# APPENDIX A: 9B REGULATIONS AND APPLICATION OF THE REGULATIONS

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## 36 C.F.R. PART 9 SUBPART B
## NON-FEDERAL OIL AND GAS RIGHTS REGULATIONS

AUTHORITY: Act of August 25, 1916, 39 Stat. 535 (16 U.S.C. §§ 1, *et seq.*); and the acts establishing the units of the National Park System, including but not limited to: Act of April 25, 1947, 61 Stat. 54 (16 U.S.C. §§ 241, *et seq.*); Act of July 2, 1958, 72 Stat. 285 (16 U.S.C. §§ 410, *et seq.*); Act of October 27, 1972, 86 Stat. 1312 (16 U.S.C. §§ 460dd, *et seq.*); Act of October 11,1974, 88 Stat. 1256 (16 U.S.C. §§ 698 -- 698e); Act of October 11, 1974, 88 Stat. 1258 (16 U.S.C. §§ 698f -- 698m); Act of December 27,1974, 88 Stat. 1787 (16 U.S.C. §§ 460ff *et seq.*).

SOURCE: 43 FR 57825, Dec. 8, 1978, unless otherwise noted.

### § 9.30 Purpose and scope.

(a) These regulations control all activities within any unit of the National Park System in the exercise of rights to oil and gas not owned by the United States where access is on, across or through federally owned or controlled lands or waters. Such rights arise most frequently in one of two situations: (1) When the land is owned in fee, including the right to the oil and gas, or (2) When in a transfer of the surface estate to the United States, the grantor reserved the rights to the oil and gas. These regulations are designed to insure that activities undertaken pursuant to these rights are conducted in a manner consistent with the purposes for which the National Park System and each unit thereof were created, to prevent or minimize damage to the environment and other resource values, and to insure to the extent feasible that all units of the National Park System are left unimpaired for the enjoyment of future generations.

These regulations are not intended to result in the taking of a property interest, but rather to impose reasonable regulations on activities which involve and affect federally-owned lands.

(b) Regulations controlling the exercise of minerals rights obtained under the Mining Law of 1872 in units of the National Park System can be found at 36 C.F.R. Part 9, Subpart A. In area where oil and gas are owned by the United States, and leasing is authorized, the applicable regulations can be found at 43 C.F.R., Group 3100.

(c) These regulations allow operators the flexibility to design plans of operations only for that phase of operations contemplated. Each plan need only describe those functions for which the operator wants immediate approval. For instance, it is impossible to define, at the beginning of exploratory activity, the design that production facilities might take. For this reason, an operator may submit a plan which applies only to the exploratory phase, allowing careful preparation of a plan for the production phase after exploration is completed. This allows for phased reclamation and bonding at a level commensurate with the level of operations approved. However, it must be noted that because of potential cumulative impacts, and because of qualitative differences in the nature of the operations, approval of a plan of operations covering one phase of operations does not guarantee later approval of a plan of operations covering a subsequent phase.

[43 FR 57825, Dec. 8, 1978, as amended at 44 FR 37914, June 29, 1979]

## §9.31 Definitions.

The terms used in this Subpart shall have the following meanings:

(a) Secretary. The Secretary of the Interior.

(b) Director. The Director of the National Park Service or his designee.

(c) Operations. All functions, work and activities within a unit in connection with exploration for and development of oil and gas resources, the right to which is not owned by the United States, including: gathering basic information required to comply with this subpart, prospecting, exploration, surveying, preproduction development and production; gathering, onsite storage, transport or processing of petroleum products; surveillance, inspection, monitoring, or maintenance of equipment; reclamation of the surface disturbed by such activities; and all activities and uses reasonably incident thereto performed within a unit, including construction or use of roads, pipelines, or other means of access or transportation on, across, or through federally owned or controlled lands and waters, regardless of whether such activities and uses take place on Federal, State or private lands.

(d) Operator. A person conducting or proposing to conduct operations.

(e) Person. Any individual, firm, partnership, corporation, association, or other entity.

(f) Superintendent. The Superintendent, or his designee, of the unit of the National Park System containing lands subject to the rights covered by these regulations.

(g) Commercial Vehicle. Any motorized equipment used in direct or indirect support of operations.

(h) Unit. Any National Park System area.

(i) Owner. The owner, or his legal representative, of the rights to oil and gas being exercised.

(j) Designated Roads. Those existing roads determined by the Superintendent in accordance with 36 C.F.R. 1.5 and § 4.19 to be open for the use of the general public or for the exclusive use of an operator.

(k) Oil. Any viscous combustible liquid hydrocarbon or solid hydrocarbon substance easily liquifiable on warming which occurs naturally in the earth, including drip gasoline or other natural condensates recovered from gas without resort to manufacturing process.

(l) Gas. Any fluid, either combustible or noncombustible, which is produced in a natural state from the earth and which maintains a gaseous or rarefied state at ordinary temperature and pressure conditions.

(m) Site. Those lands or waters on which operations are to be carried out.

(n) Contaminating substances. Those substances, including but not limited to, salt water or any other injurious or toxic chemical, waste oil or waste emulsified oil, basic sediment, mud with injurious or toxic additives, or injurious or toxic substances produced or used in the drilling, development, production, transportation, or on-site storage, refining, and processing of oil and gas.

(o) Statement for Management. A National Park Service planning document used to guide short- and long-term management of a unit; to determine the nature and extent of planning required to meet the unit's management objectives; and, in the absence of more specific planning documents, to provide a general framework for directing park operations and communicating park objectives to the public.

[43 F R 57825, Dec. 8, 1978; 44 FR 37914, June 29, 1979, as amended at 60 FR 55791, Nov. 3 1995; 62 FR 30234, June 3, 1997]

### § 9.32 Access.

(a) No access on, across or through lands or waters owned or controlled by the United States to a site for operations will be granted except for operations covered by § 9.33 and, except as provided by § 9.38, until the operator has filed a plan of operations pursuant to § 9.36 and has had the plan of operations approved in accordance with § 9.37. An approved plan of operations serves as the operator's access permit.

(b) No operations shall be conducted on a site within a unit, access to which is on, across or through federally owned or controlled lands or waters except in accordance with an approved plan of operations, the terms of § 9.33 or approval under § 9.38.

(c) Any operator intending to use aircraft of any kind for access to a federally-owned or controlled site must comply with these regulations. Failure of an operator to receive the proper approval under these regulations prior to using aircraft in this manner is a violation of both these regulations and 36 C.F.R. 2.17.

(d) No access to a site outside a unit will be permitted across unit lands unless such access is by foot, pack animal, or designated road. Persons using designated roads for access to such a site must comply with the terms of § 9.50 where applicable.

(e) Any operator on a site outside the boundaries of a unit must comply with these regulations if he is using directional drilling techniques which result in the drill hole crossing into the unit and passing under any land or water the surface of which is owned by the United States. Except, that the operator need not comply in those areas where, upon application of the operator or upon his own action, the Regional Director is able to determine from available data, that such operations pose no significant threat of damage to park resources, both surface and subsurface, resulting from surface subsidence fracture of geological formations with resultant fresh water aquifer contamination, or natural gas escape, or the like.

### § 9.33 Existing operations.

(a) Any person conducting operations on January 8, 1979 in accordance with a Federal or State issued permit may continue to do so as provided by this section. After expiration of such existing permits no operations shall be conducted except under an approved plan of operations, unless access is granted by the Regional Director under § 9.38.

(1) All Federal special use permits dealing with access on, across or through lands or waters owned or controlled by the United States to a site for the conduct of operations within any unit issued prior to January 8, 1979 shall expire according to their terms and shall not be renewed, unless by the terms of the existing permit it must be renewed.

(2) All operations on a site in a unit access to which is on, across, or through federally owned or controlled lands or waters conducted pursuant to a valid State access permit may be continued for the term of that permit, exclusive of any renewal period whether mandatory or discretionary, if conducted in accordance with the permit.

(b) Any person conducting operations on January 8, 1979 in a unit where Federal or State permits were not required prior to January 8, 1979 may continue those operations pending a final decision on his plan of operations; Provided, That:

(1) The operator (within thirty (30) days of January 8, 1979), notifies the Superintendent in writing of the nature and location of the operations; and

(2) Within sixty (60) days after such notification, the operator submits, in accordance with these regulations, a substantially complete proposed plan of operations for those operations;

(3) Failure to comply with § 9.33(b) (1) and (2) shall constitute grounds for the suspension of operations.

(c) At any time when operations which are allowed to continue under § 9.33 (a) and (b) pose an immediate threat of significant injury to federally owned or controlled lands or waters, the Superintendent shall require the operator to suspend operations immediately until the threat is removed or remedied. The Superintendent must, within five (5) days of this suspension notify the operator in writing of the reasons for the suspension and of his right to appeal the suspension under § 9.49.

[43 FR 57825, Dec. 8, 1978; 44 FR 37914, June 29, 1979]

### § 9.34 Transfers of interest.

(a) Whenever an owner of rights being exercised under an approved plan of operations sells, assigns, bequeaths, or otherwise conveys all or any part of those rights, he, his agent, executor, or representative must notify the Superintendent within sixty (60) days of the transfer of: the site(s) involved; the name and address of the person to whom an interest has been conveyed; and a description of the interest transferred. Failure to so notify the Superintendent shall render the approval of any previously approved plan of operations void.

(b) The transferring owner shall remain responsible for compliance with the plan of operations and shall remain liable under his bond until such time as the Superintendent is notified of the transfer in accordance with paragraph (a). At that time the Superintendent will prohibit the new owner from operating until such time as the new owner has filed with the Superintendent: (1) A statement ratifying the existing plan of operations and stating his intent to be bound thereby, or a new plan of operations, and (2) a suitable substitute performance bond which complies with the requirements of § 9.48.

## § 9.35 Use of water.

No operator may use for operations any water from a point of diversion which is within the boundaries of any unit unless authorized in writing by the Regional Director. The Regional Director shall not approve a plan of operations requiring the use of water from such source unless the operator shows either that his right to the use of the water is superior to any claim of the United States to the water, or where the operator's claim to the water is subordinate to that of the United States that the removal of the water from the water system will not damage the unit's resources. In either situation, the operator's use of water must comply with appropriate State water laws.

## § 9.36 Plan of operations.

(a) The proposed plan of operations shall include, as appropriate to the proposed operations, the following:

(1) The names and legal addresses of the following persons: The operator and the owner(s) or lessee(s) (if rights are State-owned) other than the operator;

(2) Copy of the lease, deed, designation of operator, or assignment of rights upon which the operator's right to conduct operations is based;

(3) A map or maps showing the location of the perimeter of the area where the operator has the right to conduct operations, as described in § 9.36(a)(2), referenced to the State plane coordinate system or other public land survey as acceptable to the Superintendent;

(4) A map or maps showing the location, as determined by a registered land surveyor or civil engineer, of a point within a site of operations showing its relationship to the perimeter of the area described in § 9.36(a)(2) and to the perimeter of the site of operations; the location of existing and proposed access roads or routes to the site; the boundaries of proposed surface disturbance; the location of proposed drilling; location and description of all surface facilities including sumps, reserve pits and ponds; location of tank batteries, production facilities and gathering, service and transmission lines; wellsite layout; sources of construction materials such as fill; and the location of ancillary facilities such as camps, sanitary facilities, water supply and disposal facilities, and airstrips. The point within the site of operations identified by registered land surveyor or civil engineer shall be marked with a permanent ground monument acceptable to the Superintendent, shall contain the point's State plane coordinate values, and shall be placed at least to an accuracy of third order, class I, unless otherwise authorized by the Superintendent;

(5) A description of the major equipment to be used in the operations, including a description of equipment and methods to be used for the transport of all waters used in or produced by operations, and of the proposed method of transporting such equipment to and from the site;

(6) An estimated timetable for any phase of operations for which approval is sought and the anticipated date of operation completion;

(7) The geologic name of the surface formation;

(8) The proposed drilling depth, and the estimated tops of important geologic markers;

(9) The estimated depths at which anticipated water, brines, oil, gas, or other mineral bearing formations are expected to be encountered;

(10) The nature and extent of the known deposit or reservoir to be produced and a description of the proposed operations, including:

(i) The proposed casing program, including the size, grade, and weight of each string, and whether it is new or used;

(ii) The proposed setting depth of each casing string, and the amount of type of cement, including additives, to be used;

(iii) The operator's minimum specifications for pressure control equipment which is to be used, a schematic diagram thereof showing sizes, pressure ratings, and the testing procedures and testing frequency;

(iv) The type and characteristics of the proposed circulating medium or mediums to be employed for rotary drilling and the quantities and types of mud and weighting material to be maintained;

(v) The testing, logging, and coring programs to be followed;

(vi) Anticipated abnormal pressures or temperatures expected to be encountered; or potential hazards to persons and the environment such as hydrogen sulfide gas or oil spills, along with plans for mitigation of such hazards;

(11) A description of the steps to be taken to comply with the applicable operating standards of § 9.41 of this subpart;

(12) Provisions for reclamation which will result in compliance with the requirements of § 9.39:

(13) A breakdown of the estimated costs to be incurred during the implementation of the reclamation plan;

(14) Methods for disposal of all rubbish and other solid and liquid wastes, and contaminating substances;

(15) An affidavit stating that the operations planned are in compliance with all applicable Federal, State and local laws and regulations

(16) Background information, including:

(i) A description of the natural, cultural, social and economic environments to be affected by operations, including a description and/or map(s) of the location of all water, abandoned, temporarily abandoned, disposal, production, and drilling wells of public record within a two-mile radius of the proposed site. Where such information is available from documents identified in § 9.36(d), specific reference to the document and the location within the document where such information can be found will be sufficient to satisfy this requirement

(ii) The anticipated direct and indirect effects of the operations on the unit's natural, cultural, social, and economic environment;

(iii) Steps to be taken to insure minimum surface disturbance and to mitigate any adverse environmental effects, and a discussion of the impacts which cannot be mitigated

(iv) Measures to protect surface and subsurface waters by means of casing and cement, etc.

(v) All reasonable technologically feasible alternative methods of operations their costs, and their environmental effects, and

(vi) The effects of the steps to be taken to achieve reclamation

(17) Any other facets of the proposed operations which the operator wishes to point out for consideration; and

(18) Any additional information that is required to enable the Superintendent to establish whether the operator has the right to conduct operations as specified in the plan of operations; to effectively analyze the effects that the operations will have on the preservation, management and public use of the unit, and to make a recommendation to the Regional Director regarding approval or disapproval of the plan of operations and the amount of the performance bond to be posted.

(b) Where any information required to be submitted as part of a proposed plan of operations has been submitted to the Superintendent in substantially the same form in a prior approved plan of operations, a specific cross-reference to that information contained in the prior approved plan of operations will be sufficient to incorporate it into the proposed plan and will satisfy the applicable requirement of this section.

(c) Information and materials submitted in compliance with this section will not constitute a plan of operations until information required by § 9.36(a) (1) through (18), which the Superintendent determines as pertinent to the type of operations proposed, has been submitted to and determined adequate by the Regional Director.

(d) In all cases the plan of operations must consider and discuss the unit's Statement for Management and other planning documents as furnished by the Superintendent, and activities to control, minimize or prevent damage to the recreational, biological physical, scientific, cultural, and scenic resources of the unit, and any reclamation procedures suggested by the Superintendent.

[43 FR 57825, Dec. 8, 1978; 44 FR 37914, June 29, 1979]

### § 9.37 Plan of operations approval.

(a) The Regional Director shall not approve a plan of operations:

(1) Until the operator shows that the operations will be conducted in a manner which utilizes technologically feasible methods least damaging to the federally-owned or controlled lands, waters and resources of the unit while assuring the protection of public health and safety.

(2) For operations at a site the surface estate of which is not owned by the federal government, where operations would constitute a nuisance to federal lands or waters in the vicinity of the operations, would significantly injure federally-owned or controlled lands and waters; or

(3) For operations at a site the surface estate of which is owned or controlled by the federal government, where operations would substantially interfere with management of the unit to ensure

the preservation of its natural and ecological integrity in perpetuity, or would significantly injure the federally-owned or controlled lands or waters; Provided, however, that if the application of this standard would under applicable law, constitute a taking of a property interest rather than an appropriate exercise of regulatory authority, the plan of operations may be approved if the operations would be conducted in accordance with paragraph (a)(1) of this section, unless a decision is made to acquire the mineral interest.

(4) Where the plan of operations does not satisfy each of the requirements of § 9.36 applicable to the operations proposed.

(b) Within sixty (60) days of the receipt of a plan of operations, the Regional Director shall make an environmental analysis of such plan, and:

(1) Notify the operator that the plan of operations has been approved or rejected, and, if rejected, the reasons for the rejection; or

(2) Notify the operator that the plan of operations has been conditionally approved, subject to the operator's acceptance of specific provisions and stipulations; or

(3) Notify the operator of any modification of the plan of operations which is necessary before such plan will be approved or of additional information needed to effectively analyze the effects that the operations will have on the preservation, management and use of the unit, and to make a decision regarding approval or disapproval of the plan of operations and the amount of the performance bond to be posted; or

(4) Notify the operator that the plan of operations is being reviewed, but that more time, not to exceed an additional thirty days, is necessary to complete such review, and setting forth the reasons why additional time is required. Provided, however, That days during which the area of operations is inaccessible for such reasons as inclement weather, natural catastrophe acts of God, etc., for inspection shall not be included when computing either this time period, or that in subsection (b) above; or

(5) Notify the operator that the plan of operations has been reviewed, but cannot be considered for approval until forty-five (45) days after a final environmental statement has been prepared and filed with the Environmental Protection Agency; or

(6) Notify the operator that the plan of operations is being reviewed, but that more time to provide opportunities for public participation in the plan of operations review and to provide sufficient time to analyze public comments received is necessary. Within thirty (30) days after closure of the public comment period specified by the Regional Director, he shall comply with § 9.37(b) (1) through (5).

(c) The Regional Director shall act as expeditiously as possible upon a proposed plan of operations consistent with the nature and scope of the operations proposed. Failure to act within the time limits specified in this section shall constitute a rejection of the plan of operations from which the operator shall have a right to appeal under § 9.49.

(d) The Regional Director's analysis shall include:

(1) An examination of all information submitted by the operator;

(2) An evaluation of measures and timing required to comply with reclamation requirements;

(3) An evaluation of necessary conditions and amount of the bond or security deposit (See § 9.48);

(4) An evaluation of the need for any additional requirements in the plan;

(5) A determination regarding the impact of this operation and cumulative impacts of all proposed and existing operations on the management of the unit; and

(6) A determination whether implementation by the operator of an approved plan of operations would be a major Federal action significantly affecting the quality of the human environment or would be sufficiently controversial to warrant preparation of an environmental statement pursuant to section 102(2)(c) of the National Environmental Policy Act of 1969.

(e) Prior to approval of a plan of operations, the Regional Director shall determine whether any properties included in, or eligible for inclusion in the National Register of Historic Places or National Registry of Natural Landmarks may be affected by the proposed operations. This determination will require the acquisition of adequate information, such as that resulting from field surveys, in order to properly determine the presence and significance of cultural resources within the areas to be affected by operations. Whenever National Register properties or properties eligible for inclusion in the National Register would be affected by operations, the Regional Director shall comply with Section 106 of the Historic Preservations Act of 1966 as implemented by 36 C.F.R. Part 800.

(f) Approval of each plan of operations is expressly conditioned upon the Superintendent having such reasonable access to the site as is necessary to properly monitor and insure compliance with the plan of operations.

[43 FR 57825, Dec. 8, 1978; 44 FR 37914, June 29, 1979]

### § 9.38 Temporary approval.

(a) The Regional Director may approve on a temporary basis:

(1) Access on, across or through federally-owned or controlled lands or waters for the purpose of collecting basic information necessary to enable timely compliance with these regulations. Such temporary approval shall be for a period not in excess of sixty (60) days.

(2) The continuance of existing operations, if their suspension would result in an unreasonable economic burden or injury to the operator; provided that such operations must be conducted in accordance with all applicable laws, and in a manner prescribed by the Regional Director designed to minimize or prevent significant environmental damage; and provided that within sixty (60) days of the granting of such temporary approval the operator either:

(i) Submits an initial substantially complete plan of operations; or

(ii) If a proposed plan of operations has been submitted, responds to any outstanding requests for additional information.

(b) The Regional Director may approve new operations on a temporary basis only when:

(1) The Regional Director finds that the operations will not cause significant environmental damage or result in significant new or additional surface disturbance to the unit; and either

(2) The operator can demonstrate a compelling reason for the failure to have had timely approval of a proposed plan of operations; or

(3) The operator can demonstrate that failure to grant such approval will result in an unreasonable economic burden or injury to the operator.

[43 FR 57825, Dec. 8, 1978, as amended at 44 FR 37914, June 29, 1979]

### § 9.39 Reclamation requirements.

(a) Within the time specified by the reclamation provisions of the plan of operations, which shall be as soon as possible after completion of approved operations and shall not be later than six (6) months thereafter unless a longer period of time is authorized in writing by the Regional Director, each operator shall initiate reclamation as follows:

(1) Where the Federal government does not own the surface estate. the operator shall at a minimum:

(i) Remove or neutralize any contaminating substances; and

(ii) Rehabilitate the area of operations to a condition which would not constitute a nuisance or would not adversely affect, injure, or damage federally-owned lands or waters, including removal of above ground structures and equipment used for operations, except that such structures and equipment may remain where they are to be used for continuing operations which are the subject of another approved plan of operations or of a plan which has been submitted for approval.

(2) On any site where the surface estate is owned or controlled by the Federal government, each operator must take steps to restore natural conditions and processes. These steps shall include but are not limited to:

(i) Removing all above ground structures, equipment and roads used for operations, except that such structures, equipment and roads may remain where they are to be used for continuing operations which are the subject of another approved plan of operations or of a plan which has been submitted for approval, or unless otherwise authorized by the Regional Director consistent with the unit purpose and management objectives;

(ii) Removing all other man-made debris resulting from operations;

(iii) Removing or neutralizing any contaminating substances;

(iv) Plugging and capping all nonproductive wells and filling dump holes, ditches, reserve pits and other excavations;

(v) Grading to reasonably conform the contour of the area of operations to a contour similar to that which existed prior to the initiation of operations, where such grading will not jeopardize reclamation;

(vi) Replacing the natural topsoil necessary for vegetative restoration; and

(vii) Reestablishing native vegetative communities.

(b) Reclamation under paragraph (a)(2) of this section is unacceptable unless it provides for the safe movement of native wildlife, the reestablishment of native vegetative communities, the normal flow of surface and reasonable flow of subsurface waters, and the return of the area to a condition which does not jeopardize visitor safety or public use of the unit.

### § 9.40 Supplementation or revision of plan of operations.

(a) A proposal to supplement or revise an approved plan of operations may be made by either the operator or the Regional Director to adjust the plan to changed conditions or to address conditions not previously contemplated by notifying the appropriate party in writing of the proposed alteration and the justification therefore.

(b) Any proposed supplementation or revision of a plan of operations initiated under paragraph (a) of this section by either party shall be reviewed and acted on by the Regional Director in accordance with § 9.37. If failure to implement proposed changes would not pose an immediate threat of significant injury to federally-owned or controlled lands or waters, the operator will be notified in writing sixty (60) days prior to the date such changes become effective, during which time the operator may submit comments on proposed changes. If failure to implement proposed changes would pose immediate threat of significant injury to federally-owned or controlled lands or waters, the provisions of § 9.33(c) apply.

### § 9.41 Operating Standards.

The following standards shall apply to operations within a unit:

(a) Surface operations shall at no time be conducted within 500 feet of the banks of perennial, intermittent or ephemeral watercourses; or within 500 feet of the high pool shoreline of natural or man-made impoundments; or within 500 feet of the mean high tide line; or within 500 feet of any structure or facility (excluding roads) used for unit interpretation, public recreation or for administration of the unit unless specifically authorized by an approved plan of operations.

(b) The operator shall protect all survey monuments, witness corners, reference monuments and bearing trees against destruction, obliteration, or damage from operations and shall be responsible for the reestablishment, restoration, or referencing of any monuments, corners and bearing trees which are destroyed, obliterated, or damaged by such operations.

(c) Whenever drilling or producing operations are suspended for 24 hours or more, but less than 30 days, the wells shall be shut in by closing wellhead valves or blowout prevention equipment. When producing operations are suspended for 30 days or more, a suitable plug or other fittings acceptable to the Superintendent shall be used to close the wells.

(d) The operator shall mark each and every operating derrick or well in a conspicuous place with his name or the name of the owner, and the number and location of the well, and shall take all necessary means and precautions to preserve these markings.

(e) Around existing or future installations, *e.g.*, well, storage tanks, all high pressure facilities, fences shall be built for protection of unit visitors and wildlife, and protection of said facilities unless otherwise authorized by the Superintendent. Fences erected for protection of unit visitors and wildlife shall be of a design and material acceptable to the Superintendent, and where appropriate, shall have at least one gate which is of sufficient width to allow access by fire trucks. Hazards within visitor use areas will be clearly marked with warning signs acceptable to the Superintendent.

(f) The operator shall carry on all operations and maintain the site at all times in a safe and workmanlike manner, having due regard for the preservation of the environment of the unit. The operator shall take reasonable steps to prevent and shall remove accumulations of oil or other materials deemed to be fire hazards from the vicinity of well locations and lease tanks, and shall remove from the property or store in an orderly manner all scrap or other materials not in use.

(g) Operators will be held fully accountable for their contractor's or subcontractor's compliance with the requirements of the approved plan of operations.

[43 FR 57825, Dec. 8, 1978; 44 FR 37915, June 29, 1979]

### § 9.42 Well records and reports, plots and maps, samples, tests and surveys.

Any technical data gathered during the drilling of any well, including daily drilling reports and geological reports, which are submitted to the State pursuant to State regulations, or to any other bureau or agency of the Federal government shall be available for inspection by the Superintendent upon his request.

### § 9.43 Precautions necessary in areas where high pressures are likely to exist.

When drilling in "wildcat" territory, or in any field where high pressures are likely to exist, the operator shall take all necessary precautions for keeping the well under control at all times and shall install and maintain the proper high-pressure fittings and equipment to assure proper well control. Under such conditions the surface string must be cemented through its length, unless another procedure is authorized or prescribed by the Superintendent, and all strings of casing must be securely anchored.

### § 9.44 Open flows and control of "wild" wells.

The operator shall take all technologically feasible precautions to prevent any oil, gas, or water well from blowing open or becoming "wild," and shall take immediate steps and exercise due diligence to bring under control any "wild" well, or burning oil or gas well.

### § 9.45 Handling of wastes.

Oilfield brine, and all other waste and contaminating substances must be kept in the smallest practicable area, must be confined so as to prevent escape as a result of percolation, rain high water or other causes, and such wastes must be stored and disposed of or removed from the area as quickly as practicable in such a manner as to prevent contamination, pollution, damage or injury to the lands, water (surface and subsurface), facilities, cultural resources, wildlife, and vegetation of or visitors of the unit.

### § 9.46 Accidents and fires.

The operator shall take technologically feasible precautions to prevent accidents and fires, shall notify the Superintendent within 24 hours of all accidents involving serious personal injury or death, or fires on the site, and shall submit a full written report thereon within ninety (90) days. This report supersedes the requirement outlined in 36 C.F.R. 2.17, but does not relieve persons from the responsibility of making any other accident reports which may be required under State or local laws.

### § 9.47 Cultural resource protection.

(a) Where the surface estate of the site is owned by the United States, the operator shall not, without written authorization of the Superintendent, injure, alter, destroy, or collect any site, structure, object, or other value of historical, archeological, or other cultural scientific importance in violation of the Antiquities Act (16 U.S.C. 431-433 (See 43 C.F.R. Part 3).

(b) Once approved operations have commenced, the operator shall immediately bring to the attention of the Superintendent any cultural or scientific resource encountered that might be altered or destroyed by his operation and shall leave such discovery intact until told to proceed by the Superintendent. The Superintendent will evaluate the discoveries brought to his attention, and will determine within ten (10) working days what action will be taken with respect to such discoveries.

### § 9.48 Performance bond.

(a) Prior to approval of a plan of operations, the operator shall be required to file a suitable performance bond with satisfactory surety, payable to the Secretary or his designee. The bond shall be conditioned upon faithful compliance with applicable regulations, and the plan of operations as approved, revised or supplemented. This performance bond is in addition to and not in lieu of any bond or security deposit required by other regulatory authorities.

(b) In lieu of a performance bond, an operator may elect to deposit with the Secretary or his designee, cash or negotiable bonds of the U.S. Government. The cash deposit or the market value of such securities shall be at least equal to the required sum of the bond. When bonds are to serve as security, there must be provided to the Secretary a power of attorney.

(c) In the event that an approved plan of operations is revised or supplemented in accordance with § 9.40, the Regional Director may adjust the amount of the bond or security deposit to conform to the modified plan of operations.

(d) The bond or security deposit shall be in an amount:

(1) Equal to the estimated cost of reclaiming the site, either in its entirety or in phases, that has been damaged or destroyed as a result of operations conducted in accordance with an approved, supplemented, plan of operations; plus

(2) An amount set by the Superintendent consistent with the type of operations proposed, to bond against the liability imposed by § 9.51(a); to provide the means for rapid and effective cleanup; and to minimize damages resulting from an oil spill, the escape of gas, wastes, contaminating substances, or fire caused by operations. This amount shall not exceed twenty-five thousand dollars ($25,000) for geophysical surveys when using more than one field party or five thousand dollars ($5,000) when operating with only one field party, and shall not exceed fifty thousand dollars ($50,000) for each wellsite or other operation.

(3) When an operator's total bond or security deposit with the National Park Service amounts to two hundred thousand dollars ($200,000) for activities conducted within a given unit, no further

bond requirements shall be collected for additional activities conducted within that unit, and the operator may substitute a blanket bond of two hundred thousand dollars ($200,000) for all operations conducted within the unit.

(e) The operator's and his surety's responsibility and liability under the bond or security deposit shall continue until such time as the Superintendent determines that successful reclamation of the area of operations has occurred and, where a well has been drilled, the well has been properly plugged and abandoned. If all efforts to secure the operator's compliance with pertinent provisions of the approved plan of operations are unsuccessful, the operator's surety company will be required to perform reclamation in accordance with the approved plan of operations.

(f) Within thirty (30) days after determining that all reclamation requirements of an approved plan of operations are completed, including proper abandonment of the well, the Regional Director shall notify the operator that the period of liability under the bond or security deposit has been terminated.

[43 FR 57825, Dec. 8, 1978; 44 FR 37915 June 29, 1979]

### § 9.49 Appeals.

(a) Any operator aggrieved by a decision of the Regional Director in connection with the regulations in this Subpart may file with the Regional Director a written statement setting forth in detail the respects in which the decision is contrary to, or is in conflict with the facts, the law, or these regulations, or is otherwise in error. No such appeal will be considered unless it is filed with the Regional Director within thirty (30) days after the date of notification to the operator of the action or decision complained of. Upon receipt of such written statement from the aggrieved operator, the Regional Director shall promptly review the action or decision and either reverse his original decision or prepare his own statement, explaining that decision and the reasons therefor, and forward the statement and record on appeal to the Director for review and decision. Copies of the Regional Director's statement shall be furnished to the aggrieved operator, who shall have thirty (30) days within which to file exceptions to the Regional Director's decision. The Department has the discretion to initiate a hearing before the Office of Hearing and Appeals in a particular case (See 43 C.F.R. 4.700).

(b) The official files of the National Park Service on the proposed plan of operations and any testimony and documents submitted by the parties on which the decision of the Regional Director was based shall constitute the record on appeal. The Regional Director shall maintain the record under separate cover and shall certify that it was the record on which his decision was based at the time it was forwarded to the Director of the National Park Service. The National Park Service shall make the record available to the operator upon request.

(c) If the Director considers the record inadequate to support the decision on appeal, he may provide for the production of such additional evidence or information as may be appropriate, or may remand the case to the Regional Director, with appropriate instructions for further action.

(d) On or before the expiration of forty-five (45) days after his receipt of the exceptions to the Regional Director's decision, the Director shall make his decision in writing: provided however, that if more than forty-five (45) days are required for a decision after the exceptions are received, the Director shall notify the parties to the appeal and specify the reason(s) for delay. The decision of the Director shall include: (1) A statement of facts; (2) conclusions; and (3) reasons upon which the conclusions are based. The decision of the Director shall be the final administrative action of the agency on a proposed plan of operations.

(e) A decision of the Regional Director from which an appeal is taken shall not be automatically stayed by the filing of a statement of appeal. A request for a stay may accompany the statement of appeal or may be directed to the Director. The Director shall promptly rule on requests for stays. A decision of the Director on request for a stay shall constitute a final administrative decision.

(f) Where, under this Subpart, the Superintendent has the authority to make the original decision, appeals may be taken in the manner provided by this section, as if the decision had been made by the Regional Director, except that the original statement of appeal shall be filed with the Superintendent, and if he decides not to reverse his original decision, the Regional Director shall have, except as noted below, the final review authority. The only decision of a Regional Director under this paragraph which shall be appealable by the Director is an appeal from a suspension under § 9.51(b). Such an appeal shall follow the procedure of paragraphs (a)-(3) of this section.

[43 FR 57825, Dec. 8, 1978; 44 FR 37915, June 29, 1979]

### § 9.50 Use of roads by commercial vehicles.

(a) After January 8, 1978, no commercial vehicle shall use roads administered by the National Park Service without being registered with the Superintendent. Roads must be used in accordance with procedures outlined in an approved plan of operations.

(1) A fee shall be charged for such registration and use based upon a posted fee schedule. The fee schedule posted shall be subject to change upon sixty (60) days of notice.
(2) An adjustment of the fee may be made at the discretion of the Superintendent where a cooperative maintenance agreement is entered into with the operator.

(b) No commercial vehicle which exceeds roadway load limits specified by the Superintendent shall be used on roads administered by the National Park Service unless authorized in writing by the Superintendent, or unless authorized by an approved plan of operations.

(c) Should a commercial vehicle used in operations cause damage to roads, resources or other facilities of the National Park Service, the operator shall be liable for all damages so caused.

### § 9.51 Damages and penalties.

(a) The operator shall be held liable for any damages to federally-owned or controlled lands, waters, or resources resulting from his failure to comply with either his plan of operations, or where operations are continued pursuant to § 9.33, failure to comply with the applicable permit or, where operations are temporarily approved under § 9.38, failure to comply with the terms of that approval.

(b) The operator agrees, as a condition for receiving an approved plan of operations, that he will hold harmless the United States and its employees from any damages or claims for injury or death of persons and damage or loss of property by any person or persons arising out of any acts or omissions by the operator, his agents, employees or subcontractors done in the course of operations.

(c) Undertaking any operations within the boundaries of any unit in violation of this Subpart shall be deemed a trespass against the United States and shall be cause for revocation of approval of the plan of operations.

(1) When a violation by an operator under an approved plan of operations is discovered, and if it does not pose an immediate threat of significant injury to federally-owned or controlled lands or waters, the operator will be notified in writing by the Superintendent and will be given ten (10) days to correct the violation; if the violation is not corrected within ten (10) days approval of the plan of operations will be suspended until such time as the violation is corrected.

(2) If the violation poses an immediate threat of significant injury to federally-owned or controlled lands or waters, approval of the plan of operations will be immediately suspended until such time as the violation is corrected. The operator will be notified in writing within five (5) days of any suspension and shall have the right to appeal that decision under § 9.48.

(3) Failure to correct any violation or damage to federally owned or controlled lands, waters or resources caused by such violations will result in revocation of plan of operations approval.

[43 FR 57825, Dec. 8, 1978; 44 FR 37915, June 29, 1979]

### § 9.52 Public inspection of documents.

(a) When a Superintendent receives a request for permission for access on, across or through federally-owned or controlled lands or waters for the purpose of conducting operations, the Superintendent shall publish a notice of this request in a newspaper of general circulation in the county(s) in which the lands are situated, or in such publications as deemed appropriate by the Superintendent.

(b) Upon receipt of the plan of operations in accordance with § 9.35(c), the Superintendent shall publish a notice in the FEDERAL REGISTER advising the availability of the plan for public review and comment. Written comments received within thirty (30) days will become a part of the official record. As a result of comments received or if otherwise deemed appropriate by the Superintendent, he may provide additional opportunity for public participation to review the plan of operations.

(c) Any document required to be submitted pursuant to the regulations in this Subpart shall be made available for public inspection at the office of the Superintendent during normal business hours, unless otherwise available pursuant to § 9.51(b). This does not include those records only made available for the Superintendent's inspection under § 9.41 of this Subpart or those records determined by the Superintendent to contain proprietary or confidential information. The availability of such records for inspection shall be governed by the rules and regulations found at 43 C.F.R. Part 2.

[43 FR 57825, Dec. 8, 1978; 44 FR 37915, June 29, 1979]

# APPLICATION OF THE 9B REGULATIONS

The 9B regulations provide the NPS with an existing regulatory framework to manage the effects of oil and gas operations within the parks. The application and implementation of these regulations must be assessed parkwide as well as for each site specific oil and gas activity to determine if these activities have the potential to impair park resources and values. As mentioned previously, these regulations apply to operations that require access on or through federally owned or controlled lands or waters in connection with nonfederally owned oil and gas in all National Park system units (36 CFR § 9.30(a)). "Operations" is broadly defined under the regulations to include all activities associated with the exploration for and production of nonfederally owned or controlled oil and gas, from gathering basic information to comply with the regulations to the transport of petroleum products (36 CFR § 9.31(c)). "Access" means any and all ways of entering, going over, across, or underneath an area of land or water. It includes travel by vehicle, watercraft, fixed-wing aircraft, helicopter, off-road vehicle, mobile heavy equipment, snowmobile, pack animal, and by foot. It also includes travel of the drill bit during drilling operations (NPS 2006c).

In applying the NPS Nonfederal Oil and Gas Rights Regulations, the NPS respects the constitutionally guaranteed property rights of mineral owners. As set forth in the Fifth Amendment to the Constitution, "...no person shall be deprived of property without due process of law; nor shall private property be taken for public use without just compensation." In two places, §§ 9.30(a) and 9.37(a)(3), the 9B regulations emphasize that they are not intended to result in the taking of a property interest, but rather are designed to impose reasonable regulations on activities that involve and affect federally-owned lands. Furthermore, the NPS has complied fully, and will continue to comply fully, with Exec. Order No. 12,630, 3 CFR 554 (1989), "Governmental Actions and Interference with Constitutionally Protected Property Rights." Any alternative selected and applied to oil and gas activities in the park as a result of this planning process would be subject to the NPS's statutory mandates, regulatory provisions, policies, and Executive Orders, including the above described limitations regarding the taking of private property interests.

If the National Park Service determines that the proposed oil and gas operation within a park unit would conflict with preservation, management, or use of the parks, or would impair park resources or values, the 36 CFR 9B regulations and NEPA process would result in identifying measures to mitigate impacts. Mitigation measures may be applied to the Plan of Operations as conditions of approval, subject to the operator's acceptance of specific provisions and operating stipulations (36 CFR § 9.37(b)(2)). However, if the Service determines that the proposed mineral development would impair park resources, values, or purposes, or does not meet approval standards under applicable NPS regulations and cannot be sufficiently modified to meet those standards, the Service will seek to extinguish the associated mineral right through acquisition, unless otherwise directed by Congress.

# PLANS OF OPERATIONS

The critical component of the regulations is the requirement that an operator submit and obtain NPS approval of a proposed plan of operations before commencing oil and gas exploration or production activities (36 CFR § 9.36). Such plans are essentially a prospective operator's "blueprint" for conducting activities including impact mitigation and site reclamation. Operators are responsible for preparing a plan of operations that addresses all information requirements applicable to proposed operations. Operators must supply this information in sufficient detail to enable the NPS to effectively analyze the impacts of the proposed operations on the particular unit's resources and values, and to determine whether to approve the proposed plan (36 CFR § 9.36(c)). The NPS reviews the operator's plan to make sure that the information is complete and, in turn, to ensure that park resources will be protected. Once the NPS has completed its review and environmental compliance responsibilities, it may approve the operator's plan. The approved plan allows the operator to conducts operations in a unit of the National Park system.

## 36 CFR 9B Plan of Operations Process

Under the 36 CFR 9B regulations, each operator requiring access on, across, or through NPS lands or water may conduct activities only under a Plan of Operations approved by the NPS. Once a Plan of Operations is approved, it serves as the operator's permit to operate in the park. Through the plan, the operator must show that the "…operations will be conducted in a manner which utilizes technologically feasible methods least damaging to the federally owned or controlled lands, waters and resources of the unit while assuring the protection of public health and safety" (36 CFR § 9.37(a)(1)). However, some nonfederal oil and gas operations in NPS units may qualify for an exemption to the Plan of Operations requirement. These exemptions are described in appendix A.

A key component of preparing the Plan of Operations is a detailed description of the environment that will be affected by the proposed activities. Operators first conduct plant, animal, cultural, hydrological, and topographic surveys as needed to adequately describe the resources in the areas in which they plan to work. Once the environmental conditions are known, operators must plan the use of methods and equipment that are least damaging to park resources. The surveys also provide a basis for designing reclamation activities.

Based on the scale of operations, the Plan of Operations preparation can be in the range of $1,000 and up to and exceeding $45,000. The wide range in costs to prepare a Plan of Operations demonstrates the differences in a plan's scope and content, variations in the number and types of environmental surveys needed, and the operator's approach to planning (in-house or contracted).

Next, operators may need to modify proposed activities from their standard methods to minimize environmental impacts. For example, to avoid harming certain resources, an operator may need to construct a longer access road or use directional drilling techniques. Sometimes avoidance of areas (such as wetlands or sensitive vegetation communities) is necessary to protect park resources. Disposing of wastes and contaminants at an approved disposal facility outside of the park is another method used to protect park resources. These and other modifications can add to the overall project cost.

Some upfront project costs may prevent the need for operators to do costly clean-up and remediation activities in future. For example, the NPS requires dikes or berms around drilling and production operations and impermeable barriers underneath these operations to provide secondary containment in the event of a spill. An uncontained spill or unnoticed leaks from a tank can contaminate large areas, flow into nearby surface waters, and seep into the groundwater. Clean-up and restoration of the damaged area to meet federal and state requirements could cost the operator hundreds of thousands of dollars.

The NPS also commonly requires operators to take a more active role in reclamation of the site compared with areas outside of the park. Following proper plugging of wells and removal of surface equipment, operators must clean up contaminated soil; remove debris and non-native materials used in operations; re-establish natural contours and vegetation; and monitor the results of the reclamation operations.

Maintaining a performance bond to guarantee compliance with the Plan of Operations is an annual cost to the operator. The 36 CFR 9B regulations limit the maximum bond amount to $200,000 for a single operation or multiple operations by the same operator in a given park. Annual costs to maintain bonds through a surety company range from 1 to 3 percent of face value, or up to 70 percent, depending on the operator. Operators typically file a corporate surety bond but may elect to file other types of acceptable securities such as an irrevocable letter of credit, cash, certified check, certificates of deposit, or government bonds. The bond or security required by the NPS is in addition to and not in lieu of any bond or security deposit required by other regulatory authorities.

Another issue facing operators in NPS units is the length of time it takes to obtain a permit. Table A-1 provides an explanation of the Plan of Operations permitting process and associated timeframes. Under current management practices, the NPS looks at each individual oil and gas proposal under the 36 CFR 9B regulations, and processing time is typically 3 to 4 months.

Under the NPS 36 CFR 9B regulations, the NPS has jurisdiction to regulate nonfederal oil and gas operations occurring within park boundaries. Activities located outside park boundaries but connected to operations occurring within a park are beyond the jurisdiction of the NPS. This means that the NPS cannot assert regulatory control over them. Nonetheless, the NPS can work cooperatively with the operator and permitting agencies with jurisdiction to get park protection concerns addressed. In the event that activities outside park boundaries damage or destroy park resources or values, Congress has given the NPS a means for recovering monetary damages under 16 USC § 19jj as discussed in appendix C.

### TABLE A-1. NPS PROCESSING TIME FOR A 36 CFR 9B PLAN OF OPERATIONS

| Action | NPS Response Time | Limiting Factor |
|---|---|---|
| Operator contacts park regarding interest in conducting oil and gas operations. Operator provides the NPS with written documentation demonstrating right to conduct operations. | Same day | Subject to park staff availability |
| Park provides operator copies of 36 CFR 9B regulations, performance standards, plan of operations requirements, and other information as necessary. | Same day | Subject to park staff availability |
| Operator meets with park staff to discuss proposed operation, scope resource issues relevant to the proposed operation, determine resources that could be affected by the operation; identify environmental planning and compliance requirements; and determine affected local, state and federal agencies. | Variable – NPS provides assistance as needed. Scoping meeting typically lasts one day. | Subject to park staff and operator availability |
| Operator meets with park staff and affected federal, state, and local agencies to identify resource issues, permitting requirements, and impact mitigation strategies. | Variable – NPS provides assistance as needed. | Subject to park staff, other agency staff, and operator availability |
| Operator submits written request for temporary access to gather basic information needed to complete the plan of operations. | Variable - NPS provides assistance as needed. | Subject to operator response |
| Park issues 60-day data collection permit with park resource/visitor protection requirements; and publishes a notice in the local newspaper pursuant to 36 CFR § 9.52(a). | 1 - 2 days | Subject to park staff availability |
| Operator conducts necessary surveys, including natural and cultural surveys, as applicable and surveys/stakes the operations area. | Variable - NPS provides assistance as needed. | Subject to operator response or timing requirements |
| Operator submits draft plan of operations to park. | Variable - NPS provides assistance as needed. | Subject to operator response |
| NPS performs a completeness and technical review of the plan of operations. Park accepts plan of operations as complete or returns it to the operator with specific directions on how to revise the plan. | 30 days | NPS policy from NPS procedures governing nonfederal oil and gas rights, 1992; and 36 CFR § 9.36(c) |

**TABLE A-1. NPS PROCESSING TIME FOR A 36 CFR 9B PLAN OF OPERATIONS**

| Action | NPS Response Time | Limiting Factor |
|---|---|---|
| Operator revises plan of operations, as necessary. | Variable - NPS provides assistance as needed. | Subject to operator response |
| Park staff prepares NEPA document (EA or EIS) or adopts operator's (or consultant-prepared) NEPA document, incorporates other environmental compliance (ESA, NHPA, wetlands, floodplains, CZM etc.), and initiates mandated consultations with other agencies. Park completes public review process, finalizes decision documents, and notifies the operator if the plan has been approved, conditionally approved, or rejected. | 60 days<br>(includes 30-day public review of EA) | 36 CFR § 9.37, 36 CFR<br>§ 9.52(b), NPS DO-77.1 for wetlands compliance, NPS DO 77.2, and DO-12 for NEPA compliance. Operator notified if additional time is needed per 36 CFR § 9.37(b)(6) |
| Operator agrees to any conditions of approval (if any), submits applicable state and federal permits, and files suitable performance bond with the NPS. | Variable | Subject to operator response |
| TOTAL NPS RESPONSE TIME | Minimum of 3 to 4 months | Dependent on compliance requirements |

## PERFORMANCE BONDS

The 9B regulations require the filing of a performance bond or other acceptable type of security payable to the NPS for all types and phases of nonfederal oil and gas operations. This bond, in addition to any bonds required by other regulatory agencies (e.g., the states of Kentucky and Tennessee), can be used only to pay for damages caused when an operator fails to comply with the conditions in a plan of operations, and is currently capped at $200,000. These bonds are set by the NPS regional director, taking into consideration the cost of reclamation as well as the liability amount. For further details on how bonds are set, including specific information regarding the considerations for the cost of reclamation and the liability amount, see the NPS Operators Handbook for Nonfederal Oil and Gas Development in Units of the National Park System (NPS 2006a).

Other key provisions of the 9B regulations include requirements for:

- Demonstrating ownership rights before granting temporary approval, reviewing a plan of operations, or evaluating an application under 36 CFR 9.32(3) for directional drilling (a well drilled underneath the park from a surface location outside the park);
- The scope of the plan of operations;
- Reclamation;
- Directional drilling;
- Changing plans of operations;
- Selling or transferring of an operation;
- Exemptions to the regulations;
- Administrative appeal of an NPS decision; and
- Damages and penalties.

# EXEMPTIONS

The 9B regulations do not apply to every oil and gas operation in a park unit. Operations that do not fall under the regulations include those that do not require access across federally controlled lands or waters (36 CFR 9.30(b)); operations on federal leases (36 CFR 9.30(b)); operations on mining claims (36 CFR 9.30(b)); or transportation pipelines associated with rights-of-way (discussed further below under “Applicability of 9B Regulations to Transpark Pipelines”). In addition other exemptions from the 9B regulations may be granted to existing operations and operations involving directional drilling.

## Existing Operations

Under the 9B regulations, an operator conducting “existing operations” may continue without submitting a plan of operations or filing a performance bond or security deposit. These operations are "grandfathered" (36 CFR 9.33) if the operator was conducting operations under a valid state or federal permit as of January 8, 1979 (effective date of the 9B regulations), when the area became a new park unit, or when the area came into the national park system by expansion of an existing unit.

If an operator was not required to obtain a federal or state permit prior to January 8, 1979, prior to the establishment of a new park unit, or prior to the expansion of an existing unit, he/she must come into compliance with the 9B regulations in accordance with the provisions of 36 CFR 9.33(b).

Situations may arise where an existing operation can lose its grandfathered status and an operation must comply with the 9B regulations, including filing a plan of operations and submitting a performance bond, as well as when a valid state or federal permit expires by its own terms (e.g., when an operation has a change in operator, when well work requires new state approval, or when an operator proposes activities that would disturb new land). Operators proposing to plug and reclaim existing operations require a new state permit, and as a result must file a plan of operations covering these activities, received NPS approval, and submit a performance bond (NPS 2006a).

In addition, under 36 CFR 9.33(c), the superintendent of a national park may require an operator to suspend operations if there are immediate threats of “significant injury” to federally owned or controlled lands, such as the escape of toxic or noxious gases, disturbances outside the area currently approved for the operation, uncontained or chronic spills, well blow-out, leaching or release of contaminants, fire or fire hazard, unmaintained storage tanks that lack secondary containment such as berms, inadequate safeguards for controlling well pressures; inadequate safeguards for protecting visitors and wildlife from serious injury, or damage to cultural resources.

## Directional Drilling

Section 9.32(e) of the 9B regulations governs operators that propose to develop their nonfederal oil and gas rights in any unit of the National Park System by directionally drilling a well from a surface location outside unit boundaries to a location under federally owned or controlled lands within park boundaries. Per section 9.32(e), an operator may obtain an exemption from the 9B regulations if the Regional Director is able to determine from available data that a proposed drilling operation under the park poses "no significant threat of damage to park resources, both surface and subsurface, resulting from surface subsidence, fracture of geological formations with resultant fresh water [aquifer] contamination or natural gas escape or the like." It is limited in scope to those aspects of the directional drilling operation occurring within park boundaries. Operators seeking an exemption to the 9B regulations must submit a section 9.32(e) Application for Directional Drilling. Further guidance on the NPS's directional drilling provision under section 9.32(e) is provided in the following sections.

## 36 CFR 9.32(d) Application Process

Section 9.32(e) of the 9B regulations governs operators that propose to develop their nonfederal oil and gas rights in a park unit by directionally drilling a well from a surface location outside unit boundaries to a location under federally-owned or controlled lands or waters within park boundaries. It is limited in scope to those aspects of the directional drilling operation occurring within park boundaries.

Per § 9.32(e), an operator may obtain an exemption from the 9B regulations if a Regional Director is able to determine from available data that a proposed drilling operation under the park poses “no significant threat of damage to park resources, both surface and subsurface, resulting from surface subsidence, fracture of geological formations with resultant fresh water acquifer [sic] contamination or natural gas escape or the like." The regulations define operations as "all functions, work and activities within a unit in connection with exploration for and development of oil and gas resources, the right to which is not owned by the United States..." (36 CFR § 9.31(c), underlining added). The potential impacts considered in the § 9.32(e) exemption process relate only to effects on park resources from downhole activities occurring within the boundary of the park, not threats to park resources associated with the operation outside park boundaries.

Under the regulations, the NPS may determine that an operator: (1) qualifies for an exemption from the regulations with no needed mitigation to protect park resources from activities occurring within park boundaries; (2) qualifies for an exemption from the regulations with needed mitigation to protect subsurface park resources from activities occurring within park boundaries; or (3) must submit a proposed plan of operations and a bond to the NPS for approval. These legally permissible options are briefly described as follows:

**Exemption with No Mitigation (no approval or permit issued)**—The NPS determines that the proposed operation inside the park qualifies for an exemption under § 9.32(e) without any mitigation or conditions required by the NPS on the downhole activities. This option will arise when there is no potential for surface or subsurface impacts in the park from the downhole activities (e.g., the wellbore does not intercept an aquifer within the park). Under this option, the NPS is not granting an approval or issuing a permit.

**Exemption with Mitigation (no approval or permit issued)**—The NPS determines that the proposed operation inside the park qualifies for an exemption under § 9.32(e) if there is no potential for surface impacts to park resources from downhole operations in the park and the operator adopts mitigation measures or conditions that reduce potential impacts on subsurface resources (e.g., an aquifer) to "no measurable effect." As in option #1 above, the NPS is not granting an approval or issuing a permit.

**Plan of Operations (approval and "permit" issued)**—This regulatory option would apply if NPS determines that it cannot make the requisite finding for a § 9.32(e) exemption because (1) impacts to surface resources are involved, or (2) impacts to subsurface resources cannot be adequately mitigated to yield "no measurable effect." This option would also apply if an operator does not apply for an exemption and the NPS does not consider granting an exemption on its own initiative. In these cases a prospective operator must submit and obtain NPS approval of a proposed plan of operations and file a bond before commencing directional drilling activities inside a park. The required plan and bond will be limited in scope to those aspects of the directional drilling operation that occur within park boundaries. As a result, many of the general plan information requirements set forth under § 9.36 will not apply. Mitigation measures and/or conditions of approval would be integral to this option. Mitigation measures would protect cultural resources, cave/karst resources, aquifers, floodplains, wetlands and other surface resources from operations occurring inside the park. Under this option, an operator must have NPS approval of a proposed plan before commencing any activity in the boundaries of the park. The approved plan constitutes the operator's "permit".

**Applicability of NEPA**—For purposes of public disclosure and education, NPS prepares NEPA documents on all directional drilling proposals submitted to the NPS. Through its NEPA analysis, the NPS assesses impacts both in and outside of the park associated with the downhole operations in addition to the connected actions outside of the park. The downhole activities occurring in the park are analyzed to determine if there is a significant threat to park resources and if a § 9.32(e) exemption should be granted. As required by NEPA, the analysis of the impacts from the connected actions occurring outside of the park are presented in addition to the downhole operations both inside and outside of the park to disclose to the public all of the potential impacts on the human environment. Cumulative impacts are presented for the analysis area which includes areas inside and outside of the park. Table A-2 summarizes the applicability of NEPA, the Endangered Species Act (ESA), the National Historic Preservation Act (NHPA), Executive Order 11988 – Floodplain Management, and Executive Order 11990 – Protection of Wetlands, as well as mitigation measures, to directional drilling applications

**TABLE A-2. SUMMARY OF COMPLIANCE REQUIREMENTS FOR DIRECTIONAL DRILLING PROPOSALS FROM SURFACE LOCATIONS OUTSIDE A PARK**

| Option | Scope of NEPA Analysis | Endangered Species Act | National Historic Preservation Act | Floodplains Executive Order | Wetlands Executive Order | Mitigation Measures |
|---|---|---|---|---|---|---|
| Exemption with No Mitigation | The NEPA analysis (most likely an EA) would focus on environmental effects from the downhole operations in the park. The potential impacts of the connected actions on park resources and values would also be disclosed. Impacts outside the park would be assessed. | Granting an exemption is non-discretionary under this option. ESA § 7 consultation for activities occurring in the park is not required because there would be no effect on federally listed threatened and endangered species and/or critical habitat.<br>In the event that connected operations outside the park could affect a T&E species or critical habitat in or outside the park, consultation and mitigation under the ESA would be required. The NPS would be the lead federal agency carrying out the ESA consultations outside of the park if there is no other federal entity with broader regulatory involvement. | There is no potential for impact on cultural resources in the park from the downhole operations in the park.<br>The NPS has no Section 106 responsibility with respect to the National Historic Preservation Act of 1966, as amended, for wells that originate on non-federal lands located outside the Unit, for which the wellbores would cross through the Unit to extract non-federally owned hydrocarbons from beneath the Unit. The Advisory Council on Historic Preservation concurred with this finding on September 13, 2004. | There is no potential for impact to federally-owned or controlled floodplains in the park from the downhole operations in the park. No action is required by the NPS under the Executive Order. Other federal agencies having broader permitting authority for the proposal would need to comply with the Executive Order if floodplains would be affected by the operation. | There is no potential for impact to federally-owned or controlled wetlands in the park from the downhole operations in the park. No action is required by the NPS under the Executive Order. Other federal agencies having broader permitting authority for the proposal would need to comply with the Executive Order if wetlands would be affected by the operation. | • NPS mitigation measures/ conditions would not be applied to the exemption.<br>• The operator can voluntarily apply mitigation measures to reduce indirect impacts on park resources and values from connected actions outside the park.<br>• The NPS will work cooperatively with other agencies during their permitting processes to identify potential impacts on park resources and values and recommend mitigation measures/conditions of approval.<br>• If NPS is "lead" federal agency following ESA § 7 consultation, the Service may require mitigation measures/ conditions to protect threatened and endangered species and habitat both inside and outside the park. |

**TABLE A-2. SUMMARY OF COMPLIANCE REQUIREMENTS FOR DIRECTIONAL DRILLING PROPOSALS FROM SURFACE LOCATIONS OUTSIDE A PARK**

| Option | Scope of NEPA Analysis | Endangered Species Act | National Historic Preservation Act | Floodplains Executive Order | Wetlands Executive Order | Mitigation Measures |
|---|---|---|---|---|---|---|
| Exemption with Mitigation | Same as Option #1 | Granting an exemption is discretionary under this option. NPS is required to determine if federally listed threatened and endangered species and/or critical habitat may be affected inside the park from in-park operations.<br>The NPS would be the lead federal agency carrying out the consultations both inside and outside of the park if there is no other federal entity with broader regulatory involvement. | Same as Option #1 | Mitigation/conditions applied to ensure the integrity of downhole operations in the park reduces the likelihood of impacts to floodplains in the park; no action is required by the NPS under the Floodplains Executive Order. | Mitigation/conditions applied to ensure the integrity of downhole operations in the park reduces the likelihood of impacts to wetlands in the park; no action is required by the NPS under the Wetlands Executive Order. | The compliance responsibilities are the same as Option # 1, except:<br>NPS may require mitigation measures/conditions to reduce impacts to subsurface park resources associated with downhole operations inside the park. |
| Plan of Operations | Same as Option #1 | Same as Option #2. | If potential impacts to cultural resources could not be mitigated, the NPS would follow its standard procedures for conducting consultations with the SHPO/THPO but focus its consultation on the downhole operations inside the park. | Same as Option #2. If potential impacts to floodplains could not be mitigated, the NPS must follow its standard procedures in the NPS Director's Order/ Procedures Manual and prepare a *Floodplains Statement of Finding*s pertaining to the downhole operations within the park. | Same as Option #2. If potential impacts to wetlands could not be mitigated, the NPS must follow its standard procedures in the NPS Director's Order/ Procedures Manual and prepare a *Wetlands Statement of Finding*s pertaining to the downhole operations within the park. | Same as Option #2. |

**Collection of Resource Information by Prospective Operators**—The NPS may only require a prospective operator of a directional drilling operation to conduct resource surveys inside a park when there is a correlation between downhole operations within the park and potential impacts on park resources and values. In contrast, the NPS may request, but cannot require, operators to conduct resource surveys inside a park associated with operations outside the park but connected to the downhole activities in the park or to conduct resource surveys outside the park. Overall costs and timeframes for the operator to prepare a § 9.32(e) application and timeframes for NPS review and approval should be less than for a Plan of Operations, in part because less data will be collected and used in the NEPA analysis.

When the NPS is the "lead" federal agency responsible for consultation under section 7 of the Endangered Species Act (ESA), the NPS may require biological surveys both inside and outside the park if, during consultation, it is determined that these surveys are needed. The ability to require biological surveys stems from authority under the ESA, not the 9B regulations.

**Access to Surface Location Outside Park Boundaries**—If the United States does not own the surface estate where operations are located outside the park, NPS access to these operations must be coordinated with the operator, including obtaining the operator's permission to be on location. NPS access also must relate to obtaining information to complete the needed compliance work or to ensuring compliance with mitigation measures related to downhole operations inside the park. The 9B regulations provide no authority for requiring an operator to grant the NPS access for the purpose of observing compliance with terms unrelated to the downhole activities in the park.

**Monitoring**—The NPS's ability to monitor and inspect directional drilling operations is limited to downhole operations within the park (e.g., surface casing, cementing, plugging operations, etc.). As a practical matter, monitoring of downhole activities inside the park can only be accomplished from the surface location outside the park. As a result, the NPS may need to access the surface location and should make such access a condition of an exemption under option #2 or a condition of approval under option #3. The NPS must coordinate the timing of such access with the operator. The 9B regulations provide no authority to require an operator to grant the NPS access for the purpose of observing compliance with terms unrelated to the downhole activities inside the park. When the NPS has made an upfront determination that a directional drilling operation is exempt without conditions from the regulations because of the lack of impacts, there is no 9B regulatory reason to access the surface location outside the park.

To ensure that directional drilling operations inside a park are being conducted in accordance with an exemption determination or an approved plan, the NPS has two monitoring options. The Service can have a qualified individual (NPS employee or a mutually agreed upon third-party contractor hired by the operator) on location to witness the well casing, cementing and well plugging programs within the park, or the NPS can require the operator to submit drilling records that demonstrate that the well casing, cementing program, and plugging program were completed as proposed. Selection of the appropriate option or combination of options should be worked out with the operator.

## Applicability of the 9B Regulations to Transpark Pipelines

Existing transpark oil and gas pipelines and their rights-of-way lie outside the scope of the 9B regulations. Transpark oil and gas pipelines have their point of origin and end point outside national parks, and, for the most part are not supporting nonfederal oil and gas operations in parks. As a result, they are not subject to the existing 9B regulations. However, if a nonfederal oil and gas operation in a park connects to such a pipeline via a flowline or a gathering line, that portion of the flowline or gathering line crossing the park would be subject to the 9B regulations, including the Plan of Operations requirement.

While most transpark oil and gas pipelines are not subject to the 9B regulations, they are either subject to federal Department of Transportation (DOT) regulations at 49 CFR Parts 190-199 or State of Texas requirements, and all other applicable federal and state laws. The DOT regulations govern safety and environmental protection considerations affiliated with interstate pipelines. Specifically, the DOT regulations cover testing, reporting, inspection, maintenance, corrosion control, and spill contingency plans of these pipelines. State regulations often mirror the federal requirements and govern intrastate pipelines. The Railroad Commission of Texas administers state requirements on all oil and gas pipelines under Texas law (see TX. Rev. Stat. S81.011(a) et seq.). Transpark pipeline operators should note that if park system resources are damaged from the operation of their pipeline in a park unit, the NPS can exercise its authority under the Act of July 27, 1990, PL No. 101-337, 104 Stat. 379, codified as amended at 16 USC 19jj through 19jj-4 (2000), to undertake all necessary actions to protect park system resources. Operators will be held liable to the United States for its response costs as well as for any damages to park system resources (see section 19jj-1).

# APPENDIX B: SUMMARY OF NON-FEDERAL OIL AND GAS OPERATIONS LEGAL AND POLICY MANDATES

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updated January 2007

This appendix summarizes many, but not all, of the legal and policy mandates that pertain to the exercise of nonfederal oil and gas rights in units of the National Park System. The first five laws pertain specifically to the National Park Service. They are followed by:

- Other federal laws and regulations,
- Executive Orders,
- NPS policies, guidelines, and procedures, and
- Selected Kentucky and Tennessee laws and regulations relevant to oil and gas operations.

The following summaries are intended to acquaint the reader with many of the legal and policy requirements that apply to nonfederal oil and gas operations in National Park System units and are not meant as legal interpretations. They cannot be relied upon to create any rights, substantive or procedural, enforceable by any party in litigation with the United States. Congress may change statutes and agencies may update their regulations and policies. <u>During project planning, operators are responsible for ensuring they have current and complete information on legal and policy requirements for nonfederal oil and gas operations on NPS lands.</u>

Table B.1, summarizes many, but not all, of the legal and policy mandates governing the exercise of nonfederal oil and gas operations in national park units. These include statutes, regulations, executive orders and policies. This appendix contains summary descriptions of many of the Current Legal and Policy Requirements listed in the following table.

[1] The following persons have contributed to this appendix: Lisa Norby, Petroleum Geologist, NPS; Pat O'Dell, Petroleum Engineer, NPS; Edward Kassman, regulatory specialist, NPS; Madoline Wallace, environmental protection specialist, former NPS employee; Sandy Hamilton, environmental protection specialist, NPS; and Michael Graetz, law student, NPS.

## Table B.1. Legal and Policy Mandates Pertaining to Nonfederal Oil and Gas Operations

| AUTHORITIES | RESOURCES AND VALUES AFFORDED PROTECTION |
|---|---|
| **National Park Service Statutes and Applicable Regulations** | |
| NPS Organic Act of 1916, as amended, 16 U.S.C. §§ 1 *et seq.* | All resources, including air resources, cultural and historic resources, natural resources, biological diversity, human health and safety, endangered and threatened species, visitor use and experience, and visual resources |
| National Park System General Authorities Act, 16 U.S.C. §§ 1a-1 *et seq.* | All resources, including air resources, cultural and historic resources, natural resources, biological diversity, human health and safety, endangered and threatened species, visitor use and experience, and visual resources |
| National Park Service Omnibus Management Act of 1998, 16 U.S.C. §§ 5901 *et seq.* | Any living or non-living resource |
| NPS Nonfederal Oil and Gas Rights regulations – 36 C.F.R. Part 9, Subpart B | All, *e.g.*, air resources, cultural and historic resources, natural resources, biological diversity, human health and safety, T&E species, visitor use and experience |
| Park System Resource Protection Act, 16 U.S.C. § 19jj | Any living or non-living resource that is located within the boundaries of a unit of the National Park System, except for resources owned by a nonfederal entity |
| **Other Applicable Federal Laws and Regulations** | |
| American Indian Religious Freedom Act, as amended, 42 U.S.C. §§ 1996 – 1996a; 43 C.F.R. Part 7 | Cultural and historic resources |
| Antiquities Act of 1906, 16 U.S.C. §§ 431-433; 43 C.F.R. Part 3 | Cultural, historic, archeological, paleontological resources |
| Archeological Resources Protection Act of 1979, 16 U.S.C. §§ 470aa – 470mm; 18 C.F.R. Part 1312; 36 C.F.R. Part 296; 43 C.F.R. Part 7 | Archeological resources |
| Clean Air Act, as amended, 42 U.S.C. §§ 7401-7671q; 40 C.F.R. Parts 23, 50, 51, 52, 58, 60, 61, 82, and 93; 48 C.F.R. Part 23 | Air resources |
| Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended, 42 U.S.C. §§ 9601-9675; 40 C.F.R. Parts 279, 300, 302, 307, 355, and 373 | Human health and welfare and the environment |
| Endangered Species Act of 1973, as amended, 16 U.S.C. §§ 1531-1544; 36 C.F.R. Part 13; 50 C.F.R. Parts 10, 17, 23, 81, 217, 222, 225, 402, and 450 | Plant and animal species or subspecies and their habitat, which have been listed as threatened or endangered by the U.S. Fish and Wildlife Service (FWS) or the National Marine Fisheries Service (NMFS). |
| Farmland Protection Policy Act, 7 U.S.C. §§ 4201-4209, 7 C.F.R. Part 658 | Prime and unique farmland and soils |
| Federal Insecticide, Fungicide, and Rodenticide Act, as amended (commonly referred to as Federal Environmental Pesticide Control Act of 1972), 7 U.S.C. §§ 136 *et. seq.;* 40 C.F.R. Parts 152-180, except Part 157 | Human health and safety and the environment |
| Federal Land Policy and Management Act of 1976, 43 U.S.C. §§ 1701 *et seq.;* 43 C.F.R. Part 2200 for land exchanges and 43 C.F.R. Parts 1700-9000 for all other BLM activities | Federal lands and resources administered by the Bureau of Land Management |
| Federal Water Pollution Control Act of 1972 (commonly referred to as Clean Water Act), 33 U.S.C. §§ 1251 *et seq.;* 33 C.F.R. Parts 320-330; 40 C.F.R. Parts 110, 112, 116, 117, 122, and 230-232 | Water resources, wetlands, and waters of the U.S. |
| Fish and Wildlife Coordination Act, 16 U.S.C. §§ 661 – 666c | Water resources, fish and wildlife |

| AUTHORITIES | RESOURCES AND VALUES AFFORDED PROTECTION |
|---|---|
| Historic Sites, Buildings, and Antiquities Act (Historic Sites Act of 1935), 16 U.S.C. §§ 461-467; 18 C.F.R. Part 6; 36 C.F.R. Parts 1, 62, 63, and 65 | Historic sites, buildings and objects |
| Lacey Act, as amended, 16 U.S.C. §§ 3371 *et seq.;* 15 C.F.R. § 904; 50 C.F.R. Parts 10, 11, 12, 14, and 300 | Fish and wildlife, vegetation |
| Migratory Bird Treaty Act, as amended, 16 U.S.C. §§ 703-712; 50 C.F.R. Parts 10, 12, 20, and 21 | Migratory birds |
| National Environmental Policy Act of 1969, 42 U.S.C. §§ 4321 *et seq.;* 40 C.F.R. Parts 1500-1508 | Human environment (cultural and historic resources, natural resources, biodiversity, human health and safety, socioeconomic environment, visitor use and experience) |
| National Historic Preservation Act of 1966, as amended, 16 U.S.C. §§ 470 et seq.; 36 C.F.R. Parts 18, 60, 63, 78, 79, 800 | Cultural and historic properties listed in or determined to be eligible for listing in the National Register of Historic Places |
| Native American Graves Protection and Repatriation Act, 25 U.S.C. §§ 3001-3013; 43 C.F.R. Part 10 | Native American human remains, funerary objects, sacred objects, objects of cultural patrimony |
| Noise Control Act of 1972, 42 U.S.C. §§ 4901-4918; 40 C.F.R. Part 211 | Human health and welfare |
| Oil Pollution Act, 33 U.S.C. §§ 2701-2762; 15 C.F.R. Part 990; 30 C.F.R. Part 253; 33 C.F.R. Parts 135 and 150; 40 C.F.R. Part 112 | Water resources, natural resources |
| Pipeline Safety Act of 1992, 49 U.S.C. §§ 60101 *et seq*.; 49 C.F.R. Parts 190-199 | Human health and safety, the environment |
| Resource Conservation and Recovery Act, 42 U.S.C. §§ 6901 *et. seq*.; 40 C.F.R. Parts 240-282; 49 C.F.R. Parts 171-179 | Natural resources, human health and safety |
| Rivers and Harbors Act of 1899, as amended, 33 U.S.C. §§ 401 *et. seq*.; 33 C.F.R. Parts 114, 115, 116, 320-325, and 333 | Shorelines and navigable waterways, tidal waters, wetlands |
| Safe Drinking Water Act of 1974, 42 U.S.C. §§ 300f *et seq*.; 40 C.F.R. Parts 141-148 | Human health, water resources |
| Wild and Scenic Rivers Act of 1968, 16 U.S.C. §§1271 *et seq*.; 36 C.F.R. Part 297 | Water resources, recreational values, geologic resources, fish and wildlife, historic, cultural and other similar values |
| Enabling Act for Big South Fork National River and Recreation Area (Water Resources Act of 1974) 16 USC § 460ee | Cultural, historic, geologic, fish, wildlife, and archeologic resources; scenic and recreational values |
| Enabling Act for Obed Wild and Scenic River, P.L. 90-542, 16 USC § 1274 | Rivers, geologic, fish and wildlife, historic, cultural resources; and recreational and scenic values |
| **Executive Orders** | |
| Executive Order No. 11593 – Protection and Enhancement of the Cultural Environment, 36 Fed. Reg. 8921 (1971), 3 C.F.R. 1971 Comp., 36 C.F.R. §§ 60, 61, 63, 800 | Cultural resources |
| Executive Order No. 11644 – Use of Off-Road Vehicles on the Public Lands, 37 Fed Reg. 2877 (1972) reprinted in 42 U.S.C. § 4321, as amended by Executive Order No. 11989 (1977), 42 Fed. Reg. 26959; Executive Order No. 12608 (1987), § 21, 52 Fed. Reg. 34617 | Natural and cultural resources, aesthetic and scenic values |
| Executive Order No. 11988 – Floodplain Management, 42 Fed. Reg. 26951 (1977), 3 C.F.R. 121 Comp., as amended by Executive Order No. 12148 (1979), 44 Fed. Reg. 43239, 3 C.F.R. 1979 Comp., p. 412 | Floodplains, human health, safety, and welfare |
| Executive Order No. 11990 – Protection of Wetlands, 42 Fed. Reg. 26961 (1977), 3 C.F.R. 121 | Wetlands |
| Executive Order No. 12088 – Federal Compliance with Pollution Control Standards, 43 Fed. Reg. 47707 (1978); as amended by Executive Order No. 12580 – Superfund Implementation, 52 Fed. Reg. 2923 (1987) | Natural resources, human health and safety |

| AUTHORITIES | RESOURCES AND VALUES AFFORDED PROTECTION |
|---|---|
| Executive Order No. 12630 – Governmental Actions and Interference with Constitutionally Protected Property Rights, 53 Fed. Reg. 8859 (1988) | Private property rights, public funds |
| Executive Order No. 12898 – Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations, amended by Executive Order No. 12948, 60 Fed. Reg. 6379 (1995) | Human health and safety |
| Executive Order No. 13007 – Indian Sacred Sites, 61 Fed. Reg. 26771 (1996) | Native Americans' sacred sites |
| Executive Order No. 13112 – Invasive Species, 64 Fed. Reg. 6183 (1999), as amended by Executive Order 13286, 68 Fed. Reg. 10619 (2003) | Vegetation and wildlife |
| Executive Order No. 13186 – Responsibilities of Federal Agencies to Protect Migratory Birds, 66 Fed. Reg. 3853 (2001) | Migratory birds |
| Executive Order No. 13212 – Actions to Expedite Energy-Related Projects, 66 Fed. Reg. 28357 (2001), as amended by Executive Order No. 13302, 68 Fed. Reg. 27429 (2003) | Production, transmission, conservation of energy |
| Executive Order No. 13352 – Facilitation of Cooperative Conservation, 69 Fed. Reg. 52989 (2004) | Natural resources, property rights, public health and safety |
| **Federal Policies, Guidelines and Procedures** | |
| NPS Management Policies (2006) | All resources including air resources, cultural and historic resources, natural resources, biological diversity, human health and safety, endangered and threatened species, visitor use and experience, visual resources |
| Dept. of the Interior, Departmental Manual, 516 DM 1 - 15 –NEPA policies (2005) | All resources including cultural resources, historic resources, natural resources, human health and safety |
| Dept. of the Interior, Departmental Manual, 517 DM 1 - Pesticides (1981) | Human health and safety, the environment |
| Dept. of the Interior, Departmental Manual, 519 DM 1 - 2 – Protection of the Cultural Environment (1994) | Archeological, prehistoric resources, historic resources, Native American human remains, cultural objects |
| Department of the Interior, Departmental Manual, 520 DM 1 – Protection of the Natural Environment - Floodplain Management and Wetlands Protection Procedures (2001) | Floodplains and wetlands |
| Dept. of the Interior, Onshore Oil and Gas Order Number 2, Section III, Drilling Abandonment Requirements, 53 Fed. Reg. 46,810 - 46,811 (1988) | Human health and safety |
| NPS Director's Order 12 and Handbook – Conservation Planning, Environmental Impact Analysis, and Decision Making (2001) | All resources including natural resources, cultural resources, human health and safety, socioeconomic environment, visitor use |
| NPS Director's Order 28 – Cultural Resource Management (1998) | Cultural, historic, and ethnographic resources |
| NPS Director's Order 28A – Archeology (2004) | Archeological resources |
| NPS Director's Order 47 – Sound Preservation and Noise Management (2000) | Natural soundscapes |
| NPS Director's Order and Reference Manual 53 – Special Park Uses (2005) | All resources, including air resources, cultural and historic resources, natural resources, biological diversity, human health and safety, endangered and threatened species, visitor use and experience, visual resources. |
| RM 77 – Natural Resources Management (2004) | Natural resources |
| NPS Director's Order and Procedural Manual 77-1 – Wetland Protection (2002) | Wetlands |
| NPS Director's Order and Procedural Manual 77-2 – Floodplain Management (2003) | Floodplains |

| AUTHORITIES | RESOURCES AND VALUES AFFORDED PROTECTION |
|---|---|
| Secretary of the Interior's Standards and Guidelines for Archeology and Historic Preservation," 48 Fed. Reg. 44716 (1983), also published as Appendix C of NPS Director's Order 28 – Cultural Resource Management | Cultural and historic resources |
| Government-to-Government Relations with Native American Tribal Governments, Presidential Memorandum (April 29, 1994) | Native Americans – Tribal rights and interests |
| **Selected Kentucky and Tennessee Laws and Regulations** | |
| Tenn. Code, Title 60, Oil and Gas (2006) | Permitting and operations – public health and safety |
| Tenn. Code, Title 68, Health and Safety and Environmental Protection (2006) | Permitting and operations – all resources, public health and safety |
| Tenn. Code, title 70, Wildlife Resources (2006) | Plants and wildlife |
| KY Rev. Stat. Title 28, Mines and Minerals (2005) Title 805 §§ 040 - 170 | Permitting and operations – public health and safety |
| KY Rev. Stat., Title 12, Conservation and State Development (2005) | All resources, public health and safety |

# NATIONAL PARK SERVICE LAWS

## NATIONAL PARK SERVICE ORGANIC ACT OF 1916, as amended, 16 U.S.C. §§ 1 et seq.

**Resources afforded protection:** all resources including air resources, cultural and historic resources, natural resources, biological diversity, human health and safety, endangered and threatened species, visitor use and experience, visual resources
**Applicable regulation(s):** 36 C.F.R. Parts 1-10, 12-14, 20, 21, 25, 28, 30, 34, and 51

Through this Act, Congress established the National Park Service and mandated that it "shall promote and regulate the use of federal areas known as national parks, monuments…by such means and measures as conform to the fundamental purpose of said parks, monuments…which purpose is to conserve the scenery and the natural and historic objects and the wild life therein and to provide for the enjoyment of the same in such manner and by such means as will leave them unimpaired for the enjoyment of future generations."

Section 3 of the Organic Act provides the Secretary of the Interior with the authority to adopt rules and regulations to govern the use and the management of park units. Through this provision of the Organic Act, the NPS promulgated regulations governing the exercise of nonfederal oil and gas rights at 36 C.F.R. Part 9, Subpart B. These regulations control all activities during the exercise of rights to oil and gas not owned by the United States where access is on, across or through federally owned or controlled lands or waters within any NPS unit. The NPS does not intend the regulations to result in the taking of a property interest, but rather to impose reasonable regulations on activities that involve and affect federally owned lands. These regulations are written to ensure that operators conduct oil and gas activities in a manner consistent with the purposes for which Congress created the NPS unit. Likewise, the regulations prevent or minimize damage to the environment and other resource values and insure that all NPS units remain unimpaired for the enjoyment of future generations.

The courts have consistently interpreted the Organic Act and its amendments to elevate resource conservation above visitor recreation. Michigan United Conservation Clubs v. Lujan, 949 F.2d 202, 206 (6th Cir. 1991) states, "Congress placed specific emphasis on conservation." National Rifle Association of America v. Potter, 628 F. Supp. 903, 909 (D.D.C. 1986) states, "In the Organic Act Congress speaks of but a single purpose, namely, conservation." The NPS Management Policies (NPS 2006) also recognize that resource conservation takes precedence over visitor recreation. The policy dictates, "when there is a conflict between conserving resources and values and providing for enjoyment of them, conservation is to be predominant."

Because conservation remains predominant, the NPS seeks to avoid or minimize adverse impacts on park resources and values; however, the NPS has the discretion to allow impacts when necessary to fulfill park purposes (NPS 2006, §§ 1.4.3, 1.4.3.1). While some actions and activities cause impacts, the NPS cannot allow an adverse impact that constitutes resource impairment (NPS 2006, § 1.4.3). The Organic Act prohibits actions that impair park resources unless a law directly and specifically allows for the acts (16 U.S.C. § 1a-1). An action constitutes an impairment when its impacts "harm the integrity of park resources or values, including the opportunities that otherwise would be present for the enjoyment of those resources or values" (NPS 2006, § 1.4.5). An impact on any park resource or value may constitute an impairment, but an impact would be more likely to constitute an impairment to the extent that it has a major adverse effect on a resource or value whose conservation is:

- necessary to fulfill specific purposes identified in the establishing legislation or proclamation of the park, or
- key to the natural or cultural integrity of the park or to opportunities for enjoyment of the park, or
- identified in the park's general management plan or other relevant NPS planning documents as being of significance. (NPS 2006 § 1.4.5)

To determine impairment, the NPS must evaluate "the particular resources and values that would be affected, the severity, duration, and timing of the impact, the direct and indirect effects of the impact, and the cumulative effects of the impact in question and other impacts" (NPS 2006, § 1.4.5).

## NATIONAL PARK SYSTEM GENERAL AUTHORITIES ACT, 16 U.S.C. §§ 1a-1 et seq.

**Resources afforded protection:** all resources, including air resources, cultural and historic resources, natural resources, biological diversity, human health and safety, endangered and threatened species, visitor use and experience, visual resources
**Applicable regulation(s):** 36 C.F.R. Parts 1-199

This act affirmed that while all national park system units remain "distinct in character," they are "united through their interrelated purposes and resources into one national park system as cumulative expressions of a single national heritage." The purpose of this act was "to include all such areas in the system and to clarify the authorities applicable to the system." The act made it clear that the NPS Organic Act and other protective mandates apply equally to all units of the system. Further, amendments stated that NPS management of park units should not "derogat[e] ...the purposes and values for which these various areas have been established."

## NATIONAL PARK SERVICE OMNIBUS MANAGEMENT ACT OF 1998, 16 U.S.C. §§ 5901 et seq.

**Resources afforded protection:** any living or non-living resource
**Applicable regulation(s):** none

This statute requires the Secretary of the Interior to continually improve the NPS's ability to provide management, protection and interpretation of National Park System resources. The statute directs the NPS to manage the units by employing high quality science and information; to inventory the system's resources to create baseline information so that NPS can monitor and analyze future data to determine trends in the resources' conditions; and to use the results of the scientific studies for park management. In the oil and gas context, this requires operators to support their plans of operations with scientific data. Further, it requires the operators to monitor their operations area to ensure that their operations do not adversely impact the park's resources.

## PARK SYSTEM RESOURCE PROTECTION ACT, 16 U.S.C. § 19jj

**Resources afforded protection:** any living or non-living resource that is located within the boundaries of a unit of the National Park System, except for resources owned by a nonfederal entity
**Applicable regulation(s):** none

The Park System Resource Protection Act makes any person who destroys, causes the loss of, or injures any park system resource strictly liable to the United States for response costs and for damages resulting from such destruction, loss, or injury. A park system resource includes any living or non-living resource located within the boundaries of a NPS unit, except for resources owned by a non-federal entity. Because the statute imposes strict liability the only defenses arise when an act of god or war caused the damage, a third party who constituted neither an employee or nor an agent of the owner/operator caused solely the damage, or an activity authorized by federal or state law caused the damage.

The Park System Resources Protection Act authorizes the Secretary of the Interior to request the Department of Justice to file a civil action for the costs of replacing, restoring or acquiring the equivalent of a park system resource; the value of any use loss pending its restoration; replacement, or acquisition, the cost of damage assessments; and the cost of response including actions to prevent, to minimize, or to abate injury. Response costs include actions taken by the NPS "…to prevent or minimize destruction, loss of, or injury to park system resources; to abate or minimize the imminent risk of such destruction, loss or injury; or to monitor ongoing effects of incidents causing such destruction, loss or injury."

The Park System Resource Protection Act applies to nonfederal oil and gas activities in units of the National Park System. Operators need to make sure that they operate within the specifications of their approved 9B plan, comply with all other relevant legal requirements, and take precautions to avoid actions that may damage park system resources.

**NOTE:** The 36 CFR Part 9 Subpart B Nonfederal Oil and Gas Rights regulations are described in Chapter 2 of the Plan/EIS.

# OTHER APPLICABLE FEDERAL LAWS AND REGULATIONS

## AMERICAN INDIAN RELIGIOUS FREEDOM ACT, as amended, 42 U.S.C. §§ 1996 –1996a

**Resources afforded protection:** cultural and historic resources
**Applicable regulation(s):** 43 C.F.R. Part 7

This Act requires the federal government to protect and to preserve Native Americans', Eskimos', Aleuts', and Native Hawaiians' inherent right to believe, to express, and to exercise their traditional religions. It allows them to access, to use, and to possess sacred objects and gives them the freedom to worship through ceremonials and traditional rites. It further directs various federal departments, agencies, and other administrative bodies to evaluate their policies and procedures in consultation with native traditional religious leaders to determine changes necessary to protect and preserve Native American religious cultural rights and practices.

If the NPS anticipates a conflict between proposed oil and gas operations and tribal religious rights, it will consult with the tribe as part of the 9B plan approval process. To ensure compliance with this Act, the NPS will consult with tribes during the plan of operations approval process.

### Antiquities Act of 1906, 16 U.S.C. §§ 431 – 433

**Resources afforded protection:** cultural, historic, archeological and paleontological resources
**Applicable regulation(s):** 43 C.F.R. Part 3

As the Archeological Resources Protection Act's forerunner, the Antiquities Act constituted the first general act providing protection for archeological resources. It protects all historic and prehistoric ruins or monuments on federal lands and prohibits their excavation, destruction, injury or appropriation without the departmental secretary's permission. It also authorizes the President of the United States' to proclaim as national monuments public lands having historic landmarks, historic and prehistoric structures, and other objects of historic or of scientific interest. The Antiquities Act also authorizes the President to reserve federal lands, to accept private lands, and to accept relinquishment of unperfected claims for that purpose.

The Act authorizes the departmental secretary to issue permits to qualified institutions to examine ruins, excavate archeological sites, and gather objects of antiquity. Regulations at 43 C.F.R. Part 3 establish procedures for permitting the excavation or collection of prehistoric and historic objects on federal lands. ARPA permits replace Antiquities Act permits.

Operators who excavate, injure, destroy or appropriate any "object of antiquity" while engaging in mineral activities on federal lands without or contrary to an approved plan of operations violate the Antiquities Act and trigger its penalties.

## ARCHEOLOGICAL RESOURCES PROTECTION ACT OF 1979, 16 U.S.C. §§ 470aa –470mm

**Resources afforded protection:** archeological resources
**Applicable regulation(s):** 18 C.F.R. § 1312; 36 C.F.R. Part 79, 296; 43 C.F.R. Part 7

Congress enacted the Archeological Resources Protection Act (ARPA) to preserve and protect archeological resources and sites on federal and Indian lands. The law makes it illegal to excavate or to remove from federal or Indian lands any archeological resources without a permit from the federal land manager. It also prohibits the removal, sale, receipt, and interstate transport of archeological resources obtained illegally (*i.e.*, without permits) from federal or Indian lands.

Agencies may issue permits only to educational or to scientific institutions if the resulting activities will increase knowledge about archeological resources. The law defines archeological resources as material remains of past human life or activities that are of archeological interest and are at least 100 years old. All materials collected on federal lands as a result of permitted activities remain the property of the United States. Those excavated from Indian lands remain the property of the Indian or Indian tribe having rights of ownership over such resources.

Congress amended the law to require development of plans for surveying public lands for archeological resources and of systems for reporting incidents of suspected violations.

ARPA also fosters cooperation between governmental authorities, professionals, and the public. The ARPA permit process ensures that individuals and organizations wishing to work with federal resources have the necessary professional qualifications and that these persons follow federal standards and guidelines for research and curation. The process allows the State Historic Preservation Officer (SHPO) to review and comment on ARPA permit applications. Federal agencies do not issue ARPA permits to themselves or to their contractors. The scope of work and contractor's proposal, which constitute the contract, insures that contractors comply with federal standards and guidelines. The ARPA permit replaces the permit required by the Antiquities Act of 1906.

ARPA imposes severe criminal and civil penalties on anyone who excavates, removes, damages, or otherwise alters or defaces archeological resources without a permit. However, ARPA applies only to lands owned by the United States and lands held in trust by the United States for Indian tribes and individual Indians. ARPA does not apply on the nonfederal surface estate.

A contractor hired by an operator to conduct a cultural resource survey that involves any collection of archeological resources, whether or not excavation or subsurface testing is involved, must obtain an ARPA permit. Operations under an approved 9B plan do not need an ARPA permit for incidental disturbance of archeological resources because these operations occur exclusively for purposes other than excavation or removal of archeological resources. General earth-moving excavations performed under an approved plan of operations do not constitute "excavation or removal" of archeological resources. However, agencies require an ARPA permit before an operator under 36 C.F.R. Part 9B salvages previously unknown archeological resources discovered during operations.

ARPA regulations appear at 43 C.F.R. Part 7, Subparts A and B. Subpart A - "Protection of Archeological Resources, Uniform Regulations," promulgated pursuant to ARPA's section 10(a) jointly by the Secretaries of Interior, Agriculture, and Defense, and the Chairman of the Board of the Tennessee Valley Authority, establishes the uniform definitions, standards, and procedures that all federal land managers must follow when providing protection for archeological resources located on public and on Indian lands. Subpart B - "Department of the Interior Supplemental Regulations," provides definitions, standards, and procedures for federal land managers to protect archeological resources and provides further guidance for Interior bureaus concerning definitions, permitting procedures, and civil penalty hearings. In addition, NPS regulations at 36 C.F.R. § 9.47 discuss 9B plans and archeological resources.

Operators who remove, excavate, damage, alter, or deface archeological resources without or contrary to an approved plan of operations, while on federal property violate ARPA and trigger both its civil and criminal penalties.

## CLEAN AIR ACT,
## as amended, 42 U.S.C. §§ 7401 – 7671q

**Resources afforded protection:** air resources
**Applicable regulation(s):** 40 C.F.R. Parts 23, 50, 51, 52, 58, 60, 61, 82, and 93; and 48 C.F.R. Part 23

The Clean Air Act (CAA) seeks to "protect and enhance" the quality of the nation's air resources; to promote the public health and welfare and the productive capacity of its population; to initiate and to accelerate a national research and development program to achieve the prevention and control of air pollution; to provide technical and financial assistance to state and local governments for aid in their development and execution of air pollution programs; and to encourage and to assist the development and the operation of regional air pollution control programs.

The Act requires the U.S. Environmental Protection Agency (EPA) to establish national primary standards to protect human health and more stringent national secondary standards to protect human welfare (National Ambient Air Quality Standards or NAAQS). The statute makes states and local governments responsible for the prevention or control of air pollution. NAAQS exist for sulfur dioxide, particulate matter, ozone, nitrogen dioxide, carbon monoxide, and lead.

Divided into air quality control regions, states must submit Implementation Plans for EPA approval. These plans provide strategies for the implementation, maintenance, and enforcement of national primary and secondary ambient air quality standards for each air quality control region.

Other provisions of the Act include: new source review permit programs, standards of performance for new stationary sources (NSPS), motor vehicle emission and fuel standards, national emission standards for hazardous air pollutants (NESHAPS), studies of particulate emissions from motor vehicles, studies of the cumulative effect of all substances and activities that may affect the stratosphere (especially ozone in the stratosphere), programs to Prevent Significant air quality Deterioration (PSD) in areas attaining the NAAQS, and programs to protect visibility in large national parks and wilderness areas.

All sources of air pollution, including publicly or privately owned facilities, must meet all federal, state, and local requirements under the CAA. In most cases, States and local authorities regulate air pollution control. For the National Park Service, the Prevention of Significant Deterioration of Air Quality (PSD) (42 U.S.C. §§ 7470-7475) and the Visibility Protection (42 U.S.C. § 7479) constitute the most important CAA sections.

The PSD provisions establish a classification system for the United States' clean air areas, which include those designated as Class I, Class II or Class III. National Park System units are designated as Class I or Class II areas. This classification indicates the additional increment of air quality degradation from particulate matter, sulfur dioxide ($S0_2$), nitrogen dioxide ($NO_2$), allowed in that area. Class I areas may only degrade by a very small increment of new pollution while Class III areas can degrade substantially. There are currently no Class III areas designated in the country.

As part of the Prevention of Significant Deterioration (PSD) program, Congress designated many National Parks and wilderness areas (including U.S. Fish and Wildlife Service and U.S. Forest Service wilderness areas) mandatory Class I areas. Because states may not redesignate these areas, Congress provided those areas with maximum protection from future air quality degradation. EPA designated all other parts of the country where air quality did not violate the national ambient air quality standards Class II areas where moderate pollution increases may occur. States or Indian tribes may reclassify Class II areas as Class III, thus, allowing significant pollution increases. However, no entity can designate certain Class II areas, such as national monuments and national recreation areas, as Class III but only Class II, or, at the option of the state, Class I.

Generally, the PSD rules apply only to major new or expanding facilities planning to locate or expand operations in clean air areas. An operator of a facility seeking a new source permit for location or for expansion in a clean air area must meet several requirements including National Ambient Air Quality Standards; PSD Classes I, II and III air pollution increments; and, a special "adverse impact determination" for Class I areas.

To protect the scenic value of visibility in National Parks and wilderness areas, Congress established a national visibility goal in section 169A of the CAA. Congress stated the agencies' goals as “the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I federal areas which impairment results from manmade air pollution”. Under current EPA regulations, the thirty-six states with mandatory Class I areas must assure reasonable progress toward the national visibility goal with respect to impairment reasonably attributed to major stationary sources of air pollution. EPA reviews new major stationary sources under permitting programs (*i.e.*, PSD and nonattainment area new source review) to assure visibility protection of Class I areas from potential future emissions.

These permitting programs also require that new major sources analyze visibility and other air quality impacts in the general area affected by the new source's emissions regardless of the classification of the area as Class I or Class II. If oil and gas development and operations result in major emissions of air pollutants as defined in PSD and nonattainment area permitting provisions, then such major emitting facilities would need to comply with these requirements as well as any other applicable, federal, state, and local air quality rules and regulations. EPA issued new regulations in July 1999 to address visibility impairment caused by regional haze, but implementation of this program will not occur for several more years.

The Clean Air Act Amendments of 1990 required EPA to promulgate rules to ensure that federal actions conform to appropriate nonattainment area SIPs. These rules prohibit federal agencies from taking any action that causes or contributes to any new violation of the NAAQS, increases the frequency or severity of an existing violation, or delays the timely attainment of a standard. The NPS will need to make a conformity determination for any oil and gas permitting decisions made under this management plan as it pertains to existing ozone nonattainment SIPs applicable in the area of the parks.

## COMPREHENSIVE ENVIRONMENTAL RESPONSE, COMPENSATION, AND LIABILITY ACT OF 1980, as amended, 42 U.S.C. §§ 9601 – 9675

**Resources afforded protection:** human health and welfare and the environment
**Applicable regulation(s):** 40 C.F.R. Parts 279, 300, 302, 307, 355, and 373

The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), also known as "Superfund," provides for cleanup of sites contaminated by hazardous substances in the United States. CERCLA defines "hazardous substance" as any substance: listed under the Resources Conservation and Recovery Act (42 U.S.C. § 6921) as hazardous waste or having the characteristics identified under that section; listed under the Clean Water Act (33 U.S.C. § 1321(b)(2)(a)) as a hazardous substance or (33 U.S.C. § 1317(a)) as a toxic pollutant; listed under the Clean Air Act (42 U.S.C. § 7412) as a hazardous air pollutant; listed under the Toxic Substances Control Act (15 U.S.C. § 2606) as an imminently hazardous chemical substance or mixture; or listed under CERCLA (42 U.S.C. § 9602) as a hazardous substance.

CERCLA explicitly excludes petroleum from the definition of hazardous substance, including crude oil or any fraction of petroleum that is not otherwise specifically listed or designated as a hazardous substance under statutory provisions listed above. It also excludes natural gas, natural gas liquids, liquefied natural gas, or synthetic gas usable as fuel from the definition of hazardous substances. (42 U.S.C. § 9601(14)).

Owners or operators of a facility that stored, treated, or disposed of hazardous substances must notify EPA of the location and of the type of waste at the site. EPA puts the most seriously contaminated sites on a National Priorities List (NPL) and updates it annually. Sites on the NPL are eligible for long-term clean up actions funded by the EPA administered Superfund program.

CERCLA also includes reporting requirements for spills or other releases of hazardous substances. CERCLA requires persons in charge of a vessel or facility to report releases (except federally permitted releases) of hazardous substances into the environment to the National Response Center. If releases constitute less than the reportable quantity established by EPA (40 C.F.R. § 302.4), then it does not have to be reported. Failure to report a reportable quantity release warrants a fine of up to $10,000 and imprisonment not to exceed one year (42 U.S.C. § 9603). "Release" means any spilling, leaking, pumping, pouring, emitting, emptying, discharging, injecting, dumping or disposing into the environment. "Release" also includes the abandonment of barrels or containers that contain hazardous substances.

CERCLA directs the president to revise and to publish a National Contingency Plan (NCP) for the cleanup of petroleum and hazardous waste spills. EPA developed the original NCP under section 311 of the Clean Water Act. The NCP details how the EPA will respond to spills of oil or hazardous substances regulated under CERCLA and/or the Clean Water Act. EPA publishes the plan, called the National Oil and Hazardous Substances Pollution Contingency Plan, at 40 C.F.R. Part 300.

CERCLA authorizes the EPA to clean up sites using the Superfund, to issue administrative orders requiring potentially responsible parties (PRPs) to clean up sites, and to obtain court orders requiring PRPs to clean up sites. If EPA uses the Superfund, then CERCLA authorizes EPA to sue PRPs to recover costs of the cleanup. PRPs who have incurred costs cleaning up may sue other PRP's to recover part of the cost of the cleanup.

Under CERCLA, the EPA tries to find all PRPs, including the present owner or operator of a vessel or facility that released or threatened a release of hazardous substances, past owners or operators of a vessel or facility at the time of disposal of the hazardous substance; persons who arranged for disposal of the hazardous substance at the facility; and persons who transported a hazardous substance to the facility.

However, if the PRP can establish that the release or threatened release and the resulting damages occurred solely by an act of God, an act of war, or an unforeseen act or omission of a third party who neither constituted an agent nor an employee of the PRP, then no liability attaches. CERCLA provides an innocent landowner defense under limited circumstances.

Persons liable under CERCLA remain responsible for all response costs incurred by the United States, a state or an Indian tribe. They may also incur liability for damages for injury to, destruction of, or loss of natural resources, including the reasonable costs of assessing the injury, and for the destruction or loss of natural resources. Furthermore they may be responsible for costs of certain health assessments or studies.

CERCLA imposes strict liability meaning the government does not have to prove that the person intended to release, acted negligently in releasing, or caused the release of a hazardous substance into the environment. Moreover, in most cases, any of the liable parties may be held responsible for the entire cost of the cleanup. To recover part of the cleanup costs, the party then sues other liable parties for contribution.
Operators and their contractors should thoroughly investigate waste disposal sites before sending hazardous substances. They should check to make sure disposal sites have the relevant state and federal permits and that the disposal company has provided enough money to properly close the site. If a release occurs from the disposal site, then the persons who disposed of hazardous substances could incur large cleanup bills.

Operators should avoid releases of hazardous substances. Release of an operator's performance bond required under 36 C.F.R. § 9.48 does not affect possible subsequent liability under CERCLA for releases of a hazardous substance into the environment.

## ENDANGERED SPECIES ACT OF 1973, as amended, 16 U.S.C. §§ 1531 – 1544

**Resources afforded protection:** plant and animal species or subspecies and their habitat, which have been listed as threatened or endangered by the U.S. Fish and Wildlife Service (FWS) or the National Marine Fisheries Service (NMFS). Distinct population segments of species of vertebrate fish or wildlife, which interbreed when mature, may also be listed as threatened or endangered, and are afforded protection.
**Applicable regulation(s):** 36 C.F.R. Part 13; and 50 C.F.R. Parts 10, 17, 23, 81, 217, 222, 225 402, and 450

The Endangered Species Act (ESA) requires federal agencies to ensure that their activities (authorized, funded, or carried out) will not jeopardize the continued existence of any listed threatened or endangered species or result in the destruction or adverse modification of critical habitat of such species. The FWS and NMFS administer the Act. The ESA makes it illegal to "take" an endangered species of fish or wildlife without a permit from the FWS or NMFS. "Taking" includes direct killing, hurting, trapping, or harassing. It also includes disrupting a habitat critical to the species' survival. Protective regulations issued at the time of listing for a threatened species of fish or wildlife may also prohibit or limit taking of the species without a permit.

Other federal agencies must formally consult with the FWS or NMFS when they believe that their own actions (including permitting) may affect a listed or a proposed threatened or endangered (T & E) species. The ESA prohibits agency actions occurring within the United States that jeopardize the continued existence of a T & E species and/or destroy or adversely affect designated critical habitat necessary for the species' survival.

When an operator submits a proposed plan of operations, the NPS and operators must comply with the requirements of the Endangered Species Act and the regulations FWS and NMFS have promulgated to implement it (50 C.F.R. Part 402). First, the NPS requests the FWS or NMFS to provide a list of proposed or listed species and proposed or designated critical habitat in the proposed operations area.

If the FWS or NMFS advises the NPS that listed or proposed T&E species may be present, then the NPS must prepare a biological assessment (BA). The BA evaluates the potential effects of the action on listed and proposed species and designated and proposed critical habitat. The BA will be concurrently released for public review and comment with the National Environmental Policy Act (NEPA) document (most likely an environmental assessment). The BA should include a list of listed and proposed threatened or endangered species occurring in the project area; impacts the project could have on these species and their habitat; project measures intended to mitigate, or reduce adverse impacts to these species and their habitat; and a description of the formal and informal consultation with the FWS or NMFS.

If the BA indicates that the action will not adversely affect any remaining listed species or designated critical habitat and the FWS or NMFS concurs, then formal consultation is not required. Likewise, if the BA indicates that the action is not likely to jeopardize the continued existence of proposed species or result in the destruction or adverse modification of proposed critical habitat, and FWS or NMFS concurs, then a conference is not required.

However, if the BA indicates that the action will adversely affect a listed species or critical habitat, then the NPS must formally consult with the FWS or NMFS. At the end of the consultation, the FWS or NMFS provides the NPS and the applicant with its "biological opinion." If the opinion finds the proposed action will jeopardize the continued existence of the species or result in the destruction or adverse modification of designated critical habitat, then the FWS or NMFS must suggest reasonable and prudent alternatives to the proposed action. If the FWS or NMFS cannot develop any reasonable and prudent alternatives, then it will indicate that to the best of its knowledge there are no reasonable and prudent alternatives exist. The FWS or NMFS may also formulate conservation recommendations, which will help the NPS reduce or eliminate the impacts the proposed action may have on listed species or designated critical habitat. The NPS will comply with prescribed alternatives when approving the plan of operations or implementing any other related action.

The NPS cannot approve a plan of operations if the FWS or NMFS has found that, no matter how the proposed operation is modified, it will result in "jeopardy" to a listed species or "destruction or adverse modification to habitat" critical to a listed species. Jeopardizing a listed species or habitat critical to a listed species' survival constitutes a "significant injury to federal lands" in the meaning of 36 C.F.R. Part 9B. The 36 C.F.R. Part 9B regulations do not allow the NPS to approve proposed plan of operations that will result in a "significant injury to federal lands."

## FARMLAND PROTECTION POLICY ACT,
## 7 U.S.C. §§ 4201, 4209

**Resources afforded protection:** prime and unique farmland and soils
**Applicable regulation(s):** 7 C.F.R. Part 658

Federal agencies must assess the effects of their actions on prime or unique farmland and land of statewide or local importance classified by the U.S. Department of Agriculture's Natural Resources Conservation Service. The FPPA does not authorize the Federal Government to regulate the use of private or nonfederal land or, in any way, affect the property rights of owners. Projects are subject to FPPA requirements if they may irreversibly convert farmland (directly or indirectly) to nonagricultural use and are completed by a Federal agency or with assistance from a Federal agency. Farmland subject to FPPA requirements does not have to be currently used for cropland. It can be forest land, pastureland, cropland, or other land, but not water or urban built-up land. Prime farmland is land that has the physical and chemical characteristics for producing food, feed, fiber, forage, oilseed, and other agricultural crops. Prime farmland includes land that possesses the above characteristics but is being used currently to produce livestock and timber. Unique farmland is land other than prime farmland that is used for production of specific high-value food and fiber crops, such as citrus, tree nuts, olives, cranberries, fruits, and vegetables. Farmland that is of statewide or local importance for the production of food feed, fiber, forage, or oilseed crops, as determined by the appropriate state or unit of local government agency or agencies, and that the Secretary determines should be considered as farmland for the purposes of this subtitle.

## FEDERAL INSECTICIDE, FUNGICIDE, AND RODENTICIDE ACT, as amended (commonly referred to as FEDERAL ENVIRONMENTAL PESTICIDE CONTROL ACT OF 1972), 7 U.S.C. §§ 136 *et. seq*.

**Resources afforded protection:** human health and safety, and the environment
**Applicable regulation(s):** 40 C.F.R. Parts 152-180, except Part 157

The Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA), as amended, regulates pesticides in the United States. FIFRA prohibits the distribution or sale of unregistered pesticides and establishes procedures for registering pesticides with the EPA. EPA has the authority to suspend or to cancel registrations for pesticides, which cause unreasonable adverse effects on the environment. To gain registration approval, a pesticide must meet EPA criteria regarding efficacy, labeling, and environmental safety. The statute makes it illegal to use a pesticide in a manner inconsistent with its labeling. EPA determines whether it should classify pesticides for general or restricted use. People may only use pesticides classified for restricted use under the direct supervision of a certified applicator or subject to other restrictions imposed by regulation.

FIFRA also requires EPA to establish regulations for storage and disposal of pesticide containers, excess pesticides, and pesticides with canceled registration. The Act also outlines penalties, indemnities, and administrative procedures. In addition, EPA may exempt from any provision of the Act any federal or state agency, if it determines emergency conditions, requiring such exemption, exist.

The appropriate NPS pesticide specialist must review and approve use of pesticides, including herbicides and rodenticides, before anyone can use them in units of the National Park System, including those where nonfederal oil and gas operations occur. An NPS Integrated Pest Management Specialist must review and approve the proposed use of herbicides for clearing areas for oil and gas operations. The parks follow Department of the Interior Departmental Manual - 517; Reference Manual – 77, Natural Resources Management; and NPS Procedures for Pesticide Use Requests when considering proposals for pesticide use in NPS units.

## FEDERAL LAND POLICY AND MANAGEMENT ACT OF 1976, 43 U.S.C. §§ 1701 et seq.

**Resources afforded protection:** federal lands and resources administered by the Bureau of Land Management
**Applicable regulation(s):** 43 C.F.R. Part 2200 for land exchanges and 43 C.F.R. Parts 1700-9000 for all other BLM activities

The Federal Land Policy and Management Act (FLPMA), also known as the “BLM Organic Act”, controls Bureau of Land Management’s (BLM) administration of more than three hundred million acres of federal lands in the western United States and Alaska. FLPMA also contains a land exchange authority (43 U.S.C. § 1716) under which the Secretary of the Interior may exchange federal lands or interests outside National Park System units for nonfederal lands or interests within National Park System units. When appropriate, the NPS and BLM may use this exchange authority to acquire private mineral interests in National Park System units.

BLM regulations at 43 C.F.R. Part 2200 govern federal land exchanges authorized by FLPMA. The regulations describe the appraisal and other procedures BLM uses while conducting land exchanges. However, if the enabling or exchange act for a unit remains inconsistent with these regulations, then the enabling or exchange act applies.

## FEDERAL WATER POLLUTION CONTROL ACT OF 1972, (commonly referred to as Clean Water Act), 33 U.S.C. §§ 1251 *et. seq.*

**Resources afforded protection:** water resources, wetlands, and waters of the U.S.
**Applicable regulation(s):** 33 C.F.R. §§ 320-330; and 40 C.F.R. Parts 110, 112, 116, 117, 122, and 230-232

Originally titled the Federal Water Pollution Control Act of 1972 (FWPCA) and significantly amended in 1977 and 1987, the Clean Water Act established a federal policy to restore and to maintain the chemical, physical, and biological integrity of the nation’s waters; to enhance the quality of water resources; and to prevent, control and abate water pollution.

To achieve this objective, the FWPCA establishes the ultimate goal of eliminating the discharge of pollutants into navigable waters of the United States and the interim goal of maintaining water quality that provides for the protection and propagation of fish, shellfish, and wildlife, and for recreation in and on the water. The FWPCA prohibits the discharge of toxic pollutants in toxic amounts; provides federal assistance to construct publicly owned waste treatment works; develops and implements area-wide waste treatment management processes to assure adequate control of source pollutants in each state; makes a major research and demonstration effort to develop technology necessary to eliminate the discharge of pollutants into navigable waters, waters of the contiguous zone, and the oceans; and develops and implements programs for the control of nonpoint sources of pollution to control both point and nonpoint sources of pollution.

As with most environmental programs, the FWPCA requires that states set and enforce water quality standards to meet minimum federal (EPA) requirements, including: effluent limitations for point sources of pollution; permits for discharges of pollutants into waters of the United States; and permits for discharges of dredged or fill material into waters of the U.S., including wetlands.

The following sections of the CWA remain relevant to oil and gas operators in National Park System units: Section 311 - spill reporting and spill control; Section 401 - state certification of project compliance; Section 402 - National Pollutant Discharge Elimination System (NPDES); Section 404 - Corps of Engineers dredge and fill permits.

Section 311 (33 U.S.C. § 1321)
Under section 311 no person can discharge oil or hazardous substances in harmful quantities into or upon navigable waters of the U.S., into or upon adjoining shorelines, or into or upon waters of the contiguous zone. Likewise, a person cannot discharge in connection with activities under the Outer Continental Shelf Lands Act or the Deepwater Port Act of 1974. For oil, a harmful quantity (*i.e.*, quantity that requires reporting) equals that amount which causes a violation of the applicable water quality standard or that amount which causes a film, sheen, or discoloration of the water surface. Persons who discharge a reportable quantity" must report the spill as soon as possible to the U.S. Coast Guard, EPA, and/or state agency, which agency depends on the geographic location of the spill and the type of substance spilled.

Hazardous substances are handled differently. Title 40 C.F.R. Part 116 lists about 300 hazardous substances. Title 40 C.F.R. Part 117 defines the reportable quantities for each substance. The reporting requirements of 40 C.F.R. Part 117 do not apply to permitted discharges. (See Section 402 permits below.) Failure to report a discharge can result in criminal penalties including fines and imprisonment. Section 311 also provides for federal cleanup of the spill and places the costs of cleanup on the entity that caused the spill. The section also protects the person in charge who reports the spill from criminal prosecution, but offers no immunity from civil penalties that may apply.

Under section 311, EPA issued regulations (40 C.F.R. Part 112) to prevent the discharge of oil and hazardous substances into the navigable waters of the United States. These regulations require that any of the facilities described below prepare a Spill Prevention Control and Countermeasure Plan (SPCCP). 40 C.F.R. Part 112 addresses the requirements for a SPCC Plan.

The SPCCP requirement applies to non-transportation related onshore and offshore facilities that drill, produce, gather, store, process, refine, transfer, distribute or consume oil or oil products. It only applies if the facilities due to their location, could potentially discharge oil in harmful quantities into or on the navigable waters of the United States or the adjoining shoreline. (Note: facilities with an underground storage capacity less than 42,000 gallons, or facilities with an above-ground storage capacity less than 1,320 gallons, are exempt from this requirement.)

Under its regulations at 36 C.F.R. Part 9B, the NPS requires a nonfederal oil and gas operator to submit a Spill Control and Emergency Preparedness Plan to deal with oil spills and other environmental hazards. A copy of the SPCCP, if one is required under 40 C.F.R. Part 112, will often meet most of the requirements for the Spill Control and Emergency Preparedness Plan under 36 C.F.R. Part 9B.

Section 401 Water Quality Certification (33 U.S.C. § 1341)
Section 401 requires certification from the state or interstate water control agency that a proposed activity complies with established effluent limitations and water quality standards. Applicants for federal permits or licenses must obtain this certification from the state agency that has been delegated authority to administer the FWPCA.

Section 402 Permits (33 U.S.C. § 1342(I)(2))
Under the National Pollutant Discharge Elimination System (NPDES), the EPA controls the discharges of pollutants from their point source into waters of the United States by using a permitting system. A "point source" could be a tank battery, for example. Any entity proposing to or discharging waste flows into U. S. waters needs a NDPES permit. EPA or states with EPA-approved programs issue NDPES permits.

The NPDES permit sets specific discharge limits. The limits rely on most recent pollution control technology, water quality standards, and government imposed schedules for installation of new pollution control equipment. The permit gives directions to the operator for monitoring and reporting discharges. The regulations provide for individual permits, group permits for like facilities, and general permits.

The Water Quality Act of 1987 amended the CWA to address stormwater runoff from industrial facilities. EPA requires a NPDES stormwater runoff permit for runoff that may touch machinery or contaminated material onsite and cause contamination of adjacent property. Industrial facilities include oil and gas exploration, production and development operations. The EPA published its rule on NPDES permit application regulations for storm water discharges at 55 Fed. Reg. 47990 (November 16, 1990).

The CWA exempts mining and oil and gas operations from the Section 402 stormwater permit requirements if,

"…discharges of stormwater runoff from mining operations, oil and gas exploration, production, processing, or treatment operations or transmission facilities, [are] composed entirely of flows which are from conveyances or systems of conveyances (including but not limited to pipes, conduits, ditches, and channels) used for collecting and conveying precipitation runoff and…are not contaminated by contact with, or do not come into contact with, any overburden, raw material, intermediate products, finished product, by-product, or waste products located on the site of such operations." (33 U.S.C. § 1342(l)(2))

"Contaminated storm water runoff" includes runoff containing a hazardous substance in excess of reporting quantities established at 40 C.F.R. § 117.3 or 40 C.F.R. § 302.4, containing oil in excess of the reporting quantity established at 40 C.F.R. § 110.3 (*e.g.*, causes a visible sheen), or contributing to a violation of a water quality standard.

The EPA issued a Final Rule on June 12, 2006 that permanently exempts the NPDES stormwater permitting requirements for oil and gas construction activities under Section 402 of the Act (Federal Register Vol. 71 No. 112 6/12/2006). Discharges containing contaminated stormwater run-off require NPDES permits. The Final rule additionally clarifies that stormwater containing sediment run-off (associated with gas well construction activities) is not considered contaminated and will not trigger NPDES permitting requirements (40 C.F.R. § 122.26(a)(2)(ii).

Section 404 Permits (33 U.S.C. § 1344)
Under section 404, anyone who discharges dredge or fill material into navigable waters needs a permit from the U.S. Army Corps of Engineers. "Navigable waters" mean "…those waters that are subject to the ebb and flow of the tide and/or are presently used, or have been used in the past, or may be susceptible for use to transport interstate or foreign commerce." (33 C.F.R. § 329.4)

A determination of navigability, once made, applies over the entire surface of the waterbody and remains in effect even if later actions or events impede or destroy its navigability.

Section 404 regulates discharges into virtually all surface waters where the use, degradation, or destruction of these waters could affect interstate commerce. It also applies to all tributaries and adjacent wetlands of such waters. The COE defines wetlands as areas “inundated or saturated by surface or ground water at a frequency and duration sufficient to support and under normal circumstances do support, a prevalence of vegetation typically adapted for life in saturated soil conditions…” (33 C.F.R. § 328.3(b).

The Corps of Engineers may issue individual permits or general permits on a state, regional, or nationwide basis. It issues general permits for certain kinds of similar activities in wetlands that will cause only minimal adverse effects on the environment. General permits do not cover many operators of nonfederal oil and gas properties in National Parks. They must obtain an individual "404" permit to conduct any operations that involve dredging or discharge of fill material into wetlands.

Under the 404 permit program, the COE may issue individual permits or general permits on a state, regional, or nationwide basis. COE uses general permits for certain categories of activities that have only minimal adverse and cumulative effects on the environment. Many operators of nonfederal oil and gas properties in National Parks do not hold general permits. Operators must obtain an individual “404” permit to conduct operations that involve dredging or discharging fill material into wetlands.

Before the issuance of either a NPDES or section 404 permit, the applicant must obtain a section 401 certification. This declaration states that any discharge complies with all applicable effluent limitations and water quality standards.

The NPS cannot waive CWA requirements for oil and gas operators. An operator has full responsibility for obtaining section 402 (NPDES) or/and section 404 (dredge and fill) permits and for reporting spills of oil, or other contaminating and hazardous substances.

## FISH AND WILDLIFE COORDINATION ACT,<br>16 U.S.C. §§ 661 – 666c 1935), 16 U.S.C. §§ 461 – 467

**Resources afforded protection:** water resources, fish and wildlife
**Applicable regulation(s):** none

This Act applies to major federal water resources development plans (impounding, diverting, deepening the channel, or otherwise controlling or modifying streams or other bodies of water). Requires federal agencies to consult with the Fish and Wildlife Service and applicable state agencies whenever such plans result in alteration of a body of water. The Act requires that wildlife conservation receive equal consideration with other features of water resource development. It also triggers coordination with the Fish and Wildlife Service upon application for a 404 permit.

## HISTORIC SITES, BUILDINGS, AND ANTIQUITIES ACT (Historic Sites Act of 1935), 16 U.S.C. §§ 461 – 467

**Resources afforded protection:** historic sites, buildings and objects
**Applicable regulation(s):** 18 C.F.R. Part 6; and 36 C.F.R. Parts 1, 62, 63, and 65

This Act establishes a national policy "to preserve for public use, historic sites, buildings, and objects of national significance for the inspiration and benefit" of the American people. The Act authorizes the designation of national historic sites and landmarks, authorizes interagency efforts to preserve historic resources, and establishes fines for violations of the Act. It authorizes surveys of historic and archeological sites, buildings, and objects to determine which remain significant, and provides for the restoration, reconstruction, rehabilitation, preservation, and maintenance of historic and prehistoric properties of national significance. The Act authorizes the Secretary of the Interior, through the National Park Service, to conduct surveys and studies, to collect information, and purchase significant historic properties. The Secretary may also restore, preserve, maintain, and rehabilitate structures and sites; establish museums; and operate and manage historic sites, and develop educational programs.

## LACEY ACT, as amended, 16 U.S.C. §§ 3371 *et seq.*

**Resources afforded protection:** fish and wildlife, vegetation
**Applicable regulation(s):** 15 C.F.R. 904; 50 C.F.R. Parts 10, 11, 12, 14, and 300

The Lacey Act prohibits the import, export, transport, sales, receipt, acquisition, or purchase of fish, wildlife, or plants that are taken, possessed, transported, or sold in violation of any federal law, treaty, regulation or Indian tribal law. The act also makes illegal importing, exporting, transporting, selling, receiving, acquiring, or purchasing in interstate or foreign commerce any fish, wildlife or plants taken, possessed, transported or sold in violation of a state law or state regulation (or foreign law for fish and wildlife, but not for plants). The Act also establishes marking requirements for containers or packages containing fish or wildlife.

The 1981 amendments to the Act strengthened federal laws and improved federal assistance to states and foreign governments for enforcement of fish and wildlife laws. The Act has significant civil and criminal penalties for violations and has emerged as a vital tool in efforts to control smuggling and trade in illegally taken fish and wildlife.

The U.S. Fish and Wildlife Service regulations implementing the Lacey Act and other related laws describe the procedures for the assessment of civil penalties (50 C.F.R. Part 11) and for government seizure and forfeiture (50 C.F.R. Part 12).

## MAGNUSON-STEVENS FISHERY CONSERVATION AND MANAGEMENT ACT, 16 U.S.C. § 1801

**Resources afforded protection:** commercial and recreational fisheries, fish habitat
**Applicable regulation(s):** none

The Magnuson Act provides for the management of the nations' fisheries within the exclusive economic zone. Regulations on commercial fishing activities are prescribed consistent with the terms of fishery management plans adopted through a collaborative process involving regional fishery management councils. Although the restrictions on commercial and recreational fishing activities are enforceable against those activities through criminal and civil sanctions, the Magnuson Act does not impose prohibitions on activities other than commercial and recreational fishing. To improve the conservation of any essential fish habitat identified by the Secretary of Commerce, the Magnuson Act requires that each “federal agency shall consult with the Secretary with respect to any action authorized, funded, or undertaken, or proposed to be authorized, funded, or undertaken, by such agency that may adversely affect any essential fish habitat...” 16 U.S.C. § 1855(b)(2). This consultation requirement provides the Secretary of Commerce with the opportunity to offer recommendations to the federal action agency on ways to avoid, mitigate, or offset the impact of the proposed action on essential habitat. While the federal agency is not bound to implement such recommendations, it must explain its reasons for not following them.

## MARINE MAMMAL PROTECTION ACT (MMPA), as amended, 16 U.S.C. §§ 1361 – 1407

**Resources afforded protection:** marine mammals
**Applicable regulation(s):** none

The MMPA, enacted in 1972, was the first modern wildlife conservation law adopted at the federal level. Using dramatic, broad-scale moratoria on the taking and importation of marine mammals and marine mammal products, as well as the imposition of an absolute preemption on all state laws that relate to the taking of marine mammals (subject to an opportunity for transfer of management authority), the Congress adopted the MMPA to conserve these species and their marine habitats. The MMPA prohibits the taking of marine mammals within the United States (both territorial and resource jurisdiction) and on the high seas (for persons subject to U.S. jurisdiction). No permit or authorization may be issued for the taking of a marine mammal (for activities other than commercial fishing) unless one of the following exceptions applies:

1. The permitted taking would be for public display purposes (non-depleted marine mammals only), scientific research, photography for educational or commercial purposes (harassment take only), or enhancing the survival or recovery of a marine mammal species or stock, consistent with the requirements of Section 104.
2. The Secretary of the Interior (or Commerce for cetaceans and pinnipeds other than walruses) decides to waive the taking moratorium for a particular marine mammal species or stock after determining that such species or stock is at its “optimum sustainable population” level and adopts regulations for such taking under Section 103 pursuant to the formal rulemaking requirements of the APA [agency rulemaking on the record with an opportunity for a formal hearing before an administrative law judge].
3. The activity involves the non-lethal deterrence of marine mammals to prevent damage to fishing gear or catch or to other private or public property, consistent with guidelines adopted by the Secretary under Section 101(a)(4).
4. Incidental take of small numbers of marine mammals may be authorized by regulation for specified activities that occur within a specific geographic area for a period of not more than 5 years, provided that the total of such taking will have a negligible impact on the species or stock and will not have an unmitigable adverse impact on the availability of the species for the subsistence uses of Alaska natives (if the incidental take involves harassment only, regulations are not necessary and the Secretary may issue annual authorizations). In the event of a conflict between the terms of the Endangered Species

Act and the Marine Mammal Protection Act, the more restrictive requirement of the MMPA takes precedence (16 U.S.C. § 1543).

## MIGRATORY BIRD TREATY ACT, as amended, 16 U.S.C. §§ 703 – 712

**Resources afforded protection:** migratory birds
**Applicable regulation(s):** 50 C.F.R. Parts 10, 12, 20, and 21

The Migratory Bird Treaty Act (MBTA) implements various treaties and conventions between the United States, Canada, Japan, Mexico, and Russia for the protection of migratory birds. Unless permitted by regulations, under the MBTA a person cannot attempt or succeed at pursuing, hunting, taking, capturing, or killing, possessing, offering to sell, selling, bartering, purchasing, delivering, shipping, exporting, importing, transporting, carrying or receiving any migratory bird, body part (*e.g.* feathers), nest, egg, or product. The U.S. Fish and Wildlife Service regulations provide procedures for obtaining a migratory bird permit (50 C.F.R. Part 21). Regulations at 50 C.F.R. 20 cover hunting of migratory birds, and regulations at 50 C.F.R. Part 12 cover seizure and forfeiture procedures.

Operators and their employees should avoid actions with respect to migratory birds that could violate the Migratory Bird Treaty Act (*e.g.* destroying nests and eggs or picking up dead birds).

## NATIONAL ENVIRONMENTAL POLICY ACT OF 1969, 42 U.S.C. §§ 4321 et seq.

**Resources afforded protection:** human environment (*e.g.* cultural and historic resources, natural resources, biodiversity, human health and safety, socioeconomic environment, visitor use and experience)
**Applicable regulation(s):** 40 C.F.R. Parts 1500-1508

The National Environmental Policy Act (NEPA) mandates that federal agencies assess the environmental effects of a proposed action and engage the public in the analyses of environmental impacts before agencies make decisions affecting the human environment. NEPA requires that federal agencies "utilize a systematic interdisciplinary approach" to ensure the integrated use of resource information in federal decision-making affecting the environment. Federal agencies must complete all analyses, public input, and NEPA documentation in time to aid decision-making. Initiating or completing environmental analysis after making a decision, whether formally or informally, violates both the spirit and the letter of NEPA.

Besides setting environmental planning policy goals, NEPA created the Council on Environmental Quality (CEQ), an agency of the president's office, as the "caretaker" of NEPA. CEQ published NEPA regulations in 1978 (40 C.F.R. Parts 1500-1508). The CEQ regulations apply to all federal agencies and require each agency to "implement procedures to make the NEPA process more useful to agency decision-makers and the public" (40 C.F.R. 1500.2). Agencies must review and update their regulations as necessary. In 1981 CEQ also published a guidance document titled "Forty Most Asked Questions Concerning CEQ's NEPA Regulations" (46 Fed. Reg. 18026, (1981)). Director's Order 12 and Handbook (2001) is the National Park Service's guidance on implementing NEPA.

The NEPA process constitutes an essential component of conservation planning and resource management through the integration of scientific and technical information into management decisions. In order to be effective, agencies cannot fulfill NEPA compliance by conducting an after-the-fact "compliance" effort. A well-crafted NEPA analysis provides useful information about the environmental pros and cons (*i.e.* impacts) of a variety of reasonable choices (alternatives), similar to an economic cost-benefit analysis, technical planning, or logistical planning. It remains an essential prelude to the effective management of park resources.

NEPA represents a procedural or process-oriented statute rather than a substantive or substance-oriented statute. Other substantive laws may prevent an agency from taking action or components of an action which have “too great” an impact on a particular resource. Within the NPS, the process of environmental analysis under NEPA provides the needed information to make substantive decisions for the long-term conservation of resources.

NEPA has a broad reach. NEPA is triggered whenever there is a major federal action, regardless of who proposes the action (NPS, private individuals, federal agencies, states, or local governments) or whether the action could impact the human environment. Even though the CEQ regulations give less emphasis to the socioeconomic environment than the physical or natural environment, the NPS considers the socioeconomic environment as an integral part of the human environment. Consequently, NPS will do NEPA analysis even if the impacts remain primarily socioeconomic, including potential impacts on minority and low-income communities (see Executive Order No. 12948, Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations).

The National Park Service undertakes its environmental analyses in a number of ways. When the NPS considers taking a “major federal action”, it prepares an environmental assessment (EA) to assess the impacts of the proposed operation and to determine if the NPS must prepare an environmental impact statement (EIS). If, based on the EA’s analysis and public comments, the NPS determines that the proposed action would not significantly affect the human environment, the NPS would prepare a decision document called a Finding of No Significant Impact (FONSI). Conversely, if NPS determines the proposed action would likely cause significant affects on the human environment, then it prepares an EIS. The NPS may prepare an EIS, without first preparing an EA if the action will likely cause significant environmental impacts. If the proposal has been previously analyzed in site-specific detail, a “memo to files” may be prepared. Some actions or types of proposals fall under a NEPA “categorical exclusion” (CE). A categorical exclusion is used where the proposal meets specific criteria defined under Department of the Interior regulations and NPS Director’s Order 12, for activities that do not have the potential for measurable impacts on park resources.

## NATIONAL HISTORIC PRESERVATION ACT OF 1966, as amended, 16 U.S.C. §§ 470 – 470x-6

**Resources afforded protection:** cultural and historic properties listed in or determined to be eligible for listing in the National Register of Historic Places
**Applicable regulation(s):** 36 C.F.R. Parts 60, 63, 65, 78, 79, 800, 801, and 810

The National Historic Preservation Act (NHPA) declared a national policy of historic preservation. It encouraged preservation on the state and the private levels, authorized the Secretary of the Interior to expand and to maintain a National Register of Historic Places, established the Advisory Council on Historic Preservation, and required federal agencies to conduct studies of potential effects of their proposed actions on National Register properties and to provide the Advisory Council opportunities to comment (§ 106). The Advisory Council has promulgated regulations, “Protection of Historic and Cultural Properties,” at 36 C.F.R. Part 800, to implement section 106 and presidential directives issued under it.

The NHPA also required federal agencies to identify, evaluate, and nominate cultural resources for inclusion in the National Register. Likewise, agencies must manage for preservation those National Register eligible or listed properties that under their jurisdiction or control.

In 1980 Congress passed a series of amendments to the NHPA and other preservation legislation. These amendments: codified portions of Executive Order No. 11593, which required inventories of federal resources and federal agency programs to protect historic resources; clarified that federal agencies can exclude inventory and evaluation of resources from the one percent fund limit under the 1974 amendments to the Reservoir Salvage Act; and authorizes federal agencies to charge federal permittees and licensees reasonable costs for protection activities.

The 1992 amendments to the Act explicitly call for Native American consultations when potential traditional cultural properties may be on federal lands. If such properties are discovered through the consultations, they should be evaluated for possible eligibility and/or listing in the National Register of Historic Places.

The NPS must consider the potential effects of any proposed oil and gas activities on cultural resources listed on or eligible for listing on the National Register. This responsibility cannot be delegated to nonfederal parties. NPS regulations at 36 C.F.R. § 9.37(e) state that the regional director may not approve a proposed plan of operations until the NPS complies with the NHPA. NPS regulations also require that operators provide the information needed for the NPS to make the determinations required under the NHPA. Operators must submit, as part of the environmental section in a proposed plan of operations, a description of the environment to be affected, including the natural and cultural environment.

In general, the NPS will have surveyed its lands as required by section 110 of the NHPA. The NPS cultural resource survey typically constitutes a careful inspection of the ground surface. The NPS uses standard archeological methodology that may include exploratory subsurface testing. The data from the survey indicate whether the lands fulfill the eligibility requirements for listing on the National Register. Operators may obtain data gathered during NPS surveys for the environmental section of the proposed plan.

When an operator submits a proposed plan of operations, the NPS reviews the cultural resources section. Based upon that review, the staff’s knowledge of the affected area's history and prehistory, and the NPS cultural resource surveys, the regional director determines if the operations would affect a property listed or eligible for listing on the National Register.

If the NPS finds that the operations would not affect a property listed or eligible for listing, the NPS consults with the State Historic Preservation Officer (SHPO) to obtain agreement. If the SHPO agrees with the NPS, then the regional director may issue an archeological clearance for any ground-disturbing operations on federal park lands.

However, if the NPS finds that operations would affect listed or eligible properties, then the NPS prepares an "Assessment of Effect on Cultural Resources". The NPS then consults with the SHPO to determine what steps to take to protect the site. If the NPS and the SHPO cannot agree on a course of action, then the matter is referred to the Advisory Council on Historic Preservation (ACHP). If the operation may affect a park also designated a National Historic Landmark, then the NPS must automatically consult with the ACHP.

Even if the property is listed on the National Register, private surface owners may take any lawful action they want on their own property. Under the authority of the NPS Organic Act and certain unit enabling legislation directing the NPS to regulate mineral activities to protect natural and cultural resources, the NPS can include stipulations in its plan approval to protect cultural resources on private property inside unit boundaries during the course of mineral operations.

NPS regulations at 36 C.F.R. § 9.47 require operators to stop all operations and to notify the superintendent if cultural resources are “discovered during operations. For the NPS to meet its obligations under the NHPA and the NPS Organic Act, an operator must notify the NPS of cultural resources that may be destroyed by a NPS-approved oil and gas operation. The notification requirement applies even though the operator may own the cultural resources. Notification gives the NPS an opportunity to judge the historic value of the resources, and, if warranted, acquire them from the owner.

An operator under 36 C.F.R. Part 9B may have to salvage cultural resources discovered in the course of operations. The operator may salvage the resources only after the NPS, in consultation with the SHPO, approves a mitigation and salvage plan and chooses a contractor to do the data recovery.

## NATIVE AMERICAN GRAVES PROTECTION AND REPATRIATION ACT, 25 U.S.C. §§ 3001 – 3013

**Resources afforded protection:** Native American human remains, funerary objects, sacred objects, and objects of cultural patrimony
**Applicable regulation(s):** 43 C.F.R. Part 10

The Native American Graves Protection and Repatriation Act (NAGPRA) protects Native American and Native Hawaiian cultural items and establishes a process for the authorized removal of human remains, funerary objects, sacred objects, and objects of cultural patrimony for sites located on lands owned or controlled by the federal government. The Act also provides for the transfer of ownership of cultural objects to Native American or Native Hawaiian individuals, organizations, or tribes. It addresses the recovery, treatment, and repatriation of Native American and Native Hawaiian cultural items by federal agencies and museums. NAGPRA contains data gathering, reporting, consultation, and permitting provisions. The Act emphasizes consultation with Native American and Native Hawaiian organizations to ensure that these entities play a major role in the treatment of specific cultural objects.

Regulations at 43 C.F.R. Part 10 address the rights of lineal descendants, Indian tribes, and Native Hawaiian organizations to Native American human remains, funerary objects, sacred objects, and objects of cultural patrimony. They require federal agencies and institutions that receive federal funds to provide information about these items to these people and, upon presentation of a valid request, to dispose of or to repatriate these objects to them. Section 10.4 describes the regulatory requirements under NAGPRA for inadvertent discoveries of human these items.

Appendix R - “NAGPRA Compliance,” in NPS Director’s Order 28 - Cultural Resources Management, describe NPS-specific guidance for implementing NAGPRA. If NPS anticipates an operation may impact Native American human remains, funerary objects, sacred objects, or objects of cultural patrimony protected by NAGPRA, then it will consult with the appropriate Native American or Native Hawaiian organization as part of the 9B plan approval process.

## NOISE CONTROL ACT OF 1972, 42 U.S.C. §§ 4901 – 4918

**Resources afforded protection:** human health and welfare
**Applicable regulation(s):** 40 C.F.R. Part 211

The Act establishes a national policy to promote an environment free from noise that jeopardizes the public’s health and welfare. To accomplish this, the Act provides for the coordination of federal research and activities to control noise, authorizes the establishment of federal noise emission standards for products distributed in commerce, and provides information to the public respecting the noise emission reduction characteristics of such products.

The Act authorizes and directs that federal agencies carry out the programs within their control in a manner that furthers the Act’s policies. Agencies having jurisdiction over any property or facility or engaged in any activity resulting or potentially resulting in increased noise must comply with federal, state, interstate, or local requirements. Agencies must, upon request, furnish information to the EPA regarding the nature, scope, and results of noise research and noise control programs and must consult with EPA in prescribing standards or regulations respecting noise. The Act also provides for citizen lawsuits. Any person may commence civil action against the United States or any government instrumentality or agency that violates any noise control requirement.

Operators must ensure that their facilities, equipment, and operations comply with all applicable federal, state, interstate, or local noise emission requirements. NPS management policies provide that the NPS will strive to preserve the natural quiet and natural sounds associated with the physical and biological resources of the parks (*e.g.* waves breaking on the shore, wind in the trees, and bird and wildlife sounds). NPS should prevent or minimize unnatural sounds that adversely affect park resources or values or the visitors’ enjoyment of them.

## OIL POLLUTION ACT, 33 U.S.C. §§ 2701 – 2762

**Resources afforded protection:** water resources, natural resources
**Applicable regulation(s):** 15 C.F.R. Part 990; 30 C.F.R. Part 253; 33 C.F.R. Parts 135 and 150; 40 C.F.R. Part 112

The Oil Pollution Act (OPA) expands the federal role in spill response, establishes contingency planning requirements for vessels and certain facilities, establishes the Oil Spill Liability Trust Fund, increases liability for spills of oil or hazardous substances from vessels and facilities, creates requirements for double hulls on new tankers, and increases requirements for research and development of spill response technologies.
OPA imposes liability for removal costs and damages resulting from discharge of oil into the U.S.’s navigable waters, its adjoining shorelines, or the exclusive economic zone. Damages

incurred include injuries to natural resources, loss of natural resources, and loss of use of natural resources. Natural resources include land, fish, wildlife, biota, air, water, groundwater, drinking water supplies, and other resources belonging to the United States, state, local, foreign governments or Indian tribes.

Liability does not apply to discharges allowed by a permit issued under a federal, state or local law. In addition, liability does not apply if the responsible party establishes that the discharge, damages, or removal costs occurred solely because of an act of God, an act of war, or a third party who constitutes neither an agent nor employee of the responsible party. However, despite these defenses, the responsible party remains liable if he fails to report the incident, help or cooperate as requested, or comply with certain orders. Also, OPA has increased penalties for regulatory noncompliance, broadened the response and enforcement authorities of the federal government, and preserved state authority to establish law governing oil spill prevention and response.

OPA provides new requirements for government and industry oil spill contingency planning. The "National Oil and Hazardous Substances Pollution Contingency Plan" (NCP) was expanded to encompass a three-tiered approach. The federal government directs all public and private response efforts for certain types of spill events. Area committees, composed of federal, state, and local government officials, must develop detailed, location-specific Area Contingency Plans. Owners or operators of vessels and certain facilities that pose a serious threat to the environment must prepare their own facility response plans.

OPA may require operators of nonfederal oil and gas operations in units of the National Park System to develop contingency plans. Contingency plans developed to meet the requirements of OPA may also satisfy the NPS 9B requirement for a contingency plan. NPS would determine if the OPA required plan meets NPS requirements as part of the 9B plan approval process.

## PIPELINE SAFETY ACT OF 1992,<br>49 U.S.C. §§ 60101 et seq.

**Resources Afforded Protection:** human health and safety, and the environment
**Applicable Regulation(s):** 49 C.F.R. Parts 190-199

This Act allows the Department of Transportation (DOT) to create and to enforce oil and gas pipeline safety regulations. The act creates design, construction, maintenance, and testing standards for all new, changed, or relocated interstate and intrastate pipelines. DOT's Office of Pipeline Safety regulates interstate pipeline safety but state agencies may also be approved to regulate intrastate pipelines. States that get approval to implement the program may enforce stricter standards than those in the Act. Violations of the Act can lead to civil and criminal penalties. The Act replaced the Hazardous Liquid Pipeline Safety Act of 1979, the Hazardous Materials Transportation Act, and the Natural Gas Pipeline Safety Act of 1968.

Oil and gas pipelines exist within several units of the National Park System. Operators of oil and gas pipelines crossing NPS units must comply with the Pipeline Safety Act of 1992. NPS regulations at 36 C.F.R. 9B require a 9B plan of operations for the construction or use of oil and gas pipelines (flowlines and gathering lines) in connection with nonfederal oil and gas operations within a NPS unit. Transpark pipelines (those owned and operated by persons or entities exercising rights not tied to the oil and gas ownership within the park boundary) located in rights-of-way that predate the establishment of the park unit do not qualify as an existing operations exempted from a plan of operations by 36 C.F.R. § 9.33. Rather, the NPS will issue a Special Use Permit (SUP) to regulate maintenance activities along the right-of-way corridor, including but not limited to mowing and trimming vegetation, pipeline inspection and testing, removal of fluids from oil and gas pipelines, and installing, shutting down, or replacing pipelines (36 C.F.R. § 1.6).

## RESOURCE CONSERVATION AND RECOVERY ACT, 42 U.S.C. §§ 6901 et seq.

**Resources afforded protection:** natural resources, human health and safety
**Applicable regulation(s):** 40 C.F.R. 240-282 and 49 C.F.R. Parts 171-179

The Resource Conservation and Recovery Act (RCRA) seeks to promote the protection of health and the environment and to conserve valuable material and energy resources. RCRA regulates the management of hazardous waste from generation to final disposal. The law consists of nine subtitles. Two subtitles create significant regulatory programs: Subtitle C establishes a hazardous waste program from generation to disposal; Subtitle D addresses disposal of nonhazardous solid waste. "Solid waste" includes garbage, refuse, and other discarded materials. It includes solids, liquids, and containerized gases.

The requirements of Subtitle C apply if the waste falls under EPA's criteria governing hazardous waste. EPA codified the regulatory criteria for hazardous waste at 40 C.F.R. Parts 260 and 261. EPA codified a list of hazardous wastes (known as listed wastes) in Subpart D of Part 261. Subpart C of Part 261 establishes the criteria for determining whether a solid waste constitutes a hazardous waste by exhibiting a characteristic of corrosivity, reactivity, ignitability, or toxicity (known as characteristic waste). EPA can regulate a solid waste because it either appears on the hazardous waste lists or displays a characteristic of a hazardous waste.

The 1980 amendments to RCRA excluded certain oil, gas, and geothermal drilling and production wastes from the hazardous waste requirements of Subtitle C. The amendments specifically exempt drilling fluids, produced water, and other drilling and production wastes. In 1988, the EPA decided to keep the exemption for oil and gas exploration and production wastes. State agencies regulate the exempted wastes under the less strict Subtitle D governing nonhazardous waste.

Oil field workers must understand how RCRA works because mistakes can be costly for operators. The Act dictates that when Subtitle C and Subtitle D wastes are mixed, the mixture becomes a Subtitle C hazardous waste. It does not matter if the mixture loses all of its hazardous characteristics. For example, if the rig mechanic dumps used motor oil into the reserve pit, the entire volume of drilling muds, cuttings, rig wash, excess cement, and completion fluids becomes a hazardous waste. This remains true even if it does not exhibit hazardous properties.

RCRA provides for strict civil and criminal penalties. Persons who do not comply with RCRA will receive fines of as much as $25,000 per day per violation. It does not matter whether or not EPA first served the person with a compliance order. It is up to the operator to know and comply with RCRA. The operator cannot wait to receive a compliance order and make corrections to avoid a penalty. Also, RCRA’s criminal penalties can fine an operator as much as $50,000 and imprison the operator for as many as two years if they "knowingly" cause transportation of hazardous materials without a manifest.

In addition, the RCRA exemption from Subtitle C for oil and gas drilling and production waste does not exclude these wastes from the operation of RCRA section 7003. Section 7003 allows EPA to compel any person who contributed or contributes to the handling, storage, treatment, transportation or disposal of the hazardous waste in a manner that causes an imminent and substantial danger to take any action to protect human health and the environment. Because this can include expensive cleanup actions to protect human health and the environment, operators should handle waste from their operations in such a way that it does not contaminate the environment either now or in the future.

Regardless of oil and gas exploration and production wastes' exemption from Subtitle C regulation, the NPS will likely require operators to dispose of all wastes associated with the oil and gas operation outside of the park. NPS requirements for waste disposal in an operator's plan of operations will provide for the strict protection of park resources and values.

## RIVERS AND HARBORS ACT OF 1899, As Amended, 33 U.S.C. §§ 401 *et seq.*

**Resources afforded protection:** shorelines and navigable waterways, tidal waters, wetlands
**Applicable regulation(s):** 33 C.F.R. Parts 114, 115, 116, 320 -325, and 333

Section 10 of the Rivers and Harbors Act of 1899 prohibits the unauthorized obstruction or alteration of any navigable waterway of the United States. In order to obstruct or alter the waterway, a person must obtain a permit from the Army Corps of Engineers. Activities requiring a permit include constructing structures in or over any waters of the U.S., excavating material from the water, conducting stream channelization, and depositing materials in such waters.

## SAFE DRINKING WATER ACT OF 1974, 42 U.S.C. §§ 300f *et seq.*

**Resources afforded protection:** human health, water resources
**Applicable regulation(s):** 40 C.F.R. Parts 141-148

The Safe Drinking Water Act (SDWA) protects the safety of drinking water supplies throughout the United States by establishing national standards enforceable by each state. The Act provides for the establishment of primary regulations to protect human health and of secondary regulations relating to the taste, odor, and appearance of drinking water. Primary drinking water regulations include either a maximum contaminant level (MCL) or a prescribed treatment technique that prevents adverse health effects to humans. A MCL constitutes the permissible level of a contaminant in water delivered to any user of a public water system. States should only use prescribed treatment techniques when a MCL remains uneconomical or technologically infeasible.

The Act's 1986 amendments require EPA to publish a list of contaminants every three years, which EPA knows or anticipates will occur in public water systems.
The most important part of the SDWA as far as the NPS and petroleum operators are concerned is the Underground Injection Control (UIC) permit program. Under the program, the EPA regulates underground injection of wastes or other materials. The EPA has authorized many states to administer the UIC permit program.

Owners of underground injection wells must obtain permits or be authorized by rule under the UIC program to operate the wells. The permit holder must prove to the state or federal permitting agency that, through sound and prudent practice and well construction, the underground injection will not endanger drinking water sources. The NPS will approve a plan of operations involving underground injection only when the wells have valid UIC permits.

The UIC program defines five classes of underground injection wells. Class II wells may relate to oil and gas operations in National Parks. The following fluids may be injected into Class II wells: 1). waste fluids produced by oil and gas operations and that are exempt from the hazardous waste requirements of RCRA, subtitle C (for example, produced brine, recovered treatment fluids, and waste waters from gas plants), 2). fluids used for enhanced recovery of oil and natural gas, and 3). fluids for below ground storage of hydrocarbons.

## WILD AND SCENIC RIVERS ACT, as amended 16 U.S.C. §§ 1271 et seq.

**Resources afforded protection:** water resources, recreational values, geologic resources, fish and wildlife, historic, cultural and other similar values
**Applicable regulation(s):** 36 C.F.R. § 297

The Wild and Scenic Rivers Act (Act) was passed by Congress in October 1968. The Act establishes a policy that certain rivers in the U.S. which, with their immediate environments, possess outstanding remarkable scenic, recreational, geologic, fish, and wildlife, historic, cultural and other similar values shall be preserved in free-flowing condition, and that their immediate environments shall be protected for the benefit and enjoyment of present and future generations. The Act identifies specific river reaches for designation as wild and scenic, and provides criteria to be used for classifying additional river reaches. “Wild river areas” are those rivers or sections of rivers that are free from impoundments and generally are inaccessible except by trail, with watersheds or shorelines essentially primitive and the waters are unpolluted. “Scenic river areas” are those rivers or sections of rivers that are free from impoundments, with shorelines or watersheds that are still largely primitive and shorelines undeveloped, but the river is accessible in places by roads. “Recreational river areas” are rivers or sections of rivers that are readily accessible by road or railroad, that may have some development along their shorelines, and that may have undergone some impoundment or diversion in the past.

The national Wild and Scenic River system was established to protect the environmental values of free-flowing streams from degradation by impacting activities, including water resources projects. The system is jointly administered by the U.S. Forest Service and the National Park Service. U. S. Army Corps of Engineers activities on the streams included in the system are subject to review by whichever of these agencies is responsible for the specific stream. In all planning for the use and development of water and related land resources, consideration shall be given to potential national wild, scenic, and recreational river areas, and all river basin and project plan reports submitted to Congress shall consider and discuss such potential.
Under the Wild and Scenic Rivers Act, valid existing mineral rights within the Wild and Scenic river boundary remain in effect, and activities may be allowed if the projects avoid or minimize surface disturbance, water sedimentation, pollution, and visual impairment. Based on the park’s enabling statute and applicable regulations, reasonable access to develop nonfederal oil and gas rights will be permitted. Compliance with the Clean Water Act or non-degradation of existing

water quality, whichever is more protective is required, including the development and implementation of management actions that protect and enhance water quality.

# EXECUTIVE ORDERS

## EXECUTIVE ORDER NO. 11593 – PROTECTION AND ENHANCEMENT OF THE CULTURAL ENVIRONMENT, 36 Fed. Reg. 8921 (1971)

**Resources afforded protection:** cultural resources
**Applicable regulation(s):** 3 C.F.R. 1971 Comp., 36 C.F.R. §§ 60, 61, 63, 800

Executive Order No. 11593 instructs all federal agencies to support the preservation of cultural properties. It directs them to identify and nominate cultural properties under their jurisdiction to the National Register. Moreover, the executive order states that federal agencies must "exercise caution…to assure that any federally owned property that might qualify for nomination is not inadvertently transferred, sold, demolished, or substantially altered."

## EXECUTIVE ORDER NO. 11644 – USE OF OFF-ROAD VEHICLES ON THE PUBLIC LANDS, 37 FR 2877 (1972), reprinted in 42 U.S.C. § 4321, as amended by Executive Order No. 11989 (1977), 42 Fed. Reg. 26959; Executive Order No. 12608 (1987), § 21, 52 Fed. Reg. 34617

**Resources afforded protection:** natural resources, aesthetic and scenic values

The order establishes a uniform federal policy to ensure that use of off-road vehicles on public lands are controlled and directed to protect resources, promote safety of all users of those lands and to minimize conflicts among users. Areas and trails shall be located in units of the National Park System only if the director determines that such use in those areas will not adversely affect their natural, aesthetic or scenic values. Within six months of the date of this order, each respective director shall designate specific areas and trails on public lands on which the use of off-road vehicles may be permitted, and areas in which the use of off-road vehicles may not be permitted, and set a date by which such designation of all public lands shall be completed. Those regulations shall direct that the designation of such areas and trails will be based upon the protection of the resources of the public lands, promotion of the safety of all users of those lands, and minimization of conflicts among the various uses of those lands.

Executive Order No. 11989 promulgates guidelines for the controlled use of off-road vehicles on public lands. The order directs that agency heads shall, whenever he determines that the use of off-road vehicles will cause or is causing considerable adverse effects on the soil, vegetation, wildlife, wildlife habitat or cultural or historic resources of particular areas or trails of the public lands, immediately close such areas or trails to the type of off-road vehicle causing such effects, until such time as he determines that such adverse effects have been eliminated and that measures have been implemented to prevent future recurrence.

## EXECUTIVE ORDER NO. 11988 – FLOODPLAIN MANAGEMENT OF 1977, 42 FED. REG. 26951 (1977), as amended by Executive Order No. 12148 (1979), 44 Fed. Reg. 43239, 3 C.F.R. 1979 COMP., P. 412

**Resources afforded protection:** floodplains, human health, safety, and welfare

Executive Order No. 11988 seeks to avoid, where practicable alternatives exist, the short-term and long-term adverse impacts associated with floodplain development. In carrying out agency responsibilities, federal agencies must reduce the risk of flood losses, minimize the impacts of floods on human safety, health, and welfare, and restore and preserve the natural and beneficial values served by floodplains. If an agency proposes an action in a floodplain, then the agency must consider alternatives to avoid adverse effects and incompatible development in the floodplain. Agencies must also provide opportunity for early public review of any plans for actions in floodplains.

## EXECUTIVE ORDER NO. 11990 – PROTECTION OF WETLANDS, 42 Fed. Reg. 26961 (1977)

**Resources afforded protection:** wetlands

Executive Order No. 11990 seeks to avoid adverse impacts on wetlands when there is a practicable alternative. Executive agencies, in carrying out their land management responsibilities, must minimize wetlands destruction, loss, or degradation and preserve and enhance the wetlands' natural and beneficial values.

## EXECUTIVE ORDER NO. 12088 – FEDERAL COMPLIANCE WITH POLLUTION CONTROL STANDARDS, 43 Fed. Reg. 47707 (1978), amended by Executive Order No. 12580, Superfund Implementation, 52 Fed. Reg. 2923 (1987)

**Resources afforded protection:** natural resources, human health and safety

Executive Order No. 12088 delegates each executive agency head the responsibility for taking all necessary actions to prevent, control, and abate environmental pollution. It gives the EPA authority to conduct reviews and inspections for the purpose of monitoring federal facility compliance with pollution control standards. Section 1-101 requires prevention, control, and abatement of pollution from federal facilities. Section 1-201 requires federal agencies to cooperate with state, interstate, and local agencies to prevent, to control, and to abate environmental pollution.

## EXECUTIVE ORDER NO. 12630 – GOVERNMENTAL ACTIONS AND INTERFERENCE WITH CONSTITUTIONALLY PROTECTED PROPERTY RIGHTS, 53 Fed. Reg. 8859 (1988)

**Resources afforded protection:** private property rights, public funds

Executive Order No. 12630 seeks the following: to assist agencies in reviewing their actions to prevent unnecessary takings and in proposing, planning, and implementing agency actions with due regard for the constitutional protections provided by the 5th Amendment to the U.S. Constitution; to account in decision-making for those takings necessitated by statutory mandate; and to reduce the risk of undue or inadvertent burdens on the federal treasury resulting from lawful government action.

When an agency requires a private party to obtain a permit to undertake a specific use of private property, any conditions imposed on the permit must substantially advance the governmental interest that is impacted by the land use. The permitting processes must be kept to the minimum necessary so that the government does not interfere with the use of private property during the process.

## EXECUTIVE ORDER NO. 12898 – FEDERAL ACTIONS TO ADDRESS ENVIRONMENTAL JUSTICE IN MINORITY POPULATIONS AND LOW-INCOME POPULATIONS, as amended by Executive Order No. 12948, 60 Fed. Reg. 6379 (1995)

**Resources afforded protection:** human health and safety

This executive order requires that federal agencies incorporate environmental justice into their mission. Environmental justice promotes the fair treatment of people of all races, incomes, and cultures with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. Fair treatment implies that no person or group of people should receive a disproportionate share of the negative environmental impacts from the execution of this country's domestic and foreign policy programs.

## EXECUTIVE ORDER NO. 13007 – INDIAN SACRED SITES, 61 Fed. Reg. 26771 (1996)

**Resources afforded protection:** Native Americans' sacred sites

To the extent practicable, permitted, and consistent with essential agency functions, all federal land management agencies must accommodate access to and ceremonial use of Indian sacred sites by Indian religious practitioners and avoid adversely affecting the physical integrity of such sacred sites. Consistent with this executive order, if a proposed plan of operations may affect the physical integrity of, the ceremonial use of or the access to these sites by Native American religious practitioners in federally recognized tribes, then the superintendent will consult with the tribe as part of the 9B approval process.

## EXECUTIVE ORDER NO. 13112 – INVASIVE SPECIES, 64 Fed. Reg. 6183 (1999), as amended by Executive Order 13286, 68 Fed. Reg. 10619 (2003)

**Resources afforded protection:** vegetation and wildlife

This executive order seeks to prevent the introduction of invasive species, to provide for their control, and to minimize the economic, ecological, and human health impacts they cause. It outlines federal agency duties, creates a new Invasive Species Council, defines the council's duties, and authorizes the creation an Invasive Species Management Plan. Executive Order No. 13112 also creates a framework for planning and for coordination involving all stakeholders, which it defines as states, tribal entities, local government agencies, academic institutions, scientific communities, and non-governmental entities such as environmental groups, agricultural groups, conservation organizations, trade groups, commercial interests, and private landowners.

Federal agencies should use the programs and authorities to prevent the introduction of invasive species; detect and respond rapidly to control populations of such species in a cost-effective and an environmentally sound manner; monitor invasive species populations accurately and reliably; provide for restoration of native species and habitat conditions in invaded ecosystems; conduct research on invasive species and develop technologies to prevent their introduction; provide environmentally sound control of invasive species; promote public education on invasive species and means to address them.

The order directs agencies not to authorize, fund, or carry out any action likely to cause or promote the introduction or the spread of invasive species in the United States or elsewhere. However, agencies can determine that the benefits outweigh the potential harm and ensure that they take prudent measures to minimize harm. Federal agencies should consult with the Invasive Species Council and undertake actions consistent with the Invasive Species Management Plan with the cooperation of stakeholders.

## EXECUTIVE ORDER NO. 13186 – RESPONSIBILITIES OF FEDERAL AGENCIES TO PROTECT MIGRATORY BIRDS, 66 Fed. Reg. 3853 (2001)

**Resources afforded protection:** migratory birds

This executive order defines federal agency responsibilities to protect migratory bird populations, in furtherance of the purposes of the migratory bird conventions, the Migratory Bird Treaty Act (16 U.S.C. §§ 703-711), the Bald and Golden Eagle Protection Acts (16 U.S.C. §§ 668-668d), the Fish and Wildlife Coordination Act (16 U.S.C. §§ 661-666c), the Endangered Species Act of 1973 (16 U.S.C. §§ 1531-1544), the National Environmental Policy Act of 1969 (42 U.S.C. §§ 4321-4347), and other pertinent statutes.

This executive order directs each federal agency taking actions that have, or are likely to have, a measurable negative effect on migratory bird populations to develop and implement, within two years, a Memorandum of Understanding (MOU) with the Fish and Wildlife Service that shall promote the conservation of migratory bird populations.

## EXECUTIVE ORDER NO. 13212 – ACTIONS TO EXPEDITE ENERGY – RELATED PROJECTS, 66 Fed. Reg. 28357 (2001), as amended by Executive Order 13302, 68 Fed. Reg. 27429 (2003)

**Resources afforded protection:** all resources, production, transmission, and conservation of energy

This executive order establishes an interagency task force to coordinate, monitor, and assist executive departments and federal agencies to expedite the increased production, transmission, and conservation of energy, in a safe and environmentally sound manner. Specifically, it provides for executive departments and federal agencies where appropriate to expedite their review of permits or take other actions as necessary to accelerate the completion of such projects, while maintaining safety, public health, and environmental protections, to the extent permitted by law and regulations.

### EXECUTIVE ORDER 13352 – FACILITATION OF COOPERATIVE CONSERVATION, 69 Fed. Reg. 52989 (2004)

**Resources afforded protection:** natural resources, property rights, public health and safety

This order seeks to ensure that laws relating to the environment and natural resources are implemented "in a manner that promotes cooperative conservation, with an emphasis on appropriate inclusion of local participation in Federal decision making." The Secretary of the Interior is directed to implement laws in a way that: "(i) facilitates cooperative conservation; (ii) takes appropriate account of and respects the interests of persons with ownership or other legally recognized interests in land and other natural resources; (iii) properly accommodates local participation in Federal decision making; and (iv) provides that the programs, projects, and activities are consistent with protecting public health and safety."

## POLICIES, GUIDELINES, AND PROCEDURES

### NATIONAL PARK SERVICE MANAGEMENT POLICIES (2006)

**Resources afforded protection:** all resources including air resources, cultural and historic resources, natural resources, biological diversity, human health and safety, endangered and threatened species, visitor use and experience, visual resources

The NPS Management Policies is the service-wide policy document of the National Park Service. These policies provide the overall foundation, set the framework, and provide direction for management decisions within the NPS. Management policy direction may be general or specific; it may prescribe the process through which decisions are made, how an action is to be accomplished, or the results to be achieved. Management Policies guide NPS staff to manage National Park System units consistently and professionally to achieve the Congressional mandate of the National Park System. Adherence to NPS policy is mandatory, unless specifically waived or modified by the Secretary, the Assistant Secretary, or the Director of the NPS.

These policies cover park system planning, land protection, natural resource management, cultural resource management, wilderness preservation and management, interpretation and education, use of the parks, park facilities, and commercial visitor services.

The second tier of NPS policies (level 2 guidance) are Director's Orders which clarify or supplement the NPS Management Policies. As they are completed, Director's Orders will replace existing NPS guidelines and special directives. The most detailed and comprehensive guidance implementing service-wide policy, called level 3 guidance, are handbooks or reference manuals and are a compilation of legal references, operating policies, standards, procedures, general information, recommendations, and examples to assist field staff in carrying out the NPS Management Policies.

## DEPARTMENT OF THE INTERIOR, DEPARTMENTAL MANUAL, 516 DM 1 – 15 – NATIONAL ENVIRONMENTAL POLICY ACT OF 1969 (2005)

**Resources afforded protection:** all resources including cultural resources, historic resources, natural resources, human health and safety

Section 516 of the Departmental Manual establishes the Department of Interior's policies for implementing the National Environmental Policy Act. It includes policies about initiating the NEPA process, categorical exclusions, and preparing environmental assessments and environmental impact statements.

## DEPARTMENT OF THE INTERIOR, DEPARTMENTAL MANUAL, 517 DM 1 – PESTICIDES (1981)

**Resources afforded protection:** human health and safety and the environment

DM 517 establishes Department of the Interior policy for the use of pesticides on the lands and waters under its jurisdiction and for compliance with the Federal Insecticide, Fungicide, and Rodenticide Act.

## DEPARTMENT OF THE INTERIOR, DEPARTMENTAL MANUAL, 519 DM 1 - 2 – PROTECTION OF THE CULTURAL ENVIRONMENT (1994)

**Resources afforded protection:** archeological, prehistoric resources, historic resources, Native American human remains, and cultural objects

DM 519 describes the policies and responsibilities of the Department of the Interior for managing, preserving, and protecting prehistoric resources, historic resources, Native American human remains, and Native American cultural objects located on Indian and public lands administered by the Department.

## DEPARTMENT OF THE INTERIOR, DEPARTMENT MANUAL, 520 DM 1 – PROTECTION OF THE NATURAL ENVIRONMENT – FLOODPLAIN MANAGEMENT AND WETLANDS PROTECTION PROCEDURES (2001)

**Resources afforded protection:** wetlands and floodplains

DM 520 describes the policies and responsibilities of the Department of the Interior for implementing Executive Order No. 11988, Floodplain Management (May 24, 1977) and Executive Order No. 1199, Protection of Wetlands (May 24, 1977).The Department's policy is to:

A. Exercise leadership and take action to avoid, to the extent possible, the long- and short-term adverse impacts associated with the occupancy and modification of wetlands and floodplains;

B. Avoid the direct or indirect support of wetland or floodplain development whenever there is a practicable alternative;

C. Reduce the risk of flood loss and minimize the impact of floods on human health, safety and welfare;

D. Restore and preserve the natural and beneficial values served by floodplains and wetlands;

E. Develop an integrated process to involve the public in the floodplain management decision making process;

F. Incorporate the Unified National Program for Floodplain Management into relevant Departmental programs.

## NPS DIRECTOR'S ORDER 12 AND HANDBOOK – CONSERVATION PLANNING, ENVIRONMENTAL IMPACT ANALYSIS, AND DECISION MAKING (2001)

**Resources afforded protection:** all resources including natural resources, cultural resources, human health and safety, socioeconomic environment, visitor use

Director's Order 12 and Handbook sets forth policy and procedures for the NPS to comply with the National Environmental Policy Act (NEPA), including direction on the analysis process and documentation of environmental impact assessments. The Director's Order and handbook are derived in whole or part from the CEQ regulations and Department of Interior NEPA guidelines. Director's Order 12 and the handbook include specific NPS requirements beyond those imposed by CEQ to help facilitate the mandates of the Organic Act, other laws and policies that guide NPS actions, and to help NPS managers and staff make day-to-day decisions related to implementation of the NEPA.

## NPS DIRECTOR'S ORDER 28 – CULTURAL RESOURCE MANAGEMENT (1998)

**Resources afforded protection:** cultural, historic, and ethnographic resources

Director's Order 28 is the comprehensive guideline for management of cultural resources in units of the National Park Service. It elaborates on the policies articulated in the "NPS Management Policies" and offers guidance in applying federal laws and the Secretary's Standards to establish, to maintain, and to refine park cultural resource programs. Director's Order 28 also establishes procedures for complying with NHPA sections 10 and 106.

Director's Order 28, Appendix R: NAGPRA Compliance provides direction on complying with the Native American Graves Protection and Repatriation Act. Appendix R requires that an operator who inadvertently discovers human remains, funerary objects, sacred objects, or objects of cultural patrimony immediately notify the park's superintendent first by telephone and then in writing. The operator must stop activity in the area of the discovery for a specified time and make a reasonable effort to protect the human remains or objects. The superintendent will notify the appropriate Native American tribes or Native Hawaiian organizations and begin consultation about the disposition of the items.

## DIRECTOR'S ORDER 28A – ARCHEOLOGY (2004)

**Resources afforded protection:** archeological resources

DO 28A promotes a common management framework for planning, reviewing and undertaking archeological activities and other activities that may affect archeological resources within the National Park System. This DO also addresses the manner in which the Service will meet its archeological assistance responsibilities outside the national parks. General archeological requirements are covered in DO-28: Cultural Resource Management (http://www.nps.gov/policy/DOrders/DOrder28.html), and the Cultural Resource Management Guideline Release No. 5 (http://www.cr.nps.gov/history/online_books/nps28/28contents.htm).

## DIRECTOR'S ORDER 47 – SOUND PRESERVATION AND NOISE MANAGEMENT (2000)

**Resources afforded protection:** natural soundscapes

The purpose of this Director's Order is to articulate National Park Service operational policies that will require, to the fullest extent practicable, the protection, maintenance, or restoration of the natural soundscape resource in a condition unimpaired by inappropriate or excessive noise sources. For nonfederal oil and gas operations, soundscape management goals are to reduce noise to minimum levels consistent with the appropriate service or activity, as long as that service or activity continues to be needed.

## DIRECTOR'S ORDER 53 AND REFERENCE MANUAL 53 – SPECIAL PARK USES (2005)

**Resources afforded protection:** all resources including air resources, cultural and historic resources, natural resources, biological diversity, human health and safety, endangered and threatened species, visitor use and experience, visual resources

DO 53 defines and clarifies legal and policy requirements for special uses in NPS units and describes Special Use Permit (SUP) requirements and provisions. Applicable regulations for Special Use Permits are 36 C.F.R. Parts 1 – 5.

Special park uses are defined as activities that take place in a unit of the National Park System and: provide a benefit to an individual, group or organization, rather than the public at large; require written authorization and some degree of management control from the NPS in order to protect park resources and the public interest; are not prohibited by law or regulation; and are neither initiated, sponsored, nor conducted by the NPS. A special park use may involve either rights or privileges, and may or may not support the purposes for which a park was established.

The NPS applies the Special Use Permit regulations at 36 C.F.R. Parts 1 – 5 and guidance in Director's Order/Reference Manual 53 to control activities within rights-of-way associated with transpark oil and gas pipelines. Mowing and trimming vegetation, inspection or testing pipelines, removal of fluids from oil and gas pipelines and installing, shutting down or replacing pipelines, are common activities in pipeline rights-of-way requiring an approved NPS Special Use Permit. Special Use Permits for transpark pipelines must be approved before these activities can occur. The SUP must include a performance bond and mitigation measures to protect park resources, values, and ensure the protection of public health and safety.

## REFERENCE MANUAL 77 – NATURAL RESOURCE MANAGEMENT (2004)

**Resources afforded protection:** all natural resources

Natural Resource Management Reference Manual 77 offers comprehensive guidance to National Park Service employees responsible for managing, preserving, and protecting the natural resources found in National Park System units. It guides the actions of park managers so that natural resource activities comply with federal law, federal regulation, Department of Interior policy, and National Park Service policy. Natural resources include native plants, native animals, water, air, soils, topographic features, geologic features, paleontologic resources, natural quiet, and clear night skies. Reference Manual 77 covers natural resources management, uses in parks, planning, and program administration and management. A listing of topics included in RM 77 can be found at: http://www.nature.nps.gov/rm77/.

Reference Manual 77 serves as the primary “Level 3” guidance on natural resource management in units of the National Park System, replacing NPS-77, The Natural Resource Management Guideline, issued in 1991 under the previous NPS guideline series. The transition of NPS-77 into Reference Manual 77 is still in progress. Some sections are still being revised while others have undergone a field review with comments from the field incorporated as applicable.

## NPS DIRECTOR’S ORDER AND PROCEDURAL MANUAL 77-1 – WETLAND PROTECTION (2002)

**Resources afforded protection:** wetlands

NPS Director’s Order 77-1 and Procedural Manual implement Executive Order No. 11990, Protection of Wetlands. They establish policies, requirements, and standards to protect wetlands. Operators must perform a wetlands delineation when proposed operations could potentially cause direct and/or indirect impacts to wetlands. The Corps of Engineers and the NPS review the wetlands delineation for adequacy. When proposed operations cannot avoid direct and/or indirect impacts on wetlands, the operator must compensate for these impacts by restoring a disturbed wetlands area in the unit at a minimum 1:1 compensation ratio. The compensation ratio can be greater if the functional values of the site being impacted are high and the restored wetlands will be of a lower functional value. Operators must perform the compensation before or concurrently with the occurrence of impacts associated with approved oil and gas operations. When operations are completed, the operator must restore the site to its pre-impact wetlands condition.

NPS must comply with Executive Order No. 11990 and the NPS Wetland Protection Guideline (DO 77-1) as part of the 36 C.F.R. 9B procedure for approving a plan of operations for nonfederal oil and gas operations within a unit of the National Park System.

## NPS DIRECTOR’S ORDER AND PROCEDURAL MANUAL 77-2 – FLOODPLAIN MANAGEMENT (2003)

**Resources afforded protection:** floodplains

Director’s Order and Procedural Manual 77-2 replaces NPS Special Directive 93-4 and provides NPS policies and procedures for implementing Executive Order No. 11988, Floodplain Management. NPS policy seeks to reduce the risk of flood loss, minimize the impact of floods on human safety, health and welfare; and restore and preserve the natural and beneficial values served by floodplains.

The NPS will protect and preserve the natural resources and functions of floodplains; avoid the long- and short-term environmental effects associated with the occupancy and modification of floodplains; avoid direct and indirect support of floodplain development and actions that could adversely affect the natural resources and functions of floodplains or increase flood risks; and restore, when practicable natural floodplain values previously affected by land use activities within floodplains. If it is not practicable to locate or relocate development or inappropriate human activities outside the floodplain, the NPS will, prepare a Statement of Findings in accordance with the Procedural Manual 77-2; take all reasonable actions to minimize the impact to the natural resources in floodplains; use nonstructural methods to reduce hazards to human life and property; and ensure that structures and facilities located in floodplains are designed to be consistent with the intent of the standards and criteria of the National Flood Insurance Program (44 C.F.R. Part 60).

The Director's Order requires the NPS to classify proposed actions into one of three action classes - the 100-year (base floodplain), 500-year, or extreme regulatory floodplain. If a preliminary floodplain assessment shows that the area may experience flooding, then the applicable regulatory floodplain must be shown on a map, and information on flood conditions and hazards must be developed.

During project planning, the NPS identifies and evaluates practicable alternative sites for the proposal outside of the regulatory floodplain. If practicable sites are identified, NPS policy gives preference to locating the proposed action at a site outside the regulatory floodplain. If there is no practicable alternative site for the proposal, then the NPS will apply mitigation measures to protect floodplain resources, values, and human life and property.

NPS must comply with Executive Order No. 11988 and the NPS Floodplain Management Guideline as part of the 36 C.F.R. 9B process for approving a plan of operations for nonfederal oil and gas operations within a unit of the National Park System.

## SECRETARY OF THE INTERIOR'S "STANDARDS AND GUIDELINES FOR ARCHEOLOGY AND HISTORIC PRESERVATION," 48 FR 44716 (1983) (also published as Appendix C of NPS Director's Order 28 – Cultural Resource Management)

**Resources afforded protection:** cultural and historic resources

Prepared under the authority of sections 101(f), (g), and (h) and 110 of the National Historic Preservation Act, the Standards and Guidelines provide basic technical standards, guidelines, and advice about archeological and historical preservation activities and methods. While the standards and guidelines are not regulatory, NPS Director's Order 28 requires the NPS to comply with their substantive and procedural requirements.

## GOVERNMENT-TO-GOVERNMENT RELATIONS WITH NATIVE AMERICAN TRIBAL GOVERNMENTS, Presidential Memorandum signed April 29, 1994

**Resources afforded protection:** Native Americans

In order to ensure that NPS recognizes and respects the rights of sovereign tribal governments, this memorandum instructs each executive department and agency to operate in a government-to-government relationship with federally recognized tribes and to consult with tribal governments prior to taking any action that might affect them. The memorandum directs agencies to assess the impacts of their programs and policies on tribes and to take their rights and concerns into consideration during development of any plan, programs, or projects. NPS must also remove any impediments to working directly with tribal governments in designing agency plans, programs, and projects. Finally, it instructs agencies to try to work cooperatively to carry out the intent of the memorandum and to tailor federal programs to meet the unique needs of tribal communities.

## SELECTED TENNESSEE AND KENTUCKY LAWS AND REGULATIONS

### TENN. CODE, TITLE 60, OIL AND GAS, CHAPTER 1, PART 1 (2006) Production of Oil and Gas: General Provisions

This part of the Tennessee code provides a general overview for operational requisites including permitting (section 103), mandatory record compilation and reporting (section 104). Section 102 prohibits production methods that result in waste. Section 106 provides well spacing requirements.

### TENN. CODE, TITLE 60, OIL AND GAS, CHAPTER 1, PART 2 (2006) Production of Oil and Gas: Oil and Gas Board

The Oil and Gas Board has vested authority to regulate oil and gas operations within the State of Tennessee. Oil and Gas Board rules, regulations and forms are published in Tennessee Compiled Rules and Regulations §1040-1-1-.01 through §1040-8-1 (2006). Oil and gas permit applicants must provide surface owners of oil and gas estates with notice of the applicant's intent to drill. (§ 209).

The following is a list of statewide rules promulgated by the Oil and Gas Board. Additional statewide rules may apply in conjunction with other relevant legal and policy mandates for oil and gas operations.

Rules of the Tennessee Oil and Gas Board, Statewide Order No. 2, Terms:

- Chapter 1040-1-1, Definitions

Rules of the Tennessee Oil and Gas Board, Statewide Order No. 2, Drilling, Re-Entering, Plugging and Abandoning Exploratory and Exploitation Oil Gas Wells:

- Chapter 1040-2-1, Bond
- Chapter 1040-2-2, Permits
- Chapter 1040-2-3, Well Location Plats
- Chapter 1040-2-4, Well Spacing
- Chapter 1040-2-5, Well Identification
- Chapter 1040-2-6, Drilling Wells
- Chapter 1040-2-7, Casing Program
- Chapter 1040-2-8, Directional Drilling
- Chapter 1040-2-9, Well Abandonment
- Chapter 1040-2-10, Filing of Well Data, Reports and Maps
- Chapter 1040-2-11, Exceptions and Hearings
- Chapter 1040-2-12, Violations – Penalties – Notice - Hearing

Rules of the Tennessee Oil and Gas Board, Statewide Order No. 2, Testing and Completing Wells for Production:

- Chapter 1040-3-1, Completion, Recompletion, and Related Downhole Work
- Chapter 1040-3-2, Tubing and Well Equipment

Chapter 1040-3-3, Prevention of Hazards and Pollution

Rules of the Tennessee Oil and Gas Board, Statewide Order No. 2, Production:

Chapter 1040-4-1, Pollution and Safety Controls

Chapter 1040-4-2, Procedures and Equipment for Metering, Measuring and Producing Oil Condensate and Gas

Chapter 1040-4-3, Requirements for Reporting the Volume and Disposition of Oil and Gas Produced

Chapter 1040-4-4, Ratable Take

Chapter 1040-4-5, Commingling and Automatic Custody Transfer of Hydrocarbons

Chapter 1040-4-6, Limiting Production

Chapter 1040-4-7, Regulating High Gas/Oil Ratio Wells and Preventing Waste of Gas

Chapter 1040-4-8, Subterranean Gas Storage

Chapter 1040-4-9, Pressure Maintenance Projects and Secondary Recovery

Rules of the Tennessee Oil and Gas Board, Statewide Order No. 2, Unitization:

Chapter 1040-5-1, Unit Operations

Rules of the Tennessee Oil and Gas Board, Statewide Order No. 2, Administrative Procedures:

Chapter 1040-6-1, Hearings and Administrative Approval

Chapter 1040-6-2, Rules of Procedure for Hearing Contested Cases

Rules of the Tennessee Oil and Gas Board, Statewide Order No. 2, Forms:

Chapter 1040-7-1, List of Forms

Rules of the Tennessee Oil and Gas Board, Statewide Order No. 2, NGPA Processing

Chapter 1040-8, Determinations Under Federal Natural Gas Policy Act of 1978

## TENN. CODE, TITLE 60, OIL AND GAS, CHAPTER 1, PART 5 (2006) Production of Oil and Gas: Mineral Test Hole Regulatory Act

This part codifies the Mineral Test Hole Regulatory Act of 1982 and authorizes regulation of mineral test hole drilling in order to prevent surface and subsurface pollution from natural brines, oil, gas, or mineralized waters.

## TENN. CODE, TITLE 60, OIL AND GAS, CHAPTER 1, PART 6 (2006) Production of Oil and Gas: Oil and Gas Surface Owners Compensation

This part codifies the Oil and Gas Surface Owners Compensation Act of 1984. Oil and gas developers must compensate surface owners for damages and deprivations resulting from drilling operations.

## TENN. CODE, TITLE 60, OIL AND GAS, CHAPTER 1, PART 7 (2006) Production of Oil and Gas: Environmental Protection

Operators must take measures that prevent or minimize soil erosion and surface water pollution from the time a drilling or re-entry well permit is granted until the well is abandoned.

## TENN. CODE, TITLE 68, HEALTH SAFETY AND ENVIRONMENTAL PROTECTION, CHAPTER 216 (2006)
## Environmental Protection: Oil Spill Cleanup

This Chapter codifies the Tennessee Oil Spill Cleanup and Environmental Preservation Act of 1995. Statute imposes liability on operators for oil spills.

## TENN. CODE, TITLE 70, WILDLIFE RESOURCES, CHAPTER 8, PART 1 (2006)
## Species Protection and Conservation: Nongame and Endangered Species

This part codifies the Tennessee Nongame and Endangered or Threatened Wildlife Species Conservation Act of 1974 and prohibits takings of listed endangered animal species.

## TENN. CODE, TITLE 70, WILDLIFE RESOURCES, CHAPTER 8, PART 3 (2006)
## Rare Plant Protection and Conservation

This part codifies the Rare Plant Protection and Conservation Act of 1985 and prohibits takings of listed endangered plant species.

## KY. REV. STAT., TITLE 28, MINES AND MINERALS, CHAPTER 353 (2005)
## Mineral Conservation and Development

- §353.010, Definitions for Chapter
- §353.020, Oil and Gas Lease or Contract, When Lessor May Avoid
- §353.030, Nonproductive Well, When Lease or Contract Satisfied By
- §353.040, When Offset Wells to Be Drilled
- §353.050, Plat, Showing Well, to Be Filed If well Is to Extend Through Coal-Bearing Strata - Copies to Certain Persons
- §353.060, Objections to Location of Well - Hearing
- §353.070, Index of Plats - Agreement Permitting Well Operator to Select Location
- §353.080, Drilling Through Coal Bed
- §353.090, Gas Found Beneath or Between Coal Beds
- §353.100, Casings to Remain In Place During Life of Productive Well
- §353.110, Abandonment of Well Drilled Through Coal Strata - Plugging of Well *-- Incorporates Regulation: Public Protection and Reg. Cabinet Dep't of Mines and Minerals, Title 805, §1:070, Plugging Wells; Coal-Bearing Strata*
- §353.120, Method of Plugging Well Drilled Through Coal-Bearing Strata *-- Incorporates Regulation: Public Protection and Reg. Cabinet Dep't of Mines and Minerals, Title 805, §1:070, Plugging Wells; Coal-Bearing Strata*
- §353.130, Alternative Methods That May Be Used When Strata Shot
- §353.140, Gas Escape Pipe, When to Be Used
- §353.150, Unused Oil, Gas or Salt Water Well to Be Closed To Prevent Waste
- §353.160, Gas Waste to Be Prevented - Presumption of Negligence
- §353.170, Putting Pressure on Strata - Wells May Remain Open If Conforming to Federal Safe Drinking Water Act.
- §353.180, Requirements for Plugging Abandoned Well - Bids - Remedy for Possessor of Adjacent Land or for Department
- §353.190, Salt and Saltpetre Works to Be Inclosed - Liability

§353.200, Department of Mines and Minerals to Enforce Oil and Gas Law – Hearings
§353.205, Department to Release Production Data on Crude Oil and Natural Gas
§353.210, Agreement Consolidating Oil and Gas Leases May Be Executed by Trustee Representing Contingent Future Interests
§353.220, Nature of Agreement
§353.230, Petition for Court Approval - Affidavits - Guardian Ad Litem - Order of Approval
§353.240, Agreement Consolidating Oil and Gas Leases May be Executed by Guardian.
§353.250, Nature of Agreement
§353.260, Petition for Court Approval - Affidavits - Guardian Ad Litem - Order of Approval
§353.300, Appointment of Trustee to Execute Mineral Lease Where Contingent Future Interests are Involved.
§353.310, Jurisdiction of court
§353.320, Who May Institute Proceedings
§353.330, Parties - Representation of Minors, Mentally Disabled, and Persons Not in Being
§353.340, Alignment of Parties - Process
§353.350, Bond of Trustee - Terms of sale of Lease
§353.360, Execution of Sale of Lease - Report - Confirmation
§353.370, Separate Lease By Guardian or Conservator Unnecessary
§353.380, Disposition of Proceeds

## KY. REV. STAT., TITLE 28, MINES AND MINERALS, CHAPTER 353 (2005) Mineral Conservation and Development: Severed Mineral Interests of Unknown or Missing Owners

§353.460, Definitions
§353.462, Jurisdiction in Circuit Court.
§353.464, When Court May Declare Trust and Appoint Trustee - Persons Authorized to Institute Proceedings
§353.466, Persons to Be Joined as Defendants - Verified Petition Showing Effort to Locate Owners - Advertisement and Lis Pendens Notice, Contents - Trustee Ad Litem
§353.468, If Advantageous to Unknown or Missing Owner, Court May Declare Trust - Bond of Trustee - Sale of Lease - Trustee's Report - When Court Not to Authorize Trustee's Lease - Trustee to Use Percentage of Funds to Search for Owner - Period During Which Unknown or Missing Owner May Establish Identity and Title
§353.470, When Trustee May Convey Title in Mineral Interest to Surface Owner - Payment to Surface Owner - Final Report of Trustee - Termination of Trust
§353.472, Payment to Surface Owner When Leased mineral Never Produced Commercially
§353.474, Payment of Attorneys' Fees, Expenses, and Court Costs
§353.476, When Action by Unknown or Missing Owner is Barred

## KY. REV. STAT., TITLE 28, MINES AND MINERALS, CHAPTER 353 (2005) Mineral Conservation and Development: Oil and Gas Conservation

§353.500, Declaration of Policy of KRS 353.500 to 353.720
*-- Incorporates Regulation: Public Protection and Reg. Cabinet Dep't of Mines and Minerals, Title 805, §1:080, Gas Storage Reservoirs; Drilling, Plugging in Vicinity*
*-- Incorporates Regulation: Public Protection and Reg. Cabinet Dep't of Mines and Minerals, Title 805, §1:160, Posting of a Danger Sign on a Facility Used for the Storage of Oil*
*-- Incorporates Regulation: Public Protection and Reg. Cabinet Dep't of Mines and Minerals, Title 805, §1:190, Gathering Lines*
§353.510, Definitions for KRS 353.500 to 353.720
§353.520, Territorial Application of KRS 353.500 to 353.720 - Waste of Oil and Gas Prohibited
*-- Incorporates Regulation: Public Protection and R. Cabinet Dep't of Mines and Minerals, Title 805, §1:020, Protection of Fresh Water Zones*
*-- Incorporates Regulation: Public Protection and Reg. Cabinet Dep't of Mines and Minerals, Title 805, §1:080, Gas Storage Reservoirs; Drilling, Plugging in Vicinity*
*-- Incorporates Regulation: Public Protection and Reg. Cabinet Dep't of Mines and Minerals, Title 805, §1:110, Underground Injection Control*
*-- Incorporates Regulation: Public Protection and Reg. Cabinet Dep't of Mines and Minerals, Title 805, §1:120, Operating or Deepening Existing Wells and Drilling Deeper Than the Permitted Depth.*
*-- Incorporates Regulation: Public Protection and Reg. Cabinet Dep't of Mines and Minerals, Title 805, §1:130, Deep Well Administrative Regulation Relating to Casing, Cementing, Plugging, Gas Detection and Blow-Out Prevention*
*-- Incorporates Regulation: Public Protection and Reg. Cabinet Dep't of Mines and Minerals, Title 805, §1:140, Directional and Horizontal Wells*
*-- Incorporates Regulation: Public Protection and Reg. Cabinet Dep't of Mines and Minerals, Title 805, §1:170, Content of the Operations and Reclamation Proposal; form on Which the Proposal is Filed*
§353.530, Director of Division of Oil and Gas Conservation - Qualifications – Duties - Oath.
§353.540, Authority of Department - Jurisdiction
*-- Incorporates Regulation: Public Protection and Reg. Cabinet Dep't of Mines and Minerals, Title 805, §1:080, Gas Storage Reservoirs; Drilling, Plugging in Vicinity*
§353.550, Specific Authority over Oil and Gas Operators
*-- Incorporates Regulation: Public Protection and Reg. Cabinet Dep't of Mines and Minerals, Title 805, §1:030, Well Location Plat, Preparation, Form and Contents*
*-- Incorporates Regulation: Public Protection and Reg. Cabinet Dep't of Mines and Minerals, Title 805, §1:060, Plugging wells; noncoal-Bearing Strata*
*-- Incorporates Regulation: Public Protection and Reg. Cabinet Dep't of Mines and Minerals, Title 805, §1:070, Plugging Wells; Coal-Bearing Strata*
*-- Incorporates Regulation: Public Protection and Reg. Cabinet Dep't of Mines and Minerals, Title 805, §1:080, Gas Storage Reservoirs; Drilling, Plugging in Vicinity*

*-- Incorporates Regulation: Public Protection and Reg. Cabinet Dep't of Mines and Minerals, Title 805, §1:180, Production Reporting*

§353.560, Further Authority

*-- Incorporates Regulation: Public Protection and Reg. Cabinet Dep't of Mines and Minerals, Title 805, §1:040, Vacuums; use of*

*-- Incorporates Regulation: Public Protection and Reg. Cabinet Dep't of Mines and Minerals, Title 805, §1:080, Gas Storage Reservoirs; Drilling, Plugging in Vicinity*

§353.565, Kentucky Oil and Gas Conservation Commission

§353.570, Permit Required - May Authorize Operation Prior to Issuance of Permit

*-- Incorporates Regulation: Public Protection and Reg. Cabinet Dep't of Mines and Minerals, Title 805, §1:170, Content of the Operations and Reclamation Proposal; form on Which the Proposal is Filed*

§353.575, Duty of Applicant to Meet and Confer with Permittee if Drilling Will Disturb Permitted Area.

§353.580, Expiration of Permit - Extensions

§353.590, Application for permit - Fees - Plat - Bond to Insure Plugging - Use of Forfeited Funds - Wells Not Included in "Water Supply Well"

*-- Incorporates Regulation: Public Protection and Reg. Cabinet Dep't of Mines and Minerals, Title 805, §1:050, Surety Bonds; Requirements, Cancellation*

*-- Incorporates Regulation: Public Protection and Reg. Cabinet Dep't of Mines and Minerals, Title 805, §1:170, Content of the Operations and Reclamation Proposal; form on Which the Proposal is Filed*

§353.5901, Operations and Reclamation Proposal for Land with Complete Severance - Contents, Distribution, and Agreement or Mediation - Mediation Report

*-- Incorporates Regulation: Public Protection and Reg. Cabinet Dep't of Mines and Minerals, Title 805, §1:170, Content of the Operations and Reclamation Proposal; form on Which the Proposal is Filed*

*-- Incorporates Regulation: Public Protection and Reg. Cabinet Dep't of Mines and Minerals, Title 805, §1:190, Gathering Lines*

§353.591, Purpose and Application of KRS 353.592 and 353.593

§353.592, Powers of the Department.

§353.593, Appeals

§353.595, Notice to Surface Owner of Intent to Drill Oil or Gas Well – Compensation for Damage to Surface - Restoration of Surface

*-- Incorporates Regulation: Public Protection and Reg. Cabinet Dep't of Mines and Minerals, Title 805, §1:170, Content of the Operations and Reclamation Proposal; Form on Which the Proposal is Filed*

§353.597, Replacement of Disrupted Water Supply by Well Operator

*-- Incorporates Regulation: Public Protection and Reg. Cabinet Dep't of Mines and Minerals, Title 805, §1:170, Content of the Operations and Reclamation Proposal; form on Which the Proposal is Filed*

§353.610, Conditions under Which Permits May be Issued - Exceptions

§353.620, Variance from Requirements of KRS 353.610

§353.630, Pooling of Oil and Gas Interests - Conditions

§353.640, Pooling Order - Notice - Provisions - Surrender or Sharing of Interest – Limited Participation

§353.645, Operation and Development as a Unit of Oil and Gas Interests in a Pool or Pools - Application for Unit - Hearing - Unitization Order

§353.650, Exclusion of Royalty Interest in Computing Share of Production –

Limitation

§353.651, Deep Wells - Establishment and Regulation of Drilling Units - Pooling of Interests - Exceptions.
*-- Incorporates Regulation: Public Protection and Reg. Cabinet Dep't of Mines and Minerals, Title 805, §1:100, Commission's Rules of Procedure; Spacing of Deep Well Drilling; Wildcat Wells and Pooling of Interests*

§353.652, Unit Operation of Pool - Procedure
*-- Incorporates Regulation: Public Protection and Reg. Cabinet Dep't of Mines and Minerals, Title 805, §1:100, Commission's Rules of Procedure; Spacing of Deep Well Drilling; Wildcat Wells and Pooling of Interests*

§353.653, Share of Production from Drilling Unit or Unitized Pool

§353.654, Drilling Without Consent of Landowner Prohibited

§353.655, Use of Shackle Rods or Related Cables

§353.656, Display of Danger Signs on Oil Storage facilities
*-- Incorporates Regulation: Public Protection and Reg. Cabinet Dep't of Mines and Minerals, Title 805, §1:160, Posting of a Danger Sign on a Facility Used for the Storage of Oil*

§353.660, Report Required After Termination of Operations - Contents – Confidentiality of Information - Exceptions

§353.670, Promulgation of Regulations - Hearing - Written Record of Hearing

§353.690, Production of Evidence - Failure to Comply

§353.700, Review of Order of Department by Civil Action - Appeal

§353.710, Suit to Enjoin Violation - By Department, Person Adversely Affected, Attorney General

§353.720, Construction of KRS 353.500 to 353.720

§353.730, Investigation of Abandoned Wells - Application - Report - Bond

**KY. REV. STAT., TITLE 28, MINES AND MINERALS, CHAPTER 353 (2005)**
**Mineral Conservation and Development: Kentucky Gas Pipeline Authority**

§353.750, Definitions for KRS 353.750 to 353.776.

§353.752, Kentucky Gas Pipeline Authority Established - Membership

§353.754, Procedure and Organization - Regulations

§353.756, Purpose of Authority - Powers of the Authority

§353.758, Issuance of Revenue Bonds - Proceeds of Bonds - Notes or Temporary Bonds

§353.760, Bonds of Authority Not Debts of Commonwealth

§353.762, Discretionary Securing of Bonds by Trust Indentures

§353.764, Enforcement of Rights by Bond Holder or Trustee of Trust Indenture

§353.766, Status of Authority Bonds as Securities

§353.768, Issuance of Revenue Refunding Bonds

§353.770, Treatment of Moneys Received

§353.772, Exemptions from Taxation

§353.774, KRS 45A.045 Not Applicable to Authority Projects

§353.776, Reporting of Activities

## KY. REV. STAT., TITLE 28, MINES AND MINERALS, CHAPTER 353 (2005)
## Mineral Conservation and Development: Penalties

§353.990, Penalties
§353.991, Penalties for Violation of KRS 353.500 to 353.720
§353.992, Penalties

## KY. REV. STAT., TITLE 12, CONSERVATION AND STATE DEVELOPMENT, CHAPTER 146 (2005)
## Natural Resources and Environmental Protection Cabinet: Endangered and Threatened Plants

# APPENDIX C: AIR QUALITY AND OIL AND GAS DEVELOPMENT AT BIG SOUTH FORK NATIONAL RECREATION AREA AND OBED WILD AND SCENIC RIVER

Our nation's air quality is protected under several provisions of the *Clean Air Act*, including the national ambient air quality standards (NAAQS) and the prevention of significant deterioration (PSD) program. The NAAQS consist of numerical standards for air pollution promulgated by the U.S. Environmental Protection Agency (EPA). They are broken into "Primary" and "Secondary" standards for the purpose of protecting public health and public welfare, respectively. Both Big South Fork NRRA and Obed WSR are located in the Tennessee River Valley-Cumberland Mountains Air Quality Control Region, which is currently in attainment of the NAAQS.

The PSD permitting program is administered by Tennessee Department of Environment and Conservation Division of Air Pollution Control, and the Kentucky Department for Environmental Protection Division of Air Quality. The program applies to defined categories of new or modified sources of air pollution with emissions greater than 100 tons per year and all other sources greater than 250 tons per year. Emissions from pollution sources affecting the park units are considered on a project-by-project basis in the assessment of air quality impacts required under the PSD program. Petroleum storage and transfer facilities exceeding a 300,000 barrel capacity, for instance, would be subject to PSD permitting. Based on the level of emissions, oil and gas wells, including pump jacks, would not be subject to PSD permitting. However, the regulatory thresholds are relevant benchmarks to consider in impact analysis.

The PSD program is designed to "preserve, protect, and enhance the air quality in national parks, national wilderness areas, national monuments, national seashores, and other areas of special national or regional natural, recreational, scenic, or historic value" (EPA 2010). Under this program, park units and other areas that are in attainment or unclassifiable under the NAAQS are designated as either Class I or Class II areas. Class I areas are areas of special national or regional natural, scenic, recreational, or historic value for which the PSD regulations provide special protection. The *Clean Air Act* mandates Federal Class I areas as certain national parks (over 6,000 acres), wilderness areas (over 5,000 acres), national memorial parks (over 5,000 acres), and international parks that were in existence as of August 7, 1977. Class II areas include park units that do not fit the above criteria. Both Big South Fork NRRA and Obed WSR are designated Class II air quality areas under the PSD program which protects air quality in the park units by allowing limited increases (i.e., allowable increments) over baseline concentrations of pollution for sulfur dioxide ($SO_2$), nitrogen dioxide, and particulate matter, provided that the NAAQS, established by the EPA, are not exceeded.

From the perspective of the NPS, the air pollutants most relevant to park resources are those that have the potential to result in the greatest effects to ecosystems. Plant damage resulting from high concentrations of ozone, for instance, can result in chlorosis, the symptoms of which include browning on leaves that occurs in a mottled pattern. Ozone damage can also result in slow growth and severe leaf browning, followed by premature leaf drop (Hales n.d.). A risk assessment carried out for the Appalachian Highlands Network of parks (NPS 2004d) found that the risk of ozone-related foliar injury to plants in both Big South Fork NRRA and Obed WSR is high. Secondary pollutants such as sulfates and nitrates, which are produced by industrial sources and automobile emissions, can result in the deterioration of visibility in park units and contribute to acid deposition which leads to impacts in forests. The main chemical precursors leading to acidic conditions are atmospheric concentrations of $SO_2$ and nitrogen oxides (NOx). When these two compounds react with water, oxygen, carbon dioxide, and sunlight in the atmosphere, the result is sulfuric and nitric acids, the primary agents of acid deposition (ESA 2000). While there are currently no standards for levels of sulfates or nitrates in ambient air, these pollutants present a major concern for ecosystem health in park units. Regional studies have shown that sulfates are the primary pollutant contributing to visibility degradation in the southeast, and that the majority of the primary $SO_2$ emissions come from utilities and industries (Vistas 2007). Excess nitrogen deposition in soils can also contribute to the spread of exotic and invasive plant species (Vasquez et al. 2008).

Current air quality conditions for Big South Fork NRRA and Obed WSR can be interpreted from recent air quality estimates for Big South Fork NRRA and Obed WSR for the 2004-2008 reporting period (NPS 2008h). Interpolated data for this period show that, for Big South Fork NRRA, average $4^{th}$ max ozone is 75.2 ppb, total-N wet deposition is 5 kg/ha/yr, total-S wet deposition is 6.5 kg/ha/yr and the group 50 visibility condition minus natural conditions is 13.6 DV.

Given the programmatic nature of this plan, the exact locations of future operations are unknown. Therefore, a quantitative screening analysis of impacts was undertaken to determine if air quality impacts would exceed minor levels and if the topic of air quality would be carried forward for further analysis. The NPS ARD has issued guidance for determining the appropriate level of air quality analysis necessary for the proposed action, with appropriate screening levels (NPS 2010c). Therefore, the NPS performed a screening-level emissions inventory for Big South Fork NRRA and Obed WSR in which it was assumed that the reasonably foreseeable oil and gas activities would occur in a similar distribution as compared to locations of existing activities. Other assumptions included an average of one new well drilled per year, 36 currently active wells, 6 workovers per year, and 2 open well casings. All future assumptions were based on the reasonably foreseeable development (RFD) scenario as described in chapter 4 and used throughout the impact analysis.

The screening thresholds used to assess level of impacts in an attainment area as indicated by emissions inventory calculations are shown in table 1.

**TABLE 1. EMISSION THRESHOLDS - ATTAINMENT AREAS**

| Impact Level<br>Proposed Action (Emissions)<br>Current Air Quality | Proposed Action (Emissions) | Duration |
|---|---|---|
| Negligible | <50 tons per year (TPY) (any pollutant) | One to several days or very low daily emissions over an annual period. |
| Minor | >50 & <100 TPY (any pollutant) | Several days to weeks or very low daily emissions over an annual period. |
| Moderate | >100 TPY (any pollutant) | Several weeks to months |
| Major | >250 TPY (any pollutant) | Long-term, one year to several years |

Emissions inventory calculations were completed to determine potential NOx and volatile organic compound (VOC) emissions from various sources at the parks (NPS 2010d). VOCs are precursors of ozone, and could be a pollutant of concern as to known ozone impacts on vegetation and health effects for visitors and park employees. The sources analyzed included active wells, oil storage and venting from active wells, drilling, workovers, and leaking /capped wells. The sources and methodology are briefly described below:

- **Active Wells**—Emissions from active wells were estimated using emissions from an emission inventory and subsequent air quality modeling project performed for the Four Corners Air Quality Task Force (Stoeckinius et al. 2009). The Four Corners work provides a reasonably robust data set on which to base a Big South Fork NRRA and Obed WSR estimate with 152 engines of less than 100 hp that reflects a variety of engine ages and emission characteristics.

Average per engine emissions were derived from the Four Corners data which is 0.578 tons per year (tpy) for NOx and 0.026 tpy for VOCs. These were then scaled based on hours of operation, an average of 5,629 for the Four Corners as compared to 1095 for Big South Fork NRRA and Obed WSR. Therefore, this is a per engine estimate of 0.112 tpy for NOx and 0.005 tpy for VOC. With 36 engines in this size classification, an estimate of total NOx emitted would be about four tpy and would be about 0.2 tpy for VOC.

- **Drilling Operations**—The following equation from various Western Regional Air Partnership characterizations of drilling activities was used (Stoeckenius et al. 2009).

$$E = (EF \times HP \times LF \times t) / 907,185$$

where

E = emissions from a drill rig engine
EF = emission factor for such an engine
HP = engine horsepower
LF = load factor
t = number of hours on the engine per spud

The emission factor was taken from the Texas Commission on Environmental Quality work cited above, while a typical horsepower of 350 hp and how long it takes to drill a well, seven days, are from best judgment of observed drilling operations. Assuming an average of one well per year, emissions from drilling operations would be about 0.7 tpy of NOx. VOC emissions would be minimal.

- **Workovers**—Using the same approach as above with similar engines (350 hp) and load factor (0.75) and assuming there would be six workovers a year lasting perhaps three days results in per workover emissions estimates of 0.3 tons of NOx with minimal levels of VOC. An average of six of these per year would result in 1.8 tpy of NOx. These estimates are based on best professional judgment from observations in and around Big South Fork NRRA and Obed WSR
- **Oil Storage and Venting from Active Wells**—Based on information from Arrow engines for a small pumpjack engine and 100% load, natural gas consumed would be approximately 60 square cubic feet (scf) per hour. Assuming an average of three hours a day of operation per well, daily natural gas used in pumpjacks would be 180 scf. Expanded to 36 wells, the total would be 6,480 scf per day.
- As a conservative assumption, it was assumed that all remaining gas contained in oil pumped to the surface is released either through venting at the wellhead or while stored prior to transport. Based on best judgment it was assumed all wells in Big South Fork NRRA and Obed WSR produce 40 barrels per day. Based on how the oil is produced and best professional judgment, the gas oil ratio was estimated at 350 scf/STB. This would then total 14,000 scf of natural gas, of which the 6,480 scf from above is used in engines, so that the remaining 7,520 scf is released to the atmosphere either through venting or off-gassed during storage. Assuming conservatively that all natural gas is volatile, the annual VOC emissions from storage tanks and venting would be about 61 tpy.
- **Open Casing and Shut-In Wells**—Estimates were conducted for the two open casing situations; it was estimated that 3,400 scf/day is released to the atmosphere. Using the same assumptions as above, VOC emissions from open casing wells would be about 28 tpy. Seventeen leaking shut-in wells were also estimated to release 3,400 scf/day, which would then also result in about 28 tpy emitted. As a result of a current project to plug leaking wells, these emissions will be eliminated. The results are summarized in table 2.

**Table 2. Summary of Emissions**

| Source | NOx Emissions (tpy) | VOC Emissions (tpy) |
|---|---|---|
| Active Wells | 4.0 | 0.2 |
| Drilling | 0.7 | |
| Workovers | 1.8 | |
| Storage & Venting | | 61.0 |
| Leaking Wells | | 56.0 |
| Capped Wells | | -56.0* |
| TOTAL | 6.5 | 61.2 |

* These emissions will be eliminated as a result of a current project to plug leaking wells

As can be seen, screening calculations completed to determine potential NOx VOC emissions from oil and gas activities in the park under the RFD scenario resulted in a total estimated 61.2 tons per year of VOCs and 6.5 tons per year of NOx emissions from all sources. These levels would be considered minor (>50 and <100 tpy of any pollutant) under the current ARD guidance for evaluating emissions from NEPA projects. Also, emissions from oil and gas activities in the park under the RFD scenario indicated that there would be 56 tons per year of VOC emissions from open casing and leaking shut-in wells, but all of these would be eliminated as a result of a current project to plug leaking wells, and similar reductions would occur as other wells are plugged in the future.

At the site-specific level, operations under the proposed plan would comply with the recommended mitigation measures contained in appendix D, such as spraying existing gravel roads and access routes with freshwater and reducing vehicle speeds to minimize dust, as well as using properly designed, maintained, and operated equipment to reduce emissions. Operations would also have to comply with NPS requirements in order to receive approval for the Plan of Operations; therefore, operators inside the park would be required to follow operating procedures to minimize emissions. These include use of blowout preventers; a prohibition on burning of vegetation, construction debris, or site-produced wastes; use of clean (i.e., low sulfur) fuels; proper maintenance of engines; use of pollution control devices on vehicles (e.g., catalytic converters); and inspection and maintenance of flares and treater facilities.

Finally, there are very few wells forecast for development under the RFD scenario: only up to 20 wells total over a 15 to 20 year period at Big South Fork NRRA, and only up to 5 wells at Obed WSR. Overall, the actions expected under this plan would have a minor or less impact because of both the extensive plugging and reclamation that would be expected and because of the low estimated number of existing and new wells (over the course of the life of the plan). Given this, the site-specific mitigations that would be included in any plan of operations, and the low level of emission predicted by the screening level analysis, air quality was not further analyzed in this EIS.

# APPENDIX D: SOCIOECONOMIC IMPACTS ANALYSIS

**Big South Fork National River and Recreation Area (2/1/2008)**

*Past, present and potential future oil and gas development and production from resources underlying the Big South Fork National River and Recreation Area are linked to the social and economic environment of the surrounding community. Although the economic costs of compliance with the proposed regulations may accelerate shutdown and reclamation of older, marginal wells and defer development of some new wells within the Big South Fork NRRA, the overall impacts on regional social and economic conditions would be very limited in scope and economic importance when considered in the context of the overall regional economy. As a result, the net effects on social and economic conditions associated with implementation would be negligible, and therefore eliminated from detailed consideration.*

Sufficient description of the affected environment and consideration of the potential impacts on social and economic conditions in the region to support the preceding conclusion are presented below.

Social and Economic Conditions

The area of influence for socioeconomics for purposes of the oil and gas management plan is comprised of five counties: McCreary, Kentucky and Fentress, Morgan, Pickett and Scott counties in Tennessee. These five counties encompass all federal surface lands and the federal oil and gas estate within the Congressionally-approved boundaries of the Big South Fork National River and Recreation Area. Most of the surface lands and federal oil and gas estate are located in Scott and Morgan counties. The entire area is predominately rural in character, with settlement patterns, land use, and economic activity influenced heavily by terrain, natural resources, and transportation networks.

The resident populations of the individual counties in 2006 ranged from 4,855 in Pickett County to 21,926 in Scott County, with a five-county total of 81,723 residents – see **Table 1**. The five-county total represents a net increase of 2,189 residents, or 2.8 percent, since 2000. Fentress and Scott counties both registered solid population gains since 2000, together accounting for more than 75 percent of the total regional growth. More modest gains occurred in Morgan and McCreary counties, while Pickett County experienced a net decline of 90 residents during the same period.

**Table 1. Population Change, 2000 to 2006, BISO Socioeconomic Influence Area**

| | Fentress, TN | Morgan, TN | Pickett, TN | Scott, TN | McCreary, KY | Regional Total |
|---|---|---|---|---|---|---|
| Population, 2000 | 16,625 | 19,757 | 4,945 | 21,127 | 17,080 | 79,534 |
| Population, 2006 | 17,480 | 20,108 | 4,855 | 21,926 | 17,354 | 81,723 |
| Population change, 2000 to 2006 | 855 | 351 | -90 | 799 | 274 | 2,189 |
| Percent change, 2000 to 2006 | 5.1% | 1.8% | -1.8% | 3.8% | 1.6% | 2.8% |

Sources: U.S. Census Bureau, 2002, U.S. Census Bureau, 2006(a), and U.S. Census Bureau 2006(b)

The majority of the region's residents live in unincorporated areas. The largest communities in the region are Oneida (2006 pop. of 3,682), Helenwood (2000 pop. of 856), Huntsville (2006 pop. of 1,033), and Winfield (2006 pop. of 988) in Scott County, Jamestown (2006 pop. of 1,898) in Fentress County, Wartburg (2006 pop. of 909) in Morgan County, and Byrdstown (2006 pop. of 880) in Pickett County. In McCreary County the largest nearby communities are Pine Knot (2000 pop. of 1,680) and Whitley City (2000 pop. of 1,111), although neither is an incorporated municipality.

Whitley City, Pine Knot, Oneida, Helenwood, Huntsville, and Wartburg, along with several other smaller communities, are all east of BISO, generally along the U.S. highway 27 that runs north-south through the area. Jamestown lies to the west on U.S. highway 127. Oneida is the local commercial and industrial center in the area, and along with Jamestown are the primary gateway communities to the southern half of BISO via Tennessee highway 297.

Knoxville, about 65 miles southeast of BISO, is the nearest major metropolitan area, providing job opportunities for some local residents who chose to commute, and also serving as the major trade, services, and entertainment center for the region. The city of Oak Ridge and Oak Ridge National Laboratory, about 55 miles southeast, is another job center for some local residents. Individuals and households employed in the two locations but interested in a more rural lifestyle factor into the recent population growth in the region, particularly in Scott and Morgan counties.

Residents of Pickett and Fentress counties tend to be older, as is characterized by larger shares of residents over 65 and higher median ages -- see **Table 2**. Among the five counties, McCreary County has the lowest share of seniors and lowest median age, both of which are below the statewide averages.

**Table 2. Selected Demographic Characteristics, BISO Socioeconomic Influence Area**

| | Fentress, TN | Morgan, TN | Pickett, TN | Scott, TN | McCreary, KY | Regional Total |
|---|---|---|---|---|---|---|
| **DEMOGRAPHICS** | | | | | | |
| Persons 65 years & older, 2000 Number / Percent of Total | 2,270 / 13.7% | 2,277 / 11.5% | 878 / 17.8% | 2,384 / 11.3% | 1,810 / 10.6% | 9,619 / 12.1% |
| Median Age (years), 2000 | 38.0 | 36.5 | 41.6 | 34.7 | 34.2 | n.a. |
| | | | | | | |
| Total Housing Units, 2000 | 7,598 | 7,714 | 2,956 | 8,909 | 7,405 | 34,582 |
| Housing, Percent vacant | 11.9% | 9.4% | 29.3% | 7.9% | 12.0% | 11.8% |
| | | | | | | |
| Median Household Income, 2004 | $25,926 | $30,387 | $27,101 | $26,868 | $21,822 | NA |
| Individuals in Poverty, 2004 | 21.9% | 18.7% | 17.1% | 21.1% | 30.1% | NA |

Sources: U.S. Census Bureau, 2002, U.S. Census Bureau, 2007(a), and U.S. Census Bureau 2007(b)

In 2000, the housing inventory in the five county region totaled 34,582 units. Scott County, with 8,909 units, accounted for the single largest share of the total, Pickett the smallest. Homeownership rates range from 75.7 percent (McCreary) to 84.3 percent (Pickett), higher than the respective statewide averages. Overall occupancy averaged 88.2 percent. Vacancy rates ranged from 7.9 percent in Scott County to 29.3 percent in Pickett County. The high vacancy rate in Pickett County is primarily a reflection of the large number of cabins and homes held for seasonal use; more than 20 percent of the county's total housing inventory. The Census Bureau estimates a net addition of approximately 1,300 housing units from 2000 to 2006, with the largest increments in Scott (390 units) and Fentress (324 units).

Personal income in the area, as measured by the median household income, tends to be below the respective statewide averages, with correspondingly higher than average poverty rates. Morgan County's median household income of $30,387 in 2004 was 22 percent below the statewide median of $38,945, and the local poverty rate (18.7%) was 25 percent higher than the statewide figure (15%). In Fentress County, the median household income was 37 percent below the statewide median and the poverty rate was 46 percent higher. Among the five counties, McCreary County residents have the lowest median income and highest rates of poverty, the former more than 41 percent below the statewide average and the latter 85 percent higher.

The economies of the five counties in the study area differ in scale, composition, and other characteristics. Total employment in Scott County was 8,957 in 2004; more than four times that of the 1,902 jobs in Pickett (see **Table 3**) and also 30 percent of all jobs in the region. Farm employment accounted for 23 percent of all employment in Pickett County, less than three percent in McCreary County and 6.3 percent of the regional total. The high share of public land in McCreary, including lands in BISO, the Daniel Boone National Forest, lands managed by the U.S. Army Corps of Engineers, and state lands, contribute to the relatively low level of farm employment in McCreary County. Farm and other proprietors accounted for 40 percent of all employment in the region, and between 29 percent and 48 percent of all employment in the individual counties. The overall level of proprietorship activity is double the 20 percent for Tennessee and 19 percent for the state of Kentucky as a whole. Although proprietorship activity can be correlated with entrepreneurialism and is often viewed as a positive sign for economic development, economic income data suggest that many local proprietorships are secondary or part-time endeavors, yielding average earnings of only about half of the statewide averages.

Private sector employment accounts for between 61 percent and 82 percent of the employment and government jobs provide between 12 percent and 26 percent of all jobs in the individual counties. Most of the public sector jobs are in local government, however, state agencies provide a significant number of jobs in Morgan County and Federal employment, primarily associated with the Federal penitentiary, is important in McCreary County.

**Table 3. Selected Economic Characteristics, BISO Socioeconomic Influence Area**

| | Fentress, TN | Morgan, TN | Pickett, TN | Scott, TN | McCreary, KY | Regional Total |
|---|---|---|---|---|---|---|
| **ECONOMICS** | | | | | | |
| Total employment, 2004 | 7,886 | 6,133 | 1,902 | 8,957 | 4,752 | 29,630 |
| Farm employment, percent of total, 2004 | 8% | 7% | 23% | 3% | 3% | 7% |
| Private employment, percent of total, 2004 | 80% | 67% | 61% | 82% | 71% | 75% |
| Government, percent of total, 2004 | 12% | 26% | 16% | 15% | 26% | 18% |
| | | | | | | |
| Labor force, 2005 | 7,062 | 8,103 | 1,911 | 8,434 | 6,066 | 31,576 |
| Average unemployment, 2005 | 503 | 624 | 160 | 601 | 547 | 2,435 |
| Annual unemployment rate, 2005 | 7.1% | 7.7% | 8.4% | 7.1% | 9.0% | 7.7% |
| Net Flow of Workers, 2000 | Net 1,353 out | Net 3,620 out | Net 295 out | Net 33 out | Net 1,390 out | NA |
| | | | | | | |
| Per Capita Income, 2004 | $21,847 | $17,975 | $18,790 | $18,375 | $16,381 | NA |
| Average earnings per job, 2004 | $23,814 | $21,363 | $17,056 | $26,378 | $26,189 | NA |

Sources: U.S. Census Bureau, 2002, U.S. Census Bureau, 2007(a), and U.S. Census Bureau 2007(b)

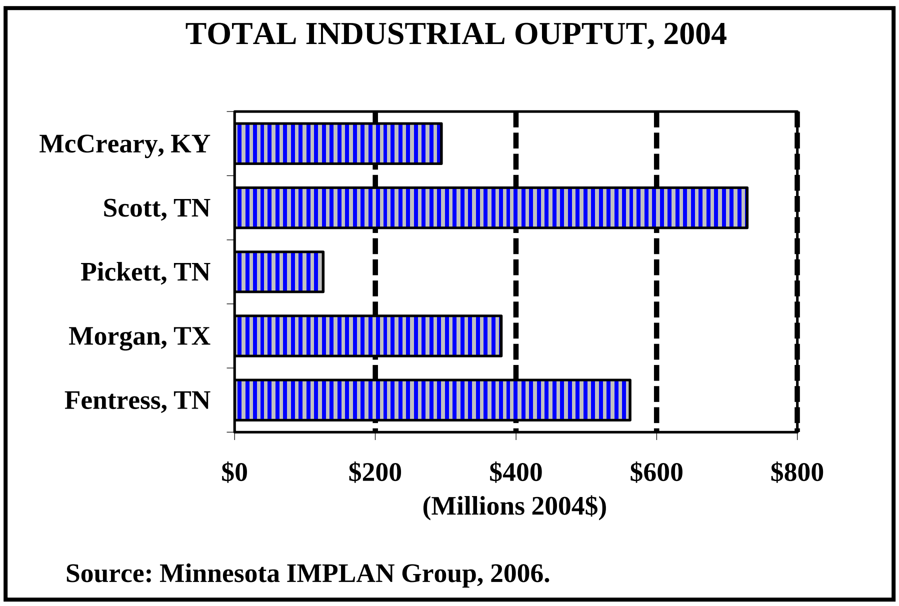
Continuing long-standing trends, local unemployment rates, which ranged from 7.1 percent in Fentress and Scott counties to 9.0 percent in McCreary County in 2005, are higher than the respective statewide averages.

Workforce commuting plays an important role in the local economies, as many local residents avail themselves of job opportunities in nearby communities while maintaining their local place of residence. Data from the 2000 Census indicated some level of commuting into these counties by non-residents, as well as out-commuting by local residences. The net flow was outward in all five counties, with significant outflows in Morgan, McCreary and Fentress counties. The net outflow in Morgan County was 3,620 workers, the equivalent of nearly 60 percent of the total employment based in the county. The net income inflows associated with such commuting is substantial, ranging from more than $15 million in Pickett County to $114 million in Morgan County in 2005, and help support local trade and services industries.

Among the five counties, residents of Fentress County had the highest per capita income in 2004, $21,847, while those of McCreary County had the lowest, $16,381. Average earnings per job in the same year ranged from $17,056 in Pickett County, to $26,378 in Scott County. Both measures of economic well-being trailed the respective statewide averages: $29,641 and $39,446 in Tennessee and $27,020 and $36,670 in Kentucky.

Differences in the scale and composition of the local county economies are apparent in their respective economic production. Farms, private businesses and governmental agencies in Pickett County produced goods and services with a combined value of $126 million in 2004 (see Figure 1 and **Table 4**). Scott County, the largest economy in terms of output, had total output of good and services valued at $729 million in 2004; nearly six times the size of neighboring Pickett County. The five-county region had a total annual economic of $2.1 billion in 2004.

**Figure 1. Total Economic Output in 2004, By County**




In terms of economic output, manufacturing, government services, health and social services, retail trade and utilities were the five largest industries in the region, together producing 69 percent of the total regional output of goods and services (see **Table 4**). Manufacturing alone, anchored by the more than $310 million in output in Scott County accounted for 27 percent of the annual output; $563 million. Wood products, fabricated metals, miscellaneous durable goods and textile and leather product manufacturing were the three largest manufacturing sub-sectors.

Government was the second largest sector in terms of annual output, at nearly $427 million in 2004.[1] McCreary, Scott and Morgan counties each had more than $100 million in government services. The third

[1] The total includes a small amount of output associated with establishments that were not classified in one of the North American Industry Classification Scheme (NAICS).

through fifth ranked health care and social services, utilities and retail trade sectors had combined total output of $442 million, just $15 million higher than the second-ranked government sector.

The top five sectors in terms of economic output in Scott and McCreary counties were the same as those on the regional level. The government and utilities sectors industries also rank among the top five industries in the other three counties as well. A factor contributing to the high ranking of the utilities sector are billings to commercial, industrial and residential consumers by local electrical, gas and telephone utilities, including deliveries by Citizens Gas Utility District of locally produced gas. Agricultural services and forestry is among the top five in Fentress, Morgan and Pickett counties, and other services completes the top five ranking in Morgan County.

**Table 4. Total Economic Output, 2004 (Millions of 2004$)**
***(Sorted in descending order of the Regional Total)***

| | Fentress, TN | Morgan, TN | Pickett, TN | Scott, TN | McCreary, KY | Regional Total |
|---|---|---|---|---|---|---|
| Manufacturing | $10.10 | **$49.00** | **$29.10** | **$310.70** | **$64.40** | **$563.30** |
| Government and non-NAICS establishments | **$85.50** | **$101.90** | **$21.70** | **$101.00** | **$116.50** | **$426.60** |
| Health and social services | **$62.70** | $17.30 | $ - | **$53.00** | **$17.20** | **$150.20** |
| Utilities | **$51.30** | **$33.00** | **$14.80** | **$33.90** | **$13.00** | **$146.00** |
| Retail Trade | **$46.80** | $19.00 | **$10.60** | **$42.90** | **$26.70** | **$146.00** |
| Ag., Forestry, Fishing & Hunting | **$64.10** | **$26.10** | **$15.00** | $10.80 | $3.00 | $119.00 |
| Other Services | $34.80 | **$35.60** | $4.60 | $30.30 | $2.80 | $108.10 |
| Finance & Insurance | $33.20 | $15.80 | $5.80 | $20.30 | $11.80 | $86.90 |
| Transportation & Warehousing | $14.70 | $12.70 | $2.50 | $34.90 | $6.20 | $71.00 |
| Construction | $3.70 | $14.40 | $2.00 | $25.10 | $2.90 | $48.10 |
| Real estate and rental | $10.50 | $16.40 | $7.40 | $4.50 | $3.80 | $42.60 |
| Accommodation & Food Services | $10.80 | $4.90 | $2.30 | $16.10 | $8.00 | $42.10 |
| Professional, scientific and technical services | $14.60 | $4.20 | $1.10 | $9.00 | $4.30 | $33.20 |
| Wholesale Trade | $5.90 | $8.90 | $0.40 | $12.20 | $5.70 | $33.10 |
| Mining, including Oil and Gas | $4.40 | $2.90 | $ - | $16.90 | $0.40 | $24.60 |
| Information | $2.10 | $8.10 | $0.40 | $2.90 | $5.50 | $19.00 |
| Administrative & Waste Services | $4.00 | $3.80 | $0.90 | $3.40 | $0.60 | $12.70 |
| Arts, entertainment & recreation | $2.10 | $3.30 | $2.90 | $0.30 | $0.30 | $8.90 |
| Educational Services | $0.80 | $0.60 | $4.30 | $0.10 | $0.70 | $6.50 |
| Management of Companies | $ - | $1.00 | $ - | $0.20 | $ - | $1.20 |
| TOTALS | $ 562.1 | $ 378.9 | $ 125.8 | $ 728.5 | $ 293.8 | $ 2,089.1 |

Note: Shaded cells indicate the top 5 industrial sectors in each county and the region, based on estimated economic output in 2004.

Source: Minnesota IMPLAN Group, 2006.

Tourism and outdoor recreation are important to the regional economies. BISO and other recreation and tourism attractions and opportunities in the region attract visitors from outside the region, as well as use by year-round and seasonal residents. These other attractions include the Big South Fork Scenic Railway, Pickett State Park and Rustic Forest and Scott State Forest, and the Daniel Boone National Forest, all of which attract visitors from outside the region, as well as use by year-round and seasonal residents. Much of the economic stimulus associated with tourism and recreation is captured in the arts, entertainment and recreation and accommodation and food services industries. Establishments in those sectors generated total output of $51 million in 2004. Although also serving demands of local residents, a substantial portion of that output was associated with tourism.

Not readily apparent in **Table 4** is the economic contribution of BISO within the regional economy. BISO hosted 622,807 recreation visitors in 2006, nearly 69,000 of which were overnight stays. Those visitors spent an estimated $21.9 million in the local economy, supporting 375 jobs and $ 6.5 million in personal income. In addition, the park had $ 3.5 million in annual payroll, plus other on-going operating outlays which directly and indirectly supported 71 jobs and $ 4.0 million in personal income within the economy (NPS 2007). The synergies between BISO and these other attractions likely compound the economic contributions of BISO beyond those directly associated with its operations and expenditures of visitors.

BISO staff report an increase in dispersed recreation use, including hiking, horseback riding, cross-country skiing, and OHV use, in southern portion of the park. Much of this use is believed to be associated with increasing residential development near the park, with homes being marketed as principal homes for year-round occupancy but also as seasonal/second homes for households whose primary residence is in Knoxville, Nashville, or elsewhere. Having the national recreation area as a “backyard” neighbor is likely viewed as an amenity because it diminishes (eliminates?) future development potential in the area and is also seen as offering relatively quick and easy access to trails and other recreation opportunities. Recent oil and gas development and related production and maintenance activities within the recreation area factor into the increased visitor use because the roads improve access into interior portions of the recreation area.

In 2004, the local mining sector in the region produced $24.6 million in output, approximately 1.2% of the total regional output, two-thirds of that occurring in Scott County. Natural gas and crude oil production, including that from wells within the boundaries of BISO accounts for a substantial but undisclosed portion of the mining output in Scott County. The economic significance of the local mining industry, including oil and gas, is limited in the other counties, with total output ranging from $0.4 million in McCreary County to $4.4 million in Fentress County. Data on recent oil and gas production data are not available for the local counties, however, data published by the U.S. Energy Information Administration indicates that statewide production of oil and gas in Tennessee has declined over the past several years. Crude oil production in Kentucky has also been declining, but natural gas production has been increasing.

Detailed data on the local oil and gas industry is not published due to its small size. However, available data suggest 6 to 8 oil and gas drilling, production and services firms, with a total of 40 to 50 employees based in the Scott and Morgan counties (Tennessee Department of Labor and Workforce Development, 2007 and Dun & Bradstreet 2006). Those firms and employees are, however, not strictly tied to development and production related to resources underlying BISO due to other existing oil and gas development and production in the surrounding area. Neither is new oil and gas development confined to the recreation area, but rather is also occurring on private fee lands in surrounding areas. Some of that development is readily visible along public roads in the area and also near some of the new residential developments.

Other potential social and economic linkages with local oil and gas production include contributions to local natural gas supply, tax revenues, and royalty income for private mineral rights owners.

With respect to the relationship to natural gas supply, most all local production flows into a local gathering system which is then marketed regionally. Little if any locally produced gas flows into the interstate market because Tennessee is a net importer of natural gas; the 400 producing gas wells in the state produced about 2.66 billion cubic feet of gas, just over one percent of statewide consumption in 2006 (EIA 2007). Approximately 40 percent of the total statewide natural gas production was from Morgan, Scott or Fentress counties (Tennessee Energy Division 2007). Neither the portion of that total from resources underlying BISO, nor the share of regional consumption supplied by BISO-related gas is known. Local production does not meet all demand and Citizens Gas Utility District, the local gas utility has tie-ins to several existing pipelines. Thus, were local production to be restricted, the local market would not be left without a source of natural gas, although local consumers might experience some increases in energy prices. The magnitude of those price effects is indeterminate due to uncertainty regarding the potential extent of effects on production and overall future energy supply and demand conditions. However, based on the areal extent of potentially affected production, the effects would be expected to be minor.

Statewide crude oil production in 2006 was 261,575 barrels. Of that, 107,442 barrels (41% of the total) was produced in Morgan, Scott or Fentress Counties (Tennessee Energy Division 2007). Crude is initially stored in on-site tank batteries, from where it is collected via tanker truck. Local production is thought to be trucked to a refinery in Kentucky (unverified at this time).

Tennessee imposes a 3 percent severance tax on the sale prices of crude oil and gas produced in the state. The tax is allocated two-thirds to the state general fund and one-third to the county in which the wellhead is located. For fiscal year 2006/07, total statewide receipts were about $1,041,000; a 28 percent increase as compared to 2004/05 due primarily to higher prices. Data on the distributions to local governments is not available, but assuming pro-rata distribution based on production would result in total distributions of about $400,000 to Morgan, Fentress and Scott counties, a nontrivial sum, but relatively limited given the combined general fund revenues of more than $21 million for these counties and in comparison to local property and local option sales taxes (Tennessee Comptroller 2007). Furthermore, only a portion of the production and the revenues are associated with resources underlying BISO. Consequently any constraints to future production from resources underlying BISO would likely have little adverse impact on county budgets.

A final consideration in this determination is the potential that some local residents could see a reduction in income associated with the loss of royalty/lease revenue from production. The number and distribution of mineral royalty/lease recipients associated with the BISO-related wells is unknown. Given the following: 1) such royalties/lease payments are a fractional share of the total value of production, 2) the approximate value of all local crude oil and natural gas production, based on recent production and energy prices, is $10 to $13 million per year, 3) not all royalty/lease recipients would be expected to be local residents, 4) not all production would be affected, and 5) the combined personal income of the two counties exceeds $1.5 billion annually with nearly $181 million in dividends, interest and rent, then, it is reasonable to conclude that any prospective reduction associated with the oil and gas management plan would not constitute more than a negligible impact to income in the local economy, though one or more individuals may experience a more substantial adverse income impact.

The economic impact of compliance on the local oil and gas industry

There is insufficient data available on which to estimate the potential economic effects of the higher compliance costs. Instead, the analysis focuses on how the costs may impact existing and future development.

Compliance with the 9B regulations imposes additional economic costs on owners/operators of existing wells and factors into the overall economic feasibility assessment for prospective future wells. In the case of the former, these costs affect an owner/operator's assessment of continued production and operation versus plugging and reclamation. For the latter, the compliance costs affect the cost of new well development and expected returns, and hence, the investment decision about whether to proceed.

There are four major elements of the overall compliance costs: (1) plan preparation, (2) compliance with reclamation standards, (3) compliance with operating standards, and (4) performance bonding. Actual costs associated with each element will vary in response to topography, access and other site conditions, and the expected extent of necessary natural and cultural surveys. Furthermore, the overall costs are comprised of both one-time and recurrent costs, with some one-time outlays required upfront and others coming at the end of a well's economic production life during plugging and reclamation. Cost estimates prepared by the NPS suggest a range of one-time costs of $13K to $38K and $3.5K in annual costs, on a per well basis. The majority of the one-time costs, $10K - $30K, are associated with elements (1), (2) and (3) and would be incurred in conjunction with initial compliance, that is, to bring an existing well into compliance or developing a new well. An estimated $3K to $8K would be incurred as part of final plugging and reclamation. A decision to plug and reclaim a marginal well would avoid the recurrent costs.

In the case of existing wells, foreseeable effects include decisions by operators of marginal properties, i.e., low volume producers, to plug and reclaim these wells. In the short-term such a decision would temporarily support a higher level of employment activity, but would thereafter result in marginal reductions in local economic activity over the long-term. Temporary boosts in activity would also result in conjunction with the initial compliance work for existing wells with current and anticipated rates of production adequate to justify the initial investments and recurrent costs.

Once a new well is completed and initial compliance achieved, the future decisions regarding sustaining production versus plugging and reclaiming would be largely a function of production rates, gas prices and the operating expenses. By definition, an operator’s decision to plug and abandon a well would come into play primarily with wells at or near the end of their productive lives. All other things being equal, principally future production and gross revenues, one could reasonably expect the net impact of higher recurrent and reclamation costs to be a decision to plug and reclaim a well several years sooner than would otherwise have occurred. Consequently, the net effects would be limited as they relate to local economic output, the level of local production available for marketing within the region, the income and profitability of operators and mineral interest owners, local employment in the oil and gas industry, and state and local government taxes.

The impacts of compliance on future development is uncertain as such development is contingent upon numerous factors, including the prospects for successful well development, the anticipated production, other development costs, and market prices of oil and natural gas. Many of these factors are beyond the control of the operators, mineral interest owners, or the National Park Service. Given these factors, the likely effects of the higher compliance costs, particularly the one-time upfront costs, would be to delay/defer the development of some new wells within the Park, shifting more development interest to other locations. This would occur in cases where the expected return on investment is unsatisfactory. In general, the higher the share of total well development costs represented by the $10K to $30K, the more pronounced the impacts.

In instances when an operator decides to proceed with a new well, such wells would be subject to ongoing assessment of economic viability, given the recurrent costs and pending plugging and reclamation costs. Once operational, the economic impact of the compliance requirements would be to reduce long-term operator profitability. However, the overall reduction in profitability may not accrue locally. On one hand, reductions in profitability would result due to the need to hire additional staff or contractors to conduct the compliance assessments, complete the requisite actions identified in the assessments, and complete the ongoing reporting and monitoring activities. The increased costs would translate into lower investment in the industry and lower income for operators and owners, an unknown portion of which accrues locally. On the other hand, reductions in profitability would be largely manifest in terms of marginally higher employment and labor income during well development and operations. Such employment and income effects would accrue primarily within the local economy, offsetting some or much of the reduction in profitability with respect to the local economy.

Despite the offset between wage and salary earnings of workers and the reduced profitability for operators and owners, some members of the latter group would experience declines in income and economic welfare due to the higher compliance. The number of individuals affected, the magnitude of the impacts, and overall effect of these declines is uncertain. In individual instances, typically affecting more marginal operations, the effects could be dramatic, potentially resulting in a complete cessation of operations.

The potential adverse impacts on some individual operations notwithstanding, the net economic effects of the compliance regulations are likely to be negligible in the short-term and long-term given current production levels and the size and structure of the regional oil and gas industry.

Overall Conclusion

The regulations would affect only a segment of the industry's operations. The oil and gas industry has only a limited presence in the regional economy. Current oil and gas production levels in the region are relatively low, less than 110,000 barrels of oil and about 1.0 billion cubic feet of natural gas in 2006.[2] Much, if not most, of the current production is from outside of the Big South Fork National River and Recreation Area and the industry is actively engaged in new drilling outside of the Park. Thus, although the costs of compliance with the proposed regulations may accelerate the shutdown of older, marginal wells and defer development of some new wells within the Big South Fork NRRA, the overall impacts on regional social and economic conditions would be very limited in scope and economic importance when considered in the context of the regional economy. As a result, the net effects on social and economic conditions associated with implementation would be negligible.

[2] Production is for the Morgan, Scott, Fentress and Pickett counties. Production data for McCreary County is not available.

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**Obed Wild and Scenic River (2/1/2008)**

*Past, present and potential future oil and gas development and production from resources underlying the Obed Wild and Scenic River are linked to the social and economic environment of the surrounding community. Although the economic costs of compliance with the proposed regulations may accelerate shutdown and reclamation of older, marginal wells and defer development of some new wells within the Obed WSR, the overall impacts on regional social and economic conditions would be very limited in scope and economic importance when considered in the context of the overall regional economy. As a result, the net effects on social and economic conditions associated with implementation would be negligible, and therefore eliminated from detailed consideration.*

Sufficient description of the affected environment and consideration of the potential impacts on social and economic conditions in the region to support the preceding conclusion are presented below.

Social and Economic Conditions

Cumberland and Morgan counties would comprise the influence area for socioeconomics for purposes of the oil and gas management plan. These two counties encompass all federal surface lands and the federal oil and gas estate within the Congressionally-approved boundaries of the Obed Wild and Scenic River. Both counties are predominately rural in character, with settlement patterns, land use, and economic activity influenced heavily by terrain, natural resources, and transportation networks.

Cumberland County had an estimated 51,346 residents in 2005, an increase of nearly 10 percent since 2000 and double the statewide population growth of 4.8 percent during the same period. Of the residents in 2005, 10,547 lived in Crossville, the county seat, with approximately twice that number living in the nearby surrounding unincorporated area. Much of the remaining population resides in and around several unincorporated communities situated along the U.S. 70 corridor to the west and southeast of Crossville, and in an area known as Fairfield Glade south/southwest of the Obed River.

Morgan County had 20,157 residents in 2005, a modest 2.0 increase over the population in 2000 (see Table 5 below). About 900 of these residents lived in Wartburg, the county seat and largest community in the county. The remaining population tends to be relatively more concentrated in the southern portion of the county, south and southeast of the Obed River, due to its proximity to Oak Ridge, Knoxville and the I-40 corridor.

**Table 5. Selected Demographic Characteristics, Obed Socioeconomic Influence Area**

| Demographic Measure | Cumberland, TN | Morgan, TN | Total |
|---|---|---|---|
| Population, 2000 | 46,802 | 19,757 | 66,559 |
| Population, 2005 Estimate | 51,346 | 20,157 | 71,503 |
| Population, change, 2000 to 2005 | 4,544 / 9.7% | 400 / 2.0% | 4,944 / 7.4% |
| | | | |
| Persons 65 years & older, 2000 | 9,615 / 20.5% | 2,277 / 11.5% | 11,892 / 17.9% |
| Median age (years), 2000 | 42.5 | 36.5 | 35.9 |
| | | | |
| Total Housing Units, 2000 | 22,442 | 7,714 | 30,156 |
| Housing, Percent vacant (2000) | 13.1% | 9.4% | 12.1% |
| | | | |
| Median Household Income, 2004 | $34,061 | $30,387 | NA |
| Percent of Population in Poverty, 2004 | 14.7% | 18.7% | NA |

Sources: U.S. Census Bureau, 2002, U.S. Census Bureau, 2006(a), and U.S. Census Bureau 2006(b)

More than 80 percent of all households in the two counties own their homes. Residents of Cumberland County tend to be older and have higher incomes than those in Morgan County. However, the 2004 median income in Cumberland County ($34,061) was 13% below the statewide figure of $38,945. The overall poverty rate in Cumberland County (14.7%) was lower than both Morgan County (18.67%) and the statewide average of 15 percent. In 2000, there were nearly 3,000 vacant housing units in Cumberland County, of which 1,400 were for seasonal, recreational, or other occasional use.

Home ownership among Morgan County households was 83 percent. However, the median income of $30,387 in 2004 was 22 percent below the statewide median of $38,945, and the local poverty rate (18.7%) was 25 percent higher than the statewide figure (15%). In 2000, housing vacancy rates averaged 9.4 percent in Morgan County, however, unlike in Cumberland County, relatively few of these units were for seasonal, recreational or other occasional use. Rather they were primarily vacant rental units.

The economies of Cumberland and Morgan counties differ in scale, composition, and other characteristics. Total employment in Cumberland County was 24,376 in 2004; nearly four times the 6,133 jobs in Morgan County (see Table 6). Farm and other proprietors accounted for 28 percent of all employment in Cumberland County and 53 percent in Morgan County. Farm and other proprietors accounted for 20 percent of all employment statewide.

**Table 6. Selected Economic Characteristics, Obed Socioeconomic Influence Area**

| Economic Measure | Cumberland, TN | Morgan, TN | Total |
|---|---|---|---|
| Total employment, 2004 | 24,376 | 6,133 | 30,509 |
| Farm employment, percent of total 2004 | 3.8% | 6.9% | 4.4% |
| Private non-farm employment, percent of total, 2004 | 87.2% | 67.0% | 83.1% |
| Government, percent of total, 2004 | 9.0% | 26.1% | 12.4% |
| | | | |
| Total Personal Income (millions), 2004 | $ 1,174.3 | $ 372.9 | $ 1,547.2 |
| Per Capita Income, 2004 | $23,671 | $17,975 | NA |
| Average earnings per job, 2004 | $28,283 | $21,363 | NA |
| | | | |
| Labor force, 2005 | 22,163 | 8,103 | 30,266 |
| Average unemployment, 2005 | 1,417 | 624 | 2,041 |
| Annual unemployment rate, 2005 | 6.4% | 7.7% | 6.7% |
| Net flow of workers, 2000 | Net 456 out | Net 3,620 out | NA |

Sources: U.S. Bureau of Economic Analysis, 2006 and U.S. Bureau of Labor Statistics, 2006.

The relatively large difference in jobs, when compared to the relative difference in population, is accounted for by the fact that many Morgan County residents commute to work in Oak Ridge and Knoxville – in 2000, 3,620 more residents commuted to work elsewhere than commuted into Morgan County for jobs. A net outflow of workers also occurred in Cumberland County, but at a much lower rate.

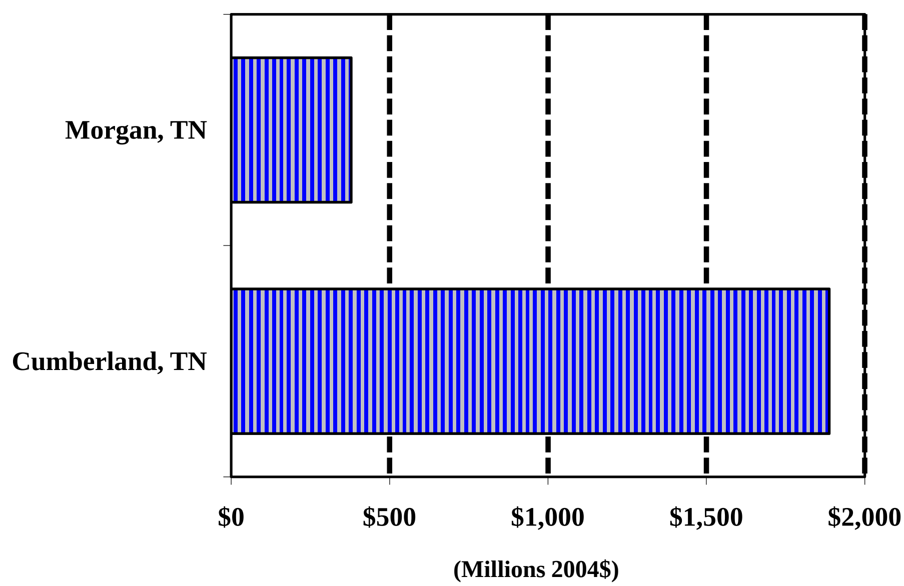
The per capita incomes of residents and average earnings per job in Cumberland County are each higher than the corresponding measures in Morgan County (see Table 6), but much lower than the statewide averages of $29,641 and $39,446, respectively.

Continuing a long-standing trend, average annual unemployment rates in 2005 were 6.4 percent and 7.7 percent in Cumberland and Morgan counties, respectively, above the statewide average of 5.6 percent.

The two counties are differentiated from one another in terms of economic structure. Private non-farm employment accounted for 87.2 percent of all jobs in Cumberland County in 2004. Farm and government positions accounted for 3.8 and 9.0 percent of the jobs, respectively. In Morgan County, private non-farm jobs accounted for 67 percent of employment, while farm and public sector jobs accounted for 6.9 percent and 26.1 percent of jobs, respectively. Statewide, private non-farm jobs represented 84.9 percent of the total.

Differences in the scale and composition of the two county economies are also apparent in their respective economic production. Farms, private businesses and governmental agencies in Cumberland County produced goods and services with a combined value of $1.89 billion in 2004 (see Figure 2). The corresponding measure of the output of good and services in Morgan County in 2004 was $379 million; one-fifth that of its neighbor.

**Figure 2. Total Annual Economic Output in 2004**




**Source: Minnesota IMPLAN Group, 2006.**

In terms of economic output, manufacturing, government services, retail trade, health and social services, and utilities were the five largest industries in Cumberland County, together producing 60 percent of the annual value of goods and services (see Table 7). Manufacturing by itself accounted for 22 percent of the annual output, with ceramic, glass and motor vehicle parts the three largest sub-sectors. The five largest industries in terms of economic output in Morgan County are government, manufacturing, other services (e.g. equipment repair, dry-cleaning, pet care and photofinishing services), utilities, and agriculture, forestry, fishing and hunting. These five industry groups accounted for 65 percent of the total annual local output of goods and services.

Not readily apparent in Table 7 is the economic contribution of OBRI within the regional economy. OBRI hosted 184,573 recreation visitors in 2005. It is estimated that those visitors spent $ 7.1 million in the local economy, supporting 139 jobs and $ 2.6 million in personal income. In addition, the park had $ 0.5 million in annual payroll, plus other on-going operating outlays which directly and indirectly supported 23 jobs and $ 0.6 million in personal income within the economy. (NPS 2006)

| Table 7. Total Economic Output, 2004 (Millions of 2004$) *(Sorted in descending order of the Regional Total)* | | | |
|---|---|---|---|
| **Major Industrial Sector** | **Cumberland, TN** | **Morgan, TN** | **Regional Total** |
| Manufacturing | $407.50 | $49.00 | $456.50 |
| Government and non-NAICS establishments | $234.30 | $101.90 | $336.20 |
| Retail Trade | $175.60 | $19.00 | $194.60 |
| Health and social services | $169.10 | $17.30 | $186.40 |
| Utilities | $151.50 | $33.00 | $184.50 |
| Real estate and rental | $121.10 | $16.40 | $137.50 |
| Other Services | $71.40 | $35.60 | $107.00 |
| Transportation & Warehousing | $81.10 | $12.70 | $93.80 |
| Accommodation & Food Services | $72.40 | $4.90 | $77.30 |
| Information | $67.20 | $8.10 | $75.30 |
| Finance & Insurance | $59.20 | $15.80 | $75.00 |
| Ag., Forestry, Fishing & Hunting | $46.50 | $26.10 | $72.60 |
| Wholesale Trade | $53.30 | $8.90 | $62.20 |
| Mining, including Oil and Gas | $47.30 | $2.90 | $50.20 |
| Professional, scientific and technical services | $45.90 | $4.20 | $50.10 |
| Arts, entertainment & recreation | $34.90 | $3.30 | $38.20 |
| Administrative & Waste Services | $30.00 | $3.80 | $33.80 |
| Construction | $14.10 | $14.40 | $28.50 |
| Management of Companies | $3.90 | $1.00 | $4.90 |
| Educational Services | $1.50 | $0.60 | $2.10 |
| **TOTALS** | **$ 1,887.8** | **$ 378.9** | **$ 2,266.7** |

Source: Minnesota IMPLAN Group, 2006.

The local mining sector in Cumberland County produced $47.3 million in output, approximately 2.5% of the county total, most of that was from coal, stone and sand and gravel. Data for the local oil and gas industry are not published due to its small size. However, available data suggest 1 or 2 oil and gas production firms and 1 or 2 drilling or other oil and gas service firms, with a total of 15 to 25 employees based in the county (Tennessee Department of Labor and Workforce Development, 2007 and Dun & Bradstreet 2006). Those firms and employees are, however, not strictly tied to development and production related to resources underlying OBRI due to other development and production in the surrounding area.

The economic significance of the local mining industry, including oil and gas, is even more limited in Morgan County. In 2004, the industry's total annual output was $2.9 million, 0.8 percent of the county total. As in Cumberland County, stone quarries account for a substantial portion of that total. Available data again suggest 3 or 4 small oil and gas production and/or service establishments with local operations (Tennessee Department of Labor and Workforce Development, 2007 and Dun & Bradstreet 2006).

Other firms/operators are thought to be active in the area. However, the inference from the available data is that their activities are supported from locations outside of Cumberland and Morgan Counties, which would further diminish the relative significance of potential social and economic effects of potential actions associated with the oil and gas management plan.

Other potential social and economic linkages with local oil and gas production include contributions to local natural gas supply, tax revenues, and royalty income for private mineral rights owners.

With respect to the relationship to natural gas supply, most all local production flows into a local gathering system which is then marketed regionally. Little if any locally produced gas flows into the interstate market because Tennessee is a net importer of natural gas; the 400 producing gas wells in the state produced about 2.66 billion cubic feet of gas, just over one percent of statewide consumption in 2006 (EIA 2007). Approximately 27 percent of the total statewide natural gas production was from Morgan County. None of the production occurred in Cumberland County. (Tennessee Energy Division 2007). Neither the portion of that total from resources underlying OBRI, nor the share of regional consumption supplied by OBRI-related gas is known.

Local production does not meet all demand and Citizens Gas Utility District, the local gas utility has tie-ins to several existing pipelines. Thus, were local production to be restricted, the local market would not be left without a source of natural gas, although local consumers might experience some increases in energy prices. The magnitude of those price effects is indeterminate due to uncertainty regarding the potential extent of effects on production and overall future energy supply and demand conditions. However, based on the areal extent of potentially affected production, the effects would be expected to be minor.

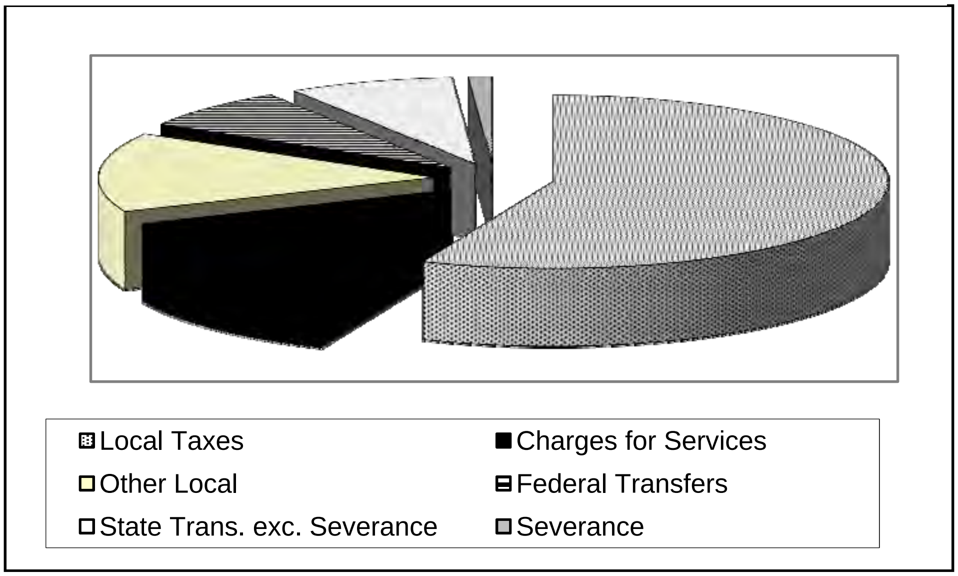
Statewide crude oil production in 2006 was 261,575 barrels. Of that, 203 barrels (less than 0.1%) were produced in Cumberland County with 49,963 barrels (19%) produced in Morgan County (Tennessee Energy Division 2007). Crude is initially stored in on-site tank batteries, from where it is collected via tanker truck. Local production is thought to be trucked to a refinery in Kentucky (unverified at this time).

Tennessee imposes a 3 percent severance tax on the sale prices of crude oil and gas produced in the state. The tax is allocated two-thirds to the state general fund and one-third to the county in which the wellhead is located. For fiscal year 2006/07, total statewide receipts were about $1,041,000; a 28 percent increase as compared to 2004/05 due primarily to higher prices.

Data on the distributions to local governments is not available, but pro-rata distribution suggest annual oil and gas severance revenues to Morgan County, based on all oil and gas production in the county,[3] of $60,000 to $70,000 per year. Such revenues are about 1.1 percent of the county's annual general fund budget of $5.8 million; nontrivial but limited as compared to local property and local option sales taxes (see Figure 3) (Tennessee Comptroller 2007). Cumberland County receives little or no oil and gas severance taxes due to the limited production in the county.

[3] A total of approximately 324,000 barrels of crude oil were produced in Tennessee that same year, 16 percent of that from within Morgan County (Tennessee Energy Division 2007).

**Figure 3. Morgan County General Fund Revenues 2005**




Once again, any limitations on future production from resources underlying OBRI would likely have little adverse impact on the county's budget.

A final consideration in this determination is the potential that some local residents could see a reduction in income associated with the loss of royalty/lease revenue from production. The number and distribution of mineral royalty/lease recipients associated with the OBRI-related wells is unknown. Given the following: 1) such royalties/lease payments are a fractional share of the total value of production, 2) the approximate value of all local crude oil and natural gas production, based on recent production and energy prices, is $5 to $8 million per year, 3) not all recipients would be expected to be local residents, 4) not all production would be affected, and 5) the combined personal income of the two counties exceeds $1.5 billion annually with more than $236 million in dividends, interest and rent, then, it is reasonable to conclude that any prospective reduction associated with the oil and gas management plan would not constitute more than a negligible impact to income in the local economy, though one or more individuals may experience a more severe adverse income impact.

The economic impact of compliance on the local oil and gas industry

There is insufficient data available on which to estimate the potential economic effects of the higher compliance costs. Instead, the analysis focuses on how the costs may impact existing and future development.

Compliance with the 9B regulations imposes additional economic costs on owners/operators of existing wells and factors into the overall economic feasibility assessment for prospective future wells. In the case of the former, these costs affect an owner/operator's assessment of continued production and operation versus plugging and reclamation. For the latter, the compliance costs affect the cost of new well development and expected returns, and hence, the investment decision about whether to proceed.

There are four major elements of the overall compliance costs: (1) plan preparation, (2) compliance with reclamation standards, (3) compliance with operating standards, and (4) performance bonding. Actual costs associated with each element will vary in response to topography, access and other site conditions, and the expected extent of necessary natural and cultural surveys. Furthermore, the overall costs are comprised of both one-time and recurrent costs, with some one-time outlays required upfront and others coming at the end of a well's economic production life during plugging and reclamation. Cost estimates prepared by the NPS suggest a range of one-time costs of $13K to $38K and $3.5K in annual costs, on a per well basis. The majority of the one-time costs, $10K - $30K, are associated with elements (1), (2) and (3) and would be incurred in conjunction with initial compliance, that is, to bring an existing well into compliance or developing a new well. An estimated $3K to $8K would be incurred as part of final plugging and reclamation. A decision to plug and reclaim a marginal well would avoid the recurrent costs.

In the case of existing wells, foreseeable effects include decisions by operators of marginal properties, i.e., low volume producers, to plug and reclaim these wells. In the short-term such a decision would temporarily support a higher level of employment activity, but would thereafter result in marginal reductions in local economic activity over the long-term. Temporary boosts in activity would also result in conjunction with the initial compliance work for existing wells with current and anticipated rates of production adequate to justify the initial investments and recurrent costs.

Once a new well is completed and initial compliance achieved, the future decisions regarding sustaining production versus plugging and reclaiming would be largely a function of production rates, gas prices and the operating expenses. By definition, an operator’s decision to plug and abandon a well would come into play primarily with wells at or near the end of their productive lives. All other things being equal, principally future production and gross revenues, one could reasonably expect the net impact of higher recurrent and reclamation costs to be a decision to plug and reclaim a well several years sooner than would otherwise have occurred. Consequently, the net effects would be limited as they relate to local economic output, the level of local production available for marketing within the region, the income and profitability of operators and mineral interest owners, local employment in the oil and gas industry, and state and local government taxes.

The impacts of compliance on future development is uncertain as such development is contingent upon numerous factors, including the prospects for successful well development, the anticipated production, other development costs, and market prices of oil and natural gas. Many of these factors are beyond the control of the operators, mineral interest owners, or the National Park Service. Given these factors, the likely effects of the higher compliance costs, particularly the one-time upfront costs, would be to delay/defer the development of some new wells within the Park, shifting more development interest to other locations. This would occur in cases where the expected return on investment is unsatisfactory. In general, the higher the share of total well development costs represented by the $10K to $30K, the more pronounced the impacts.

In instances when an operator decides to proceed with a new well, such wells would be subject to ongoing assessment of economic viability, given the recurrent costs and pending plugging and reclamation costs. Once operational, the economic impact of the compliance requirements would be to reduce long-term operator profitability. However, the overall reduction in profitability may not accrue locally. On one hand, reductions in profitability would result due to the need to hire additional staff or contractors to conduct the compliance assessments, complete the requisite actions identified in the assessments, and complete the ongoing reporting and monitoring activities. The increased costs would translate into lower investment in the industry and lower income for operators and owners, an unknown portion of which accrues locally. On the other hand, reductions in profitability would be largely manifest in terms of marginally higher employment and labor income during well development and operations. Such employment and income effects would accrue primarily within the local economy, offsetting some or much of the reduction in profitability with respect to the local economy.

Despite the offset between wage and salary earnings of workers and the reduced profitability for operators and owners, some members of the latter group would experience declines in income and economic welfare due to the higher compliance. The number of individuals affected, the magnitude of the impacts, and overall effect of these declines is uncertain. In individual instances, typically affecting more marginal operations, the effects could be dramatic, potentially resulting in a complete cessation of operations.

The potential adverse impacts on some individual operations notwithstanding, the net economic effects of the compliance regulations are likely to be negligible in the short-term and long-term given current production levels and the size and structure of the regional oil and gas industry.

Overall Conclusion

The regulations would affect only a segment of the industry's operations. The oil and gas industry has only a limited presence in the regional economy. Current oil and gas production levels in the region are relatively low, less than 50,000 barrels of oil and about 717 million cubic feet of natural gas in 2006.[4] Much, if not most, of the current production is from outside of the Obed Wild and Scenic River and the industry is actively engaged in new drilling outside of the Park. Thus, although the costs of compliance with the proposed regulations may accelerate the shutdown of older, marginal wells and defer development of some new wells within the Obed Wild and Scenic River, the overall impacts on regional social and economic conditions would be very limited in scope and economic importance when considered in the context of the regional economy. As a result, the net effects on social and economic conditions associated with implementation would be negligible.

[4] Production is for the Morgan and Cumberland counties.

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# APPENDIX E: NON-IMPAIRMENT DETERMINATION

## FIRST DRAFT

In addition to determining the environmental consequences of implementing the preferred and other alternatives, NPS *Management Policies 2006* (section 1.4) requires analysis of potential effects to determine whether or not the preferred alternative would impair a park's resources and values. The preferred alternative in this plan/EIS is alternative C.

The fundamental purpose of the national park system, established by the *Organic Act* and reaffirmed by the *General Authorities Act*, as amended, begins with a mandate to conserve park resources and values. NPS managers must always seek ways to avoid, or to minimize to the greatest degree practicable, adverse impacts on park resources and values. However, the laws do give the NPS the management discretion to allow impacts on park resources and values when necessary and appropriate to fulfill the purposes of the park. That discretion is limited by the statutory requirement that the NPS must leave resources and values unimpaired unless a particular law directly and specifically provides otherwise.

The prohibited impairment is an impact that, in the professional judgment of the responsible NPS manager, would harm the integrity of park resources or values, including the opportunities that otherwise would be present for the enjoyment of those resources or values (NPS *Management Policies 2006*). Whether an impact meets this definition depends on the particular resources that would be affected; the severity, duration, and timing of the impact; the direct and indirect effects of the impact; and the cumulative effects of the impact in question and other impacts.

An impact on any park resource or value may, but does not necessarily, constitute impairment. An impact would be more likely to constitute impairment to the extent that it affects a resource or value whose conservation is:

- necessary to fulfill specific purposes identified in the establishing legislation or proclamation of the park, or
- key to the natural or cultural integrity of the park or to opportunities for enjoyment of the park, or
- identified in the park's general management plan or other relevant NPS planning documents as being of significance.

An impact would be less likely to constitute impairment if it is an unavoidable result of an action necessary to preserve or restore the integrity of park resources or values and it cannot be further mitigated.

Impairment may result from visitor activities, NPS administrative activities, or activities undertaken by concessioners, contractors, and others operating in the park. Impairment may also result from sources or activities outside the park.

A determination of impairment is made for each of the resource impact topics carried forward and analyzed in the environmental impact statement for the preferred alternative. Impairment findings are not necessary for visitor experience, public health and safety, environmental justice, and park operations. These impact areas are not generally considered to be park resources or values according to the *Organic Act*, and cannot be impaired the same way that an action can impair park resources and values.

The park purpose and significance were used as a basis for determining if the preferred alternative would cause impairment.

The following describes each resource or value for which impairment is assessed and the reasons why impairment would not occur. **However, for all the resources listed below:**

- In the case of Big South Fork NRRA, the park's enabling legislation states that the Secretary of the Interior shall allow mineral exploration and development, subject to appropriate regulations. Thus, the NPS must provide for these activities while protecting resources for the enjoyment of future generations.
- A site-specific analysis of the potential for impairment of park resources and values will be required on all proposed oil and gas projects in the park. The analysis must be included in the *National Environmental Policy Act* document on the plan of operations for all oil and gas projects and would ensure that impairment of resources would not occur. Also, under all alternatives, if mitigation measures are not adequately applied during the conduct of nonfederal oil and gas operations, there could be impacts on park resources and values. If this were to occur, the NPS would be required to suspend the operation until appropriate mitigation is applied. If mitigation is not technically feasible to avoid the impairment, the oil and gas operation would not be allowed to continue.
- If an accidental spill of hydrocarbons or other contaminating substance were to occur in the park, there could be major, short-term, adverse impacts particularly to water, vegetation, wetlands, soils, fish and wildlife resources. Even if there were a catastrophic spill, the site would be remediated and would not result in an impairment of park resources and values.
- Special Management Areas (SMAs) have been designated in alternative C that would protect resources and values particularly susceptible to adverse impacts from oil and gas operations. Geology and soils, water resources, floodplains, wetlands, sensitive vegetation communities, and specific visitor use areas would be provided specific protection. Operating stipulations in SMAs, including setbacks and a No Surface Use stipulation (unless otherwise authorized in a plan of operations) would be required to avoid or minimize adverse impacts and would further reduce the likelihood of impairment of resources and values in the park.
- Due to the designation of SMAs under alternative C, more wells may be directionally drilled from outside the park to develop hydrocarbons underlying the park. While indirect impacts on park resources and values could be greater from directional wells drilled from outside the park compared to operations inside the park, park resources and values would not be impaired by directional drilling and production. In some cases, directional drilling proposals would involve other federal agencies applying other permitting requirements (i.e., *Clean Water Act* Section 504 permitting). The NPS would participate with the other federal entity through its permitting process to request any necessary mitigation measures be applied to reduce the potential for major adverse impacts on park resources and values. If NPS is the only federal entity involved, and a directional drilling and production proposal could pose major adverse impacts on park resources and values, the NPS would need to base its § 9.32(e) exemption on the findings of an EIS. In most cases, operators would preclude the need to prepare an EIS by locating directional wells a sufficient distance from the park, and applying other necessary mitigation measures to reduce impacts.

## Geology and Soils

Both parks are located in the Cumberland Plateau, which is characterized by flat or rolling upland areas, deeply incised river gorges, and a long line of cliffs that separate it from the lower elevations of the Ridge and Valley Province, which begins at the Cumberland Plateau's eastern escarpment. Both parks have soils that are representative of the Cumberland Plateau with a wide range of compaction, erodability, and runoff characteristics. Both parks are also known for their significant geologic features including prominent rock formations, as well as the massive gorges and accompanying bluffs.

The parks' geologic qualities and features are necessary to fulfill the purposes for which the parks were established and are key to the natural integrity of the park. Geologic resources and geologic features of the parks, including the gorge, bluffs, cliff lines, arches, and other geologic formations, are specifically identified in the parks' enabling legislation and planning documents. Actions in the preferred alternative include oil and gas exploration and development that would cause both short-term and long-term adverse impacts on soils and geological features. The designation of SMAs would limit the effects on geology and soils within SMA boundaries. Limiting drilling and production operations in the Sensitive Geomorphic Feature and Cliff Edge SMAs would reduce the degree of adverse impacts on soils and sensitive geomorphic features susceptible to adverse impacts from oil and gas operations. However, the construction and maintenance of access roads, wellpads, flowlines, and pipelines could erode, compact, and rut soils; introduce non-native construction materials; and reduce soil permeability; and releases of hazardous or contaminating substances during drilling or production operations could adversely affect soils. Additionally, the new management framework for plugging and reclamation would promote efficient plugging and reclamation of abandoned wells to applicable standards. This would ultimately enhance natural conditions in the park.

Adverse impacts would be negligible to minor, localized, and would affect up to 36 acres of the park surface – a small fraction (0.03 percent) of the 130,000 acres within the park units. Long-term impacts would be mitigated through site reclamation, and the preferred alternative includes actions to plug and reclaim existing sites that would reclaim up to 87 acres and provide long-term beneficial impacts. In addition, alternative C would make only a minor contribution to overall adverse cumulative impacts on geology and soils.

Because adverse impacts of the preferred alternative on geology and soils would be long-term and minor and the contribution to overall adverse cumulative impacts would be limited, there would be no impairment of geology and soils under alternative C.

## Water Resources

One of the primary reasons the Big South Fork NRRA was established was to preserve the Big South Fork of the Cumberland River as a natural, free-flowing stream for the benefit and enjoyment of present and future generations. The Big South Fork River is formed by the New River and the Clear Fork, and drains the northern portion of the Cumberland Plateau in Tennessee. As the Big South Fork flows from south to north, it is fed by a variety of sources ranging from perennial streams, such as North White Oak Creek, to many ephemeral creeks. The Obed River flows east for approximately 45 miles to its junction with the Emory River, of which it is the largest tributary (NPS 1998b). The Obed River drains approximately 520 square miles at its mouth (NPS 1998b). The two principal tributaries of the Obed River—Clear Creek and Daddys Creek—join the Obed River within the Obed WSR area.

The parks' water resources are necessary to fulfill the purposes for which the parks were established and are key to the natural integrity of the parks. The significance of Big South Fork NRRA includes the free-flowing river system with a wide variety of habitats, including a world-class mussel assemblage. It is designated as a Tier III Outstanding Natural Water under the *Clean Water Act*. The significance of the Obed River's Wild and Scenic River (WSR) designation is described in its Strategic Plan. It is one of the last remaining wild rivers in the eastern United States, and is designated as a Tier II Outstanding Natural Water under the *Clean Water Act* because of its superior water quality.

Gorge restrictions at Big South Fork NRRA, deed restrictions at Obed WSR, and the regulatory requirement that surface operations shall at no time be conducted within 500 feet of the banks of perennial, intermittent, or ephemeral watercourses or within 500 feet of the high pool shoreline of natural or man-made impoundments (36 CFR 9.41(a)) would provide protection for park waters. In locations where water bodies fall within the 1,500-foot buffer provided for visitor use and administrative areas, additional protection of water resources could be anticipated. Establishing the Obed WSR SMA would preclude non-federal oil and gas operations (exploration, drilling, and production) on all federal lands in the park unit, providing protection of water resources here.

Actions in the preferred alternative include oil and gas exploration and development that would cause both short-term negligible to moderate adverse impacts to water resources. The long-term impacts of well development would be mitigated through site reclamation, and the preferred alternative includes actions to plug and reclaim existing sites that would remove sources of contamination and provide long-term beneficial impacts. Additionally, the new management framework for plugging and reclamation would promote efficient plugging and reclamation of abandoned wells to applicable standards. This would ultimately enhance natural conditions in the park. In the event of catastrophic well failure or uncontrolled release, long-term or major adverse impacts to water resources would be unlikely because production sites would be placed at least 500 feet from water sources and remediation would be required. In addition, alternative C would make only limited contributions to overall adverse cumulative impacts on water resources.

Because adverse impacts of the preferred alternative on water resources would be short-term and negligible to moderate, and the contribution to overall adverse cumulative impacts would be limited, there would be no impairment of water resources under alternative C.

## Floodplains

Floodplains have not been delineated in Big South Fork National River and Recreation Area. However, there are narrow floodplains in the gorge area, and small ones throughout the rest of the property. In the headwater areas of the major rivers within the area, slopes are steep, and floodplains are therefore not well-formed. Floodplains of limited extent increase in occurrence farther downstream. As with Big South Fork NRRA, floodplains have not been delineated within Obed WSR. However, the extremely narrow, confined nature of this valley, and the associated high-energy water regimes, place a firm limit on the extent of natural floodplain development within the Obed WSR. Seasonally flooded habitat does exist, but it is on alluvial point bars, rather than on floodplains.

Although floodplains are not specifically identified as significant in the purpose and significance statements included in the enabling legislation or park planning documents, floodplains are important to the parks’ free flowing systems and ecosystem health. Oil and gas operations could cause short and long-term, negligible to minor adverse effects on floodplains, mainly through road development, and the preferred alternative includes actions to plug and reclaim existing wells, which would remove sources of contamination and structures in floodplains, and provide long-term beneficial impacts. While none of the SMAs were developed to specifically protect floodplains, SMA restrictions would provide more consistent direct protection of floodplains. Specifically, the 500-foot setback from rivers and streams would provide a great deal of floodplain protection. In locations where floodplains occur within the 1,500-foot buffer provided for visitor use and administrative areas, additional protection of floodplain functions could be anticipated. However, oil and gas development on lands adjacent to floodplains d continue to have indirect effects. Additionally, the new management framework for plugging and reclamation would promote efficient plugging and reclamation of abandoned wells to applicable standards. This would ultimately enhance natural conditions in the park. In addition, alternative C would make only a minor contribution to overall adverse cumulative impacts on floodplain functions. In the event of catastrophic well failure or uncontrolled release, impacts to floodplains would be unlikely because production sites would be set back from water courses.

Because long-term adverse impacts of the preferred alternative on floodplains would be no greater than long-term and minor, and the contribution to overall adverse cumulative impacts would be limited, there would be no impairment of floodplains under alternative C.

## Wetlands

The parks contain approximately 2,800 acres of wetlands, the vast majority of which are associated with the parks' rivers (riverine) or lakes (lacustrine) and are permanently flooded. In addition, palustrine wetlands (vegetated with varying inundation periods) comprise just over 4 percent of the total wetland acreage. Although wetlands are not specifically identified as significant in the purpose and significance statements included in the enabling legislation or park planning documents, wetlands are and important habitat and critical to ecosystem health.

Oil and gas operations could cause up to long-term minor adverse effects on wetlands, mainly through indirect impacts of potential sediment deposition from drilling, production, plugging, and reclamation activities. While none of the SMAs were developed to specifically protect wetlands, wetlands would indirectly benefit from the SMAs and setbacks located in or near wetlands, or on the edges of the gorge, where spills could reach wetlands in the gorge. Oil and gas activities would not be expected to directly affect wetlands because gorge restrictions at Big South Fork NRRA, deed restrictions at Obed WSR, and the regulatory requirement that surface operations shall at no time be conducted within 500 feet of the banks of perennial, intermittent, or ephemeral watercourses or within 500 feet of the high pool shoreline of natural or man-made impoundments (36 CFR 9.41(a)) would provide protection for park wetlands, most of which are associated with river and stream channels. Additionally, the new management framework for plugging and reclamation would promote efficient plugging and reclamation of abandoned wells to applicable standards. This would ultimately enhance natural conditions in the park. In the event of catastrophic well failure or uncontrolled release, long- term major adverse impacts would be unlikely, as wetlands would be protected by setback distances and spill prevention and required clean-up/remediation measures. In addition, alternative C would make a minimal contribution to overall adverse cumulative impacts on wetlands and wetland functions.

Because long-term adverse impacts of the preferred alternative on wetlands would be no greater than long-term and minor, and the contribution to overall adverse cumulative impacts would be limited, there would be no impairment of wetlands under alternative C.

## Vegetation

Both parks are located in the Cumberland Plateau, which is characterized by flat or rolling uplands, deep river gorges, and a long line of cliffs. A wide variety of vegetation communities occur in the parks – from coniferous forests to hardwood forests to deciduous shrublands – depending on elevation, slope, soils, and water availability. As described above in the Geology and Soils finding, up to 36 acres of park lands would be disturbed by oil and gas activities, with 87 acres reclaimed.

Although vegetation is not specifically identified as significant in the purpose and significance statements included in the enabling legislation or park planning documents, vegetative communities are important as wildlife habitat and for ecosystem function and health. While none of the SMAs were developed to specifically protect vegetation in general, vegetative communities in many of the SMAs would benefit from new requirements. Oil and gas operations could cause localized, short and long-term, minor adverse effects on approximately 0.03 percent of the parks' native vegetation, mainly through road development, drilling, and production activities. Long-term impacts would be mitigated through site reclamation, of up to 87 acres, providing long-term benefits to vegetation. The new management framework for plugging and reclamation would promote efficient reclamation of abandoned wells to applicable standards. This would ultimately enhance natural conditions in the park. In addition, alternative C would make a beneficial, long-term contribution to overall cumulative impacts on native vegetation. In the event of catastrophic well failure or uncontrolled release, impacts would be localized, and damaged sites would be reclaimed and replanted.

Because long-term adverse impacts of the preferred alternative on native vegetation would be no greater than minor, and the contribution to overall adverse cumulative impacts would be beneficial, there would be no impairment of vegetation under alternative C.

## Wildlife and Aquatic Species

One of the reasons the Big South Fork NRRA was established was to conserve and interpret the unique wildlife of the gorges and valleys. A wide variety of vegetation communities occur in the parks, along with a corresponding wide variety of terrestrial and aquatic wildlife species. A total of 48 mammalian species, 180 bird species, and 28 reptiles inhabit the terrestrial acreage of the parks. Freshwater aquatic species include a diverse assemblage of fishes and aquatic invertebrates – including several mussel and crayfish species.

The Managed Fields SMA was developed partly to enhance wildlife habitat, and the SMA for Honey Creek and Twin Arches state natural areas was set aside primarily for their rich, undisturbed forest community. In general, there would be no surface use in these areas. Wildlife in the SMAs would benefit directly from restricted oils and gas access, restoration of disturbed lands, and enhanced habitat protection. Oil and gas operations could cause localized, short and long-term, minor adverse effects on wildlife. Terrestrial species would be disturbed and experience small amounts of habitat loss (up to 36 acres). Long-term habitat impacts would be mitigated through habitat reclamation of up to 87 acres. The new management framework for plugging and reclamation would promote efficient reclamation of abandoned wells to applicable standards. This would ultimately enhance natural conditions in the park. In addition, alternative C would make a limited contribution to overall adverse cumulative impacts on wildlife. In the event of catastrophic well failure or uncontrolled release, impacts to wildlife would be localized, and damaged habitats would be reclaimed and replanted.

Aquatic species would be adversely affected by short-term changes in water quality, producing localized minor adverse impacts. In the event of catastrophic well failure or uncontrolled release, long- term major adverse impacts to aquatic species would be unlikely, as aquatic environments would be protected by setback distances and spill prevention and required clean-up/remediation measures. In addition, alternative C would make a limited contribution to overall adverse cumulative impacts on aquatic species.

Because long-term adverse impacts of the preferred alternative on wildlife and aquatic species would be no greater than minor, and the contribution to overall adverse cumulative impacts would be limited, there would be no impairment of vegetation under alternative C.

## Federally Listed Threatened and Endangered Species

Big South Fork NRRA is home to 17 species that are protected under the *Endangered Species Act*. Of these, there are ten freshwater mussel species and three fishes in park waters. Listed terrestrial species include four plants. Critical habitat within the park has been designated in stream reaches inhabited by a variety of mussel species. Within the Obed WSR, six listed species occur – one fish, two mussels, two plants, and one bat. The entire length of the Obed WSR has been designated as critical habitat for the spotfin chub. In addition, NPS policy requires that state-listed species, and others identified as species of special concern by the park, are to be managed in park units in a manner similar to those that are federally listed (NPS 2006c) (See “Species of Special Concern” below.).

Within the SMAs, 500-foot setbacks from water bodies would provide a high level of protection for wildlife inhabiting water, and wetland vegetation within this protective zone which supports many listed species. The Cliff Edge SMA would also protect listed species found in that location. Through project-specific consultation with USFWS under the ESA, and scoping with other state agency biologists, the setback could be increased. The 500-foot standard setback would provide primary protection to all of the fish and mussel species described in chapter 3, including the duskytail darter, blackside dace, spotfin chub, Cumberland bean mussel, little-winged pearlymussel, purple bean mussel, dromedary pearlymussel, and the spectaclecase mussel. Additional protection of these habitats would be provided by the wetlands and floodplains Executive Orders, NPS Director’s Orders, and project-specific permitting requirements.

Listed species that occupy upland areas outside the 500-foot shoreline setbacks include bats (gray bat) and upland plants (Cumberland sandwort). Bat species could be affected by the presence of seismic crews and the noise associated with the surveys, but there would be little if any trimming of vegetation or clearing required. All these species would be protected by consultation required under the ESA.

Through the regulatory process under the ESA, required biological surveys and consultations with USFWS and TWRA or other state agency biologists would result in identification of potential impacts on listed species and their habitat, and the implementation of an oil and gas management plan, the designation of SMAs, and the application of mitigation measures would result in short- to long-term negligible to minor adverse impacts on listed species. A limited risk of major adverse effects from spills or leaks would also be possible, but no long –term major adverse effects would be expected given the required setbacks and remediation requirements. Additionally, the new management framework for plugging and reclamation would increase the certainty that wells would be plugged and reclaimed to applicable standards. This would ultimately enhance natural conditions in the parks. In addition, the preferred alternative would make a limited contribution to overall adverse cumulative impacts on listed species and their habitats.

Because long-term adverse impacts of the preferred alternative on threatened and endangered wildlife and critical habitat would be no greater than minor, and the contribution to overall adverse cumulative impacts would be limited, there would be no impairment of threatened and endangered species and critical habitat under alternative C.

## Species of Special Concern

Together, the parks are home to a variety of state-listed species of special concern – eight mammals, ten birds, one reptile, two amphibians, ten aquatic invertebrates (mussels), nine fishes, and 44 plants. These species have been identified by the states of Tennessee and Kentucky as warranting special management concern, because they may become threatened in the future through habitat loss, commercial exploitation or other means. NPS policy requires that state-listed species, and others identified as species of special concern by the park, are to be managed in park units in a manner similar to those that are federally listed (NPS 2006c).

Undertaking the required biological surveys and consultations with state agency biologists before approving a plan of operations, and beginning drilling and production activities, would result in identification of potential impacts on species of special concern and their habitat. As described for threatened and endangered species above, implementation of alternative C would include the designation of SMAs, and the application of mitigation measures. Designation of the Cliff Edge SMA, Sensitive

Geomorphic features SMA, and Managed fields SMA would help protect state-listed species found in those locations. Impacts on species of special concern would be short to long term, negligible to minor, and adverse. Additionally, the new management framework for plugging and reclamation would increase the certainty that wells would be plugged and reclaimed to applicable standards. This would ultimately enhance natural conditions in the park. In addition, the preferred alternative would make a limited contribution to overall adverse cumulative impacts on species of special concern.

Because long-term adverse impacts of the preferred alternative on species of special concern would be no greater than minor, and the contribution to overall adverse cumulative impacts would be limited, there would be no impairment of species of special concern under alternative C.

## Soundscapes

The natural sounds within a park unit are frequently cited as an important part of the visitor experience, and protecting parks from high levels of intrusive sounds is a growing concern. Although no formal studies of the parks' acoustic environments have been conducted, using data from the nearby Great Smoky Mountains, it is assumed that ambient sounds range from 26 to 43 dBA. These sound levels are a mixture of natural sounds associated with forest and shrubland habitats. The natural soundscapes of both Big South Fork NRRA and Obed WSR are affected primarily by vehicular noise, both inside and outside the park boundaries. Oil and gas exploration and production also affect the natural soundscape locally and for limited periods of time.

Because management actions, particularly road building and drilling, could continue over a period of months, impacts would be considered both short and long-term. During exploration, drilling, production, and site reclamation, oil and gas operations would have the potential to affect the integrity of the natural sounds within the park. However, impacts would be no greater than moderate (i.e., unnatural sounds from oil and gas operations would not mask natural sounds for extended periods of time such that they would be commonly present throughout the park over the life of the management plan), and a maximum of 20 new wells are planned within the parks. SMAs and associated setbacks would reduce noise levels within the SMAs because the noise source would be located further from the sensitive resources within the SMA. Elevated noise levels would continue to occur in operational locations. There would also be long-term beneficial impacts on soundscapes in the park from the restoration of vegetation (in areas where depleted wells are plugged) that would aid in attenuation of unnatural sounds. The preferred alternative would make a limited contribution to overall adverse cumulative impacts on the natural soundscapes within the parks.

Because long-term adverse impacts of the preferred alternative on soundscapes would be localized and no greater than moderate, and the contribution to overall adverse cumulative impacts would be limited, there would be no impairment of soundscapes under alternative C.

## Cultural Resources

One of the primary reasons the Big South Fork NRRA was established was to protect the cultural heritage of Cumberland Plateau and the record of human habitation contained therein. Humans have occupied the area for approximately 12,000 years, and the parks contain a rich and diversified cultural context. Archeological resources include ancient rock shelters, seasonal hunting camps, and more modern gristmills, moonshine stills, coal mines and saltworks. Historic structures and resources in the parks include farmsteads, transportation routes (railroads and canals), mines, and other engineering structures, all listed on or eligible for inclusion on the National Register of Historic Places. Cultural landscapes are defined based on associated with historic events or persons. Big South Fork NRRA includes the overall Big South Fork Rural Historic District, the Charit Creek Farmstead, and the abandoned townsite of No

Business. In addition, the parks contain “ethnographic resources” that are of significance to American Indian Tribes.

Several of the SMAs proposed for alternative C were developed to protect cultural resources. The Sensitive Geomorphic Feature, Cliff Edge, Cultural Landscapes and Cemeteries and Managed Fields SMA all include No Surface Use measures to preserve these irreplaceable resources, and up to 1,500-foot setback for exploration near sensitive sites. A qualified third-party monitor would be present during drilling and plugging activities, consultation with seven American Indian tribes would be conducted as project-specific plans for oil and gas operations are developed, and setbacks required in the SMAs would be enforced or else mitigation would be provided in approved plans of operation that would provide comparable resource protection. With consultation and mitigation, impacts to cultural resources would be localized (to a total of 36 acres), long-term, and no more than moderate. There would also be long-term beneficial impacts to cultural landscapes from the restoration of vegetation. In addition, the preferred alternative would make a limited contribution to overall adverse cumulative impacts on the cultural resources

Because long-term adverse impacts of the preferred alternative on cultural resources would be localized and no greater than moderate, and the contribution to overall adverse cumulative impacts would be limited, there would be no impairment of cultural resources under alternative C.

## Summary

The NPS has determined that the implementation of the NPS preferred alternative (alternative C) will not constitute an impairment of the resources or values of Big South Fork National River and Recreation Area or to Obed WSR. As described above, adverse impacts anticipated as a result of implementing the preferred alternative on a resource or value whose conservation is necessary to fulfill specific purposes identified in the establishing legislation or proclamation of the park, key to the natural or cultural integrity of the park or to opportunities for enjoyment of the park, or identified as significant in the park’s GMP or other relevant NPS planning documents, would not rise to levels that would constitute impairment. This conclusion is based on consideration of each parks’ purpose and significance, a thorough analysis of the environmental impacts described in the EIS, relevant scientific studies, the comments provided by the public and others, and the professional judgment of the decision-maker guided by the direction of the NPS *Management Policies 2006*.

# APPENDIX F: SUMMARY OF NPS *MANAGEMENT POLICIES 2006* OIL AND GAS OPERATIONS GUIDANCE

The following sections summarize the guidance provided in NPS *Management Policies 2006* that relate to oil and gas operations. The first section discussed is dedicated to mineral exploration and development (section 8.7). The remainder of the sections focuses on guidance in NPS *Management Policies 2006* that influence performance standards for protecting parks from oil and gas operations. These sections are organized by resource topic as some of them span more than one section of the NPS *Management Policies 2006*.

## MINERAL EXPLORATION AND DEVELOPMENT

Section 8.7 of NPS *Management Policies 2006* addresses mineral exploration and development in units of the National Park system, limiting these activities to prospective operators that can demonstrate that they hold rights to valid mining claims, federal mineral leases or nonfederally owned minerals. This section provides guidance regarding the ability of the NPS to acquire mineral rights if it is determined that proposed mineral developments would impair park resources or values, would be inconsistent with park purposes, or do not meet the standards of applicable NPS regulations and cannot be modified to meet such standards (NPS 2006c).

Section 8.7.3 of NPS *Management Policies 2006* specifically addresses nonfederally owned minerals, which include nonfederal oil and gas interests underlying Big South Fork National River and Recreation Area and Obed Wild and Scenic River. This section states that nonfederal oil and gas interests must be approved under the standards and procedures of 36 CFR 9B, and reiterates the ability of the NPS to acquire rights should an operator's plan fail to meet these standards. NPS *Management Policies 2006* also make clear that the application of the 9B regulations is not intended to result in the taking of the property interest, but rather to impose reasonable regulation of the activity (NPS 2006c).

## AIR QUALITY

Section 4.7.1 of NPS *Management Policies 2006* states that the NPS "will seek to perpetuate the best possible air quality in parks to (1) preserve natural resources and systems; (2) preserve cultural resources; and (3) sustain visitor enjoyment, human health, and scenic vistas." The NPS will also actively promote and pursue measures to protect air quality-related values (e.g., resources sensitive to air pollution, including vegetation, visibility, water quality, wildlife, historic and prehistoric structures and objects, and cultural landscapes) from adverse impacts of air pollution (NPS 2006c).

### AIR QUALITY PERFORMANCE STANDARD

Design and conduct operations in a manner that minimizes air pollution emissions and impacts.

### Soil Resource Management

Per section 4.8.2.4, "The Service will actively seek to understand and preserve the soil resources of parks, and to prevent, to the extent possible, the unnatural erosion, physical removal, or contamination of the soil, or its contamination of other resources" (NPS 2006c).

### Soil Resources Performance Standards

- Avoid or minimize soil compaction.
- Avoid or minimize soil loss or removal.
- Avoid or minimize soil erosion.
- Prevent soil contamination.
- Re-establish contours and soil chemistry to support and sustain native vegetative communities that existed prior to the initiation of operations.

## WATER RESOURCE MANAGEMENT

Per section 4.6.1, "The National Park Service will perpetuate surface waters and groundwaters as integral components of park aquatic and terrestrial ecosystems." Also, section 4.6.2 states, "Park surface waters or groundwater will be withdrawn for consumptive use only when such withdrawal is absolutely necessary for the use and management of the park." Finally, section 4.6.3 states, "The Service will determine the quality of park surface and groundwater resources and avoid, whenever possible, the pollution of park waters by human activities occurring within and outside the parks."

### SURFACE WATER PERFORMANCE STANDARDS

- Maintain existing quality of all surface waters.
- Avoid diminishing the quantity of surface waters.
- Avoid altering drainage characteristics of the area or hydrology of the soils.

### GROUNDWATER PERFORMANCE STANDARDS

- Maintain the existing quality of groundwater.
- Avoid diminishing the quantity of groundwater.
- Avoid altering the natural movement of groundwater.

## FLOODPLAINS

In accordance with section 4.6.4 of NPS *Management Policies 2006*, "In managing floodplains on park lands, the National Park Service will (1) manage for the preservation of floodplain values; (2) minimize potentially hazardous conditions associated with flooding; and (3) comply with the NPS Organic Act and all other federal laws and Executive Orders related to the management of activities in flood-prone areas, including Executive Order 11988 (Floodplain Management), NEPA, applicable provisions of the Clean Water Act, and the Rivers and Harbors Appropriation Act of 1899" (NPS 2006c).

### FLOODPLAIN PERFORMANCE STANDARDS

- Restore and preserve natural floodplain values.
- Avoid the long- and short-term environmental impacts associated with the occupancy and modification of floodplains.

- Avoid direct and indirect support of floodplain development wherever there is a practical alternative. When no practical alternative exists, avoid adverse environmental impacts as well as risk to life and property through appropriate mitigation utilizing nonstructural methods when possible.

## WETLANDS

Section 4.6.5 of NPS *Management Policies 2006* states "The Service will (1) provide leadership and take action to prevent the destruction, loss, or degradation of wetlands; (2) preserve and enhance the natural and beneficial values of wetlands; and (3) avoid direct and indirect support of new construction in wetlands unless there are no practicable alternatives and the proposed action includes all practicable measures to minimize harm to wetlands" (NPS 2006c).

The NPS will also implement a "no net loss of wetlands" policy, "and will strive to achieve a longer-term goal of net gain of wetlands across the National Park system through restoration of previously degraded or destroyed wetlands" (NPS 2006). To the extent practicable, wetlands will be restored to predisturbance conditions, and compensation for wetland impacts or losses will require that at least 1 acre of wetlands be restored for each acre destroyed or degraded (NPS 2006c).

### WETLAND PERFORMANCE STANDARDS

- Avoid to the extent possible the long- and short-term adverse impacts associated with the destruction or modification of wetlands.
- Avoid direct or indirect support of new construction in wetlands wherever there is a practicable alternative.
- Preserve the natural and beneficial values of wetlands.

## VEGETATION, FISH, AND WILDLIFE

In accordance with section 4.4.1 of NPS *Management Policies 2006*, the NPS will "maintain as parts of the natural ecosystems of parks all plants and animals native to park ecosystems." The NPS will achieve this by:

- "Preserving and restoring the natural abundances, diversities, dynamics, distributions, habitats, and behaviors of native plant and animal populations and their communities and ecosystems in which they occur;
- Restoring native plant and animal populations in parks when they have been extirpated by past human-caused actions; and
- Minimizing human impacts on native plants, animals, populations, communities, and ecosystems, and the processes that sustain them" (NPS 2006c).

In addition, the NPS will seek to return areas disturbed by humans to the natural conditions and processes characteristic of the ecological zone in which the damaged resources are situated (NPS 2006c, section 4.1.5).

(Also refer to the Species of Special Concern section in this appendix.)

### VEGETATION PERFORMANCE STANDARDS

- Avoid or minimize damage to or removal of vegetation communities, particularly rare or imperiled plants communities identified by the states of Kentucky and Tennessee.
- Reclaim all disturbed areas to a condition that will be approximately equivalent to the pre-disturbance condition in terms of sustained support of functional physical processes, biological productivity, biological organisms, and land uses.
- Prevent establishment of non-native (exotic) vegetation in all disturbed areas.

### FISH AND WILDLIFE PERFORMANCE STANDARDS

- Avoid or minimize disturbances to native fish and wildlife habitat.
- Prevent fish and wildlife exposure to contaminants.
- Avoid or minimize injury or death to fish and wildlife.
- Reclaim disturbed fish and wildlife habitat to provide for their survival.

## SPECIES OF SPECIAL CONCERN

Per section 4.4.2.3 of NPS *Management Policies 2006*, "The Service will survey for, protect, and strive to recover all species native to national park system units that are listed under the Endangered Species Act. The Service will fully meet its obligations under the NPS Organic Act and the Endangered Species Act to both proactively conserve listed species and prevent detrimental effects on these species."

In addition, the NPS will inventory, monitor, and manage state and locally listed species in a manner similar to its treatment of federally listed species to the greatest extent possible. The NPS will also inventory other native species that are of special management concern to parks (such as rare, declining, sensitive, or unique species and their habitats) and will manage them to maintain their natural distribution and abundance. Finally, the NPS will determine all management actions for the protection and perpetuation of federally, state, or locally listed species through the park management planning process, and will include consultation with lead federal and state agencies as appropriate (NPS 2006c).

### SPECIES OF SPECIAL CONCERN PERFORMANCE STANDARDS

- Avoid adverse impacts on state and federally listed threatened, endangered, rare, declining, sensitive, and candidate plant and animal species and their habitats.
- Ensure the continued existence of state and federally listed threatened, endangered, rare, declining, sensitive, and candidate plant and animal species and their habitats.
- Ensure that permitted operations aid in the recovery of state and federally listed threatened, endangered, rare, declining, sensitive, and candidate plant and animal species and their habitats.

# CULTURAL RESOURCES

Per chapter 5 of NPS *Management Policies 2006*, the NPS is the steward of many of America's most important cultural resources. These resources are categorized as archeological resources, cultural landscapes, ethnographic resources, historic and prehistoric structures, and museum collections (see definitions in the Glossary of this plan/EIS). The NPS's cultural resource management program involves:

- Research to identify, evaluate, document, register, and establish basic information about cultural resources and traditionally associated peoples;
- Planning to ensure that management processes for making decisions and setting priorities integrate information about cultural resources, and provide for consultation and collaboration with outside entities; and
- Stewardship to ensure that cultural resources are preserved and protected, receive appropriate treatments (including maintenance) to achieve desired conditions, and are made available for public understanding and enjoyment.

The cultural resource management policies of the NPS are derived from a suite of historic preservation, environmental, and other laws, proclamations, executive orders, and regulations. A comprehensive list can be found in the Cultural Resource Management Handbook issued pursuant to Director's Order 28. Taken collectively, they provide the NPS with the authority and responsibility for managing cultural resources in every unit of the national park system so that those resources may be preserved "unimpaired" for future generations.

## CULTURAL RESOURCES PERFORMANCE STANDARDS

- Provide for the protection of all cultural resources by preventing the destruction, alteration, or impairment of all or part of the cultural property.
- Prevent the isolation from or alteration to cultural resources with its surrounding environment.
- Prevent the alteration or introduction of visual, audible, or atmospheric elements that are out of character with the cultural resources property or its setting.

## ARCHEOLOGICAL SURVEYS

The NPS has developed the following approach for archeological surveys to identify, evaluate, and protect historic properties in compliance with the National Historical Preservation Act, other statutes, and NPS policy and be feasible for the operators in NPS units:

- Any activities that do not qualify as ground disturbing (i.e., hand-held drilling of shot holes of 3-inch diameter or less, and non-rutting vehicles) will not require an archeological survey.
- Wells and related facilities will not be allowed on any historic properties within an appropriate distance of these properties to avoid direct or indirect impacts to the integrity of such resources.
- Archeological surveys (including shovel testing) will be conducted prior to any ground-disturbing activities. Ground disturbance is defined as earth moving activities (blading, rutting, etc.) below 2 inches of the present ground surface. Particular care should be taken in areas where there is a high probability of archeological sites occurring. Areas of ground disturbance typically include access roads, storage areas, heavy equipment parking areas, well and production pads, and other related use areas, including areas where fill has been removed or brought in to create roads or wellpads.

> Areas of disturbance should be restricted to an absolute minimum required for safe operation and construction of facilities.

When a cultural resource survey is required, the operator shall provide the NPS the necessary cultural resources survey of the project area or area of potential effect. The cultural resource survey may include identification and evaluation of archeological sites, historic structures, cultural landscapes, and traditional cultural properties, and must be conducted by professionally qualified cultural resource experts who have knowledge of the specific resource type in question. The NPS will provide operators with existing site-specific cultural resource information, where available.

Operator surveys will result in a final report that allows the NPS to determine National Register eligibility and effect. All newly discovered archeological sites will be recorded both on State of Tennessee site survey forms and NPS Archeological Sites Management Information System (ASMIS) forms. Global positioning system locations (requested in North American Datum (NAD) 83) and site location maps will also be required.

Operators shall employ a qualified archeologist to monitor all ground-disturbing activities. Qualified archeologists are those who meet the Secretary of Interior standards and guidelines for Archeology and Historic Preservation.

## UNANTICIPATED DISCOVERY

The NPS is responsible, under 36 CFR 800.11, for providing a plan of action to address properties discovered during project implementation.

If any unknown cultural resource is discovered during the conduct of approved operations, and such resource might be altered or destroyed by the operations, the operator must immediately cease operations in the immediate area and notify the superintendent. The operator must leave the discovery intact until the superintendent grants permission to proceed with the operations (36 CFR 9.47(b)). Before any further activities occur, a qualified cultural resource expert will assess the cultural resources, evaluate their National Register eligibility, and consult with the State Historic Preservation Officer. Minor recordation, stabilization, or data recovery may be necessary during this action and will be conducted at the operator’s expense. Until eligibility of the discovered historic properties can be determined, no further disturbance to the cultural resources may occur. Any plans for mitigating the negative impacts on historic properties will be subject to approval of the NPS, and it is the operator’s responsibility to provide for any necessary mitigation measures.

## DAMAGE TO PREVIOUSLY IDENTIFIED SITES

This stipulation applies to situations where operations have damaged a previously identified cultural resource that was visible on the ground surface. If, in its operations, a nonfederal oil and gas operator damages, or is found to have damaged, any historic or prehistoric ruin, monument, or site, or any object of antiquity subject to the Antiquities Act of 1906 or the Archaeological Resources Protection Act of 1979 (16 USC 470) and the National Historic Preservation Act, as amended, the operator will prepare and implement a data recovery plan at his/her expense. The operator will obtain at his/her expense, a qualified permitted archeologist to carry out the specific NPS requirements.

A qualified cultural resource monitor may be required during operations or reclamation activities if the work is located in a particularly sensitive area and/or reclamation was not done immediately following operations. Additionally, the NPS may require an archeologist to inspect reroutes to determine if cultural sites were successfully avoided. If required, this information shall be included in a monitoring report submitted to the NPS, along with an assessment of the damage, if any, to the cultural resources that were to be avoided.

The operator's employees and subcontractors must be made aware that any collection of artifacts is punishable by law and that the company is liable under trespass regulations, the Antiquities Act, and the Archaeological Resources Protection Act for fines and possible costs for any cultural resources damaged by vehicular traffic or collection.

## VISITOR USE AND EXPERIENCE: LIGHTSCAPE AND SOUNDSCAPE MANAGEMENT

In accordance with section 4.10 of NPS *Management Policies 2006*, "The Service will preserve, to the greatest extent possible, the natural lightscapes of parks, which are natural resources and values that exist in the absence of human-caused light…Recognizing the roles that light and dark periods and darkness play in natural resource processes and the evolution of species, the Service will protect natural darkness and other components of the natural lightscape in parks."

Park natural soundscape resources encompass all the natural sounds that occur in parks, including the physical capacity for transmitting those natural sounds and the interrelationships among park natural sounds of different frequencies and volumes (NPS 2006c). Section 4.9 of NPS *Management Policies 2006* states "The National Park Service will preserve, to the greatest extent possible, the natural soundscapes of parks…The Service will restore to the natural condition wherever possible those park soundscapes that have become degraded by unnatural sounds (noise), and will protect natural soundscapes from unacceptable impacts."

### LIGHTSCAPE PERFORMANCE STANDARD

Minimize the visibility of operations from public use areas, including information stations, day and overnight use areas, public access roads, hiking trails, and administrative use areas.

### SOUNDSCAPE PERFORMANCE STANDARD

Preserve the natural quiet and natural sounds associated with Big Thicket National Preserve.

## HUMAN HEALTH AND SAFETY

According to section 8.2.5.1 of NPS *Management Policies 2006*, "The saving of human life will take precedence over all other management actions as the Park Service strives to protect human life and provide for injury-free visits…While recognizing that there are limitations on its capability to totally eliminate all hazards, the Service and its concessioners, contractors, and cooperators will seek to provide a safe and healthful environment for visitors and employees…The Service will strive to identify and prevent injuries from recognizable threats to the safety and health of persons and to the protection of property by applying nationally accepted codes, standards, engineering principles, and the guidance contained in Director's Orders 50, 58, and 83 and their associated reference manuals. When practicable, and consistent with congressionally designated purposes and mandates, the Service will reduce or remove known hazards and apply other appropriate measures, including closures, guarding, signing, or other forms of education. In doing so, the Service's preferred actions will be those that have the least impact on park resources and values."

### General Health and Safety Performance Standard

The operator shall take all necessary precautions to prevent human exposure to hazards (physical, chemical, and fire).

### Performance Standard for High Pressure Precautions and Open Flow/Control of Wild Wells

The operator must ensure that all equipment, methods, and materials will ensure proper control of the well, including pressure control.

## CONTROL OF CONTAMINATING AND HAZARDOUS SUBSTANCES

Per section 9.1.6.2 of NPS *Management Policies 2006*, “The Service will make every reasonable effort to prevent or minimize the release of contaminants on, or that will affect, NPS lands or resources, and the Service will take all necessary actions to control or minimize such releases when they occur… The Service will take affirmative and aggressive action to ensure that all NPS costs and damages associated with the release of contaminants are borne by those responsible for the contamination of NPS property.”

Contaminating substances is defined at 36 CFR § 9.31(n) as “those substances, including but not limited to, salt water, or any other injurious or toxic chemical, waste oil or waste emulsified oil, basic sediment, mud [drilling fluid] with injurious or toxic additives, or injurious or toxic substances produced or used in the drilling, development, production, transportation, or on-site storage, refining, and processing of oil and gas.”

### Contaminating Substances Performance Standards

- Operator shall take all necessary precautions to prevent the release of contaminating and hazardous substances into the environment.
- Operator shall respond quickly and effectively to contain and clean up spills and restore damaged resources.

Operators conducting oil and gas drilling and production operations will often use or generate substances that meet the regulatory definition of contaminating substances under 36 CFR 9.31(n), and are therefore required to fully comply with the provisions of 36 CFR 9.45 during the conduct of operations. Operators must include a "Contaminating or Toxic Substance Spill Control Plan" in their Plan of Operations (36 CFR 9.36(a)(10)(vi)). The Spill Control Plan will:

- List the types and amounts of contaminating substances proposed for use in operations;
- Describe potential hazards to humans and the environment and respective mitigation measures;
- Describe actions to be taken to handle, store, clean up, and dispose of such substances;
- Describe the equipment and methods for containment and clean up of contaminating substances, including a description of the equipment available on-site versus those available from local contractors; and
- Include an emergency spill response plan prepared by a qualified spill specialist in the event of accidents, fires, or spills.

If determined to be adequate by the superintendent, a Spill Prevention Control and Countermeasure Plan, required under 40 CFR 112, may be used to satisfy the oil spill contingency plan requirements under 36 CFR 9.36(a)(10)(vi).

- Confine brine water and all other waste and contaminating substances to the smallest practicable area, and prevent escape of such substances due to percolation, rain, high water, or other causes. Properly store and promptly remove all wastes and contaminating substances to prevent contamination, pollution, damage, and injury to unit resources and values (36 CFR 9.45).
- The operator will immediately stop work if contamination is found in the operating area and notify the park superintendent or his/her designated representative.
- The operator will be liable for pollution or other damages, as a result of their operations, to government-owned lands and property.
- Operators shall make efforts to use the least hazardous and/or contaminating substances necessary in the conduct of operations if those choices are available; and to store the minimum quantity on site needed to maintain operations.
- Hazardous and contaminating substances shall be properly stored in secondary containment systems.
- The operator shall indemnify the United States against any liability for damage to life or property arising from the occupancy or use of public lands under an approved Plan of Operations. This shall include liability arising from the occupancy or use of public lands under an approved Plan of Operations. This shall include liability arising from the release of any hazardous substance or hazardous waste (as these terms are defined in the Comprehensive Environmental Response, Compensation and Liability Act of 1980, 42 USC 9601, et seq., or the Resource Conservation and Recovery Act, 42 USC 6901, et seq.) on this approved surface use (unless the release or threatened release is wholly unrelated to operator's activity in this approved surface use), or resulting from the activity of operator on this approved surface use. This applies without regard to whether a release is caused by the operator, their agent, or unrelated third parties.

Any collection and laboratory analyses of soil sediment, surface or groundwater samples conducted before or after well drilling, production, or a change of ownership or lease rights, shall follow the NPS “Guideline for the Detection and Quantification of Contamination at Oil and Gas Operations,” contained in appendix K.

## INTEGRATED PEST MANAGEMENT

In accordance with section 4.4.5 of NPS *Management Policies 2006*, all park employees, concessioners, contractors, permittees, licensees, and visitors on all lands managed or regulated by the NPS will comply with NPS pest management policies. Integrated pest management (IPM) is a decision-making process that coordinates knowledge of pest biology, the environment, and available technology to prevent unacceptable levels of pest damage, by cost-effective means, while posing the least possible risk to people, resources, and the environment. The NPS and each park unit will use an IPM approach to address pest issues. Proposed pest management activities must be conducted according to the IPM process prescribed in Director’s Order 77-7: Integrated Pest Management. Pest issues will be reviewed on a case-by-case basis. Controversial issues, or those that have potential to negatively impact the environment, must be addressed through established planning procedures and be included in an approved park management or IPM plan. IPM procedures will be used to determine when to implement pest management actions and which combination of strategies will be most effective for each pest situation.

Under the NPS IPM program, all pesticide use on lands managed or regulated by the NPS, whether that use was authorized or unauthorized, must be reported annually (NPS 2006c).

### Integrated Pest Management Performance Standard

Avoid or minimize adverse impacts of pesticide use to nontarget species or resources.

## PROTECTION OF PARK DEVELOPMENT AND SURVEY MONUMENTS

Although there is no applicable NPS management policy for this topic, supporting laws include the NPS Organic Act of 1916, as amended (16 USC 1 et seq.) and the Park System Resource Protection Act (16 USC 19jj), 36 CFR 9.41(a, b).

### Park Development Performance Standards

- Avoid impacts on existing or future park structures, development, and survey markers.
- If impacts occur, restore, replace, or compensate for damages.
- Reduce fire hazards to acceptable levels.

# APPENDIX G: ROAD AND TRAIL CLASSIFICATIONS AND STANDARDS

Road and trail standards are used to guide the attainment and maintenance of desired resource conditions and visitor experiences. The specific standard selected for a certain route is based on the designated uses, the management objectives for the surrounding area, and cost.

Use designations and standards may not always appear to be consistent. For example, a trail designated and signed for horse use may also occasionally be needed for vehicle access to an oil and gas well. In such a case, the “public use designation” would be as a horse trail, but the physical standard applied must be sufficient for vehicles. Therefore, the standard would reflect a “road” use, while the general public use would be as a “trail.” The discussion of each road and trail in this plan indicates both designation and standard.

## ROADS

Roads are also classified by function. Classes and their definitions are from *Park Road Standards*, National Park Service, 1984. Road standards are guided by *Park Road Standards* but are developed specifically for application in the National Area.

CLASS 1 – Principal park roads or through roads: *Roads that provide the main access routes or that are through roads, for example, TN 297, TN 52, and KY 92*

Standard A – Relatively high traffic volume

- Two paved 12-feet travel lanes 2-feet paved shoulders
- 45-feet cleared right-of-way; 20-feet cleared height
- 1:4 fore slope and 1:2 back slope, except where rock prohibits grading
- 1-foot deep ditches, except flat bottom ditches, which will be 2-feet deep

Standard B – Moderate traffic volume

- 18- to 22-feet road width; paved or gravel (adequate for two vehicles to pass)
- 2-feet paved or gravel shoulders
- 30-feet cleared right-of-way; 20-feet cleared height
- Slopes and ditches same as A

CLASS 2 – Connector roads: *Roads that provide access within a park to areas of scenic, scientific, recreational, or cultural interest, such as overlooks, campgrounds, etc.*

Standard A – Moderate-to-high traffic volume, including campers, horse trailers

- 22-feet road width; paved or gravel (adequate for oncoming vehicles to pass)
- 2-feet paved or gravel shoulders
- 35-feet cleared right-of-way; 20-feet cleared height
- Slopes and ditches same as Class 1

Standard B – Moderate traffic volume, and may be used by trucks

- 16- to 18-feet road width; paved or gravel (oncoming vehicles would have to slow and may have to use shoulder to ensure safety)
- 1-foot paved or gravel shoulders
- 30-feet cleared right-of-way; 20-feet cleared height
- Slopes and ditches same as Class 1

Standard C – Low traffic volume, and may be used by trucks, e.g., oil/gas trucks

- 8- to 12-feet wide “one lane” gravel road (no constructed pull-outs)
- No shoulders
- 12- to 16-feet cleared right-of-way; 12-feet cleared height
- Normally no slopes and ditches

CLASS 3 – Special purpose roads: *Roads that provide circulation within public use areas (Development Zones), such as campgrounds*

- Standard A – Two-way, low speed, high volume traffic; including trailers, campers
- 20-feet paved or gravel road
- No shoulders
- 22-feet cleared right-of-way; 20-feet cleared height
- Normally no slopes and ditches

Standard B – One-way, low speed, high volume traffic; including trailers, campers

- 12-feet paved or gravel road
- No shoulders
- 14-feet cleared right-of-way; 20-feet cleared height
- Normally no slopes and ditches

CLASS 4 – Primitive roads: *Low traffic volume roads that provide access to remote or undeveloped areas*

- Standard
- No specific design standard; mostly old roads
- Maximum 8-feet cleared right-of-way; 10-feet cleared height
- Monitoring for maintenance needs and resource/safety issues

CLASS 5 – Administrative roads: *Roads intended mainly for administrative purposes but are normally open to public use also*

- Standard A
- Two 11-feet lanes; paved or gravel
- 2-feet shoulders
- 35-feet cleared right-of-way; 20-feet cleared height
- Slopes and ditches same as Class 1

Standard B

- 10- to 12-feet gravel or dirt road
- No shoulder
- 12- to 14-feet cleared right-of-way; 10-feet cleared height
- Normally no slopes and ditches
- May be gated

CLASS 6 – Administrative roads: *Roads intended for administrative purposes that are normally closed to public use*

- Standard
- Same as 2C

# TRAILS

The following standards shall apply to new construction and to major rehabilitation of existing trails. These are target standards and every attempt will be made to meet them; however, site conditions may not allow for strict compliance in every case. Existing trails may not currently meet these standards, but will be rehabilitated, upgraded, or re-routed to meet these standards as funding and staffing permit. Existing trails causing immediate environmental damage will receive the top priority for rehabilitation.

The standards for specific trail types are typically expressed in terms of maximum widths. Trails can and should be narrower in more remote areas and in areas within the Sensitive Resource Protection Zone. Where the decision is made to maintain a trail on a former roadbed, it need not necessarily be maintained to road width.

GENERAL STANDARDS:

- Outslope on trails should be between 5 and 10%.
- Grade or slope of the trail will vary according to type of use. The target grade will be between 3% and 10% for all trails. For hiking trails, grades up to 18% will be allowed for distances up to 25 feet. For horse trails, grades up to 25% will be allowed for distances up to 50 feet. In cases where the grade exceeds 10%, efforts will be made to control drainage and erosion using drainage dips, water bars, steps and other structures.
- Although Full Bench construction is preferred, Partial Bench construction may be utilized wherever deemed necessary during the design process.
- Backslope will be determined as a part of the design and will depend upon the existing soil conditions. The backslope will vary from near vertical for rocky areas to 1:2 for areas where the soil has little cohesion.

# HORSE TRAILS

LEVEL 1 (H-1): Major trails with heavy use, typically around development areas (e.g., connector trails for Bandy Creek Stables and Station Camp and Bear Creek Horse Camps

- Maximum 8-feet trail tread; hardened surface
- Maximum 4-feet clearance each side; 10-feet cleared height
- Liberal use of structures, e.g., bridges, earth/gravel water bars
- For slope information, see General Standards

LEVEL 2 (H-2): Major trails with frequent high levels of use (e.g., Pilot – Wines Loop and Cumberland Valley Loop

- Maximum 8-feet trail tread; hardened surface
- Maximum 4-feet clearance each side; 10-feet cleared height
- Some structures
- For slope information, see General Standards

LEVEL 3 (H-3): Trails with medium to heavy use, often with seasonal peaks; usually on flatter areas with fewer stream crossings (e.g., Jack’s Ridge Loop)

- Maximum 6-feet trail tread; hardened surface or dirt
- Maximum 3-feet clearance each side; 10-feet cleared height
- Structures as needed
- For slope information, see General Standards

LEVEL 4 (H-4): Extra-wide trails capable of use by horse drawn wagons (e.g., Gobbler's Knob Trail)

- Maximum 10-feet trail tread; hardened surface
- Maximum 4-feet clearance each side; up to 12-feet cleared height
- For slope information, see General Standards

LEVEL 5 (H-5): Trails supporting moderate to heavy use, mostly in the backcountry. Considered the standard for most new trails

- Maximum 6-feet trail tread; hardened surface
- Maximum 3-feet clearance each side; 10-feet cleared height
- Structures on all stream crossings
- For slope information, see General Standards

LEVEL 6 (H-6): Trails in the backcountry that are mostly lightly used and follow old roadbeds

- Old roadbed serves as trail tread; maximum 8-feet wide, dirt surface
- No specific standard width or cleared area in order to retain character
- Monitored for safety deficiencies and resource impacts; maintenance as needed
- For slope information, see General Standards

## FOOT TRAILS

LEVEL 1 (F-1): Heavily used major trails (e.g., Yahoo Falls Trail)

- Maximum 30-inch trail tread; hardened surface where needed
- Maximum 3-feet clearance each side; 8-feet cleared height
- Liberal use of structures
- For slope information, see General Standards

LEVEL 1A (F-1A): Heavily used shorter trails (e.g., Blue Heron overlook trail, Mine 18 trails). These trails experience heavy use due to their proximity to developed areas or because they are short trails that are useable by most visitors.

- Maximum 6-feet trail tread; paved
- Maximum 3-feet clearance each side; 8-feet cleared height
- For slope information, see General Standards

LEVEL 1B (F-1B): Trails accessible to the physically challenged

- Trail width, surface, slope and other standards vary according to challenge level; ADA standards apply For slope information, see General Standards

LEVEL 2 (F-2): Trails moderately to heavily used (e.g., Oscar Blevins Farm Loop)

- Maximum 30-inch trail tread on constructed sections; other portions on old roads; hardened surface where needed
- Where trail utilizes old roadbeds, Maximum 8-feet trail tread width
- Maximum 3-feet clearance each side; 8-feet cleared height
- Some structures
- For slope information, see General Standards

LEVEL 3 (F-3): Trails moderately used in more backcountry settings (e.g., Laurel Fork Creek Trail)

- Maximum 2-feet trail tread
- Maximum 2-feet clearance each side; 8-feet cleared height

- Some structures
- For slope information, see General Standards

LEVEL 4 (F-4): Mainly long-distance trails with varying use levels depending on location and season (e.g., John Muir Trail, Sheltowee Trace)

- Maximum 30-inch trail tread where constructed; some portions on old roads
- Where trail utilizes old roadbeds, Maximum 8-feet trail tread width
- Maximum 2-feet clearance each side; maximum 8-feet cleared height Liberal use of permanent structures
- For slope information, see General Standards

BICYCLE TRAILS

As used here, the bicycle trail standard (B) refers to those trails, or trail segments, that are constructed for and used exclusively by mountain bikes. Where bikes are allowed on hiking trails, the standard applied would be within the maximum hiking standard. Bicycles are also allowed on public roads and horse trails, unless specifically disallowed.

- “Single track” trails only
- Maximum 3-feet trail tread; dirt (avoid gravel and sand)
- Maximum 1-foot clearance each side; 8-feet cleared height
- For slope information, see General Standards

MULTIPLE-USE TRAILS

Multiple-use trails (MU) provide for use by horses and motor vehicles on the same route. The trail is designed for slow vehicle traffic.

- 10-feet maximum tread width; can be a hardened surface
- Maximum 2-feet clearance each side; 12-feet cleared height
- Shoulders and drainage as needed
- For slope information, see General Standards
- Speed reduction devices and warning signs as necessary to slow vehicle traffic

ALL-TERRAIN VEHICLE (ATV) TRAILS

ATV usage would be allowed on multiple-use trails (during big game season only, by licensed hunters) and on specifically designated trail(s) in the ATV Planning Area. For purposes of this plan, an ATV is defined as a licensed or unlicensed three- or four-wheeled motorized vehicle that has a seat/saddle a rider straddles and

- Maximum 5-feet tread width; dirt
- No extra side clearance; 6-feet cleared height
- Drainage as needed
- For slope information, see General Standards

# Appendix H: Types of Oil and Gas Operations

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## Introduction

The petroleum industry is a continuous cycle of searching for new oil and gas reservoirs, developing and producing them, and finally abandoning the property once the hydrocarbons are depleted.

There are four general phases of petroleum development. The phases are (1) exploration, (2) drilling, (3) production, and (4) abandonment/reclamation. Surface uses vary for each phase in terms of intensity and duration. Also, operations related to one or all of the phases may be occurring in the same area at any given time. In Big South Fork National River and Recreation Area and Obed Wild and Scenic River, most oil and gas activities will likely be part of the production and abandonment/reclamation phases. Drilling is expected to occur on a less frequent basis. Although described below, exploration work such as geophysical surveys is not expected because zones of interest in the area are shallow (economics of seismic survey versus just drilling an explorations well) and there is a good number of wells that provide information for interpreting the subsurface.

To be of interest to the petroleum industry, petroleum deposits must be commercially valuable. There must be a reasonable chance of making a profit on the eventual sale of the oil and gas. Factors such as the market price of oil and gas, the amount of recoverable petroleum, the expected production rates, and the cost of drilling wells, producing, and transporting the product to market all determine the economic viability of developing a deposit once it is discovered.

The following sections are meant to provide the reader with a general understanding of common activities associated with each phase of oil and gas development.

## Exploration Operations

### OCCURRENCE OF PETROLEUM

Petroleum deposits are not large underground caverns filled with oil and gas as the term reservoir might suggest. Rather, petroleum accumulates in tiny spaces within the buried rock layers. Most scientists today agree that petroleum was formed from large amounts of very small plant and animal life. These organic materials accumulated in ancient seas, which, over great periods of time, have covered much of the present land area. As time passed, sediments rich in organic matter were buried deeper and deeper. The increased pressure and temperature caused these organic remains to change into oil and natural gas. Once formed, the oil and gas migrated upward until certain forms and shapes of underground rocks halted the upward movement, trapping the hydrocarbons in large quantities. The search for these traps is the focus of the first phase of oil and gas development and exploration.

## GEOLOGICAL EXPLORATION

The search for oil and gas often begins with geological exploration. The exploration geologist is looking for clues on the surface that would suggest the possibility of petroleum deposits below. Surface studies comprise the first stage of exploratory fieldwork. Geological surveys of the land surface are made using aerial photographs, satellite photographs, maps of surface outcrops of specific formations or rock types, and geochemical analyses. Field crews map surface attributes and collect surface samples of rock for analysis.

Creating maps of surface outcrops and geochemical analyses requires fieldwork. Little equipment is needed other than surveying gear and rock and soil sampling supplies. These activities require a small field party of two to four persons who can work out of a single vehicle or on foot. Access to remote areas can be gained by a four-wheel-drive vehicle, small all-terrain vehicles, helicopter, pack animals, or by walking. A small boat may be used where navigable water occurs near the area being studied. Constructing roads or channels in shallow water areas is not required at this early stage.

Geochemical analysis often requires subsurface samples to be taken from a ditch or a shallow corehole. The coreholes are usually shallow, but may generate some cuttings.

## GEOPHYSICAL EXPLORATION

Geological exploration can narrow the area being searched, but subsurface geology may or may not be accurately indicated by surface outcrops. Geophysical prospecting extends the search beneath the earth’s surface. The surveys identify and map characteristics favorable to oil and gas accumulation deep underground. Geophysical operations include gravitational, magnetic, and seismic surveys. Of these, the seismic survey is most common.

**Gravitational and Magnetic Surveys**—Gravitational and magnetic field studies yield regional or reconnaissance-type data. These surveys detect variation in gravitational attractions and magnetic fields of the various types of rock below the surface.

Gravity surveys are generally done with small, portable instruments called gravity meters or gravimeters. The number and placement of measurement points in a gravity survey depend on the site’s characteristics. These include feasibility of access and the spacing pattern necessary to detail the features selected for mapping. The field party required is not large, usually 3 to 6 people. Travel on foot is possible with the smaller portable gravimeters. Progress, however, is slow, so most surveys use four-wheel-drive vehicles. In marshy areas, the use of special swamp or marsh buggies is quite common with gravity survey crews. Airborne survey operations are not yet practical due to present instrument limitations and the relatively large and rapid changes in altitude and acceleration characteristic to aircraft.

The objective of most surveys can be achieved when gravity stations are confined to existing roads or waterways. Where roads or waterways do not exist, a large level of latitude in positioning stations is possible to account for logistical or environmental constraints. Disturbance of the land surface is minimal when established access is already available. Methods of access to roadless areas are similar to those required for geological explorations described above. The surveying technique itself does not require any physical disturbance of the surface.

Magnetic surveys are often used in place of or to supplement gravity surveys. These surveys are done with relatively small airborne or portable ground instruments called magnetometers. Flight patterns usually consist of a series of parallel lines at 1- to 2-mile intervals.

Airborne surveys require geodetic and ground control points. These must be installed on the ground before the survey can take place, if not already present. A majority of the lower 48 states have been surveyed, so these points are already in place. If not, however, the area must be accessed by overland vehicles or helicopters. The size of the field party required is not large. The access to roadless areas is similar to that required for geological exploration described above. The surveying technique itself does not require any physical disturbance of the surface.

**Seismic Surveys**—Whereas gravity and magnetic surveys provide regional information, seismic survey can provide enough subsurface detail to locate potential oil and gas traps.

A seismic survey gathers subsurface geological information by recording impulses from an artificially generated shock wave. The energy waves travel downward toward underground formations. A series of sensitive instruments, called geophones, set out at surveyed points on the ground, record the energy waves as they are reflected off the subsurface formations and back to the surface. Cables or radio transmitters transfer information from the geophones to a recorder truck that receives and records the reflected seismic energy. Sophisticated computers analyze the data and generate a “picture” of the rocks underground. Each survey line provides a cross-section of the rock formations beneath it, and many lines may be run to create a complete picture.

In remote areas where there is little known subsurface data, a series of short seismic lines may be required to determine the attitude of the subsurface formations. After this, the pattern of seismic lines or grids is designed to make the final data more accurate and valuable. Although alignment is fairly critical, some source and recording stations may be moved or skipped for environmental or logistical reasons without seriously affecting the results of the investigation.

A more recent technique called 3-D Seismic works on the same principle as conventional seismic, but energy and recording stations are placed at a much denser spaced grid. There may be up to 150 energy source locations and 200 recording stations per square mile on a 3-D seismic project. Surveys commonly exceed a 25-square-mile-area. The 3D-Seismic surveys can provide enough detail to locate traps that have been “missed” by conventional geophysical methods and exploratory drilling. Even in areas that have been heavily explored and developed, 3D-Seismic is helping to optimize new field development and find new targets within producing fields. New life is being brought to areas thought to have been played out.

Seismic methods are usually referred to by the various methods of generating the shock wave. These include weight drop, vibrators, dinoseis (combustible gas expansion), and explosives. No matter what method of generating energy is used, the procedures for preparing the line and recording the data are relatively similar. The procedure typically consists of first surveying and flagging the locations for the geophones and the positions of the energy sources. Second, the geophones and the connecting cable are laid down. The cable is either connected with more cable to the recording truck or to a radio transmitter to send the data to the recording truck. Normally the recording truck will be within a short distance of the transmitter or within line of sight. Once the geophones and ground cable are in place, the energy source is put in place. The initiation of the energy source, whether by a “vibroseis” truck or by explosive, is controlled by the recording truck. The shock wave is set off, and the seismic signal recorded by multiple geophones. Once the signal is recorded, the ‘shooting crew travels to the next source point, and the process is repeated.

The most common energy source in seismic work is explosives placed in holes drilled to depths of several feet up to 200 feet. Explosives may range from ½- to 50-pound charges and typically increase in size with increased setting depths. Drills can be mounted on trucks, boats, or specially designed airboats or ATVs, depending on the type of access required. In rugged topography, or to reduce surface disturbance associated with access, portable drills are sometimes carried by helicopter or by hand. Other field equipment can include vehicles to carry water for drilling operations, personnel, surveying equipment, recording equipment, and computers.

Existing roads are used if possible, but reaching some lines may require clearing vegetation and loose rock to improve access for the crews and the trucks. Each mile of seismic line cleared to a width of 8 to 15 feet represents disturbance of about an acre of land. A network of low-standard temporary roads and trails can result from these operations. The alignment of these trails usually consists of straight lines dictated by the grid, often with little regard for steep slopes or rough terrain. Level topography with few trees and shrubs would require little or no trail construction. An area with rugged topography or larger vegetative types such as trees and large shrubs would require more trail preparations. Temporary roads and trails are usually constructed with bulldozers.

Seismic crews consist of several surveying people, people for laying and retrieving the cable and geophones, the truck drivers and drillers for the energy source, personnel in the recording truck and miscellaneous water truck drivers, cleanup people, and field crew managers. The size of the seismic crews varies from 15 to 80 people. On most seismic jobs, the people and equipment are transported in trucks or four-wheel-drive vehicles. However, the surveying, cable laying, and sometimes the drilling can be done on foot in some situations.

Under normal conditions, 3 to 5 miles of line can be surveyed each day using the explosive methods. Crews may be in the field for 1 to 4 weeks for an average conventional survey. An average 3-D survey may take several months to complete.

# DRILLING AND PRODUCTION OPERATIONS

## OIL AND GAS WELL DRILLING

**Classification of Wells**—Wells drilled for oil and gas are classified as either exploratory or development wells. An exploratory well is drilled either in search of an as-yet-undiscovered pool of oil or gas (a wildcat well) or to extend greatly the limits of a known pool. Exploratory wells may be classified as (1) wildcat, drilled in an unproven area; (2) field extension or step-out, drilled in an unproven area to extend the proved limits of a field; or (3) deep test, drilled within a field area but to unproven deeper zones. Development wells are wells drilled in proven territory in a field to complete a pattern of production.

Similar to geophysical surveys, drilling operations are relatively short-term. However the intensity of impacts is much higher due to the equipment and materials needed to drill a well and the potential duration of the operation. At a common height of 180 feet, the rig stands as tall as a 12-story building. An average drilling rig needs a level location of about 3 acres. The drilling pad and access road must be capable of supporting thousands of tons of equipment. Existing access roads may need to be widened and upgraded to accommodate heavy loads. Rigs commonly used in Tennessee and Kentucky are somewhat smaller and locations perhaps 1 to 2 acres in size.

**Choosing the Site**—Once exploration activities have narrowed the search to specific drilling targets, the operator must select an exact spot on the surface to drill the well. The industry prefers to drill vertically, and usually chooses a drill site directly above the desired bottomhole location. When topographical, geological, or environmental constraints prevent a drill site from being located directly above the bottomhole location, the use of direction drilling can achieve the objective. Reaches of over a mile are common for 10,000-foot-deep wells, and extended reach wells have been drilled with over 2 miles of horizontal departure.

Directional drilling involves deviating a wellbore from its vertical along a predetermined course to a target located at some depth and some horizontal distance away. It is a common practice in the industry today, with a number of uses. Directional drilling techniques can be applied if the target zone lies underneath an inaccessible location such as a heavily urbanized area, mountain, or water body, and the drill rig must be located elsewhere. The technique is most often used in offshore applications to allow many wells to be drilled from one location. It can be used to drill around or through fault planes, salt domes, or obstructions in the hole, and to provide relief to a nearby well that has blown out. More recently, the technique has been used to move surface locations as an environmental protection measure.

While directional drilling allows flexibility in the selection of the drill site, there are technical, physical, and economic constraints on its use. Geological factors such as target depths, formation properties (stability, type, dip angle, etc.), and contemplated horizontal departures physically complicate and restrict the opportunities for using directional drilling. Sophisticated equipment and specialized personnel are needed to monitor and guide the direction of the well as it is being drilled. The cost of using this technique typically ranges from 10 percent to 50 percent higher than the cost of a vertical well. While directional drilling can be applied in a wide variety of situations, project specific conditions must always be taken into account.

**Accessing the Site**—Wildcat drilling often takes place in remote areas. Preliminary exploration work will not have contributed any new roads to an area, although there may be some cross-country trails. Temporary access roads will have to be constructed. Existing roads may need upgrading to accommodate the heavier loads associated with truck traffic. One lane is usually adequate, but turnouts and/or traffic control are necessary to accommodate two-way traffic on longer routes. Installation of culverts or other engineering structures will be needed in steep terrain or when crossing stream channels. Soil texture, topography, and moisture conditions might dictate that roads be surfaced with material such as gravel, oyster shells, caliche, or ground limestone. Heavy equipment such as graders, bulldozers, front-end loaders, and dump trucks are commonly used in constructing roads. In marshy areas, a roadbed may be laid with heavy boards.

**Preparing the Drill Site**—To accommodate the rig and equipment, the drill site must be prepared. Site preparation may include extensive clearing, grading, cutting, filling, and leveling of the drill pad using heavy construction equipment. Soil material suitable for plant growth is often removed first and stockpiled for later use in reclamation. The operator may also dig reserve pits to hold large volumes of drilling mud and drill cuttings. In environmentally sensitive areas, a large effort is made not to alter the surface area comprising the drill site more than is necessary. For example, reserve pits may not be dug. Instead, large steel bins are placed on the site to receive the cuttings and other materials that are normally dumped into the reserve pits. These bins can then be trucked away from the site and the material inside them disposed of properly. Also, even in areas where reserve pits are excavated, they are often lined with thick plastic sheeting to prevent any contaminated water or other materials from seeping into the ground. The drill pad typically occupies about 2 to 3 acres.

Directional drilling may require a larger-sized rig and additional support facilities that may lead to larger pad sizes. For inland water sites, drilling barges that sit on the bottom may be used as a foundation for the drill rig. Some dredging may be done on these sites to create a slip, and protective skirts or pilings may be installed around the barge to prevent erosion by currents and tidal flow. In deeper water, jack-up, submersible and semi-submersible, rigs and drill ships may be used to drill wildcat wells. An offshore platform is typically used to drill development wells in deep water.

Since a source of freshwater is required for the drilling mud and for other purposes, a water well is sometimes drilled prior to moving the rig onto the location. If other sources are available, the water may be piped or trucked to the site.

At the exact spot on the surface where the hole is to be drilled, a rectangular pit called a cellar is dug, or culvert-like pipe is driven into the ground. If the cellar is dug, it may be lined with boards, or forms may be built and concrete poured to make walls for the cellar. The cellar is needed to accommodate drilling accessories that will be installed under the rig later.

In the middle of the cellar, the top of the well is started, sometimes with a small truck-mounted rig. The conductor hole is large in diameter, perhaps as large as 36 inches or more; is about 20 to 100 feet deep; and is lined with conductor casing, which is also called conductor pipe. If the topsoil is soft, the conductor pipe may be driven into the ground with a pile driver. In either case, the conductor casing keeps the ground near the surface from caving in. Also, it conducts drilling mud back to the surface from the bottom when drilling begins, thus the name conductor pipe.

Usually, another hole considerably smaller in diameter than the conductor hole is dug beside the cellar and also lined with pipe. Called the rathole, it is used as a place to store the kelly when it is temporarily out of the borehole during certain operations. Sometimes on small rigs, a third hole, called the mousehole, is dug. On large rigs, it is not necessary to dig a mousehole because of the rig floor's height above the ground. In either case, the mousehole is lined with pipe and extends upward through the rig floor and is used to hold a joint of pipe ready for makeup.

**Rigging Up**—With the site prepared, the contractor moves in the rig and related equipment. The process, known as rigging up, begins by centering the base of the rig, called the substructure, over the conductor pipe in the cellar. The substructure supports the derrick or mast, pipe, drawworks, and sometimes the engines. If a mast is used, it is placed into the substructure in a horizontal position and hoisted upright. A standard derrick is assembled piece by piece on the substructure. Meanwhile, other drilling equipment such as the mud pumps are moved into place and readied for drilling.

Other rigging-up operations include erecting stairways, handrails, and guardrails; installing auxiliary equipment to supply electricity, compressed air, and water; and setting up storage facilities and living quarters for the toolpusher and company man. Further, drill pipe, drill collars bits, mud supplies, and many other pieces of equipment and supplies must be brought to the site before the rig can make hole.

Mobilizing the drill rig to the location requires moving 10 to 25 large truckloads of equipment over public highways and smaller roads. In very remote locations, entire drilling crews and service personnel may be temporarily housed onsite. A typical drilling crew consists of five people. Drilling operations are continuous, 24 hours a day and 7 days a week. The crews usually work two 12-hour shifts. With the drilling crew, geologists, engineers, supervisors, and specialized service providers, there may be anywhere from 5 to over 20 people on a drilling location at any given time. An irregular stream of traffic to and from the rig occurs day and night.

**Drilling the Surface Hole**—Rotary drilling is used almost universally in modern-day drilling. Drilling is accomplished by rotating special bits under pressure. Starting to drill is called “spudding in” the well. To spud in, a large bit, say 17 ½ inches in diameter as an example, is attached to the first drill collar and is lowered into the conductor pipe by adding drill collars and drill pipe one joint at a time until the bit reaches the bottom. While drilling, the rig derrick and associated hoisting equipment support the drill string’s weight. The combination of rotary motion and weight on the bit causes rock to be chipped away at the bottom of the hole.

The rotary motion is created by a square or hexagonal rod, called a kelly, which fits through a square or hexagonal hole in a large turntable, called a rotary table. The rotary table sits on the drilling rig floor and as the hole advances, the kelly slides down through it. With the kelly attached to the top joint of pipe, the pump is started to circulate mud, the rotary table is engaged to rotate the drill stem and bit, and weight is set down on the bit to begin making hole. When the kelly has gone as deep as it can, it is raised, and a joint of drill pipe about 30 feet long is attached in its place. The drill pipe is then lowered, the kelly is attached to the top of it, and drilling recommences. By adding more and more drill pipe, the hole can steadily penetrate deeper.

Large volumes of fluid, generically called drilling mud, circulate down the drill pipe to the drill bit and back to the surface. The mud lubricates and cools the bit and carries drill cuttings to the surface. The composition of the mud system depends on the types of formations being drilled, economics, water availability, pressure, temperature, and many other significant factors. Mud can be as simple as freshwater, or a complex emulsion of water, oil, chemicals, clays, and weighting material. Chemicals added to the mud help drill and protect the hole's integrity. Weighting material is often added to prevent formation fluids from flowing into the well as it is being drilled. Mud systems can be highly toxic or relatively benign. The drilling mud along with cuttings from the well account for the largest volume of waste generated at the wellsite. In areas around Big South Fork NRRA and Obed WSR, wells are often drilled using compressed air instead of drilling mud. Drill cuttings and fluids produced from formations while drilling are blown into a lined pit next to the drilling rig through what is known as a blooey line.

The first part of the hole is known as the surface hole. Even though the formation that contains the hydrocarbons may lie many thousands of feet below this point, drilling ceases temporarily because steps must now be taken to protect and seal off the formations that occur close to the surface. For example, freshwater zones must be protected from contamination by drilling mud. To protect them, special pipe called casing is run into the hole and cemented.

**Tripping Out**—The first step in running casing is to pull the drill stem and bit out of the hole. Pulling the drill stem and bit out of the hole in order to run casing, change bits, or perform some other operation in the borehole is called tripping out. To trip out, the drilling crew uses the rig's hoisting system, or drawworks, to raise the drill stem out of the hole.

Attached to the traveling block is a set of drill pipe lifting devices called elevators. Elevators are gripping devices that can be latched and unlatched around the tool joints of the drill pipe. The crew latches the elevators around the drill pipe, and the driller raises the traveling block to pull the pipe upward. When the third joint of pipe clears the rotary table, the rotary helpers set the slips and use the tongs to break out the pipe. The pipe is usually removed in stands of three joints. Removing pipe in three-joint stands, rather than in single joints, speeds the tripping out process. With the stand of pipe broken out, the crew guides it into position on the rig floor to the side of the mast or derrick.

The derrickman unlatches the elevators from the top of the pipe and stands the pipe back in the derrick. Working as a close-knit team, the driller, rotary helpers, and derrickman continue tripping out until all the drill pipe, the drill collars, and the bit are out of the hole. At this point, the only thing in the hole is drilling mud, because mud was pumped into the hole while pipe was tripped out.

**Running Surface Casing**—Once the drill stem is out, often a special casing crew moves in to run the surface casing. Casing is large-diameter steel pipe, and is run into the hole with the use of special heavy-duty casing slips, tongs, and elevators. Casing accessories include centralizers, scratchers, a guide shoe, a float collar, and plugs.

Centralizers keep the casing in the center of the hole so that when the casing is cemented, the cement can be evenly distributed around the outside of the casing. Scratchers help remove mud cake from the side of the hole so that the cement can form a better bond. The guide shoe guides the casing past debris in the hole, and has an opening in its center out of which cement can exit the casing. The float collar serves as a receptacle for special cementing plugs, and allows drilling mud to enter the casing at a controlled rate.

The plugs begin and end the cementing job, and serve to keep cement separated from the mud so that the mud cannot contaminate the cement. The casing crew, with the drilling crew available to help as needed, runs the surface casing into the hole one joint at a time. Casing is available in joints of about 40 feet. Once the hole is lined from bottom to top with casing, the casing is cemented in place.

**Cementing**—The cementing of oil well casing annuli is a universal practice done for a number of reasons, depending on casing type. Conductor casings can be cemented to prevent the drilling fluid from circulating outside the casing, causing the very surface erosion the casing was intended to prevent. Surface casings must be cemented to seal off and protect freshwater formations, provide an anchor for blowout preventer equipment, and give support at the surface for deeper strings of casing. Intermediate strings of casing are cemented in order to seal off abnormal pressure formations, effectively isolate incompetent formations that might cause drilling problems unless supported by casing and cement, and shut off zones of lost circulation. Production casing is cemented to prevent the migration of fluids to thief zones, to prevent sloughing of formations that could result in reduced production, and to isolate productive zones for future development.

An oilwell cementing service company usually performs the job of cementing the casing in place. The cement used to cement oilwells is not too different from the cement used as a component in ordinary concrete. Basically, oilwell cement is Portland cement with special additives to make it suitable for various conditions of pumping, pressure, and temperature.

Cementing service companies stock various types of cement and use special trucks to transport the cement in bulk to the well site. Bulk cement storage and handling at the rig location make it possible to mix the large quantities needed in a short time. The cementing crew mixes the dry cement with water, often using a recirculating mixer (RCM). This device thoroughly mixes the water and cement by recirculating part of the already-mixed components through a mixing compartment. Powerful cementing pumps move the liquid cement (slurry) through a pipe to a special valve made up on the topmost joint of casing. This valve is called a cementing head, or plug container. As the cement slurry arrives, the bottom plug is released from the cementing head and precedes the slurry down the inside of the casing. The bottom plug keeps any mud that is inside the casing from contaminating the cement slurry where the two liquids interface. Also, the plug wipes off mud that adheres to the inside wall of the casing and prevents it from contaminating the cement.

The plug travels ahead of the cement until it reaches the float collar. At the collar the plug stops, but continued pump pressure breaks a seal in the top of the plug and allows the slurry to pass through a passageway in it. The slurry flows out through the guide shoe, and starts up the annulus between the outside of the casing and the wall of the hole until the annulus is filled.

A top plug is released from the cementing head and follows the slurry down the casing. The top plug keeps the displacement fluid, usually drilling mud, from contaminating the cement slurry. When the top plug comes to rest on the bottom plug in the float collar, the pumps are shut down and the slurry is allowed to harden. Allowing time for the cement to set is known as waiting on cement (WOC) and varies in length. In some cases, it may be only a matter of a few hours; in other cases, it may be 24 hours or even more, depending on well conditions. Adequate WOC time must be given to allow the cement to set properly and bond the casing firmly to the wall of the hole. After the cement hardens and tests indicate that the job is good -- that is, that the cement has made a good bond and no voids exist between the casing and the hole -- drilling can be resumed.

**Tripping In**—To resume drilling, the drill stem and a new, smaller bit that fits inside the surface casing must be tripped back into the hole. The bit is made up on the bottommost drill collar. Then, working together, the driller, floormen, and derrickman make up the stands of drill collars and drill pipe and trip them back into the hole.

When the drill bit reaches bottom, circulation and rotation are begun and the bit drills through the small amount of cement left in the casing, the plugs, the guide shoe, and into the new formation below the cemented casing. As drilling progresses and hole depth increases, formations tend to get harder; as a result, several round trips (trips in and out of the hole) are necessary to replace worn bits.

**Controlling Formation Pressure**—During all phases of drilling, an important consideration is well control. Well control is preventing the well from blowing out by using proper procedures and equipment. A blowout is the uncontrolled flow of fluids -- oil, gas, water, or all three -- from a formation that the hole has penetrated.

Blowouts threaten lives, property, and pollution of the environment. Rig crews receive extensive training in how to recognize and react to impending blowouts, making them relatively rare events.

The key to well control is understanding pressure and its effects. Pressure exists in the borehole because it contains drilling mud and in some formations because they contain fluids. All fluids --drilling mud, water, oil, gas, and so forth -- exert pressure. The denser the fluid (the more the fluid weighs), the more pressure the fluid exerts. A heavy mud exerts more pressure than a light mud. For effective control of the well, the pressure exerted by the mud in the hole should be higher than the pressure exerted by the fluids in the formation.

Pressure exerted by mud in the hole is called hydrostatic pressure. Pressure exerted by fluids in a formation is called formation pressure. The amount of hydrostatic pressure and formation pressure depends on the depth at which these pressures are measured and the density, or weight, of each fluid. Regardless of the depth, hydrostatic pressure must be equal to or slightly greater than formation pressure, or the well kicks. The well kicks, formation fluids enter the hole, if hydrostatic pressure falls below formation pressure. Thus, one of the crew's main concerns during all phases of the drilling operation is to keep the hole full of mud whose weight is sufficiently high to overcome formation pressure.

However, unexpectedly high formation pressures can be encountered. Formation fluids can be swabbed, or pulled, into the hole by the piston-like action of the bit as pipe is tripped out of the hole. Also, the mud level in the hole can fall so that the hole is no longer full of mud. Whatever the reason, when hydrostatic pressure falls below formation pressure, crew members have a kick on their hands, and they must take quick and proper action to prevent the kick from becoming a blowout.

Helping the crew keep an eye on the rig's operation are various control instruments located on the driller's console. Some rigs have data processing systems that utilize slave computer display terminals, or CRTs (short for cathode ray tubes), on the rig floor, in the mud logging trailer, in the toolpusher's trailer, and in the company man's trailer. When limits that have been programmed into the system are exceeded, the system goes into an alarm condition.

Whether the kick warning signs come from electronic monitors, a computer printout, or the behavior of the mud returning from the hole, an alert drilling crew detects the signs and takes proper action to shut the well in. To shut a well in, large valves called blowout preventers, which are installed on top of the cemented casing, are closed to prevent further entry of formation fluids into the hole. Once the well is shut in, procedures are begun to circulate the intruded kick fluids out of the hole. Also, weighting material is added to the mud to increase its density to the proper amount to prevent further kicks, and the weighted up mud is circulated into the hole. If the mud has been weighted the proper amount, then normal operations can be resumed.

When drilling with air, there is very little hydrostatic pressure exerted downhole, and formations are drilled through in an “underbalanced” mode. This means the formations can flow into the wellbore as drilling progresses. With air drilling, well control is more dependent on the blowout preventers. It is prudent and often a regulatory requirement to have 1) extra storage capacity to hold formation fluids and 2) materials and equipment on location to “mud up” if necessary to maintain well control and wellbore integrity.

**Running and Cementing Intermediate Casing**—At a predetermined depth, drilling stops again in order to run another string of casing. Depending on the depth of the hydrocarbon reservoir, this string of casing may be the final one, or it may be an intermediate one. Intermediate casing is smaller than surface casing because it must be run inside the surface string and to the bottom of the intermediate hole. In general, it is run and cemented in much the same way as surface casing.

**Final Depth and Well Evaluation**—Using a still smaller bit that fits inside the intermediate casing, the next part of the hole is drilled. Often, the next part of the hole is the final part of the hole unless more than one intermediate string is required. After cementing the intermediate casing, drilling resumes by tripping the new bit and drill stem back in the hole. The intermediate casing shoe is drilled out, and drilling the new hole resumes.

While drilling and once reaching the total depth (TD) of the well, the operator collects information to determine if hydrocarbons have been encountered. To help the operator decide whether to abandon the well or to set a final, or production, string of casing, several techniques can be used. A thorough examination of the cuttings made indicates whether the formation contains sufficient hydrocarbons. A geologist catches cuttings at the shale shaker and analyzes them in a portable laboratory at the well site. He often works closely with a mud logger logger – a technician who monitors and records information brought to the surface by the drilling mud as the hole penetrates formations of interest.

Well logging is another valuable method of analyzing downhole formations. Using a mobile laboratory, well loggers lower sensitive tools to the bottom of the well on wireline and then pull them back up the hole. As they pass back up the hole, the tools measure and record certain properties of the formations and the fluids (oil, gas, and water) that may reside in the formations. Logging tools can also be run as part of the drill string to measure hole conditions and formation properties as the well is being drilled. This is called “measurement while drilling” or MWD.

If logging results indicate commercial quantities, a drill stem test (DST) may be run. Tools are positioned on the drill pipe to isolate the zone to be flow tested. Downhole formation pressure and fluids enter the tool and activate a recorder. Test may be designed to allow formation fluids to flow to the surface during the test or just to allow a certain volume to enter into the wellbore. In either case, provisions must be made at the surface to separate formation fluids from the mud, and to store and dispose of formation liquids. Natural gas produced during drill stem test is vented or flared. A properly designed and run DST can give excellent indication of the types and volumes of fluid the zone is capable of producing.

In addition to well logging and drill stem testing, formation core samples can be taken from the hole and examined in a laboratory.

**Setting Production Casing**—After the drilling contractor has drilled the hole to final depth and the operating company has evaluated the formations, the company decides whether to set production casing or plug and abandon the well. If the well is judged to be a dry hole --that is, not capable of producing oil or gas in commercial quantities -- the well will be plugged and abandoned.

Several cement plugs will be put in the well to seal it permanently. Cement plugs will be designed and placed to protect the zones of usable water from pollution and to prevent escape of oil, gas, or other fluids to the surface or other zones. Plugging and abandoning a well is considerably less expensive than completing it.

On the other hand, if evaluation reveals that commercial amounts of hydrocarbons exist, the company may decide to set casing and complete the well. The services of a casing crew and cementing company will once more be arranged for; and the production casing will be run and cemented in the well.

The drilling contractor nears the end of his job when the hole has been drilled to total depth and production casing has been set and cemented. In some cases, the rig and crew remain on the location to “complete” the well, or make it ready for production. In other cases, the drilling contractor moves his rig, and the operator brings in a smaller, less expensive completion rig and crew to finish up the job.

**Well Completion**—Completion equipment and methods employed are quite varied. The perforated completion is by far the most popular method of completing a well. Perforating is the process of piercing the casing wall, cement, and rock to provide openings through which formation fluids may enter the wellbore. Perforating is accomplished by placing guns holding special explosive charges opposite the zone to be produced. The charges are shaped so that an intense, directional explosion is formed. The well must have a good cement job and well-designed and well-executed perforation methods to get effective formation flow.

Explosives used in perforating guns are very stable. Accidents are rare as long as the people involved use proper procedures. Perforating guns may be run in the well on tubing or by wireline. Firing is accomplished by applying electric current, pressure, or mechanical force to a firing head located on the perforating gun.

In some areas, formations are competent enough that production casing is not used. The drilled hole is left uncased. Many wells in Tennessee and Kentucky are constructed with only surface casing and open hole below.

The final string of pipe usually run in a producing well is the tubing. Tubing is a string of relatively small diameter pipe through which the hydrocarbons are produced. Tubing sizes vary from less than 2 inches in diameter up to 4½ inches for large volume producers. In a flowing well, its smaller diameter produces more efficient flow than casing. Also, since it is not cemented in the hole, tubing may be removed when it becomes plugged or damaged. Tubing, when used with a packer, keeps well fluids and formation pressures away from the casing. Well fluids and high pressures can damage casing, necessitating costly repairs.

The packer consists of a pipe like device through which well fluids can flow. Rubber sealing elements form a fluid tight seal around the inside of the casing. Gripping elements, called slips, hold the packer in place. Because the packer seals off the space between the tubing and the casing, produced fluids are forced into and up the tubing.

Another device often installed in the tubing string near the surface is a “subsurface safety valve.” The valve remains opened, as long a flow is normal. When the valve senses a loss in pressure or significantly increased flow (such as would occur with a flowline break), the valve closes automatically. Subsurface safety valves can prevent uncontrolled well flow in the event of massive surface equipment failure.

Finally, a tubing head is installed at the top of the well to support the tubing. Valves, gauges, and flow control devices are installed on top of the tubing head. Together, they make up what is commonly called a Christmas tree.

When reservoir pressures are not sufficient for the well to flow on its own, operators employ artificial lift methods. The most common by far is rod pumping. A plunger pump is installed deep in the well and connected by rods to a pumping unit on the surface. The pump jack moves the rods up and down to work the downhole pump. Pump jacks are often driven with electric motors or natural gas engines. The gas lift method works by injecting high-pressure gas into the fluid column of a swell to lighten and raise the fluid by expansion of the gas. Instead of pump jacks, there will be a source of high-pressure gas in the field, usually from a gas compressor. The hydraulic pumping method uses a fluid to drive a downhole motor, which in turns drives a pump that pumps the oil to the surface. Surface equipment for hydraulic pumping includes a high-pressure pump and vessels to separate the hydraulic fluid from produced fluid. Yet another type of artificial lift is electric submersible pumping, usually only used on very high-volume wells. An electric motor attached to a pump is installed downhole. Electric current is supplied to the motor through special heavy-duty armored cable. Surface facilities may just be a small transformer/control box.

The well may be stimulated to enhance flow. Stimulation may be performed before or after the completion equipment is installed. Two common types of stimulation are formation acidization and hydraulic fracturing. Stimulation treatments can improve flow to the point where commercial production is achieved in an otherwise uneconomical well.

Formation acidizing is treating the hydrocarbon-bearing rock with large volumes of acid. The most common types of acid used are hydrochloric (HCl) and hydrofluoric (HF). Oilfield acids contain additives to prevent of delay corrosion of the well’s tubulars, inhibit sludging and emulsion reactions with oil in the formation, and make the acid easier to pump. The aim in acidizing is to enlarge the pore spaces and passages by dissolving rock, thus enlarging existing flow channels and opening new ones to the wellbore.

Acid is brought to the well location in tanker trucks and pumped using one or more truck-mounted pumps. Spent acid that is flowed back from the well is often kept separate from field production. The spent acid may be put into temporary tanks until it is trucked off to disposal.

In hydraulic fracturing, fluid is pumped into the formation at high enough pressures and rates to split the rock. Proppants are pumped with the fluid to hold the crack open once pumping stops. Sand and sintered bauxite beads are two common propping agents. Fracturing fluid must not only break down the formation, but also extend and transport the proppant into the fracture. The industry has developed a multitude of complex fluid and proppant systems to achieve the best results in the many varied types of reservoirs.

Many truck-mounted pumps and temporary storage tanks are needed on location to fracture-treat wells. Larger well locations may be needed if hydraulic fracturing is part of a completion procedure.

**Field Development**—If the wildcat well produces oil or gas in commercial quantities, one or more additional wells are normally drilled to confirm the initial finding and further test and define the extent of the oil or gas reserves. Location of the confirmation wells is dependent upon analysis of discovery well data and any existing seismic surveys. Confirmation progresses by drilling one well after another, each dependent on the results of the previous wells.

With more information in hand, facilities can be designed to handle production from the field. Next, development wells are drilled as needed to efficiently drain the reservoir. The procedures for drilling development wells are about the same as for wildcats, except that there may be a variation in the amount and type of subsurface sampling, testing, and evaluation. More detailed seismic work may be performed to aid in the location of development wells.

A state Oil & Gas Commission usually establishes the field well spacing pattern. Typical well spacing may be one well every 640, 320, 160, 80, or 40 acres. Completely filled spacing patterns would translate to 1, 2, 4, 8, or 16 wells per square mile, respectively. In general, oil well spacing is denser for oil wells than for gas wells, and shallow well spacing is denser than for deeper wells.

Access roads to development wells are usually better planned and constructed than those for wildcat wells because these wells are expected to have longer lives. Typically a lease area will have one main route, with side roads to each well or multi-well pad location. Change from temporary to permanent roads does not take place until a well has been established as being capable of production. The amount of roadway required per square mile of field is 4 miles, based upon a spacing pattern of 40 acres and a separate pad for each well.

Directional drilling is sometimes used to concentrate the surface locations of two or more wells in one area. This technique minimizes the amount of surface area (roads and well pads) needed to develop a field. Multiple well pads may be used when developing a field inside the limits of a city or in environmentally sensitive areas.

Other surface equipment and support facilities are brought in or constructed during field development. For example, a battery of storage tanks or a pipeline may be required to handle produced oil or gas. Separation and treatment facilities are required to separate gas and water from oil. Storage tanks are required to hold brines produced during oil extraction, and a proper disposal capability, most typically reinjection, must be developed. Natural gas must be properly disposed of (usually flared) or treated to remove impurities if it is to used or sold.

**Well Servicing and Workover Operations**—Sometimes it is necessary to repair downhole mechanical problems. Workover rigs are often used to repair downhole equipment or assist in large stimulation jobs. The most common well servicing operation is related to artificial lift installation, tubing string repairs, and work on other downhole completion equipment that may be malfunctioning. More involved workover operations might include cleanout of sand, scale, or paraffin deposits that accumulate in the well, casing repair, cementing, perforating new or existing zones of production, or even some limited drilling operations.

Workover rigs are scaled-down drilling rigs. They are usually equipped to stand the pipe in the derrick, rotate pipe while it is in the hole, and circulate workover fluids down and back up the well. Workover rigs are usually self-contained on a truck. They are highly mobile and can be rigged up and rigged down quickly. A well servicing jog to replace a rod pump may last only 1 or 2 days. A major workover operation to change or “recomplete” to another productive zone may last more than a month.

## PLUGGING/ABANDONMENT/RECLAMATION

Workover rigs are also used to plug and abandon wells once they are depleted. Plugging operations consist of removing the tubing, packer, and other completion equipment; pumping cement across producing zones; and placing cement plugs at various depths to protect freshwater zones. Finally, a cement plug is set at the surface to cap the well, and wellhead equipment is cut off. A permanent abandonment marker is often placed to identify the well’s location.

The surface owner and regulatory agencies often dictate surface reclamation. Reclamation can range from just removing equipment to reclaiming the area to conditions that existed before drilling the well.

Full-scale reclamation can include the following:

- Removal of structures, equipment, and debris used or generated during operations;
- Removal or remediation of contaminated soils;
- Recontouring of disturbed areas to near original grade;
- Spreading and preparation of topsoil;
- Planting of native vegetation, usually grasses, but sometimes also tree saplings;
- Erosion protection measures such as mulching; and
- Monitoring of revegetation and erosion control efforts.

Reclamation may last a few days or a few years, depending on the degree of contamination on the site and the ability of native species to grow.

# APPENDIX I: USGS OPEN-FILE REPORT 2006-1048

USGS
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# An Allocation of Undiscovered Oil and Gas Resources to Big South Fork National Recreation Area and Obed Wild and Scenic River, Kentucky and Tennessee

By Christopher J. Schenk, Timothy R. Klett, Ronald R. Charpentier, Troy A. Cook, and Richard M. Pollastro

Open-File Report 2006-1048

**U.S. Department of the Interior**
**U.S. Geological Survey**

**U.S. Department of the Interior**
P. Lynn Scarlett, Acting Secretary

**U.S. Geological Survey**
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*Suggested citation:*
Schenk, C.J, Klett, T.R., Charpentier, R.R., Cook, T.A., Pollastro, R.M., 2006, An Allocation of Undiscovered Oil and Gas Resources to Big South Fork National Recreation Area and Obed Wild and Scenic River, Kentucky and Tennessee: U.S. Geological Survey Open File Report 2006-1048, 7 p.

# Contents



# Figures



# Tables

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By Christopher J. Schenk, Timothy R. Klett, Ronald R. Charpentier, Troy A. Cook, and Richard M. Pollastro

## Abstract

The U.S. Geological Survey (USGS) estimated volumes of undiscovered oil and gas resources that may underlie Big South Fork National Recreation Area and Obed Wild and Scenic River in Kentucky and Tennessee. Applying the results of existing assessments of undiscovered resources from three assessment units in the Appalachian Basin Province and three plays in the Cincinnati Arch Province that include these land parcels, the USGS allocated approximately (1) 16 billion cubic feet of gas, 15 thousand barrels of oil, and 232 thousand barrels of natural gas liquids to Big South Fork National Recreation Area; and (2) 0.5 billion cubic feet of gas, 0.6 thousand barrels of oil, and 10 thousand barrels of natural gas liquids to Obed Wild and Scenic River. These estimated volumes of undiscovered resources represent potential volumes in new undiscovered fields, but do not include potential additions to reserves within existing fields.

## Introduction

The Central Energy Team of the U.S. Geological Survey (USGS) was requested by the National Park Service to estimate volumes of undiscovered oil and gas resources that may underlie Big South Fork National Recreation Area (NRA) in Kentucky and Tennessee and Obed Wild and Scenic River (WSR) in Tennessee (fig. 1). Big South Fork NRA is almost entirely within the USGS Appalachian Basin Province, but a small parcel lies within the USGS Cincinnati Arch Province. Obed WSR is entirely within the USGS Appalachian Basin Province. The undiscovered oil and gas resources of the Appalachian Basin Province were assessed most recently by the USGS in 2002 (Milici and others, 2003), and the undiscovered oil and gas resources of the Cincinnati Arch Province were assessed most recently in 1995 (Gautier and others, 1996). These quantitative assessments form the basis for the allocation of resources that may underlie Big South Fork NRA and Obed WSR in the present study.

The USGS defined twenty-six geologic assessment units (AU) within the Appalachian Basin Province. Twenty-two of these were assessed for undiscovered oil and gas resources (Milici and others, 2003), including three AUs that are in the areas of Big South Fork NRA and Obed WSR (table 1). Three plays from the Cincinnati Arch Province assessment (Gautier and others, 1996) included a part of Big South Fork NRA (table 1). For the purpose of our study, we did not reassess the areas of Big South Fork and Obed, but we applied the results of the earlier assessments to allocate undiscovered oil and gas resources for these six AUs or plays. This report summarizes the methodology and results of the allocation process.

## Methodology Used for Resource Allocation

For the six AUs or plays that encompass parts of Big South Fork NRA and Obed WSR, we made the general assumption that the undiscovered resources that had been estimated previously for each of these were evenly distributed across the entire AU or play. This was considered to be the only feasible approach to the resource allocation process. Therefore, we allocated the undiscovered resources to either Big South Fork NRA or Obed WSR according to the percentage of the total land area of each

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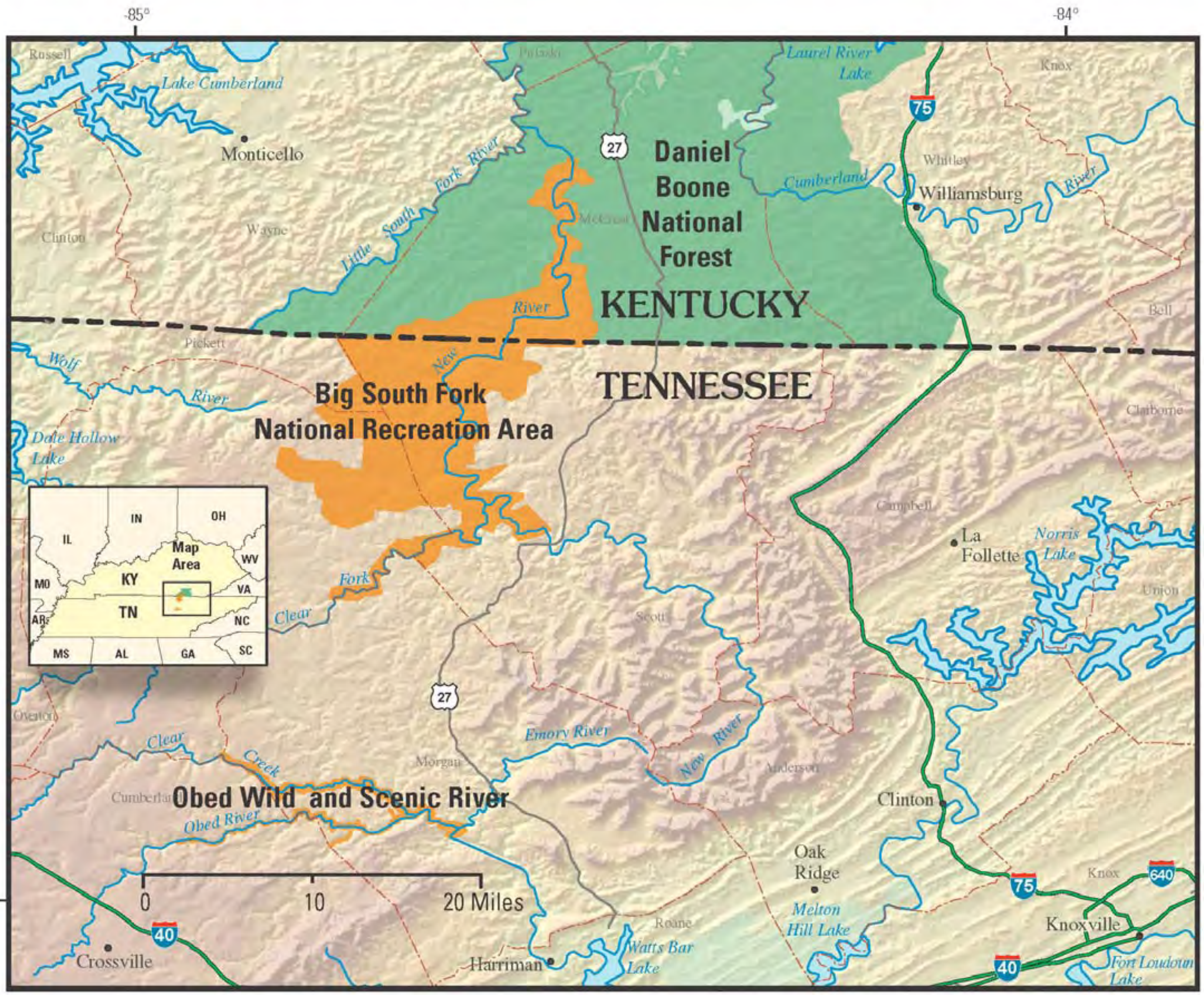



**Figure 1.** Map showing locations of Big South Fork National Recreation Area and Obed Wild and Scenic River in Kentucky and Tennessee.

**Table 1.** Acreages for those parts of assessment units (AU) and plays that lie within the Big South Fork National Recreation Area (NRA) and the Obed Wild and Scenic River (WSR), Kentucky and Tennessee.

[AU names and code numbers from Milici and others (2003); those for plays from Gautier and others (1996)]

| Name of AU or play (Code no.) | Total AU or play acreage | NRA | | WSR | |
|---|---|---|---|---|---|
| | | Acreage within AU or play | Percent of AU or play | Acreage within AU or play | Percent of AU or play |
| Appalachian Basin Province Assessment Units | | | | | |
| Rome Trough (50670101) | 39,594,309 | 124,264 | 0.314 | — | — |
| Cambrian Limestone (50670403) | 22,702,637 | 124,264 | 0.547 | 5,324 | 0.023 |
| Northwest Ohio Shale (50670462) | 29,337,139 | 124,264 | 0.423 | 5,324 | 0.018 |
| Cincinnati Arch Province Plays | | | | | |
| Cambrian and Lower Ordovician Carbonate (6601) | 41,585,845 | 3,720 | 0.0089 | — | — |
| Middle and Upper Ordovician Carbonate (6602) | 39,457,623 | 3,720 | 0.0094 | — | — |
| Devonian Black Gas Shale (6604) | 8,515,786 | 3,720 | 0.044 | — | — |

AU or play that lay within one or another of these tracts (table 1). For example, if Big South Fork NRA represented one percent of the land area of a given AU, we allocated one percent of the mean undiscovered resource to Big South Fork NRA from the USGS assessment of that AU; this procedure was followed for each AU or play. We then aggregated the allocations into a total volume of undiscovered resources for Big South Fork NRA and Obed WSR. The allocated potential resources, however, are only in terms of undiscovered fields. We did not estimate either the number of undiscovered fields or the number of wells that may be necessary to recover these potential, undiscovered resources.

## Results

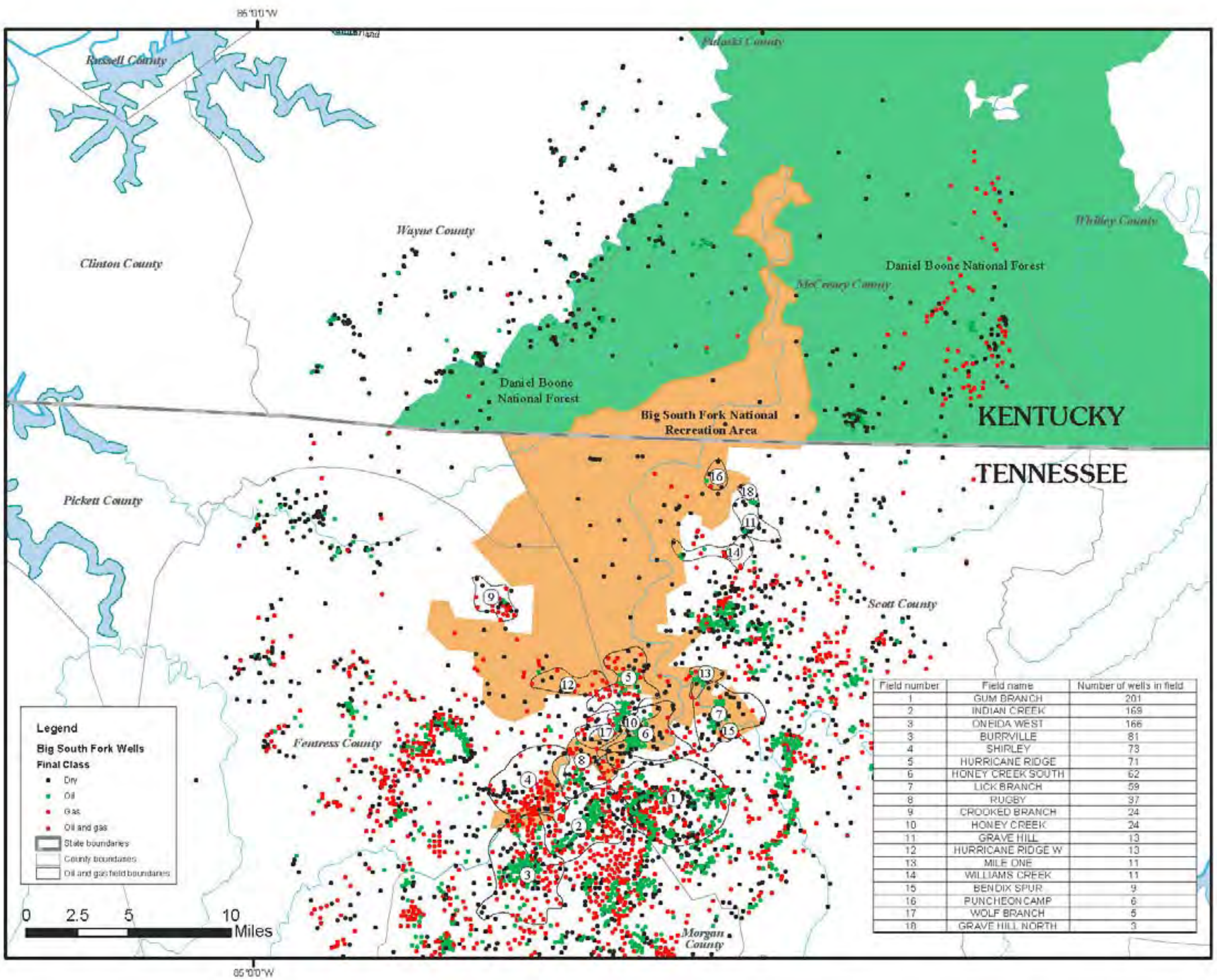
As discussed above, the allocation procedure provided estimates of the total volumes of undiscovered oil and gas resource that may underlie Big South Fork NRA and Obed WSR (table 2). The resulting estimates are: (1) 16 billion cubic feet of gas (BCFG), 15 thousand barrels of oil (MBO), and 232 thousand barrels of natural gas liquids (MBNGL) for the Big South Fork NRA; and (2) 0.5 BCFG, 0.6 MBO, and about 10 MBNGL for the Obed WSR.

Several oil and gas fields exist partly or wholly within the boundary of Big South Fork NRA (fig. 2) and within the boundary of Obed WSR (fig. 3). Field boundaries as shown in figures 1 and 2 are not state-defined boundaries, but are areas we outlined within which oil and gas wells were assigned to a specific field. Undiscovered resources allocated to Big South Fork and Obed would, by definition, be located outside existing fields.

**Table 2.** Allocations of undiscovered oil and gas resources for Big South Fork National Recreation Area (NRA) and Obed Wild and Scenic River (WSR), Kentucky and Tennessee.

[Assessment Unit (AU) names and code numbers from Milici and others (2003); those for plays from Gautier and others (1996). Resource volumes are stated as mean values. Abbreviations: MBO, thousand barrels of oil; BCF, billion cubic feet of gas; MBNGL, thousand barrels of natural gas liquids]

| Name of AU or play (Code no.) | NRA | | | WSR | | |
|---|---|---|---|---|---|---|
| | Oil (MMBO) | Gas (BCF) | Liquids (MBNGL) | Oil (MMBO) | Gas (BCF) | Liquids (MBNGL) |
| Appalachian Basin Province Assessment Units | | | | | | |
| Rome Trough (50670101) | — | 1.9 | — | — | — | — |
| Cambrian Limestone (50670403) | 13.4 | 0.7 | 7.6 | 0.6 | — | 0.3 |
| Northwest Ohio Shale (50670462) | — | 11.2 | 224.5 | — | 0.5 | 9.6 |
| Cincinnati Arch Province Plays | | | | | | |
| Cambrian and Lower Ordovician Carbonate (6601) | 0.7 | 0.7 | — | — | — | — |
| Middle and Upper Ordovician Carbonate (6602) | 0.8 | 0.8 | — | — | — | — |
| Devonian Black Gas Shale (6604) | — | 0.6 | — | — | — | — |




| Field number | Field name | Number of wells in field |
|---|---|---|
| 1 | GUM BRANCH | 201 |
| 2 | INDIAN CREEK | 169 |
| 3 | ONEIDA WEST | 166 |
| 3 | BURRVILLE | 81 |
| 4 | SHIRLEY | 73 |
| 5 | HURRICANE RIDGE | 71 |
| 6 | HONEY CREEK SOUTH | 62 |
| 7 | LICK BRANCH | 59 |
| 8 | RUGBY | 37 |
| 9 | CROOKED BRANCH | 24 |
| 10 | HONEY CREEK | 24 |
| 11 | GRAVE HILL | 13 |
| 12 | HURRICANE RIDGE W | 13 |
| 13 | MILE ONE | 11 |
| 14 | WILLIAMS CREEK | 11 |
| 15 | BENDIX SPUR | 9 |
| 16 | PUNCHEON CAMP | 6 |
| 17 | WOLF BRANCH | 5 |
| 18 | GRAVE HILL NORTH | 3 |

**Figure 2.** Map showing oil and gas wells and selected oil and gas fields in and around Big South Fork National Recreation Area, Kentucky and Tennessee.

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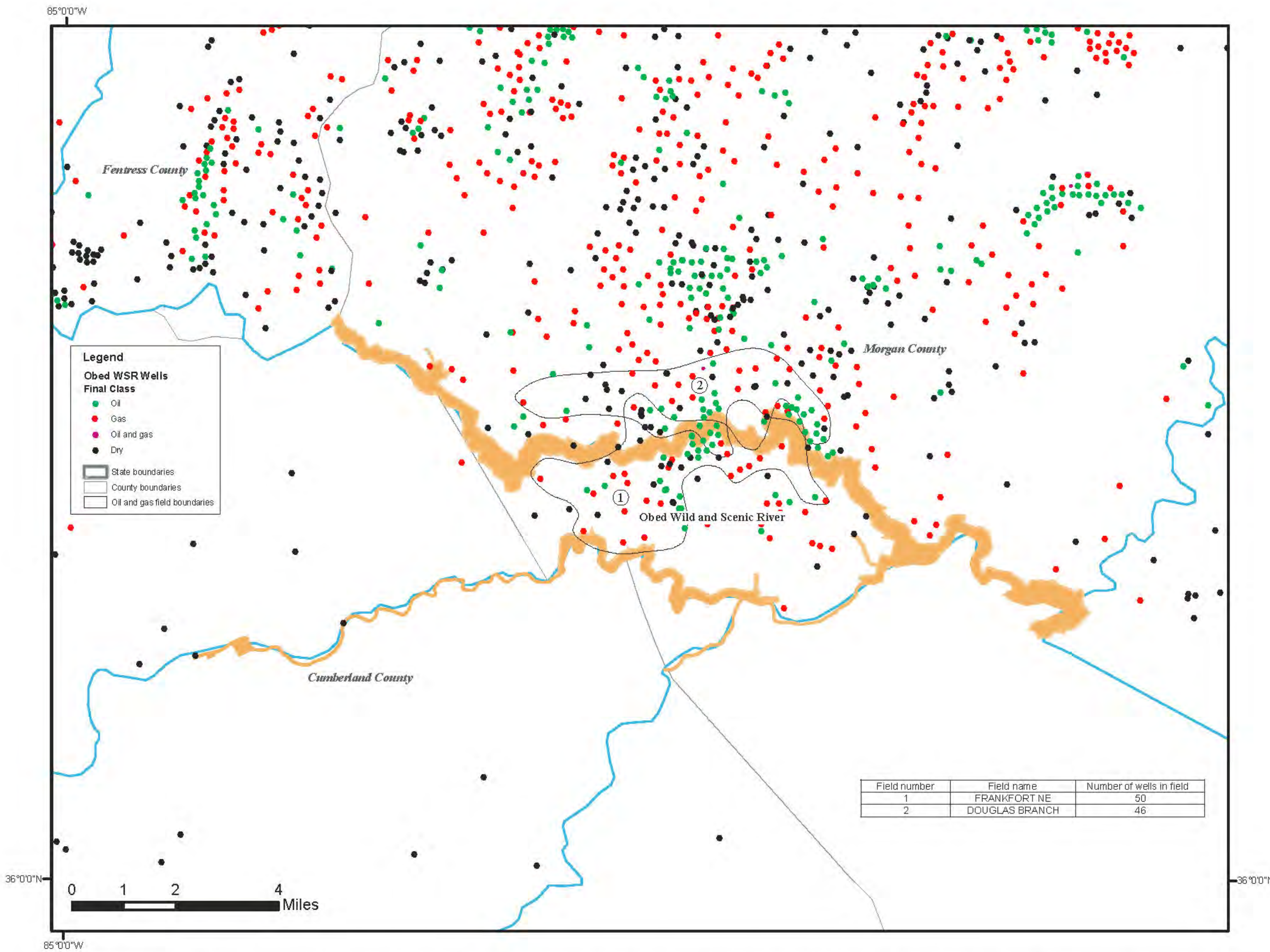


| Field number | Field name | Number of wells in field |
|---|---|---|
| 1 | FRANKFORT NE | 50 |
| 2 | DOUGLAS BRANCH | 46 |

**Figure 3.** Map showing oil and gas wells and selected oil and gas fields in and around Obed Wild and Scenic River, Tennessee

## References


Gautier, D.L., Dolton. G.L., Takahashi, K.I., and Varnes, K.L., eds., 1996, 1995 National assessment of United States oil and gas resources—results, methodology, and supporting data: U.S. Geological Survey Digital Data Series DDS-30, Release 2, one CD-ROM.

Milici, R.C., Ryder, R.T., Swezey, C.S., Charpentier, R.R., Cook, T.A., Crovelli, R.A., Klett, T.R., Pollastro, R.M., and Schenk, C.J., 2003, Assessment of undiscovered oil and gas resources of the Appalachian Basin Province, 2002: U.S. Geological Survey Fact Sheet FS-009-03.

# APPENDIX J: NATIONAL PARK SERVICE RESPONSIBILITIES - OIL AND HAZARDOUS MATERIALS EMERGENCY RESPONSE

## A. INITIAL PARK STAFF ACTIONS FOLLOWING DISCOVERY OF A RELEASE

1. First On-Scene – Always Operate From a Position of Safety. Approach spill site upwind and upgradient (at least 90 degrees crosswind side). Do not walk or drive through any spilled material, especially vapor clouds. (Preserve area for evidence collection and preservation).
2. Secure the area to protect human health and safety. Evacuate the area of all non-essential personnel and deny entry to others.
3. Eliminate ignition sources if suspected spilled material may be flammable or combustible (secure power, ban smoking, do not use road flares, do not mike radios, do not operate motor vehicles or internal combustion engines, use only non-sparking tools/equipment).
4. At a safe upwind distance utilizing binoculars determine:
    a. spill location,
    b. spill source/cause (fixed facility, pipeline, rail, motor vehicle, vessel, aircraft, natural disaster, operator error),
    c. material spilled, amount spilled,
    d. responsible party/shipper/carrier (company address, UN placard numbers, DOT hazard class, container shape, shipping papers, MSDS),
    e. spill site information (fire, injuries/casualties, adjacent navigable waterways, weather, environmentally sensitive areas), and
    f. situation evaluation (disaster, imminent danger, low risk). Explain the evaluation.
5. Perform rescue of injured personnel only if the spill has been stabilized and there is minimal health and safety risk to response personnel.
6. Initiate downwind evacuation (Utilize DOT Emergency Response Guidebook (ERG)) at a minimum distance of 1000 feet.
7. Establish spill response zones and command post (upwind and upgradient, install barriers and/or flagging tape to delineate red, yellow, green zones).
8. Conduct an initial site assessment to identify park resources potentially as risk from the release (surface water, wetlands, cultural resources, etc.), and quantity of released substance.
9. Obtain 5 liter sample of released substance (note: collection of samples must meet preservation and storage requirements) and initiate chain of custody documentation.
10. Oversee operator containment actions and maintain security.
11. Park staff prepares a detailed Case Incident Report on the spill event.

## B. PARK NOTIFICATION DUTIES

1. Report the incident as a possible hazmat incident to dispatch, 911, or patrol ranger. Report if any persons are involved or injured. Request assistance (Is hazwopper trained staff available? Do they have proper PPE? Is a rescue necessary?)

   **NOTE**: All hazardous materials incidents MUST be reported to Shenandoah Dispatch Center @ 540-999-3422. (Report exact location in latitude/longitude, mile marker or by description of surroundings).

2. Notify the operator of the release and immediate need to control the source and contain the release, and obtain information of the released substance. Park Superintendent advises operator that the operation is immediately “suspended” pursuant to NPS regulations at 36 CFR §9.51(c)(2)
3. Contact National Response Center to get clean-up and other assistance, and to advise them of release. Note: it is the operator’s responsibility to notify the National Response Center to obtain a case number for the incident.
4. Spill Coordinator would notify the following NPS offices:
   a. Regional Hazardous Materials Coordinator,
   b. Environmental Quality Division,
   c. Geologic Resources Division,
   d. Regional Minerals Coordinator, and
   e. Water Resources Division if release threatens water resources.
5. Coordinate a conference call with NPS offices noted above and park staff to define appropriate course of action relative to spill containment, public health and safety, site assessment, damage assessment, and operator responsiveness and capability.
6. Coordinate with pertinent state regulatory agencies and state and federal trustees.

## C. COORDINATION OF RESPONSE, CLEAN-UP AND DAMAGE ASSESSMENT

1. All involved NPS staff must track time and all other expenditures associated with the spill event.
2. Park Superintendent prepares formal suspension notice for Regional Director’s signature in accordance with NPS regulations at 36 CFR §9.51(c)(2).
3. Park staff coordinates with designated On Scene Coordinator (EPA, Coast Guard, or NPS staff expert if EPA or Coast Guard does not dispatch a coordinator) and state regulatory agencies to oversee operator spill response and initial clean-up actions.
4. Park staff coordinates with On Scene Coordinator (OSC) and state and federal trustee agencies in the conduct of resource damage assessment (Note: operator may contract with approved consulting firm/laboratory to conduct assessment work).
5. All involved NPS offices evaluate site assessment results and reach consensus on additional remediation actions and reclamation goals, and communicate recommendations to park Superintendent. (Note: NPS regulations at 36 CFR §9.39(a)(1)(i) and §9.39(a)(2)(iii) require operators to remove or neutralize any contaminating substance).
6. Park staff coordinates with OSC and state and federal trustees in monitoring remediation and reclamation actions.

7. Park Superintendent and NPS technical working group evaluates final remediation/reclamation success and determines if further legal action against the operator is required. (Note: operators are liable for any damages to federally-owned or controlled lands, waters or resources pursuant to 36 CFR §9.51(a) and 16 U.S. C. § 19jj.

# APPENDIX K: WELL SITE PLUGGING AND RECLAMATION ACTIVITIES

## SPECIFICATIONS

FOR

## PLUGGING WELLS IN THE BIG SOUTH FORK NATIONAL RIVER AND RECREATION AREA

### Section 1.0 – Introduction

The following specifications are for oil and gas well plugging and surface reclamation services at 45 well sites in the Big South Fork National River and Recreation Area.

Summary of Work

The majority of the work to be performed under this contract consists of the following:

- The mobilization of the contractor's employees, equipment and materials
- Site and access road preparation, including clearing and grubbing, minor grading and erosion and sediment control
- Plugging abandoned oil and gas wells
- The revegetation of all disturbed areas and blocking access on roads that will be restored to natural conditions.

Attachment A is a summary table of road access conditions including length, presence of steep slope, and overgrowth.

Attachment B includes copies of available well records from the State of Tennessee.

Attachment C provides sample wellbore schematics for plugging.

### Section 2.0 – General Specifications

2.1 – Mobilization. The work in this section consists of furnishing all plant, equipment, labor, materials and supervision, and performing all operations in connection with mobilization of the contractor's forces and equipment necessary for performing the work required under this contract.

Mobilization shall include the purchase of contract bonds; transportation of personnel, equipment, and operating supplies to the site; establishment of temporary offices and sanitation facilities, and other necessary facilities at the site; and other preparatory work at the site. The specification covers mobilization for work required by the contract at the time of award. No adjustment of the contract price shall be made for additional mobilization cost incurred by the contractor unless they are incurred as the result of a written change order issued by the Program Manager of the Land Reclamation Section.

Demobilization is also included under this pay item.

Measurement and payment will be one (1) lump sum of which will include mobilization.

Payment will be made lump sum for completion of the work in this section.

2.2 – Delivery Time. All work specified in this contract must be completed within 365 days after your receipt of order.

Once work begins, the contractor shall use the necessary labor, equipment and materials to actively pursue the work.

Repeatedly moving on and off the job and arriving at noon is not considered actively pursuing the work. Therefore, an unsatisfactory report will be filed with the contracting office for delaying the work.

2.3 – Operator Qualifications. All equipment operators shall be competent and experienced with the type of equipment for which they are assigned.

2.4 – Increase or Decrease in Quantities. All quantities set forth in these specifications and on the bid sheet are estimates. The NPS reserves the right to increase or decrease the actual quantities as site conditions warrant. The unit price bid shall remain unchanged. Any increase in contract quantities will be made in writing prior to performing any work.

2.5 – Partial Payments. Partial payments will be made based on the amount of work accomplished at the time of the payment request. Payment request shall be accompanied by supporting measurement and calculation documents. Payment request shall be mutually developed by the contractor and project officer. Any payment request without the concurrence of these two will not be processed. Final payment shall be calculated using the total number of units utilized and measured in the project at the unit price bid for each item.

2.6 – Care of Public and Private Property. The contractor shall take all necessary precautions to prevent damage to all overhead, underground, and above ground structures and to protect and preserve property within or adjacent to the project and shall be responsible for all damage thereto. The contractor shall exercise special care in the execution of the work to avoid interference or damage to all operating facilities or structures. The contractor shall be responsible for any damage or injury to public or private property and shall otherwise restore or replace such damage or injury to property as may be deemed necessary by the engineer.

The contractor shall cooperate with utilities during any relocation work adjustment removal and reconstruction of any such utility or facility within the work areas.

2.7 – Preparation of Erosion Control Measures. Temporary Project Water Pollution Control of the Tennessee Department of Transportation Bureau of Highways Standard Specifications for Road and

Bridge Construction, March 1, 1981 Edition, shall apply except as modified herein. Special care shall be taken during all phases of construction to prevent pollution of streams with harmful or polluting materials such as but not limited to fuels, oils, bitumen, and calcium chloride. Payment will be a subsidiary of Section 201, Clearing and Grubbing.

2.8 – Working Hours. All work on this project will be restricted to daylight hours. Monday through Friday unless specifically approved in writing by the project officer.

2.9 – Maintenance During Construction. The contractor shall maintain the work during construction and until the project is accepted. This maintenance shall constitute continuous and effective work prosecuted day by day, with adequate equipment and forces to that end, and that the area is kept in a satisfactory condition at all times. No separate payment will be made for this item.

All cost of maintenance work during construction and before the project is accepted shall be a subsidiary to the lump sum bid price for mobilization.

2.10 – Unacceptable Material and Workmanship. All material not conforming to the requirements of the specifications will be considered as unacceptable. All unacceptable materials and workmanship, whether in place or not, will be rejected and shall be removed immediately from the site of the work unless otherwise directed by the engineer. In case of failure by the contractor to comply promptly with any order by the engineer to remove rejected material and workmanship, the engineer shall have authority to have such rejected work and materials removed by other means and to deduct the expense of such removal from any monies due, or to become due, to the contractor.

2.11 – Final Inspection and Acceptance.

(a) All work (which term includes but is not limited to materials, workmanship, and manufacture and fabrication of components) shall be subject to inspection and test by the NPS at all reasonable times and at all places prior to acceptance. Any such inspection and test is for the sole benefit of the NPS and shall not relieve the Contractor of the responsibility of providing quality control measures to assure that the work strictly complies with the contract requirements. No inspection or test by the NPS shall be construed as constituting or implying acceptance. Inspection or test shall not relieve the Contractor of responsibility for damage to or loss of the material prior to acceptance, nor in any way affect the continuing rights of the NPS after acceptance of the completed work under the terms of paragraph (f) of this clause, except as hereinabove provided.

(b) The Contractor shall, without charge, replace any material or correct any workmanship found by the NPS not to conform to the contract requirements, unless in the public interest the NPS consents to accept such material or workmanship with an appropriate adjustment in contract price. The Contractor shall promptly segregate and remove rejected material from the premises.

(c) If the Contractor does not promptly replace rejected material or correct rejected workmanship, the NPS (1) may, by contract or otherwise, replace such material or correct such workmanship and charge the cost thereof to the Contractor, or (2) may terminate the Contractor's right to proceed in accordance with the clause of this contract entitled "Cancellation."

(d) The Contractor shall furnish promptly, without additional charge, all facilities, labor, and material reasonably needed for performing such inspection and test as may be required by the engineer. All inspection and test by the NPS shall be performed in such manner as not unnecessarily to delay the work.

(e) Should it be considered necessary or advisable by the State at any time before acceptance of the entire work to make an examination of work already completed, by removing or tearing out same, the Contractor shall, on request, promptly furnish all necessary facilities, labor, and material. If such work is found to be defective or nonconforming in any material respect, due to the fault of the Contractor or his subcontractors, he shall defray all the expenses of such examination and of satisfactory reconstruction. If, however, such work is found to meet the requirements of the contract, an equitable adjustment shall be made in the contract price to compensate the Contractor for the additional services involved in such examination and reconstruction and, if completion of the work has been delayed thereby, he shall, in addition, be granted a suitable extension of time.

(f) Unless otherwise provided in this contract, acceptance by the NPS shall be made as promptly as practicable after completion and inspection of all work required by this contract, or that portion of the work that the engineer determines can be accepted separately. Acceptance shall be final and conclusive except as regards latent defects, fraud, or such gross mistakes as may amount to fraud, or as regards the NPS's rights under any warranty or guarantee.

(g) Upon due notice from the Contractor of presumptive completion of the entire project work, the engineer will make an inspection. If all construction provided for and contemplated by the contract is found completed to his satisfaction, a final inspection will be scheduled within five (5) days. The final inspection shall be conducted by the Program Manager of the Land Reclamation Section or his designee, the Division Engineer and the Project Officer. The Contractor shall be present along with his superintendent and all subcontractors, if any, that have worked on the project.

The Contractor shall not remove any equipment from the site until after he receives written notice of final acceptance of the work. Written notice of the final inspection and acceptance will be issued to the Contractor stating final acceptance and the date of release.

If, however, the inspection discloses any work in whole or in part, as being unsatisfactory, the engineer will give the Contractor the necessary instructions for the correction of the deficiencies and the Contractor shall immediately comply with and execute such instructions. Upon completion of the corrective work, another inspection shall be made which shall constitute the final inspection provided all work has been satisfactorily completed.

2.12 – Accidents

The contractor shall provide, at the site and at his own expense, such equipment and medical facilities as are necessary to supply first-aid service to anyone who may be injured in connection with the work.

The contractor must promptly report in writing to the project officer all accidents whatsoever arising out of, or in connection with, the performance of the work, whether on, or adjacent to the site which caused death, personal injury, or property damages, giving full details and statements of witnesses. In addition, if death, serious injuries, or serious damages are caused, the accident shall be reported immediately by telephone or messenger to both the project officer and the contracting officer.

If any claim is made against the contractor or any subcontractor on account of any accident, the contractor shall promptly report the facts in writing to the project officer, giving full details of the claim.

2.13 – Completion Time

The completion time is approximately 365 days which includes no days for bad weather, holidays and weekends. The contractor shall take this time frame for completion into consideration when bidding on this project. An extension shall not be granted unless there are unusual circumstances, such as an act of God. Poor planning, inefficiency, equipment breakdown, or any other factor of which the contractor has control over shall not be justification for time extensions.

2.14 – Safety

The contractor shall conduct his operations in such a manner that all applicable laws and regulations are adhered to during performance of this contract. Personal protective equipment (PPE) including hardhats, safety glasses, gloves, and steel-toed boots shall be use in work areas. Additional PPE shall be used as warranted by working conditions.

2.15 – Barricades, Warning Signs and Other Devices. The contractor shall provide, erect and maintain all necessary barricades, suitable and sufficient lights, danger signals, signs and other traffic control devices, and shall take all necessary precautions for the protection of the work and safety of the public.

No direct payment will be made for work required in this section, but the cost thereof will be considered to be included in bid price for mobilization.

2.16 – Dust Control

The contractor shall take all available precautions to control dust. Dust shall be controlled by sprinkling, by applying fresh water or by other methods as approved. If sprinkling is the selected method for controlling dust the contractor shall water as often as necessary to control dust that is produced as a result of the movement of construction equipment and vehicles. The use of other methods shall be effective in preventing dust formation. Oil will not be used.

2.17 – Superintendence By Contractor

The contractor at all times during performance and until all the work is completed and accepted, shall give his personal superintendence to the work or have on the project a competent superintendent, satisfactory to the NPS and with authority to act for the contractor.

## Section 3.0 – Access Roads and Well Sites: Repair and Maintenance

The contractor shall be responsible for maintaining the access roads in a passable condition during the life of the contract. No other access points will be used unless approved by the engineer.

Passable condition means roadway shall be graded as often as necessary to remove ruts that will trap water or erode. Access roads will be ditched, waterbarred, graded, culverts installed or whatever other measures are necessary to protect the road from erosion and to maintain a relatively smooth surface.

3.1 – Opening Access Roads and Production Pads

This work shall consist of removing vegetation (by trimming, mowing, bush hogging, or like methods) to the minimum amount necessary to gain access for personnel and equipment to perform the work specified during the project. Site preparation shall include the repair, maintenance of access roads, remedial drainage measures, and the production areas. Roadways shall be left in a passable condition for a two-wheel drive vehicle at all times during the project work. Site preparation shall include use of flag persons, traffic lights and barricades to safely control vehicle, foot or horse traffic throughout the construction period and protection and maintenance of utilities.

Access roads shall be cleared not to exceed 12 feet in width. All downed or dead trees can be cut into manageable lengths and placed to the side of the access roads. All live trees that are removed may be scattered in the woods or chipped in place. All stumps that are removed from the ground must be hauled out of the BSFNRRA and disposed of in accordance with local laws.

Production pads must be cleared by a means that minimizes soil disturbance. Standing trees shall be cut off at ground level and either removed from the BSFNRRA or chipped and spread in the adjacent woods. Clearing limits shall not exceed the original footprint established during the drilling. No clearing on any site may exceed one-half acre without written approval.

3.1.1 – Construction Requirements

Vegetative Clearing. All debris, trees, stumps, roots, and other protruding obstructions within the clearing limits, not designated to remain, shall be cleared, grubbed, removed, and disposed of.

Road Repair and Maintenance. No access road shall exceed 12 feet in width. Overhanging limbs will be removed only high enough to allow passage of equipment. Onsite material will be used for fill when possible. If additional fill is required, appropriate material will be determined and approved by the project officer. Existing road drainage ditches will be pulled and utilized. The material pulled from these ditches may be used to fill gullies or to build a crown on the road. Water bars will be constructed on slopes that exceed 10%. Locations of water bars will be flagged by the project officer.

Removal of Abandoned Oil and Gas Field Equipment and Debris. The Contractor shall be responsible for removal of abandoned oil and gas field equipment, piping, fittings, meters, etc. and other debris associated with the wells. The materials become the property of the contractor and must be removed from the park.

3.1.2 – Measurement and Payment

Measurement will be made to the nearest 1/10 acre for all complete and accepted work. Payment shall be made at the contract unit price per acre for complete and accepted work.

3.2 – Ditches, Terraces and Channels

This work shall consist of the layout and construction of diversion ditches, terraces and channels necessary to prevent or minimize erosion, and control water flow and direction on the project sites and access roads.

3.2.1 – Equipment

Equipment size and quantity suited for the size drainage shall be available to perform the work. Large equipment shall not be permitted when cutting small diversion ditches if an excessive area of disturbance is the result of the use of large equipment. Equipment shall be in good serviceable condition with all required safety features operational. An inoperative emergency shutdown switch is an example of an unacceptable safety feature. Frayed or worn sling cable is an example of unacceptable equipment.

3.2.2 – Construction Requirements

The excavation proposed under all areas of this project shall be unclassified. It is anticipated that the majority of material to be removed will consist of a mixture of loose unconsolidated soil and rock, along with organic material and other debris. Some excavation of rock may be required to properly install the items included in these plans and specifications. Blasting will not be permitted on this project.

Before performing the work described in this section, the proposed diversion ditch location shall be cleared and grubbed in accordance with Section 3.1 and/or as approved by the project officer.

No payment will be made under this section; the work is considered a subsidiary of Section 701.0, Road Restoration.

## Section 4.0 – Well Plugging

4.1 – Quality Control-Well Plugging Technicians

The contractor shall provide a Well Plugging Technician for each active plugging rig who is able to satisfactorily perform the duties listed below.

The Technician shall be qualified in all aspects of well plugging and must have a minimum of five (5) years experience. The contractor must submit a summary of the Technician's qualifications and experience along with his bid. Qualifications and experience may include: Type of plugging experience, any training or certifications received, previous jobs summary. A minimum of two references must be provided.

The contract shall not be awarded until the NPS has approved the Well Plugging Technician.

It shall be the responsibility of the Technician to review and become thoroughly familiar with the contract requirements. He/she shall continuously inspect the work in progress to assure that the work is in compliance with contract plans and specifications. The Technician shall be on the project site during working hours.

The Technician shall conduct and observe all plugging phases of work in progress and advise the "on site superintendent" of any work which is not in compliance with specifications. It shall be the responsibility of the contractor to immediately correct any work that is out of compliance.

The Technician shall have a working knowledge of equipment performance and safety regulations.

The Technician shall immediately notify the NPS project officer of any contract work which is not in compliance with contract requirements. A notation of any non-compliance work and the correction of same shall be made in the Daily Project Inspection Report.

The Technician shall maintain a project daily diary, the units of work accomplished and document with measurements or personal witness in the case of lump sum work. Measurements and calculations for unit items of work, that can be measured, will be submitted along with each payment request.

Special Conditions.

a. If at any time during the term of the contract the Technician cannot satisfactorily (at the discretion of the NPS) his duties, the contractor shall immediately replace the Technician with a qualified individual. No plugging work shall be performed during the absence of the Technician.

b. The Technician shall be capable of communicating with the contractor's personnel and the NPS personnel. He must be capable of anticipating problems and suggesting corrective or alternative action that is consistent with contract requirements. The Technician selected shall be on the project for the duration of the project and shall not be replaced without written approval of the NPS.

c. In the event a firm submits an individual for consideration, that same person must meet all the qualifications stated herein. A group of people with experience in certain phases will not be considered a Technician.

4.2 – General Well Plugging Specifications

This work shall consist of plugging vertical wells in accordance with the following specifications, drawings and the rules and regulations of the Tennessee State Oil and Gas Board, additional Federal regulations that may apply, or a combination thereof.

The plugging contractor is required to submit a Plugging and Abandonment Report for each well that is plugged. The Report must be signed by the operator and the State Inspector and must be notarized.

4.3 – Spill Prevention and Control Practices.

4.3. 1 – Prevention. During site preparation, the contractor will note the runoff point or points on the location and construct a small berm or berms capable of containing no less that 5 barrels. For most locations, it is anticipated this can be accomplished using materials available onsite and hand shovels.

All operations shall be carried out through an approved (by the project officer) control head, in good working order, which is attached to the surface casing at all times. The plugging rig shall include personnel trained in well control.

Saltwater, oils and sludge generated during the plugging operations may be temporarily stored only in properly constructed, liquid tight tanks. No pits, lined or otherwise shall be permitted. Such material must be removed and disposed of (in accordance with local laws) when requested by the project officer or at the time of plugging completion.

The contractor shall take precautions to prevent oil, brine, chemicals and other materials from contacting the ground during well plugging operations. Precautions will include the use of plastic liners beneath the plugging rig, pipe racks, and other equipment as necessary. When necessary to bleed pressure from wellheads, blowdown lines attached to collection tanks shall be used. The well location site will be prepared such that the liners will direct spilled liquids to a collection point for pickup.

Workers will be properly trained to reduce the number of human errors that often cause spills.

Visual inspection during rig-up to assure the satisfactory condition of storage tanks, piping, fittings, and other rig equipment that normally hold contaminating substances such as drilling mud, oil, fuel, lubricating oil, hydraulic fluid, etc.

During operations, workers will be observant for signs of spills or leakage and the need for equipment maintenance.

The contractor will visually inspect rainwater for sheen. If necessary, steps will be taken to prevent contaminated stormwater discharges. Such steps might include placement of absorbent materials at runoff points or vacuuming up of contaminated stormwater.

The following cleanup equipment will be available on the location for immediate use by on-site personnel in response to small spills, and for initial spill containment and cleanup efforts in response to larger spills: absorbent pads and material, a hand-held fire extinguisher, shovels, rake, and an assortment of hand tools.

4.3.2 – Spill Response. Any spills would be promptly contained and picked up.

In the event a spill is encountered, initial response actions will be aimed at controlling the spill, then containing spilled materials. Person(s) onsite will immediately assess the situation and take steps to control the source of the spill (if it can be done safely) by shutting valves, shutting down equipment, or closing in wells as needed.

For small spills, onsite personnel will use equipment on hand to contain the spread of the spill. This would typically involve placing absorbent pads or booms, or by constructing a retaining dike from dirt, boards, synthetic absorbents, hay, straw, etc. Small spills will be picked up immediately with absorbent materials.

For larger spills, will direct actions to immediately isolate and shut off source of the material being spilled (if it can be done safely). The supervisor will assess containment needs and call out contract equipment and services as determined necessary. Onsite personnel will use equipment and materials on hand to slow the spread of oil or contaminants until additional equipment/services can reach the site.

In the rare event that spilled materials escape from the location, the contractor will consult with the park superintendent, or designated representative, and obtain consent prior to mobilizing equipment that may have lingering impacts to natural resources outside the area of operations.

If a tank truck is involved in a spill incident outside the well plugging area or access road, but inside the park, the contractor will respond in the same manner as spills within the approved contract work area.

4.3.3 – Cleanup. Cleanup and removal of spills will be performed using accepted industry practices. Such practices include the pickup of free liquids with vacuum equipment, application of absorbent booms, materials, and pads; removal of contaminated wellpad material, and replacement with clean wellpad material.

All contaminated cleanup materials will be stored in impermeable, weatherproof containers and removed from the site as early as practical. All contaminated materials will be disposed of according to state and federal guidelines.

Should a spill occur or reach beyond the approved work area, the contractor will take actions to restore the disturbed area to the natural conditions and processes that existed before the spill. Restoration of the affected area will be performed in consultation with the superintendent and meet the same standards as Section 5.

4.4 – Downhole Plugging Operations

The following objectives will be applied to each well-plugging operation:

1. Set cement plugs to isolate all formations bearing oil, gas, geothermal resources and other minerals from zones of usable quality water (freshwater).

2. Set cement plugs to isolate all formations bearing usable quality water.

3. Set a cement plug to isolate the surface of intermediate casing from the open hole below the casing shoe.

4. Set a cement plug to seal the well at the surface. The top of surface plug shall be no deeper than 3 feet from ground level.

5. Remove the surface casing below grade and cap the well. The contractor will cut off all casing 18 inches below grade or to solid rock. The wellhead excavation shall not be backfilled until the cement has cured and shows no sign of leaking fluids or gas and the project officer has approved it.

4.4.1 – Plugging Requirements

Well Plugging Design. In order to achieve the above objectives in light of unknown depths of casings, freshwater zones, and hydrocarbon/brine bearing zones, the approach to plugging design is to the fill the entire wellbore with cement from the top of fluid found in the well or 1000 feet, whichever is deeper. If fluid level is below 1000 feet in a well, individual cement plugs may be set to meet state requirements for mineral zone isolation. Attachment C provides sample wellbore schematics for plugging scenarios.

Cement Quality. All cement for plugging shall be approved API oil well cement without volume extenders and shall be mixed in accordance with API standards. Slurry weights shall be reported on the Plugging and Abandonment Report.

Cement Placement. Cement plugs must be placed through tubing or drill pipe at depths greater than 500 feet or all depths below the fluid level in the well. The dump bailer method may be used only to place cement caps above a bridge plug or retainer. For depths above 500 feet, cement may be placed from surface provided that 1) the unplugged wellbore is free of liquids, and 2) there is a solid base such as the top of a previously set cement plug or a bridge plug present.

Plugging Fluid Where Pressure is Encountered. Each of the intervals between plugs must be filled with mud having sufficient density to exert hydrostatic pressure exceeding the greatest formation pressure encountered while drilling. In the absence of known data, a minimum mud weight of 9 pounds per gallon will be required.

Measurement and payment will be each well that is plugged and accepted.

Payment will be at the price per unit bid for each well. Attachment B includes available well records from the State of Tennessee with the exception of any well logs. The NPS cannot guarantee that all information is accurate.

4.4.2 – Equipment/Rigging Removal & Pumping Fluids

In the event that wells contain rigging or if abandoned equipment is present, the contractor shall log all hours spent upon removal and may charge at the unit price bid per hour. All hours must be approved by the Project Officer.

In the event fluid is present in the hole and must be removed (at the discretion of the project officer) the contractor shall log all hours spent pumping, containing and disposing of fluids at the unit price bid per hour. All pumped fluids shall be temporarily stored only in properly constructed, liquid tight tanks. All fluids must be disposed of in accordance with local, state and federal laws and regulations and disposal method must be approved by the Project Officer.

Measurement shall be to the nearest hour. Payment will be made at the unit price bid per hour.

## Section 5.0 – Access Roads and Well Site Reclamation

Site Clean Up. All work areas and/or areas disturbed during the course of the work shall be thoroughly cleaned of all rubbish, debris, construction waste, or other unsightly materials. Sanitary facilities shall be removed and/or backfilled in a manner acceptable to the project officer.

All roads not designated as permanent or designated as trails shall be closed and erosion controls such as broad-based dips implemented to effectively and permanently abandon access roads. Vegetation cut and removed from road to gain access may be pulled back onto the road as a means of preventing unauthorized use.

The removal or remediation of any contamination from past operations is not within the scope of this contract. Should contamination be discovered in quantities or concentrations that would require action, the NPS may elect to keep the access road and/or a portion of the well pad open until such time the contamination is removed or remediated. If the road was scheduled to be restored to natural conditions as part of this contract, and the NPS cannot address the contamination within the timeframe of this contract, the NPS reserves the right to reduce the contract amount by the per acre bid amount for reclamation time the number of acres left unreclaimed. The contractor would be relieved of any further responsibility for maintenance or reclamation of that section of road and well pad.

5.1 – Vegetation Establishment

Work Description. Seeding shall consist of furnishing and placing seed and mulch all in accordance with these specifications, on all newly graded earthen areas.

All disturbed areas must be scarified mechanically to a depth of 3 inches. Seeding and mulching must occur within 48 hours of scarification. If precipitation occurs within those 48 hours, all areas must be re-scarified prior to seeding.

Seeding on this project will be done with a seeder, either hand driven or mechanical, which is capable of disseminating the following seed mixture evenly over the disturbed areas.

The project officer shall be on site during the revegetation process.

5.1.1 – Seed requirements and rates are as follows:

| Seed Material | lbs/acre |
|---|---|
| little bluestem (Andropogon scoparius) | 3 lbs/acre |
| indian grass (Sorghastrum nutans) | 3 lbs/acre |
| big bluestem (Andropogon geradi) | 3 lbs/acre |
| switchgrass (Panicum virgatum) | 1 lb/acre |
| winter/common oats (Avena sativa) | 30 lbs/acre |
| Virginia wild rye (Elymus virginicus) | 10 lbs |
| crimson clover (Trifolium incarnatum) | 15 lbs/acre |
| partridge pea (Chamaecrista fasciculata) | 5 lbs/acre |

Plus 10 lbs/acre total of any or all of the following:

roundhead lespedeza (Lespedeza capitata)

hairy lespedeza (Lespedeza hirta)

intermediate lespedeza (Lespedeza intermedia)

trailing lespedeza (Lespedeza procumbens)

creeping lespedeza (Lespedeza repens)

violet lespedeza (Lespedeza violacea)

Three tons of straw mulch per acre is required and mulch shall be held in place by using a crimper or other compatible method to anchor the mulch into the soil to a depth of two inches.

5.1.2 – Seed and Mulch Materials

Materials used in this construction shall meet the requirements of the following specifications:

5.1.2.1 – Grass Seed.

The seed shall meet the requirements of the Tennessee Department of Agriculture and no "Below Standard" seed will be accepted.

Grass seed furnished under these specifications shall be packed in new bags or bags that are sound and not mended.

The vendor shall notify the Department before shipments are made so that arrangements can be made for inspection and testing of stock.

The vendor shall furnish the Department a certified laboratory report from an accredited commercial seed laboratory or from a State seed laboratory showing the analysis of the seed to be furnished. The report from an accredited commercial seed laboratory shall be signed by a Registered Member of the Society of Commercial Seed Technologists. At the discretion of the Department, samples of the seed may be taken for check against the certified laboratory report. Sampling and testing will be in accordance with the requirements of the Tennessee Department of Agriculture.

The seed mixture shall be uniformly mixed using a mechanical mixer and bagged in 50-pound bags. Group seed shall not be mixed until after each type seed that is used to form the "Group" has been tested and inspected separately and approved for purity and germination by the Department. Seed mixed before tests and inspection are made will not be accepted.

Inoculants for Legumes. Inoculants for treating legume seed shall be standard cultures of nitrogen-fixing bacteria that are adapted to the particular kind of seed to be treated. The inoculants shall be supplied in convenient containers of a size sufficient to treat the amount of seed to be planted. The label on the container shall indicate the specified legume seed to be inoculated and the date period to be used. Twice the amount recommended by the manufacturer shall be used.

5.1.2.2 – Mulch Material.

All straw mulch material shall be air dried and reasonably free from noxious weeds and weed seeds or other materials detrimental to plant growth on the project or on adjacent agricultural lands.

Straw shall be stalks of rye, oats, wheat or other approved grain crops.

The mulch shall be reasonably free from weeds, seeds, and foreign materials and shall contain no Johnson grass or wild onions. Weight tickets shall be furnished to verify the quantity of mulch furnished.

Straw shall be suitable for spreading with standard mulch blower equipment.

All equipment necessary for the satisfactory performance of this work shall be on the project and approved before work will be permitted to begin.

5.1.3 – Care During Construction and Acceptable Stand. All seeded areas shall be properly cared for until acceptance of the work.

Areas which have been previously seeded and mulched in accordance with this section but which have been damaged or failed to successfully establish an acceptable stand of grasses or legumes shall be repaired as directed by the project officer.

The contractor shall notify the project officer at least 48 hours in advance of the time he intends to begin seeding operations and shall not do so until permission has been granted by the project officer. Before starting seeding operations, sloping, shaping and dressing shall have been completed in accordance with these specifications. If the contractor fails to notify the project officer within the specified time, then the seeding operation will not be accepted.

It shall be imperative that the contractor have on site all equipment, materials, labor and any other incidentals necessary for performing the work to satisfactory completion.

The contractor shall proceed, with vigor, the vegetation process once the process is begun.

Seeding. Seed of the specified groups shall be sown as soon as preparation of the seedbed has been completed. It shall be sown uniformly by an approved means. Seeds of legumes shall be inoculated before sowing in accordance with the manufacturer's recommendations and as approved by the project officer.

Mulching. Mulch material shall be spread evenly over the seedbed area using a mulching machine at an approximate rate of three (3) tons per acre immediately following seeding operations.

On extremely rocky finished grades where crimping will not be practical, crimping will not be permitted and a mulch binder shall be required. Also, crimping will not be permitted except on flat slopes (3:1 or flatter).

When crimpers are used to anchor the mulch into the soil, crimpers shall be capable of pushing the mulch into the soil to a depth of two inches.

Measurement and Payment

Measurement shall be one (1) job for all work completed and accepted.

Payment shall be made lump sum for complete and accepted work and shall constitute full and complete payment for all work in this section.

# APPENDIX L: DEPARTMENT OF INTERIOR'S ONSHORE OIL AND GAS ORDER NUMBER 2, SECTION III.G., DRILLING ABANDONMENT

**BUREAU OF LAND MANAGEMENT**
**43 CFR 3160**

**Federal Register / Vol. 53, No. 223**
**Friday, November 18, 1988**
**Effective date: December 19, 1988**

**Onshore Oil and Gas Operations; Federal and Indian Oil and Gas Leases;**
**Onshore oil and Gas Order No. 2, Drilling Operations**



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## Onshore Oil and Gas Order No. 2
## Drilling Operations on Federal and Indian Oil and Gas Leases

## I. Introduction

### A. Authority

This order is established pursuant to the authority granted to the Secretary of the Interior pursuant to various Federal and Indian mineral leasing statutes and the Federal Oil and Gas Royalty Management Act of 1982. This authority has been delegated to the Bureau of Land Management and is implemented by the onshore oil and gas operating regulations contained in 43 CFR Part 3160. Section 3164.1 thereof specially authorizes the Director, Bureau of Land Management, to issue Onshore Oil and Gas Orders when necessary to implement and supplement the operating regulations and provides that all such Orders shall be binding on the lessees and operators of Federal and restricted Indian (except Osage tribe) oil and gas leases that have been, or may hereafter be issued.

Specific authority for the provisions contained in this Order is found at: 3162.3-1 Drilling Applications and Plans; 3162.3-4 Well Abandonment; 3162.4-1 Well Records and Reports; 3162.4-3 Samples, Tests, and Surveys; 3162.5-1 Environmental Obligations; 3162.5-2 Control of Wells; 3162.5-2(a) Drilling Wells; 3162.5-3 Safety Precautions; and Subpart 3163 Noncompliance, Assessments, and Penalties.

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### B. Purpose

This Order details the Bureau's uniform national standards for the minimum levels of performance expected from lessees and operators when conducting drilling operations on Federal and Indian lands (except Osage Tribe) and for abandonment immediately following drilling. The purpose also is to identify the enforcement actions that will result when violations of the minimum standards are found, and when those violations are not abated in a timely manner.

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### C. Scope

This Order is applicable to all onshore Federal and Indian (except Osage Tribe) oil and gas leases.

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### D. General

1. If an operator chooses to use higher rated equipment than that authorized in the Application for Permit to Drill (APD), testing procedures shall apply to the approved working pressures, not the upgraded higher working pressures.

2. Some situations may exist either on a well-by-well or field-wide basis whereby it is commonly accepted practice to vary a particular minimum standard(s) established in this Order. This situation may be resolved by requesting a variance (See section IV of this Order), by the inclusion of a stipulation to the APD, or by the issuance of Notice to Lessees and Operators (NTL) by the appropriate BLM office.

3. When a violation is discovered and if it does not cause or threaten immediate substantial and adverse impact on public health and safety, the environment, production accountability or royalty, it will be reissued as a major violation if not corrected during the abatement period and continued drilling has changed the adverse impact of the violation so that it meets the specific definition of a major violation.

4. This Onshore Order is not intended to circumvent the reporting requirements or compliance aspects that may be stated elsewhere in Existing NTL's, Onshore Orders, etc. A lessee's compliance with the requirements of the regulations in this Part shall not relieve the lessee of the obligation to comply with other applicable laws and regulations in accordance with 43 CFR 3162.5-1(c). Lessee's should give special attention to the automatic assessment provisions in 43 CFR 3163.1(b).

5. This Order is based upon the assumption that operations have been approved in accordance with 43 CFR Part 3160 and Onshore Oil and Gas Order No.1. Failure to obtain approval prior to commencement of drilling or related operations shall subject the operator to immediate assessment under 43 CFR 3163.1(b)(2).

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## II. Definitions.

A. Abnormal Pressure Zone means a zone that has either pressure above or below the normal gradient for an area and/or depth.

B. Bleed Line means the vent line that bypasses the chokes in the choke manifold system; also referred to as Panic Line.

C. Blooie Line means a discharge line used in conjunction with a rotating head. D. Drilling Spool means a connection component with both ends either flanged or hubbed with an internal diameter at least equal to the bore of the casing, and with smaller side outlets for connecting auxiliary lines.

E. Exploratory Well means any well drilled beyond the known producing limits of a pool.

F. Filled-up Line means the line used to fill the hole when the drill pipe is being removed from the well. It is usually connected to a 2-inch collar that is welded into a drilling nipple.

G. Flare Line means a line used to carry gas from the rig to be burned at a safer location. The gas comes from the degasser, gas buster, separator, or when drill stem testing, directly from the drill pipe.

H. Functionally Operated means activating equipment without subjecting it to well-bore pressure.

I. Isolating means using cement to protect, separate, or segregate usable water and mineral resources.

J. Lease means any contact, profit-share agreement, joint venture, or other agreement issued or approved by the United States under a mineral leasing law that authorizes exploration for, extraction of, or removal of oil or gas (See 43 CFR 3160.0-5).

K. Lessee means a person holding record title in a lease issued by the United States (See 43 CFR 3160.0-5).

L. Make-up Water means water that is used in mixing slurry for cement jobs and plugging operations, and is compatible with cement constituents being used.

M. Manual Locking Device means any manually activated device, such as a hand wheel, etc., that is used for the purpose of locking the preventer in the closed position.

N. Mud for Plugging Purposes means a slurry of bentonite of similar flocculent/viscosfer, water, and additive needed to achieve the desired weight and consistency to stabilize the hole.

O. Mudding Up means adding materials and chemicals to water to control the viscosity, weight, and filtrate loss of the circulating system.

P. Operating Rights Owner (or Owner) means a person or entity holding operating rights in a lease issued by the United States. A lessee also may be an operating rights owner if the operating rights in a lease or portion thereof have not been severed from record title.

Q. Operational means capable of functioning as designed and installed without undue force or further modification.

R. Operator means any person or entity , including but not limited to the lessee or operating rights owner, who has stated in writing to the authorized officer his/her responsibility for the operations conducted in the leased lands or a portion thereof.

S. Precharge Pressure means the nitrogen pressure remaining in the accumulator after all the hydraulic fluid has been expelled from beneath the movable barrier.

T. Prompt Correction means immediate correction of violations, with drilling suspended if required in the discretion of the authorized officer.

U. Prospectively Valuable Deposit of Minerals means any deposit of minerals that the authorized officer determines to have characteristics of quantity and quality that warrant its protection.

V. Tagging the Plug means running in the hole with a string of tubing or drill pipe and placing sufficient weight on the plug to insure its integrity. Other methods of tagging the plug may be approved by the authorized officer.

W. Targeted Tee or Turn means a fitting used in pressure piping in which a bull plug or blind flange of the same pressure rating as the rest of the approved system is installed at the end of a tee or cross, opposite the fluid entry arm, to change the direction of flow and to reduce erosion.

X. 2M, 3M, 5M, 10M, and 15M mean the pressure ratings used for equipment with a working pressure rating of the equivalent thousand pounds per square inch (psi) (2M=2,000 psi, 3M=3,000 psi, etc.)

Y. Usable Water means generally those waters containing up to 10,000 ppm of total dissolved solids.

Z. Weep Hole means a small hole that allows pressure to bleed off through the metal plate, used in covering well bores after abandonment operations.

[57 FR 3025, Jan. 27, 1992]

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## Requirements

### A. Well Control Requirements

1. Blowout preventer (BOP) and related equipment (BOPE) shall be installed, used, maintained, and tested in manner necessary to assure well control and shall be in place and operational prior to drilling the surface casing shoe unless otherwise approved by the APD. Commencement of drilling without the approved BOPE installed, unless otherwise approved, shall subject the operator to immediate assessment under 43 CFR 3163.1(b)(1). The BOP and related control equipment shall be suitable for operations in those areas which are subject to sub-freezing conditions. The BOPE shall be based on known or anticipated sub-surface pressures, geologic conditions, accepted engineering practice, and surface environment. The working pressure of all BOPE shall exceed the anticipated surface pressure to which it may be subjected, assuming a partially evacuated hole with a pressure gradient of 0.22 psi/ft.

2. The gravity of the violations for many of the well control minimum standards listed below are shown as minor. However, very short abatement periods in this Order are often specified in recognition that by continuing to drill, the violation which was originally determined to be of a minor nature may cause or threaten immediate, substantial and adverse impact on public health and safety, the environment, production accountability, or royalty income, which would require it reclassification as a major violation.

a. Minimum standards and enforcement provisions for well control equipment. i. A well control device shall be installed at the surface that is capable of complete closure of the well bore. This device shall be closed whenever the well is unattended.

Violation: Major.
Corrective Action: Install the equipment as specified.
Normal Abatement Period: Prompt correction required.

ii. 2M system:

- Annular preventer, or double ram, or two rams with one being blind and onebeing a pipe ram *
- kill line (2 inch minimum)
- 1 kill line valve (2 inch minimum)
- 1 choke line valve
- 2 chokes (refer to diagram in Attachment 1)
- Upper kelly cock valve with handle available
- Safety valve and subs to fit all drill strings in use
- Pressure gauge on choke manifold
- 2 inch minimum choke line
- Fill-up line above the uppermost preventer.

Violation: Minor (all items unless marked by asterisk).
Corrective Action: Install the equipment as specified.
Normal Abatement Period: 24 hours.

*Violation: Major.
Corrective Action: Install the equipment as specified.
Normal Abatement Period: Prompt correction required.

iii. 3M system:

- Annular preventers*
- Double ram with blind rams and pipe rams*
- Drilling spool, or blowout preventer with 2 side outlets (choke side shall be a 3-inch minimum diameter, kill side shall be at least 2-inch diameter)*
- Kill line (2 inch minimum)
- A minimum of 2 choke line valves (3 inch minimum)*
- 3 inch diameter choke line
- 2 kill line valves, one of which shall be a check valve (2 inch minimum)*
- 2 chokes (refer to diagram in Attachment 1)
- Pressure gauge on choke manifold
- Upper kelly cock valve with handle available
- Safety valve and subs to fit all drill string connections in use
- All BOPE connections subjected to well pressure shall be flanged, welded, or clamped*
- Fill-up line above the uppermost preventer.

Violation: Minor (all items unless marked by asterisk).
Corrective Action: Install the equipment as specified.
Normal Abatement Period: 24 hours.

*Violation: Major.
Corrective Action: Install the equipment as specified.
Normal Abatement Period: Prompt correction required.

iv. 5M system:

- Annular preventer*
- Pipe ram, blind ram, and, if conditions warrant, as specified by the authorized officer, another pipe ram shall also be required*
- A second pipe ram preventer shall be used with a tapered drill string
- Drilling spool, or blowout preventer with 2 side outlets (choke side shall be a 3-inch minimum diameter, kill side shall be at least 2-inch diameter)*
- 3 inch diameter choke line
- 2 choke line valves (3 inch minimum)*
- Kill line (2 inch minimum)
- 2 chokes with 1 remotely controlled from rig floor (refer to diagram in Attachment 1)
- 2 kill line valves and a check valve (2 inch minimum)*
- Upper kelly cock valve with handle available
- When the expected pressures approach working pressure of the system, 1 remote kill line tested to stack pressure (which shall run to the outer edge of the substructure and be unobstructed)
- Lower kelly cock valve with handle available
- Safety valve(s) and subs to fit all drill string connections in use
- Inside BOP or float sub available
- Pressure gauge on choke manifold
- All BOPE connections subjected to well pressure shall be flanged, welded, orclamped*
- Fill-up line above the uppermost preventer.

Violation: Minor (all items unless marked by asterisk).
Corrective Action: Install the equipment as specified.
Normal Abatement Period: 24 hours.

*Violation: Major.
Corrective Action: Install the equipment as specified.
Normal Abatement Period: Prompt correction required.

v. 10M & 15M system:

- Annular preventer*
- 2 pipe rams*
- Blind rams*
- Drilling spool, or blowout preventer with 2 side outlets (choke side shall be a 3-inch minimum diameter, kill side shall be at least 2-inch diameter)*
- 3 inch choke line*
- 2 kill line valves (2 inch minimum) and check valve*
- Remote kill line (2 inch minimum) shall run to the outer edge of the substructure and be unobstructed
- Manual and hydraulic choke line valve (3 inch minimum)*
- 3 chokes, 1 being remotely controlled (refer to diagram in Attachment 1)
- Pressure gauge on choke manifold
- Upper kelly cock valve with handle available
- Lower kelly cock valve with handle available
- Safety valves and subs to fit all drill string connections in use
- Inside BOP or float sub available
- Wearing ring in casing head
- All BOPE connections subjected to well pressure shall be flanged, welded, orclamped*
- Fill-up line installed above the uppermost preventer.

Violation: Minor (all items unless marked by asterisk).
Corrective Action: Install the equipment as specified.
Normal Abatement Period: 24 hours.

*Violation: Major. Corrective Action:
Install the equipment as specified.
Normal Abatement Period: Prompt correction required.

vi. If repair or replacement of the BOPE is required after testing, this work shall be performed prior to drilling out the casing shoe.

Violation: Major.
Corrective Action: Install the equipment as specified.
Normal Abatement Period: Prompt correction required.

vii. When the BOPE cannot function to secure the hole, the hole shall be secured using cement, retrievable packer or a bridge plug packer, bridgeplug, or other acceptable approved method to assure safe well conditions.

Violation: Major.
Corrective Action: Install the equipment as specified.
Normal Abatement Period: Prompt correction required.

[54 FR 39528, Sept. 27, 1989]

b. Minimum standards and enforcement provisions for choke manifold equipment.

i. All choke lines shall be straight lines unless turns use tee blocks or are targeted with running tees, and shall be anchored to prevent whip and reduce vibration.

Violation: Minor.
Corrective Action: Install the equipment as specified.
Normal Abatement Period: 24 hours.

ii. Choke manifold equipment configuration shall be functionally equivalent to the appropriate example diagram shown in Attachment 1 of this Order. The configuration of the chokes may vary.

Violation: Minor.
Corrective Action: Install the equipment as specified.
Normal Abatement Period: Prompt correction required.

iii. All valves (except chokes) in the kill line choke manifold, and choke line shall be a type that does not restrict the flow (full opening) and that allows a straight through flow (same enforcement as item ii).

iv. Pressure gauges in the well control system shall be a type designed for drilling fluid service (same enforcement as above).

[57 FR 3025, Jan. 27, 1992]

c. Minimum standards and enforcement provisions for pressure accumulator system.

i. 2M system accumulator shall have sufficient capacity to close all BOP's and retain 200 psi above precharge. Nitrogen bottles that meet manufacturer's specifications.

Violation: Minor.
Corrective Action: Install the equipment as specified.
Normal Abatement Period: 24 hours.

ii. 3M system accumulator shall have sufficient capacity to open the hydraulically-controlled choke line valve(if so equipped), close all rams plus the annual preventer, and retain a minimum of 200 psi above precharge on the closing manifold without the use of the closing pumps. this is a minimum requirement. The fluid reservoir capacity shall be double the usable fluid volume of the accumulator system capacity and the fluid level shall be maintained at the manufacturer's recommendations. The 3M system shall have 2 independent power sources to close the preventers. Nitrogen bottles (3 minimum) may be 1 of the independent power sources and, if so, shall maintain a charge equal to the manufacturer's specifications.

Violation: Minor
Corrective Action: Install the equipment as specified.
Normal Abatement Period: 24 hours.

iii. 5M and higher system accumulator shall have sufficient capacity to open the hydraulically-controlled gate valve (if so equipped) and close all rams plus the annular preventer (for 3 ram systems add a 50 percent safety factor to compensate for any fluid loss in the control system or preventers) and retain a minimum pressure of 200 psi above precharge on the closing manifold without use of the closing unit pumps. The fluid reservoir capacity shall be double the usable fluid volume of the accumulator system capacity and the fluid level of the reservoir shall be maintained at the manufacturer's recommendations. Two independent sources of power shall be available for powering the closing unit pumps. Sufficient nitrogen bottles are suitable as a backup power source only, and shall be recharged when the pressure falls below manufacturer's specifications.

Violation: Minor.
Corrective Action: Install the equipment as specified.
Normal Abatement Period: 24 hours.

[57 FR 3025, Jan. 27, 1992]

d. Minimum standards and enforcement provisions for accumulator precharge pressuretest. This test shall be conducted prior to connecting the closing unit to the BOP stack and at least once every 6 months. The accumulator pressure shall be corrected if the measured precharge pressure is found to be above or below the maximum or minimum limit specified below (only nitrogen gas may be used to precharge):

| Accumulator working pressure rating | Minimum acceptable operating pressure | Desired precharge pressure | Maximum acceptable precharge pressure | Minimum acceptable precharge pressure |
|---|---|---|---|---|
| 1,500 psi | 1,500 psi | 750 psi | 800 psi | 700 psi |
| 2,000 psi | 2,000 psi | 1,000 psi | 1,100 psi | 900 psi |
| 3,000 psi | 3,000 psi | 1,000 psi | 1,100 psi | 900 psi |

Violation: Minor.
Correction Action: Perform test.
Normal Abatement Period: 24 hours.

e. Minimum standards and enforcement provisions for power availability. Power for the closing unit pumps shall be available to the unit at all times so that the pumps shall automatically start when the closing valve manifold pressure has decreased to the pre-set level.

Violation: Major.
Corrective Action: Install the equipment as specified.
Normal Abatement Period: Prompt correction required.

f. Minimum standards and enforcement provisions for accumulator pump capacity. Each BOP closing unit shall be equipped with sufficient number and sizes of pumps so that, with the accumulator system isolated from service, the pumps shall be capable of opening the hydraulically-operated gate valve (if so equipped), plus closing the annular preventer on the smallest size drill pipe to be used within 2 minutes, and obtain a minimum of 200 psi above specified accumulator precharge pressure.

g. Minimum standards and enforcement provisions for locking devices. A manual locking device (i.e., hand wheels) or automatic locking devices shall be installed on all systems of 2M or greater. A valve shall be installed in the closing line as close as possible to the annular preventer to act as a locking device. This valve shall be maintained in the open position and shall be closed only when the power source for the accumulator system is inoperative.

Violation: Minor.
Corrective Action: Install the equipment as specified.
Normal Abatement Period: 24 hours.

h. Minimum standards and enforcement provisions for remote controls. Remote controls shall be readily accessible to the driller. Remote controls for all 3M or greater systems shall be capable of closing all preventers. Remote controls for 5M or greater systems shall be capable of both opening and closing all preventers. Master controls shall be at the accumulator and shall be capable of opening and closing all preventers and the choke line valve (if so equipped). No remote control for a 2M system is required.

Violation: Minor.
Correction Action: Install the equipment as specified.
Normal Abatement Period: 24 hours.

i. Minimum standards and enforcement provisions for well control equipment testing.

i. Perform all tests described below using clear water or an appropriate clear liquid for subfreezing temperatures with a viscosity similar to water.

ii. Ram type preventers and associated equipment shall be tested to approved (see item I.D.1. of this order) stack working pressure if isolated by test plug or to 70 percent of internal yield pressure of casing if BOP stack is not isolated from casing. Pressure shall be maintained for at least 10 minutes or until requirements of test are met, whichever is longer. If a test plug is utilized, no bleed-off of pressure is acceptable. For a test not utilizing a test plug, if a decline in pressure of more than 10 percent in 30 minutes occurs, the test shall be considered to have failed. Valve on casing head below test plug shall be open during test of BOP stack.

iii. Annular type preventers shall be tested to 50 percent of rated working pressure. Pressure shall be maintained at least 10 minutes or until provisions of test are met, whichever is longer.

iv. As a minimum, the above test shall be performed:

A. when initially installed;
B. whenever any seal subject to test pressure is broken;
C. following related repairs; and
D. at 30-day intervals.

v. Valves shall be tested from working pressure side during BOPE tests with all down stream valves open.

vi. When testing the kill line valve(s), the check valve shall be held open or the ball removed.

vii. Annular preventers shall be functionally operated at least weekly.

viii. Pipe and blind rams shall be activated each trip, however, this function need not be performed more than once a day.

ix. A BOPE pit level drill shall be conducted weekly for each drilling crew.

x. Pressure tests shall apply to all related well control equipment.

xi. All of the above described tests and/or drills shall be recorded in the drilling log.

Violation: Minor.
Corrective action: Perform the necessary test or provide documentation.
Normal Abatement Period: 24 hours or next trip, as most appropriate.

[54 FR 39528, Sept. 27, 1989]

## B. Casing and Cementing Requirements

The proposed casing and cementing programs shall be conducted as approved to protect and/or isolate all usable water zones, lost circulation zones, abnormally pressured zones, and any prospectively valuable deposits of minerals. Any isolating medium other than cement shall receive approval prior to use. The casing setting depth shall be calculated to position the casing seat opposite a competent formation which will contain the maximum pressure to which it will be exposed during normal drilling operations. Determination of casing setting depth shall be based on all relevant factors, including: presence/absence of hydrocarbons; fracture gradients; usable water zones; formation pressures; lost circulation zones; other minerals; or other unusual characteristics. All indications of usable water shall be reported.

- Minimum design factors for tensions, collapse, and burst that are incorporated into the casing design by an operator/lessee shall be submitted to the authorized operator for his review and approval along with the APD for all exploratory wells or as otherwise specified by the authorized officer.

- Casing design shall assume formation pressure gradients of 0.44 to 0.50 psi per foot for exploratory wells (lacking better data).

- Casing design shall assume fracture gradients from 0.70 to 1.00 psi per foot for exploratory wells (lacking better data).

- Casing collars shall have a minimum clearance of 0.422 inches on all sides in the hole/casing annulus, with recognition that variances can be granted for justified exceptions.

- All waiting on cement times shall be adequate to achieve a minimum of 500 psi compressive strength at the casing shoe prior to drilling out.

1. Minimum Standards and Enforcement Provisions for Casing and Cementing.

a. All casing, except the conductor casing, shall be new or reconditioned and tested casing. All casing shall meet or exceed API standards for new casing. The use of reconditioned and tested used casing shall be subject to approval by the authorized officer; approval will be contingent upon the wall thickness of any such casing being verified to be at least 87 1/2 percent of the nominal wall thickness of new casing.

Violation: Major.

Corrective Action: Perform remedial action as specified by the authorized officer.
Normal Abatement Period: Prompt correction required.

[57 FR 3025, Jan. 27, 1992]

b. For liners, a minimum of 100 feet of overlap between a string of casing and the next larger casing is required. The interval of overlap shall be sealed and tested. The liner shall be tested by a fluid entry or pressure test to determine whether a seal between the liner top and next larger string has been achieved. The test pressure shall be the maximum anticipated pressure to which the seal will be exposed. No test shall be required for liners that do not incorporate or need a seal mechanism.

Violation: Minor.
Corrective Action: Perform remedial action as specified by the authorized officer.
Normal Abatement Period: Upon determination of corrective action.

c. The surface casing shall be cemented back to surface either during the primary cement job or by remedial cementing.
Corrective Action: Perform remedial cementing.
Normal Abatement Period: Prompt correction required.

d. All of the above described tests shall be recorded in the drilling log.

Violation: Minor.
Corrective Action: Perform the necessary test or provide documentation.
Normal Abatement Period: 24 hours.

e. All indications of usable water shall be reported to the authorized officer prior to running the next string of casing or before plugging orders are requested, whichever occurs first. Violation: Major.
Corrective Action: Report information as required.
Normal Abatement Period: Prompt correction required.

f. Surface casing shall have centralizers on the bottom 3 joints of the casing (a minimum of 1 centralizer per joint, starting with the shoe joint).

Violations: Major.
Corrective Action: Logging/testing may be required to determine the quality of the job. Recementing may then be specified.
Normal Abatement Period: Prompt correction upon determination of corrective action.

[57 FR 3025, Jan. 27, 1992]

g. Top plugs shall be used to reduce contamination of cement by displacement fluid. A bottom plug or other acceptable technique, such as a preflush fluid, inner string cement method, etc., shall be utilized to help isolate the cement from contamination by the mud fluid being displaced ahead of the cement slurry. Violation: Major.
Correction Action: Logging may be required to determine the quality of the cement job. Recementing or further recementing may then be specified.
Normal Abatement Period: Based upon determination of corrective action.

h. All casing strings below the conductor shall be pressure tested to 0.22 psi per foot of casing string length or 1500 psi, whichever is greater, but not to exceed 70 percent of the minimum internal yield. If pressure declines more than 10 percent in 30 minutes, corrective action shall be taken.

Violation: Minor.
Corrective Action: Perform the test and/or remedial action as specified by the authorized officer.
Normal Abatement Period: 24 hours.

i. On all exploratory wells, and on that portion of any well approved for a 5M BOPE system or greater, a pressure integrity test of each casing shoe shall be performed. Formation at the shoe shall be tested to a minimum of the mud weight equivalent anticipated to control the formation pressure to the next casing depth or at total depth of the well. This test shall be performed before drilling more than 20 feet of new hole.

Violation: Minor.
Corrective Action: Perform the specified test.
Normal Abatement Period: 24 hours.

## C. Mud Program Requirements

The characteristics, use, and testing of drilling mud and the implementation of related drilling procedures shall be designed to prevent the loss of well control. Sufficient quantities of mud materials shall be maintained or readily accessible for the purpose of assuring wellcontrol.

Minimum Standards and Enforcement Provisions for Mud Program and Equipment

1. Record slow pump speed on daily drilling report after mudding up.

Violation: Minor.
Corrective Action: Record required information.
Normal Abatement Period: 24 hours.

2. Visual mud monitoring equipment shall be in place to detect volume changes indicating loss or gain of circulating fluid volume.

Violation: Minor.
Corrective Action: Install necessary equipment.

Normal Abatement Period: 24 hours.

3. When abnormal pressures are anticipated, electronic/mechanical mud monitoring equipment shall be required, which shall include as a minimum; pit volume totalizer (PVT); stroke counter; and flow sensor.

Violation: Minor.
Corrective Action: Install necessary instrumentation.
Normal Abatement Period: 24 hours.

4. A mud test shall be performed every 24 hours after mudding up to determine, as applicable: density, viscosity, gel strength, filtration, and pH.

Violation: Minor.
Correction Action: Perform necessary tests.
Normal Abatement Period: 24 hours.

5. A trip tank shall be used on 10M and 15M systems and on upgraded 5M systems as determined by the authorized officer.

Violation: Minor.
Corrective Action: Install necessary equipment.
Normal Abatement Period: 24 hours.

6. a. Gas detecting equipment shall be installed in the mud return system for exploratory wells or wells where abnormal pressure is anticipated, and hydrocarbon gas shall be monitored for pore pressure changes.

b. Hydrogen sulfide safety and monitoring equipment requirements may be found in Onshore Oil and Gas Order No. 6 - Hydrogen Sulfide Operations.

Violation: Minor.
Corrective Action: Install necessary equipment.
Normal Abatement Period: 24 hours.

7. All flare systems shall be designed to gather and burn all gas. The flare line(s) discharge shall be located not less than 100 feet from the well head, having straight lines unless turns are targeted with running tees, and shall be positioned downwind of the prevailing wind direction and shall be anchored. The flare system shall have an effective method for ignition. Where noncombustible gas is likely or expected to be vented, the system shall be provided supplemental fuel for ignition and to maintain a continuous flare.

Violation: Major.
Corrective Action: Install equipment as specified.
Normal Abatement Period: 24 Hours.

8. A mud-gas separator (gas buster) shall be installed and operable for all systems of 10M or greater and for any system where abnormal pressure is anticipated beginning at a point at least 500 feet above any anticipated hydrocarbon zone of interest.

Violation: Minor.
Corrective Action: Install required equipment.
Normal Abatement Period: Prompt correction required.

[54 FR 39528, Sept. 27, 1989, further amended at 57 FR 3026, Jan.27, 1992]

## D. Drill Stem Testing Requirements

Initial opening of drill stem test tools shall be restricted to daylight hours unless specific approval to start during other hours is obtained from the authorized officer. However, DSTs may be allowed to continue at night if the test was initiated during daylight hours and the rate of flow is stabilized and if adequate lighting is available (i.e., lighting which is adequate for visibility and vapor-proof for safe operations). Packers can be released, but tripping shall not begin before daylight, unless prior approval is obtained from the authorized officer. Closed chamber DSTs may be accomplished day or night.

Minimum Standards for Drill Stem Testing.

**1.** A DST that flows to the surface with evidence of hydrocarbons shall be eitherreversed out of the testing string under controlled surface conditions or displaced into the formation prior to pulling the test tool. This would involve providing some means forreserve circulation.

Violation: Major.
Corrective Action: Contingent on circumstances and as specified by the authorizedofficer.
Normal Abatement Period: Prompt correction required.

2. Separation equipment required for the anticipated recovery shall be properly installed before a test starts.

Violation: Major.
Corrective Action: Install required equipment.
Normal Abatement Period: Prompt correction required.

3. All engines within 100 feet of the wellbore that are required to "run" during the test shall have spark arresters or water cooled exhausts.

Violation: Major.
Corrective Action: Contingent on circumstances and as specified by the authorized officer.
Normal Abatement Period: Prompt correction required.

## E. Special Drilling Operations

1. In addition to the equipment already specified elsewhere in this onshore order, the following equipment shall be in place and operational during air/gas drilling:

- Properly lubricated and maintained rotating head*
- Spark arresters on engines or water cooled exhaust*
- Blooie line discharge 100 feet from well bore and securely anchored
- Straight run on blooie line unless otherwise approved
- Deduster equipment*
- All cuttings and circulating medium shall be directed into a reserve or blooie pit*
- Float valve above bit*
- Automatic igniter or continuous pilot light on the blooie line*
- Compressors located in the opposite direction from the blooie line a minimum of 100 feet from the well bore
- Mud circulating equipment, water, and mud materials (does not have to be premixed) sufficient to maintain the capacity of the hole and circulating tanks or pits

Violation: Minor (unless marked by an asterisk).
Corrective Action: Install the equipment as specified.
Normal Abatement Period: 24 hours.

*Violation: Major.
Corrective Action: Install the equipment as specified.
Normal Abatement Period: Prompt correction required.

2. Hydrogen sulphide operation is specifically addressed under Onshore Oil and Gas Order No. 6.

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## F. Surface Use

Onshore Oil and Gas Order No. 1 specifically addresses surface use. That Order provides for safe operations, adequate protection of surface resources and uses, and other environmental components. The operator/lessee is responsible for, and liable for, all building, construction, and operating activities and subcontracting activies conducted in association with the APD. Requirements and special stipulations for surface use are contained in or attached to the approved APD.

Minimum Standards and Enforcement Provisions for Surface Use.

The requirements and stipulations of approval shall be strictly adhered to by the operator/lessee and any contractors. Violation: If a violation is identified by the authorized officer he shall dtermine wherther it is major or minor, considering the definitions in 43 CFR 3160.0-5, and shall specify the appropriate corrective action and abatement period.

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## G. Drilling Abandonment Requirements

The following standards apply to the abandonment of newly drilled dry or non- productive wells in accordance with 43 CFR 3162.3-4 and section V of Onshore Oil and Gas Order No. 1. Approval shall be obtained prior to the commencement of abandonment. All formations bearing usable-quality water, oil, gas, or geothermal resources, and/or a prospectively valuable deposit of minerals shall be protected. Approval may be given orally by the authorized officer before abandonment operations are initiated. This oral request and approval shall be followed by a written notice of intent to abandon filed not later than the fifth business day following oral approval. Failure to obtain approval prior to commencement of abandonment operations shall result in immediate assessment of under 43 CFR 3163.1(b)(3). The hole shall be in static condition at the time any plugs are placed (this does not pertain to plugging lost circulation zones). Within 30 days of completion of abandonment, a subsequent report of a abandonment shall be filed. Plugging design for an abandonment hole shall include the following:

1. Open Hole.

i. A cement plug shall be placed to extend at least 50 feet below the bottom (except as limited by total depth (TD) or plugged back total depth (PBTD)), to 50 feet above the top of:
a. Any zone encountered during which contains fluid or gas with a potential to migrate;
b. Any prospectively valuable deposit of minerals.

ii. All cement plugs, except the surface plug, shall have sufficient slurry volume to fill 100 feet of the hole, plus an additional 10 percent of slurry for each 1,000 feet of depth.

iii. No plug, except the surface plug, shall be less than 25 sacks without receiving specific approval from the authorized officer.

iv. Extremely thick sections of single formation may be secured by placing 100-foot plugs across the top and bottom of the formation, and in accordance with item ii hereof. v. In the absence of productive zones or prospectively valuable deposits of minerals which otherwise require placemnt of cement plugs, long sections of open hole shall be plugged at least every 3,000 feet. Such plugs shall be placed across in gauge sections of the hole, unless otherwise approved by the authoriuzed officer.

2. Cased Hole. A cement plug shall be placed opposite all open perforation and extend to a minimum of 50 feet below (except as limited by TD or PBTD) to 50 feet above the perforated interval. All cement plugs, except the surface plug, shall have sufficient slurry volume to fill 100 feet of hole, plus an additional 10 percent of slurry for each 1,000 feet of depth. In lieu of the cement plug, a bridge plug is acceptable, provided:

i. The bridge plug is set within 50 feet to 100 feet above the open perforations;
ii. The perforations are isolated from any open hole below; and
iii. The bridge plug is capped with 50 feet of cement. If a bailer is used to cap this plug, 35 feet of cement shall be sufficient.

3. Casing Removed from Hole. If any casing is cut and recovered, a cement plug shall be placed to extend at least 50 feet above and below the stub. The exposed hole resulting from the casing removal shall be secured as required in items 1i and 1ii hereof.

4. An additional cement plug placed to extend a minimum of 50 feet above and below the shoe of the surface casing for intermediate string, as appropriate).

5. Annular Space. No annular space that extends to the surface shall be left open to the drilled hole below. If this condition exists, a minimum of the top 50 feet of annulus shall be plugged with cement.

6. Isolating Medium. Any cement plug which is the only isolating medium for a usable water interval or a zone containg a prspectively valuable deposit of minerals shall be testedby tagging with the drill string. Any plugs placed where the fluid level will not remain static also shall be tested by either tagging the plug with the working pipe string, or pressuring to a minimum pump (surface) pressure of 1,000 psi, with no more than a 10 percent drop during a 15-minute period (cased hole only). If the integrity of any other plug is questionable, or if the authorized officer has specific concerns for which he/she orders a plug to be tested, it shall be tested in the same manner.

7. Silica Sand or Silica Flour. Silica sand or silica flour shall be added to cement exposed to bottom hole static temperatures above 230 øF to prevent heat degradation of the cement.

8. Surface Plug. A cement plug of at least 50 feet shall be placed across all annuluses. The top of this plug shall be placed as near the eventual casing cutoff point as possible.

9. Mud. Each of the intervals between plugs shall be filled with mud of suffcient density to exert hydrostatic pressure exceeding the greatest formation pressure encountered while drilling such interval. In the absense of other information at the time plugging is approved, a minimum mud weight of 9 pounds per gallon shall be specified.

10. Surface Cap. All casing shall be cut-off at the base of the cellar or 3 feet below final restored ground level (whichever is deeper). The well bore shall then be covered with a metal plate at least 1/4 inch thick and welded in place, or a 4-inch pipe, 10-feet in length, 4 feet above ground and embedded in cement as specified by the authorizedofficer. The well location and identity shall be permanently inscribed. A weep hole shall be left if a metal plate is welded in place.

11. The cellar shall be filled with suitable material as specified by the authorized officer and the surface restored in accordancxe with the instructions of the authorized officer.

Minimum Standard

All plugging orders shall be strictly adhered to.

Violation: Major.
Corrective Action: Contingent upon circumstances.
Normal Abatement Period: Prompt correction required.

[54 FR 39528, Sept. 27, 1989]

## IV. Variances From Minimum Standard

An operator may request the authorized officer to approve a variance from any ofthe minimum standards prescribed in section III hereof. All such request shall be submitted in writing to the appropriate authorized officer and provide information as to the circumstances which warrant approval of the variance(s) requested and the proposed alternative methods by which the related minimum standard(s) are to be satisfied. The authorized officer, afterconsidering all relevant factors, if appropriate, may approve the requested variance(s) if it is determined that the proposed alternative(s) meet or exceed the objectives of the applicable minimum standard(s).

Emergency or other situations of an immediate nature that could not be reasonably forseen at the time of APD approval may recieve oral approval. However, such requests shall be followed up by a written notice filed not later than the fifth business day following oral approval.

## ATTACHMENTS

I. Diagrams of Choke Manifold Equipment
II. Sections From 43 CFR Subparts 3163 and 3165 (Not Included With Federal Register Publication)

# APPENDIX M: GUIDELINE FOR THE DETECTION AND QUANTIFICATION OF CONTAMINATION AT OIL AND GAS OPERATIONS

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## I. WHAT IS THE PURPOSE OF THIS DOCUMENT?

This document is to be used as a guideline for collecting samples at sites within National Park Service (NPS) units where there are oil or gas operations. Samples will indicate whether or not contamination exists at the site as a result of an operation.

It is important that specific contaminants are tested for and that specific methodology is used so that contamination is accurately defined and so that results taken at different times by different people at the same site can be reliably compared. This guideline presents methodology for analyzing soil, sediment, groundwater, and surface water.

Specifically, guidelines are presented for: 1) when owner/operators must collect samples, 2) what contaminants to test for, 3) how to collect samples, 4) quality assurance/quality control, 5) how to analyze samples in the laboratory, 6) required detection limits and choosing environmental benchmarks, and 7) sample plan and reporting requirements.

Note that in this guideline “Superintendent” refers to the Superintendent and/or members of his/her staff who will represent him/her on these issues. In many cases, the Superintendent's actual involvement may be only that of approving the recommendations of the staff member(s).

## II. WHEN AND WHERE TO COLLECT SAMPLES

The Superintendent can require sampling by an operator at a site if it has recently experienced a release, has a history of releases, or the facility is operated in a manner that poses a risk of releasing crude oil, natural gas condensates, produced water, or any other “contaminating substance” associated with an oil or gas operation.

Sampling can occur at any time during or after an operation. (“After” refers to when an owner/operator sells the operation, transfers its leasing rights, or closes the operation and abandons the site.) In most instances, sampling by the operator should be conducted under the direction of a Sampling and Analysis Plan that has been approved by the Superintendent to ensure all work will be performed in a professional manner, meets the resource protection needs of the park, and with the knowledge of the appropriate Park staff.

Sampling will be biased, not random, focusing on areas where contamination is obvious (visible) or suspected (such as near production or storage facilities). The exact sample locations and number of samples collected are site-specific and will be determined by the Superintendent, or proposed by the site operator in a Sampling and Analysis Plan or Work Plan submitted to the Superintendent for review and approval. Owner/operators are responsible for sample collection, sample analyses, and reporting of results, not NPS.

Sample data from a nearby (but off-site) “clean” location will be needed to determine “background” concentrations at the site for the contaminants of concern. A comparison of the contaminated site data with “background” data will allow resource managers to determine how contaminated the site is. If the site has been remediated, comparisons of sample data with “background” data can indicate if the clean-up met the Superintendent’s remediation goals for the site.

Note that incoming owner/operators at new or existing oil or gas operations may wish to test the site for contamination before they begin operations. If they choose to do so, it is strongly suggested they test for the contaminants and use the methodology given in this guideline so that if samples are required during or after the operation for any reason, all data can be reliably compared.

## III. WHAT CONTAMINANTS TO TEST FOR

Contaminating substances that can be found at oil and gas sites are primarily crude oil, natural gas condensate, produced water, drilling mud, lube (motor) oil, and solvents. The individual contaminants found in these substances are listed in Table 1. Though other contaminants also are found in these substances, those in Table 1 were chosen because of their greater environmental toxicity and because they are good indicators of the presence of the contaminating substance(s) of interest.

When contamination of a site by one of these six contaminating substances is being investigated, sampling and analyses for some or all of the individual contaminants found in that contaminating substance should occur. Two lists of contaminants were compiled and are designated as “Tier I” (the smaller group, indicated by “xx” in Table 1) and “Tier II” (the more comprehensive group, indicated by both “xx” and “x”). Having two tiers to choose from allows the Superintendent flexibility in what contaminants he/she requires that the operator test for. The Tier I contaminants are included in the Tier II contaminants and therefore will always be tested for.

Tier I sampling should be conducted when basic information is needed. For instance, if contamination at a site is suspected but not known, testing for Tier I contaminants will confirm this; it will also give an idea of the severity of contamination. Tier I sampling might also be conducted where Park natural resources (like groundwater, vegetation, or surface water) are at low/no risk.

### TABLE 1: CONTAMINANTS TO TEST FOR WHEN INVESTIGATING VARIOUS TYPES OF CONTAMINATION AT OIL AND GAS SITES.

Contaminants that should be tested for during Tier I sampling are indicated by “xx”, while those with either an “x” or “xx” should be tested for during Tier II sampling.

| containmant | where found: soil/sediment = S groundwater/surface water = W | Contaminating substances individual contaminants are associated with: | | | | | |
|---|---|---|---|---|---|---|---|
| | | crude oil | condensate [j] | produced water | drilling mud | lube (motor) oil | solvents [k] |
| PAHs [a] | S, W | x | x | x | x | x | x |
| TPH [b] | S, W | xx | xx | x | x | xx | xx |
| BTEX [c] | S, W | x | xx | x | x | x | xx |
| metals | | | | | | | |
| arsenic | S, W | x | | x | x | | |
| barium | S, W | x | | xx | xx | x | |
| cadmium | S, W | x | | x | x | x | |
| chromium | S, W | x | | x | xx | | |
| copper | S, W | x | | x | x | x | |
| iron | S, W | | x | | | x | |
| lead | S, W | x | | x | x | xx | |
| magnesium | S, W | x | | x | x | x | |
| mercury [e] | S, W | x | | x | x | | |
| nickel | S, W | xx | | x | | x | |
| selenium | S, W | x | | | x | | |
| strontium | S, W | x | | xx | | | |
| vanadium | S, W | xx | | x | x | | |
| zinc | S, W | x | | xx | x | xx | |
| ammonia | W | x | | x | | | |
| calcium | W | | | x | x | x | |
| chloride | S, W | | | xx | | | |
| potassium | W | x | | x | x | | |
| sodium | S, W | | | | xx | xx | xx |
| sulfates | W | | | x | | | |
| gross alpha emissions [g] | W | | | x | | | |
| radium-226 [g] | S | | | xx | | | |
| pentachlorophenol | S, W | | | | x | | |
| surfactants | S, W | | | | x | | |
| pH | S, W | x | x | x | x | | |
| conductivity/salinity [h] | S, W | | x | xx | xx | | |
| TDS | W | | | x | x | | |
| grain size | S | x | x | x | xx | x | |
| total organic carbon | S | x | x | x | x | x | x |
| percent moisture [i] | S | xx | xx | xx | xx | xx | xx |
| static water level [j] | W | xx | xx | xx | xx | xx | xx |
| temperature | W | xx | xx | xx | xx | xx | xx |

a = Polycyclic Aromatic Hydrocarbons. The lab analysis required in this guideline detects approximately 38 individual compounds including the priority pollutant “parent” compounds and their alkylated homologs. See Table 2 for a full list of these. Note that these 38 compounds are measured with a single analytical test (i.e. there is not a separate test for each compound). When testing water for PAHs, do for groundwater only unless ongoing surface water contamination from adjacent contaminated soil, sediment, or aquifer is suspected.

b = Total Petroleum Hydrocarbons. Certain "ranges" of hydrocarbons should be analyzed for, depending on the contaminating substance. For crude oil, a “full range” or “wide range” TPH scan should be conducted; for natural gas condensate a “lighter end” TPH scan, like for “gasoline range organics” (GRO) or total volatile petroleum hydrocarbons (TVPH) $C_6$-$C_{10}$ should be conducted; and for diesel fuel a TPH scan for “diesel range organics” (DRO) or total extractable petroleum hydrocarbons (TEPH) $C_{11}$-$C_{34}$ should be conducted. See section VI.A for details.

c = Benzene, Toluene, Ethylbenzene, Xylene. Only test for these in soil, sediment, or surface water if contamination is very recent and sampling is for initial (preliminary) assessment purposes.

d = analyze all metals for the “total recoverable” fraction

e = analyze soil (or sediment) for mercury only if mercury manometers are suspected to have been used on-site in the past (natural gas operations only)

f = report both the “total” and “unionized” fractions

g = note that if gross alpha in water exceeds a certain level, further testing for radioactive elements may be required. Radium-226 analyses must use gamma spectroscopy; this test takes approx. 30 days. At sites where produced water contamination may be more recent (in the last 10 yrs), gamma ray emissions in the soil can be preliminarily measured in the field (e.g. with a MicroRmeter) to determine if the radium-226 soil analyses are necessary.

h = salinity can be calculated from conductivity measurements

i = percent moisture is necessary to calculate the required dry weight and wet weight units

j = for groundwater only

k = can be from a gas production facility or a gas pipeline

l = various solvents can be used on-site (e.g. benzene, toluene, ethylbenzene, xylene, various petroleum products, etc.). Analyte tested for depends on the particular solvent used on-site.

**Table 2:** Polycyclic aromatic hydrocarbons (PAHs) detected by the recommended “expanded scan” analysis for PAHs (see section VI.A). These compounds include the so-called priority pollutant “parent” compounds plus their alkylated homologs. Note that the 38 compounds below are measured with a single analytical test (that is, there is not a separate analytical test for each compound).

Acenaphthene
Acenaphthylene

Anthracene
Benzo(a)anthracene
Benzo(b)fluoranthene
Benzo(k)fluoranthene
Benzo(g,h,i)perylene
Benzo(e)pyrene
Benzo(a)pyrene
Biphenyl
Chrysene
Chrysene, C1-
Chrysene, C2-
Chrysene, C3-
Chrysene, C4-
Dibenzo(a,h)anthracene
Dibenzothiophene
Dibenzothiophene, C1-
Dibenzothiophene, C2-
Dibenzothiophene, C3-
Fluoranthene
Fluoranthenes/Pyrenes, C1-
Fluorene
Fluorene, C1-
Fluorene, C2-
Fluorene, C3-
Ideno(1,2,3,c,d)pyrene
Naphthalene
Naphthalene, C1-
Naphthalene, C2-
Naphthalene, C3-
Naphthalene, C4-
Perylene
Phenanthrene
Phenanthrenes/Anthracenes, C1-
Phenanthrenes/Anthracenes, C2-
Phenanthrenes/Anthracenes, C3-
Phenanthrenes/Anthracenes, C4-

Tier II sampling should be conducted when more detailed information is needed. For instance, if clean-up activities at a site have been completed, testing for Tier II contaminants will confirm if all (or nearly all) the contaminants have, in fact, been removed. Tier II sampling might also be conducted at sites where important Park natural resources are at a higher risk of being exposed to contaminants and where more stringent cleanup standards than those promulgated by a State regulatory body may be appropriate.

The Superintendent will determine whether Tier I or II is needed. Some combination of the two may also be used. He/she may also choose to omit or add contaminants to the Tier I or II lists should the situation warrant it.

Note that Table 1 does not include all possible contaminants associated with oil or gas operations. Other contaminating substances involved are: caustic solutions used in natural gas sweetening (these can contain sodium, pH, amines, and EDTA contaminants); glycols used in natural gas dehydration; and surfactants, acidizing agents, corrosion inhibitors, solvents, biocides, etc. used in oil or gas well workover and completion. The Superintendent may require that contaminants associated with these substances be tested for if they are suspected of having been released on-site.

# IV. HOW TO COLLECT SAMPLES

## A. Sample Locations

### 1. Soil

Background samples should be collected from an area as close to the site as possible where it is certain no contaminating substances from the site could have reached (from surface runoff, off-site dumping, migration from wind, etc.).

For soils that are known to be contaminated, samples should be collected from the spot and depth where contamination appears to be highest. For sites where soils are suspected of being contaminated, seek out areas near production facilities, storage tanks, valves, etc., and adjacent low points in the topography where contaminated runoff may have passed over or "puddled up" and concentrated. Collect sample at a depth where contamination would be highest: in most cases probably the top one to two inches. Note that releases in very porous (e.g. sandy) soil may percolate down and pool immediately above deeper, less porous soil layers (e.g. clay or silt strata, particularly if saturated), pool at the water table, or concentrate in highly organic layers.

For sites where removal of contaminated soils has already occurred, a sample should be collected in the top inch or so of the newly exposed soil to insure that all the contaminants that percolated down into the soil were, in fact, removed. (Note: At hydrocarbon release sites, screening of soils at the base of the excavation for volatile organic compounds/VOCs with a photo-ionization detector could improve the confidence that Tier II sample selection is sufficient to confirm a site is clean.)

All samples will be grab samples. (As a rule, composite samples should not be collected.) Where contamination is suspected but not known, the sampling device probably should be some type of tube or auger in order to capture equal amounts of soil over the depth of the profile; depending on the properties of the soil (like how hard or rocky it is), however, other devices (like a trowel) may work better. Sample collectors may have to communicate with the laboratory to ensure that enough soil is collected for the various analyses.

For BTEX samples, see section B.1. below.

The total number of samples to be collected will be site-specific and determined by the Superintendent. Enough samples should be collected and analyzed to meet the Tier I or Tier II sampling objective (see section III).

### 2. Sediment

Background samples should be collected from sediment adjacent to the sediments in question, but where it is reasonably certain no contaminating substances from the site (or other sites in the area) could have reached (from surface runoff, off-site dumping, etc.).

As with soils, sediments known to be contaminated should be sampled from the spot and depth where contamination appears to be highest. For sediments suspected of being contaminated, seek out areas near production facilities, storage tanks, valves, etc., and adjacent areas where potentially contaminated sediment in runoff could have settled out. Sample the sediment that has accumulated since the spill/release began. In some cases this may be the top ¼ inch, in others it may be the top several inches.

For sites where removal of contaminated sediments has already occurred, samples should be collected in the newly exposed sediment to insure that all contaminants were, in fact, removed.

All samples will be grab samples. (As a rule, composite samples should not be collected.) Where contamination is suspected but not known, or the layer of contaminated sediment is more than a couple inches thick, the sampling device probably should be some type of tube or auger in order to capture equal amounts of sediment over the depth of the profile; depending on the properties of the sediment (like how rocky it is) and the depth of the water, however, other devices may work better. Sample collectors may have to communicate with the laboratory to ensure that enough sediment is collected for the various analyses.

The total number of samples to be collected will be site-specific and determined by the Superintendent. Enough samples should be collected and analyzed to meet the Tier I or Tier II sampling objective (see section III).

### 3. Groundwater

Groundwater samples should be collected if the Superintendent determines that hydrogeological conditions at the site are such that groundwater resources under or near the site are reasonably at risk. Samples can be collected either via established monitoring wells or with “push” technology (such as Geoprobe®).

It is critical that: a) sampling occurs in the right areas (for example, one location must be upgradient of the potential point of impact and at least two must be downgradient); and b) wells are screened at the appropriate depths to intercept any contaminant plume(s). (This will require knowledge of the local hydrogeology and the contaminants involved and their environmental fate characteristics). If “push” technology is used to collect soil samples for lab analysis or for on-site screening of various media (soil, ground water) for contaminants and samples are collected on more than one occasion, care must be taken to sample the exact same locations and at the same depths in the aquifer. Typically, once contamination is found in ground water using screening methodologies, monitoring wells are required by State regulatory agencies to ensure sample quality and integrity is sufficient to base regulatory decisions.

“Low-flow” sample collection methods should be used as per the EPA guidance document in IV.B.3 below.

Groundwater samples should not be filtered.

For BTEX samples, see section B.3. below.

All samples will be grab samples. (As a rule, composite samples should not be collected.) Sample collectors may have to communicate with the laboratory to ensure that enough sample is collected for the various analyses.

The total number of samples to be collected will be site-specific and determined by the Superintendent or through his/her approval of the owner/operator's Sampling and Analysis Plan after consultation with Park resource staff. Enough samples should be collected and analyzed to meet the Tier I or Tier II sampling objective (see section III).

### 4. Surface Water

Background samples should be collected upstream of any possible inputs of contaminated water (e.g. surface runoff or shallow groundwater) from the site.

Where contamination is obvious, such as in a surface sheen, collect samples right at the surface, avoiding any scum, algae, or other detritus on the water surface if possible (and note in fieldbook if present). Where a contaminating substance such as chlorinated solvents (dense nonaqueous phase liquids, or DNAPLs) was released or is suspected at the bottom of an aquifer (e.g. above a clay layer or aquitard), then collect samples at a depth immediately above the base of the aquifer, the depth of the first fine-grained layer below the water table, or both. For surface water suspected of being contaminated but it is unknown whether the contaminants are "floaters" or "sinkers," collect samples at a depth of 3-12 inches.

For BTEX samples, see section B.4. below.

Again, all samples will be grab samples. (As a rule, composite samples should not be collected.) Sample collectors may have to communicate with the laboratory to ensure that enough sample is collected for the various analyses.

The total number of samples to be collected will be site-specific and determined by the Superintendent. Factors such as flow, depth, and the size of the water body are important here. Enough samples should be collected and analyzed to meet the Tier I or Tier II sampling objective (see section III).

## B. Sample Collection Methodologies

Acceptable sampling methodology must be used so that results are as representative as possible. Sample collection can be complex and should be conducted by experienced professionals (typically a contractor). This could also help if the values or methods are challenged by one of the interested parties involved (State regulatory agency, Park, owner/operator etc.). Furthermore, experienced professionals are also trained in the appropriate precautions to protect the health and safety of the sample collector(s) from exposure to potentially harmful contaminants or hazardous situations that could develop.

Methodologies that should be used are typically those accepted/sanctioned by the appropriate State regulatory agency or are found in publications of widely recognized organizations (e.g. EPA, NOAA) that conduct environmental research. Acceptable methodologies are listed below for each environmental media (soil, sediment, etc.). In general, the State is authorized as the lead regulatory agency and should be the initial contact for appropriate sampling methodologies to employ when various environmental media are believed contaminated. In site-specific situations where a sensitive Park resource is threatened and more stringent cleanup than that required by a State agency may be appropriate, Park staff should consult WASO support offices as needed for appropriate criteria prior to discussion of more stringent cleanup levels with the owner/operator. If sample collection methodologies other than the above are used, they must contain the following to be acceptable: 1) Applicability of the procedure, 2) Equipment required,

3) Detailed description of procedures to be followed in collecting the samples, 4) Common problems encountered and corrective actions to be followed, and 5) Precautions to be taken. The methodology to be used must be cited in the sample plan. A basic description of collection methodology should be included in the report to the Superintendent (section VIII).

### 1. Soil

Methods from source documents published by the following organizations are acceptable:

-State Governing Regulatory Agency
-U.S. EPA
-American Society for Testing and Materials
-U.S. Department of the Interior
-American Petroleum Institute

Note that when collecting soil samples for BTEX analysis, specialized equipment and collection methods are necessary. Use a coring device such as the EnCore™ sampler or disposable plastic syringes. For detailed guidance, see section 4.1 and method 5035 in Chapter 4 of EPA's SW-846, Update III (full reference in section VI.A. below).

### 2. Sediment

Methods from source documents published by the following organizations are acceptable:

-State Governing Regulatory Agency
-U.S. EPA
-American Society for Testing and Materials
-U.S. Department of the Interior
-American Petroleum Institute

### 3. Groundwater

Use: Environmental Protection Agency. 1992. RCRA Ground-Water Monitoring: Draft Technical Guidance. EPA/530/R-93-001. Office of Solid Waste, EPA, Washington, D.C.; or Publications of State Governing Regulatory Agency (DEQ, DEM, State EPA etc.)

"Low-flow" sampling should be conducted; for guidance, see:

Puls, R.W. and M.J. Barcelona. 1996. Ground Water Issue: Low-Flow (Minimal Drawdown) Ground-Water Sampling Procedures. EPA/540/S-95/504. Office of Solid Waste and Emergency Response, EPA, Washington, D.C.

Note that when collecting water samples for BTEX analysis, specialized equipment and collection methods are necessary. For detailed guidance, see section 4.1 and method 5030B in Chapter 4 of EPA's SW-846, Update III (full reference in section VI.A. below).

### 4. Surface Water

Methods from source documents published by the following organizations are acceptable:

-State Governing Regulatory Agency
-U.S. EPA
-American Society for Testing and Materials
-U.S. Department of the Interior
-American Petroleum Institute

Also recommended is this NPS guidance: Stednick, J.D. and D.M. Gilbert. 1998. Water quality inventory protocol: Riverine environments. National Park Service, Water Resources Division, Technical Report no. NPS/NRWRD/NRTR-98/177. Fort Collins, CO, 103 pp.

Note that when collecting water samples for BTEX analysis, specialized equipment and collection methods are necessary. For detailed guidance, see section 4.1 and method 5030B in Chapter 4 of EPA's SW-846, Update III (full reference in section VI.A. below).

## C. Sample Containers, Preservation, Storage

Refer to documents listed in sections VI.A. below and IV.B. above for specific guidance, including 40 CFR Part 136, if necessary. EPA's SW-846, Update III is especially helpful.

Note that sediment samples should not be acidified for metals and that neither groundwater nor surface water samples should be filtered. Remember special conditions when sampling for BTEX (see section 4.1 and methods 5030 and 5035 in Chapter Four of SW-846, Update III) and for any metals requiring unusually low detection limits.

## D. Chain of Custody

Proper chain-of-custody procedures must be used in sample handling (collection, shipping, storage, analysis). For examples, see Standard Methods for the Examination of Water and Wastewater for general guidance, and SW-846, Update III, Chapter 9, section 9.2.2.7 for detailed guidance.

# V. QUALITY ASSURANCE/QUALITY CONTROL

Quality assurance/quality control (QA/QC) plans or Quality Assurance Project Plans (QAPPs) ensure that the data generated are scientifically valid, defensible, and of known precision and accuracy. Some of the basic elements of QA/QC or QAPP plans are:

- data quality objectives (DQO)
- field operating procedures (such as sample management, decontamination, equipment calibration, etc.)
- field QA/QC requirements (such as data handling, collection of control samples like blanks, spikes and duplicates, etc.)
- lab operating procedures (such as sample management, equipment calibration, etc.)
- lab QA/QC procedures (such as data handling, control samples, etc.).

A QA/QC plan should be in place before any sampling begins. Basic QA/QC procedures to be followed should be described briefly in the sample plan (section VIII). If a certain QA/QC guidance document is used, it should be cited in the sample plan. Many guidance documents are available—several through EPA—including the following, recommended here:

> Environmental Protection Agency. 1997. Test methods for evaluating solid waste, physical/chemical methods (SW-846), 3rd edition, Update III, Chapter One. EPA Office of Solid Waste and Emergency Response, EPA, Washington, D.C.

Adherence to the QA/QC plan should be documented throughout the project and demonstrated in the final report to the Superintendent.

Aspects of quality assurance that may be helpful can be found in:

> Environmental Protection Agency. 1996. The volunteer monitor's guide to quality assurance project plans. EPA Office of Wetlands, Ocean and Watersheds 4503F. EPA publication number: EPA 841-B-96-003. Also available at: http://www.epa.gov/owow/monitoring/volunteer/qappcover.htm

# VI. HOW TO ANALYZE SAMPLES IN THE LABORATORY

## A. Analytical Methods

Metals analyses must use the methods in EPA's SW-846, Update III (or more recent). This applies to soil, sediment, groundwater, and surface water samples. Groundwater and surface water methods can also include EPA's 200 series for metals, or the 1600 series where extremely low (state-of-the-art) detection limits are desired. The full reference for the SW-846 document is:

> Environmental Protection Agency. 1997. Test methods for evaluating solid waste, physical/chemical methods (SW-846), 3rd edition, Update III. EPA Office of Solid Waste and Emergency Response, EPA, Washington, D.C.

Polycyclic aromatic hydrocarbon (PAH) analyses must use a modification of method 8270 in EPA's SW-846, Update III. Developed by the National Oceanic and Atmospheric Administration (NOAA), this method is referred to as "GC/MS method 8270 in selective ion mode (SIM)", and is informally referred to as the "expanded scan" for PAHs. Consult the following for a detailed explanation of methodology:

> Lauenstein, G.G., and A.Y. Cantillo (1998). Sampling and analytical methods of the National Status and Trends Program Mussel Watch Project: 1993-1996 update. NOAA Technical Memorandum NOS ORCA 130. 233 pp.

Total petroleum hydrocarbons (TPH) analyses will be for certain "ranges" of hydrocarbons, depending on the contaminating substance present. For crude oil, a **"wide range" or "full range" TPH scan** should be conducted to measure the heavier fractions. For natural gas condensate a "lighter end" TPH scan, such as for **"gasoline range organics" (GRO)**, should be conducted. For diesel fuel, a TPH scan for **"diesel range organics" (DRO)** should be conducted to measure the mid-range fractions. Although many analytical methods are available for TPH, samples should be analyzed using only GC/FID (gas chromatograph/flame ionization detection) methodology. Method 8015B in EPA's SW-846, Update III is highly recommended.

Benzene, toluene, ethylbenzene, and xylene (BTEX) analyses should use method 8260B in EPA's SW-846, Update III. Analysis for BTEX compounds is typically done in place of a TPH analysis when a refined product is released as opposed to crude oil.

Ammonia analyses should use EPA method 350.1 (or equivalent APHA method 4500-NH3 H, or USGS method 4523-85). Samples should not be filtered.

For all other contaminants in Table 1, use methods approved in 40 CFR Part 136 (EPA, Standard Methods for the Examination of Water and Wastewater (latest edition), ASTM, or USGS). Methods in the NPS, Water Resources Division "Water quality inventory protocol" (section IV.B.4 above) can also be used.

## B. Laboratories

Samples must be sent to an experienced lab that can: 1) perform the above analytical methods; 2) achieve the required detection limits (section VII below); 3) perform the required QA/QC procedures (section V above); and 4) provide the information required in the sample plan and the final report to the Superintendent (section VIII below).

Note that in regards to the PAH analytical method (as specified in VI.A. above), only a few labs nationwide (perhaps a dozen) currently can perform this analysis. Many of these same labs can also "fingerprint" samples; that is, by analyzing hydrocarbon-contaminated samples, they can identify the type and source of the petroleum product at the site. A partial list of these labs follows (no government endorsement implied):

Arthur D. Little, Inc.
25 Acorn Park
Cambridge, MA. 02140
(617) 498-5000

Geochemical and Environmental Research Group
Texas A&M University
833 Graham Rd.
College Station, TX. 77845
(409) 862-2323 ext. 115

Battell Marine Science Lab
1529 West Sequim Bay Rd.
Sequim, WA 98382
(360) 683-4151

Woods Hole Group, Environmental Laboratories
375 Paramount Drive, Suite B
Raynham, MA 02767-5154
(508) 822-9300 or 563-5030

# VII. DETECTION LIMITS

Note: The term "detection limit" used herein refers to what is commonly called the "reporting limit" and occasionally called the "quantitation limit. A detection limit is what a lab (using a particular instrument in some combination with analytical method and skill level of operator) can quantify low levels of a contaminant substance with acceptable confidence. It does not refer to the sometimes much lower "instrument detection limit" or "method detection limit" where how well the value obtained represents the true value may be of low confidence. Also note that detection limits should not be confused with cleanup standards or cleanup criteria. Required cleanup levels/criteria are usually set by State regulatory authorities as the acceptable contaminant residue (usually well above detection limits) that may remain in some environmental media after a remedial effort has occurred. NPS is authorized to require more stringent cleanup criteria on a case-by-case basis, particularly in site-specific situations where sensitive ecological resources could be threatened. Widely accepted, peer-reviewed research may then be used to support the NPS position that State criteria are not sufficiently protective and lower cleanup criteria are warranted.

Labs should achieve the detection limits (DLs) provided in Table 3 below. These DLs are below federal (and presumably state) standards and most other criteria currently in the literature. Therefore, analytical methods that achieve these DLs will be able to indicate if most standards and criteria are being met. Note, however, that the DLs for two contaminants—PAHs and mercury—are above some of the more strict standards or criteria that exist. This is because many labs cannot achieve DLs this low, and the DLs in the table were chosen so that most experienced and well-equipped labs could achieve them. Lower DLs are achievable for PAHs and mercury at some labs that have the expertise and special instrumentation (see section VI.B. above for examples).

If the natural resources at or near the site are particularly sensitive, pristine, or important to the Park, the Superintendent may wish to choose the strictest available standard or criteria as the remediation goal. He/she would then have to request some lower DLs (lower than those in Table 3) from the lab for PAHs and mercury.

For the contaminants in Table 1 that are not listed in Table 3, commonly reported DLs are acceptable.

Table 3: Maximum acceptable detection limits ("reporting limits") for surface water, groundwater, soil, and sediment samples. Lower detection limits are also acceptable.

| Contaminant | Detection limit for surface water and groundwater samples | Detection limit for soil and sediment samples (dry weight) |
|---|---|---|
| PAHs | 10 ppt [a] | 1 ppb [c] |
| TPH | 50 ppb | 0.1 ppm |
| benzene | 1 ppb | 25 ppb |
| toluene | 5 ppb | 25 ppb |
| ethylbenzene | 5 ppb | 25 ppb |
| xylene | 5 ppb | 25 ppb |
| ammonia | 0.05 ppm | -- |
| arsenic | 5 ppb | 0.5 ppm |
| barium | 1 ppb | 1 ppm |
| cadmium | 0.5 ppb | 0.2 ppm |
| chromium | 3 ppb | 1 ppm |
| copper | 5 ppb | 1 ppm |
| iron | 0.1 ppm | 10 ppm |
| lead | 1 ppb | 5 ppm |
| mercury | 0.2 ppb [b] | 0.2 ppm [d] |
| nickel | 5 ppb | 5 ppm |
| selenium | 1 ppb | 1 ppm |
| strontium | 10 ppb | 5 ppm |
| vanadium | 10 ppb | 1 ppm |
| zinc | 10 ppb | 5 ppm |

water units:

ppm = parts per million = milligrams per liter = mg/L
ppb = parts per billion = micrograms per liter = ug/L
ppt = parts per trillion = nanograms per liter = ng/L

soil/sediment units:

ppm = parts per million = milligrams per kilogram = mg/kg = micrograms per gram = ug/g
ppb = parts per billion = micrograms per kilogram = ug/kg = nanograms per gram = ng/g

a - DLs as low as 1 ppt may be achievable
b - DLs as low as 0.1 ppb, or even 10 ppt, may be achievable
c - DLs as low as 0.25 ppb may be achievable
d - DLs as low as 25 ppb, or even 1 ppb, may be achievable

For an extensive list of federal standards and other published environmental criteria for most of the contaminants in Table 1, consult NPS Water Resources Divisions' "Environmental Contaminants Encyclopedia" at the website http://www.aqd.nps.gov/toxic. Note that there may be state standards, other criteria, or in some cases, updated federal standards that are not listed in this Encyclopedia.

# VIII. SAMPLE PLAN AND REPORTING REQUIREMENTS

## A. Sample Plan

The owner/operator should submit a Sampling and Analysis Plan to the Superintendent for approval before samples are collected. The plan must include:

- sampling objectives (such as, “identify contaminants and concentrations involved,” “determine spatial extent of spill,” “determine if remediation is complete,” etc.)
- the contaminating substances being investigated (such as crude oil, natural gas condensate, produced water, etc.)
- list of individual contaminants that will be tested for (see Table 1)
- analytical methods to be used (see section VI. A.)
- type of samples to be collected (such as soil, sediment, groundwater, or surface water)
- citation and brief description of sample collection methodology to be used (see section IV. B.)
- specific sample locations and number of samples at each (Superintendent will walk the site and choose exact locations; this information may not be available until the time when samples are actually collected)
- total number of samples (this information may not be available until the time when samples are actually collected)
- acknowledgment that detection limits (that is, “reporting limits”) specified herein (section VII) will be achieved
- brief description of QA/QC procedures to be followed and citation of any guidance document used (see section V)
- acknowledgment that proper chain-of-custody procedures will be initiated and followed

## B. Reporting Requirements

Upon completing sample collection and analyses, the owner/operator shall submit a report to the Superintendent. This report shall include:

- sample ID number/name
- description of sample locations (include maps, sketches, or photos)
- sample depth
- brief description of spill area (apparent extent of spill, topography, vegetation, surface water features, apparent soil conditions, etc.)
- date and time of sampling
- name of sample collector
- information pertinent to the sample collection methodology used (sampling devices used, how samples were collected, etc.)
- sample containers used, any preservation methods, and storage conditions of samples
- date and time of analyses
- name of chemist/technician performing analyses
- type of sample (soil, sediment, groundwater, or surface water)
- sample fraction measured (such as “total”, “total recoverable”, etc.)
- analytical results and units (mg/kg, µg/L, etc.)
- percent moisture (for soil/sediment samples)
- wet weight *and* dry weight units (for soil/sediment samples)
- analytical methods used

- detection limits (that is, “reporting limits”) achieved
- method detection limits (MDL) for the analytical methods used
- indication of analyses done in the field (such as pH, conductivity, etc.)
- field observations made while collecting samples
- lab and field QA/QC results and procedures followed
- name of analytic equipment used
- appropriate chain-of-custody forms

# IX. SPILL RESPONSE AND NOTIFICATION PROCEDURE FOLLOWING RELEASE OF A CONTAMINATING SUBSTANCE FROM A NONFEDERAL OIL AND GAS OPERATION IN A PARK UNIT

## A. Initial Park Staff Actions Following Discovery of a Release

1. Secure the area to protect human health and safety

2. Notify operator of the release and immediate need to control the source and contain the release, and obtain information of the released substance

3. Initial site assessment to identify park resources potentially as risk from the release (surface water, wetlands, cultural resources, etc.), and quantity of released substance

4. Direct operator during initial spill containment actions to protect natural and cultural resources at risk, and to protect human health and safety

5. Notify Regional Spill Response Coordinator and relay all pertinent information

6. Obtain 5 liter sample of released substance (Note: need preservation and storage guidance for park staff) and initiate chain of custody documentation

7. Continue to oversee operator containment actions and maintain security

8. Park Superintendent advises operator that the operation is immediately “suspended” pursuant to NPS regulations at 36 CFR §9.51(c)(2)

9. Park staff prepares a detailed Case Incident Report on the spill event

## B. Regional Spill Response Coordinator Notification Duties

1. Contact National Response Center to advise of release and obtain case number

2. Notify Environmental Quality Division (Dan Hamson), Geologic Resources Division (Jim Woods), Regional Minerals Coordinator (Linda Dansby), and Water Resources Division (Matt Hagermann) if release threatens water resources

3. Coordinate a conference call with above technical offices and park staff to define appropriate course of action relative to spill containment, public health and safety, site assessment, damage assessment, and operator responsiveness and capability

4. Notify pertinent state regulatory agencies and state trustees

## C. Coordination of Response, Clean-up and Damage Assessment

1. All involved NPS staff track time and all other expenditures associated with the spill event

2. Park Superintendent prepares formal suspension notice for Regional Director's signature in accordance with NPS regulations at 36 CFR §9.51(c)(2)

3. Park staff coordinates with designated On Scene Coordinator (EPA, Coast Guard, or NPS staff expert if EPA or Coast Guard does not dispatch a coordinator) and state regulatory agencies to oversee operator spill response and initial clean-up actions

4. Park staff coordinates with On Scene Coordinator (OSC) and state trustee agencies in the conduct of resource damage assessment (Note: operator may contract with approved consulting firm/laboratory to conduct assessment work)

5. All involved NPS offices evaluate site assessment results and reach consensus on additional remediation actions and reclamation goals, and communicate recommendations to park Superintendent. (Note: NPS regulations at 36 CFR §9.39(a)(1)(i) and §9.39(a)(2)(iii) require operators to remove or neutralize any contaminating substance)

6. Park staff coordinates with OSC and state trustee agencies in monitoring remediation and reclamation actions

7. Park Superintendent and NPS technical working group evaluates final remediation/reclamation success and determines if further legal action against the operator is required (Note: operators are liable for any damages to federally-owned or controlled lands, waters or resources pursuant to 36 CFR §9.51(a).

# APPENDIX N: TRIBAL CONSULTATION LETTERS AND RESPONSES

IN REPLY REFER TO:

United States Department of the Interior

National Park Service
Big South Fork
National River and Recreation Area
4564 Leatherwood Road
Oneida, Tennessee 37841

L3023

December 29, 2006

Larry Nuckolls, Governor
Absentee-Shawnee Tribe of Oklahoma
2025 S. Gordon Cooper Drive
Shawnee, OK 74801

Dear Governor Nuckolls:

Federal regulations for the implementation of Section 106 of the National Historic Preservation Act of 1966, as amended, require consultation with federally recognized American Indian tribes (36 CFR 800.2) on a government-to-government basis, as specified in Executive Order 13175. The administration of the Big South Fork National River and Recreation Area and the Obed National Wild and Scenic River (collectively "the Parks") is committed to honoring in full good faith its obligations and responsibilities toward the sovereign, federally recognized Indian tribes under all United States laws, regulations, and policies. As part of my responsibility to "make a reasonable and good faith effort to identify Indian tribes…that shall be consulted in the 106 process," I am writing to inquire if the Absentee-Shawnee Tribe of Oklahoma desires to consult with the National Park Service regarding a proposed Oil and Gas Management Plan/Environmental Impact Statement (EIS) covering oil and gas operations at the Parks. We are also making a similar inquiry of six other tribal governments traditionally associated with Eastern Tennessee. The purpose and need for the proposed Oil and Gas Management Plan/EIS is described in the enclosed scoping brochure. You may also find additional information at our Planning, Environment, and Public Comment (PEPC) website:

http://parkplanning.nps.gov/projectHome.cfm?parkId=354&projectId=10911

If the Absentee-Shawnee Tribe of Oklahoma wishes to consult with the National Park Service regarding the proposed plan as provided for under the regulations for the National Historic Preservation Act, please contact me at the address above, by phone at 423-569-9778 or email at biso_superintendent@nps.gov in order that we may arrange mutually agreeable time(s) and location(s) for consultation. To ensure that our planning process continues on schedule, please respond to this letter within 30 days. We are looking forward to your reply and to maintaining a continuing relationship with the tribal government of the Absentee-Shawnee Tribe of Oklahoma.

Sincerely,

***/s/Reed E. Detring***

Reed E. Detring
Superintendent

cc: Ms. Karen Kaniatobe, THPO

tblount:eh:12/22/06:423-569-2404 X252

United States Department of the Interior

National Park Service
Big South Fork
National River and Recreation Area
4564 Leatherwood Road
Oneida, Tennessee 37841

IN REPLY REFER TO:

L3023

December 29, 2006

Chad "Corntassle" Smith, Principal Chief
Cherokee Nation
P.O. Box 948
Tahlequah, OK 74465

Dear Chief Smith:

Federal regulations for the implementation of Section 106 of the National Historic Preservation Act of 1966, as amended, require consultation with federally recognized American Indian tribes (36 CFR 800.2) on a government-to-government basis, as specified in Executive Order 13175. The administration of the Big South Fork National River and Recreation Area and the Obed National Wild and Scenic River (collectively "the Parks") is committed to honoring in full good faith its obligations and responsibilities toward the sovereign, federally recognized Indian tribes under all United States laws, regulations, and policies. As part of my responsibility to "make a reasonable and good faith effort to identify Indian tribes…that shall be consulted in the 106 process," I am writing to inquire if the Cherokee Nation desires to consult with the National Park Service regarding a proposed Oil and Gas Management Plan/Environmental Impact Statement (EIS) covering oil and gas operations at the Parks. We are also making a similar inquiry of six other tribal governments traditionally associated with Eastern Tennessee. The purpose and need for the proposed Oil and Gas Management Plan/EIS is described in the enclosed scoping brochure. You may also find additional information at our Planning, Environment, and Public Comment (PEPC) website:

http://parkplanning.nps.gov/projectHome.cfm?parkId=354&projectId=10911

If the Cherokee Nation wishes to consult with the National Park Service regarding the proposed plan as provided for under the regulations for the National Historic Preservation Act, please contact me at the address above, by phone at 423-569-9778 or email at biso_superintendent@nps.gov in order that we may arrange mutually agreeable time(s) and location(s) for consultation. Please forward this letter to your Tribal Historic Preservation

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Officer (THPO) or Acting THPO. To ensure that our planning process continues on schedule, please respond to this letter within 30 days. We are looking forward to your reply and to maintaining a continuing relationship with the tribal government of the Cherokee Nation.

Sincerely,

***/s/Reed E. Detring***

Reed E. Detring
Superintendent

tblount:eh:12/22/06:423-569-2404 X252

2

United States Department of the Interior

National Park Service
Big South Fork
National River and Recreation Area
4564 Leatherwood Road
Oneida, Tennessee 37841

IN REPLY REFER TO:

L3023

December 29, 2006

Michell Hicks, Principal Chief
Eastern Band of Cherokee Indians
Qualla Boundary
P.O. Box 455
Cherokee, NC 28719

Dear Principal Chief Hicks:

Federal regulations for the implementation of Section 106 of the National Historic Preservation Act of 1966, as amended, require consultation with federally recognized American Indian tribes (36 CFR 800.2) on a government-to-government basis, as specified in Executive Order 13175. The administration of the Big South Fork National River and Recreation Area and the Obed National Wild and Scenic River (collectively "the Parks") is committed to honoring in full good faith its obligations and responsibilities toward the sovereign, federally recognized Indian tribes under all United States laws, regulations, and policies. As part of my responsibility to "make a reasonable and good faith effort to identify Indian tribes…that shall be consulted in the 106 process," I am writing to inquire if the Eastern Band of Cherokee Indians desires to consult with the National Park Service regarding a proposed Oil and Gas Management Plan/Environmental Impact Statement (EIS) covering oil and gas operations at the Parks. We are also making a similar inquiry of six other tribal governments traditionally associated with Eastern Tennessee. The purpose and need for the proposed Oil and Gas Management Plan/EIS is described in the enclosed scoping brochure. You may also find additional information at our Planning, Environment, and Public Comment (PEPC) website:

http://parkplanning.nps.gov/projectHome.cfm?parkId=354&projectId=10911

If the Eastern Band of Cherokee Indians wishes to consult with the National Park Service regarding the proposed plan as provided for under the regulations for the National Historic Preservation Act, please contact me at the address above, by phone at 423-569-9778 or email at biso_superintendent@nps.gov in order that we may arrange mutually agreeable time(s) and location(s) for consultation. To ensure that our planning process continues on

TAKE PRIDE IN AMERICA

schedule, please respond to this letter within 30 days. We are looking forward to your reply and to maintaining a continuing relationship with the tribal government of the Eastern Band of Cherokee Indians.

Sincerely,

***/s/Reed E. Detring***

Reed E. Detring
Superintendent

cc: Russell Townsend, THPO

tblount:eh:12/22/06:423-569-2404 X252

2

United States Department of the Interior

IN REPLY REFER TO:

National Park Service
Big South Fork
National River and Recreation Area
4564 Leatherwood Road
Oneida, Tennessee 37841

L3023

December 29, 2006

Robin Dushane, Chief
Eastern Shawnee Tribe of Oklahoma
P.O. Box 350
Seneca, MO 64865

Dear Chief Dushane:

Federal regulations for the implementation of Section 106 of the National Historic Preservation Act of 1966, as amended, require consultation with federally recognized American Indian tribes (36 CFR 800.2) on a government-to-government basis, as specified in Executive Order 13175. The administration of the Big South Fork National River and Recreation Area and the Obed National Wild and Scenic River (collectively "the Parks") is committed to honoring in full good faith its obligations and responsibilities toward the sovereign, federally recognized Indian tribes under all United States laws, regulations, and policies. As part of my responsibility to "make a reasonable and good faith effort to identify Indian tribes…that shall be consulted in the 106 process," I am writing to inquire if the Eastern Shawnee Tribe of Oklahoma desires to consult with the National Park Service regarding a proposed Oil and Gas Management Plan/Environmental Impact Statement (EIS) covering oil and gas operations at the Parks. We are also making a similar inquiry of six other tribal governments traditionally associated with Eastern Tennessee. The purpose and need for the proposed Oil and Gas Management Plan/EIS is described in the enclosed scoping brochure. You may also find additional information at our Planning, Environment, and Public Comment (PEPC) website:

http://parkplanning.nps.gov/projectHome.cfm?parkId=354&projectId=10911

If the Eastern Shawnee Tribe of Oklahoma wishes to consult with the National Park Service regarding the proposed plan as provided for under the regulations for the National Historic Preservation Act, please contact me at the address above, by phone at 423-569-9778 or email at biso_superintendent@nps.gov in order that we may arrange mutually agreeable time(s) and location(s) for consultation. Please forward this letter to your Tribal Historic Preservation Officer (THPO) or Acting THPO. To ensure that our planning process continues on schedule,

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please respond to this letter within 30 days. We are looking forward to your reply and to maintaining a continuing relationship with the tribal government of the Eastern Shawnee Tribe of Oklahoma.

Sincerely,

***/s/Reed E. Detring***

Reed E. Detring
Superintendent

tblount:ch:12/22/06:423-569-2404 X252

2

United States Department of the Interior

National Park Service
Big South Fork
National River and Recreation Area
4564 Leatherwood Road
Oneida, Tennessee 37841

IN REPLY REFER TO:

L3023

December 29, 2006

Ron Sparkman, Chairman
Shawnee Tribe
P.O. Box 189
Miami, OK 74355

Dear Chairman Sparkman:

Federal regulations for the implementation of Section 106 of the National Historic Preservation Act of 1966, as amended, require consultation with federally recognized American Indian tribes (36 CFR 800.2) on a government-to-government basis, as specified in Executive Order 13175. The administration of the Big South Fork National River and Recreation Area and the Obed National Wild and Scenic River (collectively "the Parks") is committed to honoring in full good faith its obligations and responsibilities toward the sovereign, federally recognized Indian tribes under all United States laws, regulations, and policies. As part of my responsibility to "make a reasonable and good faith effort to identify Indian tribes…that shall be consulted in the 106 process," I am writing to inquire if the Shawnee Tribe desires to consult with the National Park Service regarding a proposed Oil and Gas Management Plan/Environmental Impact Statement (EIS) covering oil and gas operations at the Parks. We are also making a similar inquiry of six other tribal governments traditionally associated with Eastern Tennessee. The purpose and need for the proposed Oil and Gas Management Plan/EIS is described in the enclosed scoping brochure. You may also find additional information at our Planning, Environment, and Public Comment (PEPC) website:

http://parkplanning.nps.gov/projectHome.cfm?parkId=354&projectId=10911

If the Shawnee Tribe wishes to consult with the National Park Service regarding the proposed plan as provided for under the regulations for the National Historic Preservation Act, please contact me at the address above, by phone at 423-569-9778 or email at biso_superintendent@nps.gov in order that we may arrange mutually agreeable time(s) and

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location(s) for consultation. To ensure that our planning process continues on schedule, please respond to this letter within 30 days. We are looking forward to your reply and to maintaining a continuing relationship with the tribal government of the Shawnee Tribe.

Sincerely,

***/s/Reed E. Detring***

Reed E. Detring
Superintendent

cc: Ms. Rebecca Hawkins, Administrator/THPO

tblount:eh:12/22/06:423-569-2404 X252

2

United States Department of the Interior

IN REPLY REFER TO:

National Park Service
Big South Fork
National River and Recreation Area
4564 Leatherwood Road
Oneida, Tennessee 37841

L3023

December 29, 2006

Bill Anoatubby, Governor
Chickasaw Nation
P.O. Box 1548
Ada, OK 74821

Dear Governor Anoatubby:

Federal regulations for the implementation of Section 106 of the National Historic Preservation Act of 1966, as amended, require consultation with federally recognized American Indian tribes (36 CFR 800.2) on a government-to-government basis, as specified in Executive Order 13175. The administration of the Big South Fork National River and Recreation Area and the Obed National Wild and Scenic River (collectively "the Parks") is committed to honoring in full good faith its obligations and responsibilities toward the sovereign, federally recognized Indian tribes under all United States laws, regulations, and policies. As part of my responsibility to "make a reasonable and good faith effort to identify Indian tribes…that shall be consulted in the 106 process," I am writing to inquire if the Chickasaw Nation desires to consult with the National Park Service regarding a proposed Oil and Gas Management Plan/Environmental Impact Statement (EIS) covering oil and gas operations at the Parks. We are also making a similar inquiry of six other tribal governments traditionally associated with Eastern Tennessee. The purpose and need for the proposed Oil and Gas Management Plan/EIS is described in the enclosed scoping brochure. You may also find additional information at our Planning, Environment, and Public Comment (PEPC) website:

http://parkplanning.nps.gov/projectHome.cfm?parkId=354&projectId=10911

If the Chickasaw Nation wishes to consult with the National Park Service regarding the proposed plan as provided for under the regulations for the National Historic Preservation Act, please contact me at the address above, by phone at 423-569-9778 or email at biso_superintendent@nps.gov in order that we may arrange mutually agreeable time(s) and location(s) for consultation. Please forward this letter to your Tribal Historic Preservation

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Officer (THPO) or Acting THPO. To ensure that our planning process continues on schedule, please respond to this letter within 30 days. We are looking forward to your reply and to maintaining a continuing relationship with the tribal government of the Chickasaw Nation.

Sincerely,

***/s/Reed E. Detring***

Reed E. Detring
Superintendent

tblount:eh:12/22/06:423-569-2404 X252

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United States Department of the Interior

National Park Service
Big South Fork
National River and Recreation Area
4564 Leatherwood Road
Oneida, Tennessee 37841

IN REPLY REFER TO:

L3023

December 29, 2006

George Wickliffe, Chief
United Keetoowah Band of Cherokee Indians in Oklahoma
P.O. Box 746
Tahlequah, OK 74465

Dear Chief Wickliffe:

Federal regulations for the implementation of Section 106 of the National Historic Preservation Act of 1966, as amended, require consultation with federally recognized American Indian tribes (36 CFR 800.2) on a government-to-government basis, as specified in Executive Order 13175. The administration of the Big South Fork National River and Recreation Area and the Obed National Wild and Scenic River (collectively "the Parks") is committed to honoring in full good faith its obligations and responsibilities toward the sovereign, federally recognized Indian tribes under all United States laws, regulations, and policies. As part of my responsibility to "make a reasonable and good faith effort to identify Indian tribes…that shall be consulted in the 106 process," I am writing to inquire if the United Keetoowah Band of Cherokee Indians in Oklahoma desires to consult with the National Park Service regarding a proposed Oil and Gas Management Plan/Environmental Impact Statement (EIS) covering oil and gas operations at the Parks. We are also making a similar inquiry of six other tribal governments traditionally associated with Eastern Tennessee. The purpose and need for the proposed Oil and Gas Management Plan/EIS is described in the enclosed scoping brochure. You may also find additional information at our Planning, Environment, and Public Comment (PEPC) website:

http://parkplanning.nps.gov/projectHome.cfm?parkId=354&projectId=10911

If the United Keetoowah Band of Cherokee Indians in Oklahoma wishes to consult with the National Park Service regarding the proposed plan as provided for under the regulations for the National Historic Preservation Act, please contact me at the address above, by phone at 423-569-9778 or email at biso_superintendent@nps.gov in order that we may arrange mutually agreeable time(s) and location(s) for consultation. To ensure that our planning process continues on

TAKE PRIDE IN AMERICA

schedule, please respond to this letter within 30 days. We are looking forward to your reply and to maintaining a continuing relationship with the tribal government of the United Keetoowah Band of Cherokee Indians in Oklahoma.

Sincerely,

***/s/Reed E. Detring***

Reed E. Detring
Superintendent

cc: Lisa C. Stopp, Acting THPO

tblount:eh:12/22/06:423-569-2404 X252

**United Keetoowah Band**
**Of Cherokee Indians in Oklahoma**
P.O. Box 746 • Tahlequah, OK 74465
2450 S. Muskogee • Tahlequah, OK 74464
Phone: (918) 431-1818 • Fax: (918) 431-1873
www.ukb-nsn.gov

*Historic Preservation Program*



January 22, 2007

Reed E. Detring
National Park Service
Big South Fork
National River and Recreation Area
4564 Leatherwood Road
Oneida, TN 37841

Dear Mr. Detring:

We are in receipt of your letter dated December 29, 2007, and I apologize for the delay in responding. We suffered a severe ice storm, and our office was temporarily closed.

The United Keetoowah Band of Cherokee Indians in Oklahoma would like to be a consulting party to the proposed Oil and Gas Management Plan/EIS.

You may contact me at the above address, phone 918-456-9200 and e-mail lstopp@unitedkeetoowahband.org if you have any questions.

Best Regards,

Lisa C. Stopp

Lisa C. Stopp
Acting Tribal Historic Preservation Officer

The Tribal Historic Preservation Office of the Eastern Band of Cherokee Indians is in receipt of the above-referenced project information and would like to thank you for the opportunity to comment on this proposed NHPA Section 106 activity.

The project's location is within the aboriginal territory of the Cherokee people. This area may have cultural, archaeological, or religious significance to the Eastern Band of Cherokee Indians. Potential cultural resources are subject to damage or destruction from land disturbing activities requiring new ground disturbance, or vegetation manipulation.

Adverse effects to ethnographic sites, such as traditional Native American campsites or burials, can reduce the interpretative or spiritual significance of a site to Tribal and United States culture and history. The EBCI THPO requests any cultural resource data, including phase I archeological reports, topographic maps, historical research, or archives research, forwarded to the Kentucky Heritage Council for comment also be sent to this office. The EBCI THPO looks forward to participating in the project review process as a consulting party as stipulated in Section 106 of the National Historic Preservation Act of 1966. If we can be of further service, or if you have any comments or questions, please feel free to contact me at (828) 554-6852.

Sincerely,

Tyler B. Howe
Tribal Historic Preservation Specialist
Eastern Band of Cherokee Indians
828-554-6852