Missouri River Recovery Management Plan and Environmental Impact Statement

Thermal Power Environmental Consequences Analysis

Technical Report

August 2018

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Acronyms and Abbreviations

BiOp	2003 Amended Biological Opinion
CO_2	carbon dioxide
EIA	Energy Information Administration
EIS	environmental impact statement
EPA	U.S. Environmental Protection Agency
EQ	environmental quality
ER	Engineering Regulation
ERDC	Engineering Research and Development Center
ESA	Endangered Species Act
ESH	emergent sandbar habitat
°F	degrees Fahrenheit
FERC	Federal Energy Regulatory Commission
GDP	gross domestic product
H&H	hydrologic and hydraulic (Model)
HC	human considerations
HEC	Hydrologic Engineering Center
HEC-RAS	Hydrologic Engineering Center - River Analysis System
HEC-RAS-NSM	Hydrologic Engineering Center - River Analysis System - Nutrient Simulation Module
IRC	interception and rearing complex
LMP	locational marginal pricing
MISO	Midcontinent Independent System Operator
MROW	Midwest Reliability Organization – West
MRRMP-EIS	Missouri River Recovery Management Plan and Environmental Impact Statement
MRRP	Missouri River Recovery Program
NED	national economic development
NERC	North American Electric Reliability Corporation
NOx	oxides of nitrogen
NPDES	National Pollutant Discharge Elimination System
OSE	other social effects
P&G	1983 Economic and Environmental Principles and Guidelines for Water and Related Land Resources Implementation Studies
POR	period of record, 1931–2012, excluding 2011
period of analysis	1975–2012, excluding 2011
RED	regional economic development
RTO	Regional Transmission Organization

SCC	social cost of carbon
SOx	oxides of sulfur
SPP	Southwest Power Pool
USACE	U.S. Army Corps of Engineers
USFWS	U.S. Fish and Wildlife Service

1.0 Introduction

The Kansas City and Omaha Districts of the U.S. Army Corps of Engineers (USACE), in cooperation with the U.S. Fish and Wildlife Service (USFWS), have developed the Missouri River Recovery Management Plan and Environmental Impact Statement (MRRMP-EIS). The purpose of the MRRMP-EIS is to develop a suite of actions that meets Endangered Species Act (ESA) responsibilities for the piping plover, the interior least tern, and the pallid sturgeon.

The purpose of the Thermal Power Environmental Consequences Analysis Technical Report is to provide supplemental information on the Thermal Power analysis in addition to the MRRMP-EIS. Additional details on the National Economic Development (NED), Regional Economic Development (RED), and Other Social Effects (OSE) methodology and results are provided in this report. No Environmental Quality (EQ) analysis was undertaken for thermal power.

1.1 Summary of Alternatives

The MRRMP-EIS evaluates the following alternatives. A detailed description of the alternatives is provided in Chapter 2 of the MRRMP-EIS.

- **Alternative 1 – No Action.** This is the No Action alternative, in which the Missouri River Recovery Program (MRRP) would continue to be implemented as it is currently, including a number of management actions associated with the MRRP and 2003 Amended Biological Opinion (BiOp) compliance. Management actions under Alternative 1 include creation of early life stage habitat for the pallid sturgeon and emergent sandbar habitat (ESH), as well as a spring pulse for pallid sturgeon. The construction of habitat would be focused in the Garrison and Gavins reaches for ESH (an average rate of 164 acres per year) and between Ponca to the mouth near St. Louis for pallid sturgeon early life stage habitat (3,999 additional acres constructed).
- **Alternative 2 – USFWS 2003 Biological Opinion Projected Actions.** This alternative represents the USFWS interpretation of the management actions that would be implemented as part of the 2003 Amended BiOp Reasonable and Prudent Alternative (RPA) (USFWS 2003). Whereas Alternative 1 only includes the continuation of management actions USACE has implemented to date for BiOp compliance, Alternative 2 includes additional iterative actions and expected actions that the USFWS anticipates would ultimately be implemented through adaptive management and as impediments to implementation were removed. Considerably more early life stage habitat (10,758 additional acres constructed) and ESH (an average rate of 1,331 acres per year) would be constructed under Alternative 2 than under Alternative 1. In addition, a spring pallid sturgeon flow release would be implemented every year if specific conditions were met. Alternative 2 would also modify System operations to allow for summer flows that are sufficiently low to provide for early life stage habitat as rearing, refugia, and foraging areas for larval, juvenile, and adult pallid sturgeon.
- **Alternative 3 – Mechanical Construction.** The USACE would mechanically construct ESH at an average rate of 332 acres per year distributed between the Garrison, Fort Randall, and Gavins Point Reaches. This amount represents the acreage necessary to meet the bird habitat targets after accounting for available ESH resulting from System operations. The average annual construction amount includes replacing ESH lost to erosion and vegetative growth, as well as constructing new ESH. An estimated 3,380

acres of early life stage habitat for the pallid sturgeon would be constructed under Alternative 3. There would not be any reoccurring flow releases or pulses implemented under this alternative; however, should new information be learned through Level 1 and 2 studies over the next 9 years suggesting that spring discharges result in stronger aggregation of adult pallid sturgeon at spawning locations or increased reproductive success, a one-time spawning cue test could be implemented to provide additional information to support or refute this hypothesis. At the present time, it is assumed the test release would be similar to the timing, magnitude, duration, and pattern of the spawning cue included as a recurring release under Alternative 6.

- **Alternative 4 – Spring ESH Creating Release.** The USACE would mechanically construct ESH annually at an average rate of 195 acres per year distributed between the Garrison, Fort Randall, and Gavins Point Reaches. This amount represents the acreage necessary to meet the bird habitat targets after accounting for available ESH resulting from implementation of an ESH-creating reservoir release in the spring. Alternative 4 would be similar to Alternative 1 (the No Action alternative), with the addition of a spring release designed to create ESH for the least tern and piping plover. An estimated 3,380 acres of early life stage habitat for the pallid sturgeon would be constructed under Alternative 4.
- **Alternative 5 – Fall ESH Creating Release.** The USACE would mechanically construct ESH annually at an average rate of 253 acres per year distributed between the Garrison, Fort Randall, and Gavins Point Reaches. This amount represents the acreage necessary to meet the bird habitat targets after accounting for available ESH resulting from implementation of an ESH-creating reservoir release in the fall. Alternative 5 is similar to Alternative 1 (the No Action alternative), with the addition of a release in the fall designed to create sandbar habitat for the least tern and piping plover. An estimated 3,380 acres of early life stage habitat for the pallid sturgeon would be constructed under Alternative 5.
- **Alternative 6 – Pallid Sturgeon Spawning Cue.** The USACE would mechanically construct ESH annually at an average rate of 245 acres per year distributed between the Garrison, Fort Randall, and Gavins Point Reaches. In addition, the USACE would attempt a spawning cue pulse every three years in March and May. These spawning cue pulses would not be started and/or would be terminated whenever flood targets are exceeded. An estimated 3,380 acres of early life stage habitat for the pallid sturgeon would be constructed under Alternative 6.

1.2 USACE Planning Accounts

Alternative means of achieving species objectives were evaluated including consideration for the effects of each action or alternative on a wide range of human considerations (HC). Human considerations to be evaluated in the MRRMP-EIS alternatives are rooted in the economic, social, and cultural values associated with the natural resources of the Missouri River. The HC effects evaluated in the Final MRRMP-EIS are required under the National Environmental Policy Act and its implementing regulations (40 CFR Parts 1500–1508). The 1983 Economic and Environmental Principles and Guidelines for Water and Related Land Resources Implementation Studies (P&G) also served as the central guiding regulation for the economic and environmental analysis included within the MRRMP-EIS. Further guidance that is specific to USACE is described in Engineering Regulation (ER) 1105-2-100, Planning Guidance Notebook, which provides the overall direction by which USACE Civil Works projects are formulated, evaluated, and selected for implementation. These guidance documents describe four accounts that were established to facilitate evaluation and display the effects of alternative plans:

- The NED account displays changes in the economic value of the national output of goods and services expressed in monetary units. Contributions to NED are the direct net benefits that accrue in the planning area and the rest of the nation.
- The RED account registers changes in the distribution of regional economic activity (i.e., jobs and income).
- The EQ displays non-monetary effect of significant natural and cultural resources.
- The OSE account registers plan effects from perspective that are relevant to the planning process, but are not reflected in the other three accounts. In a general sense, OSE refers to how the constituents of life that influence personal and group definitions of satisfaction, well-being, and happiness are affected by some condition or proposed intervention.

The accounts framework enables consideration of a range of both monetary and non-monetary values and interests that are expressed as important to stakeholders, while ensuring impacts are not double counted. The USACE planning accounts evaluated for thermal power include NED, RED, and OSE. The Thermal Power Technical Report includes information on the NED and RED methodology and results.

1.3 Approach for Evaluating Environmental Consequences of MRRMP-EIS

There are twenty thermal power plants located along the Missouri River. One power plant is located on Lake Sakakawea and six are located between Garrison Dam and Lake Oahe (this river reach is referred to as both the Garrison reach). The Garrison Reach and Lake Sakakawea are also referred to the “upper river” for the purposes of consistency with the figures in the NED evaluation. The remaining 13 plants are located in the lower river below Gavins Point Dam, near the following cities: Sioux City, Omaha, Nebraska City, Kansas City, and St. Louis.

Evaluation of the environmental consequences of the MRRMP-EIS to thermal power requires an understanding of how the physical conditions of the river would change under each of the MRRMP-EIS alternatives. Generally, thermal power plants are impacted by the Missouri River flows, stages and temperature conditions affecting intake access to water, the ability to discharge cooling water, and power plant operations and generation. Power plants need sufficient river stages to accommodate intake elevations. River temperatures can affect power plant operational efficiency and power generation. In addition, state water quality standards include a maximum river water temperature and maximum change in river water temperature within the mixing zone. Maximum temperatures requirements are 90°F for plants along the lower sections of the Missouri River. When the river temperatures start to approach 90°F in the lower river, power plants would need to curtail power generation to meet these temperature requirements. River water temperatures can also affect operational efficiencies for power plants in the upper river. River temperatures affect one of the power plants in the Garrison reach. The remaining six plants in Lake Sakakawea and the Garrison reach either have cooling towers or systems and/or not affected by river temperatures.

The conceptual flow chart shown in Figure 1 demonstrates, in a stepwise manner, how changes to the physical conditions of the Missouri River and its floodplain can impact thermal power operations and power generation. This figure also shows the intermediate factors and criteria that were applied in assessing the NED, RED, and OSE consequences to thermal power.

The environmental consequences analysis first focused on an analysis of the river stage, river flow, or temperatures at specified locations near power plants along the river relative to important intake and temperature thresholds under each of the MRRMP-EIS alternatives. The results of this analysis provided important inputs for the NED, RED, and OSE evaluation, the second step in the process. The NED, RED, and OSE evaluation estimated impacts associated with changes in power plant operations and power generation under the MRRMP-EIS alternatives. Figure 2 illustrates an overview of the approach for the thermal power evaluation.

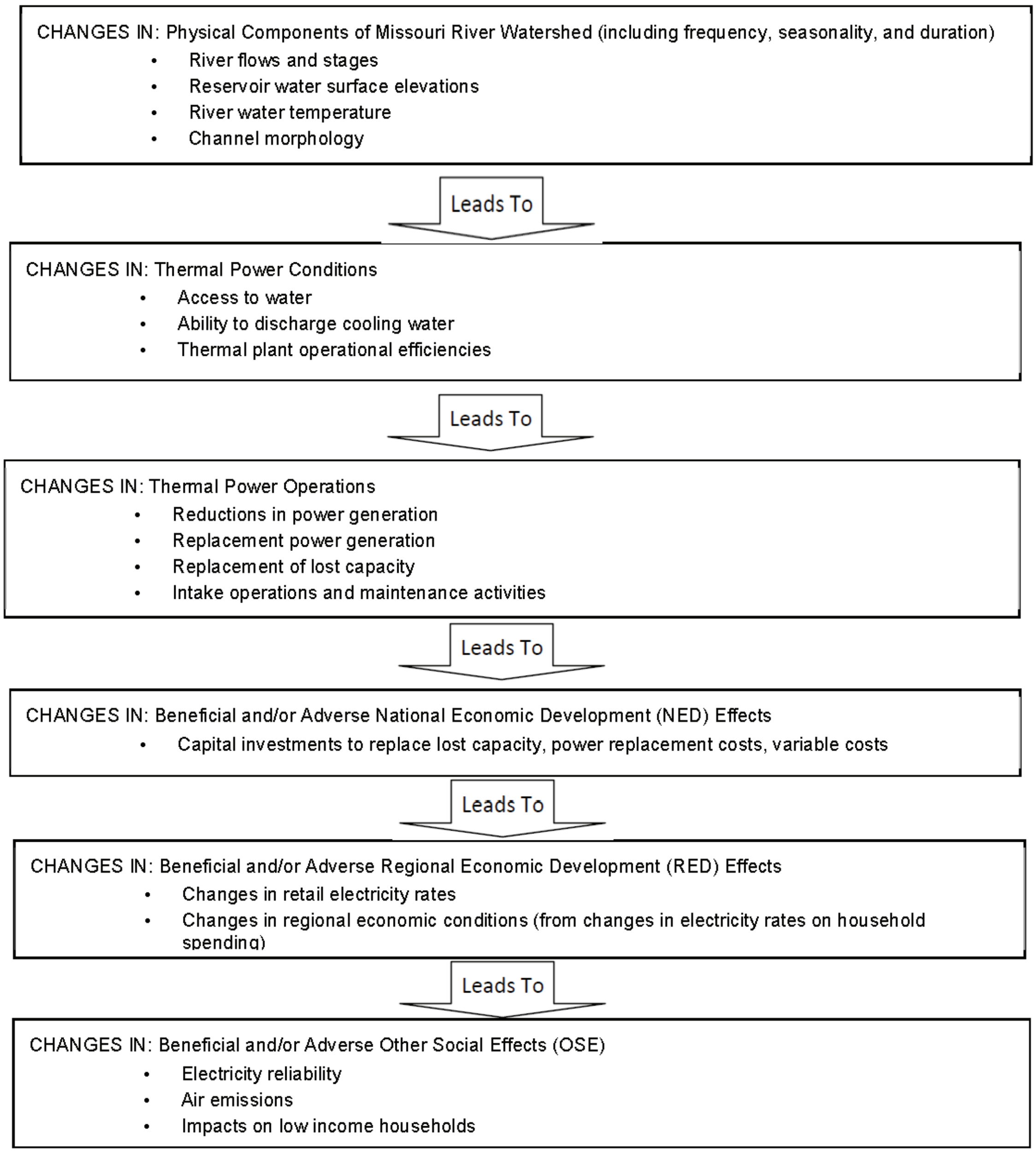

Figure 1. Flow Chart of Inputs Considered in Thermal Power Evaluation

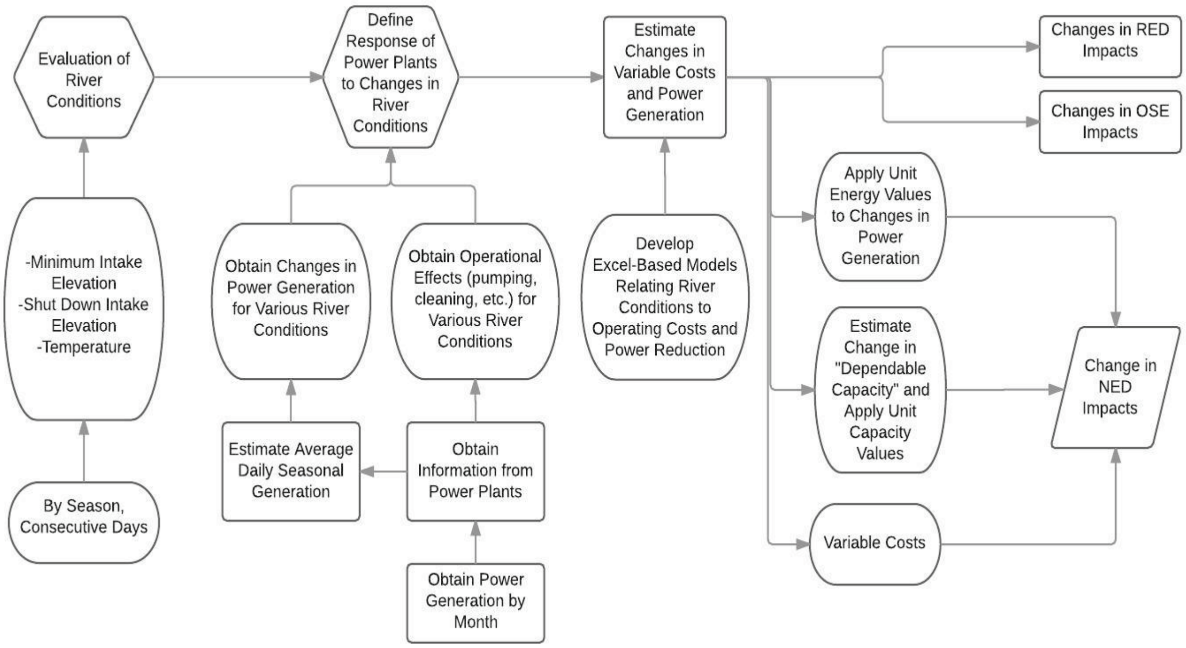

Figure 2. Environmental Consequences Approach for Thermal Power

The analysis of changes in river stages (relative to intake elevations) and river flows uses USACE Hydrologic Engineering Center River Analysis System (HEC-RAS) data for the period of record (POR) between 1931 and 2012 to assess when and how often intake access to water is affected. In addition, the Engineering Research and Development Center (ERDC) developed a HEC-RAS Water Quality temperature model to estimate daily temperatures for a 37-year period between 1975 and 2012 (excluding 2011) for the river reaches below Gavins Point Dam and the Garrison reach.[1] Please see the Hydrology and Hydraulics Water Quality Temperature Technical Report (available on the MRRP website at www.moriverrecovery.org) for additional details on the river temperature modeling. River temperatures are used to assess impacts to power generation from reduced operational efficiency and regulatory requirements. Because it was necessary to consider both water access and temperature impacts simultaneously to estimate accurate energy value and capacity value impacts to thermal power plants, the NED evaluation is based on the 37-year period of analysis.[2] The following sections in this report provide further details on the methodology.

[1] Years 2011 in the HEC-RAS water quality temperature model were excluded from the analysis for the Final EIS due to model limitations. Updates to the model will be incorporated into the analysis as available.

[2] The NED, RED, and OSE results tables summarized the impacts from both temperature and access to water. However, where possible, the data and results for the access to water are shown for the entire POR. The tables and figures note the POR.

2.0 Methodology and Assumptions

The methodology includes an evaluation of the relationship between river conditions and thermal power plants and uses this information to assess the NED, RED, and OSE impacts; these steps in the process are described in these sections.

2.1 Assumptions and Limitations

In modeling the environmental consequences to thermal power plants from the MRRMP-EIS alternatives, the project team established a set of assumptions. The following discussion highlights these assumptions to give the reviewer a better understanding of the objectives for the modeling effort. In addition, this section discusses the limitations of this modeling effort.

The key assumptions used in the modeling effort are as follows.

- The analysis uses data from the hydrologic and hydraulic (H&H) modeling of the river and reservoir System. The analysis assumes that the H&H models reasonably estimate river flows and reservoir levels over the 81-year POR under each of the MRRMP-EIS alternatives as well as Alternative 1 (the No Action alternative).
- The analysis uses data from a water quality/river temperature model developed by USACE ERDC. The analysis assumes that the ERDC temperature models reasonably estimate river temperatures over 37 years (1975–2012, excluding 2011) under each of the MRRMP-EIS alternatives as well as Alternative 1 (the No Action alternative).
- The project team conducted considerable outreach to power plants to understand how various river stages, flows, and temperature conditions adversely impact power plants (i.e., reduced power generation, increased costs). The project team has utilized information from interviews with power plants to assess how adverse effects would affect power generation and variable costs. Some of these conditions have not occurred in the recent past and therefore represent the anticipated operational response of a power plant to a hypothetical situation. It is assumed that the information provided by power plant officials adequately describes the impacts included in the modeling effort.
- Based on input from power plant representatives, in general, it was assumed that all plants in the lower river would shut down when the river temperature was above 90°F because discharging cooling water would violate the maximum temperature water quality standards. This is a conservative assumption because power plants may not shut down during these conditions, but would negotiate with regulators to continue operations, if possible.
- Unit capacity values, estimated by Federal Energy Regulatory Commission (FERC) and provided by the Hydropower Analysis Center, are used to represent the capital cost or major investment needed to replace lost capacity. The unit values are assumed to represent the cost to replace the capacity with an alternative source – combined cycle natural gas.
- The analysis depicts relatively large adverse impacts to power generation expected during dry years under current System operations. Some of these impacts would occur when river stages fall below critical intake thresholds. Recent bed degradation is likely causing water surface elevations to fall below critical thresholds in some locations. Since these conditions exist under current System management, which are modeled with a 2012 channel geometry, power plants would need to improve intakes to address these

issues. The analysis presented here does not attempt to evaluate intake modifications resulting from bed degradation issues, but instead focuses on change in power generation and capacity relative to Alternative 1 as a result of the action alternatives.

- Investments to replace lost capacity during peak power demand seasons in this modeling effort may not reflect specific plant requirements and constraints. For consistency across all power plants, a standard approach to replacing losses in dependable capacity (used in hydropower evaluations) was used.
- The power generation modeling assumes that there would always be a market for the power generated. Conversely, if reductions in power generation would occur from Missouri River thermal power plants, it is assumed that there would replacement power available from the market. There is likely to be power available from the market even in the worst-modeled seasons (SPP 2018). Changes in power generation from Missouri River plants can affect the market prices as replacement sources of electricity that would need to come on-line to replace the generation are typically higher-cost sources. However, many other factors affect energy prices, including fuel costs, demand for energy, availability of substitute power sources, among others. A 2016 estimated Energy Information Administration (EIA) energy price was used in the thermal power evaluation in conjunction with the historic pattern of energy prices as well as price forecasts from EIA to estimate specific monthly weekend and weekday energy prices in 2018 dollars.

2.2 Risk and Uncertainty

Risk and uncertainty are inherent with any model that is developed and used for water resource planning. Much of the risk and uncertainty with the overall MRRMP-EIS is associated with the operation of the Missouri River System and the extent to which flows and reservoir levels will mimic conditions that have occurred over the 81-year POR. Unforeseen events such as climate change and weather patterns may cause river and reservoir conditions to change in the future and would not be captured by the HEC-RAS models or carried through to the thermal power model described is this document (for additional description on climate change, please refer to the Hydrology and Hydraulics Technical Report: Climate Change Assessment). The project team has attempted to address risk and uncertainty in the MRRMP-EIS by defining and evaluating a reasonable range of plan alternatives that include an array of management actions within an adaptive management framework for the Missouri River. All of the alternatives were modeled to estimate impacts to thermal power plants.

A source of uncertainty associated with the thermal power analysis is predicting how thermal power plants would react to long-term changes in river and reservoir conditions. The project team has utilized information from interviews with power plants to assess how adverse effects would affect power generation and variable costs. Some of these river conditions have not occurred in the recent past and therefore represent the anticipated operational response of a power plant to a hypothetical situation. However, while these operational responses may be reasonable under current conditions or in the near future, unforeseen conditions may arise that may alter the operational response to the adverse conditions.

2.3 Evaluation of the Relationship between River Conditions and Thermal Power

The purpose of this analysis is to link the HEC-RAS modeling efforts, which simulate river operations of the Missouri River under each of the MRRMP-EIS alternatives, with the economic analysis necessary to estimate the consequences to thermal power plants. Specialized software was used to simulate river and reservoir operations for planning studies and decision support developed by the Institute for Water Resources, Hydrologic Engineering Center. HEC-RAS and HEC-RAS-NSM (Nutrient Simulation Module) temperature model data were used to provide a profile of river conditions at locations that approximately corresponded to locations of thermal power intakes. The analysis used Microsoft Excel® to evaluate potential effects of changes in river flows, river stages, and river temperatures on thermal power operations and power generation.

2.3.1 Thermal Power Intake Elevation and Flow Analysis

The following section describes the approach and structure of the analysis used to measure impacts to thermal power plant operations from changes in Missouri River flows and stages. The intake elevation and flow analysis was used to evaluate when changes in river stages and flow levels would adversely affect thermal power plant intakes. Generally, power plants have specified two intake elevations: minimum intake elevation and shut down intake elevation. Minimum intake elevations are the water surface levels below which there would be small adverse impacts to power plant operations, such as additional pumping requirements as well as higher operations and maintenance costs for cleaning debris and sediment, compared to river stages at the shutdown intake elevation. When river stages fall below shut down intake elevations, more severe impacts occur to plants and most plants must shut down. HEC-RAS data was used to provide a profile of river behavior at locations that approximately corresponded to locations of thermal power plants intakes. River behavior for each location was modeled over a period of 81 years, from 1931 to 2012, excluding 2011.

The USACE developed the initial list of thermal power plants along the Missouri River as well as one conversion station that could be potentially affected by changes in Missouri River flows and stages. Further research and discussions with thermal power plants eliminated two plants from analysis and several units at various plants as these plants or units are already decommissioned or planned for decommissioning in the next year. As a result, 20 thermal power plants located along the Missouri River were included in the analysis. One power plant in the upper river did not have any days below shut down intake elevations (and also had a cooling tower) and therefore was removed from further evaluation in the NED, RED, and OSE evaluation.

All of the power plant representatives and utilities provided input on the specific river stages and river flows that would adversely impact access to water for cooling. Eleven utilities representing 18 plants along with one electricity conversion station[3] provided feedback in follow-up discussions associated with operational changes and changes in power generation.

Information on minimum and shut down intake elevations was initially obtained from USACE and then verified or changed during interviews with utility or power plant operators. All intake

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[3] An electricity conversion station operated by Minnesota Power is affected when river stages at the Minnkota Power Missouri River Intake are below the shut down intake elevation.

elevation thresholds in the analysis are shown in feet above mean sea level in the NAVD 88 vertical datum. Many of the intake elevations were converted from NAVD 29 to NAD 88 to be consistent with the H&H models.

Inclusion of critical low flows in the analysis was based on feedback from utilities and power plant operators. Specifically, a number of power plants indicated a critical low flow, while others indicated that intake elevations and temperature were sufficient conditions to evaluate potential adverse impacts to power plants. Power plant representatives provided critical low-flow thresholds for plants where this was relevant. In most cases, these low-flow thresholds were an indication of severe adverse impacts to power plants, when power generation must be reduced. Several plant operators indicated that the average summer flow (July and August) is an important indicator that must be considered along with temperature conditions to determine the adverse impacts to plant operation and power generation. The summer flow threshold was used along with intake elevations only for the power plants that indicated that this condition was an important consideration. One plant provided operating curves that showed how many intake pumps would be in operation relative to the flow and temperature of the river at any given time.

Table 1 identifies the specific measures that were calculated for the thermal power intake elevation and flow analysis. As previously described, only those measures identified by the plants/utilities as important to consider were included in the NED analysis for the specific power plant.

Table 1. Thermal Power Intake Elevation and Flow Analysis Conditions

River Conditions	Measure	Description
Condition 1 – Number of days river stages fall between the minimum intake elevation and the shutdown intake elevation	Number of days by season	This measure is an estimate of the number of days in a season that a thermal power plant intake would experience minor adverse operating conditions (i.e., impacts to pumping, sediment clogging of intake, etc.). The focus was on operating conditions (and not shut down conditions).
Condition 2 – Number of days river stages fall below the shutdown intake elevation	Number of days by season	This measure is an estimate of the number of days in a season that river stages fall below the shutdown intake elevation and the plant will have to shut down due to low water elevations. The focus was on shut down conditions.
Condition 3 – Number of days river flows will fall below plant operating flow requirements	Number of days by season	This measure is an estimate of the number of days in a season that river flows fall below an important operating threshold when plants will incur severe operational impacts and will reduce power generation. The focus was on shut down conditions.

This analysis specifically evaluated the number of days river flow and stage are below intake thresholds on a seasonal basis each year. Seasons are important to consider when power reductions occur because replacement costs for electricity (i.e., energy values) vary based on peak periods when demand for energy is greatest in the winter and summer months. In addition, plants also tend to produce more energy during peak periods when demand for electricity is highest, often operating close to full capacity. Refer to Section 2.4.4 for additional information on energy replacement values (energy values) and the seasons identified for the analysis.

2.3.2 Thermal Power Temperature Analysis

The following section describes the approach and structure of the analysis used to measure impacts to thermal power plant operations from changes in Missouri River water temperature. The temperature analysis was used to evaluate how thermal power plant operations would be affected by changes in river temperature. River temperatures can affect the cooling efficiency of plants, with potential impacts to power generation. In addition, state water quality standards for thermal power discharges specify a maximum river water temperature and maximum change in river water temperature within the mixing zone. Maximum temperature requirements are 90°F for the 13 power plants located below Gavins Point Dam. When the river temperatures start to approach 90°F, power plants in the lower river usually need to curtail power generation to meet the National Pollutant Discharge Elimination System (NPDES) temperature requirements. River temperatures affect one of the power plants in the Garrison reach. The remaining six plants in Lake Sakakawea and the Garrison reach either have cooling towers or systems and/or not affected by river temperatures. The analysis uses outputs from H&H models and the HEC-RAS-NSM temperature model (USACE ERDC 2017). ERDC provided daily temperature data for the years 1975 through 2012, excluding 2011, which was excluded due to model limitations.

The ERDC report noted that the temperature models had a reasonable fit with the observed temperature data. Limitations in the predictability of the model include over predicting the peak water temperatures during the summer seasons in the lower river (USACE ERDC 2017). As a result, the reductions in power generation due to high river temperatures during the summer months would be overestimated with the river temperature results. However, since the focus of the evaluation was to compare Alternative 1 with the action alternatives, the project team concluded that the model limitation as not critical.

The project team collected information from power plant operators and utilities to specify the temperatures thresholds that would result in adverse conditions to power plants. These conditions were used with the ERDC daily temperature data[4] to estimate the number of days during a season that the plant would experience these temperature conditions. For the plants in the lower river, the temperature analysis was based on various temperature groups – for example, a number of plants are assessed at each degree between 87°F and 90°F and a sixth group was specified for days that the temperature was above 90°F. One plant in particular provided operating curves that showed how many intake pumps would be in operation relative to the flow and temperature of the river at any given time. Each power plant operator or utility provided input into the temperature conditions and resulting power generation impacts for their plant(s). Some plants start to derate or reduce power generation at lower temperatures than others depending on their design standards. In addition, based on input from plant representatives, power plants in the lower river would be shut down above 90°F because discharging cooling water at this river temperature would be in violation of their state water quality standards and their operating permits. Temperature conditions could affect plants in the

[4] The ERDC notes that observed water temperatures do not completely match the non-linear ERDC temperature which is to be expected in developing regression as often a 100 percent goodness of fit for the modeled equation cannot fit real-world observations. In particular, the model deviates from observed conditions during low summer flow events. Therefore, estimates in this analysis, and particularly those using low summer flows as an indicator for high water temperatures may not fully represent real-world observations or conditions. However, it should be noted that these inaccuracies are assumed to act in a similar way under each of these alternatives and as this analysis seeks only to compare the action alternatives against the No Action alternative the risk of inaccuracy of the ERDC water temperature data was assumed to have a less than meaningful impact on this analysis.

Garrison reach, and various temperature conditions based on input from power plant representatives were specified for these plants to assess their operational impacts. However, only one power plant in the Garrison reach was shown to be affected by river temperatures. Table 2 identifies the measures calculated in the temperature analysis.

Table 2. Temperature Conditions

River Conditions	Measure	Description
Condition 1 – Number of days river temperatures are above or within critical threshold temperature(s)	Number of days per season	This measure is an estimate of the number of days in a season that the Missouri River is within critical temperature thresholds. The thresholds were determined based on input from power plants.

2.4 National Economic Development

An economic analysis was developed that builds upon the evaluation of river conditions to evaluate the change in NED associated with thermal power operations and power generation as a result of the MRRMP-EIS alternatives. Thermal power NED impacts include: 1) energy values and power replacement costs (changes in energy values); 2) capacity values and costs to replace loss capacity; and 3) variable costs.

The evaluation of the impact of river conditions on thermal power generation was based on interviews with power plant operators and utilities. Energy and capacity values (obtained from the hydropower analysis) were applied to the estimates of power generation and dependable capacity. Unit energy values represent the cost or price to replace reductions in power generation with electricity generated at other plants within the Regional Transmission Organizations (RTOs). Unit capacity values were applied to the change in dependable capacity relative to Alternative 1, which was based on decreases in power generation during peak power demand seasons. The changes in variable costs and energy and capacity values were aggregated for all power plants to estimate the NED impacts for each alternative. This section describes each of the steps included in the NED thermal power analysis and data sources used in the analysis.

2.4.1 Estimate Average Daily Seasonal Generation

One of the first steps in the NED analysis process was to obtain the available power generation for potentially affected plants. Monthly generation was obtained from the U.S. Energy Information Administration (EIA) for the net generation for each power plant. Net generation is the amount of gross generation less the electrical energy consumed at the generating station(s) for station service or auxiliaries (EIA 2016). Power plants are obligated to report their monthly net generation through a form titled EIA 923. Because power plants are periodically taken off-line for repairs and maintenance, power plants and utilities were asked during interviews to provide a year that represented “typical” generation between 2012 and 2015 with no adverse impacts to power generation. Alternatively, an average of the three or four years was also provided as an option to use in the analysis.

Power generation was assessed seasonally because replacement costs of power (energy values) vary by season, with peak demand for electricity driving power replacement prices higher in the winter and summer months. In addition, power generation is also affected by demand for electricity, generally with higher generation demand occurring during the peak summer and winter seasons. The determination of the seasons for the analysis included an assessment of the monthly energy prices (i.e., energy values), estimated through locational marginal pricing (described in Section 2.4.4). The months were grouped into seasons that reflected similar monthly prices. The seasons for the analysis were: spring (March through June), summer (July and August), fall (September through December), and winter (January and February).

The next step in the process was to estimate the average seasonal daily net generation. The monthly net generation from EIA for the appropriate units was aggregated for the months in each season. To estimate the average daily generation for each season, the total seasonal generation for each plant was divided by the number of days in each season to estimate the daily seasonal generation for each affected plant or unit.

2.4.2 Adverse Conditions for Power Plants

Fourteen utilities were contacted for information regarding how river conditions affect power generation and variable costs (variable costs are described further Section 2.4.6). There are 20 thermal power plants located along or very close to the Missouri River. In addition, there is an electricity conversion station that can be affected when one thermal power plant is shut down. All power plant operators or utilities provided input on the shut down and minimum intake elevations for their associated power plants. Eleven utilities representing 18 power plants and one electricity conversion station provided information on temperature conditions that would affect power generation for the economic evaluation.

After the utilities or power plant operators were contacted, telephone meetings were scheduled to describe the MRRMP-EIS alternatives and share the results of the intake elevation analyses associated with each power plant. As noted above, the initial analysis results included the number of days below the minimum and the shutdown intake elevation as well as the number of days above specific temperatures. These discussions provided the context for the discussion of the MRRMP-EIS impacts and provided the team with an opportunity to obtain more detailed information from the power plant representatives on their operational constraints. Given daily and seasonal information on the river flows, river stages, and temperature conditions for the MRRMP-EIS alternatives, the plants were asked to specify and/or verify the intake elevations, river flows or temperature conditions under which they would experience adverse impacts and to describe those impacts. Multiple iterative discussions were held with the power plant representatives to elicit this information.

Based on these discussions, relationships between river stages, flows, and temperatures and adverse operating conditions were developed. If plants did not provide input despite several efforts to contact them, data and assumptions were based on input from representative plants (in a similar location and types of plant) for the analysis. This section generally describes how the relationships were established between power generation and river stages and flows; power generation and temperature conditions; and river stages and variable costs.

Adverse Effects Associated with River Stage Thresholds

Critical intake elevation thresholds were confirmed with all of the power plants, including both the shutdown intake elevation and the minimum operating intake elevation. Most power plants were assumed to fully shut down when river stages drop below the shutdown intake elevations, which was consistent with input from power plant representatives. For most plants, it is assumed that all average daily net power generation for the season (estimated under Section

2.4.1) would be lost for every day that the plant is shut down. There are exceptions to this approach when plants have reserve supplies of water; two such plants were identified in the outreach to power plants (see the section Additional Plant Input on Shutdown Conditions for additional details). Additionally, six power plants do not experience any days below the shutdown intake elevations over the 81-year POR.

Power plant operators were also asked to describe adverse impacts associated with power plant operations below minimum operating intake elevation, but above the shutdown intake elevation. Only one utility indicated that power generation would be affected under these river stage conditions, which was included in the analysis. A number of plants indicated that variable costs would be affected when river stages are below minimum intake operating elevations (see Section 2.4.6 for additional details).

Adverse Effects Associated with River Flows Thresholds

Due to a dynamic channel in the Garrison reach and the river flow/river stage relationship built into the HEC-RAS model, one plant indicated that river flow levels would provide a better indicator for simulating potential effects to their plant. For a number of the power plants in the lower river, river flow thresholds were used along with river temperatures to assess the impact to power generation.

A plant in the lower river uses supplemental pumps to access the river water during the non-navigation season, typically in the late fall though the spring. They indicated that when river flows fall below a specific threshold, especially in the summer and fall, they do not have permits for supplemental pumps, and access to water and impacts from rising temperatures would be an issue, causing shut down conditions. Plants are not permitted to have supplemental pumps during the navigation season due to navigation during this period. Most of the low river flows occur in the late fall and winter when the navigation season is over. The plant was assumed to shut down between July and October when the river flows were below the specified threshold during this period. Supplemental pumps and sufficient river flows maintain access to water through the intake for the remainder of the year.[5]

Additional Plant Input on Shut Down Conditions

Input was also obtained from two plants with reserve supplies of water. One power plant has a reserve of water that would allow it to continue to operate for approximately two weeks with the Missouri River intake shut down. However, these reserves would take about 10 days to replenish once the intake was able to access the water. Because the number of days shut down is dependent on the consecutive nature of the days, an assessment was undertaken using HEC-RAS daily stage data for the alternatives to evaluate when the plant would be affected.

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[5]It should be noted that EPA rule 316(b) is likely to affect the use of supplemental pumps for power plants along the Missouri River. This rule covers roughly 1,065 existing facilities that are designed to withdraw at least 2 million gallons per day of cooling water. The power plants are required to implement technology options to reduce mortality to fish and other aquatic organisms through entrainment or impingement controls. The affected plant indicated that it would likely invest in lowering the intake structure so as to not use supplemental pumps in the future. Because the investments are uncertain at this point, the evaluation assumed the use of supplemental pumps in the navigation season and shut down conditions would occur in the summer and fall when river conditions fall below the noted river flow thresholds.

Similar to the aforementioned plant, another intake pumps water to a lake and a separator impoundment. The lake and separator impoundment provide approximately 25 days of supply of water. A similar evaluation was undertaken on the consecutive days below the shutdown intake elevation, along with input from the utility on the evaporation and refill factors, to assess when the plant and the conversion station would be affected. A conversion facility is affected when the Missouri River intake is shut down and cannot transmit production tax credits (wind energy) during the summer.

Adverse Effects Associated with River Temperature Conditions

River temperatures have the potential to affect power generation through decreased operational plant efficiencies in cooling the condenser of the plant; as river water temperatures increase to a point at which the cooling efficiency is affected, the plant may have to decrease power generation, also known as derating the plant. Some power plants prefer to address temperature issues through an assessment of river flows, which are highly correlated with river temperatures (discussed above under river flow conditions). In addition, state water quality standards in the lower river (Missouri, Kansas, Nebraska, Iowa) include maximum river water temperatures that are included in the NPDES permits for the plant. When the river temperature approaches the maximum river temperatures in the NPDES permits, most plants need to reduce power generation to meet the permit temperature requirements.

The ERDC daily temperature model and results were discussed with the power plants. The power plant operators were asked to describe the adverse conditions and power generation reductions associated with specific river water temperatures or river flows.

The thermal power temperature analysis then associated the river temperatures or flows that adversely impacted plant operations and generation. According to all power plants located in the lower river that provided input, above a river water temperature of 90°F (the state water quality standard for Missouri, Kansas, Nebraska, and Iowa), the power plants would need to fully shut down due to water quality standards. These temperature conditions and maximum river temperatures only apply to plants in the river below Gavins Point Dam.

Many of the power plants with once through cooling systems need to derate due to higher temperatures because of decreases in the cooling efficiency at the plant. The operational efficiency of power plants with recirculating cooling systems is not affected by higher river temperatures because the plant relies on the cooling tower or system and not the river water temperature to cool its condensers.

Five utilities representing nine power plants provided information on temperature impacts to power generation for the plants located below Gavins Point Dam. Based on input from power plant representatives, it was assumed that all plants (including those plants that did not provide input) in the lower river were affected by river water temperatures. Plants that did not provide input were assumed to incur impacts similar to neighboring plants. One plant in particular provided operating curves for its intake pumps that related river water temperatures with river flows. This plant derated by reducing the number of pumps that were active based on river temperature and flow conditions.

Four plants in the Garrison reach have recirculating cooling systems and are not anticipated to be impacted by river water temperatures. Three utilities in the Garrison reach provided temperature impacts for their plants and were incorporated into the NED model. In addition, it is possible that river water temperature conditions near Bismarck, North Dakota as modeled in the mid-2000s would be higher than indicated in the ERDC temperature model due to changes in operational releases from Garrison Dam during drought conditions to support the cold water fishery in the reservoir. These specific operational considerations are not included in the ERDC temperature model or in the NED modeling, therefore, impacts associated with temperatures on these three plants could be greater than simulated.[6]

2.4.3 Estimate Power Generation

The evaluation of river conditions described under section 2.3 was used along with the average daily seasonal generation described in section 2.4.1 and the information obtained from power plants in section 2.4.2 to estimate power generation. An Excel®-based model was used to estimate the seasonal and annual estimates of power generation over the 37-year period of analysis, which is defined as 1975 through 2012, excluding 2011. In addition, power generation was estimated over the POR that includes adverse effects to power generation associated with river temperatures and river flows and stages between 1975 and 2012 (excluding 2011) and adverse effects to power generation associated with river flows and stages (not temperature) between 1931 and 1974.

There were several instances when there were estimated impacts to power generation from both river stages, flows and river water temperatures. The potential for double counting of days was considered in situations where plants experienced reductions in power generation from river stages falling below shut down intake or flow thresholds and with impacts from higher river water temperature conditions. A manual comparison of flow and stage results against temperature results was done to ensure that the model did not double count power generation reductions from these conditions. Where double counting of impacts was found to occur, the double counting of reductions in power generation were manually removed. The larger adverse impacts from either flow and stage or temperature remained in the NED model. Only one power plant experienced shut down conditions where power generation was affected under both water access and river water temperature. River water temperature impacts usually occur in the summer (some in the spring) and river flows and stages are generally higher during these seasons. Lower river flows and stages typically occur in the fall and winter season when river water temperatures are not as high.

2.4.4 Estimate Energy Benefits

In general energy benefits are calculated as the product of energy generation and the appropriate energy price in terms of $/MWh. Energy benefits are also called energy values. The approach to estimate the power generation was described in Sections 2.3, 2.4.1, 2.4.2 and 2.4.3. The energy prices used are based on the cost of energy from a combination of generation plants that would replace the lost energy from the thermal plants.

The energy price was based on the cost to purchase electricity in the market. Energy values for the Missouri River were estimated by the Hydropower Analysis Center using locational marginal

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[6] Three power plant representatives in the Garrison reach described issues related to temperature during the mid-2000s (2005-2009). Plywood was installed at Garrison Dam to release water from the top of the reservoir to preserve cold water in the reservoirs to support the cold water fishery in Lake Sakakawea. The release of relatively warmer water from Garrison Dam during these drought conditions adversely affected the power plants. The temperature model does not incorporate the higher river temperatures due to the releases between 2005 and 2009. The temperatures could be higher in the mid-2000s than modeled here.

pricing (LMP) from the Western Area Power Administration hub of both the Midcontinent Independent System Operator (MISO) RTO and the Southwest Power Pool (SPP). LMP is a computational technique that determines a shadow price for an additional MWh of demand.

Power plants along the Missouri River are members of the MISO and SPP RTOs, generally with more northern utilities being members of MISO and southern utilities being members of SPP. The MISO and SPP energy prices were used for the member plants in the analysis.

The energy prices represent the full cost of the replacement energy, and they are inclusive of any variable costs associated with changes in power generation. The energy prices include "blocks" based on peak and non-peak times, and vary by month as well as weekends and weekdays. Because the thermal power plants are generally base load plants, an average price by month for weekday and weekend was estimated and used in the evaluation. A seasonal energy value (spring, summer, fall, and winter) was estimated from the monthly and weekend/weekend energy prices; months with similar energy values were combined to estimate the seasonal values. The seasonal energy prices (2018 present value of forecasted values) were estimated by weighting the number of the weekend days and weekdays in the relevant season. The peak seasons of summer (July and August) and winter (January and February) reflect higher values than other months of the year.

The energy prices used in the analysis are shown in Table 3.

Table 3. MISO and SPP Energy Prices, 2018$

Season	MISO Weighted Seasonal Energy Price ($/MWh)	SPP Weighted Seasonal Energy Price ($/MWh)
Summer	$25.57	$26.61
Fall	$22.97	$21.86
Winter	$24.58	$23.35
Spring	$21.02	$23.50

Source: Hydropower Analysis Center pers. comm. 2018

The energy prices were applied to the estimated power generation under the various conditions for each power plant, for each year and season, and for each alternative to estimate energy values and replacement costs for changes in energy generation.

2.4.5 Estimate Capacity Values

Capacity values represent the cost to construct and operate a new power plant or a major investment to replace lost capacity. Capacity values are relevant when a new plant needs to be constructed or large capital investment needs to be made. Capacity values should be applied when an investment is needed to replace lost capacity with a new source. The potential need to replace capacity is estimated through an evaluation of the long-term effects of the alternative on the power plant and its power generation, especially during peak periods when all capacity is being used. The approach to estimate the capacity values through a dependable capacity approach is provided in the following subsections.

Estimate Dependable Capacity

The dependable capacity of a thermal power plant or unit is a measure of the amount of capacity that the unit or power plant can reliably contribute towards meeting system peak power demands. Dependable capacity can be computed in several ways. The method that is appropriate for evaluating the dependable capacity of a predominantly thermal-based power system such as the Missouri River Basin is the specified availability method, which is described in Section 6 of EM 1110-2-1701, Hydropower Engineering and Design (USACE 1985). The following steps were used to model dependable capacity.

1. Estimate the amount of power generation that would occur in the peak seasons (winter and summer) by power plant in each year.
2. Estimate the number of hours within each season, which is the number of days in the season multiplied by 24 hours/day.
3. Estimate the capacity for each year, peak season, and plant: divide the amount of power generated in the peak seasons (step 1) by the total number of hours in the season (step 2).
4. Estimate the dependable capacity: Based on discussions with the Hydropower Analysis Center and guidance in the Hydropower Engineer Manual 1110-2-1701, the 15th percentile (85th percent exceedance) of the annual peak season capacity estimates for each power plant was used. This represents the amount of capacity that a plant can reliably contribute to meeting peak season needs (Hydropower Analysis Center pers. comm. 2015; USACE 1985).

Estimate Unit Capacity Values

Capacity values represent the cost to construct and operate a new power facility or major investment to replace lost capacity. Capacity values are reported as a dollar amount per KW or MW per year and include fixed plant costs and variable operating costs. The unit capacity value is applied to the dependable capacity to estimate the capacity values under each alternative for each plant and each peak season.

The unit capacity values are based on a FERC spreadsheet model that estimates annual regional capacity values for different generating resources (Hydropower Analysis Center pers. comm. 2018). The capacity values for the Midwest Reliability Council – West (MROW) electricity market module as defined by the EIA are:

- Coal $327.24 per KW-year
- Combined cycle $133.65 per KW-year
- Combustion turbine $113.19 per KW-year

Because a combined cycle gas-fired thermal plant would the most likely replace a coal or nuclear-fired plant (Hydropower Analysis Center pers. comm. 2018), the capacity value that was used for this analysis is $133.65/KW-year. For consistency with the dependable capacity unit (MW), the capacity value was multiplied by 1,000 to provide a unit capacity value of $133,650 per MW-year in 2018 dollars. Capacity values do not include decommissioning costs if a plant or a unit would need to be retired or decommissioned. Therefore, these capacity values (i.e., capital cost estimates) reflect low estimates of the possible capital costs to replace the capacity under the alternatives. In particular, nuclear plant decommissioning costs are substantial and could increase these capacity impacts to power plants if decommissioning a unit or facility would need to occur.[7] As a result, when dependable capacity is affected under the alternatives, the evaluation notes that the estimates to replace reduced capacity could be larger than estimated with these unit capacity values.

Estimate Capacity Values

The unit capacity value of $133,650 was applied to the dependable capacity (15th percentile of the capacity in each year for each peak season). The focus of the capacity value impacts was on the change in capacity (replacement capacity costs) under the action alternatives compared to Alternative 1 (the No Action alternative). The capacity values under Alternative 1 were assessed for summer capacity because the largest changes in capacity occur under the action alternatives during the summer season. If there was no change in capacity relative to Alternative 1, the change in capacity value would be zero.

The final step in the process was to choose the larger of the two changes in capacity values (from Alternative 1) for summer and winter for each power plant under each action alternative, which represents the worst-case requirement to replace capacity (Hydropower Analysis Center pers. comm. 2015). The change in capacity value represents an annualized capital cost (or decrease in capital cost), and therefore the capacity value is applied to each year to estimate the capital cost impacts (fixed and variable costs) to replace lost capacity under the MRRMP-EIS alternatives.

2.4.6 Estimate Variable Costs

The power plant representatives were asked how the river stages, flows, and river water temperatures could affect their operations, other than power generation, and to specify the associated variable costs. Any costs incurred when power generation was also being reduced were assumed to be captured within the energy values analysis because energy values reflect the full replacement cost of the power to be purchased in the market. Two power plant operators (located in the Garrison reach) were able to specify increased variable costs incurred during periods between minimum and shut down intake elevations when the power plants were not reducing their power generation. Costs would include intake cleaning and potentially dredging around the intake. A separate plant provided an intake cleaning cost when river stages are between shut down and minimum intake elevations. Most of the power plant operators or utility representatives felt that the impacts to power generation captured the bulk of the adverse impacts to their plants from adverse river conditions.

2.5 Regional Economic Development

The RED analysis used power generation information from the SPP and MISO RTOs and consultation with RTO experts to describe the potential impacts of the reductions in power generation on wholesale electricity prices and how changes to those prices could impact

[7] Nuclear Regulatory Commission Minimum or Site-Specific Cost Estimates (Nuclear Regulatory Commission 2015) for decommissioning Callaway and Cooper Nuclear Plants range from $500 to $650 million, and more recent estimates could be considerably higher. A 1800 MW coal plant could cost as much as $140 million to completely decommission (Missouri Energy Task Force 2006). An estimate of a recently retired Missouri City Power Plant for decommission and dismantlement of the plant was $926,733 and $16.3 million, respectively (Independence Power & Light 2015).

consumer electricity rates that are set by retail electricity providers. Any changes in retail electricity rates could impact household and business spending, with implications for jobs and income in regional economies. If consumers must spend more of their income on higher electricity rates, they would have less disposable income to spend on other goods and services, which could adversely impact jobs and income in affected industries in a particular region. The RED analysis considered the overall percentage of the RTO generation that would be impacted between the lowest and highest generation seasons under Alternative 1 and the difference in the power generation relative to Alternative 1. The potential impact to consumers, the timing of the reductions in power generation within the peak season, and input from SPP was used to qualitatively assess the potential impacts to electricity rates and RED effects.[8]

A reduction in power generation due to adverse river conditions would result in the use of alternative sources of power. The thermal power plants along the Missouri River are typically base load plants and are generally lower-priced electricity generators compared to other fossil fuel plants. Therefore, if these power plants must reduce power generation because of adverse conditions, the next available power source could be at a marginally higher price than these base-load generators. If multiple power plants reduce power generation during peak summer seasons, the cost of wholesale electricity providers would temporarily increase because the next marginal energy producer would charge more per unit of energy produced. When there are reductions in power generation in peak periods during adverse conditions (i.e., high river water temperatures), the price increases would be higher than if power generation were reduced during off-peak times (i.e., fall and spring). In the situation where RTO capacity is limited during peak periods, some of the highest-cost resources would be made operational, increasing wholesale electricity prices. If the Missouri River thermal power plants must reduce power generation for a long period or on a recurring basis during peak periods, this could create an increase in the wholesale cost of electricity to retail electrical providers, although it would take time for price changes in the wholesale market to be reflected in the consumer market.

Consumer electricity rates are typically regulated by the state utility commission, but can also be unregulated. If the rates are regulated, the retail electricity provider, with sufficient justification, petitions the state utility regulatory commission to change the rates. The commission then makes the decision on whether the retail electricity rates should be increased. In an unregulated market, the retail electricity provider can change the consumer electricity rate without permission from a state regulating authority.

Input was also obtained from experts to better understand the magnitude of power reductions during peak seasons which could affect wholesale electricity prices such that retail electricity providers would have justification to petition for electricity rate change (SPP pers. comm. 2016; WAPA pers. comm. 2016). If multiple power plants must reduce power generation simultaneously during peak summer seasons or if Missouri River thermal power plants must reduce power generation for a long period or on a re-occurring basis during peak periods, this could create the conditions for an increase in the wholesale cost of electricity to retail electrical providers. The providers may then have sufficient rationale to petition state utility commissions for an increase in consumer electricity rates.

Power generation from the MISO 2013 Annual Market Assessment Report and the SPP 2014 State of the Market Report were obtained to better understand the level of generation and

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[8] Additional information on USACE RED methodology is available within the IWR 2011 Report on Regional Economic Development Procedures Handbook (USACE 2011).

relative importance of the reductions in power generation in each of the RTO markets from Missouri River plants during peak seasons (MISO 2014, 2016; SPP 2015, 2016). The average power generation during these two years for each RTO is presented seasonally in the analysis (Tables 4 and 5). The analysis considers the variation in power generation under Alternative 1, the largest adverse difference in power generation during peak seasons between the action alternatives and Alternative 1, and the percent of the RTO generation affected over the 37-year period. The RED evaluation used the RTO average season power generation along with RTO input, and the anticipated timing (i.e., number of plants affected simultaneously) to qualitatively assess potential impacts to wholesale electricity prices, consumer electricity rates, and regional economic conditions. Tables 4 and 5 summarize the total generation in megawatt hours (MWh) by month within each RTO.

2.6 Other Social Effects

The power plants included in this evaluation include both coal-fired and nuclear power plants. Coal-fired power plants generate air emissions and greenhouse gas emissions, while the operation of nuclear power plants does not result in emissions. Increases in air emissions would result in adverse environmental impacts, while decreases in air emissions would result in environmental benefits. Changes in thermal power generation under the MRRMP-EIS alternatives would be replaced with power generation from the market. The changes in the fuel source mix is likely to affect air emissions. Different regions have different electricity-generating resource (fuel) mixes, resulting in varying emissions factors for replacement power generation.

Table 4. Annual Generation within SPP by Month (Monthly Average 2014–2015)

Month	Total SPP Gen (MWh)
1	20,674,110
2	18,739,453
3	18,332,751
4	16,364,566
5	17,476,396
6	20,568,204
7	23,198,268
8	23,251,014
9	19,782,663
10	18,162,332
11	18,502,615
12	20,054,707

Source: SPP 2015, 2016

Table 5. Total Generation within MISO by Month (Monthly Average 2013–2014)

Month	Total MISO Generation (MWh)
1	51,691,786
2	45,020,612
3	45,675,629
4	40,455,915
5	42,552,243
6	45,990,174
7	49,928,354
8	51,024,159
9	43,827,539
10	42,308,793
11	44,092,782
12	50,577,387

Source: MISO 2014, 2016

The primary inputs for this analysis would be those from the thermal power NED model, described in detail in the Section 2.4, NED methodology. This model produces seasonal and annual average electricity generation for each power plant for each alternative. Changes in electricity generation and the associated air emissions for each power plant was compared to replacement power generation from the region and associated regional market emission rate to estimate the change in air emissions.

Air emissions (e.g., SOx, NOx, CO_2, etc.) associated with thermal power generation depend on the type of fuel, nuclear or coal-fired, being used to fuel the power plant. Therefore, a change in thermal power generation may result in an increase or decrease in air emissions depending on the impacted power plant and the replacement power generation sources in the regional power mix. Specific air emission rates for carbon dioxide, methane, and nitrous oxide per MWh of electricity generated for each power plant were obtained from 2016 eGRID data (EPA 2016a). These rates were used to estimate the change in greenhouse gas emissions that would occur as a result of reduced power generation for a particular power plant.

The EPA's 2016 eGRID data includes a comprehensive database of environmental attributes of electric power systems, which incorporates data from several federal agencies. The eGRID database includes emission rates for 26 eGRID subregions (EPA 2016b). These regions are contained within a single North American Electric Reliability Corporation (NERC) region with similar emissions and generating resource mixes. Emission rates from the eGRID database are defined as pounds per MWh for three greenhouse gases: carbon dioxide, methane, and nitrous oxide. The thermal power plants in this study are located in three subregions depending on the power plant: SPP North, SERC Midwest, and MROW (Midwest Reliability Organization – West). Emissions factors for these three subregions are listed in Table 6. These rates were used to estimate the replacement greenhouse gas air emissions for reductions in power generation for power plants identified within the specified eGrid subregion.

Table 6. Emissions Factors for Replacement Generation by eGRID Subregion

eGRID Subregion	Carbon Dioxide (lbs/MWh)	Methane (lbs/MWh)	Nitrous Oxide (lbs/MWh)
SPP North	1,412.40	0.149	0.022
MROW	1,238.80	0.115	0.020
SERC Midwest	1,612.60	0.082	0.026

Source: EPA 2016b

In order to measure the change in greenhouse gases produced under each alternative, each power plant's electricity generation reductions compared to Alternative 1 were multiplied by the value of its plant-specific eGRID emissions rate for SOx, NOx, and CO_2. Subsequently, the air emissions rates for the replacement power generation were applied for the eGRID subregion with which the power plant was identified. The resulting air emissions provide the net change in greenhouse gases by plant.

The OSE evaluation used EPA guidance for valuing the social cost of carbon. EPA has developed an estimated cost index for the social cost of carbon. The technical support documentation on the Social Cost of Carbon for Regulatory Impact Analysis (EPA 2016, page 3) states that:

> The purpose of the social cost of carbon (SCC) estimates…is to allow agencies to incorporate the social benefits of reducing carbon emission into cost-benefit analyses of regulatory actions that impact cumulative global emissions. The SCC is an estimate of the monetized damages associated with an incremental increase in carbon emission in a given year. It is intended to include (but is not limited to) changes in net agricultural productivity, human health, property damages from increase flood risk, and the value of ecosystem services due to climate change.

The OSE evaluation estimates the SCC using cost ranges that vary based on the discount rate, the year, and probability of impacts in the future. For this evaluation, a range of SCC values based on different scenarios (year and probability) was used to demonstrate the potential range of impacts including average estimates and a 95th percentile (a low probability, high-consequence scenario), all using a three percent discount rate. SCC values are published in 2007 values and were indexed to 2018 values using the gross domestic product (GDP) (Chained) Price Index for this evaluation. The average SCC estimates in 2018 dollars were used for 2018 ($48), 2035 ($66), and 2050 ($82). In addition, the 95th percentile of the cost estimate simulations presenting a worst-case SCC for 2018 ($138), 2035 ($200), and 2050 ($253) per metric ton of carbon were also estimated.

The total SCC was estimated by multiplying the total CO_2-equivalent air emissions by the values described above. The final result of this evaluation provides the estimated SCC for the three representative years at each probability. The focus of the evaluation was on the change in air emissions and SCC-equivalent emissions relative to Alternative 1.

3.0 River Condition Results

This section provides the results from the H&H evaluation, specifically how the changes in river stages and river temperature affect thresholds that are important for power plants. Section 3.1 summarizes the results in terms of power plants access to water for cooling and operations, and

Section 3.2 summarizes the river temperature conditions, when river temperatures are above 90°F.

3.1 Access to Water

This section presents the results for the number of days when river stages are below shut down intake elevations, using the HEC-RAS data. The figures also indicate how many plants or units would be affected over the POR (1931–2012, excluding 2011). In the evaluation, some of the power plants have more than one unit, which can have different shut down intake elevations.

3.1.1 Alternative 1 – No Action

Figure 3 presents the number of days below shutdown intake elevation by year by power plant or unit, and Figure 4 presents the information for the upper and lower river power plants. The droughts of the 1930s and early 1940s and the mid-2000s cause the number of power plants affected and the number days below shut down intake elevations to increase. Power plants in both the upper and lower river are affected by these drought conditions. In addition, relatively drier periods in the late 1950s and early 1960s and the late 1980s and early 1990s adversely affect the river stages during these conditions.

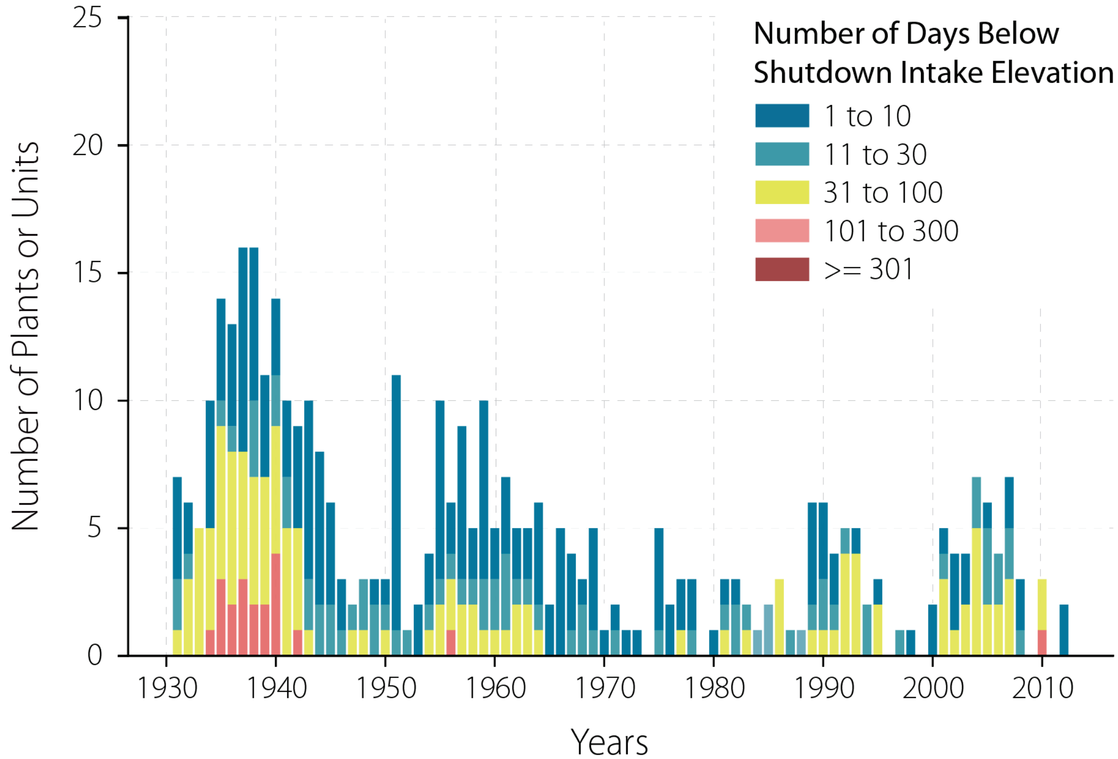


Figure 3. The Number of Days Below Shutdown Intake Elevations by Power Plant (or Unit) for Alternative 1

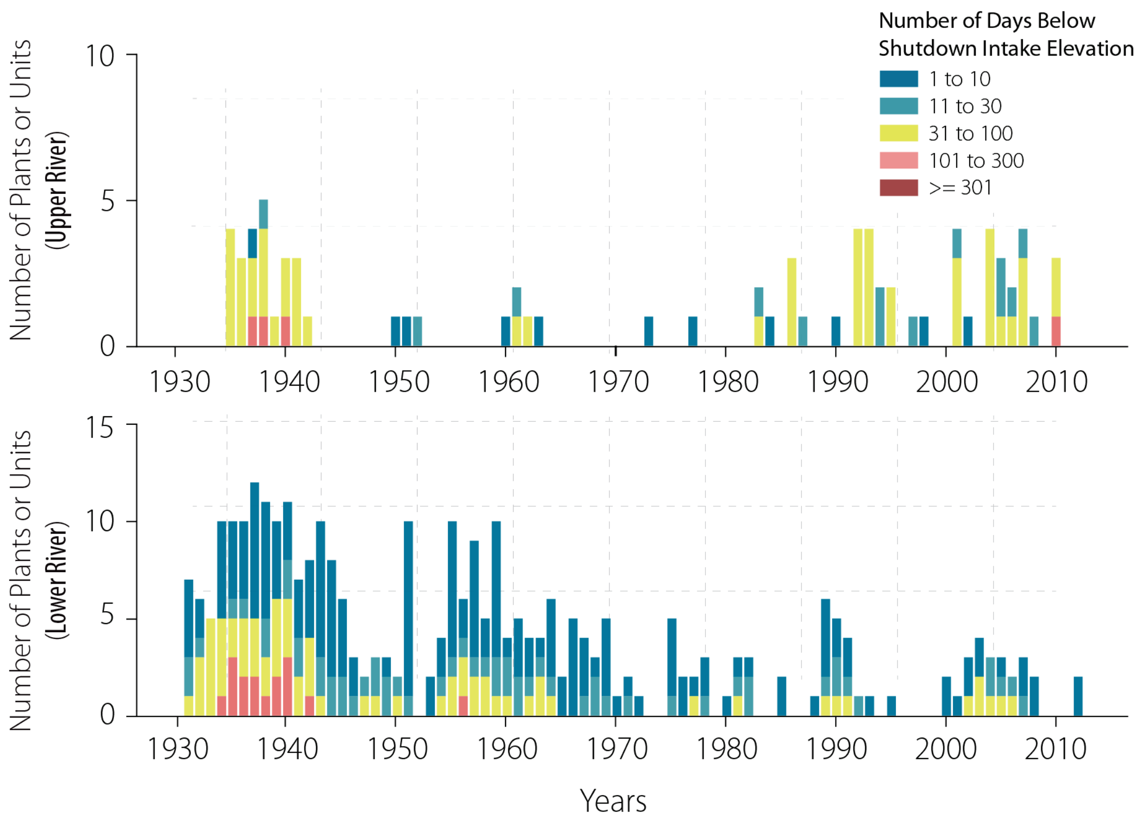


Figure 4. The Number of Days Below Shutdown Intake Elevations by Upper and Lower River Power Plant (or Unit) for Alternative 1

3.1.2 Alternative 2 – USFWS 2003 Biological Opinion Projected Actions

Figure 5 presents the difference in the number of days below shutdown intake elevation by year by power plant or unit for Alternative 2 compared to Alternative 1, and Figure 6 presents the information for the upper and lower river power plants. Alternative 2 would result in years with both increases and decreases in the number of days below shut down intake elevations. Notable increases in days below the shutdown intake elevation would occur in the upper river plants in the early 1960s following a partial spawning cue releases in 1960; in 1988 when a full spawning cue and low summer flow occurs; and in the mid-2000s following two full spawning cues in 2002 and 2003.

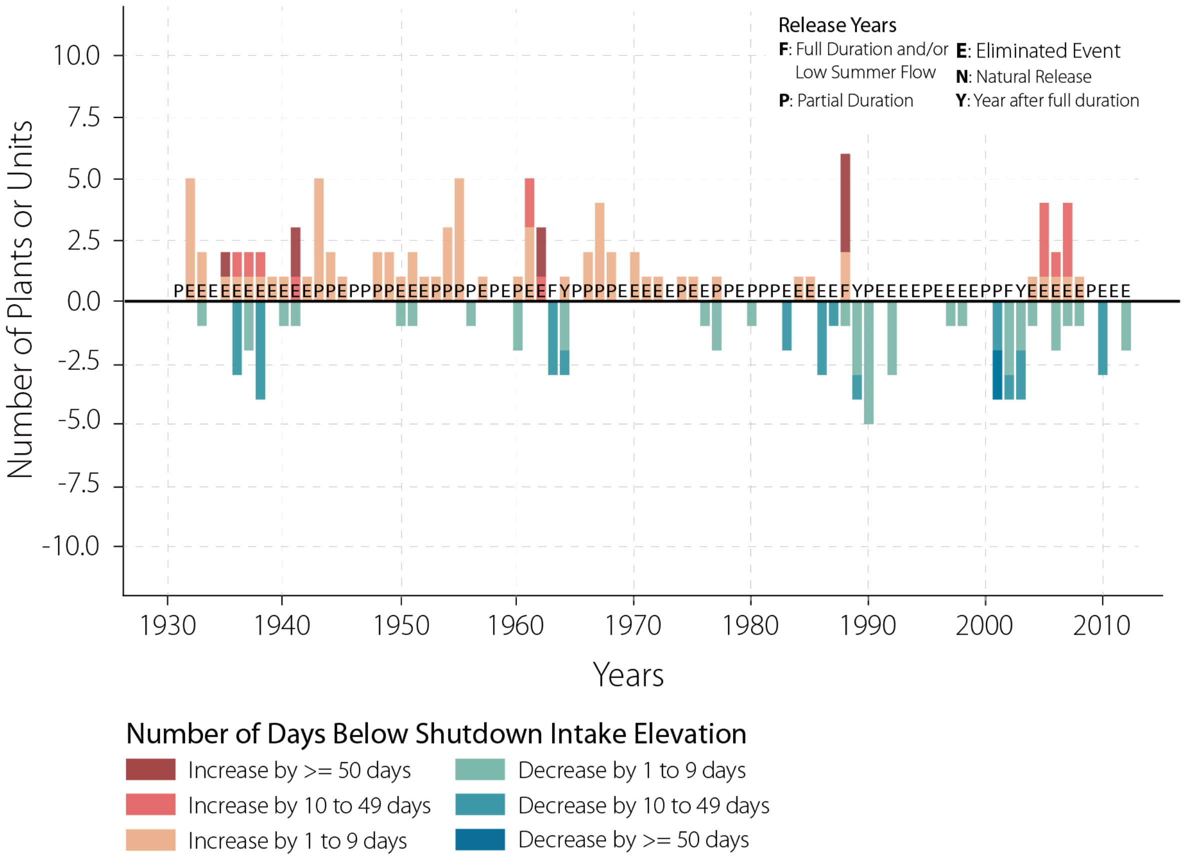


Figure 5. The Difference in the Number of Days Below Shutdown Intake Elevations by Power Plant (or Unit) for Alternative 2 Compared to Alternative 1

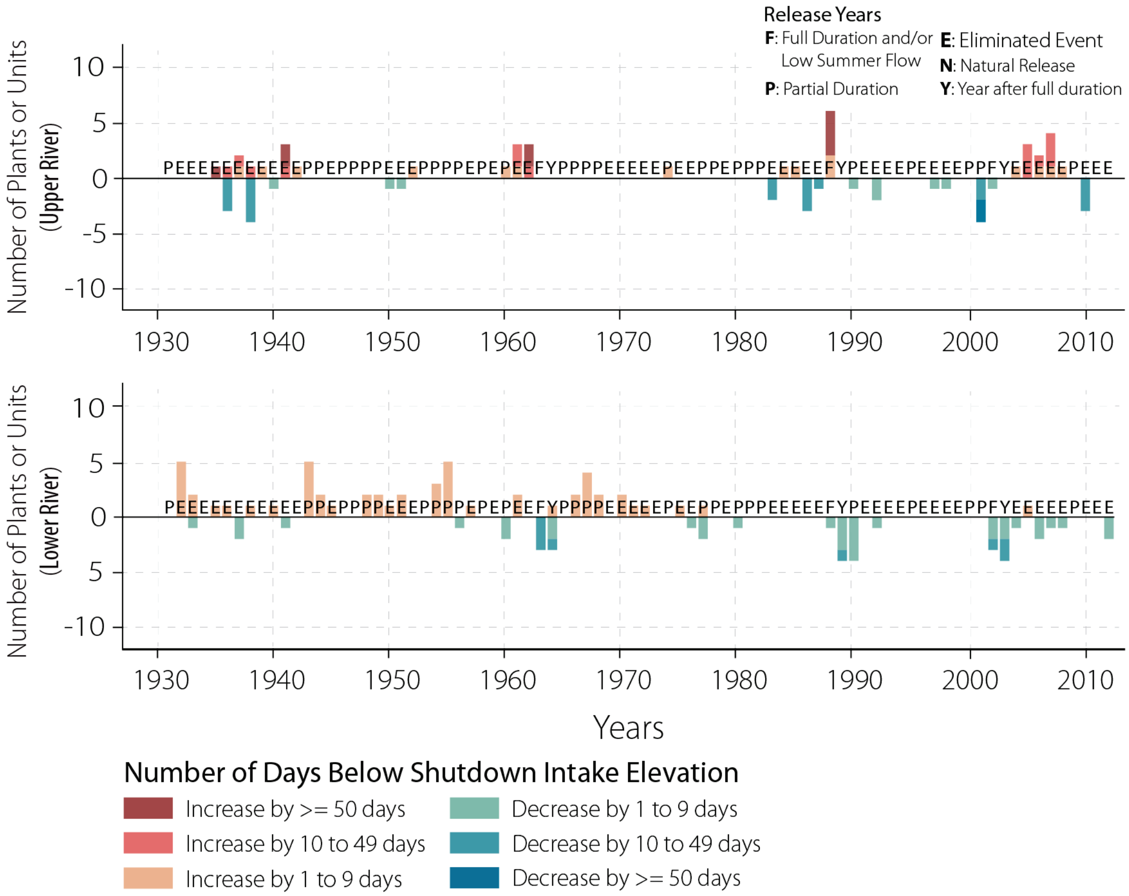


Figure 6. The Difference in the Number of Days Below Shutdown Intake Elevations by Upper and Lower River Power Plants (or Units) for Alternative 2 Compared to Alternative 1

3.1.3 Alternative 3 – Mechanical Construction Only

Figure 7 presents the difference in the number of days below shutdown intake elevation by year by power plant or unit for Alternative 3 compared to Alternative 1, and Figure 8 presents the information for the upper and lower river power plants. Alternative 3 would result in years with both increases and decreases in the number of days below shut down intake elevations. On average, there are fewer days below shut down intake elevations compared to Alternative 1 for power plants in the upper and lower river.

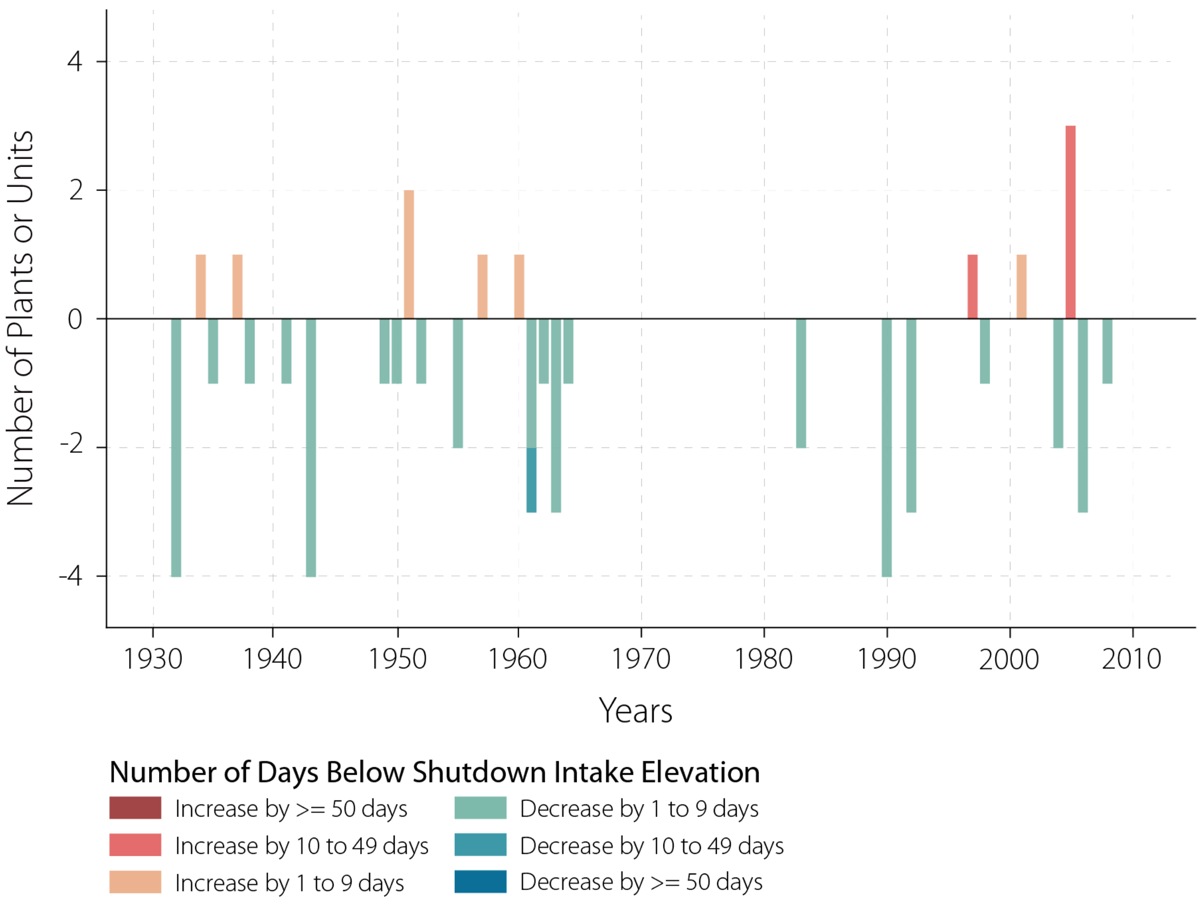


Figure 7. The Difference in the Number of Days Below Shutdown Intake Elevations by Power Plant (or Unit) for Alternative 3 Compared to Alternative 1

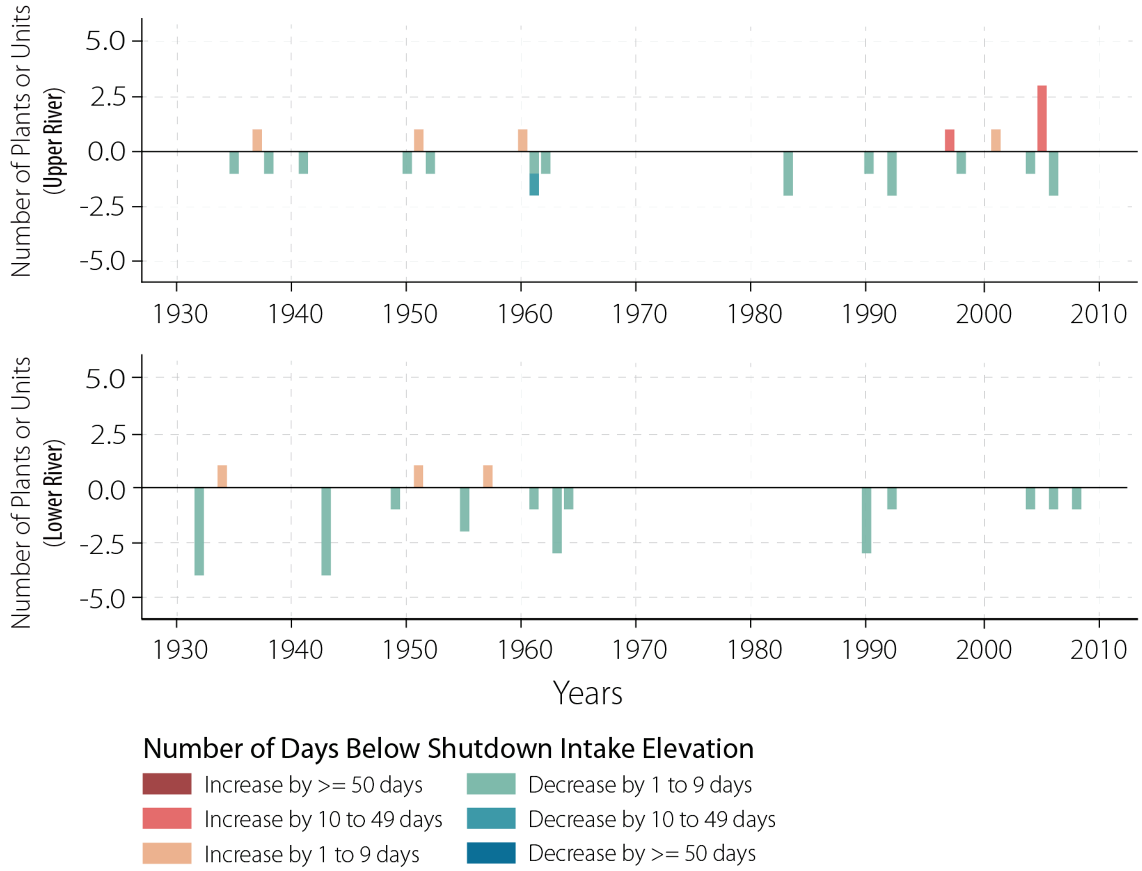


Figure 8. The Difference in the Number of Days Below Shutdown Intake Elevations by Upper and Lower River Power Plants (or Units) for Alternative 3 Compared to Alternative 1

3.1.4 Alternative 4 – Spring ESH Creating Release

Figure 9 presents the difference in the number of days below shutdown intake elevation by year by power plant or unit for Alternative 4 compared to Alternative 1, and Figure 10 presents the information for the upper and lower river power plants. Alternative 4 would result in years with both increases and decreases in the number of days below shut down intake elevations. On average, there would be more days below shut down intake elevations in the upper and lower river compared to Alternative 1. Up to five power plants or units in the lower river would experience more than one additional day shut down in approximately 20 years over the POR when compared to Alternative 1. In the upper river, fewer years would be adversely affected with additional days below shut down intake elevation; however, the power plants or units would be more adversely affected in those years with more days below shut down intake elevation.

Figure 9. The Difference in the Number of Days Below Shutdown Intake Elevations by Power Plant (or Unit) for Alternative 4 Compared to Alternative 1

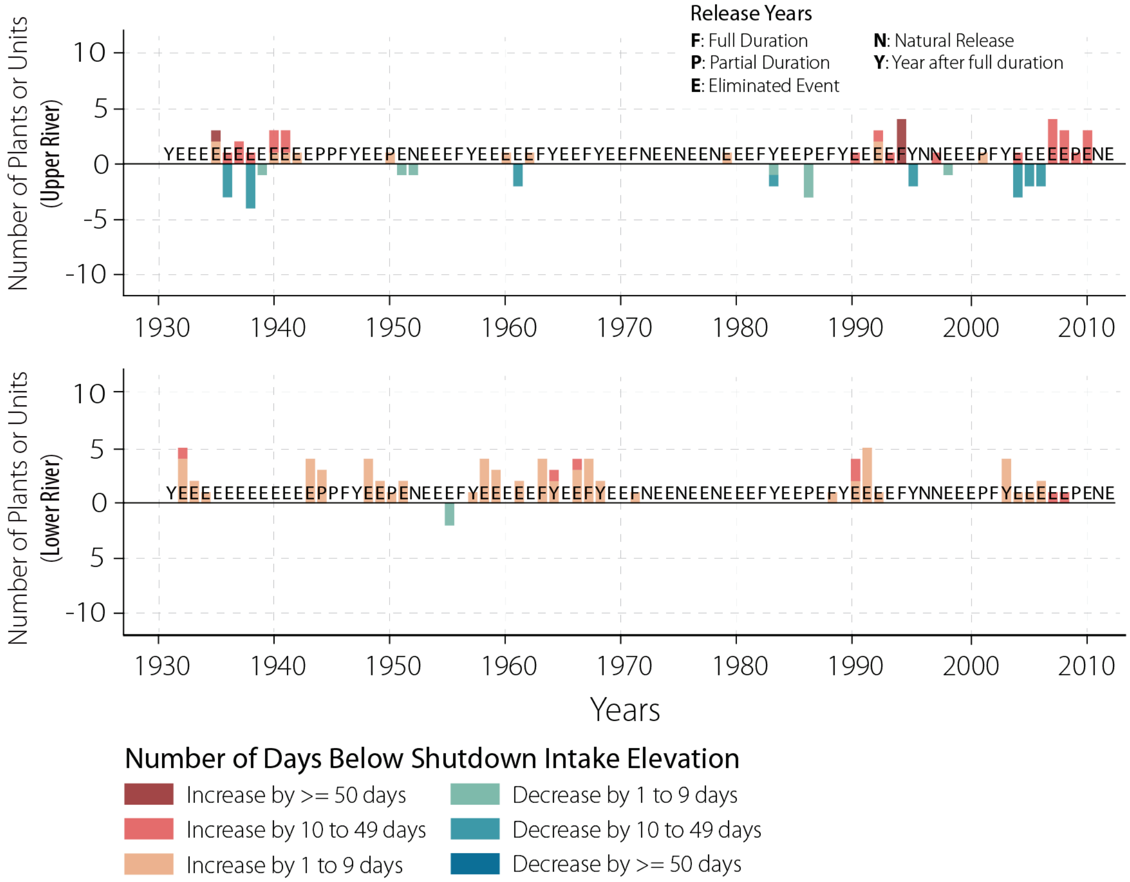


Figure 10. The Difference in the Number of Days Below Shutdown Intake Elevations by Upper and Lower River Power Plants (or Units) for Alternative 4 Compared to Alternative 1

3.1.5 Alternative 5 – Fall ESH Creating Release

Figure 11 presents the difference in the number of days below shutdown intake elevation by year by power plant or unit for Alternative 5 compared to Alternative 1, and Figure 12 presents the information for the upper and lower river power plants. Alternative 5 would result in years with both increases and decreases in the number of days below shut down intake elevations. Up to six power plants would be affected as simulated in 1990 with from one to nine more days below the shutdown intake elevation; in 2005 as simulated, three power plants or units would experience between 10 and 49 additional days below shut down intake elevation in the upper river. There are many years where there would be fewer days below the shutdown intake elevation as well in both the upper and lower river.

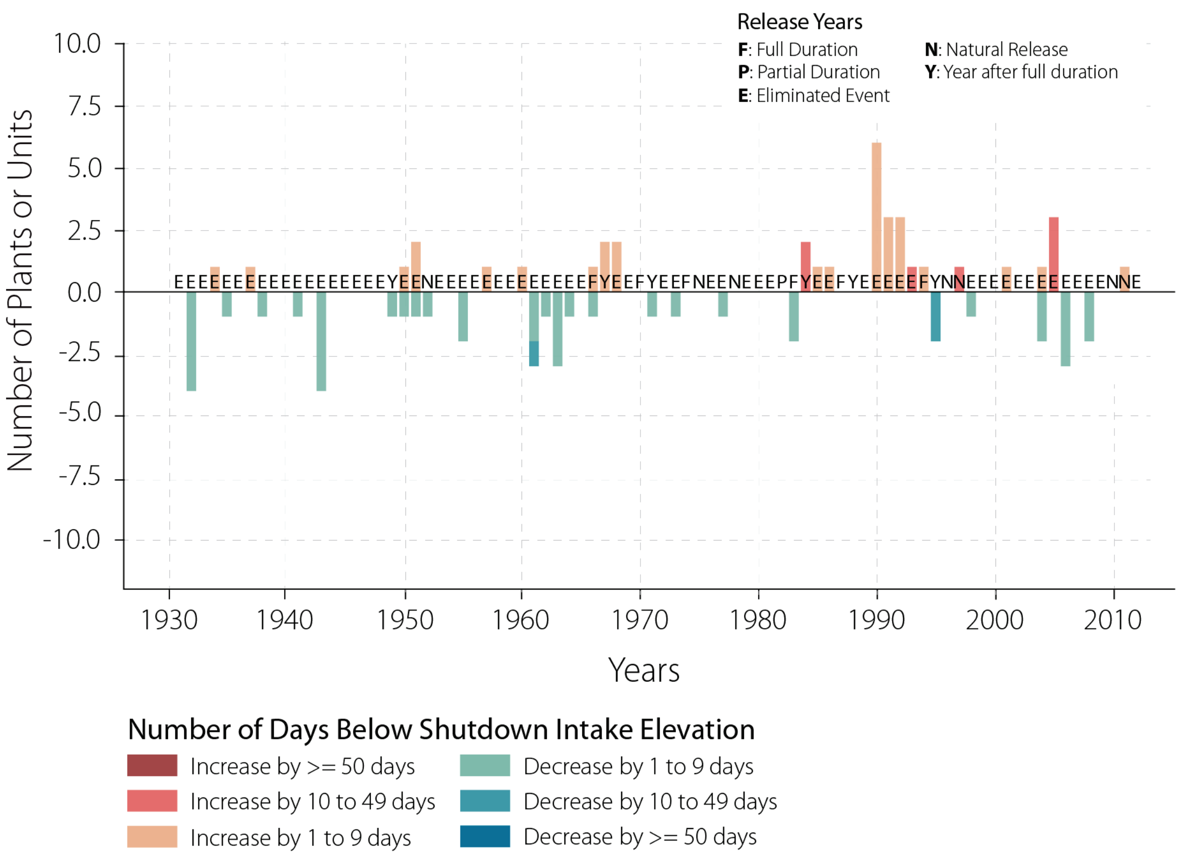


Figure 11. The Difference in the Number of Days Below Shutdown Intake Elevations by Power Plant (or Unit) for Alternative 5 Compared to Alternative 1

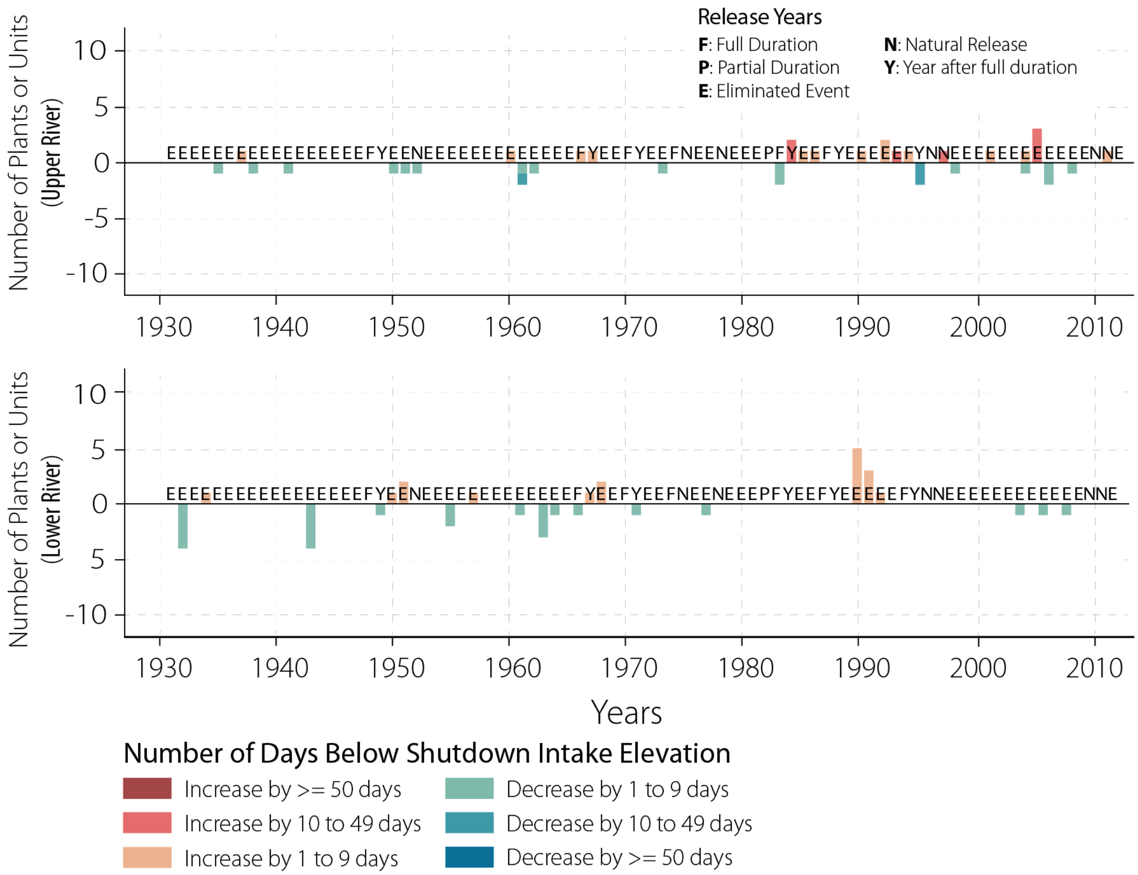


Figure 12. The Difference in the Number of Days Below Shutdown Intake Elevations by Upper and Lower River Power Plants (or Units) for Alternative 5 Compared to Alternative 1

3.1.6 Alternative 6 – Pallid Sturgeon Spawning Cue

Figure 13 presents the difference in the number of days below shutdown intake elevation by year by power plant or unit for Alternative 6 compared to Alternative 1, and Figure 14 presents the information for the upper and lower river power plants. Alternative 6 would result in years with both increases and decreases in the number of days below shut down intake elevations. Power plants in the upper and lower river would experience more years with days below the shutdown intake elevation under Alternative 6 compared to Alternative 1 over the POR. The upper river power plants would experience adverse impacts in fewer years than power plants in the lower river, but would have a larger number of days below shut down intake elevation in each of the years impacted. The upper river power plants would also experience a number of years with fewer days below the shutdown intake elevations.

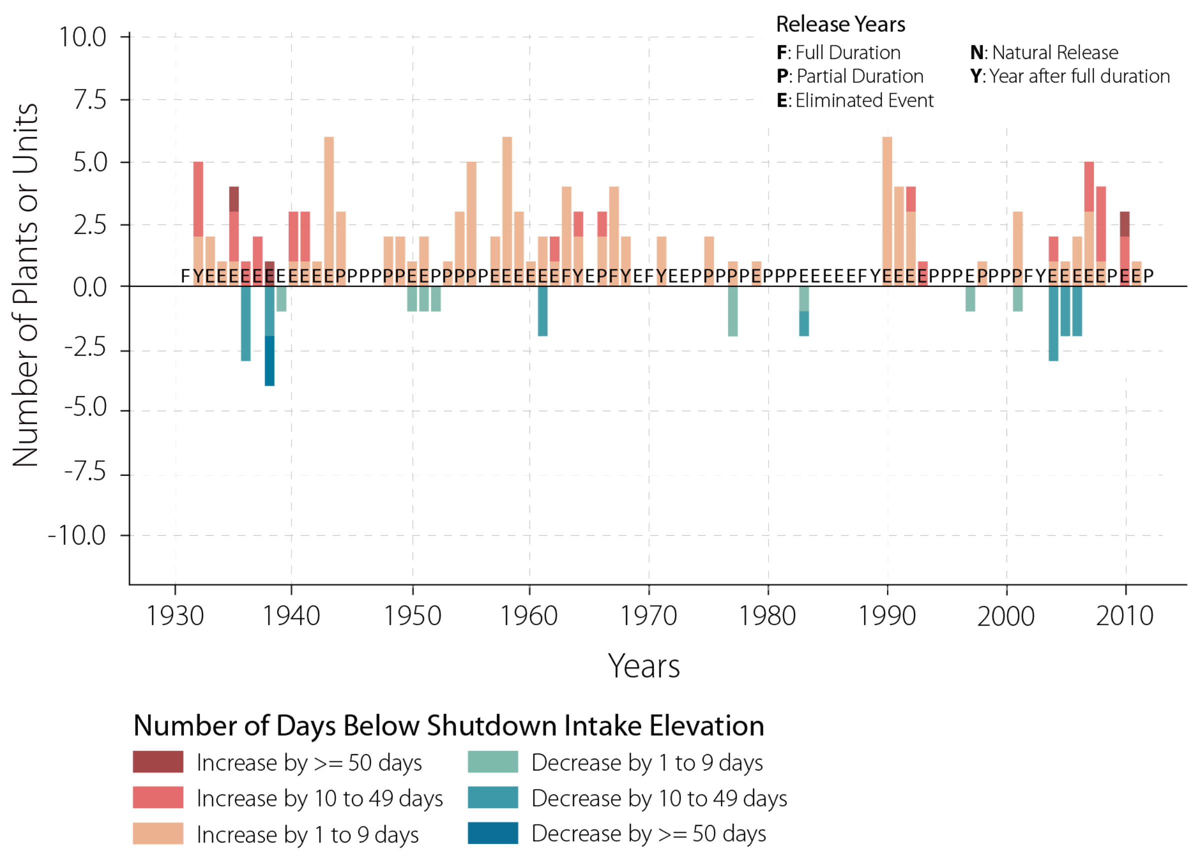


Figure 13. The Difference in the Number of Days Below Shutdown Intake Elevations by Power Plant (or Unit) for Alternative 6 Compared to Alternative 1

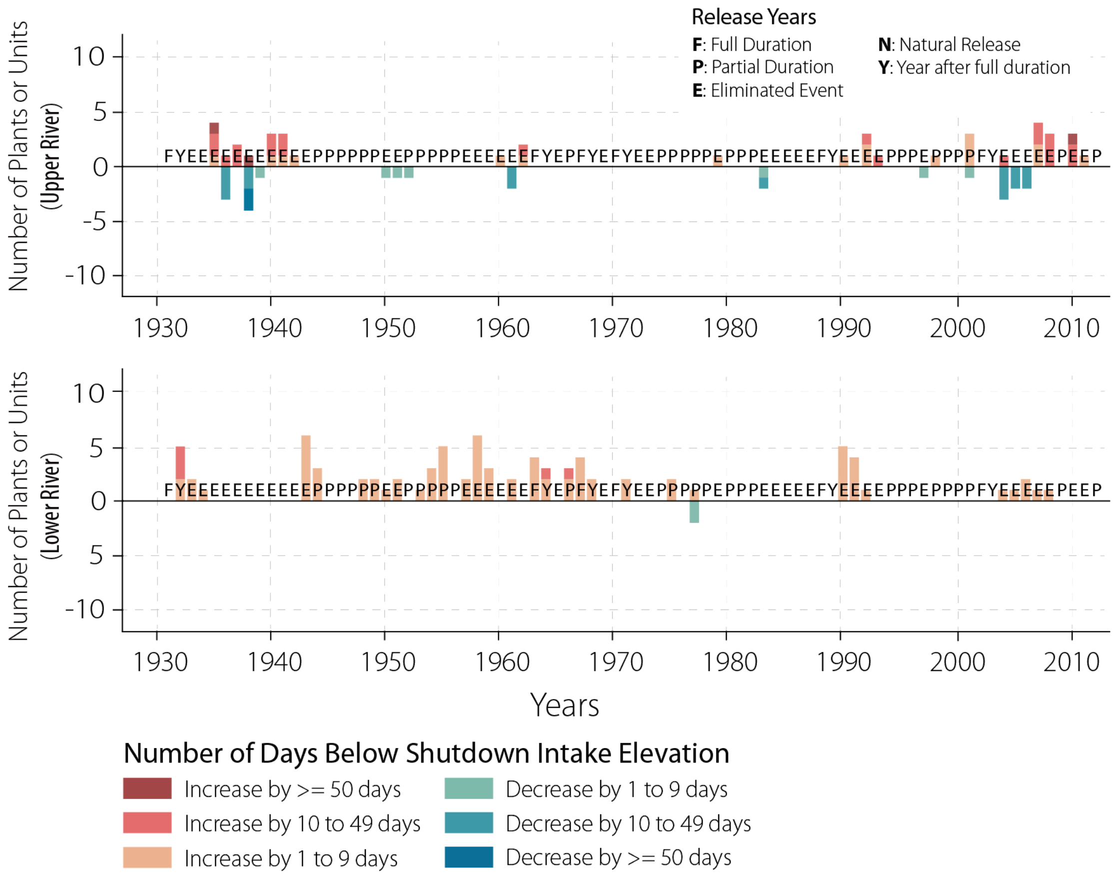


Figure 14. The Difference in the Number of Days Below Shutdown Intake Elevations by Upper and Lower River Power Plants (or Units) for Alternative 6 Compared to Alternative 1

3.2 River Water Temperatures

This section presents the results from the river water temperature modeling effort, which uses the ERDC river water temperature model (USACE 2018). The results focus on the power plants in the lower river that experience river water temperatures above 90°F, a water quality standard for the power plants in the lower river. The results show the number of days when river water temperatures are above 90°F over the POR as simulated by the river water temperature model for the period of analysis, 1975–2012 (excluding 2011), for power plants or units in the lower river.

3.2.1 Alternative 1 – No Action

Figure 15 presents the number of days when river water temperatures are above 90°F by year by power plant or unit for Alternative 1. Power plants in the lower river would experience higher river water temperatures under Alternative 1 during relatively drier or drought conditions. In 1987 simulated, 16 power plants or units would experience more than one day above 90°F, and eight power plants would experience over 11 days above 90°F. In the mid-2000s, up to three power plants in the lower river would experience between 31 and 100 days above the 90°F river water temperature threshold.

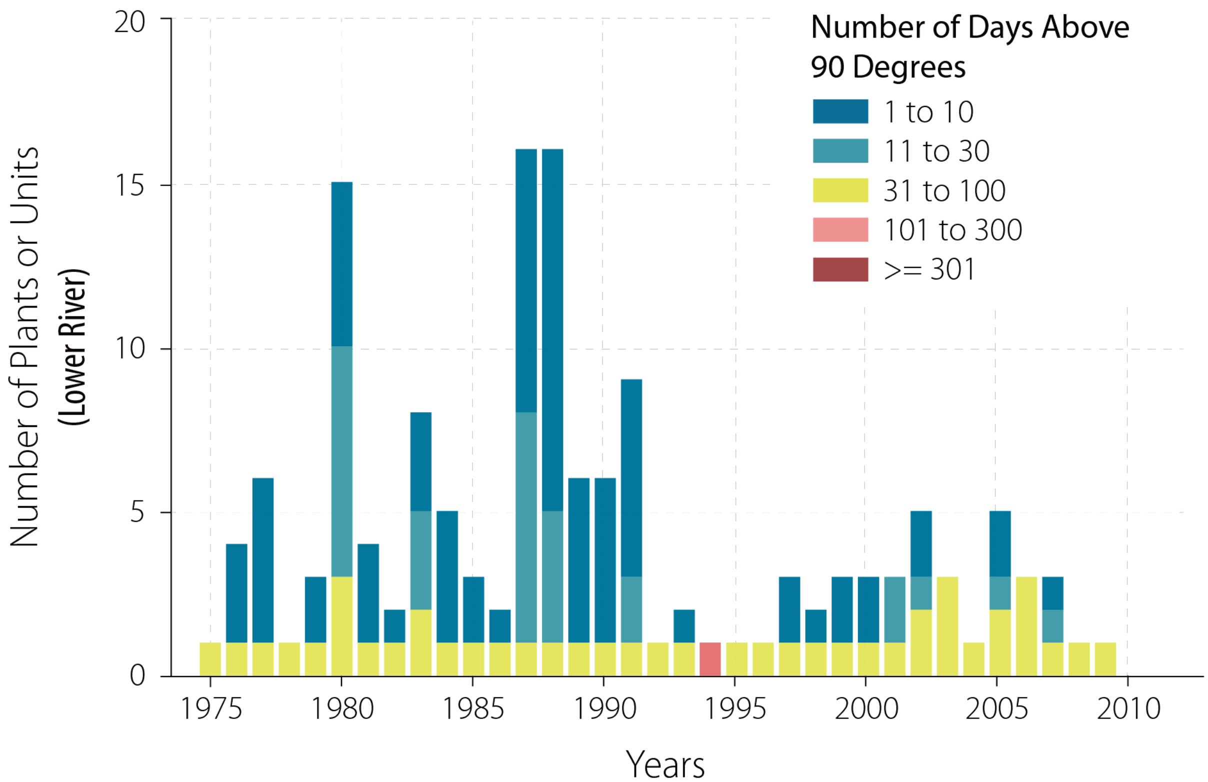


Figure 15. The Number of Days Above 90°F for Lower River Power Plants (or Units) for Alternative 1

3.2.2 Alternative 2 – USFWS 2003 Biological Opinion Projected Actions

Figure 16 presents the difference in the number of days when river water temperatures are above 90°F by year by power plant or unit for Alternative 2 compared to Alternative 1. Alternative 2 results in the largest changes from Alternative 1 in river water temperatures compared to the other action alternatives. Notable years with more days above the 90°F threshold occur during the low summer flow events, as simulated in 1988, 1989, 2002, and 2003. In 1988, there are 13 power plants or units in the lower river that would experience between 10 and 49 days above 90°F compared to Alternative 1.

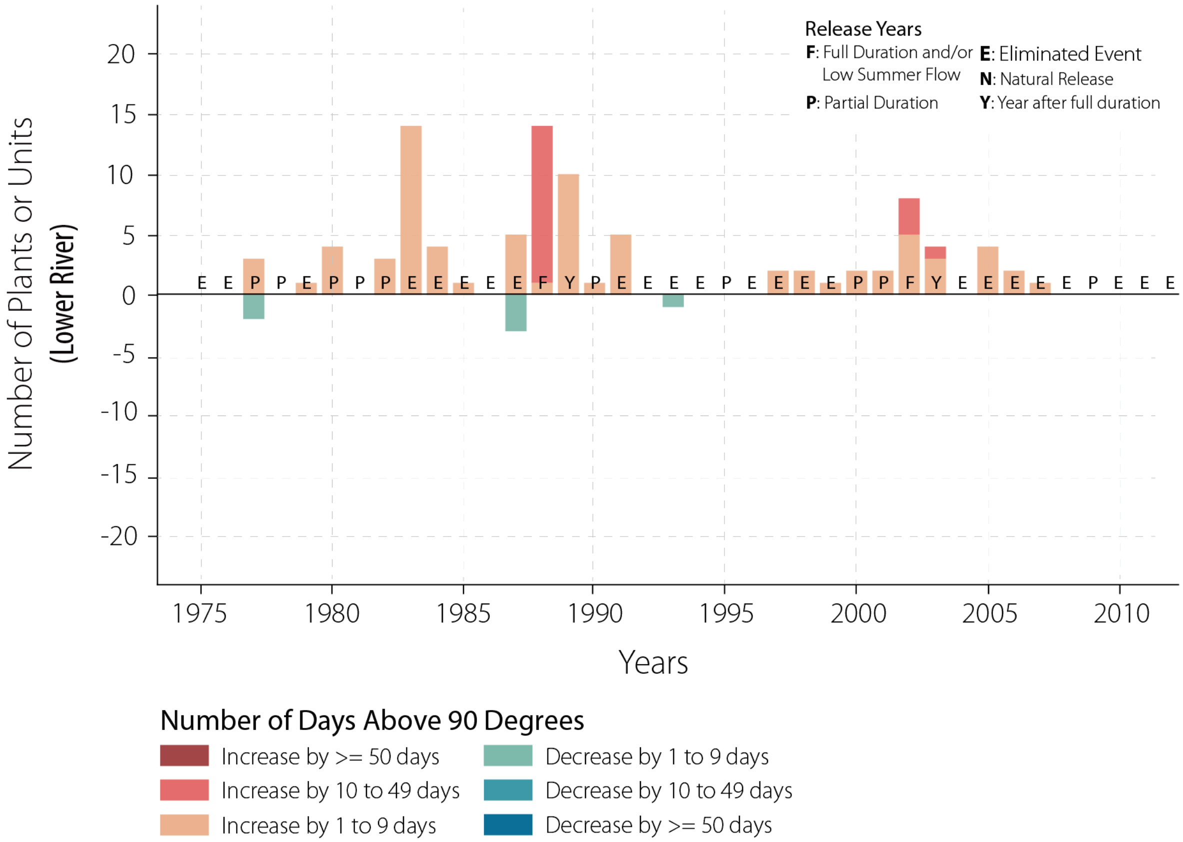


Figure 16. The Difference in the Number of Days Above 90°F by Lower River Power Plant (or Unit) for Alternative 2 Compared to Alternative 1

3.2.3 Alternative 3 – Mechanical Construction Only

Figure 17 presents the difference in the number of days when river water temperatures are above 90°F by year by power plant or unit for Alternative 3 compared to Alternative 1. Alternative 3 results in the least amount of adverse change from Alternative 1 in river water temperatures compared to the other action alternatives. Alternative 3 would result in fewer days above 90°F on average across the POR, with benefits to power plants in these years.

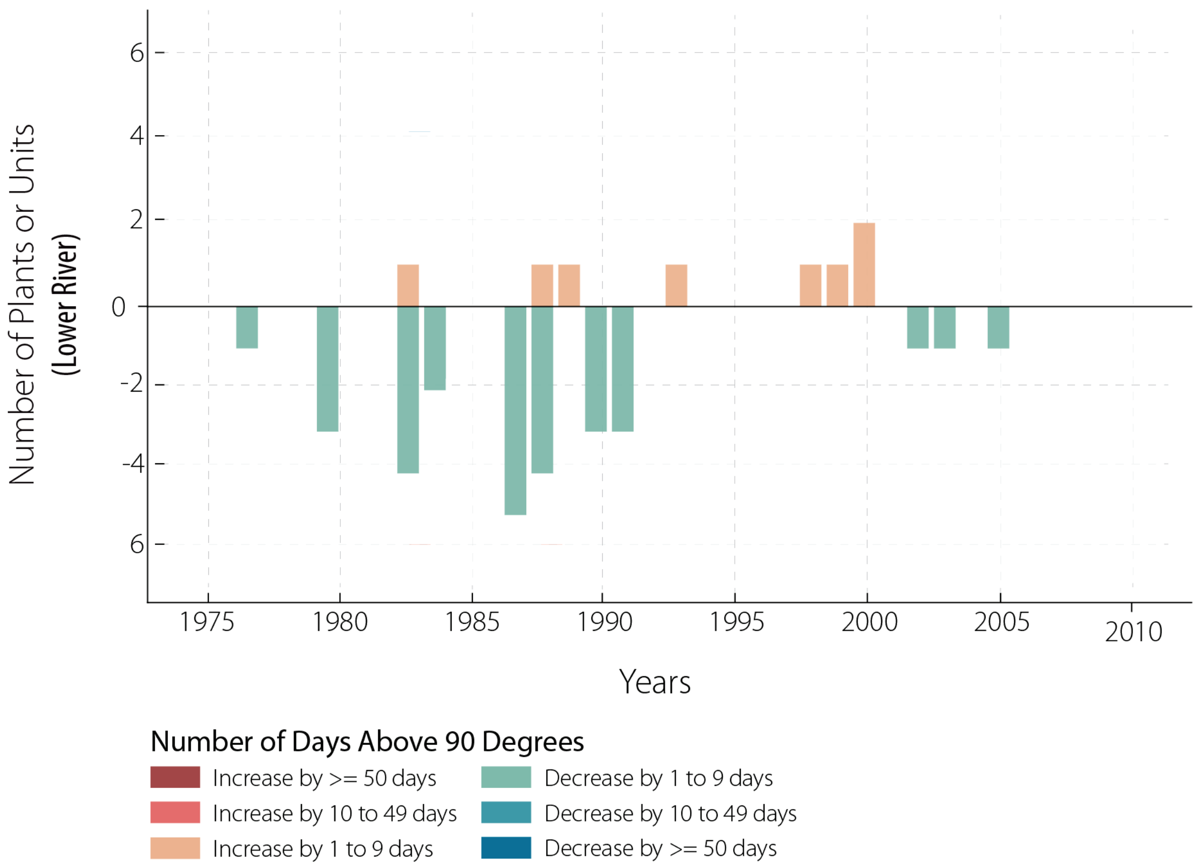


Figure 17. The Difference in the Number of Days Above 90°F by Lower River Power Plant (or Unit) for Alternative 3 Compared to Alternative 1

3.2.4 Alternative 4 – Spring ESH Creating Release

Figure 18 presents the difference in the number of days when river water temperatures are above 90°F year by power plant or unit for Alternative 4 compared to Alternative 1. Alternative 4 would result in fewer days above 90°F on average across the POR, with benefits to power plants in these years.

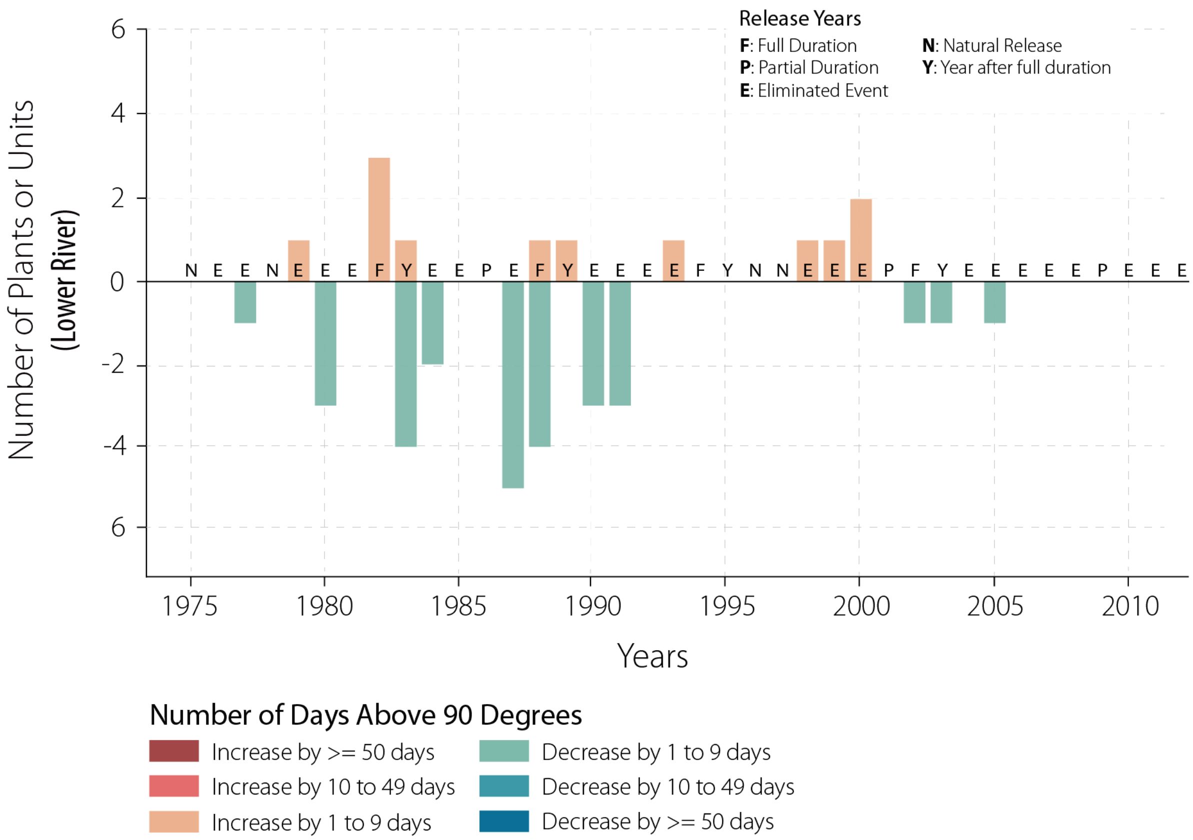


Figure 18. The Difference in the Number of Days Above 90°F by Lower River Power Plant (or Unit) for Alternative 4 Compared to Alternative 1

3.2.5 Alternative 5 – Fall ESH Creating Release

Figure 19 presents the difference in the number of days when river water temperatures are above 90°F by year by power plant or unit for Alternative 5 compared to Alternative 1. Alternative 5 would result in fewer days above 90°F on average across the POR, with benefits to power plants in these years.

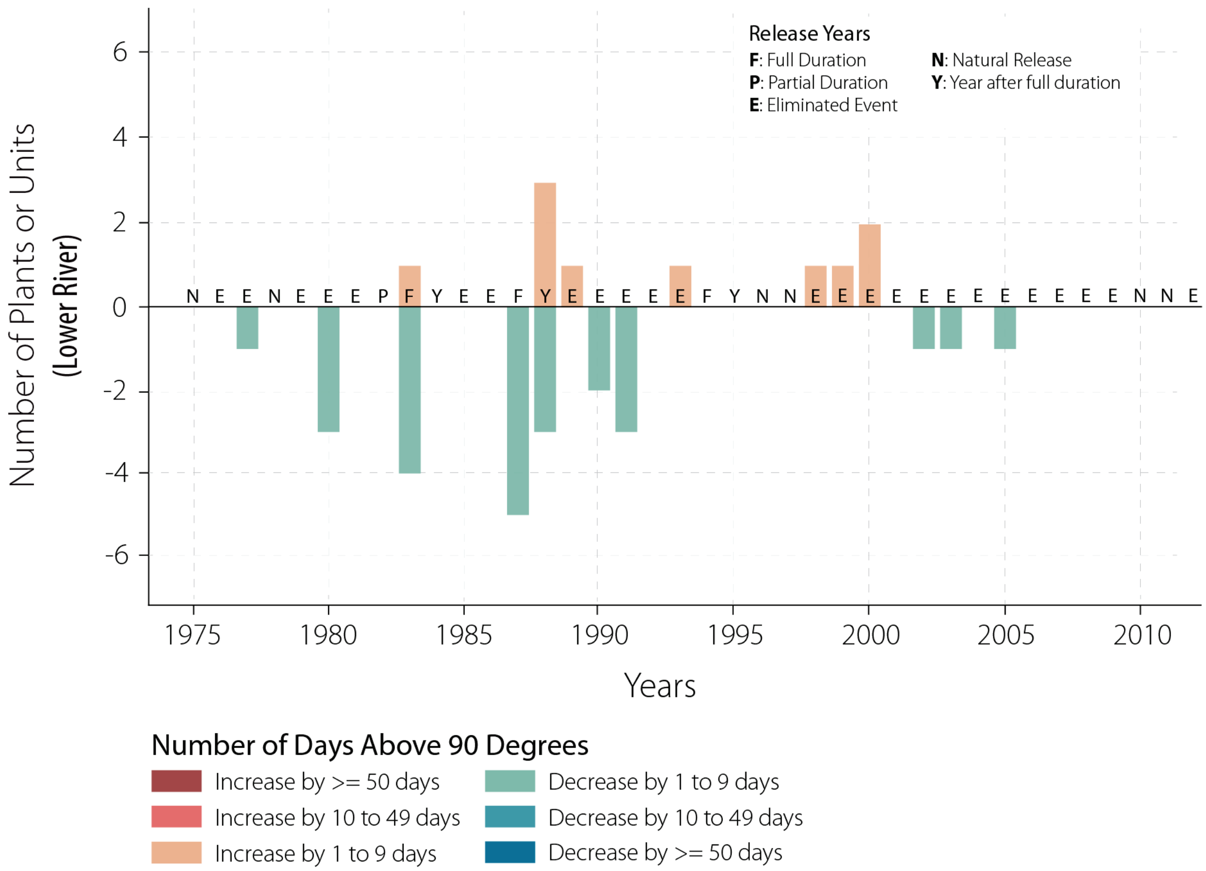


Figure 19. The Difference in the Number of Days Above 90°F by Lower River Power Plant (or Unit) for Alternative 5 Compared to Alternative 1

3.2.6 Alternative 6 – Pallid Sturgeon Spawning Cue

Figure 20 presents the difference in the number of days when river water temperatures are above 90°F by year by power plant or unit for Alternative 6 compared to Alternative 1. Alternative 6 would result in fewer days above 90°F on average across the POR, with benefits to power plants in these years.

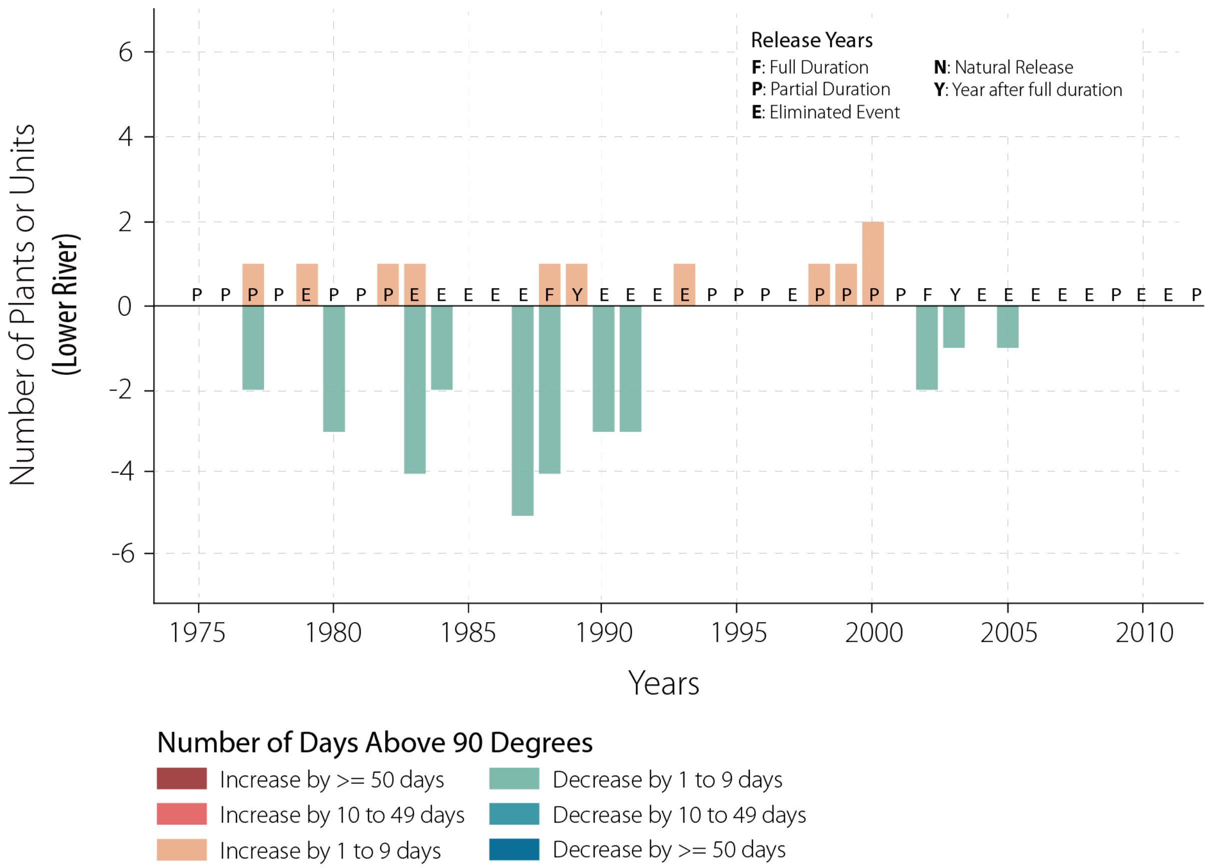


Figure 20. The Difference in the Number of Days Above 90°F by Lower River Power Plant (or Unit) for Alternative 6 Compared to Alternative 1

4.0 National Economic Development Results

This section provides the results of the NED analysis. A summary of results across all alternatives is presented first, followed by a detailed description of the results by alternative. It should be noted that the results include data presented for two analysis periods. The first period is from 1975 to 2012, excluding 2011, and includes impacts to thermal power plants from both access to water and river water temperatures. The "period of record," from 1931 to 2012, excluding 2011, includes impacts from the POR that include both access to water and river temperatures as well as the period from 1931 to 1974, when impacts to thermal power plants were only evaluated based on access to water (the ERDC river water temperature model does not include these years).

4.1 Summary of Alternatives

Adverse river conditions, such as reduced river flows or elevations or increased river water temperature, can affect thermal power operations and power generation. The NED analysis for thermal power focused on estimating the changes in variable costs and energy and capacity values as a result of changing physical conditions along the Missouri River under the MRRMP-EIS alternatives. The results of the H&H modeling show that water surface elevations, flows, and temperatures would impact thermal power plants evaluated under all the MRRMP-EIS alternatives, including Alternative 1. The impacts to thermal power plants would include a change in costs to replace lost electricity generation, capacity, and to address adverse operating conditions (variable costs) relative to Alternative 1.

Tables 7, 8, and 9 provide a summary of the NED analysis for each of the MRRMP-EIS alternatives. Table 7 summarizes the results for all of the thermal power plants under analysis. As currently modeled over the 37-year period of analysis, the effect of changing river conditions relative to Alternative 1 on average annual thermal power NED values would range from a decrease of $59.8 million under Alternative 2 (the most adverse impact) to a slight increase of $16,800 in under Alternative 3 (the most beneficial impact). Alternative 3 would result in slight beneficial impacts on average annual NED values compared to Alternative 1, while Alternatives 2, 4, 5, and 6 would result in adverse impacts compared to Alternative 1. The low summer flow events, which would occur as simulated in 4 of the 37 years under Alternative 2, would result in adverse impacts to thermal power NED values in the lower and upper river, with an average annual decrease in NED values of 1.6 percent compared to Alternative 1 (Table 9). Alternative 4 would result in an average annual change in thermal power NED values compared to Alternative 1 of $3.1 million, a 0.1 percent decrease.

Table 8 and Figure 21 summarize the NED analysis for thermal power plants in the Garrison reach (i.e., the upper river). As currently modeled over the 37-year period of analysis, the average annual decrease in NED values would range from $231,000 under Alternative 3 (least adverse impacts) to $2.5 million (most adverse impact) under Alternative 4. Relative to Alternative 1, Alternative 4 would result in the largest decrease in average annual NED values ($2.5 million or 0.2 percent). Annual average changes in power generation and energy values compared to Alternative 1 under all alternatives for power plants in the upper river would be less than 0.3 percent.

Table 7. Estimated Thermal Power National Economic Development Results for MRRMP-EIS Alternatives for All Power Plants, 1975–2012

NED Values	Alternative 1	Change from Alternative 1				
		Alternative 2	Alternative 3	Alternative 4	Alternative 5	Alternative 6
Average Annual Power Generation (MWh)	98,387,644	98,136,018	98,400,709	98,289,821	98,380,892	98,360,036
Annual Average Energy Values[a]	$2,288,928,200	$2,282,241,157	$2,289,290,985	$2,286,731,477	$2,288,803,952	$2,288,325,063
Change in Average Annual Energy Values from Alternative 1	N/A	−$6,687,044	$362,785	−$2,196,723	−$124,248	−$603,137
Percent Change in Energy Values from Alternative 1	N/A	−0.3%	0.0%	−0.1%	0.0%	0.0%
Average Annual Capacity Value (Summer)[b]	$1,356,767,317	$1,303,686,367	$1,364,062,963	$1,363,037,660	$1,362,910,806	$1,363,479,594
Change in Summer Capacity Value from Alternative 1	N/A	−$53,080,950	$7,295,646	$6,270,343	$6,143,489	$6,712,277
Average Annual Capacity Values (Winter)[b]	$1,589,606,071	$1,589,927,540	$1,589,606,071	$1,589,606,071	$1,589,501,898	$1,589,606,071
Change in Winter Capacity Value from Alternative 1	N/A	$321,470	$0	$0	−$104,173	$0
Max Change in Average Annual Capacity Value from Alternative 1	N/A	−$53,080,950	−$346,498	−$836,642	−$824,656	−$480,772
Average Annual Variable Costs[c]	−$308,760	−$535,100	−$308,235	−$400,311	−$366,700	−$470,375
Average Annual NED Values[d]	$3,645,386,757	$3,585,392,423	$3,645,403,570	$3,642,261,841	$3,644,379,913	$3,644,141,233
Change in Average Annual NED Values	N/A	−$59,994,334	$16,813	−$3,124,916	−$1,006,844	−$1,245,525
Percent Change in Alternative 1	N/A	−1.6%	0.0%	−0.1%	0.0%	0.0%

Notes:

a The upper river includes five power plants in the Garrison Dam to Lake Oahe river reach and one power plant in Lake Sakakawea, while the lower river includes all power plants below Gavins Point Dam.

b Capacity values are estimated by multiplying the 15th percentile of the available seasonal capacity during the summer and winter peak seasons from 1975 to 2012 by the unit capacity value. Capacity values represent an annualized capital cost to replace the estimated lost capacity; the unit capacity value was $133,650 /MW-year (Hydropower Analysis Center pers. comm. 2018).

c Variable costs include operations and maintenance costs incurred under adverse conditions when power generation is not affected. In addition, the variable costs include losses in renewable energy credits for Minnesota Power when Minnkota Power Cooperative Missouri River intake is impacted during the summer.

d NED values for Alternative 1 include summer capacity figures because the bulk of the capacity impact occurs during the summer months. For Alternatives 2 through 6, either winter or summer dependable capacity is used to calculate the capacity value impacts depending on which season incurs the greater adverse impact for that particular alternative for that particular power plant.

Table 8. Estimated Thermal Power National Economic Development Results for MRRMP-EIS Alternatives for Power Plants in the Upper River, 1975–2012

NED Values	Alternative 1	Change from Alternative 1				
		Alternative 2	Alternative 3	Alternative 4	Alternative 5	Alternative 6
Average Annual Power Generation (MWh)	28,225,382	28,184,800	28,217,480	28,143,640	28,212,552	28,213,091
Annual Average Energy Values [a]	$656,024,824	$654,891,917	$655,842,581	$654,145,676	$655,719,721	$655,734,747
Change in Average Annual Energy Values from Alternative 1	NA	−$1,132,907	−$182,243	−$1,879,148	−$305,103	−$290,077
Percent Change in Energy Values from Alternative 1	NA	−0.2%	0.0%	−0.3%	0.0%	0.0%
Average Annual Capacity Value (Summer)[b]	$386,141,980	$385,979,045	$386,092,400	$385,817,155	$386,123,097	$385,903,896
Change in Summer Capacity Value from Alternative 1	NA	−$162,936	−$49,580	−$324,825	−$18,883	−$238,084
Average Annual Capacity Values (Winter)[b]	$396,957,835	$396,957,835	$396,957,835	$396,957,835	$396,853,663	$396,957,835
Change in Winter Capacity Value from Alternative 1	NA	$0	$0	$0	−$104,173	$0
Max Change in Average Annual Capacity Value from Alternative 1	NA	−$162,936	−$49,580	−$539,725	−$127,277	−$412,690
Average Annual Variable Costs[c]	−$308,760	−$535,100	−$308,235	−$400,311	−$366,700	−$470,375
Average Annual NED Values[d]	$1,041,858,044	$1,040,335,861	$1,041,626,746	$1,039,347,621	$1,041,367,724	$1,040,993,662
Change in Average Annual NED Values	NA	−$1,522,184	−$231,298	−$2,510,423	−$490,320	−$864,382
Percent Change in Alternative 1	NA	−0.1%	0.0%	−0.2%	0.0%	−0.1%

Notes:

a The upper river includes five power plants in the Garrison Dam to Lake Oahe river reach and one power plant in Lake Sakakawea, while the lower river includes all power plants below Gavins Point Dam.

b Capacity values are estimated by multiplying the 15th percentile of the available seasonal capacity during the summer and winter peak seasons from 1975 to 2012 by the unit capacity value. Capacity values represent an annualized capital cost to replace the estimated lost capacity; the unit capacity value was $133,650 /MW-year (Hydropower Analysis Center 2017).

c Variable costs include operations and maintenance costs incurred under adverse conditions when power generation is not affected. In addition, the variable costs include losses in renewable energy credits for Minnesota Power when Minnkota Power Cooperative Missouri River intake is impacted during the summer.

d NED values for Alternative 1 include summer capacity figures because the bulk of the capacity impact occurs during the summer months. For Alternatives 2 through 6, either winter or summer dependable capacity is used to calculate the capacity value impacts depending on which season incurs the greater adverse impact for that particular alternative for that particular power plant.

Table 9. Estimated Thermal Power National Economic Development Results for MRRMP-EIS Alternatives for Power Plants in the Lower River, 1975–2012

NED Values	Alternative 1	Change from Alternative 1				
		Alternative 2	Alternative 3	Alternative 4	Alternative 5	Alternative 6
Average Annual Power Generation (MWh)	70,162,262	69,951,218	70,183,229	70,146,181	70,168,340	70,146,945
Annual Average Energy Values[a]	$1,632,903,376	$1,627,349,240	$1,633,448,405	$1,632,585,801	$1,633,084,231	$1,632,590,316
Change in Average Annual Energy Values from Alternative 1	NA	−$5,554,136	$545,028	−$317,575	$180,855	−$313,060
Percent Change in Energy Values from Alternative 1	NA	−0.3%	0.0%	0.0%	0.0%	0.0%
Average Annual Capacity Value (Summer)[b]	$970,625,337	$917,707,322	$977,970,563	$977,220,505	$976,787,709	$977,575,698
Change in Summer Capacity Value from Alternative 1	NA	−$52,918,015	$7,345,226	$6,595,168	$6,162,372	$6,950,361
Average Annual Capacity Values (Winter)[b]	$1,192,648,235	$1,192,969,705	$1,192,648,235	$1,192,648,235	$1,192,648,235	$1,192,648,235
Change in Winter Capacity Value from Alternative 1	NA	$321,470	$0	$0	$0	$0
Max Change in Average Annual Capacity Value from Alternative 1	NA	−$52,918,015	−$296,918	−$296,918	−$697,379	−$68,082
Average Annual Variable Costs[c]	$0	$0	$0	$0	$0	$0
Average Annual NED Values[d]	$2,603,528,713	$2,545,056,562	$2,603,776,824	$2,602,914,220	$2,603,012,189	$2,603,147,570
Change in Average Annual NED Values	NA	−$58,472,151	$248,111	−$614,493	−$516,524	−$381,143
Percent Change in Alternative 1	NA	−2.2%	0.0%	0.0%	0.0%	0.0%

Notes:

a The upper river includes five power plants in the Garrison Dam to Lake Oahe river reach and one power plant in Lake Sakakawea, while the lower river includes all power plants below Gavins Point Dam.

b Capacity values are estimated by multiplying the 15th percentile of the available seasonal capacity during the summer and winter peak seasons from 1975 to 2012 by the unit capacity value. Capacity values represent an annualized capital cost to replace the estimated lost capacity; the unit capacity value was $133,650 /MW-year (Hydropower Analysis Center 2017).

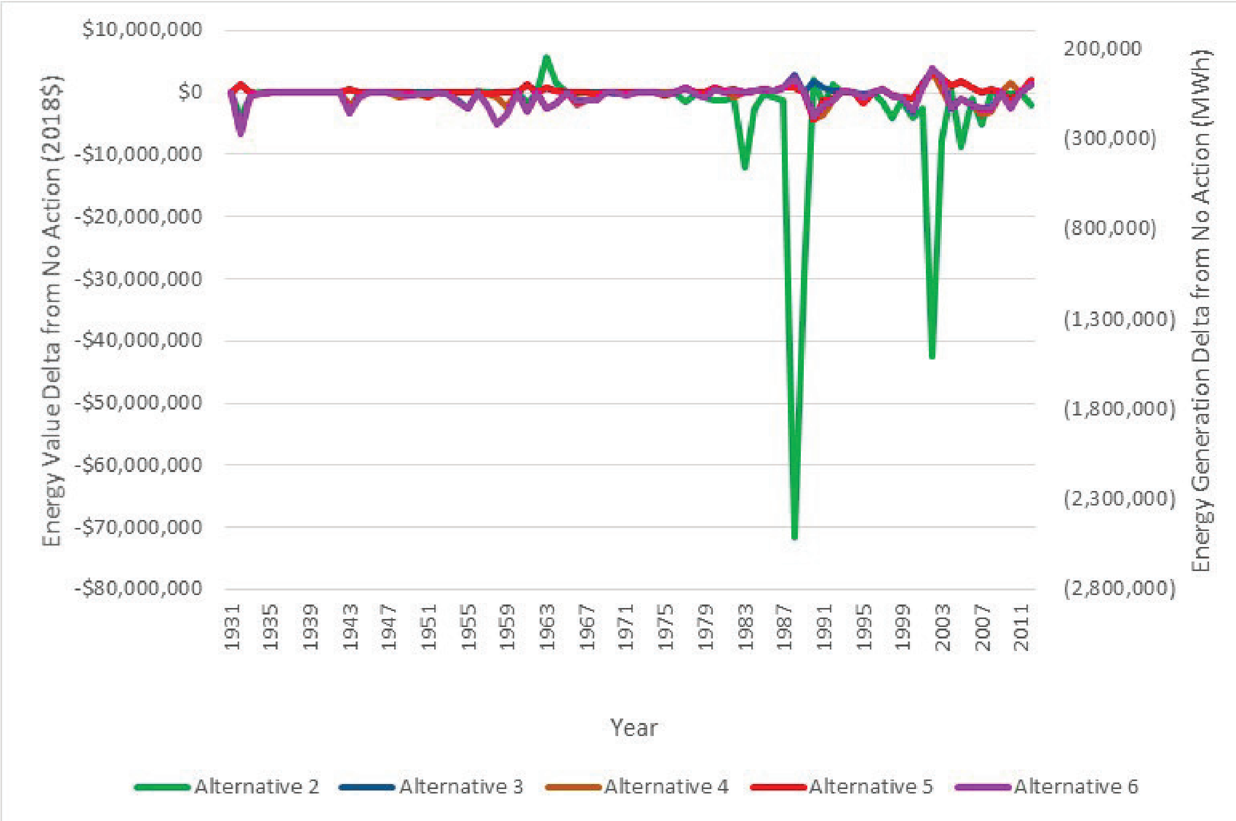
c Variable costs include operations and maintenance costs incurred under adverse conditions when power generation is not affected. In addition, the variable costs include losses in renewable energy credits for Minnesota Power when Minnkota Power Cooperative Missouri River intake is impacted during the summer.

d NED values for Alternative 1 include summer capacity figures because the bulk of the capacity impact occurs during the summer months. For Alternatives 2 through 6, either winter or summer dependable capacity is used to calculate the capacity value impacts depending on which season incurs the greater adverse impact for that particular alternative for that particular power plant.

Note: The years 1931–1974 do not include impacts due to river temperatures.

Figure 21. Change in Energy Values and Generation Relative to Alternative 1 for the Upper River Power Plants

The MRRMP-EIS alternatives have varying impacts on power plants in the lower river (Table 9 and Figure 22). Thermal power plants in the lower river would be mostly impacted by changes in the river water temperature. The average annual changes in NED values would range from a decrease of $58.5 million (most adverse impact) under Alternative 2 to an increase of $248,111 under Alternative 3 (most beneficial impact) over the 37-year period of analysis relative to Alternative 1. Very small, beneficial impacts to thermal power NED values would occur under Alternative 3 compared to Alternative 1, averaging $248,111 annually. Relative to Alternative 1, Alternative 2 would result in an average annual decrease in NED values of $58.5 million (2.2 percent) for thermal power plants in the lower river (under the 37-year period of analysis). The low summer flow events as simulated under Alternative 2 result in adverse impacts to power generation and energy and capacity replacement costs compared to Alternative 1. As simulated in 1988, the worst impacted-year compared to Alternative 1, there would be a 21 percent (2.6 million MWh) decline in power generation relative to average annual generation in the summer under Alternative 1. Alternative 2 would result in the largest adverse impact to capacity for the power plants in the lower river, a reduction in 396 MW and $52.9 million in average annual replacement capacity costs.



Note: The years 1931–1974 do not include impacts due to river temperatures.

Figure 22. Change in Energy Values and Generation Relative to Alternative 1 for the Lower River Power Plants

4.2 Alternative 1 – No Action (Current System Operations and MRRP Management Actions)

Alternative 1 represents current System operations including a number of management actions associated with the MRRP and BiOp compliance. Management actions under Alternative 1 include creation of early life history habitat for the pallid sturgeon and ESH habitat, as well as a spring plenary pulse. The construction of habitat will be focused in the Garrison Dam to Lake Oahe and Gavins Point Dam to Rulo reaches for ESH habitat creation and between Ponca, Nebraska to the mouth near St. Louis for pallid sturgeon early life stage habitat.

Management of the Missouri River System under Alternative 1 would result in an annual average generation of 98.4 million MWh, equivalent to $2.3 billion in energy values over the 37-year period of analysis. Seventy-one percent of the power generation and energy values is associated with power plants in the lower river, and the remainder (29 percent) is associated with power generation from power plants in the upper river. Considering the 81-year POR, power generation would vary, with a low of 93.8 million MWh in 1937 and a high of almost 100 million MWh in a number of years (Figure 23).

Capacity values are defined as the amount of capacity that a power plant can reliably contribute to meeting peak season needs (USACE EM 1110-2-1701). The total value of dependable capacity in the summer would be $386.1 million in the upper river and $970.6 million in the lower river. Under Alternative 1, dependable capacity would be higher in the winter (11,894 MW) compared to the summer (10,152 MW) for all power plants because river water temperatures in the summer season during drought conditions would decrease power generation, affecting dependable capacity in the summer season. Average annual variable costs would be small under Alternative 1, averaging $308,760 annually over 37 years. The NED analysis for Alternative 1 is summarized in Table 10 and the annual power generation under Alternative 1 is presented in Figure 23.

Table 10. Summary of Thermal Power NED Values for Alternative 1, 1975–2012 (2018$)

NED Values	Upper River[a]	Lower River	All Locations
Average Annual Missouri River Power Generation (MWh)	28,225,382	70,162,262	98,387,644
Average Annual Energy Values	$656,024,824	$1,632,903,376	$2,288,928,200
Average Annual Dependable Capacity – Summer (MW)	2,889	7,262	10,152
Average Annual Dependable Capacity Value – Summer	$386,141,980	$970,625,337	$1,356,767,317
Average Annual Dependable Capacity – Winter (MW)[b]	2,970	8,924	11,894
Average Annual Dependable Capacity Value – Winter	$396,957,835	$1,192,648,235	$1,589,606,071
Average Annual Variable Costs[c]	−$308,760	$0	−$308,760
Average Annual NED Values[d]	$1,041,858,044	$2,603,528,713	$3,645,386,757

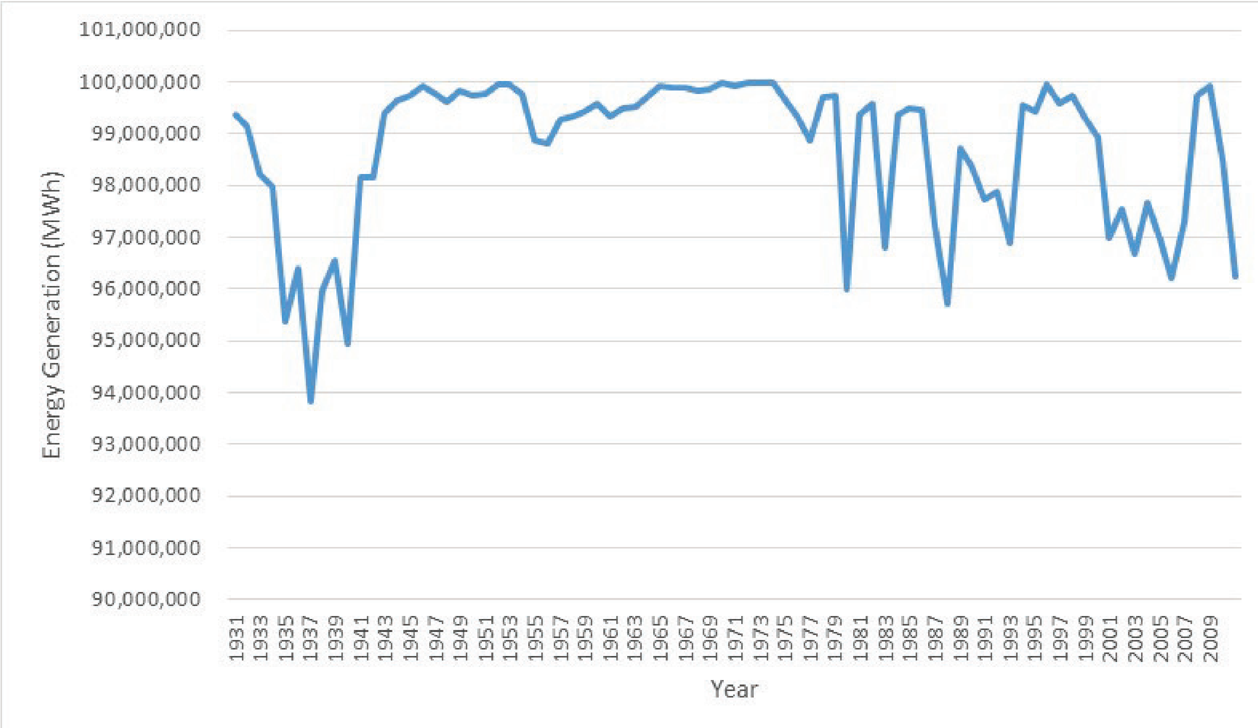
Notes:

a The upper river includes five power plants in the Garrison Dam to Lake Oahe river reach and one power plant in Lake Sakakawea, while the lower river includes all power plants below Gavins Point Dam.

b Capacity values are estimated by multiplying the 15th percentile of the available seasonal capacity during the summer and winter peak seasons from 1975 to 2012 by the unit capacity value. Capacity values represent an annualized capital cost to replace the estimated lost capacity; the unit capacity value was $133,650 /MW-year (Hydropower Analysis Center 2017).

c Variable costs include operations and maintenance costs incurred under adverse conditions when power generation is not affected. In addition, the variable costs include losses in renewable energy credits for Minnesota Power when Minnkota Power Cooperative Missouri River intake is impacted during the summer.

d NED values for Alternative 1 include summer capacity figures because the bulk of the capacity impact occurs during the summer months. For Alternatives 2 through 6, either winter or summer dependable capacity is used to calculate the capacity value impacts depending on which season incurs the greater adverse impact for that particular alternative for that particular power plant.



Note: The years 1931 to 1974 do not include impacts from river water temperatures.

Figure 23. Annual Power Generation Between 1931 and 2012 under Alternative 1

4.3 Alternative 2 – USFWS 2003 Biological Opinion Projected Actions

Alternative 2 includes a spawning cue pulse and low summer flows, as well as considerably more construction of early life history habitat for the pallid sturgeon and ESH than would occur under Alternative 1. Alternative 2 would result in $3.6 billion in average annual thermal power NED values, a decrease in $59.9 million (1.6 percent) compared to Alternative 1. Average annual replacement energy costs are estimated to be $6.6 million over the 37-year period of analysis (1975–2012, excluding 2011) when compared to Alternative 1, a decrease of 0.3 percent. Most of this impact (85 percent) would occur at power plants in the lower river. The years as simulated with low summer flows in the lower river would cause the largest adverse impacts compared to Alternative 1. Modeled river water temperatures during the low summer flow events during the peak summer river water temperatures would range from 1°F to 3°F higher than under Alternative 1. In addition, higher river water temperatures would also adversely impact energy values during non-low summer flow years compared to Alternative 1. Because there would be an increase in the amount of early life history habitat and associated shallow water under Alternative 2 relative to Alternative 1 there would be a slight increase in peak summer river water temperatures.

On average, energy values under Alternative 2 would decrease in the Garrison reach relative to Alternative 1 by $1.0 million or 0.2 percent over the period of analysis. Alternative 2 would result in an increase in average annual change in variable costs compared to Alternative 1 of $226,000 in the upper river.

Lost capacity occurs if power generation would be impacted during peak summer and winter seasons compared to Alternative 1. Dependable capacity for power plants in the lower river would decrease by an estimated 396 MWh relative to Alternative 1, representing approximately 2.4 percent of nameplate capacity for all power plants in the lower river. Average annual capacity replacement costs, relative to Alternative 1, are estimated to be $52.9 million over the POR for power plants in the lower river. There would be negligible impacts to replacement capacity of power plants in the Garrison reach.

The reductions in power generation in the lower river would typically occur during peak summer high-temperature periods when multiple plants with simultaneous power generation losses would be affected; these conditions would adversely affect the availability of replacement power, electricity prices (i.e., increase unit energy values), and costs to replace lost capacity, possibly resulting in more adverse impacts than reported here. The NED Analysis for Alternative 2 is summarized in Table 11.

The annual impacts are shown in Figures 24, 25, 26, and 27. Figure 24 shows the annual change in thermal power NED values under Alternative 2 in both the upper and lower river relative to Alternative 1. The difference in NED values between Alternative 1 and 2 are plotted and color-coded based on the type of release occurring each year. Figure 25 presents the annual results for the upper river, while Figures 26 and 27 present the annual thermal power NED results and thermal power energy values. The results show that overall changes in NED values for thermal power are predominantly due to impacts to thermal power plants in the lower river. However, in 1988, power plants are adversely affected in the upper and the lower river. In all years in the analysis, annual changes in thermal power NED values would be greater than $59 million relative to Alternative 1 because annual replacement capacity costs under Alternative 2 would be $53.0 million, which is applied to each year to estimate the NED impacts. Low summer flow events, as simulated under Alternative 2 in 1988, 1989, 2002, and 2003, would result in adverse impacts to thermal power NED values with a worst-case change of $200 million in 1988 relative to Alternative 1.

The releases out of Garrison dam associated with the spawning cue release and low summer flow events as simulated in 1988 would result in adverse impacts to power generation and energy values in the Garrison reach as releases out of Garrison Dam would be between 8,000 and 10,000 cfs under Alternative 2 in July and August compared to between 17,000 and 22,000 cfs under Alternative 1. All power plants in the Garrison reach would be affected as river stages would fall below shut down intake elevations. The low summer flows as simulated in the other years (1963, 1964, 1989, 2002, and 2003) do result in lower river flows in the Garrison reach relative to Alternative 1, but not as low as those simulated to occur in 1988. There are no changes in capacity replacement costs estimated in the upper river.

In the upper river, as simulated under Alternative 2 with conditions in 2001, there would be benefits to power plants, which would occur because river flows in the fall would be slightly higher, providing more access to water for operations (fewer days below shut down intake elevation under Alternative 2). The full spawning cue release and low summer flows as simulated in conditions similar to 2002 and 2003 would provide some small benefits to power plants in the Garrison reach (in 2005 and 2007) due to slightly higher System storage in these years and slightly higher river flows in the fall compared to Alternative 1.

Table 11. Summary of Thermal Power NED Values for Alternative 2, 1975–2012 (2018$)

NED Values	Upper River [a]	Lower River	All Locations
Average Annual Missouri River Power Generation (MWh)	28,184,800	69,951,218	98,136,018
Change in Average Annual Generation from Alternative 1 (MWh)	−40,582	−211,044	−251,626
Average Annual Energy Values	$655,003,759	$1,627,349,240	$2,282,241,157
Change in Average Annual Energy Values from Alternative 1	−$1,021,065	−$5,554,136	−$6,687,044
Percent Change in Average Energy Values from Alternative 1	−0.2%	−0.3%	−0.3%
Average Annual Dependable Capacity – Summer (MW)	2,888	6,866	9,754
Average Annual Dependable Capacity Value – Summer	$385,979,045	$917,707,322	$1,303,686,367
Average Annual Dependable Capacity – Winter (MW) [b]	2,970	8,926	11,896
Average Annual Dependable Capacity Value – Winter	$396,957,835	$1,192,969,705	$1,589,927,540
Max Change in Average Annual Capacity Value from Alternative 1	−$162,936	−$52,918,015	−$53,080,950
Average Annual Variable Costs [c]	−$535,100	$0	−$535,100
Change in Average Annual Variable Costs from Alternative 1	−$226,341	$0	−$226,341
Average Annual NED Values [d]	$1,040,447,704	$2,545,056,562	$3,585,392,423
Change in Average Annual NED Values from Alternative 1	−$1,410,341	−$58,472,151	−$59,994,334
Percent Change in Average Annual NED Values	−0.1%	−2.2%	−1.6%

Notes:

a The upper river includes five power plants in the Garrison Dam to Lake Oahe river reach, while the lower river includes all power plants below Gavins Point Dam.

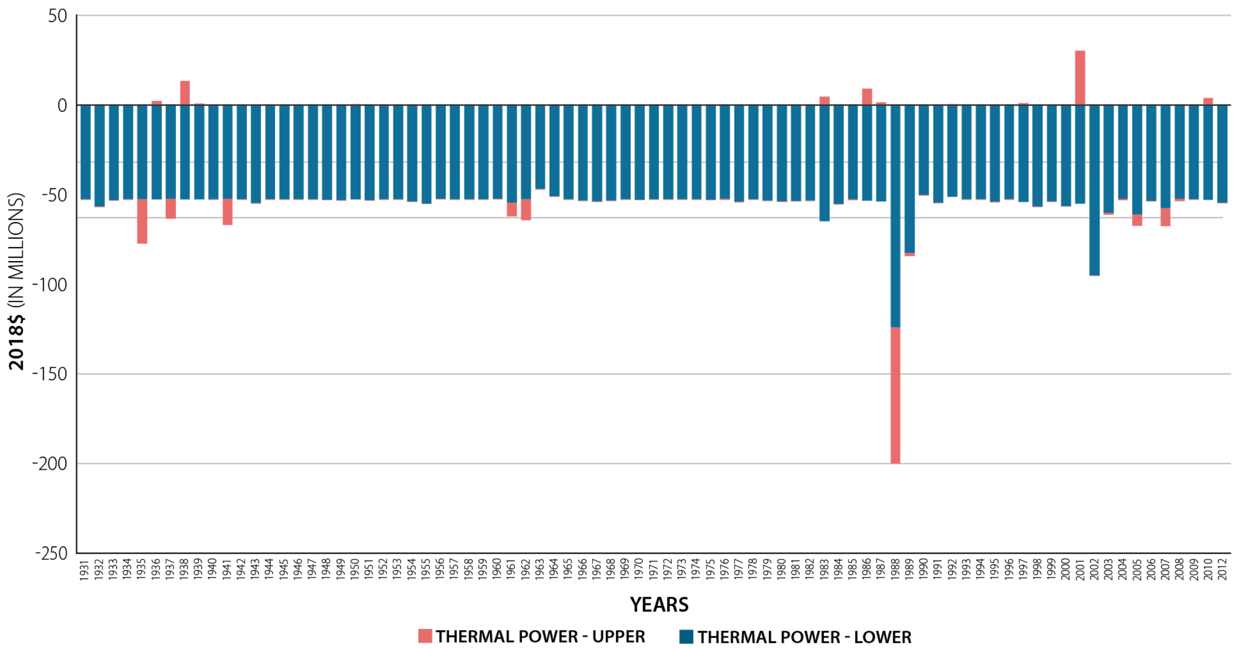
b Capacity values are estimated by multiplying the 15th percentile of the available seasonal capacity during the summer and winter peak seasons from 1975 to 2012 by the unit capacity value. Capacity values represent an annualized capital cost to replace the estimated lost capacity; the unit capacity value was $133,650 /MW-year (Hydropower Analysis Center 2017).

c Variable costs include operations and maintenance costs incurred under adverse conditions when power generation is not affected. In addition, the variable costs include losses in renewable energy credits for Minnesota Power when Minnkota Power Cooperative Missouri River intake is impacted during the summer.

d NED values for Alternative 1 include summer capacity figures because the bulk of the capacity impact occurs during the summer months. For Alternatives 2 through 6, either winter or summer dependable capacity is used to calculate the capacity value impacts depending on which season incurs the greater adverse impact for that particular alternative for that particular power plant.

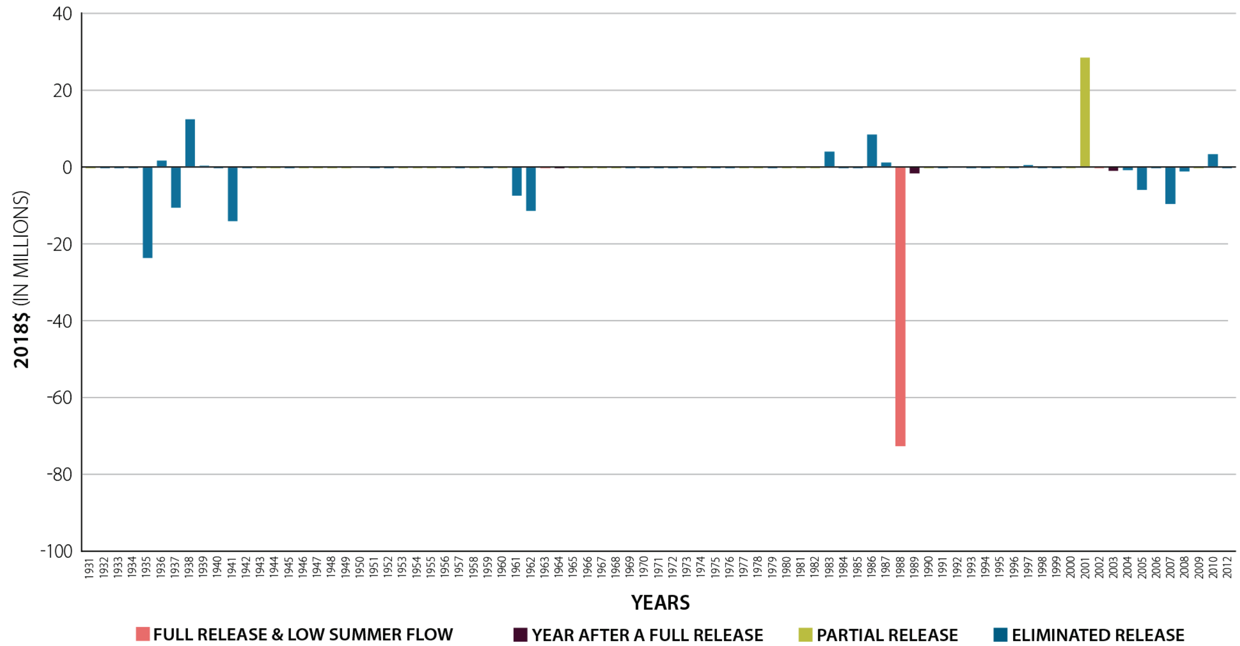
The low summer flow years as simulated in 1988, 1989, and 2002 would result in the largest changes in thermal power NED values relative to Alternative 1 between 1975 and 2012 for power plants in the lower river. The adverse impacts under Alternative 2 during these simulated low summer flow events would result in relatively higher river water temperatures compared to Alternative 1 during peak summer season when the demand for electricity is high. As simulated in 1988, many of the power plants would experience additional days above 90°F, resulting in reduced power generation for these power plants (see Section 3.2 of this report).

Power plants in the lower river would experience adverse impacts to power generation and energy values from considerably more early life history habitat constructed under Alternative 2, which slightly raises the peak river water temperatures in the summer in the lower river. Temperatures in the peak summer period would rise by less than 1°F under this alternative in an average year relative to Alternative 1. These impacts would occur throughout the POR because the channel geometry as simulated in the HEC-RAS and HEC-RAS-NSM models under Alternative 2 would be different (more early life history habitat) from the channel geometry under Alternative 1. Please See the H&H Water Quality Technical Report (USACE 2018).



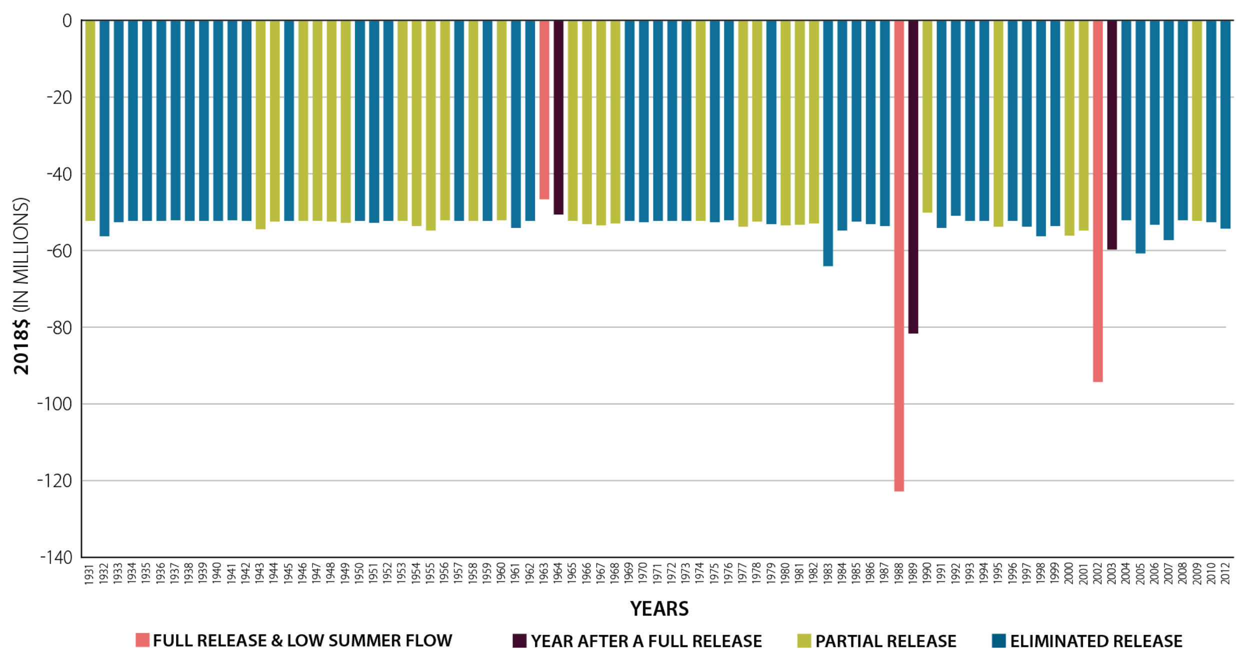
Note: The years 1931–1974 do not include impacts due to river temperatures.

Figure 24. Alternative 2 Change in Thermal Power NED Values from Alternative 1 in the Upper and Lower River



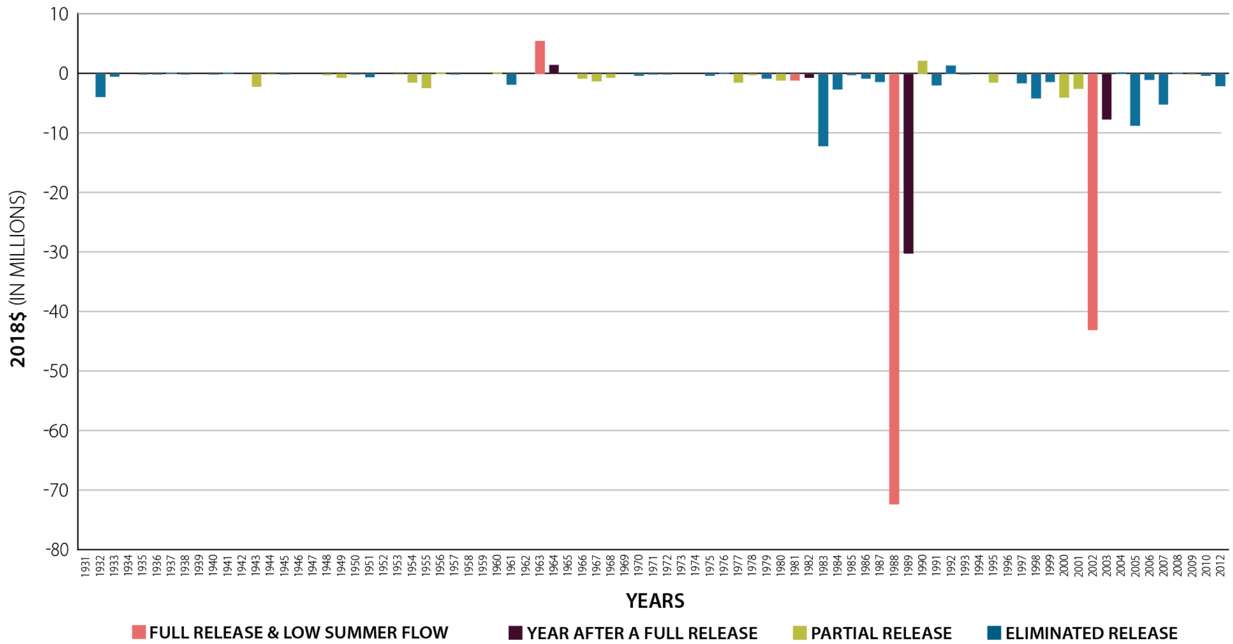
Note: The years 1931–1974 do not include impacts due to river temperatures.

Figure 25. Alternative 2 Change in Thermal Power NED Values from Alternative 1 in the Upper River



Note: The years 1931–1974 do not include impacts due to river temperatures.

Figure 26. Alternative 2 Change in Thermal Power NED Values from Alternative 1 in the Lower River



Note: The years 1931–1974 do not include impacts due to river temperatures.

Figure 27. Alternative 2 Change in Thermal Power Energy Values from Alternative 1 in the Lower River

4.4 Alternative 3 – Mechanical Construction Only

Alternative 3 includes mechanical habitat construction of ESH and interception and rearing complex (IRC) habitat. Alternative 3 includes fewer acres of IRC habitat compared to the acres of early life history habitat constructed under Alternative 1 (3,380 acres under Alternative 3 and 3,999 acres under Alternative 1). Alternative 3 would result in slight benefits compared to Alternative 1, with an average annual increase in thermal power NED values of $16,800 compared to Alternative 1 over the 37-year period of analysis (1975–2012, excluding 2011). Table 12 summarizes the NED analysis for Alternative 3.

The lower river would experience slight increases in power generation and energy values, on average, while the upper river would experience slight decreases in power generation and energy value. There would be increases to power generation compared to Alternative 1 in the lower river due to slightly higher river flows, with an increase in average annual energy values of $545,000. The power plants in the lower river would experience slightly lower river water temperatures as well under Alternative 3 compared to Alternative 1. These benefits would occur in the summer months due to fewer acres of early life history habitat for the pallid sturgeon would be constructed under Alternative 3 compared to Alternative 1, which would result in very small benefits to power generation (see Section 3.2 for the number of days above 90°F and the number of power plants affected).

Variable costs for power plants in the upper river would be slightly less than the costs incurred under Alternative 1. Dependable capacity in the peak season in the summer would be slightly higher for plants in the lower river and the same for plants in the upper river compared to Alternative 1. The maximum adverse change in capacity values (by plant) would result in negligible impacts to capacity values in the upper and lower river under Alternative 3.

Table 12. Summary of Thermal Power NED Values for Alternative 3

NED Values	Upper River [a]	Lower River	All Locations
Average Annual Missouri River Power Generation (MWh)	28,217,480	70,183,229	98,400,709
Change in Average Annual Generation from Alternative 1 (MWh)	−7,902	20,967	13,065
Average Annual Energy Values	$655,842,581	$1,633,448,405	$2,289,290,985
Difference in Average Annual Energy Values	−$182,243	$545,028	$362,785
Percent Change in Average Energy Values from Alternative 1	0.0%	0.0%	0.0%
Average Annual Dependable Capacity – Summer (MW)	2,889	7,317	10,206
Average Annual Dependable Capacity Value – Summer	$386,092,400	$977,970,563	$1,364,062,963
Average Annual Dependable Capacity – Winter (MW)[b]	2,970	8,924	11,894
Average Annual Dependable Capacity Value – Winter	$396,957,835	$1,192,648,235	$1,589,606,071
Max Change in Average Annual Capacity Value from Alternative 1	−$49,580	−$296,918	−$346,498
Average Annual Variable Costs[c]	−$308,235	$0	−$308,235
Change in Average Annual Variable Costs	$525	$0	$525
Average Annual NED Values[d]	$1,041,626,746	$2,603,776,824	$3,645,403,570
Change in Average Annual NED Values	−$231,298	$248,111	$16,813
Percent Change in Average Annual NED Values	0.0%	0.0%	0.0%

Notes:

a The upper river includes five power plants in the Garrison Dam to Lake Oahe river reach and one power plant in Lake Sakakawea, while the lower river includes all power plants below Gavins Point Dam.

b Capacity values are estimated by multiplying the 15th percentile of the available seasonal capacity during the summer and winter peak seasons from 1975 to 2012 by the unit capacity value. Capacity values represent an annualized capital cost to replace the estimated lost capacity; the unit capacity value was $133,650 /MW-year (Hydropower Analysis Center 2017).

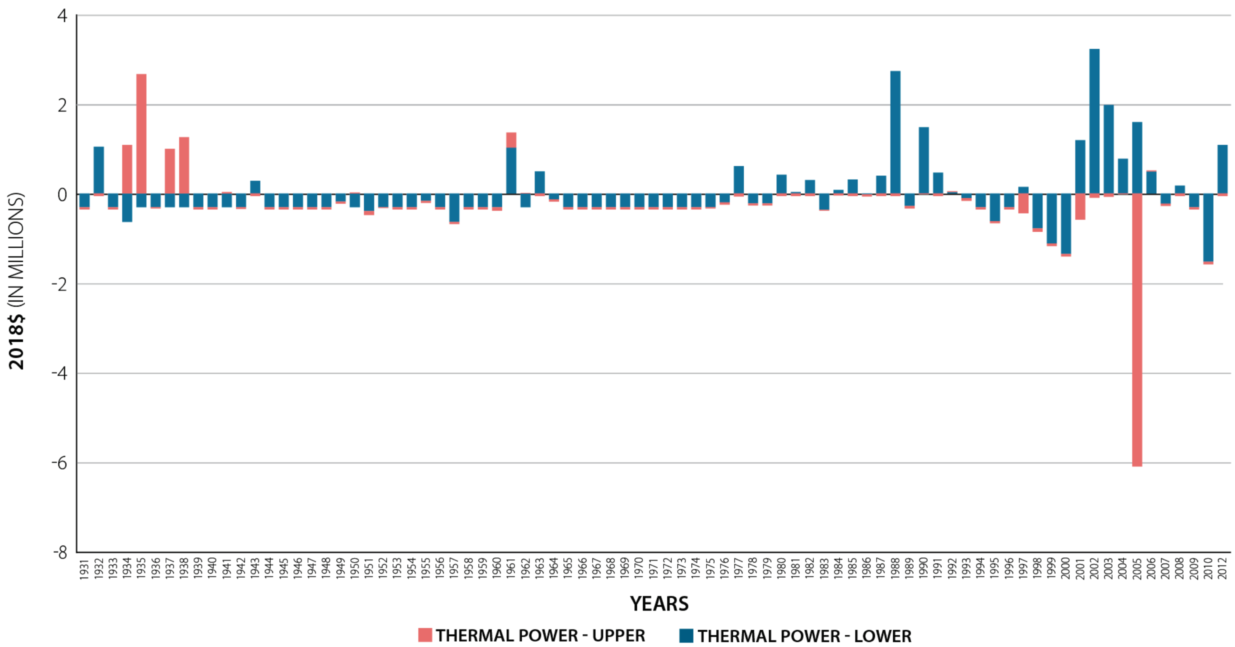
c Variable costs include operations and maintenance costs incurred under adverse conditions when power generation is not affected. In addition, the variable costs include losses in renewable energy credits for Minnesota Power when Minnkota Power Cooperative Missouri River intake is impacted during the summer.

d NED values for Alternative 1 include summer capacity figures because the bulk of the capacity impact occurs during the summer months. For Alternatives 2 through 6, either winter or summer dependable capacity is used to calculate the capacity value impacts depending on which season incurs the greater adverse impact for that particular alternative for that particular power plant.

The one-time spawning cue test (Level 2) release that may be implemented under Alternative 3 was not included in the hydrologic modeling for this alternative because of the uncertainty of the hydrologic conditions that would be present if implemented. Hydrologic modeling for Alternative 6 simulates reoccurring implementation (Level 3) of this spawning cue over the wide range of hydrologic conditions in the POR. Therefore, the impacts from the potential implementation of a one-time spawning cue test release under Alternative 3 would be bound by the range of impacts described for individual releases under Alternative 6.

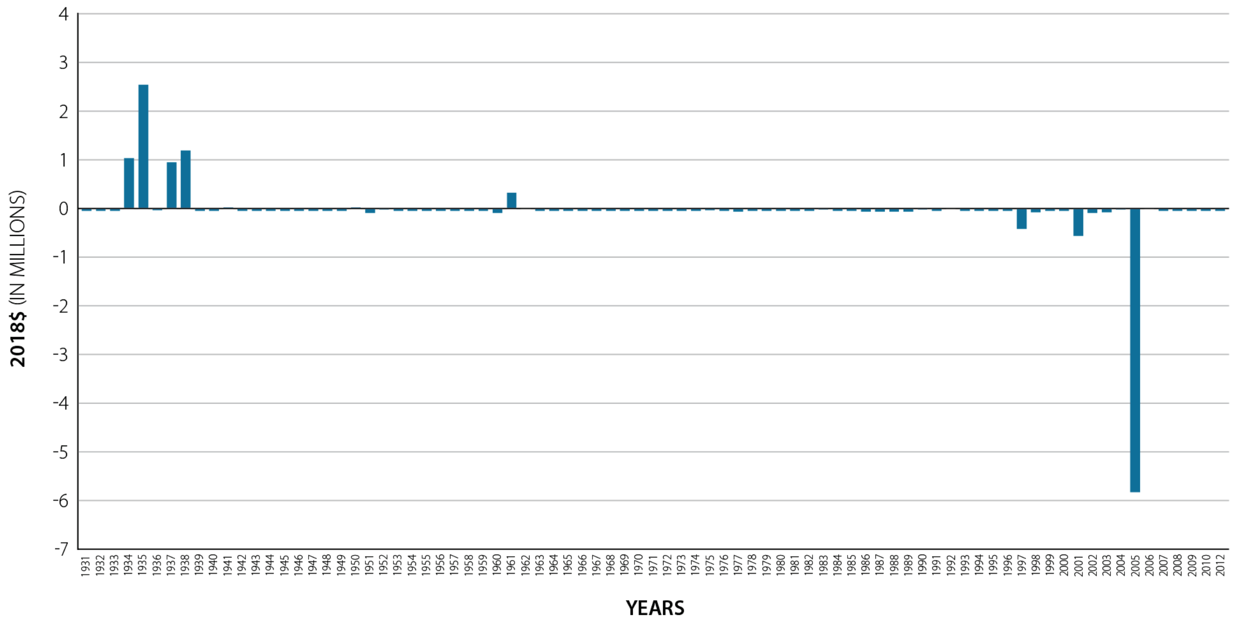
Figure 28 shows the annual thermal power NED values in the upper and lower river as modeled in the NED analysis. Additional results are shown in Figures 9 and 10. Figure 29 presents the annual results for the upper river, while Figure 30 presents the annual results for the lower river.

In the upper river, there would be very minimal changes in thermal power NED values for most years compared to Alternative 1. However, as simulated in 2005, there would be a decrease in thermal power NED values of about $6.0 million compared to Alternative 1, most of which would occur in the fall when the releases out of Garrison Dam would be less than those simulated under Alternative 1 (from 300 to 700 cfs less under Alternative 3 than under Alternative 1) based on the elimination of the spawning cue and the rebalancing of the reservoirs. This would result in additional days below shut down intake elevations at three power plants in the Garrison reach (See Section 3.2 for additional information).



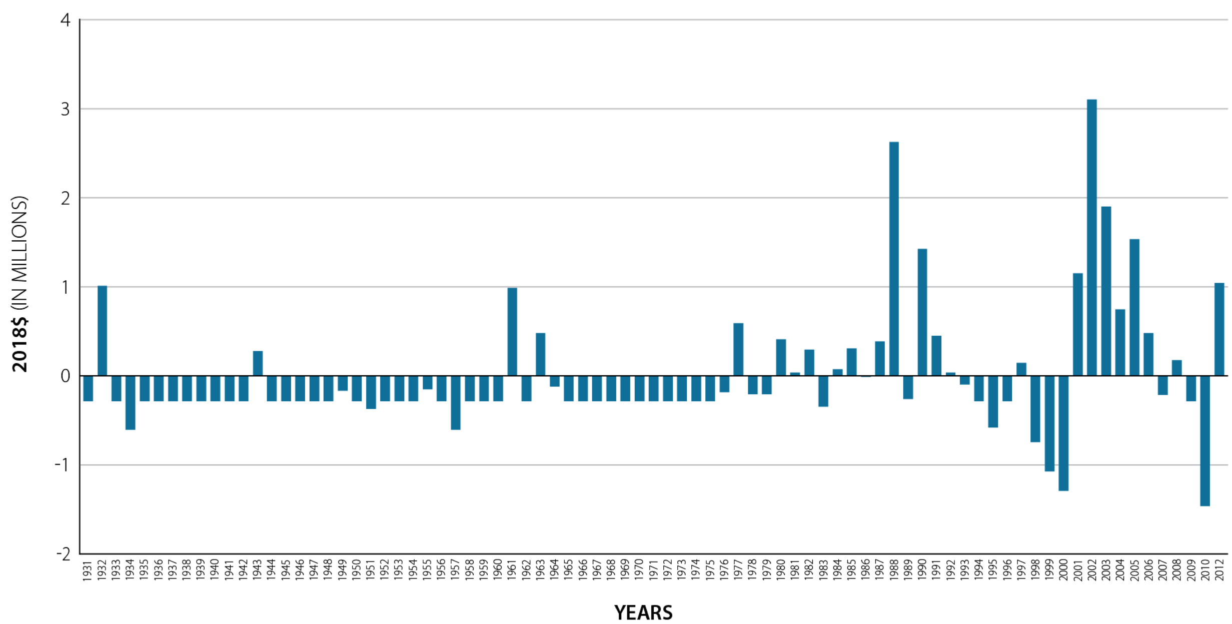
Note: The years 1931–1974 do not include impacts due to river water temperatures.

Figure 28. Alternative 3 Change in Thermal Power NED Values from Alternative 1 in the Upper and Lower River



Note: The years 1931–1974 do not include impacts due to river water temperatures.

Figure 29. Alternative 3 Change in Thermal Power NED Values from Alternative 1 in the Upper River



Note: The years 1931–1974 do not include impacts due to river temperatures.

Figure 30. Alternative 3 Change in Thermal Power NED Values from Alternative 1 in the Lower River

As modeled in the lower river, there would be very small increases in power generation under Alternative 3 compared to Alternative 1 for a number of power plants in a number of years due to slightly lower river water temperatures during relatively drier conditions (2001–2006) in the summer. During these summers as simulated in the HEC-RAS model, there would be no change in releases from Gavins Point Dam; the slight reduction in river water temperatures, (often less than 1°F) would result from slightly less early life history habitat created under Alternative 3 compared to Alternative 1. As simulated in 1999 and 2000, one power plant in the St. Louis area would be affected by relatively lower river flows leading to higher river water temperatures under Alternative 3 compared to Alternative 1. This would cause the power plant to shut down more intake pumps for the plant in these summers resulting in reduced generation relative to Alternative 1.

4.5 Alternative 4 – Spring ESH Creating Release

Alternative 4 includes a spring release in April and part of May to create ESH. Compared to Alternative 1, Alternative 4 includes fewer acres of IRC habitat construction compared to the acres of early life history habitat constructed under Alternative 1 in the lower river (3,380 acres under Alternative 4 and 3,999 acres under Alternative 1). Alternative 4 would result in adverse impacts in the lower and upper river, with an average annual decrease in thermal power NED values of $3.1 million and an average annual decrease in energy values of $2.2 million in all locations relative to Alternative 1 over the 37-year period of analysis. Under Alternative 4, the upper river would account for the majority (approximately 80 percent) of the adverse impact, driven by adverse impacts as simulated in a number of years. Dependable capacity would decrease slightly under Alternative 4 in the summer in the lower river, with annual increases in capacity replacement costs relative to Alternative 1. Variable costs for power plants in the upper river would be higher than the costs incurred under Alternative 1 with an average annual change of $91,551. Table 13 summarizes the NED impacts under Alternative 4.

Figure 31 shows the changes in annual thermal power NED values in upper and lower river. Additional results are shown in Figures 32 and 33. The difference in NED values between Alternative 1 and Alternative 4 are plotted and color-coded based on the type of release occurring each year. Figure 32 presents the annual results for the upper river, while Figure 33 presents the annual results for the lower river.

As modeled, there would not be a lot of changes in the NED impacts relative to Alternative 1 in most of the years over the POR in the upper river. Almost all the adverse impact to power plants in the upper river would occur in three years, 1994, 2007, and 2010 (as well as in the 1930s). In the upper river, the simulated full or partial releases in these years or in prior years would result in relatively lower flows in the late summer and fall in the Garrison reach, causing adverse impacts to power generation from river stages falling below shut down intake elevations more than under Alternative 1. Reductions in power generation relative to Alternative 1 were estimated to be 2.4 million MWh during the fall season in 1994 in the upper river. Four power plants would be affected by lower river flows as simulated in 1994 under Alternative 4 and Alternative 1, with two plants each incurring over $15 million in reduced energy values. The reductions in power generation relative to Alternative 1 would occur during off-peak months of September, October, and November, and therefore, there were very small adverse impacts to dependable capacity.

Table 13. Summary of Thermal Power NED Values for Alternative 4, 1975–2012 (2018$)

NED Values	Upper River [a]	Lower River	All Locations
Average Annual Missouri River Power Generation (MWh)	28,143,640	70,146,181	98,289,821
Change in Average Annual Generation from Alternative 1 (MWh)	−81,742	−16,080	−97,823
Average Annual Energy Values	$654,145,676	$1,632,585,801	$2,286,731,477
Difference in Average Annual Energy Values	−$1,879,148	−$317,575	−$2,196,723
Percent Change in Average Energy Values from Alternative 1	−0.3%	0.0%	−0.1%
Average Annual Dependable Capacity – Summer (MW)	2,887	7,312	10,199
Average Annual Dependable Capacity Value – Summer	$385,817,155	$977,220,505	$1,363,037,660
Average Annual Dependable Capacity – Winter (MW)[b]	2,970	8,924	11,894
Average Annual Dependable Capacity Value – Winter	$396,957,835	$1,192,648,235	$1,589,606,071
Max Change in Average Annual Capacity Value from Alternative 1	−$539,725	−$296,918	−$836,642
Average Annual Variable Costs[c]	−$400,311	$0	−$400,311
Change in Average Annual Variable Costs	−$91,551	$0	−$91,551
Average Annual NED Values[d]	$1,039,347,621	$2,602,914,220	$3,642,261,841
Change in Average Annual NED Values	−$2,510,423	−$614,493	−$3,124,916
Percent Change in Average Annual NED Values	−0.2%	0.0%	−0.1%

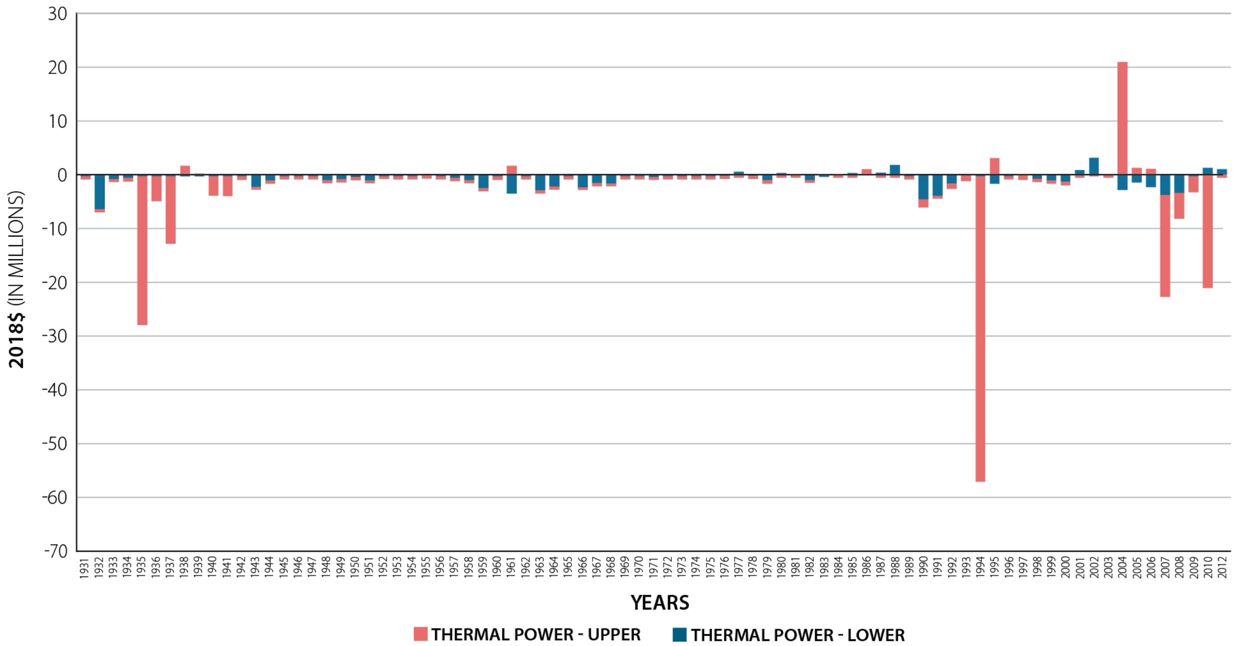
Notes:

a The upper river includes five power plants in the Garrison Dam to Lake Oahe river reach and one power plant in Lake Sakakawea, while the lower river includes all power plants below Gavins Point Dam.

b Capacity values are estimated by multiplying the 15th percentile of the available seasonal capacity during the summer and winter peak seasons from 1975 to 2012 by the unit capacity value. Capacity values represent an annualized capital cost to replace the estimated lost capacity; the unit capacity value was $133,650 /MW-year (Hydropower Analysis Center 2017).

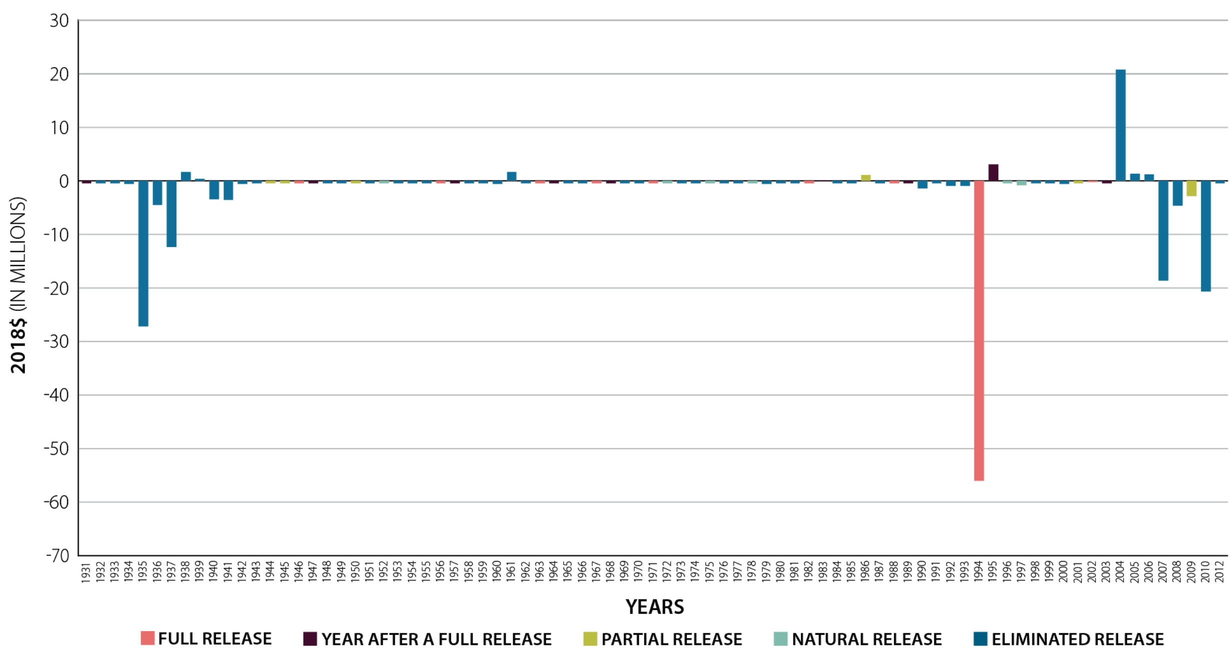
c Variable costs include operations and maintenance costs incurred under adverse conditions when power generation is not affected. In addition, the variable costs include losses in renewable energy credits for Minnesota Power when Minnkota Power Cooperative Missouri River intake is impacted during the summer.

d NED values for Alternative 1 include summer capacity figures because the bulk of the capacity impact occurs during the summer months. For Alternatives 2 through 6, either winter or summer dependable capacity is used to calculate the capacity value impacts depending on which season incurs the greater adverse impact for that particular alternative for that particular power plant.



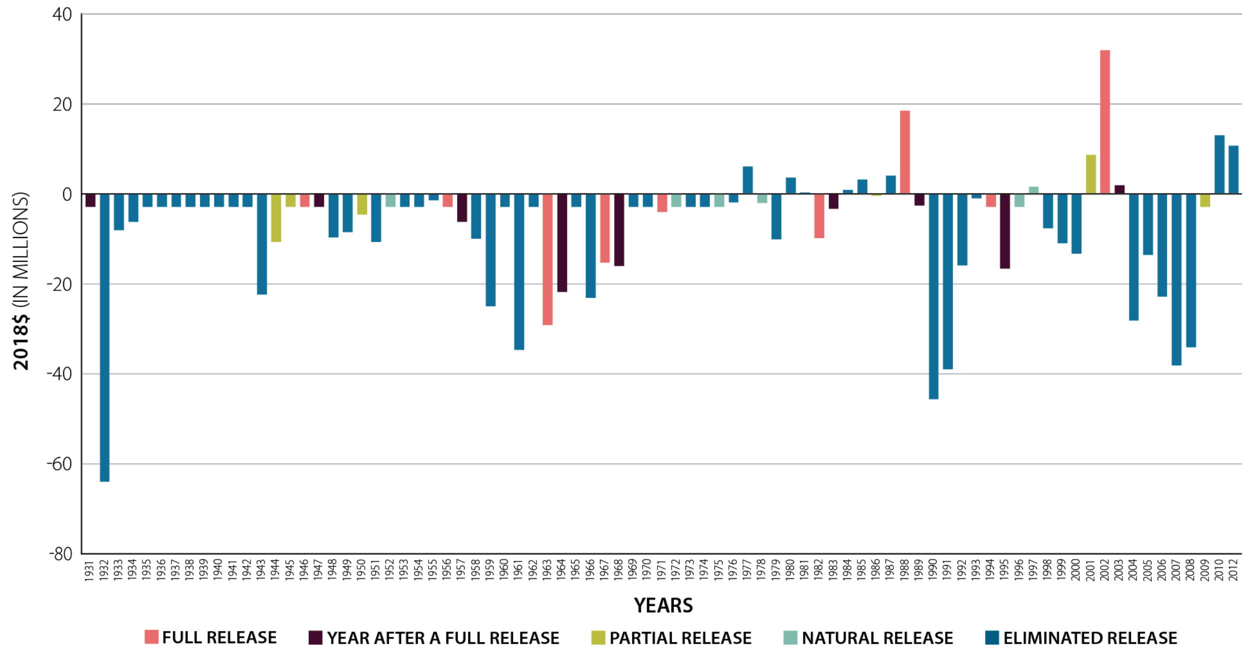
Note: The years 1931–1974 do not include impacts due to river water temperatures.

Figure 31. Alternative 4 Change in Thermal Power NED Values from Alternative 1 in the Upper and Lower River



Note: The years 1931–1974 do not include impacts due to river temperatures.

Figure 32. Alternative 4 Change in Thermal Power NED Values from Alternative 1 in the Upper River



Note: The years 1931–1974 do not include impacts due to river water temperatures.

Figure 33. Alternative 4 Change in Thermal Power NED Values from Alternative 1 in the Lower River

In the lower river, there would be years with increases and decreases in NED values relative to Alternative 1, with more years with adverse impacts to NED values over the POR. Adverse impacts would occur in a number of years between 1975 and 2012, as simulated in 1990, 1991, 2004, 2006, 2007, and 2008. Fully implemented spring releases would be simulated to occur in 1988 and 2002, which would reduce river flows in the subsequent years. One to five power plants would be affected with more days below shut down intake elevations than under Alternative 1 in the years following the release. In two of the modeled years when full releases would be simulated to occur (1988 and 2002), there would be slightly lower river water temperatures during the summer, with small increases in power generation for a number of power plants in the lower river.

4.6 Alternative 5 – Fall ESH Creating Release

Alternative 5 includes a fall release in October and November to create ESH. Alternative 5 includes fewer acres of IRC habitat compared to the acres of early life stage habitat constructed under Alternative 1 in the lower river. ESH construction would include an average of 253 aces per year, while Alternative 1 would result in an average of 164 per year in years when construction occurs.

Alternative 5 would result in average annual decrease in thermal power NED values compared to Alternative 1 of $1.0 million. The Missouri River power plants in the upper river would experience a decrease in average annual energy values of $305,000, while power plants in the lower river would experience an average annual increase of $180,855 when compared to energy values under Alternative 1 over the 37-year period of analysis. Alternative 5 would result in a decrease in average annual capacity values in the upper and lower river of $825,000, most of which is driven by power plants in the lower river. Variable costs for power plants in the upper river under Alternative 5 would be slightly higher than the costs incurred under Alternative 1. Table 14 summarizes the thermal power NED values.

Figure 34 shows the annual NED impacts to thermal power plants in upper and lower river. Additional results are shown in Figures 35 and 36. The difference in NED values between Alternative 1 and Alternative 5 are plotted and color-coded based on the type of release occurring each year. Figure 35 presents the annual results for the upper river, while Figure 36 presents the annual results for the lower river.

In the upper river over the POR, there are negligible changes in annual thermal power NED values in most years. However, in the simulated years of 1984 and 2005, there were adverse impacts in the upper river relative to Alternative 1. Within the model, two simulated years, 1984 and 2005, would account for decreases of $11 and $6 million in thermal power NED values, respectively, when river flows would be lower under Alternative 5 than under Alternative 1. Impacts in the year 1984 are driven by lower river flows in the spring and summer following a fall full release in 1983, as the reservoir System rebalances. Impacts in 2005 are driven by slightly lower river flows in the fall relative to Alternative 1.

In the lower river, power plants would experience years with both increases and decreases in thermal power NED values. As simulated in 1990, the Missouri River power plants would experience almost a $5 million decrease in thermal power NED values in the fall when river flows would be lower than under Alternative 1 as the reservoir System rebalances following the fall releases in 1987. In 1990, five power plants in the lower river would experience more days when river stages were below the shut down intake elevation. Similarly, in 1995, the lower river Missouri River power plants would experience over a $2 million decrease in thermal power NED values in the spring and fall when river flows would be lower than under Alternative 1 as the reservoir System rebalances following the fall release in 1994.

Table 14. Summary of Thermal Power NED Values for Alternative 5, 1975–2012 (2018$)

NED Values	Upper River [a]	Lower River	All Locations
Average Annual Missouri River Power Generation (MWh)	28,212,552	70,168,340	98,380,892
Change in Average Annual Generation from Alternative 1 (MWh)	−12,830	6,079	−6,752
Average Annual Energy Values	$655,719,721	$1,633,084,231	$2,288,803,952
Change in Average Annual Energy Values from Alternative 1	−$305,103	$180,855	−$124,248
Percent Change in Average Energy Values from Alternative 1	0.0%	0.0%	0.0%
Average Annual Dependable Capacity – Summer (MW)	2,889	7,309	10,198
Average Annual Dependable Capacity Value – Summer	$386,123,097	$976,787,709	$1,362,910,806
Average Annual Dependable Capacity – Winter (MW)[b]	2,969	8,924	11,893
Average Annual Dependable Capacity Value – Winter	$396,853,663	$1,192,648,235	$1,589,501,898
Max Change in Average Annual Capacity Value from Alternative 1	−$127,277	−$697,379	−$824,656
Average Annual Variable Costs[c]	−$366,700	$0	−$366,700
Change in Average Annual Variable Costs from Alternative 1	−$57,940	$0	−$57,940
Average Annual NED Values[d]	$1,041,367,724	$2,603,012,189	$3,644,379,913
Change in Average Annual NED Values from Alternative 1	−$490,320	−$516,524	−$1,006,844
Percent Change in Average Annual NED Values[d]	0.0%	0.0%	0.0%

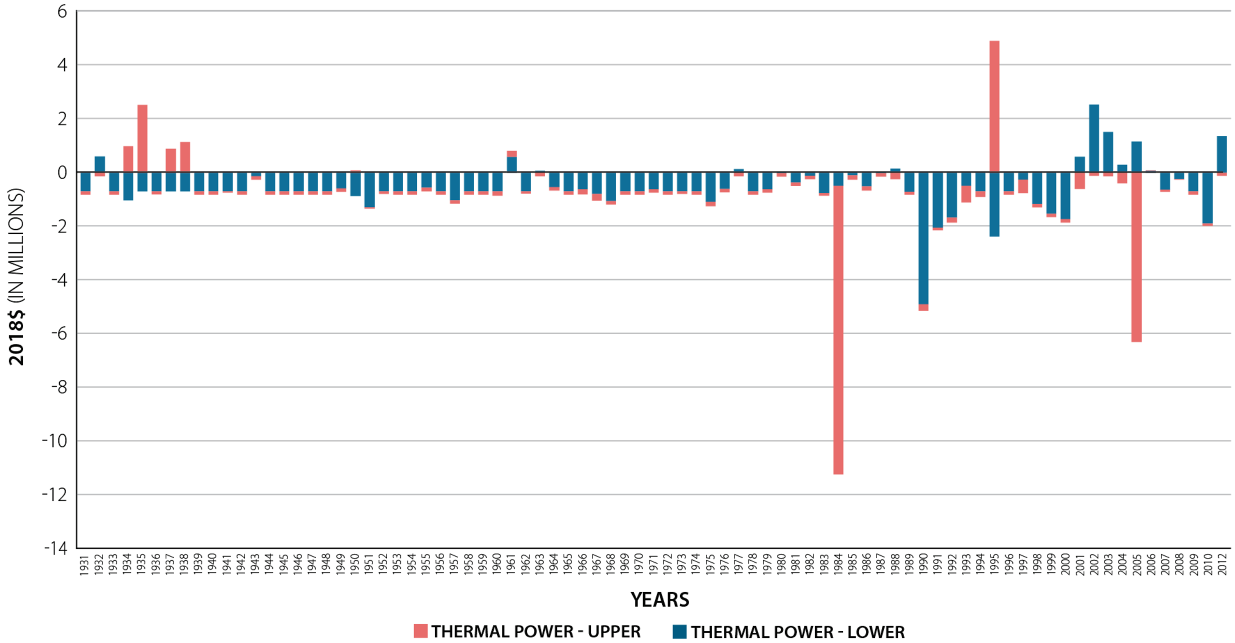
Notes:

a The upper river includes five power plants in the Garrison Dam to Lake Oahe river reach and one power plant in Lake Sakakawea, while the lower river includes all power plants below Gavins Point Dam.

b Capacity values are estimated by multiplying the 15th percentile of the available seasonal capacity during the summer and winter peak seasons from 1975 to 2012 by the unit capacity value. Capacity values represent an annualized capital cost to replace the estimated lost capacity; the unit capacity value was $133,650 /MW-year (Hydropower Analysis Center 2017).

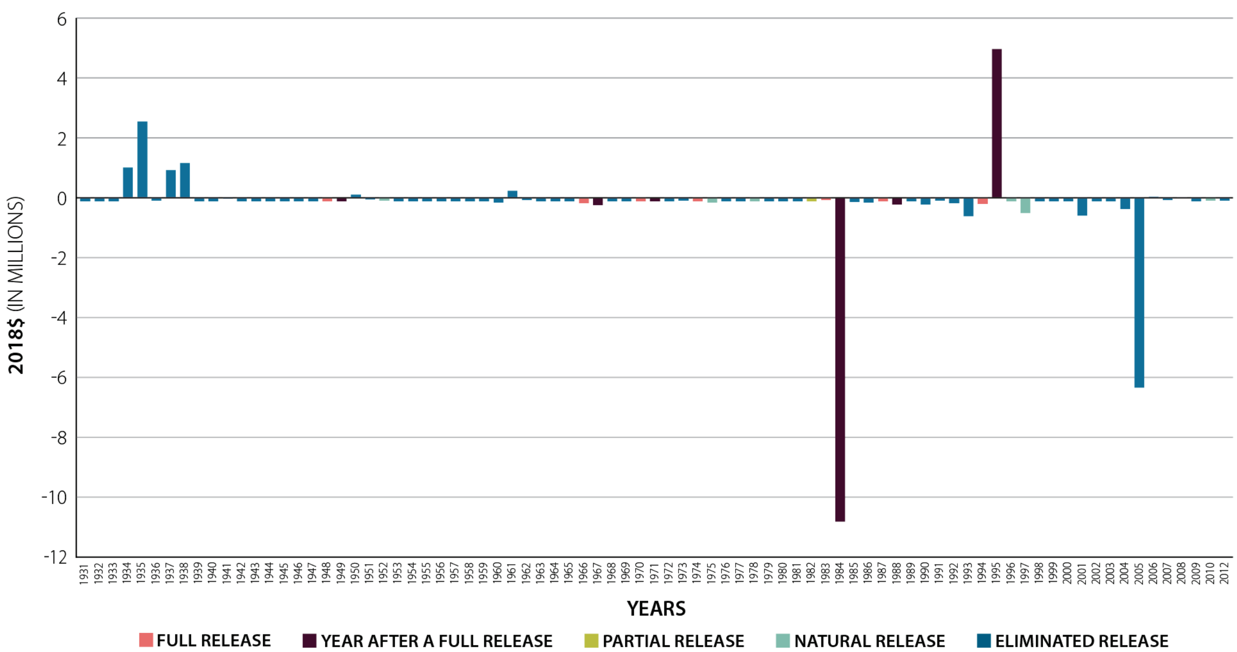
c Variable costs include operations and maintenance costs incurred under adverse conditions when power generation is not affected. In addition, the variable costs include losses in renewable energy credits for Minnesota Power when Minnkota Power Cooperative Missouri River intake is impacted during the summer.

d NED values for Alternative 1 include summer capacity figures because the bulk of the capacity impact occurs during the summer months. For Alternatives 2 through 6, either winter or summer dependable capacity is used to calculate the capacity value impacts depending on which season incurs the greater adverse impact for that particular alternative for that particular power plant.



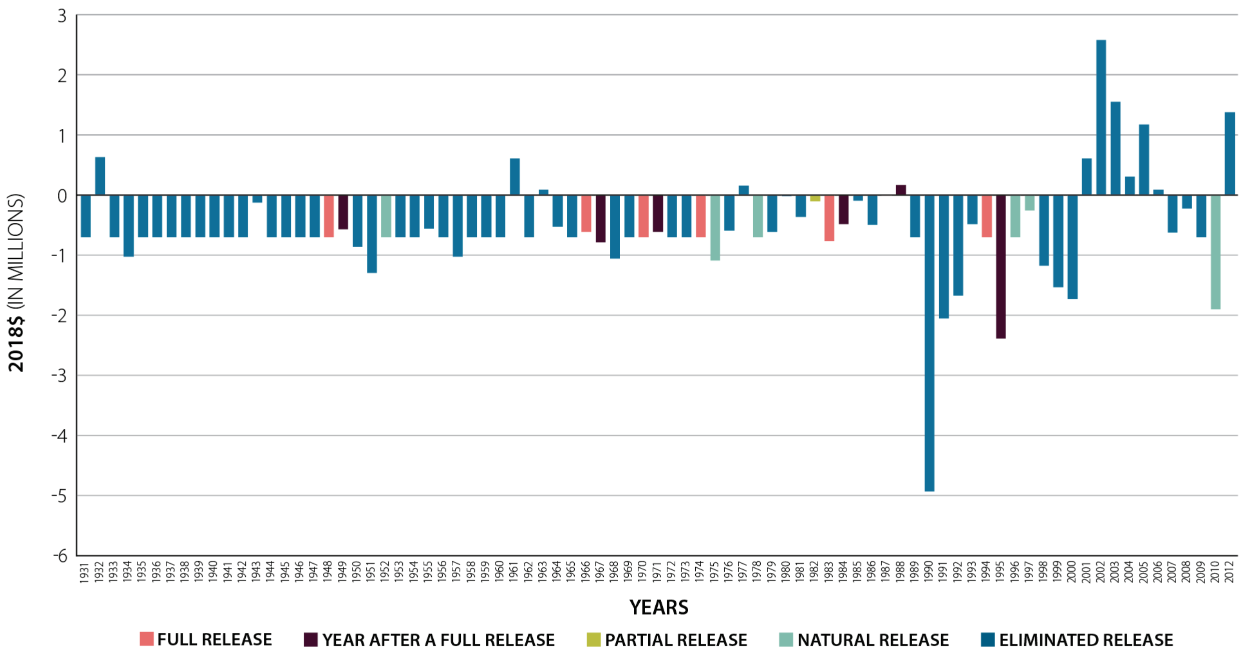
Note: The years 1931–1974 do not include impacts due to river temperatures.

Figure 34. Alternative 5 Change in Thermal Power NED Values from Alternative 1 in the Upper and Lower River



Note: The years 1931–1974 do not include impacts due to river water temperatures.

Figure 35. Alternative 5 Change in Thermal Power NED Values from Alternative 1 in the Upper River



Note: The years 1931–1974 do not include impacts due to river temperatures.

Figure 36. Alternative 5 Change in Thermal Power NED Values from Alternative 1 in the Lower River

4.7 Alternative 6 – Pallid Sturgeon Spawning Cue

Alternative 6 includes a bi-modal spawning cue in March and May to benefit the pallid sturgeon. Alternative 6 includes fewer acres of IRC habitat compared to the acres of early life history habitat constructed under Alternative 1 in the lower river (3,380 acres under Alternative 6 and 3,999 acres under Alternative 1). However, ESH construction would include an average of 245 aces per year, while Alternative 1 would result in an average of 164 per year in years when construction occurs. Alternative 6 results in reduced average annual thermal power NED values compared to Alternative 1, with an average annual decrease of $1.2 million over the 37-year period of analysis (Table 15). There would be relatively small adverse impacts to power plant generation and energy values under Alternative 6 due to small decreases in river flows in the fall and winter that adversely impact access for intake cooling water slightly decreasing power generation relative to Alternative 1.

Variable costs for power plants in the upper river would be slightly higher than the costs incurred under Alternative 1 though these changes would have negligible impacts on power plants. Capacity values under Alternative 6 would be adversely affected under Alternative 6, resulting in $480,772 in capacity replacement costs relative to Alternative 1, with most of the capacity affected in the power plants in the upper river. The adverse impacts to capacity would occur at three plants in the upper river in relatively drier years when the reservoir System is rebalancing in the year or two following a spawning cue release.

Figure 37 shows the annual NED impacts to thermal power plants in upper and lower river. Additional results are shown in Figures 38 and 39. The difference in NED values between

Alternative 1 and Alternative 6 are plotted and color-coded based on the type of release occurring each year. Figure 38 presents the annual results for the upper river, while Figure 39 presents the annual results for the lower river.

Table 15. Summary of Thermal Power NED Values for Alternative 6, 1975–2012 ($2018)

NED Values	Upper River [a]	Lower River	All Locations
Average Annual Missouri River Power Generation (MWh)	28,213,091	70,146,945	98,360,036
Change in Average Annual Generation from Alternative 1 (MWh)	−12,291	−15,317	−27,608
Average Annual Energy Values	$655,734,747	$1,632,590,316	$2,288,325,063
Change in Average Annual Energy Values from Alternative 1	−$290,077	−$313,060	−$603,137
Percent Change in Average Energy Values from Alternative 1	0.0%	0.0%	0.0%
Average Annual Dependable Capacity – Summer (MW)	2,887	7,314	10,202
Average Annual Dependable Capacity Value – Summer	$385,903,896	$977,575,698	$1,363,479,594
Average Annual Dependable Capacity – Winter (MW)[b]	2,970	8,924	11,894
Average Annual Dependable Capacity Value – Winter	$396,957,835	$1,192,648,235	$1,589,606,071
Max Change in Average Annual Capacity Value from Alternative 1	−$412,690	−$68,082	−$480,772
Average Annual Variable Costs[c]	−$470,375	$0	−$470,375
Change in Average Annual Variable Costs from Alternative 1	−$161,615	$0	−$161,615
Average Annual NED Values[d]	$1,040,993,662	$2,603,147,570	$3,644,141,233
Change in Average Annual NED Values from Alternative 1	−$864,382	−$381,143	−$1,245,525
Percent Change in Average Annual NED Values	−0.1%	0.0%	0.0%

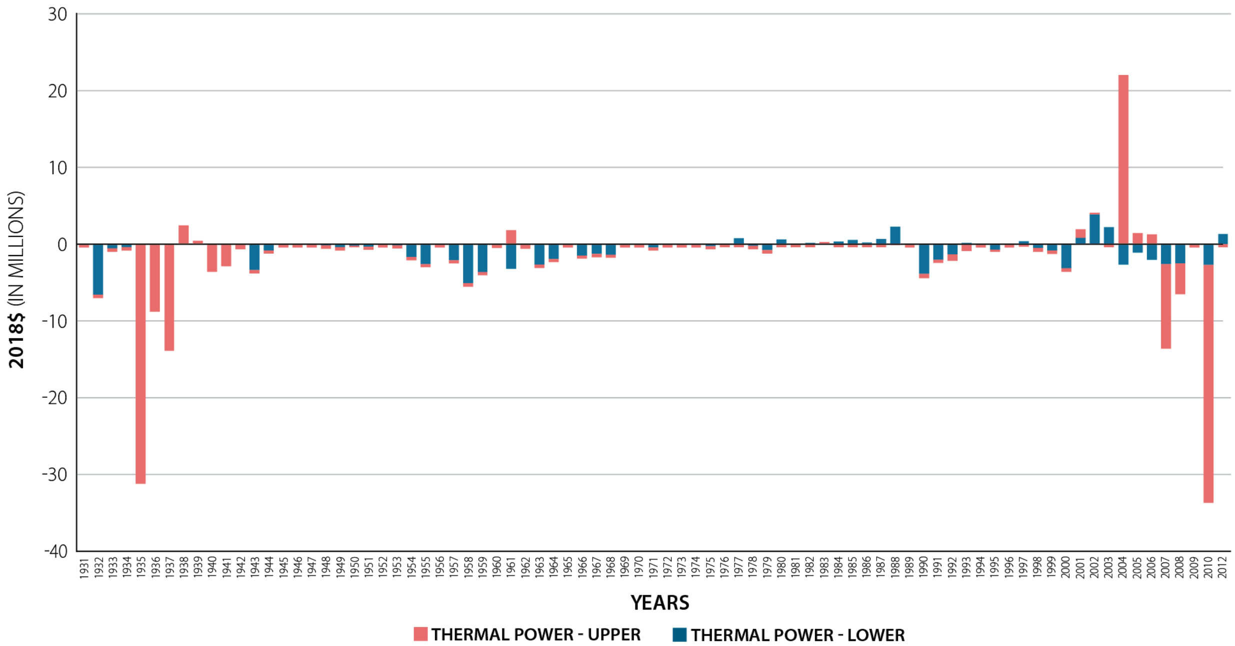
Notes:

a The upper river includes five power plants in the Garrison Dam to Lake Oahe river reach and one power plant in Lake Sakakawea, while the lower river includes all power plants below Gavins Point Dam.

b Capacity values are estimated by multiplying the 15th percentile of the available seasonal capacity during the summer and winter peak seasons from 1975 to 2012 by the unit capacity value. Capacity values represent an annualized capital cost to replace the estimated lost capacity; the unit capacity value was $133,650 /MW-year (Hydropower Analysis Center pers. comm. 2018).

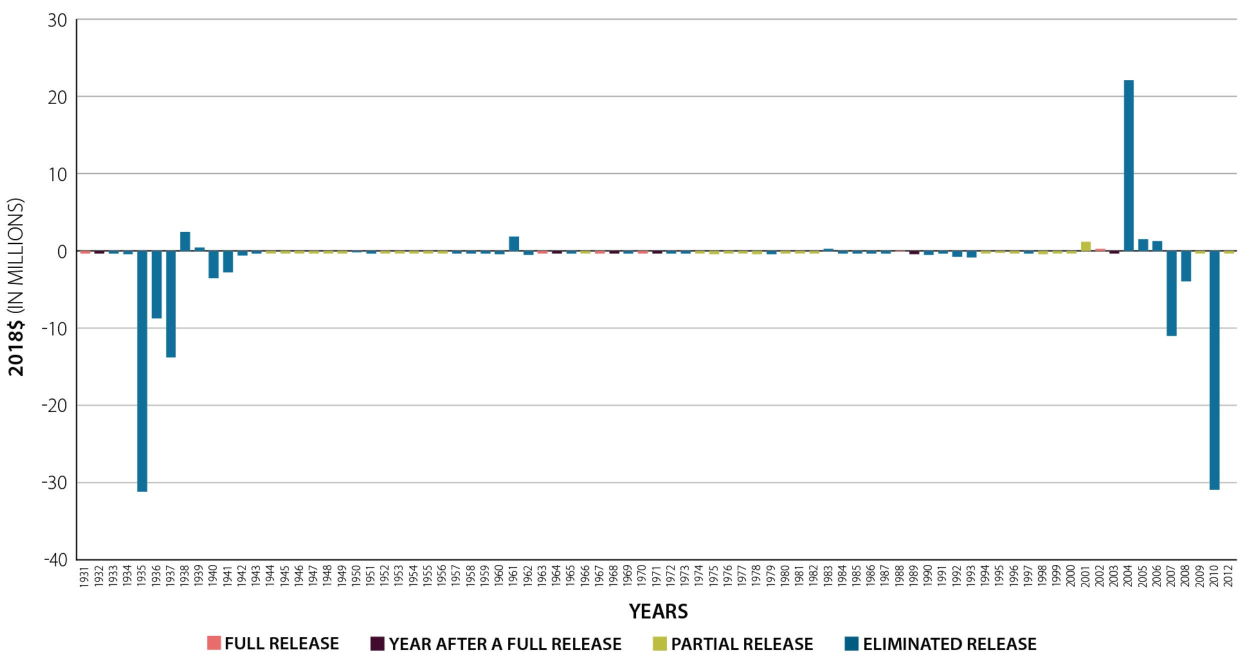
c Variable costs include operations and maintenance costs incurred under adverse conditions when power generation is not affected. In addition, the variable costs include losses in renewable energy credits for Minnesota Power when Minnkota Power Cooperative Missouri River intake is impacted during the summer.

d NED values for Alternative 1 include summer capacity figures because the bulk of the capacity impact occurs during the summer months. For Alternatives 2 through 6, either winter or summer dependable capacity is used to calculate the capacity value impacts depending on which season incurs the greater adverse impact for that particular alternative for that particular power plant.



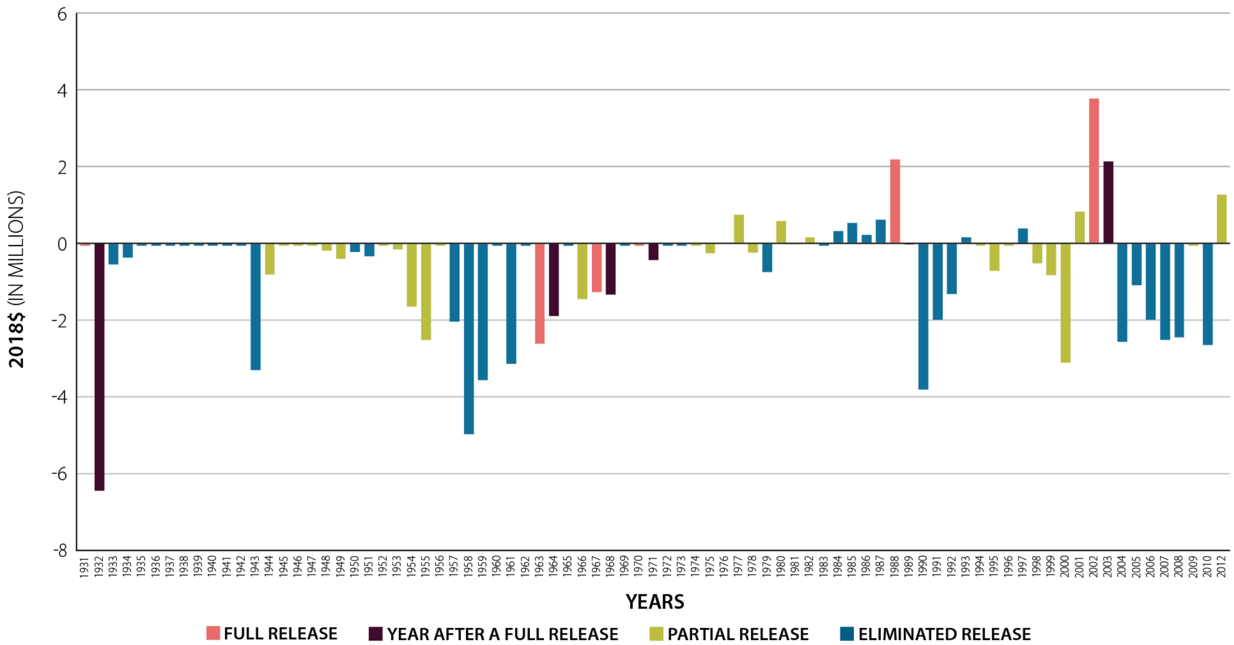
Note: The years 1931–1974 do not include impacts due to river water temperatures.

Figure 37. Alternative 6 Change in Thermal Power NED Values from Alternative 1 in the Upper and Lower River



Note: The years 1931–1974 do not include impacts due to river water temperatures.

Figure 38. Alternative 6 Change in Thermal Power NED Values from Alternative 1 in the Upper River



Note: The years 1931–1975 do not include impacts due to river water temperatures.

Figure 39. Alternative 6 Change in Thermal Power NED Values from Alternative 1 in the Lower River

As modeled in the upper river, there are four years with notable decreases in thermal power NED values relative to Alternative 1 over the 81-year POR with between $10 and $32 million in reduced thermal power NED values, as simulated in 1935, 1937, 2007, and 2010. A partial release in 1930 and a full spawning cue release in 1931 would cause lower reservoir elevations at Lake Sakakawea, with a higher number of days below shut down intake elevations at the power plant located on the reservoir. As simulated under Alternative 6, there would be partial spawning cue releases in 2000, 2001, and 2009, and full spawning cue release in 2002, which would reduce the river flows in the Garrison reach in 2007 and 2010, reducing river stages below shut down intake elevations at three power plants. In 2010, one power plant would also experience reduced power generation from relatively higher river water temperatures under Alternative 6 compared to Alternative 1. Conditions simulated in 2004 in the upper river would result in relatively higher thermal power NED values ($22 million) compared to Alternative 1 from relatively higher river flows in the Garrison reach as the reservoir System rebalances after the spawning cue releases.

In the lower river, there would be adverse impacts to power generation and energy values in quite a few years over the 81-year POR, with 16 years with more than $2 million in reduced thermal power NED values. The adverse impacts would be driven by relatively lower river flows in the fall and winter in the year or years following the spawning cue releases as the reservoir System rebalances. In 1932 and 1990 as simulated, five power plants in the lower river would have lower power generation and higher energy replacement costs than under Alternative 1 due to lower river stages affecting the ability to access water. In 1958 as simulated, two power plants would have lower power generation and higher energy replacement costs than under Alternative 1. As simulated in 1988 and 2002, there would be full implementation of the spawning cue release in March and May. During these releases, there would be small decreases in river water temperatures of about 1°F that would allow for increased power generation and energy values relative to Alternative 1; two to five power plants in the lower river would experience fewer days above 90°F.

5.0 Regional Economic Development Results

This section provides the results of the RED analysis. A summary of results across all alternatives is presented first followed by a detailed description of the results by alternative.

5.1 Summary Across Alternatives

The focus of the RED analysis for thermal power is on the potential of the MRRMP-EIS alternatives to impact wholesale energy prices and consumer electricity rates, which could have implications for household and business spending and regional economic conditions. Any changes in retail electricity rates could impact household and business spending, with implications for jobs and income in regional economies. If consumers must spend more of their income on higher electricity rates, they would have less disposable income to spend on other goods and services, which could adversely impact jobs and income in affected industries.

The NED results indicate that a number of plants would likely have to shut down or de-rate temporarily under all of the alternatives as a result of low flow or river stages or increased river water temperatures. As described in Section 2.5, wholesale electricity prices would be affected if low-cost power plant generation is reduced and more expensive sources need to come on line. When this occurs, the prices that retail electricity providers pay for electricity would temporarily increase because the next marginal energy producer would likely charge more per unit of energy produced. In addition, when reductions in power generation occur in the peak demand periods during adverse conditions (i.e., high river water temperature), the price increases are likely to be much higher than if the generation was reduced during off-peak times (i.e., fall and spring). In this situation, when capacity in the RTO is limited, some of the highest-cost resources would need to be brought online, potentially considerably increasing wholesale electricity prices. If the Missouri River thermal power plants must reduce power generation for a long period of time or on a re-occurring basis, the wholesale price that retail electrical providers pay for their electricity could increase, and the providers may then have the rationale to petition state utility commissions for an increase in consumer electricity rates.

Reductions in power generation under Alternative 2 relative to Alternative 1 would occur during low summer flow events (low summer flow events under Alternative 2 are simulated to occur in 1988, 1989, 2002 and 2003 during the 37-year period of analysis [1975–2012, excluding 2011]). Further analysis of the impacts to power generation during the summers of these years indicate that high river water temperatures tend to affect multiple plants simultaneously in the lower river in one or two periods within the summer season. During these periods, it is likely that wholesale electricity prices would increase, and potentially, with re-occurring low summer flow events under Alternative 2, there would be the potential for higher retail electricity prices in the long-term. Higher electricity rates under Alternative 2 would result in adverse impacts to household and business spending because with higher electricity rates, households and business would have less money to spend on personal or business expenses, with adverse impacts to regional economic conditions. Impacts under Alternatives 3, 4, 5, and 6 would result in negligible impacts to consumer electricity rates and regional economic conditions compared to Alternative 1 because any adverse impacts to power generation would be small compared to the all RTO generation and would occur primarily during the fall off-peak seasons, when replacement capacity is available in the RTO (SPP pers. comm. 2018).

5.2 Alternative 1 – No Action

Under Alternative 1, as modeled for years 1975 to 2012 (excluding 2011), there would be varying impacts to power generation. Lower power generation would occur as simulated in the mid-2000s when drought conditions would affect river flows and temperatures (Figure 23). This occurs when river water temperatures are relatively higher in the lower river in the summer. In the worst-case summer scenario, power generation from plants along the Missouri River in the SPP RTO would be 1,684,712 MWh lower than under typical power generation with no adverse impacts. This reduction in power generation represents a 22 percent decrease from the highest power generation summer season (available generation with no adverse conditions) and accounts for 3.6 percent of SPP generation during the summer season (Table 16). Within the MISO RTO, power generation from all power plants during the worst-case summer season would be reduced by 2,590,991 MWh, which is a reduction of 23 percent from the highest power generation summer season and accounts for 2.6 percent of MISO generation during the summer season. There would be only small changes in winter power generation under Alternative 1.

Table 16. Impacts to Power Generation by RTO and Season under Alternative 1, 1975–2012

Season	SPP	MISO
Lowest Power Generation Season (MWh)		
Winter	6,419,124 (2004)	10,667,282 (1994)
Summer	5,879,876 (1980)	8,689,583 (2003)
Highest Power Generation Season (MWh)		
Winter	6,603,508 (1979)	10,709,591 (1975)
Summer	7,564,048 (1992)	11,280,574 (1992)
Change and Percent Change in Power Generation from Highest Generation Season (MWh and %)		
Winter	184,384 (3%)	42,308 (0%)
Summer	1,684,172 (22%)	2,590,991 (23%)
Impacted Power Generation as a Percent of RTO Generation		
Winter	0.5%	0.04%
Summer	3.6%	2.6%

Source: SPP 2015, 2016; MISO 2014, 2016

Although drought conditions in the off-peak demand season over the POR would result in reductions in power generation from lower river flows and stages affecting access to water, replacement generation would likely be available and cost less than during peak seasons and would not affect the retail electricity rates. Therefore, reductions in power during these off-peak seasons would not likely contribute to higher consumer electricity rates.

In some years during drought conditions, it is possible that seasonal reductions in power generation could occur during at some point during peak power demand seasons, when replacement power from MISO, SPP or other markets may be scarce. In addition, these impacts could occur over multiple years during the POR, supporting rationale for retail electricity providers to increase consumer electricity rates compared to current rates because of the higher prices to purchase the wholesale electricity. As a result, there could be temporary reductions in power generation that could increase the price that retail electricity providers pay for wholesale electricity, which could cause providers to increase consumer electricity rates in the long term. The exact impact on electricity prices (wholesale prices) and consumer electricity rates are uncertain. If retail electricity rates increase in the long term, there may be impacts to household and business spending with higher rates as there would be less disposable income to spend on other goods and services in the community or region, causing adverse effects to local and regional economies.

5.3 Alternative 2 – USFWS 2003 Biological Opinion Projected Actions

Alternative 2 would result in the largest reductions in power generation compared to Alternative 1, which would be driven by changes in power generation from power plants in the lower river affected by low summer flow events and a higher prevalence of early life history habitat. In the worst-case year, as simulated in 1988, power generation for power plants in the SPP RTO would be reduced relative to Alternative 1 during the summer by 1.5 million MWh, representing a change of 3.2 percent of total generation in SPP during this summer period. Within the MISO RTO, the largest decrease in power generation during the summer months compared to Alternative 1 is estimated to be 3.7 million MWh, which represents 3.7 percent of total generation of the MISO RTO. Table 17 presents largest seasonal reduction in power generation relative to Alternative 1 as a percent of total generation for each RTO by peak season.

Table 17. Largest Season Reduction in Power Generation from Alternative 1 under Alternative 2, 1975–2012

Season	SPP	MISO
Largest Reduction in Power Generation Relative to Alternative 1 (MWh)		
Winter	−3,787 (2005)	−1,839 (1988)
Summer	−1,465,488 (1988)	−3,705,979 (1988)
Percent of Power Generation Reduction as a Percent of RTO Generation		
Winter	0.0%	0.0%
Summer	−3.2%	−3.7%

Source: SPP 2015, 2016; MISO 2014, 2016

Further analysis of the impacts to power generation during low summer flow events in 1988, 1989, 2002, and 2003 indicates that high river water temperatures tend to affect multiple plants simultaneously in the lower river in one or two periods within the summer season. During these low summer flow events, it is probable that there is capacity elsewhere on the grid to replace lost thermal power plant capacity (SPP pers. comm. 2018). In extreme conditions (with other extenuating circumstances), it is possible that local power providers would need to shed load to reduce power demand during these conditions, which could result in localized issues with maintaining voltage pressure and power outages (SPP pers. comm. 2018).

When multiple plants are affected by reduced power generation, wholesale electricity prices would increase, and potentially, with re-occurring low summer flow events under Alternative 2, there would be the potential for higher retail electricity prices in the long term (SPP pers. comm. 2016). Re-occurring higher wholesale electricity prices would provide the rationale for state regulating agencies to increase consumer electricity rates higher than under Alternative 1. The impacts to retail electricity rates under Alternative 2 relative to Alternatives 1 could be long term, relatively small to large, and adverse, although the exact impact on energy prices (wholesale prices) and consumer electricity rates is uncertain. Higher electricity rates under Alternative 2 would result in adverse impacts to household and business spending because with higher electricity rates, households and business would have less money to spend on personal or business expenses, with resulting impacts to regional economic conditions.

5.4 Alternative 3 – Mechanical Construction Only

Under Alternative 3, power generation would be very similar to Alternative 1. Under the worst-case summer season, there would be a negligible change from Alternative 1 (Table 18), resulting in no change to wholesale electricity rates, consumer electricity rates and household spending and associated regional economic conditions compared to Alternative 1.

Table 18. Largest Season Reduction in Power Generation from Alternative 1 under Alternative 3, 1975–2012

Season	SPP	MISO
Largest Reduction in Power Generation Relative to Alternative 1 (MWh)		
Winter	0 (1975)	0 (1975)
Summer	−7,491 (2010)	−39,343 (2010)
Percent of Power Generation Reduction as a Percent of RTO Generation		
Winter	0.0%	0.0%
Summer	0.0%	0.0%

Source: SPP 2015, 2016; MISO 2014, 2016

5.5 Alternative 4 – Spring ESH Creating Release

There would be slight adverse impacts to power generation under Alternative 4 in the lower river and upper river compared to Alternative 1. Within the SPP RTO, power generation would be slightly lower in the summer and have no losses in the winter under the worst-case change from Alternative 1 (Table 19). Impacts to power generation in the summer season under Alternative 4 within the MISO RTO would be small relative to the total MISO power generation, 0.2 percent, with the bulk of the power generation impacts occurring during non-peak periods. There would be negligible change in power generation during the winter season. Because peak season summer power generation would have only slight adverse impacts under Alternative 4, there would not be noticeable changes in wholesale electricity prices, consumer electricity rates, household spending and associated regional economic conditions compared to Alternative 1.

Table 19. Largest Season Reduction in Power Generation from Alternative 1 under Alternative 4, 1975–2012

Season	SPP	MISO
Largest Reduction in Power Generation under the MRRMP-EIS Alternative Relative to Alternative 1 (MWh)		
Winter	0 (1975)	−20,234 (1993)
Summer	−23,767 (1982)	−225,581 (2010)
Percent of Power Generation Reduction as a Percent of RTO Generation		
Winter	0.0%	0.0%
Summer	−0.1%	−0.2%

Source: SPP 2015, 2016; MISO 2014, 2016

5.6 Alternative 5 – Fall ESH Creating Release

Impacts to power generation during peak seasons within the SPP and MISO RTOs would be very similar to those described under Alternative 4 (Table 20). Similar to Alternative 4, the potential impacts to consumer electricity rates associated with higher wholesale electricity prices would be long-term and adverse relative to current prices, although the exact impact on electricity prices (wholesale prices) are uncertain. There would be a negligible change in the impacts to consumer electricity rates and household spending and associated regional economic conditions compared to Alternative 1.

Table 20. Largest Season Reduction in Power Generation from Alternative 1 under Alternative 5, 1975–2012

Season	SPP	MISO
Largest Reduction in Power Generation under the MRRMP-EIS Alternative Relative to Alternative 1 (MWh)		
Winter	0 (1975)	−20,234 (1993)
Summer	−16,051 (1975)	−184,440 (1984)
Percent of Power Generation Reduction as a Percent of RTO Generation		
Winter	0.0%	0.0%
Summer	0.0%	−0.2%

Source: SPP 2015, 2016; MISO 2014, 2016

5.7 Alternative 6 – Pallid Sturgeon Spawning Cue

Reductions in power generation under the worst-case summer season under Alternative 6 would represent a very small percent of SPP and MISO generation, 0.2 and 0.4 percent, respectively (Table 21). Impacts to power generation in the summer under Alternative 6 within the MISO RTO would be small relative to the total MISO power generation, with the bulk of the power generation impacts occurring during non-peak periods. Because peak summer season power generation would have only slight adverse impacts under Alternative 6, there would not be noticeable changes in wholesale electricity prices, consumer electricity rates, household spending and associated regional economic conditions compared to Alternative 1.

Table 21. Largest Season Reduction in Power Generation from Alternative 1 under Alternative 6, 1975–2012

Season	SPP	MISO
Largest Reduction in Power Generation under the MRRMP-EIS Alternative Relative to Alternative 1 (MWh)		
Winter	−6,407 (1975)	−20,234 (1993)
Summer	−81,595 (2010)	−425,586 (2010)
Percent of Power Generation Reduction as a Percent of the RTO's Generation		
Winter	0.0%	0.0%
Summer	−0.2%	−0.4%

Source: SPP 2015, 2016; MISO 2014, 2016

6.0 Other Social Effects Results

The OSE analysis for thermal power relied on the results of the NED analysis to show how changes to thermal power generation could impact air emissions. In addition to the air emissions results presented in this section, Section 3.17 of the Final EIS provides a qualitative assessment of possible impacts to electricity reliability.

6.1 Summary Across Alternatives

A summary of OSE Impacts for the MRRMP-EIS alternatives is summarized in Table 22. Alternative 2 would result in increases in air emissions and associated social costs of carbon, while Alternatives 3 through 6 would result in decreased air emissions and social costs. When comparing the Missouri River coal-fired power plant-specific emission factors with the market replacement emissions factors, the Missouri River plants have higher emissions rates for carbon dioxide, while the eGrid market replacement power generation has lower per unit air emissions rates for methane and nitrous oxide. When coal-fired power plants along the Missouri River have to reduce power, they are replaced with energy sources that have, on average, lower carbon dioxide emissions and higher methane and nitrous oxide emissions. Reducing power generation from the two nuclear plants would increase all air emissions.

Table 22. Average Annual Changes in Emissions and Social Cost of Carbon, 1975–2012

Alternative	Carbon Dioxide (lbs)	Methane (lbs)	Nitrous Oxide (lbs)	Carbon Dioxide Equivalent (metric tons)	Social Cost of Carbon (2018$) ($48–$253/metric ton)
Alternative 2 Difference from Alternative 1	15,411,804	−3,501	−102	6,939	$340,000 to $1,803,000
Alternative 3 Difference from Alternative 1	−5,861,079	415	−117	−2,670	−$131,000 to −$694,000
Alternative 4 Difference from Alternative 1	−113,835,363	321	−1,964	−51,911	−$2,544,000 to −$13,485,000
Alternative 5 Difference from Alternative 1	−18,924,703	358	−340	−8,628	−$423,000 to −$2,241,000
Alternative 6 Difference from Alternative 1	−33,970,013	4,288	−580	−15,443	−$757,000 to −$4,011,000

Note: Negative costs are cost savings or social benefits while positive values represent increases in social costs (adverse impacts) relative to no action.

Under Alternative 2, air emissions would increase for carbon dioxide and decrease for methane and nitrous oxide. The increase in carbon dioxide is likely due to reductions in power generation from relatively clean Missouri River nuclear power plants under this alternative, and replacement power generation would produce comparatively more carbon dioxide per unit of replacement energy. Additionally, decreases in methane and nitrous oxide air emissions under Alternative 2 would be driven by reductions in power generation from Missouri River coal-fired power plants with relatively higher methane and nitrous oxide emissions being replaced with lower per unit air emission sources from the market. Alternative 2 would result in the largest increase in carbon dioxide equivalent emissions amongst the action alternatives, with a 0.009

percent increase relative to No Action, which is considered to be a negligible change in air emissions.

Under Alternatives 3 through 6, there would be average annual decreases in both carbon dioxide and nitrous oxide emissions and an increase in methane emissions relative to the Alternative 1. Many of the coal fired power plants under analysis have methane emission factors that are lower than the unit emission factors for methane of replacement energy generation in their respective regions. When these power plants reduce generation under Alternatives 4, 5, and 6, it is replaced regionally by sources in the market that would produce relatively higher methane air emissions. Average annual reductions in carbon dioxide and nitrous oxide, especially under Alternative 4 would occur from relatively cleaner replacement energy when Missouri River coal-fired power plants would need to reduce power generation. The largest decrease in carbon dioxide equivalent emissions amongst Alternatives 3 through 6, would be a decrease of 0.068 percent relative to No Action, which would occur under Alternative 4.

6.2 Alternative 1 – No Action (Current System Operations and MRRP Management Actions)

Changes in thermal power plant generation have the potential to affect air emissions. The power plants along the Missouri River use coal and nuclear fuel sources. In general, the coal-fired power plants emit more carbon dioxide and nitrous oxide emissions per MWH than the average replacement power sources from the market. Plant-specific methane emission sources are both higher and lower than the average replacement power sources from the market. Under Alternative 1, the Missouri River power plants would generate 167 billion pounds of carbon dioxide, 14.7 million pounds of methane, and 2.8 million pounds of nitrous oxide on average annually.

The SCC evaluation discussed in the methodology section is intended to estimate the social costs of air emissions under Alternative 1. The average annual SCC under Alternative 1 is estimated to be between $3.6 billion in 2018 and $10.6 billion in 2050 under the 95th percentile worst case scenario.

6.3 Alternative 2 – USFWS 2003 Biological Opinion Projected Actions

Under Alternative 2, average annual carbon dioxide emissions relative to Alternative 1 would increase, as the reduced power generation primarily from the Missouri River nuclear plants would be replaced by the regional power mix with thermal power sources that produce more carbon dioxide emissions than those that are being replaced. There would be small average annual reduction in methane and nitrous oxide emissions compared to Alternative 1 from reductions in power generation from Missouri River coal-fired power plants which have relatively higher methane and nitrous oxide emission rates than those generation sources in the market that would replace the reductions in power generation. One plant in particular that would have its generation replaced by the RTO produces more carbon dioxide but less methane and nitrous oxide than the RTO replacement power generation on average, which would result in higher methane and nitrous oxide emissions and lower carbon dioxide emissions as a result of other RTO plants replacing energy generation at this plant. However, on average for all plants methane and nitrous oxide emissions would decrease and carbon dioxide emissions would increase as the replacement sources for the Missouri River power plant generation would have higher carbon dioxide, and lower methane and nitrous oxide emissions across all power plants. The average annual SCC under Alternative 2 would increase between $340,000 and $1.8 million compared to Alternative 1. Table 23 summarizes the emissions and SCC impacts relative to Alternative 1.

Table 23. Average Annual Change in Air Emissions and Social Costs under Alternative 2, 1975–2012 (2018$)

OSE Indicator	Emissions or Costs
Average Annual Change in Carbon Dioxide Relative to Alternative 1 (lbs and % Change from No Action)	15,411,804 (0.009%)
Average Annual Change in Methane Relative to Alternative 1 (lbs and % Change from No Action)	−3,501 (−0.024%)
Average Annual Change in Nitrous Oxide Relative to Alternative 1 (lbs and % Change from No Action)	−102 (−0.004%)
Average Annual Change in Carbon Dioxide Equivalent Relative to Alternative 1 (metric tons and % Change from No Action)	6,939 (0.009%)
Average Annual Change in the Social Cost of Carbon – 2018 Average ($48/ton)	$340,000
Average Annual Change in the Social Cost of Carbon – 2035 Average ($66/ton)	$468,000
Average Annual Change in the Social Cost of Carbon – 2050 Average ($82/ton)	$587,000
Average Annual Change in the Social Cost of Carbon – 2018 95th percentile ($138/ton)	$986,000
Average Annual Change in the Social Cost of Carbon – 2035 95th percentile ($200/ton)	$1,428,000
Average Annual Change in the Social Cost of Carbon – 2050 95th percentile ($253/ton)	$1,803,000

Note: Negative costs are cost savings or social benefits while positive values represent increases in social costs. Percentage values show change relative to no action.

6.4 Alternative 3 – Mechanical Construction Only

On average there would be slight increases in power generation under Alternative 3 compared to Alternative 1. Higher power generation from Missouri River power plants on average under this alternative would reduce carbon dioxide and nitrous oxide emissions and increase methane emissions relative to Alternative 1. Slightly higher power generation by nuclear plants drives the overall decrease in carbon dioxide and nitrous oxide emissions; however, this generation would not be enough to offset the relative increase in methane emissions from other coal-fired thermal power plants that would also experience increases in power generation relative to Alternative 1 and produce more methane per MWh than the RTO on average, resulting in a net increase in methane emissions under this alternative. There would be decreased SCC under Alternative 3 (benefits), ranging from $131,000 and $694,000, relative to Alternative 1. Table 24 summarizes the changes in average annual air emissions and SCC compared to Alternative 1.

Table 24. Average Annual Change in Emissions and Social Costs under Alternative 3, 1975–2012 (2018$)

OSE Indicator	Emissions or Costs
Average Annual Change in Carbon Dioxide Relative to Alternative 1 (lbs and % Change from No Action)	−5,861,079 (−0.003%)
Average Annual Change in Methane Relative to Alternative 1 (lbs and % Change from No Action)	415 (0.003%)
Average Annual Change in Nitrous Oxide Relative to Alternative 1 (lbs and % Change from No Action)	−117 (−0.004%)
Average Annual Change in Carbon Dioxide Equivalent Relative to Alternative 1 (metric tons and % Change from No Action)	−2,670 (−0.003%)
Average Annual Change in the Social Cost of Carbon – 2018 Average ($48/ton)	−$131,000
Average Annual Change in the Social Cost of Carbon – 2035 Average ($66/ton)	−$180,000
Average Annual Change in the Social Cost of Carbon – 2050 Average ($82/ton)	−$226,000
Average Annual Change in the Social Cost of Carbon – 2018 95th percentile ($138/ton)	−$380,000
Average Annual Change in the Social Cost of Carbon – 2035 95th percentile ($200/ton)	−$550,000
Average Annual Change in the Social Cost of Carbon – 2050 95th percentile ($253/ton)	−$694,000

Note: Negative costs are cost savings or social benefits while positive values represent increases in social costs.

6.5 Alternative 4 – Spring ESH Creating Release

Under Alternative 4, average annual carbon dioxide and nitrous oxide emissions would decrease relative to Alternative 1, as slightly higher power generation by nuclear plants would drive the overall decrease in carbon dioxide and nitrous oxide emissions. The power generation by the nuclear plants would not be enough to offset the relative increase in methane emissions from other coal-fired thermal power plants that would experience small average annual increases in power generation relative to Alternative 1. There would be some coal-fired power plants that would experience small reductions in average annual power generation relative to Alternative 1, but the changes in air emissions would not be enough to offset increases in air emissions from other plants experiencing higher average annual power generation. There would be decreased average annual SCC under Alternative 4 (benefits), ranging from $2.5 million to $13.5 million, compared to Alternative 1. Table 25 summarizes the changes in air emissions and SCC associated with average annual changes in power generation compared to Alternative 1.

Table 25. Average Annual Change in Emissions and Social Costs under Alternative 4, 1975–2012 (2018$)

OSE Indicator	Emissions or Costs
Average Annual Change in Carbon Dioxide Relative to Alternative 1 (lbs and % Change from No Action)	−113,835,363 (−0.068%)
Average Annual Change in Methane Relative to Alternative 1 (lbs and % Change from No Action)	321 (0.002%)
Average Annual Change in Nitrous Oxide Relative to Alternative 1 (lbs and % Change from No Action)	−1,964 (−0.069%)
Average Annual Change in Carbon Dioxide Equivalent Relative to Alternative 1 (metric tons and % Change from No Action)	−51,911 (−0.068%)
Average Annual Change in the Social Cost of Carbon – 2018 Average ($48/ton)	−$2,544,000
Average Annual Change in the Social Cost of Carbon – 2035 Average ($66/ton)	−$3,498,000
Average Annual Change in the Social Cost of Carbon – 2050 Average ($82/ton)	−$4,389,000
Average Annual Change in the Social Cost of Carbon – 2018 95th percentile ($138/ton)	−$7,378,000
Average Annual Change in the Social Cost of Carbon – 2035 95th percentile ($200/ton)	−$10,686,000
Average Annual Change in the Social Cost of Carbon – 2050 95th percentile ($253/ton)	−$13,485,000

Note: Negative costs are cost savings or social benefits while positive values represent increases in social costs.

6.6 Alternative 5 – Fall ESH Creating Release

Under Alternative 5, average annual carbon dioxide and nitrous oxide emissions would decrease and methane emissions would increase relative to Alternative 1, as slightly higher power generation by nuclear plants would drive the overall decrease in carbon dioxide and nitrous oxide emissions, but would not be enough to offset the relative increase in methane emissions from other coal-fired thermal power plants that would also experience a slight increase in power generation relative to Alternative 1. There would be some coal-fired power plants that would experience reductions in average annual power generation; however, the changes in air emissions would not be enough to offset the increased methane emissions from power plants that would experience slight increases in power generation. There would be decreased average annual SCC under Alternative 5 (benefits), ranging from $423,000 to $2.2 million, compared to Alternative 1. Table 26 summarizes the changes in air emissions and social cost of carbon associated with average annual changes in power generation compared to Alternative 1.

Table 26. Average Annual Change in Emissions and Social Costs under Alternative 5, 1975–2012 (2018$)

OSE Indicator	Emissions or Costs
Average Annual Change in Carbon Dioxide Relative to Alternative 1 (lbs and % Change from No Action)	−18,924,703 (−0.011%)
Average Annual Change in Methane Relative to Alternative 1 (lbs and % Change from No Action)	358 (0.002%)
Average Annual Change in Nitrous Oxide Relative to Alternative 1 (lbs and % Change from No Action)	−340 (−0.012%)
Average Annual Change in Carbon Dioxide Equivalent Relative to Alternative 1 (metric tons and % Change from No Action)	−8,628 (−0.011%)
Average Annual Change in the Social Cost of Carbon – 2018 Average ($48/ton)	−$423,000
Average Annual Change in the Social Cost of Carbon – 2035 Average ($66/ton)	−$581,000
Average Annual Change in the Social Cost of Carbon – 2050 Average ($82/ton)	−$729,000
Average Annual Change in the Social Cost of Carbon – 2018 95th percentile ($138/ton)	−$1,226,000
Average Annual Change in the Social Cost of Carbon – 2035 95th percentile ($200/ton)	−$1,776,000
Average Annual Change in the Social Cost of Carbon – 2050 95th percentile ($253/ton)	−$2,241,000

Note: Negative costs are cost savings or social benefits while positive values represent increases in social costs.

6.7 Alternative 6 – Pallid Sturgeon Spawning Cue

Under Alternative 6, average annual carbon dioxide and nitrous oxide emissions would decrease and methane emissions would increase relative to Alternative 1. Slightly lower power generation would occur for a number of power plants compared to Alternative 1, and replacement power sources would be cleaner in terms of carbon dioxide and nitrous oxide emissions, with reductions in these air emissions. However, replacement power sources would have higher methane emissions, with a small increase I methane air emissions. There would be some nuclear power plants that would experience slight increases in average annual power generation under Alternate 6 relative to Alternative 1, which would contribute to decreases in carbon dioxide and nitrous oxide emissions. However, the relative decreases in methane emissions from the nuclear plants would not be enough to offset the increased methane emissions from decreased power generation from Missouri River plants with replacement sources with higher methane emissions. There would be decreased average annual SCC under Alternative 6 (benefits), ranging from $757,000 to $4.0 million, compared to Alternative 1. Table 27 summarizes the changes in air emissions and social cost of carbon associated with average annual changes in power generation compared to Alternative 1.

Table 27. Average Annual Change in Emissions and Social Costs under Alternative 6, 1975–2012 (2018$)

OSE Indicator	Emissions or Costs
Average Annual Change in Carbon Dioxide Relative to Alternative 1 (lbs and % Change from No Action)	−33,970,013 (−0.020%)
Average Annual Change in Methane Relative to Alternative 1 (lbs and % Change from No Action)	4,288 (0.029%)
Average Annual Change in Nitrous Oxide Relative to Alternative 1 (lbs and % Change from No Action)	−580 (−0.020%)
Average Annual Change in Carbon Dioxide Equivalent Relative to Alternative 1 (metric tons and % Change from No Action)	−15,443 (−0.020%)
Average Annual Change in the Social Cost of Carbon – 2018 Average ($48/ton)	−$757,000
Average Annual Change in the Social Cost of Carbon – 2035 Average ($66/ton)	−$1,041,000
Average Annual Change in the Social Cost of Carbon – 2050 Average ($82/ton)	−$1,306,000
Average Annual Change in the Social Cost of Carbon – 2018 95th percentile ($138/ton)	−$2,195,000
Average Annual Change in the Social Cost of Carbon – 2035 95th percentile ($200/ton)	−$3,179,000
Average Annual Change in the Social Cost of Carbon – 2050 95th percentile ($253/ton)	−$4,011,000

Note: Negative costs are cost savings or social benefits while positive values represent increases in social costs.

7.0 Coupled Effects from Changes in Power Generation from Thermal Power and Hydropower Plants

If both hydropower and thermal power generation are affected during peak periods, there is a potential for coupled effects from reductions in both hydropower and thermal power plants. Simultaneous reductions in power generation, especially during peak seasons in the summer and winter, can exacerbate (i.e., increase) the adverse impacts to wholesale power prices and potentially retail electricity rates, electricity reliability, and regional economic conditions. Power generation estimates for both hydropower and thermal power were compared for each peak season (for every year) over the 37-year period (1975–2012 not including 2011) to evaluate the potential for coupled effects. The reductions in power generation relative to Alternative 1 were compared with the seasonal RTO generation. Table 28 summarizes seasonal power generation in both the SPP and MISO RTOs for each season. This data was averaged over two years of daily generation data from MISO and SPP (SPP 2015, 2016; MISO 2014, 2016).

Table 28. Average Power Generation by Season by RTO (MWh)

RTO	Winter	Spring	Summer	Fall
SPP	39,413,563	72,741,917	46,449,282	76,502,318
MISO	96,712,399	174,673,962	100,952,513	180,806,500
Total	136,125,962	247,415,879	147,401,794	257,308,818

Source: SPP 2015, 2016; MISO 2014, 2016

7.1 Summary Across Alternatives

All alternatives show some years when both hydropower and thermal power generation would be reduced relative to Alternative 1. Under Alternative 2, coupled effects could potentially occur during summer months when low summer flow events would occur, causing the greatest potential for adverse impacts. Although Alternatives 3 through 6 would result in coupled effects during some years when both hydropower and thermal power generation is reduced compared to Alternative 1, the power generation affected as a percent of MISO and SPP generation is very small and the reductions typically occur in non-peak power demand seasons. Under these conditions, there would be replacement capacity within SPP and MISO, and therefore, there would be minimal adverse impacts to wholesale power prices, electricity rates, grid stability, and regional economic conditions.

7.2 Alternative 1 – No Action

Under Alternative 1, seasonal power generation by year from both hydropower and thermal power plants along the Missouri River account for between 12 and 14 percent of seasonal power generation in the MISO and SPP RTOs (Table 29). During drought conditions, power generation under Alternative 1 would be a relatively lower percentage, especially in the summer season, from reduced power generation from both hydropower and thermal power plants. Compared to a high of 14.9 percent of MISO and SPP summer power generation (summer of 1975), drought conditions can cause the contribution of power generation from hydropower and thermal power from the Missouri River to drop to 11.7 percent of the RTO generation (summer of 1980), a drop of 3.2 percent. In 1975, power generation from hydropower would be 3.2 million MWh and thermal power would be 18.7 million MWh, and in 1980, power generation from hydropower and thermal power plants would reduce to 2.2 million MWh and 14.9 million MWh, respectively.

Table 29. Combined Hydropower and Thermal Power Generation as a Percent of MISO and SPP Total Generation under Alternative 1, 1975–2012

Year	Winter	Spring	Summer	Fall
1975	13.6%	14.1%	14.9%	14.6%
1976	13.7%	14.6%	14.3%	14.2%
1977	13.5%	13.7%	13.5%	13.7%
1978	13.3%	13.7%	14.5%	14.6%
1979	13.8%	14.3%	14.4%	14.0%
1980	13.6%	13.8%	11.7%	14.1%
1981	13.5%	13.8%	13.8%	13.9%
1982	13.4%	13.5%	14.0%	14.3%
1983	13.7%	13.5%	12.1%	14.2%
1984	13.7%	13.6%	13.9%	14.1%
1985	13.7%	13.8%	13.8%	13.7%
1986	13.4%	13.4%	14.1%	14.2%
1987	14.0%	13.6%	12.3%	13.9%
1988	13.5%	13.5%	11.8%	13.8%
1989	13.4%	13.7%	13.6%	13.5%

Year	Winter	Spring	Summer	Fall
1990	13.4%	13.5%	13.5%	13.2%
1991	13.2%	13.4%	12.8%	13.6%
1992	13.4%	13.6%	13.7%	12.5%
1993	13.3%	13.0%	13.1%	12.2%
1994	13.3%	13.7%	14.0%	13.6%
1995	13.3%	13.4%	13.9%	14.2%
1996	13.8%	14.6%	14.8%	14.2%
1997	13.6%	14.6%	14.8%	14.8%
1998	13.7%	13.7%	14.2%	14.0%
1999	13.6%	14.4%	14.0%	14.0%
2000	13.6%	14.0%	13.6%	13.8%
2001	13.4%	13.0%	12.9%	13.1%
2002	13.3%	13.6%	12.6%	13.5%
2003	13.3%	13.6%	12.0%	13.5%
2004	13.3%	13.5%	13.8%	12.5%
2005	13.2%	13.3%	12.4%	13.0%
2006	13.3%	13.3%	12.0%	13.1%
2007	13.3%	13.2%	13.0%	12.8%
2008	13.3%	13.2%	13.6%	13.4%
2009	13.3%	13.3%	13.7%	13.6%
2010	13.3%	12.8%	13.9%	14.1%
2012	13.6%	13.9%	12.0%	14.0%

7.3 Alternative 2 – USFWS 2003 Biological Opinion Projected Actions

Under Alternative 2, coupled effects could potentially occur during summer months with low summer flow events simulated to occur over the 37-year period of analysis (1975–2012, excluding 2011) in 1988, 1989, 2002 and 2003. During the low summer flow events, both hydropower and thermal power would experience reductions in power generation during a season when demand for electricity is also typically high. These decreases in power generation in the summer would come during relatively drier conditions when power generation is already being affected, especially as simulated in 1988, 2002, and 2003. Reductions in power generation compared to Alternative 1, as simulated, would be greatest in 1988 with a change of 5.9 million MWh, the bulk of which (88 percent) would be from reductions in thermal power generation. In the summer of 1988, the change in power generation under Alternative 2 as a percent of SPP and MISO summer power generation is estimated to be 4.0 percent. Table 30 summarizes the change in power generation from Alternative 1 by season and by year as a percent of SPP and MISO power generation.

Table 30. Seasonal Change in Power Generation under Alternative 2 Compared to Alternative 1 as a Percent of Seasonal MISO and SPP Generation, 1975–2012

Year	Winter	Spring	Summer	Fall
1975	−0.05%	−0.03%	−0.02%	−0.05%
1976	−0.05%	−0.02%	−0.16%	0.05%
1977	0.15%	0.06%	−0.05%	0.00%
1978	0.00%	0.02%	−0.02%	−0.03%
1979	−0.03%	0.09%	−0.22%	0.02%
1980	0.06%	0.11%	−0.01%	0.03%
1981	0.07%	0.02%	−0.10%	−0.05%
1982	−0.02%	0.06%	−0.01%	−0.01%
1983	−0.08%	0.54%	−0.07%	−0.22%
1984	−0.10%	0.09%	−0.25%	−0.16%
1985	−0.08%	−0.04%	−0.03%	−0.01%
1986	0.00%	0.38%	0.07%	−0.13%
1987	−0.30%	0.24%	−0.01%	−0.07%
1988	−0.10%	−0.05%	−4.01%	0.00%
1989	0.03%	0.03%	−1.42%	0.23%
1990	0.07%	0.07%	0.00%	0.09%
1991	0.02%	0.00%	−0.05%	0.00%
1992	0.00%	−0.01%	−0.05%	0.04%
1993	0.01%	0.01%	0.00%	0.00%
1994	0.00%	0.10%	−0.03%	0.01%
1995	0.00%	0.00%	−0.01%	0.09%
1996	−0.17%	−0.01%	−0.02%	0.03%
1997	−0.19%	0.03%	−0.03%	−0.19%
1998	0.08%	0.22%	−0.18%	−0.01%
1999	−0.08%	−0.03%	−0.08%	0.02%
2000	−0.02%	−0.12%	−0.07%	−0.01%
2001	−0.02%	0.03%	−0.08%	0.45%
2002	0.03%	0.05%	−1.49%	0.18%
2003	0.02%	−0.02%	−0.66%	0.25%
2004	0.07%	−0.02%	−0.03%	−0.02%
2005	0.00%	−0.01%	−0.27%	−0.11%
2006	−0.01%	−0.05%	−0.07%	0.05%
2007	0.00%	0.00%	−0.24%	−0.14%
2008	0.01%	0.00%	−0.01%	−0.01%
2009	0.00%	0.02%	−0.02%	0.02%
2010	0.00%	0.22%	0.02%	0.05%
2012	−0.08%	0.02%	−0.12%	0.07%

These coupled effects in the summer season during the low summer flow events would exacerbate impacts to wholesale power prices, with relatively higher wholesale power prices with both reductions in both sources of electricity. Although replacement capacity within the markets is likely to be available during these conditions, it is possible that simultaneous reductions in power generation especially during a condensed period of time could adversely impact voltage pressure, local grid stability, available transmission capacity, and the availability of local electricity (SPP pers. comm. 2018).

The re-occurrence of these low summer flow events under Alternative 2 could lead to higher retail electricity rates over time. An increase in retail electricity rates may cause households to have less disposable income to spend on other goods and services in the community or region, causing adverse effects on local and regional economies. Similarly, businesses may have lower net revenue and less money to spend on other business expenses in the region.

7.4 Alternative 3 – Mechanical Construction

Under Alternative 3, there would be negligible coupled effects to both hydropower and thermal power generation. The fall of the modeled year 2005 shows the greatest impact of a power generation reduction of 259,022 MWh, 0.10 percent of both MISO and SPP generation, the bulk of which would be from reductions in thermal power generation (Table 31).

Table 31. Seasonal Change in Power Generation under Alternative 3 Compared to Alternative 1 as a Percent of Seasonal MISO and SPP Generation, 1975–2012

Year	Winter	Spring	Summer	Fall
1975	0.00%	0.00%	0.01%	0.00%
1976	0.00%	0.01%	0.00%	0.00%
1977	0.00%	−0.03%	0.02%	0.00%
1978	0.00%	−0.01%	0.00%	0.01%
1979	0.00%	0.00%	0.00%	0.00%
1980	0.00%	−0.02%	0.02%	0.00%
1981	0.00%	−0.01%	0.02%	0.00%
1982	0.00%	−0.02%	0.03%	0.02%
1983	0.02%	−0.01%	0.00%	0.00%
1984	0.00%	0.00%	0.01%	0.00%
1985	0.00%	0.00%	0.02%	0.00%
1986	0.00%	0.00%	0.01%	0.00%
1987	0.00%	−0.01%	0.02%	0.00%
1988	0.02%	−0.02%	0.07%	0.00%
1989	0.00%	−0.02%	0.00%	0.00%
1990	0.00%	0.00%	0.02%	0.03%
1991	0.01%	0.00%	0.02%	0.00%
1992	0.00%	0.00%	0.00%	0.01%
1993	0.01%	0.00%	0.01%	0.00%
1994	0.00%	0.02%	0.01%	0.00%
1995	0.00%	−0.01%	0.01%	0.00%
1996	−0.01%	0.00%	0.00%	0.00%
1997	0.00%	0.00%	0.02%	−0.01%
1998	0.00%	0.00%	−0.03%	0.00%
1999	0.00%	0.00%	−0.02%	0.00%
2000	0.00%	0.00%	−0.02%	0.00%

Year	Winter	Spring	Summer	Fall
2001	0.00%	0.00%	0.04%	−0.01%
2002	0.00%	−0.02%	0.09%	0.00%
2003	0.00%	−0.01%	0.06%	0.00%
2004	0.00%	0.00%	0.01%	0.03%
2005	0.00%	0.00%	0.08%	−0.10%
2006	0.00%	0.00%	0.01%	0.01%
2007	0.00%	0.00%	0.00%	0.00%
2008	0.00%	0.00%	0.01%	0.01%
2009	0.00%	−0.01%	0.00%	0.00%
2010	0.00%	0.01%	−0.02%	0.01%
2012	0.03%	0.00%	0.04%	0.00%

7.5 Alternative 4 – Spring ESH Creating Release

Alternative 4 could result in adverse impacts resulting from coupled effects to generation of hydropower and thermal power, although these conditions would occur in the fall months (Table 32). The year 1994, when a full spring release is simulated to occur, would result in the largest power reduction of 2.6 million MWh compared to Alternative 1, 2.4 million of which would be from thermal power plants. These reductions would be up to 1 percent of MISO and SPP generation in the fall in a modeled year like 1994. Because the reductions in power generation from hydropower and thermal power would occur in the fall and demand for electricity is generally lower during the fall season, there would be replacement capacity available, with minimal impacts to wholesale power prices, electricity rates, grid stability, and regional economic conditions.

Table 32. Seasonal Change in Power Generation under Alternative 4 Compared to Alternative 1 as a Percent of Seasonal MISO and SPP Generation, 1975–2012

Year	Winter	Spring	Summer	Fall
1975	0.00%	0.00%	0.00%	0.00%
1976	0.00%	0.00%	0.00%	0.00%
1977	0.00%	−0.03%	0.02%	0.00%
1978	0.00%	−0.01%	0.01%	0.01%
1979	0.00%	0.11%	−0.05%	−0.03%
1980	−0.01%	−0.02%	0.01%	0.00%
1981	0.00%	−0.02%	0.00%	−0.01%
1982	−0.01%	0.38%	−0.13%	−0.30%
1983	−0.09%	−0.03%	0.02%	0.00%
1984	0.01%	0.00%	0.01%	0.00%
1985	0.00%	0.00%	0.02%	0.00%
1986	0.00%	0.06%	0.00%	−0.02%
1987	0.00%	−0.01%	0.02%	0.01%
1988	0.02%	0.33%	0.05%	−0.09%
1989	−0.03%	−0.03%	−0.02%	−0.01%
1990	−0.01%	−0.01%	0.00%	−0.16%

Year	Winter	Spring	Summer	Fall
1991	−0.02%	−0.01%	0.01%	−0.13%
1992	−0.02%	0.00%	0.01%	−0.05%
1993	−0.02%	0.00%	0.00%	0.00%
1994	0.00%	0.31%	−0.08%	−1.02%
1995	−0.01%	−0.24%	0.01%	−0.10%
1996	−0.04%	0.00%	0.00%	0.00%
1997	0.00%	0.00%	0.02%	−0.01%
1998	0.00%	0.00%	−0.03%	0.01%
1999	0.00%	0.00%	−0.02%	0.00%
2000	0.00%	0.00%	−0.03%	0.00%
2001	0.00%	0.11%	0.01%	−0.02%
2002	0.00%	0.37%	0.12%	−0.01%
2003	−0.01%	−0.03%	0.04%	−0.06%
2004	−0.02%	−0.02%	−0.07%	0.28%
2005	0.02%	−0.02%	−0.02%	−0.06%
2006	0.01%	−0.01%	−0.02%	−0.05%
2007	0.00%	−0.01%	0.04%	−0.43%
2008	−0.01%	−0.02%	−0.01%	−0.17%
2009	−0.03%	0.33%	−0.09%	−0.15%
2010	−0.05%	−0.32%	−0.26%	−0.13%
2012	0.01%	0.00%	0.05%	0.01%

7.6 Alternative 5 – Fall ESH Creating Release

Alternative 5 could result in adverse impacts from coupled effects of generation from hydropower and thermal power, although these conditions would primarily occur in the spring months (Table 33). The simulated impacts in 1984, a year after a full fall release would result in the largest power reduction of 709,000 MWh compared to Alternative 1, 654,000 MWh of which would be from hydropower plants. These power reductions, as simulated, would be up to 0.3 percent of MISO and SPP generation in the spring. Because the reductions in power generation from hydropower and thermal power would occur in the spring and demand for electricity is generally lower at this time of year, there would be replacement capacity available, with minimal impacts to wholesale power prices, electricity rates, grid stability, and regional economic conditions.

Table 33. Seasonal Change in Power Generation under Alternative 5 Compared to Alternative 1 as a Percent of Seasonal MISO and SPP Generation, 1975–2012

Year	Winter	Spring	Summer	Fall
1975	0.02%	−0.15%	−0.07%	−0.14%
1976	0.05%	−0.02%	0.03%	0.03%
1977	0.00%	−0.03%	0.01%	0.00%
1978	0.00%	−0.01%	0.00%	0.00%
1979	0.00%	0.00%	0.00%	0.00%

Year	Winter	Spring	Summer	Fall
1980	0.00%	−0.01%	0.02%	0.00%
1981	0.00%	−0.01%	0.01%	0.00%
1982	0.00%	−0.03%	0.03%	0.15%
1983	−0.05%	−0.11%	0.02%	0.17%
1984	−0.03%	−0.29%	−0.18%	0.02%
1985	−0.01%	−0.01%	0.02%	0.00%
1986	0.00%	−0.01%	0.00%	−0.01%
1987	0.00%	0.00%	0.02%	0.33%
1988	0.00%	−0.12%	0.00%	−0.07%
1989	−0.02%	−0.03%	−0.02%	−0.01%
1990	−0.01%	−0.01%	0.00%	−0.13%
1991	−0.02%	0.00%	0.01%	−0.07%
1992	−0.01%	0.00%	0.00%	−0.03%
1993	−0.02%	0.00%	0.01%	0.00%
1994	0.00%	−0.13%	−0.04%	0.39%
1995	0.02%	−0.19%	−0.06%	−0.12%
1996	−0.09%	0.00%	−0.01%	0.00%
1997	0.00%	0.00%	0.02%	−0.01%
1998	0.00%	0.00%	−0.03%	0.01%
1999	0.00%	0.00%	−0.02%	0.00%
2000	0.00%	0.00%	−0.02%	0.00%
2001	0.00%	0.00%	0.04%	−0.01%
2002	0.00%	−0.01%	0.08%	0.00%
2003	0.00%	−0.01%	0.06%	0.00%
2004	0.00%	0.00%	0.01%	0.02%
2005	0.00%	−0.01%	0.08%	−0.11%
2006	0.00%	0.00%	0.02%	0.01%
2007	0.00%	0.00%	0.00%	0.00%
2008	0.00%	0.00%	0.01%	0.01%
2009	0.00%	−0.01%	0.00%	0.00%
2010	0.00%	0.00%	−0.03%	0.11%
2012	−0.02%	0.00%	0.07%	0.00%

7.7 Alternative 6 – Pallid Sturgeon Spawning Cue

Under Alternative 6, coupled effects of reductions in thermal power and hydropower generation would affect up to 0.4 percent of SPP and MISO generation (Table 34). The spring of the modeled year 2010 shows the greatest impact of a reduction of 0.4 percent of both MISO and SPP generation, the year after a partial release simulated to occur in 2009. Because the relatively small amount of power generation affected relative to Alternative 1, there would be replacement capacity available from other sources, with minimal impacts to wholesale power prices, electricity rates, grid stability, and regional economic conditions.

Table 34. Seasonal Change in Power Generation under Alternative 6 Compared to Alternative 1 as a Percent of Seasonal MISO and SPP Generation, 1975–2012

Year	Winter	Spring	Summer	Fall
1975	−0.04%	0.04%	−0.02%	−0.04%
1976	0.00%	0.02%	−0.01%	0.01%
1977	0.01%	0.14%	0.03%	−0.03%
1978	−0.01%	−0.04%	−0.06%	−0.12%
1979	−0.01%	0.13%	−0.05%	−0.02%
1980	−0.01%	0.00%	0.01%	0.00%
1981	0.00%	0.11%	−0.01%	−0.05%
1982	−0.01%	0.06%	−0.01%	−0.08%
1983	−0.05%	−0.01%	0.05%	−0.01%
1984	−0.01%	0.00%	0.02%	0.00%
1985	0.00%	0.00%	0.02%	0.00%
1986	0.00%	0.00%	0.01%	0.00%
1987	0.00%	−0.01%	0.02%	0.00%
1988	0.00%	0.20%	0.09%	−0.04%
1989	0.00%	−0.03%	−0.01%	−0.01%
1990	−0.01%	−0.01%	0.01%	−0.13%
1991	−0.02%	0.00%	0.01%	−0.09%
1992	−0.02%	0.00%	0.00%	−0.05%
1993	−0.02%	0.00%	0.00%	0.00%
1994	0.00%	−0.06%	−0.03%	0.01%
1995	0.00%	−0.01%	0.02%	−0.01%
1996	−0.01%	0.00%	−0.01%	0.00%
1997	0.00%	0.00%	0.01%	0.05%
1998	0.00%	0.01%	−0.02%	0.00%
1999	0.00%	0.00%	−0.02%	0.00%
2000	0.00%	0.08%	−0.05%	−0.03%
2001	0.03%	0.03%	−0.01%	−0.01%
2002	0.00%	0.19%	0.17%	0.01%
2003	0.00%	−0.03%	0.04%	−0.01%
2004	−0.01%	−0.02%	−0.08%	0.31%
2005	0.03%	−0.02%	−0.01%	−0.06%
2006	0.01%	−0.01%	−0.02%	−0.05%
2007	0.00%	−0.01%	0.03%	−0.27%
2008	−0.01%	−0.01%	0.00%	−0.14%
2009	−0.02%	0.06%	−0.04%	−0.02%
2010	0.00%	−0.41%	−0.35%	0.07%
2012	0.02%	0.02%	0.05%	0.01%

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