National Park Service
U.S. Department of the Interior
Big Thicket National Preserve
Texas

Environmental Assessment

BP America Production Company
Proposal to
Directionally Drill and Produce
up to 9 Wells from 6 Surface Locations Outside the
Neches Bottom / Jack Gore Baygall Unit

Big Thicket National Preserve,
Hardin County, Texas

December 2016

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BP America Production Company
Proposal to
Directionally Drill and Produce
up to 9 Wells from 6 Surface Locations Outside the
Neches Bottom / Jack Gore Baygall Unit

Summary: In accordance with the National Park Service (NPS) regulations for nonfederal oil and gas rights, BP America Production Company (BP) has submitted an application to directionally drill and produce up to nine (9) wells from six (6) surface locations 42 to 649 feet outside the Neches Bottom / Jack Gore Baygall Unit (Unit) of Big Thicket National Preserve (Preserve). BP holds rights to nonfederally-owned oil and gas beneath the Unit.

This Environmental Assessment (EA) evaluates impacts of two alternatives. Alternative, A, No Action, evaluates conditions in which the wells would not be drilled; therefore, there would be no new impacts on the environment. Alternative B evaluates BP's proposal to directionally drill and produce the wells. BP's proposal to locate all surface activities outside the Unit and apply mitigation measures required by other state and federal agencies or voluntarily applied by BP would result in avoiding or substantially reducing potential impacts on Unit resources and values. Three impact topics, natural soundscapes, night skies, and air quality, in and outside the Unit, are carried into Section 3.0 for detailed analysis. Negligible to moderate adverse impacts on these resources would extend from the surface activities outside the Unit and into the Unit. Duration of impacts would range from 30 days during construction of each well pad to 30-45 days during drilling of each well, and extend over the potentially long-term producing life of the wells, until the wells are plugged and surface reclamation is completed.

Public Comment: If you wish to comment on this EA, you may do so online at the NPS website **"**Planning, Environment, and Public Comment" http://parkplanning.nps.gov/bith/, or you may mail or hand deliver comments to the address below. This EA will be on public review for 30 days ending January 19, 2017. Before including your address, phone number, e-mail address, or other personal identifying information in your comment, you should be aware that your entire comment, including your personal identifying information, may be made publicly available at any time. While you can ask us in your comment to withhold your personal identifying information from public review, we cannot guarantee that we will be able to do so.

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1.0 PURPOSE AND NEED FOR ACTION

1.1 PROPOSED ACTION

The NPS proposes to grant BP a § 9.32(e) exemption with no NPS-required mitigation to directionally drill and produce the T well from a location outside the Neches Bottom/Jack Gore Baygall Unit (Unit) of the Big Thicket National Preserve (Preserve). The NPS also would consider granting exemptions to directionally drill and produce up to eight additional wells, if BP decides to move forward with them.

An exemption may be granted under § 9.32(e) of the NPS Nonfederal Oil and Gas Rights Regulations at Title 36 of the Code of Federal Regulations (CFR), Part 9, Subpart B (9B regulations) when the relevant NPS regional director determines from available data, that a proposal to directionally drill a well from a site outside the boundaries of a unit of the National Park System to reach a bottomhole target inside the unit 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."

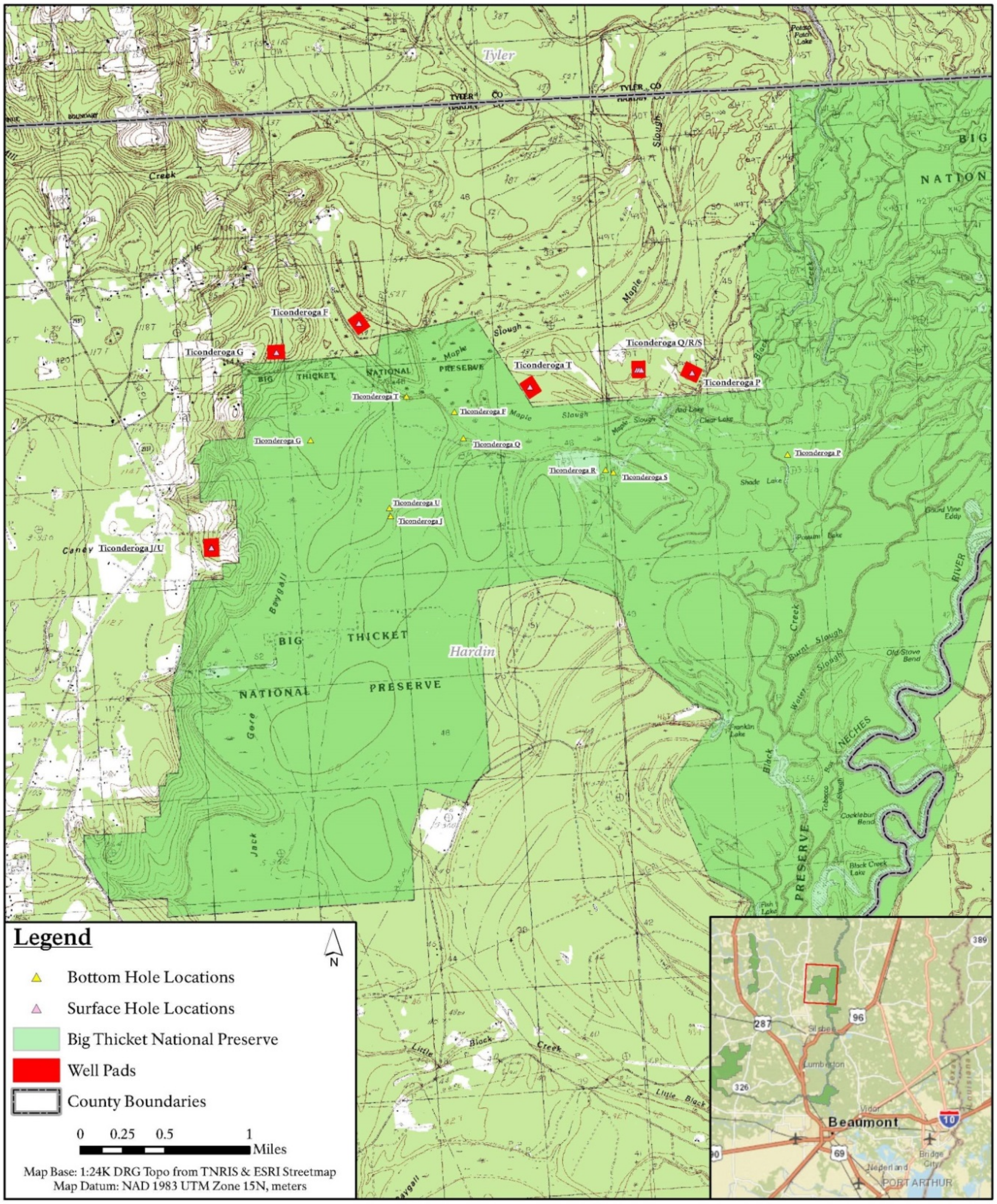
1.2 PURPOSE AND NEED

On December 28, 2015, BP submitted an application to the NPS requesting a § 9.32(e) exemption to directionally drill and produce up to nine wells from six surface locations outside the Unit of the Preserve to develop nonfederally-owned oil and gas beneath the Unit. The application provided the directional drilling and production program for the first of the nine wells BP proposed to drill, the T well, and included an approved state of Texas drilling permit as well as a Groundwater Protection Determination from the Groundwater Advisory Unit (GAU) of the Railroad Commission of Texas stating the protection depth of the usable quality water to be 1,950 feet from surface. On February 15, 2016, BP submitted a supplement to the application that proposed the use of a hydraulic fracturing process as an available means for extracting hydrocarbons from the proposed nine wells. All nine wells are shown on Figure 1 as wells F, G, J, P, Q, R, S, T, and U.

It is the NPS' responsibility to evaluate BP's § 9.32(e) application and other available data to determine whether to grant the exemption. As part of this evaluation, the NPS has prepared this environmental assessment (EA) in accordance with the National Environmental Policy Act (NEPA) of 1969 (as amended). The results of this EA will inform the NPS regional director's decision regarding the exemption.

To the extent possible, the NPS has analyzed the potential impacts of all nine proposed wells in this EA. However, because BP has provided complete information for only the T well, it is the only well that could, at this time, qualify for an exemption. Depending on the success of this well, BP may decide to proceed with directionally drilling the eight additional wells from five other surface locations. For these subsequent eight wells, BP would be required to submit to the NPS a supplement to its application that includes the following information for the other eight wells: 1) an approved state of Texas drilling permit, 2) a Groundwater Advisory Unit, and if applicable, 3) any revisions to the currently-proposed methodology to

FIGURE 1: REGIONAL/VICINITY MAP



directionally drill and produce the wells. Upon receipt of this supplemental information – and before implementation could occur – the NPS would review and determine whether the NEPA analysis provided in this EA is valid for each of the additional eight wells and whether each well qualifies for a § 9.32(e) exemption with no mitigation.

1.3 SPECIAL MANDATES AND DIRECTION

The NPS evaluates project-specific proposals to directionally drill and produce wells from surface locations outside units of the National Park System on a case-by-case basis prior to deciding whether to issue an exemption from the NPS's 9B regulations. The following discussion is a summary of the basic management direction the NPS follows for issuing such an exemption.

1.3.1 Big Thicket National Preserve Enabling Act

Congress established the Preserve with the Big Thicket National Preserve Enabling Act of October 11, 1974, Pub. L. No. 93-439, 88 Stat. 1254, codified as amended at 16 USC § 698-698e (2000), as the nation's first preserve, "[i]n order to assure the preservation, conservation, and protection of the natural, scenic and recreational values of a significant portion of the Big Thicket area in the State of Texas and to provide for the enhancement and public enjoyment thereof." Upon establishment of the Preserve, the U.S. Government acquired surface ownership of the area. Private entities retained the subsurface mineral interests on most of these lands, while the state of Texas retained the mineral interests under the Neches River and navigable reaches of Pine Island Bayou. Thus, the federal government does not own any of the subsurface oil and gas rights in the Preserve.

To protect the Preserve from oil and gas operations that may adversely impact or impair Preserve resources and values, the NPS regulates those operations in accordance with NPS laws, policies, and regulations. The authorizing legislation directs the Secretary of the Interior to administer the lands within the Preserve "in a manner which will assure their natural and ecological integrity in perpetuity." The ability for the NPS to exempt directional drilling operations under the governing NPS' 9B regulations is described in § 1.3.2, below. The NPS recognizes that BP possesses private property rights to nonfederal oil and gas in the Preserve. Such rights are accorded protection under the 5th Amendment of the U.S. Constitution, which states "…no person shall be deprived of property without due process of law; nor shall private property be taken for public use without just compensation."

Given the park's enabling statute, oil and gas exploration and development activities at the Preserve are activities clearly contemplated by Congress and addressed in both statute and NPS regulations, and are not unusual or unexpected occurrences. Mineral exploration and development are also addressed in the Preserve's Oil and Gas Management Plan (NPS 2006a), and the Preserve's recently updated General Management Plan (NPS 2014), as described below under Approved Park Planning Documents.

1.3.2 NPS Nonfederal Oil and Gas Regulations, 36 CFR 9B

The NPS controls nonfederal oil and gas development in parks through the 36 CFR 9B regulations, which apply to all activities associated with bona fide nonfederally owned oil and gas rights within any unit of the National Park System where "access is on, across, or through federally owned or controlled lands or waters." (36 CFR § 9.30(a)).

Section 9.32(e) of the regulations governs operators that propose to develop their nonfederal oil and gas rights in a unit of the National Park System by directionally drilling wells from a surface location outside unit boundaries to nonfederal oil and gas minerals under federally-owned or controlled lands or waters within unit boundaries. As per § 9.32(e), an operator may obtain an exemption from the 9B regulations if an NPS regional director is able to determine from available data that a proposed drilling operation under the unit 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 [sic] contamination or natural gas escape or the like." The regulations define operations as "all functions, work and activities <u>within a unit</u> 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 unit ("in-park operations"), not threats to park resources associated with the operation outside of unit boundaries. As promulgated, § 9.32(e) does not provide a means for the NPS to assert regulatory authority under the 9B regulations over surface and subsurface operations occurring outside park boundaries.

Under the regulations, the NPS may determine that 1) an operator qualifies for an exemption from the regulations with no needed mitigation to protect park resources from activities occurring within park boundaries; 2) an operator qualifies for an exemption from the regulations with needed mitigation to protect subsurface park resources from activities occurring within park boundaries; or 3) an operator must submit a proposed plan of operations and a bond to the NPS for approval. Each one of these legally permissible options is briefly described below, and is excerpted from the "*Operator's Handbook for Nonfederal Oil and Gas Development in Units of the National Park System, October 2006*" (NPS 2006b).

> **Option 1.** <u>Exemption with No Mitigation</u> (*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 [the hole that forms the well] does not intercept an aquifer within the park). Under this option, <u>the NPS is not granting an approval or issuing a permit.</u>
>
> **Option 2.** <u>Exemption with Mitigation</u> *(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 on 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, <u>the NPS is not granting an approval or issuing a permit.</u>

Option 3. Plan of Operations (approval and "permit" issued): This regulatory option would apply if the NPS determines that it cannot make the requisite finding for a § 9.32(e) exemption because (1) impacts on surface resources from the downhole operations are involved, or (2) impacts on subsurface resources cannot be adequately mitigated to yield "no measurable effect." 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. Any required plan and bond would be limited in scope to those aspects of the directional drilling operation that would occur within park boundaries (in-park operations).

Chapter 5 of the "*Operator's Handbook for Nonfederal Oil and Gas Development in Units of the National Park System, October 2006*" (NPS 2006b), describes the following steps taken in determining whether a § 9.32(e) exemption should be granted:

1. The operator decides if the well drilling objectives can be achieved using a surface location outside of the park.

2. The operator scopes the project with the NPS and submits an application for a regulatory exemption from the plan of operations and performance bonding requirements. In the application, the operator provides the NPS with specific information that can be used to prepare an environmental assessment under NEPA. The information includes contact and legal ownership information, a description of the operation, methods that would be used to minimize or avoid impacts on park resources and values, and supporting data collected for other agency permits.

3. The NPS performs a completeness and technical adequacy review and, with the available information, prepares the required NEPA documentation.

4. Based on the environmental analysis, the NPS regional director decides if the operation, as proposed, poses a significant threat of damage to park resources. The regional director also decides whether there would be an "impairment" under the NPS Organic Act. If not, the regional director grants a regulatory exemption from the plan of operations and bonding requirements and other 9B provisions, as appropriate.

1.3.3 NPS Monitoring of Nonfederal Oil and Gas Operations

The NPS's ability to monitor and inspect directional drilling operations is limited to downhole operations within the NPS unit (e.g., setting and cementing surface casing and plugging operations, etc.). As a practical matter, monitoring of downhole activities inside the unit can only be accomplished from the surface location outside the unit. 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 (see § 1.3.2, above, for description of options). The NPS must coordinate the timing of such access with the operator. For directional drilling operations sited outside the unit, 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 unit. When the NPS has made an upfront determination that a directional drilling operation is exempt with no mitigation, there is no 9B regulatory reason to access the surface location outside the unit (option 1; see § 1.3.2, above, for description of options). Where a state or federal agency, other than the NPS, has applied mitigation measures via their respective environmental compliance or permitting processes, that agency, not the NPS, has sole responsibility for monitoring and enforcing its mitigation measures. In the event the NPS becomes aware of a compliance concern related to another agency's jurisdiction, the NPS should alert that agency in a constructive manner.

1.3.4 Protecting Park Resources from External Activities

In the event that damage is caused to unit resources from activities associated with directional drilling and production activities outside unit boundaries, the NPS has authority to recover up to treble damages from the company under the System Unit Resource Protection Act, 54 USC §§ 100721 – 100725. This statute is a strict liability statute that authorizes the NPS to recover response costs and damage from a person who destroys, causes the loss of, or injures park system resources. "Park system resources" include any living or nonliving resource that is located within a park. While recovering such compensation is always an option for the NPS, the NPS has a practice of encouraging operators to take appropriate measures in advance to protect park resources. Making the investment now to employ mitigation measures to lower the risk of potential impacts to park resources is a fiscally responsible step that will lower the operator's potential liability exposure.

1.3.5 Park Planning Documents

Park planning documents also provide a framework for determining how nonfederal oil and gas operations are conducted within the Preserve.

The NPS completed an Oil and Gas Management Plan (OGMP) for the Preserve in 2006. The OGMP identifies Preserve resources and values susceptible to adverse impacts from oil and gas operations; describes performance standards and lists required operating stipulations and recommended mitigation measures to avoid or minimize impacts and prevent impairment to Preserve resources and values; and provides pertinent information to oil and gas operators to facilitate planning and compliance with NPS and other applicable regulations (NPS 2006a).

The General Management Plan (GMP) is the major planning document for all National Park System units. The GMP sets forth the basic philosophy of the unit, and provides strategies for resolving issues, and achieving identified management objectives required for resource management and visitor use. The NPS completed a revised GMP for the Preserve in 2014, replacing the 1980 GMP. As per the GMP, the Preserve's OGMP, combined with the NPS' 9B regulations, will continue to provide guidance on the NPS regulation of oil and gas activity within the Preserve (NPS 2014).

BP's proposal is in accordance with the goals and objectives articulated in the above-mentioned planning documents.

1.4 ISSUES AND IMPACT TOPICS

Issues describe a cause-and-effect relationship between an activity and the resource (or impact topic). Identifying issues and impact topics allows the NPS to emphasize the important environmental concerns related to a proposal and helps focus the analysis in an EA.

As noted above in § 1.3.2, the § 9.32(e) exemption process only requires the NPS to consider the issues and impacts on park resources from in-park operations (in this case, from downhole activities occurring within the boundary of the Neches Bottom/Jack Gore Baygall Unit of the Preserve). However, NEPA regulations require the NPS to also consider the issues and resource impacts of related oil and gas activities occurring on surface locations outside of the Unit, because these activities are “connected actions” (40 CFR § 1508.25; 2015 NPS NEPA Handbook § 4.2C).

According to BP’s § 9.32(e) application, the in-park operations and connected actions associated with the nine proposed wells are as follows:

> **In-Park Operations** would consist of the subsurface operations taking place under the Unit (i.e., the wellbores crossing into the Unit at substantial depth, so as not to cross usable quality groundwater, to reach bottomhole targets beneath the Unit to extract hydrocarbons and other associated fluids).
>
> **Connected Actions** would consist of activities associated with construction and maintenance of access roads; construction and maintenance of well pads, production facilities and flowlines; drilling and completion of the wells; hydrocarbon production and transportation; and eventual well plugging and surface reclamation.

Sections 1.4.1 and 1.4.2 below explain how issues and impact topics related to in-park operations and connected actions are addressed in this EA.

1.4.1 Issues and Impact Topics Related to In-Park Operations

On January 11, 2016, the NPS completed a completeness and technical adequacy review of BP’s application, concluding that directionally drilling and producing the T well would qualify for a § 9.32(e) exemption with no mitigation (option 1). BP’s submittal of the application supplement related to hydraulic fracturing did not change this conclusion. The following discussion provides the basis for the finding.

NPS’ exemption analysis focuses on the distance between the portion of the well bore inside the Unit and the base of usable quality water zones. The T well surface location would be approximately 261 feet from the Unit boundary and the wellbore would enter the Unit at approximately 9,300 feet from surface. Operations in the Unit for the T well would occur approximately 7,350 feet below the protection depth of the usable quality water zone located 1,950 feet from the surface. Setting and cementing of the surface casing to protect the groundwater would be completed outside the Unit.

Based primarily on the separation between downhole activities inside the Unit and the groundwater protection depth, the NPS finds there is no reasonable expectation of impacts to the Unit resources from drilling and production operations conducted inside the Unit (in-park operations). Surface subsidence caused by fluid withdrawals and hydraulic fracturing are not a reasonable expectation because of the properties of the target reservoirs (depth of 9,500 feet or greater, average porosity of 15%, compaction, hydropressure, etc.), and the adjacent overlying sediments. Fracture of geologic formations with resultant usable quality water zone contamination is not an issue because the proposed drilling and production activities inside the Unit would occur at previously mentioned depths.

Hydraulic fracturing operations in the Unit from the T well would occur approximately 7,350 feet below usable quality water. The expected fracture length for the hydraulic fracturing operation is 500 to 1,000 feet. Fracture of geologic formations with resultant usable quality water zone contamination is not a reasonable expectation given 1) the properties – depth, porosity, compaction, hydropressure, etc., of the target reservoirs and adjacent overlying sediments, and 2) that the proposed completion activities inside the Unit would occur at least 6,350 feet below the deepest usable quality water zones.

Although the above analysis focuses on the T well, the NPS anticipates BP's eight additional directional wells would also qualify for an exemption with no mitigation because the wells would be located in close proximity to the T well and the protection depth of the usable quality water zone located at 1,950 feet from the surface is would be consistent over the small geographic area for all nine wells. Further, it is anticipated that BP would submit to the NPS the requisite supplement(s) to the exemption application for the eight additional wells that would demonstrate how the wells would be directionally drill to cross into the plane of the Unit at substantial depth below the protection depth of the usable quality water zone, similar to the T well. With these assumptions, it is likely that the exemption with no mitigation findings would also apply to the other eight wells. As a result, the NPS has determined that there would be no impacts on park resources from the in-park operations of any of the nine proposed wells; therefore, no issues and impact topics related to in-park operations warrant further analysis in this EA.

1.4.2 Issues and Impact Topics Related to Connected Actions

Based on project scoping, the NPS has identified several issues and impact topics related to the connected actions of BP's proposal that warrant further analysis in this EA. These are presented in Table 1 and are described and analyzed fully in § 3.

Table 1: ISSUES AND IMPACT TOPICS RELATED TO CONNECTED ACTIONS THAT WARRANT FURTHER ANALYSIS

Issue Statement	Impact Topic
Use of earth-moving and other construction equipment to construct and maintain access roads, well pads and flowlines, drilling and producing the wells, and eventual plugging and reclamation activities would increase noise in the vicinity of well drilling and production activities.	Natural Soundscapes in and outside the Unit
For all wells, drilling would require the use of rig and location lighting. If the wells prove to be productive, location lighting may be temporarily installed for various activities during the life of the well. Artificial lighting could interfere with views of the night sky in the area of the activity.	Night Skies in and outside the Unit
Oil and gas activities, including construction, drilling and production, and eventual well plugging and reclamation could impact air quality in the area of point sources and also contribute pollutants to the nearby Beaumont/Port Arthur and Houston/Galveston airsheds.	Air Quality in and outside the Unit

A number of potential impacts related to connected actions were initially considered, but have since been dismissed from full analysis. Brief explanations for dismissal are provided for each of these topics below.

1.4.2.1 Catastrophic Incidents, such as Well Blowouts, Well Fires, or Major Spills

One issue related to the proposed actions is the potential for catastrophic incidents, including well blowouts, well fires, or major spills. The Texas Railroad Commission (RRC) oversees the state's oil and gas industry, gas utilities, pipelines, safety in the liquefied petroleum gas industry, and surface mining and reclamation of coal and uranium. The RRC divides the state up into 12 Districts for purposes of administering and regulating oil and gas operations under its jurisdiction. The RRC maintains statistics on blowout, well control problems, and spills for each District. In this section, the NPS compiled data from the RRC website for calendar years 2006-2015 for incidents reported in RRC District 3, which includes the Preserve and would be representative of incidents that occur in or adjacent to the Preserve. RRC District 3 includes 29 counties in southeast Texas. Data are also presented for the seven counties with in District 3 in which the Preserve is located.

As of February 2016, there were approximately 8,505 oil producing wells and 3,075 gas producing wells in RRC District 3, totaling 11,580 wells, of which 2,719 wells (2,129 oil wells and 590 gas wells) or 23 percent of the District total are located within the seven counties where the Preserve is located (RRC 2016a).

Tables 2 and 3 below, show the number of reported well control problems, well fires, and major spills in RRC District 3 and the seven counties of the Preserve from calendar years 2006-2015 (RRC 2016b).

TABLE 2: WELL CONTROL PROBLEMS, WELL FIRES, AND MAJOR SPILLS IN RRC DISTRICT 3 FROM 2006 – 2015

Type of Incident	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Blowouts or Well Control Problems (during drilling operations)	3	0	0	0	0	5	1	3	1	1
Well Fires	0	0	0	0	0	0	0	0	0	0
Major Oil Spills (defined as exceeding 5 barrels)	44	50	82	35	58	27	37	79	47	24

Table 2 shows the highest number of blowouts or well control problems in RCC District 3 occurred during 2011, with five incidents (RRC 2016b). In 2011, a total of 318 wells were completed (RRC 2016a); thus, the probability for blowouts or well control problems was 0.0157 or 1.6 percent. The highest number of major oil spills occurred in 2008 with 82 incidents. During 2008, there were 7,393 producing oil wells (RRC 2016a); thus the probability for a major oil spill was 0.0111 or 1.1 percent.

TABLE 3: WELL CONTROL PROBLEMS, WELL FIRES, AND MAJOR SPILLS IN THE 7 COUNTIES OF BIG THICKET NATIONAL PRESERVE FROM 2006 – 2015

Type of Incident	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Blowouts or Well Control Problems (during drilling operations)	2	0	0	0	0	1	0	1	0	0
Well Fires	0	0	0	0	0	0	0	0	0	0
Major Oil Spills (defined as exceeding 5 barrels)	10	9	15	4	14	6	12	10	7	2

Table 3 shows the highest number of blowouts or well control problems in the seven counties the Preserve is located occurred in 2006 with two incidents (RRC 2016b). A breakdown of wells completed during 2006 in the seven counties the Preserve is located is not available on the Railroad Commission of Texas website; the probability for blowouts or well control problems was not calculated. The highest number of major oil spills occurred during 2006 with 10 incidents. During 2006, there were 1,991 producing oil wells (RRC 2016a); thus the probability for a major spill was 0.0050 or 0.5 percent.

Well Blowouts. The term "blowout" means the uncontrolled release of formation fluids (water/brine, oil, gas) from a well. Given present day technology, a well blowout is extremely rare. According to RRC data, the vast majority of reports deal with well control problems that never manifested in full, sustained blowouts.

Of the approximately 40 directional wells drilled outside the Preserve since 1986 for which the NPS issued § 9.32(e) exemption determinations, the Comstock Black Stone B1 well, drilled approximately 300 feet from the Big Sandy Creek Unit of the Preserve (approximately 32 miles northeast of the project location) in 2005, is the only well that reported well control problems. The well control problems reported by Comstock for the Black Stone B1 well did not result in a well blowout or well fire. During wireline operations to retrieve the measured well depth, the internal float on the drill string and the pickoff on the wireline lubricator failed resulting in oil-based drilling mud flowing up the drill pipe. The wireline was pulled out of the hole, the safety valve was shut in, and the well was secured. No injuries or fatalities occurred during the incident. The well control problems did not result in impacts off the well pad and there were no impacts on the resources and values in the Preserve.

Well Fires. From 2006 – 2015, no well fires were reported in District 3.

Major Spills. The RRC defines “major spills” as those exceeding five barrels of oil and requires reporting releases of that amount (Tex. Admin. Code Tit. 16, § 1.30 (2005). From 2006 - 2015, in RRC District 3, there were 483 spills reported greater than 5 barrels of oil, equating to approximately 1 spill for every 216 wells per year. Of the 483 spills, 89 were located in the seven counties where the Preserve is located. This equates to 1 spill for every 275 wells per year in the seven counties. Between January and July of 2015 in RRC District 3, there were 24 spills reported greater than 5 barrels of oil, equating to approximately 1 spill for every 483 wells per year. Of the 24 spills, 2 were located in the seven counties where the Preserve is located (RRC 2016b).

Any oil and gas operator that could reasonably be expected to discharge oil in harmful quantities, as defined in 40 CFR 110.3, into navigable waters, as defined by 40 CFR 110.1, is required to have a Spill Prevention, Control, and Countermeasure Plan (SPCC Plan) in accordance with 40 CFR Part 112. Some of the specific requirements that an operator of onshore oil drilling and workover facilities must adhere to include:

- Meet the general requirements listed under Sec. 112.7 and also meet the specific discharge prevention and containment procedures listed under this section.
- Position or locate mobile drilling or workover equipment so as to prevent a discharge as described in Sec. 112.1(b).
- Provide catchment basins or diversion structures to intercept and contain discharges of fuel, crude oil, or oily drilling fluids.
- Install blowout prevention (BOP) assembly and well control system before drilling below any casing string or during workover operations. The BOP assembly and well control system must be capable of controlling any well-head pressure that may be encountered while that BOP assembly and well control system are on the well.

Due to these requirements, in the rare event of a major spill consisting of five or more barrels of oil, the spill would be rapidly contained and removed so that impacts are short-lived and limited to the immediate area of operations. The RRC requires all soil containing over 1% Total Petroleum Hydrocarbon (TPH) be removed or remediated.

The NPS recognizes that unplanned incidents associated with oil and gas operations such as well blowouts, fires, and major spills near the boundaries of the Unit pose a risk to the immediate area and to Unit resources and values. However, the number of occurrences for such incidents is low as noted under Tables 2 and 3. If such an incident did occur, required onsite containment (described in the ‘Major Spills’ section) would reduce the potential for spilled substances or a well fire to spread into the Unit, and would provide for timely response and cleanup. Therefore, there is a reasonable expectation due to mitigation measures incorporated, that the spill would be confined to the well pads. In the event that there is a release into the Unit, the NPS could seek damages and restoration costs under the System Unit Resources Protection Act, 54 USC §§ 100721-100725.

Collectively, the RRC data indicates a low risk for catastrophic incidents. The addition of nine wells under the proposed action and the required mitigation actions taken (such as onsite containment) would not increase the risk of catastrophic incidents. Because the likelihood of well control problems, fires, and major spills is low, and it is not expected that a catastrophic incident would have more than a negligible impact, this topic was dismissed from further analysis.

1.4.2.2 Geology and Soils in and outside the Unit

The soils where BP proposes to construct and maintain roads, well pads and flowlines, and directionally drill and produce up to nine wells were examined using the Natural Resources Conservation Service soils data (NRCS 2013). The soils and topographic setting in these areas, and extending ½ mile into the Unit, are described below:

P, Q/R/S, and T Wells – The three well pads for these five wells, and the 200 foot long spur road for the Q/R/S wells, would be located in an area of nearly level sloped (0-1%) river valley terrace on a coastal plain mapped as Kenefick-Caneyhead (Ken(A)) soil complex. The Kenefick component makes up 52% of the map unit and consists of thick, well-drained, fine sand to sandy loamy soil. Depth to the root restrictive layer is greater than 60 inches. Water movement in the most restrictive layer is moderately low. Common properties include depths to water table ranging from 46 to 70 inches, and soil that is not flooded or ponded. The soil does not meet hydric conditions. The Caneyhead component, 40% of the map unit, is very poorly drained clay, silt, and very fine sandy loam. Depth to the root restrictive layer is greater than 60 inches. Water movement in the most restrictive layer is moderately low. Soil is not flooded but frequently ponded, and meets hydric conditions.

G Well – The well pad and 2,000 foot long spur road for this well would be located on a side slope of an interfluvial area mapped as Otanya very fine sandy loam making up 89% of the map unit, and Silsbee loamy fine sand making up 95% of the Silsbee map unit. Otanya is gently sloping (1-3%), whereas Silsbee is moderately sloping (5-12%). Both soils are thick and well drained, not flooded or ponded, and do not meet hydric conditions. Depth to the root restrictive layer is greater than 60 inches in both soils. Water movement in the most restrictive layer is moderately high. Depths to water table range from about 54 to 60 inches in Otanya soil to 80 inches in Silsbee.

J/U Wells – The well pad for this well would be located on gently sloping (1-3%) side of an interfluvial area mapped as Otanya very fine sandy loam. The soil is thick, well drained, with no flooding or pooling. The soil is not hydric. Depth to the root restrictive layer is greater than 60 inches. Water movement in the most restrictive layer is moderately high. Depths to water table range from approximately 54 to 60 inches.

F Well – The well pad for this well would be located on Ken (A) soil complex described above for the P, Q/R/S and T Wells, in the Votaw soil unit. Votaw landforms are nearly level sloping (0–1%) point bars on terraces. The map unit consists of thick, moderately well-drained, fine sand, with no flooding or pooling. The soil does not meet hydric conditions. Depth to the root restrictive layer is greater than 60 inches. Water movement in the most restrictive layer is high. Depths to water table are approximately 44 to 70 inches.

The general topography of the project areas can be characterized as low relief. Historic aerial imagery shows that a majority of the project area has been used as timberland since before 1995 (Google Earth 2015).

Construction of the well pads would have a direct adverse impact on soils on approximately 3.1 acres per well pad, totaling 18.6 acres if all six pads are constructed. Construction of a 200 foot long by 14 foot wide spur road to connect the Q/R/S well pad to an existing road would directly adversely impact 0.06 acres; and construction of a 2,000 foot long by 14 foot wide spur road to connect the G well pad to an existing road would directly adversely impact 0.64 acres. The total acreage that would be impacted from construction of well pads and spur roads would be approximately 19.3 acres, and could be long-term, extending over the potentially long producing life of the wells. To construct the well pads and spur roads, the areas would be mechanically cleared and leveled using heavy machinery and the soil amended with soil cement to provide a solid foundation, causing local effects to soil characteristics by decreasing soil permeability, changing surface drainage patterns, and hindering the penetration of plant roots. Removal of vegetation and earth-moving activities would increase soil erosion. Measures would be applied to reduce soil erosion. Soil exposure could last approximately 30 days for construction of each 3.1-acre well pad and associated spur roads. Construction of flowlines along access roads would result in a temporary impact on soils due to short-term excavation of a trench to lay the flowline and backfilling.

Accidental spills can occur during all phases of oil and gas activities and adversely impact soils. Vehicles used to access the wells and heavy equipment used to construct and maintain, and ultimately reclaim well pads, spur roads and flowlines, could leak fuel, lubricant, or coolant. Drilling and production activities could result in accidental releases of hydrocarbons, produced waters, and treatment chemicals

The probability for a major spill would be very low, as previously described (see § 1.4.2.1, "Catastrophic Incidents" above). The potential for spilled substances to be released off of well pads and transported to the Unit would be remote, based on the application of mitigation measures listed below. Most of the sites are relatively flat with low gradient sheet flow drainage towards the Unit. The distance from the well pads to the boundary of the Unit ranges from 42 to 649 feet. Unpaved forestry and other roads would serve as buffers between the well pads and the Unit. The following list of mitigation measures would contribute towards minimizing the potential for accidental spills to be released off the well pads (see Table 7 for a complete list of mitigation):

- Constructing a berm around the well pad and additional secondary containment for chemical storage,
- Constructing a washout/emergency pit,
- Using a closed-loop containerized mud system when using an oil-based drilling mud,
- Constructing a central delivery point (CDP) system for hydrocarbon and produced water instead of tank storage at each of the six well sites,

- Constructing secondary containment around the tank battery at the CDP that adheres to the SPCC Plan requirements that has sufficient capacity for the largest single container within the secondary containment plus sufficient freeboard for precipitation,
- Erosion control measures - the use of mulching, seeding, silt fences, and/or hay bales, and

Plugging the wells would result in cementing the well bores to prevent fluids from escaping to the surface. Surface reclamation would result in surface restoration as per the agreement with the surface owner.

Based on these measures and site conditions, there would be a low potential for migration of contaminants off the well pads, or to be transported into the Unit. The potential adverse impacts on geology and soils outside the Unit would be minor, with no potential for impacts in the Unit.

As described in § 3.3, Impacts on Air Quality, all phases of oil and gas activities could result in emissions of particulate matter, nitrogen oxides (NO_X), carbon monoxide (CO), carbon dioxide (CO_2), methane (CH_4), sulfur dioxide (SO_2), and volatile organic compounds (VOCs). Drilling of wells would have the greatest impact during the drilling operations due to increased use of vehicles and large gasoline and diesel engines used to power the drill rig, pumps, and auxiliary equipment during drilling. The dispersion of these emissions from point sources depends on a variety of factors, including the physical and chemical nature of the pollutants, meteorological conditions such as wind speed and direction, and downwind topography. In significant quantities, regional emissions of NO_x, SO_2 and particulate matter can impair visibility, or deposit on terrestrial and aquatic surfaces where they can affect soil nutrient cycling, acidify soils and surface waters, and contribute to detrimental ecosystem effects. However, due to the short-term drilling period for each of the nine wells, and the relatively small magnitude of emissions over this period, such impacts would be negligible.

Because the connected actions would have minor or less adverse impacts on geology and soils in and outside the Unit, this topic was dismissed from further analysis.

1.4.2.3 Water Resources, including Nearby Waterbodies, Groundwater, Floodplains and Wetlands in and outside the Unit

The six proposed well pads and two spur roads would be located within commercial timber lands last harvested in 2012. They would be within the Neches River drainage basin. As described above in the geology and soils section, the topography in the area is level to gently sloping towards the Unit (NRCS 2013).

Nearby Waterbodies. The nearest waterbodies are Maple Slough, Ard Lake, Clear Lake, and Black Creek located more than 900 feet from three proposed well pads for the F, P and Q/R/S wells.

Groundwater. As per the Groundwater Protection Determination letter from the Groundwater Advisory Unit provided in BP's application, the protection depth of the usable quality groundwater is located 1,950 feet from surface.

Floodplains. Sites for three proposed well pads for the P, Q/R/S, and T wells, and for the 200 feet long by 14 feet wide spur road to connect the Q/R/S well pad to an existing road, are located in a 100-year floodplain (high risk flood hazard zone with a 1% chance of flooding) (FEMA, 2010-2011).

Wetlands. Depressional hardwood wetland drainages are present in the vicinity and would be avoided by well pad placement. Well pads would be located a minimum 200 feet from any wetlands. Rainfall runoff from the roads is collected within these forested depression areas. Depressional hardwood wetland drainages are dominated by several wetland oak species and also include other common hardwood species. Groundcover can vary greatly in these depressional wetlands.

As described under § 1.4.1 (Issues and Impact Topics Related to In-Park Operations), BP's proposed surface casing and cementing program would result in no adverse impacts on usable quality groundwater resulting from the directional drilling and extraction of hydrocarbons at substantial depth beneath the Unit.

The proposed construction of well pads, spur roads connecting two well pads to existing roads, and flowlines; and the drilling, production and eventual plugging of wells and surface reclamation activities outside the Unit would have no impacts on nearby waterbodies or usable quality groundwater zones. Flowlines would be located along access routes, and would be buried a minimum 3 feet below surface. Construction of flowlines that cross wetland areas would comply with U.S. Army Corps of Engineers Nationwide Permit #12 that allows for the construction of pipelines that does not result in the loss of greater than ½ acre of waters of the United States for each single and complete project.

Three well pads upon which five wells would be drilled, and a 200 foot long by 14 foot wide spur road connecting the Q/R/S well pad to an existing road, would be located in the 100-year floodplain. The spur road would be constructed with culverts to avoid impounding stormwater. Locating the three well pads, and conducting oil and gas activities in the 100-year floodplain could increase flood hazards by potentially modifying the direction and velocity of surface water flow around the well pads, and providing a transport mechanism for any spilled substances that escape off of the wellpad to be carried into adjacent areas. However, with BP's proposed mitigation measures designed to confine any accidental spills to the pads, transport of contaminants off the pads and into floodwaters should be prevented, resulting in a minor adverse impact on floodplains..

As described in § 3.3, Impacts on Air Quality, all phases of oil and gas activities could result in emissions of particulate matter, nitrogen oxides (NO_X), carbon monoxide (CO), carbon dioxide (CO_2), methane (CH_4), sulfur dioxide (SO_2), and volatile organic compounds (VOCs). Drilling of wells would have the greatest impact during the drilling operations due to increased use of vehicles and large gasoline and diesel engines used to power the drill rig, pumps, and auxiliary equipment during drilling. The dispersion of these emissions from point sources depends on a variety of factors, including the physical and chemical nature of the pollutants, meteorological conditions such as wind speed and direction, and downwind topography. In significant quantities, regional emissions of NO_x, SO_2 and particulate matter can impair visibility, or deposit on terrestrial and aquatic surfaces where they can affect soil nutrient cycling, acidify soils and surface waters, and contribute to detrimental ecosystem effects. However, due to the short-term drilling period for each of the nine wells, and the relatively small magnitude of emissions over this period, such impacts would be negligible.

Because there would be no impact on groundwater, and minor or less impacts on nearby waterbodies, wetlands, and floodplains, this topic was dismissed from further analysis.

1.4.2.4 Vegetation in and outside the Unit

The proposed well pads, spur roads, and flowlines would be located on commercial timber lands, last harvested in 2012. The proposed sites are located in upland loblolly pine and pine plantations with advanced regeneration and upland hardwood forests. However, the hardwoods in the areas adjacent to the proposed well pad sites have remained forested for the last 20 plus years (Google Earth 2015).

The construction and maintenance of six well pads would convert 18.6 acres of commercial timber lands to oil and gas development, with additional impacts from construction of two spur roads measuring 200 and 2,000 feet long, and 14 feet wide, occupying 0.06 and 0.64 acres respectively. Installation of flowlines would result in temporary disturbance to vegetative cover until vegetation is naturally restored following excavation of trenches to place the flowlines and backfilling. Ground-disturbing activities could lead to the unintentional introduction and spread of non-native plant species transported to the site on earth-moving equipment used in construction activities. The vegetation that would be removed is primarily young pine plantation, not natural forest. Impacts from construction and maintenance would be localized at well pads, spur roads and along flowlines, lasting from days to one month over the potentially long-term producing life of the wells.

Accidental release of hydrocarbons and other contaminating and hazardous substances from vehicles and equipment could occur during all phases of oil and gas development, and if transported off the well pads and into adjacent areas could adversely affect adjacent vegetation. Mitigation measures to minimize the potential for spills and confine releases to the well pads, include complying with a SPCC plan, constructing and lining washout/emergency pit around wells with a plastic liner, siting developments in cleared areas from recent timber harvests, using a close-loop containerized mud system, and using silt fencing/hay bales to prevent soil erosion. All of the measures are intended to minimize and contain any spilled substances, resulting in low potential for accidental release, and for timely response in the event of a release.

If the wells are produced, flowlines would be constructed to carry products to a central delivery point. The trenching and boring used to install the flowlines would directly impact vegetation localized along the route of the flowline. Excavation of a trench approximately one foot wide by three feet deep would be located along existing roads to reach the central delivery point. Should flowlines be located across depressional wetland areas, the flowlines would be bored beneath the wetlands. Minor, short-term adverse impacts from the construction of flowlines lasting several days would be localized along the flowline routes. Vegetation along the flowline routes are anticipated to naturally recover within 1-2 years.

When wells are depleted, the wells would be plugged. This would have no impact on vegetation, as the plugging would be confined to the well pads and spur roads. After the wells are plugged, the well pads and spur roads would be reclaimed. Reclamation activities would consist of the same heavy equipment and vehicles used during the construction phase, and result in restoring the surface according to the land use agreement with the surface owner, and returning the lands for commercial timber development. Flowlines would be emptied and abandoned in-place.

Within the Unit, the vegetation within 0.5 miles of the three wellpads for the J/U, G, and F wells is upper slope pine oak forest; near the two wellpads for the T and Q/R/S wells, the vegetation is lower slope hardwood pine forest; and near the wellpad for the P well, the vegetation to the south and east is Flatland Hardwood Forest/Floodplain Hardwood Forest. The transition from upper slope, dry soils, to wetter soils reflects the changes from longleaf and shortleaf pine to loblolly pine. The species composition of oaks also shifts, with Southern red oak dominating on the upper slopes and white oak (*Quercus alba*) in high abundance on the mesic mid-slopes. Other significant lower slope hardwood species include Southern magnolia (*magnolia grandiflora*) and American beech (*Fagus grandifolia*).

The Flatland Hardwood Forest type occurs on flat, low elevation areas where drainage patterns are poorly developed and precipitation remains ponded for long periods of time. Dominant deciduous tree species include swamp chestnut oak (*Quercus michauxii*), willow oak (*Quercus phellos*) and laurel oak (*Quercus laurifolia*). An interesting geomorphic feature known as sand mounds are abundant in this community, and the drier microsites on these mounds frequently support loblolly pine. Jungle-like thickets of dwarf palmetto often dominate the understory in flatland forests. Along with baygalls, these dense palmetto thickets perhaps best exemplify the original and seemingly impenetrable “Big Thicket.” The Floodplain Hardwood Forest community is associated with higher order streams. This vegetation type is often generally referred to as bottomland hardwood forest. Extensive examples of these forests are found along the Neches River floodplain, especially in the Jack Gore Baygall and Neches Bottom Unit. Dominant tree species in this type include willow oak, laurel oak, and water oak (*Quercus nigra*) (NPS 2006a).

The Unit ecological classifications and descriptions used are derived from Harcombe and Marks, (1979) predicted vegetation types though the NPS and other federal agencies now use the United States National Vegetation Classification System (USNVC) alliances to describe vegetation types (USNVC 2016). Outside the Unit, the upperslope pine oak forest and mid slope pine oak forest would equate to Loblolly Pine-(Southern Red Oak, White Oak, Post Oak) Forest Alliance. In the upper slope areas, southern red oak would be codominant with loblolly pine. In the Mid Slope Pine Oak Forest white oak would be codominant with loblolly pine. This alliance may also include longleaf and shortleaf pine as being present or codominant species. The Lower slope Hardwood Pine Forest equates to the Beech-Magnolia Forest Alliance, Loblolly Pine (Willow Oak, Laurel Oak, Water Oak) Forest Alliance, where water oak is codominant with loblolly pine, and other similar alliances.

Within the Unit, Flatland and Bottomland Hardwood Forest can equate to a number of alliances. In areas where loblolly pine is present and codominant, the USNVC classification would be Loblolly Pine (Willow Oak, Laurel Oak, Water Oak) Forest Alliance. In areas where loblolly pine is absent, the most common classification would be Willow Oak, Laurel Oak, Water Oak Forest Alliance. Depending on the soil types and hydrologic regimes a number of other species could be present and would determine the classifications.

Also within the Unit, baygalls are generally associated with two USNVC alliances depending on the presence of sweetbay magnolia and other wetland trees. In areas where sweetbay magnolia is present, the classification would be Sweetbay Magnolia-Gallberry Holly

Saturated Forest Alliance. Other areas where sweetbay magnolia and other canopy trees are absent, the classification would be Gallberry Holly Shrubland Alliance.

Impacts on vegetation in the Unit from connected actions would be negligible based on the low chance of a catastrophic release, mitigation to prevent releases and offsite contamination, and the relatively flat topography and low runoff potential.

As described in § 3.3, Impacts on Air Quality, all phases of oil and gas activities could result in emissions of particulate matter, nitrogen oxides (NO_X), carbon monoxide (CO), carbon dioxide (CO_2), methane (CH_4), sulfur dioxide (SO_2), and volatile organic compounds (VOCs). Drilling of wells would have the greatest impact during the drilling operations due to increased use of vehicles and large gasoline and diesel engines used to power the drill rig, pumps, and auxiliary equipment during drilling. The dispersion of these emissions from point sources depends on a variety of factors, including the physical and chemical nature of the pollutants, meteorological conditions such as wind speed and direction, and downwind topography. In significant quantities, regional emissions of NO_x and VOCs contribute to ozone formation. Ozone is a photochemical oxidant that can harm sensitive vegetation through foliar injury and growth effects such as premature leaf low or reduced photosynthesis. A risk assessment concluded that sensitive plants present in the Preserve were at high risk for ozone damage (Kohut 2007; Kohut 2004). Excess nitrogen deposition can also affect plants through altered soil nutrient cycling, and changes in plant communities and species. However, due to the short-term drilling period for each of the nine wells and the relatively small magnitude of emissions over this period, such impacts from this project would be negligible.

Because there would be minor or less adverse impacts on vegetation in and outside the Unit, this impact topic was dismissed from further analysis.

1.4.2.5 Fish and Wildlife in and outside the Unit

The analysis area includes 1,900 feet from each proposed well, which represents the distance required for elevated noise levels from well drilling, the highest noise-producing activity, to attenuate to the background level of 41 dBA measured in the Unit (see § 3.1, Impacts on Natural Soundscapes in and outside the Unit).

The nearest waterbodies that provide fish habitat are Maple Slough, Ard Lake, Clear Lake, and Black Creek, located more than 900 feet from three proposed well pads for the F, P and Q/R/S wells. Fish in these waterbodies are likely to include largemouth bass, bluegill sunfish, and channel catfish (TPWD 2016a). Due to the distance of the well pads from these waterbodies, the proposed directional drilling and production of up to nine wells is not anticipated to impact fish.

Typical species that inhabit the general area includes such large mammals as raccoon, striped skunk, gray fox, eastern cottontail rabbit, Virginia opossum, coyote, beaver, and white-tailed deer, which are often found in relatively disturbed or urbanized settings and are generally distributed throughout Texas.

BP contracted with DESCO Environmental Consultants, LP (DESCO) to conduct a threatened and endangered species survey within the analysis area. DESCO and the NPS reviewed the Texas Parks and Wildlife Department's list of 27 state-listed species that may occur in Hardin County (TPWD 2016b). DESCO conducted field surveys on August 25 and September 22, 2015, and found marginally suitable habitat in the analysis area for four state-listed species (peregrine falcon, American peregrine falcon, black bear, and Louisiana black bear); and suitable habitat in the analysis area for two state-listed species (Northern scarlet snake and timber rattlesnake). The peregrine falcon and American peregrine falcon may be potential migratory transients in the area. The peregrine falcon and American peregrine falcon could utilize open areas for hunting during migration. The Louisiana black bear and black bear may be found in the forests of Hardin County, though a sighting would be extremely rare due to the sparse transient nature of the black bear population in east Texas. The black bear subspecies are bottomland generalists and will forage in adjacent uplands. Northern scarlet snake and timber rattlesnake are present in forested habitats within the area. The presence of Northern scarlet snake may be limited due to the silty nature of the soils in the analysis area. Timber rattlesnakes in the area are generally associated with bottomlands but may utilize adjacent upland habitats for hunting. None of these species were observed during the field surveys. An analysis of potential impacts for fish and wildlife follows.

Construction of the well pads and spur roads would convert commercial timber lands to oil and gas development on 3.1 acres per well pad, totaling 18.6 acres if all six pads were constructed, and on 0.06 and 0.64 acres for the two spur roads. Short-term modification to habitat could also occur from the construction of flowlines. All surface activities would be situated in areas with existing degraded wildlife habitat, with histories of extensive land disturbance, primarily from commercial timber lands (clear cutting). Wildlife would be displaced from habitat modified for well pads and spur roads. Construction activities would last approximately 30 days per well pad/road, with routine maintenance lasting one to several days occurring intermittently over the potentially long producing life of the wells, resulting in minor adverse impacts on wildlife localized near developments outside the Unit. Impacts may extend into the Unit due to wildlife moving away from the surface activities and into the Unit.

Areas within the Unit that are located adjacent to the proposed well pads support more diverse wildlife communities, as the Preserve has been protected from commercial timber harvest and agriculture for some time and provides a variety of natural habitats. Wildlife that inhabit the outer boundaries of the Unit, however, become more acclimated to nearby disturbances and noise, since forestry operations, roadways, and various densities of private residences and other uses occur in close proximity to the Unit.

All phases of oil and gas operations can introduce elevated noise levels. During the drilling phase for each well, increased noise would occur for the longest period of time, 30 to 45 days for each well, and would be continuous, 24-hours a day. As described in § 3.1, Impacts on Natural Soundscapes in and outside the Unit, elevated noise from well drilling would measure 66 dBA at the edge of the well pad and decrease to the background level measured in the Unit of 41dBA within 1,900 feet from the well. Elevated noise could cause wildlife that occupy habitat near the oil and gas facilities to move away from the noise sources and possibly displace wildlife in adjacent areas. Due to the distance of the nine wells ranging from 261 (T well) to 920 feet from the Unit boundary, elevated noise levels could encroach 980 to 1,639 feet into the Unit.

Artificial lighting could also affect wildlife. Lighting would be greatest during the 30-45 days of drilling for each well. “Animals can experience increased orientation or disorientation from additional illumination and are attracted to or repulsed by glare, which affects foraging, reproduction, communication, and other critical behaviors. Artificial light disrupts interspecific interactions evolved in natural patterns of light and dark” (Longcore and Rich 2004). As described in § 3.2 (Impacts on Night Skies in and outside the Unit), the NPS calculated the distance that illuminance from a drill rig would decrease to reach the baseline level in the Unit. However, the dense vegetation in the Unit is expected to drastically lower the calculated 1,500-foot distance that light would travel from the drill rig and into the Unit. Due to the distance of the nine wells ranging from 261 (T well) to 920 feet from the Unit boundary, artificial lighting could extend up to 580 to 1,239 feet into the Unit. However, the dense vegetation and tall forest canopy in the Unit is expected to reduce the distance that artificial light could extend into the Unit.

The potential for leaks and spills exists for all phases of oil and gas activities. However, no major spills would be likely and the potential for runoff to reach lands and impact wildlife habitat and food sources inside the Unit would be remote, based on soil type, site topography, geographic features, and mitigation measures that BP has committed to for all phases of operations.

As compared to the drilling phase, impacts to wildlife would be reduced during the production phase, which has the potential to be long-term over the producing life of the wells (2-50 years or longer). Similar to elevated noise levels during the drilling phase, elevated noise would occur during short periods when work-overs are conducted on wells to improve production levels. Work-over typically occur at 5-10 year intervals and last for 1 to 2 weeks.

Plugging of wells and reclamation activities would involve the use of heavy equipment that would introduce elevated noise levels. Reclamation would return the surface to active timber management.

As described in § 3.3, Impacts on Air Quality, all phases of oil and gas activities could result in emissions of particulate matter, nitrogen oxides (NO_X), carbon monoxide (CO), carbon dioxide (CO_2), methane (CH_4), sulfur dioxide (SO_2), and volatile organic compounds (VOCs). Drilling of wells would have the greatest impact during the drilling operations due to increased use of vehicles and large gasoline and diesel engines used to power the drill rig, pumps, and auxiliary equipment during drilling. The dispersion of these emissions from point sources depends on a variety of factors, including the physical and chemical nature of the pollutants, meteorological conditions such as wind speed and direction, and downwind topography. In significant quantities, regional emissions of such pollutants can affect fish and wildlife habitat. For instance, regional emissions of NO_x and SO_2 can deposit on terrestrial and aquatic surfaces where they can affect soil nutrient cycling, acidify soils and surface waters, and contribute to detrimental ecosystem effects, which may result in habitat effects. However, due to the short-term drilling period for each of the nine wells, and the relatively small magnitude of emissions over this period, such impacts would be negligible.

Due to the low level of impacts, this impact topic was dismissed from further analysis.

1.4.2.6 Federally-listed Threatened and Endangered Species in and outside the Unit

Under the Endangered Species Act of 1973 (ESA), the NPS has responsibility to address impacts on federally-listed, candidate, and proposed species. The proposed operations would qualify for an exemption with no mitigation, because the wells would originate on lands located outside of the Unit, and the wellbores would cross through the Unit at a sufficient depth to preclude any effect on surface resources (species or habitat) within the Unit. As a result, there would be no effect on federally listed threatened and endangered species and/or critical habitat from in-park operations.

For connected actions, the analysis area encompasses an area within a 1,900 feet radius from each proposed well, which represents the distance required for elevated noise levels from well drilling, the highest noise-producing activity, to attenuate to the background level of 41 dBA measured in the Unit (see § 3.1, Impacts on Natural Soundscapes in and outside the Unit).

DESCO and the NPS reviewed the U.S. Fish and Wildlife Service list of federally-listed threatened or endangered species known or are believed to occur in Hardin County (USFWS 2016). The list includes five species: the endangered least tern (*Sterna antillarum*), threatened piping plover (*Charadrius melodus*), threatened red knot (*Calidris canutus rufa*), endangered red cockaded woodpecker (*Picoides borealis*), and endangered Texas trailing phlox (*Phlox nivalis* ssp. *texensis*). There is no suitable or critical habitat for least tern, piping plover, and red knot within the analysis area. These three species are migratory and need only be considered for wind related projects, which is not applicable to the proposed action. There is no suitable or critical habitat present within the analysis area for either red cockaded woodpecker or Texas trailing phlox. These five species would not utilize the analysis area or habitat. DESCO conducted field surveys on August 25 and September 22, 2015. There are no federally-listed species or critical habitat in the analysis area nor would these species utilize the analysis area, resulting in a “no effect” ESA determination for connected actions. For the above reasons, this impact topic was dismissed from further analysis.

1.4.2.7 Cultural Resources in and outside the Unit

Impacts from in-park operations was dismissed in § 1.4.1 because the wellbores crossing into the plane of the Unit at sufficient depth below the protection depth for the usable quality groundwater zone would have no impact on the usable quality groundwater or the surface of the Unit. Under a § 9.32(e) exemption with no mitigation, actions by the NPS with respect to the National Historic Preservation Act are non-discretionary; the NPS has no § 106 responsibility, nor authority, associated with the wells for the proposed in-park operations for which a § 9.32(e) exemption is being evaluated (NPS 2006a). As part of the NEPA analysis, however, the NPS is providing the following analysis, using available data, of the effects of the connected actions occurring outside the Unit on cultural resources.

Although the NPS has no authority to require BP to contract an archeological survey in the project area on lands outside the Unit, BP voluntarily contracted with DESCO to conduct a records search for the presence of any previously recorded archeological sites or cemeteries in the areas where ground-disturbing activities are proposed to construct well pads, spur roads, and flowlines, and extending up to approximately one mile from the proposed developments. Review of the Texas Historical Commission's (THC) Texas Archaeological Sites Atlas (http://atlas.thc.state.tx.us/) found no sites within the analysis area. One historic structure is located outside the Unit, within approximately 1,900 feet of the J/U well pad, and nine archeological sites located inside the Unit, are located within approximately 0.2 to 1.3 miles (1,000 to 6,900 feet) from the proposed well pads.

The NPS reviewed the list of National Register of Historic Places website and found no sites listed in or near the project area (http://www.nationalregisterofhistoricplaces.com/tx/hardin/state.html/). The review of the NPS' Archeological Sites Management Information System database found the same sites identified through DESCO's research.

As described in the limited impact analysis for Catastrophic Incidents, such as Well Blowouts, Well Fires, or Major Spills in § 1.4.2.1, there is a low risk for such incidents. Further, as described in the limited impact analysis for Geology and Soils in § 1.4.2.2, due to the low gradient topography sloping towards the Unit, and BP's design for production for all nine wells to be centralized at a central delivery point on one well pad, in addition to the mitigation measures BP would apply to minimize the potential for an accidental release and measures to contain any spilled substances on the well pad, there is a low probability for hydrocarbons and associated liquids or other contaminating substances to escape the well pads and be transported into the Unit. The potential for accidental releases to impact archeological sites in the Unit would be negligible; however, the potential could be long-term, extending over the potentially long producing life of the wells.

Because there are no known cultural resources located in the areas where BP proposes to construct well pads, spur roads, and flowlines; and there would be low risk for catastrophic incidents and low probability for accidental releases from escaping the well pads and being transported into the Unit, the impact topic, cultural resources, was dismissed from further analysis.

1.4.2.8 Visitor Use and Experience in the Unit

Few visitors would be expected in the Unit near the proposed surface locations, since there are limited visitor use developments or amenities within the Unit adjacent to the well pads. The primary visitor uses in the area includes fishing and canoeing in and around Ard and Clear Lakes, located more than 900 feet from three proposed well pads for the F, P and Q/R/S wells. Some visitors, however, may hike off of access roads to enjoy the solitude and view the natural scenery. Most recreational use in the Unit would occur during daylight hours.

Constructing and maintaining up to six well pads, drilling and producing up to nine wells, constructing and maintaining flowlines, and the eventual plugging and reclamation would introduce elevated noise levels, artificial lighting, air quality impacts, and pose a threat of hydrocarbon contamination to Unit visitors.

As described in § 3.1, Impacts on Natural Soundscapes in and outside the Unit, elevated noise would be greatest during the 30-45 day drilling period for each well, and to a lesser extent during construction and maintenance of well pads, roads and flowlines, and during occasional well workovers over the producing life of the wells. Elevated noise levels can extend up to 1,900 from the drilling rig. Well pads would be located within 42 to 649 feet from the Unit boundaries, and the wells would be within 261 to 920 feet from the Unit boundaries. The construction, drilling and production, and eventual plugging and abandonment activities outside the Unit would result in elevated noise levels encroaching into the Unit approximately 980 to 1,639 feet, resulting in negligible to minor, adverse impacts on visitor use and experience in the Unit.

As described in § 3.2, Impacts on Night Skies in and outside the Unit, the introduction of artificial lighting would occur during the drilling phase due to the use of drilling rigs around the clock for 30-45 days per well, with little artificial lighting proposed during the construction, production, and eventual plugging and reclamation phases. Lighting from drill rigs would extend approximately 1,500 feet and encroach up to 580 to 1,239 feet into the boundary of the Unit, resulting in short-term, negligible, adverse impacts on visitor use and experience in the Unit.

As described in § 3.3, Impacts on Air Quality in and outside the Unit, all phases of oil and gas activities could result in emissions of particulate matter, nitrogen oxides (NO_x), carbon monoxide (CO), carbon dioxide (CO_2), methane (CH_4), sulfur dioxide (SO_2), and volatile organic compounds (VOCs), that would be discernible by odor and visual quality. Impacts on visitor use and experience in the Unit would be greatest during the drilling of the wells when the greatest volume of emissions would occur, resulting in minor adverse impacts on visitor use and experience in the Unit, localized near the wells, and reducing to negligible adverse impacts extending over the potentially long producing life of the wells.

Impacts on Unit visitors from connected actions could also result from releases of hydrocarbons and other contaminating substances from activities outside the Unit. The potential for contamination is very low, as described under “Catastrophic Incidents,” “Geology and Soils,” “Water Resources” and “Vegetation” described earlier. The possibility of catastrophic release was dismissed, based on the very low probability of occurrences in the area. Also, BP has included mitigation measures to reduce the potential for accidental spills and to prevent the escape of any accidental releases from the well pads. Based on the low visitation in the Unit, the distance of surface activities proposed outside the Unit, and mitigation measures to reduce the potential for spills and the transport of contaminants offsite, there would be a very low potential for impacts on visitor use and experience in the Unit.

Based on the low level of visitor use in these areas, the distance of proposed operations from the Unit, and the mitigation measures that would be applied, the effects of elevated noise levels, artificial lighting, increased air emissions, and the very low probability for release and transport into the Unit of hydrocarbons and other contaminating substances, the impacts of the proposed directional drilling and production of up to nine wells would have short- to long-term, negligible to minor, adverse impacts on visitor use and experience in the Unit. Due to the low level of impacts anticipated, visitor use and experience in the Unit was dismissed from further analysis.

1.4.2.9 Greenhouse Gas Emissions

The proposed actions analyzed in this assessment would involve the use of vehicles to access operations locations, the use of earthmoving equipment to construct and eventually reclaim access roads, well pads and flowlines, and the use of combustion engines to power the drilling rig. Air quality impacts are analyzed in § 3.3, Impacts on Air Quality in and outside the Unit, which describes short-term, moderate adverse impacts from drilling activities, to long-term, minor adverse impacts over the producing life of the wells. The proposed action would have a negligible contribution towards cumulative, moderate adverse effects on the Beaumont/Port Arthur airshed. Based on the emissions anticipated from drilling the proposed wells, the proposal would not have more than negligible effects on the amount of greenhouse gas emissions for the surrounding airshed; therefore, this topic was dismissed from further analysis in this EA.

1.4.2.10 Socioeconomics

Socioeconomic issues include the effect of the proposed drilling and production of the wells on the local and regional economies. BP's proposal to directionally drill and produce up to 9 wells would generate revenue for the local economy through mineral leases and/or royalties paid to adjacent private landowners and revenues for local businesses from the purchase of food, fuel, lodging, and other incidental purchases by construction, drilling, production, and eventual well plugging and site reclamation crews. Because lease, bonus payment, and royalty revenue from oil and gas production of the wells would likely affect only private landowners, and revenues to the local and regional economies would have a minor effect, socioeconomics was dismissed from further analysis

1.4.2.11 Environmental Justice

Executive Order 12898, "General Actions to Address Environmental Justice in Minority Populations and Low-Income Populations," requires all Federal agencies to incorporate environmental justice into their missions by identifying and addressing disproportionately high and adverse human health or environmental effects of their programs and policies on minority and low-income populations and communities. Per the United States Census Bureau, Hardin County is not considered "low income" as less than 20 percent of their residents is below the poverty level (12.9 percent per the United States Census Bureau, 2016). Hardin County consists of 91.9 percent caucasian (U.S. Census Bureau 2016). Furthermore, the proposed action would not have disproportionate health or environmental effects on the community. Therefore, environmental justice was dismissed from further analysis.

1.4.2.12 Indian Trust Resources and Indian Sacred Sites in the Unit

There are no Indian Trust resources or Indian sacred sites in the Unit; therefore, this impact topic was dismissed from further analysis.

2.0 ALTERNATIVES, INCLUDING THE PROPOSED ACTION

Two alternatives are described and evaluated in this EA: Alternative A, No Action, and Alternative B, Proposed Action, Application as Submitted. Alternatives considered but dismissed from further analysis are described, and the reasons for dismissing them are provided.

2.1 ALTERNATIVE A, NO ACTION

Under No Action, the NPS would not provide a § 9.32(e) exemption with no mitigation and, therefore, no directional wells would be drilled.

2.2 ALTERNATIVE B, PROPOSED ACTION, APPLICATION AS SUBMITTED (NPS PREFERRED ALTERNATIVE

Under Alternative B, the NPS would grant BP a § 9.32(e) exemption with no mitigation for BP's first proposed directional well, T well. The NPS also would consider granting exemptions to directionally drill and produce an additional eight wells in the Ticonderoga Gas Unit if BP decides to move forward with them and provides the NPS with the additional information required, including, for each well, 1) an approved state of Texas drilling permit, 2) a Groundwater Advisory Unit, and if applicable, and 3) any revisions to the currently-proposed methodology to directionally drill and produce the wells. (See §§ 1.1 and 1.2 for BP's application history.)

Figure 1 shows the proposed surface and bottomhole locations of all nine wells in relation to the boundaries of the Unit, existing roads, and land features. The nine wells are identified as F, G, J, P, Q, R, S, T, and U. All surface activities, including construction of well pads and spur roads, drilling and production, and eventual well plugging and surface reclamation, would be located outside of the Unit. Operations inside the Unit boundaries (in-park operations) would consist only of the wellbores (i.e., drill holes) crossing into the plane of the Unit boundary substantially below the State-identified protection depth of the usable quality ground water zones.

2.2.1 Locations of the Proposed Wells

The surface and bottomhole locations for the wells are provided in Table 4, below. Surface locations for the wells would be located 261 to 920 feet from the Unit boundary.

TABLE 4: LOCATION FOR THE PROPOSED WELLS

Well	Location (U.S. State Plane Coordinate System, NAD 1983 UTM Zone 15N, meters)		Distance from the Surface Well Location to the Unit Boundary
	X	Y	Feet
Well F (Surface Location)	389715.8	3375618.3	762
Well F (Bottomhole)	390565.8	3374719.2	
Well G (Surface Location)	388912.2	3375395.1	292
Well G (Bottomhole)	389183.6	3374537.6	
Well J (Surface Location)	388175.8	3373577.9	598
Well J (Bottomhole)	389896.8	3373767.8	
Well P (Surface Location)	392846.4	3374941.3	711
Well P (Bottomhole)	393700.9	3374105.8	
Well Q (Surface Location)	392323.8	3375002.1	920
Well Q (Bottomhole)	390635.5	3374460.9	
Well R (Surface Location)	392344.1	3375001.9	919
Well R (Bottomhole)	391965.8	3374072.6	
Well S (Surface Location)	392366.8	3375000.5	914
Well S (Bottomhole)	392037.1	3374045.7	
Well T (Surface Location)	391300.6	3374906.4	261
Well T (Bottomhole)	390121.4	3374894.4	
Well U (Surface Location)	388175.9	3373584.1	615
Well U (Bottomhole)	389888.4	3373843.5	

2.2.2 Construction of Spur Roads and Well Pads

The well pads would be accessed via existing unpaved roads outside the west and north boundaries of the Unit. Spur roads would be constructed to connect existing roads to the well pads. Each of the well pads would measure approximately 300 x 450 feet, or approximately 3.1 acres each, totaling 18.6 acres for the six well pads. Two new spur roads would be approximately 200 feet long to the Q/R/S well pad, and 2,000 feet long to the G well pad. Each of the two spur roads would be 14 feet wide and occupy 0.06 to 0.64 acres for each spur road. The well pads and spur roads would be mechanically cleared by heavy machinery. Woody debris would be chipped and deposited on location. The soil would be amended with soil cement to provide a solid foundation. Aggregate would be hauled in by dump trucks and placed over the stabilized soil. This would significantly reduce the amount of nuisance dust generated by vehicular traffic.

Approximate minimum distances from each well pad to the boundary of the Unit are shown in Table 5, and would range from 42 to 649 feet.

Construction activities would take place during daylight hours and last approximately 30 days per well pad/associated spur road.

The Q/R/S, P, and T well pads and Q/R/S spur road would be located within a FEMA designated high risk flood hazard zone area, meaning an area of 1% chance of flood hazard (FEMA 2010 and 2011). The Q/R/S spur road design would include culverts, as appropriate, to avoid impeding storm water within the floodplain. The J/U, F, and G well pads would be located outside the 1% chance of flood hazard area. Throughout the construction phase of each well pad, BP would implement the following voluntary stormwater best management practices, to prevent potential contaminated fluids and sediments from leaving the site and impacting surface water:

- Minimize the footprint of the disturbed area,
- Construct a berm around the approximate 3.1-acre well pads,
- Plan the site location to choose low-slope sites away from waterways,
- Manage slopes to decrease steepness,
- Maintain the maximum amount of vegetative cover as possible,
- Practice good housekeeping including proper material storage, and
- Use erosion control measures, including the use of mulching, seeding, silt fences, and/or hay bales.

Construction of the well pads and spur roads would not result in discharging dredge or fill material into waters of the U.S. and, therefore, would not require a § 404 permit from the U.S. Army Corps of Engineers per §404 of the Clean Water Act.

TABLE 5: WELL PAD DISTANCE TO THE UNIT BOUNDARY

Well Pad	Minimum Distance from Well Pad to Unit Boundary (feet)
F Well Pad	433
G Well Pad	82
J/U Well Pad	422
P Well Pad	394
Q/R/S Well Pad	649
T Well Pad	42

2.2.3 Drilling

BP would comply with all provisions of the RRC's statewide oil and gas regulations to drill, operate, and eventually plug the wells to ensure the protection of usable quality water zones.

BP's proposed directional drilling of the T well would consist of installing a 9-5/8-inch surface casing to an approximate depth of 3,300 feet true vertical depth (TVD). This surface casing would be cemented from the installed depth of approximately 3,300 feet TVD back to the surface. No oil or gas production zones would be intersected during the installation of the surface casing. All surface casing would remain outside the boundaries of the Unit. Surface casing would be installed per state requirements and in a manner that is protective of groundwater bearing zones. The casing would extend below the protection depth of the usable quality ground water zone located 1,950 feet from surface, and the cement would meet quality requirements per RRC Statewide Rule 13 (i.e., the cement standards set forth in API Specification 10A: Specification for Cement and Material for Well Cementing or the American Society for Testing and Materials (ASTM) Specification C150/C150M, Standard Specification for Portland Cement). Cement would be circulated back to surface to provide a barrier between groundwater bearing zones (approximately 1,950 feet) and the production zones (greater than 9,000 feet). The well would continue to be drilled vertically to an approximately depth of 9,300 feet before deviating directionally into the plane of the Unit to reach 10,000 TVD / 13,749 measured depth (MD).

A 7-inch intermediate casing would be landed in the directional target sand at approximately 10,000 TVD and cemented back to the surface.

The completion method for the lateral portion of each of the wells would be selected among several options after the target zone has been drilled based on the best available information at that time, such as data gathered during the process of drilling, data from other nearby wells, and the expertise of the subsurface team. Potential options to be considered for each well include, but are not limited to, the following: (1) 4-1/2 inch slotted liner, (2) cemented liner with perforations, and (3) open-hole completion within the lateral section.

Hydraulic fracturing is a formation stimulation practice used to create additional permeability in a producing formation, thus allowing gas and oil to flow more readily toward the wellbore. Hydraulic fracturing involves the pumping of a fracturing fluid into a formation at a calculated, predetermined rate and pressure to generate fractures or cracks in the target formation. Fracture fluids are primarily water-based fluids mixed with additives which help the water to carry sand proppant into the fractures. The sand proppant is needed to “prop” open the fractures once the pumping of fluids has stopped (Ground Water Protection Council 2009).

If the completion method selected includes hydraulic fracturing, the hydraulic fracturing operation would occur approximately 7,350 feet below usable quality water. The expected fracture length for the hydraulic fracturing operation would be 500 to 1,000 feet. The NPS determined that compliance with RRC Statewide Oil and Gas Rules should provide the necessary protection of usable quality water zones. However, should the Chemical Disclosure Register known as FracFocus be inoperable, BP would need to supply the NPS with a full chemical disclosure and well completion report within 90 days of completing the hydraulic fracturing stimulation treatment.

A reserve pit would be constructed to contain the water-based drilling mud used for drilling the surface casing portion of the hole. The size of the reserve pit would measure approximately 85 feet x 30 feet x 8 feet and would be used only for the surface casing portion of the hole. The drill site pad size would be reduced accordingly.

All additional drilling operations would utilize a closed-loop system to manage the drilling mud and cuttings. A closed-loop system maintains mud and cuttings in aboveground storage tanks to recirculate drilling mud and contain drill cuttings prior to removal from the site. Earthen pits would not be utilized to store oil-based drilling mud or the cuttings, and all fluids and cuttings would be hauled offsite for recycling or disposal. Other waste streams such as general refuse, used oil, solvents, etc. generated during the process of drilling or production would be properly managed and disposed of at offsite third-party recycling or disposal facilities.

BP anticipates the drilling rig to be on location outside of the Unit for 30-45 days per well; however, certain circumstances may require an extended presence. During this time, operations would occur 24 hours per day, 7 days per week.

During drilling operations, the drilling company contracted by BP would have a Spill Prevention Control and Countermeasures (SPCC) Plan in place that covers the drilling rig and its associated operations in accordance with 40 CFR Part 112. Once drilling is complete and production operations begin, BP would have an SPCC Plan in place that covers normal production operations (also in accordance with 40 CFR Part 112). The SPCC Plans would address secondary containment for containers containing/storing oil and measures to prevent a discharge of oil to waters of the U.S. The SPCC Plans would also address resources (e.g., emergency response contractors) in the event of a spill.

Traffic would be highest during drilling (approximately 30-45 days) when there would be 2-10 delivery/equipment trucks per day plus 10-15 passenger vehicles per day entering and leaving the well location. While the drilling rig is moved to and from location, there would be 10-15 delivery/equipment trucks for 1-2 days. If hydraulic fracturing is needed, there would be 25-40 delivery/equipment trucks over a period of 4-5 days. During the completion period (approximately 15-20 days), there would be 1-2 delivery/equipment trucks per day plus 2-5 passenger vehicles per day. Once the well has been completed, the only traffic to the well would be occasional maintenance vehicles. All other traffic would be focused at the centralized delivery point.

2.2.4 Production

Should any well be successfully completed as a producing oil and/or gas well, flowlines would be installed outside of the boundaries of the Unit to transport produced products to a central delivery point. Flowlines would be located along access routes, and would be buried a minimum three feet below the ground surface. Any crossings of wetland areas would comply with the U.S. Army Corps of Engineers' Nationwide Permit #12 that allows for the construction of pipelines that does not result in the loss of greater than ½ acre of waters of the United States for each single and complete project.

A wellhead, meter run, solar panel, and remote telemetry unit (RTU) would remain at each producing well. The well would flow full well stream to a central delivery point (CDP) located completely outside of the Unit. Certain production equipment such as a test separator(s), artificial lift and/or wellhead compression may be located at the surface well location facility as warranted. Some factors that may be considered in placement of subsequent production equipment are reservoir pressure and the operating pressure of the production flowlines and associated gathering system into which the production would flow.

The potential exists for utilizing chemical tanks to assist in the production and maintenance of these wells. The chemical tank(s) would be approximately 500 gallons in size and would be located within secondary containment. The types of substances that could be stored in the chemical tanks and used for or result in production activities include diesel fuel, motor oil, tri-ethylene glycol, condensate, and corrosion inhibitor.

As suggested above, the potential exists for utilizing artificial lift, for which there are various methods such as the use of electric submersible pumps (ESPs) or pumping units. The ESP or pumping unit would require power from an electric generator or from an engine or electric generator, respectively. In either case, fuel for the engine would most likely be natural gas, but could potentially be diesel in certain instances.

The potential also exists for wellhead compression or gas lift at the wellsite. In either case, an engine or generator would be required to drive the compressor, which would most likely be fueled by natural gas, (or potentially diesel in certain instances).

Real-time wellhead data (pressure, flow rates, temperature) would be remotely monitored by BP to ensure that the well is producing properly and safely. This would reduce the amount of vehicular traffic to the wellsite. It would also allow for early detection of any upset conditions. The real-time data would also be analyzed by a programmable logic controller (PLC) to automatically take pre-programmed actions based on recorded wellhead data.

Produced water that comes to the surface/is produced along with the oil and gas from the successful wells would be collected at the central delivery point (CDP) and injected into either commercial third-party Class II disposal wells or BP's own Class II injection wells regulated under the Underground Injection Control (UIC) regulations administered by the Railroad Commission of Texas. In the case of third-party wells, the produced water would be transported to the wells via truck. In regard to BP's own injection wells, the water would be either trucked or piped to BP's well(s). The determination of which method would be used would depend on several factors including the volume of produced water generated by the producing wells. An operator would be in the general vicinity conducting daily visits to the CDP. Abnormalities observed at the CDP may prompt a visit to a particular wellsite.

Over the potentially long-term production life of the well, the NPS anticipates BP would undertake occasional workover operations. Usually these occur every 5 to 10-years and take one to two weeks to complete. Workovers and well servicing are sometimes necessary to repair downhole 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. The NPS defines workover rigs as 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 job 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 (NPS 2006a).

2.2.5 Plugging/Reclamation

Equipment and related materials would be removed, the area returned to its original contour or as agreed to with the surface owner as long as the location is contoured to discourage pooling of surface water at or around the facility site, and the wells plugged according to RRC Statewide Oil and Gas Rules 13 and 14. Flowlines buried three feet below the ground surface would be emptied and abandoned in-place per RRC 3.14(d). The sites would be reclaimed in conformance with any surface use agreement between the surface owner(s) and BP. It is anticipated that the plug and abandonment activities would take 3-4 days during daylight hours only.

2.2.6 Mitigation Measures

In order to reduce impacts on the environment, BP has incorporated the following mitigation measures listed in Table 6 as part of their application for the proposed operations. While many of the mitigation measures are required by other state and federal requirements, the NPS does not have the regulatory authority under § 9.32(e) to require mitigation under option #1, Exemption with No Mitigation.

TABLE 6: MITIGATION MEASURES UNDER ALTERNATIVE B, PROPOSED ACTION

No.	Mitigation Measures	Resource(s) Protected	Required or Voluntary
Project Planning and General Procedures			
1.	Conduct a desktop archeological survey (i.e. a data file search of existing sites in the vicinity (Class II survey)) of the proposed project pad area(s) and immediate vicinity	Archeological and cultural resources	Voluntary: The NPS has no NHPA §106 responsibility for wells that originate on nonfederal lands located outside of the Unit, where the wellbore crosses into the Unit to extract nonfederally-owned hydrocarbons from beneath the Unit. (NPS 2006b)
2.	Prepare and comply with a Spill Prevention Control and Countermeasure (SPCC) Plan	All resources, and human health and safety	EPA requirement as per 40 CFR, Chapter 1, Subchapter D, Part 112 – Oil Pollution Prevention
3.	Site wells, flowlines, and production facilities outside of the Preserve boundary	All resources and visitor use and experience in the Unit	Required to qualify for NPS exemption under 36 CFR § 9.32 (e)
4.	Use existing cleared areas to the extent possible and use existing roads to minimize construction of new roads	All resources outside the Unit	Voluntary
5.	Cover all pits, ponds, or other containment areas and unprotected oil field equipment containing hydrocarbon liquids with screen, netting or other appropriate materials to prevent migratory birds, other wildlife, and sensitive species from being attracted to and entrapped in collected liquid.	Wildlife (with emphasis on migratory birds, bats, rodents, and herptiles)	Required for any open-top storage tanks, skimming pits and collections pits. RRC Statewide Rule 3.22, Protection of Birds.
Construction of Spur Roads and Well Pads			
6.	Implement the following stormwater best management practices, to prevent potential contaminated fluids and sediments from leaving the site and impacting surface water: • Minimize the footprint of the disturbed area, • Construct a berm around the approximately 3.1-acre well pads, • Plan the site location to choose low-slope sites away from waterways, • Manage slopes to decrease steepness, • Maintain the maximum amount of vegetative cover as	All natural resources, and human health and safety	Voluntary

No.	Mitigation Measures	Resource(s) Protected	Required or Voluntary
	possible, • Practice good housekeeping including proper material storage, and • Use erosion control measures, including the use of mulching, seeding, silt fences, and/or hay bales.		
Drilling			
7.	Begin drilling the wells outside of the Preserve and directionally drill wells so that wellbores, after being cased, isolates useable quality groundwater and contains and isolates produced fluids, inside and outside of the Preserve.	Groundwater	Required to qualify for NPS exemption with no mitigation measures
8.	Design the hydraulic fracturing treatment such that the resulting fractures are contained within the targeted rock formation, both inside and outside of the Preserve.	Groundwater	Required to qualify for NPS exemption with no mitigation measures
9.	Construct washout / emergency pit and line with plastic.	All resources, and human health and safety	Construction, design and maintenance of pit in conformance with RRC Statewide Rule 8; liner would be voluntary
10.	BP would switch from using a reserve pit to contain the water-based mud for drilling the surface casing portion of the hole to a closed-loop containerized mud system to continue the drilling using an oil-based mud	All resources, and human health and safety	Voluntary
11.	Set surface casing according to State of Texas RRC requirements	All resources, and human health and safety	Required per RRC Statewide Rule 13(b)(2)
12.	Dispose of drilling mud and well cuttings offsite or downhole	All resources, and human health and safety	Disposal in accordance with RRC Statewide Rule 8
Production			
13.	Backfill washout / emergency and water pits with native soil in accordance with RRC Statewide Rule 8	All resources, and human health and safety	Fill in washout/emergency and water pits required by RRC Statewide Rule 8(d)(4)(G)
14.	Construct an earthen, rock covered firewall around the tank battery with a capacity of the largest tank plus precipitation from a 25-year/24-hour storm event.	All resources, and human health and safety	Voluntary to build capacity for holding the volume of the largest tank plus precipitation from a 25-year/24-hour storm event. Secondary containment as required per 40 CFR, Chapter 1, Subchapter D, § 112.9(c)(2) to construct secondary containment (earthen, steel, etc.) capable of holding the volume of largest tank plus sufficient freeboard to contain precipitation.
15.	Notify regulatory authorities and Big Thicket Superintendent within 24 hours in the event of a release or spill of hydrocarbon condensate, crude oil, or other contaminating	All resources, and human health and safety	Required release reporting in accordance with applicable regulations including RRC requirement to report well blowout/well control problems or spills exceeding 5 barrels as per Statewide

No.	Mitigation Measures	Resource(s) Protected	Required or Voluntary
	substance exceeding five barrels		Rules 20 and 91(e); in the event of any condensate spill, operator must consult with RRC as per Statewide Rule 91(b) and any spills of crude oil into water must be reported to the RRC as per Statewide Rule 91(e)(3); spills of other contaminating substances may require reporting to the TCEQ or EPA under a variety of laws and regulations depending on the substance released, the amount, whether or not the release was into soil, water or air, whether the release was ongoing, etc.; notification to NPS would be voluntary.
Well Plugging			
16.	Consult RRC district office regarding well plugging, plug well to isolate each productive horizon and usable water quality strata according to RRC Statewide Rules 13 and 14	All resources, and human health and safety	Required per RRC Statewide Rule 14
Reclamation			
17.	If the wells are not produced, equipment and related materials would be removed and the area would be restored to original contours to the extent possible and/or as agreed to with the surface owner.	All resources, and human health and safety	Required per RRC Statewide Rule § 14(d)(12), this section of the Statewide Rules requires an operator to “contour the location to discourage pooling of surface water at or around the facility site,” restoration of original contour voluntary
18.	Use of crushed aggregate with cement binding at the well pad to allow for easier removal and restoration of the site, when compared to the use of cement well pads.	All natural resources	Voluntary
19.	Reclamation in conformance with the Land Entry Permit or surface agreement between surface owner and BP.	All resources	Required per RRC Statewide Rule 14(d)(12), required by landowner as per surface use agreement

2.3 Alternatives Considered but Dismissed from Further Analysis

For the reasons described below, these alternatives were dismissed from further analysis.

Locate the Wells inside the Unit. Drilling vertical wells from surface locations inside the Unit directly over the bottomhole targets was considered. Also considered were directional wells from surface locations within the Unit. This alternative would have required access into the Unit and approved plans of operations. There are limited existing roads inside the Unit near the locations considered; therefore, new access roads would have been needed. Access through the Unit would have required crossing and potential development in wetlands and floodplains and possible disruption of wildlife travel corridors. Although drilling wells from inside the Unit is technically feasible, this alternative was judged to be unreasonable in terms of economics, logistics, degree of environmental impact, and time required to implement the proposals and was, therefore, dismissed.

NPS Acquisition of Mineral Rights that are Part of BP's Proposal. In the event that an oil and gas proposal cannot be sufficiently modified to prevent the impairment of park resources and values, the NPS may seek to extinguish the associated mineral right through acquisition, subject to the appropriation of funds from Congress. With respect to BP's proposal, directional drilling from surface locations outside the Unit would substantially reduce the potential for adverse impacts on the Unit's resources and values, visitor use and experience, and public health and safety. As a result, the acquisition of mineral rights was dismissed from further consideration in this EA.

3.0 AFFECTED ENVIRONMENT AND ENVIRONMENTAL CONSEQUENCES

This section describes the affected environment and environmental consequences that connected actions could have on each of the three impact topics carried forward for detailed analysis (re: connected actions in this case are those activities associated with construction and maintenance of access roads; construction and maintenance of well pads, production facilities and flowlines; drilling and completion of the wells; hydrocarbon production and transportation; and eventual well plugging and surface reclamation). As described in § 1.4.1, in-park operations (i.e., the wellbores crossing into the Unit at substantial depth, so as not to cross usable quality groundwater, to reach bottomhole targets beneath the Unit to extract hydrocarbons and other associated fluids), would have no impacts on any resources either in or outside the Unit and are, therefore, not discussed here.

3.1 IMPACTS ON NATURAL SOUNDSCAPES IN AND OUTSIDE THE UNIT

Background. The NPS defines natural soundscape as the aggregate of all natural sounds that occur in parks, absent human-caused noise, together with the physical capacity for transmitting the natural sounds (NPS 2006c). It includes all of the sounds of nature, including such “non-quiet” sounds as birds calling, waterfalls, thunder, and waves breaking against the shore. Natural sounds occur within and beyond the range of sounds that humans can perceive, and can be transmitted through water, air, or solid material. Sound levels are measured in decibels (dB), a logarithmic measure of acoustic energy. Because the human ear is not uniformly sensitive to all noise frequencies, the “A” weighted decibel (dBA) was derived to correspond with the ear’s sensitivity. The A-weighted frequency scale uses specific weighting of sound pressure level to better approximate human response to sound. The L90 corresponds to the 10th percentile, or the sound level that is exceeded 90% of the time. This number is analogous to the “background”, or residual sound level (ANSI/ASA S3/SC1.100-2014/S12.100-2014).

Analysis Area. For the purposes of understanding the impacts of the alternatives on the natural soundscape, the area of analysis has been delineated to include the site of the well drilling, representing the highest noise-producing activity, and includes the distance required for the drilling noise to attenuate to the measured background sound level of 41 dBA. Beyond this distance, there is an increased likelihood that noise sources will no longer adversely affect the natural sounds of the Unit. The following discussion provides a more detailed explanation for how the analysis area was determined.

In 1999, short-term sound level monitoring was conducted in the late morning hours at a helicopter landing area along Timber Slough Road within the Upper Slope Pine Oak Forest of the Unit. The ambient L90 value recorded during this time was 41dBA (Foch 1999). Table 7 provides a list of sound levels, equivalent sounds, and how they might feel to a human listener (NPS 2006a) in relation to the measurement recorded in the Unit. Based on this table, the ambient L90 value of 41dBA recorded along Timber Slough Road is considered equivalent to sound levels experienced during a quiet evening at home, a drilling rig at 1,500 feet, and bird calls.

TABLE 7: SOUND LEVEL COMPARISON CHART

How it Feels	Equivalent Sounds	Decibels	Sound Level Recorded in the Unit
Near permanent damage level from short exposure	Large caliber rifles (e.g., .243, 30-06)	140-160	
Pain to ears	.22 caliber weapon	130-140	
Very loud	Air compressor @ 20 ft. Garbage trucks and city buses	100	
Conversation Stops	Power Lawnmower		
	Diesel truck @ 25 ft.		
Intolerable for phone use	Steady flow of freeway traffic 10 HP outboard motor Garbage disposal	90	
	Near drilling rig (@ 50 ft.) Automatic dishwasher Muffled jet ski @ 50 ft. Vacuum cleaner	80	
	Drilling rig @ 200 ft. Window air conditioner outside @ 2 ft.	70	
Quiet	Window air conditioner in room Drilling rig @ 800 ft. Normal conversation	60	
Sleep interference		50	
	Quiet home in evening		
	Drilling rig @ 1500 ft. Bird calls Library	40	Neches Bottom/Jack Gore Baygall Unit
	Soft whisper	30	
	In a quiet house at midnight Leaves rustling	20	

Spherical spreading describes the decrease in level when a sound wave propagates away from a source uniformly in all directions (http://www.dosits.org/science/advancedtopics/spreading/). Due to spherical spreading loss, sound attenuates at 6 decibels per doubling of distance. Site-specific environmental conditions, including ground surface, atmospheric absorption, presence of dense leafy vegetation, and terrain shielding, can increase this attenuation rate, particularly over large distances. Based on published sound power data for drilling rigs (Leaf Cavern Energy Center, LLC 2011) and the available standards for outdoor propagation with atmospheric absorption (ISO 9613-1) and dense foliage attenuation (ISO 9613-2), NPS estimated drilling rig noise levels at various distances in Table 9. Assumed conditions included local annual average meteorological conditions (66.5º F and 82.9%RH).

The predicted noise levels were corroborated using sounds level data collected by BP at an operating drilling rig near the location of the proposed wells. BP recorded the sound level at 66 dBA at 228 feet from the drilling rig. Table 8 shows the distance that the sound level would attenuate over distance, showing that a distance of 1,900 feet from the drill rig, the sound level drops to a value equivalent with the ambient sound level of 41 A-weighted decibels (dBA) within the Unit. The area of analysis for natural soundscapes therefore encompasses the area located within a 1,900 foot radius of each of the proposed well sites.

TABLE 8: SOUND LEVEL ATTENUATION

Distance from Drill Rig (ft)	Noise Level (dBA)
100	73
288	66*
400	57.5
800	51
1600	43
1900	41**
3200	25

* Predicted noise level value corroborated by BP America measurement

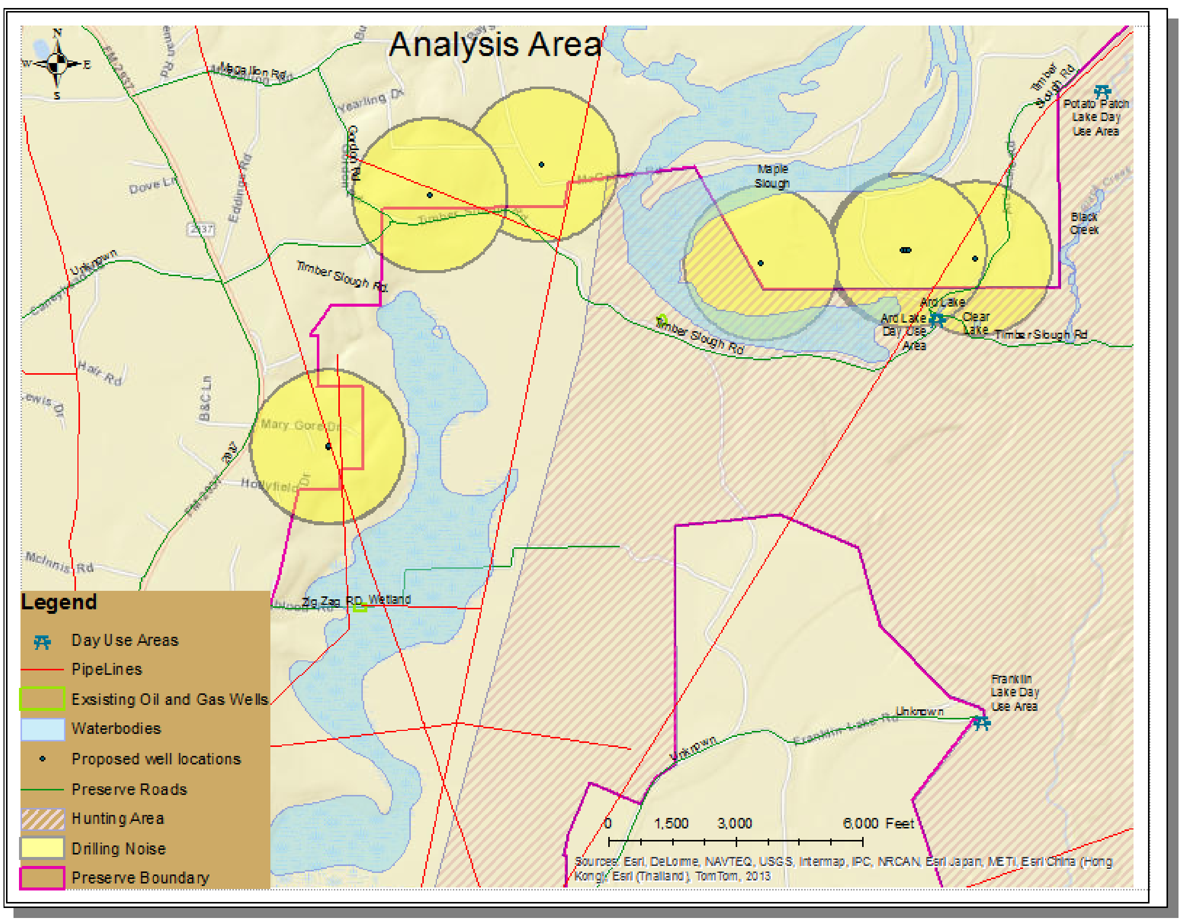
** Ambient sound level of Neches Bottom/Jack Gore Baygall Unit (Foch 1999)

Table 9 shows the distance from each well that elevated noise levels from the drilling of each well could encroach into the Unit. Figure 2 depicts the 1,900-foot distance around each well that elevated noise levels could reach before attenuating to a value equivalent with the ambient sound level in the Unit.

TABLE 9: DISTANCE ELEVATED NOISE FROM WELL DRILLING COULD EXTEND INTO THE UNIT

Well	Distance (ft) from the Well to the Unit Boundary	Distance (ft) sound would travel into the Unit
Well T (Surface Location)	261	1639
Well F (Surface Location)	762	1138
Well G (Surface Location)	292	1608
Well J (Surface Location)	598	1302
Well P (Surface Location)	711	1189
Well Q (Surface Location)	920	980
Well R (Surface Location)	919	981
Well S (Surface Location)	914	986
Well U (Surface Location)	615	1285

FIGURE 2: MAP OF AREA OF ANALYSIS FOR NATURAL SOUNDS



Affected Environment. Within the area of analysis that extends into the Unit boundary are the Ard Lake Day Use Area, Clear Lake Day Use Area, Timber Slough Road, five pipeline right-of-ways, and three water bodies (Ard Lake, Clear Lake, and Maple Slough). The lands adjacent to the Unit are primarily commercial timber lands with periodic thinning and extensive clear-cut harvests occurring on a regular basis. A majority of these timber lands are also leased out to hunting clubs during the state mandated hunting seasons, with feral hog, rabbit, non-game, and non-native hunting authorized the remainder of the year. Improvements inside the Unit related to visitor experience are limited to unpaved road access to Ard and Potato Patch Lakes, and the Neches River. Congressionally authorized hunting and trapping are allowed within some areas of the Preserve, including a portion of the Unit, with measures in place to reduce their impacts on other visitor uses. Management activities in the Unit include the use of on- and off-road vehicles in previously disturbed areas (pipeline right-of–ways) and heavy equipment (during Timber Slough Road regrading).

Sources of man-made noise within the Unit are seasonal in duration and localized near sources that include: the Preserve's maintenance activities (mowers, masticators, chainsaws, tractors, power tools), operator's maintenance of transpark oil and gas pipeline right-of-ways and utility easements (mowers and brush grinders), hunters' use of firearms (during the general hunting season and extended feral hog season), oil and gas operations in and outside the Unit, powerboats on the lower Neches River, conversational noise from large groups canoeing and kayaking on the river or from visitors who often gather in large groups to recreate along the banks of waterbodies. Sources of noise in the area includes frequent semi-trucks (oil tankers, logging trucks, freight, etc.) and automobiles on roadways, aircraft flying overhead, outboard and other boat motors, motorcycles, all-terrain vehicles, various types of equipment (e.g., tractors with brush hog mowers or masticators, log skidders and feller bunchers, chainsaws, lawn mowers, oil and gas separation and treatment vessels, compressors, etc.), power lines/transformers, firearms, and residential. These activities occurring in and outside the Unit result in localized, intermittent and seasonal elevated sound levels that exceed the ambient sound levels of 41 dBA recorded in the Unit.

Impacts on Natural Soundscapes in and outside the Unit under Alternative A, No Action

Direct and Indirect Impacts. Under Alternative A, No Action, the NPS would not provide a § 9.32(e) exemption with no mitigation for the T well and would not consider exemptions for the other eight wells. Therefore, BP would not drill the wells or build related infrastructure and there would be no new direct or indirect impacts on natural soundscapes.

Cumulative Impacts. Because there would be no direct or indirect impacts on natural soundscapes under this alternative, there would be no cumulative impacts.

Impacts on Natural Soundscapes in and outside the Unit under Alternative B, Proposed Action (NPS Preferred)

Direct and Indirect Impacts. Potential impacts are described below, by phase of activity: construction, drilling, production, and eventual plugging/reclamation.

Construction. The use of heavy equipment to construct well pads and spur roads would be the predominant source of noise during the construction phase. Bull dozers and graders have noise levels reported at 85 dBA at 50 feet from the source (FHWA 2015), similar to that of a drill rig. The noise from construction operations would only occur during daytime hours during the approximately 30 days needed to construct the well pads and roads. Construction activities would be intermittent, with equipment, operating singly or with other equipment, and intermingled with the pronounced back-up alarms (FHWA 2015).

Using the same calculations for spherical spreading (attenuation) as described earlier, the predicted noise levels for construction equipment would need to travel 1,900 feet to attain equilibrium with the ambient sound level of 41 A-weighted decibels (dBA) within the Unit.

Drilling. Noise from a drilling rig is measured at 85 dBA 50 feet from the rig (FHWA 2015). Elevated noise would be greatest during the drilling of the wells, because the noise would be continuous over the approximately 30-45 days, 24-hours-a-day, drilling of each well. In addition, mobilizing the rig to the location would require moving 10 to 25 large truckloads of equipment to the site, with trucks. Sound levels for the trucks would be similar to the construction phase described above, with noise levels at approximately 85 dBA at 50 feet from the source. Elevated noise would be greatest near the well locations, and would attenuate with distance to reach background levels measured in the Unit at 41 dBA within 1,900 feet. As shown in Table 11, elevated noise from drilling each well could extend 980-1,639 feet into the Unit.

Production. If the wells are placed into production, flowlines would be constructed using heavy equipment to excavate trenches, lay the pipe, cut and weld the pipe, and backfill the trenches. Noise from heavy equipment would reach levels of 85 dBA within 50 feet (FHWA 2015).

Production equipment, especially gas compression or other pumping equipment powered by internal combustion engines could result in 80 dBA (FHWA 2015). Elevated noise levels could be intermittent or continuous, extending over the possibly long life of the wells (2-50 years or longer).

During the long-term producing life of the wells, occasional workover operations could occur at five to 10-year intervals and take one to two weeks to complete. Workover rigs are essentially a scaled–down version of drill rigs and would increase noise levels, but at much lower intensity and duration (less than 85 dBA within 50 feet) than drilling a well. Workovers would be conducted during daylight hours, and may involve intermittent use of noise-producing equipment.

Plugging/Reclamation. Plugging and reclamation involve the use of heavy equipment (85 dBA) and trucks to plug wells, remove surface equipment, cut/flush/cap flowlines, and reclaim the surface areas. Noise from earthmoving equipment and trucks would occur only for the period of plugging and reclamation preparation, usually a period of only a few days, and only during daylight hours.

In summary, the level of noise related to the proposed directional drilling and production of up to nine wells, from initial construction through plugging and surface reclamation, would be no greater than 85 dBA, 50 feet from the source. As noted above, such elevated noise levels would attenuate to background levels of 41 dBA recorded in the Unit within 1,900 feet of the source. Though these localized impacts would be intermittent during the construction and plugging/reclamation phases, elevated noise would be continuous over the 30-45 days to drill each well, and a variety of activities over the possibly long-term producing life of the wells could introduce elevated noise levels that would range from intermittent to continuous. This level of noise is appropriate to oil and gas development, as the exercise of nonfederal mineral rights is provided for in the enabling legislation of the Preserve (Public Law 93-439, 16 USC § 698 c(b)). Following the Preserve's General Management Plan (NPS 2014), areas within the Unit boundaries that could be affected by elevated noise generated by the proposed drilling and production of the directional wells would be part of the exploration/mining subzone for the duration of proposed activities. Therefore, impacts on the natural soundscape from drilling and production operations would be considered moderate and adverse.

Cumulative Impacts. Past, present, and reasonably foreseeable future actions that have impacted the soundscapes of the Unit and extend approximately ½ mile outside the Unit include vehicle use, existing and future oil and gas operations in and outside the Unit, maintenance of transpark oil and gas pipelines, routine park operations, recreational activities including hunting in and outside the Unit, and forestry operations adjacent to the Unit. These activities introduce elevated noise levels ranging in magnitude from 40 to 160 dBA. Periodic larger caliber gun fire would attain the loudest of the noises (160 dBA). Other activities that routinely contribute to the noise from outside the Unit are: timber harvesting, oil and gas exploration and production, hunting (year round), residential reoccurring noises (lawn maintenance), and traffic along county roads. Activities within the Unit consist of vehicle traffic from recreational users and routine preserve maintenance, hunting (again accounts for the loudest sound level) during the limited state and extended hog hunting season, and oil and gas practices. Collectively, these actions result in negligible to moderate adverse cumulative impacts due to the variable intensity of elevated noise levels encroaching on the natural soundscape within and adjacent to the Unit. As previously described, under Alternative B would contribute negligible to moderate impacts on natural soundscape. When the effects of Alternative B are combined with other past, present, and reasonably foreseeable future impacts, the total cumulative impact on natural soundscapes in and outside the Preserve would be moderate and adverse. The incremental impacts of Alternative B would contribute slightly to, but would not substantially change, the overall cumulative impacts.

3.2 IMPACTS ON NIGHT SKIES IN AND OUTSIDE THE UNIT

Background. Light, visible electromagnetic radiation streaming through the atmosphere, has a tremendous amount of natural variation. From the brightest day to the darkest night spans over eight orders of magnitude (NPS 2003). Disruption of this cycle can have substantial ecological effects. Darkness is an important habitat component, providing cover, security, navigation, or predatory advantage to both nocturnal and diurnal species. Light pollution, defined as stray unwanted light outside the range and timing of natural variation, is not only an ecological disrupter, but also adversely affects the natural scenery of the night. Table 10 provides examples of lux (the unit of light measurement taking area into consideration i.e. light intensity) pertaining to different origins of light illuminated on a surface.

TABLE 10: EXAMPLES OF LUX MEASUREMENTS ON A GIVEN SURFACE

Examples	
Illuminance	**Surfaces illuminated by:**
0.0001 lux	Moonless, overcast night sky (starlight)[1]
0.0014 lux	Venus at brightest[1]
0.002 lux	Moonless clear night sky with airglow[1]
0.1 lux	Quarter moon
0.27–1.0 lux	Full moon on a clear night[1][2]
3.4 lux	Dark limit of civil twilight under a clear sky[3]

[1] Paul Schlyter, Radiometry and photometry in astronomy FAQ (2006)
[2] Bunning, Erwin; Moser, Ilse (April 1969). "Interference of moonlight with the photoperiodic measurement of time by plants, and their adaptive reaction." Proceedings of the National Academy of Sciences of the United States of America 62 (4): 1018–1022.
[3] "Electro-Optics Handbook" (pdf). photonis.com. p. 63.

The degree of impact of artificial light is highly dependent on the distance and the type and brightness of the light fixture. Atmospheric characteristics such as humidity and particulates further influence the apparent effect of artificial light. Whether the light fixture is fully shielded is also important; fully shielded fixtures can greatly decrease the creation of both point and diffuse source light pollution. The perception of light pollution would vary from one location to another caused by differences in vegetation cover, sight lines and horizon visibility, and even the color of the ground. Atmosphere of greater clarity tends to amplify distant light sources and attenuate nearby light sources, while more humid and polluted air tends to amplify close light sources, especially those within 10 km (6.2 miles) of an observer. Air quality considerations can play a role in the context of lightscape impacts, because the presence of air pollution can increase light scattering.

Analysis Area. The area of analysis shown in Figure 3 is defined as the location of the light source and the surrounding area, to the distance of 1,500 feet, in which the light diminishes to the level equivalent to a clear night with a quarter moon shining on a surface, or 0.1 lux (see Table 11 above). As the distance from the well drilling grows the interference from other light sources affects the ability to discern between them.

Affected Environment. Within the 1,500-foot area of analysis that extends into the Unit boundary are Timber Slough Road, five pipeline right-of-ways, and three water bodies. Sources of artificial light adjacent to and within the Unit are oil and gas operations, vehicle traffic in and outside the Unit and residential communities outside the Unit.

Both the level to gently sloping topography of the Unit area and the prevalence of canopy layer vegetation in most of the Preserve naturally limit the experience of vistas in which a substantial portion of the night skies could be observed. This is especially true for the horizon, the part of the sky in which lightscape impacts are first noted.

BP provided light measurement data collected from a current well drilling project located in the vicinity of the proposed projects which provided the basis for the NPS to determine the distance that lighting from the drill rig could extend, to define the area of analysis. Figure 4 shows the measurements were: 14.1 to 0.49 lux (across 177 feet) to the west, 17.8 to 1.3 lux (across 300 feet) to the south, and 5.3 - 0.95 lux (across 75 feet) to the north. Eastern transect data was not analyzed due to vegetation interference. Although this survey was not taken at the same location as the proposed well pads, it is representative of the type of drilling rig and well pad location by proximity to the Unit. The variability in distance of measurements collected in the survey is based on the type of lighting and the angle at which lights are placed. Using this information, the strongest direction that light shined from the source was from the south with 1.3 lux at 300 feet. Since this was the strongest light direction and the variability of the drill rig orientation can change on future well drilling projects; this direction was used to produce a radius that would show the largest distance light would travel from the source in any direction. The final distance light would need to travel to reach 0.1 lux is 1,500 feet in all directions, providing no obstructions. This distance does not take into account anthropogenic and natural barriers such and walls and vegetation, which would drastically lower the distance light would travel from the source.

Figure 5 is a map that shows that the existing lightscape surrounding the proposed project area represent an increase in artificial light of 100-299% from natural conditions between zenith and 45◦ (Cinzano et al. 2001). Artificial lighting from a variety of light sources extends from the City of Beaumont located approximately 25 miles south of the Unit.

FIGURE 3: MAP OF AREA OF ANALYSIS FOR NIGHT SKIES

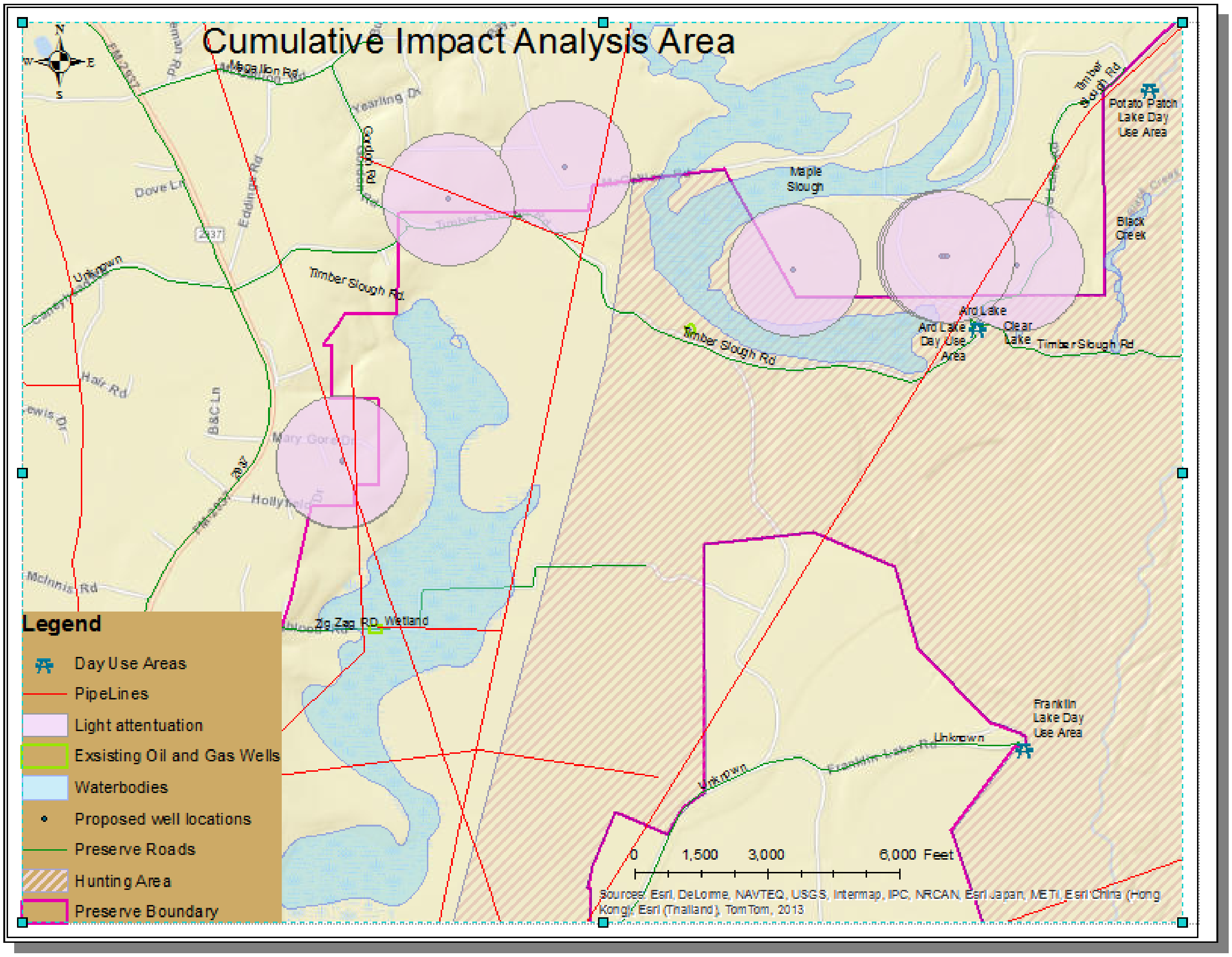


FIGURE 4: MAP OF LIGHT SURVEY

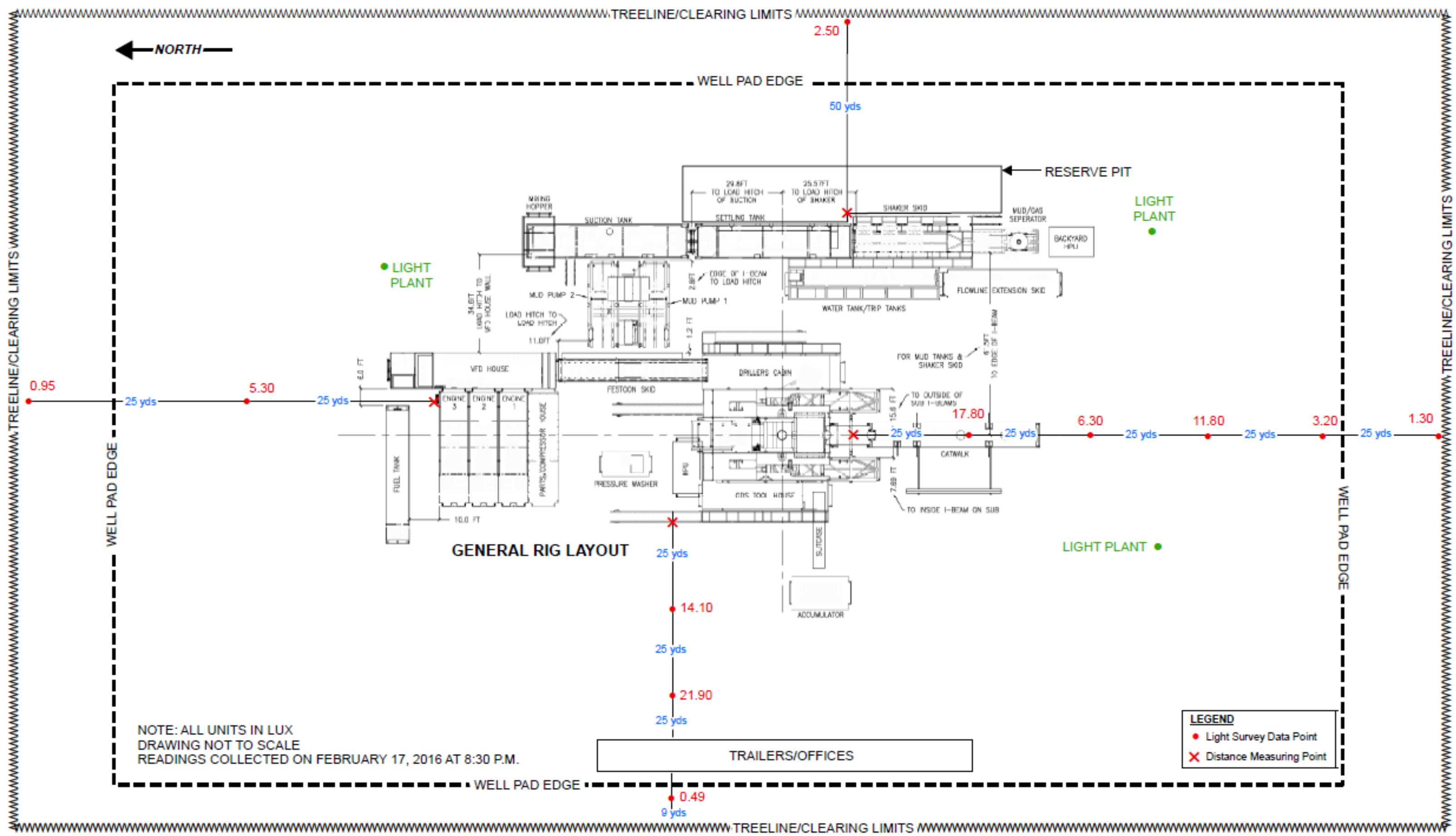
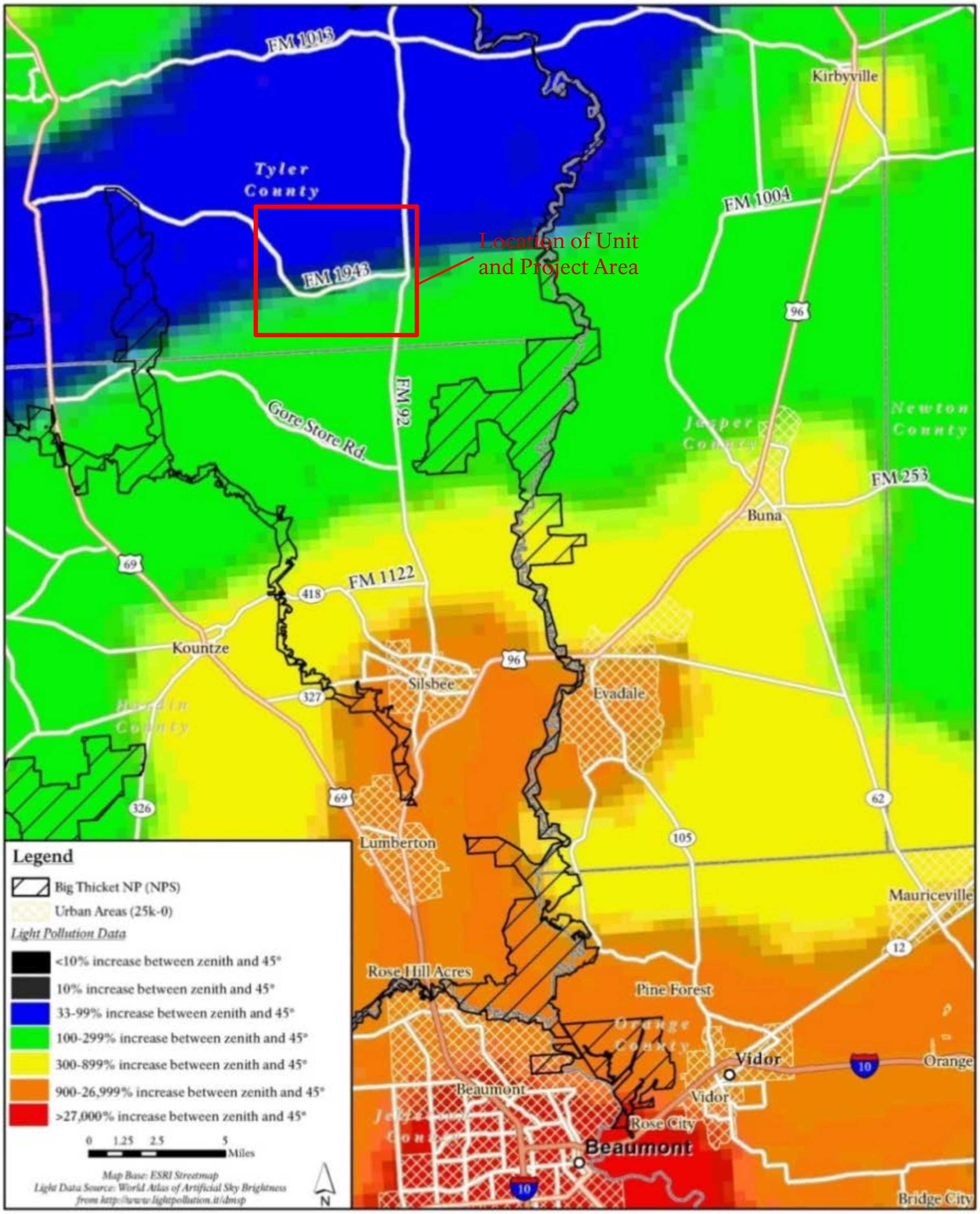


FIGURE 5: MAP OF ARTIFICIAL SKY BRIGHTNESS IN THE VICINITY OF BIG THICKET NATIONAL PRESERVE



Impacts on Night Skies in and outside the Unit under Alternative A, No Action

Direct and Indirect Impacts. Under Alternative A, No Action, the NPS would not provide a § 9.32(e) exemption with no mitigation for the T well and would not consider exemptions for the other eight wells. Therefore, BP would not drill the wells or build related infrastructure and there would be no new direct or indirect impacts on night skies.

Cumulative Impacts: Because there would be no direct or indirect impacts on night skies under this alternative, there would be no cumulative impacts.

Impacts on Night Skies in and outside the Unit under Alternative B, Proposed Action

Direct and Indirect Impacts. Potential impacts are described below, by phase of activity: construction, drilling, production, and eventual plugging/reclamation.

Construction. Construction of well pads and spur roads to connect well pads to existing access roads would be conducted during daylight hours; however, vehicles accessing the work sites and heavy equipment at work sites could use lighting, resulting in localized increases in artificial light over the approximately 30-day period to construct each well pad and two/associated spur roads.

Drilling. Elevated light levels would be greatest during the drilling of each well over 30-45 days due to drilling continuing 24 hours a day. During drilling, lighting on the derrick (the framework supporting the drilling rig), rig floor, and well pad would be necessary to provide for worker safety during nighttime operations. The introduction of light during the drilling phase would be more pronounced in the area immediately surrounding the well and would attenuate with distance. As described in the description of the affected environment, lighting measurements collected by BP at its drilling rig operating in the vicinity of the proposed wells showed variability in the lighting on each side of the drilling operations. Based on the highest light measurement taken, the NPS calculated the 1,500-foot distance that light values would attenuate to background levels found in the Unit. Table 11 below shows the distance that artificial light from well drilling could extend into the Unit. The areas where the proposed wells would be located outside the Unit were most recently harvested for timber in 2012, allowing open space for artificial light to carry from the drilling operations to the boundary of the Unit. However, the dense vegetation and tall forest canopy in the Unit would reduce the distance that artificial light from well drilling could extend into the Unit.

TABLE 11: DISTANCE ARTIFICIAL LIGHT FROM WELL DRILLING COULD EXTEND INTO THE UNIT

Well	Distance (ft) from the Well to the Unit Boundary	Distance (ft) light would travel into the Unit
Well T (Surface Location)	261	1,239
Well F (Surface Location)	762	738
Well G (Surface Location)	292	1,208
Well J (Surface Location)	598	902
Well P (Surface Location)	711	789
Well Q (Surface Location)	920	580
Well R (Surface Location)	919	581
Well S (Surface Location)	914	586
Well U (Surface Location)	615	885

Production. During the potentially long-term production life of the wells, a security light could be placed at each well, and the central delivery point (CDP). Periodic vehicle traffic (mainly to the CDP) would be the main source of lighting during this phase. Occasional workovers on the wells could occur every 5-10 years and take 1 to 2 weeks to complete, but would be conducted during daylight hours.

Plugging and Reclamation. Plugging and reclamation would involve the use of heavy equipment and trucks to plug the wells, remove surface equipment, and reclaim surface areas. Light sources would be similar in scope to the construction phase, with time being 3-4 days, with no nighttime lighting required during this phase.

In summary, all phases of the proposed action could introduce artificial lighting and impact the dark night skies. Drilling of each well would introduce the greatest levels of artificial lighting over the 30-45 days of drilling with a lux value of 1.3 measured at 300 feet from the drilling operations. This level of lighting would take 1,500 feet to attenuate to the background levels of 0.1 lux, the illumination by the quarter moon. The dense vegetation and tall forest canopy in the Unit would block the passage of light. All other activities proposed outside the Unit, including construction of the well pads and spur roads, production operations including construction of flowlines, and eventual well plugging and surface reclamation would be conducted during daylight hours; low levels of artificial lighting would be introduced due to vehicle access, heavy equipment use on overcast days, individual security lights at wells, and nighttime security lighting at the CDP. Impacts would be localized near light sources and extend up to 1,500 feet. This level of impacts on night skies is appropriate to oil and gas development, as the exercise of nonfederal mineral rights is provided for in the enabling legislation of the Preserve (Public Law 93-439, 16 USC § 698 c(b)). Following the Preserve's General Management Plan (NPS 2014), areas within the Unit boundaries that could be affected by artificial lighting generated by the proposed drilling and production of the directional wells would be part of the exploration/mining subzone for the duration of proposed activities. Therefore, adverse impacts on night skies in and outside the unit would be moderate and short-term over the 30-45 days of drilling each well, while impacts from all other phases of activities would be negligible.

Cumulative Impacts. Past, present, and reasonably foreseeable future actions that impact the lightscape within the 1,500-foot area of analysis that extends into the Unit boundary are Timber Slough Road, five pipeline right-of-ways, and three water bodies. Sources of light adjacent to and within the Unit are oil and gas operations, vehicle traffic in and outside the Unit and residential communities outside the Unit. Artificial light from these activities would be the intermittent vehicle traffic on roads, drilling rigs used to drill new wells and low numbers of nighttime lighting at oil and gas production sites and rural residences. The Preserve's *Oil and Gas Management Plan* (NPS 2006a) analyzed night lighting as a component of "Visitor Use and Experiences" and described cumulative short- to long-term, negligible to moderate, adverse impacts. As previously described, under Alternative B would contribute negligible to moderate impacts on night skies. When the effects of Alternative B are combined with other past, present, and reasonably foreseeable future impacts, the total cumulative impact on night skies in and outside the Preserve would be negligible to moderate, and adverse. The incremental impacts of Alternative B would contribute slightly to, but would not substantially change, the overall cumulative impacts.

3.3 IMPACTS ON AIR QUALITY IN AND OUTSIDE THE UNIT

Analysis Area. The area of analysis is defined as the point source and up to 2 miles from the well pad. As distance increases from the well other variables begin to add interference that creates difficulty in discerning between different point sources of emissions. Atmospheric conditions and other oil and gas wells in the area lead to the dispersal and combination of emissions from other sources.

Affected Environment. The Preserve is a Class II area under the Prevention of Significant Deterioration (PSD) provisions of the CAA; Class II areas may undergo only moderate air quality deterioration. In no case, however, may pollution concentrations violate any of the National Ambient Air Quality Standards (NAAQS). Areas that do not meet the NAAQS for a pollutant are designated as "non-attainment areas." Areas that were once designated non-attainment, but are now achieving the NAAQS are termed "maintenance areas." In non-attainment areas, states must develop plans to reduce emissions and bring the areas back into attainment of the NAAQS, and proposed actions must "conform" to the State Implementation Plan (SIP), which establishes *de minimus* values for certain pollutants which cannot be exceeded, so as to limit pollution and reach attainment. Once the area has met attainment and been approved as a "maintenance area," the state may revise the SIP as needed.

The Preserve is located generally north of the Beaumont/Port Arthur airshed and northeast of the Houston airshed. "The primary pollutants transported from airsheds affecting the Preserve are volatile organic compounds (VOCs), and nitrogen oxides (NO_x). Other air pollutants that could affect the Preserve include carbon monoxide (CO), sulfur dioxide (SO_2), and particulate matter (PM) (including heavy metals and lead)" (NPS 2006a) Industrial activities and urbanization account for the majority of impacts to air quality in the Preserve when compared to nonfederal oil and gas operations or Preserve management activity (Ibid.).

BP's proposal is in Hardin County, one of four Texas counties (Hardin, Jefferson, Liberty and Orange) that are not in compliance with the NAAQS for eight-hour ozone. Ground-level ozone (sometimes referred to as smog) is formed by the reaction of volatile organic compounds (VOCs) and nitrogen oxides (NO_x) in the atmosphere in the presence of sunlight. These two pollutants, often referred to as ozone precursors, are emitted by many types of pollution sources, including on-road and off-road motor vehicles and engines, power plants and industrial facilities, and smaller sources, collectively referred to as area sources. Like many areas in Texas, the ozone season in the Beaumont/Port Arthur nonattainment area is typically eight months long, lasting from March through October with peak high ozone events occurring generally late August and September (Ibid.).

Other values may be affected by air quality. These are referred to as "air quality-related values" and include such things as vegetation that may be sensitive to a variety of air pollutants, especially ozone, visibility, and fish and wildlife resources that can be affected by air quality and effects of pollutant deposition in water. The analysis in this document focuses on the emissions of ozone precursors that can affect Unit vegetation. Since it is difficult to relate these effects to a single oil and gas operation, and because the actual impacts to air quality related values depend on their chronic exposure to air affected by many industrial activities and urbanization in the area, a specific analysis of these values is not included, but the potential effects can be indirectly assessed by an analysis of emissions and impact levels.

Impacts on Air Quality in and outside the Unit under Alternative A, No Action

Direct and Indirect Impacts. Under Alternative A, No Action, the NPS would not provide a § 9.32(e) exemption with no mitigation for the T well and would not consider exemptions for the other eight wells. Therefore, BP would not drill the wells or build related infrastructure and there would be no new direct or indirect impacts on air quality.

Cumulative Impacts. Because there would be no direct or indirect impacts on air quality under this alternative, there would be no cumulative impacts.

Impacts on Air Quality in and outside the Unit Under Alternative B, Proposed Action

BP's proposal is in Hardin County, one of four Texas not in compliance with the NAAQS for eight-hour ozone. Therefore, this analysis focuses on the emissions of ozone precursors. The drilling rig ozone precursor emissions were estimated based on work by Russell and Pollack (2005) and Pollack et al. (2006) which used survey information from oil and gas operators in Wyoming and New Mexico to estimate oil and gas emissions in reference oil and gas fields. These reference values may be used along with well depth and drilling duration estimates provided by applicants to establish a range of application specific, per-well, emissions factors for VOCs and NOX using the equation:

$$EF_A = EF_{San\ Juan\ Basin} \times \left(D_A / D_{San\ Jaun\ Basin} \right) \times \left(T_A / T_{San\ Juan\ Basin} \right)$$

Where EF is the emissions factor, D is the drilling depth (measured depth) and T is the drilling duration. Subscript A refers to the application, and subscript San Juan Basin refers to the Blanco-Mesa Verde Field in northwestern New Mexico. Emissions factors regarding both NO_X (1.484 tons/well) and VOCs (0.042 tons/well) are available for the San Juan Basin. The average depth of wells drilled in this area is 5,436 feet according to data from the Oil and Gas Division of the New Mexico Energy, Minerals and Natural Resources Department (Pollack 2007). The average drilling duration reported by oil and gas producers was 12 days in this field. By using data from the San Juan Basin, the NPS has assumed that similar rigs would be used to drill the wells.

Direct and Indirect Impacts. Potential impacts are described below, by phase of activity: construction, drilling, production, and eventual plugging/reclamation.

Construction. Ground-disturbing activities associated with construction and maintenance of well pads and spur roads would result in increased emissions of particulates in the vicinity of the activities. Greater use of motor vehicles during construction of the access roads and well pads would increase particulate matter from vehicles exhaust and dust from paved and unpaved surfaces. Dust abatement actions would limit dust. Exhaust from machinery and equipment used intermittently during construction would also contribute to an increase in particulate matter, as well as emissions of hydrocarbons (HC), NO_X, and CO. Prevailing winds from the south/southeast would disperse pollutants to the north/northwest away from the Unit, but variable winds related to passing high pressure fronts could change the direction of these winds into the Unit. These impacts would last throughout the 30-day period of construction, resulting in adverse effects on air quality in and outside the Unit, localized near wellsites.

Drilling. The use of vehicles and other machinery to drill the wells would result in increased particulates in the vicinity of the activities. Emissions of particulate matter, NO_X, CO, CO_2, and

SO_2 would have the greatest impact during the short-term (30-45 days) drilling operations due to increase use of vehicles and large gasoline and diesel engines used to power the drill rig, pumps, and auxiliary equipment during drilling. Large diesel engines which are used to power the drill rig, pumps, and auxiliary equipment emit NO_x, and smaller amounts of CO and HC. Sulphur dioxide ($SO_{2)}$ would be emitted due to the burning of gasoline and diesel fuels (which contain minor amounts of sulfur). The amount of engine emissions would depend on the drill rig size, percent sulfur in the fuel used, gallons of fuel burned per hour, the hours per day, number of days the rig operates, and the use of any emission control devices.

Potential emissions of both NOx and VOCs were estimated for the T well based on the equation above. Using the proposed measured depth of 13,749 feet, potential emissions of NO_x would range from 9.4 to 14.1 tons for 30 to 45 days of drilling, respectively. Potential emissions of VOCs would range from 0.26 to 0.40 tons for 30 to 45 days of drilling, respectively. In its application, BP describes that the remaining eight directional wells may be drilled up to a depth of 19,500 feet. Assuming a measured depth of 19,500 feet, potential emissions of NO_x would range from 13.3 tons for 30 days of drilling, and up to 20.0 tons for 45 days of drilling; and potential emissions of VOCs would range from 0.38 to 0.56 tons for 30 to 45 days of drilling, respectively. Should all of the remaining eight wells be drilled to a measured depth of 19,500 feet, total NO_x emissions for all nine wells could total 115.8 to 174.1 tons for drilling over 30 to 45 days, respectively, and total VOC emissions could total 3.3 to 4.9 tons for 30 to 45 days of drilling, respectively. If BP drills all nine wells, and drilling were to occur non-stop, drilling of the wells could extend over 270 days (30-day drilling term) and up to 405 days (45-day drilling term).

These impacts on air quality would be greatest during the well drilling, lasting 30 to 45 days for each well, resulting in adverse impacts, localized near drilling activities, but dispersing by wind into adjacent areas and potentially the greater Beaumont/Port Arthur airshed. If all nine wells proposed were drilled consecutively, the drilling phase could extend 270 (30-day drilling term) to 405 days (45-day drilling term).

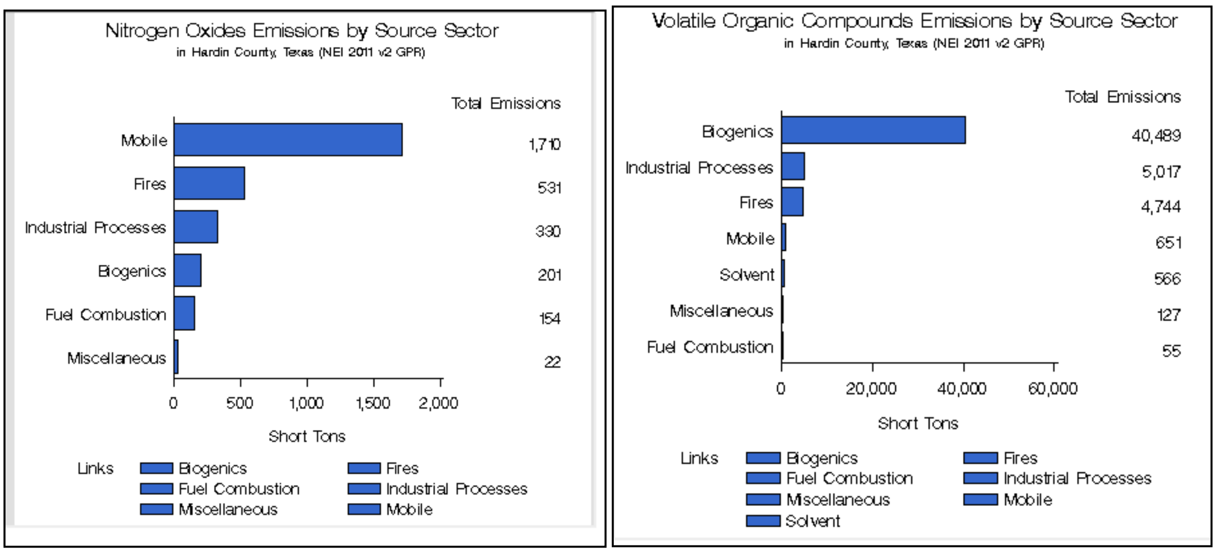
Production. If the wells are placed into production, the operation of separation and treatment equipment, truck to transport fluids from the sites, and possible gas compression equipment would result in continued emissions for a period of 2 to 50 years depending on the life of the wells, but emissions would be at a much reduced levels as compared to well drilling. Routine maintenance activities during production would result in increased particulates in the vicinity of the activities. Emissions of PM, NO_X, CO, CO_2, and SO_2 would occur during workover operations due to increased use of vehicles and large gasoline and diesel engines used to power the drill rig, pumps, and auxiliary equipment. Workovers could occur every 5-10 years and take 1 to 2 weeks to complete.

Plugging/Reclamation. Plugging/abandonment/reclamation of the wells would result in increases in particulate matter during the 3-4 days of ground-disturbing activities, and the use of vehicles and other machinery, with short-term, negligible adverse impacts.

In summary, all phases of oil and gas activities could result in emissions of particulate matter, NO_X, CO, CO_2, and $SO_{2.}$ Drilling of wells would have the greatest impact during the short-term (30-45 days) drilling operations due to increased use of vehicles and large gasoline and diesel engines used to power the drill rig, pumps, and auxiliary equipment during drilling. Total emission levels for each well, for all phases of operations, would fall well below the regulatory emission threshold of 100 tons of total emissions per year per well for the *de minimis* values for NO_X and VOCs in non-attainment areas. Therefore, this alternative would result in moderate adverse impacts on air quality. Emissions from all phases of activities would be greatest near sources of emissions, and depending on wind and atmospheric conditions could disperse to contribute towards air quality impacts in the Beaumont/Port Arthur airshed.

Cumulative Impacts. The analysis area for cumulative impacts consists of the Beaumont/Port Arthur airshed (consisting of Hardin, Orange, and Jefferson Counties). The primary pollutants transported from airsheds affecting the Unit are VOCs and nitrogen oxides (NOx). Other pollutants that could affect the Unit include carbon monoxide (CO), sulfur dioxide (SO_2), and particulate matter (PM) (including heavy metals and lead) (NPS, 2006b). Table 12 shows the EPA data collected on VOC and NO_x emission totals (Leaf Cavern Energy Center, LLC 2011) for sources found in Hardin County, Texas. Mobile, biogenic, fires, and industrial sources account for the majority of impacts on air quality in the area.

TABLE 12: NOX AND VOC EMISSIONS IN HARDIN COUNTY



Due to the prevailing wind directions, air quality in the analysis area is influenced by activities occurring in the Beaumont/Port Arthur airshed, as well as from the Houston/Galveston and Lake Charles, Louisiana, airsheds.

Past, present and reasonably foreseeable future impacts on air quality would continue primarily as the result of industrial sources including pulp mills, oil refineries, and petro-chemical manufacturing plants, public utilities, and urban sources. Activities in and outside the Unit that would contribute to air quality impacts would include oil and gas operations, prescribed fires in the Unit, and farming and commercial timber activities occurring adjacent to the Unit. The use of vehicles and other combustion engines, and fires would also emit PM, NO_X, CO, CO_2, and SO_2. The Preserve's *Oil and Gas Management Plan* (NPS 2006a) describes moderate, adverse cumulative impacts on the regional airshed. As previously described, under Alternative B would contribute moderate impacts on air quality. When the effects of Alternative B are combined with other past, present, and reasonably foreseeable future impacts, the total cumulative impact on night skies in and outside the Preserve would be moderate and adverse. The incremental impacts of Alternative B would contribute slightly to, but would not substantially change, the overall cumulative impacts.

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4.0 CONSULTATION

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