy projects such as in New York and Massachusetts. Consequently, we examined the tidal energy possibilities for the community of Gustavus, Alaska with several technologies in mind. Currently, unducted axial-flow and cross-axis "free-flow turbines" show the greatest potential for commercially viable tidal (and river) energy. The other types of free-flow turbines are either unproven or still too conceptual.

Given the basic principles of physics that apply (the sweep of the blade and the speed of the water), the two types of turbines require a minimum water velocity of five feet per second or about three knots of tidal or river current. We completed a "desk-top" reconnaissance for possible tidal energy sites with currents in excess of three knots and near Gustavus. The included chart shows at least four deep water tidal sites. The nearest possible site, Beardslee Island, is 11.8 miles from Gustavus. We did not examine any nearby rivers because of concerns about icing severely hampering winter operations. However, this is not an insurmountable problem and would require further study.

We are fairly confident that a field of bi-directional free-flow turbines will more than meet the power needs of Gustavus, especially if it is a hybrid energy project that includes storage batteries or stationary fuel cells (for dispatchable power during slack tide). Without knowing the bottom composition and local resources for deploying a field of turbines (both are important for determining how best to secure and retrieve the turbines for efficient O&M), we can only guess at costs. Installation costs would range between $2,500 and $3,000 per kW. Production costs would range between $0.07 and $0.09 per kWh. This does not include transmission and distribution costs. Nor does it include costs for building a hybrid sustainable energy project. (Please note: river turbines would not need to be deployed as a hybrid project.)

In conclusion, there are tidal waters, and there may be rivers, that are fast enough to efficiently run free-flow turbines in producing hydroelectric power for Gustavus. The costs for doing so still need to be worked out. This would require further assessment and analysis. We would propose a study to determine where is the energy (rivers may be closer to Gustavus than tidal sites); the amount of energy; and the most cost-effective way to extract and deliver the energy.

Sincerely,

William H. "Trey" Taylor
President

Appendix B: Example Calculations for Low Transmission Cost Case

	Interest	Principle	Debt	Equity	Depreciation	Ratebase	% Debt	% Equity	Return	Federal Tax	State Tax	Net Income
1	454,758	50,179	5,634,351	50,179	113,691	5,570,840	99.12%	0.88%	6,393	3,293	1,005	10,691
2	450,744	54,194	5,580,158	104,373	113,691	5,457,149	98.16%	1.84%	13,026	6,710	2,048	21,784
3	446,409	58,529	5,521,628	162,902	113,691	5,343,459	97.13%	2.87%	19,907	10,255	3,129	33,291
4	441,726	63,212	5,458,417	226,114	113,691	5,229,768	96.02%	3.98%	27,043	13,931	4,251	45,226
5	436,669	68,268	5,390,148	294,382	113,691	5,116,078	94.82%	5.18%	34,443	17,743	5,414	57,600
6	431,208	73,730	5,316,418	368,112	113,691	5,002,387	93.52%	6.48%	42,112	21,694	6,620	70,426
7	425,309	79,628	5,236,790	447,741	113,691	4,888,696	92.12%	7.88%	50,057	25,787	7,869	83,714
8	418,939	85,999	5,150,791	533,739	113,691	4,775,006	90.61%	9.39%	58,284	30,025	9,162	97,472
9	412,059	92,879	5,057,913	626,618	113,691	4,661,315	88.98%	11.02%	66,797	34,411	10,501	111,709
10	404,629	100,309	4,957,604	726,927	113,691	4,547,624	87.21%	12.79%	75,600	38,946	11,884	126,430
11	396,604	108,333	4,849,271	835,260	113,691	4,433,934	85.31%	14.69%	84,695	43,631	13,314	141,641
12	387,938	117,000	4,732,270	952,260	113,691	4,320,243	83.25%	16.75%	94,083	48,467	14,790	157,340
13	378,578	126,360	4,605,910	1,078,620	113,691	4,206,553	81.03%	18.97%	103,763	53,454	16,312	173,529
14	368,469	136,469	4,469,441	1,215,089	113,691	4,092,862	78.62%	21.38%	113,732	58,589	17,879	190,201
15	357,551	147,387	4,322,055	1,362,476	113,691	3,979,171	76.03%	23.97%	123,985	63,871	19,491	207,347
16	345,760	159,177	4,162,877	1,521,653	113,691	3,865,481	73.23%	26.77%	134,514	69,295	21,146	224,955
17	333,026	171,912	3,990,966	1,693,565	113,691	3,751,790	70.21%	29.79%	145,308	74,856	22,843	243,006
18	319,273	185,665	3,805,301	1,879,230	113,691	3,638,100	66.94%	33.06%	156,352	80,545	24,579	261,476
19	304,420	200,518	3,604,783	2,079,747	113,691	3,524,409	63.41%	36.59%	167,628	86,354	26,351	280,333
20	288,379	216,559	3,388,224	2,296,306	113,691	3,410,718	59.60%	40.40%	179,112	92,270	28,157	299,538
21	271,054	233,884	3,154,340	2,530,190	113,691	3,297,028	55.49%	44.51%	190,776	98,279	29,990	319,045
22	252,343	252,595	2,901,746	2,782,785	113,691	3,183,337	51.05%	48.95%	202,587	104,363	31,847	338,796
23	232,136	272,802	2,628,943	3,055,587	113,691	3,069,647	46.25%	53.75%	214,502	110,501	33,720	358,723
24	210,311	294,626	2,334,317	3,350,213	113,691	2,955,956	41.06%	58.94%	226,474	116,669	35,602	378,745
25	186,741	318,196	2,016,121	3,668,410	113,691	2,842,265	35.47%	64.53%	238,447	122,836	37,484	398,767
26	161,286	343,652	1,672,469	4,012,062	113,691	2,728,575	29.42%	70.58%	250,353	128,970	39,356	418,678
27	133,793	371,144	1,301,324	4,383,206	113,691	2,614,884	22.89%	77.11%	262,116	135,029	41,205	438,350
28	104,102	400,836	900,488	4,784,042	113,691	2,501,193	15.84%	84.16%	273,647	140,970	43,018	457,635
29	72,035	432,903	467,586	5,216,945	113,691	2,387,503	8.23%	91.77%	284,845	146,738	44,778	476,362
30	37,403	467,535	51	5,684,480	113,691	2,273,812	0.00%	100.00%	295,593	152,275	46,468	494,336
Avg.									39,366	20,280	6,188	

Appendix C

Financial Analysis of the Otter Creek Hydro Project (P-11588)

Filed as a Separate Document

ALASKA POWER & TELEPHONE COMPANY
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(360) 385-1733 • (800) 982-0136
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REGULATORY
COMMISSION

October 28, 1999

David P. Boergers, Secretary
Federal Energy Regulatory Commission
888 First Steet, N.E.
Washington, D.C. 20426

Re: Otter Creek Hydroelectric Project 001
Project No. 11588-00~~-AK~~
Application for License

Dear Mr. Boergers:

Enclosed is the Otter Creek Hydroelectric Project (Project No. 11588) Application for License for your consideration. The purpose of this application is to construct and maintain a Major Water Power Project of 5 megawatts or less. This application is made per Federal Energy Regulatory Commission (Commission) regulations 18 CFR, Subpart G, Paragraph 4.32 and 4.61.

The Applicant has made a good faith effort to comply with the terms and conditions of the Preliminary Permit the Commission issued on November 19, 1996. In January, 1997 the Applicant entered into the Applicant Prepared Environmental Assessment (APEA) process. A draft environmental assessment is enclosed herein (Exhibit E). Consultation has included local communities, Federal and State resource agencies, and other non-governmental parties.

Enclosed is an original and fourteen (14) copies of three (3) volumes of the Application for License: Volume 1: Exhibits A, B, C, D, F, & G; Volume 2: Exhibit E; and Volume 3: Appendicies.

This Application for License has been sent certified mail to the local communities, resource agencies, and other non-governmental parties. A notary has certified within this document that the Applicant has done this.

We respectfully request the Commission's consideration of this matter.

FERC DOCKETED

OCT 29 1999

AH

9911040201-2

Respectfully Submitted

Robert S. Grimm
President

Enc. (as stated)

Table D-1

Otter Creek Hydroelectric Project FERC No. 11588

Estimated Construction Costs in 2002 $$

Major Civil Works	
Diversion structure	$ 600,000
Penstock	$2,520,000
Powerhouse	$ 600,000
Generation Equipment	
Turbine	$ 900,000
Generator	$ 660,000
Switchgear	$ 300,000
Substation	$ 120,000
Total Direct Costs	$5,700,000
Indirect Costs	
Licensing and Permits	$ 600,000
Design and Engineering	$ 660,000
Total Direct and Indirect Costs	$6,960,000

Goat Lake Hydro, Inc. $1,139,054

Otter Creek Project Ferc # 11588

Table D-2

ASSUMPTIONS:					
			Insurance/MWH	$1.00	
COST	$6,960,000				
Cap/KW	3000		Bond Rate	6.00%	
inflation	4.00%		Term of Loan	30	Years
Hydro Cap.	12,000	MWH	Return	14.50%	
Clean Air Costs	0.00%		Diesel O&M/KWH	$0.036	Ave.93,94,95 (actuals)
O&M/KWH	0.005		Fuel price	$0.67	
dep./life	50	Years	KHW/GAL	12.2	
Loan Amt.	$6,960,000		Fuel inflator	0.50%	

[Year]	[1] Otter Creek MWH Sales	[2] Hydro O&M	[3] Loan Principal	[4] Loan Int.	[5] Loan Pay	[6] Loan Balance	[7] Return on Equity	[8] Income Taxes	[9] Insurance	[10] Plant at Cost
2002	5739	$28,695	$88,036	$417,600	$505,636	$6,960,000	$0	($2,186)	$5,739	$6,960,000
2003	6336	$32,947	$93,319	$412,318	$505,636	$6,871,964	$12,255	$6,054	$6,589	$6,960,000
2004	6715	$36,315	$98,918	$406,719	$505,636	$6,778,645	$24,719	$14,434	$7,263	$6,960,000
2005	7131	$40,107	$104,853	$400,784	$505,636	$6,679,727	$37,388	$22,952	$8,021	$6,960,000
2006	7573	$44,297	$111,144	$394,492	$505,636	$6,574,874	$50,259	$31,606	$8,859	$6,960,000
2007	8015	$48,757	$117,813	$387,824	$505,636	$6,463,730	$63,324	$40,390	$9,751	$6,960,000
2008	8430	$53,333	$124,881	$380,755	$505,636	$6,345,918	$76,576	$49,300	$10,667	$6,960,000
2009	8860	$58,296	$132,374	$373,262	$505,636	$6,221,037	$90,006	$58,330	$11,659	$6,960,000
2010	9313	$63,727	$140,317	$365,320	$505,636	$6,088,662	$103,602	$67,471	$12,745	$6,960,000
2011	9781	$69,607	$148,736	$356,901	$505,636	$5,948,346	$117,352	$76,716	$13,921	$6,960,000
2012	10278	$76,070	$157,660	$347,977	$505,636	$5,799,610	$131,240	$86,054	$15,214	$6,960,000
2013	10801	$83,138	$167,119	$338,517	$505,636	$5,641,950	$145,249	$95,473	$16,628	$6,960,000
2014	11348	$90,843	$177,147	$328,490	$505,636	$5,474,831	$159,359	$104,959	$18,169	$6,960,000
2015	11809	$98,318	$187,775	$317,861	$505,636	$5,297,684	$173,546	$114,498	$19,664	$6,960,000
2016	12000	$103,901	$199,042	$306,595	$505,636	$5,109,909	$187,784	$124,071	$20,780	$6,960,000
2017	12000	$108,057	$210,984	$294,652	$505,636	$4,910,867	$202,045	$133,659	$21,611	$6,960,000
2018	12000	$112,379	$223,643	$281,993	$505,636	$4,699,882	$216,293	$143,240	$22,476	$6,960,000
2019	12000	$116,874	$237,062	$268,574	$505,636	$4,476,239	$230,493	$152,787	$23,375	$6,960,000
2020	12000	$121,549	$251,286	$254,351	$505,636	$4,239,177	$244,602	$162,273	$24,310	$6,960,000
2021	12000	$126,411	$266,363	$239,273	$505,636	$3,987,891	$258,573	$171,667	$25,282	$6,960,000
2022	12000	$131,467	$282,345	$223,292	$505,636	$3,721,528	$272,355	$180,933	$26,293	$6,960,000
2023	12000	$136,726	$299,285	$206,351	$505,636	$3,439,183	$285,890	$190,033	$27,345	$6,960,000
2024	12000	$142,195	$317,243	$188,394	$505,636	$3,139,898	$299,114	$198,924	$28,439	$6,960,000
2025	12000	$147,883	$336,277	$169,359	$505,636	$2,822,655	$311,956	$207,559	$29,577	$6,960,000
2026	12000	$153,798	$356,454	$149,183	$505,636	$2,486,378	$324,338	$215,883	$30,760	$6,960,000
2027	12000	$159,950	$377,841	$127,795	$505,636	$2,129,925	$336,173	$223,841	$31,990	$6,960,000
2028	12000	$166,348	$400,511	$105,125	$505,636	$1,752,084	$347,368	$231,368	$33,270	$6,960,000
2029	12000	$173,002	$424,542	$81,094	$505,636	$1,351,572	$357,818	$238,394	$34,600	$6,960,000
2030	12000	$179,922	$450,015	$55,622	$505,636	$927,030	$367,408	$244,842	$35,984	$6,960,000
2031	12000	$187,119	$477,015	$28,621	$505,636	$477,015	$376,013	$250,628	$37,424	$6,960,000
2032	12000	$194,604	$0	($0)	$0	($0)	$383,496	$255,659	$38,921	$6,960,000
	326129		6960000							

Otter Creek Hydro 10/18/00 Page 2

Otter Creek Cost of Energy

Table D-2

30 year life cycle cost analysis
2002 through 2032

Fuel Saved
26,731,921 Gallons
636,474 Barrels

[11] Annual Deprec.	[12] Accum. Deprec.	[13] Net Plant	[14] Project Equity	[15] Hydroelectric Production Costs Total	[16] $/KWH	Diesel Avoided Costs $/KWH [17] Fuel	[18] O&M	[19] Total $/KWH	[20] Avoided Prod. Costs Diesel	Avoided Capital Costs Diesel	[illegible] Capital Costs Diesel	Avoided Diesel Costs
$139,200	$139,200	$6,820,800	0.00%	$589,048	$0.103	$0.055	$0.036	$0.091	$520,650	$900,000	$0	$1,420,650
$139,200	$278,400	$6,681,600	1.26%	$609,363	$0.096	$0.057	$0.037	$0.095	$599,546	$0	$0	$599,546
$139,200	$417,600	$6,542,400	2.61%	$628,649	$0.094	$0.060	$0.039	$0.099	$662,756	$974,000	$0	$1,636,756
$139,200	$556,800	$6,403,200	4.03%	$648,453	$0.091	$0.063	$0.040	$0.103	$734,109	$0	$0	$734,109
$139,200	$696,000	$6,264,000	5.53%	$668,713	$0.088	$0.066	$0.042	$0.107	$813,173	$0	$0	$813,173
$139,200	$835,200	$6,124,800	7.13%	$689,247	$0.086	$0.069	$0.043	$0.112	$897,689	$0	$0	$897,689
$139,200	$974,400	$5,985,600	8.82%	$709,831	$0.084	$0.072	$0.045	$0.117	$984,826	$0	$0	$984,826
$139,200	$1,113,600	$5,846,400	10.62%	$730,753	$0.082	$0.075	$0.047	$0.122	$1,079,637	$0	$0	$1,079,637
$139,200	$1,252,800	$5,707,200	12.52%	$752,066	$0.081	$0.078	$0.049	$0.127	$1,183,717	$0	$0	$1,183,717
$139,200	$1,392,000	$5,568,000	14.54%	$773,697	$0.079	$0.082	$0.051	$0.133	$1,296,757	$0	$0	$1,296,757
$139,200	$1,531,200	$5,428,800	16.67%	$795,754	$0.077	$0.085	$0.053	$0.138	$1,421,356	$0	$0	$1,421,356
$139,200	$1,670,400	$5,289,600	18.94%	$818,205	$0.076	$0.089	$0.055	$0.144	$1,558,044	$0	$0	$1,558,044
$139,200	$1,809,600	$5,150,400	21.34%	$841,019	$0.074	$0.093	$0.057	$0.150	$1,707,494	$2,880,000	$0	$4,587,494
$139,200	$1,948,800	$5,011,200	23.88%	$863,087	$0.073	$0.098	$0.059	$0.157	$1,853,511	$0	$0	$1,853,511
$139,200	$2,088,000	$4,872,000	26.58%	$882,331	$0.074	$0.102	$0.062	$0.164	$1,964,607	$0	$0	$1,964,607
$139,200	$2,227,200	$4,732,800	29.44%	$899,224	$0.075	$0.106	$0.064	$0.171	$2,049,306	$0	$0	$2,049,306
$139,200	$2,366,400	$4,593,600	32.47%	$915,580	$0.076	$0.111	$0.067	$0.178	$2,137,667	$0	$0	$2,137,667
$139,200	$2,505,600	$4,454,400	35.69%	$931,303	$0.078	$0.116	$0.070	$0.186	$2,229,850	$0	$0	$2,229,850
$139,200	$2,644,800	$4,315,200	39.09%	$946,284	$0.079	$0.122	$0.072	$0.194	$2,326,021	$0	$0	$2,326,021
$139,200	$2,784,000	$4,176,000	42.70%	$960,407	$0.080	$0.127	$0.075	$0.202	$2,426,352	$0	$0	$2,426,352
$139,200	$2,923,200	$4,036,800	46.53%	$973,541	$0.081	$0.133	$0.078	$0.211	$2,531,025	$0	$0	$2,531,025
$139,200	$3,062,400	$3,897,600	50.59%	$985,546	$0.082	$0.139	$0.081	$0.220	$2,640,228	$0	$0	$2,640,228
$139,200	$3,201,600	$3,758,400	54.89%	$996,266	$0.083	$0.145	$0.085	$0.230	$2,754,157	$4,264,000	$0	$7,018,157
$139,200	$3,340,800	$3,619,200	59.44%	$1,005,533	$0.084	$0.151	$0.088	$0.239	$2,873,018	$0	$0	$2,873,018
$139,200	$3,480,000	$3,480,000	64.28%	$1,013,162	$0.084	$0.158	$0.092	$0.250	$2,997,024	$0	$0	$2,997,024
$139,200	$3,619,200	$3,340,800	69.40%	$1,018,950	$0.085	$0.165	$0.095	$0.261	$3,126,400	$0	$0	$3,126,400
$139,200	$3,758,400	$3,201,600	74.83%	$1,022,679	$0.085	$0.173	$0.099	$0.272	$3,261,377	$0	$0	$3,261,377
$139,200	$3,897,600	$3,062,400	80.58%	$1,024,108	$0.085	$0.181	$0.103	$0.284	$3,402,201	$0	$0	$3,402,201
$139,200	$4,036,800	$2,923,200	86.68%	$1,022,978	$0.085	$0.189	$0.107	$0.296	$3,549,124	$0	$0	$3,549,124
$139,200	$4,176,000	$2,784,000	93.15%	$1,019,005	$0.085	$0.197	$0.111	$0.309	$3,702,411	$0	$0	$3,702,411
$139,200	$4,315,200	$2,644,800	100.00%	$1,011,879	$0.084	$0.206	$0.116	$0.322	$3,862,339	$0	$0	$3,862,339
$6,960,000				$26,746,663	$0.082				$63,146,369	$9,018,000	$0	$72,164,369
			npv @6%	$11,598,302	$0.036			npv @6%	$22,895,778	$4,381,410	$0	$27,277,188
									$0.1936			$0.2213
									$0.0702			$0.0836

Economic Benefit Summary Tabulation	Nominal $	NPV @ 6.00%	
Diesel Costs	$72,164,369	$27,277,188	
Otter Creek Costs	$26,746,663	$11,598,302	2.352
Net Benefit	$45,417,706	$15,678,886	
Levelized Annual Benefit @ 6.00% over 30 years		$1,139,054	

Table D-2

[annual period]	[21] Annual Savings from Otter Creek vs. Die (Nominal dollars)	[22] 1997 PV by year 6.00% Discount rate	[23] 1997 PV Cummulative from Otter vs. Diesel
1	$831,601	$831,601	$831,601
2	($9,817)	($9,261)	$822,340
3	$1,006,107	$897,211	$1,719,551
4	$85,656	$71,918	$1,791,469
5	$144,459	$114,425	$1,905,895
6	$208,442	$155,760	$2,061,655
7	$274,995	$193,860	$2,255,515
8	$348,884	$232,028	$2,487,543
9	$431,651	$270,823	$2,758,366
10	$523,059	$309,598	$3,067,964
11	$625,602	$349,333	$3,417,297
12	$739,840	$389,738	$3,807,035
13	$3,746,474	$1,861,883	$5,668,918
14	$990,425	$464,350	$6,133,268
15	$1,082,276	$478,692	$6,611,960
16	$1,150,062	$479,889	$7,091,849
17	$1,222,086	$481,070	$7,572,919
18	$1,298,547	$482,234	$8,055,153
19	$1,379,736	$483,382	$8,538,535
20	$1,465,945	$484,514	$9,023,049
21	$1,557,484	$485,631	$9,508,679
22	$1,654,682	$486,734	$9,995,413
23	$6,021,891	$1,671,105	$11,666,518
24	$1,867,485	$488,902	$12,155,421
25	$1,983,863	$489,971	$12,645,392
26	$2,107,449	$491,033	$13,136,425
27	$2,238,696	$492,088	$13,628,514
28	$2,378,092	$493,140	$14,121,654
29	$2,526,145	$494,190	$14,615,844
30	$2,683,406	$495,241	$15,111,085
31	$2,850,460	$496,294	$15,607,379
	$45,417,706	$15,607,379	
npv @6%	$15,607,379		

Otter Creek Hydro 10/18/00 Page 1

Goat Lake Hydro, Inc. $350,827

Otter Creek Project Ferc # 11588

Table D-3

ASSUMPTIONS:					
			Insurance/MWH	$1.00	
COST	$6,960,000				
Cap/KW	3000		Bond Rate	6.00%	
inflation	0.00%		Term of Loan	30	Years
Hydro Cap.	12,000	MWH	Return	14.50%	
Clean Air Costs	0.00%		Diesel O&M/KWH	$0.036	Ave.93,94,95 (actuals)
O&M/KWH	0.005		Fuel price	$0.67	
dep./life	50	Years	KHW/GAL	12.2	
Loan Amt.	$6,960,000		Fuel inflator	0.00%	

[Year]	[1] Otter Creek MWH Sales	[2] Hydro O&M	[3] Loan Principal	[4] Loan Int.	[5] Loan Pay	[6] Loan Balance	[7] [illegible] Equity	[8] [illegible] Taxes	[9] [illegible] Insurance	[10] [illegible] Cost
2002	5739	$28,695	$88,036	$417,600	$505,636	$6,960,000	$0	($2,186)	$5,739	$6,960,000
2003	6336	$31,680	$93,319	$412,318	$505,636	$6,871,964	$12,255	$6,054	$6,336	$6,960,000
2004	6715	$33,575	$98,918	$406,719	$505,636	$6,778,645	$24,719	$14,434	$6,715	$6,960,000
2005	7131	$35,655	$104,853	$400,784	$505,636	$6,679,727	$37,388	$22,952	$7,131	$6,960,000
2006	7573	$37,865	$111,144	$394,492	$505,636	$6,574,874	$50,259	$31,606	$7,573	$6,960,000
2007	8015	$40,075	$117,813	$387,824	$505,636	$6,463,730	$63,324	$40,390	$8,015	$6,960,000
2008	8430	$42,150	$124,881	$380,755	$505,636	$6,345,918	$76,576	$49,300	$8,430	$6,960,000
2009	8860	$44,300	$132,374	$373,262	$505,636	$6,221,037	$90,006	$58,330	$8,860	$6,960,000
2010	9313	$46,565	$140,317	$365,320	$505,636	$6,088,662	$103,602	$67,471	$9,313	$6,960,000
2011	9781	$48,905	$148,736	$356,901	$505,636	$5,948,346	$117,352	$76,716	$9,781	$6,960,000
2012	10278	$51,390	$157,660	$347,977	$505,636	$5,799,610	$131,240	$86,054	$10,278	$6,960,000
2013	10801	$54,005	$167,119	$338,517	$505,636	$5,641,950	$145,249	$95,473	$10,801	$6,960,000
2014	11348	$56,740	$177,147	$328,490	$505,636	$5,474,831	$159,359	$104,959	$11,348	$6,960,000
2015	11809	$59,047	$187,775	$317,861	$505,636	$5,297,684	$173,546	$114,498	$11,809	$6,960,000
2016	12000	$60,000	$199,042	$306,595	$505,636	$5,109,909	$187,784	$124,071	$12,000	$6,960,000
2017	12000	$60,000	$210,984	$294,652	$505,636	$4,910,867	$202,045	$133,659	$12,000	$6,960,000
2018	12000	$60,000	$223,643	$281,993	$505,636	$4,699,882	$216,293	$143,240	$12,000	$6,960,000
2019	12000	$60,000	$237,062	$268,574	$505,636	$4,476,239	$230,493	$152,787	$12,000	$6,960,000
2020	12000	$60,000	$251,286	$254,351	$505,636	$4,239,177	$244,602	$162,273	$12,000	$6,960,000
2021	12000	$60,000	$266,363	$239,273	$505,636	$3,987,891	$258,573	$171,667	$12,000	$6,960,000
2022	12000	$60,000	$282,345	$223,292	$505,636	$3,721,528	$272,355	$180,933	$12,000	$6,960,000
2023	12000	$60,000	$299,285	$206,351	$505,636	$3,439,183	$285,890	$190,033	$12,000	$6,960,000
2024	12000	$60,000	$317,243	$188,394	$505,636	$3,139,898	$299,114	$198,924	$12,000	$6,960,000
2025	12000	$60,000	$336,277	$169,359	$505,636	$2,822,655	$311,956	$207,559	$12,000	$6,960,000
2026	12000	$60,000	$356,454	$149,183	$505,636	$2,486,378	$324,338	$215,883	$12,000	$6,960,000
2027	12000	$60,000	$377,841	$127,795	$505,636	$2,129,925	$336,173	$223,841	$12,000	$6,960,000
2028	12000	$60,000	$400,511	$105,125	$505,636	$1,752,084	$347,368	$231,368	$12,000	$6,960,000
2029	12000	$60,000	$424,542	$81,094	$505,636	$1,351,572	$357,818	$238,394	$12,000	$6,960,000
2030	12000	$60,000	$450,015	$55,622	$505,636	$927,030	$367,408	$244,842	$12,000	$6,960,000
2031	12000	$60,000	$477,015	$28,621	$505,636	$477,015	$376,013	$250,628	$12,000	$6,960,000
2032	12000	$60,000	$0	($0)	$0	($0)	$383,496	$255,659	$12,000	$6,960,000
	326129		6960000							

Otter Creek Cost of Energy

Table D-3

30 year life cycle cost analysis
2002 through 2032

Fuel Saved
26,731,921 Gallons
636,474 Barrels

[11] Annual Deprec.	[12] Accum. Deprec.	[13] Net Plant	[14] Project Equity	[15] Hydroelectric Production Costs Total	[16] $/KWH	Diesel Avoided Costs $/KWH [17] Fuel	[18] O&M	[19] Total $/KWH	[20] Avoided Prod Costs Diesel	Avoided Capital Costs Diesel	Capital Costs Diesel	Avoided Diesel Costs
$139,200	$139,200	$6,820,800	0.00%	$589,048	$0.103	$0.055	$0.036	$0.091	$520,650	$900,000	$0	$1,420,650
$139,200	$278,400	$6,681,600	1.26%	$607,842	$0.096	$0.055	$0.036	$0.091	$574,810	$0	$0	$574,810
$139,200	$417,600	$6,542,400	2.61%	$625,361	$0.093	$0.055	$0.036	$0.091	$609,194	$900,000	$0	$1,509,194
$139,200	$556,800	$6,403,200	4.03%	$643,110	$0.090	$0.055	$0.036	$0.091	$646,934	$0	$0	$646,934
$139,200	$696,000	$6,264,000	5.53%	$660,995	$0.087	$0.055	$0.036	$0.091	$687,032	$0	$0	$687,032
$139,200	$835,200	$6,124,800	7.13%	$678,828	$0.085	$0.055	$0.036	$0.091	$727,131	$0	$0	$727,131
$139,200	$974,400	$5,985,600	8.82%	$696,411	$0.083	$0.055	$0.036	$0.091	$764,781	$0	$0	$764,781
$139,200	$1,113,600	$5,846,400	10.62%	$713,958	$0.081	$0.055	$0.036	$0.091	$803,791	$0	$0	$803,791
$139,200	$1,252,800	$5,707,200	12.52%	$731,471	$0.079	$0.055	$0.036	$0.091	$844,888	$0	$0	$844,888
$139,200	$1,392,000	$5,568,000	14.54%	$748,855	$0.077	$0.055	$0.036	$0.091	$887,345	$0	$0	$887,345
$139,200	$1,531,200	$5,428,800	16.67%	$766,139	$0.075	$0.055	$0.036	$0.091	$932,434	$0	$0	$932,434
$139,200	$1,670,400	$5,289,600	18.94%	$783,245	$0.073	$0.055	$0.036	$0.091	$979,881	$0	$0	$979,881
$139,200	$1,809,600	$5,150,400	21.34%	$800,096	$0.071	$0.055	$0.036	$0.091	$1,029,505	$1,800,000	$0	$2,829,505
$139,200	$1,948,800	$5,011,200	23.88%	$815,962	$0.069	$0.055	$0.036	$0.091	$1,071,368	$0	$0	$1,071,368
$139,200	$2,088,000	$4,872,000	26.58%	$829,650	$0.069	$0.055	$0.036	$0.091	$1,088,656	$0	$0	$1,088,656
$139,200	$2,227,200	$4,732,800	29.44%	$841,556	$0.070	$0.055	$0.036	$0.091	$1,088,656	$0	$0	$1,088,656
$139,200	$2,366,400	$4,593,600	32.47%	$852,726	$0.071	$0.055	$0.036	$0.091	$1,088,656	$0	$0	$1,088,656
$139,200	$2,505,600	$4,454,400	35.69%	$863,054	$0.072	$0.055	$0.036	$0.091	$1,088,656	$0	$0	$1,088,656
$139,200	$2,644,800	$4,315,200	39.09%	$872,426	$0.073	$0.055	$0.036	$0.091	$1,088,656	$0	$0	$1,088,656
$139,200	$2,784,000	$4,176,000	42.70%	$880,714	$0.073	$0.055	$0.036	$0.091	$1,088,656	$0	$0	$1,088,656
$139,200	$2,923,200	$4,036,800	46.53%	$887,780	$0.074	$0.055	$0.036	$0.091	$1,088,656	$0	$0	$1,088,656
$139,200	$3,062,400	$3,897,600	50.59%	$893,475	$0.074	$0.055	$0.036	$0.091	$1,088,656	$0	$0	$1,088,656
$139,200	$3,201,600	$3,758,400	54.89%	$897,632	$0.075	$0.055	$0.036	$0.091	$1,088,656	$1,800,000	$0	$2,888,656
$139,200	$3,340,800	$3,619,200	59.44%	$900,074	$0.075	$0.055	$0.036	$0.091	$1,088,656	$0	$0	$1,088,656
$139,200	$3,480,000	$3,480,000	64.26%	$900,604	$0.075	$0.055	$0.036	$0.091	$1,088,656	$0	$0	$1,088,656
$139,200	$3,619,200	$3,340,800	69.40%	$899,010	$0.075	$0.055	$0.036	$0.091	$1,088,656	$0	$0	$1,088,656
$139,200	$3,758,400	$3,201,600	74.83%	$895,061	$0.075	$0.055	$0.036	$0.091	$1,088,656	$0	$0	$1,088,656
$139,200	$3,897,600	$3,062,400	80.58%	$888,506	$0.074	$0.055	$0.036	$0.091	$1,088,656	$0	$0	$1,088,656
$139,200	$4,036,800	$2,923,200	86.68%	$879,072	$0.073	$0.055	$0.036	$0.091	$1,088,656	$0	$0	$1,088,656
$139,200	$4,176,000	$2,784,000	93.15%	$866,462	$0.072	$0.055	$0.036	$0.091	$1,088,656	$0	$0	$1,088,656
$139,200	$4,315,200	$2,644,800	100.00%	$850,355	$0.071	$0.055	$0.036	$0.091	$1,088,656	$0	$0	$1,088,656
$6,960,000				$24,759,477	$0.076				$29,586,891	$5,400,000	$0	$34,986,891
			npv @6%	$11,029,243	$0.034			npv @6%	$12,763,274	$3,095,051	$0	$15,858,325
									$0.0907			$0.1073
									$0.0391			$0.0486

Economic Benefit Summary Tabulation	Nominal $	NPV @ 6.00%	
Diesel Costs	$34,986,891	*$15,858,325*	
Otter Creek Costs	$24,759,477	*$11,029,243*	1.438
Net Benefit	$10,227,413	*$4,829,061*	
Levelized Annual Benefit @ 6.00% over 30 years		*$350,827*	

Table D-3

[annual period]	[21] Annual Savings from Otter Creek vs. Die (Nominal dollars)	[22] 1997 PV by year, 6.00% Discount rate	[23] 1997 PV Cumulative from Otter vs. Diesel
1	$831,601	$831,601	$831,601
2	($33,032)	($31,162)	$800,439
3	$883,832	$786,608	$1,587,047
4	$3,823	$3,210	$1,590,257
5	$26,037	$20,624	$1,610,881
6	$48,303	$36,095	$1,646,976
7	$68,369	$48,198	$1,695,173
8	$89,833	$59,744	$1,754,917
9	$113,416	$71,159	$1,826,076
10	$138,490	$81,972	$1,908,049
11	$166,295	$92,858	$2,000,907
12	$196,636	$103,585	$2,104,492
13	$2,029,409	$1,008,554	$3,113,046
14	$255,408	$119,744	$3,232,791
15	$259,005	$114,558	$3,347,349
16	$247,100	$103,106	$3,450,455
17	$235,930	$92,873	$3,543,328
18	$225,602	$83,780	$3,627,109
19	$216,230	$75,755	$3,702,864
20	$207,942	$68,728	$3,771,591
21	$200,875	$62,634	$3,834,225
22	$195,181	$57,414	$3,891,639
23	$1,991,024	$552,519	$4,444,158
24	$188,582	$49,370	$4,493,528
25	$188,052	$46,445	$4,539,973
26	$189,646	$44,187	$4,584,160
27	$193,595	$42,554	$4,626,714
28	$200,150	$41,505	$4,668,219
29	$209,584	$41,001	$4,709,220
30	$222,194	$41,007	$4,750,227
31	$238,301	$41,491	$4,791,718
	$10,227,413	$4,791,718	
npv @6%	$4,791,718		

Exhibit 2

<u>**DECLARATION OF SOPHIE MCKINLEY**</u>

I, Sophie McKinley, declare the following:

1. The facts stated herein are known personally to me.

2. I am 73 years old. I currently reside at 9061 Miners Ct., Juneau, AK 99803.

3. I am the sole owner of the George Allotment. The deed to the allotment identifies it as U.S. Geological Survey Plot # 945, and specifies 103.75 acres within Glacier National Monument. My allotment is located less than a mile west of Falls Creek within the boundary of Glacier Bay National Park.

4. I inherited the allotment upon my husband's, Levi McKinley, Sr., death in 1993. My husband inherited the Allotment from his maternal grandfather, Charlie George. Charlie George applied for the Native Allotment in 1909; it was conveyed to him in 1922. My husband spent much time and energy on matters related to the allotment. He felt strongly that it remain in our family and be passed on to our five children.

5. Our family ties to this land pre-date the establishment of Glacier Bay National Monument. The Tlingit are seasonal, and used the area for subsistence activities including hunting, fishing, trapping, and collecting edible plants and other materials. My family will continue to use the land for these customary and traditional activities.

6. Re-designation of federally owned wilderness land to state owned land will reduce the level of protection afforded the land, making it available for road building, timber harvest, rock pits, quarries, increased access and other development and uses on lands adjacent to my allotment. It will open the area to increased access and will result in increased use by other hunters, trappers, all terrain vehicle operators, and recreational users. Increased use will

cause injury to me, in the form of trespass, property damage, excessive traffic, increased noise, and possible liability. I also fear increased access will result in destruction of fish and wildlife habitat, which will adversely affect my family's subsistence use of the allotment. These injuries will cause the economic value of my land to decrease.

7. Increased access by others will also diminish the allotment's cultural, ecological and spiritual value for my children, future generations and me. It would negatively impact our sense of solitude and security.

8. I do not want increased commercial development of the area surrounding my allotment. Development near my allotment will decrease its economic value, and will diminish the value of my family's ongoing customary and traditional use of this property. Although currently I am not interested in developing my allotment, I fear that the proposed hydropower project will limit my future options to do so. I am not interested in selling any developmental rights, or rights of way, to or across my property to Gustavus Electric Company.

9. I do not agree that the applicant has adequately or responsibly addressed the cumulative negative impacts that the proposed project will have on the value of native owned properties adjacent to the project area. The Section 810 analysis, Appendix C in the Draft Economic Impact Analysis (DEIS), fails to acknowledge, let alone thoroughly analyze, the numerous adverse impacts to subsistence uses in the study area and adjacent federal land areas. I believe more time is needed to provide complete information to determine the potential impact on subsistence activities. I favor the no-action alternative discussed in the DEIS.

I declare under penalty of perjury of the laws of the State of Alaska and of the United States of America that the foregoing is true and correct and that this declaration was executed through the Tribal Offices of the Hoonah Indian Association located at 254 Roosevelt, Hoonah, Alaska 99829.

Respectfully Submitted,

Dated: January 6, 2004

____

Sophie McKinley,
George Allotment Owner

Exhibit 3

DECLARATION OF THOMAS MILLS SR.

I, Thomas Mills Sr., declare the following.

1. I am 58 years old. I currently live in Hoonah, Alaska.

2. I inherited the Albert Mills Native Allotment from my grandfather Albert Mills. I am teaching my children to become the next generation of caretakers for the land. My family's claim to the land pre-dates the establishment of the Glacier Bay National Monument in 1925. My grandparents lived there in a log cabin with a tent roof. It was my grandfather who recorded the family's claim to the land. I lived on the allotment with my grandparents until I was nine years old and forced to attend school.

3. Falls Creek, also known as *Kahtaheena River*, goes through the Albert Mills Native Allotment. This "Restricted" land is under the protection of the Secretary of the Interior who holds "Trust Responsibility" to this Native Allotment. This stream is as important to us today, as it was to our ancestors, who chose it for its customary and traditional value. We are culturally and spiritually connected with this land.

4. My children and I use the land for subsistence uses, including fishing, crabbing, hunting, and gathering edible, medicinal plants and other materials. Currently, my family and I spend as much time as possible at the allotment, and in the next month I plan to move there permanently from Hoonah. Once I move, I plan to rely almost exclusively on what the land provides for survival. Falls Creek is the exclusive source of drinking water on the allotment.

5. I have been diagnosed with cancer, and have chosen to treat it with medicinal plants that I find along the creek. I learned the medicinal qualities of plants from my

grandmother who was a shaman. My chosen treatment has been effective, which has baffled doctors in Washington State.

6. I am a disabled United States veteran from the Vietnam War. I must live in the cabin on my family's allotment because of my need for solitude. The allotment is my refuge. It is beautiful, quiet, and inhabited by numerous wild animals. This land is unique, and extremely valuable.

7. I am opposed to the proposed hydropower project on Falls Creek. The project will degrade the value and purposes of our inheritance through increased access and development. These impacts will harm the natural systems of the surrounding fish and wildlife habitat. I worry that the project and increased access will degrade the water quality, my sole source of drinking water, and possibly destroy the medicinal plants and herbs that I use to treat my cancer.

8. Since the hydroelectric project was proposed, I have seen Gustavus Electric Company (GEC) employees walking across my allotment without my permission on several occasions. If the project is approved, I expect instances of trespass by GEC employees will increase. I am not interested in granting GEC any easements across my allotment.

9. Vandalism is an increasing problem to my cabin and personal property since the project was first proposed. I have had 17 crab pots, 5 machetes, 5 splitting axes, and my great grandfather's Winchester rifle stolen. In addition the door to my cabin and several locks have been chopped off, and new sleeping bags and dry goods ruined. I fear that increased access to the project lands will increase incidents of vandalism to my property.

10. In the 1990s, I filed an individual water rights claim with the Alaska Department of Natural Resources and paid $500 for it. The State cashed my check. I applied for five million gallons of water a day to supply one to five houses and the rest of the water to protect the spawning salmon and different species of ocean trout. There is not enough water in this system to sustain my use, salmon and other natural fish habitat, and a hydropower project. Falls Creek fluctuates a great deal. Flow is often reduced to trickle in cold temperatures, and warm days without rain. Individual water rights are not addressed in the Draft Environmental Impact Statement (DEIS) for Project 11659.

11. Moose, bear, otter, wolves and ducks use the river and geese, swans and cranes heading north and south, set down to feed and rest on the mud flats of Falls Creek. My family, friends, and I refer to it as their "Pit Stop". Seeing and hearing the birds brings us great joy and happiness. If the creek were altered, it would have a devastating effect on those migrating birds. Human activities must not be allowed to risk damaging this protected habitat. Impacts relative to the Migratory Bird Act have not been considered adequately in the DEIS.

12. Mother Nature maintains the creek by flooding out and cleaning the spawning beds of silt and wood debris. This would not happen if the hydroelectric plant was installed and the natural flow altered. Again, traditional ecological knowledge tells us that human activities risk damaging this protected place. The analysis in the DEIS is inconsistent with traditional, sustainable land use principles.

13. As a Huna Tlingit, I have long been dismayed with the history of regulations and protections that the National Park Service (NPS) put so firmly in place within our ancestral homeland. For generations the federal government has denied original occupants of Glacier

Bay access for subsistence use. For the federal government to now consider allowing a project that involves the exchange of designated Wilderness to the State of Alaska for the purpose of providing a small private group of utility investors an opportunity to exploit the limited water resources of Falls Creek and its surrounding environment is irresponsible and disrespectful.

I declare under penalty of perjury of the laws of the State of Alaska and of the United States of America that the foregoing is true and correct and that this declaration was executed at the Tribal Offices of the Hoonah Indian Association, 254 Roosevelt, Hoonah, Alaska 99829

Respectfully Submitted,

Dated: January 6, 2004

____

Thomas L. Mills, Sr.
Mills Allotment Owner

Exhibit 4

DECLARATION OF JACK HESSION

I, Jack Hession, declare the following:

1. I have lived in Alaska since 1968, in Fairbanks, Juneau, and Anchorage (since 1971). Since December 1970 I have been employed by the Sierra Club in the Alaska Office in Anchorage. My current position is Senior Regional Representative.

2. The Sierra Club has a long history of interest in Glacier Bay National Park and Monument and its protection. John Muir, founder of the Sierra Club, traveled to Glacier Bay beginning in 1879. His publications describing its natural wonders were instrumental in the eventual designation of the area as a national monument in 1925.

3. More recently, the Sierra Club participated in the national campaign to enact the Alaska National Interest Lands Conservation Act of 1980, in which Congress added approximately 525,000 acres to the monument and established a 57,000-acre national preserve; re-designated the unit as a national park and preserve, and designated most of the new park/preserve as wilderness, including about 9 percent of the marine waters.

4. Over the years the Sierra Club has defended the park against proposed developments and activities that would impair its values and resources. The Sierra Club helped block legislation to legalize commercial fishing, and was at the forefront of the successful effort to phase out commercial fishing in Glacier Bay proper. An effort continues to limit cruise ship entries to an appropriate level. Currently, the Sierra Club is an intervener with several other conservation organizations and individuals in the Federal Energy Regulatory Commission's consideration of a license application for a hydroelectric power project in the Glacier Bay Wilderness.

5. The Alaska Chapter of the Sierra Club has members in Gustavus and in Juneau who are familiar with the park/preserve, including the Falls Creek area. Sierra Club members from elsewhere in Alaska and the nation have also visited the park. I have visited the park several times beginning in 1972, including two trips down the Tatshenshini River in the Glacier Bay wilderness. I have not visited the Outer Coast south of Dry Bay, but am looking forward to a trip into this least-traveled part of the park/preserve. I have visited the Falls Creek area twice, including an October 2003 hike with Sierra Club leaders from Gustavus and Juneau.

6. The Falls Creek drainage is an especially important component of the Glacier Bay Wilderness, as I know from personal experience that allows me to compare the drainage with other areas of the park I have visited, and as documented in the Draft Environmental Impact Statement on the proposed Falls Creek hydro project (FERC/NPS, October 2003). The Falls Creek drainage offers a range of diverse habitats and landscapes, including an estuary, tidal flats, marsh, wet meadows, old-growth forest, muskegs, fens, and alpine tundra, all in a relatively small area. Opportunities for viewing wildlife are excellent, and the falls of Falls Creek, and the creek itself, are well worth the visit. This area is unique in the park in being close to Gustavus, allowing park visitors easy access.

7. If a hydroelectric project were licensed, Falls Creek and much of its drainage would be seriously impaired and lose its value as national park land. It would be marred by the construction and operation of the project features-dam, penstock, powerhouse, project roads, borrow pits etc. Several hundred acres of park wilderness would be transferred to the State and face an uncertain future. Given the State's mediocre land management record, the

outlook for the ex-park lands would be grim. Commercial development and land disposal would be a definite threat, and the effects of such development would be felt on the adjacent parklands, further impairing park resources and values.

8. If the project were authorized, the Falls Creek area would be shunned by Sierra Club members, who would be most conscious of the loss of park values and resources, and the outright loss of several hundred acres of prime wilderness. Our members would have no interest, for example, in visiting the Lower Falls, passing the powerhouse and its related facilities on the way, to view an unnatural, reduced flow over the falls.

9. As a Falls Creek project would be the first new hydroelectric facility in a national park in decades, it would represent a crack in Congress's long-standing policy of no new dams in the national parks, and therefore might invite proposals by the hydropower industry to dam rivers in other national parks and wilderness areas in Alaska, and perhaps elsewhere in the nation.

I declare under penalty of perjury of the laws of the State of Alaska and of the United States of America that the foregoing is true and correct and that this declaration was executed at 201 Barrow Street, Ste. 101Anchorage, Alaska 99501-2429.

Respectfully Submitted,

Dated: January 6, 2004

____
Jack Hession,
Senior Regional Representative
Sierra Club – Alaska Office

Exhibit 5

DECLATION OF MIKE OLNEY

I, Michael Olney, declare the following,

1. The facts stated herein are personally known to me.

2. I am 40 years old. I currently reside at the end of Rink Creek Road, Gustavus, Alaska. I own 97 acres there. I have lived in Gustavus, Alaska for 11 years. I own and operate Glacier Bay's Bear Track Inn.

3. Glacier Bay's Bear Track Inn is a multi million-dollar lodge that caters to outdoor enthusiasts. I host approximately 1,000 guests every year. My guests are attracted by the pristine wilderness experience our inn offers.

4. I have paid utilities to the Gustavus Electric Company (GEC) for the past eight years. During this time GEC has charged the most expensive electricity rates in the country. The average monthly bill, which only covers lighting and refrigeration, is about $2,000 per month. I am seriously considering going off-line because GEC power is too expensive. Several other local lodge and business owners agree. I could generate electricity at half the cost GEC charges by installing my own diesel generator. I also have done extensive research on alternative, clean energy sources such as fuel cells. I am not willing to pay the higher rates that would likely result if the project is built.

5. My resolve to go off-line was strengthened when GEC ran unregulated current through its transmission lines on October 15, 2003. The resulting power surge cost me over $10,000 in damage, and I expect that is not the full extent of the damage. The following appliances were either damaged or destroyed: a commercial dishwasher, smoke alarms and power strips throughout the building, an ice machine, a satellite television receiver, three

computers, water pumps for the fish ponds, and a microwave. I was out of the state when the power surge occurred, and was forced to make an unplanned trip to Gustavus at my own expense to assess the damage. I had to make time to meet with vendors and repairmen to repair or replace the damaged appliances, and negotiate with my insurance company. I have spoken to GEC representatives, and written two letters to them regarding the power surge. To date I have not received an apology or a course of action as to how they will compensate me.

6. I am strongly against the proposed hydropower project. The proposed project will have numerous adverse impacts on my business and myself.

7. I expect to lose 50% of my business during the estimated 2-year period of construction for the project. When the road that runs through Glacier Bay National Park was widened, 90% of Glacier Bay Lodge's customers complained and demanded a refund because the bulldozers, chainsaws, fires, and other loud, disturbing activities ruined their wilderness experience. This does not equate with anyone's idea of a wilderness lodge. I expect a similar effect on my business if GEC constructs the access road and transmission line to the project. Approximately 99% of my customers take hikes to Falls Creek. They will be unable to do so during proposed project construction.

8. Business at the Inn will also suffer from the excess traffic after completion. Because I currently live at the end of the road, there is little to no traffic. After the project is completed there will be at least twice as much traffic. Although the location of the access road has not been determined yet, I have been told by GEC that the access road will either go through the middle of my property, or I can pay $19,000 to have the road go around my

property. GEC does not believe it has a duty to protect my property or the interests of my business.

9. Currently my business is adjacent to parkland. If that land is transferred to the state, my business will suffer and the value will decrease significantly. My property is worth more due to the fact that it adjoins Glacier Bay National Park. If the land transfer occurs, my property will no longer have direct access to the park.

I declare under penalty of perjury of the laws of the State of Alaska and of the United States of America that the foregoing is true and correct and that this declaration was executed this 6 January 2004 at Glacier Bay's Bear Track Inn, Gustavus, Alaska 99826.

Respectfully Submitted,

Dated: January 6, 2004

____

Mike Olney,
Glacier Bay's Bear Track Inn Owner

Exhibit 6

January 6, 2004

Magalie R. Salas, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Draft Environmental Impact Statement, Falls Creek Hydroelectric Project (FERC No. 11659) and Land Exchange.

Dear Secretary Salas:

The Sierra Club is an intervener in the Federal Energy Regulatory Commission's (FERC) consideration of an application by Gustavus Electric Company (GEC) to construct a hydroelectric project on Falls Creek within Glacier Bay National Park and Preserve, Alaska. Our intervention is in opposition to the proposed project.

On behalf of the Sierra Club, I am submitting the following comments on the Draft Environmental Impact Statement (DEIS) on the Falls Creek Project (project). The comments refer to the impacts of the project on the values and resources of the park. For our views on the issue of economic feasibility of the project, please see the report prepared by Eric Cutter and David Deputy entitled Economic Analysis of the Proposed Gustavus Electric Hydro Project and Potential Alternatives.

I am also attaching the comments of the Juneau Group of the Alaska Chapter of the Sierra Club.

The Sierra Club recommends adoption of the No-Action Alternative.

<u>Major omissions of the DEIS</u>

In the Glacier Bay National Park Boundary Adjustment Act of 1998 (Act), Congress specified that the project may be licensed if FERC and the Secretary of the Interior (Secretary) conclude that the proposed project would not adversely affect the purposes and values of the park as constituted after the land exchange authorized by the Act. In addition, FERC must determine if the proposed project would be economically feasible.

On the issue of park impacts, FERC staff concludes that GEC's proposal and two variations on it—the Maximum Boundary Alternative and the Corridor Alternative—would not adversely impact the purposes and values of GBNPP as constituted after the land exchange. However, the conclusion of the National Park Service (NPS) staff on this key question is missing, an omission that is particularly troubling because the NPS is the agency best qualified to evaluate the likely effects of the project on park values and resources.

On the issue of economic feasibility, the DEIS does not include a FERC staff conclusion, even a preliminary one, despite the staff's finding that the proposed project would lose several hundred thousand dollars annually for several years following its construction.

Thus Congress's two basic questions have gone unanswered in the DEIS. A complete answer on park impacts requires both FERC and the Secretary to respond, but only FERC has responded. And FERC staff has not provided its conclusion on economic feasibility.

These omissions undercut the credibility and utility of the DEIS, and they indicate a failure on the part of FERC and the NPS staffs to fully comply with the requirements of the Act.

<u>Specific comments</u>

xxviii, <u>line 29</u>, and 2-2, <u>lines 15-23</u>. A 12-foot-high, 150-foot-wide structure is described as a "diversion/intake structure." Such a structure is obviously a dam that includes an intake structure, as shown in Fig. 2-6. Why is this feature not described as "dam with diversion/intake structure?"

xxix, <u>13-24</u>. The adverse effects listed would destroy the value of a visit for those interested in a true park experience. In addition to solitude and quiet, a true park experience includes aesthetic appreciation, wilderness appreciation in the event the park area is designated wilderness, an opportunity to view wildlife not hunted or trapped, and the enjoyment and challenge of traversing pristine and often rugged landscapes. If the project was constructed and hundreds of acres dropped out of the Glacier Bay Wilderness, most persons seeking a true national park experience would avoid visiting the project area.

xxix, <u>24-27</u>. GEC's Proposed Alternative "…could provide additional recreational opportunities that are not currently allowed on GBNNP lands (e.g., all-terrain vehicle (ATV) use, dog walking, hunting, trapping) and could provide a positive experience for those visitors." The FEIS should also acknowledge that visitors seeking a true park experience could have a negative experience when encountering persons engaged in the additional recreational opportunities.

xxix, <u>35-38</u>: "Overall wilderness resources in GBNPP would be diminished because the wilderness parcels that would be designated elsewhere in [the park] would not contain the same qualities as the wilderness lands that would be removed from the project area."

Wilderness resources in the park would be diminished but not for the reason cited. Wilderness resources would be lost outright due to the hundreds of acres of designated wilderness that would be cut out of the park under the three action alternatives. Park wilderness adjoining the deleted acreage would be diminished if activities allowed on the former park land intentionally or unintentionally spilled over into the adjoining park.

xxix, 38-40. "However, this [diminishment of wilderness resources] would not result in an overall adverse impact on park wilderness, as the reduction in wilderness values would be compensated by more than 2.5 million acres of designated wilderness that would remain in existence."

The above quote is a classic *non sequitur*. A reduction of wilderness resources would result from the transfer of hundreds of acres of park wilderness (680, 850, or 1145 acres) into state ownership for hydropower development and other uses not allowed on park lands. This deletion cannot be compensated for by the mere presence of wilderness elsewhere in the park.

xxxi, 15-18. "…over time this effect would diminish and could result in a positive effect on park management as the state of Alaska takes over management of the fisheries resources and recreational opportunities in the conveyed stretch of the Kahtaheena River."

It is wishful thinking to assume that the State would take over active management. The Falls Creek project area the State would own, whether 680, 850, or 1145 acres in size, would be an isolated tract unsuitable as a management unit. The State would be unlikely to expend funds to manage it, even if the State could afford the expense. The State faces years of severe budget shortfalls, with existing programs being eliminated or cut back and state employees being laid off.

xxxi, 24-26. "The Maximum Boundary Alternative would include GEC's proposed environmental measures and the additional FERC staff recommended environmental measures that would be needed to protect, mitigate, and enhance environmental resources." It is not desirable to try enhancing pristine, unimpaired resources that need no enhancement. Protection for these resources could be maintained at the current high level—the highest level available under federal law—by selecting the No-Action Alternative.

xxxi, 26-28. "The estimated project costs of the project and proposed mitigation and environmental measures under the Maximum Boundary Alternative would be the same as under GEC's alternative." Cost figures presented on p. xxx, 1-4, and 16-19, show that the Maximum Boundary Alternative would cost significantly more than the GEC Alternative.

1-1, 4-16. This paragraph notes that the Glacier Bay National Park Boundary Adjustment Act of 1998 "…authorizes FERC to accept and consider a hydroelectric license application" from GEC. The FEIS should acknowledge that the Act was necessary because Congress, in enacting the Federal Power Act, does not allow the Commission to accept license applications for new hydropower projects within national parks.

1-20, 4-7, 1-21, 6-33, 1-22, 35-37, and 1-23, 1-4.   "According to NPS policy, an effect could constitute impairment to the extent that it affects a resource or value whose conservation is necessary to fulfill specific purposes identified in the establishing legislation or proclamation of the park…"

Among the specific purposes identified for national conservation system units in the Alaska National Interest Land Conservation Act (ANILCA) are "to protect and preserve...rivers" and "to preserve wilderness resource values and related recreational opportunities… on freeflowing (sic) rivers." (ANILCA Sec. 101(b)). This purposes does not appear in the DEIS's otherwise complete list of ANILCA purposes and mandates. The omission was probably an oversight.

Unfortunately, the omission means that the effects of the project on the Kahtaheena River as a free-flowing river were not among the issues and effects topics analyzed in the DEIS.   According to NPS policy, "Before approving a proposed action, an NPS decision-maker must consider the effects of the proposed action and determine, in writing, that the activity will not lead to impairment of park resources and values." (1-20, 12-13). Accordingly, the final EIS should include an analysis of the effect the project would have on the free-flowing quality of Falls Creek and its associated wilderness values and related recreational opportunities, then determine whether or not the project is consistent with the intent of Congress in ANILCA and NPS policy.

1-31, 28, and 1-32, 11-12.   In referring to an exchange of Falls Creek project lands for state lands at Long Lake in WSE NPP, the FEIS should state that the NPS would be trading national park wilderness acreage (Falls Creek) for land that would become national preserve non-wilderness.   How would this trade constitute an equal value exchange, as required by the Act?

2-6, 13-16. GEC proposes a lease agreement with ADNR that limits vehicles on the access road to those necessary to construct, operate, and maintain the project.   Does the ADNR Northern Southeast Area Plan include a provision for restricting use of the access road as proposed by GEC? A provision prohibiting snowmobiles and all-terrain vehicles on the project lands the State would acquire?

4-16, 31-37.   Importing project road materials from outside the project area.   If GEC has to bring in road construction materials from outside the project area, as the NPS did in building its new road to Bartlett Cove, what would be the estimated increased cost of the Falls Creek project? Did FERC staff include an estimate of the increased road construction costs in its analysis of economic feasibility of the project?

In summary, the impact analysis of the DEIS indicates that the proposed project would result in major adverse effects on the values and resources of the park and the Glacier Bay wilderness. The project has also been found to be economically infeasible, although FERC staff stops short of stating this obvious conclusion of its economic analysis. Consultants to the Sierra Club Alaska Chapter have also found the project to be economically infeasible.

The Sierra Club recommends rejection of the GEC license application.

Thank you for this opportunity to offer our views.

Sincerely,

Senior Regional Representative
Sierra Club

Hoonah Indian Association

PO Box 602
Hoonah, Alaska 99829
Phone (907) 945-3545

January 5, 2004

Federal Energy Regulatory Commission
Attn: Magalie R. Salas, Secretary
888 First Street, N.E.
Washington, D.C. 20426

RE: Comments on the DEIS regarding FERC Project No. 11659-002, Falls Creek (Kahtaheena River) Hydroelectric Project and Land Exchange, Alaska.

The Hoonah Indian Association is a federally recognized tribe in accordance with and by the authority of the Acts of Congress of June 18, 1934 (48 Stat. 984) and May 1, 1936 (49 Stat. 1250). We submit these comments for review by the Federal Energy Regulatory Commission and the National Park Service with respect to the Government-to-Government Relationship that we share based on this federal recognition.

Dear Members of the Commission,

Sharing a common bond of ancestral family lineage, Hoonah Tlingit people have been recognized by practically all authors dealing with the Tlingit as the original people occupying the Icy Strait Region, including all of Glacier Bay and the surrounding area, prior to European contact and recorded history.

The lands, waters, forests and streams of Glacier Bay National Park and Preserve, including the area now called Gustavus, are and will always be recognized as our Ancestral Homeland. It is this place that for many generations has and will continue to define the Huna People.

Although some archeological sites in and around traditional Huna territory indicate human occupation of the area nine thousand years ago by an early culture, evidence of a material culture much like that of the Huna Tlingit of the historic period has been dated in this area from five hundred to nine hundred years ago. Indeed, the connection of the Huna People with this *place* is pre-historic and was certainly well established and recognized at the time Huna seal hunters introduced John Muir to Glacier Bay, less than one-hundred and twenty-five years ago.

Further evidence of historical occupancy in the Glacier Bay area is demonstrated by the number of Native Allotments located in and around the Park. The Mills Family Allotment and the Charlie George Family Allotment are two such native allotments that are in the immediate vicinity of the proposed Falls Creek Hydroelectric Project.

As Theodore Catton so accurately suggests in his 1995 work, *Land Reborn: A History of Administration and Visitor Use in Glacier Bay National Park and Preserve,* "…most Hoonah Tlingits feel a spiritual or cultural connection to Glacier Bay drawn from their clan legends and origin myths."

This coherence to *place* remains strong today and it is for this reason that the Hoonah Indian Association opposes the proposed exchange of federally protected Wilderness lands within Glacier Bay National Park and Preserve, to the state of Alaska, for the development of a private hydroelectric utility on Falls Creek. For us this is an unacceptable prospect and we ask that the National Park Service not consider further, setting this precedent.

For over seventy-five years the Huna People have had a long and often tumultuous relationship with the federal caretakers of the land we consider to be the heart of our sacred, ancestral home. In that time our loss and diminished customary and traditional opportunity, within the Glacier Bay National Park and Preserve has been substantial. Occupation of historical dwelling sites and access to many subsistence resources and traditional opportunity has been denied, justified by National Park Service purposes and values.

Yet, in spite of past events, positive progress has been forged in recent years, relative to our to our relationship with the local managers of Glacier Bay National Park and Preserve. This is in part due to efforts by the National Park Service to acknowledge the Huna People's connection to this *place* and the National Park Service's commitment to its protection. To support the exchange of these federally protected Wilderness lands, to the state of Alaska for the development of a private utility, owned by a small group of private investors, is seen as a conspicuous violation of that commitment.

The Hoonah Indian Association is proud that our ancestral home has been acknowledged as an *International Treasure* having been recognized by the United Nations in 1986 as a Biosphere Reserve and in 1992 as a world Heritage Site. It shares this designation with three contiguous areas, including Wrangell-St. Elias National Park and Preserve, the Tatshenshini-Alsek Park in (Canada) and Kluane National Park and Reserve (Canada). Together, these parks form a 25 million acre reserve making it one of the world's largest internationally protected wild areas.

To dismiss this status by allowing an exchange of lands for the development of the Falls Creek Project is unthinkable. We would expect the international community to support us in this determination.

Certainly, the Gustavus Electric Company seeks an extraordinary privilege that the Hoonah Indian Association cannot support. We feel that to continue this consideration would be a violation of National Park Service policy in that this project would impair the value of lands and cultural landscapes whose conservation is key to the natural and cultural integrity of Glacier Bay National Park and Preserve.

The Hoonah Indian Association determines that the lands and waters of the proposed project area must be preserved in their natural state and recognized for their nationally, indeed internationally significant scenic, historical, wilderness, cultural, and wildlife values. We disagree with the determination that the proposed actions, within the Falls Creek Hydroelectric Project area, would not affect any traditional cultural properties and we feel it would indeed constitute a gross violation of Glacier Bay National Park and Preserve's intended purpose and the trust we continue to develop with the National Park Service regarding our ancestral home.

We thank you for this opportunity to submit these comments regarding the Gustavus Electrical Company's application for the Falls Creek Hydroelectric Project, FERC number 11659-002.

Respectfully,

____________________________ __________________________

Frank Wright Jr.
President
Hoonah Indian Association

Date

____________________________ __________________________

Johanna K. Dybdahl
Tribal Administrator
Hoonah Indian Association

Date

January 5, 2004

Magalie R. Salas, Secretary
Federal Energy Regulatory Commission
888 1st Street NE
Washington, DC 20426.

Chad Soiseth
P.O. Box 294
Gustavus, AK 99826

Re: FERC No. 11659-002 Falls Creek Hydroelectric Project and Land Exchange

Dear FERC,

As a Gustavus citizen, I must comment on the Glacier Bay National Park and Preserve Falls Creek Hydroelectric Project and Land Exchange (FERC No. 11659-02). I am adamantly opposed to this project and urge you to select the No Action alternative for this project as outlined in the October 2003 Draft Environmental Impact Statement. My specific comments are outlined below.

First and foremost, I am opposed to this project on basic principal. National Parks were created to protect our collective national heritage treasures for public enjoyment now and in the future. Opening up any national park for development and exploitation of natural resources (be it minerals, timber or hydropower) is just plain wrong. Congress' passage of Public Law 105-317 (the Glacier Bay National Park Boundary Adjustment Act of 1998), in my opinion, is a violation of public trust. Removing designated wilderness status from federal lands is equally objectionable. National parks and wilderness designation were created to prevent these types of activities.

Second, the estimated costs for construction of this project appear to have been grossly underestimated. Despite this underestimate, the project does NOT appear to be economically feasible, in direct violation of Section 2 (6) (c) (1) (C) of the Glacier Bay National Park Boundary Adjustment Act of 1998 (Public Law 105-317). Project costs do not accurately reflect connecting the National Park Service to this project, the existence of previous cost estimates for a similar project in 1984 by the Corps of Engineers or other associated costs. These suggest the true cost of this project is underestimated by at least half of what the true costs would be.

Gustavus Electric Company (GEC) estimates cost of construction for this project at $4.2 million. These projected costs are simplistic and overly optimistic. They assume that the National Park Service (NPS) will tie in to the project and comprise a significant portion (ca. 25%) of demand. Yet, project costs do not consider the cost of connecting the NPS facility with the existing GEC power grid. These costs (estimated at ca. $500K per mile) could double the cost of this project.

The U.S. Army Corps of Engineers (COE) previously evaluated a small-scale hydropower project in the Falls Creek area. Their 1984 report (citing rugged terrain and poor foundation conditions along the penstock route) states, "The estimated first cost of this project is $7,958,000." This is nearly twice the amount of the projected GEC cost for the Falls Creek hydro project despite the fact that these estimates were almost two decades ago. The COE concludes that "The selected plan would be uneconomical because construction costs . . . would be high." Further, they state that ". . . no further study . . . is recommended . . . as the project would not pass the Federal economic evaluation criteria." In the final analysis the COE determined that "The Falls Creek hydroelectric plan is not capable of recovering the estimated cost of construction, operation, and maintenance over a 50-year project life at a rate competitive with a diesel system." Although the COE evaluated project was different[2] from the proposed GEC project, the cost difference suggests the current GEC cost estimate to be overly optimistic[1].

The project as it stands appears to be only marginally viable assuming unrealistic high population growth and power demands as well as increased diesel fuel costs. Moreover, it would not completely replace diesel-powered generation due to inadequate flows. I respectfully request the FERC conduct a more realistic assessment of project construction and operation costs. Costs should incorporate connection of the NPS facility with the GEC power grid, accurate accounting of the costs of road construction, cable trenching and material, and project structure construction costs as well as Rink Creek Road maintenance and road repair costs (see further comment below) among other unaccounted costs. All costs should be itemized and incorporated into the final EIS document. FERC/NPS's draft EIS states "A positive annual net benefit would occur in 2016 if both diesel fuel costs and generation are higher than our baseline projects. However, the 2016 annual net benefit would be negative under all other scenarios that we examined (see Fig. 6-8 FERC/NPS 2003)." A more realistic accounting of project costs, population growth and corresponding demand as well as diesel and construction-associated costs would make this project even less economically viable.

Third, I am opposed to this project because the GEC preferred instream flow would likely not be adequate to sustain the lower reach of resident Dolly Varden char during operation

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[1] U.S. Army Corps of Engineers (COE). 1984. Small scale hydropower for Gustavus, Alaska. Letter Report, June 1984. Alaska District, U.S. Army COE. Anchorage, Alaska.

[2] The 1984 COE project includes a 20 ft. high, 100 ft. wide diversion dam; 1,200-1,800 ft. of 34 in. diameter penstock; 170-185 feet of head; prefabricated powerhouse with two 400 KW generators; 2 mile long access road, ten mile long transmission line to Bartlett Cove and 2 mile long spur line between Falls Creek and the Gustavus powerplant.

of the proposed project. Although other isolated Dolly Varden populations are known to occur in other areas of Southeast Alaska, this population may be the only isolated population in Glacier Bay National Park. Although this is not known for certain, it makes good sense to protect and preserve, rather than impact this population. Some would say that the project impacts only a portion of the Falls Creek Dolly Varden population (an estimated 14%). Yet, fish in this lower reach may be genetically unique (more diverse) compared with Dolly Varden higher up in the watershed. The No Action alternative would ensure continued genetic diversity of Dolly Varden char throughout the Falls Creek drainage. The 5 cfs minimum winter instream flow is likely inadequate to support Dolly Varden due to icing conditions. Such low flows at this time of year would likely further stress resident fish exhibiting poor reproduction and recruitment under existing natural conditions.

Finally, GEC proposes to access the proposed building site over Rink Creek Road. I live along this road, which is maintained and repaired at direct cost to Rink Creek residents. This road is not built to state standards. It is extremely narrow, low in elevation and subject to flooding. It is comprised primarily of sand and clay sediment. Proposed project construction site access would require crossing an old log bridge about half a mile from the current end of the road.

The Rink Creek Road becomes nearly impassable to vehicles at certain times during fall flooding and spring break up. In fact last spring, travel was limited only to high-clearance, four-wheel drive vehicles due to extreme rutting and deep mud. Portions of this road have washed out due to flooding and have become impassable for up to two days at a time on more than one occasion over the last five years.

It is not fair for Rink Creek residents to be burdened with the increased costs and maintenance needs that will be required should this project be approved. I am concerned about the increased traffic, dust, noise, rutting and impacts to the road and bridge that project-associated traffic will incur. It is unknown whether the existing log bridge will even support the heavy equipment and traffic associated with this project. In recent public meetings, GEC says that they will be a good neighbor . . . maintain the road and rebuild the Rink Creek Bridge if necessary. Yet, the cost of the project evaluated in the draft EIS does not reflect the costs of maintaining the Rink Creek road or a bridge rebuild. GEC will likely not be concerned with the impact of Rink Creek Road traffic associated with the proposed project but rather on their bottom line.

Thank you for the opportunity to comment. I trust you will do the right thing. I can't see how this project could possibly be allowed to proceed given that it is not economically viable, will still require diesel fueled power generation and will likely increase utility costs to the consumer.

Sincerely,

Chad Soiseth

Wayne Howell
P.O. Box 32
Gustavus, Alaska 99826

To: Magalie R. Salas, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426
FERC Project No: 11659-002

These comments are an addendum to my comments provided at the public meeting held in Gustavus in December. I reiterate here that I am concerned that Gustavus Electric Company has grossly underestimated the cost of the project. For example, I refer to the study conducted by the US Army Corps of Engineers in the early 1980s. That study estimates the cost of the hydroelectric project on the lower stretch of Falls Creek at $7.95M n 1980 dollars. Gustavus Electric Company, in order to gain more head and address several environmental concerns, outlines a more ambitious project; they place their diversion structure significantly higher on the stream, requiring more road and penstock, and place the powerhouse in the canyon below the lower falls, requiring an ambitious road construction challenge. Yet GEC estimates the cost of the project at $5.1M in 2003 dollars. I would like the final EIS to address this huge discrepancy, and explain how GEC intends to build a more ambitious project for significantly less money.

I also would like to see a plan and realistic cost estimate for the access road, and how it is to be built. I note that the proposed rock source for the project is located about 1.5 miles into the project area from the existing roadway, meaning that that material will not be available until the road is built to it, requiring that all of the material up to that point will have to be imported. I would like to see a realistic cost estimate for that portion of the project. This road plan cannot sidestep several important issues, such as the need to build a substantial roadbed in the extremely wet lower section (I am personally familiar with the condition of the lower section of the proposed road, having helped a private landowner build an ATV trail through there in the late 1980s). This lower section of road will have to withstand the significant heavy truck traffic that will be required to haul in road material and heavy equipment and haul out logs. The plan and cost estimate should realistically reflect the cost of culverts and drainage ditches, as the area is exceedingly wet.

I am also concerned that the project will take place off the end of a 7 mile long private road. It is unreasonable that the private landowners be expected to pay the cost of maintaining this road, including a bridge structure, both during construction and during the life of the project. I would recommend that if this permit is granted, and the project lands are transferred from Federal to State ownership, that the responsibility for maintaining the road be transferred to the State of Alaska.

I support the No-action alternative. However, if that alternative is not chosen, then I would support the Maximum Boundary Alternative. I support this alternative in that the

FERC project boundary would encompass the entire project area, and hence stipulations written into the permit would pertain to the entire area, and not just lands immediately underlying project facilities, as outlined in GEC's preferred alternative. I do not support the Corridor Alternative because it leads to a fragmented landscape pattern, with parklands sandwiched between project lands and native allotments, and thus very difficult to manage. If the Maximum Boundary Alternative is chosen, I would recommend that the public be able to participate in the process of drawing up permit stipulations so that community concerns be incorporated into the management regime for the project area once it is transferred into State ownership.

Lastly, I am concerned that GEC is currently being investigated by the Regulatory Commission of Alaska regarding its rate structure, which has not been reviewed in more than a decade. Since the economic analysis of this study is dependent upon an accurate set of rate numbers, an accurate analysis is not possible until we are sure that the numbers are reliable and projectible into the future. I would request that no permit be issued until the RCA investigation has been completed, and reliable numbers can be used for the economic analysis.

Wayne Howell
Gustavus

Craig H. Wilson

Box 278
Gustavus, AK 99826
cwilson@gustavus.ak.us
(907)697-2778

January 6, 2004

Magalie R. Salas, Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Dear Secretary:

Subject: FERC Project No. 11659, Falls Creek Hydro Project proposed by Gustavus Electric Company, Gustavus, AK

This letter is a public comment on the draft environmental impact statement (DEIS) for an 800 kW run of the river hydroelectric power plant proposed for Falls Creek near Gustavus, Alaska by the Gustavus Electric Company (GEC). This letter will address issues regarding baseline alternatives as described in the DEIS, economic concerns regarding the economic viability of the project, and cumulative impacts on Gustavus as they are described in the DEIS.

Baseline Alternatives

The suggestion in the DEIS that the choice is either a $4 million hydroelectric power plant or continued use of the present diesel electric generators is incomplete. System efficiency increases through use of improved diesel generators, battery banks, load management, distributed power, and other efficiency improvements have the potential to provide lower cost electrical energy compared to proposed hydroelectric power plant or the current electric power generation system.

Diesel Electric Generator Efficiencies

The cost/benefit analysis in the DEIS assumes a status quo of the current diesel generators at 10 - 13.75 kwH/gallon. It doesn't consider efficiency increases in diesel electric generation, or efficiencies that could be brought about by effectively sizing multiple generator sets to more closely match the electric load demand. Alaska Village Electric Cooperative (AVEC), which provides electric power to small rural villages similar in size to Gustavus, has put in diesel electric generators in several villages that achieve ~17kwH/gallon. A presentation at a rural energy conference in Fairbanks, AK in September 2002 indicated that increases in fuel efficiency of 5% are often sufficient to justify replacement of diesel electric generator sets with more efficient models. Unfortunately, the present arrangement of the State of Alaska's power cost equalization (PCE) program and the close relationship between GEC and the fuel distributor combine to form a powerful disincentive for system efficiency increases.

Another alternative that is overlooked in the DEIS is distributed power, mixing a variety of energy sources. A smaller hydroelectric plant, mixed with more efficient diesel-electric generators and battery storage could potentially produce electricity at a significantly lower rate than the present proposed project. A demonstration project in Lime Village utilizing load shaving using battery storage and smaller diesel electric generators has achieved efficiencies of ~20kwH/gallon.

Economic Concerns

I have several concerns regarding the economics of this project, predominantly involving the economic analysis of the DEIS and the economic viability of the project. The Glacier Bay National Park Boundary

Adjustment Act which transfers the Falls Creek area over to GEC contains specific requirements over and above other applicable legislation for GEC to show that the Falls Creek Project can be completed in an economically feasible manner, which I am doubtful can be done. This is of personal concern for me as a rate payer, since any cost overruns on the project or increases in generating cost will no doubt be reflected in my monthly electric bill.

In general, any proposed electric power project would hopefully be designed to reduce electric rates in Gustavus. Our electric rates are extremely high, among the highest in the United States. Gustavus electric rates are very high due to a number of factors, including debt service, higher than average overhead costs, higher than normal distribution costs, and high fuel costs for the current diesel-electric generators. Unfortunately, switching from the present diesel electric generators to hydroelectric power as proposed will not reduce GEC's significant overhead and distribution costs and will trade reduced diesel fuel costs for large increases in debt service costs. Statements by GEC staff have made it clear that there will be no reduction in consumer electric rates by switching to hydroelectric power.

Population Growth

The DEIS assumes an unrealistically optimistic rate of population growth. Population growth in Gustavus is highly dependent upon National Park Service employment, since Glacier Bay National Park and the agencies represented there are directly responsible for approximately 60% of the full-time employment in Gustavus. Glacier Bay National Park has been undergoing an extensive growth in personnel, but it is now near the end of its projected growth and future growth in personnel is likely to be at much lower rate than in the past 10 years. Declining federal budgets and a flat tourism economy make it unlikely that population growth in Gustavus will meet the projections contained in the DEIS.

Load/Demand Growth

The proposed hydroelectric generating plant is sized much larger than is conceivably required by community growth during the lifespan of the project. The size of the proposed hydroelectric project was established in the mid 1990s, assuming the population growth rate and electric demand increases that were seen in Gustavus in the early 1990s would continue and the inclusion of Glacier Bay National Park into the distribution system. Neither of these two assumptions is valid any more.

The DEIS, and testimony by GEC staff, assumes an increase in electrical demand will appear because of a switch from diesel-electric to hydroelectric generation, due to consumer demand for "green" power. Data submitted by both GEC in the DEIS and by Eric Cutter for the Sierra Club both agree that the predominant factor in electrical demand growth in Gustavus is cost, as reflected in the rate of power cost equalization (PCE) funding by the State of Alaska. The changes in load demand growth with changes in PCE are significant and directly correlated. When PCE was cut in 1999, electrical demand decreased in Gustavus, even while the population increased. Since then load demand has increased, but at lower rate of growth commensurate with the lower PCE offset rate. PCE is likely to decrease again or get cut entirely in the future, given the financial and political situation of the state government.

The cost of electricity in Gustavus is such that increases in electrical demand are likely to be at a significantly lower rate than population growth rate. The present project, at 800kW, would require substantial continued population growth of Gustavus and inclusion of Glacier Bay National Park to efficiently utilize that amount of power at any time during the life of the project.

The National Park Service, as a co-lead agency in the preparation of the project NEPA documents, cannot take a position on whether it would utilize power from the proposed hydroelectric project. However, given the higher cost of GEC power and the significant cost of connecting Bartlett Cove to the GEC distribution system, it makes little economic sense for the National Park Service to utilize GEC for electric power.

The cost of connecting Glacier Bay National Park to the GEC distribution system is estimated at approximately $510,000/mile for the 4-mile section from the park boundary to the housing and facilities at Bartlett Cove, plus a lower amount per mile for the connection form the park boundary to the present endpoint of the GEC distribution system (about 2 miles). It is unlikely that the National Park Service will invest something over $2 million to hook into private hydro power when they have recently completed a new electric generation facility at Bartlett Cove that produces electric power at a lower $/kwH rate than GEC. Glacier Bay National Park has installed a new generating facility within the past six years. Its generated cost is significantly lower than GEC, due to lower fuel costs and lack of debt service.

Project Cost

Construction projects in rural Alaska have a well-deserved reputation for significant cost overruns. I do not believe that a 15% contingency cost, as documented in GEC's application for license, is sufficient. The proposed economic analysis is also missing realistic inputs for the following overhead costs:

- O&M costs for Rink Creek Road and the access road to the hydroelectric plant (see "Cumulative Impacts – Increased Traffic on Rink Creek Road" below),
- Additional O&M costs for both a hydroelectric plant and diesel generator backup, and
- Increased insurance costs due to increased infrastructure.

Cumulative Impacts

The cumulative effects of the project on the community of Gustavus are also a concern, as follows.

Increased Traffic on Rink Creek Road

Rink Creek Road is identified as the primary access to the project. This road has an unimproved dirt roadbed, not built to highway standards, floods regularly, and has water crossings which are insufficiently constructed to handle heavy construction equipment loads. The costs of necessary improvements to the road and continued road maintenance during and after construction are not included in the projected costs.

Rock Quarry

Gustavus is built on a glacial outwash, consisting primarily of sand, silt, and clay. The proposed rock quarry for construction will be an attraction to the community, which has little in the way of crushed rock resources for construction or other uses. The development of the rock quarry for construction will drive a local demand for crushed rock from the same quarry. This will lead to a continued increase in heavy truck traffic on Rink Creek Road.

Native Allotment Development

Development of Falls Creek would likely lead to development of native allotments abutting the project area. Such development would seriously compromise the ecology of the area. The native allotment contains most of the bear habitat in the area, habitat that would likely be adversely impacted by the project.

Summary

In summary, I do not support the project as it presently stands, for the reasons outlined above.

Respectfully,

Craig H. Wilson

ORIGINAL

FILED
OFFICE OF THE
SECRETARY

Thursday, January 1, 2004

2004 JAN -6 P 3: 25

Magalie R. Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E
Washington, DC 20426

Dear Secretary Salas,

I am writing regarding the Falls Creek Hydroelectric Project, FERC No. 11659-002. I love national parks and support the policies that protect them. I urge you to choose the No-Action Alternative for the following reasons:

· I am opposed to trading designated wilderness in Glacier Bay National Park to the state of Alaska. The project's justification to provide power to a community outside of the park is not in keeping with the purposes of national parks and is unacceptable.
· I am concerned about impacts to fish and wildlife and their habitat that would result from this land trade and subsequent project development.
· I am opposed to giving over management of lands to the state that were previously wilderness. This will significantly change the existing uses by allowing snowmobiles, ATVs, logging, and mining.
· The proposed hydropower project provides little benefit to the community of Gustavus and most likely will increase electric rates.
· The economic feasibility of this project is highly questionable. Even under the unlikely scenario of high load growth, high diesel fuel cost increases, and including Park Service demand, the project is barely possible.
· As a taxpayer, I am appalled at the prospect of the National Park Service mothballing their new generating facility to buy hydropower at a higher cost.
· This project will not eliminate the need for diesel power generation.
· Better alternatives, such as conservation measures to lower the use of diesel power combined with emerging technologies like fuel cells and tidal energy, may be available in the near future.

Glacier Bay National Park is one of the crown jewels of our National Park System. It is also of international significance and is designated a World Heritage Site. Please choose park protection and common sense over an unnecessary project with dubious benefits. Select the No-Action Alternative.

Sincerely,

Melanie Picciotti
376 McNaughton St.
Rochester, NY 14606 - 2646
purrcila@hotmail.com

ORIGINAL

MAGALIE R. SALAS, SECRETARY

FEDERAL ENERGY REGULATORY COMMISSION

888 FIRST ST. NE WASHINGTON, D.C. 20426

RE: FERC PROJECT #11659-002 FALL CREEK HYDROELECTRIC PROJECT AND LAND EXCHANGE

I LODGE STRONG OBJECTION TO THIS UNNECESSARY PROJECT. THE DRAFT ENVIRONMENTAL IMPACT STATEMENT (DEIS) STATES HOW VALUABLE THE FALLS CREEK WATERSHED IS AS A WILDERNESS ATTRACTION BUT GIVES INADEQUATE JUSTIFICATION FOR DESTRUCTION OF THIS WORLD HERITAGE PARK.

WITH THE EXCHANGE AGREEMENT THE INTERESTS OF NATIVE ALLOTMENT OWNERS ARE ALSO IN JEOPARDY. THE (DEIS) ANALYSIS FINDS THAT THE FALLS CREEK PROJECT FAILS TO PASS THE ECONOMIC VIABILITY TEST REQUIRED FOR APPROVAL. GIVEN THE LACK OF URGENT NEED FOR THE POWER AND THE QUESTIONABLE ECONOMICS OF THE FALLS CREEK PROJECT DEFERRAL FOR SEVERAL YEARS IS BEST TO EVALUATE NEW TECHNOLOGY: UPGRADED DIESEL POWER COMBINED WITH ENERGY EFFICIENCY AND CONSERVATION MEASURES.

WE MUST NOT BE SO QUICK TO DESTROY IRREPLACEABLE NATURAL NATIONAL TREASURES WHEN ALTERNATIVES ARE NEAR AT HAND.

FILED
OFFICE OF THE
SECRETARY
2004 JAN -8 P 3:
FEDERAL ENERGY
REGULATORY COMMISSION

Michael E Bialas

MICHAEL E BIALAS
3941 E. 37TH PL
TULSA, OK 74135-[illegible]

ORIGINAL

3710 Ember Spring Drive
Kingwood, TX 77339-1932
December 21, 2003

Dear Sir or Madam,

I am completely opposed to the ~~Project No. 11659-002,~~ Falls Creek Hydroelectric Project and Land Exchange. This is a ~~totally unnecessary~~ project for the following reasons.

1. It would inflict on Glacier Bay National Park damage to its wilderness, fish, wildlife, aesthetics, visitor use and enjoyment.

2. It would be contrary to the interests of the Native allotment owners.

3. This is a World Heritage park, and one of the most pristine wildlife and wilderness parks in the word, and this project would ruin this. Remember that this is a benchmark against with other national parks and areas are measured.

I strongly recommend that the FERC and the NPS reject the project in favor of an alternative not considered in the DEIS. Upgraded diesel power along with energy conservation and improved energy efficiency.

Cordially,

Robert Markeloff

Robert Markeloff

PS - May the park remain unsoiled for you and your great-grandchildren too!

January 1, 2004
Magalie R. Salas, Secretary
888 First Street, N.E.
Washahington, D.C. 20426

ORIGINAL

FILED
OFFICE OF THE
SECRETARY

2004 JAN 13 P 12:07

FEDERAL ENERGY
REGULATORY COMMISSION

REFERENCE PROJECT NO. 11659-002

Dear Secretary,

I have listened to Park Service employees give testimony at a public hearing that FERC should deny a license for Falls Creek Hydroelectric Project because they do not want to see land come out of a park on a wilderness area. The place to argue this is before Congress, not FERC. FERC is mandated to process this application as though the land has already been exchanged, as I understand it. It is not FERC's or the Park Services' place to decide if the legislation was good or bad.

I strongly urge you to issue a license for this project as soon as possible. It is the best thing that could happen for National Park wilderness land and the community of Gustavus.

Sincerely,

Edward A Cahill Jr.

Edward Cahill
PO Box 61
Gustavus, Alaska 99826

January 1, 2004

ORIGINAL

FILED
OFFICE OF THE
SECRETARY

2004 JAN 13 P 1:07

FEDERAL ENERGY
REGULATORY COMMISSION

Magalie R. Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E
Washington, DC 20426

Dear Secretary Salas,

I am writing to you to express my opposition to the Falls Creek Hydroelectric project proposed for Glacier Bay National Park. This is Project number FERC No. 11659-002.

National Parks are lands that are owned by all Americans and should be protected from projects such as this one. These lands are better used as wilderness area for all Americans to enjoy than as a way for a private company to make a few bucks.

Lands in the National Park Service system have been placed there because Congress recognized them as important places. I oppose the precedent of giving away NPS lands for private commercial activities. These lands should not be removed from NPS jurisdiction.

Please take whatever actions are needed to prevent the Falls Creek Hydroelectric project from going forward. This project needs to be stopped and Glacier Bay NP needs to be protected and preserved.

Thank you for your attention to this matter.

Sincerely,

Robert Cherry

Robert Cherry
301 Perkins St.
Boone, NC 28607-5313
(828) 265-2827

Magalie R. Salas, Secretary ORIGINAL 2-2-04
Federal Energy Regulatory Commission
888 First Street N.E
Washington D>C> 20426

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OFFICE OF THE SECRETARY

2004 JAN 13 P 12:37

FEDERAL ENERGY REGULATORY COMMISSION

Reference to FERC No. 11659-002

Dear Secretary Salas,

I am a resident of Gustavus Alaska. I care and love this small bush community that I live in and want the very best for it in regards to our source of power. I feel very strongly that our only option is hydro power via Falls Creek. I know that this is taking way too long to provide this power because of the issue of changing land from National Park to State Land. I feel that where Falls Creek is located is not prime land and is perfect for building this little dam. We need hydroelectric power and I hope you can speed this up. I know Mr. Levitt has been working on this for almost 20 years and has devoted his life to making this rural area a better place to live with providing us with power. For our future children and grandchildren and anyone else who decides to make this community their home, hydroelectric power is the only option. Please listen to us and help us get this going....it is taking far too long.

Sincerely,

Don Duke

Don Duke
PO Box 44
Gustavus, Alaska 99826

WILDERNESS WATCH

P.O. Box 9175 • Missoula, MT 59807 • p: 406.542.2048 • f: 406.542.7714 • wild@wildernesswatch.org • www.wildernesswatch.org

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2004 JAN 13 P 12:16

FEDERAL ENERGY
REGULATORY COMMISSION

January 5, 2004

Magalie R. Salas, Secretary
Federal Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

RE: Comments on Falls Creek Hydroelectric Project (Project No. 11659-002) and Land Exchange, Glacier Bay National Park and Preserve, Draft EIS

Dear Magalie Salas,

Wilderness Watch is submitting the following comments on the proposed hydroelectric project and land exchange proposed for the Falls Creek area within Glacier Bay National Park and Preserve.

Wilderness Watch is a national conservation organization dedicated to ensuring the good stewardship of lands and waters within the National Wilderness Preservation System and Wild & Scenic Rivers System. Our mission is to ensure that the wilderness character of these special places is preserved and not allowed to diminish.

Wilderness Watch opposes transferring federal land in the Falls Creek area to the State of Alaska. We understand that construction of the proposed hydroelectric facility on Falls Creek is contingent upon completion of a land exchange. Our concerns are outlined as follows.

Impairment to Wilderness

The land in the Falls Creek area that is proposed for transfer to the State of Alaska is designated wilderness, and part of our National Wilderness Preservation System. The Glacier Bay National Park Boundary Adjustment Act of 1998 allows the conveyance of these federally protected wilderness lands to the State of Alaska if various terms and conditions are met. One of those conditions is that an environmental analysis under NEPA must demonstrate that construction and operation of the hydroelectric project will not adversely impact the purposes and values of Glacier Bay National Park and Preserve (GBNPP), as constituted after the consummation of the land exchange.

Wilderness and wilderness-related recreational opportunities are key purposes of GBNPP, as described on page 1-23 of the Draft EIS. Transferring this wilderness land to the State would undesignate the Falls Creek area as federally protected wilderness. Although the Boundary Adjustment Act stipulates that impacts be assessed *after* wilderness undesignation has occurred via the land exchanges, significant impacts to wilderness nonetheless will be incurred.

Two of those impacts are to the NWPS and National Park System as a whole if this project is allowed to move forward. Undesignating wilderness to allow development of a commercial enterprise that is not pre-existing would be an unprecedented impact on the integrity and permanence of the entire NWPS. No National Park Service lands nationwide, whether wilderness or non-wilderness, have ever been undesignated to accommodate a new commercial enterprise. It is not in the broad public interest to begin down this dangerous path now, at Glacier Bay. Such action would seriously jeopardize the permanence and protection of both the NWPS and the National Park System.

Congress passed the Wilderness Act of 1964 with the following opening statement of the statute's intent:

> "To establish a National Wilderness Preservation system for the permanent good of the whole people, and for other purposes."
>
> *The Wilderness Act*, P.L. 88-577

Approving the proposed project and land exchanges would send a strong signal that wilderness is not permanent after all, and that the whole American people cannot count on retaining the enduring benefits of wilderness for future generations to know and enjoy. Congress intended that Wilderness would be forever, not bartered away after a year, or 10, or 20. The Wilderness Act was passed almost unanimously by both Houses of Congress; the Glacier Bay Boundary Adjustment Act was a little-recognized rider attached to a national appropriations bill, at the behest of a single citizen, the owner of the Gustavus Electric Company. Unlike the Wilderness Act, the Boundary Adjustment Act primarily represents the "will of one" rather than the "will of the people." Benefitting the Gustavus Electric Company at the expense of the permanent good of the whole people is not the right choice for the NPS and the Federal Energy Regulatory Commission (FERC) to make.

Furthermore, the proposal would destroy the area's existing wilderness qualities and cancel all opportunity to re-designate it as wilderness in the future. The proposal would develop the currently pristine Falls Creek area through new road construction, construction of a diversion site, placement of a pipeline down the Kahtaheena River, placement of the hydro facility, and installation of power transmission lines.

This level of development and expanded motorized access would cause significant impairment to existing opportunities for the residents of Gustavus to experience the wilderness values of Falls Creek. It is difficult for residents to access much of the land-based wilderness within GBNPP, so the current wilderness condition of the nearby Falls Creek area offers Gustavus' residents a unique opportunity for land access to a high quality wilderness portion of the park. The proposed developments would impair this unique opportunity by transforming the area with roads and other developments.

Land Exchanges

The state lands that would be acquired by the NPS through exchange of the Falls Creek land are of lesser quality, so the proposed exchange represents a loss to the general public in terms of value and benefits. Unlike Falls Creek, the lands that would be acquired are not unique in terms of geographic or biological value. Falls Creek, on the other hand, contains a multi-canopied mature forest of spruce and hemlock. This is a uniquely rich environment at Glacier Bay, where most lands are only recently becoming re-forested with small trees as the glaciers of the last ice age recede. This unique scientific, geologic, and biological value of the Falls Creek area is important to the historic value and unique opportunities for the study of glaciers and associated plant and animal community success processes, as described on pages 1-22 and 1-23 of the draft EIS.

The proposed project would therefore violate the terms of the Boundary Adjustment Act which specify that specify the project and land exchanges can only be approved if they will not adversely impact the purposes and values of GBNPP (see page 1-13, EIS).

To make up for wilderness acreage lost at Falls Creek through de-designation, the proposal calls for wilderness designation of other lands in the park. The public gains nothing from the proposed designations, and in fact loses in terms of wilderness quality. The unnamed island near Blue Mouse Cove is situated within the most heavily used area in the park for anchoring boats. This means the wilderness quality of the island would almost constantly be compromised by the sight and sound of many motorized boats and people, resulting in the island having little value in terms of providing wilderness solitude and sense of remoteness from crowds and the contrivances of modern civilization.

The other island proposed for wilderness designation is Cenotaph Island. Again, the public has nothing to gain by giving up the superlative wilderness qualities of Falls Creek in exchange for designating Cenotaph Island. This island is frequently subjected to major mudslides and massive tidal waves caused by geologic occurrences in the area. For this reason, this island will always remain undeveloped, and therefore de facto wilderness on-the-ground regardless of being wilderness on paper. Designating it as wilderness brings no new wilderness benefits to the public that don't already exist for this island.

Acreage

The various Alternatives present a range of acreages for the land exchange, ranging from 680 acres to 1,145 acres of the Falls Creek area that would be conveyed to the State of Alaska. However, the EIS indicates that all developments associated with the hydroelectric project would only encompass a total of 9-12 acres. This leads us to seriously question why hundreds of acres must be exchanged in order to accomplish the project if it is approved. We ask that the Final EIS explain in detail how the number of acres for exchange was determined, based on the project's limited needs.

If an exchange is approved, we also urge that the boundary of the exchange be drawn along geographic contour lines rather than straight lines to create a geographically identifiable and manageable boundary.

Road

If approved, the project will entail constructing a road to access the diversion structure at the top of the proposed pipeline. Through the land exchange, the State of Alaska would gain jurisdiction over the road and land along both sides of it. This would give the State unrestricted opportunities to allow other new developments along the road, further eroding the currently remote and wild qualities of the Falls Creek area.

To help mitigate some of these threats of expanding new development, Wilderness Watch strongly urges that the Final EIS include provisions under each of the development alternatives that would mandate that a permanent non-development easement along the new road be one of the stipulations for completing the land exchange with the state.

Thank you for the opportunity to comment. Please keep us updated as this decision process progresses.

Sincerely

TinaMarie Ekker

TinaMarie Ekker
Policy Director

ORIGINAL

Jim and Denise Healy
PO Box 7
Gustavus, Ak 99826

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2004 JAN 13 P 12: 36

FEDERAL ENERGY
REGULATORY COMMISSION

FERC PROJECT: 11659-002

Magalie R. Salas, Secretary
FERC
888 First Street N.E.
Washington, D.C. 20426

Dear Secretary,

We are residents of Gustavus and own a business here. We have been watching the progress of a potential hydroelectric facility at Falls Creek for a long, long time now. Over five years ago, Congress passed a law that says Gustavus could develop hydropower there, and still there is nothing. Politics is out of the picture now, so it is taking far too long to get their project built. Please see to it that this project gets built as soon as possible. Gustavus need to get off diesel now. The cost of diesel electricity will only continue to go up and up. Hydroelectric has been used for decades and has a long history of stabilizing the cost of electricity.

Sincerely,

Denise Healy

Jim and Denise Healy

Jim Healey

ORIGINAL

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2004 JAN 13 P 12: 19

FEDERAL ENERGY
REGULATORY COMMISSION

P-11659-002

2440 East Tudor Road,
Anchorage, AK 99501
January 1, 2004

Magalie Sales, Secretary
Federal Energy Regulatory Commission
888 First St., NE
Washington, DC 20426

RE: Proposed Falls Creek Hydroelectric Project, Glacier Bay National Park and Preserve, Gustavus, Alaska

Dear Ms. Sales:

I am a cabin and property owner in Gustavus, Alaska, and have been since 1974. I have hiked and explored the Glacier Bay National Park extensively over the past 30 years, including the wilderness areas adjacent to Gustavus. I am opposed to the construction of a hydroelectric project on Falls Creek for several reasons. First, Falls Creek is designated Wilderness in the park. These values cannot be replaced, once lost, and the replacement tracts that would be "traded" for Falls Creek are not wilderness and do not have the same high quality wilderness characteristics. If the Falls Creek area is developed for hydropower, the lands will then be open to other uses which conflict with the wilderness values of Glacier Bay. The contiguous boundaries of Glacier Bay National Park, set aside in 1925, and enlarged in 1980, were drawn to protect a World Heritage area. Taking this land out of the park essentially whittles away at the park's integrity, and destroys an area of old-growth forest, important waterfalls, and wetlands.

Second, measures have not been taken to pursue other alternatives for energy in Gustavus. This is a very small community, and there are many other possibilities for generating power. Prior to the mid-1980s, community members were self-sufficient, and took care of their own power needs. When Gustavus Electic came into the community, power was subsidized to a great degree, so that residents did not have to pay the true cost of diesel-powered electricity, nor did Gustavus Electric have to pay the true cost to generate electricity. Yet even with a rise in the cost of electricity over the past 15 years, it is still cheaper and more efficient to generate power using diesel, than it is to destroy wilderness to generate power. The true cost of the hydroelectric project is not reflected in the DEIS. The National Park Service has generated its own electricity since power came to the park, and the cost of bringing any electricity generated at Falls Creek will be considerable, considering that a 9 to 10-mile transmission line must be built. The National Park Service certainly has no obligation to link up to the Falls Creek project if it is expected to foot the cost for a powerline. It seems hypocritical for a national park to sanction the destruction of its own lands in order to have electricity. Has the community of Gustavus and the National Park Service performed energy audits to find ways to conserve energy? Have other methods of producing energy been explored? The Park

Service should be setting the example on innovative solutions to energy needs—not allowing the destruction of the park.

As I recall, there are Native allotments in the Falls Creek area. Have these owners been consulted in this project. How does the project affect them? These issues have not been considered in the FEIS

I do not believe that this project is financially feasible, given the small population of Gustavus, and the cost to get power to the far ends of the community. Furthermore, the project does not eliminate the need for a diesel-fuel-powered generator when flow is insufficient in the falls. The whole project seems designed to benefit the power company, rather than the American people, who set aside Glacier Bay National Park as part of our natural heritage. This project is unnecessary.

I recommend that FERC reject this project, and urge that more effort go into conservation measures and other alternative energies.

Sincerely,

Karen Jettmar

ORIGINAL

January 1, 2004

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2004 JAN 13 P 12:36

FEDERAL ENERGY
REGULATORY COMMISSION

Magalie R. Salas
FERC
888 First Street, NE.
Washington D.C. 20426

ATTENTION: REFERENCE PROJECT NO: 11659-002

Dear Ms. Salas,

Thank you for the opportunity to comment on the Falls Creek Hydroelectric Project. I attended the FERC public hearings in Gustavus but did not testify then. However, I did do a slow boil while listening to some folks say that land should not be taken out of the Park. That is ridiculous. That land is of no value to the park. It is much more worthwhile used for electric generation. Nobody ever visits there. People who live here and who visit here have many better options of places to go and things to do than visit that area. I have been there several times and it is hard to get to and nothing to write home about when you get there.

There was much discussion on the economics of the project. Without going into the specifics, common sense would tell any idiot that as time goes on, diesel will get more expensive and harder to get if you can get it at all. Hydroelectric has proven all over the world that it is reliable, cheap, easy and will be there forever, or as long as it keeps raining in S.E. Alaska.

The Sierra Club came to town a while back and tried to tell everybody that the hydro would raise their electric rates. And that tidal power would be a cheaper alternative. This is all laughable. Just because they don't want land to come out of wilderness, that should not be wilderness to begin with.

Another thing they talked about was where the new park boundary should be. I don't know anything about the new land the Park will get, but they should take as much land out of the Park at Falls Creek as they possibly can, and give it to the State. I think they should trade even more land to the State than in the biggest alternative at the hearing.

In conclusion, this is a no-brainer! If we don't do it now, in 30 years we will be kicking ourselves in the rear for not having done it. Let's get it done now!

Sincerely,

Bruce Kruger

Bruce Kruger
Box 61
Gustavus, Alaska 99826

ORIGINAL

January 2, 2004

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2004 JAN 13 P 12:33

FEDERAL ENERGY
REGULATORY COMMISSION

Magalie R. Salas
FERC
888 First Street, NE.
Washington D.C. 20426

ATTENTION REFERENCE PROJECT NO 11659-002

Dear Ms. Salas,

I live in Gustavus and really want to have Hydroelectric Power via Falls Creek. I was at the Public Hearing and decided I better send a letter in support of the Hydroelectric Project.

Sincerely,

William L. Kruger
Box 191
Gustavus, Alaska 99826

ORIGINAL

Priscilla Mooney
2511 So. 286th PL #D201
Federal Way, WA. 98003

FILED
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2004 JAN 13 P 1:04

FEDERAL ENERGY
REGULATORY COMMISSION

December 28, 2003

Reference: P-11659-002

Magalie R. Salas
Secretary, FERC
888 First St. NE
Washington, D.C. 20426

Dear Secretary Salas,

Thank you for sending me a copy of the Draft Environmental Impact Statement for the Falls Creek Electric Project. And thank you for allowing me to comment on the project.

I own 5/12 of the Albert Mills Native Allotment near the project. I inherited this land from my mother, Margaret Mills McKinley. I know that my cousin, Tom Mills, claims to own the allotment and claims to speak for all other descendants of Albert Mills who have interest in the allotment. Tom Mills does not speak for me. I speak for myself when it comes to the allotment and the hydro project.

I am in favor of this project being built. I would like it if the project could use some of my land. But I know this cannot happen without full approval of all allotment holders. I would like to see the access road go through the property or at least as close as possible to it. I would like the road to be located so that it could be used for access by me and my son to our property. I would like my son and me to have a cabin or two on the property to use or even rent. I would like to see the property used for some useful purpose.

I am glad the stream has salmon in it and I am glad Gustavus Electric is not going to harm the salmon. The property was logged for timber 30 years ago and has not grown back yet. Therefore, the property should be used for other purposes. I would like to see electricity available on the property.

I look forward to this project being built and my family using our property. I appreciate your efforts in making this happen. This project has been going on for a long time and I hope you can make it happen soon. I will be glad to help make this happen.

Thank You,

Priscilla Mooney

Priscilla Mooney

ORIGINAL

Jan 2, 2004

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2004 JAN 13 P 12:32

FEDERAL ENERGY
REGULATORY COMMISSION

From Gary Owen
Box 15
Gustavus, AK 99826

FERC Project No. 11659-002
Falls Creek
Hydroelectric

TO: Magalie R. Salas, Secretary
Federal Energy Regulatory Commission
888 First St NE
Washington DC, 20426

Dear Secretary Salas,

I am a resident of Gustavus for over 50 years. My family homesteaded here in the 1950's.

I would like to see this hydroproject built because, in the future, the cost of oil will do nothing but increase. Hydo has been used in Alaska since the 1890's, and been very reliable. Hydro will make the cost of electricity more stable.

Thank you for your attention to this

Sincerely

Gary Owen

P.S. It would have already paid for itself if it was build 15 years ago like it should have been.

ORIGINAL

January 2, 2004
180 South Main Avenue
Albany, NY 12208

RE:
Glacier Bay National Park

Project No. 11659-002
Falls Creek Hydro Project and Land Exchange

Magalie R. Salas,
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Dear Ms. Salas,

I am appalled to learn that this project is even being considered.

- I object to the damage this unnecessary project would inflict on the park!

- I protest the proposed raid on this superb World Heritage Park, one of the most pristine wildlife and wilderness parks in the world, and a benchmark against which other national parks and wilderness areas are measured.

- I recommend that the FERC and the NPS reject this project in favor of an alternative not considered in the DEIS: upgraded diesel power combined with energy efficiency and conservation measures.

- As a frequent visitor to Alaska's National Parks, I can tell you that they are special places. These places represent the chance to do it right the first time. Weren't our national parks and wilderness areas established to protect what little our natural heritage remains?

Please reject this project. Thank you for your time and attention.

Sincerely,

David Pisaneschi

cc: Senator Clinton
Senator Schumer
Congressman McNulty

Project - 11659-002 Jan 2, 2003

Falls Creek Hydroelectric

DATE

ORIGINAL

Sam Rice
Box 326
Gustavus, AK 99826

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2003 JAN 13 P 12:04
FEDERAL ENERGY REGULATORY COMMISSION

Magalie R. Salas, Secretary
FERC
888 First Street, NE
Washington DC 20426

Dear Ms Magalie,

I have lived in Gustavus for over 20 years. I am glad to have electricity here, as I remember when there was no electricity here.

I am hearing a bunch of talk about park people living here not wanting this hydro project to happen. They say they dont want the land to come out of the park. I thought Congress already said the land could be used for hydroelectricity. What gives? I thought the matter was already settled. Can these people really stop this project? It would be outrageous if they could, and I for one would be damn mad. Just about this whole town would be mad if it did not go through.

This whole thing has been going on a long time - much too long.

PREPARED BY

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DATE

Enough of this crap! Let's get going and get thing built.

Thank you for your attention to this.

Sam [signature]

PREPARED BY

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ORIGINAL 12-29-03

TO: MAGALIE R. SALAS
SECRETARY, FERC
888 FIRST ST NE
WASHINGTON DC

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2004 JAN 13 P 3:56

FEDERAL ENERGY
REGULATORY COMMISSION

FERC PROJECT NO 11659-002

FROM: JOE VANDERZANDEN
BOX 122
GUSTAVUS, AK, 99826

SECRETARY SALAS,

I AM A EMPLOYEE OF GUSTAVUS ELECTRIC CO. BUT THE FOLLOWING COMMENTS ARE STRICTLY FROM A PERSONAL VIEWPOINT

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2004 JAN 13 P 3:56
FEDERAL ENERGY
REGULATORY COMMISSION

THE FOLLOWING ARE A FEW THOUGHTS TO KEEP THINGS IN PERSPECTIVE ABOUT THE HYDRO PROJECT.

I'VE BEEN WORKING FOR GUSTAVUS ELECTRIC SINCE 1992, AND FOR MUCH OF THAT TIME IT'S BEEN MY RESPONSIBILITY TO DO GENERATOR CHECKS AND MAINTENANCE. BASICALLY, DICK PAYS ME TO WORRY ABOUT WHETHER THE LIGHTS ARE GOING TO STAY ON. MY BEST DAYS ARE WHEN I CAN GO HOME AT NIGHT AND TAKE FOR GRANTED, LIKE EVERYONE ELSE, THAT THE POWER WILL STAY ON TILL MORNING. THIS IS NOT ALWAYS THE CASE. ENGINE MAINTENANCE IS ALWAYS IN A STATE OF FLUX. A NEWLY OVERHAULED ENGINE CAN, WITHIN A COUPLE MONTHS, ALREADY BE NEEDING REPLACEMENT PARTS. THIS MAY LEAVE US RUNNING A MORE TIRED BACKUP ENGINE, WHICH MAY SEEM RELIABLE, BUT AT ANY TIME COULD NEED NEW SEALS, OR A WATER PUMP, OR INJECTORS, OR WHATEVER.

ELEVEN MONTHS AGO, I WAS RUNNING AN ENGINE WITH A FRESH OVERHAUL. IT HAD BEEN DOING WELL AND I FELT GOOD ABOUT IT. LATE ONE EVENING A TEN CENT BOLT VIBRATED LOOSE FROM AN INJECTOR LINE CLAMP, CAUSING A FUEL LEAK WHICH STARTED A FIRE AND WE WERE FORTUNATE TO ONLY LOUSE THE ENGINE AND NOT THE ENTIRE PLANT.

OUR RECENT VOLTAGE SPIKE, WHICH DID SO MUCH DAMAGE, WAS CAUSED BY A SINGLE WIRE TO THE

VOLTAGE REGULATOR THAT BROKE FROM VIBRATION. SINCE THEN WE'VE SPENT ABOUT $2000 TRYING TO LESSEN VIBRATION ON THAT ENGINE WITH ONLY LIMITED SUCCESS.

MY POINT HERE IS THAT MY BEST EFFORTS ARE NOT ALWAYS GOING TO KEEP THE LIGHTS ON, AND DIESEL ENGINES ARE NEVER GOING TO BE AS RELIABLE AS A WATER DRIVEN TURBINE.

ANOTHER RESPONSIBILITY THAT I HAVE WITH MY JOB IS SCHEDULING FUEL BARGES, WHEN THEY ARE NEEDED, TO KEEP THE TANK FARM FULL. I'VE ALWAYS THOUGHT IT PRUDENT, DUE TO OUR REMOTE LOCATION, TO NOT LET THE TANK FARM GET MUCH BELOW HALF FULL. HOWEVER, THEIR HAVE BEEN TIMES WHEN, DUE TO SCHEDULING, OR DELAYS OR WEATHER, THAT WE HAVE BEEN WITHIN A COUPLE DAYS OF RUNNING OUT OF A PRODUCT. ADD TO THAT THE INCREASING DISREPAIR OF THE DOCK WITH THE PIPELINE ATTACHED TO IT AND SOME POOR SCENARIOS BEGIN TO TAKE SHAPE. WE HAVE NO CONTINGENCY PLAN FOR HOW TO GET FUEL TO THE TANK FARM WITHOUT THE PIPELINE; THE BARGE ONLY CARRIES 1000' OF 2" HOSE AND THAT'S NOT ENOUGH.

HOWEVER, PROBLEMS LIKE THESE HAVE A WAY OF WORKING THEMSELVES OUT, BUT AS PEDR WAS SAYING AT THE TUESDAY MEETING, WE ARE DISCUSSING PROBABILITIES OVER A 30 YEAR PERIOD. IS IT PROBABLE TO EXPECT THAT THE DOCK AND PIPELINE

DATE

WILL BE INTACT IN EVEN 10 YEARS, OR THAT WE CAN GO 30 YEARS WITHOUT ANOTHER FIRE OR SOME OTHER CRISIS AT THE GENERATOR BUILDING, OR THAT THE PRICE OF DIESEL WONT DOUBLE IN THAT TIME?

THEIR WAS MUCH TALK AT THE TUES. MEETING OF THE ECONOMIC VIABILITY OF THE HYDRO PROJECT AND THAT IT COULD COST MORE THAN EXPECTED, AND I'VE WONDERED WHY THIS IS SUCH AN ISSUE. IF COSTS ARE HIGH, THEN DICK WILL FIND HIMSELF DEEPER IN DEBT THAN HE WANTS TO BE, BUT HE DEALS WITH THAT ON A REGULAR BASIS. AND HE WILL PROBABLY CONTINUE TO CHARGE WHATEVER THE MARKET WILL BARE TO COVER THE COSTS. THIS CAUSES PEOPLE TO SQUIRM, BUT THAT BRAND OF ECONOMICS CAN BE FOUND THROUGHOUT THE COMMUNITY, AND STILL LIFE GOES ON.

THE ISSUE THAT CONCERNS ME THE MOST IS THAT WE TEND TO TAKE SO MUCH FOR GRANTED. THE WORLD IS A VOLATILE PLACE AND WE ARE A BUSH COMMUNITY - TOTALLY DEPENDENT ON THE OUTSIDE WORLD, AND VOTING TO BECOME A SECOND CLASS CITY ISN'T GOING TO CHANGE THAT. THE PROBABILITY OF SOME FORM OF ECONOMIC UPHEAVAL IN OUR NATION OVER THE NEXT FEW DECADES IS A VERY REAL ONE, AND IF WE HAVE THE CHANCE TO HARNESS VIRTUALLY FREE ENERGY AT WHATEVER COST TO US NOW, WE SHOULD

DATE

TAKE THAT CHANCE. IF THE AVAILABILITY OF FUEL FOR THIS COMMUNITY WAS HINDERED EVEN FOR A SHORT PERIOD, THE EFFECTS WOULD BE CRIPPLING AND LONG TERM. HYDRO-POWER WOULD MAKE A HUGE DIFFERENCE.

IF THOSE WITH ENVIRONMENTAL CONCERNS WISH TO STOP THIS PROJECT BECAUSE OF IT'S IMPACT, THEY SHOULD AT LEAST PREPARE THEMSELVES, (IF THEY HAVEN'T ALREADY), TO LIVE HERE WITHOUT ELECTRICITY AND SOME OF THE OTHER LUXURIES THAT WE CURRENTLY ENJOY. THE BEAR, AND MOOSE AND DEVIL'S CLUB WILL CONTINUE TO DO FINE WITH OR WITHOUT A HYDRO PROJECT. IN S.E. ALASKA, IT'S THE PEOPLE THAT HAVE A HARD TIME OF IT.

SINCERELY -

ORIGINAL

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 10
1200 Sixth Avenue
Seattle, WA 98101

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2004 JAN 20 P 2: 46

FEDERAL ENERGY
REGULATORY COMMISSION

January 13, 2004

Reply To
Attn Of: ECO-088

Ref: 02-347-FRC

Magalie Salas, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Dear Ms. Salas:

The U.S. Environmental Protection Agency (EPA) has completed its review of the draft Environmental Impact Statement (EIS) for the proposed **Falls Creek Hydroelectric Project and Land Exchange** (CEQ No. 030502) in accordance with our authorities and responsibilities under the National Environmental Policy Act (NEPA) and Section 309 of the Clean Air Act. The draft EIS has been prepared in response to a proposal to construct and operate a 800 kilowatt hydroelectric project on the Kahtaheena River near Gustavus in southeast Alaska. The EIS evaluates the applicant's proposed project, two additional action alternatives and the No Action alternative. An agency-preferred alternative is not identified in the draft EIS.

Based on our review and evaluation, we have assigned a rating of EC-2 (Environmental Concerns - Insufficient Information) to the draft EIS. This rating, and a summary of our comments, will be published in the *Federal Register*. A copy of the rating system used in conducting our review is enclosed for your reference.

Our concerns are related to the following topics which are discussed in greater detail in the enclosure to this letter:

- *Project Impacts and Needed Mitigation Measures;*
- *Need for Power;*
- *Continued Use of Diesel Generators;*
- *Access;*
- *Developmental Analysis; and*
- *Recommendations.*

Thank you for the opportunity to provide comments on the draft EIS. I urge you to contact Bill Ryan of my staff at (206) 553-8561 at your earliest opportunity to discuss our comments and how they might best be addressed in the EIS.

Sincerely,

Judith Leckrone Lee

Judith Leckrone Lee, Manager
Geographic Implementation Unit

Enclosures

cc: Bruce Greenwood, NPS

EPA Comments
on the
Draft Environmental Impact Statement (EIS)
for the
Proposed Falls Creek Hydroelectric Project (FERC No. 11659) and Land Exchange

Project Impacts and Needed Mitigation Measures

The EIS reveals a high reliance on yet-to-be-developed operation, mitigation and monitoring efforts or plans to ensure that natural resources would be protected. While we believe that all of the plans identified for development are necessary, we are concerned that the information they would generate is necessary to define the effects from the proposed project and/or identify necessary mitigation measures. Such information should be reflected in the EIS, per the direction of the implementing regulations for the National Environmental Policy Act (NEPA) to "insure that environmental information is available to public officials and citizens before decisions are made and before actions are taken" (40 CFR 1500.1(b)) and to "include appropriate mitigation measures not already included in the proposed action or alternatives" (40 CFR 1502.14(f)). For example, the draft EIS suggests that the following will not be developed until after the final EIS and license are issued:

- Prepare erosion and soil control plan;
- Prepare and implement a road management plan;
- Prepare and implement a water quality monitoring plan;
- Prepare oil and hazardous substances spill and containment plan;
- Prepare fish passage facility evaluation plan;
- Prepare biotic evaluation plan;
- Prepare and implement wetland mitigation plan;
- Prepare bear-human conflict plan; and
- Prepare land use management plan.

These efforts appear to be necessary to define project-specific effects and identify measures needed to mitigate identified impacts. Consequently, they should be completed and reflected in the EIS. We recommend that the Federal Energy Regulatory Commission (FERC) and National Park Service (NPS) ensure that all necessary analyses/studies are completed and included in the EIS so that effects and appropriate mitigation approaches are defined and disclosed to the public in the EIS before decisions are made, as directed by the NEPA regulations.

Need for Power

Section 1.1.2 of the draft EIS is not clear in its presentation of projected electrical loads on the Gustavus Electrical Company (GEC) system 2016 and their relationship to the proposed hydroelectric project. While information in the EIS indicates that loads are projected to increase from roughly 1.7 million kilowatt-hours (kWh) in 2002 to roughly 2.8 million kWh in 2016, the EIS presents no discussion or analyses related to the ability of the current diesel-powered generation system to meet projected power needs. Page 1-2 indicates that the current generation facilities consist of four (4) diesel generators with a combined capacity of 1150 kilowatts (kW), and states that currently two (2) of the 4 units (representing 600 kW of generating capacity) are generally not used. This suggests that a significant amount of current capacity is relatively unused and appears to be available to meet projected power demand. The EIS also presents current diesel capacity, estimated at 2.4 kWh annually, which assumes the operation of the two primary generating units (Units 1 and 3) at 50 percent of their maximum theoretical annual output. Figure 1-4 of the EIS suggests that operation of the 2 primary units at roughly 60 percent of their annual rated capacity would meet projected power demand.

This potential change in operation, when combined with increased utilization of the other generating units (Units 2 and 4), suggests that current installed generating capacity is more than sufficient to meet expected demand for Gustavus well into the future. Because the proposed project would result in irreversible and irretrievable commitments of natural resources, it is critically important for the EIS to present a clear and direct connection between the projected need for power and why the proposed hydroelectric project is required to meet that need. In so doing, the EIS should demonstrate that the FERC and the NPS have identified and assessed the reasonable alternatives that will avoid or minimize adverse effects (see 40 CFR 1500.2(e)) and have used all practicable means to avoid or minimize any possible adverse effects of their actions (see 40 CFR 1500.2(f)). Such a demonstration should include an analysis which shows that projected demand cannot be met using the current diesel-fired generating facility.

Page 1-5 of the EIS indicates that the continued use of diesel generators would "possibly increase associated environmental impacts, such as negative effects on air quality and fuel storage and transportation concerns." We were unable to locate analyses in the EIS that reflect the future air quality impacts and effects related to future fuel storage and transportation with the continued use of diesel generators to meet power demand. As these would be effects associated with implementing the No Action alternative, they should be assessed and presented in the EIS, per the National Environmental Policy Act (NEPA) implementing regulations (40 CFR 1502.14 and 1502.16).

Continued Use of Diesel Generators

The EIS indicates that the existing diesel generators would continue to be used to supplement power generated by the proposed hydroelectric project. We were unable to locate information in the EIS that indicates why diesel generation would be necessary with operation of the hydroelectric project and if so, under what situations operation of the diesel generators would be necessary. This information should be included in the EIS to ensure that the public and the decision makers are fully informed about how GEC would meet forecasted power demand with the operation of the proposed hydroelectric project. This is particularly important because the proposed hydroelectric project would apparently not eliminate the need for or use of the existing diesel generating system.

Access

We are concerned that the EIS presents only one (1) alignment for the proposed access road and penstock, particularly with the potential that these project features pose for increasing the risks of runoff and mass wasting and their associated impacts to water quality. Page 4-8 of the EIS states that GEC evaluated other access options and did not pursue them for environmental and cost reasons. The EIS provides not indication that the FERC and NPS have conducted an independent evaluation of the options for accessing the proposed project and the associated environmental effects. In developing the EIS, it is the responsibility of the Federal government to ensure that all reasonable alternatives have been identified, assessed and all practicable means taken to avoid or reduce adverse effects (40 CFR 1500.2(e) and (f)). We recommend that the EIS be revised to reflect that the FERC and NPS have independently assessed reasonable access options for the project. Should additional reasonable alternatives for accessing the project be identified, they should be included and evaluated in the EIS.

Developmental Analysis (Section 5)

The information presented in Section 5 of the EIS is inconsistent with information presented elsewhere in the EIS. For example, page 5-1 indicates that the developmental analysis considers 3 alternatives:

1. The proposed project;
2. The proposed project with staff-recommended modifications; and
3. The No Action alternative.

While the No Action alternative and the proposed project are evaluated elsewhere in the EIS, an alternative consisting of the proposed project with staff-recommended modifications has not been identified nor evaluated in the EIS until this section. This section should be revised to reflect analyses of the alternatives being evaluated throughout the EIS, as required by the NEPA regulations (40 CFR 1502.16 and 1502.23).

Page 5-8 discusses a "staff-recommended licensing alternative" which appears to conflict with the statement on Page 6-1 that "neither FERC not NPS has identified a preferred alternative." This inconsistency should be resolved and analyses should be developed and presented consistent with that resolution.

Recommendations (Section 6)

Page 6-29 discusses a "project as recommended by FERC staff" which appears to conflict with the statement on Page 6-1 that "neither FERC not NPS has identified a preferred alternative." This inconsistency should be resolved and analyses should be developed and presented consistent with that resolution.

U.S. Environmental Protection Agency Rating System for Draft Environmental Impact Statements Definitions and Follow-Up Action*

Environmental Impact of the Action

LO – Lack of Objections

The U.S. Environmental Protection Agency (EPA) review has not identified any potential environmental impacts requiring substantive changes to the proposal. The review may have disclosed opportunities for application of mitigation measures that could be accomplished with no more than minor changes to the proposal.

EC – Environmental Concerns

EPA review has identified environmental impacts that should be avoided in order to fully protect the environment. Corrective measures may require changes to the preferred alternative or application of mitigation measures that can reduce these impacts.

EO – Environmental Objections

EPA review has identified significant environmental impacts that should be avoided in order to provide adequate protection for the environment. Corrective measures may require substantial changes to the preferred alternative or consideration of some other project alternative (including the no-action alternative or a new alternative). EPA intends to work with the lead agency to reduce these impacts.

EU – Environmentally Unsatisfactory

EPA review has identified adverse environmental impacts that are of sufficient magnitude that they are unsatisfactory from the standpoint of public health or welfare or environmental quality. EPA intends to work with the lead agency to reduce these impacts. If the potential unsatisfactory impacts are not corrected at the final EIS stage, this proposal will be recommended for referral to the Council on Environmental Quality (CEQ).

Adequacy of the Impact Statement

Category 1 – Adequate

EPA believes the draft EIS adequately sets forth the environmental impact(s) of the preferred alternative and those of the alternatives reasonably available to the project or action. No further analysis of data collection is necessary, but the reviewer may suggest the addition of clarifying language or information.

Category 2 – Insufficient Information

The draft EIS does not contain sufficient information for EPA to fully assess environmental impacts that should be avoided in order to fully protect the environment, or the EPA reviewer has identified new reasonably available alternatives that are within the spectrum of alternatives analyzed in the draft EIS, which could reduce the environmental impacts of the action. The identified additional information, data, analyses or discussion should be included in the final EIS.

Category 3 – Inadequate

EPA does not believe that the draft EIS adequately assesses potentially significant environmental impacts of the action, or the EPA reviewer has identified new, reasonably available alternatives that are outside of the spectrum of alternatives analyzed in the draft EIS, which should be analyzed in order to reduce the potentially significant environmental impacts. EPA believes that the identified additional information, data, analyses, or discussions are of such a magnitude that they should have full public review at a draft stage. EPA does not believe that the draft EIS is adequate for the purposes of the National Environmental Policy Act and or Section 309 review, and thus should be formally revised and made available for public comment in a supplemental or revised draft EIS. On the basis of the potential significant impacts involved, this proposal could be a candidate for referral to the CEQ.

* From EPA Manual 1640 Policy and Procedures for the Review of Federal Actions Impacting the Environment. February, 1987.

John R. Swanson
3400 Edmund Blvd.
Minneapolis, MN 55406-2942

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5 January 2004.

2004 JAN 14 A 8:37

Magalie R. Salas, Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426.

FEDERAL ENERGY
REGULATORY COMMISSION

attention:

please accept my comments on the FERC Project No. 11659-002, Falls Creek Hydroelectric Project and Land Exchange.

I am opposed to this project!

It will destroy wilderness, wildlife, fish and scenic attributes of certain natural significance

Please reject this project.

Sincerely,
John R. Swanson.

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December 5,2004

2005 JAN 15 P 2:13

FEDERAL ENERGY
REGULATORY COMMISSION

Magalie R. Salas,Secretary
Federal Energy Regulatory Commission
888 First Street N.E.
Washington, D.C. 20426

Ref. Project No. 11659-002

Dear People:

Here I sit this beautiful morning, a 37 year resident of Gustavus. Around me are various publications of conservation and environmental organizations to which I belong and have supported for many years.

With the deadline approaching for FERC receiving comments on the Falls Creek Hydroelectric Proposal, there follow my comments:

I am in favor of the proposal because I believe it will reduce the amount of particulate matter now spewing into the air from the diesel generators; it will cut down on community noise; there will be that much less use of fossil fuels, the "shortage" of which worrys our present "fossil fuel loving" National Administration; and finally may be more dependable as a source of energy in an emergency situation.

As to the concerns of at least one of the groups to which I belong regarding the precedent setting nature of this intrusion into an area designated as wilderness have this to say. After thirty years in the National Park Service as a Park Ranger, Wildlife Management Biologist, and retiring as Superintendent of Glacier Bay National Park I can point out many instances of departures from the ideals and regulations of the Park Service. The fear was that the changes would be precedent setting In none of these instance has this occurred.

Robert E. Howe

Robert E. Howe
Box 67
Gustavus, AK 99826

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2004 JAN 15 P 2: 13

FEDERAL ENERGY
REGULATORY COMMISSION

Wayne Howell
P.O. Box 32
Gustavus, Alaska 99826

To: Magalie R. Salas, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426
FERC Project No: 11659-002

These comments are an addendum to my comments provided at the public meeting held in Gustavus in December. I reiterate here that I am concerned that Gustavus Electric Company has grossly underestimated the cost of the project. For example, I refer to the study conducted by the US Army Corps of Engineers in the early 1980s. That study estimates the cost of the hydroelectric project on the lower stretch of Falls Creek at $7.95M n 1980 dollars. Gustavus Electric Company, in order to gain more head and address several environmental concerns, outlines a more ambitious project; they place their diversion structure significantly higher on the stream, requiring more road and penstock, and place the powerhouse in the canyon below the lower falls, requiring an ambitious road construction challenge. Yet GEC estimates the cost of the project at $5.1M in 2003 dollars. I would like the final EIS to address this huge discrepancy, and explain how GEC intends to build a more ambitious project for significantly less money.

I also would like to see a plan and realistic cost estimate for the access road, and how it is to be built. I note that the proposed rock source for the project is located about 1.5 miles into the project area from the existing roadway, meaning that that material will not be available until the road is built to it, requiring that all of the material up to that point will have to be imported. I would like to see a realistic cost estimate for that portion of the project. This road plan cannot sidestep several important issues, such as the need to build a <u>substantial</u> roadbed in the extremely wet lower section (I am personally familiar with the condition of the lower section of the proposed road, having helped a private landowner build an ATV trail through there in the late 1980s). This lower section of road will have to withstand the significant heavy truck traffic that will be required to haul in road material and heavy equipment and haul out logs. The plan and cost estimate should realistically reflect the cost of culverts and drainage ditches, as the area is exceedingly wet.

I am also concerned that the project will take place off the end of a 7 mile long private road. It is unreasonable that the private landowners be expected to pay the cost of maintaining this road, including a bridge structure, both during construction and during the life of the project. I would recommend that if this permit is granted, and the project lands are transferred from Federal to State ownership, that the responsibility for maintaining the road be transferred to the State of Alaska.

I support the No-action alternative. However, if that alternative is not chosen, then I would support the Maximum Boundary Alternative. I support this alternative in that the

FERC project boundary would encompass the entire project area, and hence stipulations written into the permit would pertain to the entire area, and not just lands immediately underlying project facilities, as outlined in GEC's preferred alternative. I do not suppon the Corridor Alternative because it leads to a fragmented landscape pattern, with parklands sandwiched between project lands and native allotments, and thus very difficult to manage. If the Maximum Boundary Alternative is chosen, I would recommend that the public be able to participate in the process of drawing up permit stipulations so that community concerns be incorporated into the management regime for the project area once it is transferred into State ownership.

I am also concerned that the Gustavus Electric Company is currently under investigation by the Regulatory Commission of Alaska (RCA) regarding its rate structure. Since the rates it can charge is at the core of its economic viability, and the rate base underlies all economic analysis for this report, I would request that no decision be made regarding this permit until the investigation by the RCA is completed.

Wayne Howell
Gustavus

'N JAN 15 PM 3:52

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DATE: 1-3-04

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2004 JAN 20 P 12:41

FEDERAL ENERGY
REGULATORY COMMISSION

FROM:

Friends of Glacier Bay

PO Box 135

Gustavus, AK 99826

TO:

Magalie R. Salas, Secretary

Federal Energy Regulatory Commission

888 1st Street NE

Washington, DC 20426.

RE:

FRIENDS OF GLACIER BAY (FOGB) RESPONSE

TO FERC No. 11659-002 Falls Creek Hydroelectric Project and Land Exchange

Friends of Glacier Bay (FOGB) is a local environmental organization, founded in 1979, whose mission is dedicated to "preserving ecological intactness and opportunities for solitude in Glacier Bay". One of our main purposes is to work with the National Park Service to ensure that park management strives to maintain the natural environment in a pristine condition.

The Falls Creek Hydropower Project proposal is philosophically very difficult for our organization. Because our mission is to help protect "ecological intactness and opportunities for solitude", we have many concerns about the environmental impact of this project. At the same time, we recognize the benefits of a clean source of electrical power for this community with a reduction in fossil fuel importation, consumption and pollution.

Below it will be noted that both preservation and social issues favor the no action alternative. **Therefore, Friends of Glacier Bay stands opposed to the Falls Creek Hydropower Project.**

Our concerns to FERC:

A. Preservation Issues:

1. **Stream Flow:** It is not clear that there is enough water in the stream to significantly reduce our community's reliance on diesel power. (Studies show that there will NOT be enough stream flow to eliminate diesel power year round). It is not clear that enough power will be generated by this hydro project to balance the economic and environmental costs.

2. **Continued Fossil Fuel Consumption and its Transport**: We are concerned about the hazards of continuing to transport diesel fuel over the rich waters of Icy Strait. Yet, recognizing that hydroelectric is now the only practical alternative to diesel generation in Gustavus, as acknowledged in the 100th Meridian analysis, we predict that there will eventually be something workable; leading contenders include tidal power or hydrogen (fuel cell technology) using surplus hydropower elsewhere in the region.

3. **Habitat Loss**:

Because there is no way to permanently restrict access to the native allotments once a road is built to them, and because there is no way to permanently "lock up" the state land once it is transferred out of the park, we must assume that these developments will eventually lead to loss of critical wildlife habitat, including:

a) Fish Habitat:
With hydropower, there will be loss of 14% of Dolly Varden in the creek above the falls.

b) Bear Habitat:
This hydroelectric project may be the only reasonable near-term alternative to burning fossil fuel for electricity. But there is a grave risk that the hydroelectric project will eventually cost the bears their prime meadow habitat because there is no way to guarantee that vehicular access can be restricted in the long term. If the land is removed from the park and a road built right to the boundaries of both native allotments, they will eventually be developed to the detriment of the meadow habitat. The two negative factors of fossil fuel consumption versus prime habitat loss are almost equally undesirable. Conversely, the preservation of the habitat or using renewable energy seem equally desirable, but they are clearly mutually exclusive.

If we are thinking only about the next 10 (or even 20) years we might discount both the risk of habitat loss and the likelihood of finding something better than hydropower. But as we look farther into the future it seems both become more likely. Given enough time they both approach certainty, making the choice clear. Put another way, the long-term risk of losing bear habitat from hydroelectric development seems much greater than the long-term risk of not finding other suitable alternative energy. In a much more developed Gustavus 30 years from now, we could easily be using neither hydro nor diesel for electricity and be quite relieved that we made the right choice in keeping the bear habitat.

4. **Precedence:** As a "Friends of Parks" organization, we are especially concerned about the precedence this legislative removal of wilderness lands from a National Park will have in the future for this and other parks.

B. Social Issues:

1. **Economic feasibility:** Is this project economically viable enough to benefit the residents and businesses of Gustavus, and will the park be able to pay the costs of hooking into the system? If not, how will this affect costs to the local consumers? The current contradictory and elusive economical information on this project is of great concern to our organization. An under-funded project that could not be constructed or completed with the best of engineering and environmental considerations would be unacceptable. Gustavus Electric has to obtain public funding or the land transfer will be denied. Rates may even be lower if public financing is a large enough component and if the Park Service becomes a customer, but this will not affect the typical PCE-subsidized ratepayer at all. It behooves us to help FERC reasonably define 'feasible" and to make sure that definition is actually met, but these considerations are not as important as the ecological considerations.

2. **Local Social Factors**:

The native inholdings adjoining the project, whose owners include generations of land stewardship at the mouth of Falls Creek, are not eager to live with a hydro-electric plant upstream approximately 1/4 mile from their home.

Many local folks used to hike or ski several times a year up Falls Creek to the falls. Given the concerns of the inholding owners, and the concerns of Beartrack Inn about the increased traffic crossing to the falls project during the 5-year study work, this area is no longer welcoming to local users. With a hydropower facility there, park hikers cannot expect "opportunities for solitude" with a pipeline, road and generator, next to potentially developed private inholding lands made easily accessible by the hydro project.

NOTE: If this project is permitted, it is imperative that vehicular road access should be off-limits to the public, and that the "Corridor Alternative" should be chosen.

Comments about the DEIS

Erosion of the wilderness preservation system is a cumulative impact, with negative ecological factors. The possible effects on the traded state lands, adjacent native allotments, and adjacent tide lands must be most thoroughly examined. For example, could the state land be sold and developed? There is no way that anyone can guarantee otherwise and this needs to be made obvious. Could the native allotments gain road access through the project area? The road would go right to the boundaries of both parcels , opening up the possibility of inholder development which would have significant negative effects on wildlife using the adjacent tide flats. Those effects need to be examined in detail.

The real costs of the Park tie-in need to be addressed, as do the costs of road upgrade/maintenance.

In conclusion, with all these considerations in mind, Friends of Glacier Bay stands opposed to the development of this hydro project.

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2004 JAN 21 P 3:53

FEDERAL ENERGY
REGULATORY COMMISSION

Donald D. and Martha V. Romero
P.O. Box 284
Gustavus, Alaska 99826
907-697-3070

Magalie R. Salas, Secretary
FERC
888 First Street N. E.
Washington DC 20426

ATTENTION: FERC PROJECT: 11659-002

Dear Ms. Salas,

We are life long residents of the great state of Alaska and have lived in Gustavus for the past nine years. Since living here we have heard of the Falls Creek hydro project, and as of yet there hasn't been anything finalized. How long does it take?

We all know the effects of the use diesel for electric generation on the environment, that plus the rising costs should show FERC how important this project truly is.

We know the concerns of the NPS with the particular piece of land coming out of Park lands, but this land is not crucial to Glacier Bay National Park and Preserve. Besides that hasn't this already been taken care through Congress?!!

We have lived in Southeast Alaska the majority of our lives and we know all about liquid sunshine (rain) and how much we get and how often we get it and if it runs into the ocean and we are not using it for our benefit, SHAME ON US!

When we moved to Gustavus, we came and built a place not just for us but for our children and our granddaughters and hopefully their children. We can not see the future of electricity derived from diesel generation but a much more efficient way through using what God has given to us.

Thank you for reading this letter and please except it as a definite yes to the Falls Creek Hydroelectric Project.

Sincerely,

Donald D. Romero
Martha V. Romero

Donald D. and Martha V. Romero

ORIGINAL

January 6, 2004

Magalie Salas, Sec.
FERC
888 First St., NE
Washington, DC 20426

FILED OFFICE OF THE SECRETARY 2004 JAN 26 P 2:05 FEDERAL ENERGY REGULATORY COMMISSION

Dear Magalie:

I am writing in reference to FERC #11659-002 in regards to the proposed Hydroplant at Falls Creek. First of all, I am not in favor of the opening of wilderness to commercial development. As an employee of Glacier Bay National Park, and speaking for myself only, I do cherish the heritage of wilderness that this generation has been charged to steward for its protection and the enjoyment of future generations. Operation of the proposed hydro-plant would lessen but not negate this community's dependence on oil. We can continue to be responsible in our use of oil and allow the wilderness to remain so.

I am not in favor of public money on public land being placed into the hands of a private individual. I do not believe that the development of the hydro-plant would be for the benefit of the community. In fact, we have been told that power generated in this means would not even lower our electric bills!

I am a resident of Rink Creek Road whose dirt surface is maintained solely by the residents. Mr. Levitt and companies use and yet contribute nothing to the support and upkeep of this road which includes many gradings and some plowings each year, rebuild of wash-outs, and maintenance of a very small bridge over the creek. What believable assurance would he offer to the contrary in the future?

As I understand it, FERC is mainly involved with the actual building of an actual plant on the actual site. To whom would Mr. Levitt be held accountable for other community concerns. I do not want increased noise, traffic, sightseers, and road damage in my neighborhood. I live out Rink Creek Road because I appreciate the peace and quiet. Solitude is priceless. What assurance could we be given that there would be no open door to the development of any other business by Mr. Levitt and companies?

Helicopter flights to and from the Beartrack Inn (located at the end of Rink Creek Road) was voted down by the community of Gustavus because, on the whole, we place a high priority on solitude. Would we be given an assurance that there would be NO helicopter usage in the development, construction, operation and maintenance of such a facility?

What exactly would be ALL the expenses involved in such a project for Gustavus as a community, for the Park, for Rink Creek Road and neighborhood, for the individual customer?

Thank you for your assistance.

Sincerely,

Jeanie Farrell

Jeanie Farrell
P.O. Box 232
Gustavus, AK 99826

ORIGINAL

Tara Walker
6918 Gemini
Anchorage, Alaska 99504

P-11659

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2004 FEB -9 P 3:50

FEDERAL ENERGY
REGULATORY COMMISSION

Dear Commissioner Salas,
I am writing to voice my opposition to the Falls Creek Hydro Project in Glacier Bay National Park. I was fortunate enough to visit that area of my state this summer, and take a one-week kayak trip, and the thought of the powerhouse site at Falls Creek is horrifying. Some places are so special, they should never be developed. The biological diversity there is great for Alaska, and the pipeline, road route and powerhouse site would be damaging to the Park. Tourism, as you know, is the major industry of this area, and anything that disrupts tourism is not good for the people of Juneau and Gustavus.
I would agree with the locals that alternate sources of energy must be explored, such as tidal, to mention the obvious, and wind, the South-Central Intertie, and fuel cell technology. This dam should not be allowed in a National Park, that is the mandate of a Park.

I don't think the economic feasibility of the project has been proven. We cannot lose 1147 acres of irreplaceable wilderness and wildlife habitat for an unproven economic benefit. The estimate of demand growth and generating costs made by Gustavus Electic are unreasonably projected. NPS is currently using diesel at a lower cost, and it is unlikely they will switch to the Gustavus Electiric Program. Energy conservation measures could also save up to 30% of the overall power costs, and this is a more sensible measure to buy time to wait for the new technologies, such as tidal power, to become viable alternatives.

Please don't use our National Parks to fill a development plan for a local utilities company. The Parks belong to all Americans, and the role they must play is to be our last wilderness areas, to be treasured for future generations. Thank you for your protection of Glacier National Park. Say "NO" to the Falls Creek Hydro Project, and support diesel with energy conservation measures for the present demand.

Sincerely,

Tara Walker
6918 Gemini
Anchorage, Alaska 99504

Tara Walker

APPENDIX E

FALLS CREEK HYDROELECTRIC PROJECT AND LAND EXCHANGE EIS

SUPPORTING DETAILS FOR ECONOMIC ANALYSIS

In section 6.1.1.4 of the final EIS, we provide economic information on the proposed Falls Creek hydroelectric project. This appendix contains the supporting details, calculations, and spreadsheets used in that analysis.

Stakeholder Comments and Analyses

In response to the publication of the draft EIS, one individual, the applicant, and two organizations submitted economic analyses of the proposed project:

- Eric Cutter (Cutter) filed a report on December 16, 2003, prepared by 100th Meridian for the Sierra Club entitled "Economic Analysis of the Proposed Gustavus Electric Falls Creek Hydro Project and Potential Alternatives."
- GEC filed comments on the draft EIS on January 2, 2004.
- Alaska Industrial Development and Export Authority/Alaska Energy Authority (AIDEA) filed an analysis on January 6, 2004, prepared by the Financial Engineering Company.
- National Heritage Institute (NHI) filed a report on January 6, 2004, prepared by 100th Meridian entitled "Comments on the Economic Analysis in the Draft Environmental Impact Statement for the Falls Creek Hydroelectric Project (P-11659)."

Cutter Analysis. This report does not provide a complete analysis of the economics of the proposed project, but it does examine certain related variables:

- electric demand and load growth;
- required generation versus sales;
- construction and operating costs;
- financing and rates;
- project firm capacity; and
- GEC rates versus rates in similar communities.

Cutter also discusses overall generation costs throughout his report when justifying the impact of the above-mentioned variables, although he does not submit a complete analysis or calculation methodology.

Cutter notes that the peak observed demand in the GEC system was about 315 kW and that, based on current energy and load projections, the demand in the GEC system would not exceed the 550 kW capacity of the two primary generating units for many years. He states that load growth may be lower than projected by GEC because of socioeconomic factors, including reduced economic activity, decreased travel and tourism in the GEC service area, and reduced rate of growth in the town of Gustavus. Cutter notes that there is a significant difference, on the order of 15 percent, between generation required by the GEC system and ultimate sales to GEC consumers. He states that, because of flow limitations, hydropower generation would be available a lower percentage of the time than determined by GEC. He also states that interconnection to serve the GBNPP load would strand costs recently incurred by the NPS for new generation equipment at GBNPP. Cutter states that financing costs for the proposed project are likely to be higher than shown by GEC, and that the significant increase in GEC's rate base would appreciably increase the cost of generation. He notes that diesel generation would be needed to supplement hydroelectric generation during low flow periods. Finally, he notes that GEC already has high electrical rates compared with other parts of the state, and that any measure that would further increase those rates should be carefully reviewed because of its effects on ratepayers.

Cutter states, in conclusion, that examination of the above-mentioned variables shows that proposed project costs would be much higher than those realized for existing diesel generation. Therefore, he concludes that development of the project would not be worth its associated impacts.

In section 1.1.2, *Need for Power*, we present the available capacity of the existing diesel generating units and note that the capacity of these units would not be exceeded for many years. We identify load growth scenarios beyond our baseline projection and present those later in this section. Although there is a difference between energy generated and energy sold, we focus on energy generation values only and distinguish this throughout our analysis. We also note that GEC system losses would be identical under hydroelectric or diesel generation.

In chapter 5, as well as in this section, we show the results of our hydrological modeling that determine when hydroelectric generation is available to meet GEC energy requirements. For the baseline projection, flow available for hydroelectric generation would be sufficient to meet GEC's current generation requirements 98 percent of the time over the first 10 years of project operations, and would meet GEC's generation requirements 86 percent of the time over the period of analysis.

We do not analyze stranded costs associated with interconnection to the GBNPP system. Interconnection is not a part of the proposed project before the Commission and an economic analysis of this action is beyond the scope of this proceeding. GEC provided revised and updated financing rates for the proposed project, which we use in chapter 5 as well as the baseline projection in this section. We also include an analysis of the effect of borrowing costs in our revised analysis in section 6.1.1.4.

The value of GEC's assets, also known as its rate base, would significantly increase if the project was developed, but GEC's profit would not increase because the project would be financed through borrowing.

GEC Analysis. GEC submitted comments on:

- project completion date;
- insurance, property tax, and income tax rates;
- term of analysis;
- financing terms, including interest rates, grant availability, and term of analysis;
- GBNPP interconnection costs;
- projected generation under minimum flow scenarios; and
- fuel specific and general inflation values.

GEC notes that a project completion date of 2007 may be in doubt because of the time associated with regulatory requirements. GEC provides updated values for insurance, property tax, and income tax rates, and notes that insurance costs accounted for using standard FERC methodology appear to have double-counted this cost, in that insurance costs were already a part of annual costs submitted by GEC. GEC also notes that the property occupied by the project would not be subject to income tax but rather to a land lease payment arrangement, and this cost has already been accounted for in its presented values. GEC notes that the project would not be funded by equity financing, and thus would not be subject to income taxes based on return on equity. GEC provides information on a grant available from the Denali Commission for the development of this project, as well as the availability of lower interest loans from the AIDEA and the Rural Utility Service. It also states that project economics should be evaluated for the life of the initial project license period of 48 years (accounting for 2 years of construction activity after license issuance and before project operation would begin). GEC notes that the analyses presented in the draft EIS did not include the cost of interconnection with the GBNPP system, and provides a cost for that connection. GEC provides annual generation values based on its operations model for a zero minimum flow scenario as well as the GEC- and staff-recommended minimum flow alternative. GEC discusses general and diesel fuel-specific inflation values based on historical trends, and suggests recommended values.

GEC also provides a discussion of the methodology used in the draft EIS, and prepared its own benefit-cost ratio calculation. It presents an analysis of the benefit cost ratio for the project under several different scenarios as a function of mitigation cost, park load inclusion or exclusion, instream flow requirement, diesel fuel cost, grant amount, and project operation date. These analyses determine the total construction cost of the project including interconnection as appropriate and develop an annual debt service value from this cost. Annual project costs including O&M, lease fees, insurance, and mitigation are determined and discounted to 2003 dollar values, where they are compared with the value of equivalent diesel fueled generation, and a benefit-cost value is calculated from these values.

GEC performed cost-benefit analyses to summarize its conclusions, resulting in a benefit-cost ratio of 1.14 including GBNPP loads and 1.06 excluding GBNPP loads.[1]

At this time, project operations are planned to commence in 2007. The project license, if issued, would establish terms for when construction and operation would begin and the actual date for initial operation could be different than 2007.

We assume that the insurance costs would be 0.25 percent of the construction costs. GEC agreed with this assumption in its comments on the draft EIS. The lands proposed for the project would not be subject to property taxes, and the project would be funded with 100 percent debt; however, the property would be subject to some income tax as project equity is developed as borrowed funds are repaid. The calculation of income taxes would initially include credits due to accelerated depreciation in the early years of project operation.

The grant from the Denali Commission is based on the inclusion of GBNPP load into the GEC system, and we thus have not included the grant monies in our developmental analysis in chapter 5, which does not consider interconnection with GBNPP. In this section, however, we analyze the economics of the proposed project with and without the proposed grant, regardless of the inclusion of GBNPP load into the GEC system. We note that lower interest loans available from AIDEA and the Rural Utility Service are not contingent on the inclusion of GBNPP load into the GEC system. Thus, we include these financing rates in chapter 5 as well as our middle scenario presented in this section, although we also analyze the effect of higher debt costs in this section to address the possibility of increased interest rates.

Although the term of a new project license can be 50 years, we limit our economic analysis in section 6.1.1.4 to 30 years. If the project shows positive economic benefit within 30 years, those benefits would reasonably be expected to increase in subsequent years, should the Commission issue a 50-year license.

Our analysis of project costs do not include the cost of interconnection with the GBNPP system since this is not part of the proposed project. However, we discuss the cost of interconnection in section 6.1.1.4 and describe the cost GEC supplied along with costs for interconnection supplied by other commenters.

GEC provided annual hydroelectric generation values based on its operations model; however, in chapter 5 we model minimum flow alternatives proposed by other stakeholders and for which no generation estimates were provided by GEC. In the draft EIS we used our model results for all generation estimates, however, in the final EIS we adjusted all of the estimates to be consistent with GEC's model results.

[1] Although GEC presents benefit-cost ratios for other scenarios including no instream flow and GEC's proposals for mitigation costs, we only discuss those results that directly relate to measures proposed for this project.

GEC comments that the price of diesel fuel is subject to higher inflation rates than general inflation rates reflected by increases in the consumer price index (CPI). We agree that diesel fuel prices may increase at a faster rate than the price of other consumer goods and considered the effect of other inflation rates on project economics in the final EIS.

AIDEA Analysis. AIDEA submitted comments focusing on draft EIS chapter 5 in the following areas:

- discount and inflation rates;
- additional capacity requirements;
- project operating costs;
- the GEC/GBNPP interconnection; and
- a discussion of the analysis presented in the draft EIS, as well as AIDEA's own analysis.

AIDEA comments that chapter 5 does not include inflation or escalation of values beyond the starting year of the project, and that a real discount rate was used in the analysis. AIDEA also notes that the value of diesel generation does not include cost for the addition of new diesel generation if the proposed hydroelectric project is not built, both to retire existing units as well as to increase capacity. AIDEA states that insurance premiums on existing diesel units may be reduced if the project is reduced, payment of federal income taxes is independent of the analysis, and there would be no property tax on the project. AIDEA observes that a GEC/GBNPP interconnection is needed for GEC to supply the park with energy from the proposed project, and estimates the cost of this connection at about $100,000 per mile, or $500,000 in total.

AIDEA provides a 30-year pro forma that compared the annual total expenses for development and operation of the hydroelectric project versus existing diesel generation. This analysis compares net present value of the amortized cost of capital additions as well as the cost of fuel, O&M, and overhauls related to diesel generation, to the amortized project cost, O&M, and insurance related to hydroelectric generation. This analysis uses an amortization rate of 7 percent, a discount rate of 8 percent, and an inflation rate of 3 percent.

In regards to AIDEA's comment on inflation and escalation, we note that the analysis in section 6.1.1.4 addresses the escalation of costs beyond the initial year of project operations.

Section 1.1.2, *Need for Power*, of the final EIS reflects on the available capacity of the existing diesel generators without the addition of the GBNPP load. Even if the GBNPP load were added, there would be sufficient capacity without the addition of new diesel generating units. We have no information regarding the replacement cycles for these units, but we speculate that annual overhauls should allow continued unit operation well beyond a 15-year cycle. We do examine the replacement of diesel units within two scenarios of our analysis.

We have no quantitative information on which to base a reduction in insurance premiums associated with diesel generation and have not included these cost reductions in our analysis. There would be income taxes directly associated with return on the rate base associated with this project. However, due to the complete dependence on debt financing, we anticipate initial income tax credits due to the deferment of taxes, with these deferments immediately realized as part of GEC's overall tax payments, as well as later tax requirements as project equity is realized by GEC.

Our analysis of project costs do not include the cost of interconnection with the GBNPP system since this is not part of the proposed project. However, we discuss the cost of interconnection in section 6.1.1.4 and describe the cost AIDEA supplied along with costs for interconnection supplied by other commentors.

AIDEA concludes that, based on its analysis of project economics including use of its values for the variables discussed above, the project would realize a cumulative net benefit of about $2,500,000 over the 30 year period of analysis.

NHI Analysis. NHI filed comments on both chapters 5 and 6. NHI submitted a cover letter and a report reviewing the analysis, covering the following issues:

- the potential for and timing behind the decision to interconnect to serve GBNPP load;
- the need to account for additional environmental enhancement costs to address Section 3(C)(3) of the Act;
- the absence of costs including depreciation, return on rate base, recovery of taxes, and GBNPP transmission line construction;
- load growth in the GEC service area;
- the need for additional capacity in the GEC service area;
- financing costs related to project construction;
- a skew created by the current cost methodology in the developmental analysis;
- income taxes related to project operation; and
- an assessment of GEC's final rates to consumers, including an analysis of generation versus sales.

NHI comments that the NPS has not reached a decision on interconnection with the GEC system, would not do so as a direct function of this proceeding, and would strand generation as a result of interconnection. NHI also notes that Section 3(C)(3) of the Act allows for the NPS to institute additional measures to protect the values of GBNPP, and thus observes that these potential measures should be accounted for in a quantitative manner. NHI observes that the developmental analysis does not account for depreciation, return on rate base, recovery of tax payments, and that the cost associated with development of a transmission line to interconnect GBNPP to the GEC system is not included in the draft EIS. NHI notes that generation requirements in the GEC service area may grow at less than the rates shown in the draft EIS due to recent trends, and also notes that there is not much difference between the mid-range and low-range growth scenarios GEC presented. NHI states that GEC has adequate existing diesel capacity to serve its current and project future load, and that the draft EIS utilized higher interest rates for financing of project debt versus those rates presented by GEC. NHI states that the current cost methodology used in the draft EIS developmental analysis underestimates project costs due to the lack of cost escalation, and that the failure to account for interest costs during construction also skews the results. NHI makes contradictory comments relative to the inclusion of income taxes in our developmental analysis Finally, NHI notes that this analysis does not include an accounting of the impact on the ultimate cost to consumers of project generation.

NHI also provides an analysis of the first-year cost of this project incorporating several factors, including a determination of current cost, interest during construction, environmental enhancements, and NPS transmission line development (if NPS load is included). NHI determines annual debt service, as well as O&M, taxes based on a 10-year average, the annual cost of environmental enhancements, return on equity, and depreciation to determine the annual cost to ratepayers in both dollars and dollars per kWh.

NHI concluded that the cost of generation to ratepayers would be between $290 and $310/MWh if park load were excluded and between $350 and $440/MWh if park load were included and the cost of transmission was $2.25 million. These values are higher than the $130/MWh cost of existing diesel generation.

Interconnection of GBNPP to the GEC system is not part of the proceeding before the Commission at this time; however, in this section we consider both inclusion and exclusion of GBNPP loads as part of our economic analysis of the proposed project. Because the GEC-GBNPP transmission line is not part of the proposed project we do not include these costs in our economic analysis. We do not analyze stranded costs associated with interconnection to the GBNPP system. Interconnection is not a part of the proposed project before the Commission and an economic analysis of this action is beyond the scope of this proceeding.

In regard to environmental enhancements that could be required by NPS in the future to preserve the values of the GBNPP, it is not possible to forecast what those measures might be or to associate costs with those measures at this time. Therefore, we do not include estimates of these potential future costs in our economic analysis.

As indicated by NHI, our analysis in the developmental analysis section examines principal payments instead of depreciation and does not explicitly calculate return on rate base, although income taxes are accounted for. In section 6.1.1.4, we analyze income taxes, including deferrals due to accelerated depreciation schedules, and depreciation as part of net income, as well as principal repayment when analyzing cash flows.

NHI states that the GEC system currently has adequate capacity to serve peak load for the foreseeable future. We confirm this statement in section 1.1.2 of the draft and final EIS.

GEC has provided references for interest on debt, as well as a commitment for a grant of approximately $1 million. Our analysis of GEC's balance sheet shows that this project would be funded with 100 percent debt is reasonable, because GEC has no apparent source of internal equity to fund this project.

NHI presents a current year analysis of the cost of hydroelectric generation. This analysis accounts for interest during construction and the cost of environmental enhancements, as well as costs associated with the GBNPP transmission line. However, this first-year analysis does not account for the increase in diesel generation cost over time due to escalation. Because fuel is the largest component of diesel generation cost, the difference in costs would decrease over time as hydroelectric costs rise more slowly than diesel generation costs. The treatment of taxes is unclear in the NHI analysis; because there is essentially no initial project equity, there should be no income to be taxed in the initial years of project operation. Similarly, a return on equity is calculated; presumably this value is a function of the rate base associated with the project. However, for a project where funding is 100 percent debt, the return on rate base would cover bond interest and taxes, without return on non-existent equity. Also, if depreciation were included in this analysis, the principal repayment component of debt service would be eliminated from the ratepayer's cost, as principal repayment reflects cash repayment of the project, while depreciation reflects a similar value but from a non-cash basis.

Lastly, this proceeding only concerns generation of electricity, not final delivery to consumers; once the energy enters the GEC system, line losses would be the same regardless of the generation source. Thus, we focus our analysis on the difference in generation costs between hydroelectric and diesel.

Independent Commission Analysis

In this section we describe the methods we employed for our economic analysis of the proposed hydroelectric project.

As a certificated utility, GEC determines the cost of recovering ownership and operation of its generating facilities using methodologies approved by the RCA, and the determination of those costs is based on standard utility rate-making practices. We base our analysis on the determination of acceptable costs based on utility rate-making practices, and the determination of annual project income and cash flows as a function of the requirement to meet those charges.

We assume that it is necessary for the project to maintain a positive or zero net income[2] and cash flow.[3] Net income and cash flow can differ significantly throughout a project analysis due to depreciation versus principal repayment, and the deferment of tax liability due to accelerated depreciation.[4] We calculate both net income and cash flow, and solve for the required income to ensure that both values are at least zero.

We determine operating revenues and corresponding cost of generation as follows. From the determination of net income, expenses incurred by the project include operating and maintenance (O&M) expenses, interest on long-term debt, depreciation, and taxes. Interest earned on the debt and operating reserves is credited against these expenses. The net cash flow of the project is based on expenses as calculated above, but depreciation is subtracted and debt principal is added to net income expenses to determine cash flow expenses. From the above calculations, we then determined the operating revenues required to ensure that both the net income and net cash flow are at least zero and the resulting cost of generation is then the operating revenue divided by the projected project generation.

Annual O&M costs are determined as discussed in chapter 5. The depreciation expense is assumed to be constant (straight-line) over the analysis period. Interest income from the debt service reserve and operating reserve accounts (discussed in the *Project Construction Cost* and *Interest Earnings on Reserve Accounts* areas of this section) are calculated as a function of fixed account balances and interest rates. The interest on long-term debt is calculated as a function of the projected interest rate on funds borrowed as well as the remaining loan principal. Federal and state income taxes are calculated as shown on the carrying charges sheets in appendix E of this EIS. We calculate the available tax deferrals due to the difference between book (straight-line) and tax (accelerated, or MACRS as described by the IRS) and assess the tax benefit or liability due on a year-by-year basis, showing taxes net of the provision for deferred taxes. For early project years, where accelerated tax depreciation provides a net tax credit due to the 100 percent debt financing of this project, we assume this credit can be realized in the year it occurs because it can be applied to other tax liabilities incurred by GEC's operations.

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2 This is the difference between revenues and expenses from an accounting standpoint.

3 The actual difference between money received and money paid out. Note that this differs from net income due to the difference between depreciation (a non-cash expense) and principal repayment.

4 Depreciation as allowed by the Internal Revenue Service, known as a MACRS depreciation schedule, which allows for a higher percentage of a project to be depreciated earlier in the project's life to reduce earlier taxes, with resulting higher taxes later on in the project's life. The difference between MACRS and straight-line depreciation values indicates the deferred tax credit or liability available.

We determine the annual net benefit as the yearly difference in the cost of generation from the proposed hydroelectric project versus existing diesel generation over the 30-year life of the project. The net present value of the proposed hydroelectric project is then calculated by discounting the annual net benefit by the weighted cost of capital on an annual basis and summing those values.

Key Assumptions

As commenters note, many of the values used in this analysis can vary. We examined the following variables as part of this analysis:

- GEC system load growth;
- general cost escalation;
- diesel fuel cost escalation;
- other costs associated with diesel generation;
- grant availability; and
- interest rate on debt.

To examine the effect of a range of values for these variables on project economics, we developed the following five scenarios covering a range of assumed values for each variable: Low, Low-middle, Middle, High-middle, and High. A general description of the values used for each variable under each scenario is provided below.

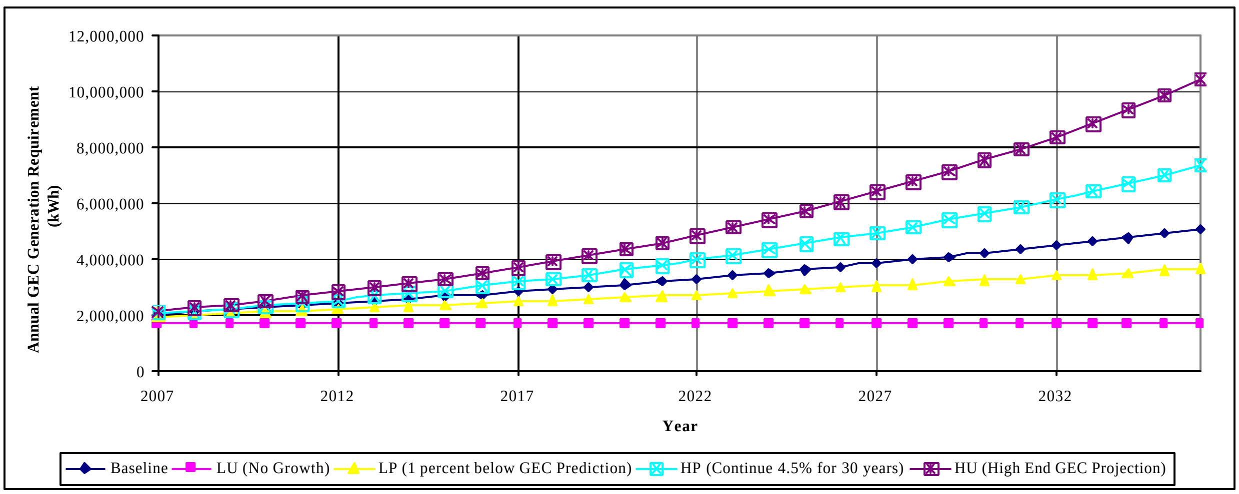
- Low estimate: the lowest reasonably expected value, assuming a change in market/economic conditions, that would decrease the value of the project versus the middle estimate.
- Low-middle estimate: a value that is possible under current market/economic conditions and would reduce the value of the project versus the middle estimate.
- Middle estimate: our opinion of the most likely value for a particular variable.
- High-middle estimate: a value that is possible under current market/economic conditions and would increase the value of the project versus the middle estimate.
- High estimate: the highest reasonably expected value, assuming a change in market/economic conditions, that would increase the value of the project versus the middle estimate.

1. Load Growth

GEC projected electricity loads for low, middle, and high growth scenarios through the year 2016 to cover the first 10 years of project operations. GEC's middle growth projection is based on reported population and energy usage trends. This projection is a reasonable estimate of projected energy usage in the GEC service area and serves as the basis for our middle growth projection. For our analysis, we continued the trend of annual costs in GEC's growth projections for the first 10 years through a 30 year period of analysis. Because slight changes in annual growth rates would cause significant changes in future generation requirements, we examined alternative projections. The improving economy and continued interest in GBNPP and Alaskan tourism in general during the last year led to a 4.5 percent load growth rate in Gustavus. This rate reflects a relatively optimistic outlook for the region, and we use it as our middle-high estimate. GEC has also developed a high growth scenario, which we adopted as our high estimate.

A slowdown in economic growth in the area or the reduction in commercial fishing or tourism in the area could lead to a reduction in projected growth, and we thus adopt a growth rate of 1 percent below the middle estimate as our middle-low estimate. To account for possible cut backs at GBNPP or Gustavus or a significant decrease in tourism or slowdown of the economy, a zero growth rate forms the basis of our low estimate. Figure E-1 shows load growth projections, and table E-1 shows the growth projections[5] using our assumptions.

Figure E-1. Annual generation requirements projections, GEC service area. (Source: Preparers)



[5] Since the delivery of power and energy from the proposed hydroelectric project would take place at the same location as currently delivered, we distinguish no line losses between the proposed hydroelectric project and the current GEC generating station. We assume that transmission line losses between the proposed project and the current generating station are accounted for in the "water-to-wire" generation efficiency ratio used when modeling hydroelectric generation.

Table E-1. Projections for growth in GEC's service area. (Source: Preparers)

Estimate	Load Growth
Low	No growth
Middle-Low	Annual growth one percent below annual generation growth rate predicted by GEC
Middle	Load growth as predicted by GEC
Middle-High	Continue 2002-2003 growth rate of 4.5 percent
High	GEC high growth scenario

2. General Cost Escalation

Our independent review of general cost escalation includes review of values developed by the Energy Information Administration (EIA) and the Congressional Budget Office (CBO), as well as commenters on the draft EIS. For this analysis, we use the gross domestic product (GDP) implicit price deflator (IPD) instead of the CPI. The IPD reflects cost escalation throughout the economy, while the CPI only reflects the cost escalation of general consumer goods, which can track very differently than cost trends for items such as labor and raw materials. The EIA and CBO have developed separate projections for future cost escalation of the IPD. Commenters on the draft EIS present projections of cost escalations that include values of 3.0 and 3.5 percent per annum, while GDP cost escalation has averaged at about 2 percent over the past 5 years.

The IPD as projected by EIA appears to track most reasonably with predictions from other sources, including the Survey of Professional Forecasters of the Federal Reserve Bank. This index is also likely to have an energy-price bias in its result as a function of the annual energy outlook model it is developed from, which is appropriate for this analysis. For these reasons, we used the EIA values as our middle estimate.

Recent events such as an improved economy and upward pressure on interest rates make it prudent to account for the possibility of rates exceeding general escalation projections. We assume rates of 3.0 and 3.5 percent for general escalation as our middle-high and high estimates, respectively. These values are higher than recent trends have shown for short-term escalation, but have occurred in the past and could possibly reoccur as interest rates rise and inflationary pressures increase.

Our middle-low estimate assumes escalation would reflect recent current rates of 2 percent. We use the CBO data as our low estimate due to historical trends as well as recent events that have occurred since CBO projections were developed which would tend to increase rates.

Note that the EIA and CBO values represent trends, while the remaining values, based on comments on the draft EIS, exhibit constant values throughout the period of analysis. These constant values realistically represent the average of a trend, while the

EIA and CBO values represent the trend itself. We do not speculate whether the CBO or EIA trend is more realistic.

Figure E-2 shows these projections, and table E-2 categorizes the projections for our assumptions.

Figure E-2. General cost escalation projections. (Source: Preparers)

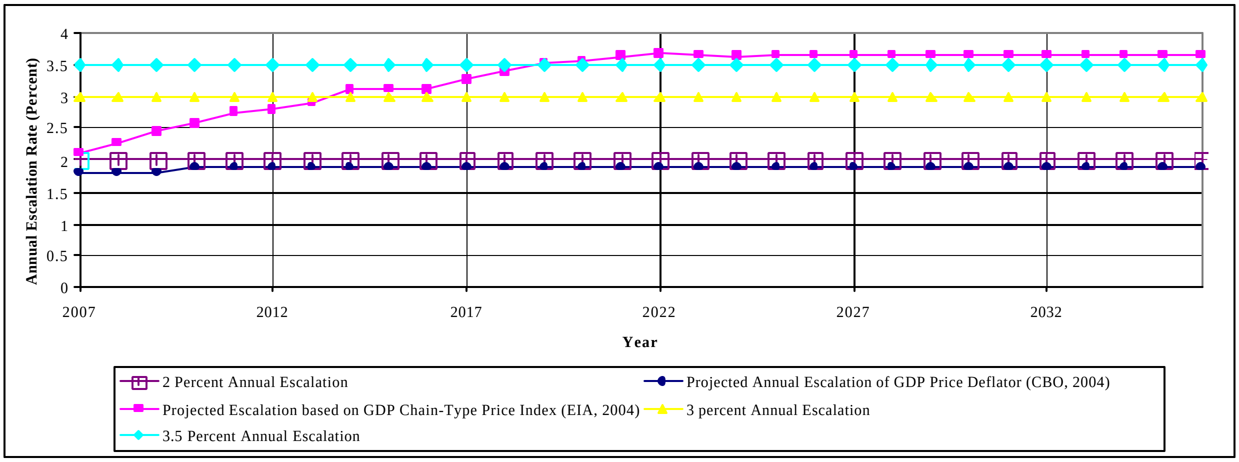


Table E-2. Projections for annual general cost escalation. (Source: Preparers)

Estimate	Annual General Cost Escalation
Low	CBO projections
Middle-low	2 percent
Middle	EIA projections
Middle-high	3 percent
High	3.5 percent

3. Diesel Fuel Cost Escalation

Because diesel fuel cost is by far the largest component of the avoided cost of generation, escalation of diesel fuel cost would have a major impact on project economics. GEC provided some analysis of future diesel fuel price projections based on escalation of diesel fuel costs above a set percentage of general cost escalation. The EIA also provides, as part of its 2004 Annual Energy Outlook, its projections for the future cost of diesel fuel. This trend, as figure E-3 shows, varies by year as a function of projected supply and demand of all energy including diesel fuel and electricity, as well as macroeconomic trends and other factors. Variation from year-to-year in this trend is reflective of changes in the availability of sources and uses of fuels, including the anticipated opening or retirement of fossil fuel sources and large energy users such as a group of generating facilities. We use this index as the baseline source for examination of the trend for diesel fuel escalation versus general cost escalation and these values for our middle estimate.

The average annual increase in diesel fuel projections is 0.55 percent above general inflation. However, recent events and shifting trends that could occur subsequent to development of the EIA projections could lead to future escalation rates that are higher than these projections. Therefore, rates follow the trend of the EIA projections but average 1.0 and 1.5 percent above general escalation rates provide the basis of the middle-high and high estimates, respectively. We also assume the middle-low estimate to follow the EIA projections but at an average increase at the general escalation rate, and our low estimate to follow the EIA trend at an average value of 0.5 percent below general escalation.

With current world events significantly affecting the price of petroleum-based products, price volatility is likely to have a significant effect on the avoided cost of this project; however, the EIA cost trend values provide a researched index into these anticipated price trends and thus are a reasonable estimate of future diesel fuel price trends. Figure E-3 and table E-3 show these projections using our assumptions.

Figure E-3. Diesel fuel cost escalation projections relative to overall inflation. (Source: Preparers)

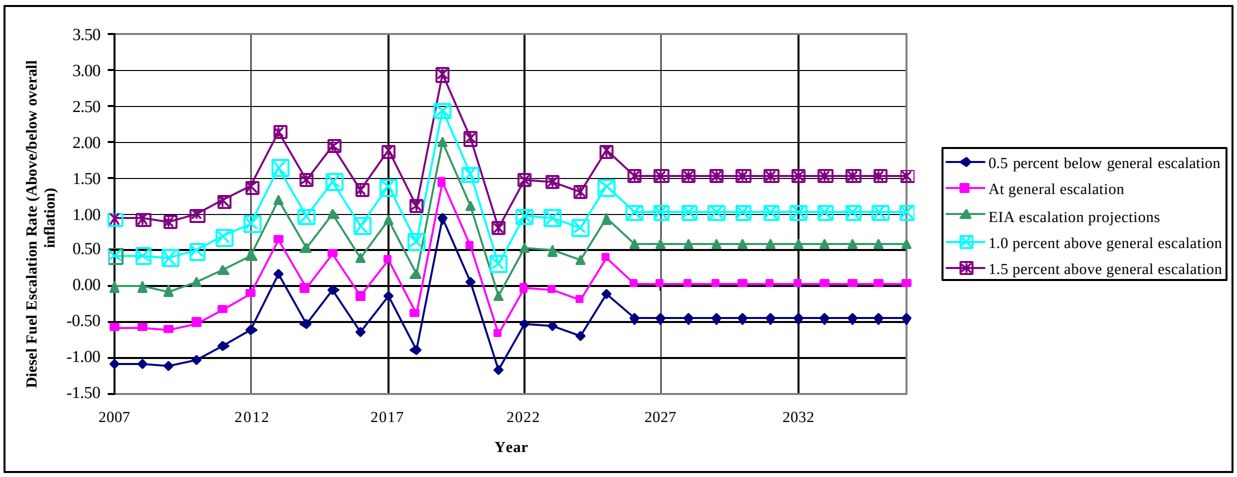


Table E-3. Projections for diesel fuel cost escalation. (Source: Preparers)

Estimate	Annual Diesel Fuel Cost Escalation
Low	EIA trend; averaging 0.5 percent below general escalation
Middle-low	EIA trend; averaging at general escalation
Middle	EIA projections (average 0.55 percent above general escalation)
Middle-high	EIA trend; averaging at 1.0 percent above general escalation
High	EIA trend; averaging at 1.5 percent above general escalation

4. Other Costs associated with Diesel Generation

Other costs associated with diesel generation, particularly overhaul and replacement of generating units, can have an impact on the avoided cost of the project. GEC provided values for the variable O&M and overall rates for its existing diesel generation units; commenters also noted that unit replacement may be necessary periodically throughout the term of analysis.

Variable O&M costs are a direct function of unit operations. If the diesel generating units are operated less due to the existence of hydroelectric generation, this cost would be reduced proportionately. Unit overhaul requirements would probably be reduced if the units are operated less frequently. Examination of the age of the generating units shows that generating units may need to be replaced during the term of analysis, even if the hydroelectric project is developed and commences generation.

O&M and overhaul costs could remain the same if hydroelectric generation becomes available. This scenario, based on GEC's costs, serves as our middle estimate.

It is possible that one diesel generating unit would need to be replaced at the midpoint of the analysis at a cost of $200,000, which is the basis for our middle-high estimate. We used the less likely event of one generating unit being replaced at a cost of $200,000 every 10 years during the period of analysis for our high estimate.

With reduced diesel generation it is feasible that no diesel generating unit would need to be replaced and that overhaul costs would be reduced by approximately half due to reduced operating hours and corresponding wear, which is the basis for our middle-low estimate. We used the less likely possibility that none of the units would need to be replaced and that the rate for overhaul costs would be reduced in direct proportion to the reduced diesel generation requirements for our low estimate.

Table E-4 shows the projections using our assumptions.

Table E-4. Projections for other costs associated with diesel fuel generation.[a] (Source: Preparers)

Estimate	Other Diesel Fuel Generation Costs
Low	Cost of overhaul from GEC, replacement of one unit each 10 years at $200,000
Middle-Low	Cost of overhaul from GEC, replacement of one unit at 15 year point in analysis at $200,000
Middle	Cost of overhaul from GEC, no unit replacement
Middle-High	Cost of overhaul at 50 percent of GEC's rate, no unit replacement
High	Cost of overhaul at about 15 percent of GEC's rate, no unit replacement

[a] We define variable O&M at $5.66/MWh for all projections.

5. Grant Availability

AIDEA performed an economic analysis of this project and determined that GEC may be eligible for a grant of $1,083,685 from the Denali Commission. AIDEA's analysis includes GBNPP generation requirements. In chapter 5 of the EIS we exclude the grant because there is no certainty that GBNPP would interconnect with GEC and this interconnection is not part of the current proposal before the Commission. The Denali Commission based its grant decision on the economic benefit provided by the project in serving both GEC's existing costumers and GBNPP; however, our initial economic analyses showed a reasonable chance of realization of a positive net present value; therefore, we include the value of the Denali Commission grant as our middle estimate even when GBNPP load is not included. We also used this grant amount for our middle-high estimate. We have not identified any other possible sources for grants; however, it is possible that GEC could receive additional money from some other entity, and to account for this possibility we used a grant amount of $2 million for our high estimate. In the event that no grants would be available we used a grant amount of zero for our middle-low and low estimates.

Table E-5 shows the projections using our assumptions.

Table E-5. Projections for grant availability. (Source: Preparers)

Estimate	Amount of Grant
Low	$0
Middle-Low	$0
Middle	$1,083,685 (Denali Commission)
Middle-High	$1,083,685 (Denali Commission)
High	$2,000,000

6. Interest Rate on Debt

Several commenters submitted projections for the cost of debt. This rate directly influences the cost of capital because the project is to be 100 percent financed with debt. Similarly, the return on rate base as defined by the RCA and APUC Form 101 is a direct function of the cost of debt for this project. GEC is an investor-owned utility and not eligible for low cost tax exempt municipal financing. However, GEC states that AIDEA would be able to provide a $1 million loan at an interest rate of 5.43 percent, and that loans would be available from the Rural Utility Service at a rate of 5.50 percent to cover the remainder of financing needs. It should be noted that the Rural Utility Service is currently posting a rate of 5.13 percent on 30-year loans, which is lower than the loan rate noted by GEC. It is possible that Rural Utility Service funding would not be available to GEC. If so, GEC may need to access credit on the open market. We estimate that this funding would be available at the current cost of 30-year treasury bonds (5.375 percent) plus 300 basis points, or 8.375 percent as of this analysis.

Our middle estimate of 5.48 percent assumes combined funding from AIDEA of $1 million and the remainder provided by Rural Utility Service at rates as noted by GEC.

Our middle-high estimate of 5.2 percent assumes funding from the AIDEA, and the Rural Utility Service at the lower posted rate. This composite rate assumes that the Rural Utility Service would want the AIDEA to share credit risk in the project although the Rural Utility Service interest rate is lower than the AIDEA rate. As such, the possibility of GEC receiving 100 percent funding from the Rural Utility Service at current posted rates is less likely and serves as the basis for our high estimate.

Our middle-low estimate assumes funding from the AIDEA but no Rural Utility Service funding, with the remainder of funding from an open market loan. Our low estimate assumes the project is financed completely on the open market.

Table E-6 shows the projections using our assumptions.

Table E-6. Projections for debt service interest rate. (Source: Preparers)

Estimate	Interest Rate on Debt
Low	8.38 percent[a]
Middle-Low	7.68 percent (combined AIDEA and open market rate)[a]
Middle	5.48 percent (combined AIDEA and Rural Utility Service rate provided by GEC)
Middle-High	5.20 percent[b]
High	5.13 percent[b]

[a] Low estimates based on open bond market rate of (4/30/2004) 30-year treasury bond rate (5.375 percent) plus 300 basis points (3 percent).

[b] High estimates based on 30-year treasury loan rate (4/30/2004) from Rural Utility Service.

Other Assumptions

We use other assumptions throughout our analysis that do not vary, including: (1) operation start date; (2) term of analysis; (3) construction cost; (4) annual O&M cost; (5) interest during construction and interest earnings on reserve accounts; (6) minimum flow requirements; and (7) GBNPP generation requirements.

1. Operation Start Date

GEC noted in its comments on the draft EIS that a 2007 project operational start date may be optimistic due to the length of time required to complete the regulatory process. However, for our analysis we assumed, consistent with the schedule in the license application, that project operations would commence in 2007. The project license, if issued, would establish terms for when construction and operation would begin and the actual date for initial operation could be different than 2007; however, we do not believe a different start date would significantly affect the accuracy of our economic analysis.

2. Term of Analysis

Although the term of a new project license can be 50 years, we limit our economic analysis in section 6.1.1.4 to 30 years. If the project shows positive economic benefit within 30 years, those benefits would reasonably be expected to increase in subsequent years, should the Commission issue a 50-year license.

3. Construction Cost

The only comment received on project construction cost noted the existence of a 1984 ACOE report (ACOE, 1984) that estimated the capital cost of developing a hydroelectric project on the Kahtaheena River at about $8 million. We reviewed this report and note the following substantial differences between the ACOE costs and the costs presented herein:

- The ACOE report includes the cost of land acquisition, which is not an issue for the proposed project.
- The diversion dam/intake structure recommended by the ACOE is larger than that for the proposed project.
- The cost of the penstock for the proposed project is lower than the ACOE costs, although the proposed length is greater; this is largely due to the lower cost of HDPE pipe versus steel.
- The cost for roads and bridges is lower for the proposed project. GEC's proposal is based on current conditions in the project area, and the ACOE report bases its assessment on conditions from the early 1980s.
- The length of the transmission line in the ACOE report is longer. The ACOE report assumed transmission to Bartlett Cove as well as the existing GEC generating station, while the proposed project would include transmission to the existing GEC generating station only.

We base our construction costs on GEC's 2001 construction cost value, initially escalated to 2003 dollars using actual observed inflation based on the GDP IPD, and further escalated to 2007 dollars using IPD projections. We add in the cost of environmental enhancements as recommended by staff. We recompute engineering and contingency values to account for all costs, account for the funding of debt service and operating reserves, and analyze interest during construction and the escalation of costs during the construction period. It is standard practice for a lender to require an entity borrowing funds for a project such as the proposed project to retain funds to cover a year of debt service in case of lower than projected financial performance, and to require the maintenance of a operating reserve account holding several (assumed to be three in this case) months of operating revenues to cover short-term cash shortfalls. Because GEC's financial statements show that it does not have adequate cash on hand to fund these accounts, we assume it would be funded through borrowings, and account for borrowing cost and interest from these accounts in our analysis of project income. All above-mentioned values are shown in the calculation sheets presented at the end of this appendix.

4. Annual O&M Cost

GEC clarified annual enhancement costs that were included in its initial estimate of project costs; otherwise, no comments were received on actual annual costs. We therefore use the costs presented by GEC, where available, and developed our own estimates elsewhere. We escalated GEC's estimates using actual and projected values for the GDP IPD.

5. Interest during Construction and Interest Earnings on Reserve Accounts

We base our analysis of the interest rate paid on funds during construction as well as the interest earning on reserve accounts (as discussed above) on the current rates for United States Treasury Bonds. We assume that short-term borrowing for funding construction costs would be a function of the 6-month Treasury Bond with a 300 basis point (3 percent) added. We further assume that debt service reserves would be able to earn interest at a rate equivalent to the 5-year Treasury Bond. We finally assume that operating reserves would need to be relatively liquid to cover immediate short-term expenses and float between billing cycles. Therefore, these funds would earn interest at a rate equivalent to the 3-month Treasury Bond.

6. Minimum Flow Requirement

GEC's proposed flow regime is the flow regime recommended in this EIS. GEC has indicated that it is in negotiations to eliminate the minimum flow requirement in lieu of an undetermined payment for environmental enhancements. Nothing has been filed with the Commission to indicate that any such agreement has been reached; therefore, we continue to use GEC's proposed minimum flows in estimating generation for our economic analyses.

7. GBNPP Generation Requirement

GBNPP has recently completed a multi-year development of new park facilities, and at this time has indicated that no new significant facilities will be constructed in the near future. Although park generation requirements have grown significantly in the past few years, GBNPP has indicated that further growth in generation requirements is unlikely due to the end of new facilities construction. Therefore, we assume that the

2003 GBNPP generation requirement of about 1,001,000 kWh represents the generation required at Bartlett Cove to serve the park throughout the period of this analysis.[6]

The following tables show our calculations for each of the 10 scenarios we modeled using the methodology described above, as well as our analysis of the sensitivity of each variable examined. We present and discuss the results of our analysis in section 6.1.1.4.

Table E-7. Summary of financial performance measures, GBNPP load excluded. (Source: Preparers)

	Low Estimate	**Low-Middle Estimate**	**Middle Estimate**	**High-Middle Estimate**	**High Estimate**
Net present value	-$4,266,000	-$2,928,000	$1,521,000	$2,281,000	$4,786,000
Year annual net benefit realized	N/A[a]	2036	2016	2015	2010
Year cumulative net benefit realized	N/A[b]	N/A[b]	2025	2022	2013

a Diesel costs did not exceed the cost of hydropower during the 30 year period of analysis.

b The discounted sum of the annual net benefit was not positive during the 30 year period of analysis.

6 These generation values assume the delivery of power and energy at the current GBNPP generating station at Bartlett Cove. Due to line losses in the system between the proposed project and the current GBNPP delivery point, we use the observed 14.3 percent system loss factor to determine the additional generation required above GBNPP's generation projections to account for system line losses from the proposed project to Bartlett Cove.

Table E-8. Summary of financial performance measures, GBNPP load included.[a] (Source: Preparers)

	Low Estimate	Low-Middle Estimate	Middle Estimate	High-Middle Estimate	High Estimate
Net present value	-$2,876,000	-$1,621,000	$3,057,000	$3,927,000	$6,650,000
Year annual net benefit realized	N/A[b]	2032	2009	2008	2007
Year cumulative net benefit realized	N/A[c]	N/A[c]	2011	2009	2007

[a] The economic analysis only addresses the economics of the hydroelectric project. None of the costs of the interconnection of GBNPP to GEC are included in these estimates. This economic analysis should not be considered as an endorsement of or argument against interconnection.

[b] Diesel costs did not exceed the cost of hydropower during the 30 year period of analysis.

[c] The discounted sum of the annual net benefit was not positive during the 30 year period of analysis.

Table E-9. Effect of variation of individual variables on net present value. (Source: Preparers.)

	Net present value for each projection				
Value	**Low Estimate**	**Middle-Low Estimate**	**Middle Estimate**	**Middle-High Estimate**	**High Estimate**
Load growth	-$1,120,000	$937,000	$1,521,000	$1,578,000	$1,610,000
General cost escalation	$630,000	$698,000	$1,521,000	$1,369,000	$1,754,000
Diesel fuel cost escalation	$606,000	$1,021,000	$1,521,000	$1,476,000	$1,974,000
Other diesel generation costs	$1,197,000	$1,333,000	$1,521,000	$2,087,000	$2,332,000
Grant availability	$233,000	$233,000	$1,521,000	$1,521,000	$2,611,000
Interest rate on debt	-$690,000	-$273,000	$1,521,000	$1,808,000	$1,884,000

ECONOMIC ANALYSIS – SUPPORTING WORKSHEETS

- Construction cost calculation
- List of key variables for carrying charge and income statement analyses
- Calculation of relevant carrying charges
- Pro forma income statement, statement of cash flows, and analysis of net present value

CONSTRUCTION COST DEVELOPMENT

CONSTRUCTION COST CALCULATIONS

Based on License Application, page A-9

		Middle Estimate	No Grant	$2MM Grant	Baseline Grant w/ Transmission				
					Low	Middle-Low	Middle	Middle-High	High
CONSTRUCTION COST									
Description	Estimated Construction Cost, 2001	Estimated Construction Cost, 2003							
Land and Land Rights	$0	$0							
Mobilization and Logistics	$75,000	$77,000							
Structures and Improvements	$281,000	$290,000							
Reservoirs, Dams, and Waterways									
Diversion/Intake Structure	$421,000	$435,000							
Pipeline/Penstock	$645,000	$666,000							
Tailrace Pipeline	$155,000	$160,000							
Turbines and Generators	$420,000	$434,000							
Accessory Electrical Equipment	$130,000	$134,000							
Miscellaneous Mechanical Equipment	$143,000	$148,000							
Roads and Bridges	$640,000	$661,000							
Substation Equipment and Structures	$35,000	$36,000							
Transmission Line	$260,000	$268,000							
Environmental Enhancements (Staff-recommended alternative)		$189,480							
SUBTOTAL	$3,205,000	$3,498,000							
Contingencies (15% of Subtotal)	$481,000	$525,000							
Engineering (15% of Subtotal excluding mobilization and logistics)	$470,000	$485,000							
TOTAL CONSTRUCTION COST, 2003	$4,156,000	$4,508,000	$4,508,000	$4,508,000	$10,814,000	$7,661,000	$6,505,000	$5,349,000	$5,209,000
GEC-GBNPP Transmission Cost, 2003					*$4,500,000*	*$2,250,000*	*$1,425,000*	*$600,000*	*$500,000*
GEC-GBNPP Transmission Cost, 2007					*$4,850,540*	*$2,425,270*	*$1,536,004*	*$646,739*	*$538,949*
GRANT VALUE		$1,083,685	$0	$2,000,000	$1,083,685	$1,083,685	$1,083,685	$1,083,685	$1,083,685
TOTAL CONSTRUCTION COST, 2005-2006 (adjusted for grant and inflation)		$3,494,000	$4,600,000	$2,560,000	$9,927,000	$6,712,000	$5,531,000	$4,352,000	$4,210,000
INTEREST DURING CONSTRUCTION		$178,000	$234,000	$130,000	$506,000	$342,000	$282,000	$222,000	$214,000
FUNDING OF DEBT SERVICE RESERVE (upwards to nearest $1000)		$289,000	$376,000	$214,000	$799,000	$544,000	$450,000	$357,000	$345,000
FUNDING OF OPERATIONAL RESERVE		$150,000	$150,000	$150,000	$150,000	$150,000	$150,000	$150,000	$150,000
FINANCING COSTS (as a function of total construction cost)		$84,000	$109,000	$62,000	$232,000	$158,000	$131,000	$104,000	$100,000
TOTAL CONSTRUCTION COST		$4,195,000	$5,469,000	$3,116,000	$11,614,000	$7,906,000	$6,544,000	$5,185,000	$5,019,000
CONSTRUCTION COST SCHEDULE									
Construction Cost (minus grant) adjusted for IPD, assume borrowed at beginning of period									
2005.0		$3,462,000	$4,558,000	$2,536,000	$9,837,000	$6,650,000	$5,481,000	$4,312,000	$4,171,000
2005.5		$3,481,000	$4,583,000	$2,550,000	$9,891,000	$6,687,000	$5,511,000	$4,336,000	$4,194,000
2006.0		$3,500,000	$4,608,000	$2,564,000	$9,945,000	$6,724,000	$5,541,000	$4,360,000	$4,217,000
2006.5		$3,532,000	$4,649,000	$2,587,000	$10,035,000	$6,785,000	$5,591,000	$4,399,000	$4,255,000
25% share									
2005.0		$866,000	$1,140,000	$634,000	$2,459,000	$1,663,000	$1,370,000	$1,078,000	$1,043,000
2005.5		$870,000	$1,146,000	$638,000	$2,473,000	$1,672,000	$1,378,000	$1,084,000	$1,049,000
2006.0		$875,000	$1,152,000	$641,000	$2,486,000	$1,681,000	$1,385,000	$1,090,000	$1,054,000
2006.5		$883,000	$1,162,000	$647,000	$2,509,000	$1,696,000	$1,398,000	$1,100,000	$1,064,000
Cumulative Share									
2005.0		$866,000	$1,140,000	$634,000	$2,459,000	$1,663,000	$1,370,000	$1,078,000	$1,043,000
2005.5		$1,736,000	$2,286,000	$1,272,000	$4,932,000	$3,335,000	$2,748,000	$2,162,000	$2,092,000
2006.0		$2,611,000	$3,438,000	$1,913,000	$7,418,000	$5,016,000	$4,133,000	$3,252,000	$3,146,000
2006.5		$3,494,000	$4,600,000	$2,560,000	$9,927,000	$6,712,000	$5,531,000	$4,352,000	$4,210,000
Interest on Construction Cost									
2005.0		$18,000	$23,000	$13,000	$50,000	$34,000	$28,000	$22,000	$21,000
2005.5		$36,000	$47,000	$26,000	$101,000	$68,000	$56,000	$44,000	$43,000
2006.0		$53,000	$70,000	$39,000	$152,000	$103,000	$85,000	$67,000	$64,000
2006.5		$71,000	$94,000	$52,000	$203,000	$137,000	$113,000	$89,000	$86,000
Annual Payment, AIDEA Component		$68,274	$68,274	$68,274	$68,274	$68,274	$68,274	$68,274	$68,274
Annual Payment, Remaining Component		$219,833	$307,491	$145,592	$730,300	$475,170	$381,457	$287,951	$276,529
Total Annual Payment		$288,108	$375,766	$213,867	$798,575	$543,444	$449,731	$356,225	$344,803
CONST. COST		$3,494,000	$4,600,000	$2,560,000	$9,927,000	$6,712,000	$5,531,000	$4,352,000	$4,210,000
AFDUC, FINANCING		$701,000	$869,000	$556,000	$1,687,000	$1,194,000	$1,013,000	$833,000	$809,000
TOTAL		$4,195,000	$5,469,000	$3,116,000	$11,614,000	$7,906,000	$6,544,000	$5,185,000	$5,019,000
Percentage Const. Cost		0.833	0.841	0.822	0.855	0.849	0.845	0.839	0.839
Percentage AFDUC, Financing		0.167	0.159	0.178	0.145	0.151	0.155	0.161	0.161

CONSTRUCTION COST CALCULATIONS
Based on License Application, page A-9

	Low Interest	Middle-Low Interest	Middle-High Interest	High Interest	Low Estimate	Middle-Low Estimate	Middle-High Estimate	High Estimate
CONSTRUCTION COST								
Description								
Land and Land Rights								
Mobilization and Logistics								
Structures and Improvements								
Reservoirs, Dams, and Waterways								
Diversion/Intake Structure								
Pipeline/Penstock								
Tailrace Pipeline								
Turbines and Generators								
Accessory Electrical Equipment								
Miscellaneous Mechanical Equipment								
Roads and Bridges								
Substation Equipment and Structures								
Transmission Line								
Environmental Enhancements (Staff-recommended alternative)								
SUBTOTAL								
Contingencies (15% of Subtotal)								
Engineering (15% of Subtotal excluding mobilization and logistics)								
TOTAL CONSTRUCTION COST, 2003	$4,508,000	$4,508,000	$4,508,000	$4,508,000	$4,508,000	$4,508,000	$4,508,000	$4,508,000
GEC-GBNPP Transmission Cost, 2003								
GEC-GBNPP Transmission Cost, 2007								
GRANT VALUE	$1,083,685	$1,083,685	$1,083,685	$1,083,685	$0	$0	$1,083,685	$2,000,000
TOTAL CONSTRUCTION COST, 2005-2006 (adjusted for grant and inflation)	$3,494,000	$3,494,000	$3,494,000	$3,494,000	$4,600,000	$4,600,000	$3,494,000	$2,560,000
INTEREST DURING CONSTRUCTION	$178,000	$178,000	$178,000	$178,000	$234,000	$234,000	$178,000	$130,000
FUNDING OF DEBT SERVICE RESERVE (upwards to nearest $1000)	$396,000	$370,000	$279,000	$277,000	$517,000	$491,000	$279,000	$206,000
FUNDING OF OPERATIONAL RESERVE	$150,000	$150,000	$150,000	$150,000	$150,000	$150,000	$150,000	$150,000
FINANCING COSTS (as a function of total construction cost)	$86,000	$86,000	$84,000	$84,000	$112,000	$112,000	$84,000	$62,000
TOTAL CONSTRUCTION COST	$4,304,000	$4,278,000	$4,185,000	$4,183,000	$5,613,000	$5,587,000	$4,185,000	$3,108,000
CONSTRUCTION COST SCHEDULE								
Construction Cost (minus grant) adjusted for IPD, assume borrowed at beginning of peric								
2005.0	$3,462,000	$3,462,000	$3,462,000	$3,462,000	$4,558,000	$4,558,000	$3,462,000	$2,536,000
2005.5	$3,481,000	$3,481,000	$3,481,000	$3,481,000	$4,583,000	$4,583,000	$3,481,000	$2,550,000
2006.0	$3,500,000	$3,500,000	$3,500,000	$3,500,000	$4,608,000	$4,608,000	$3,500,000	$2,564,000
2006.5	$3,532,000	$3,532,000	$3,532,000	$3,532,000	$4,649,000	$4,649,000	$3,532,000	$2,587,000
25% share								
2005.0	$866,000	$866,000	$866,000	$866,000	$1,140,000	$1,140,000	$866,000	$634,000
2005.5	$870,000	$870,000	$870,000	$870,000	$1,146,000	$1,146,000	$870,000	$638,000
2006.0	$875,000	$875,000	$875,000	$875,000	$1,152,000	$1,152,000	$875,000	$641,000
2006.5	$883,000	$883,000	$883,000	$883,000	$1,162,000	$1,162,000	$883,000	$647,000
Cumulative Share								
2005.0	$866,000	$866,000	$866,000	$866,000	$1,140,000	$1,140,000	$866,000	$634,000
2005.5	$1,736,000	$1,736,000	$1,736,000	$1,736,000	$2,286,000	$2,286,000	$1,736,000	$1,272,000
2006.0	$2,611,000	$2,611,000	$2,611,000	$2,611,000	$3,438,000	$3,438,000	$2,611,000	$1,913,000
2006.5	$3,494,000	$3,494,000	$3,494,000	$3,494,000	$4,600,000	$4,600,000	$3,494,000	$2,560,000
Interest on Construction Cost								
2005.0	$18,000	$18,000	$18,000	$18,000	$23,000	$23,000	$18,000	$13,000
2005.5	$36,000	$36,000	$36,000	$36,000	$47,000	$47,000	$36,000	$26,000
2006.0	$53,000	$53,000	$53,000	$53,000	$70,000	$70,000	$53,000	$39,000
2006.5	$71,000	$71,000	$71,000	$71,000	$94,000	$94,000	$71,000	$52,000
Annual Payment, AIDEA Component	$0	$68,274	$68,274	$0	$0	$68,274	$68,274	$0
Annual Payment, Remaining Component	$395,920	$301,539	$210,269	$276,156	$516,333	$421,952	$210,269	$205,186
Total Annual Payment	$395,920	$369,813	$278,544	$276,156	$516,333	$490,227	$278,544	$205,186
CONST. COST	$3,494,000	$3,494,000	$3,494,000	$3,494,000	$4,600,000	$4,600,000	$3,494,000	$2,560,000
AFDUC, FINANCING	$810,000	$784,000	$691,000	$689,000	$1,013,000	$987,000	$691,000	$548,000
TOTAL	$4,304,000	$4,278,000	$4,185,000	$4,183,000	$5,613,000	$5,587,000	$4,185,000	$3,108,000
Percentage Const. Cost	0.812	0.817	0.835	0.835	0.820	0.823	0.835	0.824
Percentage AFDUC, Financing	0.188	0.183	0.165	0.165	0.180	0.177	0.165	0.176

INCOME STATEMENT AND BACKGROUND

MIDDLE ESTIMATE

Variable	Value	Source
Interest on Construction	4.09%	FERC (4/29/2004 6-month T-Bond & 300 basis points)
Financing Cost	2%	FERC
Debt Service Reserve	1 year	FERC
Operational Reserve	3 months	FERC
Term of Analysis	30 years	FERC
Starting Year	2007	FERC
Grant Value	$1,083,685	GEC
Interest on Debt, AIDEA Component	5.43%	GEC
AIDEA Loan Component	$1,000,000	GEC
Interest on Debt, Remainder	5.50%	GEC
Term of Financing, AIDEA Component	30 years	GEC
Term of Financing, Remaining Component	30 years	GEC
2003 O&M (including Staff-recommended environmental enhancements)	$58,600	FERC/GEC
Insurance (% of Initial Investment including granted $)	0.25%	FERC
Interest Rate on Debt Reserve	3.60%	FERC (4/29/2004 5-year T-Bond)
Interest Rate on Operating Reserve	0.85%	FERC (4/29/2004 3-month T-Bond)
Net Cost of Debt	5.483%	Calculated
Operating Reserve Requirement	$150,000	FERC (approx. 3 months operating revenues in last year of operations, rounded up to nearest 25K)
Federal Tax Rate	34%	FERC
State Tax Rate	8%	FERC
Percent Funding by Equity	0.0%	FERC/GEC
Percent Funding by Debt	100.0%	FERC/GEC

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*1,791,330*	*1,863,960*	*1,930,600*	*1,990,220*	*2,050,860*	*2,114,190*	*2,177,870*	*2,244,930*	*2,311,250*	*2,379,370*	*2,448,095*	*2,517,806*	*2,588,921*	*2,661,484*	*2,735,540*
Hydro Rate (mills/kWh)	*193.90*	*190.02*	*186.68*	*183.91*	*180.94*	*177.64*	*174.26*	*170.64*	*165.32*	*159.74*	*154.42*	*149.31*	*144.37*	*139.58*	*137.16*
Operating Revenues	$347,332	$354,184	$360,407	$366,013	$371,087	$375,559	$379,516	$383,064	$382,095	$380,080	$378,032	$375,928	$373,775	$371,481	$375,216
OPERATING EXPENSES															
Operating Expense	$74,435	$76,113	$77,963	$79,961	$82,158	$84,453	$86,909	$89,609	$92,407	$95,272	$98,373	$101,701	$105,277	$109,026	$112,969
Maintenance Expense															
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$156,431	$161,605	$165,977	$169,585	$172,463	$174,639	$176,140	$176,989	$173,222	$168,341	$163,192	$157,760	$152,031	$145,987	$145,780
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$54,300	$53,541	$52,741	$51,898	$51,008	$50,071	$49,083	$48,040	$46,942	$45,783	$44,562	$43,274	$41,917	$40,486	$38,977
Remaining Component	$175,725	$173,299	$170,740	$168,040	$165,191	$162,186	$159,015	$155,670	$152,141	$148,418	$144,490	$140,346	$135,974	$131,362	$126,496
NET INCOME BEFORE TAXES	-$61,915	-$53,557	-$45,825	-$38,673	-$32,058	-$25,939	-$20,278	-$15,042	-$14,181	-$14,181	-$14,181	-$14,181	-$14,181	-$14,181	-$8,014
Federal Income Taxes	-$49,305	-$42,649	-$36,492	-$30,797	-$25,529	-$20,656	-$16,148	-$11,979	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293
State Income Taxes	-$12,610	-$10,908	-$9,333	-$7,876	-$6,529	-$5,283	-$4,130	-$3,064	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,168
STATEMENT OF CASH FLOWS															
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,168
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$13,974	$14,733	$15,533	$16,377	$17,266	$18,203	$19,192	$20,234	$21,333	$22,491	$23,712	$25,000	$26,357	$27,789	$29,297
Remaining Component	$44,108	$46,534	$49,094	$51,794	$54,642	$57,648	$60,818	$64,163	$67,692	$71,415	$75,343	$79,487	$83,859	$88,471	$93,337
NET CASH FLOW	$58,384	$55,199	$51,840	$48,296	$44,558	$40,616	$36,457	$32,069	$27,442	$22,560	$17,411	$11,980	$6,250	$207	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	122.35	125.09	128.05	131.37	135.25	139.57	145.17	150.38	156.47	161.89	168.54	174.50	183.88	192.33	199.05
Net Benefit	-$128,164	-$121,030	-$113,193	-$104,548	-$93,702	-$80,485	-$63,345	-$45,467	-$20,454	$5,117	$34,574	$63,433	$102,273	$140,405	$169,300
Annual PV of Net Benefit	-$121,501	-$108,774	-$96,443	-$84,447	-$71,751	-$58,427	-$43,594	-$29,664	-$12,651	$3,001	$19,219	$33,428	$51,094	$66,498	$76,015
Cumulative PV of Net Benefit	-$121,501	-$230,275	-$326,718	-$411,164	-$482,915	-$541,342	-$584,936	-$614,600	-$627,251	-$624,251	-$605,032	-$571,604	-$520,510	-$454,011	-$377,996
NPV	$1,520,511														

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*2,808,947*	*2,871,303*	*2,933,140*	*2,994,977*	*3,056,813*	*3,118,650*	*3,180,486*	*3,242,323*	*3,304,160*	*3,365,996*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*
Hydro Rate (mills/kWh)	*135.05*	*133.60*	*132.28*	*131.08*	*129.99*	*139.20*	*148.12*	*146.92*	*145.83*	*144.84*	*145.30*	*147.09*	*148.96*	*150.89*	*152.89*
Operating Revenues	$379,351	$383,613	$388,007	$392,591	$397,342	$434,123	$471,083	$476,373	$481,856	$487,538	$493,427	$499,531	$505,858	$512,415	$519,211
OPERATING EXPENSES															
Operating Expense	$117,104	$121,366	$125,760	$130,344	$135,095	$140,019	$145,123	$150,413	$155,895	$161,577	$167,467	$173,571	$179,897	$186,455	$193,251
Maintenance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$145,780	$145,780	$145,780	$145,780	$145,780	$177,637	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$37,386	$35,709	$33,940	$32,076	$30,111	$28,038	$25,853	$23,550	$21,121	$18,561	$15,862	$13,016	$10,015	$6,852	$3,516
Remaining Component	$121,363	$115,947	$110,233	$104,205	$97,845	$91,136	$84,058	$76,590	$68,712	$60,400	$51,631	$42,380	$32,620	$22,324	$11,460
NET INCOME BEFORE TAXES	-$1,289	$5,804	$13,286	$21,178	$29,503	$70,142	$111,262	$121,033	$131,340	$142,212	$153,680	$165,777	$178,538	$191,998	$206,196
Federal Income Taxes	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	$14,075	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444
State Income Taxes	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	$3,600	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088
NET INCOME	$12,892	$19,985	$27,467	$35,360	$43,685	$52,466	$61,730	$71,501	$81,808	$92,680	$104,148	$116,245	$129,006	$142,466	$156,664
STATEMENT OF CASH FLOWS															
NET INCOME	$12,892	$19,985	$27,467	$35,360	$43,685	$52,466	$61,730	$71,501	$81,808	$92,680	$104,148	$116,245	$129,006	$142,466	$156,664
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$30,888	$32,566	$34,334	$36,198	$38,164	$40,236	$42,421	$44,724	$47,153	$49,713	$52,413	$55,259	$58,259	$61,423	$64,758
Remaining Component	$98,471	$103,886	$109,600	$115,628	$121,988	$128,697	$135,775	$143,243	$151,121	$159,433	$168,202	$177,453	$187,213	$197,510	$208,373
NET CASH FLOW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	207.31	215.81	224.36	234.51	244.81	255.56	266.79	278.51	290.75	303.53	316.87	330.80	345.34	360.52	376.37
Net Benefit	$202,975	$236,056	$270,072	$309,747	$350,989	$362,889	$377,445	$426,662	$478,841	$534,147	$582,668	$623,860	$666,912	$711,907	$758,933
Annual PV of Net Benefit	$86,398	$95,256	$103,317	$112,335	$120,675	$118,281	$116,630	$124,985	$132,978	$140,626	$145,426	$147,613	$149,597	$151,389	$153,000
Cumulative PV of Net Benefit	-$291,598	-$196,342	-$93,025	$19,310	$139,985	$258,266	$374,896	$499,881	$632,859	$773,485	$918,912	$1,066,525	$1,216,122	$1,367,511	$1,520,511

Income Statement-Middle

Starting Year	2007	
Direct Construction Expense	83.3%	
AFDUC and Financing Expense	16.7%	
Percentage of AFUDC as Debt	100%	
Percentage of Total Expense as Land	0%	
Tax Life: MACRS Half year Conv.	20	year
Book Life	30	year
Declining Balance Rate	1.5	
State Tax Rate	8.0%	
Federal Tax Rate	34.0%	
DEFERRED TAX -NORM (1) OR FLOW THROUGH (0)	1	
Total Tax Rate	39.3%	
Book Depreciation (SL-1 or IRR-0)	1	
Interim Retirement Rate	1.0%	
Salvage Rate	0.0%	
Return on Equity	5.48%	
Interest Rate on Debt	5.48%	
Percent Funding by Equity	0.0%	
Percent Funding by Debt	100.0%	
WACC	5.48%	
Insurance (Percent of Initial Construction Cost)	0.25%	

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
TAX DEPRECIATION															
BOY Tax Value	100.00%	92.50%	85.56%	79.15%	73.21%	67.72%	62.64%	57.94%	53.60%	49.31%	45.02%	40.73%	36.45%	32.16%	27.87%
Declining Balance Depr.	7.50%	6.94%	6.42%	5.94%	5.49%	5.08%	4.70%	4.35%	4.02%	3.70%	3.38%	3.05%	2.73%	2.41%	2.09%
Straight Line Depr.	2.44%	4.74%	4.63%	4.52%	4.44%	4.37%	4.32%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%
Tax Depr.	7.50%	6.94%	6.42%	5.94%	5.49%	5.08%	4.70%	4.35%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%
RATE BASE															
Book Depr.	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%
Cumulative Book Depr.	3.33%	6.67%	10.00%	13.33%	16.67%	20.00%	23.33%	26.67%	30.00%	33.33%	36.67%	40.00%	43.33%	46.67%	50.00%
Deferred Taxes	1.64%	1.42%	1.21%	1.02%	0.85%	0.69%	0.54%	0.40%	0.37%	0.37%	0.37%	0.37%	0.37%	0.37%	0.37%
Cumulative Deferred Taxes	1.64%	3.05%	4.26%	5.29%	6.13%	6.82%	7.36%	7.75%	8.13%	8.50%	8.88%	9.25%	9.63%	10.00%	10.38%
Rate Base	95.03%	90.28%	85.74%	81.38%	77.20%	73.18%	69.31%	65.58%	61.87%	58.16%	54.46%	50.75%	47.04%	43.33%	39.62%
RETURN & TAXES															
Return on WACC	5.21%	4.95%	4.70%	4.46%	4.23%	4.01%	3.80%	3.60%	3.39%	3.19%	2.99%	2.78%	2.58%	2.38%	2.17%
Bond Interest	5.21%	4.95%	4.70%	4.46%	4.23%	4.01%	3.80%	3.60%	3.39%	3.19%	2.99%	2.78%	2.58%	2.38%	2.17%
Federal Income Taxes	-1.30%	-1.13%	-0.96%	-0.81%	-0.67%	-0.55%	-0.43%	-0.32%	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%
State Income Taxes	-0.33%	-0.29%	-0.25%	-0.21%	-0.17%	-0.14%	-0.11%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%
Property Taxes & Insurance	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
Year	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
TAX DEPRECIATION															
BOY Tax Value	23.58%	19.29%	15.01%	10.72%	6.43%	2.14%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Declining Balance Depr.	1.77%	1.45%	1.13%	0.80%	0.48%	0.16%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Straight Line Depr.	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Tax Depr.	4.29%	4.29%	4.29%	4.29%	4.29%	2.14%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RATE BASE															
Book Depr.	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%
Cumulative Book Depr.	53.33%	56.67%	60.00%	63.33%	66.67%	70.00%	73.33%	76.67%	80.00%	83.33%	86.67%	90.00%	93.33%	96.67%	100.00%
Deferred Taxes	0.37%	0.37%	0.37%	0.37%	0.37%	-0.47%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%
Cumulative Deferred Taxes	10.75%	11.13%	11.50%	11.88%	12.25%	11.78%	10.47%	9.17%	7.86%	6.55%	5.24%	3.93%	2.62%	1.31%	0.00%
Rate Base	35.91%	32.21%	28.50%	24.79%	21.08%	18.22%	16.19%	14.17%	12.14%	10.12%	8.10%	6.07%	4.05%	2.02%	0.00%
RETURN & TAXES															
Return on WACC	1.97%	1.77%	1.56%	1.36%	1.16%	1.00%	0.89%	0.78%	0.67%	0.55%	0.44%	0.33%	0.22%	0.11%	0.00%
Bond Interest	1.97%	1.77%	1.56%	1.36%	1.16%	1.00%	0.89%	0.78%	0.67%	0.55%	0.44%	0.33%	0.22%	0.11%	0.00%
Federal Income Taxes	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%	0.37%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%
State Income Taxes	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	0.10%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%
Property Taxes & Insurance	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%

INCOME STATEMENT AND BACKGROUND

LOW OVERALL ESTIMATE
MIDDLE-LOW OVERALL ESTIMATE
MIDDLE-HIGH OVERALL ESTIMATE
HIGH OVERALL ESTIMATE

Variable	Value		Source
Interest on Construction	4.09%		FERC (4/29/2004 6-month T-Bond & 300 basis points)
Financing Cost	2%		FERC
Debt Service Reserve	1	year	FERC
Operational Reserve	3	months	FERC
Term of Analysis	30	years	FERC
Starting Year	2007		FERC
Grant Value	$0		GEC
Interest on Debt, AIDEA Component	5.43%		GEC
AIDEA Loan Component	$0		GEC
Interest on Debt, Remainder	8.38%		GEC
Term of Financing, AIDEA Component	30	years	GEC
Term of Financing, Remaining Component	30	years	GEC
2003 O&M (including Staff-recommended environmental enhancements)	$58,600		FERC/GEC
Insurance (% of Initial Investment including granted $)	0.25%		FERC
Interest Rate on Debt Reserve	3.60%		FERC (4/29/2004 5-year T-Bond)
Interest Rate on Operating Reserve	0.85%		FERC (4/29/2004 3-month T-Bond)
Net Cost of Debt	8.375%		Calculated
Operating Reserve Requirement	$150,000		FERC (approx. 3 months operating revenues in last year of operations, rounded up to nearest 25K)
Federal Tax Rate	34%		FERC
State Tax Rate	8%		FERC
Percent Funding by Equity	0.0%		FERC/GEC
Percent Funding by Debt	100.0%		FERC/GEC

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*1,601,307*	*1,617,372*	*1,632,586*	*1,644,091*	*1,653,845*	*1,664,227*	*1,671,653*	*1,678,987*	*1,685,834*	*1,692,917*	*1,699,893*	*1,706,869*	*1,712,705*	*1,713,000*	*1,713,000*
Hydro Rate (mills/kWh)	*371.09*	*373.03*	*374.52*	*376.24*	*377.78*	*378.56*	*379.46*	*379.90*	*376.67*	*372.43*	*368.03*	*363.40*	*358.78*	*354.97*	*350.84*
Operating Revenues	$594,222	$603,333	$611,444	$618,567	$624,782	$630,012	$634,333	$637,840	$635,002	$630,498	$625,611	$620,283	$614,478	$608,060	$600,984
OPERATING EXPENSES															
Operating Expense	$74,435	$76,113	$77,963	$79,961	$82,158	$84,453	$86,909	$89,609	$92,407	$95,272	$98,373	$101,701	$105,277	$109,026	$112,969
Maintenance Expense															
Depreciation Expense	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333
NET OPERATING INCOME	$366,454	$373,887	$380,147	$385,272	$389,291	$392,225	$394,091	$394,898	$389,262	$381,892	$373,905	$365,248	$355,867	$345,700	$334,682
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$18,612	$18,612	$18,612	$18,612	$18,612	$18,612	$18,612	$18,612	$18,612	$18,612	$18,612	$18,612	$18,612	$18,612	$18,612
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Remaining Component	$470,089	$466,216	$462,019	$457,470	$452,540	$447,197	$441,407	$435,132	$428,332	$420,961	$412,974	$404,318	$394,936	$384,770	$373,751
NET INCOME BEFORE TAXES	-$83,748	-$72,442	-$61,984	-$52,310	-$43,362	-$35,085	-$27,429	-$20,347	-$19,182	-$19,182	-$19,182	-$19,182	-$19,182	-$19,182	-$19,182
Federal Income Taxes	-$66,692	-$57,688	-$49,360	-$41,657	-$34,531	-$27,940	-$21,843	-$16,203	-$15,275	-$15,275	-$15,275	-$15,275	-$15,275	-$15,275	-$15,275
State Income Taxes	-$17,057	-$14,754	-$12,624	-$10,654	-$8,831	-$7,146	-$5,586	-$4,144	-$3,907	-$3,907	-$3,907	-$3,907	-$3,907	-$3,907	-$3,907
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
STATEMENT OF CASH FLOWS															
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Add back Depreciation	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333
Subtract Principal Payment															
AIDEA Component	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Remaining Component	$46,244	$50,117	$54,314	$58,863	$63,793	$69,136	$74,926	$81,201	$88,001	$95,371	$103,359	$112,015	$121,396	$131,563	$142,582
NET CASH FLOW	$107,089	$103,216	$99,019	$94,470	$89,540	$84,198	$78,408	$72,133	$65,332	$57,962	$49,975	$41,318	$31,937	$21,770	$10,752
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	122.35	123.41	124.46	125.76	127.32	129.15	131.92	133.97	136.64	138.61	141.29	143.10	147.30	150.47	152.06
Net Benefit	-$398,302	-$403,726	-$408,251	-$411,800	-$414,213	-$415,081	-$413,807	-$412,907	-$404,654	-$395,846	-$385,427	-$376,032	-$362,194	-$350,306	-$340,512
Annual PV of Net Benefit	-$367,522	-$343,739	-$320,731	-$298,517	-$277,062	-$256,188	-$235,664	-$216,980	-$196,210	-$177,107	-$159,119	-$143,244	-$127,310	-$113,616	-$101,905
Cumulative PV of Net Benefit	-$367,522	-$711,261	-$1,031,992	-$1,330,509	-$1,607,571	-$1,863,759	-$2,099,423	-$2,316,403	-$2,512,613	-$2,689,720	-$2,848,839	-$2,992,083	-$3,119,393	-$3,233,009	-$3,334,914
NPV	-$4,265,810														

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*1,713,000*	*1,713,000*	*1,713,000*	*1,713,000*	*1,713,000*	*1,713,000*	*1,713,000*	*1,713,000*	*1,713,000*	*1,713,000*	*1,713,000*	*1,713,000*	*1,713,000*	*1,713,000*	*1,713,000*
Hydro Rate (mills/kWh)	*346.97*	*349.46*	*352.03*	*354.70*	*357.48*	*385.51*	*413.64*	*416.73*	*419.93*	*423.25*	*426.68*	*430.25*	*433.94*	*437.77*	*441.74*
Operating Revenues	$594,368	$598,629	$603,024	$607,608	$612,359	$660,373	$708,567	$713,857	$719,339	$725,022	$730,911	$737,015	$743,342	$749,899	$756,695
OPERATING EXPENSES															
Operating Expense	$117,104	$121,366	$125,760	$130,344	$135,095	$140,019	$145,123	$150,413	$155,895	$161,577	$167,467	$173,571	$179,897	$186,455	$193,251
Maintenance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation Expense	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333
NET OPERATING INCOME	$323,930	$323,930	$323,930	$323,930	$323,930	$367,021	$410,111	$410,111	$410,111	$410,111	$410,111	$410,111	$410,111	$410,111	$410,111
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$18,612	$18,612	$18,612	$18,612	$18,612	$18,612	$18,612	$18,612	$18,612	$18,612	$18,612	$18,612	$18,612	$18,612	$18,612
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Remaining Component	$361,810	$348,869	$334,843	$319,644	$303,171	$285,319	$265,971	$245,003	$222,280	$197,653	$170,963	$142,038	$110,691	$76,719	$39,901
NET INCOME BEFORE TAXES	-$17,993	-$5,051	$8,974	$24,174	$40,646	$101,589	$164,027	$184,995	$207,719	$232,345	$259,035	$287,960	$319,307	$353,279	$390,097
Federal Income Taxes	-$15,275	-$15,275	-$15,275	-$15,275	-$15,275	$19,039	$53,353	$53,353	$53,353	$53,353	$53,353	$53,353	$53,353	$53,353	$53,353
State Income Taxes	-$3,907	-$3,907	-$3,907	-$3,907	-$3,907	$4,869	$13,645	$13,645	$13,645	$13,645	$13,645	$13,645	$13,645	$13,645	$13,645
NET INCOME	$1,190	$14,131	$28,156	$43,356	$59,829	$77,681	$97,028	$117,996	$140,720	$165,347	$192,036	$220,961	$252,308	$286,281	$323,098
STATEMENT OF CASH FLOWS															
NET INCOME	$1,190	$14,131	$28,156	$43,356	$59,829	$77,681	$97,028	$117,996	$140,720	$165,347	$192,036	$220,961	$252,308	$286,281	$323,098
Add back Depreciation	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333
Subtract Principal Payment															
AIDEA Component	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Remaining Component	$154,523	$167,464	$181,489	$196,689	$213,162	$231,014	$250,362	$271,329	$294,053	$318,680	$345,370	$374,294	$405,642	$439,614	$476,432
NET CASH FLOW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	154.56	157.08	159.45	162.69	165.54	168.44	171.41	174.45	177.55	180.72	183.95	187.26	190.65	194.11	197.64
Net Benefit	-$329,602	-$329,556	-$329,879	-$328,920	-$328,794	-$371,828	-$414,935	-$415,027	-$415,199	-$415,454	-$415,797	-$416,233	-$416,764	-$417,397	-$418,135
Annual PV of Net Benefit	-$91,017	-$83,972	-$77,559	-$71,357	-$65,818	-$68,680	-$70,720	-$65,269	-$60,250	-$55,628	-$51,372	-$47,452	-$43,840	-$40,514	-$37,449
Cumulative PV of Net Benefit	-$3,425,931	-$3,509,903	-$3,587,462	-$3,658,819	-$3,724,636	-$3,793,317	-$3,864,036	-$3,929,305	-$3,989,555	-$4,045,183	-$4,096,555	-$4,144,007	-$4,187,847	-$4,228,361	-$4,265,810

Starting Year	2007	
Direct Construction Expense	83.3%	
AFDUC and Financing Expense	16.7%	
Percentage of AFUDC as Debt	100%	
Percentage of Total Expense as Land	0%	
Tax Life: MACRS Half year Conv.	20	year
Book Life	30	year
Declining Balance Rate	1.5	
State Tax Rate	8.0%	
Federal Tax Rate	34.0%	
DEFERRED TAX -NORM (1) OR FLOW THROUGH (0)	1	
Total Tax Rate	39.3%	
Book Depreciation (SL-1 or IRR-0)	1	
Interim Retirement Rate	1.0%	
Salvage Rate	0.0%	
Return on Equity	8.38%	
Interest Rate on Debt	8.38%	
Percent Funding by Equity	0.0%	
Percent Funding by Debt	100.0%	
WACC	8.38%	
Insurance (Percent of Initial Construction Cost)	0.25%	

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
TAX DEPRECIATION															
BOY Tax Value	100.00%	92.50%	85.56%	79.15%	73.21%	67.72%	62.64%	57.94%	53.60%	49.31%	45.02%	40.73%	36.45%	32.16%	27.87%
Declining Balance Depr.	7.50%	6.94%	6.42%	5.94%	5.49%	5.08%	4.70%	4.35%	4.02%	3.70%	3.38%	3.05%	2.73%	2.41%	2.09%
Straight Line Depr.	2.44%	4.74%	4.63%	4.52%	4.44%	4.37%	4.32%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%
Tax Depr.	7.50%	6.94%	6.42%	5.94%	5.49%	5.08%	4.70%	4.35%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%
RATE BASE															
Book Depr.	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%
Cumulative Book Depr.	3.33%	6.67%	10.00%	13.33%	16.67%	20.00%	23.33%	26.67%	30.00%	33.33%	36.67%	40.00%	43.33%	46.67%	50.00%
Deferred Taxes	1.64%	1.42%	1.21%	1.02%	0.85%	0.69%	0.54%	0.40%	0.37%	0.37%	0.37%	0.37%	0.37%	0.37%	0.37%
Cumulative Deferred Taxes	1.64%	3.05%	4.26%	5.29%	6.13%	6.82%	7.36%	7.75%	8.13%	8.50%	8.88%	9.25%	9.63%	10.00%	10.38%
Rate Base	95.03%	90.28%	85.74%	81.38%	77.20%	73.18%	69.31%	65.58%	61.87%	58.16%	54.46%	50.75%	47.04%	43.33%	39.62%
RETURN & TAXES															
Return on WACC	7.96%	7.56%	7.18%	6.82%	6.47%	6.13%	5.80%	5.49%	5.18%	4.87%	4.56%	4.25%	3.94%	3.63%	3.32%
Bond Interest	7.96%	7.56%	7.18%	6.82%	6.47%	6.13%	5.80%	5.49%	5.18%	4.87%	4.56%	4.25%	3.94%	3.63%	3.32%
Federal Income Taxes	-1.30%	-1.13%	-0.96%	-0.81%	-0.67%	-0.55%	-0.43%	-0.32%	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%
State Income Taxes	-0.33%	-0.29%	-0.25%	-0.21%	-0.17%	-0.14%	-0.11%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%
Property Taxes & Insurance	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
Year	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
TAX DEPRECIATION															
BOY Tax Value	23.58%	19.29%	15.01%	10.72%	6.43%	2.14%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Declining Balance Depr.	1.77%	1.45%	1.13%	0.80%	0.48%	0.16%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Straight Line Depr.	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Tax Depr.	4.29%	4.29%	4.29%	4.29%	4.29%	2.14%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RATE BASE															
Book Depr.	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%
Cumulative Book Depr.	53.33%	56.67%	60.00%	63.33%	66.67%	70.00%	73.33%	76.67%	80.00%	83.33%	86.67%	90.00%	93.33%	96.67%	100.00%
Deferred Taxes	0.37%	0.37%	0.37%	0.37%	0.37%	-0.47%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%
Cumulative Deferred Taxes	10.75%	11.13%	11.50%	11.88%	12.25%	11.78%	10.47%	9.17%	7.86%	6.55%	5.24%	3.93%	2.62%	1.31%	0.00%
Rate Base	35.91%	32.21%	28.50%	24.79%	21.08%	18.22%	16.19%	14.17%	12.14%	10.12%	8.10%	6.07%	4.05%	2.02%	0.00%
RETURN & TAXES															
Return on WACC	3.01%	2.70%	2.39%	2.08%	1.77%	1.53%	1.36%	1.19%	1.02%	0.85%	0.68%	0.51%	0.34%	0.17%	0.00%
Bond Interest	3.01%	2.70%	2.39%	2.08%	1.77%	1.53%	1.36%	1.19%	1.02%	0.85%	0.68%	0.51%	0.34%	0.17%	0.00%
Federal Income Taxes	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%	0.37%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%
State Income Taxes	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	0.10%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%
Property Taxes & Insurance	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%

Variable	Value		Source
Interest on Construction	4.09%		FERC (4/29/2004 6-month T-Bond & 300 basis points)
Financing Cost	2%		FERC
Debt Service Reserve	1	year	FERC
Operational Reserve	3	months	FERC
Term of Analysis	30	years	FERC
Starting Year	2007		FERC
Grant Value	$0		GEC
Interest on Debt, AIDEA Component	5.43%		GEC
AIDEA Loan Component	$1,000,000		GEC
Interest on Debt, Remainder	8.38%		GEC
Term of Financing, AIDEA Component	30	years	GEC
Term of Financing, Remaining Component	30	years	GEC
2003 O&M (including Staff-recommended environmental enhancements)	$58,600		FERC/GEC
Insurance (% of Initial Investment including granted $)	0.25%		FERC
Interest Rate on Debt Reserve	3.60%		FERC (4/29/2004 5-year T-Bond)
Interest Rate on Operating Reserve	0.85%		FERC (4/29/2004 3-month T-Bond)
Net Cost of Debt	7.848%		Calculated
Operating Reserve Requirement	$150,000		FERC (approx. 3 months operating revenues in last year of operations, rounded up to nearest 25K)
Federal Tax Rate	34%		FERC
State Tax Rate	8%		FERC
Percent Funding by Equity	0.0%		FERC/GEC
Percent Funding by Debt	100.0%		FERC/GEC

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*1,750,582*	*1,810,980*	*1,864,373*	*1,910,138*	*1,956,381*	*2,004,421*	*2,052,372*	*2,102,548*	*2,151,643*	*2,201,670*	*2,251,657*	*2,301,893*	*2,352,775*	*2,404,317*	*2,456,532*
Hydro Rate (mills/kWh)	*322.15*	*316.38*	*311.62*	*307.86*	*303.74*	*299.07*	*294.20*	*288.88*	*281.03*	*272.69*	*264.57*	*256.61*	*248.74*	*240.92*	*233.12*
Operating Revenues	$563,956	$572,958	$580,984	$588,045	$594,227	$599,454	$603,806	$607,382	$604,683	$600,367	$595,720	$590,686	$585,238	$579,247	$572,676
OPERATING EXPENSES															
Operating Expense	$74,435	$76,113	$77,963	$79,961	$82,158	$84,453	$86,909	$89,609	$92,407	$95,272	$98,373	$101,701	$105,277	$109,026	$112,969
Maintenance Expense															
Depreciation Expense	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333
NET OPERATING INCOME	$336,188	$343,512	$349,687	$354,751	$358,736	$361,667	$363,564	$364,440	$358,943	$351,761	$344,013	$335,651	$326,627	$316,888	$306,374
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$17,676	$17,676	$17,676	$17,676	$17,676	$17,676	$17,676	$17,676	$17,676	$17,676	$17,676	$17,676	$17,676	$17,676	$17,676
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$54,300	$53,541	$52,741	$51,898	$51,008	$50,071	$49,083	$48,040	$46,942	$45,783	$44,562	$43,274	$41,917	$40,486	$38,977
Remaining Component	$384,161	$380,996	$377,566	$373,849	$369,820	$365,454	$360,722	$355,594	$350,037	$344,014	$337,487	$330,413	$322,746	$314,438	$305,433
NET INCOME BEFORE TAXES	-$83,323	-$72,074	-$61,669	-$52,045	-$43,142	-$34,907	-$27,290	-$20,243	-$19,085	-$19,085	-$19,085	-$19,085	-$19,085	-$19,085	-$19,085
Federal Income Taxes	-$66,353	-$57,395	-$49,109	-$41,445	-$34,355	-$27,798	-$21,732	-$16,121	-$15,198	-$15,198	-$15,198	-$15,198	-$15,198	-$15,198	-$15,198
State Income Taxes	-$16,970	-$14,679	-$12,560	-$10,600	-$8,787	-$7,109	-$5,558	-$4,123	-$3,887	-$3,887	-$3,887	-$3,887	-$3,887	-$3,887	-$3,887
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
STATEMENT OF CASH FLOWS															
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Add back Depreciation	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333
Subtract Principal Payment															
AIDEA Component	$13,974	$14,733	$15,533	$16,377	$17,266	$18,203	$19,192	$20,234	$21,333	$22,491	$23,712	$25,000	$26,357	$27,789	$29,297
Remaining Component	$37,791	$40,956	$44,386	$48,104	$52,132	$56,498	$61,230	$66,358	$71,916	$77,939	$84,466	$91,540	$99,206	$107,515	$116,519
NET CASH FLOW	$101,568	$97,644	$93,414	$88,853	$83,935	$78,632	$72,911	$66,741	$60,085	$52,904	$45,155	$36,794	$27,770	$18,030	$7,517
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	122.35	124.19	126.03	128.04	130.32	132.89	136.47	139.32	142.85	145.67	149.27	151.96	157.24	161.46	163.99
Net Benefit	-$349,772	-$348,049	-$346,012	-$343,476	-$339,277	-$333,083	-$323,725	-$314,454	-$297,330	-$279,653	-$259,614	-$240,880	-$215,277	-$191,049	-$169,819
Annual PV of Net Benefit	-$324,320	-$299,238	-$275,840	-$253,893	-$232,539	-$211,681	-$190,763	-$171,816	-$150,638	-$131,372	-$113,084	-$97,289	-$80,621	-$66,341	-$54,678
Cumulative PV of Net Benefit	-$324,320	-$623,559	-$899,398	-$1,153,291	-$1,385,830	-$1,597,511	-$1,788,275	-$1,960,091	-$2,110,729	-$2,242,101	-$2,355,185	-$2,452,473	-$2,533,094	-$2,599,435	-$2,654,113
NPV	-$2,928,401														

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*2,509,434*	*2,563,038*	*2,617,359*	*2,672,412*	*2,728,211*	*2,784,774*	*2,842,115*	*2,900,251*	*2,959,200*	*3,018,977*	*3,069,568*	*3,111,566*	*3,154,447*	*3,195,328*	*3,234,274*
Hydro Rate (mills/kWh)	*226.86*	*223.78*	*220.81*	*217.98*	*215.26*	*228.06*	*240.33*	*237.34*	*234.47*	*231.70*	*229.80*	*228.66*	*227.56*	*226.70*	*226.07*
Operating Revenues	$569,295	$573,556	$577,951	$582,535	$587,286	$635,082	$683,057	$688,346	$693,829	$699,511	$705,401	$711,505	$717,831	$724,389	$731,185
OPERATING EXPENSES															
Operating Expense	$117,104	$121,366	$125,760	$130,344	$135,095	$140,019	$145,123	$150,413	$155,895	$161,577	$167,467	$173,571	$179,897	$186,455	$193,251
Maintenance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation Expense	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333
NET OPERATING INCOME	$298,858	$298,858	$298,858	$298,858	$298,858	$341,729	$384,601	$384,601	$384,601	$384,601	$384,601	$384,601	$384,601	$384,601	$384,601
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$17,676	$17,676	$17,676	$17,676	$17,676	$17,676	$17,676	$17,676	$17,676	$17,676	$17,676	$17,676	$17,676	$17,676	$17,676
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$37,386	$35,709	$33,940	$32,076	$30,111	$28,038	$25,853	$23,550	$21,121	$18,561	$15,862	$13,016	$10,015	$6,852	$3,516
Remaining Component	$295,675	$285,099	$273,637	$261,216	$247,754	$233,165	$217,354	$200,219	$181,649	$161,524	$139,713	$116,075	$90,458	$62,695	$32,608
NET INCOME BEFORE TAXES	-$15,252	-$2,999	$10,231	$24,516	$39,944	$99,477	$160,344	$179,782	$200,781	$223,467	$247,977	$274,461	$303,078	$334,005	$367,428
Federal Income Taxes	-$15,198	-$15,198	-$15,198	-$15,198	-$15,198	$18,942	$53,082	$53,082	$53,082	$53,082	$53,082	$53,082	$53,082	$53,082	$53,082
State Income Taxes	-$3,887	-$3,887	-$3,887	-$3,887	-$3,887	$4,845	$13,576	$13,576	$13,576	$13,576	$13,576	$13,576	$13,576	$13,576	$13,576
NET INCOME	$3,833	$16,086	$29,316	$43,601	$59,028	$75,690	$93,686	$113,124	$134,123	$156,809	$181,319	$207,803	$236,420	$267,346	$300,769
STATEMENT OF CASH FLOWS															
NET INCOME	$3,833	$16,086	$29,316	$43,601	$59,028	$75,690	$93,686	$113,124	$134,123	$156,809	$181,319	$207,803	$236,420	$267,346	$300,769
Add back Depreciation	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333
Subtract Principal Payment															
AIDEA Component	$30,888	$32,566	$34,334	$36,198	$38,164	$40,236	$42,421	$44,724	$47,153	$49,713	$52,413	$55,259	$58,259	$61,423	$64,758
Remaining Component	$126,278	$136,854	$148,315	$160,736	$174,198	$188,787	$204,598	$221,733	$240,303	$260,429	$282,240	$305,877	$331,494	$359,257	$389,345
NET CASH FLOW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	167.55	171.14	174.60	179.04	183.08	187.22	191.45	195.79	200.23	204.79	209.45	214.22	219.12	224.13	229.27
Net Benefit	-$148,845	-$134,925	-$120,956	-$104,054	-$87,798	-$113,722	-$138,925	-$120,503	-$101,296	-$81,269	-$62,487	-$44,934	-$26,640	-$8,221	$10,325
Annual PV of Net Benefit	-$44,437	-$37,350	-$31,047	-$24,765	-$19,376	-$23,270	-$26,359	-$21,200	-$16,524	-$12,292	-$8,764	-$5,843	-$3,212	-$919	$1,070
Cumulative PV of Net Benefit	-$2,698,551	-$2,735,901	-$2,766,948	-$2,791,713	-$2,811,088	-$2,834,358	-$2,860,717	-$2,881,917	-$2,898,441	-$2,910,733	-$2,919,497	-$2,925,340	-$2,928,552	-$2,929,472	-$2,928,401

Starting Year	2007	
Direct Construction Expense	83.3%	
AFDUC and Financing Expense	16.7%	
Percentage of AFUDC as Debt	100%	
Percentage of Total Expense as Land	0%	
Tax Life: MACRS Half year Conv.	20	year
Book Life	30	year
Declining Balance Rate	1.5	
State Tax Rate	8.0%	
Federal Tax Rate	34.0%	
DEFERRED TAX -NORM (1) OR FLOW THROUGH (0)	1	
Total Tax Rate	39.3%	
Book Depreciation (SL-1 or IRR-0)	1	
Interim Retirement Rate	1.0%	
Salvage Rate	0.0%	
Return on Equity	7.85%	
Interest Rate on Debt	7.85%	
Percent Funding by Equity	0.0%	
Percent Funding by Debt	100.0%	
WACC	7.85%	
Insurance (Percent of Initial Construction Cost)	0.25%	

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
TAX DEPRECIATION															
BOY Tax Value	100.00%	92.50%	85.56%	79.15%	73.21%	67.72%	62.64%	57.94%	53.60%	49.31%	45.02%	40.73%	36.45%	32.16%	27.87%
Declining Balance Depr.	7.50%	6.94%	6.42%	5.94%	5.49%	5.08%	4.70%	4.35%	4.02%	3.70%	3.38%	3.05%	2.73%	2.41%	2.09%
Straight Line Depr.	2.44%	4.74%	4.63%	4.52%	4.44%	4.37%	4.32%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%
Tax Depr.	7.50%	6.94%	6.42%	5.94%	5.49%	5.08%	4.70%	4.35%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%
RATE BASE															
Book Depr.	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%
Cumulative Book Depr.	3.33%	6.67%	10.00%	13.33%	16.67%	20.00%	23.33%	26.67%	30.00%	33.33%	36.67%	40.00%	43.33%	46.67%	50.00%
Deferred Taxes	1.64%	1.42%	1.21%	1.02%	0.85%	0.69%	0.54%	0.40%	0.37%	0.37%	0.37%	0.37%	0.37%	0.37%	0.37%
Cumulative Deferred Taxes	1.64%	3.05%	4.26%	5.29%	6.13%	6.82%	7.36%	7.75%	8.13%	8.50%	8.88%	9.25%	9.63%	10.00%	10.38%
Rate Base	95.03%	90.28%	85.74%	81.38%	77.20%	73.18%	69.31%	65.58%	61.87%	58.16%	54.46%	50.75%	47.04%	43.33%	39.62%
RETURN & TAXES															
Return on WACC	7.46%	7.09%	6.73%	6.39%	6.06%	5.74%	5.44%	5.15%	4.86%	4.56%	4.27%	3.98%	3.69%	3.40%	3.11%
Bond Interest	7.46%	7.09%	6.73%	6.39%	6.06%	5.74%	5.44%	5.15%	4.86%	4.56%	4.27%	3.98%	3.69%	3.40%	3.11%
Federal Income Taxes	-1.30%	-1.13%	-0.96%	-0.81%	-0.67%	-0.55%	-0.43%	-0.32%	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%
State Income Taxes	-0.33%	-0.29%	-0.25%	-0.21%	-0.17%	-0.14%	-0.11%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%
Property Taxes & Insurance	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
Year	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
TAX DEPRECIATION															
BOY Tax Value	23.58%	19.29%	15.01%	10.72%	6.43%	2.14%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Declining Balance Depr.	1.77%	1.45%	1.13%	0.80%	0.48%	0.16%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Straight Line Depr.	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Tax Depr.	4.29%	4.29%	4.29%	4.29%	4.29%	2.14%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RATE BASE															
Book Depr.	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%
Cumulative Book Depr.	53.33%	56.67%	60.00%	63.33%	66.67%	70.00%	73.33%	76.67%	80.00%	83.33%	86.67%	90.00%	93.33%	96.67%	100.00%
Deferred Taxes	0.37%	0.37%	0.37%	0.37%	0.37%	-0.47%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%
Cumulative Deferred Taxes	10.75%	11.13%	11.50%	11.88%	12.25%	11.78%	10.47%	9.17%	7.86%	6.55%	5.24%	3.93%	2.62%	1.31%	0.00%
Rate Base	35.91%	32.21%	28.50%	24.79%	21.08%	18.22%	16.19%	14.17%	12.14%	10.12%	8.10%	6.07%	4.05%	2.02%	0.00%
RETURN & TAXES															
Return on WACC	2.82%	2.53%	2.24%	1.95%	1.65%	1.43%	1.27%	1.11%	0.95%	0.79%	0.64%	0.48%	0.32%	0.16%	0.00%
Bond Interest	2.82%	2.53%	2.24%	1.95%	1.65%	1.43%	1.27%	1.11%	0.95%	0.79%	0.64%	0.48%	0.32%	0.16%	0.00%
Federal Income Taxes	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%	0.37%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%
State Income Taxes	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	0.10%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%
Property Taxes & Insurance	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%

Variable	**Value**		**Source**
Interest on Construction	4.09%		FERC (4/29/2004 6-month T-Bond & 300 basis points)
Financing Cost	2%		FERC
Debt Service Reserve	1	year	FERC
Operational Reserve	3	months	FERC
Term of Analysis	30	years	FERC
Starting Year	2007		FERC
Grant Value	$1,083,685		GEC
Interest on Debt, AIDEA Component	5.43%		GEC
AIDEA Loan Component	$1,000,000		GEC
Interest on Debt, Remainder	5.13%		GEC
Term of Financing, AIDEA Component	30	years	GEC
Term of Financing, Remaining Component	30	years	GEC
2003 O&M (including Staff-recommended environmental enhancements)	$58,600		FERC/GEC
Insurance (% of Initial Investment including granted $)	0.25%		FERC
Interest Rate on Debt Reserve	3.60%		FERC (4/29/2004 5-year T-Bond)
Interest Rate on Operating Reserve	0.85%		FERC (4/29/2004 3-month T-Bond)
Net Cost of Debt	5.202%		Calculated
Operating Reserve Requirement	$150,000		FERC (approx. 3 months operating revenues in last year of operations, rounded up to nearest 25K)
Federal Tax Rate	34%		FERC
State Tax Rate	8%		FERC
Percent Funding by Equity	0.0%		FERC/GEC
Percent Funding by Debt	100.0%		FERC/GEC

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*1,793,699*	*1,868,084*	*1,943,192*	*2,017,952*	*2,094,888*	*2,175,737*	*2,249,965*	*2,314,972*	*2,375,662*	*2,438,447*	*2,500,283*	*2,562,120*	*2,623,957*	*2,685,793*	*2,747,630*
Hydro Rate (mills/kWh)	*187.06*	*183.27*	*179.40*	*175.54*	*171.53*	*167.24*	*163.51*	*160.49*	*156.03*	*151.24*	*146.74*	*142.45*	*138.35*	*134.82*	*133.22*
Operating Revenues	$335,522	$342,372	$348,606	$354,235	$359,346	$363,870	$367,893	$371,526	$370,671	$368,790	$366,897	$364,971	$363,021	$362,107	$366,049
OPERATING EXPENSES															
Operating Expense	$74,435	$76,113	$77,963	$79,961	$82,158	$84,453	$86,909	$89,609	$92,407	$95,272	$98,373	$101,701	$105,277	$109,026	$112,969
Maintenance Expense															
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$144,620	$149,793	$154,176	$157,807	$160,722	$162,949	$164,518	$165,451	$161,798	$157,051	$152,057	$146,803	$141,276	$136,614	$136,614
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$54,300	$53,541	$52,741	$51,898	$51,008	$50,071	$49,083	$48,040	$46,942	$45,783	$44,562	$43,274	$41,917	$40,486	$38,977
Remaining Component	$163,391	$160,986	$158,457	$155,799	$153,005	$150,067	$146,979	$143,732	$140,319	$136,731	$132,958	$128,992	$124,822	$120,439	$115,831
NET INCOME BEFORE TAXES	-$61,751	-$53,415	-$45,704	-$38,571	-$31,973	-$25,870	-$20,225	-$15,003	-$14,144	-$14,144	-$14,144	-$14,144	-$14,144	-$12,992	-$6,875
Federal Income Taxes	-$49,175	-$42,536	-$36,395	-$30,715	-$25,461	-$20,601	-$16,106	-$11,947	-$11,263	-$11,263	-$11,263	-$11,263	-$11,263	-$11,263	-$11,263
State Income Taxes	-$12,577	-$10,879	-$9,308	-$7,856	-$6,512	-$5,269	-$4,119	-$3,056	-$2,881	-$2,881	-$2,881	-$2,881	-$2,881	-$2,881	-$2,881
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,152	$7,269
STATEMENT OF CASH FLOWS															
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,152	$7,269
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$13,974	$14,733	$15,533	$16,377	$17,266	$18,203	$19,192	$20,234	$21,333	$22,491	$23,712	$25,000	$26,357	$27,789	$29,297
Remaining Component	$46,879	$49,284	$51,812	$54,470	$57,264	$60,202	$63,290	$66,537	$69,950	$73,539	$77,311	$81,277	$85,447	$89,830	$94,439
NET CASH FLOW	$55,614	$52,450	$49,122	$45,620	$41,937	$38,062	$33,985	$29,696	$25,184	$20,437	$15,443	$10,190	$4,663	$0	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	122.35	125.90	129.53	133.40	137.65	142.30	148.14	153.31	159.35	164.72	171.11	176.57	185.22	192.78	235.19
Net Benefit	-$116,063	-$107,172	-$96,900	-$85,031	-$70,990	-$54,270	-$34,594	-$16,623	$7,882	$32,875	$60,923	$87,415	$122,987	$155,670	$280,178
Annual PV of Net Benefit	-$110,324	-$96,835	-$83,226	-$69,420	-$55,092	-$40,033	-$24,257	-$11,080	$4,994	$19,799	$34,877	$47,568	$63,616	$76,540	$130,947
Cumulative PV of Net Benefit	-$110,324	-$207,160	-$290,385	-$359,805	-$414,897	-$454,930	-$479,188	-$490,267	-$485,273	-$465,474	-$430,598	-$383,030	-$319,414	-$242,874	-$111,928
NPV	$2,281,359														

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*2,809,467*	*2,871,303*	*2,933,140*	*2,994,977*	*3,056,813*	*3,118,650*	*3,180,486*	*3,242,323*	*3,304,160*	*3,365,996*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*
Hydro Rate (mills/kWh)	*131.76*	*130.41*	*129.16*	*128.02*	*126.99*	*136.24*	*145.18*	*144.04*	*143.01*	*142.07*	*142.55*	*144.35*	*146.21*	*148.14*	*150.14*
Operating Revenues	$370,185	$374,446	$378,841	$383,425	$388,176	$424,872	$461,749	$467,038	$472,521	$478,203	$484,092	$490,197	$496,523	$503,080	$509,877
OPERATING EXPENSES															
Operating Expense	$117,104	$121,366	$125,760	$130,344	$135,095	$140,019	$145,123	$150,413	$155,895	$161,577	$167,467	$173,571	$179,897	$186,455	$193,251
Maintenance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$136,614	$136,614	$136,614	$136,614	$136,614	$168,386	$200,159	$200,159	$200,159	$200,159	$200,159	$200,159	$200,159	$200,159	$200,159
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$37,386	$35,709	$33,940	$32,076	$30,111	$28,038	$25,853	$23,550	$21,121	$18,561	$15,862	$13,016	$10,015	$6,852	$3,516
Remaining Component	$110,986	$105,893	$100,538	$94,909	$88,991	$82,770	$76,229	$69,353	$62,124	$54,524	$46,534	$38,134	$29,304	$20,020	$10,260
NET INCOME BEFORE TAXES	-$439	$6,331	$13,454	$20,948	$28,831	$68,898	$109,396	$118,575	$128,233	$138,393	$149,082	$160,328	$172,159	$184,606	$197,701
Federal Income Taxes	-$11,263	-$11,263	-$11,263	-$11,263	-$11,263	$14,038	$39,340	$39,340	$39,340	$39,340	$39,340	$39,340	$39,340	$39,340	$39,340
State Income Taxes	-$2,881	-$2,881	-$2,881	-$2,881	-$2,881	$3,590	$10,061	$10,061	$10,061	$10,061	$10,061	$10,061	$10,061	$10,061	$10,061
NET INCOME	$13,705	$20,475	$27,598	$35,092	$42,975	$51,269	$59,995	$69,174	$78,832	$88,992	$99,681	$110,927	$122,758	$135,205	$148,300
STATEMENT OF CASH FLOWS															
NET INCOME	$13,705	$20,475	$27,598	$35,092	$42,975	$51,269	$59,995	$69,174	$78,832	$88,992	$99,681	$110,927	$122,758	$135,205	$148,300
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$30,888	$32,566	$34,334	$36,198	$38,164	$40,236	$42,421	$44,724	$47,153	$49,713	$52,413	$55,259	$58,259	$61,423	$64,758
Remaining Component	$99,283	$104,376	$109,731	$115,360	$121,278	$127,500	$134,040	$140,917	$148,146	$155,746	$163,735	$172,135	$180,965	$190,249	$200,009
NET CASH FLOW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	242.24	249.47	256.69	265.34	273.62	282.20	291.09	300.31	309.86	319.75	330.01	340.63	351.64	363.05	374.87
Net Benefit	$310,367	$341,856	$374,074	$411,260	$448,232	$455,217	$464,074	$506,662	$551,300	$598,084	$636,609	$666,588	$697,652	$729,841	$763,195
Annual PV of Net Benefit	$137,884	$144,364	$150,158	$156,923	$162,573	$156,943	$152,086	$157,832	$163,246	$168,343	$170,327	$169,529	$168,657	$167,714	$166,707
Cumulative PV of Net Benefit	$25,956	$170,320	$320,478	$477,401	$639,974	$796,917	$949,002	$1,106,835	$1,270,081	$1,438,424	$1,608,751	$1,778,280	$1,946,937	$2,114,651	$2,281,359

Starting Year	2007	
Direct Construction Expense	83.3%	
AFDUC and Financing Expense	16.7%	
Percentage of AFUDC as Debt	100%	
Percentage of Total Expense as Land	0%	
Tax Life: MACRS Half year Conv.	20	year
Book Life	30	year
Declining Balance Rate	1.5	
State Tax Rate	8.0%	
Federal Tax Rate	34.0%	
DEFERRED TAX -NORM (1) OR FLOW THROUGH (0)	1	
Total Tax Rate	39.3%	
Book Depreciation (SL-1 or IRR-0)	1	
Interim Retirement Rate	1.0%	
Salvage Rate	0.0%	
Return on Equity	5.20%	
Interest Rate on Debt	5.20%	
Percent Funding by Equity	0.0%	
Percent Funding by Debt	100.0%	
WACC	5.20%	
Insurance (Percent of Initial Construction Cost)	0.25%	

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
TAX DEPRECIATION															
BOY Tax Value	100.00%	92.50%	85.56%	79.15%	73.21%	67.72%	62.64%	57.94%	53.60%	49.31%	45.02%	40.73%	36.45%	32.16%	27.87%
Declining Balance Depr.	7.50%	6.94%	6.42%	5.94%	5.49%	5.08%	4.70%	4.35%	4.02%	3.70%	3.38%	3.05%	2.73%	2.41%	2.09%
Straight Line Depr.	2.44%	4.74%	4.63%	4.52%	4.44%	4.37%	4.32%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%
Tax Depr.	7.50%	6.94%	6.42%	5.94%	5.49%	5.08%	4.70%	4.35%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%
RATE BASE															
Book Depr.	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%
Cumulative Book Depr.	3.33%	6.67%	10.00%	13.33%	16.67%	20.00%	23.33%	26.67%	30.00%	33.33%	36.67%	40.00%	43.33%	46.67%	50.00%
Deferred Taxes	1.64%	1.42%	1.21%	1.02%	0.85%	0.69%	0.54%	0.40%	0.37%	0.37%	0.37%	0.37%	0.37%	0.37%	0.37%
Cumulative Deferred Taxes	1.64%	3.05%	4.26%	5.29%	6.13%	6.82%	7.36%	7.75%	8.13%	8.50%	8.88%	9.25%	9.63%	10.00%	10.38%
Rate Base	95.03%	90.28%	85.74%	81.38%	77.20%	73.18%	69.31%	65.58%	61.87%	58.16%	54.46%	50.75%	47.04%	43.33%	39.62%
RETURN & TAXES															
Return on WACC	4.94%	4.70%	4.46%	4.23%	4.02%	3.81%	3.61%	3.41%	3.22%	3.03%	2.83%	2.64%	2.45%	2.25%	2.06%
Bond Interest	4.94%	4.70%	4.46%	4.23%	4.02%	3.81%	3.61%	3.41%	3.22%	3.03%	2.83%	2.64%	2.45%	2.25%	2.06%
Federal Income Taxes	-1.30%	-1.13%	-0.96%	-0.81%	-0.67%	-0.55%	-0.43%	-0.32%	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%
State Income Taxes	-0.33%	-0.29%	-0.25%	-0.21%	-0.17%	-0.14%	-0.11%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%
Property Taxes & Insurance	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
Year	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
TAX DEPRECIATION															
BOY Tax Value	23.58%	19.29%	15.01%	10.72%	6.43%	2.14%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Declining Balance Depr.	1.77%	1.45%	1.13%	0.80%	0.48%	0.16%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Straight Line Depr.	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Tax Depr.	4.29%	4.29%	4.29%	4.29%	4.29%	2.14%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RATE BASE															
Book Depr.	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%
Cumulative Book Depr.	53.33%	56.67%	60.00%	63.33%	66.67%	70.00%	73.33%	76.67%	80.00%	83.33%	86.67%	90.00%	93.33%	96.67%	100.00%
Deferred Taxes	0.37%	0.37%	0.37%	0.37%	0.37%	-0.47%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%
Cumulative Deferred Taxes	10.75%	11.13%	11.50%	11.88%	12.25%	11.78%	10.47%	9.17%	7.86%	6.55%	5.24%	3.93%	2.62%	1.31%	0.00%
Rate Base	35.91%	32.21%	28.50%	24.79%	21.08%	18.22%	16.19%	14.17%	12.14%	10.12%	8.10%	6.07%	4.05%	2.02%	0.00%
RETURN & TAXES															
Return on WACC	1.87%	1.68%	1.48%	1.29%	1.10%	0.95%	0.84%	0.74%	0.63%	0.53%	0.42%	0.32%	0.21%	0.11%	0.00%
Bond Interest	1.87%	1.68%	1.48%	1.29%	1.10%	0.95%	0.84%	0.74%	0.63%	0.53%	0.42%	0.32%	0.21%	0.11%	0.00%
Federal Income Taxes	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%	0.37%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%
State Income Taxes	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	0.10%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%
Property Taxes & Insurance	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%

Variable	Value	Source
Interest on Construction	4.09%	FERC (4/29/2004 6-month T-Bond & 300 basis points)
Financing Cost	2%	FERC
Debt Service Reserve	1 year	FERC
Operational Reserve	3 months	FERC
Term of Analysis	30 years	FERC
Starting Year	2007	FERC
Grant Value	$1,083,685	GEC
Interest on Debt, AIDEA Component	5.43%	GEC
AIDEA Loan Component	$0	GEC
Interest on Debt, Remainder	5.13%	GEC
Term of Financing, AIDEA Component	30 years	GEC
Term of Financing, Remaining Component	30 years	GEC
2003 O&M (including Staff-recommended environmental enhancements)	$58,600	FERC/GEC
Insurance (% of Initial Investment including granted $)	0.25%	FERC
Interest Rate on Debt Reserve	3.60%	FERC (4/29/2004 5-year T-Bond)
Interest Rate on Operating Reserve	0.85%	FERC (4/29/2004 3-month T-Bond)
Net Cost of Debt	5.130%	Calculated
Operating Reserve Requirement	$150,000	FERC (approx. 3 months operating revenues in last year of operations, rounded up to nearest 25K)
Federal Tax Rate	34%	FERC
State Tax Rate	8%	FERC
Percent Funding by Equity	0.0%	FERC/GEC
Percent Funding by Debt	100.0%	FERC/GEC

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*1,843,994*	*1,933,413*	*2,014,490*	*2,072,412*	*2,129,903*	*2,191,096*	*2,249,965*	*2,314,972*	*2,375,662*	*2,438,447*	*2,500,283*	*2,562,120*	*2,623,957*	*2,685,793*	*2,747,630*
Hydro Rate (mills/kWh)	*143.84*	*140.01*	*136.87*	*135.28*	*133.65*	*131.70*	*129.85*	*127.65*	*124.43*	*120.97*	*117.74*	*114.69*	*111.80*	*109.89*	*108.86*
Operating Revenues	$265,247	$270,690	$275,727	$280,360	$284,667	$288,570	$292,150	$295,510	$295,607	$294,971	$294,390	$293,848	$293,356	$295,152	$299,094
OPERATING EXPENSES															
Operating Expense	$74,435	$76,113	$77,963	$79,961	$82,158	$84,453	$86,909	$89,609	$92,407	$95,272	$98,373	$101,701	$105,277	$109,026	$112,969
Maintenance Expense															
Depreciation Expense	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333
NET OPERATING INCOME	$105,479	$109,244	$112,430	$115,065	$117,176	$118,783	$119,908	$120,568	$117,867	$114,365	$110,684	$106,813	$102,745	$100,792	$100,792
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$7,416	$7,416	$7,416	$7,416	$7,416	$7,416	$7,416	$7,416	$7,416	$7,416	$7,416	$7,416	$7,416	$7,416	$7,416
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Remaining Component	$159,440	$157,094	$154,627	$152,033	$149,306	$146,439	$143,426	$140,257	$136,927	$133,425	$129,744	$125,873	$121,805	$117,527	$113,030
NET INCOME BEFORE TAXES	-$45,270	-$39,159	-$33,506	-$28,276	-$23,440	-$18,965	-$14,827	-$10,999	-$10,369	-$10,369	-$10,369	-$10,369	-$10,369	-$8,044	-$3,547
Federal Income Taxes	-$36,050	-$31,183	-$26,682	-$22,518	-$18,666	-$15,103	-$11,807	-$8,758	-$8,257	-$8,257	-$8,257	-$8,257	-$8,257	-$8,257	-$8,257
State Income Taxes	-$9,220	-$7,975	-$6,824	-$5,759	-$4,774	-$3,863	-$3,020	-$2,240	-$2,112	-$2,112	-$2,112	-$2,112	-$2,112	-$2,112	-$2,112
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,325	$6,822
STATEMENT OF CASH FLOWS															
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,325	$6,822
Add back Depreciation	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333
Subtract Principal Payment															
AIDEA Component	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Remaining Component	$45,745	$48,092	$50,559	$53,153	$55,880	$58,746	$61,760	$64,928	$68,259	$71,761	$75,442	$79,312	$83,381	$87,658	$92,155
NET CASH FLOW	$39,588	$37,241	$34,774	$32,180	$29,454	$26,587	$23,573	$20,405	$17,074	$13,573	$9,891	$6,021	$1,952	$0	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	122.35	126.97	131.73	136.82	142.37	148.43	155.84	162.65	170.50	208.75	217.23	224.81	236.06	246.27	254.49
Net Benefit	-$39,635	-$25,208	-$10,354	$3,189	$18,567	$36,653	$58,475	$81,024	$109,452	$214,061	$248,740	$282,142	$326,061	$366,286	$400,144
Annual PV of Net Benefit	-$37,701	-$22,808	-$8,911	$2,611	$14,458	$27,149	$41,199	$54,300	$69,772	$129,799	$143,467	$154,792	$170,158	$181,822	$188,937
Cumulative PV of Net Benefit	-$37,701	-$60,509	-$69,420	-$66,809	-$52,351	-$25,202	$15,997	$70,297	$140,069	$269,868	$413,335	$568,127	$738,285	$920,107	$1,109,044
NPV	$4,785,698														

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*2,809,467*	*2,871,303*	*2,933,140*	*2,994,977*	*3,056,813*	*3,118,650*	*3,180,486*	*3,242,323*	*3,304,160*	*3,365,996*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*
Hydro Rate (mills/kWh)	*107.93*	*107.09*	*106.33*	*105.67*	*105.08*	*112.05*	*118.80*	*118.16*	*117.61*	*117.14*	*117.84*	*119.64*	*121.50*	*123.43*	*125.43*
Operating Revenues	$303,230	$307,491	$311,886	$316,470	$321,221	$349,438	$377,834	$383,123	$388,606	$394,288	$400,178	$406,282	$412,608	$419,166	$425,962
OPERATING EXPENSES															
Operating Expense	$117,104	$121,366	$125,760	$130,344	$135,095	$140,019	$145,123	$150,413	$155,895	$161,577	$167,467	$173,571	$179,897	$186,455	$193,251
Maintenance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation Expense	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333
NET OPERATING INCOME	$100,792	$100,792	$100,792	$100,792	$100,792	$124,085	$147,378	$147,378	$147,378	$147,378	$147,378	$147,378	$147,378	$147,378	$147,378
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$7,416	$7,416	$7,416	$7,416	$7,416	$7,416	$7,416	$7,416	$7,416	$7,416	$7,416	$7,416	$7,416	$7,416	$7,416
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Remaining Component	$108,303	$103,333	$98,108	$92,615	$86,840	$80,769	$74,386	$67,676	$60,622	$53,205	$45,409	$37,212	$28,595	$19,536	$10,012
NET INCOME BEFORE TAXES	$1,181	$6,151	$11,376	$16,869	$22,644	$52,008	$81,683	$88,393	$95,447	$102,863	$110,660	$118,856	$127,473	$136,532	$146,056
Federal Income Taxes	-$8,257	-$8,257	-$8,257	-$8,257	-$8,257	$10,291	$28,840	$28,840	$28,840	$28,840	$28,840	$28,840	$28,840	$28,840	$28,840
State Income Taxes	-$2,112	-$2,112	-$2,112	-$2,112	-$2,112	$2,632	$7,376	$7,376	$7,376	$7,376	$7,376	$7,376	$7,376	$7,376	$7,376
NET INCOME	$11,550	$16,520	$21,745	$27,238	$33,013	$39,084	$45,467	$52,177	$59,231	$66,647	$74,444	$82,640	$91,257	$100,316	$109,840
STATEMENT OF CASH FLOWS															
NET INCOME	$11,550	$16,520	$21,745	$27,238	$33,013	$39,084	$45,467	$52,177	$59,231	$66,647	$74,444	$82,640	$91,257	$100,316	$109,840
Add back Depreciation	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333
Subtract Principal Payment															
AIDEA Component	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Remaining Component	$96,883	$101,853	$107,078	$112,571	$118,346	$124,417	$130,800	$137,510	$144,564	$151,980	$159,777	$167,973	$176,590	$185,650	$195,173
NET CASH FLOW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	264.40	274.69	285.12	297.39	322.45	335.01	348.13	361.85	376.20	391.18	406.85	423.23	440.34	458.23	481.34
Net Benefit	$439,593	$481,223	$524,417	$574,208	$664,436	$695,328	$729,399	$790,125	$854,404	$922,439	$981,492	$1,031,000	$1,082,799	$1,136,997	$1,208,673
Annual PV of Net Benefit	$197,435	$205,586	$213,107	$221,954	$244,298	$243,181	$242,649	$250,024	$257,172	$264,102	$267,297	$267,078	$266,810	$266,493	$269,469
Cumulative PV of Net Benefit	$1,306,479	$1,512,065	$1,725,171	$1,947,125	$2,191,423	$2,434,604	$2,677,254	$2,927,278	$3,184,450	$3,448,551	$3,715,848	$3,982,926	$4,249,736	$4,516,229	$4,785,698

Starting Year	2007	
Direct Construction Expense	83.3%	
AFDUC and Financing Expense	16.7%	
Percentage of AFUDC as Debt	100%	
Percentage of Total Expense as Land	0%	
Tax Life: MACRS Half year Conv.	20	year
Book Life	30	year
Declining Balance Rate	1.5	
State Tax Rate	8.0%	
Federal Tax Rate	34.0%	
DEFERRED TAX -NORM (1) OR FLOW THROUGH (0)	1	
Total Tax Rate	39.3%	
Book Depreciation (SL-1 or IRR-0)	1	
Interim Retirement Rate	1.0%	
Salvage Rate	0.0%	
Return on Equity	5.13%	
Interest Rate on Debt	5.13%	
Percent Funding by Equity	0.0%	
Percent Funding by Debt	100.0%	
WACC	5.13%	
Insurance (Percent of Initial Construction Cost)	0.25%	

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
TAX DEPRECIATION															
BOY Tax Value	100.00%	92.50%	85.56%	79.15%	73.21%	67.72%	62.64%	57.94%	53.60%	49.31%	45.02%	40.73%	36.45%	32.16%	27.87%
Declining Balance Depr.	7.50%	6.94%	6.42%	5.94%	5.49%	5.08%	4.70%	4.35%	4.02%	3.70%	3.38%	3.05%	2.73%	2.41%	2.09%
Straight Line Depr.	2.44%	4.74%	4.63%	4.52%	4.44%	4.37%	4.32%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%
Tax Depr.	7.50%	6.94%	6.42%	5.94%	5.49%	5.08%	4.70%	4.35%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%
RATE BASE															
Book Depr.	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%
Cumulative Book Depr.	3.33%	6.67%	10.00%	13.33%	16.67%	20.00%	23.33%	26.67%	30.00%	33.33%	36.67%	40.00%	43.33%	46.67%	50.00%
Deferred Taxes	1.64%	1.42%	1.21%	1.02%	0.85%	0.69%	0.54%	0.40%	0.37%	0.37%	0.37%	0.37%	0.37%	0.37%	0.37%
Cumulative Deferred Taxes	1.64%	3.05%	4.26%	5.29%	6.13%	6.82%	7.36%	7.75%	8.13%	8.50%	8.88%	9.25%	9.63%	10.00%	10.38%
Rate Base	95.03%	90.28%	85.74%	81.38%	77.20%	73.18%	69.31%	65.58%	61.87%	58.16%	54.46%	50.75%	47.04%	43.33%	39.62%
RETURN & TAXES															
Return on WACC	4.88%	4.63%	4.40%	4.17%	3.96%	3.75%	3.56%	3.36%	3.17%	2.98%	2.79%	2.60%	2.41%	2.22%	2.03%
Bond Interest	4.88%	4.63%	4.40%	4.17%	3.96%	3.75%	3.56%	3.36%	3.17%	2.98%	2.79%	2.60%	2.41%	2.22%	2.03%
Federal Income Taxes	-1.30%	-1.13%	-0.96%	-0.81%	-0.67%	-0.55%	-0.43%	-0.32%	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%
State Income Taxes	-0.33%	-0.29%	-0.25%	-0.21%	-0.17%	-0.14%	-0.11%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%
Property Taxes & Insurance	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
Year	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
TAX DEPRECIATION															
BOY Tax Value	23.58%	19.29%	15.01%	10.72%	6.43%	2.14%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Declining Balance Depr.	1.77%	1.45%	1.13%	0.80%	0.48%	0.16%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Straight Line Depr.	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Tax Depr.	4.29%	4.29%	4.29%	4.29%	4.29%	2.14%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RATE BASE															
Book Depr.	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%
Cumulative Book Depr.	53.33%	56.67%	60.00%	63.33%	66.67%	70.00%	73.33%	76.67%	80.00%	83.33%	86.67%	90.00%	93.33%	96.67%	100.00%
Deferred Taxes	0.37%	0.37%	0.37%	0.37%	0.37%	-0.47%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%
Cumulative Deferred Taxes	10.75%	11.13%	11.50%	11.88%	12.25%	11.78%	10.47%	9.17%	7.86%	6.55%	5.24%	3.93%	2.62%	1.31%	0.00%
Rate Base	35.91%	32.21%	28.50%	24.79%	21.08%	18.22%	16.19%	14.17%	12.14%	10.12%	8.10%	6.07%	4.05%	2.02%	0.00%
RETURN & TAXES															
Return on WACC	1.84%	1.65%	1.46%	1.27%	1.08%	0.93%	0.83%	0.73%	0.62%	0.52%	0.42%	0.31%	0.21%	0.10%	0.00%
Bond Interest	1.84%	1.65%	1.46%	1.27%	1.08%	0.93%	0.83%	0.73%	0.62%	0.52%	0.42%	0.31%	0.21%	0.10%	0.00%
Federal Income Taxes	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%	0.37%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%
State Income Taxes	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	0.10%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%
Property Taxes & Insurance	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%

INCOME STATEMENT AND BACKGROUND

LOW OVERALL ESTIMATE INCLUDING GBNPP LOAD
MIDDLE-LOW OVERALL ESTIMATE INCLUDING GBNPP LOAD
MIDDLE OVERALL ESTIMATE INCLUDING GBNPP LOAD
MIDDLE-HIGH OVERALL ESTIMATE INCLUDING GBNPP LOAD
HIGH OVERALL ESTIMATE INCLUDING GBNPP LOAD

Variable	**Value**		**Source**
Interest on Construction	4.09%		FERC (4/29/2004 6-month T-Bond & 300 basis points)
Financing Cost	2%		FERC
Debt Service Reserve	1	year	FERC
Operational Reserve	3	months	FERC
Term of Analysis	30	years	FERC
Starting Year	2007		FERC
Grant Value	$0		GEC
Interest on Debt, AIDEA Component	5.43%		GEC
AIDEA Loan Component	$0		GEC
Interest on Debt, Remainder	8.38%		GEC
Term of Financing, AIDEA Component	30	years	GEC
Term of Financing, Remaining Component	30	years	GEC
2003 O&M (including Staff-recommended environmental enhancements)	$58,600		FERC/GEC
Insurance (% of Initial Investment including granted $)	0.25%		FERC
Interest Rate on Debt Reserve	3.60%		FERC (4/29/2004 5-year T-Bond)
Interest Rate on Operating Reserve	0.85%		FERC (4/29/2004 3-month T-Bond)
Net Cost of Debt	8.375%		Calculated
Operating Reserve Requirement	$150,000		FERC (approx. 3 months operating revenues in last year of operations, rounded up to nearest 25K)
Federal Tax Rate	34%		FERC
State Tax Rate	8%		FERC
Percent Funding by Equity	0.0%		FERC/GEC
Percent Funding by Debt	100.0%		FERC/GEC

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*2,490,785*	*2,511,734*	*2,530,150*	*2,542,478*	*2,555,499*	*2,568,228*	*2,582,177*	*2,594,915*	*2,605,358*	*2,615,185*	*2,623,922*	*2,623,922*	*2,623,922*	*2,623,922*	*2,623,922*
Hydro Rate (mills/kWh)	*238.57*	*240.21*	*241.66*	*243.29*	*244.49*	*245.31*	*245.66*	*245.80*	*243.73*	*241.09*	*238.43*	*236.40*	*234.18*	*231.74*	*229.04*
Operating Revenues	$594,222	$603,333	$611,444	$618,567	$624,782	$630,012	$634,333	$637,840	$635,002	$630,498	$625,611	$620,283	$614,478	$608,060	$600,984
OPERATING EXPENSES															
Operating Expense	$74,435	$76,113	$77,963	$79,961	$82,158	$84,453	$86,909	$89,609	$92,407	$95,272	$98,373	$101,701	$105,277	$109,026	$112,969
Maintenance Expense															
Depreciation Expense	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333
NET OPERATING INCOME	$366,454	$373,887	$380,147	$385,272	$389,291	$392,225	$394,091	$394,898	$389,262	$381,892	$373,905	$365,248	$355,867	$345,700	$334,682
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$18,612	$18,612	$18,612	$18,612	$18,612	$18,612	$18,612	$18,612	$18,612	$18,612	$18,612	$18,612	$18,612	$18,612	$18,612
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Remaining Component	$470,089	$466,216	$462,019	$457,470	$452,540	$447,197	$441,407	$435,132	$428,332	$420,961	$412,974	$404,318	$394,936	$384,770	$373,751
NET INCOME BEFORE TAXES	-$83,748	-$72,442	-$61,984	-$52,310	-$43,362	-$35,085	-$27,429	-$20,347	-$19,182	-$19,182	-$19,182	-$19,182	-$19,182	-$19,182	-$19,182
Federal Income Taxes	-$66,692	-$57,688	-$49,360	-$41,657	-$34,531	-$27,940	-$21,843	-$16,203	-$15,275	-$15,275	-$15,275	-$15,275	-$15,275	-$15,275	-$15,275
State Income Taxes	-$17,057	-$14,754	-$12,624	-$10,654	-$8,831	-$7,146	-$5,586	-$4,144	-$3,907	-$3,907	-$3,907	-$3,907	-$3,907	-$3,907	-$3,907
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
STATEMENT OF CASH FLOWS															
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Add back Depreciation	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333
Subtract Principal Payment															
AIDEA Component	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Remaining Component	$46,244	$50,117	$54,314	$58,863	$63,793	$69,136	$74,926	$81,201	$88,001	$95,371	$103,359	$112,015	$121,396	$131,563	$142,582
NET CASH FLOW	$107,089	$103,216	$99,019	$94,470	$89,540	$84,198	$78,408	$72,133	$65,332	$57,962	$49,975	$41,318	$31,937	$21,770	$10,752
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	122.35	123.41	124.46	125.76	127.32	129.15	131.92	133.97	136.64	138.61	141.29	143.10	147.30	150.47	152.06
Net Benefit	-$289,475	-$293,349	-$296,540	-$298,815	-$299,413	-$298,332	-$293,690	-$290,200	-$279,013	-$268,012	-$254,867	-$244,802	-$227,970	-$213,240	-$202,001
Annual PV of Net Benefit	-$267,105	-$249,762	-$232,968	-$216,614	-$200,274	-$184,130	-$167,257	-$152,498	-$135,289	-$119,912	-$105,219	-$93,254	-$80,131	-$69,161	-$60,453
Cumulative PV of Net Benefit	-$267,105	-$516,867	-$749,835	-$966,448	-$1,166,723	-$1,350,853	-$1,518,110	-$1,670,608	-$1,805,897	-$1,925,809	-$2,031,028	-$2,124,282	-$2,204,413	-$2,273,573	-$2,334,026
NPV	-$2,875,938														

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*2,623,922*	*2,623,922*	*2,623,922*	*2,623,922*	*2,623,922*	*2,623,922*	*2,623,922*	*2,623,922*	*2,623,922*	*2,623,922*	*2,623,922*	*2,623,922*	*2,623,922*	*2,623,922*	*2,623,922*
Hydro Rate (mills/kWh)	*226.52*	*228.14*	*229.82*	*231.56*	*233.38*	*251.67*	*270.04*	*272.06*	*274.15*	*276.31*	*278.56*	*280.88*	*283.29*	*285.79*	*288.38*
Operating Revenues	$594,368	$598,629	$603,024	$607,608	$612,359	$660,373	$708,567	$713,857	$719,339	$725,022	$730,911	$737,015	$743,342	$749,899	$756,695
OPERATING EXPENSES															
Operating Expense	$117,104	$121,366	$125,760	$130,344	$135,095	$140,019	$145,123	$150,413	$155,895	$161,577	$167,467	$173,571	$179,897	$186,455	$193,251
Maintenance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation Expense	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333
NET OPERATING INCOME	$323,930	$323,930	$323,930	$323,930	$323,930	$367,021	$410,111	$410,111	$410,111	$410,111	$410,111	$410,111	$410,111	$410,111	$410,111
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$18,612	$18,612	$18,612	$18,612	$18,612	$18,612	$18,612	$18,612	$18,612	$18,612	$18,612	$18,612	$18,612	$18,612	$18,612
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Remaining Component	$361,810	$348,869	$334,843	$319,644	$303,171	$285,319	$265,971	$245,003	$222,280	$197,653	$170,963	$142,038	$110,691	$76,719	$39,901
NET INCOME BEFORE TAXES	-$17,993	-$5,051	$8,974	$24,174	$40,646	$101,589	$164,027	$184,995	$207,719	$232,345	$259,035	$287,960	$319,307	$353,279	$390,097
Federal Income Taxes	-$15,275	-$15,275	-$15,275	-$15,275	-$15,275	$19,039	$53,353	$53,353	$53,353	$53,353	$53,353	$53,353	$53,353	$53,353	$53,353
State Income Taxes	-$3,907	-$3,907	-$3,907	-$3,907	-$3,907	$4,869	$13,645	$13,645	$13,645	$13,645	$13,645	$13,645	$13,645	$13,645	$13,645
NET INCOME	$1,190	$14,131	$28,156	$43,356	$59,829	$77,681	$97,028	$117,996	$140,720	$165,347	$192,036	$220,961	$252,308	$286,281	$323,098
STATEMENT OF CASH FLOWS															
NET INCOME	$1,190	$14,131	$28,156	$43,356	$59,829	$77,681	$97,028	$117,996	$140,720	$165,347	$192,036	$220,961	$252,308	$286,281	$323,098
Add back Depreciation	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333
Subtract Principal Payment															
AIDEA Component	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Remaining Component	$154,523	$167,464	$181,489	$196,689	$213,162	$231,014	$250,362	$271,329	$294,053	$318,680	$345,370	$374,294	$405,642	$439,614	$476,432
NET CASH FLOW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	154.56	157.08	159.45	162.69	165.54	168.44	171.41	174.45	177.55	180.72	183.95	187.26	190.65	194.11	197.64
Net Benefit	-$188,808	-$186,471	-$184,629	-$180,722	-$178,003	-$218,389	-$258,790	-$256,118	-$253,466	-$250,835	-$248,229	-$245,650	-$243,100	-$240,582	-$238,099
Annual PV of Net Benefit	-$52,138	-$47,513	-$43,409	-$39,206	-$35,632	-$40,338	-$44,107	-$40,278	-$36,781	-$33,586	-$30,669	-$28,005	-$25,572	-$23,352	-$21,325
Cumulative PV of Net Benefit	-$2,386,164	-$2,433,678	-$2,477,086	-$2,516,293	-$2,551,925	-$2,592,263	-$2,636,370	-$2,676,649	-$2,713,429	-$2,747,016	-$2,777,684	-$2,805,689	-$2,831,261	-$2,854,613	-$2,875,938

Variable	Value	Source
Interest on Construction	4.09%	FERC (4/29/2004 6-month T-Bond & 300 basis points)
Financing Cost	2%	FERC
Debt Service Reserve	1 year	FERC
Operational Reserve	3 months	FERC
Term of Analysis	30 years	FERC
Starting Year	2007	FERC
Grant Value	$0	GEC
Interest on Debt, AIDEA Component	5.43%	GEC
AIDEA Loan Component	$1,000,000	GEC
Interest on Debt, Remainder	8.38%	GEC
Term of Financing, AIDEA Component	30 years	GEC
Term of Financing, Remaining Component	30 years	GEC
2003 O&M (including Staff-recommended environmental enhancements)	$58,600	FERC/GEC
Insurance (% of Initial Investment including granted $)	0.25%	FERC
Interest Rate on Debt Reserve	3.60%	FERC (4/29/2004 5-year T-Bond)
Interest Rate on Operating Reserve	0.85%	FERC (4/29/2004 3-month T-Bond)
Net Cost of Debt	7.848%	Calculated
Operating Reserve Requirement	$150,000	FERC (approx. 3 months operating revenues in last year of operations, rounded up to nearest 25K)
Federal Tax Rate	34%	FERC
State Tax Rate	8%	FERC
Percent Funding by Equity	0.0%	FERC/GEC
Percent Funding by Debt	100.0%	FERC/GEC

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*2,638,116*	*2,698,003*	*2,750,255*	*2,794,232*	*2,839,750*	*2,885,508*	*2,933,538*	*2,980,243*	*3,029,012*	*3,077,506*	*3,124,234*	*3,154,981*	*3,184,999*	*3,212,925*	*3,241,437*
Hydro Rate (mills/kWh)	*213.77*	*212.36*	*211.25*	*210.45*	*209.25*	*207.75*	*205.83*	*203.80*	*199.63*	*195.08*	*190.68*	*187.22*	*183.75*	*180.29*	*176.67*
Operating Revenues	$563,956	$572,958	$580,984	$588,045	$594,227	$599,454	$603,806	$607,382	$604,683	$600,367	$595,720	$590,686	$585,238	$579,247	$572,676
OPERATING EXPENSES															
Operating Expense	$74,435	$76,113	$77,963	$79,961	$82,158	$84,453	$86,909	$89,609	$92,407	$95,272	$98,373	$101,701	$105,277	$109,026	$112,969
Maintenance Expense															
Depreciation Expense	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333
NET OPERATING INCOME	$336,188	$343,512	$349,687	$354,751	$358,736	$361,667	$363,564	$364,440	$358,943	$351,761	$344,013	$335,651	$326,627	$316,888	$306,374
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$17,676	$17,676	$17,676	$17,676	$17,676	$17,676	$17,676	$17,676	$17,676	$17,676	$17,676	$17,676	$17,676	$17,676	$17,676
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$54,300	$53,541	$52,741	$51,898	$51,008	$50,071	$49,083	$48,040	$46,942	$45,783	$44,562	$43,274	$41,917	$40,486	$38,977
Remaining Component	$384,161	$380,996	$377,566	$373,849	$369,820	$365,454	$360,722	$355,594	$350,037	$344,014	$337,487	$330,413	$322,746	$314,438	$305,433
NET INCOME BEFORE TAXES	-$83,323	-$72,074	-$61,669	-$52,045	-$43,142	-$34,907	-$27,290	-$20,243	-$19,085	-$19,085	-$19,085	-$19,085	-$19,085	-$19,085	-$19,085
Federal Income Taxes	-$66,353	-$57,395	-$49,109	-$41,445	-$34,355	-$27,798	-$21,732	-$16,121	-$15,198	-$15,198	-$15,198	-$15,198	-$15,198	-$15,198	-$15,198
State Income Taxes	-$16,970	-$14,679	-$12,560	-$10,600	-$8,787	-$7,109	-$5,558	-$4,123	-$3,887	-$3,887	-$3,887	-$3,887	-$3,887	-$3,887	-$3,887
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
STATEMENT OF CASH FLOWS															
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Add back Depreciation	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333
Subtract Principal Payment															
AIDEA Component	$13,974	$14,733	$15,533	$16,377	$17,266	$18,203	$19,192	$20,234	$21,333	$22,491	$23,712	$25,000	$26,357	$27,789	$29,297
Remaining Component	$37,791	$40,956	$44,386	$48,104	$52,132	$56,498	$61,230	$66,358	$71,916	$77,939	$84,466	$91,540	$99,206	$107,515	$116,519
NET CASH FLOW	$101,568	$97,644	$93,414	$88,853	$83,935	$78,632	$72,911	$66,741	$60,085	$52,904	$45,155	$36,794	$27,770	$18,030	$7,517
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	122.35	124.19	126.03	128.04	130.32	132.89	136.47	139.32	142.85	145.67	149.27	151.96	157.24	161.46	163.99
Net Benefit	-$241,183	-$237,888	-$234,362	-$230,279	-$224,159	-$215,993	-$203,475	-$192,173	-$172,002	-$152,071	-$129,364	-$111,242	-$84,415	-$60,492	-$41,099
Annual PV of Net Benefit	-$223,633	-$204,526	-$186,833	-$170,219	-$153,638	-$137,268	-$119,903	-$105,003	-$87,142	-$71,438	-$56,349	-$44,929	-$31,613	-$21,006	-$13,233
Cumulative PV of Net Benefit	-$223,633	-$428,159	-$614,992	-$785,211	-$938,848	-$1,076,117	-$1,196,020	-$1,301,022	-$1,388,164	-$1,459,603	-$1,515,952	-$1,560,881	-$1,592,494	-$1,613,499	-$1,626,733
NPV	-$1,620,532														

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*3,270,548*	*3,300,271*	*3,330,618*	*3,361,602*	*3,392,316*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*
Hydro Rate (mills/kWh)	*174.07*	*173.79*	*173.53*	*173.29*	*173.12*	*187.01*	*201.14*	*202.69*	*204.31*	*205.98*	*207.72*	*209.51*	*211.38*	*213.31*	*215.31*
Operating Revenues	$569,295	$573,556	$577,951	$582,535	$587,286	$635,082	$683,057	$688,346	$693,829	$699,511	$705,401	$711,505	$717,831	$724,389	$731,185
OPERATING EXPENSES															
Operating Expense	$117,104	$121,366	$125,760	$130,344	$135,095	$140,019	$145,123	$150,413	$155,895	$161,577	$167,467	$173,571	$179,897	$186,455	$193,251
Maintenance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation Expense	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333
NET OPERATING INCOME	$298,858	$298,858	$298,858	$298,858	$298,858	$341,729	$384,601	$384,601	$384,601	$384,601	$384,601	$384,601	$384,601	$384,601	$384,601
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$17,676	$17,676	$17,676	$17,676	$17,676	$17,676	$17,676	$17,676	$17,676	$17,676	$17,676	$17,676	$17,676	$17,676	$17,676
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$37,386	$35,709	$33,940	$32,076	$30,111	$28,038	$25,853	$23,550	$21,121	$18,561	$15,862	$13,016	$10,015	$6,852	$3,516
Remaining Component	$295,675	$285,099	$273,637	$261,216	$247,754	$233,165	$217,354	$200,219	$181,649	$161,524	$139,713	$116,075	$90,458	$62,695	$32,608
NET INCOME BEFORE TAXES	-$15,252	-$2,999	$10,231	$24,516	$39,944	$99,477	$160,344	$179,782	$200,781	$223,467	$247,977	$274,461	$303,078	$334,005	$367,428
Federal Income Taxes	-$15,198	-$15,198	-$15,198	-$15,198	-$15,198	$18,942	$53,082	$53,082	$53,082	$53,082	$53,082	$53,082	$53,082	$53,082	$53,082
State Income Taxes	-$3,887	-$3,887	-$3,887	-$3,887	-$3,887	$4,845	$13,576	$13,576	$13,576	$13,576	$13,576	$13,576	$13,576	$13,576	$13,576
NET INCOME	$3,833	$16,086	$29,316	$43,601	$59,028	$75,690	$93,686	$113,124	$134,123	$156,809	$181,319	$207,803	$236,420	$267,346	$300,769
STATEMENT OF CASH FLOWS															
NET INCOME	$3,833	$16,086	$29,316	$43,601	$59,028	$75,690	$93,686	$113,124	$134,123	$156,809	$181,319	$207,803	$236,420	$267,346	$300,769
Add back Depreciation	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333
Subtract Principal Payment															
AIDEA Component	$30,888	$32,566	$34,334	$36,198	$38,164	$40,236	$42,421	$44,724	$47,153	$49,713	$52,413	$55,259	$58,259	$61,423	$64,758
Remaining Component	$126,278	$136,854	$148,315	$160,736	$174,198	$188,787	$204,598	$221,733	$240,303	$260,429	$282,240	$305,877	$331,494	$359,257	$389,345
NET CASH FLOW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	167.55	171.14	174.60	179.04	183.08	187.22	191.45	195.79	200.23	204.79	209.45	214.22	219.12	224.13	229.27
Net Benefit	-$21,322	-$8,757	$3,581	$19,341	$33,788	$710	-$32,882	-$23,440	-$13,834	-$4,060	$5,883	$15,998	$26,288	$36,756	$47,403
Annual PV of Net Benefit	-$6,366	-$2,424	$919	$4,603	$7,456	$145	-$6,239	-$4,124	-$2,257	-$614	$825	$2,080	$3,170	$4,109	$4,914
Cumulative PV of Net Benefit	-$1,633,098	-$1,635,522	-$1,634,603	-$1,630,000	-$1,622,544	-$1,622,398	-$1,628,637	-$1,632,761	-$1,635,017	-$1,635,631	-$1,634,806	-$1,632,726	-$1,629,556	-$1,625,447	-$1,620,532

Variable	Value	Source
Interest on Construction	4.09%	FERC (4/29/2004 6-month T-Bond & 300 basis points)
Financing Cost	2%	FERC
Debt Service Reserve	1 year	FERC
Operational Reserve	3 months	FERC
Term of Analysis	30 years	FERC
Starting Year	2007	FERC
Grant Value	$1,083,685	GEC
Interest on Debt, AIDEA Component	5.43%	GEC
AIDEA Loan Component	$1,000,000	GEC
Interest on Debt, Remainder	5.50%	GEC
Term of Financing, AIDEA Component	30 years	GEC
Term of Financing, Remaining Component	30 years	GEC
2003 O&M (including Staff-recommended environmental enhancements)	$58,600	FERC/GEC
Insurance (% of Initial Investment including granted $)	0.25%	FERC
Interest Rate on Debt Reserve	3.60%	FERC (4/29/2004 5-year T-Bond)
Interest Rate on Operating Reserve	0.85%	FERC (4/29/2004 3-month T-Bond)
Net Cost of Debt	5.483%	Calculated
Operating Reserve Requirement	$150,000	FERC (approx. 3 months operating revenues in last year of operations, rounded up to nearest 25K)
Federal Tax Rate	34%	FERC
State Tax Rate	8%	FERC
Percent Funding by Equity	0.0%	FERC/GEC
Percent Funding by Debt	100.0%	FERC/GEC

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*2,678,150*	*2,750,140*	*2,815,350*	*2,872,730*	*2,932,460*	*2,992,930*	*3,056,710*	*3,119,420*	*3,185,330*	*3,251,530*	*3,316,169*	*3,361,455*	*3,396,000*	*3,396,000*	*3,396,000*
Hydro Rate (mills/kWh)	*129.69*	*128.79*	*128.01*	*127.41*	*126.54*	*125.48*	*124.16*	*122.80*	*119.95*	*116.89*	*114.00*	*111.83*	*110.06*	*109.39*	*110.49*
Operating Revenues	$347,332	$354,184	$360,407	$366,013	$371,087	$375,559	$379,516	$383,064	$382,095	$380,080	$378,032	$375,928	$373,775	$371,481	$375,216
OPERATING EXPENSES															
Operating Expense	$74,435	$76,113	$77,963	$79,961	$82,158	$84,453	$86,909	$89,609	$92,407	$95,272	$98,373	$101,701	$105,277	$109,026	$112,969
Maintenance Expense															
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$156,431	$161,605	$165,977	$169,585	$172,463	$174,639	$176,140	$176,989	$173,222	$168,341	$163,192	$157,760	$152,031	$145,987	$145,780
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$54,300	$53,541	$52,741	$51,898	$51,008	$50,071	$49,083	$48,040	$46,942	$45,783	$44,562	$43,274	$41,917	$40,486	$38,977
Remaining Component	$175,725	$173,299	$170,740	$168,040	$165,191	$162,186	$159,015	$155,670	$152,141	$148,418	$144,490	$140,346	$135,974	$131,362	$126,496
NET INCOME BEFORE TAXES	-$61,915	-$53,557	-$45,825	-$38,673	-$32,058	-$25,939	-$20,278	-$15,042	-$14,181	-$14,181	-$14,181	-$14,181	-$14,181	-$14,181	-$8,014
Federal Income Taxes	-$49,305	-$42,649	-$36,492	-$30,797	-$25,529	-$20,656	-$16,148	-$11,979	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293
State Income Taxes	-$12,610	-$10,908	-$9,333	-$7,876	-$6,529	-$5,283	-$4,130	-$3,064	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,168
STATEMENT OF CASH FLOWS															
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,168
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$13,974	$14,733	$15,533	$16,377	$17,266	$18,203	$19,192	$20,234	$21,333	$22,491	$23,712	$25,000	$26,357	$27,789	$29,297
Remaining Component	$44,108	$46,534	$49,094	$51,794	$54,642	$57,648	$60,818	$64,163	$67,692	$71,415	$75,343	$79,487	$83,859	$88,471	$93,337
NET CASH FLOW	$58,384	$55,199	$51,840	$48,296	$44,558	$40,616	$36,457	$32,069	$27,442	$22,560	$17,411	$11,980	$6,250	$207	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	122.35	125.09	128.05	131.37	135.25	139.57	145.17	150.38	156.47	161.89	168.54	174.50	183.88	192.33	199.05
Net Benefit	-$19,661	-$10,181	$99	$11,391	$25,538	$42,159	$64,239	$86,040	$116,313	$146,312	$180,880	$210,651	$250,678	$281,675	$300,766
Annual PV of Net Benefit	-$18,639	-$9,150	$84	$9,201	$19,555	$30,605	$44,209	$56,135	$71,941	$85,791	$100,547	$111,009	$125,235	$133,406	$135,043
Cumulative PV of Net Benefit	-$18,639	-$27,790	-$27,705	-$18,504	$1,051	$31,656	$75,865	$132,000	$203,941	$289,732	$390,279	$501,288	$626,524	$759,930	$894,973
NPV	$3,056,581														

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*
Hydro Rate (mills/kWh)	*111.71*	*112.96*	*114.25*	*115.60*	*117.00*	*127.83*	*138.72*	*140.27*	*141.89*	*143.56*	*145.30*	*147.09*	*148.96*	*150.89*	*152.89*
Operating Revenues	$379,351	$383,613	$388,007	$392,591	$397,342	$434,123	$471,083	$476,373	$481,856	$487,538	$493,427	$499,531	$505,858	$512,415	$519,211
OPERATING EXPENSES															
Operating Expense	$117,104	$121,366	$125,760	$130,344	$135,095	$140,019	$145,123	$150,413	$155,895	$161,577	$167,467	$173,571	$179,897	$186,455	$193,251
Maintenance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$145,780	$145,780	$145,780	$145,780	$145,780	$177,637	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$37,386	$35,709	$33,940	$32,076	$30,111	$28,038	$25,853	$23,550	$21,121	$18,561	$15,862	$13,016	$10,015	$6,852	$3,516
Remaining Component	$121,363	$115,947	$110,233	$104,205	$97,845	$91,136	$84,058	$76,590	$68,712	$60,400	$51,631	$42,380	$32,620	$22,324	$11,460
NET INCOME BEFORE TAXES	-$1,289	$5,804	$13,286	$21,178	$29,503	$70,142	$111,262	$121,033	$131,340	$142,212	$153,680	$165,777	$178,538	$191,998	$206,196
Federal Income Taxes	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	$14,075	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444
State Income Taxes	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	$3,600	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088
NET INCOME	$12,892	$19,985	$27,467	$35,360	$43,685	$52,466	$61,730	$71,501	$81,808	$92,680	$104,148	$116,245	$129,006	$142,466	$156,664
STATEMENT OF CASH FLOWS															
NET INCOME	$12,892	$19,985	$27,467	$35,360	$43,685	$52,466	$61,730	$71,501	$81,808	$92,680	$104,148	$116,245	$129,006	$142,466	$156,664
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$30,888	$32,566	$34,334	$36,198	$38,164	$40,236	$42,421	$44,724	$47,153	$49,713	$52,413	$55,259	$58,259	$61,423	$64,758
Remaining Component	$98,471	$103,886	$109,600	$115,628	$121,988	$128,697	$135,775	$143,243	$151,121	$159,433	$168,202	$177,453	$187,213	$197,510	$208,373
NET CASH FLOW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	207.31	215.81	224.36	234.51	244.81	255.56	266.79	278.51	290.75	303.53	316.87	330.80	345.34	360.52	376.37
Net Benefit	$324,678	$349,293	$373,919	$403,789	$434,024	$433,769	$434,942	$469,463	$505,544	$543,255	$582,668	$623,860	$666,912	$711,907	$758,933
Annual PV of Net Benefit	$138,202	$140,950	$143,044	$146,441	$149,224	$141,384	$134,397	$137,523	$140,394	$143,024	$145,426	$147,613	$149,597	$151,389	$153,000
Cumulative PV of Net Benefit	$1,033,175	$1,174,125	$1,317,169	$1,463,610	$1,612,834	$1,754,218	$1,888,615	$2,026,138	$2,166,532	$2,309,556	$2,454,982	$2,602,595	$2,752,193	$2,903,582	$3,056,581

Variable	Value	Source
Interest on Construction	4.09%	FERC (4/29/2004 6-month T-Bond & 300 basis points)
Financing Cost	2%	FERC
Debt Service Reserve	1 year	FERC
Operational Reserve	3 months	FERC
Term of Analysis	30 years	FERC
Starting Year	2007	FERC
Grant Value	$1,083,685	GEC
Interest on Debt, AIDEA Component	5.43%	GEC
AIDEA Loan Component	$1,000,000	GEC
Interest on Debt, Remainder	5.13%	GEC
Term of Financing, AIDEA Component	30 years	GEC
Term of Financing, Remaining Component	30 years	GEC
2003 O&M (including Staff-recommended environmental enhancements)	$58,600	FERC/GEC
Insurance (% of Initial Investment including granted $)	0.25%	FERC
Interest Rate on Debt Reserve	3.60%	FERC (4/29/2004 5-year T-Bond)
Interest Rate on Operating Reserve	0.85%	FERC (4/29/2004 3-month T-Bond)
Net Cost of Debt	5.202%	Calculated
Operating Reserve Requirement	$150,000	FERC (approx. 3 months operating revenues in last year of operations, rounded up to nearest 25K)
Federal Tax Rate	34%	FERC
State Tax Rate	8%	FERC
Percent Funding by Equity	0.0%	FERC/GEC
Percent Funding by Debt	100.0%	FERC/GEC

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*2,680,519*	*2,754,264*	*2,827,942*	*2,900,462*	*2,976,488*	*3,054,478*	*3,137,072*	*3,220,189*	*3,286,583*	*3,344,506*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*
Hydro Rate (mills/kWh)	*125.17*	*124.31*	*123.27*	*122.13*	*120.73*	*119.13*	*117.27*	*115.37*	*112.78*	*110.27*	*108.04*	*107.47*	*106.90*	*106.63*	*107.79*
Operating Revenues	$335,522	$342,372	$348,606	$354,235	$359,346	$363,870	$367,893	$371,526	$370,671	$368,790	$366,897	$364,971	$363,021	$362,107	$366,049
OPERATING EXPENSES															
Operating Expense	$74,435	$76,113	$77,963	$79,961	$82,158	$84,453	$86,909	$89,609	$92,407	$95,272	$98,373	$101,701	$105,277	$109,026	$112,969
Maintenance Expense															
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$144,620	$149,793	$154,176	$157,807	$160,722	$162,949	$164,518	$165,451	$161,798	$157,051	$152,057	$146,803	$141,276	$136,614	$136,614
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$54,300	$53,541	$52,741	$51,898	$51,008	$50,071	$49,083	$48,040	$46,942	$45,783	$44,562	$43,274	$41,917	$40,486	$38,977
Remaining Component	$163,391	$160,986	$158,457	$155,799	$153,005	$150,067	$146,979	$143,732	$140,319	$136,731	$132,958	$128,992	$124,822	$120,439	$115,831
NET INCOME BEFORE TAXES	-$61,751	-$53,415	-$45,704	-$38,571	-$31,973	-$25,870	-$20,225	-$15,003	-$14,144	-$14,144	-$14,144	-$14,144	-$14,144	-$12,992	-$6,875
Federal Income Taxes	-$49,175	-$42,536	-$36,395	-$30,715	-$25,461	-$20,601	-$16,106	-$11,947	-$11,263	-$11,263	-$11,263	-$11,263	-$11,263	-$11,263	-$11,263
State Income Taxes	-$12,577	-$10,879	-$9,308	-$7,856	-$6,512	-$5,269	-$4,119	-$3,056	-$2,881	-$2,881	-$2,881	-$2,881	-$2,881	-$2,881	-$2,881
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,152	$7,269
STATEMENT OF CASH FLOWS															
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,152	$7,269
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$13,974	$14,733	$15,533	$16,377	$17,266	$18,203	$19,192	$20,234	$21,333	$22,491	$23,712	$25,000	$26,357	$27,789	$29,297
Remaining Component	$46,879	$49,284	$51,812	$54,470	$57,264	$60,202	$63,290	$66,537	$69,950	$73,539	$77,311	$81,277	$85,447	$89,830	$94,439
NET CASH FLOW	$55,614	$52,450	$49,122	$45,620	$41,937	$38,062	$33,985	$29,696	$25,184	$20,437	$15,443	$10,190	$4,663	$0	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	122.35	125.90	129.53	133.40	137.65	142.30	148.14	153.31	159.35	164.72	171.11	176.57	185.22	192.78	235.19
Net Benefit	-$7,561	$4,403	$17,703	$32,700	$50,360	$70,772	$96,818	$122,154	$153,035	$182,123	$214,188	$234,650	$265,985	$292,586	$432,671
Annual PV of Net Benefit	-$7,187	$3,978	$15,205	$26,697	$39,082	$52,207	$67,889	$81,419	$96,958	$109,683	$122,616	$127,688	$137,582	$143,859	$202,217
Cumulative PV of Net Benefit	-$7,187	-$3,209	$11,996	$38,693	$77,774	$129,981	$197,869	$279,289	$376,247	$485,930	$608,545	$736,233	$873,815	$1,017,674	$1,219,891
NPV	$3,926,576														

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*
Hydro Rate (mills/kWh)	*109.01*	*110.26*	*111.55*	*112.90*	*114.30*	*125.11*	*135.97*	*137.53*	*139.14*	*140.81*	*142.55*	*144.35*	*146.21*	*148.14*	*150.14*
Operating Revenues	$370,185	$374,446	$378,841	$383,425	$388,176	$424,872	$461,749	$467,038	$472,521	$478,203	$484,092	$490,197	$496,523	$503,080	$509,877
OPERATING EXPENSES															
Operating Expense	$117,104	$121,366	$125,760	$130,344	$135,095	$140,019	$145,123	$150,413	$155,895	$161,577	$167,467	$173,571	$179,897	$186,455	$193,251
Maintenance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$136,614	$136,614	$136,614	$136,614	$136,614	$168,386	$200,159	$200,159	$200,159	$200,159	$200,159	$200,159	$200,159	$200,159	$200,159
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$37,386	$35,709	$33,940	$32,076	$30,111	$28,038	$25,853	$23,550	$21,121	$18,561	$15,862	$13,016	$10,015	$6,852	$3,516
Remaining Component	$110,986	$105,893	$100,538	$94,909	$88,991	$82,770	$76,229	$69,353	$62,124	$54,524	$46,534	$38,134	$29,304	$20,020	$10,260
NET INCOME BEFORE TAXES	-$439	$6,331	$13,454	$20,948	$28,831	$68,898	$109,396	$118,575	$128,233	$138,393	$149,082	$160,328	$172,159	$184,606	$197,701
Federal Income Taxes	-$11,263	-$11,263	-$11,263	-$11,263	-$11,263	$14,038	$39,340	$39,340	$39,340	$39,340	$39,340	$39,340	$39,340	$39,340	$39,340
State Income Taxes	-$2,881	-$2,881	-$2,881	-$2,881	-$2,881	$3,590	$10,061	$10,061	$10,061	$10,061	$10,061	$10,061	$10,061	$10,061	$10,061
NET INCOME	$13,705	$20,475	$27,598	$35,092	$42,975	$51,269	$59,995	$69,174	$78,832	$88,992	$99,681	$110,927	$122,758	$135,205	$148,300
STATEMENT OF CASH FLOWS															
NET INCOME	$13,705	$20,475	$27,598	$35,092	$42,975	$51,269	$59,995	$69,174	$78,832	$88,992	$99,681	$110,927	$122,758	$135,205	$148,300
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$30,888	$32,566	$34,334	$36,198	$38,164	$40,236	$42,421	$44,724	$47,153	$49,713	$52,413	$55,259	$58,259	$61,423	$64,758
Remaining Component	$99,283	$104,376	$109,731	$115,360	$121,278	$127,500	$134,040	$140,917	$148,146	$155,746	$163,735	$172,135	$180,965	$190,249	$200,009
NET CASH FLOW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	242.24	249.47	256.69	265.34	273.62	282.20	291.09	300.31	309.86	319.75	330.01	340.63	351.64	363.05	374.87
Net Benefit	$452,447	$472,752	$492,887	$517,668	$541,040	$533,486	$526,809	$552,812	$579,758	$607,678	$636,609	$666,588	$697,652	$729,841	$763,195
Annual PV of Net Benefit	$201,004	$199,640	$197,851	$197,524	$196,235	$183,927	$172,645	$172,209	$171,673	$171,043	$170,327	$169,529	$168,657	$167,714	$166,707
Cumulative PV of Net Benefit	$1,420,894	$1,620,535	$1,818,386	$2,015,910	$2,212,144	$2,396,072	$2,568,717	$2,740,926	$2,912,599	$3,083,642	$3,253,969	$3,423,498	$3,592,155	$3,759,869	$3,926,576

Variable	Value	Source
Interest on Construction	4.09%	FERC (4/29/2004 6-month T-Bond & 300 basis points)
Financing Cost	2%	FERC
Debt Service Reserve	1 year	FERC
Operational Reserve	3 months	FERC
Term of Analysis	30 years	FERC
Starting Year	2007	FERC
Grant Value	$1,083,685	GEC
Interest on Debt, AIDEA Component	5.43%	GEC
AIDEA Loan Component	$0	GEC
Interest on Debt, Remainder	5.13%	GEC
Term of Financing, AIDEA Component	30 years	GEC
Term of Financing, Remaining Component	30 years	GEC
2003 O&M (including Staff-recommended environmental enhancements)	$58,600	FERC/GEC
Insurance (% of Initial Investment including granted $)	0.25%	FERC
Interest Rate on Debt Reserve	3.60%	FERC (4/29/2004 5-year T-Bond)
Interest Rate on Operating Reserve	0.85%	FERC (4/29/2004 3-month T-Bond)
Net Cost of Debt	5.130%	Calculated
Operating Reserve Requirement	$150,000	FERC (approx. 3 months operating revenues in last year of operations, rounded up to nearest 25K)
Federal Tax Rate	34%	FERC
State Tax Rate	8%	FERC
Percent Funding by Equity	0.0%	FERC/GEC
Percent Funding by Debt	100.0%	FERC/GEC

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*2,730,814*	*2,819,593*	*2,909,737*	*2,999,819*	*3,059,864*	*3,113,816*	*3,172,937*	*3,226,930*	*3,286,583*	*3,344,506*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*
Hydro Rate (mills/kWh)	*97.13*	*96.00*	*94.76*	*93.46*	*93.03*	*92.67*	*92.08*	*91.58*	*89.94*	*88.20*	*86.69*	*86.53*	*86.38*	*86.91*	*88.07*
Operating Revenues	$265,247	$270,690	$275,727	$280,360	$284,667	$288,570	$292,150	$295,510	$295,607	$294,971	$294,390	$293,848	$293,356	$295,152	$299,094
OPERATING EXPENSES															
Operating Expense	$74,435	$76,113	$77,963	$79,961	$82,158	$84,453	$86,909	$89,609	$92,407	$95,272	$98,373	$101,701	$105,277	$109,026	$112,969
Maintenance Expense															
Depreciation Expense	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333
NET OPERATING INCOME	$105,479	$109,244	$112,430	$115,065	$117,176	$118,783	$119,908	$120,568	$117,867	$114,365	$110,684	$106,813	$102,745	$100,792	$100,792
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$7,416	$7,416	$7,416	$7,416	$7,416	$7,416	$7,416	$7,416	$7,416	$7,416	$7,416	$7,416	$7,416	$7,416	$7,416
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Remaining Component	$159,440	$157,094	$154,627	$152,033	$149,306	$146,439	$143,426	$140,257	$136,927	$133,425	$129,744	$125,873	$121,805	$117,527	$113,030
NET INCOME BEFORE TAXES	-$45,270	-$39,159	-$33,506	-$28,276	-$23,440	-$18,965	-$14,827	-$10,999	-$10,369	-$10,369	-$10,369	-$10,369	-$10,369	-$8,044	-$3,547
Federal Income Taxes	-$36,050	-$31,183	-$26,682	-$22,518	-$18,666	-$15,103	-$11,807	-$8,758	-$8,257	-$8,257	-$8,257	-$8,257	-$8,257	-$8,257	-$8,257
State Income Taxes	-$9,220	-$7,975	-$6,824	-$5,759	-$4,774	-$3,863	-$3,020	-$2,240	-$2,112	-$2,112	-$2,112	-$2,112	-$2,112	-$2,112	-$2,112
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,325	$6,822
STATEMENT OF CASH FLOWS															
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,325	$6,822
Add back Depreciation	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333
Subtract Principal Payment															
AIDEA Component	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Remaining Component	$45,745	$48,092	$50,559	$53,153	$55,880	$58,746	$61,760	$64,928	$68,259	$71,761	$75,442	$79,312	$83,381	$87,658	$92,155
NET CASH FLOW	$39,588	$37,241	$34,774	$32,180	$29,454	$26,587	$23,573	$20,405	$17,074	$13,573	$9,891	$6,021	$1,952	$0	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	122.35	126.97	131.73	136.82	142.37	148.43	155.84	162.65	170.50	208.75	217.23	224.81	236.06	246.27	254.49
Net Benefit	$68,867	$87,309	$107,579	$130,077	$150,966	$173,612	$202,307	$229,356	$264,767	$403,203	$443,314	$469,607	$508,312	$541,191	$565,146
Annual PV of Net Benefit	$65,507	$78,996	$92,586	$106,487	$117,556	$128,593	$142,536	$153,708	$168,781	$244,488	$255,693	$257,641	$265,267	$268,644	$266,846
Cumulative PV of Net Benefit	$65,507	$144,503	$237,089	$343,576	$461,132	$589,725	$732,261	$885,969	$1,054,750	$1,299,238	$1,554,931	$1,812,571	$2,077,838	$2,346,482	$2,613,329
NPV	$6,649,959														

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*
Hydro Rate (mills/kWh)	*89.29*	*90.55*	*91.84*	*93.19*	*94.59*	*102.90*	*111.26*	*112.82*	*114.43*	*116.10*	*117.84*	*119.64*	*121.50*	*123.43*	*125.43*
Operating Revenues	$303,230	$307,491	$311,886	$316,470	$321,221	$349,438	$377,834	$383,123	$388,606	$394,288	$400,178	$406,282	$412,608	$419,166	$425,962
OPERATING EXPENSES															
Operating Expense	$117,104	$121,366	$125,760	$130,344	$135,095	$140,019	$145,123	$150,413	$155,895	$161,577	$167,467	$173,571	$179,897	$186,455	$193,251
Maintenance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation Expense	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333
NET OPERATING INCOME	$100,792	$100,792	$100,792	$100,792	$100,792	$124,085	$147,378	$147,378	$147,378	$147,378	$147,378	$147,378	$147,378	$147,378	$147,378
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$7,416	$7,416	$7,416	$7,416	$7,416	$7,416	$7,416	$7,416	$7,416	$7,416	$7,416	$7,416	$7,416	$7,416	$7,416
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Remaining Component	$108,303	$103,333	$98,108	$92,615	$86,840	$80,769	$74,386	$67,676	$60,622	$53,205	$45,409	$37,212	$28,595	$19,536	$10,012
NET INCOME BEFORE TAXES	$1,181	$6,151	$11,376	$16,869	$22,644	$52,008	$81,683	$88,393	$95,447	$102,863	$110,660	$118,856	$127,473	$136,532	$146,056
Federal Income Taxes	-$8,257	-$8,257	-$8,257	-$8,257	-$8,257	$10,291	$28,840	$28,840	$28,840	$28,840	$28,840	$28,840	$28,840	$28,840	$28,840
State Income Taxes	-$2,112	-$2,112	-$2,112	-$2,112	-$2,112	$2,632	$7,376	$7,376	$7,376	$7,376	$7,376	$7,376	$7,376	$7,376	$7,376
NET INCOME	$11,550	$16,520	$21,745	$27,238	$33,013	$39,084	$45,467	$52,177	$59,231	$66,647	$74,444	$82,640	$91,257	$100,316	$109,840
STATEMENT OF CASH FLOWS															
NET INCOME	$11,550	$16,520	$21,745	$27,238	$33,013	$39,084	$45,467	$52,177	$59,231	$66,647	$74,444	$82,640	$91,257	$100,316	$109,840
Add back Depreciation	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333
Subtract Principal Payment															
AIDEA Component	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Remaining Component	$96,883	$101,853	$107,078	$112,571	$118,346	$124,417	$130,800	$137,510	$144,564	$151,980	$159,777	$167,973	$176,590	$185,650	$195,173
NET CASH FLOW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	264.40	274.69	285.12	297.39	322.45	335.01	348.13	361.85	376.20	391.18	406.85	423.23	440.34	458.23	481.34
Net Benefit	$594,673	$625,351	$656,389	$693,468	$773,806	$788,242	$804,427	$845,733	$888,954	$934,176	$981,492	$1,031,000	$1,082,799	$1,136,997	$1,208,673
Annual PV of Net Benefit	$267,086	$267,160	$266,736	$268,053	$284,511	$275,676	$267,609	$267,621	$267,571	$267,462	$267,297	$267,078	$266,810	$266,493	$269,469
Cumulative PV of Net Benefit	$2,880,415	$3,147,574	$3,414,310	$3,682,363	$3,966,873	$4,242,550	$4,510,158	$4,777,779	$5,045,350	$5,312,812	$5,580,109	$5,847,187	$6,113,997	$6,380,490	$6,649,959

INCOME STATEMENT AND BACKGROUND

LOW ESTIMATE FOR LOAD GROWTH
MIDDLE-LOW ESTIMATE FOR LOAD GROWTH
MIDDLE-HIGH ESTIMATE FOR LOAD GROWTH
HIGH ESTIMATE FOR LOAD GROWTH

Variable	Value	Source
Interest on Construction	4.09%	FERC (4/29/2004 6-month T-Bond & 300 basis points)
Financing Cost	2%	FERC
Debt Service Reserve	1 year	FERC
Operational Reserve	3 months	FERC
Term of Analysis	30 years	FERC
Starting Year	2007	FERC
Grant Value	$1,083,685	GEC
Interest on Debt, AIDEA Component	5.43%	GEC
AIDEA Loan Component	$1,000,000	GEC
Interest on Debt, Remainder	5.50%	GEC
Term of Financing, AIDEA Component	30 years	GEC
Term of Financing, Remaining Component	30 years	GEC
2003 O&M (including Staff-recommended environmental enhancements)	$58,600	FERC/GEC
Insurance (% of Initial Investment including granted $)	0.25%	FERC
Interest Rate on Debt Reserve	3.60%	FERC (4/29/2004 5-year T-Bond)
Interest Rate on Operating Reserve	0.85%	FERC (4/29/2004 3-month T-Bond)
Net Cost of Debt	5.483%	Calculated
Operating Reserve Requirement	$150,000	FERC (approx. 3 months operating revenues in last year of operations, rounded up to nearest 25K)
Federal Tax Rate	34%	FERC
State Tax Rate	8%	FERC
Percent Funding by Equity	0.0%	FERC/GEC
Percent Funding by Debt	100.0%	FERC/GEC

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*1,601,307*	*1,617,372*	*1,632,586*	*1,644,091*	*1,653,845*	*1,664,227*	*1,671,653*	*1,678,987*	*1,685,834*	*1,692,917*	*1,699,893*	*1,706,869*	*1,712,705*	*1,713,000*	*1,713,000*
Hydro Rate (mills/kWh)	*216.91*	*218.99*	*220.76*	*222.62*	*224.38*	*225.67*	*227.03*	*228.15*	*226.65*	*224.51*	*222.39*	*220.24*	*218.24*	*216.86*	*219.04*
Operating Revenues	$347,332	$354,184	$360,407	$366,013	$371,087	$375,559	$379,516	$383,064	$382,095	$380,080	$378,032	$375,928	$373,775	$371,481	$375,216
OPERATING EXPENSES															
Operating Expense	$74,435	$76,113	$77,963	$79,961	$82,158	$84,453	$86,909	$89,609	$92,407	$95,272	$98,373	$101,701	$105,277	$109,026	$112,969
Maintenance Expense															
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$156,431	$161,605	$165,977	$169,585	$172,463	$174,639	$176,140	$176,989	$173,222	$168,341	$163,192	$157,760	$152,031	$145,987	$145,780
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$54,300	$53,541	$52,741	$51,898	$51,008	$50,071	$49,083	$48,040	$46,942	$45,783	$44,562	$43,274	$41,917	$40,486	$38,977
Remaining Component	$175,725	$173,299	$170,740	$168,040	$165,191	$162,186	$159,015	$155,670	$152,141	$148,418	$144,490	$140,346	$135,974	$131,362	$126,496
NET INCOME BEFORE TAXES	-$61,915	-$53,557	-$45,825	-$38,673	-$32,058	-$25,939	-$20,278	-$15,042	-$14,181	-$14,181	-$14,181	-$14,181	-$14,181	-$14,181	-$8,014
Federal Income Taxes	-$49,305	-$42,649	-$36,492	-$30,797	-$25,529	-$20,656	-$16,148	-$11,979	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293
State Income Taxes	-$12,610	-$10,908	-$9,333	-$7,876	-$6,529	-$5,283	-$4,130	-$3,064	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,168
STATEMENT OF CASH FLOWS															
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,168
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$13,974	$14,733	$15,533	$16,377	$17,266	$18,203	$19,192	$20,234	$21,333	$22,491	$23,712	$25,000	$26,357	$27,789	$29,297
Remaining Component	$44,108	$46,534	$49,094	$51,794	$54,642	$57,648	$60,818	$64,163	$67,692	$71,415	$75,343	$79,487	$83,859	$88,471	$93,337
NET CASH FLOW	$58,384	$55,199	$51,840	$48,296	$44,558	$40,616	$36,457	$32,069	$27,442	$22,560	$17,411	$11,980	$6,250	$207	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	122.35	125.09	128.05	131.37	135.25	139.57	145.17	150.38	156.47	161.89	168.54	174.50	183.88	192.33	199.05
Net Benefit	-$151,413	-$151,874	-$151,354	-$150,021	-$147,399	-$143,286	-$136,835	-$130,575	-$118,313	-$106,013	-$91,529	-$78,077	-$58,845	-$42,018	-$34,239
Annual PV of Net Benefit	-$143,542	-$136,495	-$128,956	-$121,176	-$112,869	-$104,016	-$94,170	-$85,190	-$73,178	-$62,161	-$50,879	-$41,145	-$29,398	-$19,900	-$15,373
Cumulative PV of Net Benefit	-$143,542	-$280,037	-$408,993	-$530,169	-$643,039	-$747,055	-$841,224	-$926,414	-$999,592	-$1,061,753	-$1,112,632	-$1,153,777	-$1,183,175	-$1,203,076	-$1,218,449
NPV	-$1,119,728														

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*1,713,000*	*1,713,000*	*1,713,000*	*1,713,000*	*1,713,000*	*1,713,000*	*1,713,000*	*1,713,000*	*1,713,000*	*1,713,000*	*1,713,000*	*1,713,000*	*1,713,000*	*1,713,000*	*1,713,000*
Hydro Rate (mills/kWh)	*221.45*	*223.94*	*226.51*	*229.18*	*231.96*	*253.43*	*275.00*	*278.09*	*281.29*	*284.61*	*288.05*	*291.61*	*295.31*	*299.13*	*303.10*
Operating Revenues	$379,351	$383,613	$388,007	$392,591	$397,342	$434,123	$471,083	$476,373	$481,856	$487,538	$493,427	$499,531	$505,858	$512,415	$519,211
OPERATING EXPENSES															
Operating Expense	$117,104	$121,366	$125,760	$130,344	$135,095	$140,019	$145,123	$150,413	$155,895	$161,577	$167,467	$173,571	$179,897	$186,455	$193,251
Maintenance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$145,780	$145,780	$145,780	$145,780	$145,780	$177,637	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$37,386	$35,709	$33,940	$32,076	$30,111	$28,038	$25,853	$23,550	$21,121	$18,561	$15,862	$13,016	$10,015	$6,852	$3,516
Remaining Component	$121,363	$115,947	$110,233	$104,205	$97,845	$91,136	$84,058	$76,590	$68,712	$60,400	$51,631	$42,380	$32,620	$22,324	$11,460
NET INCOME BEFORE TAXES	-$1,289	$5,804	$13,286	$21,178	$29,503	$70,142	$111,262	$121,033	$131,340	$142,212	$153,680	$165,777	$178,538	$191,998	$206,196
Federal Income Taxes	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	$14,075	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444
State Income Taxes	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	$3,600	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088
NET INCOME	$12,892	$19,985	$27,467	$35,360	$43,685	$52,466	$61,730	$71,501	$81,808	$92,680	$104,148	$116,245	$129,006	$142,466	$156,664
STATEMENT OF CASH FLOWS															
NET INCOME	$12,892	$19,985	$27,467	$35,360	$43,685	$52,466	$61,730	$71,501	$81,808	$92,680	$104,148	$116,245	$129,006	$142,466	$156,664
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$30,888	$32,566	$34,334	$36,198	$38,164	$40,236	$42,421	$44,724	$47,153	$49,713	$52,413	$55,259	$58,259	$61,423	$64,758
Remaining Component	$98,471	$103,886	$109,600	$115,628	$121,988	$128,697	$135,775	$143,243	$151,121	$159,433	$168,202	$177,453	$187,213	$197,510	$208,373
NET CASH FLOW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	207.31	215.81	224.36	234.51	244.81	255.56	266.79	278.51	290.75	303.53	316.87	330.80	345.34	360.52	376.37
Net Benefit	-$24,227	-$13,922	-$3,679	$9,116	$22,013	$3,656	-$14,069	$723	$16,206	$32,411	$49,373	$67,126	$85,707	$105,154	$125,506
Annual PV of Net Benefit	-$10,312	-$5,618	-$1,407	$3,306	$7,568	$1,192	-$4,347	$212	$4,500	$8,533	$12,323	$15,883	$19,225	$22,361	$25,302
Cumulative PV of Net Benefit	-$1,228,761	-$1,234,379	-$1,235,787	-$1,232,480	-$1,224,912	-$1,223,720	-$1,228,067	-$1,227,856	-$1,223,355	-$1,214,822	-$1,202,499	-$1,186,616	-$1,167,391	-$1,145,030	-$1,119,728

Variable	Value	Source
Interest on Construction	4.09%	FERC (4/29/2004 6-month T-Bond & 300 basis points)
Financing Cost	2%	FERC
Debt Service Reserve	1 year	FERC
Operational Reserve	3 months	FERC
Term of Analysis	30 years	FERC
Starting Year	2007	FERC
Grant Value	$1,083,685	GEC
Interest on Debt, AIDEA Component	5.43%	GEC
AIDEA Loan Component	$1,000,000	GEC
Interest on Debt, Remainder	5.50%	GEC
Term of Financing, AIDEA Component	30 years	GEC
Term of Financing, Remaining Component	30 years	GEC
2003 O&M (including Staff-recommended environmental enhancements)	$58,600	FERC/GEC
Insurance (% of Initial Investment including granted $)	0.25%	FERC
Interest Rate on Debt Reserve	3.60%	FERC (4/29/2004 5-year T-Bond)
Interest Rate on Operating Reserve	0.85%	FERC (4/29/2004 3-month T-Bond)
Net Cost of Debt	5.483%	Calculated
Operating Reserve Requirement	$150,000	FERC (approx. 3 months operating revenues in last year of operations, rounded up to nearest 25K)
Federal Tax Rate	34%	FERC
State Tax Rate	8%	FERC
Percent Funding by Equity	0.0%	FERC/GEC
Percent Funding by Debt	100.0%	FERC/GEC

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*1,750,582*	*1,810,980*	*1,864,373*	*1,910,138*	*1,956,381*	*2,004,421*	*2,052,372*	*2,102,548*	*2,151,643*	*2,201,670*	*2,251,657*	*2,301,893*	*2,352,775*	*2,404,317*	*2,456,532*
Hydro Rate (mills/kWh)	*198.41*	*195.58*	*193.31*	*191.62*	*189.68*	*187.37*	*184.92*	*182.19*	*177.58*	*172.63*	*167.89*	*163.31*	*158.87*	*154.51*	*152.74*
Operating Revenues	$347,332	$354,184	$360,407	$366,013	$371,087	$375,559	$379,516	$383,064	$382,095	$380,080	$378,032	$375,928	$373,775	$371,481	$375,216
OPERATING EXPENSES															
Operating Expense	$74,435	$76,113	$77,963	$79,961	$82,158	$84,453	$86,909	$89,609	$92,407	$95,272	$98,373	$101,701	$105,277	$109,026	$112,969
Maintenance Expense															
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$156,431	$161,605	$165,977	$169,585	$172,463	$174,639	$176,140	$176,989	$173,222	$168,341	$163,192	$157,760	$152,031	$145,987	$145,780
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$54,300	$53,541	$52,741	$51,898	$51,008	$50,071	$49,083	$48,040	$46,942	$45,783	$44,562	$43,274	$41,917	$40,486	$38,977
Remaining Component	$175,725	$173,299	$170,740	$168,040	$165,191	$162,186	$159,015	$155,670	$152,141	$148,418	$144,490	$140,346	$135,974	$131,362	$126,496
NET INCOME BEFORE TAXES	-$61,915	-$53,557	-$45,825	-$38,673	-$32,058	-$25,939	-$20,278	-$15,042	-$14,181	-$14,181	-$14,181	-$14,181	-$14,181	-$14,181	-$8,014
Federal Income Taxes	-$49,305	-$42,649	-$36,492	-$30,797	-$25,529	-$20,656	-$16,148	-$11,979	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293
State Income Taxes	-$12,610	-$10,908	-$9,333	-$7,876	-$6,529	-$5,283	-$4,130	-$3,064	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,168
STATEMENT OF CASH FLOWS															
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,168
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$13,974	$14,733	$15,533	$16,377	$17,266	$18,203	$19,192	$20,234	$21,333	$22,491	$23,712	$25,000	$26,357	$27,789	$29,297
Remaining Component	$44,108	$46,534	$49,094	$51,794	$54,642	$57,648	$60,818	$64,163	$67,692	$71,415	$75,343	$79,487	$83,859	$88,471	$93,337
NET CASH FLOW	$58,384	$55,199	$51,840	$48,296	$44,558	$40,616	$36,457	$32,069	$27,442	$22,560	$17,411	$11,980	$6,250	$207	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	122.35	125.09	128.05	131.37	135.25	139.57	145.17	150.38	156.47	161.89	168.54	174.50	183.88	192.33	199.05
Net Benefit	-$133,149	-$127,657	-$121,674	-$115,069	-$106,480	-$95,805	-$81,564	-$66,879	-$45,428	-$23,650	$1,466	$25,756	$58,851	$90,944	$113,763
Annual PV of Net Benefit	-$126,228	-$114,730	-$103,668	-$92,945	-$81,536	-$69,548	-$56,133	-$43,633	-$28,097	-$13,868	$815	$13,573	$29,401	$43,073	$51,079
Cumulative PV of Net Benefit	-$126,228	-$240,957	-$344,625	-$437,570	-$519,106	-$588,654	-$644,787	-$688,420	-$716,518	-$730,385	-$729,571	-$715,998	-$686,596	-$643,524	-$592,445
NPV	$936,945														

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*2,509,434*	*2,563,038*	*2,617,359*	*2,672,412*	*2,728,211*	*2,784,774*	*2,842,115*	*2,900,251*	*2,959,200*	*3,018,977*	*3,069,568*	*3,111,566*	*3,154,447*	*3,195,328*	*3,234,274*
Hydro Rate (mills/kWh)	*151.17*	*149.67*	*148.24*	*146.91*	*145.64*	*155.89*	*165.75*	*164.25*	*162.83*	*161.49*	*160.75*	*160.54*	*160.36*	*160.36*	*160.53*
Operating Revenues	$379,351	$383,613	$388,007	$392,591	$397,342	$434,123	$471,083	$476,373	$481,856	$487,538	$493,427	$499,531	$505,858	$512,415	$519,211
OPERATING EXPENSES															
Operating Expense	$117,104	$121,366	$125,760	$130,344	$135,095	$140,019	$145,123	$150,413	$155,895	$161,577	$167,467	$173,571	$179,897	$186,455	$193,251
Maintenance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$145,780	$145,780	$145,780	$145,780	$145,780	$177,637	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$37,386	$35,709	$33,940	$32,076	$30,111	$28,038	$25,853	$23,550	$21,121	$18,561	$15,862	$13,016	$10,015	$6,852	$3,516
Remaining Component	$121,363	$115,947	$110,233	$104,205	$97,845	$91,136	$84,058	$76,590	$68,712	$60,400	$51,631	$42,380	$32,620	$22,324	$11,460
NET INCOME BEFORE TAXES	-$1,289	$5,804	$13,286	$21,178	$29,503	$70,142	$111,262	$121,033	$131,340	$142,212	$153,680	$165,777	$178,538	$191,998	$206,196
Federal Income Taxes	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	$14,075	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444
State Income Taxes	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	$3,600	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088
NET INCOME	$12,892	$19,985	$27,467	$35,360	$43,685	$52,466	$61,730	$71,501	$81,808	$92,680	$104,148	$116,245	$129,006	$142,466	$156,664
STATEMENT OF CASH FLOWS															
NET INCOME	$12,892	$19,985	$27,467	$35,360	$43,685	$52,466	$61,730	$71,501	$81,808	$92,680	$104,148	$116,245	$129,006	$142,466	$156,664
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$30,888	$32,566	$34,334	$36,198	$38,164	$40,236	$42,421	$44,724	$47,153	$49,713	$52,413	$55,259	$58,259	$61,423	$64,758
Remaining Component	$98,471	$103,886	$109,600	$115,628	$121,988	$128,697	$135,775	$143,243	$151,121	$159,433	$168,202	$177,453	$187,213	$197,510	$208,373
NET CASH FLOW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	207.31	215.81	224.36	234.51	244.81	255.56	266.79	278.51	290.75	303.53	316.87	330.80	345.34	360.52	376.37
Net Benefit	$140,883	$169,528	$199,223	$234,104	$270,545	$277,562	$287,170	$331,390	$378,543	$428,816	$479,231	$529,770	$583,495	$639,561	$698,065
Annual PV of Net Benefit	$59,968	$68,410	$76,214	$84,902	$93,017	$90,469	$88,735	$97,076	$105,125	$112,896	$119,610	$125,350	$130,885	$136,004	$140,729
Cumulative PV of Net Benefit	-$532,477	-$464,067	-$387,854	-$302,952	-$209,935	-$119,465	-$30,730	$66,346	$171,471	$284,366	$403,976	$529,326	$660,212	$796,216	$936,945

Variable	Value	Source
Interest on Construction	4.09%	FERC (4/29/2004 6-month T-Bond & 300 basis points)
Financing Cost	2%	FERC
Debt Service Reserve	1 year	FERC
Operational Reserve	3 months	FERC
Term of Analysis	30 years	FERC
Starting Year	2007	FERC
Grant Value	$1,083,685	GEC
Interest on Debt, AIDEA Component	5.43%	GEC
AIDEA Loan Component	$1,000,000	GEC
Interest on Debt, Remainder	5.50%	GEC
Term of Financing, AIDEA Component	30 years	GEC
Term of Financing, Remaining Component	30 years	GEC
2003 O&M (including Staff-recommended environmental enhancements)	$58,600	FERC/GEC
Insurance (% of Initial Investment including granted $)	0.25%	FERC
Interest Rate on Debt Reserve	3.60%	FERC (4/29/2004 5-year T-Bond)
Interest Rate on Operating Reserve	0.85%	FERC (4/29/2004 3-month T-Bond)
Net Cost of Debt	5.483%	Calculated
Operating Reserve Requirement	$150,000	FERC (approx. 3 months operating revenues in last year of operations, rounded up to nearest 25K)
Federal Tax Rate	34%	FERC
State Tax Rate	8%	FERC
Percent Funding by Equity	0.0%	FERC/GEC
Percent Funding by Debt	100.0%	FERC/GEC

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*1,793,699*	*1,868,084*	*1,943,192*	*2,017,952*	*2,094,888*	*2,175,737*	*2,249,965*	*2,314,972*	*2,375,662*	*2,438,447*	*2,500,283*	*2,562,120*	*2,623,957*	*2,685,793*	*2,747,630*
Hydro Rate (mills/kWh)	*193.64*	*189.60*	*185.47*	*181.38*	*177.14*	*172.61*	*168.68*	*165.47*	*160.84*	*155.87*	*151.20*	*146.73*	*142.45*	*138.31*	*136.56*
Operating Revenues	$347,332	$354,184	$360,407	$366,013	$371,087	$375,559	$379,516	$383,064	$382,095	$380,080	$378,032	$375,928	$373,775	$371,481	$375,216
OPERATING EXPENSES															
Operating Expense	$74,435	$76,113	$77,963	$79,961	$82,158	$84,453	$86,909	$89,609	$92,407	$95,272	$98,373	$101,701	$105,277	$109,026	$112,969
Maintenance Expense															
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$156,431	$161,605	$165,977	$169,585	$172,463	$174,639	$176,140	$176,989	$173,222	$168,341	$163,192	$157,760	$152,031	$145,987	$145,780
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$54,300	$53,541	$52,741	$51,898	$51,008	$50,071	$49,083	$48,040	$46,942	$45,783	$44,562	$43,274	$41,917	$40,486	$38,977
Remaining Component	$175,725	$173,299	$170,740	$168,040	$165,191	$162,186	$159,015	$155,670	$152,141	$148,418	$144,490	$140,346	$135,974	$131,362	$126,496
NET INCOME BEFORE TAXES	-$61,915	-$53,557	-$45,825	-$38,673	-$32,058	-$25,939	-$20,278	-$15,042	-$14,181	-$14,181	-$14,181	-$14,181	-$14,181	-$14,181	-$8,014
Federal Income Taxes	-$49,305	-$42,649	-$36,492	-$30,797	-$25,529	-$20,656	-$16,148	-$11,979	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293
State Income Taxes	-$12,610	-$10,908	-$9,333	-$7,876	-$6,529	-$5,283	-$4,130	-$3,064	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,168
STATEMENT OF CASH FLOWS															
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,168
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$13,974	$14,733	$15,533	$16,377	$17,266	$18,203	$19,192	$20,234	$21,333	$22,491	$23,712	$25,000	$26,357	$27,789	$29,297
Remaining Component	$44,108	$46,534	$49,094	$51,794	$54,642	$57,648	$60,818	$64,163	$67,692	$71,415	$75,343	$79,487	$83,859	$88,471	$93,337
NET CASH FLOW	$58,384	$55,199	$51,840	$48,296	$44,558	$40,616	$36,457	$32,069	$27,442	$22,560	$17,411	$11,980	$6,250	$207	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	122.35	125.09	128.05	131.37	135.25	139.57	145.17	150.38	156.47	161.89	168.54	174.50	183.88	192.33	199.05
Net Benefit	-$127,874	-$120,514	-$111,581	-$100,905	-$87,747	-$71,895	-$52,879	-$34,934	-$10,375	$14,681	$43,370	$71,166	$108,715	$145,081	$171,706
Annual PV of Net Benefit	-$121,227	-$108,310	-$95,069	-$81,504	-$67,191	-$52,191	-$36,391	-$22,792	-$6,417	$8,609	$24,108	$37,503	$54,313	$68,713	$77,096
Cumulative PV of Net Benefit	-$121,227	-$229,537	-$324,606	-$406,109	-$473,300	-$525,491	-$561,883	-$584,675	-$591,092	-$582,483	-$558,375	-$520,872	-$466,559	-$397,847	-$320,751
NPV	$1,577,802														

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*2,809,467*	*2,871,303*	*2,933,140*	*2,994,977*	*3,056,813*	*3,118,650*	*3,180,486*	*3,242,323*	*3,304,160*	*3,365,996*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*
Hydro Rate (mills/kWh)	*135.03*	*133.60*	*132.28*	*131.08*	*129.99*	*139.20*	*148.12*	*146.92*	*145.83*	*144.84*	*145.30*	*147.09*	*148.96*	*150.89*	*152.89*
Operating Revenues	$379,351	$383,613	$388,007	$392,591	$397,342	$434,123	$471,083	$476,373	$481,856	$487,538	$493,427	$499,531	$505,858	$512,415	$519,211
OPERATING EXPENSES															
Operating Expense	$117,104	$121,366	$125,760	$130,344	$135,095	$140,019	$145,123	$150,413	$155,895	$161,577	$167,467	$173,571	$179,897	$186,455	$193,251
Maintenance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$145,780	$145,780	$145,780	$145,780	$145,780	$177,637	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$37,386	$35,709	$33,940	$32,076	$30,111	$28,038	$25,853	$23,550	$21,121	$18,561	$15,862	$13,016	$10,015	$6,852	$3,516
Remaining Component	$121,363	$115,947	$110,233	$104,205	$97,845	$91,136	$84,058	$76,590	$68,712	$60,400	$51,631	$42,380	$32,620	$22,324	$11,460
NET INCOME BEFORE TAXES	-$1,289	$5,804	$13,286	$21,178	$29,503	$70,142	$111,262	$121,033	$131,340	$142,212	$153,680	$165,777	$178,538	$191,998	$206,196
Federal Income Taxes	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	$14,075	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444
State Income Taxes	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	$3,600	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088
NET INCOME	$12,892	$19,985	$27,467	$35,360	$43,685	$52,466	$61,730	$71,501	$81,808	$92,680	$104,148	$116,245	$129,006	$142,466	$156,664
STATEMENT OF CASH FLOWS															
NET INCOME	$12,892	$19,985	$27,467	$35,360	$43,685	$52,466	$61,730	$71,501	$81,808	$92,680	$104,148	$116,245	$129,006	$142,466	$156,664
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$30,888	$32,566	$34,334	$36,198	$38,164	$40,236	$42,421	$44,724	$47,153	$49,713	$52,413	$55,259	$58,259	$61,423	$64,758
Remaining Component	$98,471	$103,886	$109,600	$115,628	$121,988	$128,697	$135,775	$143,243	$151,121	$159,433	$168,202	$177,453	$187,213	$197,510	$208,373
NET CASH FLOW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	207.31	215.81	224.36	234.51	244.81	255.56	266.79	278.51	290.75	303.53	316.87	330.80	345.34	360.52	376.37
Net Benefit	$203,083	$236,056	$270,072	$309,747	$350,989	$362,889	$377,445	$426,662	$478,841	$534,147	$582,668	$623,860	$666,912	$711,907	$758,933
Annual PV of Net Benefit	$86,444	$95,256	$103,317	$112,335	$120,675	$118,281	$116,630	$124,985	$132,978	$140,626	$145,426	$147,613	$149,597	$151,389	$153,000
Cumulative PV of Net Benefit	-$234,307	-$139,051	-$35,734	$76,601	$197,276	$315,557	$432,187	$557,172	$690,150	$830,776	$976,203	$1,123,816	$1,273,413	$1,424,802	$1,577,802

Variable	Value	Source
Interest on Construction	4.09%	FERC (4/29/2004 6-month T-Bond & 300 basis points)
Financing Cost	2%	FERC
Debt Service Reserve	1 year	FERC
Operational Reserve	3 months	FERC
Term of Analysis	30 years	FERC
Starting Year	2007	FERC
Grant Value	$1,083,685	GEC
Interest on Debt, AIDEA Component	5.43%	GEC
AIDEA Loan Component	$1,000,000	GEC
Interest on Debt, Remainder	5.50%	GEC
Term of Financing, AIDEA Component	30 years	GEC
Term of Financing, Remaining Component	30 years	GEC
2003 O&M (including Staff-recommended environmental enhancements)	$58,600	FERC/GEC
Insurance (% of Initial Investment including granted $)	0.25%	FERC
Interest Rate on Debt Reserve	3.60%	FERC (4/29/2004 5-year T-Bond)
Interest Rate on Operating Reserve	0.85%	FERC (4/29/2004 3-month T-Bond)
Net Cost of Debt	5.483%	Calculated
Operating Reserve Requirement	$150,000	FERC (approx. 3 months operating revenues in last year of operations, rounded up to nearest 25K)
Federal Tax Rate	34%	FERC
State Tax Rate	8%	FERC
Percent Funding by Equity	0.0%	FERC/GEC
Percent Funding by Debt	100.0%	FERC/GEC

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*1,843,994*	*1,933,413*	*2,014,490*	*2,072,412*	*2,129,903*	*2,191,096*	*2,249,965*	*2,314,972*	*2,375,662*	*2,438,447*	*2,500,283*	*2,562,120*	*2,623,957*	*2,685,793*	*2,747,630*
Hydro Rate (mills/kWh)	*188.36*	*183.19*	*178.91*	*176.61*	*174.23*	*171.40*	*168.68*	*165.47*	*160.84*	*155.87*	*151.20*	*146.73*	*142.45*	*138.31*	*136.56*
Operating Revenues	$347,332	$354,184	$360,407	$366,013	$371,087	$375,559	$379,516	$383,064	$382,095	$380,080	$378,032	$375,928	$373,775	$371,481	$375,216
OPERATING EXPENSES															
Operating Expense	$74,435	$76,113	$77,963	$79,961	$82,158	$84,453	$86,909	$89,609	$92,407	$95,272	$98,373	$101,701	$105,277	$109,026	$112,969
Maintenance Expense															
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$156,431	$161,605	$165,977	$169,585	$172,463	$174,639	$176,140	$176,989	$173,222	$168,341	$163,192	$157,760	$152,031	$145,987	$145,780
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$54,300	$53,541	$52,741	$51,898	$51,008	$50,071	$49,083	$48,040	$46,942	$45,783	$44,562	$43,274	$41,917	$40,486	$38,977
Remaining Component	$175,725	$173,299	$170,740	$168,040	$165,191	$162,186	$159,015	$155,670	$152,141	$148,418	$144,490	$140,346	$135,974	$131,362	$126,496
NET INCOME BEFORE TAXES	-$61,915	-$53,557	-$45,825	-$38,673	-$32,058	-$25,939	-$20,278	-$15,042	-$14,181	-$14,181	-$14,181	-$14,181	-$14,181	-$14,181	-$8,014
Federal Income Taxes	-$49,305	-$42,649	-$36,492	-$30,797	-$25,529	-$20,656	-$16,148	-$11,979	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293
State Income Taxes	-$12,610	-$10,908	-$9,333	-$7,876	-$6,529	-$5,283	-$4,130	-$3,064	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,168
STATEMENT OF CASH FLOWS															
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,168
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$13,974	$14,733	$15,533	$16,377	$17,266	$18,203	$19,192	$20,234	$21,333	$22,491	$23,712	$25,000	$26,357	$27,789	$29,297
Remaining Component	$44,108	$46,534	$49,094	$51,794	$54,642	$57,648	$60,818	$64,163	$67,692	$71,415	$75,343	$79,487	$83,859	$88,471	$93,337
NET CASH FLOW	$58,384	$55,199	$51,840	$48,296	$44,558	$40,616	$36,457	$32,069	$27,442	$22,560	$17,411	$11,980	$6,250	$207	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	122.35	125.09	128.05	131.37	135.25	139.57	145.17	150.38	156.47	161.89	168.54	174.50	183.88	192.33	199.05
Net Benefit	-$121,720	-$112,342	-$102,451	-$93,750	-$83,011	-$69,751	-$52,879	-$34,934	-$10,375	$14,681	$43,370	$71,166	$108,715	$145,081	$171,706
Annual PV of Net Benefit	-$115,393	-$100,966	-$87,290	-$75,725	-$63,565	-$50,635	-$36,391	-$22,792	-$6,417	$8,609	$24,108	$37,503	$54,313	$68,713	$77,096
Cumulative PV of Net Benefit	-$115,393	-$216,359	-$303,649	-$379,374	-$442,938	-$493,573	-$529,964	-$552,756	-$559,174	-$550,565	-$526,457	-$488,954	-$434,641	-$365,928	-$288,833
NPV	$1,609,720														

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*2,809,467*	*2,871,303*	*2,933,140*	*2,994,977*	*3,056,813*	*3,118,650*	*3,180,486*	*3,242,323*	*3,304,160*	*3,365,996*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*
Hydro Rate (mills/kWh)	*135.03*	*133.60*	*132.28*	*131.08*	*129.99*	*139.20*	*148.12*	*146.92*	*145.83*	*144.84*	*145.30*	*147.09*	*148.96*	*150.89*	*152.89*
Operating Revenues	$379,351	$383,613	$388,007	$392,591	$397,342	$434,123	$471,083	$476,373	$481,856	$487,538	$493,427	$499,531	$505,858	$512,415	$519,211
OPERATING EXPENSES															
Operating Expense	$117,104	$121,366	$125,760	$130,344	$135,095	$140,019	$145,123	$150,413	$155,895	$161,577	$167,467	$173,571	$179,897	$186,455	$193,251
Maintenance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$145,780	$145,780	$145,780	$145,780	$145,780	$177,637	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$37,386	$35,709	$33,940	$32,076	$30,111	$28,038	$25,853	$23,550	$21,121	$18,561	$15,862	$13,016	$10,015	$6,852	$3,516
Remaining Component	$121,363	$115,947	$110,233	$104,205	$97,845	$91,136	$84,058	$76,590	$68,712	$60,400	$51,631	$42,380	$32,620	$22,324	$11,460
NET INCOME BEFORE TAXES	-$1,289	$5,804	$13,286	$21,178	$29,503	$70,142	$111,262	$121,033	$131,340	$142,212	$153,680	$165,777	$178,538	$191,998	$206,196
Federal Income Taxes	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	$14,075	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444
State Income Taxes	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	$3,600	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088
NET INCOME	$12,892	$19,985	$27,467	$35,360	$43,685	$52,466	$61,730	$71,501	$81,808	$92,680	$104,148	$116,245	$129,006	$142,466	$156,664
STATEMENT OF CASH FLOWS															
NET INCOME	$12,892	$19,985	$27,467	$35,360	$43,685	$52,466	$61,730	$71,501	$81,808	$92,680	$104,148	$116,245	$129,006	$142,466	$156,664
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$30,888	$32,566	$34,334	$36,198	$38,164	$40,236	$42,421	$44,724	$47,153	$49,713	$52,413	$55,259	$58,259	$61,423	$64,758
Remaining Component	$98,471	$103,886	$109,600	$115,628	$121,988	$128,697	$135,775	$143,243	$151,121	$159,433	$168,202	$177,453	$187,213	$197,510	$208,373
NET CASH FLOW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	207.31	215.81	224.36	234.51	244.81	255.56	266.79	278.51	290.75	303.53	316.87	330.80	345.34	360.52	376.37
Net Benefit	$203,083	$236,056	$270,072	$309,747	$350,989	$362,889	$377,445	$426,662	$478,841	$534,147	$582,668	$623,860	$666,912	$711,907	$758,933
Annual PV of Net Benefit	$86,444	$95,256	$103,317	$112,335	$120,675	$118,281	$116,630	$124,985	$132,978	$140,626	$145,426	$147,613	$149,597	$151,389	$153,000
Cumulative PV of Net Benefit	-$202,389	-$107,133	-$3,816	$108,519	$229,194	$347,475	$464,105	$589,090	$722,068	$862,695	$1,008,121	$1,155,734	$1,305,331	$1,456,720	$1,609,720

INCOME STATEMENT AND BACKGROUND

LOW ESTIMATE FOR GENERAL COST ESCALATION
MIDDLE-LOW ESTIMATE FOR GENERAL COST ESCALATION
MIDDLE-HIGH ESTIMATE FOR GENERAL COST ESCALATION
HIGH ESTIMATE FOR GENERAL COST ESCALATION

Variable	**Value**	**Source**
Interest on Construction	4.09%	FERC (4/29/2004 6-month T-Bond & 300 basis points)
Financing Cost	2%	FERC
Debt Service Reserve	1 year	FERC
Operational Reserve	3 months	FERC
Term of Analysis	30 years	FERC
Starting Year	2007	FERC
Grant Value	$1,083,685	GEC
Interest on Debt, AIDEA Component	5.43%	GEC
AIDEA Loan Component	$1,000,000	GEC
Interest on Debt, Remainder	5.50%	GEC
Term of Financing, AIDEA Component	30 years	GEC
Term of Financing, Remaining Component	30 years	GEC
2003 O&M (including Staff-recommended environmental enhancements)	$58,600	FERC/GEC
Insurance (% of Initial Investment including granted $)	0.25%	FERC
Interest Rate on Debt Reserve	3.60%	FERC (4/29/2004 5-year T-Bond)
Interest Rate on Operating Reserve	0.85%	FERC (4/29/2004 3-month T-Bond)
Net Cost of Debt	5.483%	Calculated
Operating Reserve Requirement	$150,000	FERC (approx. 3 months operating revenues in last year of operations, rounded up to nearest 25K)
Federal Tax Rate	34%	FERC
State Tax Rate	8%	FERC
Percent Funding by Equity	0.0%	FERC/GEC
Percent Funding by Debt	100.0%	FERC/GEC

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*1,791,330*	*1,863,960*	*1,930,600*	*1,990,220*	*2,050,860*	*2,114,190*	*2,177,870*	*2,244,930*	*2,311,250*	*2,379,370*	*2,448,095*	*2,517,806*	*2,588,921*	*2,661,484*	*2,735,540*
Hydro Rate (mills/kWh)	*193.90*	*189.84*	*186.25*	*183.22*	*179.94*	*176.30*	*172.54*	*168.47*	*162.70*	*156.68*	*150.87*	*145.21*	*139.68*	*134.26*	*131.21*
Operating Revenues	$347,332	$353,846	$359,582	$364,656	$369,027	$372,725	$375,777	$378,206	$376,050	$372,809	$369,332	$365,604	$361,611	$357,337	$358,933
OPERATING EXPENSES															
Operating Expense	$74,435	$75,775	$77,139	$78,604	$80,098	$81,620	$83,170	$84,751	$86,361	$88,002	$89,674	$91,378	$93,114	$94,883	$96,686
Maintenance Expense															
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$156,431	$161,605	$165,977	$169,585	$172,463	$174,639	$176,140	$176,989	$173,222	$168,341	$163,192	$157,760	$152,031	$145,987	$145,780
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$54,300	$53,541	$52,741	$51,898	$51,008	$50,071	$49,083	$48,040	$46,942	$45,783	$44,562	$43,274	$41,917	$40,486	$38,977
Remaining Component	$175,725	$173,299	$170,740	$168,040	$165,191	$162,186	$159,015	$155,670	$152,141	$148,418	$144,490	$140,346	$135,974	$131,362	$126,496
NET INCOME BEFORE TAXES	-$61,915	-$53,557	-$45,825	-$38,673	-$32,058	-$25,939	-$20,278	-$15,042	-$14,181	-$14,181	-$14,181	-$14,181	-$14,181	-$14,181	-$8,014
Federal Income Taxes	-$49,305	-$42,649	-$36,492	-$30,797	-$25,529	-$20,656	-$16,148	-$11,979	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293
State Income Taxes	-$12,610	-$10,908	-$9,333	-$7,876	-$6,529	-$5,283	-$4,130	-$3,064	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,168
STATEMENT OF CASH FLOWS															
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,168
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$13,974	$14,733	$15,533	$16,377	$17,266	$18,203	$19,192	$20,234	$21,333	$22,491	$23,712	$25,000	$26,357	$27,789	$29,297
Remaining Component	$44,108	$46,534	$49,094	$51,794	$54,642	$57,648	$60,818	$64,163	$67,692	$71,415	$75,343	$79,487	$83,859	$88,471	$93,337
NET CASH FLOW	$58,384	$55,199	$51,840	$48,296	$44,558	$40,616	$36,457	$32,069	$27,442	$22,560	$17,411	$11,980	$6,250	$207	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	122.35	124.59	126.83	129.37	132.21	135.36	139.56	143.04	147.24	150.75	155.09	158.52	164.67	169.75	173.09
Net Benefit	-$128,164	-$121,622	-$114,717	-$107,176	-$97,890	-$86,550	-$71,844	-$57,086	-$35,730	-$14,112	$10,350	$33,509	$64,706	$94,446	$114,555
Annual PV of Net Benefit	-$121,501	-$109,306	-$97,741	-$86,569	-$74,958	-$62,829	-$49,443	-$37,244	-$22,099	-$8,274	$5,753	$17,658	$32,326	$44,731	$51,435
Cumulative PV of Net Benefit	-$121,501	-$230,807	-$328,549	-$415,118	-$490,076	-$552,906	-$602,349	-$639,593	-$661,692	-$669,967	-$664,213	-$646,555	-$614,229	-$569,498	-$518,063
NPV	$629,987														

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*2,808,947*	*2,871,303*	*2,933,140*	*2,994,977*	*3,056,813*	*3,118,650*	*3,180,486*	*3,242,323*	*3,304,160*	*3,365,996*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*
Hydro Rate (mills/kWh)	*128.44*	*126.30*	*124.29*	*122.37*	*120.54*	*129.01*	*137.17*	*135.20*	*133.31*	*131.51*	*131.00*	*131.67*	*132.35*	*133.04*	*133.74*
Operating Revenues	$360,770	$362,642	$364,549	$366,493	$368,474	$402,349	$436,262	$438,358	$440,493	$442,669	$444,887	$447,147	$449,449	$451,795	$454,186
OPERATING EXPENSES															
Operating Expense	$98,523	$100,395	$102,302	$104,246	$106,226	$108,245	$110,301	$112,397	$114,533	$116,709	$118,926	$121,186	$123,488	$125,835	$128,226
Maintenance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$145,780	$145,780	$145,780	$145,780	$145,780	$177,637	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$37,386	$35,709	$33,940	$32,076	$30,111	$28,038	$25,853	$23,550	$21,121	$18,561	$15,862	$13,016	$10,015	$6,852	$3,516
Remaining Component	$121,363	$115,947	$110,233	$104,205	$97,845	$91,136	$84,058	$76,590	$68,712	$60,400	$51,631	$42,380	$32,620	$22,324	$11,460
NET INCOME BEFORE TAXES	-$1,289	$5,804	$13,286	$21,178	$29,503	$70,142	$111,262	$121,033	$131,340	$142,212	$153,680	$165,777	$178,538	$191,998	$206,196
Federal Income Taxes	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	$14,075	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444
State Income Taxes	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	$3,600	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088
NET INCOME	$12,892	$19,985	$27,467	$35,360	$43,685	$52,466	$61,730	$71,501	$81,808	$92,680	$104,148	$116,245	$129,006	$142,466	$156,664
STATEMENT OF CASH FLOWS															
NET INCOME	$12,892	$19,985	$27,467	$35,360	$43,685	$52,466	$61,730	$71,501	$81,808	$92,680	$104,148	$116,245	$129,006	$142,466	$156,664
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$30,888	$32,566	$34,334	$36,198	$38,164	$40,236	$42,421	$44,724	$47,153	$49,713	$52,413	$55,259	$58,259	$61,423	$64,758
Remaining Component	$98,471	$103,886	$109,600	$115,628	$121,988	$128,697	$135,775	$143,243	$151,121	$159,433	$168,202	$177,453	$187,213	$197,510	$208,373
NET CASH FLOW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	177.53	182.03	186.44	191.92	197.00	202.22	207.58	213.08	218.74	224.55	230.51	236.64	242.94	249.41	256.06
Net Benefit	$137,894	$160,034	$182,297	$208,304	$233,718	$228,296	$223,932	$252,522	$282,247	$313,151	$337,937	$356,497	$375,584	$395,212	$415,397
Annual PV of Net Benefit	$58,695	$64,579	$69,738	$75,545	$80,356	$74,411	$69,195	$73,973	$78,383	$82,444	$84,345	$84,352	$84,248	$84,043	$83,743
Cumulative PV of Net Benefit	-$459,368	-$394,789	-$325,051	-$249,505	-$169,150	-$94,738	-$25,543	$48,429	$126,812	$209,256	$293,601	$377,953	$462,201	$546,244	$629,987

Variable	**Value**	**Source**
Interest on Construction	4.09%	FERC (4/29/2004 6-month T-Bond & 300 basis points)
Financing Cost	2%	FERC
Debt Service Reserve	1 year	FERC
Operational Reserve	3 months	FERC
Term of Analysis	30 years	FERC
Starting Year	2007	FERC
Grant Value	$1,083,685	GEC
Interest on Debt, AIDEA Component	5.43%	GEC
AIDEA Loan Component	$1,000,000	GEC
Interest on Debt, Remainder	5.50%	GEC
Term of Financing, AIDEA Component	30 years	GEC
Term of Financing, Remaining Component	30 years	GEC
2003 O&M (including Staff-recommended environmental enhancements)	$58,600	FERC/GEC
Insurance (% of Initial Investment including granted $)	0.25%	FERC
Interest Rate on Debt Reserve	3.60%	FERC (4/29/2004 5-year T-Bond)
Interest Rate on Operating Reserve	0.85%	FERC (4/29/2004 3-month T-Bond)
Net Cost of Debt	5.483%	Calculated
Operating Reserve Requirement	$150,000	FERC (approx. 3 months operating revenues in last year of operations, rounded up to nearest 25K)
Federal Tax Rate	34%	FERC
State Tax Rate	8%	FERC
Percent Funding by Equity	0.0%	FERC/GEC
Percent Funding by Debt	100.0%	FERC/GEC

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*1,791,330*	*1,863,960*	*1,930,600*	*1,990,220*	*2,050,860*	*2,114,190*	*2,177,870*	*2,244,930*	*2,311,250*	*2,379,370*	*2,448,095*	*2,517,806*	*2,588,921*	*2,661,484*	*2,735,540*
Hydro Rate (mills/kWh)	*193.90*	*189.92*	*186.41*	*183.42*	*180.17*	*176.56*	*172.84*	*168.81*	*163.07*	*157.09*	*151.30*	*145.67*	*140.17*	*134.79*	*131.77*
Operating Revenues	$347,332	$353,995	$359,886	$365,043	$369,500	$373,288	$376,433	$378,958	$376,901	$373,764	$370,394	$366,777	$362,899	$358,743	$360,462
OPERATING EXPENSES															
Operating Expense	$74,435	$75,924	$77,442	$78,991	$80,571	$82,182	$83,826	$85,502	$87,212	$88,956	$90,736	$92,550	$94,401	$96,289	$98,215
Maintenance Expense															
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$156,431	$161,605	$165,977	$169,585	$172,463	$174,639	$176,140	$176,989	$173,222	$168,341	$163,192	$157,760	$152,031	$145,987	$145,780
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$54,300	$53,541	$52,741	$51,898	$51,008	$50,071	$49,083	$48,040	$46,942	$45,783	$44,562	$43,274	$41,917	$40,486	$38,977
Remaining Component	$175,725	$173,299	$170,740	$168,040	$165,191	$162,186	$159,015	$155,670	$152,141	$148,418	$144,490	$140,346	$135,974	$131,362	$126,496
NET INCOME BEFORE TAXES	-$61,915	-$53,557	-$45,825	-$38,673	-$32,058	-$25,939	-$20,278	-$15,042	-$14,181	-$14,181	-$14,181	-$14,181	-$14,181	-$14,181	-$8,014
Federal Income Taxes	-$49,305	-$42,649	-$36,492	-$30,797	-$25,529	-$20,656	-$16,148	-$11,979	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293
State Income Taxes	-$12,610	-$10,908	-$9,333	-$7,876	-$6,529	-$5,283	-$4,130	-$3,064	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,168
STATEMENT OF CASH FLOWS															
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,168
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$13,974	$14,733	$15,533	$16,377	$17,266	$18,203	$19,192	$20,234	$21,333	$22,491	$23,712	$25,000	$26,357	$27,789	$29,297
Remaining Component	$44,108	$46,534	$49,094	$51,794	$54,642	$57,648	$60,818	$64,163	$67,692	$71,415	$75,343	$79,487	$83,859	$88,471	$93,337
NET CASH FLOW	$58,384	$55,199	$51,840	$48,296	$44,558	$40,616	$36,457	$32,069	$27,442	$22,560	$17,411	$11,980	$6,250	$207	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	122.35	124.81	127.28	129.94	132.91	136.19	140.54	144.18	148.54	152.22	156.73	160.33	166.70	171.99	175.53
Net Benefit	-$128,164	-$121,361	-$114,157	-$106,428	-$96,929	-$85,346	-$70,354	-$55,288	-$33,578	-$11,586	$13,307	$36,908	$68,683	$99,016	$119,697
Annual PV of Net Benefit	-$121,501	-$109,072	-$97,264	-$85,965	-$74,222	-$61,955	-$48,418	-$36,072	-$20,769	-$6,794	$7,397	$19,450	$34,313	$46,896	$53,744
Cumulative PV of Net Benefit	-$121,501	-$230,573	-$327,837	-$413,801	-$488,023	-$549,979	-$598,397	-$634,468	-$655,237	-$662,031	-$654,634	-$635,184	-$600,871	-$553,975	-$500,231
NPV	$698,238														

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*2,808,947*	*2,871,303*	*2,933,140*	*2,994,977*	*3,056,813*	*3,118,650*	*3,180,486*	*3,242,323*	*3,304,160*	*3,365,996*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*
Hydro Rate (mills/kWh)	*129.03*	*126.92*	*124.94*	*123.06*	*121.27*	*129.77*	*137.96*	*136.02*	*134.18*	*132.41*	*131.94*	*132.66*	*133.40*	*134.14*	*134.91*
Operating Revenues	$362,427	$364,430	$366,474	$368,558	$370,685	$404,710	$438,779	$441,035	$443,337	$445,684	$448,079	$450,521	$453,012	$455,553	$458,145
OPERATING EXPENSES															
Operating Expense	$100,179	$102,183	$104,227	$106,311	$108,437	$110,606	$112,818	$115,075	$117,376	$119,724	$122,118	$124,561	$127,052	$129,593	$132,185
Maintenance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$145,780	$145,780	$145,780	$145,780	$145,780	$177,637	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$37,386	$35,709	$33,940	$32,076	$30,111	$28,038	$25,853	$23,550	$21,121	$18,561	$15,862	$13,016	$10,015	$6,852	$3,516
Remaining Component	$121,363	$115,947	$110,233	$104,205	$97,845	$91,136	$84,058	$76,590	$68,712	$60,400	$51,631	$42,380	$32,620	$22,324	$11,460
NET INCOME BEFORE TAXES	-$1,289	$5,804	$13,286	$21,178	$29,503	$70,142	$111,262	$121,033	$131,340	$142,212	$153,680	$165,777	$178,538	$191,998	$206,196
Federal Income Taxes	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	$14,075	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444
State Income Taxes	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	$3,600	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088
NET INCOME	$12,892	$19,985	$27,467	$35,360	$43,685	$52,466	$61,730	$71,501	$81,808	$92,680	$104,148	$116,245	$129,006	$142,466	$156,664
STATEMENT OF CASH FLOWS															
NET INCOME	$12,892	$19,985	$27,467	$35,360	$43,685	$52,466	$61,730	$71,501	$81,808	$92,680	$104,148	$116,245	$129,006	$142,466	$156,664
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$30,888	$32,566	$34,334	$36,198	$38,164	$40,236	$42,421	$44,724	$47,153	$49,713	$52,413	$55,259	$58,259	$61,423	$64,758
Remaining Component	$98,471	$103,886	$109,600	$115,628	$121,988	$128,697	$135,775	$143,243	$151,121	$159,433	$168,202	$177,453	$187,213	$197,510	$208,373
NET CASH FLOW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	180.18	184.92	189.55	195.29	200.63	206.12	211.76	217.55	223.51	229.64	235.94	242.41	249.07	255.91	262.95
Net Benefit	$143,697	$166,517	$189,499	$216,332	$242,599	$238,092	$234,706	$264,342	$295,186	$327,281	$353,165	$372,711	$392,824	$413,522	$434,822
Annual PV of Net Benefit	$61,165	$67,195	$72,493	$78,457	$83,409	$77,604	$72,524	$77,435	$81,976	$86,164	$88,146	$88,188	$88,116	$87,937	$87,660
Cumulative PV of Net Benefit	-$439,066	-$371,871	-$299,378	-$220,921	-$137,511	-$59,907	$12,617	$90,052	$172,028	$258,192	$346,338	$434,526	$522,642	$610,578	$698,238

Income Statement-GenlEsc-MidLow

Variable	Value	Source
Interest on Construction	4.09%	FERC (4/29/2004 6-month T-Bond & 300 basis points)
Financing Cost	2%	FERC
Debt Service Reserve	1 year	FERC
Operational Reserve	3 months	FERC
Term of Analysis	30 years	FERC
Starting Year	2007	FERC
Grant Value	$1,083,685	GEC
Interest on Debt, AIDEA Component	5.43%	GEC
AIDEA Loan Component	$1,000,000	GEC
Interest on Debt, Remainder	5.50%	GEC
Term of Financing, AIDEA Component	30 years	GEC
Term of Financing, Remaining Component	30 years	GEC
2003 O&M (including Staff-recommended environmental enhancements)	$58,600	FERC/GEC
Insurance (% of Initial Investment including granted $)	0.25%	FERC
Interest Rate on Debt Reserve	3.60%	FERC (4/29/2004 5-year T-Bond)
Interest Rate on Operating Reserve	0.85%	FERC (4/29/2004 3-month T-Bond)
Net Cost of Debt	5.483%	Calculated
Operating Reserve Requirement	$150,000	FERC (approx. 3 months operating revenues in last year of operations, rounded up to nearest 25K)
Federal Tax Rate	34%	FERC
State Tax Rate	8%	FERC
Percent Funding by Equity	0.0%	FERC/GEC
Percent Funding by Debt	100.0%	FERC/GEC

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*1,791,330*	*1,863,960*	*1,930,600*	*1,990,220*	*2,050,860*	*2,114,190*	*2,177,870*	*2,244,930*	*2,311,250*	*2,379,370*	*2,448,095*	*2,517,806*	*2,588,921*	*2,661,484*	*2,735,540*
Hydro Rate (mills/kWh)	*193.90*	*190.31*	*187.20*	*184.60*	*181.73*	*178.51*	*175.16*	*171.50*	*166.14*	*160.52*	*155.10*	*149.84*	*144.70*	*139.68*	*137.02*
Operating Revenues	$347,332	$354,739	$361,412	$367,389	$372,706	$377,396	$381,486	$385,001	$383,981	$381,928	$379,692	$377,262	$374,624	$371,764	$374,836
OPERATING EXPENSES															
Operating Expense	$74,435	$76,668	$78,968	$81,337	$83,777	$86,290	$88,879	$91,545	$94,292	$97,121	$100,034	$103,035	$106,126	$109,310	$112,589
Maintenance Expense															
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$156,431	$161,605	$165,977	$169,585	$172,463	$174,639	$176,140	$176,989	$173,222	$168,341	$163,192	$157,760	$152,031	$145,987	$145,780
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$54,300	$53,541	$52,741	$51,898	$51,008	$50,071	$49,083	$48,040	$46,942	$45,783	$44,562	$43,274	$41,917	$40,486	$38,977
Remaining Component	$175,725	$173,299	$170,740	$168,040	$165,191	$162,186	$159,015	$155,670	$152,141	$148,418	$144,490	$140,346	$135,974	$131,362	$126,496
NET INCOME BEFORE TAXES	-$61,915	-$53,557	-$45,825	-$38,673	-$32,058	-$25,939	-$20,278	-$15,042	-$14,181	-$14,181	-$14,181	-$14,181	-$14,181	-$14,181	-$8,014
Federal Income Taxes	-$49,305	-$42,649	-$36,492	-$30,797	-$25,529	-$20,656	-$16,148	-$11,979	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293
State Income Taxes	-$12,610	-$10,908	-$9,333	-$7,876	-$6,529	-$5,283	-$4,130	-$3,064	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,168
STATEMENT OF CASH FLOWS															
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,168
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$13,974	$14,733	$15,533	$16,377	$17,266	$18,203	$19,192	$20,234	$21,333	$22,491	$23,712	$25,000	$26,357	$27,789	$29,297
Remaining Component	$44,108	$46,534	$49,094	$51,794	$54,642	$57,648	$60,818	$64,163	$67,692	$71,415	$75,343	$79,487	$83,859	$88,471	$93,337
NET CASH FLOW	$58,384	$55,199	$51,840	$48,296	$44,558	$40,616	$36,457	$32,069	$27,442	$22,560	$17,411	$11,980	$6,250	$207	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	122.35	125.90	129.53	133.40	137.65	142.30	148.14	153.31	159.35	164.72	171.11	176.57	185.22	192.78	198.45
Net Benefit	-$128,164	-$120,058	-$111,337	-$101,884	-$90,410	-$76,554	-$58,866	-$40,835	-$15,691	$10,006	$39,198	$67,300	$104,895	$141,327	$168,025
Annual PV of Net Benefit	-$121,501	-$107,900	-$94,861	-$82,294	-$69,231	-$55,573	-$40,512	-$26,642	-$9,705	$5,867	$21,789	$35,466	$52,404	$66,935	$75,443
Cumulative PV of Net Benefit	-$121,501	-$229,402	-$324,263	-$406,557	-$475,788	-$531,361	-$571,873	-$598,515	-$608,220	-$602,353	-$580,564	-$545,098	-$492,694	-$425,759	-$350,317
NPV	$1,368,738														

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*2,808,947*	*2,871,303*	*2,933,140*	*2,994,977*	*3,056,813*	*3,118,650*	*3,180,486*	*3,242,323*	*3,304,160*	*3,365,996*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*
Hydro Rate (mills/kWh)	*134.65*	*132.93*	*131.35*	*129.87*	*128.49*	*137.41*	*146.03*	*144.52*	*143.11*	*141.79*	*141.88*	*143.25*	*144.67*	*146.13*	*147.64*
Operating Revenues	$378,214	$381,693	$385,277	$388,967	$392,769	$428,541	$464,431	$468,585	$472,864	$477,271	$481,811	$486,486	$491,302	$496,262	$501,371
OPERATING EXPENSES															
Operating Expense	$115,967	$119,446	$123,029	$126,720	$130,522	$134,438	$138,471	$142,625	$146,904	$151,311	$155,850	$160,525	$165,341	$170,301	$175,411
Maintenance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$145,780	$145,780	$145,780	$145,780	$145,780	$177,637	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$37,386	$35,709	$33,940	$32,076	$30,111	$28,038	$25,853	$23,550	$21,121	$18,561	$15,862	$13,016	$10,015	$6,852	$3,516
Remaining Component	$121,363	$115,947	$110,233	$104,205	$97,845	$91,136	$84,058	$76,590	$68,712	$60,400	$51,631	$42,380	$32,620	$22,324	$11,460
NET INCOME BEFORE TAXES	-$1,289	$5,804	$13,286	$21,178	$29,503	$70,142	$111,262	$121,033	$131,340	$142,212	$153,680	$165,777	$178,538	$191,998	$206,196
Federal Income Taxes	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	$14,075	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444
State Income Taxes	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	$3,600	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088
NET INCOME	$12,892	$19,985	$27,467	$35,360	$43,685	$52,466	$61,730	$71,501	$81,808	$92,680	$104,148	$116,245	$129,006	$142,466	$156,664
STATEMENT OF CASH FLOWS															
NET INCOME	$12,892	$19,985	$27,467	$35,360	$43,685	$52,466	$61,730	$71,501	$81,808	$92,680	$104,148	$116,245	$129,006	$142,466	$156,664
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$30,888	$32,566	$34,334	$36,198	$38,164	$40,236	$42,421	$44,724	$47,153	$49,713	$52,413	$55,259	$58,259	$61,423	$64,758
Remaining Component	$98,471	$103,886	$109,600	$115,628	$121,988	$128,697	$135,775	$143,243	$151,121	$159,433	$168,202	$177,453	$187,213	$197,510	$208,373
NET CASH FLOW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	205.49	212.72	219.95	228.59	236.87	245.46	254.35	263.56	273.11	283.01	293.26	303.88	314.89	326.30	338.13
Net Benefit	$198,992	$229,098	$259,854	$295,661	$331,310	$336,947	$344,518	$385,969	$429,539	$475,326	$514,099	$545,506	$578,081	$611,867	$646,908
Annual PV of Net Benefit	$84,702	$92,448	$99,408	$107,227	$113,909	$109,825	$106,456	$113,064	$119,287	$125,140	$128,312	$129,074	$129,671	$130,115	$130,416
Cumulative PV of Net Benefit	-$265,614	-$173,167	-$73,758	$33,468	$147,378	$257,203	$363,659	$476,723	$596,010	$721,150	$849,463	$978,536	$1,108,207	$1,238,322	$1,368,738

Variable	Value	Source
Interest on Construction	4.09%	FERC (4/29/2004 6-month T-Bond & 300 basis points)
Financing Cost	2%	FERC
Debt Service Reserve	1 year	FERC
Operational Reserve	3 months	FERC
Term of Analysis	30 years	FERC
Starting Year	2007	FERC
Grant Value	$1,083,685	GEC
Interest on Debt, AIDEA Component	5.43%	GEC
AIDEA Loan Component	$1,000,000	GEC
Interest on Debt, Remainder	5.50%	GEC
Term of Financing, AIDEA Component	30 years	GEC
Term of Financing, Remaining Component	30 years	GEC
2003 O&M (including Staff-recommended environmental enhancements)	$58,600	FERC/GEC
Insurance (% of Initial Investment including granted $)	0.25%	FERC
Interest Rate on Debt Reserve	3.60%	FERC (4/29/2004 5-year T-Bond)
Interest Rate on Operating Reserve	0.85%	FERC (4/29/2004 3-month T-Bond)
Net Cost of Debt	5.483%	Calculated
Operating Reserve Requirement	$150,000	FERC (approx. 3 months operating revenues in last year of operations, rounded up to nearest 25K)
Federal Tax Rate	34%	FERC
State Tax Rate	8%	FERC
Percent Funding by Equity	0.0%	FERC/GEC
Percent Funding by Debt	100.0%	FERC/GEC

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*1,791,330*	*1,863,960*	*1,930,600*	*1,990,220*	*2,050,860*	*2,114,190*	*2,177,870*	*2,244,930*	*2,311,250*	*2,379,370*	*2,448,095*	*2,517,806*	*2,588,921*	*2,661,484*	*2,735,540*
Hydro Rate (mills/kWh)	*193.90*	*190.51*	*187.60*	*185.20*	*182.53*	*179.51*	*176.37*	*172.90*	*167.75*	*162.33*	*157.12*	*152.08*	*147.16*	*142.35*	*139.91*
Operating Revenues	$347,332	$355,111	$362,180	$368,579	$374,345	$379,511	$384,106	$388,157	$387,705	$386,254	$384,656	$382,899	$380,974	$378,867	$382,734
OPERATING EXPENSES															
Operating Expense	$74,435	$77,040	$79,736	$82,527	$85,416	$88,405	$91,499	$94,702	$98,016	$101,447	$104,998	$108,673	$112,476	$116,413	$120,487
Maintenance Expense															
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$156,431	$161,605	$165,977	$169,585	$172,463	$174,639	$176,140	$176,989	$173,222	$168,341	$163,192	$157,760	$152,031	$145,987	$145,780
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$54,300	$53,541	$52,741	$51,898	$51,008	$50,071	$49,083	$48,040	$46,942	$45,783	$44,562	$43,274	$41,917	$40,486	$38,977
Remaining Component	$175,725	$173,299	$170,740	$168,040	$165,191	$162,186	$159,015	$155,670	$152,141	$148,418	$144,490	$140,346	$135,974	$131,362	$126,496
NET INCOME BEFORE TAXES	-$61,915	-$53,557	-$45,825	-$38,673	-$32,058	-$25,939	-$20,278	-$15,042	-$14,181	-$14,181	-$14,181	-$14,181	-$14,181	-$14,181	-$8,014
Federal Income Taxes	-$49,305	-$42,649	-$36,492	-$30,797	-$25,529	-$20,656	-$16,148	-$11,979	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293
State Income Taxes	-$12,610	-$10,908	-$9,333	-$7,876	-$6,529	-$5,283	-$4,130	-$3,064	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,168
STATEMENT OF CASH FLOWS															
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,168
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$13,974	$14,733	$15,533	$16,377	$17,266	$18,203	$19,192	$20,234	$21,333	$22,491	$23,712	$25,000	$26,357	$27,789	$29,297
Remaining Component	$44,108	$46,534	$49,094	$51,794	$54,642	$57,648	$60,818	$64,163	$67,692	$71,415	$75,343	$79,487	$83,859	$88,471	$93,337
NET CASH FLOW	$58,384	$55,199	$51,840	$48,296	$44,558	$40,616	$36,457	$32,069	$27,442	$22,560	$17,411	$11,980	$6,250	$207	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	122.35	126.45	130.67	135.16	140.07	145.44	152.07	158.08	165.03	171.35	178.78	185.30	195.25	204.12	211.04
Net Benefit	-$128,164	-$119,406	-$109,917	-$99,579	-$87,079	-$72,028	-$52,909	-$33,286	-$6,280	$21,448	$53,019	$83,640	$124,506	$164,407	$194,578
Annual PV of Net Benefit	-$121,501	-$107,314	-$93,651	-$80,432	-$66,680	-$52,288	-$36,412	-$21,717	-$3,884	$12,576	$29,472	$44,077	$62,201	$77,866	$87,365
Cumulative PV of Net Benefit	-$121,501	-$228,816	-$322,467	-$402,900	-$469,580	-$521,868	-$558,280	-$579,997	-$583,881	-$571,304	-$541,832	-$497,756	-$435,554	-$357,688	-$270,323
NPV	$1,753,517														

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*2,808,947*	*2,871,303*	*2,933,140*	*2,994,977*	*3,056,813*	*3,118,650*	*3,180,486*	*3,242,323*	*3,304,160*	*3,365,996*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*
Hydro Rate (mills/kWh)	*137.76*	*136.29*	*134.95*	*133.73*	*132.60*	*141.80*	*150.69*	*149.47*	*148.35*	*147.33*	*147.78*	*149.60*	*151.47*	*153.41*	*155.42*
Operating Revenues	$386,951	$391,316	$395,833	$400,509	$405,348	$442,213	$479,254	$484,619	$490,172	$495,920	$501,868	$508,025	$514,397	$520,993	$527,819
OPERATING EXPENSES															
Operating Expense	$124,704	$129,069	$133,586	$138,262	$143,101	$148,110	$153,293	$158,659	$164,212	$169,959	$175,908	$182,064	$188,437	$195,032	$201,858
Maintenance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$145,780	$145,780	$145,780	$145,780	$145,780	$177,637	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$37,386	$35,709	$33,940	$32,076	$30,111	$28,038	$25,853	$23,550	$21,121	$18,561	$15,862	$13,016	$10,015	$6,852	$3,516
Remaining Component	$121,363	$115,947	$110,233	$104,205	$97,845	$91,136	$84,058	$76,590	$68,712	$60,400	$51,631	$42,380	$32,620	$22,324	$11,460
NET INCOME BEFORE TAXES	-$1,289	$5,804	$13,286	$21,178	$29,503	$70,142	$111,262	$121,033	$131,340	$142,212	$153,680	$165,777	$178,538	$191,998	$206,196
Federal Income Taxes	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	$14,075	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444
State Income Taxes	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	$3,600	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088
NET INCOME	$12,892	$19,985	$27,467	$35,360	$43,685	$52,466	$61,730	$71,501	$81,808	$92,680	$104,148	$116,245	$129,006	$142,466	$156,664
STATEMENT OF CASH FLOWS															
NET INCOME	$12,892	$19,985	$27,467	$35,360	$43,685	$52,466	$61,730	$71,501	$81,808	$92,680	$104,148	$116,245	$129,006	$142,466	$156,664
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$30,888	$32,566	$34,334	$36,198	$38,164	$40,236	$42,421	$44,724	$47,153	$49,713	$52,413	$55,259	$58,259	$61,423	$64,758
Remaining Component	$98,471	$103,886	$109,600	$115,628	$121,988	$128,697	$135,775	$143,243	$151,121	$159,433	$168,202	$177,453	$187,213	$197,510	$208,373
NET CASH FLOW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	219.49	228.22	237.01	247.42	257.52	268.02	278.96	290.34	302.18	314.51	327.34	340.70	354.60	369.07	384.13
Net Benefit	$229,594	$263,982	$299,356	$340,523	$381,838	$393,661	$407,970	$456,755	$508,293	$562,729	$609,793	$648,991	$689,824	$732,361	$776,672
Annual PV of Net Benefit	$97,728	$106,525	$114,520	$123,497	$131,282	$128,311	$126,063	$133,800	$141,157	$148,151	$152,197	$153,560	$154,737	$155,738	$156,576
Cumulative PV of Net Benefit	-$172,595	-$66,070	$48,449	$171,946	$303,228	$431,539	$557,601	$691,401	$832,559	$980,710	$1,132,906	$1,286,466	$1,441,203	$1,596,941	$1,753,517

INCOME STATEMENT AND BACKGROUND

LOW ESTIMATE FOR DIESEL FUEL COST ESCALATION
MIDDLE-LOW ESTIMATE FOR DIESEL FUEL COST ESCALATION
MIDDLE-HIGH ESTIMATE FOR DIESEL FUEL COST ESCALATION
HIGH ESTIMATE FOR DIESEL FUEL COST ESCALATION

Variable	Value	Source
Interest on Construction	4.09%	FERC (4/29/2004 6-month T-Bond & 300 basis points)
Financing Cost	2%	FERC
Debt Service Reserve	1 year	FERC
Operational Reserve	3 months	FERC
Term of Analysis	30 years	FERC
Starting Year	2007	FERC
Grant Value	$1,083,685	GEC
Interest on Debt, AIDEA Component	5.43%	GEC
AIDEA Loan Component	$1,000,000	GEC
Interest on Debt, Remainder	5.50%	GEC
Term of Financing, AIDEA Component	30 years	GEC
Term of Financing, Remaining Component	30 years	GEC
2003 O&M (including Staff-recommended environmental enhancements)	$58,600	FERC/GEC
Insurance (% of Initial Investment including granted $)	0.25%	FERC
Interest Rate on Debt Reserve	3.60%	FERC (4/29/2004 5-year T-Bond)
Interest Rate on Operating Reserve	0.85%	FERC (4/29/2004 3-month T-Bond)
Net Cost of Debt	5.483%	Calculated
Operating Reserve Requirement	$150,000	FERC (approx. 3 months operating revenues in last year of operations, rounded up to nearest 25K)
Federal Tax Rate	34%	FERC
State Tax Rate	8%	FERC
Percent Funding by Equity	0.0%	FERC/GEC
Percent Funding by Debt	100.0%	FERC/GEC

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*1,791,330*	*1,863,960*	*1,930,600*	*1,990,220*	*2,050,860*	*2,114,190*	*2,177,870*	*2,244,930*	*2,311,250*	*2,379,370*	*2,448,095*	*2,517,806*	*2,588,921*	*2,661,484*	*2,735,540*
Hydro Rate (mills/kWh)	*193.90*	*190.02*	*186.68*	*183.91*	*180.94*	*177.64*	*174.26*	*170.64*	*165.32*	*159.74*	*154.42*	*149.31*	*144.37*	*139.58*	*137.16*
Operating Revenues	$347,332	$354,184	$360,407	$366,013	$371,087	$375,559	$379,516	$383,064	$382,095	$380,080	$378,032	$375,928	$373,775	$371,481	$375,216
OPERATING EXPENSES															
Operating Expense	$74,435	$76,113	$77,963	$79,961	$82,158	$84,453	$86,909	$89,609	$92,407	$95,272	$98,373	$101,701	$105,277	$109,026	$112,969
Maintenance Expense															
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$156,431	$161,605	$165,977	$169,585	$172,463	$174,639	$176,140	$176,989	$173,222	$168,341	$163,192	$157,760	$152,031	$145,987	$145,780
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$54,300	$53,541	$52,741	$51,898	$51,008	$50,071	$49,083	$48,040	$46,942	$45,783	$44,562	$43,274	$41,917	$40,486	$38,977
Remaining Component	$175,725	$173,299	$170,740	$168,040	$165,191	$162,186	$159,015	$155,670	$152,141	$148,418	$144,490	$140,346	$135,974	$131,362	$126,496
NET INCOME BEFORE TAXES	-$61,915	-$53,557	-$45,825	-$38,673	-$32,058	-$25,939	-$20,278	-$15,042	-$14,181	-$14,181	-$14,181	-$14,181	-$14,181	-$14,181	-$8,014
Federal Income Taxes	-$49,305	-$42,649	-$36,492	-$30,797	-$25,529	-$20,656	-$16,148	-$11,979	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293
State Income Taxes	-$12,610	-$10,908	-$9,333	-$7,876	-$6,529	-$5,283	-$4,130	-$3,064	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,168
STATEMENT OF CASH FLOWS															
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,168
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$13,974	$14,733	$15,533	$16,377	$17,266	$18,203	$19,192	$20,234	$21,333	$22,491	$23,712	$25,000	$26,357	$27,789	$29,297
Remaining Component	$44,108	$46,534	$49,094	$51,794	$54,642	$57,648	$60,818	$64,163	$67,692	$71,415	$75,343	$79,487	$83,859	$88,471	$93,337
NET CASH FLOW	$58,384	$55,199	$51,840	$48,296	$44,558	$40,616	$36,457	$32,069	$27,442	$22,560	$17,411	$11,980	$6,250	$207	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	122.35	124.56	127.03	129.71	132.70	135.81	139.15	142.85	146.67	150.56	154.79	159.33	164.22	169.34	174.71
Net Benefit	-$128,164	-$122,012	-$115,167	-$107,855	-$98,948	-$88,436	-$76,470	-$62,381	-$43,108	-$21,840	$906	$25,243	$51,390	$79,215	$102,703
Annual PV of Net Benefit	-$121,501	-$109,657	-$98,125	-$87,118	-$75,768	-$64,199	-$52,626	-$40,699	-$26,662	-$12,806	$503	$13,302	$25,674	$37,517	$46,113
Cumulative PV of Net Benefit	-$121,501	-$231,158	-$329,283	-$416,400	-$492,169	-$556,367	-$608,994	-$649,693	-$676,355	-$689,161	-$688,658	-$675,355	-$649,682	-$612,164	-$566,051
NPV	$605,529														

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*2,808,947*	*2,871,303*	*2,933,140*	*2,994,977*	*3,056,813*	*3,118,650*	*3,180,486*	*3,242,323*	*3,304,160*	*3,365,996*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*
Hydro Rate (mills/kWh)	*135.05*	*133.60*	*132.28*	*131.08*	*129.99*	*139.20*	*148.12*	*146.92*	*145.83*	*144.84*	*145.30*	*147.09*	*148.96*	*150.89*	*152.89*
Operating Revenues	$379,351	$383,613	$388,007	$392,591	$397,342	$434,123	$471,083	$476,373	$481,856	$487,538	$493,427	$499,531	$505,858	$512,415	$519,211
OPERATING EXPENSES															
Operating Expense	$117,104	$121,366	$125,760	$130,344	$135,095	$140,019	$145,123	$150,413	$155,895	$161,577	$167,467	$173,571	$179,897	$186,455	$193,251
Maintenance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$145,780	$145,780	$145,780	$145,780	$145,780	$177,637	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$37,386	$35,709	$33,940	$32,076	$30,111	$28,038	$25,853	$23,550	$21,121	$18,561	$15,862	$13,016	$10,015	$6,852	$3,516
Remaining Component	$121,363	$115,947	$110,233	$104,205	$97,845	$91,136	$84,058	$76,590	$68,712	$60,400	$51,631	$42,380	$32,620	$22,324	$11,460
NET INCOME BEFORE TAXES	-$1,289	$5,804	$13,286	$21,178	$29,503	$70,142	$111,262	$121,033	$131,340	$142,212	$153,680	$165,777	$178,538	$191,998	$206,196
Federal Income Taxes	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	$14,075	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444
State Income Taxes	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	$3,600	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088
NET INCOME	$12,892	$19,985	$27,467	$35,360	$43,685	$52,466	$61,730	$71,501	$81,808	$92,680	$104,148	$116,245	$129,006	$142,466	$156,664
STATEMENT OF CASH FLOWS															
NET INCOME	$12,892	$19,985	$27,467	$35,360	$43,685	$52,466	$61,730	$71,501	$81,808	$92,680	$104,148	$116,245	$129,006	$142,466	$156,664
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$30,888	$32,566	$34,334	$36,198	$38,164	$40,236	$42,421	$44,724	$47,153	$49,713	$52,413	$55,259	$58,259	$61,423	$64,758
Remaining Component	$98,471	$103,886	$109,600	$115,628	$121,988	$128,697	$135,775	$143,243	$151,121	$159,433	$168,202	$177,453	$187,213	$197,510	$208,373
NET CASH FLOW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	180.32	186.08	191.99	198.13	204.87	211.84	219.04	226.49	234.20	242.16	250.40	258.92	267.73	276.84	286.26
Net Benefit	$127,170	$150,686	$175,131	$200,818	$228,913	$226,527	$225,579	$257,988	$291,965	$327,578	$356,929	$379,754	$403,342	$427,720	$452,913
Annual PV of Net Benefit	$54,131	$60,806	$66,997	$72,830	$78,704	$73,835	$69,704	$75,574	$81,081	$86,242	$89,085	$89,855	$90,475	$90,956	$91,307
Cumulative PV of Net Benefit	-$511,920	-$451,114	-$384,117	-$311,287	-$232,583	-$158,748	-$89,045	-$13,471	$67,611	$153,853	$242,938	$332,792	$423,267	$514,223	$605,529

Variable	Value	Source
Interest on Construction	4.09%	FERC (4/29/2004 6-month T-Bond & 300 basis points)
Financing Cost	2%	FERC
Debt Service Reserve	1 year	FERC
Operational Reserve	3 months	FERC
Term of Analysis	30 years	FERC
Starting Year	2007	FERC
Grant Value	$1,083,685	GEC
Interest on Debt, AIDEA Component	5.43%	GEC
AIDEA Loan Component	$1,000,000	GEC
Interest on Debt, Remainder	5.50%	GEC
Term of Financing, AIDEA Component	30 years	GEC
Term of Financing, Remaining Component	30 years	GEC
2003 O&M (including Staff-recommended environmental enhancements)	$58,600	FERC/GEC
Insurance (% of Initial Investment including granted $)	0.25%	FERC
Interest Rate on Debt Reserve	3.60%	FERC (4/29/2004 5-year T-Bond)
Interest Rate on Operating Reserve	0.85%	FERC (4/29/2004 3-month T-Bond)
Net Cost of Debt	5.483%	Calculated
Operating Reserve Requirement	$150,000	FERC (approx. 3 months operating revenues in last year of operations, rounded up to nearest 25K)
Federal Tax Rate	34%	FERC
State Tax Rate	8%	FERC
Percent Funding by Equity	0.0%	FERC/GEC
Percent Funding by Debt	100.0%	FERC/GEC

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*1,791,330*	*1,863,960*	*1,930,600*	*1,990,220*	*2,050,860*	*2,114,190*	*2,177,870*	*2,244,930*	*2,311,250*	*2,379,370*	*2,448,095*	*2,517,806*	*2,588,921*	*2,661,484*	*2,735,540*
Hydro Rate (mills/kWh)	*193.90*	*190.02*	*186.68*	*183.91*	*180.94*	*177.64*	*174.26*	*170.64*	*165.32*	*159.74*	*154.42*	*149.31*	*144.37*	*139.58*	*137.16*
Operating Revenues	$347,332	$354,184	$360,407	$366,013	$371,087	$375,559	$379,516	$383,064	$382,095	$380,080	$378,032	$375,928	$373,775	$371,481	$375,216
OPERATING EXPENSES															
Operating Expense	$74,435	$76,113	$77,963	$79,961	$82,158	$84,453	$86,909	$89,609	$92,407	$95,272	$98,373	$101,701	$105,277	$109,026	$112,969
Maintenance Expense															
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$156,431	$161,605	$165,977	$169,585	$172,463	$174,639	$176,140	$176,989	$173,222	$168,341	$163,192	$157,760	$152,031	$145,987	$145,780
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$54,300	$53,541	$52,741	$51,898	$51,008	$50,071	$49,083	$48,040	$46,942	$45,783	$44,562	$43,274	$41,917	$40,486	$38,977
Remaining Component	$175,725	$173,299	$170,740	$168,040	$165,191	$162,186	$159,015	$155,670	$152,141	$148,418	$144,490	$140,346	$135,974	$131,362	$126,496
NET INCOME BEFORE TAXES	-$61,915	-$53,557	-$45,825	-$38,673	-$32,058	-$25,939	-$20,278	-$15,042	-$14,181	-$14,181	-$14,181	-$14,181	-$14,181	-$14,181	-$8,014
Federal Income Taxes	-$49,305	-$42,649	-$36,492	-$30,797	-$25,529	-$20,656	-$16,148	-$11,979	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293
State Income Taxes	-$12,610	-$10,908	-$9,333	-$7,876	-$6,529	-$5,283	-$4,130	-$3,064	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,168
STATEMENT OF CASH FLOWS															
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,168
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$13,974	$14,733	$15,533	$16,377	$17,266	$18,203	$19,192	$20,234	$21,333	$22,491	$23,712	$25,000	$26,357	$27,789	$29,297
Remaining Component	$44,108	$46,534	$49,094	$51,794	$54,642	$57,648	$60,818	$64,163	$67,692	$71,415	$75,343	$79,487	$83,859	$88,471	$93,337
NET CASH FLOW	$58,384	$55,199	$51,840	$48,296	$44,558	$40,616	$36,457	$32,069	$27,442	$22,560	$17,411	$11,980	$6,250	$207	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	122.35	125.11	128.15	131.43	135.04	138.82	142.85	147.29	151.89	156.60	161.70	167.17	173.05	179.21	185.69
Net Benefit	-$128,164	-$120,988	-$113,001	-$104,431	-$94,130	-$82,073	-$68,400	-$52,405	-$31,039	-$7,469	$17,820	$44,969	$74,228	$105,480	$132,742
Annual PV of Net Benefit	-$121,501	-$108,736	-$96,279	-$84,352	-$72,079	-$59,579	-$47,072	-$34,191	-$19,198	-$4,380	$9,906	$23,698	$37,083	$49,957	$59,601
Cumulative PV of Net Benefit	-$121,501	-$230,238	-$326,517	-$410,869	-$482,948	-$542,527	-$589,599	-$623,790	-$642,988	-$647,367	-$637,461	-$613,764	-$576,680	-$526,723	-$467,122
NPV	$1,020,806														

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*2,808,947*	*2,871,303*	*2,933,140*	*2,994,977*	*3,056,813*	*3,118,650*	*3,180,486*	*3,242,323*	*3,304,160*	*3,365,996*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*
Hydro Rate (mills/kWh)	*135.05*	*133.60*	*132.28*	*131.08*	*129.99*	*139.20*	*148.12*	*146.92*	*145.83*	*144.84*	*145.30*	*147.09*	*148.96*	*150.89*	*152.89*
Operating Revenues	$379,351	$383,613	$388,007	$392,591	$397,342	$434,123	$471,083	$476,373	$481,856	$487,538	$493,427	$499,531	$505,858	$512,415	$519,211
OPERATING EXPENSES															
Operating Expense	$117,104	$121,366	$125,760	$130,344	$135,095	$140,019	$145,123	$150,413	$155,895	$161,577	$167,467	$173,571	$179,897	$186,455	$193,251
Maintenance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$145,780	$145,780	$145,780	$145,780	$145,780	$177,637	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$37,386	$35,709	$33,940	$32,076	$30,111	$28,038	$25,853	$23,550	$21,121	$18,561	$15,862	$13,016	$10,015	$6,852	$3,516
Remaining Component	$121,363	$115,947	$110,233	$104,205	$97,845	$91,136	$84,058	$76,590	$68,712	$60,400	$51,631	$42,380	$32,620	$22,324	$11,460
NET INCOME BEFORE TAXES	-$1,289	$5,804	$13,286	$21,178	$29,503	$70,142	$111,262	$121,033	$131,340	$142,212	$153,680	$165,777	$178,538	$191,998	$206,196
Federal Income Taxes	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	$14,075	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444
State Income Taxes	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	$3,600	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088
NET INCOME	$12,892	$19,985	$27,467	$35,360	$43,685	$52,466	$61,730	$71,501	$81,808	$92,680	$104,148	$116,245	$129,006	$142,466	$156,664
STATEMENT OF CASH FLOWS															
NET INCOME	$12,892	$19,985	$27,467	$35,360	$43,685	$52,466	$61,730	$71,501	$81,808	$92,680	$104,148	$116,245	$129,006	$142,466	$156,664
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$30,888	$32,566	$34,334	$36,198	$38,164	$40,236	$42,421	$44,724	$47,153	$49,713	$52,413	$55,259	$58,259	$61,423	$64,758
Remaining Component	$98,471	$103,886	$109,600	$115,628	$121,988	$128,697	$135,775	$143,243	$151,121	$159,433	$168,202	$177,453	$187,213	$197,510	$208,373
NET CASH FLOW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	192.49	199.49	206.71	214.25	222.49	231.04	239.93	249.15	258.73	268.68	279.01	289.74	300.88	312.45	324.47
Net Benefit	$161,332	$189,185	$218,314	$249,079	$282,759	$286,416	$291,998	$331,457	$373,036	$416,841	$454,098	$484,428	$515,936	$548,669	$582,674
Annual PV of Net Benefit	$68,672	$76,342	$83,517	$90,333	$97,217	$93,355	$90,227	$97,096	$103,595	$109,743	$113,337	$114,622	$115,731	$116,676	$117,466
Cumulative PV of Net Benefit	-$398,450	-$322,108	-$238,591	-$148,259	-$51,042	$42,313	$132,540	$229,636	$333,232	$442,974	$556,311	$670,933	$786,664	$903,340	$1,020,806

Variable	Value	Source
Interest on Construction	4.09%	FERC (4/29/2004 6-month T-Bond & 300 basis points)
Financing Cost	2%	FERC
Debt Service Reserve	1 year	FERC
Operational Reserve	3 months	FERC
Term of Analysis	30 years	FERC
Starting Year	2007	FERC
Grant Value	$1,083,685	GEC
Interest on Debt, AIDEA Component	5.43%	GEC
AIDEA Loan Component	$1,000,000	GEC
Interest on Debt, Remainder	5.50%	GEC
Term of Financing, AIDEA Component	30 years	GEC
Term of Financing, Remaining Component	30 years	GEC
2003 O&M (including Staff-recommended environmental enhancements)	$58,600	FERC/GEC
Insurance (% of Initial Investment including granted $)	0.25%	FERC
Interest Rate on Debt Reserve	3.60%	FERC (4/29/2004 5-year T-Bond)
Interest Rate on Operating Reserve	0.85%	FERC (4/29/2004 3-month T-Bond)
Net Cost of Debt	5.483%	Calculated
Operating Reserve Requirement	$150,000	FERC (approx. 3 months operating revenues in last year of operations, rounded up to nearest 25K)
Federal Tax Rate	34%	FERC
State Tax Rate	8%	FERC
Percent Funding by Equity	0.0%	FERC/GEC
Percent Funding by Debt	100.0%	FERC/GEC

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*1,791,330*	*1,863,960*	*1,930,600*	*1,990,220*	*2,050,860*	*2,114,190*	*2,177,870*	*2,244,930*	*2,311,250*	*2,379,370*	*2,448,095*	*2,517,806*	*2,588,921*	*2,661,484*	*2,735,540*
Hydro Rate (mills/kWh)	*193.90*	*190.02*	*186.68*	*183.91*	*180.94*	*177.64*	*174.26*	*170.64*	*165.32*	*159.74*	*154.42*	*149.31*	*144.37*	*139.58*	*137.16*
Operating Revenues	$347,332	$354,184	$360,407	$366,013	$371,087	$375,559	$379,516	$383,064	$382,095	$380,080	$378,032	$375,928	$373,775	$371,481	$375,216
OPERATING EXPENSES															
Operating Expense	$74,435	$76,113	$77,963	$79,961	$82,158	$84,453	$86,909	$89,609	$92,407	$95,272	$98,373	$101,701	$105,277	$109,026	$112,969
Maintenance Expense															
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$156,431	$161,605	$165,977	$169,585	$172,463	$174,639	$176,140	$176,989	$173,222	$168,341	$163,192	$157,760	$152,031	$145,987	$145,780
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$54,300	$53,541	$52,741	$51,898	$51,008	$50,071	$49,083	$48,040	$46,942	$45,783	$44,562	$43,274	$41,917	$40,486	$38,977
Remaining Component	$175,725	$173,299	$170,740	$168,040	$165,191	$162,186	$159,015	$155,670	$152,141	$148,418	$144,490	$140,346	$135,974	$131,362	$126,496
NET INCOME BEFORE TAXES	-$61,915	-$53,557	-$45,825	-$38,673	-$32,058	-$25,939	-$20,278	-$15,042	-$14,181	-$14,181	-$14,181	-$14,181	-$14,181	-$14,181	-$8,014
Federal Income Taxes	-$49,305	-$42,649	-$36,492	-$30,797	-$25,529	-$20,656	-$16,148	-$11,979	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293
State Income Taxes	-$12,610	-$10,908	-$9,333	-$7,876	-$6,529	-$5,283	-$4,130	-$3,064	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,168
STATEMENT OF CASH FLOWS															
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,168
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$13,974	$14,733	$15,533	$16,377	$17,266	$18,203	$19,192	$20,234	$21,333	$22,491	$23,712	$25,000	$26,357	$27,789	$29,297
Remaining Component	$44,108	$46,534	$49,094	$51,794	$54,642	$57,648	$60,818	$64,163	$67,692	$71,415	$75,343	$79,487	$83,859	$88,471	$93,337
NET CASH FLOW	$58,384	$55,199	$51,840	$48,296	$44,558	$40,616	$36,457	$32,069	$27,442	$22,560	$17,411	$11,980	$6,250	$207	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	122.35	125.66	129.28	133.17	137.43	141.89	146.65	151.87	157.29	162.88	168.92	175.39	182.35	189.67	197.38
Net Benefit	-$128,164	-$119,964	-$110,825	-$100,973	-$89,240	-$75,584	-$60,130	-$42,134	-$18,552	$7,472	$35,491	$65,677	$98,320	$133,322	$164,737
Annual PV of Net Benefit	-$121,501	-$107,816	-$94,425	-$81,559	-$68,335	-$54,869	-$41,381	-$27,489	-$11,475	$4,381	$19,729	$34,611	$49,119	$63,143	$73,967
Cumulative PV of Net Benefit	-$121,501	-$229,317	-$323,742	-$405,301	-$473,636	-$528,505	-$569,886	-$597,375	-$608,850	-$604,469	-$584,740	-$550,130	-$501,010	-$437,867	-$363,900
NPV	$1,475,593														

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*2,808,947*	*2,871,303*	*2,933,140*	*2,994,977*	*3,056,813*	*3,118,650*	*3,180,486*	*3,242,323*	*3,304,160*	*3,365,996*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*
Hydro Rate (mills/kWh)	*135.05*	*133.60*	*132.28*	*131.08*	*129.99*	*139.20*	*148.12*	*146.92*	*145.83*	*144.84*	*145.30*	*147.09*	*148.96*	*150.89*	*152.89*
Operating Revenues	$379,351	$383,613	$388,007	$392,591	$397,342	$434,123	$471,083	$476,373	$481,856	$487,538	$493,427	$499,531	$505,858	$512,415	$519,211
OPERATING EXPENSES															
Operating Expense	$117,104	$121,366	$125,760	$130,344	$135,095	$140,019	$145,123	$150,413	$155,895	$161,577	$167,467	$173,571	$179,897	$186,455	$193,251
Maintenance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$145,780	$145,780	$145,780	$145,780	$145,780	$177,637	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$37,386	$35,709	$33,940	$32,076	$30,111	$28,038	$25,853	$23,550	$21,121	$18,561	$15,862	$13,016	$10,015	$6,852	$3,516
Remaining Component	$121,363	$115,947	$110,233	$104,205	$97,845	$91,136	$84,058	$76,590	$68,712	$60,400	$51,631	$42,380	$32,620	$22,324	$11,460
NET INCOME BEFORE TAXES	-$1,289	$5,804	$13,286	$21,178	$29,503	$70,142	$111,262	$121,033	$131,340	$142,212	$153,680	$165,777	$178,538	$191,998	$206,196
Federal Income Taxes	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	$14,075	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444
State Income Taxes	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	$3,600	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088
NET INCOME	$12,892	$19,985	$27,467	$35,360	$43,685	$52,466	$61,730	$71,501	$81,808	$92,680	$104,148	$116,245	$129,006	$142,466	$156,664
STATEMENT OF CASH FLOWS															
NET INCOME	$12,892	$19,985	$27,467	$35,360	$43,685	$52,466	$61,730	$71,501	$81,808	$92,680	$104,148	$116,245	$129,006	$142,466	$156,664
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$30,888	$32,566	$34,334	$36,198	$38,164	$40,236	$42,421	$44,724	$47,153	$49,713	$52,413	$55,259	$58,259	$61,423	$64,758
Remaining Component	$98,471	$103,886	$109,600	$115,628	$121,988	$128,697	$135,775	$143,243	$151,121	$159,433	$168,202	$177,453	$187,213	$197,510	$208,373
NET CASH FLOW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	205.50	213.91	222.62	231.75	241.71	252.10	262.93	274.24	286.02	298.32	311.15	324.53	338.48	353.03	368.21
Net Benefit	$197,896	$230,589	$264,980	$301,484	$341,511	$352,078	$365,171	$412,788	$463,216	$516,611	$563,229	$602,556	$643,616	$686,486	$731,244
Annual PV of Net Benefit	$84,236	$93,050	$101,369	$109,338	$117,417	$114,757	$112,838	$120,921	$128,639	$136,010	$140,575	$142,573	$144,372	$145,983	$147,418
Cumulative PV of Net Benefit	-$279,664	-$186,615	-$85,246	$24,093	$141,509	$256,266	$369,104	$490,025	$618,664	$754,673	$895,248	$1,037,821	$1,182,192	$1,328,175	$1,475,593

Variable	Value	Source
Interest on Construction	4.09%	FERC (4/29/2004 6-month T-Bond & 300 basis points)
Financing Cost	2%	FERC
Debt Service Reserve	1 year	FERC
Operational Reserve	3 months	FERC
Term of Analysis	30 years	FERC
Starting Year	2007	FERC
Grant Value	$1,083,685	GEC
Interest on Debt, AIDEA Component	5.43%	GEC
AIDEA Loan Component	$1,000,000	GEC
Interest on Debt, Remainder	5.50%	GEC
Term of Financing, AIDEA Component	30 years	GEC
Term of Financing, Remaining Component	30 years	GEC
2003 O&M (including Staff-recommended environmental enhancements)	$58,600	FERC/GEC
Insurance (% of Initial Investment including granted $)	0.25%	FERC
Interest Rate on Debt Reserve	3.60%	FERC (4/29/2004 5-year T-Bond)
Interest Rate on Operating Reserve	0.85%	FERC (4/29/2004 3-month T-Bond)
Net Cost of Debt	5.483%	Calculated
Operating Reserve Requirement	$150,000	FERC (approx. 3 months operating revenues in last year of operations, rounded up to nearest 25K)
Federal Tax Rate	34%	FERC
State Tax Rate	8%	FERC
Percent Funding by Equity	0.0%	FERC/GEC
Percent Funding by Debt	100.0%	FERC/GEC

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*1,791,330*	*1,863,960*	*1,930,600*	*1,990,220*	*2,050,860*	*2,114,190*	*2,177,870*	*2,244,930*	*2,311,250*	*2,379,370*	*2,448,095*	*2,517,806*	*2,588,921*	*2,661,484*	*2,735,540*
Hydro Rate (mills/kWh)	*193.90*	*190.02*	*186.68*	*183.91*	*180.94*	*177.64*	*174.26*	*170.64*	*165.32*	*159.74*	*154.42*	*149.31*	*144.37*	*139.58*	*137.16*
Operating Revenues	$347,332	$354,184	$360,407	$366,013	$371,087	$375,559	$379,516	$383,064	$382,095	$380,080	$378,032	$375,928	$373,775	$371,481	$375,216
OPERATING EXPENSES															
Operating Expense	$74,435	$76,113	$77,963	$79,961	$82,158	$84,453	$86,909	$89,609	$92,407	$95,272	$98,373	$101,701	$105,277	$109,026	$112,969
Maintenance Expense															
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$156,431	$161,605	$165,977	$169,585	$172,463	$174,639	$176,140	$176,989	$173,222	$168,341	$163,192	$157,760	$152,031	$145,987	$145,780
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$54,300	$53,541	$52,741	$51,898	$51,008	$50,071	$49,083	$48,040	$46,942	$45,783	$44,562	$43,274	$41,917	$40,486	$38,977
Remaining Component	$175,725	$173,299	$170,740	$168,040	$165,191	$162,186	$159,015	$155,670	$152,141	$148,418	$144,490	$140,346	$135,974	$131,362	$126,496
NET INCOME BEFORE TAXES	-$61,915	-$53,557	-$45,825	-$38,673	-$32,058	-$25,939	-$20,278	-$15,042	-$14,181	-$14,181	-$14,181	-$14,181	-$14,181	-$14,181	-$8,014
Federal Income Taxes	-$49,305	-$42,649	-$36,492	-$30,797	-$25,529	-$20,656	-$16,148	-$11,979	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293
State Income Taxes	-$12,610	-$10,908	-$9,333	-$7,876	-$6,529	-$5,283	-$4,130	-$3,064	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,168
STATEMENT OF CASH FLOWS															
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,168
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$13,974	$14,733	$15,533	$16,377	$17,266	$18,203	$19,192	$20,234	$21,333	$22,491	$23,712	$25,000	$26,357	$27,789	$29,297
Remaining Component	$44,108	$46,534	$49,094	$51,794	$54,642	$57,648	$60,818	$64,163	$67,692	$71,415	$75,343	$79,487	$83,859	$88,471	$93,337
NET CASH FLOW	$58,384	$55,199	$51,840	$48,296	$44,558	$40,616	$36,457	$32,069	$27,442	$22,560	$17,411	$11,980	$6,250	$207	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	122.35	126.21	130.41	134.93	139.85	145.02	150.54	156.58	162.88	169.41	176.46	184.03	192.17	200.75	209.84
Net Benefit	-$128,164	-$118,940	-$108,638	-$97,482	-$84,279	-$68,968	-$51,658	-$31,559	-$5,635	$23,003	$53,949	$87,412	$123,728	$162,825	$198,806
Annual PV of Net Benefit	-$121,501	-$106,895	-$92,561	-$78,739	-$64,536	-$50,067	-$35,551	-$20,590	-$3,485	$13,488	$29,989	$46,064	$61,813	$77,117	$89,263
Cumulative PV of Net Benefit	-$121,501	-$228,397	-$320,958	-$399,697	-$464,233	-$514,299	-$549,850	-$570,440	-$573,925	-$560,437	-$530,448	-$484,384	-$422,571	-$345,455	-$256,191
NPV	$1,973,962														

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*2,808,947*	*2,871,303*	*2,933,140*	*2,994,977*	*3,056,813*	*3,118,650*	*3,180,486*	*3,242,323*	*3,304,160*	*3,365,996*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*
Hydro Rate (mills/kWh)	*135.05*	*133.60*	*132.28*	*131.08*	*129.99*	*139.20*	*148.12*	*146.92*	*145.83*	*144.84*	*145.30*	*147.09*	*148.96*	*150.89*	*152.89*
Operating Revenues	$379,351	$383,613	$388,007	$392,591	$397,342	$434,123	$471,083	$476,373	$481,856	$487,538	$493,427	$499,531	$505,858	$512,415	$519,211
OPERATING EXPENSES															
Operating Expense	$117,104	$121,366	$125,760	$130,344	$135,095	$140,019	$145,123	$150,413	$155,895	$161,577	$167,467	$173,571	$179,897	$186,455	$193,251
Maintenance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$145,780	$145,780	$145,780	$145,780	$145,780	$177,637	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$37,386	$35,709	$33,940	$32,076	$30,111	$28,038	$25,853	$23,550	$21,121	$18,561	$15,862	$13,016	$10,015	$6,852	$3,516
Remaining Component	$121,363	$115,947	$110,233	$104,205	$97,845	$91,136	$84,058	$76,590	$68,712	$60,400	$51,631	$42,380	$32,620	$22,324	$11,460
NET INCOME BEFORE TAXES	-$1,289	$5,804	$13,286	$21,178	$29,503	$70,142	$111,262	$121,033	$131,340	$142,212	$153,680	$165,777	$178,538	$191,998	$206,196
Federal Income Taxes	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	$14,075	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444
State Income Taxes	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	$3,600	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088
NET INCOME	$12,892	$19,985	$27,467	$35,360	$43,685	$52,466	$61,730	$71,501	$81,808	$92,680	$104,148	$116,245	$129,006	$142,466	$156,664
STATEMENT OF CASH FLOWS															
NET INCOME	$12,892	$19,985	$27,467	$35,360	$43,685	$52,466	$61,730	$71,501	$81,808	$92,680	$104,148	$116,245	$129,006	$142,466	$156,664
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$30,888	$32,566	$34,334	$36,198	$38,164	$40,236	$42,421	$44,724	$47,153	$49,713	$52,413	$55,259	$58,259	$61,423	$64,758
Remaining Component	$98,471	$103,886	$109,600	$115,628	$121,988	$128,697	$135,775	$143,243	$151,121	$159,433	$168,202	$177,453	$187,213	$197,510	$208,373
NET CASH FLOW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	219.43	229.41	239.81	250.74	262.67	275.17	288.27	301.99	316.37	331.43	347.22	363.76	381.09	399.25	418.27
Net Benefit	$237,016	$275,101	$315,391	$358,367	$405,591	$424,037	$445,747	$502,777	$563,476	$628,067	$685,727	$735,790	$788,315	$843,423	$901,239
Annual PV of Net Benefit	$100,887	$111,012	$120,654	$129,968	$139,448	$138,212	$137,736	$147,282	$156,482	$165,353	$171,149	$174,097	$176,829	$179,356	$181,688
Cumulative PV of Net Benefit	-$155,304	-$44,292	$76,362	$206,330	$345,778	$483,990	$621,725	$769,007	$925,489	$1,090,842	$1,261,991	$1,436,088	$1,612,918	$1,792,274	$1,973,962

Income Statement-Fuel-High

INCOME STATEMENT AND BACKGROUND

LOW ESTIMATE FOR OTHER DIESEL GENERATION COSTS
MIDDLE-LOW ESTIMATE FOR OTHER DIESEL GENERATION COSTS
MIDDLE-HIGH ESTIMATE FOR OTHER DIESEL GENERATION COSTS
HIGH ESTIMATE FOR OTHER DIESEL GENERATION COSTS

Variable	Value	Source
Interest on Construction	4.09%	FERC (4/29/2004 6-month T-Bond & 300 basis points)
Financing Cost	2%	FERC
Debt Service Reserve	1 year	FERC
Operational Reserve	3 months	FERC
Term of Analysis	30 years	FERC
Starting Year	2007	FERC
Grant Value	$1,083,685	GEC
Interest on Debt, AIDEA Component	5.43%	GEC
AIDEA Loan Component	$1,000,000	GEC
Interest on Debt, Remainder	5.50%	GEC
Term of Financing, AIDEA Component	30 years	GEC
Term of Financing, Remaining Component	30 years	GEC
2003 O&M (including Staff-recommended environmental enhancements)	$58,600	FERC/GEC
Insurance (% of Initial Investment including granted $)	0.25%	FERC
Interest Rate on Debt Reserve	3.60%	FERC (4/29/2004 5-year T-Bond)
Interest Rate on Operating Reserve	0.85%	FERC (4/29/2004 3-month T-Bond)
Net Cost of Debt	5.483%	Calculated
Operating Reserve Requirement	$150,000	FERC (approx. 3 months operating revenues in last year of operations, rounded up to nearest 25K)
Federal Tax Rate	34%	FERC
State Tax Rate	8%	FERC
Percent Funding by Equity	0.0%	FERC/GEC
Percent Funding by Debt	100.0%	FERC/GEC

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*1,791,330*	*1,863,960*	*1,930,600*	*1,990,220*	*2,050,860*	*2,114,190*	*2,177,870*	*2,244,930*	*2,311,250*	*2,379,370*	*2,448,095*	*2,517,806*	*2,588,921*	*2,661,484*	*2,735,540*
Hydro Rate (mills/kWh)	*193.90*	*190.02*	*186.68*	*183.91*	*180.94*	*177.64*	*174.26*	*170.64*	*165.32*	*159.74*	*154.42*	*149.31*	*144.37*	*139.58*	*137.16*
Operating Revenues	$347,332	$354,184	$360,407	$366,013	$371,087	$375,559	$379,516	$383,064	$382,095	$380,080	$378,032	$375,928	$373,775	$371,481	$375,216
OPERATING EXPENSES															
Operating Expense	$74,435	$76,113	$77,963	$79,961	$82,158	$84,453	$86,909	$89,609	$92,407	$95,272	$98,373	$101,701	$105,277	$109,026	$112,969
Maintenance Expense															
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$156,431	$161,605	$165,977	$169,585	$172,463	$174,639	$176,140	$176,989	$173,222	$168,341	$163,192	$157,760	$152,031	$145,987	$145,780
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$54,300	$53,541	$52,741	$51,898	$51,008	$50,071	$49,083	$48,040	$46,942	$45,783	$44,562	$43,274	$41,917	$40,486	$38,977
Remaining Component	$175,725	$173,299	$170,740	$168,040	$165,191	$162,186	$159,015	$155,670	$152,141	$148,418	$144,490	$140,346	$135,974	$131,362	$126,496
NET INCOME BEFORE TAXES	-$61,915	-$53,557	-$45,825	-$38,673	-$32,058	-$25,939	-$20,278	-$15,042	-$14,181	-$14,181	-$14,181	-$14,181	-$14,181	-$14,181	-$8,014
Federal Income Taxes	-$49,305	-$42,649	-$36,492	-$30,797	-$25,529	-$20,656	-$16,148	-$11,979	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293
State Income Taxes	-$12,610	-$10,908	-$9,333	-$7,876	-$6,529	-$5,283	-$4,130	-$3,064	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,168
STATEMENT OF CASH FLOWS															
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,168
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$13,974	$14,733	$15,533	$16,377	$17,266	$18,203	$19,192	$20,234	$21,333	$22,491	$23,712	$25,000	$26,357	$27,789	$29,297
Remaining Component	$44,108	$46,534	$49,094	$51,794	$54,642	$57,648	$60,818	$64,163	$67,692	$71,415	$75,343	$79,487	$83,859	$88,471	$93,337
NET CASH FLOW	$58,384	$55,199	$51,840	$48,296	$44,558	$40,616	$36,457	$32,069	$27,442	$22,560	$17,411	$11,980	$6,250	$207	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	116.47	119.08	121.90	125.06	128.77	132.90	138.31	143.31	149.18	154.37	160.78	166.47	175.57	183.73	190.14
Net Benefit	-$138,688	-$132,227	-$125,073	-$117,109	-$107,001	-$94,578	-$78,285	-$61,345	-$37,311	-$12,775	$15,566	$43,222	$80,761	$117,502	$144,909
Annual PV of Net Benefit	-$131,478	-$118,837	-$106,565	-$94,592	-$81,935	-$68,657	-$53,875	-$40,023	-$23,077	-$7,491	$8,653	$22,777	$40,347	$55,651	$65,064
Cumulative PV of Net Benefit	-$131,478	-$250,316	-$356,881	-$451,473	-$533,407	-$602,065	-$655,940	-$695,963	-$719,040	-$726,530	-$717,878	-$695,100	-$654,753	-$599,102	-$534,039
NPV	$1,196,939														

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*2,808,947*	*2,871,303*	*2,933,140*	*2,994,977*	*3,056,813*	*3,118,650*	*3,180,486*	*3,242,323*	*3,304,160*	*3,365,996*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*
Hydro Rate (mills/kWh)	*135.05*	*133.60*	*132.28*	*131.08*	*129.99*	*139.20*	*148.12*	*146.92*	*145.83*	*144.84*	*145.30*	*147.09*	*148.96*	*150.89*	*152.89*
Operating Revenues	$379,351	$383,613	$388,007	$392,591	$397,342	$434,123	$471,083	$476,373	$481,856	$487,538	$493,427	$499,531	$505,858	$512,415	$519,211
OPERATING EXPENSES															
Operating Expense	$117,104	$121,366	$125,760	$130,344	$135,095	$140,019	$145,123	$150,413	$155,895	$161,577	$167,467	$173,571	$179,897	$186,455	$193,251
Maintenance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$145,780	$145,780	$145,780	$145,780	$145,780	$177,637	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$37,386	$35,709	$33,940	$32,076	$30,111	$28,038	$25,853	$23,550	$21,121	$18,561	$15,862	$13,016	$10,015	$6,852	$3,516
Remaining Component	$121,363	$115,947	$110,233	$104,205	$97,845	$91,136	$84,058	$76,590	$68,712	$60,400	$51,631	$42,380	$32,620	$22,324	$11,460
NET INCOME BEFORE TAXES	-$1,289	$5,804	$13,286	$21,178	$29,503	$70,142	$111,262	$121,033	$131,340	$142,212	$153,680	$165,777	$178,538	$191,998	$206,196
Federal Income Taxes	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	$14,075	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444
State Income Taxes	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	$3,600	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088
NET INCOME	$12,892	$19,985	$27,467	$35,360	$43,685	$52,466	$61,730	$71,501	$81,808	$92,680	$104,148	$116,245	$129,006	$142,466	$156,664
STATEMENT OF CASH FLOWS															
NET INCOME	$12,892	$19,985	$27,467	$35,360	$43,685	$52,466	$61,730	$71,501	$81,808	$92,680	$104,148	$116,245	$129,006	$142,466	$156,664
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$30,888	$32,566	$34,334	$36,198	$38,164	$40,236	$42,421	$44,724	$47,153	$49,713	$52,413	$55,259	$58,259	$61,423	$64,758
Remaining Component	$98,471	$103,886	$109,600	$115,628	$121,988	$128,697	$135,775	$143,243	$151,121	$159,433	$168,202	$177,453	$187,213	$197,510	$208,373
NET CASH FLOW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	198.07	206.24	214.43	224.22	234.12	244.47	255.27	266.55	278.33	290.63	303.47	316.89	330.89	345.52	360.79
Net Benefit	$177,013	$208,551	$240,957	$278,935	$318,332	$328,290	$340,803	$387,872	$437,791	$490,721	$537,169	$576,612	$617,847	$660,956	$706,022
Annual PV of Net Benefit	$75,347	$84,157	$92,179	$101,161	$109,447	$107,004	$105,308	$113,622	$121,578	$129,193	$134,070	$136,434	$138,591	$140,554	$142,333
Cumulative PV of Net Benefit	-$458,692	-$374,535	-$282,356	-$181,196	-$71,748	$35,255	$140,563	$254,185	$375,763	$504,956	$639,027	$775,461	$914,052	$1,054,606	$1,196,939

Variable	**Value**		**Source**
Interest on Construction	4.09%		FERC (4/29/2004 6-month T-Bond & 300 basis points)
Financing Cost	2%		FERC
Debt Service Reserve	1	year	FERC
Operational Reserve	3	months	FERC
Term of Analysis	30	years	FERC
Starting Year	2007		FERC
Grant Value	$1,083,685		GEC
Interest on Debt, AIDEA Component	5.43%		GEC
AIDEA Loan Component	$1,000,000		GEC
Interest on Debt, Remainder	5.50%		GEC
Term of Financing, AIDEA Component	30	years	GEC
Term of Financing, Remaining Component	30	years	GEC
2003 O&M (including Staff-recommended environmental enhancements)	$58,600		FERC/GEC
Insurance (% of Initial Investment including granted $)	0.25%		FERC
Interest Rate on Debt Reserve	3.60%		FERC (4/29/2004 5-year T-Bond)
Interest Rate on Operating Reserve	0.85%		FERC (4/29/2004 3-month T-Bond)
Net Cost of Debt	5.483%		Calculated
Operating Reserve Requirement	$150,000		FERC (approx. 3 months operating revenues in last year of operations, rounded up to nearest 25K)
Federal Tax Rate	34%		FERC
State Tax Rate	8%		FERC
Percent Funding by Equity	0.0%		FERC/GEC
Percent Funding by Debt	100.0%		FERC/GEC

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*1,791,330*	*1,863,960*	*1,930,600*	*1,990,220*	*2,050,860*	*2,114,190*	*2,177,870*	*2,244,930*	*2,311,250*	*2,379,370*	*2,448,095*	*2,517,806*	*2,588,921*	*2,661,484*	*2,735,540*
Hydro Rate (mills/kWh)	*193.90*	*190.02*	*186.68*	*183.91*	*180.94*	*177.64*	*174.26*	*170.64*	*165.32*	*159.74*	*154.42*	*149.31*	*144.37*	*139.58*	*137.16*
Operating Revenues	$347,332	$354,184	$360,407	$366,013	$371,087	$375,559	$379,516	$383,064	$382,095	$380,080	$378,032	$375,928	$373,775	$371,481	$375,216
OPERATING EXPENSES															
Operating Expense	$74,435	$76,113	$77,963	$79,961	$82,158	$84,453	$86,909	$89,609	$92,407	$95,272	$98,373	$101,701	$105,277	$109,026	$112,969
Maintenance Expense															
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$156,431	$161,605	$165,977	$169,585	$172,463	$174,639	$176,140	$176,989	$173,222	$168,341	$163,192	$157,760	$152,031	$145,987	$145,780
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$54,300	$53,541	$52,741	$51,898	$51,008	$50,071	$49,083	$48,040	$46,942	$45,783	$44,562	$43,274	$41,917	$40,486	$38,977
Remaining Component	$175,725	$173,299	$170,740	$168,040	$165,191	$162,186	$159,015	$155,670	$152,141	$148,418	$144,490	$140,346	$135,974	$131,362	$126,496
NET INCOME BEFORE TAXES	-$61,915	-$53,557	-$45,825	-$38,673	-$32,058	-$25,939	-$20,278	-$15,042	-$14,181	-$14,181	-$14,181	-$14,181	-$14,181	-$14,181	-$8,014
Federal Income Taxes	-$49,305	-$42,649	-$36,492	-$30,797	-$25,529	-$20,656	-$16,148	-$11,979	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293
State Income Taxes	-$12,610	-$10,908	-$9,333	-$7,876	-$6,529	-$5,283	-$4,130	-$3,064	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,168
STATEMENT OF CASH FLOWS															
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,168
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$13,974	$14,733	$15,533	$16,377	$17,266	$18,203	$19,192	$20,234	$21,333	$22,491	$23,712	$25,000	$26,357	$27,789	$29,297
Remaining Component	$44,108	$46,534	$49,094	$51,794	$54,642	$57,648	$60,818	$64,163	$67,692	$71,415	$75,343	$79,487	$83,859	$88,471	$93,337
NET CASH FLOW	$58,384	$55,199	$51,840	$48,296	$44,558	$40,616	$36,457	$32,069	$27,442	$22,560	$17,411	$11,980	$6,250	$207	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	118.95	121.61	124.49	127.72	131.50	135.71	141.21	146.29	152.25	157.54	164.05	169.86	179.07	187.35	193.89
Net Benefit	-$134,251	-$127,507	-$120,065	-$111,814	-$101,395	-$88,637	-$71,987	-$54,652	-$30,205	-$5,233	$23,578	$51,742	$89,829	$127,157	$155,190
Annual PV of Net Benefit	-$127,273	-$114,595	-$102,298	-$90,315	-$77,642	-$64,345	-$49,542	-$35,656	-$18,682	-$3,068	$13,107	$27,267	$44,877	$60,224	$69,680
Cumulative PV of Net Benefit	-$127,273	-$241,868	-$344,166	-$434,481	-$512,123	-$576,468	-$626,009	-$661,666	-$680,348	-$683,416	-$670,309	-$643,042	-$598,165	-$537,941	-$468,261
NPV	$1,333,336														

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*2,808,947*	*2,871,303*	*2,933,140*	*2,994,977*	*3,056,813*	*3,118,650*	*3,180,486*	*3,242,323*	*3,304,160*	*3,365,996*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*
Hydro Rate (mills/kWh)	*135.05*	*133.60*	*132.28*	*131.08*	*129.99*	*139.20*	*148.12*	*146.92*	*145.83*	*144.84*	*145.30*	*147.09*	*148.96*	*150.89*	*152.89*
Operating Revenues	$379,351	$383,613	$388,007	$392,591	$397,342	$434,123	$471,083	$476,373	$481,856	$487,538	$493,427	$499,531	$505,858	$512,415	$519,211
OPERATING EXPENSES															
Operating Expense	$117,104	$121,366	$125,760	$130,344	$135,095	$140,019	$145,123	$150,413	$155,895	$161,577	$167,467	$173,571	$179,897	$186,455	$193,251
Maintenance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$145,780	$145,780	$145,780	$145,780	$145,780	$177,637	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$37,386	$35,709	$33,940	$32,076	$30,111	$28,038	$25,853	$23,550	$21,121	$18,561	$15,862	$13,016	$10,015	$6,852	$3,516
Remaining Component	$121,363	$115,947	$110,233	$104,205	$97,845	$91,136	$84,058	$76,590	$68,712	$60,400	$51,631	$42,380	$32,620	$22,324	$11,460
NET INCOME BEFORE TAXES	-$1,289	$5,804	$13,286	$21,178	$29,503	$70,142	$111,262	$121,033	$131,340	$142,212	$153,680	$165,777	$178,538	$191,998	$206,196
Federal Income Taxes	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	$14,075	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444
State Income Taxes	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	$3,600	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088
NET INCOME	$12,892	$19,985	$27,467	$35,360	$43,685	$52,466	$61,730	$71,501	$81,808	$92,680	$104,148	$116,245	$129,006	$142,466	$156,664
STATEMENT OF CASH FLOWS															
NET INCOME	$12,892	$19,985	$27,467	$35,360	$43,685	$52,466	$61,730	$71,501	$81,808	$92,680	$104,148	$116,245	$129,006	$142,466	$156,664
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$30,888	$32,566	$34,334	$36,198	$38,164	$40,236	$42,421	$44,724	$47,153	$49,713	$52,413	$55,259	$58,259	$61,423	$64,758
Remaining Component	$98,471	$103,886	$109,600	$115,628	$121,988	$128,697	$135,775	$143,243	$151,121	$159,433	$168,202	$177,453	$187,213	$197,510	$208,373
NET CASH FLOW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	201.96	210.27	218.62	228.55	238.63	249.15	260.13	271.59	283.57	296.07	309.12	322.75	336.98	351.84	367.35
Net Benefit	$187,957	$220,146	$253,230	$291,923	$332,098	$342,874	$356,249	$404,223	$455,095	$509,027	$556,348	$596,529	$638,530	$682,434	$728,326
Annual PV of Net Benefit	$80,005	$88,835	$96,874	$105,871	$114,180	$111,757	$110,080	$118,412	$126,384	$134,013	$138,857	$141,146	$143,231	$145,121	$146,829
Cumulative PV of Net Benefit	-$388,256	-$299,421	-$202,547	-$96,676	$17,504	$129,262	$239,342	$357,754	$484,138	$618,151	$757,008	$898,154	$1,041,385	$1,186,506	$1,333,336

Variable	Value		Source
Interest on Construction	4.09%		FERC (4/29/2004 6-month T-Bond & 300 basis points)
Financing Cost	2%		FERC
Debt Service Reserve	1	year	FERC
Operational Reserve	3	months	FERC
Term of Analysis	30	years	FERC
Starting Year	2007		FERC
Grant Value	$1,083,685		GEC
Interest on Debt, AIDEA Component	5.43%		GEC
AIDEA Loan Component	$1,000,000		GEC
Interest on Debt, Remainder	5.50%		GEC
Term of Financing, AIDEA Component	30	years	GEC
Term of Financing, Remaining Component	30	years	GEC
2003 O&M (including Staff-recommended environmental enhancements)	$58,600		FERC/GEC
Insurance (% of Initial Investment including granted $)	0.25%		FERC
Interest Rate on Debt Reserve	3.60%		FERC (4/29/2004 5-year T-Bond)
Interest Rate on Operating Reserve	0.85%		FERC (4/29/2004 3-month T-Bond)
Net Cost of Debt	5.483%		Calculated
Operating Reserve Requirement	$150,000		FERC (approx. 3 months operating revenues in last year of operations, rounded up to nearest 25K)
Federal Tax Rate	34%		FERC
State Tax Rate	8%		FERC
Percent Funding by Equity	0.0%		FERC/GEC
Percent Funding by Debt	100.0%		FERC/GEC

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*1,791,330*	*1,863,960*	*1,930,600*	*1,990,220*	*2,050,860*	*2,114,190*	*2,177,870*	*2,244,930*	*2,311,250*	*2,379,370*	*2,448,095*	*2,517,806*	*2,588,921*	*2,661,484*	*2,735,540*
Hydro Rate (mills/kWh)	*193.90*	*190.02*	*186.68*	*183.91*	*180.94*	*177.64*	*174.26*	*170.64*	*165.32*	*159.74*	*154.42*	*149.31*	*144.37*	*139.58*	*137.16*
Operating Revenues	$347,332	$354,184	$360,407	$366,013	$371,087	$375,559	$379,516	$383,064	$382,095	$380,080	$378,032	$375,928	$373,775	$371,481	$375,216
OPERATING EXPENSES															
Operating Expense	$74,435	$76,113	$77,963	$79,961	$82,158	$84,453	$86,909	$89,609	$92,407	$95,272	$98,373	$101,701	$105,277	$109,026	$112,969
Maintenance Expense															
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$156,431	$161,605	$165,977	$169,585	$172,463	$174,639	$176,140	$176,989	$173,222	$168,341	$163,192	$157,760	$152,031	$145,987	$145,780
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$54,300	$53,541	$52,741	$51,898	$51,008	$50,071	$49,083	$48,040	$46,942	$45,783	$44,562	$43,274	$41,917	$40,486	$38,977
Remaining Component	$175,725	$173,299	$170,740	$168,040	$165,191	$162,186	$159,015	$155,670	$152,141	$148,418	$144,490	$140,346	$135,974	$131,362	$126,496
NET INCOME BEFORE TAXES	-$61,915	-$53,557	-$45,825	-$38,673	-$32,058	-$25,939	-$20,278	-$15,042	-$14,181	-$14,181	-$14,181	-$14,181	-$14,181	-$14,181	-$8,014
Federal Income Taxes	-$49,305	-$42,649	-$36,492	-$30,797	-$25,529	-$20,656	-$16,148	-$11,979	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293
State Income Taxes	-$12,610	-$10,908	-$9,333	-$7,876	-$6,529	-$5,283	-$4,130	-$3,064	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,168
STATEMENT OF CASH FLOWS															
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,168
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$13,974	$14,733	$15,533	$16,377	$17,266	$18,203	$19,192	$20,234	$21,333	$22,491	$23,712	$25,000	$26,357	$27,789	$29,297
Remaining Component	$44,108	$46,534	$49,094	$51,794	$54,642	$57,648	$60,818	$64,163	$67,692	$71,415	$75,343	$79,487	$83,859	$88,471	$93,337
NET CASH FLOW	$58,384	$55,199	$51,840	$48,296	$44,558	$40,616	$36,457	$32,069	$27,442	$22,560	$17,411	$11,980	$6,250	$207	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	122.35	125.09	128.05	131.37	135.25	139.57	145.17	150.38	156.47	161.89	168.54	174.50	183.88	192.33	235.80
Net Benefit	-$128,164	-$121,030	-$113,193	-$104,548	-$93,702	-$80,485	-$63,345	-$45,467	-$20,454	$5,117	$34,574	$63,433	$102,273	$140,405	$269,823
Annual PV of Net Benefit	-$121,501	-$108,774	-$96,443	-$84,447	-$71,751	-$58,427	-$43,594	-$29,664	-$12,651	$3,001	$19,219	$33,428	$51,094	$66,498	$121,150
Cumulative PV of Net Benefit	-$121,501	-$230,275	-$326,718	-$411,164	-$482,915	-$541,342	-$584,936	-$614,600	-$627,251	-$624,251	-$605,032	-$571,604	-$520,510	-$454,011	-$332,862
NPV	$2,086,941														

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*2,808,947*	*2,871,303*	*2,933,140*	*2,994,977*	*3,056,813*	*3,118,650*	*3,180,486*	*3,242,323*	*3,304,160*	*3,365,996*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*
Hydro Rate (mills/kWh)	*135.05*	*133.60*	*132.28*	*131.08*	*129.99*	*139.20*	*148.12*	*146.92*	*145.83*	*144.84*	*145.30*	*147.09*	*148.96*	*150.89*	*152.89*
Operating Revenues	$379,351	$383,613	$388,007	$392,591	$397,342	$434,123	$471,083	$476,373	$481,856	$487,538	$493,427	$499,531	$505,858	$512,415	$519,211
OPERATING EXPENSES															
Operating Expense	$117,104	$121,366	$125,760	$130,344	$135,095	$140,019	$145,123	$150,413	$155,895	$161,577	$167,467	$173,571	$179,897	$186,455	$193,251
Maintenance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$145,780	$145,780	$145,780	$145,780	$145,780	$177,637	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$37,386	$35,709	$33,940	$32,076	$30,111	$28,038	$25,853	$23,550	$21,121	$18,561	$15,862	$13,016	$10,015	$6,852	$3,516
Remaining Component	$121,363	$115,947	$110,233	$104,205	$97,845	$91,136	$84,058	$76,590	$68,712	$60,400	$51,631	$42,380	$32,620	$22,324	$11,460
NET INCOME BEFORE TAXES	-$1,289	$5,804	$13,286	$21,178	$29,503	$70,142	$111,262	$121,033	$131,340	$142,212	$153,680	$165,777	$178,538	$191,998	$206,196
Federal Income Taxes	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	$14,075	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444
State Income Taxes	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	$3,600	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088
NET INCOME	$12,892	$19,985	$27,467	$35,360	$43,685	$52,466	$61,730	$71,501	$81,808	$92,680	$104,148	$116,245	$129,006	$142,466	$156,664
STATEMENT OF CASH FLOWS															
NET INCOME	$12,892	$19,985	$27,467	$35,360	$43,685	$52,466	$61,730	$71,501	$81,808	$92,680	$104,148	$116,245	$129,006	$142,466	$156,664
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$30,888	$32,566	$34,334	$36,198	$38,164	$40,236	$42,421	$44,724	$47,153	$49,713	$52,413	$55,259	$58,259	$61,423	$64,758
Remaining Component	$98,471	$103,886	$109,600	$115,628	$121,988	$128,697	$135,775	$143,243	$151,121	$159,433	$168,202	$177,453	$187,213	$197,510	$208,373
NET CASH FLOW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	244.06	252.56	261.11	271.25	281.55	292.31	303.54	315.26	327.50	340.28	353.62	367.55	382.09	397.27	413.11
Net Benefit	$306,196	$341,568	$377,856	$419,803	$463,317	$477,490	$494,318	$545,808	$600,259	$657,838	$707,460	$748,653	$791,705	$836,700	$883,726
Annual PV of Net Benefit	$130,334	$137,833	$144,550	$152,249	$159,295	$155,634	$152,744	$159,887	$166,697	$173,191	$176,573	$177,141	$177,590	$177,926	$178,158
Cumulative PV of Net Benefit	-$202,527	-$64,694	$79,856	$232,105	$391,400	$547,034	$699,778	$859,665	$1,026,362	$1,199,553	$1,376,126	$1,553,267	$1,730,857	$1,908,783	$2,086,941

Variable	**Value**	**Source**
Interest on Construction	4.09%	FERC (4/29/2004 6-month T-Bond & 300 basis points)
Financing Cost	2%	FERC
Debt Service Reserve	1 year	FERC
Operational Reserve	3 months	FERC
Term of Analysis	30 years	FERC
Starting Year	2007	FERC
Grant Value	$1,083,685	GEC
Interest on Debt, AIDEA Component	5.43%	GEC
AIDEA Loan Component	$1,000,000	GEC
Interest on Debt, Remainder	5.50%	GEC
Term of Financing, AIDEA Component	30 years	GEC
Term of Financing, Remaining Component	30 years	GEC
2003 O&M (including Staff-recommended environmental enhancements)	$58,600	FERC/GEC
Insurance (% of Initial Investment including granted $)	0.25%	FERC
Interest Rate on Debt Reserve	3.60%	FERC (4/29/2004 5-year T-Bond)
Interest Rate on Operating Reserve	0.85%	FERC (4/29/2004 3-month T-Bond)
Net Cost of Debt	5.483%	Calculated
Operating Reserve Requirement	$150,000	FERC (approx. 3 months operating revenues in last year of operations, rounded up to nearest 25K)
Federal Tax Rate	34%	FERC
State Tax Rate	8%	FERC
Percent Funding by Equity	0.0%	FERC/GEC
Percent Funding by Debt	100.0%	FERC/GEC

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*1,791,330*	*1,863,960*	*1,930,600*	*1,990,220*	*2,050,860*	*2,114,190*	*2,177,870*	*2,244,930*	*2,311,250*	*2,379,370*	*2,448,095*	*2,517,806*	*2,588,921*	*2,661,484*	*2,735,540*
Hydro Rate (mills/kWh)	*193.90*	*190.02*	*186.68*	*183.91*	*180.94*	*177.64*	*174.26*	*170.64*	*165.32*	*159.74*	*154.42*	*149.31*	*144.37*	*139.58*	*137.16*
Operating Revenues	$347,332	$354,184	$360,407	$366,013	$371,087	$375,559	$379,516	$383,064	$382,095	$380,080	$378,032	$375,928	$373,775	$371,481	$375,216
OPERATING EXPENSES															
Operating Expense	$74,435	$76,113	$77,963	$79,961	$82,158	$84,453	$86,909	$89,609	$92,407	$95,272	$98,373	$101,701	$105,277	$109,026	$112,969
Maintenance Expense															
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$156,431	$161,605	$165,977	$169,585	$172,463	$174,639	$176,140	$176,989	$173,222	$168,341	$163,192	$157,760	$152,031	$145,987	$145,780
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$54,300	$53,541	$52,741	$51,898	$51,008	$50,071	$49,083	$48,040	$46,942	$45,783	$44,562	$43,274	$41,917	$40,486	$38,977
Remaining Component	$175,725	$173,299	$170,740	$168,040	$165,191	$162,186	$159,015	$155,670	$152,141	$148,418	$144,490	$140,346	$135,974	$131,362	$126,496
NET INCOME BEFORE TAXES	-$61,915	-$53,557	-$45,825	-$38,673	-$32,058	-$25,939	-$20,278	-$15,042	-$14,181	-$14,181	-$14,181	-$14,181	-$14,181	-$14,181	-$8,014
Federal Income Taxes	-$49,305	-$42,649	-$36,492	-$30,797	-$25,529	-$20,656	-$16,148	-$11,979	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293
State Income Taxes	-$12,610	-$10,908	-$9,333	-$7,876	-$6,529	-$5,283	-$4,130	-$3,064	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,168
STATEMENT OF CASH FLOWS															
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,168
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$13,974	$14,733	$15,533	$16,377	$17,266	$18,203	$19,192	$20,234	$21,333	$22,491	$23,712	$25,000	$26,357	$27,789	$29,297
Remaining Component	$44,108	$46,534	$49,094	$51,794	$54,642	$57,648	$60,818	$64,163	$67,692	$71,415	$75,343	$79,487	$83,859	$88,471	$93,337
NET CASH FLOW	$58,384	$55,199	$51,840	$48,296	$44,558	$40,616	$36,457	$32,069	$27,442	$22,560	$17,411	$11,980	$6,250	$207	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	122.35	125.09	128.05	131.37	135.25	139.57	145.17	150.38	156.47	192.88	199.53	205.49	214.87	223.32	230.04
Net Benefit	-$128,164	-$121,030	-$113,193	-$104,548	-$93,702	-$80,485	-$63,345	-$45,467	-$20,454	$78,856	$110,442	$141,462	$182,505	$222,886	$254,076
Annual PV of Net Benefit	-$121,501	-$108,774	-$96,443	-$84,447	-$71,751	-$58,427	-$43,594	-$29,664	-$12,651	$46,238	$61,392	$74,548	$91,177	$105,563	$114,079
Cumulative PV of Net Benefit	-$121,501	-$230,275	-$326,718	-$411,164	-$482,915	-$541,342	-$584,936	-$614,600	-$627,251	-$581,014	-$519,622	-$445,074	-$353,897	-$248,334	-$134,255
NPV	$2,332,383														

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*2,808,947*	*2,871,303*	*2,933,140*	*2,994,977*	*3,056,813*	*3,118,650*	*3,180,486*	*3,242,323*	*3,304,160*	*3,365,996*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*
Hydro Rate (mills/kWh)	*135.05*	*133.60*	*132.28*	*131.08*	*129.99*	*139.20*	*148.12*	*146.92*	*145.83*	*144.84*	*145.30*	*147.09*	*148.96*	*150.89*	*152.89*
Operating Revenues	$379,351	$383,613	$388,007	$392,591	$397,342	$434,123	$471,083	$476,373	$481,856	$487,538	$493,427	$499,531	$505,858	$512,415	$519,211
OPERATING EXPENSES															
Operating Expense	$117,104	$121,366	$125,760	$130,344	$135,095	$140,019	$145,123	$150,413	$155,895	$161,577	$167,467	$173,571	$179,897	$186,455	$193,251
Maintenance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$145,780	$145,780	$145,780	$145,780	$145,780	$177,637	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494	$209,494
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404	$10,404
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$37,386	$35,709	$33,940	$32,076	$30,111	$28,038	$25,853	$23,550	$21,121	$18,561	$15,862	$13,016	$10,015	$6,852	$3,516
Remaining Component	$121,363	$115,947	$110,233	$104,205	$97,845	$91,136	$84,058	$76,590	$68,712	$60,400	$51,631	$42,380	$32,620	$22,324	$11,460
NET INCOME BEFORE TAXES	-$1,289	$5,804	$13,286	$21,178	$29,503	$70,142	$111,262	$121,033	$131,340	$142,212	$153,680	$165,777	$178,538	$191,998	$206,196
Federal Income Taxes	-$11,293	-$11,293	-$11,293	-$11,293	-$11,293	$14,075	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444	$39,444
State Income Taxes	-$2,888	-$2,888	-$2,888	-$2,888	-$2,888	$3,600	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088	$10,088
NET INCOME	$12,892	$19,985	$27,467	$35,360	$43,685	$52,466	$61,730	$71,501	$81,808	$92,680	$104,148	$116,245	$129,006	$142,466	$156,664
STATEMENT OF CASH FLOWS															
NET INCOME	$12,892	$19,985	$27,467	$35,360	$43,685	$52,466	$61,730	$71,501	$81,808	$92,680	$104,148	$116,245	$129,006	$142,466	$156,664
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$30,888	$32,566	$34,334	$36,198	$38,164	$40,236	$42,421	$44,724	$47,153	$49,713	$52,413	$55,259	$58,259	$61,423	$64,758
Remaining Component	$98,471	$103,886	$109,600	$115,628	$121,988	$128,697	$135,775	$143,243	$151,121	$159,433	$168,202	$177,453	$187,213	$197,510	$208,373
NET CASH FLOW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	238.30	246.81	255.35	265.50	288.84	299.59	310.82	322.54	334.78	347.56	360.90	374.83	389.37	404.55	424.81
Net Benefit	$290,026	$325,040	$360,972	$402,563	$485,578	$500,201	$517,479	$569,419	$624,321	$682,350	$732,191	$773,383	$816,435	$861,431	$923,427
Annual PV of Net Benefit	$123,452	$131,163	$138,091	$145,996	$166,949	$163,037	$159,901	$166,804	$173,379	$179,644	$182,745	$182,992	$183,137	$183,186	$186,161
Cumulative PV of Net Benefit	-$10,803	$120,360	$258,451	$404,448	$571,397	$734,433	$894,334	$1,061,137	$1,234,517	$1,414,161	$1,596,906	$1,779,899	$1,963,036	$2,146,222	$2,332,383

INCOME STATEMENT AND BACKGROUND

ESTIMATE ASSUMING NO GRANT AVAILABILITY
ESTIMATE ASSUMING $2,000,000 GRANT AVAILABILITY

Variable	Value		Source
Interest on Construction	4.09%		FERC (4/29/2004 6-month T-Bond & 300 basis points)
Financing Cost	2%		FERC
Debt Service Reserve	1	year	FERC
Operational Reserve	3	months	FERC
Term of Analysis	30	years	FERC
Starting Year	2007		FERC
Grant Value	$0		GEC
Interest on Debt, AIDEA Component	5.43%		GEC
AIDEA Loan Component	$1,000,000		GEC
Interest on Debt, Remainder	5.50%		GEC
Term of Financing, AIDEA Component	30	years	GEC
Term of Financing, Remaining Component	30	years	GEC
2003 O&M (including Staff-recommended environmental enhancements)	$58,600		FERC/GEC
Insurance (% of Initial Investment including granted $)	0.25%		FERC
Interest Rate on Debt Reserve	3.60%		FERC (4/29/2004 5-year T-Bond)
Interest Rate on Operating Reserve	0.85%		FERC (4/29/2004 3-month T-Bond)
Net Cost of Debt	5.487%		Calculated
Operating Reserve Requirement	$150,000		FERC (approx. 3 months operating revenues in last year of operations, rounded up to nearest 25K)
Federal Tax Rate	34%		FERC
State Tax Rate	8%		FERC
Percent Funding by Equity	0.0%		FERC/GEC
Percent Funding by Debt	100.0%		FERC/GEC

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*1,791,330*	*1,863,960*	*1,930,600*	*1,990,220*	*2,050,860*	*2,114,190*	*2,177,870*	*2,244,930*	*2,311,250*	*2,379,370*	*2,448,095*	*2,517,806*	*2,588,921*	*2,661,484*	*2,735,540*
Hydro Rate (mills/kWh)	*240.94*	*236.13*	*231.93*	*228.40*	*224.58*	*220.31*	*215.93*	*211.20*	*204.23*	*196.91*	*189.91*	*183.16*	*176.62*	*170.25*	*166.43*
Operating Revenues	$431,612	$440,132	$447,772	$454,557	$460,582	$465,785	$470,262	$474,128	$472,024	$468,523	$464,909	$461,153	$457,257	$453,123	$455,270
OPERATING EXPENSES															
Operating Expense	$74,435	$76,113	$77,963	$79,961	$82,158	$84,453	$86,909	$89,609	$92,407	$95,272	$98,373	$101,701	$105,277	$109,026	$112,969
Maintenance Expense															
Depreciation Expense	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333
NET OPERATING INCOME	$203,843	$210,686	$216,476	$221,263	$225,090	$227,998	$230,020	$231,186	$226,284	$219,918	$213,202	$206,119	$198,646	$190,764	$188,968
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$13,536	$13,536	$13,536	$13,536	$13,536	$13,536	$13,536	$13,536	$13,536	$13,536	$13,536	$13,536	$13,536	$13,536	$13,536
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$54,300	$53,541	$52,741	$51,898	$51,008	$50,071	$49,083	$48,040	$46,942	$45,783	$44,562	$43,274	$41,917	$40,486	$38,977
Remaining Component	$245,795	$242,402	$238,822	$235,045	$231,060	$226,857	$222,422	$217,743	$212,807	$207,599	$202,105	$196,309	$190,194	$183,742	$176,936
NET INCOME BEFORE TAXES	-$81,441	-$70,446	-$60,276	-$50,869	-$42,167	-$34,118	-$26,673	-$19,786	-$18,654	-$18,654	-$18,654	-$18,654	-$18,654	-$18,654	-$12,135
Federal Income Taxes	-$64,854	-$56,099	-$48,000	-$40,509	-$33,579	-$27,170	-$21,241	-$15,756	-$14,855	-$14,855	-$14,855	-$14,855	-$14,855	-$14,855	-$14,855
State Income Taxes	-$16,587	-$14,347	-$12,276	-$10,360	-$8,588	-$6,949	-$5,432	-$4,030	-$3,799	-$3,799	-$3,799	-$3,799	-$3,799	-$3,799	-$3,799
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,519
STATEMENT OF CASH FLOWS															
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,519
Add back Depreciation	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333
Subtract Principal Payment															
AIDEA Component	$13,974	$14,733	$15,533	$16,377	$17,266	$18,203	$19,192	$20,234	$21,333	$22,491	$23,712	$25,000	$26,357	$27,789	$29,297
Remaining Component	$61,696	$65,090	$68,670	$72,446	$76,431	$80,635	$85,069	$89,748	$94,684	$99,892	$105,386	$111,182	$117,297	$123,749	$130,555
NET CASH FLOW	$77,663	$73,511	$69,131	$64,510	$59,637	$54,495	$49,072	$43,351	$37,316	$30,950	$24,235	$17,151	$9,679	$1,796	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	122.35	125.09	128.05	131.37	135.25	139.57	145.17	150.38	156.47	161.89	168.54	174.50	183.88	192.33	199.05
Net Benefit	-$212,443	-$206,977	-$200,559	-$193,093	-$183,196	-$170,711	-$154,092	-$136,531	-$110,382	-$83,326	-$52,304	-$21,792	$18,791	$58,762	$89,246
Annual PV of Net Benefit	-$201,392	-$186,004	-$170,861	-$155,943	-$140,255	-$123,898	-$106,019	-$89,050	-$68,250	-$48,841	-$29,063	-$11,479	$9,383	$27,816	$40,049
Cumulative PV of Net Benefit	-$201,392	-$387,397	-$558,257	-$714,201	-$854,455	-$978,353	-$1,084,371	-$1,173,421	-$1,241,671	-$1,290,512	-$1,319,575	-$1,331,054	-$1,321,670	-$1,293,854	-$1,253,805
NPV	$233,355														

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*2,808,947*	*2,871,303*	*2,933,140*	*2,994,977*	*3,056,813*	*3,118,650*	*3,180,486*	*3,242,323*	*3,304,160*	*3,365,996*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*
Hydro Rate (mills/kWh)	*163.55*	*161.48*	*159.58*	*157.81*	*156.17*	*168.09*	*179.60*	*177.81*	*176.14*	*174.59*	*174.79*	*176.58*	*178.45*	*180.38*	*182.38*
Operating Revenues	$459,405	$463,666	$468,061	$472,645	$477,396	$524,223	$571,230	$576,520	$582,002	$587,684	$593,574	$599,678	$606,004	$612,562	$619,358
OPERATING EXPENSES															
Operating Expense	$117,104	$121,366	$125,760	$130,344	$135,095	$140,019	$145,123	$150,413	$155,895	$161,577	$167,467	$173,571	$179,897	$186,455	$193,251
Maintenance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation Expense	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333
NET OPERATING INCOME	$188,968	$188,968	$188,968	$188,968	$188,968	$230,871	$272,774	$272,774	$272,774	$272,774	$272,774	$272,774	$272,774	$272,774	$272,774
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$13,536	$13,536	$13,536	$13,536	$13,536	$13,536	$13,536	$13,536	$13,536	$13,536	$13,536	$13,536	$13,536	$13,536	$13,536
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$37,386	$35,709	$33,940	$32,076	$30,111	$28,038	$25,853	$23,550	$21,121	$18,561	$15,862	$13,016	$10,015	$6,852	$3,516
Remaining Component	$169,756	$162,180	$154,188	$145,757	$136,861	$127,476	$117,576	$107,130	$96,110	$84,485	$72,219	$59,279	$45,628	$31,225	$16,030
NET INCOME BEFORE TAXES	-$3,363	$5,890	$15,650	$25,946	$36,807	$90,167	$144,156	$156,904	$170,353	$184,539	$199,504	$215,290	$231,942	$249,508	$268,038
Federal Income Taxes	-$14,855	-$14,855	-$14,855	-$14,855	-$14,855	$18,514	$51,883	$51,883	$51,883	$51,883	$51,883	$51,883	$51,883	$51,883	$51,883
State Income Taxes	-$3,799	-$3,799	-$3,799	-$3,799	-$3,799	$4,735	$13,269	$13,269	$13,269	$13,269	$13,269	$13,269	$13,269	$13,269	$13,269
NET INCOME	$15,291	$24,543	$34,304	$44,600	$55,461	$66,918	$79,003	$91,752	$105,200	$119,387	$134,352	$150,137	$166,790	$184,356	$202,886
STATEMENT OF CASH FLOWS															
NET INCOME	$15,291	$24,543	$34,304	$44,600	$55,461	$66,918	$79,003	$91,752	$105,200	$119,387	$134,352	$150,137	$166,790	$184,356	$202,886
Add back Depreciation	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333	$153,333
Subtract Principal Payment															
AIDEA Component	$30,888	$32,566	$34,334	$36,198	$38,164	$40,236	$42,421	$44,724	$47,153	$49,713	$52,413	$55,259	$58,259	$61,423	$64,758
Remaining Component	$137,736	$145,311	$153,303	$161,735	$170,630	$180,015	$189,916	$200,361	$211,381	$223,007	$235,272	$248,212	$261,864	$276,266	$291,461
NET CASH FLOW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	207.31	215.81	224.36	234.51	244.81	255.56	266.79	278.51	290.75	303.53	316.87	330.80	345.34	360.52	376.37
Net Benefit	$122,922	$156,002	$190,018	$229,693	$270,935	$272,789	$277,298	$326,516	$378,695	$434,001	$482,521	$523,714	$566,766	$611,761	$658,787
Annual PV of Net Benefit	$52,292	$62,912	$72,644	$83,244	$93,083	$88,845	$85,615	$95,567	$105,074	$114,155	$120,316	$123,794	$127,002	$129,954	$132,664
Cumulative PV of Net Benefit	-$1,201,513	-$1,138,601	-$1,065,957	-$982,713	-$889,630	-$800,786	-$715,170	-$619,603	-$514,529	-$400,374	-$280,058	-$156,264	-$29,262	$100,692	$233,355

Starting Year	2007	
Direct Construction Expense	84.1%	
AFDUC and Financing Expense	15.9%	
Percentage of AFUDC as Debt	100%	
Percentage of Total Expense as Land	0%	
Tax Life: MACRS Half year Conv.	20	year
Book Life	30	year
Declining Balance Rate	1.5	
State Tax Rate	8.0%	
Federal Tax Rate	34.0%	
DEFERRED TAX -NORM (1) OR FLOW THROUGH (0)	1	
Total Tax Rate	39.3%	
Book Depreciation (SL-1 or IRR-0)	1	
Interim Retirement Rate	1.0%	
Salvage Rate	0.0%	
Return on Equity	5.48%	
Interest Rate on Debt	5.48%	
Percent Funding by Equity	0.0%	
Percent Funding by Debt	100.0%	
WACC	5.48%	
Insurance (Percent of Initial Construction Cost)	0.25%	

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
TAX DEPRECIATION															
BOY Tax Value	100.00%	92.50%	85.56%	79.15%	73.21%	67.72%	62.64%	57.94%	53.60%	49.31%	45.02%	40.73%	36.45%	32.16%	27.87%
Declining Balance Depr.	7.50%	6.94%	6.42%	5.94%	5.49%	5.08%	4.70%	4.35%	4.02%	3.70%	3.38%	3.05%	2.73%	2.41%	2.09%
Straight Line Depr.	2.44%	4.74%	4.63%	4.52%	4.44%	4.37%	4.32%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%
Tax Depr.	7.50%	6.94%	6.42%	5.94%	5.49%	5.08%	4.70%	4.35%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%
RATE BASE															
Book Depr.	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%
Cumulative Book Depr.	3.33%	6.67%	10.00%	13.33%	16.67%	20.00%	23.33%	26.67%	30.00%	33.33%	36.67%	40.00%	43.33%	46.67%	50.00%
Deferred Taxes	1.64%	1.42%	1.21%	1.02%	0.85%	0.69%	0.54%	0.40%	0.37%	0.37%	0.37%	0.37%	0.37%	0.37%	0.37%
Cumulative Deferred Taxes	1.64%	3.05%	4.26%	5.29%	6.13%	6.82%	7.36%	7.75%	8.13%	8.50%	8.88%	9.25%	9.63%	10.00%	10.38%
Rate Base	95.03%	90.28%	85.74%	81.38%	77.20%	73.18%	69.31%	65.58%	61.87%	58.16%	54.46%	50.75%	47.04%	43.33%	39.62%
RETURN & TAXES															
Return on WACC	5.21%	4.95%	4.70%	4.46%	4.23%	4.01%	3.80%	3.60%	3.39%	3.19%	2.99%	2.78%	2.58%	2.38%	2.17%
Bond Interest	5.21%	4.95%	4.70%	4.46%	4.23%	4.01%	3.80%	3.60%	3.39%	3.19%	2.99%	2.78%	2.58%	2.38%	2.17%
Federal Income Taxes	-1.30%	-1.13%	-0.96%	-0.81%	-0.67%	-0.55%	-0.43%	-0.32%	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%
State Income Taxes	-0.33%	-0.29%	-0.25%	-0.21%	-0.17%	-0.14%	-0.11%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%
Property Taxes & Insurance	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
Year	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
TAX DEPRECIATION															
BOY Tax Value	23.58%	19.29%	15.01%	10.72%	6.43%	2.14%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Declining Balance Depr.	1.77%	1.45%	1.13%	0.80%	0.48%	0.16%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Straight Line Depr.	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Tax Depr.	4.29%	4.29%	4.29%	4.29%	4.29%	2.14%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RATE BASE															
Book Depr.	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%
Cumulative Book Depr.	53.33%	56.67%	60.00%	63.33%	66.67%	70.00%	73.33%	76.67%	80.00%	83.33%	86.67%	90.00%	93.33%	96.67%	100.00%
Deferred Taxes	0.37%	0.37%	0.37%	0.37%	0.37%	-0.47%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%
Cumulative Deferred Taxes	10.75%	11.13%	11.50%	11.88%	12.25%	11.78%	10.47%	9.17%	7.86%	6.55%	5.24%	3.93%	2.62%	1.31%	0.00%
Rate Base	35.91%	32.21%	28.50%	24.79%	21.08%	18.22%	16.19%	14.17%	12.14%	10.12%	8.10%	6.07%	4.05%	2.02%	0.00%
RETURN & TAXES															
Return on WACC	1.97%	1.77%	1.56%	1.36%	1.16%	1.00%	0.89%	0.78%	0.67%	0.55%	0.44%	0.33%	0.22%	0.11%	0.00%
Bond Interest	1.97%	1.77%	1.56%	1.36%	1.16%	1.00%	0.89%	0.78%	0.67%	0.55%	0.44%	0.33%	0.22%	0.11%	0.00%
Federal Income Taxes	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%	0.37%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%
State Income Taxes	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	0.10%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%
Property Taxes & Insurance	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%

Variable	Value		Source
Interest on Construction	4.09%		FERC (4/29/2004 6-month T-Bond & 300 basis points)
Financing Cost	2%		FERC
Debt Service Reserve	1	year	FERC
Operational Reserve	3	months	FERC
Term of Analysis	30	years	FERC
Starting Year	2007		FERC
Grant Value	$2,000,000		GEC
Interest on Debt, AIDEA Component	5.43%		GEC
AIDEA Loan Component	$1,000,000		GEC
Interest on Debt, Remainder	5.50%		GEC
Term of Financing, AIDEA Component	30	years	GEC
Term of Financing, Remaining Component	30	years	GEC
2003 O&M (including Staff-recommended environmental enhancements)	$58,600		FERC/GEC
Insurance (% of Initial Investment including granted $)	0.25%		FERC
Interest Rate on Debt Reserve	3.60%		FERC (4/29/2004 5-year T-Bond)
Interest Rate on Operating Reserve	0.85%		FERC (4/29/2004 3-month T-Bond)
Net Cost of Debt	5.478%		Calculated
Operating Reserve Requirement	$150,000		FERC (approx. 3 months operating revenues in last year of operations, rounded up to nearest 25K)
Federal Tax Rate	34%		FERC
State Tax Rate	8%		FERC
Percent Funding by Equity	0.0%		FERC/GEC
Percent Funding by Debt	100.0%		FERC/GEC

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*1,791,330*	*1,863,960*	*1,930,600*	*1,990,220*	*2,050,860*	*2,114,190*	*2,177,870*	*2,244,930*	*2,311,250*	*2,379,370*	*2,448,095*	*2,517,806*	*2,588,921*	*2,661,484*	*2,735,540*
Hydro Rate (mills/kWh)	*154.11*	*151.03*	*148.42*	*146.29*	*144.05*	*141.55*	*139.03*	*136.34*	*132.42*	*128.31*	*124.42*	*120.69*	*117.12*	*114.04*	*112.39*
Operating Revenues	$276,068	$281,510	$286,535	$291,145	$295,417	$299,272	$302,789	$306,071	$306,064	$305,306	$304,584	$303,880	$303,204	$303,515	$307,457
OPERATING EXPENSES															
Operating Expense	$74,435	$76,113	$77,963	$79,961	$82,158	$84,453	$86,909	$89,609	$92,407	$95,272	$98,373	$101,701	$105,277	$109,026	$112,969
Maintenance Expense															
Depreciation Expense	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333
NET OPERATING INCOME	$116,300	$120,064	$123,238	$125,851	$127,926	$129,485	$130,547	$131,129	$128,324	$124,700	$120,878	$116,846	$112,593	$109,155	$109,155
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$7,704	$7,704	$7,704	$7,704	$7,704	$7,704	$7,704	$7,704	$7,704	$7,704	$7,704	$7,704	$7,704	$7,704	$7,704
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$54,300	$53,541	$52,741	$51,898	$51,008	$50,071	$49,083	$48,040	$46,942	$45,783	$44,562	$43,274	$41,917	$40,486	$38,977
Remaining Component	$116,380	$114,773	$113,078	$111,290	$109,403	$107,413	$105,313	$103,098	$100,761	$98,295	$95,694	$92,949	$90,054	$86,999	$83,777
NET INCOME BEFORE TAXES	-$45,401	-$39,272	-$33,603	-$28,358	-$23,507	-$19,020	-$14,870	-$11,030	-$10,399	-$10,399	-$10,399	-$10,399	-$10,399	-$9,351	-$4,619
Federal Income Taxes	-$36,154	-$31,274	-$26,759	-$22,583	-$18,720	-$15,146	-$11,841	-$8,784	-$8,281	-$8,281	-$8,281	-$8,281	-$8,281	-$8,281	-$8,281
State Income Taxes	-$9,247	-$7,998	-$6,844	-$5,776	-$4,788	-$3,874	-$3,028	-$2,247	-$2,118	-$2,118	-$2,118	-$2,118	-$2,118	-$2,118	-$2,118
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,048	$5,780
STATEMENT OF CASH FLOWS															
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,048	$5,780
Add back Depreciation	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333
Subtract Principal Payment															
AIDEA Component	$13,974	$14,733	$15,533	$16,377	$17,266	$18,203	$19,192	$20,234	$21,333	$22,491	$23,712	$25,000	$26,357	$27,789	$29,297
Remaining Component	$29,212	$30,819	$32,514	$34,302	$36,189	$38,179	$40,279	$42,494	$44,832	$47,297	$49,899	$52,643	$55,538	$58,593	$61,816
NET CASH FLOW	$42,147	$39,781	$37,286	$34,655	$31,879	$28,951	$25,862	$22,605	$19,169	$15,545	$11,722	$7,690	$3,438	$0	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	122.35	125.09	128.05	131.37	135.25	139.57	145.17	150.38	156.47	161.89	168.54	174.50	183.88	192.33	199.05
Net Benefit	-$56,899	-$48,355	-$39,321	-$29,680	-$18,031	-$4,197	$13,381	$31,526	$55,577	$79,891	$108,021	$135,481	$172,845	$208,371	$237,058
Annual PV of Net Benefit	-$53,944	-$43,463	-$33,508	-$23,979	-$13,811	-$3,048	$9,212	$20,577	$34,392	$46,871	$60,083	$71,443	$86,412	$98,764	$106,526
Cumulative PV of Net Benefit	-$53,944	-$97,408	-$130,915	-$154,894	-$168,705	-$171,753	-$162,541	-$141,964	-$107,572	-$60,701	-$619	$70,824	$157,237	$256,000	$362,526
NPV	$2,610,947														

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*2,808,947*	*2,871,303*	*2,933,140*	*2,994,977*	*3,056,813*	*3,118,650*	*3,180,486*	*3,242,323*	*3,304,160*	*3,365,996*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*
Hydro Rate (mills/kWh)	*110.93*	*110.00*	*109.18*	*108.46*	*107.82*	*114.75*	*121.47*	*120.78*	*120.18*	*119.66*	*120.34*	*122.14*	*124.00*	*125.93*	*127.93*
Operating Revenues	$311,593	$315,854	$320,249	$324,833	$329,584	$357,868	$386,331	$391,621	$397,103	$402,786	$408,675	$414,779	$421,106	$427,663	$434,459
OPERATING EXPENSES															
Operating Expense	$117,104	$121,366	$125,760	$130,344	$135,095	$140,019	$145,123	$150,413	$155,895	$161,577	$167,467	$173,571	$179,897	$186,455	$193,251
Maintenance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation Expense	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333
NET OPERATING INCOME	$109,155	$109,155	$109,155	$109,155	$109,155	$132,515	$155,875	$155,875	$155,875	$155,875	$155,875	$155,875	$155,875	$155,875	$155,875
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$7,704	$7,704	$7,704	$7,704	$7,704	$7,704	$7,704	$7,704	$7,704	$7,704	$7,704	$7,704	$7,704	$7,704	$7,704
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$37,386	$35,709	$33,940	$32,076	$30,111	$28,038	$25,853	$23,550	$21,121	$18,561	$15,862	$13,016	$10,015	$6,852	$3,516
Remaining Component	$80,377	$76,790	$73,006	$69,013	$64,802	$60,358	$55,670	$50,724	$45,507	$40,002	$34,195	$28,068	$21,604	$14,785	$7,590
NET INCOME BEFORE TAXES	$372	$5,636	$11,188	$17,045	$23,222	$53,098	$83,330	$90,580	$98,226	$106,291	$114,798	$123,771	$133,235	$143,218	$153,748
Federal Income Taxes	-$8,281	-$8,281	-$8,281	-$8,281	-$8,281	$10,321	$28,924	$28,924	$28,924	$28,924	$28,924	$28,924	$28,924	$28,924	$28,924
State Income Taxes	-$2,118	-$2,118	-$2,118	-$2,118	-$2,118	$2,640	$7,397	$7,397	$7,397	$7,397	$7,397	$7,397	$7,397	$7,397	$7,397
NET INCOME	$10,771	$16,035	$21,587	$27,444	$33,621	$40,137	$47,010	$54,259	$61,905	$69,970	$78,477	$87,450	$96,914	$106,897	$117,427
STATEMENT OF CASH FLOWS															
NET INCOME	$10,771	$16,035	$21,587	$27,444	$33,621	$40,137	$47,010	$54,259	$61,905	$69,970	$78,477	$87,450	$96,914	$106,897	$117,427
Add back Depreciation	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333	$85,333
Subtract Principal Payment															
AIDEA Component	$30,888	$32,566	$34,334	$36,198	$38,164	$40,236	$42,421	$44,724	$47,153	$49,713	$52,413	$55,259	$58,259	$61,423	$64,758
Remaining Component	$65,216	$68,802	$72,587	$76,579	$80,791	$85,234	$89,922	$94,868	$100,085	$105,590	$111,398	$117,524	$123,988	$130,808	$138,002
NET CASH FLOW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	207.31	215.81	224.36	234.51	244.81	255.56	266.79	278.51	290.75	303.53	316.87	330.80	345.34	360.52	376.37
Net Benefit	$270,734	$303,815	$337,830	$377,505	$418,747	$439,144	$462,197	$511,414	$563,594	$618,900	$667,420	$708,612	$751,664	$796,659	$843,685
Annual PV of Net Benefit	$115,341	$122,713	$129,366	$137,051	$144,129	$143,300	$142,991	$150,001	$156,721	$163,163	$166,817	$167,915	$168,867	$169,681	$170,365
Cumulative PV of Net Benefit	$477,867	$600,580	$729,946	$866,997	$1,011,126	$1,154,427	$1,297,417	$1,447,418	$1,604,139	$1,767,302	$1,934,119	$2,102,033	$2,270,900	$2,440,582	$2,610,947

Starting Year	2007	
Direct Construction Expense	83.3%	
AFDUC and Financing Expense	16.7%	
Percentage of AFUDC as Debt	100%	
Percentage of Total Expense as Land	0%	
Tax Life: MACRS Half year Conv.	20	year
Book Life	30	year
Declining Balance Rate	1.5	
State Tax Rate	8.0%	
Federal Tax Rate	34.0%	
DEFERRED TAX -NORM (1) OR FLOW THROUGH (0)	1	
Total Tax Rate	39.3%	
Book Depreciation (SL-1 or IRR-0)	1	
Interim Retirement Rate	1.0%	
Salvage Rate	0.0%	
Return on Equity	5.48%	
Interest Rate on Debt	5.48%	
Percent Funding by Equity	0.0%	
Percent Funding by Debt	100.0%	
WACC	5.48%	
Insurance (Percent of Initial Construction Cost)	0.25%	

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
TAX DEPRECIATION															
BOY Tax Value	100.00%	92.50%	85.56%	79.15%	73.21%	67.72%	62.64%	57.94%	53.60%	49.31%	45.02%	40.73%	36.45%	32.16%	27.87%
Declining Balance Depr.	7.50%	6.94%	6.42%	5.94%	5.49%	5.08%	4.70%	4.35%	4.02%	3.70%	3.38%	3.05%	2.73%	2.41%	2.09%
Straight Line Depr.	2.44%	4.74%	4.63%	4.52%	4.44%	4.37%	4.32%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%
Tax Depr.	7.50%	6.94%	6.42%	5.94%	5.49%	5.08%	4.70%	4.35%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%
RATE BASE															
Book Depr.	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%
Cumulative Book Depr.	3.33%	6.67%	10.00%	13.33%	16.67%	20.00%	23.33%	26.67%	30.00%	33.33%	36.67%	40.00%	43.33%	46.67%	50.00%
Deferred Taxes	1.64%	1.42%	1.21%	1.02%	0.85%	0.69%	0.54%	0.40%	0.37%	0.37%	0.37%	0.37%	0.37%	0.37%	0.37%
Cumulative Deferred Taxes	1.64%	3.05%	4.26%	5.29%	6.13%	6.82%	7.36%	7.75%	8.13%	8.50%	8.88%	9.25%	9.63%	10.00%	10.38%
Rate Base	95.03%	90.28%	85.74%	81.38%	77.20%	73.18%	69.31%	65.58%	61.87%	58.16%	54.46%	50.75%	47.04%	43.33%	39.62%
RETURN & TAXES															
Return on WACC	5.21%	4.95%	4.70%	4.46%	4.23%	4.01%	3.80%	3.60%	3.39%	3.19%	2.99%	2.78%	2.58%	2.38%	2.17%
Bond Interest	5.21%	4.95%	4.70%	4.46%	4.23%	4.01%	3.80%	3.60%	3.39%	3.19%	2.99%	2.78%	2.58%	2.38%	2.17%
Federal Income Taxes	-1.30%	-1.13%	-0.96%	-0.81%	-0.67%	-0.55%	-0.43%	-0.32%	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%
State Income Taxes	-0.33%	-0.29%	-0.25%	-0.21%	-0.17%	-0.14%	-0.11%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%
Property Taxes & Insurance	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
Year	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
TAX DEPRECIATION															
BOY Tax Value	23.58%	19.29%	15.01%	10.72%	6.43%	2.14%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Declining Balance Depr.	1.77%	1.45%	1.13%	0.80%	0.48%	0.16%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Straight Line Depr.	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Tax Depr.	4.29%	4.29%	4.29%	4.29%	4.29%	2.14%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RATE BASE															
Book Depr.	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%
Cumulative Book Depr.	53.33%	56.67%	60.00%	63.33%	66.67%	70.00%	73.33%	76.67%	80.00%	83.33%	86.67%	90.00%	93.33%	96.67%	100.00%
Deferred Taxes	0.37%	0.37%	0.37%	0.37%	0.37%	-0.47%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%
Cumulative Deferred Taxes	10.75%	11.13%	11.50%	11.88%	12.25%	11.78%	10.47%	9.17%	7.86%	6.55%	5.24%	3.93%	2.62%	1.31%	0.00%
Rate Base	35.91%	32.21%	28.50%	24.79%	21.08%	18.22%	16.19%	14.17%	12.14%	10.12%	8.10%	6.07%	4.05%	2.02%	0.00%
RETURN & TAXES															
Return on WACC	1.97%	1.77%	1.56%	1.36%	1.16%	1.00%	0.89%	0.78%	0.67%	0.55%	0.44%	0.33%	0.22%	0.11%	0.00%
Bond Interest	1.97%	1.77%	1.56%	1.36%	1.16%	1.00%	0.89%	0.78%	0.67%	0.55%	0.44%	0.33%	0.22%	0.11%	0.00%
Federal Income Taxes	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%	0.37%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%
State Income Taxes	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	0.10%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%
Property Taxes & Insurance	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%

INCOME STATEMENT AND BACKGROUND

LOW ESTIMATE FOR INTEREST RATE ON DEBT
MIDDLE-LOW ESTIMATE FOR INTEREST RATE ON DEBT
MIDDLE-HIGH ESTIMATE FOR INTEREST RATE ON DEBT
HIGH ESTIMATE FOR INTEREST RATE ON DEBT

Variable	**Value**		**Source**
Interest on Construction	4.09%		FERC (4/29/2004 6-month T-Bond & 300 basis points)
Financing Cost	2%		FERC
Debt Service Reserve	1	year	FERC
Operational Reserve	3	months	FERC
Term of Analysis	30	years	FERC
Starting Year	2007		FERC
Grant Value	$1,083,685		GEC
Interest on Debt, AIDEA Component	5.43%		GEC
AIDEA Loan Component	$0		GEC
Interest on Debt, Remainder	8.38%		GEC
Term of Financing, AIDEA Component	30	years	GEC
Term of Financing, Remaining Component	30	years	GEC
2003 O&M (including Staff-recommended environmental enhancements)	$58,600		FERC/GEC
Insurance (% of Initial Investment including granted $)	0.25%		FERC
Interest Rate on Debt Reserve	3.60%		FERC (4/29/2004 5-year T-Bond)
Interest Rate on Operating Reserve	0.85%		FERC (4/29/2004 3-month T-Bond)
Net Cost of Debt	8.375%		Calculated
Operating Reserve Requirement	$150,000		FERC (approx. 3 months operating revenues in last year of operations, rounded up to nearest 25K)
Federal Tax Rate	34%		FERC
State Tax Rate	8%		FERC
Percent Funding by Equity	0.0%		FERC/GEC
Percent Funding by Debt	100.0%		FERC/GEC

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*1,791,330*	*1,863,960*	*1,930,600*	*1,990,220*	*2,050,860*	*2,114,190*	*2,177,870*	*2,244,930*	*2,311,250*	*2,379,370*	*2,448,095*	*2,517,806*	*2,588,921*	*2,661,484*	*2,735,540*
Hydro Rate (mills/kWh)	*263.58*	*257.23*	*251.76*	*247.17*	*242.40*	*237.27*	*232.09*	*226.61*	*219.45*	*212.00*	*204.81*	*197.82*	*190.99*	*184.26*	*177.63*
Operating Revenues	$472,164	$479,467	$486,050	$491,914	$497,133	$501,624	$505,460	$508,732	$507,201	$504,415	$501,391	$498,082	$494,464	$490,417	$485,911
OPERATING EXPENSES															
Operating Expense	$74,435	$76,113	$77,963	$79,961	$82,158	$84,453	$86,909	$89,609	$92,407	$95,272	$98,373	$101,701	$105,277	$109,026	$112,969
Maintenance Expense															
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$281,263	$286,888	$291,620	$295,486	$298,508	$300,704	$302,084	$302,657	$298,327	$292,676	$286,551	$279,914	$272,720	$264,924	$256,476
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$14,256	$14,256	$14,256	$14,256	$14,256	$14,256	$14,256	$14,256	$14,256	$14,256	$14,256	$14,256	$14,256	$14,256	$14,256
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Remaining Component	$360,460	$357,490	$354,272	$350,784	$347,004	$342,907	$338,467	$333,656	$328,441	$322,790	$316,665	$310,027	$302,834	$295,038	$286,589
NET INCOME BEFORE TAXES	-$63,666	-$55,071	-$47,121	-$39,767	-$32,964	-$26,672	-$20,852	-$15,468	-$14,583	-$14,583	-$14,583	-$14,583	-$14,583	-$14,583	-$14,583
Federal Income Taxes	-$50,700	-$43,855	-$37,524	-$31,668	-$26,251	-$21,240	-$16,605	-$12,318	-$11,613	-$11,613	-$11,613	-$11,613	-$11,613	-$11,613	-$11,613
State Income Taxes	-$12,967	-$11,216	-$9,597	-$8,099	-$6,714	-$5,432	-$4,247	-$3,150	-$2,970	-$2,970	-$2,970	-$2,970	-$2,970	-$2,970	-$2,970
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
STATEMENT OF CASH FLOWS															
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Remaining Component	$35,460	$38,429	$41,648	$45,136	$48,916	$53,013	$57,452	$62,264	$67,479	$73,130	$79,255	$85,892	$93,086	$100,882	$109,330
NET CASH FLOW	$81,007	$78,037	$74,819	$71,331	$67,551	$63,454	$59,014	$54,203	$48,988	$43,337	$37,212	$30,574	$23,381	$15,585	$7,136
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	122.35	125.09	128.05	131.37	135.25	139.57	145.17	150.38	156.47	161.89	168.54	174.50	183.88	192.33	199.05
Net Benefit	-$252,995	-$246,313	-$238,836	-$230,449	-$219,747	-$206,550	-$189,290	-$171,135	-$145,559	-$119,218	-$88,786	-$58,720	-$18,416	$21,468	$58,605
Annual PV of Net Benefit	-$233,444	-$209,715	-$187,635	-$167,055	-$146,987	-$127,482	-$107,801	-$89,930	-$70,579	-$53,340	-$36,654	-$22,369	-$6,473	$6,963	$17,539
Cumulative PV of Net Benefit	-$233,444	-$443,159	-$630,794	-$797,848	-$944,835	-$1,072,317	-$1,180,118	-$1,270,048	-$1,340,628	-$1,393,967	-$1,430,622	-$1,452,990	-$1,459,464	-$1,452,501	-$1,434,962
NPV	-$689,530														

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*2,808,947*	*2,871,303*	*2,933,140*	*2,994,977*	*3,056,813*	*3,118,650*	*3,180,486*	*3,242,323*	*3,304,160*	*3,365,996*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*
Hydro Rate (mills/kWh)	*171.92*	*169.67*	*167.59*	*165.66*	*163.86*	*172.70*	*181.24*	*179.42*	*177.72*	*176.14*	*176.32*	*178.12*	*179.98*	*181.91*	*183.91*
Operating Revenues	$482,910	$487,172	$491,566	$496,150	$500,901	$538,583	$576,445	$581,734	$587,217	$592,899	$598,788	$604,893	$611,219	$617,776	$624,572
OPERATING EXPENSES															
Operating Expense	$117,104	$121,366	$125,760	$130,344	$135,095	$140,019	$145,123	$150,413	$155,895	$161,577	$167,467	$173,571	$179,897	$186,455	$193,251
Maintenance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$249,339	$249,339	$249,339	$249,339	$249,339	$282,097	$314,855	$314,855	$314,855	$314,855	$314,855	$314,855	$314,855	$314,855	$314,855
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$14,256	$14,256	$14,256	$14,256	$14,256	$14,256	$14,256	$14,256	$14,256	$14,256	$14,256	$14,256	$14,256	$14,256	$14,256
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Remaining Component	$277,433	$267,509	$256,755	$245,100	$232,469	$218,780	$203,944	$187,867	$170,442	$151,558	$131,093	$108,914	$84,877	$58,827	$30,596
NET INCOME BEFORE TAXES	-$12,562	-$2,639	$8,115	$19,770	$32,401	$78,848	$126,442	$142,519	$159,944	$178,828	$199,293	$221,472	$245,509	$271,559	$299,790
Federal Income Taxes	-$11,613	-$11,613	-$11,613	-$11,613	-$11,613	$14,474	$40,560	$40,560	$40,560	$40,560	$40,560	$40,560	$40,560	$40,560	$40,560
State Income Taxes	-$2,970	-$2,970	-$2,970	-$2,970	-$2,970	$3,702	$10,373	$10,373	$10,373	$10,373	$10,373	$10,373	$10,373	$10,373	$10,373
NET INCOME	$2,020	$11,944	$22,698	$34,353	$46,984	$60,673	$75,508	$91,586	$109,011	$127,895	$148,360	$170,539	$194,576	$220,626	$248,857
STATEMENT OF CASH FLOWS															
NET INCOME	$2,020	$11,944	$22,698	$34,353	$46,984	$60,673	$75,508	$91,586	$109,011	$127,895	$148,360	$170,539	$194,576	$220,626	$248,857
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Remaining Component	$118,487	$128,410	$139,165	$150,820	$163,451	$177,140	$191,975	$208,053	$225,478	$244,361	$264,826	$287,006	$311,042	$337,092	$365,324
NET CASH FLOW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	207.31	215.81	224.36	234.51	244.81	255.56	266.79	278.51	290.75	303.53	316.87	330.80	345.34	360.52	376.37
Net Benefit	$99,417	$132,497	$166,513	$206,188	$247,430	$258,429	$272,084	$321,301	$373,480	$428,786	$477,307	$518,499	$561,551	$606,546	$653,572
Annual PV of Net Benefit	$27,453	$33,761	$39,149	$44,731	$49,530	$47,734	$46,373	$50,529	$54,196	$57,413	$58,971	$59,110	$59,071	$58,873	$58,536
Cumulative PV of Net Benefit	-$1,407,509	-$1,373,748	-$1,334,599	-$1,289,868	-$1,240,338	-$1,192,603	-$1,146,231	-$1,095,702	-$1,041,505	-$984,092	-$925,121	-$866,010	-$806,939	-$748,066	-$689,530

Starting Year	2007	
Direct Construction Expense	81.2%	
AFDUC and Financing Expense	18.8%	
Percentage of AFUDC as Debt	100%	
Percentage of Total Expense as Land	0%	
Tax Life: MACRS Half year Conv.	20	year
Book Life	30	year
Declining Balance Rate	1.5	
State Tax Rate	8.0%	
Federal Tax Rate	34.0%	
DEFERRED TAX -NORM (1) OR FLOW THROUGH (0)	1	
Total Tax Rate	39.3%	
Book Depreciation (SL-1 or IRR-0)	1	
Interim Retirement Rate	1.0%	
Salvage Rate	0.0%	
Return on Equity	8.38%	
Interest Rate on Debt	8.38%	
Percent Funding by Equity	0.0%	
Percent Funding by Debt	100.0%	
WACC	8.38%	
Insurance (Percent of Initial Construction Cost)	0.25%	

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
TAX DEPRECIATION															
BOY Tax Value	100.00%	92.50%	85.56%	79.15%	73.21%	67.72%	62.64%	57.94%	53.60%	49.31%	45.02%	40.73%	36.45%	32.16%	27.87%
Declining Balance Depr.	7.50%	6.94%	6.42%	5.94%	5.49%	5.08%	4.70%	4.35%	4.02%	3.70%	3.38%	3.05%	2.73%	2.41%	2.09%
Straight Line Depr.	2.44%	4.74%	4.63%	4.52%	4.44%	4.37%	4.32%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%
Tax Depr.	7.50%	6.94%	6.42%	5.94%	5.49%	5.08%	4.70%	4.35%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%
RATE BASE															
Book Depr.	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%
Cumulative Book Depr.	3.33%	6.67%	10.00%	13.33%	16.67%	20.00%	23.33%	26.67%	30.00%	33.33%	36.67%	40.00%	43.33%	46.67%	50.00%
Deferred Taxes	1.64%	1.42%	1.21%	1.02%	0.85%	0.69%	0.54%	0.40%	0.37%	0.37%	0.37%	0.37%	0.37%	0.37%	0.37%
Cumulative Deferred Taxes	1.64%	3.05%	4.26%	5.29%	6.13%	6.82%	7.36%	7.75%	8.13%	8.50%	8.88%	9.25%	9.63%	10.00%	10.38%
Rate Base	95.03%	90.28%	85.74%	81.38%	77.20%	73.18%	69.31%	65.58%	61.87%	58.16%	54.46%	50.75%	47.04%	43.33%	39.62%
RETURN & TAXES															
Return on WACC	7.96%	7.56%	7.18%	6.82%	6.47%	6.13%	5.80%	5.49%	5.18%	4.87%	4.56%	4.25%	3.94%	3.63%	3.32%
Bond Interest	7.96%	7.56%	7.18%	6.82%	6.47%	6.13%	5.80%	5.49%	5.18%	4.87%	4.56%	4.25%	3.94%	3.63%	3.32%
Federal Income Taxes	-1.30%	-1.13%	-0.96%	-0.81%	-0.67%	-0.55%	-0.43%	-0.32%	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%
State Income Taxes	-0.33%	-0.29%	-0.25%	-0.21%	-0.17%	-0.14%	-0.11%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%
Property Taxes & Insurance	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
Year	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
TAX DEPRECIATION															
BOY Tax Value	23.58%	19.29%	15.01%	10.72%	6.43%	2.14%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Declining Balance Depr.	1.77%	1.45%	1.13%	0.80%	0.48%	0.16%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Straight Line Depr.	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Tax Depr.	4.29%	4.29%	4.29%	4.29%	4.29%	2.14%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RATE BASE															
Book Depr.	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%
Cumulative Book Depr.	53.33%	56.67%	60.00%	63.33%	66.67%	70.00%	73.33%	76.67%	80.00%	83.33%	86.67%	90.00%	93.33%	96.67%	100.00%
Deferred Taxes	0.37%	0.37%	0.37%	0.37%	0.37%	-0.47%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%
Cumulative Deferred Taxes	10.75%	11.13%	11.50%	11.88%	12.25%	11.78%	10.47%	9.17%	7.86%	6.55%	5.24%	3.93%	2.62%	1.31%	0.00%
Rate Base	35.91%	32.21%	28.50%	24.79%	21.08%	18.22%	16.19%	14.17%	12.14%	10.12%	8.10%	6.07%	4.05%	2.02%	0.00%
RETURN & TAXES															
Return on WACC	3.01%	2.70%	2.39%	2.08%	1.77%	1.53%	1.36%	1.19%	1.02%	0.85%	0.68%	0.51%	0.34%	0.17%	0.00%
Bond Interest	3.01%	2.70%	2.39%	2.08%	1.77%	1.53%	1.36%	1.19%	1.02%	0.85%	0.68%	0.51%	0.34%	0.17%	0.00%
Federal Income Taxes	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%	0.37%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%
State Income Taxes	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	0.10%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%
Property Taxes & Insurance	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%

Variable	Value	Source
Interest on Construction	4.09%	FERC (4/29/2004 6-month T-Bond & 300 basis points)
Financing Cost	2%	FERC
Debt Service Reserve	1 year	FERC
Operational Reserve	3 months	FERC
Term of Analysis	30 years	FERC
Starting Year	2007	FERC
Grant Value	$1,083,685	GEC
Interest on Debt, AIDEA Component	5.43%	GEC
AIDEA Loan Component	$1,000,000	GEC
Interest on Debt, Remainder	8.38%	GEC
Term of Financing, AIDEA Component	30 years	GEC
Term of Financing, Remaining Component	30 years	GEC
2003 O&M (including Staff-recommended environmental enhancements)	$58,600	FERC/GEC
Insurance (% of Initial Investment including granted $)	0.25%	FERC
Interest Rate on Debt Reserve	3.60%	FERC (4/29/2004 5-year T-Bond)
Interest Rate on Operating Reserve	0.85%	FERC (4/29/2004 3-month T-Bond)
Net Cost of Debt	7.687%	Calculated
Operating Reserve Requirement	$150,000	FERC (approx. 3 months operating revenues in last year of operations, rounded up to nearest 25K)
Federal Tax Rate	34%	FERC
State Tax Rate	8%	FERC
Percent Funding by Equity	0.0%	FERC/GEC
Percent Funding by Debt	100.0%	FERC/GEC

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*1,791,330*	*1,863,960*	*1,930,600*	*1,990,220*	*2,050,860*	*2,114,190*	*2,177,870*	*2,244,930*	*2,311,250*	*2,379,370*	*2,448,095*	*2,517,806*	*2,588,921*	*2,661,484*	*2,735,540*
Hydro Rate (mills/kWh)	*246.69*	*240.93*	*235.98*	*231.83*	*227.50*	*222.81*	*218.07*	*213.05*	*206.33*	*199.33*	*192.60*	*186.07*	*179.70*	*173.44*	*167.28*
Operating Revenues	$441,898	$449,093	$455,590	$461,392	$466,578	$471,066	$474,933	$478,274	$476,881	$474,284	$471,499	$468,484	$465,224	$461,605	$457,603
OPERATING EXPENSES															
Operating Expense	$74,435	$76,113	$77,963	$79,961	$82,158	$84,453	$86,909	$89,609	$92,407	$95,272	$98,373	$101,701	$105,277	$109,026	$112,969
Maintenance Expense															
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$250,997	$256,514	$261,160	$264,964	$267,953	$270,146	$271,557	$272,199	$268,008	$262,545	$256,659	$250,317	$243,480	$236,112	$228,168
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$13,320	$13,320	$13,320	$13,320	$13,320	$13,320	$13,320	$13,320	$13,320	$13,320	$13,320	$13,320	$13,320	$13,320	$13,320
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$54,300	$53,541	$52,741	$51,898	$51,008	$50,071	$49,083	$48,040	$46,942	$45,783	$44,562	$43,274	$41,917	$40,486	$38,977
Remaining Component	$274,533	$272,271	$269,819	$267,163	$264,284	$261,164	$257,782	$254,118	$250,146	$245,842	$241,177	$236,122	$230,643	$224,706	$218,271
NET INCOME BEFORE TAXES	-$63,241	-$54,703	-$46,806	-$39,501	-$32,744	-$26,494	-$20,712	-$15,365	-$14,485	-$14,485	-$14,485	-$14,485	-$14,485	-$14,485	-$14,485
Federal Income Taxes	-$50,361	-$43,562	-$37,273	-$31,456	-$26,075	-$21,098	-$16,494	-$12,235	-$11,535	-$11,535	-$11,535	-$11,535	-$11,535	-$11,535	-$11,535
State Income Taxes	-$12,880	-$11,141	-$9,533	-$8,045	-$6,669	-$5,396	-$4,218	-$3,129	-$2,950	-$2,950	-$2,950	-$2,950	-$2,950	-$2,950	-$2,950
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
STATEMENT OF CASH FLOWS															
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$13,974	$14,733	$15,533	$16,377	$17,266	$18,203	$19,192	$20,234	$21,333	$22,491	$23,712	$25,000	$26,357	$27,789	$29,297
Remaining Component	$27,007	$29,268	$31,720	$34,376	$37,255	$40,375	$43,757	$47,421	$51,393	$55,697	$60,362	$65,417	$70,896	$76,833	$83,268
NET CASH FLOW	$75,486	$72,465	$69,214	$65,714	$61,946	$57,888	$53,518	$48,811	$43,741	$38,279	$32,393	$26,050	$19,214	$11,845	$3,901
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	122.35	125.09	128.05	131.37	135.25	139.57	145.17	150.38	156.47	161.89	168.54	174.50	183.88	192.33	199.05
Net Benefit	-$222,729	-$215,939	-$208,376	-$199,928	-$189,192	-$175,992	-$158,763	-$140,677	-$115,240	-$89,087	-$58,894	-$29,123	$10,824	$50,281	$86,912
Annual PV of Net Benefit	-$206,831	-$186,212	-$166,864	-$148,671	-$130,646	-$112,856	-$94,540	-$77,791	-$59,176	-$42,481	-$26,079	-$11,976	$4,133	$17,830	$28,619
Cumulative PV of Net Benefit	-$206,831	-$393,043	-$559,907	-$708,578	-$839,223	-$952,079	-$1,046,619	-$1,124,410	-$1,183,587	-$1,226,068	-$1,252,147	-$1,264,123	-$1,259,990	-$1,242,160	-$1,213,541
NPV	-$273,175														

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*2,808,947*	*2,871,303*	*2,933,140*	*2,994,977*	*3,056,813*	*3,118,650*	*3,180,486*	*3,242,323*	*3,304,160*	*3,365,996*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*
Hydro Rate (mills/kWh)	*162.99*	*160.94*	*159.04*	*157.29*	*155.66*	*164.59*	*173.22*	*171.55*	*170.00*	*168.56*	*168.81*	*170.61*	*172.47*	*174.40*	*176.40*
Operating Revenues	$457,838	$462,099	$466,494	$471,077	$475,828	$513,291	$550,934	$556,224	$561,706	$567,388	$573,278	$579,382	$585,709	$592,266	$599,062
OPERATING EXPENSES															
Operating Expense	$117,104	$121,366	$125,760	$130,344	$135,095	$140,019	$145,123	$150,413	$155,895	$161,577	$167,467	$173,571	$179,897	$186,455	$193,251
Maintenance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$224,267	$224,267	$224,267	$224,267	$224,267	$256,806	$289,344	$289,344	$289,344	$289,344	$289,344	$289,344	$289,344	$289,344	$289,344
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$13,320	$13,320	$13,320	$13,320	$13,320	$13,320	$13,320	$13,320	$13,320	$13,320	$13,320	$13,320	$13,320	$13,320	$13,320
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$37,386	$35,709	$33,940	$32,076	$30,111	$28,038	$25,853	$23,550	$21,121	$18,561	$15,862	$13,016	$10,015	$6,852	$3,516
Remaining Component	$211,297	$203,740	$195,549	$186,672	$177,052	$166,627	$155,328	$143,082	$129,812	$115,429	$99,843	$82,951	$64,644	$44,804	$23,302
NET INCOME BEFORE TAXES	-$9,822	-$587	$9,372	$20,113	$31,699	$76,736	$122,758	$137,307	$153,006	$169,949	$188,235	$207,973	$229,280	$252,284	$277,121
Federal Income Taxes	-$11,535	-$11,535	-$11,535	-$11,535	-$11,535	$14,377	$40,289	$40,289	$40,289	$40,289	$40,289	$40,289	$40,289	$40,289	$40,289
State Income Taxes	-$2,950	-$2,950	-$2,950	-$2,950	-$2,950	$3,677	$10,304	$10,304	$10,304	$10,304	$10,304	$10,304	$10,304	$10,304	$10,304
NET INCOME	$4,663	$13,898	$23,857	$34,598	$46,184	$58,682	$72,166	$86,714	$102,414	$119,356	$137,642	$157,380	$178,688	$201,691	$226,528
STATEMENT OF CASH FLOWS															
NET INCOME	$4,663	$13,898	$23,857	$34,598	$46,184	$58,682	$72,166	$86,714	$102,414	$119,356	$137,642	$157,380	$178,688	$201,691	$226,528
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$30,888	$32,566	$34,334	$36,198	$38,164	$40,236	$42,421	$44,724	$47,153	$49,713	$52,413	$55,259	$58,259	$61,423	$64,758
Remaining Component	$90,242	$97,799	$105,990	$114,867	$124,487	$134,913	$146,212	$158,457	$171,728	$186,110	$201,696	$218,588	$236,895	$256,735	$278,237
NET CASH FLOW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	207.31	215.81	224.36	234.51	244.81	255.56	266.79	278.51	290.75	303.53	316.87	330.80	345.34	360.52	376.37
Net Benefit	$124,489	$157,570	$191,586	$231,261	$272,503	$283,720	$297,594	$346,812	$398,991	$454,297	$502,817	$544,010	$587,062	$632,057	$679,083
Annual PV of Net Benefit	$38,067	$44,743	$50,519	$56,628	$61,964	$59,910	$58,354	$63,150	$67,466	$71,334	$73,317	$73,662	$73,817	$73,802	$73,633
Cumulative PV of Net Benefit	-$1,175,474	-$1,130,731	-$1,080,212	-$1,023,585	-$961,621	-$901,711	-$843,358	-$780,207	-$712,741	-$641,407	-$568,090	-$494,428	-$420,611	-$346,809	-$273,175

Starting Year	2007	
Direct Construction Expense	81.7%	
AFDUC and Financing Expense	18.3%	
Percentage of AFUDC as Debt	100%	
Percentage of Total Expense as Land	0%	
Tax Life: MACRS Half year Conv.	20	year
Book Life	30	year
Declining Balance Rate	1.5	
State Tax Rate	8.0%	
Federal Tax Rate	34.0%	
DEFERRED TAX -NORM (1) OR FLOW THROUGH (0)	1	
Total Tax Rate	39.3%	
Book Depreciation (SL-1 or IRR-0)	1	
Interim Retirement Rate	1.0%	
Salvage Rate	0.0%	
Return on Equity	7.69%	
Interest Rate on Debt	7.69%	
Percent Funding by Equity	0.0%	
Percent Funding by Debt	100.0%	
WACC	7.69%	
Insurance (Percent of Initial Construction Cost)	0.25%	

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
TAX DEPRECIATION															
BOY Tax Value	100.00%	92.50%	85.56%	79.15%	73.21%	67.72%	62.64%	57.94%	53.60%	49.31%	45.02%	40.73%	36.45%	32.16%	27.87%
Declining Balance Depr.	7.50%	6.94%	6.42%	5.94%	5.49%	5.08%	4.70%	4.35%	4.02%	3.70%	3.38%	3.05%	2.73%	2.41%	2.09%
Straight Line Depr.	2.44%	4.74%	4.63%	4.52%	4.44%	4.37%	4.32%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%
Tax Depr.	7.50%	6.94%	6.42%	5.94%	5.49%	5.08%	4.70%	4.35%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%
RATE BASE															
Book Depr.	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%
Cumulative Book Depr.	3.33%	6.67%	10.00%	13.33%	16.67%	20.00%	23.33%	26.67%	30.00%	33.33%	36.67%	40.00%	43.33%	46.67%	50.00%
Deferred Taxes	1.64%	1.42%	1.21%	1.02%	0.85%	0.69%	0.54%	0.40%	0.37%	0.37%	0.37%	0.37%	0.37%	0.37%	0.37%
Cumulative Deferred Taxes	1.64%	3.05%	4.26%	5.29%	6.13%	6.82%	7.36%	7.75%	8.13%	8.50%	8.88%	9.25%	9.63%	10.00%	10.38%
Rate Base	95.03%	90.28%	85.74%	81.38%	77.20%	73.18%	69.31%	65.58%	61.87%	58.16%	54.46%	50.75%	47.04%	43.33%	39.62%
RETURN & TAXES															
Return on WACC	7.30%	6.94%	6.59%	6.26%	5.93%	5.63%	5.33%	5.04%	4.76%	4.47%	4.19%	3.90%	3.62%	3.33%	3.05%
Bond Interest	7.30%	6.94%	6.59%	6.26%	5.93%	5.63%	5.33%	5.04%	4.76%	4.47%	4.19%	3.90%	3.62%	3.33%	3.05%
Federal Income Taxes	-1.30%	-1.13%	-0.96%	-0.81%	-0.67%	-0.55%	-0.43%	-0.32%	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%
State Income Taxes	-0.33%	-0.29%	-0.25%	-0.21%	-0.17%	-0.14%	-0.11%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%
Property Taxes & Insurance	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
Year	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
TAX DEPRECIATION															
BOY Tax Value	23.58%	19.29%	15.01%	10.72%	6.43%	2.14%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Declining Balance Depr.	1.77%	1.45%	1.13%	0.80%	0.48%	0.16%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Straight Line Depr.	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Tax Depr.	4.29%	4.29%	4.29%	4.29%	4.29%	2.14%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RATE BASE															
Book Depr.	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%
Cumulative Book Depr.	53.33%	56.67%	60.00%	63.33%	66.67%	70.00%	73.33%	76.67%	80.00%	83.33%	86.67%	90.00%	93.33%	96.67%	100.00%
Deferred Taxes	0.37%	0.37%	0.37%	0.37%	0.37%	-0.47%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%
Cumulative Deferred Taxes	10.75%	11.13%	11.50%	11.88%	12.25%	11.78%	10.47%	9.17%	7.86%	6.55%	5.24%	3.93%	2.62%	1.31%	0.00%
Rate Base	35.91%	32.21%	28.50%	24.79%	21.08%	18.22%	16.19%	14.17%	12.14%	10.12%	8.10%	6.07%	4.05%	2.02%	0.00%
RETURN & TAXES															
Return on WACC	2.76%	2.48%	2.19%	1.91%	1.62%	1.40%	1.24%	1.09%	0.93%	0.78%	0.62%	0.47%	0.31%	0.16%	0.00%
Bond Interest	2.76%	2.48%	2.19%	1.91%	1.62%	1.40%	1.24%	1.09%	0.93%	0.78%	0.62%	0.47%	0.31%	0.16%	0.00%
Federal Income Taxes	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%	0.37%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%
State Income Taxes	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	0.10%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%
Property Taxes & Insurance	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%

Variable	Value	Source
Interest on Construction	4.09%	FERC (4/29/2004 6-month T-Bond & 300 basis points)
Financing Cost	2%	FERC
Debt Service Reserve	1 year	FERC
Operational Reserve	3 months	FERC
Term of Analysis	30 years	FERC
Starting Year	2007	FERC
Grant Value	$1,083,685	GEC
Interest on Debt, AIDEA Component	5.43%	GEC
AIDEA Loan Component	$1,000,000	GEC
Interest on Debt, Remainder	5.13%	GEC
Term of Financing, AIDEA Component	30 years	GEC
Term of Financing, Remaining Component	30 years	GEC
2003 O&M (including Staff-recommended environmental enhancements)	$58,600	FERC/GEC
Insurance (% of Initial Investment including granted $)	0.25%	FERC
Interest Rate on Debt Reserve	3.60%	FERC (4/29/2004 5-year T-Bond)
Interest Rate on Operating Reserve	0.85%	FERC (4/29/2004 3-month T-Bond)
Net Cost of Debt	5.202%	Calculated
Operating Reserve Requirement	$150,000	FERC (approx. 3 months operating revenues in last year of operations, rounded up to nearest 25K)
Federal Tax Rate	34%	FERC
State Tax Rate	8%	FERC
Percent Funding by Equity	0.0%	FERC/GEC
Percent Funding by Debt	100.0%	FERC/GEC

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*1,791,330*	*1,863,960*	*1,930,600*	*1,990,220*	*2,050,860*	*2,114,190*	*2,177,870*	*2,244,930*	*2,311,250*	*2,379,370*	*2,448,095*	*2,517,806*	*2,588,921*	*2,661,484*	*2,735,540*
Hydro Rate (mills/kWh)	*187.30*	*183.68*	*180.57*	*177.99*	*175.22*	*172.11*	*168.92*	*165.50*	*160.38*	*154.99*	*149.87*	*144.96*	*140.22*	*136.05*	*133.81*
Operating Revenues	$335,522	$342,372	$348,606	$354,235	$359,346	$363,870	$367,893	$371,526	$370,671	$368,790	$366,897	$364,971	$363,021	$362,107	$366,049
OPERATING EXPENSES															
Operating Expense	$74,435	$76,113	$77,963	$79,961	$82,158	$84,453	$86,909	$89,609	$92,407	$95,272	$98,373	$101,701	$105,277	$109,026	$112,969
Maintenance Expense															
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$144,620	$149,793	$154,176	$157,807	$160,722	$162,949	$164,518	$165,451	$161,798	$157,051	$152,057	$146,803	$141,276	$136,614	$136,614
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$54,300	$53,541	$52,741	$51,898	$51,008	$50,071	$49,083	$48,040	$46,942	$45,783	$44,562	$43,274	$41,917	$40,486	$38,977
Remaining Component	$163,391	$160,986	$158,457	$155,799	$153,005	$150,067	$146,979	$143,732	$140,319	$136,731	$132,958	$128,992	$124,822	$120,439	$115,831
NET INCOME BEFORE TAXES	-$61,751	-$53,415	-$45,704	-$38,571	-$31,973	-$25,870	-$20,225	-$15,003	-$14,144	-$14,144	-$14,144	-$14,144	-$14,144	-$12,992	-$6,875
Federal Income Taxes	-$49,175	-$42,536	-$36,395	-$30,715	-$25,461	-$20,601	-$16,106	-$11,947	-$11,263	-$11,263	-$11,263	-$11,263	-$11,263	-$11,263	-$11,263
State Income Taxes	-$12,577	-$10,879	-$9,308	-$7,856	-$6,512	-$5,269	-$4,119	-$3,056	-$2,881	-$2,881	-$2,881	-$2,881	-$2,881	-$2,881	-$2,881
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,152	$7,269
STATEMENT OF CASH FLOWS															
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,152	$7,269
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$13,974	$14,733	$15,533	$16,377	$17,266	$18,203	$19,192	$20,234	$21,333	$22,491	$23,712	$25,000	$26,357	$27,789	$29,297
Remaining Component	$46,879	$49,284	$51,812	$54,470	$57,264	$60,202	$63,290	$66,537	$69,950	$73,539	$77,311	$81,277	$85,447	$89,830	$94,439
NET CASH FLOW	$55,614	$52,450	$49,122	$45,620	$41,937	$38,062	$33,985	$29,696	$25,184	$20,437	$15,443	$10,190	$4,663	$0	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	122.35	125.09	128.05	131.37	135.25	139.57	145.17	150.38	156.47	161.89	168.54	174.50	183.88	192.33	199.05
Net Benefit	-$116,353	-$109,218	-$101,392	-$92,770	-$81,961	-$68,796	-$51,723	-$33,929	-$9,030	$16,407	$45,708	$74,390	$113,028	$149,779	$178,466
Annual PV of Net Benefit	-$110,600	-$98,684	-$87,084	-$75,739	-$63,605	-$50,749	-$36,268	-$22,615	-$5,721	$9,881	$26,166	$40,480	$58,464	$73,643	$83,410
Cumulative PV of Net Benefit	-$110,600	-$209,284	-$296,368	-$372,106	-$435,711	-$486,460	-$522,728	-$545,343	-$551,064	-$541,183	-$515,016	-$474,536	-$416,072	-$342,429	-$259,020
NPV	$1,808,055														

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*2,808,947*	*2,871,303*	*2,933,140*	*2,994,977*	*3,056,813*	*3,118,650*	*3,180,486*	*3,242,323*	*3,304,160*	*3,365,996*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*
Hydro Rate (mills/kWh)	*131.79*	*130.41*	*129.16*	*128.02*	*126.99*	*136.24*	*145.18*	*144.04*	*143.01*	*142.07*	*142.55*	*144.35*	*146.21*	*148.14*	*150.14*
Operating Revenues	$370,185	$374,446	$378,841	$383,425	$388,176	$424,872	$461,749	$467,038	$472,521	$478,203	$484,092	$490,197	$496,523	$503,080	$509,877
OPERATING EXPENSES															
Operating Expense	$117,104	$121,366	$125,760	$130,344	$135,095	$140,019	$145,123	$150,413	$155,895	$161,577	$167,467	$173,571	$179,897	$186,455	$193,251
Maintenance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$136,614	$136,614	$136,614	$136,614	$136,614	$168,386	$200,159	$200,159	$200,159	$200,159	$200,159	$200,159	$200,159	$200,159	$200,159
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044	$10,044
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$37,386	$35,709	$33,940	$32,076	$30,111	$28,038	$25,853	$23,550	$21,121	$18,561	$15,862	$13,016	$10,015	$6,852	$3,516
Remaining Component	$110,986	$105,893	$100,538	$94,909	$88,991	$82,770	$76,229	$69,353	$62,124	$54,524	$46,534	$38,134	$29,304	$20,020	$10,260
NET INCOME BEFORE TAXES	-$439	$6,331	$13,454	$20,948	$28,831	$68,898	$109,396	$118,575	$128,233	$138,393	$149,082	$160,328	$172,159	$184,606	$197,701
Federal Income Taxes	-$11,263	-$11,263	-$11,263	-$11,263	-$11,263	$14,038	$39,340	$39,340	$39,340	$39,340	$39,340	$39,340	$39,340	$39,340	$39,340
State Income Taxes	-$2,881	-$2,881	-$2,881	-$2,881	-$2,881	$3,590	$10,061	$10,061	$10,061	$10,061	$10,061	$10,061	$10,061	$10,061	$10,061
NET INCOME	$13,705	$20,475	$27,598	$35,092	$42,975	$51,269	$59,995	$69,174	$78,832	$88,992	$99,681	$110,927	$122,758	$135,205	$148,300
STATEMENT OF CASH FLOWS															
NET INCOME	$13,705	$20,475	$27,598	$35,092	$42,975	$51,269	$59,995	$69,174	$78,832	$88,992	$99,681	$110,927	$122,758	$135,205	$148,300
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$30,888	$32,566	$34,334	$36,198	$38,164	$40,236	$42,421	$44,724	$47,153	$49,713	$52,413	$55,259	$58,259	$61,423	$64,758
Remaining Component	$99,283	$104,376	$109,731	$115,360	$121,278	$127,500	$134,040	$140,917	$148,146	$155,746	$163,735	$172,135	$180,965	$190,249	$200,009
NET CASH FLOW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	207.31	215.81	224.36	234.51	244.81	255.56	266.79	278.51	290.75	303.53	316.87	330.80	345.34	360.52	376.37
Net Benefit	$212,142	$245,223	$279,238	$318,913	$360,155	$372,139	$386,780	$435,997	$488,176	$543,482	$592,003	$633,195	$676,247	$721,242	$768,268
Annual PV of Net Benefit	$94,246	$103,556	$112,090	$121,686	$130,628	$128,301	$126,755	$135,819	$144,555	$152,974	$158,392	$161,037	$163,482	$165,738	$167,815
Cumulative PV of Net Benefit	-$164,773	-$61,218	$50,872	$172,559	$303,186	$431,487	$558,242	$694,061	$838,616	$991,590	$1,149,982	$1,311,019	$1,474,501	$1,640,239	$1,808,055

Starting Year	2007	
Direct Construction Expense	83.5%	
AFUDC and Financing Expense	16.5%	
Percentage of AFUDC as Debt	100%	
Percentage of Total Expense as Land	0%	
Tax Life: MACRS Half year Conv.	20	year
Book Life	30	year
Declining Balance Rate	1.5	
State Tax Rate	8.0%	
Federal Tax Rate	34.0%	
DEFERRED TAX -NORM (1) OR FLOW THROUGH (0)	1	
Total Tax Rate	39.3%	
Book Depreciation (SL-1 or IRR-0)	1	
Interim Retirement Rate	1.0%	
Salvage Rate	0.0%	
Return on Equity	5.20%	
Interest Rate on Debt	5.20%	
Percent Funding by Equity	0.0%	
Percent Funding by Debt	100.0%	
WACC	5.20%	
Insurance (Percent of Initial Construction Cost)	0.25%	

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
TAX DEPRECIATION															
BOY Tax Value	100.00%	92.50%	85.56%	79.15%	73.21%	67.72%	62.64%	57.94%	53.60%	49.31%	45.02%	40.73%	36.45%	32.16%	27.87%
Declining Balance Depr.	7.50%	6.94%	6.42%	5.94%	5.49%	5.08%	4.70%	4.35%	4.02%	3.70%	3.38%	3.05%	2.73%	2.41%	2.09%
Straight Line Depr.	2.44%	4.74%	4.63%	4.52%	4.44%	4.37%	4.32%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%
Tax Depr.	7.50%	6.94%	6.42%	5.94%	5.49%	5.08%	4.70%	4.35%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%
RATE BASE															
Book Depr.	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%
Cumulative Book Depr.	3.33%	6.67%	10.00%	13.33%	16.67%	20.00%	23.33%	26.67%	30.00%	33.33%	36.67%	40.00%	43.33%	46.67%	50.00%
Deferred Taxes	1.64%	1.42%	1.21%	1.02%	0.85%	0.69%	0.54%	0.40%	0.37%	0.37%	0.37%	0.37%	0.37%	0.37%	0.37%
Cumulative Deferred Taxes	1.64%	3.05%	4.26%	5.29%	6.13%	6.82%	7.36%	7.75%	8.13%	8.50%	8.88%	9.25%	9.63%	10.00%	10.38%
Rate Base	95.03%	90.28%	85.74%	81.38%	77.20%	73.18%	69.31%	65.58%	61.87%	58.16%	54.46%	50.75%	47.04%	43.33%	39.62%
RETURN & TAXES															
Return on WACC	4.94%	4.70%	4.46%	4.23%	4.02%	3.81%	3.61%	3.41%	3.22%	3.03%	2.83%	2.64%	2.45%	2.25%	2.06%
Bond Interest	4.94%	4.70%	4.46%	4.23%	4.02%	3.81%	3.61%	3.41%	3.22%	3.03%	2.83%	2.64%	2.45%	2.25%	2.06%
Federal Income Taxes	-1.30%	-1.13%	-0.96%	-0.81%	-0.67%	-0.55%	-0.43%	-0.32%	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%
State Income Taxes	-0.33%	-0.29%	-0.25%	-0.21%	-0.17%	-0.14%	-0.11%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%
Property Taxes & Insurance	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
Year	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
TAX DEPRECIATION															
BOY Tax Value	23.58%	19.29%	15.01%	10.72%	6.43%	2.14%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Declining Balance Depr.	1.77%	1.45%	1.13%	0.80%	0.48%	0.16%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Straight Line Depr.	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Tax Depr.	4.29%	4.29%	4.29%	4.29%	4.29%	2.14%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RATE BASE															
Book Depr.	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%
Cumulative Book Depr.	53.33%	56.67%	60.00%	63.33%	66.67%	70.00%	73.33%	76.67%	80.00%	83.33%	86.67%	90.00%	93.33%	96.67%	100.00%
Deferred Taxes	0.37%	0.37%	0.37%	0.37%	0.37%	-0.47%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%
Cumulative Deferred Taxes	10.75%	11.13%	11.50%	11.88%	12.25%	11.78%	10.47%	9.17%	7.86%	6.55%	5.24%	3.93%	2.62%	1.31%	0.00%
Rate Base	35.91%	32.21%	28.50%	24.79%	21.08%	18.22%	16.19%	14.17%	12.14%	10.12%	8.10%	6.07%	4.05%	2.02%	0.00%
RETURN & TAXES															
Return on WACC	1.87%	1.68%	1.48%	1.29%	1.10%	0.95%	0.84%	0.74%	0.63%	0.53%	0.42%	0.32%	0.21%	0.11%	0.00%
Bond Interest	1.87%	1.68%	1.48%	1.29%	1.10%	0.95%	0.84%	0.74%	0.63%	0.53%	0.42%	0.32%	0.21%	0.11%	0.00%
Federal Income Taxes	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%	0.37%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%
State Income Taxes	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	0.10%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%
Property Taxes & Insurance	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%

Variable	Value	Source
Interest on Construction	4.09%	FERC (4/29/2004 6-month T-Bond & 300 basis points)
Financing Cost	2%	FERC
Debt Service Reserve	1 year	FERC
Operational Reserve	3 months	FERC
Term of Analysis	30 years	FERC
Starting Year	2007	FERC
Grant Value	$1,083,685	GEC
Interest on Debt, AIDEA Component	5.43%	GEC
AIDEA Loan Component	$0	GEC
Interest on Debt, Remainder	5.13%	GEC
Term of Financing, AIDEA Component	30 years	GEC
Term of Financing, Remaining Component	30 years	GEC
2003 O&M (including Staff-recommended environmental enhancements)	$58,600	FERC/GEC
Insurance (% of Initial Investment including granted $)	0.25%	FERC
Interest Rate on Debt Reserve	3.60%	FERC (4/29/2004 5-year T-Bond)
Interest Rate on Operating Reserve	0.85%	FERC (4/29/2004 3-month T-Bond)
Net Cost of Debt	5.130%	Calculated
Operating Reserve Requirement	$150,000	FERC (approx. 3 months operating revenues in last year of operations, rounded up to nearest 25K)
Federal Tax Rate	34%	FERC
State Tax Rate	8%	FERC
Percent Funding by Equity	0.0%	FERC/GEC
Percent Funding by Debt	100.0%	FERC/GEC

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*1,791,330*	*1,863,960*	*1,930,600*	*1,990,220*	*2,050,860*	*2,114,190*	*2,177,870*	*2,244,930*	*2,311,250*	*2,379,370*	*2,448,095*	*2,517,806*	*2,588,921*	*2,661,484*	*2,735,540*
Hydro Rate (mills/kWh)	*185.63*	*182.07*	*179.02*	*176.49*	*173.77*	*170.71*	*167.57*	*164.19*	*159.12*	*153.79*	*148.72*	*143.85*	*139.17*	*135.19*	*132.97*
Operating Revenues	$332,524	$339,375	$345,612	$351,249	$356,370	$360,907	$364,949	$368,604	$367,777	$365,930	$364,076	$362,195	$360,295	$359,799	$363,741
OPERATING EXPENSES															
Operating Expense	$74,435	$76,113	$77,963	$79,961	$82,158	$84,453	$86,909	$89,609	$92,407	$95,272	$98,373	$101,701	$105,277	$109,026	$112,969
Maintenance Expense															
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$141,622	$146,796	$151,182	$154,821	$157,745	$159,987	$161,573	$162,528	$158,904	$154,191	$149,236	$144,027	$138,551	$134,306	$134,306
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$9,972	$9,972	$9,972	$9,972	$9,972	$9,972	$9,972	$9,972	$9,972	$9,972	$9,972	$9,972	$9,972	$9,972	$9,972
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Remaining Component	$214,588	$211,429	$208,109	$204,618	$200,948	$197,090	$193,034	$188,770	$184,287	$179,574	$174,620	$169,411	$163,935	$158,178	$152,126
NET INCOME BEFORE TAXES	-$61,719	-$53,387	-$45,680	-$38,550	-$31,956	-$25,856	-$20,214	-$14,995	-$14,136	-$14,136	-$14,136	-$14,136	-$14,136	-$12,625	-$6,573
Federal Income Taxes	-$49,149	-$42,514	-$36,376	-$30,699	-$25,448	-$20,590	-$16,097	-$11,941	-$11,257	-$11,257	-$11,257	-$11,257	-$11,257	-$11,257	-$11,257
State Income Taxes	-$12,570	-$10,873	-$9,303	-$7,851	-$6,508	-$5,266	-$4,117	-$3,054	-$2,879	-$2,879	-$2,879	-$2,879	-$2,879	-$2,879	-$2,879
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,511	$7,564
STATEMENT OF CASH FLOWS															
NET INCOME	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,511	$7,564
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Remaining Component	$61,568	$64,726	$68,047	$71,538	$75,207	$79,066	$83,122	$87,386	$91,869	$96,582	$101,536	$106,745	$112,221	$117,978	$124,030
NET CASH FLOW	$54,899	$51,740	$48,420	$44,929	$41,259	$37,401	$33,345	$29,081	$24,598	$19,885	$14,930	$9,722	$4,246	$0	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	122.35	125.09	128.05	131.37	135.25	139.57	145.17	150.38	156.47	161.89	168.54	174.50	183.88	192.33	199.05
Net Benefit	-$113,355	-$106,221	-$98,399	-$89,784	-$78,984	-$65,833	-$48,778	-$31,007	-$6,135	$19,267	$48,529	$77,166	$115,753	$152,087	$180,775
Annual PV of Net Benefit	-$107,824	-$96,107	-$84,686	-$73,501	-$61,504	-$48,762	-$34,367	-$20,780	-$3,911	$11,683	$27,990	$42,336	$60,407	$75,495	$85,357
Cumulative PV of Net Benefit	-$107,824	-$203,931	-$288,616	-$362,117	-$423,622	-$472,384	-$506,751	-$527,531	-$531,442	-$519,759	-$491,768	-$449,433	-$389,026	-$313,531	-$228,174
NPV	$1,883,880														

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
INCOME STATEMENT															
UTILITY OPERATING INCOME															
Hydro Generation (kWh)	*2,808,947*	*2,871,303*	*2,933,140*	*2,994,977*	*3,056,813*	*3,118,650*	*3,180,486*	*3,242,323*	*3,304,160*	*3,365,996*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*	*3,396,000*
Hydro Rate (mills/kWh)	*130.97*	*129.61*	*128.37*	*127.25*	*126.23*	*135.49*	*144.45*	*143.32*	*142.30*	*141.37*	*141.86*	*143.66*	*145.52*	*147.45*	*149.45*
Operating Revenues	$367,877	$372,138	$376,532	$381,116	$385,867	$422,547	$459,407	$464,696	$470,179	$475,861	$481,750	$487,855	$494,181	$500,738	$507,535
OPERATING EXPENSES															
Operating Expense	$117,104	$121,366	$125,760	$130,344	$135,095	$140,019	$145,123	$150,413	$155,895	$161,577	$167,467	$173,571	$179,897	$186,455	$193,251
Maintenance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation Expense	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
NET OPERATING INCOME	$134,306	$134,306	$134,306	$134,306	$134,306	$166,061	$197,817	$197,817	$197,817	$197,817	$197,817	$197,817	$197,817	$197,817	$197,817
OTHER INCOME & DEDUCTIONS															
Interest on Debt Reserve	$9,972	$9,972	$9,972	$9,972	$9,972	$9,972	$9,972	$9,972	$9,972	$9,972	$9,972	$9,972	$9,972	$9,972	$9,972
Interest on Operating Reserve	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275	$1,275
Interest on Long Term Debt															
AIDEA Component	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Remaining Component	$145,763	$139,074	$132,041	$124,648	$116,876	$108,705	$100,115	$91,084	$81,590	$71,608	$61,115	$50,083	$38,486	$26,293	$13,475
NET INCOME BEFORE TAXES	-$210	$6,479	$13,511	$20,904	$28,677	$68,603	$108,949	$117,980	$127,475	$137,456	$147,949	$158,981	$170,578	$182,771	$195,589
Federal Income Taxes	-$11,257	-$11,257	-$11,257	-$11,257	-$11,257	$14,031	$39,319	$39,319	$39,319	$39,319	$39,319	$39,319	$39,319	$39,319	$39,319
State Income Taxes	-$2,879	-$2,879	-$2,879	-$2,879	-$2,879	$3,588	$10,056	$10,056	$10,056	$10,056	$10,056	$10,056	$10,056	$10,056	$10,056
NET INCOME	$13,926	$20,615	$27,648	$35,041	$42,813	$50,984	$59,574	$68,605	$78,100	$88,081	$98,574	$109,606	$121,203	$133,396	$146,214
STATEMENT OF CASH FLOWS															
NET INCOME	$13,926	$20,615	$27,648	$35,041	$42,813	$50,984	$59,574	$68,605	$78,100	$88,081	$98,574	$109,606	$121,203	$133,396	$146,214
Add back Depreciation	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467	$116,467
Subtract Principal Payment															
AIDEA Component	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Remaining Component	$130,393	$137,082	$144,114	$151,508	$159,280	$167,451	$176,041	$185,072	$194,566	$204,547	$215,041	$226,072	$237,670	$249,862	$262,680
NET CASH FLOW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ANALYSIS OF PROJECT BENEFIT															
Avoided Cost Rate/Diesel Gen. (mills/kWh)	207.31	215.81	224.36	234.51	244.81	255.56	266.79	278.51	290.75	303.53	316.87	330.80	345.34	360.52	376.37
Net Benefit	$214,450	$247,531	$281,547	$321,222	$362,464	$374,465	$389,121	$438,339	$490,518	$545,824	$594,344	$635,537	$678,589	$723,584	$770,610
Annual PV of Net Benefit	$96,316	$105,749	$114,412	$124,165	$133,270	$130,964	$129,449	$138,707	$147,644	$156,274	$161,862	$164,635	$167,209	$169,596	$171,805
Cumulative PV of Net Benefit	-$131,858	-$26,109	$88,303	$212,467	$345,737	$476,701	$606,149	$744,856	$892,500	$1,048,774	$1,210,636	$1,375,270	$1,542,479	$1,712,075	$1,883,880

Starting Year	2007	
Direct Construction Expense	83.5%	
AFDUC and Financing Expense	16.5%	
Percentage of AFUDC as Debt	100%	
Percentage of Total Expense as Land	0%	
Tax Life: MACRS Half year Conv.	20	year
Book Life	30	year
Declining Balance Rate	1.5	
State Tax Rate	8.0%	
Federal Tax Rate	34.0%	
DEFERRED TAX -NORM (1) OR FLOW THROUGH (0)	1	
Total Tax Rate	39.3%	
Book Depreciation (SL-1 or IRR-0)	1	
Interim Retirement Rate	1.0%	
Salvage Rate	0.0%	
Return on Equity	5.13%	
Interest Rate on Debt	5.13%	
Percent Funding by Equity	0.0%	
Percent Funding by Debt	100.0%	
WACC	5.13%	
Insurance (Percent of Initial Construction Cost)	0.25%	

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
TAX DEPRECIATION															
BOY Tax Value	100.00%	92.50%	85.56%	79.15%	73.21%	67.72%	62.64%	57.94%	53.60%	49.31%	45.02%	40.73%	36.45%	32.16%	27.87%
Declining Balance Depr.	7.50%	6.94%	6.42%	5.94%	5.49%	5.08%	4.70%	4.35%	4.02%	3.70%	3.38%	3.05%	2.73%	2.41%	2.09%
Straight Line Depr.	2.44%	4.74%	4.63%	4.52%	4.44%	4.37%	4.32%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%
Tax Depr.	7.50%	6.94%	6.42%	5.94%	5.49%	5.08%	4.70%	4.35%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%
RATE BASE															
Book Depr.	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%
Cumulative Book Depr.	3.33%	6.67%	10.00%	13.33%	16.67%	20.00%	23.33%	26.67%	30.00%	33.33%	36.67%	40.00%	43.33%	46.67%	50.00%
Deferred Taxes	1.64%	1.42%	1.21%	1.02%	0.85%	0.69%	0.54%	0.40%	0.37%	0.37%	0.37%	0.37%	0.37%	0.37%	0.37%
Cumulative Deferred Taxes	1.64%	3.05%	4.26%	5.29%	6.13%	6.82%	7.36%	7.75%	8.13%	8.50%	8.88%	9.25%	9.63%	10.00%	10.38%
Rate Base	95.03%	90.28%	85.74%	81.38%	77.20%	73.18%	69.31%	65.58%	61.87%	58.16%	54.46%	50.75%	47.04%	43.33%	39.62%
RETURN & TAXES															
Return on WACC	4.88%	4.63%	4.40%	4.17%	3.96%	3.75%	3.56%	3.36%	3.17%	2.98%	2.79%	2.60%	2.41%	2.22%	2.03%
Bond Interest	4.88%	4.63%	4.40%	4.17%	3.96%	3.75%	3.56%	3.36%	3.17%	2.98%	2.79%	2.60%	2.41%	2.22%	2.03%
Federal Income Taxes	-1.30%	-1.13%	-0.96%	-0.81%	-0.67%	-0.55%	-0.43%	-0.32%	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%
State Income Taxes	-0.33%	-0.29%	-0.25%	-0.21%	-0.17%	-0.14%	-0.11%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%
Property Taxes & Insurance	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
Year	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
TAX DEPRECIATION															
BOY Tax Value	23.58%	19.29%	15.01%	10.72%	6.43%	2.14%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Declining Balance Depr.	1.77%	1.45%	1.13%	0.80%	0.48%	0.16%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Straight Line Depr.	4.29%	4.29%	4.29%	4.29%	4.29%	4.29%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Tax Depr.	4.29%	4.29%	4.29%	4.29%	4.29%	2.14%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RATE BASE															
Book Depr.	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%
Cumulative Book Depr.	53.33%	56.67%	60.00%	63.33%	66.67%	70.00%	73.33%	76.67%	80.00%	83.33%	86.67%	90.00%	93.33%	96.67%	100.00%
Deferred Taxes	0.37%	0.37%	0.37%	0.37%	0.37%	-0.47%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%
Cumulative Deferred Taxes	10.75%	11.13%	11.50%	11.88%	12.25%	11.78%	10.47%	9.17%	7.86%	6.55%	5.24%	3.93%	2.62%	1.31%	0.00%
Rate Base	35.91%	32.21%	28.50%	24.79%	21.08%	18.22%	16.19%	14.17%	12.14%	10.12%	8.10%	6.07%	4.05%	2.02%	0.00%
RETURN & TAXES															
Return on WACC	1.84%	1.65%	1.46%	1.27%	1.08%	0.93%	0.83%	0.73%	0.62%	0.52%	0.42%	0.31%	0.21%	0.10%	0.00%
Bond Interest	1.84%	1.65%	1.46%	1.27%	1.08%	0.93%	0.83%	0.73%	0.62%	0.52%	0.42%	0.31%	0.21%	0.10%	0.00%
Federal Income Taxes	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%	0.37%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%	1.04%
State Income Taxes	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	0.10%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%
Property Taxes & Insurance	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%

The National Park Service cares for special places
saved by the American people
so that all may experience our heritage.

EXPERIENCE YOUR AMERICA.

As the nation's principal conservation agency, the Department of the Interior has responsibility for most of our nationally owned public lands and natural and cultural resources. This includes fostering the wisest use of our land and water resources, protecting our fish and wildlife, preserving the environmental and cultural values of our national parks and historical places, and providing for enjoyment of life through outdoor recreation. The department assesses our energy and mineral resources and works to assure that their development is in the best interests of all. The department also has a major responsibility for American Indian reservation communities and for people who live in island territories under U.S. administration.

June 2004