BLM
NEVADA Elko District

United States Department of the Interior
Bureau of Land Management
Elko District Office

2015 Oil & Gas Lease Sale
Environmental Assessment

March 2015
DOI-BLM-NV-E000-2014-0006-EA

NATIONAL SYSTEM OF PUBLIC LANDS
U.S. DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

Mission Statement

It is the mission of the Bureau of Land Management to sustain the health, diversity, and productivity of the public lands for the use and enjoyment of present and future generations.

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United States Department of the Interior
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(DOI-BLM-NV-E000-2014-0006-EA)

1 - INTRODUCTION

The Elko District encompasses about 12.4 million acres, of which approximately 7.2 million acres are public lands managed by the BLM. The Bureau of Land Management (BLM) is considering offering up to 24 parcels, comprising about 25,802.47 acres of land in northeastern Nevada within the area administered by the Elko District Office, in a state-wide competitive Oil and Gas Lease Sale to be held in March, 2015. These offered parcels amount to approximately 0.38 percent of public lands in the Elko district. Over 7 million acres were nominated by industry for the March 2015 Oil and Gas Lease Sale. Of those 7 million acres, BLM adjudicated (processed) 1,323,225.584 acres. The BLM is offering approximately 0.39 percent of the publicly requested acres for March 2015 lease sale. The vast majority of the 1,323,225.584 adjudicated acres were removed from the March 2015 sale due to Greater Sage Grouse issues. Some of the adjudicated lands were removed because they were within leased areas, within a WSA, or lands with no federal mineral estate.

Maps showing the general location of the parcels and their ownership status are shown on figure 2.1.

The BLM, Elko District Office, has prepared this environmental assessment (EA) to comply with the National Environmental Policy Act of 1969 (NEPA). This EA tiers to the environmental impact statements (EISs) for the 1987 Elko Resource Management Plan and the 1985 Wells Resource Management Plan (RMPs) and the Programmatic Environmental Assessment December 2005 Oil and Gas Lease Sale. Additional NEPA documentation is needed prior to leasing to address new circumstances or information bearing on the environmental consequences of leasing that was not considered within the broad scope analyzed in the RMP/EIS.

At the time of this review, it is not known whether all nominated parcels will receive bids, if leases will be issued, or if well sites or roads might be proposed in the future. Detailed site-specific analysis of individual wells or roads would occur when an Application for Permit to Drill (APD) is submitted.

Background

For decades, domestic production of oil and gas in America has not kept pace with increasing consumption. Imported oil supply and prices are subject to world-wide political and social changes such as war and terrorism. Unpredictable events put the American economy and the security and welfare of the American citizens at risk in the form of disruption of energy supplies and drastically increased prices. Recognizing the increasing risk, the president signed Executive Order 13212, on May 18, 2001, with the intent of increasing the domestic supply of energy, including oil and gas.

1.1 NEED FOR AND PURPOSE OF ACTION

The need for the leasing of public mineral estate (oil and gas leasing) is to provide for timely exploration and development of energy resources on public lands, thus reducing U.S. dependence on imported supplies. Parcels of federal mineral estate are offered for lease to encourage development of federal onshore oil and gas resources. These parcels are listed below:

NV-15-03-001 1885.440 Acres
T.0260N, R.0520E, 21 MDM, NV
Sec. 001 LOTS 1-4;
001 S2N2,S2;
002 LOTS 1-4;
002 S2N2,SW,N2SE,SWSE;
011 ALL;
Eureka County
Elko DO
PENDING PRESALE OFFER NO.092657;

NV-15-03-002 2206.650 Acres
T.0260N, R.0520E, 21 MDM, NV
Sec. 003 LOTS 1-4;
003 S2NE,SWNW,NWSW
003 S2SW,SE,EXCL ME PATS;
010 ALL EXCL ME PATS;
014 NE,N2NW,SENW,S2;
015 N2NE,SWNE,W2,SE;
Eureka County
Elko DO
PENDING PRESALE OFFER NO.092657;

NV-15-03-003 2160.560 Acres
T.0260N, R.0520E, 21 MDM, NV
Sec. 004 LOTS 1-7;
004 SWNE,S2NW,SW,W2SE;
009 LOTS 1-4;
009 W2E2,W2;
016 LOTS 1-4;
016 W2E2,W2;
017 NE,E2SW,SE;
Eureka County
Elko DO
NEAR LEK/4-MI BUFFER;

NV-15-03-004 1280.000 Acres
T.0260N, R.0520E, 21 MDM, NV
Sec. 012 ALL;
013 ALL;
Eureka County
Elko DO
PENDING PRESALE OFFER NO.092657;

NV-15-03-005 551.320 Acres
T.0270N, R.0520E, 21 MDM, NV
Sec. 001 LOTS 1-3;
001 S2NE,SENW,NESW,S2SW,SE;
Eureka County
Elko DO
NEAR PGH;

NV-15-03-006 1675.370 Acres
T.0270N, R.0520E, 21 MDM, NV
Sec. 024 ALL;
025 ALL;
026 LOTS 1,2,6,7;
026 S2NE,SESW,NESE,S2SE;
Eureka County
Elko DO
NEAR PGH;

NV-15-03-007 880.000 Acres
T.0270N, R.0520E, 21 MDM, NV
Sec. 028 NE,NENW,N2SE,SESE;
033 NE,S2NW,S2;
Eureka County
Elko DO
NEAR PGH & LEK/4-MI BUFFER;

NV-15-03-008 1270.420 Acres
T.0270N, R.0520E, 21 MDM, NV
Sec. 034 ALL;
035 LOTS 1-4;
035 E2,E2W2;
Eureka County
Elko DO
PENDING PRESALE OFFER NO.092657;
MINING PLAN OF OPERATIONS N-84135;

NV-15-03-009 860.410 Acres
T.0260N, R.0530E, 21 MDM, NV
Sec. 007 LOTS 2,3,5-8;
007 SESW;
008 NE,N2NW,NESE;
018 LOTS 1-8;
018 E2W2;
Elko and Eureka Counties
Elko DO
PENDING PRESALE OFFER NO.092657;
NEAR PGH;
SEC. 8 CONTAINS BLMO 3/4/1959;

NV-15-03-010 1206.840 Acres
T.0280N, R.0530E, 21 MDM, NV
Sec. 030 LOTS 1,2;
030 E2,E2W2;
031 LOTS 2-4;
031 E2,E2W2;
Elko and Eureka Counties
Elko DO
ROW N78612 & ROW N78613;
NEAR PGH & PPH;

NV-15-03-011 880.000 Acres
T.0290N, R.0530E, 21 MDM, NV
Sec. 028 ALL;
033 SW,W2SE;
Elko County
Elko DO
NEAR PPH & LEK/4-MI BUFFER;

NV-15-03-012 1037.910 Acres
T.0320N, R.0530E, 21 MDM, NV
Sec. 010 N2,NESW,N2SE;
012 LOTS 2-4;
012 W2E2,W2;
Elko County
Elko DO
PENDING PRESALE OFFER NO.092661;
NEAR PGH;

NV-15-03-015 1190.090 Acres
T.0260N, R.0640E, 21 MDM, NV
Sec. 001 LOTS 1,2;
001 S2NE,W2SWNW,SENW,N2S;
001 NESE,SENWSE,S2SE;
012 E2;
013 E2,SENW,E2SW;
Elko County
Elko DO
PENDING PRESALE OFFER NO.092650;
NEAR PPH AND LEK/4-MI BUFFER;
SEC. 1 - IC002 & RR ROW;

NV-15-03-016   2000.690 Acres
T.0260N, R.0650E, 21 MDM, NV
Sec. 003 SWSW;
004 NWSW,S2S2;
005 LOTS 3,4;
005 SWNE,S2NW,S2;
009 ALL;
010 NWNE,S2NE,W2,SE;
Elko County
Elko DO
PENDING PRESALE OFFER NO.092653;
NEAR PPH & LEK/4-MI BUFFER;
SECS. 4 & 9 - MAT SITE CC018205;
SECS. 4 & 9 - ROW CC018253 & ROW N5485;

NV-15-03-017   1917.560 Acres
T.0260N, R.0650E, 21 MDM, NV
Sec. 006 LOTS 1-7;
006 S2NE,SENW,E2SW,SE;
007 LOTS 1-4;
007 E2,E2W2;
008 ALL;
Elko County
Elko DO
PENDING PRESALE OFFER NO.092653

NV-15-03-018   480.000 Acres
T.0260N, R.0650E, 21 MDM, NV
Sec. 011 SWNW,SW,W2SE,SESE;
012 S2S2;
Elko County
Elko DO
PENDING PRESALE OFFER NO.092654;
NEAR PPH & LEK/4-MI BUFFER;

NV-15-03-019   1000.000 Acres
T.0260N, R.0650E, 21 MDM, NV
Sec. 014 N2N2,SWNW;
015 N2,N2SW,SWSW,NWSE;
016 S2;
Elko County
Elko DO
PENDING PRESALE OFFER NO.092653;
NEAR PPH & LEK/4-MI BUFFER;
SEC. 15 - ROW CC018253;

NV-15-03-020   1278.560 Acres
T.0260N, R.0650E, 21 MDM, NV
Sec. 017 ALL;
018 LOTS 1-4;
018 E2,E2W2;
Elko County
Elko DO
PENDING PRESALE OFFER NO.092650;

NV-15-03-021   40.000 Acres
T.0270N, R.0650E, 21 MDM, NV
Sec. 029 SWSW;
Elko County
Elko DO
PENDING PRESALE OFFER NO.092652
NEAR PPH;
SEC. 29 - ROW CC018253;

NV-15-03-022   881.060 Acres
T.0270N, R.0650E, 21 MDM, NV
Sec. 030 LOTS 3,4;
030 E2SW,S2SE;
031 LOTS 1-4;
031 E2,E2W2;
Elko County
Elko DO
PENDING PRESALE OFFER NO.092650;
NEAR PPH;
SECS. 30 & 31 -ROW N5485 & ROW CC018253;

NV-15-03-023   80.000 Acres
T.0270N, R.0650E, 21 MDM, NV
Sec. 032 NWNW,SWSW;
Elko County
Elko DO
PENDING PRESALE OFFER NO.092653;
NEAR PPH;
SECS. 32 & 33 - ROW CC018253;
SECS. 32 & 33 - ROW N5485;

NV-15-03-024 599.590 Acres
T.0260N, R.0660E, 21 MDM, NV
Sec. 007 LOTS 4;
007 SESW,S2SE;
008 SENE,NESW,S2SW,SE;
017 N2NW;
018 NENE;
Elko County
Elko DO
PENDING PRESALE OFFER NO.092654;
NEAR PPH & LEK/4-MI BUFFER;

NV-15-03-025 200.000 Acres
T.0260N, R.0660E, 21 MDM, NV
Sec. 009 SWSW;
017 NE;
Elko County
Elko DO
PENDING PRESALE OFFER NO.092656;
NEAR PPH & LEK/4-MI BUFFER;

NV-15-03-026 240.000 Acres
T.0270N, R.0660E, 21 MDM, NV
Sec. 003 N2SW,SESW,SWSE;
010 NWNE,NENW;
Elko County
Elko DO
PENDING PRESALE OFFER NO.092655;
NEAR PGH & LEK/4-MI BUFFER;

Number of Parcels - 24

Total Acreage - 25,802.47

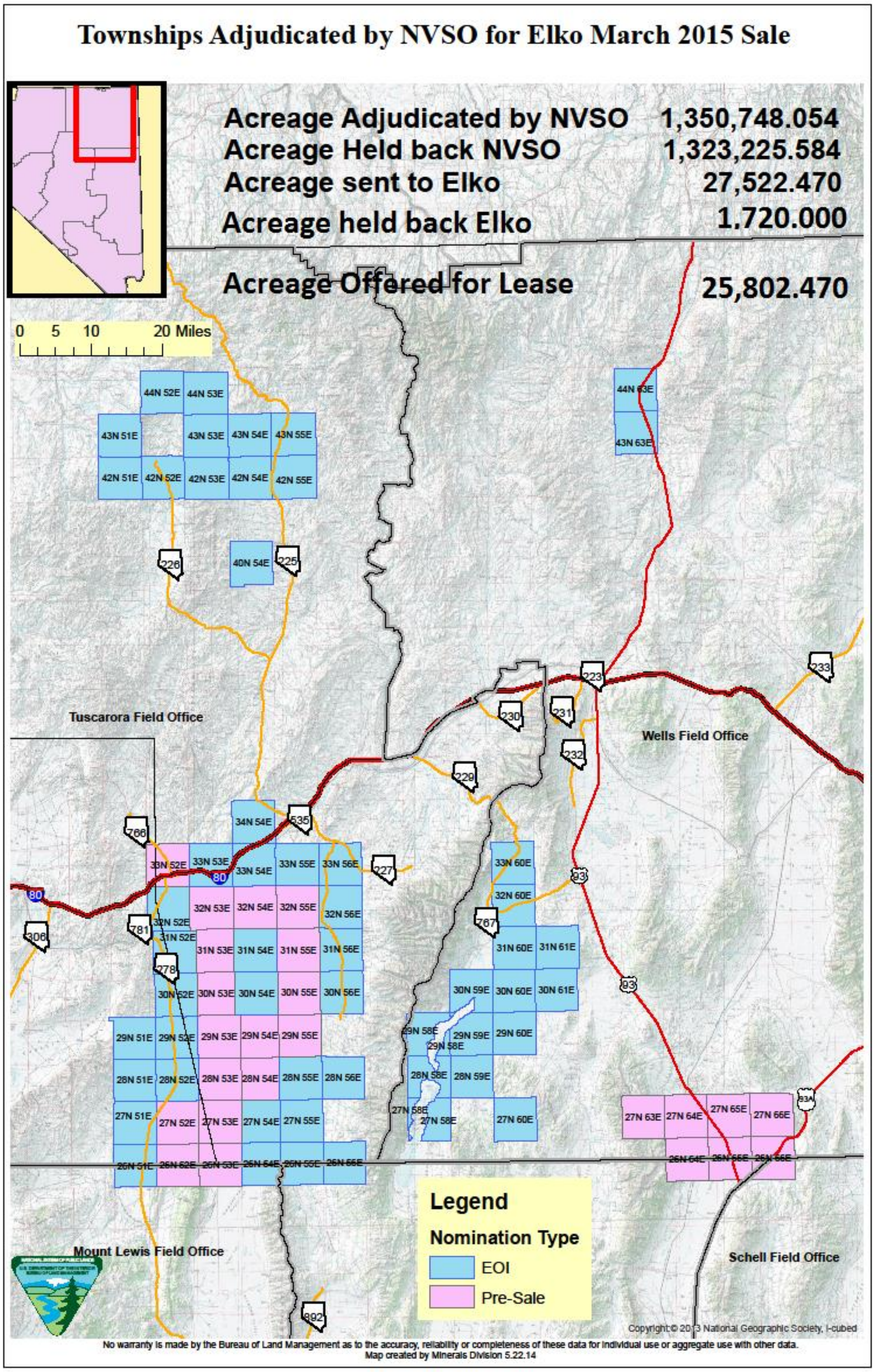
Total number of Parcels with Presale Offers - 18

Parcel Number of Parcels with Presale Offers - 001, 002, 004, 008, 009, 012, 015, 016, 017, 018, 019, 020, 021, 022, 023, 024, 025, 026

Total Acreage With Presale Offers - 18,448.38

Any portion of the listed lands may be deleted upon determination that such lands are not available for leasing

Figure 1.1


Townships Adjudicated by NVSO for Elko March 2015 Sale
Acreage Adjudicated by NVSO 1,350,748.054
Acreage Held back NVSO 1,323,225.584
Acreage sent to Elko 27,522.470
Acreage held back Elko 1.720.000
Acreage Offered for Lease 25,802.470
0 5 10 20 Miles
Tuscarora Field Office
Wells Field Office
Mount Lewis Field Office
Schell Field Office
Legend
Nomination Type
EOI
Pre-Sale
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Map created by Minerals Division 5.22.14

The purpose of this action is to facilitate energy development where appropriate. As public mineral estate is leased for development of oil and gas resources, BLM determines stipulations which are attached to the lease for a given parcel to avoid or minimize adverse impacts on resources such as wildlife, soils, watersheds and cultural resources. Stipulations are written to conform to approved land use plans governing BLM's management of resources in the area to be leased, and to be consistent with laws, regulations, policies, rules, and orders.

Leasing is authorized under the Mineral Leasing Act of 1920, as amended and modified by subsequent legislation, and regulations found at 43 CFR part 3100. Oil and gas leasing is recognized as an acceptable use of the public lands under the Federal Land Policy and Management Act of 1976 (FLPMA). BLM authority for leasing public mineral estate for the development of energy resources, including oil and gas, is listed in 43 CFR 3160.0-3.

1.2 LAND USE PLAN CONFORMANCE

FLPMA directs the BLM to develop and maintain comprehensive Resource Management Plans (RMPs) that govern all aspects of public land management, and that proposed leasing activities conform with approved RMPs. Leasing of lands within the Elko District for the production of energy resources is managed in accordance with direction provided in either the Wells RMP as approved June 28, 1985, or the Elko RMP, approved March 11, 1987. Since they were approved, both RMPs have been periodically evaluated and amended as necessary to address current policies and emerging issues. Parcels nominated for leasing are screened to identify areas open to leasing and applicable lease stipulations.

The 1985 Record of Decision (ROD) for the Wells RMP, page 25, provides that, "The public lands will be managed in a manner which recognizes the Nation's needs for domestic sources of minerals." As a standard operating procedure (SOP) pertinent to establishing special stipulations to attach to leases, the ROD prescribes that, "Time-of-day and/or time-of-year restrictions will be placed on construction activities associated with leasable and saleable mineral explorations and/or development that are in the immediate vicinity or would cross crucial sage grouse, crucial deer and pronghorn antelope winter habitats, antelope kidding areas, or raptor nesting areas."

The 1987 Elko RMP determined whether or not areas of land are subject to mineral leasing as follows (ROD, page 4 and Map 13):

> (1) <u>Open – subject to standard leasing stipulations</u> (82 percent of the RMP area)
> (2) <u>Limited – subject to no surface occupancy</u> (Special Recreation Managements Areas and sage grouse strutting grounds)
> (3) <u>Limited – subject to seasonal restrictions</u>.(crucial deer winter range, crucial antelope yearlong habitat and sage grouse brood rearing areas).
> (4) <u>Closed</u> – (wilderness and wilderness study areas recommended for designation).

The Wells and Elko RMPs state that all Wilderness Study Areas will be managed under the Bureau's Interim Management Policy for Lands Under Wilderness Review, H-8550-1 (IMP). No new leases may be issued on lands under wilderness review according to the Interim Management Policy for Lands Under Wilderness Review (H-8550-1, Rel. 8-67, 1995, page 32). The wilderness study areas (WSAs) in the Wells RMP planning area include the Bluebell, Goshute Peak, South Pequop and Bad Lands WSAs, (1985 Wells ROD; page 16 and Map 4). WSAs in the Elko planning area are the Rough Hills, Little Humboldt River, Cedar Ridge and Red Spring, and Owyhee Canyonlands WSAs (1987 Elko ROD; page18, Map 7 and page 37).

1.3 RELATIONSHIP TO OTHER LAWS, POLICIES AND PLANS

The proposed action, as described in the next chapter, is consistent with Federal, State and local laws, regulations, policies and plans to the maximum extent possible, including:

- Mineral Leasing Act of 1920, as amended and supplemented by subsequent legislation,
- Federal Land Policy and Management Act of 1976, which calls for managing the public lands for multiple use,
- 43 CFR part 3100, which provides regulations governing Onshore Oil and Gas Leasing,
- Executive Order 133212, which directs the Secretary of the Interior to expedite energy-related projects,
- National Historic Preservation Act (NHPA) and rules for implementing section 106 found at 36 CFR Part 800,
- Endangered Species Act (ESA) and rules for implementation of section 7 found at 50 CFR part 402,
- Clean Air Act The BLM has air resource program responsibilities through its permitting programs and Clean Air Act (CAA) requirements.
- Secretarial Order 3289 addresses current and future impacts of climate change on America's land, water, wildlife, cultural-heritage, and tribal resources.
- The Clean Water Act (CWA) of 1977 provides the statutory basis for regulating discharges of pollutants into waters of the United States and regulating water quality for surface waters.
- Land use plans for Elko and Eureka counties, and the
- Nevada statutes and plans governing management of wildlife and water resources.
- Washington Office Instruction Memorandum 2012-43, December 22, 2011, Greater Sage-Grouse Interim Management Policies and Procedures
- Washington Office Instruction Memorandum 2010-117, May 17, 2010, Oil and Gas Leasing Reform – Land Use Planning and Lease Parcel Reviews
- Washington Office Instruction Memorandum 2011-154, July 26, 2011, Requirement to Conduct and Maintain Inventory Information for Wilderness Characteristics and to Consider Lands with Wilderness Characteristics in Land Use Plans.

1.4 PARCEL SCREENING CRITERIA

An Interdisciplinary Parcel Review Team evaluated each parcel based on historical data, personal knowledge, field inspections and existing databases and file information to determine potential resource effects and appropriate lease stipulations as directed by IM-2010-117. Proposed parcels were reviewed to determine if they were located in an area that possessed sufficient size, naturalness, and outstanding opportunities for solitude or primitive and unconfined recreation to qualify as lands with wilderness characteristics. The Interdisciplinary Parcel Review Team also evaluated if a parcel should be deferred based on wildlife, cultural, or proximity to municipal water sources concerns. The parcels are deferred until more direction is provided by either completion of the Elko District Resource Management Plan or the Nevada and Northeastern California Greater Sage-Grouse Environmental Impact Statement is final and has amended the Elko District's respective Resource Management Plans. See Figure 2.1 for specific offered parcels; below briefly describes the reason for removal of the 1,323,225.584 acres from the parcel list.

- Some nominations are located in areas with a very high density of eligible cultural sites and potential Traditional Cultural Properties; they will be deferred until the Elko District completes a new Resource Management Plan (scheduled to begin in 2016).
- Parcels or portions of parcels within a four mile radius of Greater Sage-Grouse leks and parcels located on lands containing Greater Sage-Grouse Preliminary Priority Habitat were deferred. The four mile radius buffer is based on the National Technical Team recommendation. If the buffer covered just a portion of a parcel and an aliquot part could be described then that remaining portion was made available for potential leasing.
- Some of the adjudicated lands were removed because they were within leased areas, within a WSA, or lands with no federal mineral estate.

2 - ALTERNATIVES

2.1 NO ACTION

The No Action alternative is defined as, "Do not offer nominated parcels in the Elko District for lease in this lease sale."

2.2 PROPOSED ACTION

BLM's proposed action is to lease parcels of federal mineral estate that have been nominated and which have been determined to be suitable for leasing, subject to standard lease terms and applicable special stipulations, in the competitive oil and gas lease sale. The tracts of federal mineral estate to be offered may lie under surface administered by the BLM, or under split estate, i.e., surface owned or administered by an individual or non-federal government agency. Lands leased would then be available for exploration and development of oil and gas resources for a 10-year period, subject to stipulations attached to the lease for each parcel.

This EA analyzes the offering of leases located within the Elko District for the March 2015 lease sale. There are 24 parcels that total approximately 25,802.47 acres (see figure 2.1). Two parcels listed on this map (NV-15-03-013 and NV-15-03-014) were removed from the offered list due to very high density of eligible cultural sites and potential Traditional Cultural Properties; they will be deferred until the Elko District completes a new Resource Management Plan (scheduled to begin in 2016). Section 1.1 contains a complete list of the offered parcels and their legal descriptions. The Elko District Office has also proposed special stipulations to attach to each lease to protect other resources (see Table 2-1). These stipulations are described in the next section, and the standardized text for each stipulation is in Appendix B. The last column of Table 2-1 also identifies additional resource concerns, to the extent practical at the initial leasing stage. Such concerns would be more specifically addressed when and if a lessee proposes surface disturbance, through Standard Operating Procedures, Best Management Practices, and imposition of applicable laws, regulations consistent with the standard lease terms and special stipulations.

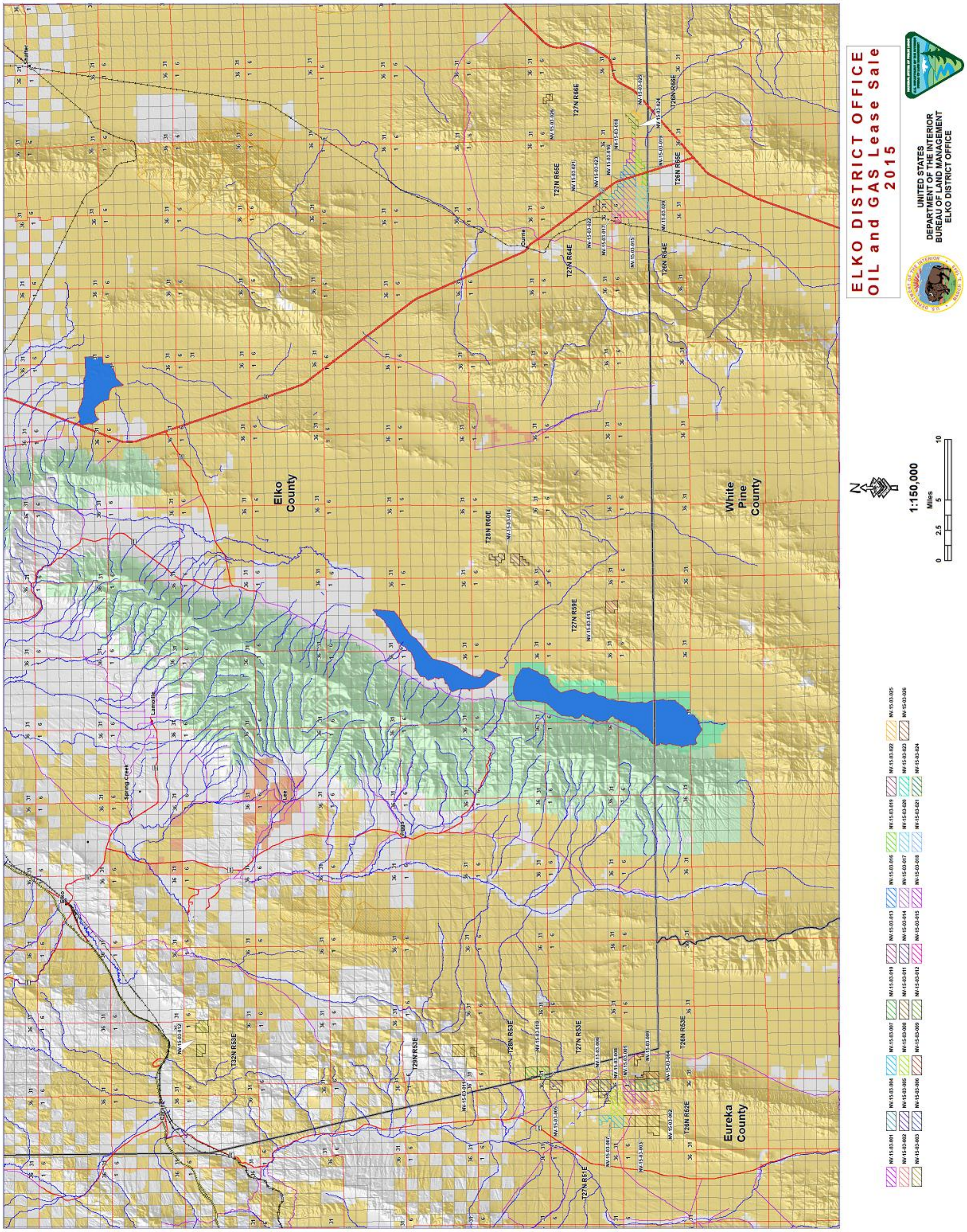
2.2.1 Resource Protection Stipulations

Once a parcel is leased, the lessee has the right to explore for and develop oil and gas resources, subject to *standard lease terms* and *special stipulations* pertaining to the conduct of operations. The conduct of operations by the lessee on all parcels would be subject to the following terms from the back of the standard lease form, which state:

"Conduct of Operations (SF-3100-11, Section 6)

> Lessee shall conduct operations in a manner that minimizes adverse impacts to the land, air, and water, to cultural, biological and other resources, and to uses or users. Lessee shall take reasonable measures deemed necessary by the lessor to accomplish the intent of this section. To the extent consistent with lease rights granted, such measures may include, but not limited to, modification to siting or design of facilities, timing of operations, and specification of interim and final reclamation measures. Lessor reserves the right to continue existing uses and to authorize future uses upon or in leased lands, including the approval of easements or right-of-way. Such uses shall be conditioned so as to prevent unnecessary or unreasonable interference with rights of lessee.
>
> Prior to disturbing the surface of the leased lands, lessee shall contact lessor to be apprised of procedures to be followed and modifications or reclamation measures that may be necessary. Areas to be disturbed may require inventories or special studies to determine the extent of impacts to other resources. Lessee may be required to complete minor inventories or short-term special studies under guidelines provided by lessor. If in the conduct of operations, threatened or endangered species, objects of historic or scientific interest or substantial unanticipated environmental effects are observed, lessee shall immediately contact lessor. Lessee shall cease any operations that would result in destruction of such species or objects."

Figure 2.1


ELKO DISTRICT OFFICE
OIL and GAS Lease Sale
2015
UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT
ELKO DISTRICT OFFICE
1:150,000
Miles
Elko County
White Pine County
Eureka County

Special stipulations are developed to conform to approved resource management plans and ensure post-leasing activities comply with pertinent laws and policies. Stipulations for **cultural resources** (including Native American consultation), **raptors,** and **threatened, endangered and sensitive species** would be attached to all leases. Other stipulations that restrict surface occupancy or impose seasonal restrictions on post-leasing activities would be applied to parcels where necessary to protect resource values or uses. Certain parcels will have a congressionally designated trails stipulation. Based on screening of the nominated parcels, Table 2-1 lists the Elko District parcels to be offered in the sale, and identifies the special stipulations that would be attached to each lease. A summary of the stipulations that can be assigned to leases to protect resources follows. The full text of each stipulation is in Appendix B.

Cultural Resources/Native American Consultation -- This stipulation is included in all leases to allow the BLM to protect cultural resources and address Native American Concerns. It advises the potential lessee that BLM will not approve any ground disturbing activities that may affect a cultural property until it completes its obligations under applicable requirements of the NHPA and other authorities. The BLM may require modification to exploration or development proposals to protect such properties, or disapprove any activity that is likely to result in adverse effects that cannot be successfully avoided, minimized or otherwise mitigated. (**WO IM 2005-003).**

Threatened, Endangered and Sensitive Species – This stipulation informs the lessee that the BLM will take whatever steps are necessary to comply with law and regulations affecting such species. Activities that could adversely affect threatened, endangered, or sensitive species habitat will not be permitted. Actions in threatened, endangered, or sensitive species habitat will be designed to benefit these species through habitat improvement. All project work will require a threatened, endangered, or sensitive species clearance before implementation. Consultation with the U.S. Fish and Wildlife Service per Section 7 of the Endangered Species Act is necessary if a threatened, endangered, or proposed threatened or endangered species, or its habitat may be impacted. Other species considered sensitive, but not under the protection of the Act, are given special management considerations through Bureau policy. If adverse impacts to these other sensitive species are identified during project planning, the project will be modified or possibly abandoned to avoid these impacts (Standard Operating Procedure, Elko ROD, p. 39; WO IM 2002-174).

Raptor Nesting Sites -- This stipulation is attached to all parcels to permit establishing a buffer zone of no activity around nesting sites during nesting seasons. (Wells RMP ROD p. 25 and Elko RMP ROD p. 25)

Mule Deer Crucial Winter Range- This stipulation prevents disturbances in crucial winter range during the winter season. (Wells RMP ROD p. 10 and Elko RMP ROD p.3)

Pronghorn Antelope Crucial Winter Range- This stipulation prevents disturbances in crucial winter range during the winter season. (Wells RMP ROD p. 25 and Elko RMP ROD p.3

Pronghorn Antelope Kidding Areas – This stipulation prevents disturbance in kidding areas during the kidding season of May 1 to June 30. (Elko RMP p. 2-6)

Sage Grouse Strutting Grounds (leks) – This stipulation restricts use of the surface within 0.5 miles of known strutting grounds. (Wells RMP ROD p. 25 and Elko RMP ROD p.3)

Sage Grouse Brood Rearing Areas – This stipulation prevents disturbance within ½ mile of brood rearing areas between May 15 and August 15. (Wells RMP ROD p. 25 and Elko RMP ROD p.3)

Sage Grouse Crucial Winter Habitat – This stipulation prevents disturbance on lands identified as crucial habitat between November 1 and March 15.

I-80 Low Visibility Corridor – This stipulation limits visual impacts within 1.5 miles of either side of Interstate 80 as it crosses the Elko District with the goal of retaining the existing character of the landscape. (Wells RMP ROD p. 3 and Elko RMP ROD p. 1)

Special Recreation Management Areas (SRMA) – This stipulation restricts surface occupancy within specified parts of the SRMAs at South Fork Canyon, Wild Horse, Wilson Reservoir, South Fork Owyhee River, Zunino/Jiggs, and the proposed Salmon Falls Creek. (Wells RMP ROD p. 25 and Elko RMP ROD p. 3)

Tabor Creek Campground – This stipulation restricts surface occupancy within the Tabor Creek Campground. (Wells RMP ROD p. 25)

No Surface Occupancy-This stipulation restricts surface occupancy in defined portions of the leased parcels.

Offered Parcels in the March 2015 Sale

The BLM is offering 24 parcels of Public land for oil and gas lease sale for a total of 25,802.47 acres. Eighteen of these parcels (18,448.38 acres) have presale offers made by industry.

Any portion of the listed lands may be deleted upon determination that such lands are not available for leasing.

Reasons for their deferment include:

- Some nominations are located in areas with a very high density of eligible cultural sites and potential Traditional Cultural Properties, and they will be deferred until the Elko District Office completes a new Resource Management Plan (scheduled to begin in 2016).
- Parcels or portions of parcels within a four mile radius of active sage grouse leks and parcels located on lands containing Greater Sage Grouse Preliminary Priority Habitat have been deferred unless they are within the operations area of pending oil & gas exploration plans. These deferred parcels will not be offered for sale until completion of the Nevada & Northeastern California Greater Sage Grouse EIS.

Table 2-1 March 2015.
Parcels deemed suitable for oil and gas leasing with stipulations where necessary.

2015 Oil & Gas Lease Sale Elko District Stipulations																
OG-010-Stip No.	OG-010-05-01	OG-010-05-02	OG-010-05-03	OG-010-05-04	OG-010-05-05	OG-010-05-06	OG-010-05-07	OG-010-05-08	OG-010-05-09	OG-010-05-10	OG-010-05-11	OG-010-05-12	OG-010-05-13			
PARCEL	T/E & Sensitive Species	Raptor Nests	Cultural Resources	Crucial Mule Deer Winter Range	Crucial Antelope Winter Range	Antelope Kidding Area	Sage Grouse Leks	Sage Grouse Brood Area	Sage Grouse Crucial Winter Habitat	VRM	Special Recreation Management Areas	Tabor Creek Camp-ground	National Historic Trails		Other	Lease Acres
NV-15-03-001	X	X	X	X				X	X						G,H	1,885.440
NV-15-03-002	X	X	X	X				X	X				X			2,206.650
NV-15-03-003	X	X	X	X			X	X								2,160.560
NV-15-03-004	X	X	X	X	X			X	X				X		G,H	1,280.000
NV-15-03-005	X	X	X	X	X		X	X	X				X		G,H	551.320
NV-15-03-006	X	X	X				X	X	X				X		G,H	1,675.370
NV-15-03-007	X	X	X				X	X	X				x		G,H	880.000
NV-15-03-008	X	X	X		X		X	X	X				X		H	1,270.420
NV-15-03-009	X	X	X				X	X							G,H	860.410
NV-15-03-010	X	X	X				X	X	X				X		H	1,206.840
NV-15-03-011	X	X	X				X		X				X			880.000
NV-15-03-012	X	X	X	X	X		X	X	X						H	1,037.910
NV-15-03-015	X	X	X										X		E,C	1,190.090
NV-15-03-016	X	X	X						X						E	2,000.690
NV-15-03-017	X	X	X			X							X		E,C	1,917.560
NV-15-03-018	X	X	X			X							X		E	480.000
NV-15-03-019	X	X	X			X							X		E	1,000.000
NV-15-03-020	X	X	X			X							X		C,E	1,278.560
NV-15-03-021	X	X	X			X							X		C,E,Q	40.000
NV-15-03-022	X	X	X			X							X		E	881.060
NV-15-03-023	X	X	X			X							X		E	80.000
NV-15-03-024	X	X	X			X							X		E	599.590
NV-15-03-025	X	X	X			X			x				X		E	200.000
NV-15-03-026	X	X	X										X		E	240.000
													Total Acres Offered			25,802.470

Key to "Other" Column

A	Historic roads or trails eligible for listing on the National Register of Historic Places are or may be present. Mitigation of impacts could require substantial buffers to protect the viewshed of the trail.
B	Historic Structures or remains of structures eligible for listing on the National Register of Historic Places are or may be present.
C	Remains of historic railroads eligible for listing on the National Register of Historic Places are or may be present. Mitigation of impacts could require substantial buffers to protect the viewshed of the railroad.
D	Although all surface use authorizations would be subject to review, and mitigative measures may be required for cultural resources in any parcel, the Elko District Office advises potential lessees that these parcels are in areas with high potential for containing important cultural resources. Implementing measures to mitigate impacts to cultural resources may delay timeliness of permit approvals and restrict surface occupancy.
E	Parcel is in a Herd Management Area
F	The proposed parcel intersects the 100 year floodplain. Special restrictions may apply to protect floodplain function.
G	High priority stream habitat (Elko RMP) or stream habitat (Wells RMP) exists in or near the proposed parcel. Special restrictions may apply to protect habitat.
H	A surface water resource for which water quality standards apply, is present in or near the proposed parcel. Special restrictions may apply to protect water quality.
I	Noxious Weeds Present
J	Portions are within 1/4 mile of WSA
K	Wildlife Habitat Concerns

2.3 ALTERNATIVES CONSIDERED BUT ELIMINATED FROM FURTHER ANALYSIS

Offer the Industry Nominated Parcels

Seven million acres in Elko District have been nominated by industry for the 2015 lease sale. This number of acres is too large to process in any one lease sale because BLM does not have the staff to evaluate such a large area.

Offer Downsized Industry Nominated Parcels

BLM has the ability to process 1,350,700 acres of the 7 million acres. After the BLM reviewed the entire 1,350,700 acres it found that a majority of these lands were encumbered by wildlife, land status, or other resource conflicts (see figure 1.1). Of the 1,350,700 acres processed, BLM is analyzing 27,522.47 acres (0.4 percent of the nominated parcels). The remaining 1,323,200 acres were deferred from further analysis due to sage grouse conflicts (which is the majority), currently leases, or are in a Wilderness Study Area, etc. After further review analysis found that two parcels (NV-15-03-013 and NV-15-03-14) totaling 1720 acres, were encumbered by Native American Cultural concerns and therefore these parcels were deferred.

3 - AFFECTED ENVIRONMENT/ENVIRONMENTAL EFFECTS

General Setting
The Elko District is typical of the Great Basin, the lands generally located between the Wasatch Range of Utah and the Sierra Nevada mountains of California. The land is characterized by north-south oriented fault block mountain ranges separated by broad, flat valleys. The land is arid with precipitation generally less than 10 inches per year except for the higher elevations where precipitation is higher. The vegetation is typically sagebrush/grassland with substantial areas of juniper or pinion/juniper woodlands. Elevations range from above 13,000 feet in the Ruby Mountains to approximately 4,200 feet along the Utah border south of Wendover. The total population within the boundaries of the District is roughly 52,000 with the great majority of more than 40,000 in the Elko/Spring Creek area. Of the 12.5 million acres within the boundaries of the Elko District, approximately 7.2 million acres are public land managed by the Elko District Office.

With the exception of wilderness study areas, incorporated cities, and non-federal lands where mineral rights are not reserved to the U.S., most of the 7.2 million acres of public lands and 3.8 million acres of split estate land within the boundaries of the Elko District are open to leasing. Activities in sensitive areas are subject to surface occupancy limitations or seasonal restrictions that affect the conduct of leasing operations. The currently proposed lease sale would offer parcels scattered throughout the District subject to special stipulations where applicable.

As of 2013, over 48 million barrels of oil have been produced from oil fields within Nevada. There are geologic strata within the 7.2 million acres of public land managed by the Elko District Office which have been identified as potential sources of oil and gas. Because of the potential for oil and gas, as estimated by United States Geological Survey, public lands and mineral estate within the Elko District have been available for oil and gas leasing for decades.

See Appendix C for a projection of leasing related activities over the next 15 years. Post-leasing activities such as geophysical exploration and development of wells when added to the effects of other past, present, and reasonably foreseeable future actions have the potential to cumulatively affect resources and uses. Other activities include those related to livestock grazing, recreation, fire, urban development, and mining activities. The existing condition of lands that are leased are reflective of effects associated with past uses in combination with natural events such as wildfire and drought. The Great Basin Restoration Initiative, stream/riparian, upland restoration, and burned area rehabilitation projects are examples of ongoing actions that, when implemented, improve the condition of public lands throughout the Elko District.

3.1 CRITICAL ELEMENTS NOT AFFECTED

The following critical elements of the human environment are not present or affected by the proposed action, and are not further analyzed in this EA:

- Farm Lands (Prime or Unique)
- Environmental Justice

- Hazardous or Solid Wastes
- Wild and Scenic Rivers

3.2. EFFECTS OF THE ALTERNATIVES AND MITIGATIONS

Resources present and brought forward for analysis are discussed by the following subsections. Discussion is not listed where no impacts are expected, i.e., as for the No Action Alternative, to minimize non-essential text for this document.

The term "mitigations" used in the following sections is used to refer to resource protection measures that could be used when actual leases are developed subsequent to this lease sale.

3.2.1 Geology

<u>Existing Conditions</u>

Because of the potential for oil and gas, public lands and mineral estate within the Elko District have been available for oil and gas leasing for decades. There are two producing oil fields within the boundaries of the Elko District. Both are in Pine Valley but only one, the Blackburn Oil Field, is on public lands. The other, the Tomera Ranch Oil Field (Nevada Division of Minerals, 2013), is on private land, as are two abandoned oil fields. Three Bar (Nevada Division of Minerals, 2013) and North Willow (Nevada Division of Minerals, 2013) produced small amounts of oil (24,000 barrels and 51,142 barrels) in the past but neither is presently producing significant amounts of oil. The Blackburn Field (Nevada Division of Minerals, 2013), which has produced about 5,477,789 barrels from the Devonian Nevada formation, Mississippian Chainman shale, Oligocene Indian Well formation, including seven oil wells of which four, all on public land, continue to produce. The Tomera Ranch Oil Field has produced about 44,471 barrels. Production rates are declining at both fields. There have been some unconfirmed reports of some production from the Phyllis lake area.

<u>Nevada's Basin and Range Province</u>

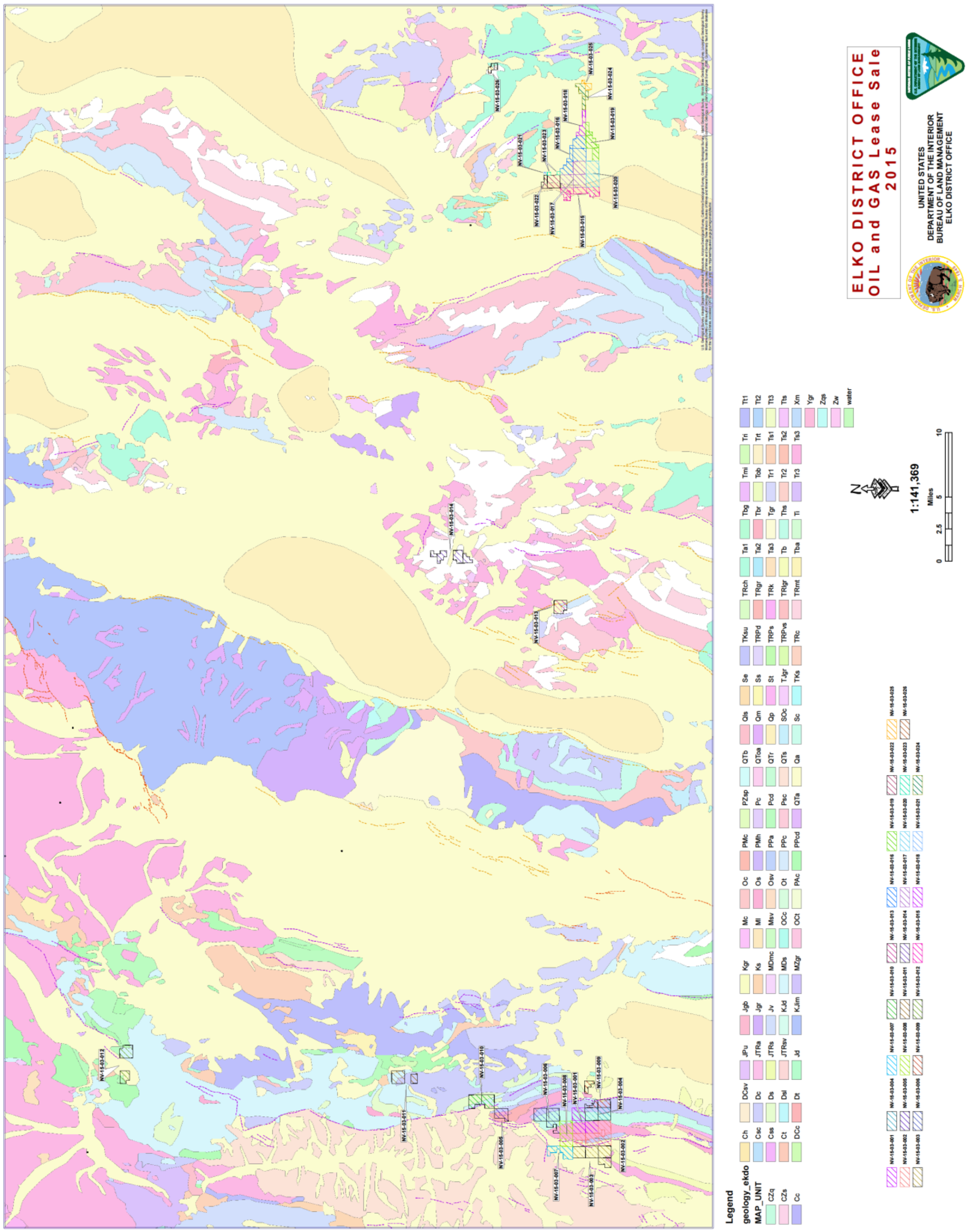
The regional geology is described by Coats (1987) as shown on Map 3.2-2. The Ruby Mountains consist of mostly granitoid intrusives of Mesozoic to Cenozoic age with relics of Paleozoic metasedimentary rocks. Fragmented ranges contain more Paleozoic carbonate rocks and an overlay of Tertiary volcanics (ash, welded tuff). Oil exploratory drilling in the late 1970s through the mid-1980s disclosed stratigraphy of Pine and Huntington valleys, consisting of up to 10,000 feet thickness of Tertiary through Recent deposits overlying mostly Paleozoic limestone basement. The lowest Tertiary unit is the Eocene-Oligocene Elko Formation, which is a lake-deposited marlstone with high kerogen content ("oil shale"), with high potential for generation of oil and gas hydrocarbons. This is overlain by up to 4,000 feet of Indian Well Formation, and up to 4,000 feet of the Hay Ranch Formation which is equivalent to the Humboldt Formation north of the valley. Hay Ranch and Indian Well formations both consist of tuffaceous volcanics, siltstone and sandstone, with conglomerate and lake-deposited limestone also present in the Indian Well Formation.

The rocks of the Pinon and Sulfur Springs range formed in a continental shelf underlain by shallow marine carbonate (middle Paleozoic) and clastic (lower Paleozoic) rocks (Foster et al, 1979). To the west was siliceous, organic rich, fine-grained shaley sediments of the Vinnini, and Valmy formations. There is some disagreement among geologists about the origin of the oil and gas deposits however the likely source is the, organic material in the Ordovician Vinnini Formation, Mississippian Chainman/White Pine Shale and the Cretaceous-Paleocene Newark Canyon Formation and the Eocene-Oligocene Elko Formation (Foster et al, 1979). Oil traps occur in all of these formations as well as the most recent sediments.

The geology in the Currie area consists of Tertiary intrusive rocks and sedimentary Tertiary carbonate rocks, shallow marine carbonate (middle Paleozoic) and fusulinid carbonate (lower Paleozoic) rocks, Coats (1987). Geology of the Maverick Medicine range includesTertiary intrusive rocks and sedimentary Tertiary carbonate rocks, shallow marine carbonate (middle Paleozoic) and fusulinid carbonate (lower Paleozoic) rocks, Coats (1987)

Fault traces shown on the geology map 3.2-2 are Quaternary displacements mapped by dePolo (2008). These are just the surface expressions of features thousands of feet deep, which have thrown the Ruby Mountains, Sulphur Springs Range and Pinon Range up and Huntington Valley, Pine Valley down. Faulting has occurred over the entire Tertiary, leading to thick accumulation of sediments in the valleys.

Map 3.2-2
Geology



As is true for the entire Basin and Range Province (which is most of the state of Nevada), in which valleys are downthrown on marginal faults up to tens of thousands of feet with respect to intervening ranges, seismic activity is continual (and has been for ten million years and more). Extensional tectonics throughout the Great Basin has thinned the crust and heat flow is higher than the continental average. This means that kerogen-bearing rocks are "matured" (in terms of generation of hydrocarbon fluids) at shallower depth than in most basins, but also potential hydrocarbon reservoirs are more likely to be fragmented by faulting.

Seismology. Six strong earthquakes (magnitude greater than 5) have occurred within the State of Nevada in a 56-year period, including a magnitude 6 quake near Wells in 2008 which damaged some older buildings. Magnitude 6 is felt by everyone, in or outside; windows break, books fall, and dishes and glassware are broken; damage is slight to moderate to poorly designed buildings. Magnitude 6 events should not damage modern buildings, and magnitude 7 events cause some damage to even well-built buildings or possibly steel construction.

Figure 3.2-2 shows a plot of earthquake data from Advanced National Seismic System records over the period 1950 to 2014, within a rectangle between Latitude 39 and 42 North, and Longitude 114 and 117 West (Elko County, extending south through Eureka County and west to Battle Mountain). This data set contains information from the Earthscope Transportable Array, a high sensitivity array on 80 km centers was deployed in northeastern Nevada for 1.5 years which detected lower magnitude earthquakes than are normally possible to detect using Nevada's typical seismograph array. The low magnitude end of the frequency is cramped by the brevity of the record with high sensitivity since all of the events smaller than magnitude 3 were recorded during the 1.5 year term that the sensitive array was deployed. The rest of the record is approximately linear on the log scale, with the single magnitude 6 event at Wells in February, 2008 showing as anomalous with respect to the rest of the record (drawing the straight line would suggest this magnitude has a return period of several hundred years in Elko County). Figure 3.2-3 shows locations and magnitudes of earthquakes in the state over a 56-year period, not including the 2008 magnitude 6 event near Wells (Nevada Seismological Lab, 2005). This indicates that earthquakes with magnitude 5 or greater occur about once every decade in Elko County. Earthquakes are much more frequent and stronger in the western side of the state, along the Sierra Nevada, Walker Lane, and the central Nevada Seismic Zone. Figure 3.2-2 also shows a number of quakes less than magnitude 3 in Elko County; magnitude 2 quakes and smaller ("micro" quakes not felt by people) are not likely to be detected by the existing seismic network.

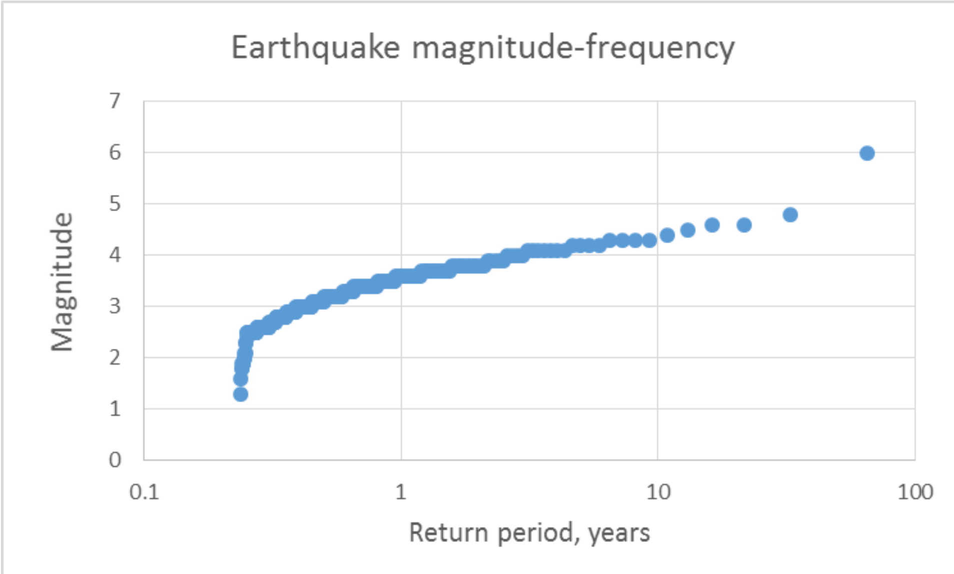


Figure 3.2-2
Earthquake Frequency in Elko County, 1950 to 2014
(Advanced National Seismic System, 2014)

Damage to oil field facilities by earthquakes has not been extensively documented, but the U.S. Geological Survey (USGS) published Professional Paper 1487 on damage by a fault near Coalingua, California, in 1987, when this was one of the larger production fields in the U.S. A magnitude 6.7 quake occurred on May 2, 1983; this is considerably stronger than the 6.0 2008 earthquake near Wells. The Coalinga quake triggered slides, severely damaged pre-1945 buildings, and toppled chimneys. There was minor damage to electric and water utilities, but power was interrupted for several days and oil production (which relied on electric pumps) was disrupted. Anchored oil field equipment and pipelines suffered minor damage, and leakage from those tanks that were affected was all contained. Some 26 of 935 active wells were found to have offsets cause by seismic activity. Damage to the oil field facilities was primarily to un-anchored tanks, no pipes were ruptured, and no environmental releases occurred.

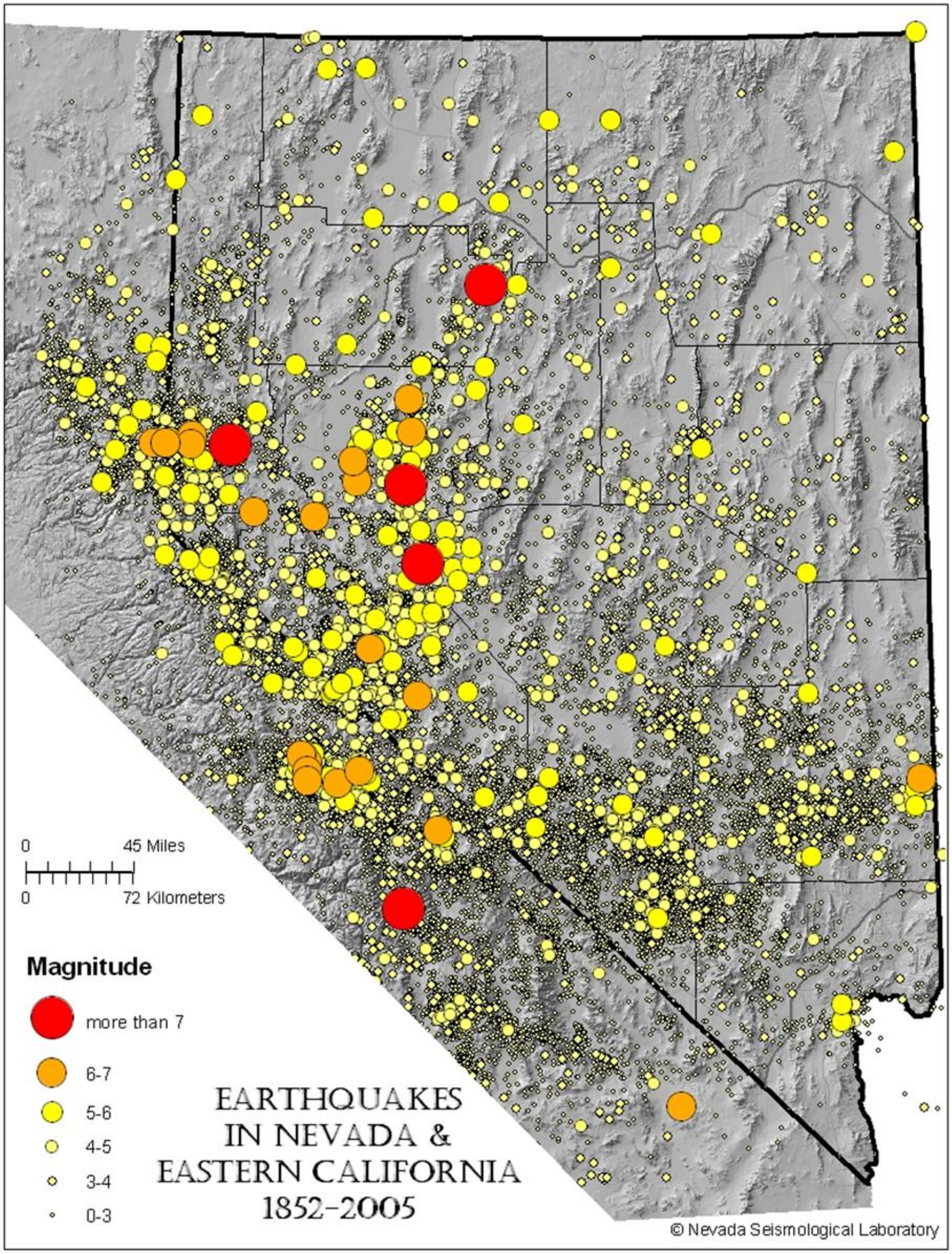


Figure 3.2-3
Earthquakes in Nevada and Eastern California 1852-2005
(Nevada Seismological Lab, 2005)

Reasonably Foreseeable Development Scenario

Anytime during the 10-year term of the lease, the lessee, or operator, may submit specific plans for exploration and development to BLM for approval. These plans may be in the form of a Notice of Intent for Geophysical Exploration, or an Application for Permit to Drill (APD), Notice of Staking or Sundry Notice. BLM then reviews the submission to determine if there are any other site-specific conditions of approval that should be applied. Such conditions of approval must be consistent with the lease rights granted. In conjunction with obtaining approval to explore or develop a leased parcel, the operator may also seek a right-of-way to access the leased lands.

The following paragraphs provide a general description of possible post-leasing activities. Detailed explanations are located in Appendix C.

Geophysical exploration is used to obtain detailed geologic information. A variety of exploration methods are employed, ranging from placing electrodes in the ground, to detonating explosives to create shockwaves, to employing specially constructed off-road vehicles to produce vibrations. The most commonly used method in eastern Nevada is the vibroseis technique, which uses large off-road vehicles with "thumpers" to generate shockwaves for two or three dimensional surveys.

Exploratory drilling (a wildcat well) begins development of a lease. An Application for Permit to Drill (APD) is filed with the BLM. A field examination is conducted and NEPA review is completed before a drilling permit can be approved. An access road and a well pad are constructed for each well, if needed. Total disturbance attributed to drilling an exploration well is usually limited to five to ten acres for the pad and access road. Statistically, over 95% of exploration wells are dry.

Well Stimulation/Hydraulic Fracturing

Well Stimulation may be used to enhance oil recovery. Several methods of well stimulation could be used. Hydraulic Fracturing is one of these methods that are reasonably foreseeable for leases on this sale. Hydraulic fracturing is the process of applying high pressure to a subsurface formation via a wellbore, to the extent that the pressure induces fractures in the rock. Typically the induced fractures will be propped open with a granular "proppant" to enhance fluid connection between the well and formation. The process was developed experimentally in 1947 and has been used routinely since 1950. The Society of Petroleum Engineers (SPE) estimates that over one million hydraulic fracturing procedures have been pumped in the United States and tens of thousands of horizontal wells have been drilled and hydraulically fractured. It can greatly increase the yield of a well, and development of hydraulic fracturing methods and the drilling technology in which it is applied (in particular, long wells drilled horizontally within the targets) have enabled production of oil and gas from tight formations formerly not economically feasible.

Hydraulic Fracturing Technology

A general description of the hydraulic fracturing technology follows:

- All exploratory, testing, and production wells use multiple layers of casing sealed with cement between the wellbore and the formation. Well integrity is tested throughout the process.
- Drilling and hydraulic fracturing fluids can be contained in a pitless system (aboveground tanks) or a lined pit. Cuttings could be contained in roll-off boxes for hauling to approved disposal facilities, or surface casing interval cuttings could be spread over the site during reclamation.
- Hydraulic fracturing fluids are recovered to a large degree in "flowback" or produced water when the well is tested or produced.
- All recovered fluids are generally handled by one of four methods.
    - Underground injection
    - Captured in steel tanks and disposed of in an approved disposal facility.
    - Treatment and reuse
    - Surface disposal pits
- Drill cuttings could be land farmed and buried on site 3 feet below root zones. Any cuttings that do not fit this waste profile will be disposed of at an approved disposal facility.

All Hydraulic Fracturing operations would be conducted to the standards of the State of Nevada, Third Revised Proposed Regulation R011-14 (See Appendix F for the text of the State of Nevada Regulations.)

<u>In-field drilling</u> of additional exploration wells typically occurs when initial drilling has located oil or gas, to define the limits of the oil or gas reservoir. The process of in-field drilling is the same as that employed for initial exploratory drilling, although new roads and pads may not be required in every instance.

<u>Production</u> begins only if oil or gas can be transported to a market and sold at a profit. In the Elko District, because of limited infrastructure, pumped oil is generally piped a short distance for temporary storage, then trucked to a refinery for processing. That is not likely to change because of the small quantity of resource estimated to be present in the Elko District. Production facilities may include one or more of the following: a well head; pumping equipment; a separation system; pipelines; a metering system; storage facilities; water treatment and injection facilities; cathodic protection systems; electrical distribution lines; compressor stations; communication sites; roads; salt water disposal systems; dehydration sites; and, fresh and salt water plant sites.

<u>Well abandonment</u> may be temporary or permanent. Wells are sometimes shut-in because pipelines or roads needed for production and marketing don't exist and the cost for construction is not justified by the quantity of oil discovered. These wells may later be reentered when their production can be marketed. The permanent abandonment of a well occurs when the well is determined to no longer have a potential for economic production, or when the well cannot be used for other purposes.

Reclamation. Abandonment includes removal of facilities and reclamation of surface disturbance. In the case of exploration wells which do not find economically recoverable amounts of oil, initial reclamation (recontouring), is usually completed the following year which provides for sufficient time for the reserve pit to dry out. After revegetation of the site is completed, usually within five to ten years, reclamation is complete. If an exploration well finds economically recoverable quantities of oil, all disturbed surface except the small amount (typically 1-2 acres in size) needed for a pump and access is reclaimed immediately.

Effects of the Proposed Alternative

Oil and gas is a nonrenewable resource. Once the oil and gas is pumped and consumed, there are no more leasing activities, including exploration and development which generates geologic information that enables geologists and engineers to expand the knowledge base for geology.

Fluid injection either associated with routine oil and gas development and production or associated with hydraulic fracturing has the potential to induce seismic activity. Nevada is the 3rd most tectonically active state in the union. Since the 1850s there have been 63 earthquakes with a magnitude greater than 5.5, the cutoff for a destructive earthquake. Geologic mapping and 2-D and 3-D seismic data can locate faults within the project boundary but current science may not be able to differentiate a “natural” earthquake in this tectonically active region as opposed to those induced by fluid injection. Any destructive earthquake has the potential to induce liquefaction in saturated soils and to cause landslides. Modern buildings in Nevada are built to code and if property owners practice earthquake preparedness, damage would be kept to a minimum.

The Reasonably Foreseeable Development Scenario from Appendix C concludes that the Elko District can expect to see a total of 1,650 miles of seismic surveys, 80 exploration wells, discovery and development of two mid-size oil fields and two small oil fields. The seismic surveys are expected to result in 788 acres of disturbance of which 683 would be reclaimed at the end of the 15 years (13 of 15 years of exploration activities). The exploration wells and development and production activities would disturb 858 acres of which 677 would be reclaimed at the end of 15 years while 181 acres would still be in use for production facilities.

Cumulative Effects of the Alternatives

The cumulative effects study area (CESA) is Elko District. Fluid injection induced seismicity is a very low but real possibility that cannot accurately be quantified. There are no cumulative impacts of concern for the Proposed Action or associated future oil and gas development with respect to geologic resources.

Mitigation

No mitigation is needed for the Proposed Action, however, BMPs, Conditions of Approval (COAs), along with the applied stipulations would minimize the potential for adverse effects if the leased parcel is developed. Site specific mitigation will be developed during the APD stage of permitting.

3.2.2 Socio-Economics

Existing Conditions

Oil and gas and energy are national issues as well as local issues. All proposed lease parcels are located in Elko County, which has a US Census estimated population of 51,212 in 2012. Elko County relies on the exploration and development of natural resources, primarily gold, to provide the basis for employment and economic activity in the county and adjacent areas which comprise the Elko District of the BLM. Natural resource jobs, including mining, usually pay relatively well, resulting in Elko County having the second highest median household income in Nevada at just over $69,459 per year. Like gold, oil and gas are shipped out of the area for processing and use. Thus the exploitation of oil and gas resources benefits both the local and national economy.

Effects of the Proposed Alternative

Leasing, exploration, and development of oil and gas resources generate revenue to the Federal, state, and local governments. The proposed action also generates economic activity in the private sector. People and equipment are required to explore for mineral deposits. This means capital investment as well as the purchase of operational supplies such as lubricating oils and drill bits for drill rigs. Employees are required for the many disparate aspects of leasing and exploration, from those who handle permitting and land ownerships issues, to those who handle the financing and payroll, to the regulatory agency employees who regulate such activities, to the on-the-ground employees who actually perform the exploration work, to the geologists who interpret the information received and advise on future exploration work.

Leasing activities also generate economically valuable information. Exploration generates information about the geology and mineral resources at a particular location. That information can usually be used to infer geology and mineral resources in a much wider area. The more information available, the greater the efficiency of future searches for mineral deposits of all kinds, not just oil and gas.

Oil production from federal lands results in a 12.5% production royalty payment to the federal government. Fifty percent of that amount is provided to the state government. Taxes are paid to government in a variety of forms including income and property taxes by both the oil production operators and the employees thereof. Government may be providing additional services such as new roads, and road maintenance which results from oil development operations. The additional economic activity and employment results in a broadening effect, supporting employment and economic activity in other sectors of the economy including housing, retail, services, and government.

A second benefit of development and production of oil and geothermal resources is increased availability and potentially lower prices for energy based on the supply/demand theory of economics. Lower prices mean increased economic activity along with the impact of diverting payments from a foreign nation to the internal US economy. Increased US energy supply also increases economic stability by decreasing the risks associated with importing energy, particularly oil and gas, from unstable source countries. Another benefit is that increased energy production helps to create the infrastructure such as roads, powerlines, service companies, housing, and the like which support the expansion of other economic activities indirectly (rather than directly) through the need of the energy industry for employees and services.

Economic expansion is increased population and increased pressure on finite resources such as water, recreation, open space, and additional demands on government services.

Mitigation

The Proposed Action is for the offer of sale of leases and does not have any negative affect on Socioeconomics in Elko County. Mitigation would be determined if leased parcels are proposed for development.

3.2.3 Cultural Resources

Cultural resources are defined as those nonrenewable remains of past human activity. For example, once the objects in an archeological site are disturbed, nothing can recover the information that might have been gained through analysis of their relationships in past human history. The primary concern of cultural resource management, therefore, is to minimize the loss or degradation of culturally significant material remains.

Protection of America's cultural resources began with the passage of the 1906 Antiquities Act. Next to pass was the Historic Sites Act of 1935. These two previous Acts were incorporated into the National Historic Preservation Act (NHPA) of 1966 and its amendments. Protection of historic properties was reiterated in the Archaeological Resources Protection Act (ARPA) of 1979, and protection was broadened by the Native American Graves Protection and Repatriation Act (NAGPRA) in 1990. Although each of these acts has its own focus and orientation, collectively they require a comprehensive, multicultural, and multi-disciplined approach to managing cultural resources on public lands.

The National Historic Preservation Act (NHPA) recognizes cultural resources as five property types: districts, sites, buildings, structures, and objects. As called for in the Act, these categories are used in the National Register of Historic Places (NRHP), the preeminent reference for properties worthy of preservation in the United States. To focus attention on management requirements within these property types, the NPS *Management Policies* categorizes cultural resources as archeological resources, cultural landscapes, structures, museum objects, and ethnographic resources.

The BLM Elko District is located in the north-central Great Basin and in the north-eastern region of the state of Nevada. The Elko District contains some of the earliest known human habitation sites in the United States. Archaeological studies of this area have shown that humans (Paleoindian hunter/gatherers) began utilizing natural resources such as mega fauna (i.e., mammoths) at least 12,000 years ago. The Great Basin's climate was much different than today; having large Pleistocene lakes such as Lake Lahontan and Lake Bonneville. As the climate began changing around 9,000 years ago to a warmer/dryer environment, the mega fauna became extinct. Due to population growth and climate change these resourceful people adapted to a nomadic plant based gathering lifestyle and hunting smaller game, traveling to where the resources became seasonally available.

The Elko District also has a rich history from the historic-era. The first known Euroamericans to enter the region were fur trappers in the early 1800's. Following on the heels of these early trappers were the emigrants following the trails to Oregon and California. The Bidwell-Bartleson party passed through in 1841 and the Donner party passed through on their way to California in 1846. With the discovery of Gold at Sutter's Mill in California in 1848, miners began utilizing the trails to California to make their fortunes in the California gold fields. Mining began in the Elko District in 1859 with discovery of gold in near the present day city of Carlin. Congress granted Nevada statehood in 1864 because the region's precious metals were key to the Union's cause in the Civil War. The construction of the transcontinental railroad (which passes through the District) began in 1863 and ended in 1869. Chinese miners began arriving in the area in 1869 after the railroad had been completed.

Less than 15% of the entire Elko District has been inventoried for cultural resources as of December 2013. The District contains over 17,700 known prehistoric-era and historic-era archaeological sites. Given the vast size of the Elko District and the small amount of cultural resource inventories, most of the proposed locations for the oil and gas lease sale have not been inventoried for cultural resources. Resources known to exist in the view shed, within or near the March 2015 Oil and Gas Lease Sale parcels include the California Emigrant Trail, the Hastings Cutoff of the California Emigrant Trail, the Northern Nevada Railway Grade, and numerous prehistoric-era and historic-era sites.

Effects of the Proposed Alternative

The act of selling oil and gas leases, although not authorizing exploration, development or production prior to site specific NEPA analysis, has the potential to adversely impact cultural resources because it gives the lessee certain irrevocable rights and can foreclose the authorized officer's use of some mitigation measures. Once issued, a lease bestows upon its owner the "right to use so much of the lease lands as is necessary to explore for, drill for, mine, extract, remove and dispose of the leased resource in the leasehold" (43 CFR§ 3101.1-2) subject to specific nondiscretionary statues and lease stipulations. "Reasonable" mitigation measures may be required by the authorized officer prior to project authorization to minimize adverse impacts to other resource values. "Such reasonable measures may include, but are not limited to, modification to siting or design of facilities, timing of operations, and specification of interim and final reclamation measures. At a minimum, measures shall be deemed consistent with lease rights granted provided that they do not: require relocation of proposed operations by more than 200 meters; require that operations be sited off the leasehold; or prohibit new surface disturbing operations for a period in excess of 60 days in any lease year" (43 CFR§ 3101.1-2).

Cultural resources management is authorized by a number of federal statutes including the National Historic Preservation Act (16 U.S.C. 470). Regulations (36CFR§ 60.4) promulgated under this act provide criteria for evaluating cultural properties to determine if they qualify for listing on the National Register of Historic Places due to their significance in American history, architecture, archaeology, engineering, and culture. In Nevada 15% to 20% of cultural resources found during inventory are typically found to be eligible for listing on the National Register and thus worthy of consideration beyond initial recording. A property can be eligible on the national, state/regional, or local level. The term “historic property” as defined at 36CFR§ 800.16(I) is used here to describe any cultural resource that qualifies for listing on the National Register of Historic Places.

Four National Register criteria are applied when evaluating cultural resources. Criterion A is used to evaluate a property’s association with events that have made a significant contribution to the broad patterns of our history. Examples of eligible properties are the California Emigrant Trail (national level) and Fort Ruby (local level). Criterion B relates to a property’s association with the lives of persons significant in our past.
The majority of eligible cultural resources in the Elko District qualify to the National Register solely under Criterion D and adverse effects can usually be avoided either through project relocation of 200 meters or less, or through data recovery because these properties are significant due to their data potential.

However the 200 meter relocation measures allowed by the oil and gas regulations may not be sufficient to avoid adverse effects to those relatively few cultural resources that qualify for National Register under Criteria A, B and/or C. This is because such properties’ significance may be in part due to their setting, feeling and association. For example an eligible segment of the California Emigrant Trail may lie in a valley where there has been little modern development and can provide the visitor a glimpse of the emigrants’ experience. Placement of a production oil well or well field in the view shed may substantially affect the setting, feeling, and association of the trail. Movement of these facilities 200 meters or less often would do little to mitigate the effects.

New directives regarding National Historic Trails is outlined in the BLM Manual 6280 “Management of National Scenic and Historic Trails under Study or Recommended as Suitable for Congressional Designation (Public)” states that BLM may not permit proposed actions along National Trails which will substantially interfere with the nature and purpose of the trail. Segments of the California National Trail have contributing (eligible for the National Register) and non-contributing (ineligible for the National Register) elements. In the eligible portions, the Trail could be adversely affected through audio or visual disturbance. For further direction of requirements refer to BLM Manuel 6280, sections 5.1 through 5.5, specifically sections 5.3 A and B.

Geophysical Exploration: The potential impacts to cultural resources are shared by all the cross-country, truck-supported seismic exploration (thumper, vibrator, spark ignition and surface/subsurface explosives) and, to a lesser degree, by non-vehicle supported surface explosives. Unidentified buried or surface cultural resources could be crushed/broken, displacement, and mixed by vehicle tires and tracks, or explosives. Similar impacts can be caused by the steel slabs, vibrator feet, and explosives used to create the seismic waves. The nature of the impacts can range from negligible to severe depending on the number and weight of the vehicles, the number of passes, soil types and conditions, and the nature of the cultural resources in the area of potential effect. Generally, for archaeological deposits, greater surface disturbance or soil compaction leads to greater impacts.

Cultural resources also could suffer impacts due to unauthorized artifact collection directly or indirectly associated with geophysical exploration. Potential impacts could result from illegal artifact collection by geoseismic crews who cover broad expanses of ground establishing the grids and laying out the cables necessary for data collection, and who usually know cultural resource site locations because they are required to route around sites to avoid impacts. Indirect impacts could result when seismic trails are used by artifact collectors to access locations which previously had limited access. Artifact collecting on public lands is prohibited by federal law. While difficult to quantify, artifact collection resulting from geophysical exploration could substantially impact cultural resources. “Arrowheads”, bottles, and other artifacts/tools sought by collectors are also among the sources of data most critical for archaeological research and/or site interpretation. Because cultural resources are nonrenewable, artifact removal and other site damages would be an irretrievable resource loss.

Visual impacts (i.e., effects to setting, feeling, and association) to cultural properties eligible under Criteria A, B or C, caused by the intrusion of exploration vehicles, would usually be of short duration and usually not adverse. Exploration lines on-the-other-hand, could remain visible for decades in this desert environment (as evidenced by the 1970s and 1980s seismic lines still visible in the Elko District) creating long-term visual impacts. Multiple parallel lines could be the most visually intrusive.

Other long-term impacts could occur if seismic lines are converted to use as roads. Impacts could result from continued driving over cultural resources and from deepening and widening of the roadbed within sites if use is heavy or certain conditions (powdery soil, excessive moisture) are present. Improved access could also result in damages such as long-term artifact collection in previously remote sites and more indirectly like those caused from increased off-road recreation in areas away from the seismic lines.

Certain exploration actions can be exempted from cultural resource inventory. The cultural resource Protocol Agreement between Nevada BLM and Nevada State Historic Preservation Office (SHPO) provide that the following geophysical exploration actions may be considered categorically no adverse situations and may be excluded from cultural resource inventory requirements: 1) vibroseis and conventional truck-mounted shothole drill routes and operations located on constructed roads or well-defined existing roads and trails; 2) pedestrian routes and placement sites for hand-carried geophone, cables, or similar equipment; 3) cross-country operations of seismic trucks and support vehicles on bare frozen ground or with sufficient snow depth (vehicle traffic does not reveal the ground) so as to prevent surface disturbance; 4) one time (single pass) routes of wheeled vehicles under 10,000 lbs. GVW; 5) above ground seismic blasting (Poulter method); 6) helicopter-supported activities, including shothole drilling and above ground seismic blasting (Poulter method) in most areas, that do not require helicopter staging area preparation and vehicle use off of roads and trails; and 7) exploration activities defined as casual use in 43 CFR 3150. The preceding exemptions would not apply if cultural resources might be impacted such as: the use of surface blasting is near historic structures, using crews in areas with high densities of artifacts that might be illicitly removed, or using vibroseis trucks on a historic wagon road.

Exploration Drilling: The various actions involved in oil and gas exploration drilling could adversely impact cultural resources physically and visually. Impact types would be similar for all drilling methods but the degree of impact could differ since some methods cause more earth disturbance than others. If drill pad or mud pit construction are not needed and scarification is not used to rehabilitate the pad then physical impacts would usually be crushing/breaking, displacement and mixing of archaeological deposits, features and artifacts, and other cultural resources. Pad construction impacts could be more severe as constructed pads are usually larger than informal pads and substantial earth disturbance is usually required, potentially obliterating any cultural resources.

Exploration pad construction and drilling activities could affect the setting, feeling, and association of cultural properties eligible to the National Register under Criteria A, B or C as discussed above under “Effects”. If the pad and associated facilities are abandoned and rehabilitated shortly after construction, these effects could be temporary and therefore not adverse if successfully rehabilitated. If the project goes to production visual impacts could be long-term as discussed below.

Improved access and an increased human presence could result in illicit artifact collection and general deterioration of cultural resources. This type of damage would typically be concentrated around the drill site and access routes, and might be expected to be more likely to occur, or result in greater damages when extended drilling times are involved.

Road Construction and Use: Road construction, like the other actions involving substantial earth disturbance, can damage or destroy any cultural resources within the road corridor. A narrow road created by a single pass of the blade would be likely to do less damage, than a crowned and ditched road built to support heavy traffic. Cultural resources outside the construction corridor could be impacted by construction induced erosion.

Road construction and use could affect the setting, feeling, and association of historic properties eligible to the National Register under Criteria A, B or C as discussed above in “Effects.” The type of road, duration of use, nature of the historic properties, and visibility of the road from these properties would have to be considered in determining effects and developing mitigation measures. If the roads were to be abandoned and rehabilitated soon after construction, effects could be determined to be temporary and therefore not adverse, assuming the rehabilitated routes did not create a substantial long-term visual effect. If new roads were not closed and rehabilitated, visual impacts could be long-term from both the intrusion of the road itself and from traffic using it.

Creation of new or improved access into areas which previously were difficult to reach could have substantial and long lasting adverse effects if cultural resources were present. A number of studies (Williams 1978, Lyneis et al. 1980; Nickens et al. 1981) have shown that that increased access leads to both intentional and incidental deterioration of nearby cultural resources. Nickens et al. (1981) found that most archaeological sites within 100 meters of improved roads exhibited evidence of vandalism and/or illegal collection. Sites at considerably greater distances also suffered damage but with less frequency as distance increased (Desjean and Wilson 1990; Ison et al. 1981; Nickens et al. 1981). With the advent of widespread ATV use in the last decade, we might anticipate that the spread of damage beyond new access roads may now be even greater especially since the Elko District Office RMPs allows off-road use in most areas.

Development: Development of individual oil wells and oil fields would have the same types of impacts as exploratory drilling if cultural resources are present but potentially at a much greater scale simply because of the increased surface disturbance, additional facilities, longer period of use, and less opportunity to effectively redesign/relocate the fields to avoid impacts. The types of potential impacts depend on many factors including the location of the oil fields, the nature of the subsurface oil/gas reservoirs, the number and type of cultural resources present, and the geography.

Physical impacts from the clearing, leveling, cutting and filling for the drill pads, tank batteries, internal pipelines, and other facilities could damage or destroy cultural resources located within the construction zones. Moving a drill pad to avoid historic resources would avoid direct physical impacts to archaeological sites or resources.. However, such actions may be insufficient to avoid the effects of incidental and intentional human actions (e.g., running equipment through sites, artifact collecting, etc.) or unanticipated secondary effects of the development such as erosion or oil spills.

The earth disturbance, facilities, operations activities (such as flaring), and traffic required by oil and gas development and operations could substantially impact the setting, feeling, and association of any nearby historic properties eligible to the National Register under Criteria A, B and C by introducing visual and noise elements that are out of character with the particular resource such as the California Trail. Intrusions could range from minor, if the historic property is some distance from the development or is screened by the topography, to overwhelming if a small resource such as a historic cabin were to be surrounded by a well field and associated facilities.

Power Lines: Power line installation and maintenance would cause earth disturbing activities at the pole locations, along access routes, and at staging areas. All of these could have adverse effects to cultural resources. The amount of disturbance depends on the size of the line. Single pole lines might only require cross country travel and drilling of pole holes without preparing a pad. The greatest damage could be from long-term use of the access route for line inspection and maintenance, and as an access route by the public.

Due to their height and visibility power lines could affect the setting, feeling, and association of historic properties eligible to the National Register under Criteria A, B and C.

Pipelines**:** Pipelines could be installed on the surface or buried. Both methods could have adverse effects to cultural resources by obliterating surface and shallow buried manifestations of archaeological and historic sites. Buried pipelines also have the potential to affect deeply buried archaeological deposits.

Surface pipelines could have long-term visual effects for some historic properties, while visual effects from buried pipelines might be of shorter duration if the line and access road are rehabilitated and revegetated.

Rehabilitation/Abandonment: Rehabilitation and abandonment of trails, roads, pads, and other facilities associated with oil and gas exploration and development could affect cultural resources, but usually not to the degree of the earlier project phases. Positive effects could be lessening or removal of project induced visual intrusions into settings of historic properties. Adverse impacts could result if new ground containing historic properties would be disturbed during leveling, recontouring, ripping, or other types of rehabilitation. Special protective measures established in the proposed action for construction would suffice for the rehabilitation/abandonment phase. However, because rehabilitation/abandonment may occur months or years after the original action, avoidance measures could be forgotten or overlooked.

Most cultural properties tend to degrade over time due to natural forces but many tend to remain intact for thousands of years. Modern human activity tends to exacerbate the damage and as a consequence cultural resources are disappearing at an ever increasing rate. Many of the impacts of fluid mineral exploration and development described above would be mitigated through implementing protective measures as part of standard operating procedures. Similar measures implemented for other types of federal undertakings would also limit cultural resource impacts. A described above, not all damages attributable to these actions are well understood or can be controlled. Taken together with other uses of the public lands, fluid mineral exploration could contribute to an overall decline in cultural resources.

Cumulative Effects

The March 2015 Oil & Gas Lease Sale does not authorize any ground disturbance and therefore has no direct effect to cultural resources. As directed by law, cultural resources inventories are conducted for any actions involving federal lands, and adverse effects to historic properties avoided or mitigated as appropriate. Avoidance through project redesign is the preferred method of mitigation; however, when avoidance is not feasible, data recovery or other forms of mitigation are implemented prior to ground-disturbing activities. Unavoidable adverse effects to historic properties would be addressed through mitigation in accordance with the appropriate processes and developed in consultation with the Nevada SHPO. In addition, any previously unknown NRHP-eligible sites potentially discovered during project activities would be mitigated in accordance with the NRHP and BLM rules and regulations in consultation with the Nevada SHPO. Therefore, and oil and gas operations subsequent to the 2015 Oil & Gas Lease Sale is not expected to cumulatively contribute to direct effects to historic properties. However, if data recovery is necessary to mitigate unavoidable adverse effects to historic properties, the process would recover a substantial amount of data but ultimately the site would be destroyed by the undertaking preventing future opportunities for scientific research, preservation, or public appreciation. Over time, this represents a cumulative loss.

Mitigation

Adverse effects to cultural resources would be mitigated through project redesign, relocation, or in some cases of historic properties eligible for their research potential (Criteria D), through data recovery. Direct physical impacts would usually be avoided by project reroutes and redesign. Buffers would be established between historic properties and proposed projects to mitigate potential direct and indirect impacts.

While avoidance measures and buffers may lessen the degree of incidental and intentional impacts to historic properties, other measures would also be required if warranted.

Such mitigation measures may include, but are not limited to:

- The proponent to ensure their actions or the actions of their employees, contractors or anyone else associated with the project do not intentionally or inadvertently adversely impact historic properties.
- Should unanticipated or unauthorized impacts occur, the proponent would be responsible for taking steps to eliminate the action causing the impact, and for the cost of repairing/stabilizing damaged properties and/or undertaking appropriate data recovery.
- If historic properties susceptible to impacts attributable to the project are located near or within long-term facilities such as oil fields, or associated access roads, photographic documentation, and establishment of base maps followed with periodic monitoring by an archaeologist funded by the proponent would be required to ensure that these historic properties are not deteriorating.
- the proponent and their employees in site protection, including but not limited to
- employee education to reporting of unauthorized artifact collecting.

3.2.4 Paleontological Resources

Regulatory Framework:

The Paleontological Resources Preservation Act (PRPA) became law in 2009 with the passage of Public Law 111-011. The PRPA includes specific provisions addressing management of these resources by the Bureau of Land Management (BLM), National Park Service (NPS), Bureau of Reclamation (BOR), U.S. Fish and Wildlife Service (USFWS), and U.S. Forest Service (USFS). The PRPA confirmed the authority for many policies these agencies already had in place for the management of paleontological resources including issuing permits for collecting paleontological resources, curation of paleontological resources, and confidentiality of locality data. The PRPA only applies to federal lands and does not affect private lands. It provides authority for the protection of paleontological resources on federal lands including criminal and civil penalties for fossil theft and vandalism. Consistent with policy before the passage of the act, the PRPA also includes provisions allowing for casual or hobby collecting of common invertebrate and plant fossils without a permit on federal lands managed by the BLM, the BOR, or the USFS, under certain conditions. The PRPA directed federal agencies to begin developing regulations, establishing public awareness and education programs, and inventorying and monitoring federal lands.

The BLM also manages paleontological resources (fossils) on federal lands under the following additional statutes and regulations (BLM 2010):

- Federal Land Policy and Management Act of 1976 (P.L. 94-579);
- National Environmental Policy Act of 1969 (P.L. 91-190); and
- Various sections of BLM's regulations found in Title 43 Code of Federal Regulations (CFR) that address the collection of invertebrate fossils and, by administrative extension, fossil plants.

In addition to the statutes and regulations previously listed, fossils on public lands are managed through the use of internal BLM guidance and manuals. Included among these are the BLM Manual 8270 and the BLM Handbook H-8270-1 (BLM 2010). Various internal instructional memoranda have been issued to provide guidance to the BLM in implementing management and protection to fossil resources.

Effects of the Proposed Alternative

The March 2015 Oil and Gas Lease Sale does not authorize ground disturbing actions and therefore would have no effect on these fragile resources. However, future exploration, drilling, and production could cause effects to paleontological resources but any effects would be mitigated by data recovery or avoidance. On-shore orders allow for the drill location to be moved up to 330 feet avoiding such impacts.

Potential Fossil Yield Classification**:**
The BLM has adopted the Potential Fossil Yield Classification (PFYC) system to identify and classify fossil resources on federal lands (BLM 2007). Paleontological resources are closely tied to the geologic units (i.e., formations, members, or beds) that contain them. The probability for finding paleontological resources can be broadly predicted from the geologic units present at or near the surface. Therefore, geologic mapping can be used for assessing the potential for the occurrence of paleontological resources.

The PFYC system is a way of classifying geologic units based on the relative abundance of vertebrate fossils or scientifically significant fossils (plants and invertebrates) and their sensitivity to adverse impacts. A higher class number indicates higher potential for presence. The PFYC is not intended to be applied to specific paleontological localities or small areas within units. Although significant localities may occasionally occur in a geologic unit, a few widely scattered important fossils or localities do not necessarily indicate a higher class. Instead, the relative abundance of significant localities is intended to be the major determinant for the class assignment.

The PFYC system is meant to provide baseline guidance for predicting, assessing, and mitigating paleontological resources. The classification should be considered at an intermediate point in the analysis, and should be used to assist in determining the need for further mitigation assessment or actions. The BLM intends for the PFYC System to be used as a guideline as opposed to rigorous definitions. Descriptions of the potential fossil yield classes are summarized in Table 8.

Paleontological resources are the fossilized remains of invertebrate and vertebrate animals and multi-cellular plants, including imprints. Paleontological resources constitute a fragile and non-renewable scientific record of the history of life on earth. Once damaged, or improperly collected, their scientific and educational value may be greatly reduced or lost forever.

The paleontological resources in the Elko District occur in sediments and tuffaceous sediments throughout the Tertiary (66 million years to 1.6 million) and are likely to be found in the Quaternary sediments (1.6 million years to 10,000).

Fossil fish are known to occur with plant fossils in the Oligocene aged (23 to 36 million years) Elko formation in tan colored silty shale (Palmer, 1984). Oligocene sediments would rate 3 in the PFYC system because vertebrate fossils are known to exist but there is very little scientific data.

Vertebrates including varieties of extinct camel, antelope, and ancestors of the horse have been found in the tuffaceous siltstone, sandstone, and limestone in the Carlin Formation (Hockett 2013), Humboldt Formation, or in similar Miocene (5 million to 23 million years) aged materials throughout the district. The depositional environment likely helped preserve the bone material of dead animals as well as the high amount of silica contained in the volcanic ash. According to Hockett (2010), the volcanic tuffs are the highly fossiliferous rocks in the Carlin formation, but the tuffs are not the predominant rock-type in the formation. The proposed type-section southwest of Carlin, Nevada described by Regnier (1960) indicates a high degree of variability of deposits within the formation. Miocene sediments would rate 3 in the PFYC system because vertebrate fossils are known to exist but there is very little scientific data.

Potential Fossil Yield Classification

Class	Description	Basis	Comments
1	Igneous and metamorphic (tuffs are excluded from this category) geologic units or units representing heavily disturbed preservation environments that are not likely to contain recognizable fossil remains.	• Fossils of any kind known not to occur except in the rarest of circumstances • Igneous or metamorphic origin • Landslides and glacial deposits	The land manager's concern for paleontological resources on Class 1 acres is negligible. Ground disturbing activities would not require mitigation except in rare circumstances.
2	Sedimentary geologic units that are not likely to contain vertebrate fossils or scientifically significant invertebrate fossils.	• Vertebrate fossils known to occur very rarely or not at all • Age greater than Devonian • Age younger than 10,000 years before present • Deep marine origin • Aeolian origin • Diagenetic alteration	The land manager's concern for paleontological resources on Class 2 acres is low. Ground disturbing activities are not likely to require mitigation.
3	Fossiliferous sedimentary geologic units where fossil content varies in significance, abundance, and predictable occurrence. Also, sedimentary units of unknown fossil potential.	• Units with sporadic known occurrences of vertebrate fossils • Vertebrate fossils and significant invertebrate fossils known to occur inconsistently; predictability known to be low • Poorly studied and/or poorly documented; potential yield cannot be assigned without ground reconnaissance	The land manager's concern for paleontological resources on Class 3 acres may extend across the entire range of management. Ground disturbing activities would require sufficient mitigation to determine whether significant paleontological resources occur in the area of a Proposed Action. Mitigation beyond initial findings would range from no further mitigation necessary to full and continuous monitoring of significant localities during the action.
4	Class 4 geologic units are Class 5 units (see below) that have lowered risks of human-caused adverse impacts and/or lowered risk of natural degradation.	• Significant soil/vegetative cover; outcrop is not likely to be impacted • Areas of any exposed outcrop are smaller than 2 contiguous acres • Outcrop forms cliffs of sufficient height and slope that most is out of reach by normal means • Other characteristics that lower the vulnerability of both known and unidentified fossil localities	The land manager's concern for paleontological resources on Class 4 acres is toward management and away from unregulated access. Proposed ground disturbing activities would require assessment to determine whether significant paleontological resources occur in the area of a proposed action and whether the action would impact the paleontological resources. Mitigation beyond initial findings would range from no further mitigation necessary to full and continuous monitoring of significant localities during the action.
5	Highly fossiliferous geologic units that regularly and predictably produce vertebrate fossils and/or scientifically significant invertebrate fossils, and that are at risk of natural degradation and/or human-caused adverse impacts.	• Vertebrate fossils and/or scientifically significant invertebrate fossils are known and documented to occur consistently, predictably, and/or abundantly • Unit is exposed; little or no soil/vegetative cover • Outcrop areas are extensive; discontinuous areas are larger than 2 contiguous acres • Outcrop erodes readily; may form badlands • Easy access to extensive outcrop in remote areas • Other characteristics that increase the sensitivity of both known and unidentified fossil localities	The land manager's highest concern for paleontological resources should focus on Class 5 acres. Mitigation of ground disturbing activities would be required and may be intense. Areas of special interest and concern should be designated and intensely managed.

Sources: BLM 2008, 2007.

A mastodon was found in Pliocene (2 million years) sand in Spring Creek, Nevada. As reported by Hockett (1997), the mastodon found in Spring Creek is important for several reasons. This specimen is the first well-documented occurrence of an American Mastodon in Nevada and the Great Basin of North America. The Great Basin covers much of Nevada, and parts of Utah, Idaho, Oregon, and California. In Nevada, *Miomastodon* remains have been reported at Stewart Valley in Esmeralda County and Thousand Creek in Humboldt County, but no American Mastodons have been previously recorded in Nevada or the Great Basin. While many 10,000 to 20,000 year-old mastodons have been found (especially in the midwestern and eastern United States), American Mastodons that date millions of years ago are relatively rare anywhere in North America. If the dating of the Spring Creek mastodon is correct, then this specimen is one of only a dozen or so American Mastodons that date to this time period (Hockett, 1997). Pliocene sediments would rate 3 in the PFYC system because vertebrate fossils are known to exist but there is very little scientific data.

All vertebrate fossils are considered significant and can occur in Devonian- aged or younger sedimentary rocks. On the Elko District vertebrate fossils have been found in most ages of Tertiary and Quaternary sediments. Invertebrate fossils occur in sedimentary rocks of all ages in the Elko District but there are no localities designated as being of significant scientific value.

Cumulative Impacts

The 2015 Oil and Gas Lease Sale does not authorize ground disturbing actions and therefore would have no direct or cumulative effect on these fragile resources. However, future exploration, drilling, and production could cause effects to paleontological resources. Cumulative impacts to fossils are possible at the exploration and development stage of oil and gas development but any effects would be mitigated by data recovery or avoidance. On-shore orders allow for the drill location to be moved up to 330 feet avoiding such impacts.

Mitigation

Most paleontological resources degrade over time due to natural forces but many survive for millions of years. Modern human activity tends to exacerbate the damage and as a consequence paleontological resources are disappearing at an increasing rate. A project specific paleontological inventory should be conducted in any future project associated with this lease sale if sedimentary rocks with the potential to contain vertebrate fossils are present. If paleontological resources are identified within the parcel, a qualified Paleontologist would mitigate the adverse effects through creating a buffer zone for avoidance or the resource could be excavated and removed from the project area. Further guidance regarding BLM's policy on paleontological resource management; refer to BLM Manual 8270 entitled "*Paleontological Resource Management.*"

Impacts of fluid mineral exploration and development would be mitigated through implementing protective measures as part of standard operating procedures. Protective measures could include avoidance by creating buffer zones or excavation by a qualified Paleontologist. Given that most of these activities do not penetrate deep into the substrate where many of these fossils occur, the cumulative impact of post-leasing activities would be minimal.

3.2.5 Soils

Existing Conditions

The soils in the proposed parcels vary in depth, texture, erosion potential, and other characteristics based on several soil forming factors. A wide range of landforms are present within the proposed parcels. Soils on valley floors are frequently deep, poorly drained and alkaline with a high salt content. Soils on piedmonts are moderately deep and overlie a silica cemented hardpan. Mountain soils are often shallow and form over bedrock. Oil and gas exploration and development is most likely to occur on piedmonts or valley bottoms. Detailed soil information for the proposed parcels is available in the following published soil surveys: Elko County Central Part (767); Elko County Northeast Part (765); Elko County Southeast Part (766).

Soil quality in and near the proposed lease parcels is affected by a variety of natural and anthropogenic factors. A detailed assessment of soil condition has not been completed for this analysis, but it can be assumed that conditions vary from parcel to parcel depending on differing land uses and natural influences. As with many other areas in the Elko District, the proposed parcels are mostly undeveloped, but there may be areas of dispersed or heavy impacts to soils associated with different land uses such as livestock grazing, vehicle use, wildland fire, and any activity which disturbs the ground surface. Soil quality is also affected by natural conditions and occurrences which affect soil quality such as wildland fire, climatic variability, weather events, climate change, and variability in soil forming factors. Natural and anthropogenic activities affect soil quality by altering soil quality characteristics such as aggregate stability, compaction, and infiltration. impacts to these characteristics alters soil productivity which can affect numerous other natural resources in the ecosystem. (USDA, 2001).

Effects of the Proposed Alternative

The act of offering, selling, and issuing federal oil and gas lease does not create direct impacts to soil quality. Impacts to soils, both direct and indirect, would occur when the lease is developed in the future. The potential impacts would be analyzed in detail on a site-specific basis prior to oil and gas development.

If oil and gas development were to occur in the proposed area(s) for leasing, most of the impacts to soil quality would be a result of the ground disturbing activities such as well pad construction, roads to access the well pad, and road spurs off of main well pad access roads. These facilities would create new areas of localized heavy impacts to soils quality. Additional impacts to soils may occur as a result of water diversion associated with the large amounts of water required for some drilling and hydraulic fracturing operations. If water is depleted by these operations, areas of hydric soils may be negatively affected. BLM would ensure that best management practices would be used to reduce negative effects. Impacts to soils would not likely result in enough disturbance to influence function and productivity of soils at a large scale. Historically, oil and gas development has been very limited in the Elko District, and development could increase by several orders of magnitude before having the potential to impacts soils at a large scale.

Cumulative Effects of the Alternatives

The cumulative effects study area (CESA) is a two mile buffer of the area encompassed by the parcels available for lease. This area was chosen because of the potential for direct impacts to soils from disturbance associated with oil and gas development, along with the potential for impacts to hydric soils outside of the lease parcels if large water diversions are proposed. As described above for the Affected Environment, levels of soil disturbance in the CESA are low and the current levels of natural and anthropogenic influences have not resulted in substantive cumulative effects. Reasonably foreseeable future actions that could occur under the No Action Alternative such as livestock grazing and permitted land disturbance could incrementally increase these impacts, but cumulative impacts of concern are not expected under this alternative.

The Proposed Action would not result in any direct incremental increase in cumulative impacts to soil resources, but subsequent development could increase impacts as described above in the Proposed Action section. The increase in impacts associated with oil and gas development would be very small when compared to the cumulative impacts described for the No Action Alternative. As a result, there are no cumulative impacts of concern for the Proposed Action or associated future oil and gas development with respect to soil resources.

3.2.6 Water Resources (Surface/Ground)

Existing Conditions:

Hydrology

The proposed lease parcels are within five watersheds classified by the United States Geological Service (USGS) as sub-basins and designated by eight digit hydrologic unit codes (HUC) (Seaber, et al. 1987).These include the South Fork Humboldt, Upper Humboldt, Long Ruby Valleys, Spring-Steptoe Valleys, and Southern Great Salt Lake Desert Sub-Basins The Nevada Division of Water Resources (NDWR) has its own delineation of watershed boundaries called hydrographic areas which differ from that of the USGS (NDCNR 1999). These watersheds are characterized by internal surface drainage and ground water flows. The South Fork Humboldt Sub-Basin flows into the Upper Humboldt Sub-Basin, which flows into the Lower Humboldt Sub-Basin. The other three sub-basins are internally drained meaning that there is no surface water outlet.

The climate of the affected area is semi-arid and surface water is limited. Precipitation within the affected sub-basins ranges between 4 and 40 inches per year and averages 12 inches per year. Precipitation is greater on the higher elevations and most precipitation falls as snow during the winter months. About 10% of precipitation reaches streams or infiltrates into groundwater and the rest is consumed by vegetation or evaporates (NDEP 2012). A portion of precipitation that falls in winter months becomes concentrated in streams primarily in springtime as snow melts. The majority of streams are ephemeral and flow only in response to this snowmelt and heavy rainfall events.

According to the National Hydrologic Dataset there are about 1,900 miles of perennial streams and over 20,000 miles of ephemeral/intermittent streams in the sub-basins where lease parcels are proposed within the Elko District boundary. There is less than one mile of perennial streams and about 500 miles of ephemeral/intermittent streams within proposed parcels. There are an additional 160 miles of perennial stream within two miles of the proposed parcels.

Beneath the surface, groundwater is abundant and interacts with surface water. Surface water gradually infiltrates into the ground and replenishes aquifers in most of the affected watershed area, but there are some areas where groundwater replenishes surface flow (Plume, 2013). Water budgets which quantify the various inputs and outputs to groundwater resources have been studied and published by USGS and NDWR (NDWR, 2013). Availability of groundwater is subject to a variety of natural influences including climatic variability and climate change. Groundwater flow in affected sub-basins generally flows in the same direction as surface water however there is some flow between basins (Heilweil, 2011).

A small portion of precipitation that falls within affected sub-basins infiltrates into the ground and resurfaces as springs. Some spring flow also comes from other sub-basins. According to BLM data there are about 1000 springs on BLM administered land within the affected sub-basins and about 50 springs in and within two miles of proposed lease parcels. These springs exhibit the full range of water chemistry and other water quality characteristics as determined by their flow paths through local, intermediate, or regional aquifers (Sada, et al. 2001). Springs on BLM lands have flows that reach as much as 7000 gallons per minute however most are small and discharge less than 0.5 gallons per minute.

Streams, springs, and reservoirs and provide water for a variety of beneficial use in the affected sub-basins including irrigation, riparian vegetation, mining, municipal, domestic, livestock, recreation, and wildlife. A large portion of available water is used for irrigation and is diverted directly from streams. Another large portion of water is consumed directly from surface and shallow groundwater by riparian vegetation. The riparian vegetation adjacent to streams, springs, and other waterbodies relies on the dependable water that these sources provide. Livestock and wildlife drink directly from springs and streams that exist on both BLM and private land.

Groundwater is also used for a variety of beneficial uses within the sub-basins. Municipalities and domestic water users divert water primarily from groundwater wells on private land however there are a few diversions from springs on BLM and private land. Mining operations divert water for mining and milling as well as dewatering on private and BLM land. NDWR data indicate there are about 1000 groundwater wells within the affected basins. About 10 of these wells are within the proposed lease sale parcels and there are about 55 wells within two miles of the parcels. The largest use of water resources in the sub-basins is irrigation, followed by municipal and other uses. Water wells within and near lease parcels are mostly stock watering wells but there are a few domestic drinking water wells.

Water diversion and use in Nevada is regulated and permitted by the Nevada Division of Water Resources (NDWR), and information regarding presence and availability of water is provided by the U.S. Geological Survey (USGS). These agencies report that many of the hydrographic areas in Elko County- including those in this lease sale - are fully appropriated or over-appropriated.

This means that that more water is being diverted and used than is being replenished by natural sources such as rainfall and snowmelt (Heilweil, 2011).

Water Quality

Quality of water within the affected sub-basins is the result of a wide variety of natural and anthropogenic characteristics, occurrences and activities. Geology, topography, climate, vegetative cover, wildfire and land use are all factors in determining the chemical, physical, and biological properties of these natural waters. Some surface waters may have naturally high levels of various dissolved solids, nutrients, or high temperature naturally while others express these attributes as a result of a combination of natural conditions and anthropogenic influence (Hem 1970).

Land use has been documented to have a considerable direct and indirect impact on water quality. Some land uses such as mining, and sewage treatment facilities discharge contaminated water directly into waterbodies and are known as point-sources. Most sources of anthropogenic water quality degradation in the affected sub-basins however, are the result of inputs throughout the watershed and are known as non-point sources. Livestock grazing is the most common and widespread land use on BLM lands in the affected sub-basins and likely is the greatest of the anthropogenic impacts on water quality from these lands. Wildlife use causes similar but less intense impact to water quality.

Water quality standards as contained in the Nevada Administrative Code (NAC) 445A define water quality goals for waterbodies in the State of Nevada. These standards are based on the beneficial uses for these waterbodies and contain both narrative and numeric criteria. Narrative standards contained in NAC 445A.121 apply to all surface waters of the state including streams and springs and require waters to be "free from" various pollutants. Numeric standards also found in NAC 445A designate specific criteria so that water is suitable to use for irrigation, domestic, stock water, or any other beneficial use (NDEP 2012).

There are 1256 miles of perennial and intermittent streams within the affected sub-basins for which the Nevada Division of Environmental Protection (NDEP) has identified beneficial uses and numeric water quality standards. Six-hundred-thirty-six (636) miles of these streams have been identified as having water quality that does not fully support their beneficial uses. These are included in Nevada's 303(d) list of impaired waters. There is a one mile reach of one stream within the proposed lease sale parcels, and about 35 miles of stream within two miles of these parcels that do not meet water quality criteria established by NDEP. Inclusion of streams on this list are most commonly due to parameters being exceeded to support aquatic life such as the temperature and total phosphorus criteria (NDEP 2012). The NDEP report did not identify any waters in exceedence of narrative standards.

NDEP has stated that some numeric water quality standards set for Nevada streams may not be appropriate, or even achievable. Although water quality standards are a good starting point, it is not known whether beneficial uses are truly supported until a total maximum daily load (TMDL) is developed for a waterbody. A TMDL is an assessment of the amount of pollutant a water body can receive and not violate water quality standards. Total phosphorus and temperature exceedences do not necessarily mean that beneficial uses are not being supported since elevated values may not necessarily be causing the associated undesirable conditions such as algal growth or low dissolved oxygen (NDEP 2009). The TMDL prepared for Hanks Creek and Dixie Creek in Elko district illustrates how better standards can be applied for streams on BLM administered land by choosing criteria that are achievable and appropriate for existing beneficial uses (Pahl 2010) Resource Area RMP's for The Elko District specify that streams must be managed in a way that prevents deterioration of habitat. This includes preventing decline of water quality. The Elko RMP identifies 22 streams that are classified as high priority stream habitat, and the Wells RMP simply identifies all stream habitat.

Effects of the Proposed Alternative

The sale of parcels and issuance of oil and gas leases is strictly an administrative action. The act of offering, selling, and issuing federal oil and gas leases does not produce impacts to water quality and surface water. On-the-ground impacts would not occur until a lessee applies for and receives approval to drill on the lease. The BLM cannot determine at the leasing stage whether or not a proposed parcel will actually be sold, or if it is sold and issued, whether or not the lease would be explored or developed. Consequently, the BLM cannot determine exactly where a well or wells may be drilled or what technology may be used to drill and produce wells, so the impacts listed below are generic, rather than site-specific.

Direct and Indirect Effects, Surface Water:
Subsequent development of a lease may result in long-and short term alterations to the hydrologic regime depending upon the intensity of development. Clearing, grading, and soil stockpiling activities associated with exploration and development actions could alter short term overland flow and natural groundwater recharge patterns resulting in *de minimis* risk[1]. Potential impacts include surface soil compaction caused by construction equipment and vehicles, which would likely reduce the soil's ability to absorb water, increasing the volume and rate of surface runoff. New oil and gas roads and pads, pipelines, and powerlines, could cut slopes and alter channel and floodplain characteristics at drainage crossings. The combination of increased surface disturbance, surface runoff, decreased infiltration and changes in drainage features could result in increased peak flows in *de minimis*. The success or failure of integrated measures, BMPs, and appropriate mitigation measures designed to manage storm water and reduce erosion during construction and operation of oil and gas facilities will determine much of the impact with regard to surface waters, including road construction.

Runoff associated with storm events could increase sediment/salt loads in surface waters down gradient of the disturbed areas. Sediment may be deposited and stored in minor drainages where it could be readily moved downstream (within closed basins) during heavy storms. Sediment from future development activity may be carried into contained basins and sloughs where water quality classifications could be exceeded. The land-locked nature of most lease parcels and

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[1] *de minimis* risk. In risk assessment, it refers to a level of risk that is too small to be concerned with. Some refer to this as a "virtually safe" level. National Library of Medicine [Toxicology Glossary - http://sis.nlm.nih.gov/enviro/iupacglossary/glossaryr.html](http://sis.nlm.nih.gov/enviro/iupacglossary/glossaryr.html)

distance of other parcels to potentially impacted surface waters would restrict effect on the amount of sediment and salt contributed by lease exploration and development activities. Surface erosion would be greatest during the construction and would be controlled through integrated measures, BMPs, and appropriate mitigation measures. The magnitude of the impacts to surface water resources from future development activities depends on the proximity of disturbances to drainage channels, slope aspect and gradient, degree and area of soil disturbance, soil character, duration of construction activities, and the timely implementation and success/failure of mitigation measures. Natural factors which attenuate the transport of sediment and salts into susceptible water bodies include water available for overland flow; the texture of the eroded material; the amount and kind of ground cover; the slope shape, gradient, and length; and surface roughness. Impacts would likely be greatest shortly after the start of construction activities and would likely decrease in time due to stabilization, reclamation, and revegetation efforts. Minor long-term direct and indirect impacts to the watershed and hydrology could continue for the life of surface disturbance from water discharge from roads, road ditches, and well pads, but would decrease once all well pads and road surfacing material has been removed and reclamation of well pads, access roads, pipelines, and powerlines has taken place (Appendix C). Short-term direct and indirect impacts to the watershed and hydrology from access roads that are not surfaced with impervious materials would occur and would likely decrease in time due to reclamation efforts. Limiting factors include absence of hydraulic connectivity, the small area affected and implementation of integrated measures, BMPs, and appropriate mitigation measures.

Although there is potential for oil and gas development to contribute sediment loads to aquatic systems, there is no reasonable likelihood that siting adjustments, State and federally-imposed sedimentation and storm-control measures, implementation of best management practices and reclamation strategies would fail to provide adequate means to effectively prevent substantive off-site transport and delivery of sediments or fluids that may impair downstream riparian or aquatic conditions in the closed basins.

Direct and Indirect Effects, Groundwater: All Hydraulic Fracturing operations would be conducted to the standards of the State of Nevada, Third Revised Proposed Regulation R011-14 (See Appendix F for the text of the State of Nevada Regulations). Hydraulic Fracturing (HF) is designed to change the producing formations' physical properties by increasing the flow of water and gas around the well bore. HF may also introduce chemical additives into the producing formations. Chemical additives used in completion activities for the well would be pumped into the producing formations through the wellbore. The amount of the chemicals coming back to the surface as "backflow" is dependent on several factors, including what type of rock formation being injected. Production zones generally do not contain freshwater.

HF is designed to change the producing formations' physical properties by increasing the flow of water, gas, and/or oil around the well bore. This change in physical properties may open up new fractures or enhance existing fractures that could result in freshwater aquifers being contaminated with natural gas, condensate and/or chemicals used in drilling, completion and hydraulic fracturing. Impacts to groundwater resources could occur due to failure of well integrity, failed cement, surface spills, and/or the loss of drilling, completion and hydraulic fracturing fluids into groundwater. Types of chemical additives used in drilling activities may include acids, hydrocarbons, thickening agents, lubricants, and other additives that are operator and location specific. Concentrations of these additives also vary considerably and are not always known since different mixtures can be used for different purposes in gas development and even in the same well bore.

Loss of drilling fluids may occur at any time in the drilling process due to changes in porosity or other properties of the rock being drilled through for both the surface casing and the production hole. When this occurs, drilling fluids may be introduced into the surrounding formations which could include freshwater aquifers, if it occurs when drilling the surface casing. Some or all of the produced water from these leases may be injected in designated injection wells for disposal. Petroleum products and other chemicals could result in groundwater contamination through a variety of operational sources including but not limited to pipeline and well casing failure, well (gas and water) construction, and spills. Similarly, although not part of the proposed action, the improper construction and management of reserve and evaporation pits could degrade ground water quality through leakage and leaching. Any deviation from the proposed action would not be authorized by the BLM. Oil and gas wells are cased and cemented at a depth below all usable water zones; consequently impacts to water quality at springs and residential wells are not expected. However, faulty cementing or well casing could result in methane migration to upper zones. Should hydrocarbon or associated chemicals for oil and gas development in excess of EPA/NDEP standards for minimum concentration levels migrate into drinking water supply wells, springs, or systems, it could result in these water sources becoming non-potable.

The potential for negative impacts to groundwater caused from HF, are currently being investigated by the Environmental Protection Agency. Authorization of the proposed projects would require full compliance with local, state, and federal directives and stipulations that relate to surface and groundwater protection. All Hydraulic Fracturing operations would be conducted to the standards of the State of Nevada, Third Revised Proposed Regulation R011-14 (See Appendix F for the text of the State of Nevada Regulations). Nationally, the BLM is also working on rules to require companies to publicly disclose the chemicals used in hydraulic fracturing operations on public and Indian lands. See Appendix I for the text of the proposed rule. The final release of those rules is still pending. For more information, visit:

www.blm.gov/wo/st/en/info/newsroom/2012/may/NR_05_04_2012.html or
www.blm.gov/wo/st/en/prog/energy/oil_and_gas.html or

If unauthorized contamination of freshwater aquifers from oil and gas development occurs, changes in groundwater quality could impact springs and residential wells if these springs and residential wells are sourced from the same aquifers that have been affected. However, this is not part of the proposed action and BLM does not allow unauthorized contamination of freshwater aquifers. All Hydraulic Fracturing operations would be conducted to the standards of the State of Nevada, Third Revised Proposed Regulation R011-14 (See Appendix F for the text of the State of Nevada Regulations).

Direct impacts to surface water would likely be greatest shortly after the start of construction activities and would likely decrease in time due to natural stabilization, and reclamation efforts. Impacts to groundwater would be less evident and occur on a longer time scale. Construction activities would occur over a relatively short period (commonly less than a month); however, natural stabilization of the soil can sometimes takes years to establish to the degree that will adequately prevent accelerated erosion caused by compaction and removal of vegetation. Spills or produced fluids (e.g., saltwater, oil, fracking chemicals, and/or condensate in the event of a breech, overflow, or spill from storage tanks) could result in contamination of the soil onsite, or offsite, and may potentially impact surface and groundwater resources in the long term.

Wells that employ the HF process typically use greater amounts of water than do conventional completions. Nevada Division of Minerals reported that Hydraulic Fracturing in Nevada has used between 250,000 gallons and 350,000 gallons of water per well for the three hydraulic fracturing operations conducted to date (Lowell Price (NDOM) pers communication). Not all wells resulting from an APD would employ fracturing and water consumption would be temporary. All Hydraulic Fracturing operations would be conducted to the standards of the State of Nevada, Third Revised Proposed Regulation R011-14 (See Appendix F for the text of the State of Nevada Regulations).

Cumulative Effects of the Alternatives

The cumulative effect study area (CESA) is the five sub-basins in which the proposed parcels are located. This area was chosen because effects associated with the development of parcels within the proposed lease sale would not likely extend beyond these basins. As described above in the Affected Environment section, water resources are over-appropriated in these basins, and many of the surface waters are listed as impaired on Nevada’s 303(d) list. Based on these facts it could be inferred that water resources have already sustained substantive cumulative effects. These impacts would continue to occur under the No Action Alternative.

The Proposed Action would not result in any direct incremental increase in cumulative impacts to water resources, but subsequent oil & gas development would likely increase impacts as described above in the Proposed Action section. Specifically, development would likely result in additional water diversion, and surface water quality could be affected by development. The incremental increase in these impacts is small when compared to the level of impacts that already exist in the sub-basins as described above in the Affected Environment section. These cumulative impacts would continue to occur under the Proposed Action.

Mitigation

Protection of water resources would be accomplished through implementation of best management practices along with specific restrictions that may be applied to individual parcels. Parcels with sensitive water resources have been identified (Table 2-1) and stipulations are attached to mitigate any known environmental or resource conflicts that may occur on a given lease parcel For example, lessees may be required to locate facilities a distance of 400 feet from streams or off of the 100 year floodplain. These restrictions would be implemented on an individual parcel basis and would be required as a condition of approval for exploration and development.

3.2.7 Air Quality

Existing Conditions

The U.S. Environmental Protection Agency (EPA) has established national ambient air quality standards (NAAQS) for criteria pollutants, including carbon monoxide (CO), nitrogen dioxide (NO_2), ozone (O_3), particulate matter (PM_{10} and $PM_{2.5}$), sulfur dioxide (SO_2), and lead (Pb). Exposure to air pollutant concentrations greater than the NAAQS has been shown to have a detrimental impact on human health and the environment. The EPA has delegated regulation of air quality under the federal Clean Air Act to the State of Nevada. In addition to the criteria pollutants, regulations also exist to control the release of hazardous air pollutants (HAPs). HAPs are chemicals that are known or suspected to cause cancer or other serious health effects, such as reproductive effects or birth defects, or adverse environmental effects. EPA currently lists 188 identified compounds as hazardous air pollutants, some of which can be emitted from oil and gas development operations, such as benzene, toluene, and formaldehyde. Ambient air quality standards for HAPs do not exist; rather these emissions are regulated by the source type, or specific industrial sector responsible for the emissions.

Ambient air quality in the affected environment (i.e. compliance with the NAAQS) is demonstrated by monitoring for ground level (i.e. receptor height) atmospheric air pollutant concentrations. In general, the ambient air measurements show that existing air quality in the region is good. For more information on pollutant monitoring values, including the other criteria pollutants not shown below, please visit the EPA's Air Data website at www.epa.gov/airdata.

Effects of the Proposed Alternative

While the act of leasing the parcels would produce no substantial air quality effects, potential future development of the lease could lead to increases in area and regional emissions. Since it is unknown if the parcels would be developed, or the extent of the development, it is not possible to reasonably quantify potential air quality effects through dispersion modeling or another applicable method at this time. Further, the timing, construction and production equipment specifications and configurations, and specific locations of activities are also unforeseeable at this time. Additional air effects will be addressed in a subsequent analysis when lessees file an APD. All proposed activities including, but not limited to, exploratory drilling activities would be subject to applicable local, State, and Federal air quality laws and regulations.

The Bureau of Land Management National Operations Center (BLM NOC) retained the Kleinfelder Team (which consisted of staff from Kleinfelder, Inc. and ENVIRON International Corporation) to prepare an emissions inventory estimate of criteria pollutants, greenhouse gases (GHG), and key hazardous air pollutants (HAPs) for a representative oil and gas well in the western United States (US). The emissions inventory was designed to be used by BLM staff, such as NEPA planners, air resource specialists, and natural resource specialists, to evaluate emissions from small, which for purposes of this inventory is approximately five wells or less, oil and gas projects.

Defining a "representative" oil and gas well for the entire western US was extremely challenging as there are numerous variables, even within a single basin and sub basin that can materially affect the emissions. Such variables include oil and gas composition, difficulty drilling the geologic formation, oil and gas production rate, equipment at the well site, emission controls, produced water that may be associated with oil and gas production, among many others.

Accordingly, to develop such an inventory, five different well types (three natural gas wells and two oil wells) representative of five different major oil and gas basins in the western US were evaluated. In order to develop the emission inventories, information that is not proprietary, not draft, and not pre-decisional was reviewed for the five selected basins plus other oil and gas developments in the western US. The characteristics of the five basins selected are similar to a large portion of the oil and gas produced in the western United States. The table, below, is taken from this March 2013 report: Erbes, Air Emissions Inventory Estimates for a Representative Oil and Gas Well in the Western United States. The Reasonably Foreseeable Development Scenario developed for this lease EA is a maximum of 80 wells drilled within the parcels in the Elko District. The number of holes that could be drilled in any given area is unknown but potential emissions would be multiplied appropriately.

Well Type	**Gas**	**Gas**	**Gas**	**Oil**	**Oil**
Pollutant	Uinta/Piceance (tpy)	Upper Green River (tpy)	San Juan (tpy)	Williston (tpy)	Denver (tpy)
NOx	15.6	14.6	5.6	15.6	6.3
CO	3.8	3.9	3.1	8.0	3.4
VOC	3.4	5.2	5.3	17.6	6.7
SO_2	0.0004	0.0004	0.001	0.001	0.001
PM_{10}	6.9	6.7	6.8	6.9	6.6
$PM_{2.5}$	0.8	0.8	0.5	0.8	0.5
CO_2	2,552.1	2,552.1	651.0	3156.4	1,049
CH_4	12.2	14.1	6.1	16.6	1.8
N_2O	0.05	0.05	0.04	0.6	0.04
GWP	2,825	3,194	791	3,682	1,099
Benzene	1.4	1.5	1.4	1.5	1.4
Toluene	1.0	1.2	1.0	1.0	1.0
Ethybenzene	0.00003	0.01	0.0008	0.0008	0.0006
Xylene	0.6	0.7	0.6	0.6	0.6
n-Hexane	7.5	7.5	7.5	7.9	7.5
Total HAPs	10.4	10.9	10.5	11.0	10.5

Note: Sums may not precisely total due to round off differences. A value of 0.00 indicates that pollutant is not emitted or emitted in *de minimis* amounts. If there is a non-zero value, at least one significant figure is reported. Greenhouse gas emissions are in terms of short tons CO_2, CH_4, and N_2O. Global Warming Potential (GWP) is in terms of short tons of CO_2 equivalent (CO_2e), using a GWP of 1 for CO_2, 21 for CH_4, and 310 for N_2O.
(Erbes, 2013)

Any subsequent activity authorized after APD approval could include soil disturbances resulting from the construction of well pads, access roads, pipelines, power lines, and drilling. Any disturbance is expected to cause increases in fugitive dust and potentially inhalable particulate matter (specifically PM_{10} and $PM_{2.5}$) in the project area and immediate vicinity. Particulate matter, mainly dust, may become airborne when drill rigs and other vehicles travel on dirt roads to drilling locations. Air quality may also be affected by exhaust emissions from engines used for drilling, transportation, gas processing, compression for transport in pipelines, and other uses. These sources will contribute to potential short and long term increases in the following criteria pollutants: carbon monoxide, ozone (a secondary pollutant, formed photochemically by combining VOC and NOX emissions), nitrogen dioxide, and sulfur dioxide. Non-criteria pollutants (for which no national standards have been set) such as carbon dioxide, methane, nitrous oxide, air toxics (e.g., benzene), and total suspended particulates (TSP) could also be emitted. Certain pollutants may be significant when evaluating AQRV for effects on visibility and atmospheric deposition. Significance will depend greatly on the proximity to sensitive receptors, area meteorology, and the background levels of AQRV at any sensitive receptor. Dust control measures, such as applying a layer of gravel over the travel surfaces, watering travel surfaces, and reducing speed along the roadways can be very effective in mitigating dust issues.

During exploration and development, 'natural gas' may at times be flared and/or vented from conventional, coal bed methane, and shale wells. The gas is likely to contain volatile organic compounds that could also be emitted from reserve pits, produced water disposal facilities, and/or tanks located at the site. The development stage may likely include the installation of pipelines for transportation of raw product. New centralized collection, distribution and/or gas processing facilities may also be necessary. The decision to offer the identified parcels for lease would not result in any direct emissions of air pollutants. However, any future exploration or development of these leases will result in emissions of criteria, HAP and GHG pollutants. The additional emissions could result in an incremental increase in overall emissions of pollutants, in the region depending on any contemporaneous activities occurring at the same time when potential exploration and development occurring on the lease would happen.

Mitigation

The BLM encourages industry to incorporate and implement BMPs to reduce impacts to air quality by reducing emissions, surface disturbances, and dust from field production and operations. In accordance with a recent BLM Memorandum of Understanding (MOU) regarding air quality analysis and mitigation; BLM would coordinate with the Environmental Protection Agency (EPA) early in the APD process to determine how best to model and mitigate for impacts to air quality. Measures may also be required as COAs on permits by either the BLM or the applicable state air quality regulatory agency. The BLM also manages venting and flaring of gas from federal wells as described in the provisions of Notice to Lessees (NTL) 4A, Royalty or Compensation for Oil and Gas Lost.

Some of the following measures could be imposed at the development stage:

- Flaring or incinerating hydrocarbon gases at high temperatures to reduce emissions of incomplete combustion;
- Emission control equipment of a minimum 95 percent efficiency on all condensate storage batteries;
- Emission control equipment of a minimum 95 percent efficiency on dehydration units, pneumatic pumps, produced water tanks;
- Vapor recovery systems where petroleum liquids are stored;
- Tier II or greater, natural gas or electric drill rig engines;
- Secondary controls on drill rig engines;
- No-bleed pneumatic controllers (most effective and cost effective technologies available for reducing VOCs);
- Gas or electric turbines rather than internal combustions engines for compressors;

- NO_x emission controls for all new and replaced internal combustion oil and gas field engines;
- Water dirt and gravel roads during periods of high use and control speed limits to reduce fugitive dust emissions;
- Interim reclamation to re-vegetate areas of the pad not required for production facilities and to reduce the amount of dust from the pads.
- Co-located wells and production facilities to reduce new surface disturbance;
- Directional drilling and horizontal completion technologies whereby one well provides access to petroleum resources that would normally require the drilling of several vertical wellbores;
- Gas-fired or electrified pump jack engines;
- Velocity tubing strings;
- Cleaner technologies on completion activities (i.e. green completions), and other ancillary sources;
- Centralized tank batteries and multi-phase gathering systems to reduce truck traffic;
- Forward looking infrared (FLIR) technology to detect fugitive emissions; and
- Air monitoring for NO_x and ozone.

More specific to reducing GHG emissions, the table below describes in detail commonly used technologies to reduce methane emissions from natural gas, coal bed natural gas, and oil production operations. Table 3.2.7-2. Selected Methane Emission Reductions Reported under the USEPA Natural Gas STAR Program, displays common methane emission technologies reported under the Program and associated emission reduction, cost, maintenance and payback data.

In the context of the oil sector, additional design features to reduce GHG emissions may include methane reinjection and CO_2 injection. Furthermore, the EPA is expected to promulgate new federal air quality regulations that would require GHG emission reductions from many oil and gas sources.

Table 3.2.7-2. Selected Methane Emission Reductions Reported Under the USEPA Natural Gas STAR Program [1]

Source Type / Technology	**Annual Methane Emission Reduction [1] (Mcf/yr)**	**Capital Cost Including Installation ($)**	**Annual Operating and Maintenance Cost ($)**	**Payback (Years or Months)**	**Payback Gas Price Basis ($/Mcf)**
Wells					
Reduced emission (green) completion	7,000 [2]	$1K – $10K	>$1,000	1 – 3 yr	$3
Plunger lift systems	630	$2.6K – $10K	NR	2 – 14 mo	$7
Gas well smart automation system	1,000	$1.2K	$0.1K – $1K	1 – 3 yr	$3
Gas well foaming	2,520	>$10K	$0.1K – $1K	3 – 10 yr	NR
Tanks					
Vapor recovery units on crude oil tanks	4,900 – 96,000	$35K – $104K	$7K – $17K	3 – 19 mo	$7

Source Type / Technology	Annual Methane Emission Reduction [1] (Mcf/yr)	Capital Cost Including Installation ($)	Annual Operating and Maintenance Cost ($)	Payback (Years or Months)	Payback Gas Price Basis ($/Mcf)
Consolidate crude oil production and water storage tanks	4,200	>$10K	<$0.1K	1 – 3 yr	NR
Glycol Dehydrators					
Flash tank separators	237 – 10,643	$5K – $9.8K	Negligible	4 – 51 mo	$7
Reducing glycol circulation rate	394 – 39,420	Negligible	Negligible	Immediate	$7
Zero-emission dehydrators	31,400	>$10K	>$1K	0 – 1 yr	NR
Pneumatic Devices and Controls					
Replace high-bleed devices with low-bleed devices					
End-of-life replacement	50 – 200	$0.2K – $0.3K	Negligible	3 – 8 mo	$7
Early replacement	260	$1.9K	Negligible	13 mo	$7
Retrofit	230	$0.7K	Negligible	6 mo	$7
Maintenance	45 – 260	Negl. to $0.5K	Negligible	0 – 4 mo	$7
Convert to instrument air	20,000 (per facility)	$60K	Negligible	6 mo	$7
Convert to mechanical control systems	500	<$1K	<$0.1K	0 – 1 yr	NR
Valves					
Test and repair pressure safety valves	170	NR	$0.1K – $1K	3 – 10 yr	NR
Inspect and repair compressor station blowdown valves	2,000	<$1K	$0.1K – $1K	0 – 1 yr	NR
Compressors					

Source Type / Technology	Annual Methane Emission Reduction [1] (Mcf/yr)	Capital Cost Including Installation ($)	Annual Operating and Maintenance Cost ($)	Payback (Years or Months)	Payback Gas Price Basis ($/Mcf)
Install electric compressors	40 – 16,000	>$10K	>$1K	>10 yr	NR
Replace centrifugal compressor wet seals with dry seals	45,120	$324K	Negligible	10 mo	$7
Flare Installation	2,000	>$10K	>$1K	None	NR
Source: Multiple EPA Natural Gas STAR Program documents. [1] Unless otherwise noted, emission reductions are given on a per-device basis (e.g., per well, per dehydrator, per valve, etc.). [2] Emission reduction is per completion, rather than per year. K = 1,000 mo = months Mcf = thousand cubic feet of methane NR = not reported yr = year					

3.2.8 Climate Change

<u>Existing Conditions</u>

Activities such as fossil fuel combustion, deforestation, and other changes in land use are resulting in the accumulation of trace greenhouse gasses (GHGs) such as carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), water vapor, and several industrial gases in our atmosphere. An increase in GHG emissions is said to result in an increase in the earth's average surface temperature, primarily by trapping and decreasing the amount of heat energy radiated by the earth back into space. The phenomenon is commonly referred to as global warming. Global warming is expected, in turn, to affect weather patterns, average sea level, ocean acidification, chemical reaction rates, precipitation rates, etc., which is commonly referred to as climate change. The Intergovernmental Panel on Climate Change (IPCC) has predicted that the average global temperature rise between 1990 and 2100 could be as great as 5.8°C (10.4°F), which could have massive deleterious impacts on the natural and human environments. Although GHG levels have varied for millennia (along with corresponding variations in climatic conditions), industrialization and burning of fossil carbon sources have caused GHG concentrations to increase measurably, from approximately 280 ppm in 1750 to 396 ppm in 2012 (as of June). The rate of change has also been increasing as more industrialization and population growth is occurring around the globe. This fact is demonstrated by data from the Mauna Loa CO_2 monitor in Hawaii that documents atmospheric concentrations of CO_2 going back to 1960, at which point the average annual CO_2 concentration was recorded at approximately 317 ppm. The record shows that approximately 70% of the increases in atmospheric CO_2 concentration or build up, since pre-industrial times has occurred within the last 50 years.

Climate is the composite of generally prevailing weather conditions of a particular region throughout the year, averaged over a series of years. Climate change includes both historic and predicted climate shifts that are beyond normal weather variations.

<u>Effects of the Proposed Alternative</u>

Climate Change Analysis Assumptions

No GHG emissions would result from the proposed action, which is administrative in nature; however, the BLM recognizes that GHG emissions are a potential indirect effect of fluid mineral exploration and/or development subsequent to leasing. As a result, the analysis is limited to a qualitative description of pollutants associated with oil and gas development and production and describes how the proposed action potentially contributes to climate change through the release of GHGs. Although the EPA recently revised GHG emission factors used to estimate emissions from oil and gas development and production, it would be a highly speculative exercise to quantify estimates of GHG emissions at the leasing stage. Any potential effects would occur if and/or when the leases were developed. While it is not possible to accurately quantify potential GHG emissions in the affected areas as a result of making the proposed parcels available for leasing, some general assumptions can be made: offering the proposed parcels may contribute to drilling new wells. Subsequent development of any leases issued would contribute a small incremental increase in overall GHG emissions. When compared to statewide, national, or global emissions, the amount released as a result of potential production from the proposed lease parcels would not have a measurable effect on global climate.

Climate Change Impacts

Secretarial Order 3289 was issued in 2009 which directs each bureau to: "consider and analyze potential climate change impacts when undertaking long-range planning exercises, setting priorities for scientific research and investigations, and/or when making major decisions affecting DOI resources."

The primary sources of greenhouse gases associated with oil and gas exploration and production are carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). In addition, nitrous oxide and VOCs are indirect air pollutants that contribute to ozone production and aid in prolonging the life of methane in the atmosphere. With respect to climate change, climate plays a significant role in the production of ozone. Sunlight and high temperatures are a major catalyst in reactions between VOCs and NOx in the production of ozone. With an increase in overall temperature, we can expect to have more hot days and less precipitation that will lead to a higher production of ozone.

GHGs are produced and emitted by various sources during phases of oil and gas exploration, well development, production, and site abandonment. The American Petroleum Institute (API) categorizes sources of emissions from all oil and gas operations into the following classifications:

Direct Emissions

- Combustion Sources – includes stationary devices (boilers, heaters, internal combustion engines, flares, burners) and mobile devices (barges, railcars, and trucks for material transport; vehicles for personnel transport; forklifts, construction equipment, etc.).

- Process Emissions and Vented Sources - includes process emissions from glycol dehydrators, stacks, vents, ducts; maintenance/turnaround; and non-routine activities such as pressure relief valves, emergency shut-down devices, etc.
- Fugitive Sources- includes fugitive emissions from valves, flanges, pumps, connectors, etc.; and other non-point sources from wastewater treatment.

Indirect Emissions
Emissions associated with company operations, such as off-site generation of electricity, hot water or steam, and compression for on-site power, heat and cooling. Direct and indirect GHG emissions may occur from various sources during each phase of exploration and development. During exploration and development, emissions are generated from well pad and access road construction, rigging up/down, drilling, well completion, and testing phases. GHG emissions for these phases are mainly CO_2 emissions from fuel in internal combustion engines of diesel trucks, equipment, and rigs.

There are currently no established thresholds of significance for GHG, but the EPA has used a reporting threshold of direct GHG emissions of 25,000 tons per year of carbon dioxide equivalent (74 FR 56260, October 30, 2009).

For this analysis, the RFD predicts that up to 80 wells will be drilled as a result of the proposed action, however, the offered parcels are scattered across the district and we cannot predict how many holes will actually be drilled in any location. More accurate analysis will be completed at the exploration and development phase, after leasing is complete.

In addition to the mandatory GHG reporting requirement and regulatory requirements to reduce GHGs, the BLM encourages federal oil and gas lessees and/or operators to implement “Best Management Practices (BMPs)” that reduce GHG emissions. As identified in the EPA Inventory of US Greenhouse Gas Emissions and Sinks, the BLM holds regulatory jurisdiction over portions of natural gas and petroleum systems. Exercise of this regulatory jurisdiction has led to development of BMPs designed to reduce emissions from field production and operations. Analysis and approval of future development would include applicable BMPs as Conditions of Approval (COAs) in order to reduce or mitigate GHG emissions. Additional measures developed at the project development stage would be incorporated as COAs in the approved APD, which is binding on the operator.

Mitigation

Such mitigation measures may include, but are not limited to:

- Flare hydrocarbon and gases at high temperatures in order to reduce emissions of incomplete combustion through the use of multi-chamber combustors;
- “Green” (flareless) completions;
- Minimizing waste during drilling and completion operations (such as requiring capture of gas when economically feasible during hydraulic fracturing operations)
- Water dirt roads during periods of (high) use in order to reduce fugitive dust emissions;
- Require that vapor recovery systems be maintained and functional in areas where petroleum liquids are stored;

- Installation of liquids gathering facilities or centralized production facilities to reduce the total number of sources and minimize truck traffic;
- Use of natural gas fired or electric drill rig engines;
- The use of selective catalytic reducers on diesel-fired drilling engines; and,
- Re-vegetate areas of the drilling pad(s) not required for production to reduce the amount of dust from the pad(s).

Measures to reduce GHG emissions include the EPA's Natural Gas STAR program and additional BMPs that are located on the BLM Washington Office webpage (http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas/best_management_practices.html). The EPA US Inventory data show that industry's implementation of BMPs proposed by the EPA's Natural Gas STAR energy program has reduced emissions from oil and gas exploration and development.

3.2.9 Vegetation

Existing Conditions

Detailed descriptions of the vegetative communities in the Elko District including meadow, big sagebrush, low sagebrush, mountain brush, pinyon-juniper woodland, broadleaf trees, shadscale, greasewood, and winterfat communities can be found in the Elko and Wells RMP EISs and the EA for the 2004 Fire Management Amendment to the RMPs and will not be repeated here. Due to the extensive acreage that has burned in recent years, the spread of cheatgrass and other annual weeds has increased in the Elko District, at the expense of native vegetation, particularly sagebrush habitat. Currently the Elko District is actively participating in restoration and rehabilitation efforts in the burned areas, as well as in Great Basin Restoration Initiative and aquatic and terrestrial wildlife habitat improvement projects to enhance present communities to meet rangeland health standards.

Effects of the Proposed Alternative

The initial action of oil and gas leasing does not affect vegetation resources. However, surface disturbing activities for exploration and production will affect vegetation resources. Activities such as well pad construction, fence construction, development of roads, pipeline construction, facility construction and power line construction would lead to the removal of vegetation and run the risk of being invaded or dominated by cheatgrass and other invasive annual weeds. As projected by the Reasonably Foreseeable Development scenario, a total of 1,360 acres are anticipated to be disturbed throughout the Elko District during the exploration and development of oil and gas resources over the next fifteen years of which approximately 744 acres would be reclaimed. This would result in a net loss of 616 acres of vegetation during the fifteen year projection. Eventually all the acreage will be reclaimed and vegetation would be reestablished. In the long term, within three to five years, seeding is used in the reclamation process to provide a more desirable plant community of native forbs and grasses. Often, an abandoned well location is seeded and fenced as an exclosure to protect the vegetation as it is being established. The protective fence is normally temporary and would be removed once reclamation is completed. A more detailed analysis of impacts to vegetation resources would be completed in a site specific EA before surface disturbing activities are authorized. The amount of disturbance, reduced by reclamation efforts, should not affect the vegetation composition, and quality of vegetation of the plant communities in which most development occurs. Therefore, the cumulative impacts to vegetation resources related to leasing activities are not considered substantive. Impacts to vegetation as a result of future actions would be analyzed on a case by case basis as exploration and development permits are proposed.

Mitigation

All seed used for reclamation on public lands would meet standards existing at the time of the proposed application. (See also section on invasive, non-native species, 3.2.18. This standard is expected to evolve as more is learned about invasive weeds.) Best management practices along with specific restrictions would be implemented to minimize negative effects to vegetation communities.

3.2.10 Livestock Grazing

Existing Conditions

Of the 7.2 million acres of public lands administered by the Elko District BLM, there are 195 livestock grazing authorizations used among 239 grazing allotments. Elko District carries 824,058 Animal Unit Months (AUMs); of which, 692,229 of these AUMs are currently active, 126,549 are historically suspended, and 5,280 have been temporarily suspended. Authorized types of livestock include cattle, sheep and horses. While several different plant communities exist throughout the district with varying amounts of forage, as an average it takes approximately 9 acres to equal one AUM. Grazing use is periodically evaluated and changes in grazing management are made to meet and rangeland health standards and allotment-specific multiple use objectives.

Effects of the Proposed Alternative

The initial action of oil and gas leasing does not affect livestock grazing. Impacts to livestock grazing could occur as a result of the subsequent actions (e.g., exploration, development, production, or abandonment) once a parcel is leased. The impact would be loss of vegetation thus, loss of forage for active areas disturbed by operations. The disturbance would be confined to small areas, usually for a temporary period of time until the vegetation is reestablished (two to five years). The vegetation would soon recover and be available for consumption by livestock and wildlife.

Short term, generally referring to a two to three year span, disturbance to livestock grazing could occur during exploration and development phases. This may include livestock avoiding certain areas due to traffic, drilling, and construction of facilities such as power lines and pipelines. This disturbance will be limited to the short term and would not cause a major impact to livestock distribution. Because of the usually dispersed nature of activity, reclamation of disturbed sites, and varying degrees of damage to vegetation, reduction in licensed use has not been required. High concentrations of surface disturbance on one or a few grazing allotments could lead to reductions in livestock grazing on those affected allotments, if the issue is identified in the allotment evaluation process.

Mitigation

Best management practices along with specific restrictions would be implemented to minimize negative impacts to grazing resources.

3.2.11 Forest Resources

Existing Condition:

Forest resources exist on some of the lands proposed for leasing within the District. The forest resource species are pinyon, juniper, aspen, and mahogany. Most oil and gas exploration occurs in valley floors, usually away from forested areas. The Wells Resource Areas has more forested areas, but also is believed to have less potential for oil and gas exploration and development activity.

Effects of the Proposed Alternative

The initial action of oil and gas leasing does not affect forest resources. Impacts to forest resources could occur as a result of the exploration, development, production or abandonment of oil and gas activities could include removal of trees for the construction of roads and facilities, loss of woodland products such as firewood or pine nuts, loss of wildlife habitat such as nesting and perch sites, and changes in risk of wildfire in the area.

Mitigation

Measures to reduce impacts of leasing activities on forest resources could include avoiding the removal of trees, except when necessary by rerouting or relocating road routes and facilities, or by limbing trees. Trees requiring removal should be disposed of by the operator. Where blading is required, stumps would be removed or buried in an area designated by the Authorized Officer. Where blading is not required, stump height should not exceed 12 inches. All slash less than four inches in diameter should be chipped, scattered outside the cleared area, or stockpiled for use during reclamation as directed by the Authorized Officer. All material four inches in diameter and greater would be removed from federal land unless otherwise directed. A wood permit from BLM for the wood removed (for the appraised value) could be required prior to any clearing. Best management practices along with specific restrictions would be implemented to minimize negative impacts to forest resources.

3.2.12 Wilderness Study Areas

Existing Conditions

The Elko District contains 10 Wilderness Study Areas (WSAs) covering 303,572 acres. These include the Badlands, Bluebell, Cedar Ridge, Goshute Peak, Little Humboldt River, Owyhee Canyon, Red Spring, Rough Hills, South Fork Owyhee River and South Pequop WSAs. Land management prescriptions are applied according to BLM Manual 6330, Management of BLM Wilderness Study Areas. No new leases may be issued on lands under wilderness review.

The Wilderness Act of 1964 described for wilderness management the following passage from Section 2(c) of the Act:

> "A wilderness ...is an area where the earth and community of life are untrammeled by man, where man himself is a visitor who does not remain. An area of wilderness is further defined to mean in this Act an area of undeveloped Federal land retaining its primeval character and influence, without permanent improvements or human habitation, which is protected and managed so as to preserve its natural conditions..."

Section 603(a) of FLPMA directed the Secretary of Interior to inventory and study remaining roadless areas of 5000 acres or more to determine which areas possess wilderness characteristics, as described in the Act of 1964. The Secretary was further directed to report to the President his recommendation as to the suitability or non-suitability of each area for preservation as wilderness. In 1991, the Nevada BLM completed a Wilderness Study Report which contained recommendations for wilderness or non-wilderness designation for each of the WSAs. Congress has the final determination on whether a WSA will be designated as Wilderness or released from study and back to multiple-use.

Effects of the Proposed Alternative

No effects, due to the fact that WSA are excluded from leasing. Land management prescriptions for WSAs are applied according to BLM Manual 6330, Management of BLM Wilderness Study Areas. The Nevada BLM memorandum dated September 24, 2004 (IM No. NV-2004-093) also establishes that "*we will offer and issue fluid mineral leases to within one quarter mile of a Wilderness or WSA boundary. Any quarter-quarter sections intersected by and including a portion of a Wilderness or WSA boundary will be excluded from the parcel nominated.*"

Cumulative Effects of the Proposed Action

There would be no cumulative effects to the Wilderness Study Areas as there is no ground disturbance associated with this action. The potential future actions of exploration, development, and decommission associated specifically from the sale of oil and gas parcels would also not impact Wilderness Study Areas. The stipulations outlined in the EA limit the sale of parcels that come within .25 miles of any WSA in the Elko District.

3.2.13 Lands with Wilderness Characteristics (LWC)

Existing Conditions

On June 1, 2011, the Secretary of the Department of the Interior issued a memorandum to the BLM Director that in part affirms BLM's obligations relating to wilderness characteristics under Sections 201 and 202 of the Federal Land Management Policy Act. The BLM released Manuals 6310 and 6320 in March 2012, which provide direction on how to conduct and maintain wilderness characteristics inventories and provides guidance on how to consider whether to update a wilderness characteristics inventory.

The primary function of an inventory is to determine the presence or absence of wilderness characteristics. An area having wilderness characteristics is defined by:

- Size - at least 5,000 acres of contiguous, roadless federal land,

- Naturalness
- Outstanding opportunities for solitude or primitive and unconfined types of recreation.
- The area may also contain supplemental values (ecological, geological, or other features of scientific, educational, scenic, or historical values).

The Nevada BLM completed the original wilderness review in 1979, and issued an initial wilderness inventory decision in 1980. At that time, the inventory found wilderness character present in several units. Those were designated as Wilderness Study Areas in 1980.

The Elko District Office BLM began updating the lands with wilderness characteristics (LWC) inventory in 2011 on a project driven basis. The 26 parcels up for lease intersect 13 LWC inventory areas. Of those 13 inventory areas 2 have been previously analyzed under other projects. In the Wells Field Office NV-EK-03-139 was studied in late 2013/early 2014 and found to lack sufficient solitude and opportunities for outstanding primitive or unconfined recreation. Also in the Wells Field Office NV-EK-03-279 was studied in 2014 and found to lack sufficient outstanding opportunities for solitude and primitive or unconfined recreation experiences. The remaining units have yet to be studied in depth, but based on the results of the 1979 initial wilderness inventory and the 1980 intensive wilderness inventory the potential exists for some unstudied areas to contain wilderness attributes, however none raise to the level to warrant deferral of the parcel pending evaluation in the Resource Management Plan.

Effects of the Proposed Alternative

The effects of the proposed action would not result in any direct impacts as the action would not result in any ground disturbing activities. The proposed action could result in several indirect activities that may cause serious impacts to wilderness character within each inventory area. Exploration, development, and decommission could all impact the naturalness of a LWC unit as well as opportunities to experience solitude and participate in primitive or unconfined types of recreation. Oil and Gas activities could also reduce the size of a study area through the development of access roads and other supporting actions leading to the area not meeting the size requirement outline in BLM Manual 6310 Conducting Wilderness Characteristics Inventory on BLM Lands.

Table 3.2.13 LWC Unit List

LWC Unit Number	Acres	Last Inventoried	Wilderness Character	Potential of LWC Since Last Survey
NV-EK-02-015	34,858	1979 Initial	No	Low
NV-EK-02-480	9,265	1979 Initial	No	Low
NV-EK-02-519	9,814	1979 Initial	No	Low
NV-EK-02-533	43,531	1980 Intensive	No	Moderate
NV-EK-02-536	57,083	1980 Intensive	No	Low
NV-EK-02-555	45,370	1980 Intensive	No	Moderate
NV-EK-03-117	13,637	1979 Initial	No	Low
NV-EK-03-130	29,737	1980 Intensive	No	Moderate
NV-EK-03-136	20,499	1980 Intensive	No	Low
NV-EK-03-261	24,764	1979 Initial	No	Low
NV-EK-03-262	11,769	1979 Initial	No	Low

If exploration activities are conducted on the lease parcels, the unsuccessful exploration wells are plugged and abandoned and they would be reclaimed immediately after drilling or construction. Therefore, in the long term, it is possible that the potential disturbances would be reclaimed allowing the area to return to a natural state; and opportunities for solitude or a primitive and unconfined type of recreation would return. Impacts to size may also be reclaimed after exploration, but depending on the extent of wells and associated facilities (roads, gravel pits, etc.) impacts may remain that could continue to eliminate LWCs based on size.

For any producing wells, the impacts would be long term (20 years) or much longer. At that point, the impacts to LWC would be considered permanent.

Cumulative Effects

There are no cumulative impacts expected to result directly from the proposed action since the proposed action does not include any surface disturbance. However, it does authorize the right to future exploration and production activities. At that time when leased parcels are proposed for exploration and development, then potential impacts would be discussed in a site-specific NEPA document as required through mineral lease regulations.

Mitigation

The potential exists for some unstudied areas to contain wilderness attributes, however none of the units contain naturalness or other LWC attributes that warrant deferral of the parcel pending evaluation in the Resource Management Plan. Potential disturbances would be reclaimed allowing the area to return to a natural state; and opportunities for solitude or a primitive and unconfined type of recreation would return, therefore, the need for additional mitigation would be evaluated at the exploration stage but may not be warranted.

3.2.14 Recreation

Existing Conditions

The Elko District has 7.2 million acres of public land open to recreational pursuits. It is estimated that in 2013, there were 1.1 million visitors to public lands in the Elko District. There are six designated Special Recreation Management Areas (SRMAs), three of those are developed campgrounds, two are boating areas and one is a natural area. Over 380 miles of designated California National Scenic and Historic Trail are in the Elko District. There are scenic byways, wildlife viewing areas, historic mining districts, many fishable lakes, reservoirs and streams, recreation trails and various other opportunities for dispersed recreation. Popular dispersed recreation activities include hunting, riding off highway vehicles (OHVs), photography, wildlife viewing, fishing, sightseeing, boating, mountain-biking, camping, and hiking.

Vehicles are limited to designated routes in all the SRMAs and Wilderness Study Areas. The Salt Lake ACEC is closed to motorized traffic annually from March 1 through August 31(1985 Wells RMP). The Spruce Mountain Planning Area (NDOW Hunt Unit 105) is restricted motorized and mechanized travel to existing routes and trails until a travel management plan is completed that would define the travel network (Federal Register E6-5992).The rest of the District is open for vehicle use according to the Elko and Wells Resource Management Plans. Users are strongly encouraged to practice accepted outdoor ethics such as Leave No Trace and Tread Lightly whenever they recreate on public lands to preserve recreational resources for future generations of outdoor enthusiasts.

The Elko District Office administers approximately 6 competitive events on the District each year and permits over 30 commercial outfitter and guides. The events are vehicle races, motorcycle races and mountain bike races. Commercial outfitter and guides offer various hunting services and guided recreation opportunities on public lands.

Effects of the Proposed Alternative

The initial action of oil and gas leasing does not affect recreation. Impacts to recreation would occur as a result of the subsequent actions (e.g. exploration, development, production and abandonment) once a parcel is leased. No leasing is proposed in or near any designated recreation areas.

Dispersed recreation would be impacted by the presence of people, structures and equipment in an area not previously occupied. Some recreationists may cease using areas for recreation because of oil and gas development. Vehicles and noise could scare off animals that recreationists are hunting or detract from the feeling of solitude in the vicinity of a new development.

Leased parcels that are developed around the designated California National Scenic and Historic Trail could also impact recreation visitors. Groups looking for vicarious experiences while traveling the trail would be influenced by the developments in and around the trail. These impacts would be mitigated in part through the stipulations listed in Appendix B. Particular impacts to trail visitors would have to be outlined in future site specific NEPA documents as parcels are developed because to do so now would be speculation.

During many phases of oil and gas development, new routes may be created as a result of fence construction, powerline construction and pipeline construction. In general, new routes lead to greater access for recreationists. Fences or development could also restrict public access by blocking off areas originally accessible the general public.

Public safety is a concern with any development and the general public would need to be prevented from accessing areas of development. With development such as well pad construction and facility construction, traffic increases in the area causing another public safety concern.

During reclamation, not all new routes will be rehabilitated; some will remain as public access routes. Over the long term, recreation access is increased.

Cumulative Effects

The incremental effects of the proposed action combine with the past, present, and reasonably foreseeable future actions may have an impact on recreational resources. The entire nature of those impacts as to the severity and duration cannot be fully discussed in this document, but would be analyzed if or when an APD is submitted to the Elko District. At that time a site specific NEPA document will analyze those effects in detail, and quantify and qualify the compound effects to recreational resources as part of the permitting process.

Mitigation

The Stipulations in Appendix B prevent impacts to high use, developed recreation areas. The Special Recreation Management Areas stipulation prevents surface occupancy within one-half mile of the high water line where reservoirs are present and restrictions to existing access within the remainder of the recreation area. The Tabor Creek Campground SOP also prevents surface occupancy within this high use area. Using best management practices will lessen the impacts to dispersed recreationists, but further discussion on potential impacts to dispersed recreationists would take place in future NEPA documents as the parcels are developed.

3.2.15 Visual Resource Management

Existing Conditions

As part of the Visual Resource Management (VRM) program, the BLM has prepared and maintains an inventory of visual values on public lands within the Elko District, called the Visual Resource Inventory (VRI). The inventory is intended to identify the visual values of areas within the field office and assign them to an inventory class based on three factors: the scenic quality of an area; the sensitivity of the public to certain changes on the landscape; and a delineation of distance zones to indicate relative visibility of the landscape from primary travel routes and observation points.

The Elko District is part of the Basin and Range landscape type. Elevations range from 4,400 ft. in the valleys to 11,000 ft. in the mountains. Much of the district could be classified as a panoramic landscape with horizontal lines forming the horizon and vertical lines forming the mountains. Many of the basins are sagebrush vegetation type with grasses and other small shrubs intermixed. Colors in the valleys are light greens and browns. As elevation increases up-slope, vegetation type changes to pinion-juniper type. Colors change to darker greens and browns. The panoramic view causes the vegetation form to be very smooth and the landform to be rough. There are various rock outcrops and variations in the soil colors.

Manmade features in the Elko District range from highways and powerlines to fences, roads, and range developments. There are many man-made features; some more dominant than others depending on location.

Visual resources are identified through the Visual Resource Management (VRM) inventory. This inventory consists of a scenic quality evaluation, sensitivity level analysis, and delineation of distance zones. Based on these factors, BLM-administered lands are placed into four visual resource inventory classes: VRM Classes I, II, III, and IV. Classes I and II are the most valued, Class III represents a moderate value and Class IV is of the least value. VRM classes serve two purposes: (1) as an inventory tool that portrays the relative value of visual resources in the area, and (2) as a management tool that provides an objective for managing visual resources. (See Table 3.2.1.5).

In addition to the above Classes, in the Elko and Wells Resource Management Plans, a Low Visibility Corridor was established along Interstate 80. Visual impacts are to be minimized within 1.5 miles on either side of the highway. Within this three-mile wide Low Visibility Corridor, the objective is for management actions not to be evident in the characteristic landscape. Management objectives for Class II VRM areas will be used as a guideline when evaluating projects within the Low Visibility Corridor. The Table 2-1(above) identifies those leases proposed to be offered at March 2014 sale where the I-80 Low Visibility Corridor stipulation would need to be attached.

Elko District BLM contains sections of the California National Scenic and Historic Trail. The Trail main segments cross the District from the northeast corner near the boarders of Idaho and Utah heading southwest towards the East Humboldt Range. Then the Trail follows the same general direction along the Humboldt River through Elko and Carlin Canyon. The main Trail continues along the Humboldt northwest after Emigrant Pass and leaves the District around Sterritt Peak and the Battle Mountain Area. The Hastings Cutoff sections enter the District at the base of Pilot Peak and continue west until the East Humboldt and Ruby Mountain Range complex. The Hastings Cutoff then routes around the southern end of the Ruby Mountains until rejoining the main section of the trail west of Elko through South Fork Canyon. According to BLM Manual 6280 visual resources around Trail segments need to be managed as a Class I or Class II resource except in areas were strong urban development has already impacted trail resources.

Table 3.2.15 VRM Classification Objectives

VRM CLASS	Visual Resource Objective	Change Allowed (Relative Level)	Relationship to the Casual Observer
Class I	Preserve the existing character of the landscape. Manage for natural ecological changes.	Very Low	Activities should not be visible and must not attract attention.
Class II	Retain the existing character of the landscape.	Low	Activities may be visible, but should not attract attention.
Class III	Partially retain the existing character of the landscape.	Moderate	Activities may attract attention, but should not dominate the view.
Class IV	Provide for management activities, which require major modification of the existing character of the landscape.	High	Activities may attract attention, may dominate the view, but are still mitigated

Effects of the Proposed Alternative

When an Application for Permit To Drill (APD) is received, an analysis is done to determine which VRM Class the development falls under using the established inventory as a guideline. Then a visual contrast rating is completed to verify if the current VRM classification is sufficient, management has the authority to adjust VRM objectives to the area if current management prescriptions are found to be lacking.

The development of leased lands for Oil and Gas resources would create strong contrasts between the project features and the existing landscape. All the dominant elements of the visual landscape (form, line color, and texture) would be affected.

Building roads would superimpose visual lines that would appear in sharp contrast with horizontally aligned hills and the continuous, uninterrupted vegetation in the area. Removal of vegetation due to road and drill pad construction would expose bare soil much lighter in color and smoother in texture than the surrounding vegetation. This would superimpose visible lines and openings in vegetation that is otherwise uniform and which covers all the landscape. Those contrasts would be visible to anyone in the area. However surface disturbances would be less visible as they moved away from the viewer. Roads would be highly visible as the observer looked along them but less visible when the observer looked across them.

Permanent structures such as steel storage tanks would cause substantial contrast to form, line, texture and potentially to color as well. Essentially, there are very few structures present in the Oil and Gas Lease area and the proposed structures would be square or rectangular or cylindrical in form, they would have a vertical alignment, and they would be smooth in texture. This would be in sharp contrast with the low, gently rolling hills and valleys of the characteristic landscape. In open country they would be visible at great distances. The visibility of the structures would be enhanced if they were painted an inappropriate color. Roads, especially as the viewer looks along them would create lines that would usually be the opposite of the natural horizontal lines in the landscape.

The length of time required for re-vegetation is fairly long. Grasses can be re-established in a season or two but it takes several years to re-establish sagebrush, the dominant vegetative species in the area.

Even though the issuance of leases would cause impacts to all the elements of the visual landscape (form, line, color, and texture), it still would conform to the Class III and IV Visual Resource Management.

Under the assumption that a number of wells would be drilled and that they would be successful, substantial changes in the visual landscape could result over the next 2-5 years.

Cumulative Effects

The reasonably foreseeable future actions would have an impact on visual resources. A number of ongoing and future activities combined could result in direct and indirect impacts to visual resources, particularly to VRM Class II areas. VRM Class III and IV areas would have site-specific design features incorporated and future activities would avoid VRM Class I areas. The stipulations required through the RMP or those determined to be needed on a site-specific basis will help to minimize impacts from these activities.

Mitigations

Design mitigation techniques would be applied to screen projects from view when project proponents submit proposals to the BLM. Strategies include color selection, layout of earthwork, vegetative manipulation, placement of structures, materials selection and reclamation or rehabilitation.

Visual effects on the California National Scenic and Historic Trail would be limited by the stipulations outlined in Appendix B.

All proposed actions on public lands would be subject to the BMPs outlined in the Participant Notebook Field Reference Guide for Visual Resource Management for Fluid Minerals Best Management Practices: Better Ways for Achieving Better Results.

3.2.16 Native American Concerns

Existing Conditions

Federal law and agency guidance require the BLM to consult with Native American tribal governments concerning the identification of cultural values, religious beliefs, and traditional practices of the Native American peoples that may be affected by actions on BLM-administered lands. This consultation includes the identification of places (i.e., physical locations) of traditional cultural importance to the affected Native American tribes. Places that may be of Native American traditional cultural importance include, but are not limited to:

- Locations associated with the traditional beliefs concerning tribal origins, cultural history, or the nature of the world.
- Locations where religious practitioners go, either in the past or the present, to perform ceremonial activities based on traditional cultural rules or practice; Ancestral habitation sites; Trails; Burial sites; and Places from which plants, animals, minerals, and waters believed to possess healing powers or used for other subsistence purposes, may be taken.
- Some of these locations may be considered sacred to particular Native American individuals or tribes.
- In 1992, the National Historic Preservation Act (NHPA) was amended to explicitly allow that “properties of traditional religious and cultural importance to an Indian tribe may be determined to be eligible for inclusion on the National Register of Historic Places.” If a resource has been identified as having importance in traditional cultural practices and the continuing cultural identity of a community, it may be considered a “traditional cultural

property" (TCP). To qualify for nomination to the National Register of Historic Places (NRHP), a TCP must:

- Be more than 50 years old;
- Be a place with definable boundaries;
- Retain integrity; and
- Meet certain eligibility criteria as outlined for cultural resources in the NHPA (Section 3.2.3 cultural Resources).

In addition to NRHP eligibility, some places of cultural and religious importance also must be evaluated to determine if they should be considered under other federal laws, regulations, directives, or policies. These include, but are not limited to, the Native American Graves Protection and Repatriation Act of 1990, American Indian Religious Freedom Act of 1978, Archaeological Resources Protection Act (ARPA) of 1979, and Executive Order (EO) 13007 (Sacred Sites) of 1996.

The effects of federal undertakings on properties of religious or cultural significance to contemporary Native Americans are given consideration under the provisions of EO 13007, American Indian Religious Freedom Act, and recent amendments to the NHPA. As amended, the NHPA now integrates Indian tribes into the Section 106 compliance process and also strives to make the NHPA and National Environmental Policy Act procedurally compatible. Furthermore, under Native American Graves Protection and Repatriation Act, culturally affiliated Indian tribes and the BLM jointly may develop procedures to be taken when Native American human remains are discovered on federal land.

Tribal Consultation/Information Sharing: The BLM, Elko District, Tuscarora and Wells Field Offices have ongoing invitation for consultation and information sharing with the groups listed in the table below. Consultation and communication with these tribal/band governments have included letters, phone calls, e-mails, and visits with individual Tribal/Band Environmental Coordinators. Consultation/Information Sharing will continue throughout the life of the project.

Tribal ethnographic resources are associated with the cultural practices, beliefs, and traditional history of a community. In general, ethnographic resources include places in oral histories or traditional places, such as particular rock formations, the geothermal water sources, or a rock cairn; large areas, such as landscapes and viewscapes; sacred sites and places used for religious practices; social or traditional gathering areas, such as racing grounds; natural resources, such as plant materials or clay deposits used for arts, crafts, or ceremonies; and places and natural resources traditionally used for non-ceremonial uses, such as trails or camping locations.

Summary of Native American Consultation/Information Sharing (Consultation is On-Going).

Name of Tribe or Band	Date of Contact	Type of Contact	Comments/Notes
Te-Moak Tribe of Western Shoshone	8-19-2014	Informational letter	Information sharing at Councils request. Comments provided, areas of concern removed.
Battle Mountain Band	8-8-2014	Data sharing meeting	Met at BLM with Band Environmental Coordinator, provided parcel maps and legal descriptions, requested band input.
	8-19-2014	Letter from BLM	Invitation to open government-to-government consultation
	9-11-2014	E-mail from BLM	E-mail correspondence with Band Environmental Coordinator
Duck Valley	8-13-2014	Phone call	Phone call to Cultural Resources Officer concerning Oil and Gas Leasing.
	8-13-2014	Meeting	Meeting Cultural Resources Officer at tribal headquarters seeking Tribal input.
	9-11-2014	E-mail	Emailed Tribal Cultural Resources Officer reminding need for tribal input by 9-16-2014
Elko Band	8-19-2014	Informational letter	Information sharing at Councils request. No Comments or concerns provided.
	9-11-2014	E-mail	E-mailed Band Environmental Coordinator reminding of need for band comments by 9-15-2014
	9-12-2014	Meeting	Meeting at Te-Moak headquarters, discussed maps and lease deferral
	9-16-2014	Meeting	Met with Environmental Coordinator at BLM, received Band input request for oil and gas parcel deferment.
Goshute Tribe	8-11-2014	Phone Call	Phone call vice Chairperson, Described Oil and Gas lease process and arranged to give them Oil and Gas Parcel Map and Legal Description
	8-15-2014	Meeting	Goshute Vice Chairperson visited BLM and received Band input of Gas and Oil Lease Parcel deferment.
	9-11-2014	Email	Emailed vice chairperson and reminded them of need to get tribal input in writing by 9-16-2014 at 8:00am
	9-12-2014	Phone Call	Phone Call to BLM informing verbally of parcels of concern. BLM asked for information in writing no later than 9-17-2014.
South Fork Band	8-8-2014	Phone Call	Phoned Band Environmental Coordinator. Arranged to provide parcel maps, legal descriptions, and requested band input.
	8-14-2014	Meeting	Meeting with Tribal Chairwoman, provided Parcel maps, legal descriptions

			and requested band input.
	9-12-2014	Meeting	Met at Te-Moak headquarters, discussed parcel maps and lease and deferral process.
	9-16-2014	Phone Call	Phoned South Fork Environmental Coordinator, informed BLM that they would miss meeting. Requested to turn in information on 9-17-2014, BLM Native American Coordinator agreed to this.
Wells Band	8-8-2014	Meeting	Meeting at BLM with Band Environmental Coordinator. Provided Maps, legal descriptions and requested band input
	8-19-2014	Informational letter	Information sharing at Councils request. No Comments or concerns provided.
	9-11-2014	Email	Emailed Band Environmental Coordinator reminding need for Band Comments by 9-16-2014 at 8:00 am.
Shoshone Paiute Tribes of the Duck Valley Indian Reservation	8-19-2014	Informational letter	Invitation to open government-to-government consultation
Confederate Tribes of the Goshute Indian Reservation	8-19-2014	Letter from BLM	Invitation to open government-to-government consultation

Name of Tribe or Band	Date of Contact	Type of Contact	Comments/Notes
Duckwater Shoshone Tribe	8-19-2014	Letter from BLM	Invitation to open government-to-government consultation
Yomba Shoshone Tribe	8-19-2014	Letter from BLM	Invitation to open government-to-government consultation
Ely Shoshone Tribe	8-19-2014	Letter from BLM	Invitation to open government-to-government consultation

The NEPA process does not require a separate analysis of impacts to religion, spirituality, or sacredness. As a result, references to such beliefs or practices convey only the terminology used by participants involved in the ethnographic studies and tribal consultation. This terminology does not reflect any BLM evaluation, conclusion, or determination that something is or is not religious, sacred, or spiritual in nature, but conveys only the information that has been gathered through tribal consultation and coordination and current and historic ethnographic study.

Effects of the Proposed Alternative

Implicitly the act of selling oil and gas leases indirectly creates the potential to adversely impact Native American sites of spiritual/cultural/traditional nature. If a lease is sold, the lessee retains irrevocable rights and can foreclose the authorized officer's use of some mitigation measures. For example, according to 43 CFR § 3101.1-2, once a lease is issued to its owner, that owner has the "right to use so much of the lease lands as is necessary to explore for, drill for, mine, extract, remove and dispose of the leased resource in the leasehold" subject to specific nondiscretionary statues and lease stipulations.

The types of resource uses by traditional activities and current religious practices often cannot be easily or effectively mitigated for. The direct and indirect activities associated with imaging, exploration, development, and mineral extraction are often terminally disruptive to traditional and religious practices.

Mitigation

Both oil and gas leasing/development are recognized and acceptable uses of lands administered by the BLM under the Federal Land Policy and Management Act of 1976 (FLPMA). However, in accordance with the National Historic Preservation Act (P.L. 89-665), the National Environmental Policy Act (P.L. 91-190), the Federal Land Policy and Management Act (P. L.94-579), the American Indian Religious Freedom Act (P.L. 95-341), the Native American Graves Protection and Repatriation Act (P.L. 101-601) and Executive Order 13007, the BLM must also provide affected tribes an opportunity to comment and consult on proposed actions. BLM must attempt to limit, reduce, or possibly eliminate any negative impacts to Native American traditional/cultural/spiritual sites, activities, and resources.

Due to the existence of additional Standard Operating Procedures (SOPs) and stipulations and limitations (law, regulations, directives), BLM has determined that parcels requested to be deferred or withdrawn, by the Te-Moak Tribe, will be deferred in the March 2015 Oil and Gas lease sale (see SOP No. 1, 2, and WO IM 2005-003). Information for areas of concern to the various tribes and bands has been gleaned from thirty years of confidential ethnographic studies and reports. These areas of concern have been added to the information proved by the Te-Moak Tribe, Elko Band Council and the South Fork Band Council.

As stated above, if, as a result of leasing, a ground disturbing plan to explore or develop is submitted to BLM, all applicable laws, regulations, directives, SOPs, and stipulations and limitations will apply.

BLM reserves the right to alter proposed activities associated with any surface occupancy that results from Oil, and Gas, leasing. Consequently, the BLM must take steps to identify locations having traditional/cultural or religious values to Native Americans and insure that its actions do not unduly or unnecessarily burden the pursuit of traditional religion or traditional values.

3.2.17 Wild Horses

Existing Conditions

There are 8 wild horse herd management areas (HMA) managed by the Elko District Office. They are the Owyhee, Rock Creek, Little Humboldt, Diamond Hills North, Maverick-Medicine, Antelope Valley, Goshute, and Spruce-Pequop HMAs. These eight HMAs total approximately 1.8 million acres and have an appropriate management level (AML) of 1,338 wild horses. Wild horses inhabit these HMAs year round. Deferred parcels 13 and 14 are within the Maverick /Medicine HMA and parcels 15 through 26 are located in the Antelope Valley HMA. The other parcels are not located within HMAs.

Effects of the Proposed Alternative

There are no direct impacts to wild horses associated with leasing, however wild horses can be found within some of the HMAs and future exploration could affect wild horses within those HMAs. Increased human and motorized activity could disrupt and displace wild horses. The wild horses inhabiting the area of the exploration could leave the area and move away from the noise and activity. During any long term or permanent activity it is probable that wild horses over time would become accustomed to the activity and resume normal activities at a reasonable distance. Construction of new fences as part of development production facilities could disrupt movement of free roaming wild horses and animals could be injured by colliding with any new fences.

Mitigations

Construction of fencing within a HMA would be evaluated during review of any development proposal to determine if flagging or other measures would be necessary to increase visibility to wild horses. Best management practices along with specific restrictions would be implemented to minimize negative impacts to wild horses.

3.2.18 Invasive, Nonnative Species

Existing Conditions

Invasive, nonnative species occur in some areas which have the potential for oil and gas exploration or development. Invasive, nonnative species, including Nevada designated noxious weed species are aggressive, typically nonnative, ecologically damaging, undesirable plants, which severely threaten biodiversity, habitat quality and ecosystems. Because of their aggressive nature, invasive, nonnative weed species may eventually spread into established plant communities. Wildland fires in the northern Great Basin have helped to cause an increase of invasive weed species. Wildland fires provide a fertile environment, usually without competition from native species, for weed species to become established. Vehicles are a primary vector in the spread of invasive weed species. Seeds and plant propagules can become lodged in tires and undercarriages and deposited in relatively weed free areas. Increased traffic from users of public lands may cause an increase of noxious and/or invasive plant species.

The State of Nevada has three categories of noxious and invasive weed species:

Category A includes noxious weeds, which are:

- Not found or limited in distribution throughout the state;
- Actively excluded from the state and actively eradicated wherever found; and
- Controlled by state for all infestations.

Category B includes noxious weed species, which are:

- Established in scattered populations in some counties of the state;
- Actively excluded where possible; and

- Controlled by the state in areas where populations are not well established or previously unknown to occur.

Category C includes noxious weeds, which are:

- Currently established and generally widespread in many counties of the state; and
- Controlled and abated at the discretion of the state quarantine officer (Nevada Department of Agriculture 2006).

A number of the parcels proposed for the March 2015 sale likely contain Nevada designated noxious weed species. Species found within the parcels include Scotch thistle (*Onopordum acanthium*), spotted knapweed (*Centaurea maculosa*), hoary cress (*Cardaria draba*), Russian knapweed (*Acroptilon repens*), perennial pepperweed (*Lepidium latifolium*), Bull thistle(*Cirsium vulgare*),
and Canada thistle (*Cirsium arvense*).

Effects of the Proposed Alternative

The act of offering, selling, issuing federal oil and gas leases does not produce invasive/non-invasive species impacts. Subsequent development produces impacts in the form of ground disturbance. The construction of an access road and well pad may unintentionally contribute to the establishment and spread of noxious weeds. Noxious weed seed could be carried to and from the project areas by numerous methods, including construction equipment, the drilling rig and transport vehicles. The main mechanism for seed dispersion on the road and well pad is by equipment and vehicles that were previously used and or driven across or through noxious weed infested areas. The potential for the dissemination of invasive and noxious weed seed may be elevated by the use of construction equipment typically contracted out to companies that may be from other areas.

Each APD would result in additional disturbance throughout the future project areas creating opportunity for noxious and invasive weeds to spread. Proposed mitigation measures, including noxious and invasive weed control, would be developed upon environmental analysis of site-specific APD. Cheatgrass and other weedy annuals are common along roadsides and disturbed areas. These and the other species of noxious weeds are spread by vehicle traffic, livestock, and wind, water, recreational vehicles, and wildlife. There would also be potential for new weeds to be transported onto the site on equipment used for construction activities. Any disturbance of soil or removal of vegetation would create opportunity for weeds to establish or spread into the surrounding plant community. In disturbed areas, bare soils and the lack of competition from an established perennial plant community would allow weed species opportunity to grow and produce seed. However, successful reclamation using a seed mix adapted to the site in conjunction with integrated weed management would create an opportunity to improve vegetative communities and reduce the amount of weed species in the project area.

Cumulative Impacts from Past, Present and Reasonably Foreseeable Future Actions

Future development within the proposed lease sale parcels would result in additional vegetation loss and surface disturbance. Past and present oil and gas activities in the area have already created disturbance, and oil and gas development is anticipated to continue throughout the area.

Successful reclamation would reduce the risk to healthy plant communities and provide an opportunity to improve degraded vegetative communities within the project area.

Mitigation

The Following principles of integrated pest management, including herbicide application, shall be employed to control and minimize noxious and invasive weeds:

- Prior to any ground disturbing activities, further analysis addressing the potential effects related to noxious, non-native species would be considered.
- Clean equipment of all mud, dirt and plant parts before moving into relatively weed-free areas.
- Include weed prevention and treatment in all plans for surface disturbance and reclamation.
- Ensure all disturbed soil is re-vegetated as soon as possible to establish competition against invasive weeds.
- Incorporate weed prevention into road layout, design and alternative evaluation (where road construction is required).
- Incorporate weed prevention into road layout, design and alternative evaluation (where road construction is required).

Use of current standards for seed used to reclaim public lands would be helpful in reducing the spread of invasive, non-native species. Best management practices along with specific restrictions would be implemented to minimize negative impacts.

3.2.19 Wetlands/Riparian Zones

Existing Conditions

Riparian areas exhibit vegetation or physical characteristics reflective of permanent surface or subsurface water influence. Typical riparian areas are lands along, adjacent to, or contiguous with perennially and intermittently flowing rivers, streams, and shores of lakes and reservoirs with stable water levels. Excluded are such sites as ephemeral streams or washes that do not exhibit vegetation dependent on free water in the soil. Wetlands are areas that are inundated or saturated by surface or groundwater at a frequency and duration sufficient to support and which, under normal circumstances, do support a prevalence of vegetation typically adapted for life in saturated soil conditions. Wetlands include marshes, swamps, lakeshores, sloughs, bogs, wet meadows, estuaries, and some riparian areas.

Riparian and wetland areas adjacent to surface waters are the most productive and important ecosystems in the planning area. Although these areas represent a small portion of the affected sub-basins, riparian, habitats play an important role in restoring and maintaining the chemical, physical, and biological integrity of water resources (Fitch and Ambrose 2003). Healthy Riparian and wetland areas have the potential for multi-canopy vegetation layers with trees, shrubs, grasses, forbs, sedges, and rushes, and are valuable habitat for a wide variety of wildlife species. Healthy systems also filter and purify water, reduce sediment loads, enhance soil stability, provide micro-climatic moderation, and contribute to groundwater recharge and base flow (Pritchard et al. 1998).

The BLM and U.S. Fish and Wildlife Service (FWS) have recorded and mapped data regarding the extent and condition of riparian/wetland areas. According to the FWS there are about 200,000 acres of wetlands within the affected sub-basin which represents about 4% of the land area.. Those riparian acres are mapped using remote sensing techniques and do not include the small riparian areas surrounding many of the smaller springs and streams within the sub-basins. The proportion of riparian area on BLM administered land is much smaller because BLM land is mostly located in the uplands As mentioned previously, BLM has inventoried around 1000 springs on BLM land within the sub-basins, and many others are present on private land.

Although detailed information on the condition and trend of riparian areas is not available for the affected basins as a whole, some data are available for the riparian areas associated with springs and streams on public land. One of the ways BLM assesses the condition of riparian areas associated with streams (lotic) and springs (lentic) is by using the Proper Functioning Condition (PFC) Assessment outlined in Pritchard et al. 1998. This technique is used by the BLM to determine whether or not riparian areas are meeting rangeland health standards. Riparian areas are considered to be in PFC when adequate vegetation, landform, or debris is present to dissipate energy, improve water quality, reduce erosion, filter sediment, aid floodplain development capture and store water, and provide for greater biodiversity. Riparian areas that are functioning at risk lack one or more soil, water, or vegetation attribute, making them susceptible to degradation. Nonfunctional riparian areas are clearly not exhibiting the attributes necessary for a functioning system. Although this protocol is not directly related to oil and gas development, the impacts associated with the Proposed Action, and other land uses such as livestock grazing could combine to create impacts which would be observed through PFC assessment.

Results of lotic and lentic PFC assessments indicate that although some improvement has been accomplished in the past 15 years, many acres of riparian area are rated as being in poor condition. A BLM summary of lotic PFC assessments for the Elko District indicated that 60% of stream miles assessed between 2000 and 2012 were rated in proper functioning condition or Functional at risk with upward trend. Results in the affected sub-basins and streams in and near the proposed parcels are similar. BLM’s lentic assessment database indicates that of the 29 assessments completed in and near (within two miles) the proposed lease parcels, eight were rated as functional at risk with downward trend, one was rated as functional at risk with upward trend, three were rated as functional at risk with no apparent trend, seven were rated as non-functional and 10 were rated as being in proper functioning condition (see Appendix G).

<u>Effects of the Proposed Alternative</u>

As previously stated, the sale of parcels and issuance of oil and gas leases is strictly an administrative action. The act of offering, selling, and issuing federal oil and gas leases does not produce impacts to riparian/wetland resources. Subsequent development of a lease may result in long-and short term alterations to surface hydrology and groundwater resources which may indirectly impact riparian/wetland resources depending upon the intensity of development. Because potential impacts to riparian/wetland resources are so strongly connected to impacts to surface and groundwater quality and quantity, the reader is encouraged to refer to the Water Resources section of this document for full analysis.

Impacts to riparian/wetland resources may include varying degrees of habitat loss depending on the sensitivity of the riparian system and the proximity of the exploration and/or construction activities. Impacts could include increased sediment loads due to ground clearing, loss of vegetative communities, as well as accelerated erosion due to road construction. Sedimentation can increase turbidity levels, reducing available light and riparian plant production. Any degree of habitat loss to a riparian system opens the area to invasion by upland and/or weed species. Exploration or construction impacts that have the potential for riparian habitat removal or degradation in combination with other actions in the area will have to be evaluated at the time the permit application is submitted.

Normal oil/ gas plant operations should have minimal effect on any nearby riparian areas once facility construction is completed. Exceptions to this are incidences where spills, emissions or plant personnel activity cause degradation to water quality or riparian communities or where large quantities of water are diverted to support the operation. Discharge of treated waters can have variable effects on the riparian community, depending on the water quality. Increased moisture in drainages can accelerate riparian plant establishment, changing the existing vegetative composition. Temperatures of discharge waters are usually high and algae and/or moss production can increase as a result of such water entering any standing water bodies. Additional monitoring measures may need to be employed where potential for impacts to riparian areas through facility operations are high.

Upland reclamation of the drilling site has the potential to increase sedimentation loads to any nearby drainage during the initial phases. It is unlikely, though, that any viable riparian area will be disturbed for oil/ gas drilling purposes. Reclamation of facilities should only result in transient effects on riparian areas. Monitoring or remediation measures to reduce possible impacts to riparian areas should be established at the time of the APD submittal.

Cumulative Effects

The cumulative effects study area (CESA) is the area within and near the proposed lease parcels including a two mile buffer. This CESA was chosen because effects associated with the development of parcels is not expected to extend beyond the two mile buffer area of the lease parcels. This rational is explained in further detail in water quality surface/ground section 3.2.6.

As described above in the Affected Environment section, 66 percent of 29 riparian assessments completed within the CESA that are non-functional or functional at risk and as such it BLM has documented that riparian/wetland resources have already sustained substantive cumulative effects. These impacts would continue to occur under the No Action Alternative.

The Proposed Action would not result in any direct incremental increase in cumulative impacts to riparian/wetland resources, but subsequent development could increase impacts as described above in the Proposed Action section. Specifically, development would likely result in additional water diversion, surface water quality could be affected by development, resulting in potential impacts to riparian/wetland resources. The incremental increase in these impacts is small when compared to the level of impacts that already exist in the sub-basins as described above in the Affected Environment section. Based on conditions of approval and stipulations imposed on

APD proposals these impacts would be minimized. These cumulative impacts would continue to occur under the Proposed Action.

Mitigation

Executive Order 11990, May 24, 1977, directs federal agencies to take appropriate actions to avoid, to the extent possible, long and short term adverse impacts associated with the destruction or modification of wetlands and to avoid direct support of new construction in wetlands wherever there is a practicable alternative. Impacts to an open body of water, such as a canal, ditch, slough, pond, creek, lake, or stream and riparian areas would be avoided by a buffer zone of 400 ft.

3.2.20 Wildlife and Fisheries

Existing Conditions

These lease parcels are expected to provide habitat for a large number of wildlife species. Many species of birds, mammals, reptiles, amphibians, fish and invertebrates may find any one of the proposed lease areas suitable habitat. A few parcels proposed for leasing fall in areas of special importance to one or more wildlife species, such as crucial winter range for mule deer. These areas may have special stipulations concerning drilling activities, which would have to be followed prior to development of specific sites (Table 2-1).

No baseline data was collected by BLM biologists for these parcels. Additional information may be needed when a specific APD is submitted.

Big Game
The lease parcels are within areas utilized by mule deer, pronghorn antelope, and elk. All species may be observed in any given location during some part of the year. Some habitat areas are crucial to the persistence of a herd or population through stressful seasons and or drought conditions. These areas have been delineated using observations of habitat use combined with the best knowledge of available forage types, water, and thermal cover. Information on parcels with known big game crucial habitat is provided in Table 2-1.

Raptors
Most lands in the Elko District may have raptor nesting sites and foraging areas including sites occupied by eagles. Nesting habitats vary between species and vary with available features. Rock ledges, high cliffs, tree tops, bare ground, and burrows are all examples of where raptor nests may be found within the lease parcels. Prey may include small mammals, other avian species, reptiles, amphibians, and carrion. Information on raptors is gathered during winter surveys as well as spring nesting surveys. Raptors may be resident or migratory. Migrating raptors may travel as far as South America to winter or may stay as residents. Information on parcels with known raptor nest occurrences is provided in Table 3.2.22b.

Fisheries
No known fisheries occur within the lease parcels.

Migratory Birds
Migratory birds are discussed in the Migratory Bird section (3.2.21).

Special Status Species

Special status species, sensitive species, threatened and endangered species, proposed species, and candidate species are discussed in the section on Special Status Species (3.2.22).

Effects of the Proposed Alternative

There would be no direct effects from issuing new oil and gas leases, leasing does not directly authorize oil and gas exploration, development, production, or any other ground disturbing activities. Indirect effects may occur during the exploration, development, and or production of the minerals within the lease parcels. These effects would be analyzed at the time that these activities are proposed. Possible effects are discussed in a general manner below.

If, following leasing, an APD is submitted for oil/gas exploration/development, and production activities, have the potential to affect wildlife in the following ways:

- Temporary disturbance, displacement, or mortality of wildlife could result from exploration and development. Impacts include habitat loss of the area surrounding the construction site due to fencing, noise and high activity levels.
- Long-term habitat loss and habitat fragmentation could result from exploration or development. Risk of permanent loss of habitat due to unsuccessfully reclaimed sites is high. Reclamation, especially in low elevation and low precipitation sites, is difficult even with the best techniques and equipment; the potential for failure is high.
- Degradation to habitat and quality forage due to the possible establishment and spread of noxious weeds from exploration and development.
- The potential of groundwater contamination from spills or evaporation pond runoff and/or overflow could change the water chemistry at springs, altering aquatic habitat. This could possibly alter survivorship and reproduction of aquatic species; however it is believed the contamination of groundwater is highly unlikely to occur.
- Changes in water quantity and quality could alter the survivorship and reproduction of aquatic species; however it is believed that the amount of water necessary for drilling would not affect neighboring springs.

Direct impacts from exploration, development, and production activities would be analyzed under a separate site-specific NEPA analysis at the time that these activities are proposed.

Big Game
Mule deer, elk, and antelope crucial habitats exist in the lease sale areas. Impacts include temporary individual or population displacement from preferred habitat to marginal habitat, potential for animal mortality, decreased fitness, or behavioral changes in the vicinity of the exploration site. Permanent habitat loss due to mechanical changes to the environment or weed invasion may occur. In addition, oil and gas development at various stages could disrupt big game movement corridors. Impacts of groundwater removal could affect spring and stream discharge changing water availability and habitat viability, and alter habitat use patterns.

Raptors
Raptors may be particularly affected during nesting season since it is generally the time of highest physiological stress. Disturbance, even a one-time occurrence, may cause species with low tolerance to disturbance (ferruginous hawk, Swainson's hawk and the short-eared owl) to abandon their nests. However, raptor timing limitations described in the RMP would be attached as stipulations to the individual lease.

Golden eagles have been documented throughout the district and compliance with the Bald and Golden Eagle Act requires surveys and protection measures for eagle nests and foraging areas. Impacts for Golden Eagles would be the same as for Raptors described above. Coordination between the USFWS, project proponents and BLM would be necessary before any surface disturbing activities would be authorized on lease parcels within these habitats.

Cumulative Effects

The incremental effects of the proposed administrative action combined with the past, present, and reasonably foreseeable future actions may have an impact on these resources. The entire nature of those impacts as to the severity and duration cannot be fully discussed in this document, but will be analyzed if or when an APD is submitted to the Elko District. At that time a site specific NEPA document will analyze those effects in detail, and quantify and qualify the compound effects to fish and wildlife resources as part of the permitting process.

Mitigation

Big Game
Seasonal restrictions from disturbance in crucial mule deer and pronghorn antelope winter ranges apply during the period 11/15-3/16, inclusive. Determining wintering seasonal buffer zones for big game on a site-specific basis would increase the protection BLM can afford these animals. Winter range is limited and dates reflect when large numbers of animals reside on these small areas. Displacement from these areas on these dates due to land use disturbance may be detrimental (Elko RMP (pg. 2-4)).

Raptors
Most lands in the Elko District may have raptor nesting sites and foraging areas and so are subject to seasonal protection from disturbance that are typically applied to a one-half mile radius around known nest sites. As indicated in Table 3.2.22b, inclusive dates of the seasonal restrictions from disturbance around the nesting sites vary depending on the species. Surveying areas to be disturbed and determining seasonal buffer zones for active raptor nests on a site-specific basis increases the protection BLM can afford raptors. An arbitrarily determined buffer zone, such as the one-half mile radius specified for each species above, may be inadequate to prevent line-of-sight contact between nesting raptor and disturbing human intrusions, particularly in open country (From *Guidelines for Raptor Conservation in the Western United States* (USFWS)). Furthermore, if a nest is readily visible to humans, it is more susceptible to vandalism. In rough or forested terrain, a one-half mile radius may be larger than necessary to prevent disturbance of a nesting raptor.

3.2.21 Migratory Birds

<u>Existing Conditions</u>

According to the BLM Elko District Office "Bird List", there are approximately 246 species that could inhabit the Field Office area of jurisdiction on a seasonal or yearlong basis (BLM, 1999). The Proposed Action area includes habitat for all of these migratory bird species on a seasonal or yearlong basis.

<u>Effects of the Proposed Alternative</u>

There would be no direct effects from issuing new oil and gas leases, leasing does not directly authorize oil and gas exploration, development, production, or any other ground disturbing activities. Indirect effects may occur during the exploration, development, and or production of the minerals within the lease parcels. These effects would be analyzed at the time that these activities are proposed. In addition to the generalized potential effects to fish and wildlife impacts to migratory birds may include temporary individual or population displacement from preferred habitat, decreased clutch survival, increased potential for animal mortality, or behavioral changes and physiological stress that negatively affect fitness. Ground disturbing activities associated with the lease parcels would need to be approved through additional NEPA analysis.

<u>Cumulative Effects</u>

The incremental effects of the proposed administrative action combined with the past, present, and reasonably foreseeable future actions may have an impact on migratory birds. The entire nature of those impacts as to the severity and duration cannot be evaluated in this document, but will be analyzed if or when an APD is submitted to the Elko District. Site specific NEPA documents will analyze those effects in detail, and quantify and qualify the compound effects to migratory birds and the habitat.

<u>Mitigations</u>

Ground disturbing activities during the nesting season (March to July) should be avoided to conserve migratory birds. Surveys for migratory birds should be conducted prior to site development during the nesting season to identify either breeding adult birds or nest sites within the areas to be disturbed. If active nests are present, the proponent would coordinate with the BLM to develop appropriate protection measures for these sites, which could include avoidance, construction constraints and or establishing buffers (Executive Order 13186, Responsibilities of Federal Agencies to Protect Migratory Birds). Best management practices along with specific restrictions would be implemented to minimize negative impacts to migratory birds.

3.2.22 Special Status Species

<u>Existing Conditions</u>

BLM Manual 6840 entitled Special Status Species Management states BLM special status species are those that 1) are listed or proposed for listing under the Endangered Species Act (ESA), and (2) species requiring special management consideration to promote their conservation and reduce the likelihood and need for future listing under the ESA, which are designated as Bureau sensitive by the State Director(s). Additionally, all federal candidate species, proposed species, and delisted species in the 5 years following delisting will be conserved as Bureau sensitive species.

BLM signed a Memorandum of Understanding with the U.S. Geological Survey, U.S. Department of Agriculture Forest Service, Smithsonian Institution, U.S. National Park Service, USFWS, and The Nature Conservancy on November 6, 1998, to conserve springsnail species throughout the Great Basin. Federally threatened, endangered, candidate, and species of concern may occur in a variety of habitat types throughout the district.

Section 7 of the Endangered Species Act (ESA) of 1973, as amended, requires that BLM land managers ensure that any action authorized, funded, or carried out by the BLM is not likely to jeopardize the continued existence of any Federally Designated Threatened or Endangered (T&E) species, and that the action avoids any appreciable reduction in the likelihood of recovery of affected species.

Threatened and Endangered Species
Lahontan cutthroat trout (*Oncorhynchus clarki henshawi*), is listed as a Threatened species under the Endangered Species Act. Lahontan cutthroat trout are native to cold, clear, perennial waters of the Great Basin. In the desert environment of the Great Basin this habitat is rare and extremely important to the survival of the species. These fish often live in small streams that are only seasonally or rarely connected to other, larger bodies of water, even a slight reduction in flows or increases in; turbidity, sediment delivery, or temperature, could have serious consequences to individual populations.

Candidate Threatened and Endangered Species
The Greater Sage-Grouse has recently been determined by the Fish and Wildlife Service (FWS) that the species is "warranted for listing but precluded by species of higher priority" and categorized it as a Candidate species. The BLM is emphasizing conservation measures to promote sustainable Greater Sage-Grouse populations and conservation of its habitat. The BLM is in the process of amending Land Use Plans with language to be applied to public lands with greater sage-grouse.

There is no Preliminary Priority Habitat (PPH) and Preliminary General Habitat (PGH) located within the 24 proposed parcels. There are no proposed parcels with PPH, which are areas that have been identified as having the highest conservation value to maintaining sustainable Greater Sage-Grouse populations which include breeding, nesting, brood-rearing, and winter concentration areas.

BLM Sensitive Species
The *Preble's shrew* is known to inhabit portions of the Elko District. This species primarily occupies streamside sagebrush, rabbitbrush, bitterbrush, bunchgrass and forbs, willow and greasewood meadows, and aspen riparian habitat. They feed primarily on insects and other small invertebrates.

Pygmy rabbits have been documented throughout the Elko District. Pygmy rabbits are usually found in areas of deep, friable soils that are suitable for creating burrows. These sites generally support basin big sagebrush and may be associated with meadows or former meadows. Stands of Wyoming big sagebrush are also utilized. Pygmy rabbits dig their own burrows and are usually found close to their burrow systems. Their primary food source is sagebrush, particularly in the winter. Grasses are more important in the summer.

Numerous *bat species* occur throughout the Elko District. Suitable habitat may include rock crevices on steep cliff faces, springs, canyons, coniferous forests (including juniper), and deciduous forests. Roosting can occur in caves or mine shafts/adits. In general, bats use water between night-time foraging bouts. They utilize the habitat types mentioned above for foraging and feed on a variety of nocturnal insects. Many bat species within the district are migratory; while others, like the Townsend's big-eared bat occupy yearlong or winter roost sites within the area of the proposed action.

Effects of the Proposed Alternative

Initial leasing of oil/gas parcels will not have a direct effect on special status species, but surface disturbing activities of oil/gas exploration and facility construction of lease parcels have a possibility of occurring within the vicinity of resident special status species populations. Oil and gas development could affect species of concern in a variety of indirect ways. Potential impacts are summarized below, but a site-specific analysis of how each species would be affected would be conducted as proposals for development of a lease are received.

Environmental impacts of oil and gas resource development are similar to other activities that affect terrestrial and aquatic species and habitats. While each species would respond differently to various impacts, all species could be affected by activities that alter thermal, physical, or chemical characteristics of aquatic and terrestrial habitats.

Stipulations are in place to prevent or minimize adverse effects to special status species that must be complied with as a term of lease purchase. An inventory for special status species is required on leased parcels in known or potential habitat for threatened, endangered, or candidate species. If BLM determines an action "may affect" a listed threatened or endangered species Section 7 Consultation with the USFWS will be initiated (Elko RMP, ROD).

The application of stipulations to leasing activities are expected to negate displacement of special status plant species, long-term changes to habitat quality and modifications in population distribution and abundance, particularly in species with restricted distribution and specific habitat requirements. In most cases, drilling activities would not be allowed in areas where such activities could have a negative impact on any special status species. The BLM would require modifications or reject any proposed action that is likely to jeopardize the continued existence of a species or result in the destruction or modification of its habitat. As such, it is unlikely that any special status plants would be adversely affected.

Cumulative Effects

The incremental effects of the proposed administrative action combined with the past, present, and reasonably foreseeable future actions may have an impact on special status species. The entire nature of those impacts as to the severity and duration cannot be fully evaluated in this document, but would be analyzed if an APD is submitted to the Elko District. Site specific

NEPA documents would analyze those effects in detail, and quantify and qualify the compound effects.

Mitigation

Inventories for special status species of vegetation and wildlife would be conducted prior to site development. If special status species were located on sites proposed for development, it would be necessary to exclude disturbance, develop mitigation measures, and/or otherwise avoid the species and its habitat both spatially and temporally.

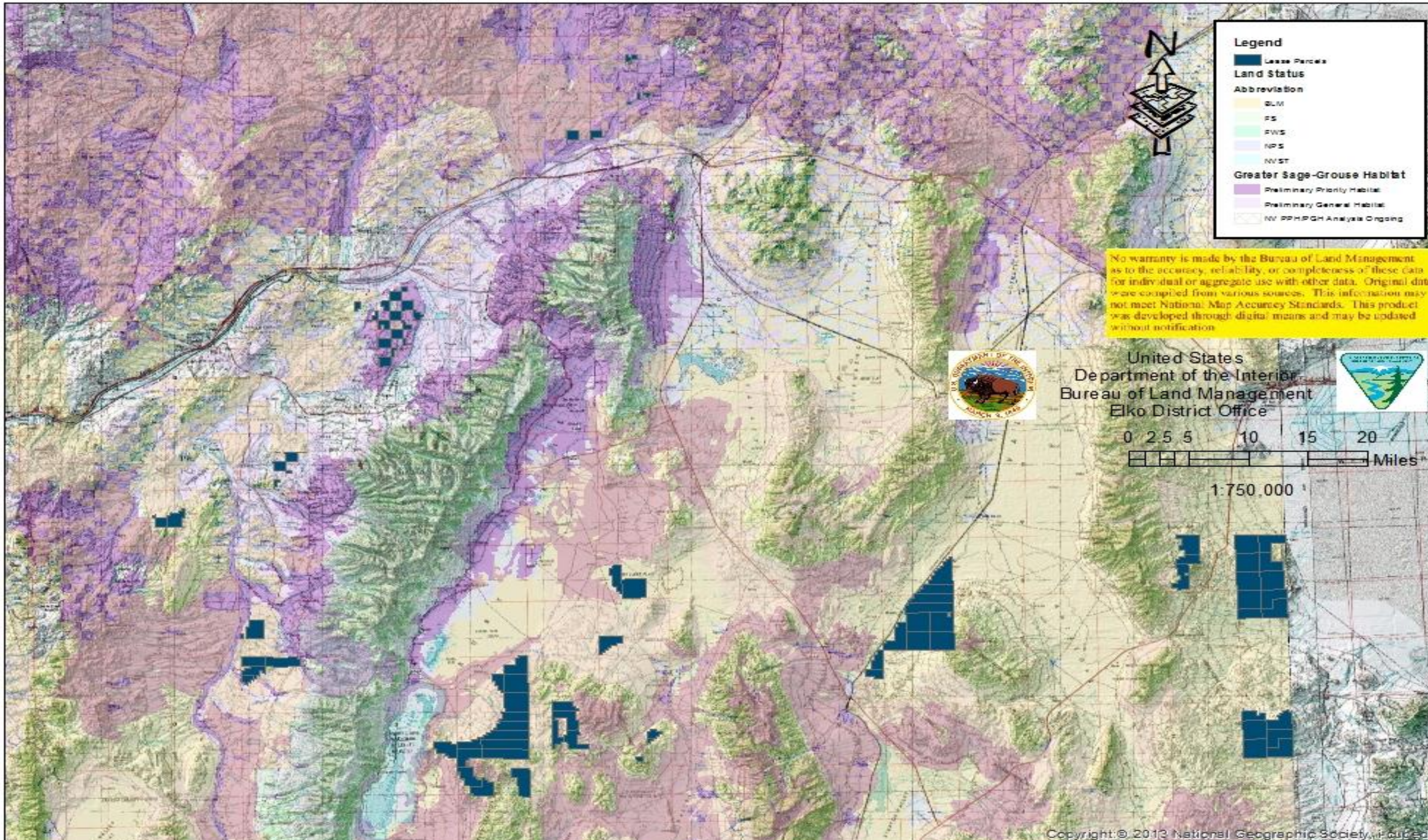
Table 3.2.22b

Nesting Raptor Timing Restrictions and Spatial Buffer Guidelines

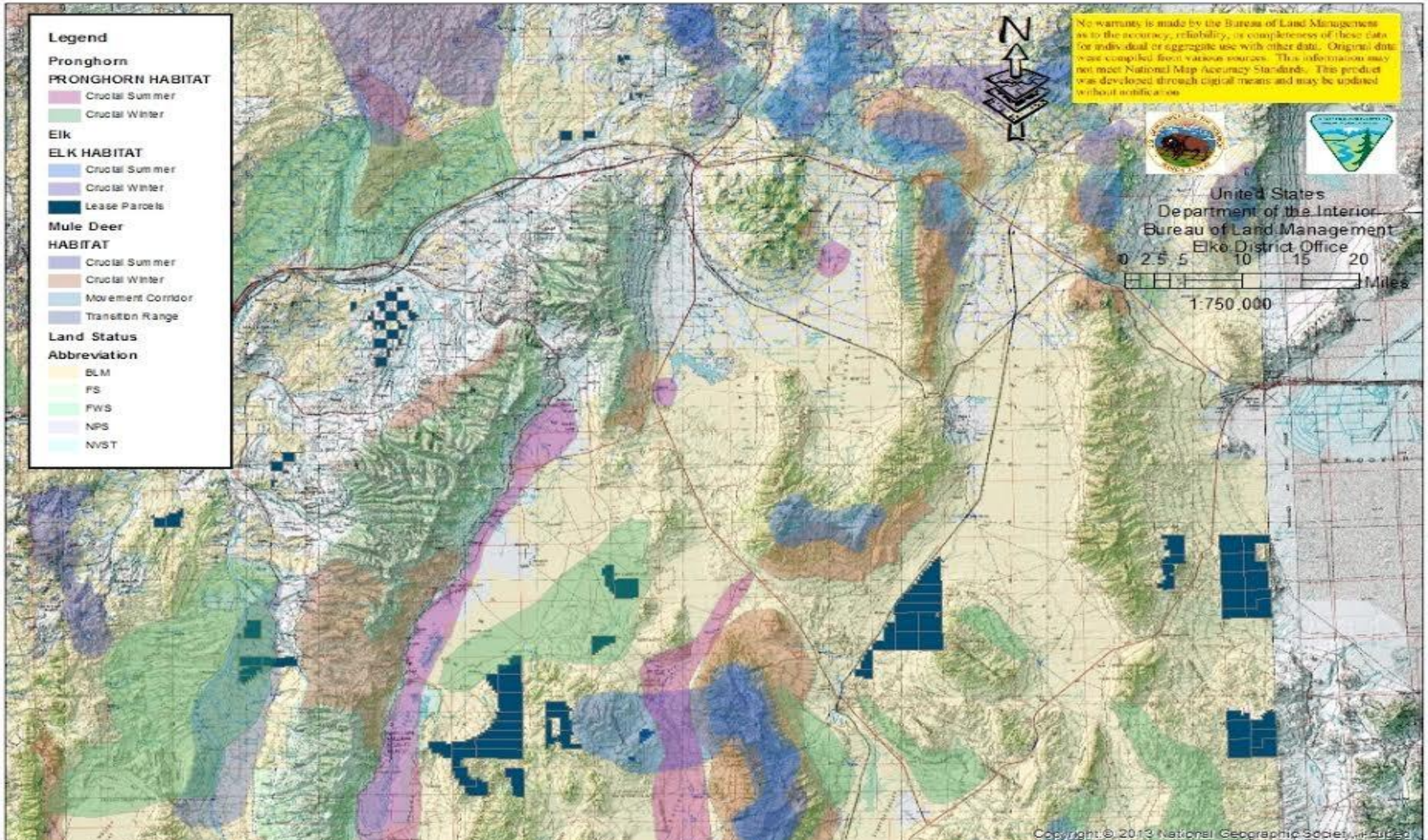
Species	Timing Restriction[1]	Spatial Buffer[2]
Bald Eagle	1/1 - 8/31	1.0 mile
Golden Eagle	1/1 - 8/31	0.5 mile
Turkey Vulture	2/1 - 8/15[3]	0.5 mile[1]
Northern Goshawk	3/1 - 8/15	0.5 mile
Northern Harrier	4/1 - 8/15	0.25 mile
Cooper's Hawk	3/15 - 8/31	0.25 mile
Sharp-shinned Hawk	3/15 - 8/31	0.25 mile
Red-tailed Hawk	3/15 - 8/31	0.33 mile
Swainson's Hawk	3/1 - 8/31	0.25 mile
Ferruginous Hawk	3/1 - 8/1	1.0 mile
American Kestrel	4/1 - 8/15	0.125 mile
Prairie Falcon	3/1 - 8/31[3]	0.5 mile
Peregrine Falcon	2/1 - 8/31	1.0 mile
Barn Owl	2/1 - 9/15	0.125 mile
Long Eared Owl	2/1 - 8/15	0.125 mile
Short Eared Owl	3/1 - 8/1	0.25 mile
Flammulated Owl	4/1 - 9/30	0.25 mile
Western Screech Owl	3/1 - 8/15	0.125 mile
Great Horned Owl	12/1 - 9/30	0.125 mile
Northern Pygmy Owl	4/1 - 8/1	0.25 mile
Burrowing Owl	3/1 - 8/31	0.25 mile
Northern Saw-whet Owl	3/1 - 8/31	0.125 mile

[1] From Utah Field Office Guidelines for Raptor Protection from Human and Land Use Disturbances (USFWS).
[2] From Guidelines for Raptor Conservation in the Western United States (USFWS).
[3] Nevada Raptors: Their Biology and Management (NDOW).

Greater Sage-Grouse Habitat Map



Big Game Crucial Habitat Map



4 – CONSULTATION AND COORDINATION

4.1 SCOPING

In addition to scoping efforts stated in Section 3.2.16., information was sent out on via press release on September 26, 2014. This document was released for public review September 26, 2014. The administrative record for the project is available at the Elko District Office.

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Appendices

Appendix A - List of Offered Parcels

Appendix B - Elko District Office Stipulations for Oil and Gas Leasing

Appendix C - Reasonably Foreseeable Development Scenario for Oil and Gas

Appendix D - Typical Oil and Gas Exploration and Development Activities

Appendix E - List of Acronyms Used

Appendix F- List of deferred parcels

APPENDIX A LIST OF OFFERED PARCELS

```
NV-15-03-001        1885.440 Acres
  T.0260N, R.0520E, 21 MDM, NV
    Sec. 001   LOTS 1-4;
         001   S2N2,S2;
         002   LOTS 1-4;
         002   S2N2,SW,N2SE,SWSE;
         011   ALL;
Eureka County
Elko DO
PENDING PRESALE OFFER NO.092657;



NV-15-03-002        2206.650 Acres
  T.0260N, R.0520E, 21 MDM, NV
    Sec. 003   LOTS 1-4;
         003   S2NE,SWNW,NWSW
         003   S2SW,SE,EXCL ME PATS;
         010   ALL EXCL ME PATS;
         014   NE,N2NW,SENW,S2;
         015   N2NE,SWNE,W2,SE;
Eureka County
Elko DO
PENDING PRESALE OFFER NO.092657;



NV-15-03-003        2160.560 Acres
  T.0260N, R.0520E, 21 MDM, NV
    Sec. 004   LOTS 1-7;
         004   SWNE,S2NW,SW,W2SE;
         009   LOTS 1-4;
         009   W2E2,W2;
         016   LOTS 1-4;
         016   W2E2,W2;
         017   NE,E2SW,SE;
Eureka County
Elko DO
NEAR LEK/4-MI BUFFER;



NV-15-03-004        1280.000 Acres
  T.0260N, R.0520E, 21 MDM, NV
    Sec. 012   ALL;
         013   ALL;
Eureka County
Elko DO
PENDING PRESALE OFFER NO.092657;



NV-15-03-005        551.320 Acres
  T.0270N, R.0520E, 21 MDM, NV
    Sec. 001   LOTS 1-3;
         001   S2NE,SENW,NESW,S2SW,SE;
```

Eureka County
Elko DO
NEAR PGH;

NV-15-03-006 1675.370 Acres

T.0270N, R.0520E, 21 MDM, NV
Sec. 024 ALL;
025 ALL;
026 LOTS 1,2,6,7;
026 S2NE,SESW,NESE,S2SE;
Eureka County
Elko DO
NEAR PGH;

NV-15-03-007 880.000 Acres

T.0270N, R.0520E, 21 MDM, NV
Sec. 028 NE,NENW,N2SE,SESE;
033 NE,S2NW,S2;
Eureka County
Elko DO
NEAR PGH & LEK/4-MI BUFFER;

NV-15-03-008 1270.420 Acres

T.0270N, R.0520E, 21 MDM, NV
Sec. 034 ALL;
035 LOTS 1-4;
035 E2,E2W2;
Eureka County
Elko DO
PENDING PRESALE OFFER NO.092657;
MINING PLAN OF OPERATIONS N-84135;

NV-15-03-009 860.410 Acres

T.0260N, R.0530E, 21 MDM, NV
Sec. 007 LOTS 2,3,5-8;
007 SESW;
008 NE,N2NW,NESE;
018 LOTS 1-8;
018 E2W2;
Elko and Eureka Counties
Elko DO
PENDING PRESALE OFFER NO.092657;
NEAR PGH;
SEC. 8 CONTAINS BLMO 3/4/1959;

NV-15-03-010 1206.840 Acres
T.0280N, R.0530E, 21 MDM, NV
Sec. 030 LOTS 1,2;
030 E2,E2W2;
031 LOTS 2-4;
031 E2,E2W2;
Elko and Eureka Counties
Elko DO
ROW N78612 & ROW N78613;
NEAR PGH & PPH;

NV-15-03-011 880.000 Acres
T.0290N, R.0530E, 21 MDM, NV
Sec. 028 ALL;
033 SW,W2SE;
Elko County
Elko DO
NEAR PPH & LEK/4-MI BUFFER;

NV-15-03-012 1037.910 Acres
T.0320N, R.0530E, 21 MDM, NV
Sec. 010 N2,NESW,N2SE;
012 LOTS 2-4;
012 W2E2,W2;
Elko County
Elko DO
PENDING PRESALE OFFER NO.092661;
NEAR PGH;

NV-15-03-015 1190.090 Acres
T.0260N, R.0640E, 21 MDM, NV
Sec. 001 LOTS 1,2;
001 S2NE,W2SWNW,SENW,N2SW;
001 NESE,SENWSE,S2SE;
012 E2;
013 E2,SENW,E2SW;
Elko County
Elko DO
PENDING PRESALE OFFER NO.092650;
NEAR PPH AND LEK/4-MI BUFFER;
SEC. 1 - IC002 & RR ROW;

NV-15-03-016 2000.690 Acres
T.0260N, R.0650E, 21 MDM, NV
Sec. 003 SWSW;
004 NWSW,S2S2;
005 LOTS 3,4;
005 SWNE,S2NW,S2;
009 ALL;
010 NWNE,S2NE,W2,SE;
Elko County
Elko DO
PENDING PRESALE OFFER NO.092653;
NEAR PPH & LEK/4-MI BUFFER;
SECS. 4 & 9 - MAT SITE CC018205;
SECS. 4 & 9 - ROW CC018253 & ROW N5485;

NV-15-03-017 1917.560 Acres

T.0260N, R.0650E, 21 MDM, NV
Sec. 006 LOTS 1-7;
006 S2NE,SENW,E2SW,SE;
007 LOTS 1-4;
007 E2,E2W2;
008 ALL;
Elko County
Elko DO
PENDING PRESALE OFFER NO.092653

NV-15-03-018 480.000 Acres

T.0260N, R.0650E, 21 MDM, NV
Sec. 011 SWNW,SW,W2SE,SESE;
012 S2S2;
Elko County
Elko DO
PENDING PRESALE OFFER NO.092654;
NEAR PPH & LEK/4-MI BUFFER;

NV-15-03-019 1000.000 Acres

T.0260N, R.0650E, 21 MDM, NV
Sec. 014 N2N2,SWNW;
015 N2,N2SW,SWSW,NWSE;
016 S2;
Elko County
Elko DO
PENDING PRESALE OFFER NO.092653;
NEAR PPH & LEK/4-MI BUFFER;
SEC. 15 - ROW CC018253;

NV-15-03-020 1278.560 Acres

T.0260N, R.0650E, 21 MDM, NV
Sec. 017 ALL;
018 LOTS 1-4;
018 E2,E2W2;
Elko County
Elko DO
PENDING PRESALE OFFER NO.092650;

NV-15-03-021 40.000 Acres

T.0270N, R.0650E, 21 MDM, NV
Sec. 029 SWSW;
Elko County
Elko DO
PENDING PRESALE OFFER NO.092652
NEAR PPH;
SEC. 29 - ROW CC018253;

NV-15-03-022 881.060 Acres

T.0270N, R.0650E, 21 MDM, NV
Sec. 030 LOTS 3,4;
030 E2SW,S2SE;
031 LOTS 1-4;
031 E2,E2W2;
Elko County
Elko DO
PENDING PRESALE OFFER NO.092650;
NEAR PPH;
SECS. 30 & 31 -ROW N5485 & ROW CC018253;

NV-15-03-023 80.000 Acres

T.0270N, R.0650E, 21 MDM, NV
Sec. 032 NWNW,SWSW;
Elko County
Elko DO
PENDING PRESALE OFFER NO.092653;
NEAR PPH;
SECS. 32 & 33 - ROW CC018253;
SECS. 32 & 33 - ROW N5485;

NV-15-03-024 599.590 Acres

T.0260N, R.0660E, 21 MDM, NV
Sec. 007 LOTS 4;
007 SESW,S2SE;
008 SENE,NESW,S2SW,SE;
017 N2NW;
018 NENE;
Elko County
Elko DO
PENDING PRESALE OFFER NO.092654;
NEAR PPH & LEK/4-MI BUFFER;

NV-15-03-025 200.000 Acres

T.0260N, R.0660E, 21 MDM, NV
Sec. 009 SWSW;
017 NE;
Elko County
Elko DO
PENDING PRESALE OFFER NO.092656;
NEAR PPH & LEK/4-MI BUFFER;

NV-15-03-026 240.000 Acres

T.0270N, R.0660E, 21 MDM, NV
Sec. 003 N2SW,SESW,SWSE;
010 NWNE,NENW;
Elko County
Elko DO
PENDING PRESALE OFFER NO.092655;
NEAR PGH & LEK/4-MI BUFFER;

Number of Parcels - 26

Total Acreage - 27,522.47

Total number of Parcels with Presale Offers - 18

Parcel Number of Parcels with Presale Offers - 001, 002, 004, 008, 009, 012, 015, 016, 017, 018, 019, 020, 021, 022, 023, 024, 025, 026

Total Acreage With Presale Offers - 18,448.38

Any portion of the listed lands may be deleted upon determination that such lands are not available for leasing.

Appendix B Elko District Office Stipulations for Oil and Gas Leasing

LEASE STIPULATION OG-010-05-01: **Threatened, Endangered and Sensitive Species**

The lease area may now or hereafter contain plants, animals, or their habitats determined to be threatened, endangered, or other special status species. BLM may recommend modifications to exploration and development proposals to further its conservation and management objective to avoid BLM-approved activity that will contribute to a need to list such a species or their habitat. BLM may require modifications to or disapprove proposed activity that is likely to result in jeopardy to the continued existence of a proposed or listed threatened or endangered species or result in the destruction or adverse modification of a designated or proposed critical habitat. BLM will not approve any ground-disturbing activity that may affect any such species or critical habitat until it complete its obligations under applicable requirements of the Endangered Species Act as amended, 16 USC&1531 et seq., including completion of any required procedure for conference or consultation.

Authority: BLM Washington Office Instruction Memorandum 2002-174; Endangered Species Act

LEASE STIPULATION OG-010-05-02: **Raptor Nesting Sites**

This lease may contain lands with active raptor nesting sites. These lands are subject to seasonal protection from disturbance to avoid displacement and mortality of raptor young. Restrictions apply up to a 0.5 mile radius around the active nesting sites of the following species during the period described. The entire Elko District may provide suitable nesting for one or more of the species listed below.

A. Golden Eagles and Great Horned Owls during the period 1/1-6/30, inclusive.
B. Long-eared Owls during the period 2/1-5/15, inclusive.
C. Prairie Falcons during the period 3/1-6/30, inclusive.
D. Ferruginous Hawks, Northern Harriers and Barn Owls during the period 3/1-7/31, inclusive.
E. Goshawk and Sharp-shinned Hawks during the period 3/15-7/15, inclusive.
F. Cooper's Hawks, Kestrels, and Burrowing Owls during the period 4/1-6/30, inclusive.
G. Red-tailed and Swainson's Hawk during the period 4/1-7/15, inclusive.
H. Short-eared Owls during the period 2/1-6/15, inclusive.

Authority/Supporting Documentation: Wells RMP ROD (p. 25); Elko RMP ROD (p. 25), Birds of the Great Basin, 1985; State Director Decision: Horse Canyon Decision, 2005;

LEASE STIPULATION OG-010-05-03: **<u>Cultural Resources</u>**

This lease may be found to contain historic properties and/or resources protected under the National Historic Preservation Act (NHPA), American Indian Religious Freedom Act, Native American Graves Protection and Repatriation Act, E.O. 13007, or other statutes and executive orders. The BLM will not approve any ground disturbing activities that may affect any such properties or resources until it completes its obligations under applicable requirements of the NHPA and other authorities. The BLM may require modification to exploration or development proposals to protect such properties, or disapprove any activity that is likely to result in adverse effects that cannot be successfully avoided, minimized or mitigated.

LEASE STIPULATION OG-010-05-04: **<u>Mule Deer Crucial Winter Range</u>**

This lease contains lands which have been identified as mule deer crucial winter range (BLM EA 2005/030, September 2005). These lands are subject to seasonal protection from disturbance to avoid displacement and mortality to animals during the winter. Seasonal restrictions from disturbance in mule deer crucial winter ranges apply during the period 11/15-3/16, inclusive.

Authority/Supporting Documentation: Wells RMP ROD (p. 10); Elko RMP ROD (pg. 3); Field Guide to Mammals (1976)

LEASE STIPULATION OG-010-05-05: **<u>Pronghorn Antelope Crucial Winter Range</u>**

This lease contains lands which have been identified as pronghorn antelope crucial winter range. These lands are subject to seasonal protection from disturbance to avoid displacement and mortality to animals during the winter. Seasonal restrictions from disturbance in pronghorn antelope crucial winter ranges apply during the period 11/15-3/16, inclusive.

Authority/Supporting Documentation: Wells RMP ROD (p. 25); Elko RMP ROD (p. 3); Field Guide to Mammals (1976)

LEASE STIPULATION OG-010-05-06: **<u>Pronghorn Antelope Kidding Areas</u>**

This lease contains lands which have been identified as pronghorn antelope kidding areas. These lands are subject to seasonal protection from disturbance to avoid displacement and mortality to animals during kidding season. Seasonal restrictions from disturbance in pronghorn antelope kidding areas apply during the period 5/1-6/30, inclusive.

Authority/Supporting Documentation: Elko RMP (pg. 2-6), ROD, Field Guide to Mammals (1976)

LEASE STIPULATION OG-010-05-07: **<u>Sage Grouse Strutting Ground (Leks)</u>**

This lease contains lands which have been identified as sage grouse strutting grounds (leks) that are subject to seasonal protection from disturbance. No Surface Occupancy is permitted within 0.5 miles, or other, lesser, appropriate distance based on site-specific conditions, of sage grouse leks.

Authority/Supporting Documentation: Wells RMP ROD (p. 10); Elko RMP ROD (p. 35); Management Guidelines for Sage Grouse and Sagebrush Ecosystems in Nevada, 2000; State Director Decision: Horse Canyon Decision, 2005

LEASE STIPULATION OG-010-05-08: **Sage Grouse Brood Rearing Areas**

This lease contains lands which have been identified as sage grouse brood rearing areas that are subject to seasonal protection from disturbance. Seasonal restrictions from disturbance n sage grouse brood rearing areas apply within 0 .5 miles or other appropriate distance based on site-specific conditions from 5/15 to 8/15, inclusive. This restriction does not apply to operating facilities.

Authority/Supporting Documentation: Wells RMP ROD (p. 25); Elko RMP ROD (p. 3 and 36) Management Guidelines for Sage Grouse and Sagebrush Ecosystems in Nevada, 2000, State Director Decision: Horse Canyon Decision, 2005

LEASE STIPULATION OG-010-05-09: Sage Grouse Crucial Winter Habitat

This lease contains lands which have been identified as sage grouse crucial winter habitat that are subject to seasonal protection from disturbance. Seasonal restrictions from disturbance in sage grouse crucial winter habitat apply during the period November 1 to March 15. This stipulation does not apply to operating facilities.

Authority/Supporting Documentation: Wells RMP ROD (p. 22 and 25); Elko RMP ROD; Management Guidelines for Sage Grouse and Sagebrush Ecosystems in Nevada, 2000;

LEASE STIPULATION OG-010-05-10: I-80 "Low Visibility Corridor"

This parcel includes lands within the I-80 Visual Corridor. Visual impacts are to be minimized within 1.5 miles on either side of Interstate 80. Within this three-mile wide Low Visibility Corridor, the objective is for management actions not to be evident in the characteristic landscape. Management objectives for Class II VRM areas will be used as a guideline when evaluating projects within the Low Visibility Corridor. The Class II VRM objective is to retain the existing character of the landscape. The level of change to the characteristic landscape should be low. Management activities may be seen but should not attract the attention of the casual observer. Any changes must repeat the basic elements of form, line, color, and texture found in the predominant natural features of the characteristic landscape.

Authority: Wells RMP ROD (p. 3); Elko RMP ROD (p. 1); Elko District Office IM NV-2004-013)

LEASE STIPULATION OG-010-05-11: Special Recreation Management Areas

This parcel includes lands within a Special Recreation Management Area (South Fork Canyon SRMA, Wild Horse SRMA, Wilson Reservoir SRMA, South Fork Owyhee River SRMA, Zunino/Jiggs SRMA, or proposed Salmon Falls Creek SRMA) that are within ½ mile of the high water line. No surface occupancy is allowed within ½ mile of the high water line.

Authority: Wells RMP ROD (p. 25); Elko RMP ROD (p. 3)

LEASE STIPULATION OG-010-05-12: Tabor Creek Campground

This parcel includes lands within the Tabor Creek Campground area. No surface occupancy is allowed on lands within the designated boundaries of Tabor Creek Campground: T41N R61E, S1/2 Section 16, S1/2SE1/4 Section 16, E1/2 Section 20, Section 21, NW1/4 Section 28, Section 29.

Authority: Wells RMP ROD (p. 25)

LEASE STIPULATION OG-010-05-13: Congressionally Designated Historic Trails

The following lease stipulation is to advise the permittees or lease operators of the presence of a congressionally designated National Trail and the BLM's responsibility not to permit uses along trails that would substantially interfere with the nature and purposes of the trail, and also to make efforts to avoid activities incompatible with the purposes for which trails were established, to the extent practicable, while respecting valid existing rights. Where a proposed action is found to be inconsistent with the purpose for which the National Trail was designated, the BLM shall consider rejecting applications for proposed projects. (BLM Manual 6280 5.3 A-B). There is no surface occupancy within one mile of the center of Congressionally designated historic trails unless approved by the authorizing officer. The lease may be limited or modified to protect the historical and scenic values of the trails.
Authority: Nevada BLM Manual 6280 Section 5.3 A-B.

LEASE STIPULATION NSO-010-64: No Surface Occupancy

This stipulation restricts surface occupancy in defined portions of the leased parcels.

Appendix C Reasonably Foreseeable Development Scenario for Oil and Gas Resources

The following reasonably foreseeable development scenario (RFDS) for the Elko District is based in part on the development history observed within Railroad Valley, as well as the observed development history in the Elko District's Pine Valley. Railroad Valley is located within the same geologic province as the Elko District and has been subjected to similar depositional, tectonic and thermal history as the southern portion of the Elko Resource Area. Railroad Valley is the site of the first producing oil fields within Nevada. We expect any future development within the Elko District will be similar to Railroad Valley. This RFDS, based on a fifteen year projection, was created as an assumption for analysis in order to estimate environmental impacts including direct, indirect, and cumulative impacts. This scenario notes that most exploration and development is expected in the Pine Valley area as that is the area in which discoveries have occurred in the past. For geologic reasons, the further east and north from Pine Valley, the less likely the possibility of discovering economic quantities of oil and gas.

ASSUMPTIONS FOR GEOPHYSICAL EXPLORATION:
The assumptions for geophysical exploration used for the preparation of this reasonable foreseeable development scenario are based on the actual geophysical exploration activities in Railroad Valley between 1954 and 1989, and in the Elko Resource Area between Oct. 1, 1979 and Jan. 29, 1991. These dates represent the most active period of exploration in the Elko District. These assumptions are also based on District wide development of oil and gas resources as opposed to the 125,220 acres in the 73 proposed parcels for this sale. In recent years, exploration has been nearly curtailed due to cyclical commodity prices, environmental regulation uncertainty, and a lack of exploration success. The last geophysical survey for oil and gas was in 2000. Table 4-1displays the data available for the Elko Resource Area from Fiscal Year 1980 to 1990.

TABLE 4-1 GEOPHYSICAL SURVEYS IN THE ELKO RESOURCE AREA

FISCAL YEAR	MILES OF SURVEY
1980	180.5
1981	252.0
1982	281.0
1983	62.0
1984	73.0
1985	64.0
1986	111.0
1987	24.0
1988	49.0
1989	108.0
1990	14.0

TOTAL 1218.5 (AVERAGE 110.7)

Within the Elko Resource Area, the subsurface geology is not always accurately represented by the surface outcrop and it is for this reason exploration geologists use geophysical methods to help locate oil and gas traps. Geophysical exploration includes a variety of instruments and techniques but all geophysical exploration is based on the measurement of one of three physical properties: A) Gravitation field, B) Magnetic field, and C) Seismic reflection characteristics.

Of those described, only seismic reflection surveys result in detectable surface disturbance. Initial geophysical surveys may cross tens of miles in what will appear to be a random pattern. These surveys attempt to piece together the local subsurface geology or confirm geologic inference. If real or perceived geologic structures of interest are located, surveys of specific areas will be intense and may be repeated frequently.

There will be an estimated average of 110 miles of line surveyed per year over the life of this project. This will vary from as many as 300 to as few as 10 miles of line in any one year. Each year up to 182 acres will be disturbed from seismic surveys. Usually, such disturbance includes crushing and destruction of brush, but survival of the understory of grasses. In steep or wet areas, the grasses may also be destroyed. In either case, reclamation will be completed on these lines within one year.

ASSUMPTIONS FOR EXPLORATION DRILLING. The exploration drilling assumptions that are used in this reasonable foreseeable development scenario were made after review of the oil and gas drilling activities in Railroad Valley between 1954 and 1989, and in the Elko Resource Area between October 1, 1979 and January 29, 1991. These dates were the most active exploration period. For instance, an average of 3 wells per year were drilled in the Elko District from 1980-1991 while the Elko District has averaged about two exploration wells per year for the last ten years (Schmidt, per comm., 2013). This pattern is consistent throughout Nevada. The Nevada Bureau of Mines and Geology Mineral Industry Report for 2002 (NBMG, 2003), shows exploration well drilling throughout Nevada to have decreased from a high of 36 wells in 1984 to a total of 16 in the four year period from 1999-2002. Table 4-2 displays the Exploration Drilling data available for the Elko Resource Area from Fiscal Year 1980 to 1991.

TABLE 4-2 SURFACE DISTURBANCE (Acres) CAUSED BY OIL AND GAS EXPLORATION ACTIVITY IN THE ELKO District (public and private)

Fiscal Year	No. of Holes	Pipelines (acres)	Roads (acres)	Drill Pads (acres)
1980	2	0	4.8	3.4
1981	3	0	19.6	6.3
1982	5	0	26.5	9.7
1983	3	0.24	4.5	4.0
1984	3	0	21.8	7.6
1985	7	0	15.6	18.7
1986	1	0	2.4	3.7
1987	4	0	2.6	6.0
1988	1	0	89.7	7.0
1989	3	0	4.3	6.9
1990	4	0	6.2	6.0
1991	1	0	2.2	2.1
Total	37	0.24	200	81.3
Ave./Yr.	3.1	0.002	16.7	6.8

AVERAGE DISTUIRBANCE = 23.5ac./year
AVERAGE Road WIDTH = 31 ft.
AVERAGE Road LENGTH = 7490 ft.

There have been over 70 recorded exploration wells for oil and gas within the Elko District. The search for oil and gas has been more or less continuous since the 1950's. Currently, there are five producing oil and gas wells in four different fields in the District (public and private lands).

For the purposes of this analysis, the following assumptions are made for exploration drilling operations:

A) An estimated 80 wells will be drilled during the fifteen year life of this projection.
B) The Elko District is considered to be a high risk (wildcat) exploration region.
C) Approximately 10% of the wells drilled will be producers.
D) An estimated 72 wells will be reclaimed during the life of the plan.
E) Drilling time will average sixty to ninety days per well.
F) The average pad size including the reserve pit is 2.0 acres.
G) The average access road is 31 feet wide by 1.4 miles long and will have one foot of gravel on the road surface (6740 bank cubic yards).
H) No more than three drill rigs will be operating in the same area at the same time.
I) Well stimulation (hydraulic fracturing) will be done on 95% of the wells.

DISTURBANCE DURING THE LIFE OF THE PROJECTION:
Using the assumptions for exploration drilling combined with the drilling and production history in Railroad Valley, it is projected that the surface disturbance from exploratory and production well pads combined with the construction of service roads and main access roads will result in 481 acres of disturbance. The construction of local pipelines to connect the wells to storage tank facilities will result in 10.6 acres of disturbance. The scenario for the greatest development impact, including a branch and trunk pipeline network to transport oil and gas from the wells to the Carlin oil terminal will result in 236 additional acres of surface disturbance. Gravel sources for construction of roads, pipelines and drill pads will result in 129.6 acres of disturbance. Total surface disturbance during the life of the projection will be 858 acres.

Recontouring and revegetation of the dry well pads, service roads and associated gravel sources will result in 676.8 acres being reclaimed for other uses. Surface disturbance from oil and gas activities would result in a net loss of 181.2 acres of vegetation over the remaining life of the plan. Drilling trends may fluctuate greatly, with no drilling occurring in as many as five consecutive years. On the other hand, in any ten year period, nearly half of the wells which are projected to be drilled in the area will be drilled.

ASSUMPTIONS FOR PRODUCTION:
The average geographic area for a producing oil and gas field in the United States is about 640 acres. Field sizes tend to be smaller in Nevada. There will be 40-acre spacing for oil wells less than 5000' in depth and 160-acre spacing for oil wells more than 5000 feet in depth. Normally, drilling depths are greater than 5000 feet; therefore, most of the oil well spacing can be expected to be 160 acres. No more than three drilling or workover rigs will be in operation in a field at the same time.

Limited reclamation work would occur until the producing field was abandoned. No producing fields will be abandoned during the life of the plan.

Well Stimulation/Hydraulic Fracturing

Well Stimulation may be used to enhance oil recovery. Several methods of well stimulation could be used. HF is one of these methods that is reasonably foreseeable for the leases on this sale. HF is the process of applying high pressure to a subsurface formation via a wellbore, to the extent that the pressure enhancesinduces fractures in the rock. Typically the enhanced fractures will be propped open with a granular “proppant” to improve fluid connection between the well and formation. The process was developed experimentally in 1947 and has been used routinely since 1950. The Society of Petroleum Engineers (SPE) estimates that over one million HF procedures have been pumped in the United States and tens of thousands of horizontal wells have been drilled and hydraulically fractured. It can greatly increase the yield of a well, and development of HF methods and the drilling technology in which it is applied (in particular, long wells drilled horizontally within the targets) have enabled production of oil and gas from tight formations formerly not economically feasible.

<u>Hydraulic Fracturing Technology</u>
A general description of the hydraulic fracturing technology follows:

- All exploratory, testing, and production wells have multiple layers of casing that are sealed with cement
  between the wellbore and the formation. Well integrity is tested throughout the process.
- Drilling and HF fluids can be contained in a pitless system (aboveground tanks) or a lined pit. Cuttings could be contained in roll-off boxes for hauling to disposal or surface casing interval cuttings could be spread over the site during reclamation.
- HF fluids are recovered to a large degree in “flowback” or produced water when the well is tested or produced.
- All recovered fluids are generally handled by one of four methods.
  - Underground injection
  - Captured in steel tanks and disposed of in an approved disposal facility.
  - Treatment and reuse
  - Surface disposal pits
- Drill cuttings could be land farmed and buried on site 3 feet below root zones. Any cuttings that do not fit this waste profile will be disposed of at an approved disposal facility.

As many as four producing fields may be discovered during the life of the plan. These fields are hypothesized to be equivalent in size and surface disturbance to the Kate Springs and Bacon Flat Oil Fields. Of the four projected producing fields, two would be the equivalent to the Kate Springs Field and two would be the equivalent to the Bacon Flat Field. The fields would be as close as one mile and as far as 20 miles from each other. The cost factors involved would usually limit drilling to depths of 6000 feet, although some operators would speculate that larger reservoirs would be encountered at greater depths (10,000 to 15,000 feet). Production rates of each field would range from negligible amounts (10 Barrels of Oil per Day (BOPD) to extremely prolific (6300 BOPD), and the production life of a field would last for 18 months to 35 years.

Assumptions for the Kate Springs Oil Field Equivalent:
For the purposes of analysis, it is assumed that during the life of the plan there will be two new small oil fields discovered within the Elko Resource Area that are equivalent in size to the Kate Springs Oil Field. For each of these fields the following assumptions are made:
A) Twenty wells will be drilled. There will be three producing wells, three injection wells and fourteen plugged and abandoned wells in the field.

B) Tank batteries will be placed on existing drill pads and no additional surface disturbance will be required.
C) The field will be six miles from a major pre-existing road. This field will require a major access road six miles long and 40 feet wide with three feet of gravel.
D) Production pads will be 200 x 250 feet with two and one-half feet of gravel.
E) Two miles of pipeline will be required. The disturbance will be 15 feet in width.
F) 28 miles of 31 -foot-wide service roads will be required with two feet of gravel.
G) Gravel will be obtained locally. Gravel pits are assumed to average 12 feet in depth.

At each Kate Springs Equivalent field, there will be a total of 176.7 acres of new surface disturbance resulting from the construction of service roads, main access roads, drill pads, local pipelines and gravel pits. There will be 125 acres of surface disturbance resulting from the construction of service roads and drill pads. The construction of a new main access road will cause an additional 29 acres of new surface disturbance, and the development of a local pipeline network to connect each producing well to the storage tank battery will result in 3.6 acres of new surface disturbance at each field. The development of gravel pits for use in road and pipeline construction will cause 19.2 acres of new surface disturbance. A component breakdown of surface disturbance for the Kate Springs Model is listed on Table 4-3.

Assumptions for the Bacon Flat Oil Field Equivalent

For the purposes of analysis, it is assumed that during the life of the plan there will be two new very small oil fields discovered within the district, that are equivalent in size to the Bacon Flat Oil Field. The following assumptions result:
A) Ten wells will be drilled. There will be 1 producing well, 1 injection well and 8 plugged and abandoned wells in the field.
B) The tank battery will be placed on existing drill pads. Thus, no additional surface disturbance will be required.
C) The field will be three miles from a major existing road requiring construction of a major access road three miles long and 40 feet wide with three feet of gravel.
D) Production pads will be 200 x 250 feet and will require two and one-half feet of gravel.
E) One mile of pipeline will be required. Surface disturbance is estimated to be 15 feet in width along the pipeline.
F) There will be fourteen miles of access roads 31 feet wide with two feet of gravel.
G) Gravel will be obtained locally. Gravel pits are assumed to average 12 feet deep.

At each Bacon Flat Equivalent field, there will be a total of 103.3 acres of new surface disturbance resulting from the construction of service roads, main access roads, drill pads, local pipelines and gravel pits distributed as follows: 72 acres from construction of service roads and drill pads,. 14.5 acres from construction of a main access road, 1.8 acres for development of a local pipeline network to connect each producing well to the storage tank battery, and 15 acres or gravel pits for use in road and pipeline construction. A component breakdown of disturbance for the Bacon Flat Oil Filed Equivalent is listed on Table 4-4.

Assumptions for Pipelines

With the production of oil and gas there is the possibility of a pipeline being built between the oil fields and the Carlin Oil Terminal. The pipeline will be constructed in a cherry stem pattern with the main trunk of the pipeline running along Pine Valley .The main trunk of the pipeline will most likely be approximately 35 miles long. Approximately 30 miles of branch lines will connect the widely spaced producing wells to the trunk line. The construction of the trunk and branch pipeline would disturb 236 acres plus 62 additional acres of disturbance at the gravel source.

Assumptions for Oil Fields

Table 4-3 lists the number of wells that are projected to be drilled in the life of the plan. Two new small fields equivalent in size to the Kate Springs Field will be discovered during the life of the plan and each will include three producing wells. Two very small fields equivalent to the Bacon Flat Field will also be discovered and each of these will include one producing well. It is projected that for the Elko Resource Area during the life of the plan there will be an additional 8 producing wells discovered and 52 dry exploration holes (Table 4-4).

TABLE 4-3 PROJECTED OIL FIELDS

TYPE	PRODUCING WELLS	EXPLORATION WELLS
Two New Small Fields (Kate Springs Type)	6 wells	34 wells
Two Very Small Fields (Bacon Flat Type)	2 wells	18 wells
TOTAL	8 wells	52 wells

The number of exploration wells may decrease if oil is discovered. In Railroad Valley, exploration dropped significantly to approximately two wildcat wells per year, after oil was found. For our scenario, exploration will maintain its current pace.

SUMMARY:

Over the fifteen year projection, Geophysical Exploration will disturb 110 miles (182 acres), all of which will be reclaimed. Exploration drilling will result in 80 wildcat wells and access roads with a total of 600 acres of disturbance, 563 of which will be reclaimed. The discovery of the two projected small oil fields (Kate Springs equivalents) will result in 353.4 acres of surface disturbance. An additional 206.6 acres of disturbance will result from the discovery of the two very small oil fields (Bacon Flat equivalents). The construction of the cherry stem pipeline network in Pine Valley and the development of the associated gravel sources will result in 298 acres of additional surface disturbance.

There will be a total surface disturbance of 1360 acres through the remaining life of the plan. Through reclamation efforts during the life of the plan, a total of 744 acres will be reclaimed. This reclamation includes recontouring and revegetation of unsuccessful exploration well pads, the associated service roads, the underground pipelines and gravel sources. No reclamation is expected on the four new producing oil fields during the life of the plan. Surface disturbance from oil and gas activities will result in a net loss of 616 acres of vegetation during the fifteen year projection. Eventually all the acreage will be reclaimed and revegetated. The total surface disturbance associated with the RFDS for oil and gas exploration and development activities is summarized in table 4-5.

TABLE 4-4 PROJECTED SURFACE DISTURBANCE CAUSED BY OIL AND GAS ACTIVITIES DURING THE LIFE OF PROJECTION

Geophysical	Acres	Reclaimed acres
Miles 110		
acres/mi 1.65		
Total acres	181.5	181.5 reclaimed
Exploration Drilling		
Holes 80		
acres/hole 2	160	
Roads 80		
acres/road 5.3	424	
gravel pits 80		
acres/pit 0.2	16	
Total acres	600	37.5 reclaimed
reclaimed acres	562.5	
Production		
Kate Springs Equivalent		
Total acres disturbed	176.7	
Bacon Flat Equivalent		
Total acres disturbed	103.3	
Pipeline to Oil Terminal		
Miles 65	65	
acre/mile 3.63	235.95	235.95ac reclaimed
Gravel pits 62		
acres/pit 1	62	62ac reclaimed
Total	297.95	
TOTAL	1359.45	
Total Reclaimed	744	
Unreclaimed	615.45	

APPENDIX D TYPICAL OIL AND GAS EXPLORATION AND DEVELOPMENT ACTIVITIES

INTRODUCTION

Typical oil and gas exploration and development operations occur in four phases, each of which in a predictable pattern that is contingent on the success or failure of the previous phase. The phases include: Exploration, Development, Production, and Abandonment. Leases are sometimes purchased after Preliminary (geophysical) Exploration but are most often obtained prior to the exploration phase.

EXPLORATION

Exploration includes all activities from the decision to explore for oil and gas resources to the discovery of economically viable oil and gas deposits. As easy-to-find oil and gas deposits have been discovered, increasingly complex and expensive technology is necessary to find those deposits which remain.

PRELIMINARY EXPLORATION

Oil and gas exploration is conducted in unexplored areas and geologic rock formations where commercial quantities of these resources are thought or known to be located. Areas where commercial quantities of petroleum are thought to occur are classified as frontier or rank wildcat areas. In recent years with declining known oil and gas reserves, along with increasing price and an unstable world market, it has now become profitable to explore for oil and gas in less promising geologic provinces and in areas where climate, terrain, and depth of deposits has previously discouraged exploration efforts. Each year, new exploration and drilling technology along with improved transportation facilities have enhanced exploration efforts and improved prospects for locating, extracting and marketing oil and gas resources.

SURFACE EXPLORATION

Oil and gas can accumulate in geologic traps which include anticlines, faults, etc., and the surface exposure of these features would lead to the discovery of the trap. In the past, it was often possible to predict where oil and gas had accumulated by a thorough study of the surface exposure of the bedrock geology. Today, most of the oil and gas traps that could be found using simple surface exploration methods have already been found and exploited. There still remains a few examples of this type of trap and therefore these surface exploration techniques are still in use. These exploration methods may include preparation of geologic maps using field studies, aerial photos, and satellite imagery. Low level aircraft may also be used to gather additional data during reconnaissance flights over a target area. This would be followed by one or more geologists conducting field studies where the geologists would sample outcrops in the area and map the surface geology. This type of exploration is performed with little or no surface damage using four wheel drive vehicles, motorcycles, all-terrain vehicles, or on foot.

GEOPHYSICAL EXPLORATION

As stated previously, most of the oil and gas traps that could be found using simple surface exploration techniques have already been found and exploited. Subsurface geology is not always accurately represented by the surface outcrop and in these cases the exploration geologist would turn to geophysical methods to help locate oil and gas traps. Geophysical exploration can be done using a variety of instruments and processes but, all geophysical exploration is based on the measurement of one of the three subsurface characteristics which are: 1) Gravitational field, 2) magnetic field, 3) seismic reflection characteristics.

Gravitational and Magnetic
Gravitational and magnetic surveys involve the use of portable units which are easily transported using light ground vehicles or by light aircraft. Off-road vehicle travel is common in these two types of surveys and on some surveys there is minor surface disturbance when small hand dug holes are used for instrument placement along survey lines.

Surface Seismic Surveys
Reflection seismologic surveys are frequently employed by the exploration geologist because these surveys can provide the largest amount of subsurface data. This type of survey involves the collection of subsurface geological information by recording the impulses from an artificially generated shock wave. On land, this would begin with the creation of a shock wave and the recording, as a function of time, the reflected seismic energy as it arrives at the vibration detectors, or geophones. The geophones are one-half to five pound seismometers which are placed on the ground at set intervals and are connected to a recorder truck that receives and records the reflected seismic energy.

The vibration detectors and shock wave generator would be located along lines on a one or two mile grid. Surveys may be laid out in excess of 40 miles in a series of grid patterns or in a single line. Seismic operations are conducted on existing roads where possible but, the clearing of vegetation and rocks may be required to improve access for seismic source and recording trucks. Completely clearing a seismic line of vegetation is unusual and most lines are not bladed except at drainage crossings. In some rough or sandy areas it may be necessary to use a bulldozer to pull the seismic trucks through the difficult spots.

In remote areas where there is little known subsurface data, a series of short seismic lines may be required to determine the characteristics of the subsurface formation. After this, seismic lines would be aligned to make seismic interpretations more accurate. Although alignment may be fairly critical, spacing of the lines can often be changed up to a quarter mile on a one mile grid before the results will affect the investigation program.

Seismic methods are usually classified by the various methods of generating the shock wave. These methods include: 1) Thumper, 2) Vibrator, 3) Spark Ignition, 4) Surface Explosive, 5) Subsurface Explosive.

The thumper method involves dropping a three ton steel slab to the ground many times in succession along a predetermined line.

The vibrator method is widely used and is replacing the explosive methods in areas where vehicle access is not difficult. An operation of this type would use three or four large vibrator trucks, four or five support vehicles, and a crew of ten to fifteen people. The four foot square vibrator pads are lowered to the ground and the vibrators on all trucks are then operated electronically from the recording truck. After the reflections are recorded the trucks move forward a short distance and the process is repeated.

The spark ignition method can be used with a variety of vehicles and consists of a bell shaped chamber mounted underneath the vehicle. The shock wave is generated by the spark ignition of a propane and oxygen mixture and is imparted to the ground through the bell shaped chamber. This method causes little surface damage.

The thumper, vibrator, and spark ignition methods all have surface disturbing factors in common. Generally, these methods involve the use of existing roads or cross-country travel by four or five energy source trucks (usually weighing to one and one-half to ten tons) plus the recording truck, cable trucks, or pickup trucks. Bulldozer assistance may be required to cross drainages or to traverse steep terrain. The vehicles may travel off road along a single trail made by the trucks as the survey progresses. The vehicles may make several parallel trails in an attempt to distribute travel loads over a broader area. Travel along the line is usually a matter of one to two passes by the vehicle since the energy source is mobile and recording is done as the vehicles move down the line.

Subsurface Seismic Surveys

Historically, both subsurface and surface explosive methods have been the most widely used process to generate shock waves. In the subsurface method, five to fifty pounds of explosive charge are detonated at the bottom of a twenty-five to two hundred foot deep drill hole. These drill holes are usually two to six inches in diameter and drilled with a truck mounted drill. Detonation of the charge in some areas causes no surface disturbance, while in other areas, a small crater up to six feet in diameter is created. The same hole may be reloaded and shot several times to find the depth and charge returning the best signal. Cuttings from the well are normally scattered by hand near the shot hole, or put back in the shot hole after detonation. Bentonite mud is often used to plug the shot hole after the survey is completed.

The trucks used while conducting explosive seismic methods are similar to the trucks used in thumper and vibrator methods except that the trucks used to transport the drill are much heavier (15 to 20 tons). As with other truck transportation operations, existing roads may be used or trails may be blazed by the drill or bulldozer. A truck mounted drill and shot operation generally takes longer to complete and requires more trips by drill service vehicles than do vibrator and thumper operations.

In areas where there are limitations, steep topography, or other restraints prevent use of truck mounted drill rigs or recording trucks, light weight portable drill equipment can be used. Various kinds of portable drills can be backpacked or delivered by helicopter to the study area. These portable operations use a pattern of holes drilled to a depth of about 25 feet, the holes are then loaded with explosives and detonated simultaneously.

The surface explosive charge method involves the placing of explosives directly on ground, on snow, or on a variety of stakes and platforms including paper cones, survey stakes, lathes, or 2x4 wooden posts up to eight feet high. For this reason, surface explosive methods are very mobile and can be transported using 4X4 vehicles or adapted to airborne or ground pack teams.

A given area may be explored several times by the same or different companies over a long period of time using one or more of the geophysical methods mentioned above. This multiple exploration may be undertaken because the initial attempts were unsuccessful, another company wants its own information, or new and different techniques and/or equipment are used.

EXPLORATION DRILLING

Drilling does not begin until a lease has been acquired by the operator. When surface investigations are favorable and warrant further exploration, exploration drilling may be justified. Stratigraphic tests and wildcat tests are the two types of exploratory drill holes. Stratigraphic tests involve drilling relatively shallow holes to supplement seismic data. These tests aid in revealing the nature of near surface structural features. The holes are usually from 100 to several thousand feet deep, and are drilled primarily by a high pressure airflow or circulating drilling mud. Samples of these chips are collected, bagged, and identified by depth and rock composition. The chips are studied by a geologist to determine age, rock type, and formation. Truck-mounted drilling equipment used for stratigraphic tests is mobile and therefore, minimal construction is necessary for access into sites on level and solid ground. In hilly or mountainous areas, more road building is necessary.

Access Roads

Generally, access roads are bladed 12 to 14 feet wide and are not crowned or ditched. Under certain conditions it may only be necessary to brush the access route to clear vegetation. Other roads may require road cuts in excess of 20 feet and fills of more than 10 feet. Stratigraphic tests that require large amounts of surface disturbance are unusual since construction costs may outweigh the value of the information gained.

Drilling

The average drill site requires an area of one-half acre or less surface disturbance in order to position the drill and support equipment. If high pressure air is used to circulate the rock chips, dust may be emitted to the air when samples are collected. If mud is used as a drilling fluid, mud pits may be dug but, it is more common to use portable mud tanks. Usually one to three days is required to drill the test holes, depending on depth to and hardness of the bedrock. In areas with shallow, high-pressure, water bearing zones, casing may be required to prevent water from entering the hole.

After the surface and subsurface geological studies, the seismic, and other geophysical surveys, comes the evaluation of the prospect. Only by drilling a wildcat well (a well drilled in unproved territory) will the oil company know if the rocks in the prospect they have identified contain oil or gas. Nationally, one in 16 wildcat wells produces significant amounts of oil or gas. The deeper wildcat wells may require several months or more to complete; shallower wells up to a few thousand feet deep may be completed in as little as a few weeks. The deeper the test, the larger the drilling rig and the longer the drilling time required. Prior to approval of drilling, on-site inspections are conducted with the proposed drill pad and access road staked out, to assess potential impacts and attach appropriate mitigations to the permit to drill. A drill pad from one to four acres in size is then cleared of all vegetation, and leveled for the drill rig, mud pumps, mud (or reserve) pit, generators, pipe rack, and tool house. Topsoil and native vegetation are removed and stockpiled for use in the reclamation process. The mud pit may be lined with plastic or bentonite to prevent fluid loss or prevent contamination of water resources. Other facilities such as storage tanks for water and fuel are located on the pad or are positioned nearby on a separate cleared area. If the well site is not large enough for the equipment required to rig-up (prepare the drilling rig for operation), a separate staging area may be constructed. Staging areas are usually no larger than 200 feet by 200 feet and may only require a wide flat spot along the access road on which vehicles and equipment are parked.

Five thousand to 15,000 gallons of water per day may be needed for mixing drilling mud, cleaning equipment, cooling engines, etc. A surface pipeline may be laid to a stream or a water/well, or the water may be trucked to the site from ponds or streams in the area.

The drill rigs are very large and may be moved in pieces. In some instances, rigs can be moved short distances on level terrain with little or no dismantling of equipment which will shorten the tearing-down and rigging-up time. Moving a dismantled rig involves use if heavy trucking equipment for transportation, and crews to erect the rig. Gross weight of vehicles may run in excess of 80,000 lbs.

In order to move a drill rig and well service equipment from one site to another, and to allow access to each site, temporary roads may be built. These roads are generally 16 feet to 18 feet wide (driving surface) and may be as short as 200 feet or as long as ten miles or more. Bulldozers, graders and other types of heavy equipment are used to construct and maintain temporary wildcat roads.

The start of a well is called "spudding in" and, this procedure is started by forcing a short piece of tubing called conductor pipe into the ground and cementing it in place. This prevents surface sand and dirt from sloughing into the well hole. Next the regular drill bit and drill string (the column of drill pipe) are then used. These pass vertically through a heavy steel turn table (the rotary table), the derrick floor and the conductor pipe. The rotary table is geared to one or more engines, and rotates the drill string and bit. As the bit bores deeper into the earth, the drill string is lengthened by adding more pipe to the upper end.

Once the hole reaches a depth below the groundwater zones another string of pipe (the surface casing) is set inside the conductor pipe and cemented in place by pumping cement between the casing and the borehole wall. Surface casing acts as a safety device to protect fresh water from drilling fluid contamination. Blowout preventors (large metal rams) are installed around the surface casing just below the derrick floor to prevent the well from "blowing out" in the event that the drill bit encounters a high pressure zone. In an emergency, these rams would be activated and the rams would close around the drill string and seal the well.

After setting the surface casing, drilling resumes using a smaller diameter bit. Depending on well conditions, additional strings of casings (intermediate casing) may be installed before the well reaches the total depth. During drilling, a mixture of water, clay and chemical additives known as "mud" are continuously pumped down the drill pipe. The mud exits through holes in the bit and returns to the surface outside the drill-pipe. As the mud circulates, it cleans and cools the bit and carries the rock chips (cuttings) to the surface. It also helps to seal off the sides of the hole (thus preventing cave-ins), and to control the pressure of any water, gas or oil encountered by the drill bit.

The mud is the first line of defense against a blow-out since it is used to control pressure. It is for this reason that a pit full of "reserve" mud (the reserve pit) is maintained on location. The reserve mud is used in emergencies to restore the proper drilling environment when a radical or unexpected change in down-hole pressure is encountered.

Testing

The cuttings are separated from the mud and sampled so that geologists can analyze the various strata through which the bit is passing. The remainder of the cuttings passes into the reserve pit as waste. Some holes are drilled at least partially with compressed air which serves the same purpose as drilling mud of cooling and cleaning the bit and circulating the cuttings out of the hole.

During completion of drilling activity, the well is logged. This entails the use of geophysical instruments to measure the physical characteristics of the rock formations and associated fluids through which the borehole passed. These instruments are lowered to the bottom of the well, and slowly raised to the surface while recording data. Other measuring procedures include the drill stem test, in which pressures are recorded and fluid samples taken from zones of interest. After studying the data from those logs and tests, the geologist and/or petroleum engineer decide if the well will produce petroleum.

Well Stimulation/Hydraulic Fracturing

Well Stimulation may be used to enhance oil recovery. Several methods of well stimulation could be used. HF is one of these methods that is reasonably foreseeable for the leases on this sale. HF is the process of applying high pressure to a subsurface formation via a wellbore, to the extent that the pressure induces fractures in the rock. Typically the induce fractures will be propped open with a granular "proppant" to enhance fluid connection between the well and formation. The process was developed experimentally in 1947 and has been used routinely since 1950. The Society of Petroleum Engineers (SPE) estimates that over one million hydraulic fracturing procedures have been pumped in the United States and tens of thousands of horizontal wells have been drilled and hydraulically fractured. It can greatly increase the yield of a well, and development of hydraulic fracturing methods and the drilling technology in which it is applied (in particular, long wells drilled horizontally within the targets) have enabled production of oil and gas from tight formations formerly not economically feasible.

Plugging and Abandonment

If the well did not encounter oil and gas, it is plugged with cement and abandoned. The well pad and access road are recontoured and revegetated.

If the well will produce, casing is run to the producing zone and cemented in place. A proper cementing of the production casing string is required to provide coverage and prevent interzonal communication between oil and gas horizons and usable water zones. The drill is usually replaced by a smaller rig that is used for the final phase of completing the well.

DEVELOPMENT

If a wildcat well becomes a discovery well (a well that yields commercial quantities of oil or gas), development wells will be drilled to confirm the discovery, to establish the extent of the field, and to efficiently drain the reservoir. The procedure for drilling development wells are about the same as for wildcats, except there is usually less subsurface sampling, testing, and evaluation. If formation pressure can raise oil to the surface, the well will be completed as a flowing well. Several down-hole acid or fracture treatments to enhance the formation permeability may be necessary to make the well flow. A free-flowing well is simply closed off with an assembly of valves, pipes, and fittings (called a christmas tree) to control the flow of oil and gas to other production facilities. A gas well may be flared for a short period to measure the amount of gas per day the well can produce, then shut in or connected to a gas pipeline.

If the well is not free-flowing, it will be necessary to use pump methods. After the pump is installed, the well may be tested for days or months to see if it is economically justifiable to produce the well and to drill additional development wells, During this phase, more detailed seismic work may be run to assist in precisely locating the petroleum reservoir and to improve previous seismic work.

FIELD DEVELOPMENT

As with wildcat wells, field development well locations will be surveyed. A well spacing pattern must be established by the state (usually the wells can be spaced no closer than 330 feet from the quarter-quarter lines). Under special conditions, this spacing can be varied somewhat. Oil well spacing for production from federal leases uses units of 160, 320, and 640 acres per well.

Spacing for both oil and gas wells is based on the characteristics of the producing zones. If oil or gas is producing from more than one formation, the surface location of the wells may be closer than one per 40 acres. Once well spacing has been approved, development of the lease proceeds. During the development stage, the road system of the area is greatly expanded. Once it is known which wells produce and the expected length of their productive life, a system of permanent roads can be designed and built. Because it often takes several years to develop a field and determine field boundaries, the permanent road system is usually built in segments. For this reason, many temporary roads (built initially for wildcats or development) end up as long term (in excess of 15 years) main access or haul roads. The planning of temporary roads for wildcats and development wells is done with road conversion to long term in mind.

Since development wells have longer life spans than wildcat wells, access roads for development wells are better planned, designed and constructed. Access roads are normally limited to one main route to serve the lease areas, with a maintained side road to each well. Upgrading of temporary roads may include ditching, draining, installing culverts, graveling, crowning, or capping the roadbed. The amount of surface area needed for roads would be similar to that for temporary roads mentioned earlier and would also be dependent on topography and loads to be transported over it. Generally, main access roads are 20 feet to 24 feet wide and side roads are 14 feet to 18 feet wide. These dimensions are for the driving surface of the road and not the maximum surface disturbance associated with ditches, cuts or fills. The difference in disturbance is simply a matter of topography. Surface disturbance in excess of 130 feet is not unusual in steep terrain (slopes exceeding 30 percent).

When an oil field is developed on the current minimum spacing pattern of 40 acres per well, the wells are 1320 feet apart in both north-south and east-west directions. If a one square mile section is developed with 16 wells, at least four miles of access roads may be increased since steep slopes, deep canyons, and unstable soil areas must often be circumvented in order to construct stable access to the wells. Surface use in a gas field may be similar to an oil field though usually less) even though the spacing of wells is usually 1600 acres. Though a 160 acre spacing requires only four wells per section, the associated pipeline system often has similar initial surface requirements (acreage of surface disturbance).

FACILITY DEVELOPMENT

Tank Batteries and Well Siting

In addition to roads, other surface uses required for development drilling may include flowlines, storage tank batteries; facilities to separate oil, gas and water (separators and treaters); and injection wells for salt water disposal. Some of the facilities may be installed at each producing well site, and others at places situated to serve several wells. Surface use in an oil and gas field may be affected by unitization of the leaseholds. In many areas with federal lands, an exploratory unit is formed before a wildcat is drilled. The boundary of the unit is based on geologic data. The developers unitize the field by entering into an agreement to develop and generate it as a unit, without regard to separate ownerships. Costs and benefits are allocated according to agreed terms.

Unitization reduces the surface-use requirements because all wells are operated as though on a single lease. Duplication of field processing facilities is minimized because development operations are planned and conducted by a single unit operator, often resulting in fewer wells. The rate of development well drilling depends on whether the field is operated on an individual lease basis or unitized, the probability of profitable production, the availability of drilling equipment, protective drilling requirements (drilling requirements to protect federal land from subsurface petroleum drainage by off-setting nonfederal wells), and the degree to which limits of the field are known. The most important development rate factor may be the quality of production. If the discovery well has a high rate of production and substantial reserves, development drilling usually proceeds at a fairly rapid pace. If there is some question whether reserves are sufficient to warrant additional wells, development chilling may occur at a much slower pace. An evaluation period to observe production performance may follow between the drilling of successive wells.

Development on an individual lease basis usually proceeds more rapidly than under unitization, since each lessee must drill his own well to obtain production from the field. On a unitized basis, however, all owners within the participating area share in a well's production regardless of upon whose lease the well is developed. Spacing requirements are not applicable to unit wells. The unit is developed on whatever the operator considers to be the optimal spacing pattern to maximize recovery. As mentioned earlier, drilling in an undeveloped part of a lease to prevent drainage of petroleum to an offset well on an adjoining lease (protective drilling) is frequently required in fields of intermingled federal and privately owned land. The terms of federal leases require such drilling if the offset well is on non-federal lands, or on federal lands leased at a lower royalty rate.

Many fields go through several development phases. A field may be considered fully developed and produce for several years, then a well may be drilled to a deeper pay zone. Discovery of a new pay zone in an existing field is a "pool" discovery, as distinguished from a new field discovery. A pool discovery may lead to the drilling of additional wells with the bore holes separated only by feet or inches. Existing wells may also be drilled deeper.

Transporting Production
Usually four to six inch diameter pipelines transport the petroleum between the well, the treating and separating facilities, and central collection points. These lines can be on the surface, buried, or elevated. Most pipelines are buried.

Trucking and pipeline are the two methods used separately or in conjunction to transport oil out of a lease or unitized area. Trucking is used to transport crude oil from small fields where installation of pipelines is not economical and the natural gas in the field is not economically marketable.

Pipelines are the most common way to transport oil and gas. If a field has substantial amounts of natural gas, separate pipelines will be necessary for oil and gas. Pipelines move the oil from gathering stations to refineries. As existing fields increase production or new fields begin production, new pipelines may be needed. These new lines usually vary in size from four to 16 inches in diameter, and range in length from a few miles (to tie into an existing pipeline), to hundreds of miles to supply a refinery. Construction of a pipeline requires excavating and hauling equipment, a temporary and/or permanent road, possibly pumping stations, clearing the right-of-way of vegetation and possibly blasting.

Natural gas pipelines transport gas from the wells (gathering or flow lines) to a trunk line then to the main transmission line from the area. Flow lines are usually two inches to four inches in diameter and mayor may not be buried. Trunk lines are generally six inches to eight inches in diameter and are buried, as are transmission lines which vary in diameter from ten inches to 36 inches. The area required to construct a pipeline varies from about 15 inches wide (for a two inch to four inch surface line) to greater than 75 feet for the larger diameter transmission lines (24 inches to 36 inches). Surface disturbance is primarily dependent on size of the line and topography of the area on which the line is being constructed.

Compressor stations may be necessary to increase production pressure to the same level as pipeline pressure. The stations vary in size from approximately one acre to as much as twenty acres for a very large compressor system. Construction techniques for natural gas lines are similar to those used for oil pipelines.

PRODUCTION

INITIAL METHODS

Production in an oil field begins just after the discovery well is completed and is usually concurrent with development operations. Temporary facilities may be used at first, but as development proceeds and reservoir limits are determined, permanent facilities are installed. The extent of such facilities are dictated by the number of producing wells, expected production, volume of gas and water produced with the oil, the number of leases, and whether the field is to be developed on a unitized basis.

The primary means of removing oil from a well is by the use of pumping jacks. The pumps are powered by electric motors (power lines required) or if there is sufficient casing head gas (natural gas produced with the pumped oil), or another gas source is available, it may be used to fuel internal combustion engines.

Some wells may produce sufficient water that must be disposed of during operation of the well. Although most produced waters are brackish to highly saline, some are fresh enough for beneficial use. If water is to be discharged, it must meet certain water quality standards. Because water may not come from the treating and separating facilities completely free of oil, oil skimmer pits may be established between separating facilities and surface discharge.

When salt water is disposed of underground, it is always introduced into a formation containing water of equal or poorer quality .It may be injected into the producing zone from which it came or into other producing zones. In some cases, it could reduce the field productivity and may be prohibited by state regulation or mutual agreement of operators. In some fields, dry holes or depleted producing wells are used for salt water disposal, but occasionally new wells are drilled for disposal purposes. Cement is squeezed between the casing and sides of the well to prevent the salt water from migrating up or down from the injection zone into other formations. Underground oil is under pressure in practically all reservoirs. This pressure is usually transmitted to the oil through gas or water in the reservoirs with the oil. When oil is pumped out of the well, pressure is reduced in the reservoir around the drill hole. This allows the gas or water in the reservoir to push more oil into the space next to the well. A reservoir that has mostly gas pushing the oil is called “gas drive”, and one that has mostly water pushing the oil is called “water drive”. Oil that is recovered under these natural pressures is considered primary production. Primary production accounts for about 25 percent of the oil in a reservoir.

INCREASING RECOVERY

Methods of increasing recovery from reservoirs generally involve pumping additional water or gas into the reservoir to maintain or increase the reservoir pressure. This process is called secondary recovery. Recently, the trend has been to institute secondary recovery processes very early in the development of a field. Surface disturbance from a water flooding recovery system is similar to drilling and development of an oil and gas well itself, i.e., a drill pad and access road are constructed and water pipelines may be built. Surface use is increased substantially since as many as four injection wells may be used for each oil well in the field (there are many different patterns as well as many other methods of secondary recovery).

Tertiary recovery methods increase recovery rates by lowering the viscosity of the oil either by heating it or by injecting chemicals into the reservoir so that the oil flows more easily. Heating of reservoir oil can be accomplished by injecting steam into the reservoir. Tertiary recovery methods are not yet widely used in this Elko Resource Area. By the year 2000, ultimate recovery (including secondary and tertiary recovery) from any given oil reservoir is expected to average 40 percent nationally.

POST PUMPING TREATMENT

Crude oil is usually transferred from the wells to tank storage facilities (tank battery) before it is transported from the lease. If it contains gas and water, they are separated before the oil is stored in the tank battery .The treating and separating facilities are usually located at a storage tank battery on or near the well site.

After the oil, gas, and water are separated, the oil is piped to storage tanks located on or near the lease. There are normally at least two tanks; so that one tank can be filling as the contents of the other is measured, sold, and transported. The number and size of tanks vary with the rate of production on the lease, and with the extent of automation in gauging the volume and sampling the quality of the tank’s contents.

ABANDONMENT

The life span of fields varies because of the unique characteristics, the nature of the petroleum, subsurface geology, and political, economic, and environmental constraints. All affect a field’s life span from discovery to abandonment. The life of a typical field is 15 to 25 years. Abandonment of individual wells may start early in a field’s life and reach a maximum when the field is depleted.

Well plugging and abandonment requirements vary with the rock formations, subsurface water, well-site, and the well. In all cases, the formations bearing useable-quality water, oil, gas or geothermal resources, and/or prospectively valuable deposits of minerals will be protected.

Generally, in dry wells, the hole below the casing is filled with heavy drilling mud, a cement plug is installed at the bottom of the casing, the casing is filled with heavy drilling mud, and a cement cap is installed on top. A pipe monument giving the location, lease number, operator, and name of the well is required unless waived by the Authorized Officer. If waived, the casing may be cut off and capped below ground level. Protection of aquifers and known oil and gas producing formations may require placement of additional cement plugs.

In some cases, wells that formerly produced are plugged as soon as they are depleted. In other cases, depleted wells are not plugged immediately but are allowed to stand idle for possible later use in a secondary recovery program. Truck-mounted equipment is used to plug former producing wells. In addition to the measures required for a dry hole, plugging of a depleted-producing well requires a cement plug in the perforated section in the producing zone. If the casing is salvaged, a cement plug is put across the casing stub. The cement pump-jack foundations are removed or buried below ground level. Surface flow and injection lines are removed, but buried pipelines are usually left in place and plugged at intervals as a safety measure.

After plugging, the drilling rig is removed and the surface, including the reserve mud pit, and the well pad area is restored to the requirements of the surface management agency. This may involve the use of bulldozers and graders to recontour those disturbed areas associated with the drill pad plus the access road to the particular pad. The reserve pit (the part of the mud pit in which a reserve supply of drilling fluid and/or water is stored) must be evaporated or pumped dry, and filled with soil material stockpiled where the site was prepared. There is little leakage if the pit was lined with plastic or bentonite. The area is reshaped to a useful layout that will allow revegetation to take place, the landform is restored as near as possible to its original contour, and erosion minimized. After grading the subsoil and spreading of the stockpiled topsoil, the site is seeded with a grass mixture that will establish a good growth. A fence may be erected to protect the site until revegetation is complete, particularly in livestock concentration areas.

APPENDIX E LIST OF ACRONYMS USED

ACEC	Area of Critical Environmental Concern
AO	Authorized Officer
APD	Application for Permit to Drill
AQRV	Air Quality Related Values
BLM	Bureau of Land Management
CFR	Code of Federal Regulations
COA	Condition of Approval
CTGR	Confederated Tribes of the Goshute Reservation
DOI	Department of the Interior
DR	Decision Record
EA	Environmental Assessment
EOI	Expression of Interest
EPA	U.S. Environmental Protection Agency
ESA	Endangered Species Act
FEIS	Final Environmental Impact Statement
FLPMA	Federal Land Policy & Management Act
FO	Field Office
FONSI	Finding of No Significant Impact
GIS	Geographic Information Systems
GHG	Greenhouse Gasses
HAP	Hazardous Air Pollutants
HF	Hydraulic Fracturing
ID	Interdisciplinary
IPCC	Intergovernmental Panel on Climate Change
LWC	Lands with Wilderness Characteristics
NAAQS	National Ambient Air Quality Standards
NCLS	Notice of Competitive Lease Sale
NDEP	Nevada Division of Environmental Protection
NDOW	Nevada Department of Wildlife

NEPA	National Environmental Policy Act
NHPA	National Historic Preservation Act
NPS	National Park Service
NSO	No Surface Occupancy
NTL	Notice to Lessee
PGH	Preliminary General Habitat
POD	Plan of Development
PPH	Preliminary Primary Habitat
RFD	Reasonably Foreseeable Development
RMP	Resource Management Plan
ROW	Right-of-Way
SHPO	Nevada State Historic Preservation Office
T&E	Threatened and Endangered
TCP	Traditional Cultural Properties
TSP	Total Suspended Particulates
USFWS	United States Fish & Wildlife Service
VOC	Volatile Organic Compounds
VRM	Visual Resource Management
WMA	Wildlife Management Area

APPENDIX F LIST OF DEFERRED PARCELS

NV-15-03-013 600.000 Acres
T.0270N, R.0590E, 21 MDM, NV
Sec. 034 N2,N2SW,SESW,SE;
Elko County
Elko DO
NEAR PGH & PPH;

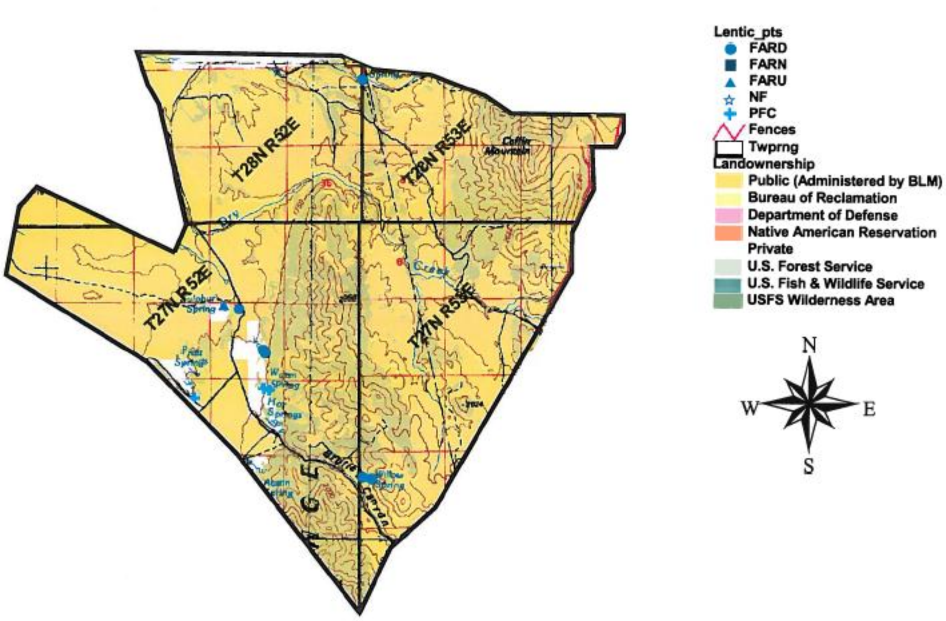
NV-15-03-014 1120.000 Acres
T.0280N, R.0600E, 21 MDM, NV
Sec. 008 N2SE,SWSE;
017 W2NE,SENE,N2NW,SENW,N2SE;
020 S2NE,SENW,S2;
029 NWNE,NW,NWSW;
Elko County
Elko DO
NEAR PGH;

Total Acres Deferred; 1720 Acres

APPENDIX G. PFC WETLANDS/RIPARIAN

NAME	RATE	TYPE	ACRES	DATE	TIME	WATER STATUS	WATER INVENTORY	Allotment	EC	TEMP(°C)	pH
Bruffy 01	NF	Spring	0.02512	11/5/2003	10:29:05am	Intermittent	Yes	South Buckhorn	596	10.2	7.92
Bruffy 02	FARD	Spring	0.05536	11/5/2003	10:48:34am	Intermittent	No	South Buckhorn			
Bruffy 03	FARU	Spring	3.74170	11/5/2003	11:58:09am	Perennial	Yes	Bruffy	1017	6.6	8.28
Bruffy 04	FARD	Spring	0.40473	11/5/2003	12:42:19pm	Perennial	Yes	Bruffy	845	8.8	8.16
Bruffy 05	PFC	Spring	0.30331	11/5/2003	01:49:12pm	Intermittent	No	Bruffy			
Bruffy 06	FARD	Spring	0.25704	11/5/2003	03:56:00pm	Perennial	Yes	Bruffy	543	13.2	7.84
Bruffy 06	FARD	REACH	0.20898	11/5/2003		Perennial	Yes				
Bruffy 7	NF	Spring	N/A	11/6/2003		Perennial	Yes	Bruffy	476	20.1	7.67
Bruffy 8	FARD	Spring	0.06435	11/6/2003	10:43:20am	Perennial	Yes	Bruffy	662	12.9	7.91
Bruffy 9	FARD	Spring	0.17610	11/6/2003	12:51:31pm	Perennial	Yes	Bruffy	641	17.6	7.70
		Total Acres:	4.78726								
		Total FARD Acres:	0.95758								
		Total FARU Acres:	3.7417								
		Total PFC Acres:	0.30331								
		Total NF Acres:	0.02512								

Bruffy Allotment



2008 Lentic Proper Functioning Condition Assessments

East Big Springs Allotment

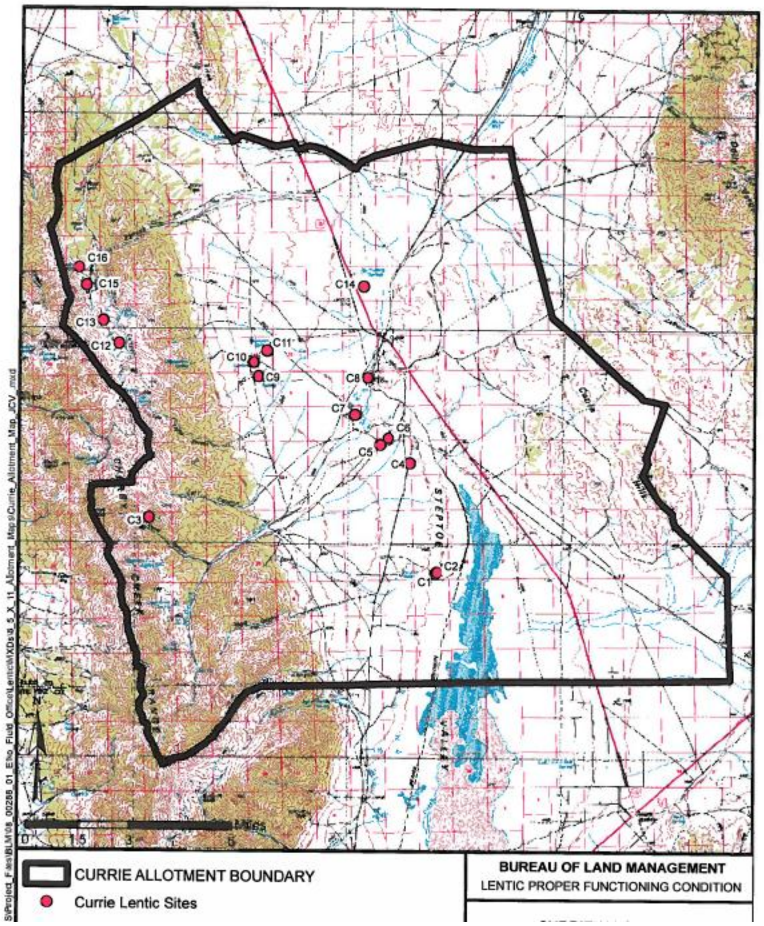
Number	Rating	Acres	Type	Date	Inventory
EBS-0	NF	0.05	Trough/seep	8/18/08	Yes
EBS-1	NF	0.05	Trough/seep/pipe	8/20/08	Yes
EBS-2	FARD	0.99	Ponded	8/20/08	Yes
EBS-4	NF	0.32	Dry	8/18/08	Yes
EBS-5			Dry	8/18/08	No
EBS-6	NF	0.08	Dry	8/18/08	Yes
EBS-7	FARNA	0.68	Old Exclosure	8/18/08	Yes
EBS-8	FARNA	0.25	Piped/old trough	8/18/08	Yes
EBS-9	FARD	0.23	Trough/pond	8/18/08	Yes
EBS-10	PFC	0.05	Old trough	8/20/08	Yes
EBS-11	PFC	0.04	Spring	8/20/08	Yes
EBS-12	FARNA	0.18	Very old trough	8/20/08	Yes
EBS-13			No spring	8/20/08	No
EBS-14	PFC	0.06	Spring	8/20/08	Yes
EBS-16			No spring	8/18/08	No
EBS-17	NF	0.63	Ponded	8/18/08	Yes
EBS-18/19		0.0	Piped/3 troughs	8/20/08	No
EBS-20		0.0	No spring	8/20/08	No

West Big Springs Allotment

Number	Rating	Acres	Type	Date	Inventory
WBS-1	NF	3'x3'	Nearly dry spring	8/22/08	Yes
WBS-2	PFC	0.02	Ponded/	8/15/08	Yes
WBS-3	NF	0.11	Dry/old trough	8/22/08	Yes
WBS-4	FARD	0.02	Piped to trough	8/11/08	Yes

Currie Allotment

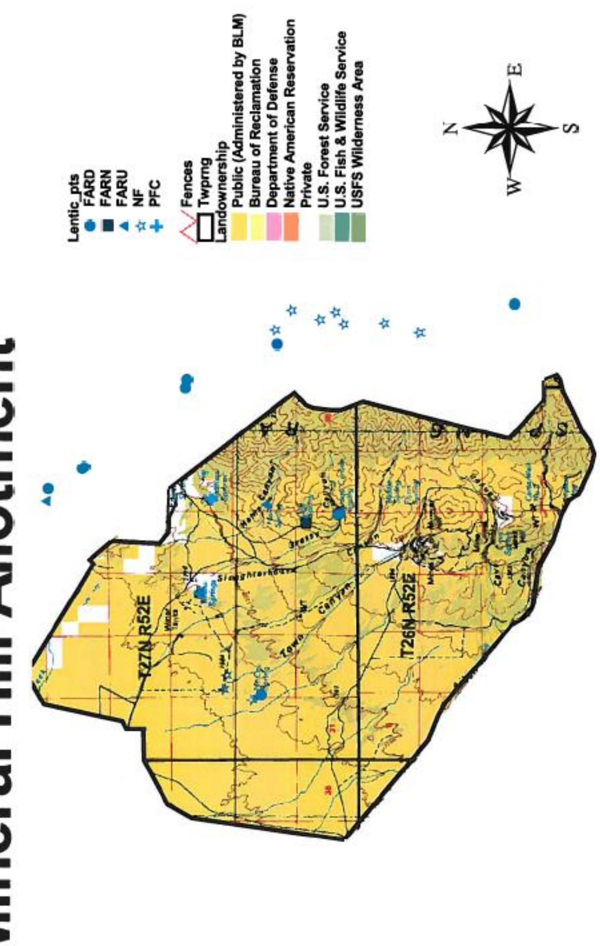
Number	Rating	Acres	Type	Date	Inventory
C-1	FARNA	14.07	Wetted Meadow	8/19/08	Yes
C-2	PFC	2.03	Spring	8/19/08	Yes
C-3	FARNA	0.02	Old trough/pipe	8/19/08	Yes
C-4	PFC	0.04	Ponded/old trough	8/19/08	Yes
C-5	NF	0.03	Old exclosure/pond	8/19/08	Yes
C-6			Private fenced	8/18/08	No
C-7			Private	8/19/08	No
C-8	FARD	0.48	Spring	8/19/08	Yes
C-9	PFC	0.08	Spring	8/19/08	Yes
C-10	FARNA	0.35	Spring/Exclosure	8/19/08	Yes
C-11	FARD	1.75	Spring	8/19/08	Yes
C-12	FARNA	2.30	Spring/Exclosure	8/13/08	Yes



Indian Springs								
Indian Springs 01		FARU	Other	0.138	11/12/2003	NONE	Perennial	NO
Indian Springs 02		NF	Spring	0.207	6/16/2004	NONE	Perennial	NO
Indian Springs 03		FARD	Spring	0.420	6/16/2004	NONE	Perennial	NO
Indian Springs 04		PFC	Spring	3.516	6/16/2004	NONE	Perennial	NO
Indian Springs 05		FARU	Spring	0.091	6/17/2004	NONE	Perennial	NO
Total Acres:				4.373				

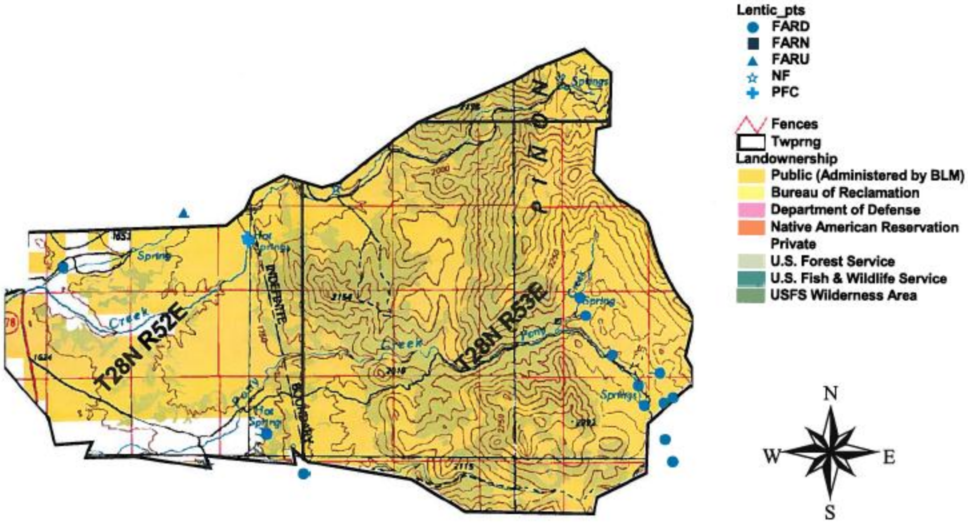
NAME	RATE	TYPE	ACRES	DATE	TIME	WATER STATUS	WATER INVENTORY
Mineral Hill 01	NF	Spring	0.16134	11/6/2003	02:32:36pm	Perennial	No
Mineral Hill 02	NF	Spring	0.05940	11/6/2003	02:57:11pm	Perennial	Yes
Mineral Hill 03	NF	Spring	0.06665	11/6/2003	03:02:09pm	Perennial	Yes
Mineral Hill 04	FARD	Spring	n/a	11/6/2003	03:14:55pm	Perennial	No
Mineral Hill 05	FARD	Spring	0.07228	11/6/2003	03:09:56pm	Intermittent	No
Mineral Hill 06	NF	Spring	0.28099	11/6/2003	03:36:05pm	Perennial	Yes
Mineral Hill 06	NF	REACH	0.02630	11/6/2003	n/a	Perennial	Yes
Mineral Hill 07	PFC	Spring	0.05817	11/21/2003	11:08:37am	Perennial	Yes
Mineral Hill 08	FARN	Spring	0.04652	11/21/2003	11:23:01am	Perennial	No
Mineral Hill 09	FARD	Spring	0.14789	11/21/2003	12:00:52pm	Perennial	Yes
Mineral Hill 10	FARD	Spring	0.05807	11/21/2003	12:35:05pm	Perennial	Yes
Mineral Hill 11	PFC	Spring	0.09712	11/22/2003	01:36:28am	Perennial	Yes
Mineral Hill 12	PFC	Spring	0.13342	11/22/2003	02:30:16am	Perennial	Yes
	Total Acres:		1.20816				
	Total FARD Acres:		0.27824				
	Total FARN Acres:		0.04652				
	Total PFC Acres:		0.28870				

Mineral Hill Allotment



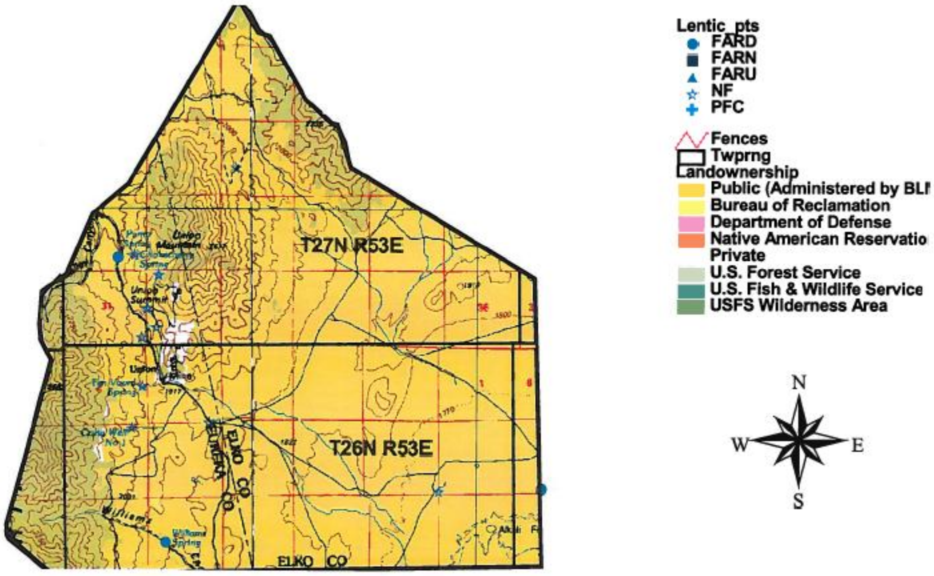
NAME	RATE	TYPE	ACRES	DATE	TIME	WATER STATUS	WATER INVENTORY
Pony Creek 01	FARD	Spring	1.97089	11/6/2003	11:38:50am	Perennial	No
Pony Creek 02	NF	Spring	n/a	11/6/2003	11:57:18am	Perennial	Yes
Pony Creek 03	FARD	Spring	0.09220	11/12/2003	09:20:39pm	Intermittent	Yes
Pony Creek 04	PFC	Spring	0.78647	11/12/2003	10:48:28pm	Perennial	Yes
Pony Creek 05	FARD	Spring	0.01761	11/13/2003	01:23:31am	Perennial	Yes
Pony Creek 06	FARD	Spring	2.25983	11/13/2003	01:40:15am	Intermittent	No
Pony Creek 07	FARD	REACH	0.13636	11/13/2003	02:05:45pm	Perennial	Yes
Pony Creek 08	FARD	Spring	2.05552	11/13/2003	02:22:34am	Intermittent	No
Pony Creek 09	FARD	Spring	0.72421	11/13/2003	02:41:54am	Perennial	No
Pony Creek 10	FARD	Spring	0.03541	11/13/2003	03:01:17am	Perennial	No
Pony Creek 11	FARD	Spring	0.11206	11/13/2003	03:23:53am	Perennial	Yes
Pony Creek 12	FARD	Spring	0.02921	11/13/2003	03:46:28am	Perennial	Yes
Pony Creek 13	NF	Spring	0.02618	11/12/2003	11:45:05pm	Perennial	Yes
	Total Acres:		8.24596				
	Total FARD Acres:		7.43332				
	Total NF Acres:		0.02618				
	Total PFC Acres:		0.78647				

Pony Creek Allotment



NAME	RATE	TYPE	ACRES	DATE	TIME	WATER STATUS	WATER INVENTORY
Union Mountain 01	FARD	Spring	0.29649	11/19/2003	09:08:52am	Perennial	Yes
Union Mountain 02	NF	Spring	0.02561	11/19/2003	09:26:37am	Perennial	Yes
Union Mountain 02	NF	REACH	0.02712	11/19/2003	09:31:50am	Perennial	Yes
Union Mountain 03	NF	REACH	0.06440	11/19/2003	09:53:19am	Perennial	Yes
Union Mountain 04	NF	Spring	0.08611	11/19/2003	10:09:01am	Intermittent	No
Union Mountain 05	NF	Spring	0.07507	11/19/2003	10:16:54am	Perennial	Yes
Union Mountain 06	NF	REACH	0.00506	11/19/2003	10:36:19am	Perennial	Yes
Union Mountain 07	NF	Spring	0.06323	11/19/2003	10:52:41am	Perennial	Yes
Union Mountain 08	NF	Spring	0.02315	11/19/2003	11:15:40am	Perennial	Yes
Union Mountain 09	NF	Spring	0.01480	11/19/2003	11:31:47am	Perennial	No
Union Mountain 10	FARD	Spring	0.02791	11/19/2003	12:22:41pm	Perennial	Yes
Union Mountain 11	NF	Spring	n/a	11/19/2003	01:24:41pm	Dry	No
Union Mountain 12	NF	Spring	0.11039	11/19/2003	02:23:19pm	Intermittent	No
	Total Acres:		**0.81934**				
	Total FARD Acres:		**0.32440**				
	Total NF Acres:		**0.49494**				

Union Mountain Allotment



APPENDIX H STATE OF NEVADA, THIRD REVISED PROPOSED REGULATION R011-14

--1-- LCB Draft of Third Revised Proposed Regulation R011-14

THIRD REVISED PROPOSED REGULATION OF THE DIVISION OF MINERALS OF THE COMMISSION ON MINERAL RESOURCES
LCB File No. R011-14

July 24, 2014
EXPLANATION – Matter in ***italics*** is new; matter in brackets **[**omitted material**]** is material to be omitted.
AUTHORITY: §§1-19 and 22, NRS 522.040 and 522.119; §20, NRS 522.040 and 522.150; §21, NRS 534A.090.

A REGULATION relating to natural resources; providing for the regulation of hydraulic fracturing in this State; revising provisions governing the operation of wells for the extraction of oil, gas and geothermal resources; and providing other matters properly relating thereto.

Legislative Counsel's Digest:
Existing law authorizes the Division of Minerals of the Commission on Mineral Resources to regulate wells drilled for the production of oil, gas and geothermal resources. (Chapters 522 and 534A of NRS) In 2013, Senate Bill No. 390 required the Division of Minerals and the Division of Environmental Protection of the State Department of Conservation and Natural Resources, jointly, to develop a hydraulic fracturing program for the State of Nevada. This regulation generally establishes that program.

Sections 9-13 of this regulation provide for the regulation of a well for which an operator intends to engage in hydraulic fracturing. **Section 9** provides for the sampling, testing and continued monitoring of certain water sources located within a specified sampling area. **Section 10** requires an operator to include with his or her application to drill certain information. **Section 11** establishes certain additional requirements for the installation and cementing of certain casing strings in a well used for hydraulic fracturing. **Section 12** establishes certain notice, reporting, monitoring and certification requirements for the operator of a hydraulic fracturing operation and additionally establishes certain requirements for the use of chemicals during the hydraulic fracturing process and the containment and disposal of liquids that are returned to the surface and discharged from the wellbore during hydraulic fracturing. **Section 13** authorizes an operator of certain existing oil or gas wells to request and the Division to approve a hydraulic fracturing operation at the oil or gas well.

Sections 14-20 of this regulation revise provisions of general applicability to all oil and gas wells.

Section 14: (1) requires an operator to maintain a copy of the drilling permit at the site of the well during the operation of the well; (2) prescribes certain notice requirements relating to spudding a well and installing or cementing casing or equipment for the prevention of a blowout; (3) requires an operator to ensure compliance with certain industry standards relating to casing;

and (4) provides for the management, containment and disposal of spills or releases and liquids that are returned to the surface and discharged from the wellbore during the drilling operation.

Section 15 prescribes certain safety measures for the safe operation of the well.

Section 18 revises provisions governing certain applications submitted to and permits issued by the Division.

Section 19 revises provisions relating to the installation and cementing of the surface casing string, an intermediate casing string or liner and a production casing string or liner in an oil or gas well.

Section 19 additionally requires an operator to report certain information to the Division of Minerals to ensure the safe operation of the well.

Section 20 increases the amount of the administrative fee that a producer or purchaser of oil or natural gas must pay to offset the expenses of the Division.

Section 21 of this regulation revises provisions prescribing certain safety measures for the safe operation of geothermal wells.

Section 22 of this regulation repeals certain regulations relating to wells drilled with cable tools and administrative fees for the new production of oil or natural gas.

Section 1. Chapter 522 of NAC is hereby amended by adding thereto the provisions set forth as sections 2 to 15, inclusive, of this regulation.

Sec. 2. ***"Area of review" means:***

1. ***The area of land located within a radius of 1 mile of a proposed oil or gas well and any surface projection of any lateral component of the wellbore that is proposed for hydraulic fracturing; and***
2. ***Any additional area of land prescribed by the Division or specified by an operator pursuant to subsection 3 of section 10 of this regulation.***

Which the person who owns, holds or has the right of use to the water source has consented to the sampling and testing of the water source and to making the results of the sampling and testing available to the public.

Sec. 4. ***"Division of Environmental Protection" means the Division of Environmental Protection of the State Department of Conservation and Natural Resources.***

Sec. 5. ***"Hydraulic fracturing" has the meaning ascribed to it in paragraph (b) of subsection 3 of NRS 522.119.***

Sec. 6. ***"Sampling area" means the area of land located within a radius of 1 mile of a proposed oil or gas well and any surface projection of any lateral component of the wellbore that is proposed for hydraulic fracturing.***

Sec. 7. ***"Water source" means a water well or spring that is regulated by the Division of Water Resources of the State Department of Conservation and Natural Resources.***

Sec. 8. ***Except as otherwise provided in section 13 of this regulation, the provisions of sections 2 to 13, inclusive, of this regulation, apply for each oil or gas well for which the operator intends to engage in hydraulic fracturing.***

Sec. 9. ***1. Except as otherwise provided in subsections 2 and 4, an operator shall collect an initial baseline sample and subsequent monitoring samples from each available water source, not to exceed four available water sources, located within the sampling area. If more than four available water sources are located within the sampling area, the operator shall select the four available water sources for sampling based on:***

(a) The proximity of the available water sources to the proposed oil or gas well. Available water sources closest to the proposed oil or gas well are preferred.

(b) The orientation of the sampling locations. To the extent that the direction of the flow of groundwater is known or can reasonably be inferred, sample locations from both down-gradient and up-gradient locations are preferred over cross-gradient locations.

(c) The depth of the available water sources. The sampling of the deepest of the available water sources is preferred.

(d) The condition of the available water sources. An operator is not required to sample an available water source if the Administrator determines that the available water source is improperly maintained or nonoperational, or has physical characteristics which would prevent the safe collection of a representative sample or which would require nonstandard sampling equipment.

2. An operator may, before a well is spudded or drilled for oil or gas, request an exception from the requirements of this section by filing a sundry notice (Form 4) with the Administrator. The Administrator may grant the request for an exception if the Administrator finds that:

(a) No available water sources are located within the sampling area;

(b) The only available water sources are unsuitable pursuant to paragraph (d) of subsection 1; or

(c) Each owner of a water source that is suitable for testing and located within the sampling area has refused to grant the operator access to the water source for sampling and additionally finds that the operator has made a reasonable and good faith effort to obtain the consent of the owner to conduct the sampling

3. Except as otherwise provided in subsections 2 and 4, an operator shall collect from each available water source for which the operator is required to collect samples pursuant to this section:

(a) An initial sample during the 12-month period immediately preceding the commencement of hydraulic fracturing at an oil or gas well.

(b) A first subsequent sample, collected not earlier than 6 months but not later than 12 months after the commencement of hydraulic fracturing. If a well that has been drilled produces hydrocarbons for a period of less than 6 months after the commencement of hydraulic fracturing and the well is subsequently plugged and abandoned, or if the well is plugged and abandoned without having produced hydrocarbons after the commencement of hydraulic fracturing, the operator shall collect each first subsequent sample at the time the well is plugged.

(c) A second subsequent sample, collected not earlier than 60 months but not later than 72 months after the commencement of hydraulic fracturing. If a well that has been drilled produces hydrocarbons for a period of less than 60 months and the well is subsequently plugged and abandoned, the operator shall collect each second subsequent sample at the time the well is plugged. An operator is not required to collect second subsequent samples if a well that is drilled is plugged and abandoned without having produced hydrocarbons.

4. For the purposes of satisfying the requirements for sampling available water sources pursuant to paragraphs (a) and (b) of subsection 3, an operator may rely on the test results of a previous sample from an available water source if:

(a) The previous sample was collected and tested during the respective period prescribed for sampling pursuant to paragraph (a) or (b) of subsection 3.

(b) The procedure for collecting and testing the sample, and the constituents for which the sample was tested, are substantially similar to those required by this section.

(c) The Administrator receives the test results not less than 14 days before the commencement of hydraulic fracturing.

5. The Administrator may require an operator to collect and test samples of an available water source in addition to the collection and testing protocol prescribed by this section if the Administrator finds that additional testing is warranted.

6. The testing of a water sample pursuant to this section must be conducted by a laboratory certified pursuant to NAC 445A.0552 to 445A.067, inclusive. Upon request, an operator shall provide his or her protocol for collection and testing to the Administrator.

7. The test results of initial and subsequent samples collected pursuant to this section must include, without limitation:

(a) The level of each analyzed constituent identified in the routine domestic water analysis of the Nevada State Public Health Laboratory of the University of Nevada School of Medicine.

(b) The levels of benzene, toluene, ethylbenzene and xylene.

(c) The levels of dissolved methane, ethane, propane and hydrogen sulfide gases within the sample.

8. If a dissolved methane concentration greater than 10 milligrams per liter (mg/l) is detected in a sample of water collected pursuant to this section, an analysis of the gas composition, including, without limitation, an analysis of the stable isotope ratios of carbon (13C vs. 12C) and hydrogen (2H vs. 1H) and an analysis of the origin (biogenic vs. thermogenic), must be performed on the sample using gas chromatography and mass spectrometry, as necessary.

9. An operator shall immediately notify the Administrator and the owner of an available water source if the test results of a sample collected pursuant to this section indicate:

(a) The presence of benzene, toluene, ethylbenzene, xylene or hydrogen sulfide in a concentration greater than the specified maximum contaminant level set forth in the primary and secondary standards for drinking water pursuant to NAC 445A.453 and 445A.455.

(b) If the sample is a subsequent sample, any change in water chemistry indicative of a degradation in water quality.

10. An operator shall provide copies of the test results of each sample collected pursuant to this section to the Administrator and to the respective owner of the available water source not later than 30 days after the operator receives the test results from a laboratory. The Division will, upon request, make the test results available to a member of the public for inspection at the office of the Division located in Carson City.

11. An operator shall include with the copy of the test results of a sample provided pursuant to subsection 10 a description of the location of the available water source and any field observations recorded by the operator during the collection of the sample. The operator shall describe the location of the available water source by public land survey and the county assessor's parcel number and shall include the global positioning system coordinates of the available water source in the manner prescribed by subparagraph (2) of paragraph (b) of subsection 2 of NAC 534.340.

12. An operator shall not commence hydraulic fracturing at a well until the operator has complied with the provisions of this section. 13. As used in this section, "public land survey" has the meaning ascribed to it in NAC 534.185.

Sec. 10. ***1. An operator must include with his or her application to drill an oil or gas well:***

(a) The water appropriation permit number and the name of the owner of each water source within the area of review that is on file with the Division of Water Resources of the State Department of Conservation and Natural Resources.

(b) The well log number, well depth and the diameter of the water well casing.

(c) The static water level below the surface of the ground or the rate of flow of the water, if any.

(d) A description of the location of each water source located within the area of review in the manner prescribed by subsection 11 of section 9 of this regulation.

(e) Publically available maps and cross-sections of the area of review which describe the surface and subsurface geology of the area of review, including, without limitation, the location of known or suspected faults.

(f) A map showing the location of each water source or perennial stream located within the area of review, the overall project area or lease holdings, the boundaries of the area of review, all known well locations, land ownership and applicable assessor parcel numbers.

(g) The source and estimated volume of water required for hydraulic fracturing in each well.

(h) A plan for the management and disposal of all fluids to be used in the proposed hydraulic fracturing operation.

2. If an operator discovers inconsistencies with respect to publically available and proprietary hydrologic or geologic information within an area of review that the operator reasonably believes to be a cause for concern with respect to potential contamination from hydraulic fracturing, the operator shall disclose the inconsistencies to the Division.

3. The Division may prescribe or an operator may specify an area of review that includes an area of land in addition to that area of land located within a radius of 1 mile of a proposed oil or gas well and any surface projection of any lateral component of the wellbore that is proposed for hydraulic fracturing for the purposes of compliance with this section or the collection of additional data based on population density, residential locations, water source locations or for other good cause as the Division or an operator may deem reasonable.

Sec. 11. ***In addition to the requirements prescribed by NAC 522.265, the operator of an oil or gas well shall:***

1. Ensure that:

(a) The surface location of the well is at a lateral distance of not less than 300 feet from any known perennial water source, existing water well or existing permitted structure.

(b) The edge of the drilling pad is at a lateral distance of not less than 100 feet from any known perennial water source, existing water well or existing permitted structure.

2. For the intermediate casing string installed in the well directly below the surface casing, install the intermediate casing string through the surface casing from the installed depth of the intermediate casing string to the surface of the ground.

3. For a production casing string, conduct a pressure test of the casing string in which the casing is pressurized to 3,000 pounds or more per square inch gauge (psig), not to exceed 80 percent of the burst-pressure rating of the casing, for a period of not less than 30 minutes. A pressure test must be conducted and the results of the test must be reported in the manner prescribed by subsection 7 of NAC 522.265.

Sec. 12. *1. An operator of an oil or gas well shall:*

(a) Not less than 14 days before the commencement of hydraulic fracturing:

(1) Provide written notice to each owner of real property and any operator of an oil, gas or geothermal well located within the area of review of the hydraulic fracturing operation.

(2) Provide written notice to the board of county commissioners in the county in which the oil or gas well is located.

(3) Submit to the Division an affidavit (Form 15) certifying that each strata is sealed and isolated with casing and cement in accordance with NAC 522.260. The affidavit must be signed by the operator or a competent person designated by the operator and must incorporate and include a copy of each relevant cement evaluation log as evidence of compliance with NAC 522.260.

(4) Submit for approval by the Division a sundry notice (Form 4) and a report describing all specific aspects of the proposed hydraulic fracturing operation. The report must identify each stage of the hydraulic fracturing operation, the measured depth and true vertical depth below the surface of the ground for each stage, the duration of each stage, all intervals to be perforated in measured depth and true vertical depth below the surface of the ground, the number and diameter of perforations per foot and the estimated hydraulic pressures to be utilized.

(b) Maintain a record as to the manner in which each owner, operator and board of county commissioners was notified pursuant to subparagraphs (1) and (2) of paragraph (a), including, without limitation, the method of notification.

(c) Before the commencement of hydraulic fracturing:

(1) Ensure that each chemical used in the hydraulic fracturing process is identified on the Internet website maintained by the Division as a chemical which is approved by the Division for hydraulic fracturing. An operator may request and the Division may approve the use of a chemical that is not identified as an approved chemical if the operator submits the request to the Division on a sundry notice (Form 4) not less than 30 days before the commencement of hydraulic fracturing.

(2) Disclose to the Division each additive that the operator intends to use in the hydraulic fracturing fluid, including, without limitation, any additive that may be protected as a trade secret. The operator shall include with the identity of each additive the trade name and vendor of the additive and a brief description of the intended use or function of the additive.

2. The operator shall monitor and record all well head pressures, including each annular space pressure, during the hydraulic fracturing operation. The maximum hydraulic pressure to which a segment of casing is exposed must not exceed the burst-pressure rating of the casing, but the Division may require a lower maximum hydraulic pressure as the Division determines is necessary. The operator shall immediately stop the hydraulic fracturing process and notify the Division if any change in annular space pressure is observed which suggests communication with the hydraulic fracturing fluids. The operator shall provide the Division with a report documenting all recorded hydraulic fracturing pressures for each stage of the hydraulic fracturing operation not later than 15 days after the completion of each stage.

3. The operator shall contain all liquids that are returned to the surface and discharged from the wellbore at the conclusion of each stage of the hydraulic fracturing operation. The operator shall contain the liquids in enclosed tanks or in the manner prescribed by the Division of Environmental Protection pursuant to chapters 445A of NRS and 445A of NAC.

4. Except as otherwise provided in subsection 5 and not later than 60 days after the completion of a hydraulic fracturing operation, the operator shall report, at a minimum, to www.fracfocus.org for inclusion in FracFocus, or its successor registry:

(a) The name of the operator, the well name and well number, and the American Petroleum Institute well number.

(b) The date of the hydraulic fracturing treatment, the county in which the well is located, any public land surveys relevant to the location of the well and the global positioning system coordinates of the well.

(c) The true vertical depth of the well and the total volume of water used in the hydraulic fracturing treatment of the well or if the operator utilizes a base fluid other than water, the type and total volume of the base fluid used in the hydraulic fracturing treatment.

(d) The identity of each additive used in the hydraulic fracturing fluid, including, without limitation, the trade name and vendor of the additive and a brief description of the intended use or function of the additive.

(e) The identity of each chemical intentionally added to the base fluid.

(f) The maximum concentration, measured in percent by mass, of each chemical intentionally added to the base fluid.

(g) The Chemical Abstracts Service Registry Number for each chemical intentionally added to the base fluid, if applicable.

5. Proprietary information with respect to a trade secret does not constitute public information and is confidential. An operator may submit a request to the Division to protect from disclosure any information which, under generally accepted business practices, would be considered a trade secret or other confidential proprietary information of the business. The Administrator shall, after consulting with the operator, determine whether to protect the information from disclosure. If the Administrator determines to protect the information from disclosure, the protected information:

(a) Is confidential proprietary information of the operator.

(b) Is not a public record. c) Must be redacted by the Administrator from any report that is disclosed to the public.

(d) May only be disclosed or transmitted by the Division:

(1) To any officer, employee or authorized representative of this State or the United States:
(I) For the purposes of carrying out any duties pursuant to the provisions of this chapter or chapter 522 of NRS; or
(II) If the information is relevant in any judicial proceeding or adversary administrative proceeding under this chapter or chapter 522 of NRS or under the provisions of any federal law relating to oil or gas wells or hydraulic fracturing, and the information is admissible under the rules of evidence; or

(2) Upon receiving the consent of the operator.
6. The Division shall make available to the public for inspection any information, other than a trade secret or other proprietary information that is maintained confidentially pursuant to subsection 5, that is submitted by an operator pursuant to this section.
7. As used in this section, "trade secret" has the meaning ascribed to it in NRS 600A.030.
Sec. 13. *1. Notwithstanding any provision of sections 2 to 12, inclusive, of this regulation to the contrary, an operator of an oil or gas well that was drilled and spudded before the effective date of this regulation may request approval from the Division to conduct a hydraulic fracturing operation at the oil or gas well by submitting a sundry notice (Form 4) to the Division. The sundry notice must include:*

(a) A cement evaluation log of the production casing string that has been conducted not less than 5 years before the submission of the sundry notice.

(b) A pressure test of the production casing string conducted in the manner prescribed by subsection 7 of NAC 522.265.

(c) Any other information required by the Division.
2. The Division will, upon receipt of a request pursuant to subsection 1, evaluate each well design which is the subject of the request and approve or disapprove the request.
Sec. 14. *An operator of an oil or gas well shall:*
1. Maintain a copy of the approved drilling permit at the site of the well during the operation of the well, including, without limitation, during the stages of drilling, hydraulic fracturing, reconditioning and completion.
2. Not less than 24 hours before a well is spudded for oil or gas, notify the Division by telephone or electronic mail.

3. Not less than 24 hours before installing or cementing casing, installing any equipment for the prevention of a blowout or conducting a formation integrity test, notify the Division by telephone or electronic mail.
4. Ensure that the casing installed in the well meets the minimum specifications for casing prescribed by the American Petroleum Institute in Specification 5CT, "Specification for Casing and Tubing, Ninth Edition," or by its successor organization, or as may be otherwise prescribed by the Administrator.

5. Notify the Division if any casing or casing material has been previously used in a hydraulic fracturing operation or in any other oil or gas well.

6. Ensure that the cementing of each casing string meets the minimum specifications prescribed by the American Petroleum Institute in Specification 10A, "Specification for Cements and Materials for Well Cementing, Twenty-Fourth Edition," or by its successor organization, or as may be otherwise prescribed by the Administrator.

7. Store and contain all materials at the site of the well in a safe and orderly manner.
8. Manage spills or releases in the manner prescribed by the Division of Environmental Protection pursuant to chapters 445A of NRS and 445A of NAC.

9. Except as otherwise provided in subsection 3 of section 12 of this regulation, contain all liquids that are returned to the surface and discharged from the wellbore in the manner prescribed by the Division of Environmental Protection pursuant to chapters 445A of NRS and 445A of NAC. A reserve pit for drilling liquids must not subsequently be used for the discharge of wellbore liquids during the testing of the well without the prior approval of the Administrator.

10. If an unintentional mechanical failure of the well or an uncontrolled flow or spill from the well site occurs, immediately notify:
(a) The Division at the telephone number of the Division.
(b) The Division of Environmental Protection at the spill reporting hotline maintained on its Internet website.

An operator may obtain information on the types of spills which must be reported pursuant to this subsection at http://ndep.nv.gov/BCA/spil_rpt.htm.
Sec. 15. *1. An operator shall take all precautions which are necessary to keep wells under control and operating safely at all times. Well control and wellhead assemblies used in an oil or gas well must meet the minimum specifications for assemblies prescribed by the American Petroleum Institute in Standard 53, "Blowout Prevention Equipment Systems for Drilling Wells, Fourth Edition," or by its successor organization, or as may be otherwise prescribed by the Administrator.*

2. Equipment for the prevention of a blowout which is capable of shutting in the well during operation must be installed on the surface casing and maintained in good operating condition at all times. The equipment must have a rating for pressure greater than the maximum anticipated pressure at the wellhead. The equipment must include casing outlet valves with adequate provisions for mud kill and bleed-off lines of appropriate size and working pressure.

3. An operator shall test the equipment for the prevention of a blowout under pressure immediately after installing the casing and the equipment at the wellhead. A representative of the Division must observe the test in person or otherwise approve the results of the test before the operator drills the shoe out of the casing. An operator shall notify the Division not less than 24 hours before conducting a test pursuant to this subsection.

4. The operator shall submit to the Division the pressure data and supporting information for the equipment for the prevention of a blowout as soon as practicable after the conclusion of the test. The operator shall record the results of each test in the daily drilling log of the operator.

Sec. 16. NAC 522.100 is hereby amended to read as follows:

522.100 "Gas well" means a well which produces primarily natural gas or any well classified as a gas well by the Division. ***The term includes an exploratory well or a well that is otherwise drilled for exploratory purposes.***

Sec. 17. NAC 522.115 is hereby amended to read as follows:
522.115 "Oil well" means any well which is not a gas well and which is capable of producing oil or condensate. ***The term includes an exploratory well or a well that is otherwise drilled for exploratory purposes.***

Sec. 18. NAC 522.210 is hereby amended to read as follows:
522.210

1. Before any well is spudded in or drilled for oil or gas, application must be made to and a permit obtained from the Division.

2. The application must be made on Form 2, properly completed and accompanied by Form 1, the required fee and a location plat prepared by a land surveyor licensed in Nevada. Evidence of a federal bond for drilling on a federal lease must be included in the space provided on Form 2. ***The source and estimated volume of water required for drilling each well must be included with the application.***

3. If the well is to be drilled on state or private land, Form 3 or 3a, properly completed, must accompany the application.

4. The Division will, upon the approval of an application for a permit to drill or a sundry notice (Form 4) for a permit to conduct a hydraulic fracturing operation, make a copy of the permit available on the Internet website maintained by the Division.

Sec. 19. NAC 522.265 is hereby amended to read as follows:

522.265 Unless a special provision requires otherwise, the following applies to all ***oil and gas*** wells **[**drilled with rotary tools:

1. Suitable and safe surface casing must be used in all wells for proper anchorage. In all wells being drilled, surface and other protection casing must be run to sufficient depth to afford safe control of any pressures which might be encountered and must be sufficiently tested therefor. Surface casing must be set into an impervious formation and be cemented with sufficient cement

to circulate to the top of the hole. If cement does not circulate, the annulus outside the casing must be cemented before drilling plug or initiating tests.

2. On all strings of casing below surface pipe, sufficient cement must be used to fill the annular volume behind the casing for a minimum distance of 500 feet above the bottom of the casing. A cement plug or shoe must not be drilled until a minimum compressive strength of 300 pounds per square inch at bottom hole conditions has been attained according to the manufacturer's tables of cement strength for the particular cement mix being used.

3. After cementing the surface casing, each well being drilled must be equipped with adequate blowout preventers. The use of blowout equipment must be in accordance with good established oil field practice. The control equipment must include casing outlet valves with adequate provisions for mudkill and bleed-off lines of proper size and working pressure. All equipment must be in good operating condition at all times.**]** ***:***

1. An operator shall install conductor casing and cement the annular space surrounding the conductor casing from the shoe to the surface with cement, cement grout or concrete grout.

2. An operator shall install surface casing to a depth of not less than 500 feet below the surface of the ground. The annular space surrounding the surface casing string must be cemented with sufficient cement to circulate to the top of the hole. If the cement does not circulate to the top of the hole, the operator shall:

(a) Measure the distance from the surface of the ground to the top of the cement and report the measurement to the Division.
(b) Take any remedial action that may be required by the Administrator to ensure compliance with NAC 522.260 before the operator resumes drilling or conducts any testing pursuant to this section.

3. Except as otherwise provided in section 11 of this regulation, each successive intermediate casing string or liner or production casing string or liner installed in a well below an existing casing string must overlap with the shoe of the existing casing string or liner, as applicable, by not less than 100 feet.

4. For each intermediate casing string or production casing string installed in a well, the operator shall cement the annular space surrounding the casing string to a depth of not less than 500 feet above the shoe of the casing string or, if the casing string enters a known hydrocarbon-producing zone of interest, to a depth of not less than 500 feet above the zone of interest.

5. As soon as practicable after an operator has completed the cementing of the surface casing string, an intermediate casing string or a production casing string, the operator shall submit to the Division a cementing evaluation report to ensure that the operator has complied with the cementing requirements prescribed by this section. The report must include, without limitation, the weight and volume of cementing materials used to cement the respective casing string and the pumping rates and pressures which are related to the cementing of the respective casing string.

6. If the Administrator determines that an operator must take remedial action to ensure compliance with NAC 522.260, the operator shall complete such remedial action before the operator resumes drilling or conducts any testing pursuant to this section.

7. Except as otherwise provided by section 11 of this regulation, before drilling the cement out of the bottom joints of the surface casing string, an intermediate casing string or a production casing string, an operator shall conduct a pressure test of the respective casing string in which the casing is pressurized to 0.22 pounds per square inch gauge (psig) per foot of casing string length or 1,500 pounds per square inch gauge (psig), whichever is greater, not to exceed the maximum anticipated bottom-hole pressure or 80 percent of the burst-pressure rating of the casing. The casing string must be pressurized for a period of not less than 30 minutes. The operator shall submit to the Division the pressure test results for the respective casing string as soon as practicable after the conclusion of the test. If the results of the test indicate a drop in pressure of 10 percent or more, the operator shall notify the Division of a failed pressure test and shall immediately cease operations at the well. In the event of a failed pressure test, an operator shall not resume operations at the well until the Administrator approves a remediation plan, the operator successfully implements the plan and the operator conducts a successful pressure test for the respective casing string. A subsequent pressure test resulting in a drop in pressure of less than 10 percent after 30 minutes or more shall be deemed to be proof satisfactory that the condition has been corrected.

8. The Administrator may require the operator to submit a cement evaluation log evaluating the bonding integrity of the cement from the shoe of the surface casing string to the surface. The Administrator may require the submission of an initial cement evaluation log pursuant to this subsection if:

(a) The Administrator determines that a significant amount of cement was lost during the cementing of the surface casing string; or
(b) The surface casing string fails a formation integrity test conducted pursuant to subsection 10.

9. An operator shall, upon completion of cementing operations with respect to an intermediate casing string or production casing string, submit to the Division a cement evaluation log evaluating the bonding integrity of the cement at the level of the respective casing string from the shoe of the casing string to the surface of the cement filling the annular space surrounding the casing string. If the initial cement evaluation log does not indicate sufficient bonding integrity of the cement occupying the annular space, the Administrator may require the operator to submit a subsequent cement evaluation log evaluating the bonding integrity of the cement occupying the annular space. An operator shall provide to the Division a copy of each cement evaluation log required pursuant to this subsection as soon as practicable after a copy of the cement bond log becomes available to the operator.

10. An operator shall, to verify that the cement and the formation below the casing shoe can withstand the wellbore pressure which is required to safely drill to the next depth at which casing will be installed, conduct a formation integrity or leakoff test at the time the operator drills the cement out of the bottom joints of the surface casing string, an intermediate casing string or a production casing string. The operator shall submit to the Division the results of a formation integrity or leakoff test conducted pursuant to this subsection as soon as practicable after the conclusion of the test. If the results of the formation integrity or leakoff test indicate

a poor cement bond at the casing shoe, an operator shall not resume operations at the well until the Administrator approves a remediation plan, the operator successfully implements the plan and the operator conducts a successful pressure test for the respective casing string to ensure compliance with NAC 522.260.

Sec. 20. NAC 522.342 is hereby amended to read as follows:
522.342

1. The amount of the administrative fee that a producer or purchaser of oil or natural gas must pay pursuant to subsection 2 of NRS 522.150 is **[**10**]** ***15*** cents per barrel of oil or per 50,000 cubic feet of natural gas, as appropriate.

2. The administrative fee must be paid on or before the last day of each month and must be prorated to reflect the amount of oil or natural gas produced during the preceding month.
Sec. 21. NAC 534A.270 is hereby amended to read as follows:

534A.270 1. **[**All necessary**]** ***An operator shall take all*** precautions **[**must be taken**]** ***which are necessary*** to keep wells under control and operating safely at all times. ***Well control and***

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wellhead assemblies used in any geothermal well must meet the minimum specifications for assemblies prescribed by the American Petroleum Institute in Standard 53, "Blowout Prevention Equipment Systems for Drilling Wells, Fourth Edition," or by its successor organization, or as may be otherwise prescribed by the Administrator.

2. Equipment for the prevention of a blowout, capable of shutting in the well during any operation, must be installed on the surface casing and maintained **[**ready for use**]** ***in good operating condition*** at all times. This equipment must **[**be made of steel and**]** have a rating for pressure **[**equal to**]** ***greater than*** the maximum anticipated pressure at the wellhead. Equipment for the prevention of a blowout is required on any well where temperatures may exceed 250°F.

3. **[**Immediately after installation, the casing and**]** ***An operator shall test the*** equipment for the prevention of a blowout **[**must be tested**]** under pressure. **[**These tests must be witnessed by**]** ***A representative of*** the Division ***must observe the test in person or otherwise approve the results of the test*** before the **[**guide**]** ***operator drills the casing*** shoe **[**is drilled**]** out of the casing. **[**The Division must be given reasonable notice of any such test. If necessary, conductor pipe must be equipped with annular blowout equipment which is hydraulically activated from a remote control station.**]** ***An operator shall notify the Division not less than 24 hours before conducting a test pursuant to this subsection.***

3. The **[**use of any equipment for the prevention of a blowout must be in accordance with established good practices of the oil field.**]** ***operator shall submit to the Division the pressure data and supporting information for the equipment for the prevention of a blowout as soon as practicable after the conclusion of the test conducted pursuant to subsection 3. The operator shall record the results of each test in the daily drilling log of the operator.***

Sec. 22. NAC 522.270 and 522.343 are hereby repealed.

TEXT OF REPEALED SECTIONS

522.270 Wells drilled with cable tools. The following applies to all wells drilled with cable tools:

1. Before drilling begins, adequate slush pits must be constructed.
2. Surface casing must be set in the same manner as described in NAC 522.265. Surface casing must be tested by bailing or pressure test to ensure a shutoff before drilling proceeds below the casing point.
3. The use of blowout equipment must be in accordance with good established oil field practice. After cementing the surface casing, a well being drilled must be equipped with adequate blowout preventers. All equipment must be in good operating condition at all times.

522.343 Reduced administrative fee for new production. (NRS 522.040, 522.150)

1. Notwithstanding the provisions of NAC 522.342, the amount of the administrative fee that a producer or purchaser of oil or natural gas must pay pursuant to subsection 2 of NRS 522.150 for new production is one-half cent per barrel of oil or per 50,000 cubic feet of natural gas, as appropriate, and in accordance with the provisions of this section.

2. Upon the filing of Form 5, the well completion report, pursuant to NAC 522.510, the Division shall determine whether the production from the well that is the subject of the report qualifies as new production. If the Division determines that the production from the well qualifies as new production, the producer or purchaser is entitled to pay the administrative fee required by subsection 2 of NRS 522.150 for that new production at the reduced rate prescribed in subsection 1 for 12 consecutive calendar months, beginning on the put-on-production date reported in Form 5 for that well. At the end of the 12-month period, the producer or purchaser must pay the administrative fee required by NRS 522.150 for further production from the well in the amount prescribed in NAC 522.342.
3. A producer or purchaser may, pursuant to NRS 522.110, challenge a determination made by the Division pursuant to subsection 2.

4. As used in this section, “new production” means production from a new or existing well that is completed in a new interval, as determined by the Division.

APPENDIX I OIL AND GAS; HYDRAULIC FRACTURING ON FEDERAL AND INDIAN LANDS

Proposed Rulemaking

The Bureau of Land Management (BLM) is proposing a rule to regulate hydraulic fracturing on public land and Indian land. The rule would (1) provide disclosure to the public of chemicals used in hydraulic fracturing on public land and Indian land, (2) strengthen regulations related to well-bore integrity, and (3) address issues related to flowback water. This rule is necessary to provide useful information to the public and to assure that hydraulic fracturing is conducted in a way that adequately protects the environment.

DATES: Send your comments on this proposed rule to the BLM on or before [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]. The BLM need not consider, or include in the administrative record for the final rule, comments that the BLM receives after the close of the comment period or comments delivered to an address other than those listed below (see ADDRESSES). If you wish to comment on the information collection requirements in this proposed rule, please note that the Office of Management and Budget (OMB) is required to make a decision concerning the collection of information contained in this proposed rule between 30 to 60 days after publication of this document in the Federal Register. Therefore, a comment to OMB is best assured of having its full effect if OMB receives it by [INSERT DATE 30 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER].
ADDRESSES: Mail: U.S. Department of the Interior, Director (630), Bureau of Land Management, Mail Stop 2134 LM, 1849 C St., NW, Washington, DC 20240, Attention: 1004–AE26. Personal or messenger delivery: Bureau of Land Management, 20 M Street, SE, Room 2134 LM, Attention: Regulatory Affairs, Washington, DC 20003. Federal eRulemaking Portal: http://www.regulations.gov. Follow the instructions at this Website.

Comments on the information collection requirement: Fax: Office of Management and Budget (OMB), Office of Information and Regulatory Affairs, Desk Officer for the Department of the Interior, fax 202-395-5806. Electronic mail: oira_docket@omb.eop.gov. Please indicate "Attention: OMB Control Number 1004-XXXX," regardless of the method used to submit comments on the information collection burdens. If you submit comments on the information

FOR FURTHER INFORMATION CONTACT: Steven Wells, Division Chief, Fluid Minerals Division, 202-912-7143 for information regarding the substance of the rule or information about the BLM's Fluid Minerals Program. Persons who use a telecommunications device for the deaf (TDD) may call the Federal Information Relay Service (FIRS) at 1-800-877-8339 to contact the above individual during normal business hours. FIRS is available 24 hours a day, 7 days a week to leave a message or question with the above individual. You will receive a reply during normal business hours.

SUPPLEMENTARY INFORMATION:
Executive Summary
"Hydraulic fracturing," a process used to stimulate production from oil and gas wells, has been a growing practice in recent years. Public awareness of fracturing has grown as new horizontal drilling technology has allowed increased access to shale oil and gas resources across the country, sometimes in areas that have not previously experienced significant oil and gas development. The extension of the practice has caused public concern about whether fracturing can allow or cause the contamination of underground water sources, whether the chemicals used in fracturing should be disclosed to the

public, and whether there is adequate management of well integrity and the “flowback” fluids that return to the surface during and after fracturing operations.

The Bureau of Land Management (BLM) oversees approximately 700 million subsurface acres of Federal mineral estate and 56 million subsurface acres of Indian mineral estate across the United States. The BLM proposes to modernize its management of well stimulation activities, including hydraulic fracturing, to ensure that fracturing operations conducted on the public mineral estate (including split estate where the Federal Government owns the subsurface mineral estate) follow certain best practices, including: (1) the public disclosure of chemicals used in hydraulic fracturing operations on Federal lands; (2) confirmation that wells used in fracturing operations meet appropriate construction standards; and (3) a requirement that operators put in place appropriate plans for managing flowback waters from fracturing operations.

The BLM proposes to apply the same rules and standards to Indian lands so that these lands and communities receive the same level of protection provided for public lands. Most of these requirements in this rule can be satisfied by submitting additional information during the process that the BLM currently applies to operators who are drilling on public or Indian lands. The proposed rule would require that disclosure of the chemicals used in the fracturing process be provided to the BLM after the fracturing operation is completed. This information is intended to be posted on a public web site, and the BLM is working with the Ground Water Protection Council to determine whether the disclosure can be integrated into the existing website known as FracFocus.org.

The BLM has developed the draft with an eye toward improving public awareness and oversight without introducing complicated new procedures or delays in the process of developing oil and gas resources on public and Indian lands. Some states have started requiring similar disclosures and oversight for oil and gas drilling operations under their own jurisdiction. This proposal seeks to create a consistent oversight and disclosure model that will work in concert with other regulators’ requirements while protecting Federal and tribal interests and resources.

The BLM proposes these changes to existing well stimulation oversight partly in response to recommendations put forward by the Secretary of Energy’s Energy Advisory Board in 2011. Also, current BLM regulations governing hydraulic fracturing operations on public lands are more than 30 years old and were not written to address modern hydraulic fracturing activities. In preparing this proposed rule, the BLM has received input from members of the public and stakeholders, and has initiated consultation with tribal representatives. The BLM is looking forward to obtaining additional public input and to ongoing tribal consultations regarding the specific proposed provisions that are set forth herein.

The BLM has analyzed the costs and the benefits of this proposed action in an accompanying Regulatory Impact Analysis available in the rulemaking docket. The estimated benefits range from $12 million to $50 million per year, with the range being based on the discount rate used for the analysis, and the estimates of the underlying risk reduced, and remediation costs avoided, by the regulation. The estimated costs range from $37 million to $44 million per year, and do not vary based on the uncertainty in the underlying risk reduced by the rule. Given the assumptions made about the costs of remediating contamination and the fact that certain benefits were not quantified, the BLM believes that the quantified range of estimated outcomes could underestimate actual net benefits.

I. Public Comment Procedures

II. Background

III. Discussion of the Proposed Rule

IV. Procedural Matters

I. Public Comment Procedures
If you wish to comment, you may submit your comments by any one of several methods: Mail: You may mail comments to U.S. Department of the Interior, Director (630), Bureau of Land Management, Mail Stop 2134LM, 1849 C Street, NW, Washington, DC 20240, Attention: 1004-AE26. Personal or messenger delivery: Bureau of Land Management, 20 M Street, SE, Room 2134 LM, Attention: Regulatory Affairs, Washington, DC 20003. Federal eRulemaking Portal:

http://www.regulations.gov.

Follow the instructions at this Website.
You may submit comments on the information collection burdens directly to the Office of Management and Budget, Office of Information and Regulatory Affairs, Desk Officer for the Department of the Interior, fax 202-395-5806, or oira_docket@omb.eop.gov. Please include "Attention: OMB Control Number 1004-XXXX" in your comments. If you submit comments on the information collection burdens, please provide the BLM with a copy of your comments, at one of the addresses shown above.

Please make your comments as specific as possible by confining them to issues directly related to the content of this proposed rule, and explain the basis for your comments. The comments and recommendations that will be most useful and likely to influence agency decisions are:
1. Those supported by quantitative information or studies; and
2. Those that include citations to, and analyses of, the applicable laws and regulations.
The BLM is not obligated to consider or include in the Administrative Record for the rule comments received after the close of the comment period (see **DATES**) or comments delivered to an address other than those listed above (see **ADDRESSES**).
Comments, including names and street addresses of respondents, will be available for public review at the address listed under **ADDRESSES** during regular hours (7:45 a.m. to 4:15 p.m.), Monday through Friday, except holidays.
Before including your address, telephone number, e-mail address, or other personal identifying information in your comment, be advised that your entire comment—including your personal identifying information—may be made publicly available at any time. While you can ask in your comment to withhold from public review your personal identifying information, we cannot guarantee that we will be able to do so.

II. Background
Well stimulation techniques, such as hydraulic fracturing, are used by oil and natural gas producers to increase the volumes of oil and natural gas that can be extracted from wells. Hydraulic fracturing techniques are particularly effective in enhancing oil and gas production from "shale" gas or oil formations. Until quite recently, shale formations rarely produced oil or gas in commercial quantities because shale does not generally generate flow of hydrocarbons to well bores unless mechanical changes to the properties of the rock can be induced. The development of horizontal drilling, combined with hydraulic fracturing, have made the production of oil and gas from shale possible.

Hydraulic fracturing involves the injection of fluid under high pressure to create or enlarge fractures in the reservoir rocks. The fluid that is used in hydraulic fracturing is usually accompanied by proppants, such as particles of sand, that are carried into the newly fractured rock and help keep the fractures open once the pressure from the fracturing operation is released. The proppant-filled fractures become conduits for fluid migration from the reservoir rock to the wellbore and the fluid is subsequently brought to the surface. In addition to the water and sand (which together typically make up 98 to 99 percent of the materials pumped into a well during a fracturing operation), chemical additives are also frequently used. These chemicals can serve many functions in hydraulic fracturing, including limiting the growth of bacteria and preventing corrosion of the well casing. The exact formulation of the chemicals used varies depending on the rock formations, the well, and the requirements of the operator.

The BLM estimates that about 90 percent (approximately 3,400 wells per year) of wells currently drilled on Federal and Indian lands are stimulated using hydraulic fracturing techniques. Over the past 10 years, there have been significant technological advances in horizontal drilling, which is frequently combined with hydraulic fracturing. This combination, together with the discovery that these techniques can release significant quantities of oil and gas from large shale deposits, has led to production from geologic formations in parts of the country that previously did not produce significant oil or gas. The resulting expansion of oil and gas drilling into new parts of the country as a result of the availability of new horizontal drilling technologies has significantly increased public awareness of hydraulic fracturing and the potential impacts that it may have on water quality and water consumption.

The BLM's existing hydraulic fracturing regulations are found at 43 CFR 3162.3-2. These regulations were established in 1982 and last revised in 1988, long before the latest hydraulic fracturing technologies became widely used. In response to public interest in hydraulic fracturing and in the BLM's regulation of hydraulic fracturing, in particular, the Department of the Interior (Department) held a forum on hydraulic fracturing on November 30, 2010 in Washington, DC, attended by the Secretary of the Interior and more than 130 interested parties. The BLM later hosted public forums in Bismarck, North Dakota on April 20, 2011; Little Rock, Arkansas on April 22, 2011; and Golden, Colorado on April 25, 2011, to collect broad input on the issues surrounding hydraulic fracturing. More than 600 members of the public attended the April forums. Some of the comments frequently heard during these forums included concerns about water quality, water consumption, and a desire for improved environmental safeguards for surface operations. Commenters also strongly encouraged the agency to require public disclosure of the chemicals used in hydraulic fracturing operations on Federal and Indian lands.

Around the time of the BLM's forums, at the President's direction, the Secretary of Energy's Advisory Board convened a Natural Gas Subcommittee (Subcommittee) to evaluate hydraulic fracturing issues. The Subcommittee met with industry, service providers, state and Federal regulators, academics, environmental groups, and many others stakeholders. Initial recommendations were issued by the Subcommittee on August 18, 2011. Among other things, the report recommended that more information be provided to the public, including disclosure of the chemicals used in fracturing fluids. The Subcommittee also recommended the adoption of progressive standards for wellbore construction and testing. The initial report was followed by a final report that was issued on November 18, 2011. The final report recommended, among other things, that operators engaging in hydraulic fracturing prepare cement bond logs and undertake pressure testing to ensure the integrity of all casings.

These reports are available to the public from the Department of Energy's web site at http://www.shalegas.energy.gov.

The BLM's proposed rule is consistent with the American Petroleum Institute's (API) guidelines for well construction and well integrity (see API Guidance Document HF 1, Hydraulic Fracturing Operations—Well Construction and Integrity Guidelines, First Edition, October 2009).
Based on the input provided from a broad array of sources, including the individuals who spoke at the BLM's public forums and the recommendations of the Subcommittee, the BLM is proposing to make critical improvements to its regulations for hydraulic fracturing. The proposed regulations would be applied to all wells administered by the BLM, including those on Federal, tribal, and individual Indian trust lands.

Tribal consultation is a critical part of this effort, and the Department is committed to making sure tribal leaders play a significant role as we work together to develop resources on public and Indian lands in a safe and responsible way. The BLM has initiated government-to-government consultation with tribes on this proposal and has offered to hold follow-up consultation meetings with any tribe that desires to have an individual meeting. The BLM held four tribal consultation meetings, to which over 175 tribal entities were invited. These initial consultations were held in Tulsa, Oklahoma on January 10, 2012; in Billings, Montana on January 12, 2012; in Salt Lake City, Utah on January 17, 2012; and in Farmington, New Mexico on January 19, 2012. Eighty-one tribal members representing 27 tribes attended the meetings.

In these sessions, tribal representatives were given a discussion draft of the hydraulic fracturing rule to serve as a basis for substantive dialogue about the hydraulic fracturing rulemaking process. The BLM asked the tribal leaders for their views on how a hydraulic fracturing rule proposal might affect Indian activities, practices, or beliefs if it were to be applied to particular locations on Indian and public lands. A variety of issues were discussed, including applicability of tribal laws, validating water sources, inspection and enforcement, wellbore integrity, and water management, among others. Additional individual consultations with tribal representatives have taken place since that time. One of the outcomes of these meetings is the proposed requirement in this rule that operators certify that operations on tribal lands comply with tribal laws.

The BLM has been and will continue to be proactive about tribal consultation under the Department's newly-formalized Tribal Consultation Policy, which emphasizes trust, respect and shared responsibility in providing tribal governments an expanded role in informing Federal policy that impacts Indian lands. The BLM will continue to consult with tribal leaders throughout the rulemaking process. Responses from tribal representatives will inform the agency's actions in defining the scope of acceptable hydraulic fracturing rule options. Tribal governments, tribal members, and individual Native Americans are also invited to comment directly on this proposed rule through the process described in the Public Comment Procedures section of this document.
Over the past few years, in response to strong public interest, several states—including Colorado, Wyoming, Arkansas, and Texas—have substantially revised their state regulations related to hydraulic fracturing. One of the BLM's key goals in updating its regulations on hydraulic fracturing is to complement these state efforts by providing a consistent standard across all public and Indian lands.

The BLM is also actively working to minimize any duplication between the reporting required for state regulations and for this regulation and to make reported information consistent and easily accessible to the public. For instance, the BLM is working closely with the Ground Water Protection

Council and the Interstate Oil and Gas Commission in an effort to integrate the disclosure called for in this rule with the existing website known as FracFocus. The FracFocus.org website is already well established and used by many states. This online database includes information from oil and gas wells in roughly 12 states and includes information from over 206 companies. The BLM understands that the database is in the process of being improved and will in the near future have enhanced search capabilities and allow for easier reporting of information.

The BLM recognizes the efforts of states to regulate hydraulic fracturing and is focused on coordinating closely with individual state governments to avoid duplicative regulatory requirements. The agency has a long history of working cooperatively with state regulators and the BLM often enters into memorandums of understanding or establishes working groups to coordinate state and Federal activities, such as the oil and gas working groups that currently exist in many of our oil and gas states.

The BLM is applying the same approach to this effort and will work closely with individual states on the implementation of the proposed regulation. The BLM's intent is to encourage efficiency in the collection of data and the reporting of information. The BLM routinely shares information on oil and gas operations with state regulatory authorities and the BLM will continue to work with individual states to ensure that duplication of efforts is avoided to the extent possible. Since the BLM is looking for all opportunities to avoid duplication of the collection of data and the reporting of information, we are specifically asking for public comment on how best to avoid duplication of requirements under this proposed rule with existing state requirements.

The BLM acknowledges that some states already have in place rules and regulations that address hydraulic fracturing and that these rules may be either more or less stringent than the provisions in this proposal. In keeping with longstanding practice and consistent with relevant statutory authorities, it is the intention of the BLM to implement on public lands whichever rules, state or Federal, are most protective of Federal lands and resources and the environment.

III. Discussion of the Proposed Rule

The BLM proposes to revise its hydraulic fracturing regulations, found at 43 CFR 3162.3-2, and adding a new section 3162.3-3. Existing section 3162.3-3 would be retained and renumbered. The Federal Land Policy and Management Act (FLPMA) directs the BLM to manage the public lands so as to prevent unnecessary or undue degradation, and to manage lands using the principles of multiple use and sustained yield. FLPMA declares multiple use to mean, among other things, a combination of balanced and diverse resource uses that takes into account long-term needs of future generations for renewable and non-renewable resources. FLPMA also requires that the public lands be managed in a manner that will protect the quality of their resources, including ecological, environmental, and water resources. The Mineral Leasing Act and the Mineral Leasing Act for Acquired Lands authorize the Secretary to lease Federal oil and gas resources, and to regulate oil and gas operations on those leases, including surface-disturbing activities. The Indian Mineral Leasing Act assigns regulatory authority to the Secretary over Indian oil and gas leases on trust lands (except those excluded by statute).

As stewards of the public lands, and as the Secretary's regulator for oil and gas leases on Indian lands, the BLM has evaluated the increased use of well stimulation practices over the last decade and determined that the existing rules for well stimulation require updating.

The current regulations make a distinction between routine fracture jobs and nonroutine fracture jobs. However, the terms "routine" and "nonroutine" are not defined in 43 CFR 3162.3-2 or anywhere else in BLM regulations, making this distinction functionally difficult to apply and confusing for both the agency and those attempting to comply with the regulations. As previously stated, the regulations are now 30 years old and need to be updated to keep pace with the many changes in technology and current best management practices. As discussed in the background section of this document, the increased use of well stimulation activities over the last decade has also generated concerns among the public about well stimulation and about the chemicals used in hydraulic fracturing. The proposed rule is intended to increase transparency for the public regarding the fluids used in the hydraulic fracturing process, in addition to providing assurances that well bore integrity is maintained throughout the fracturing process and that the fluids that flow back to the surface from hydraulic fracturing operations are properly stored and disposed of or treated.

The following chart explains the major changes between the existing regulation(s) and the proposed regulation(s).

Existing Regulation	Proposed Regulation	Substantive changes
43 CFR 3160.0-5 Onshore oil and Gas	43 CFR 3160.0-5 Onshore oil and Gas	This proposal would replace the current definition of usable water found in 43 CFR
Operations: General Definitions	Operations: General Definitions	3162.5-2(d) and define six other terms used in the oil and gas drilling industry to make the rule clearer and easier to understand. The definitions would be consistent with those used in the BLM's Oil and Gas Onshore Orders and by industry.
43 CFR 3162.3-2(a) Subsequent Well Operations	43 CFR 3162.3-2(a) Subsequent Well Operations	This proposal would remove the phrase "performing nonroutine fracturing jobs."
43 CFR 3162.3-2(b) Subsequent Well Operations	43 CFR 3162.3-2(b) Subsequent Well Operations	This proposal would remove the phrase "routine fracturing or acidizing jobs, or . . ."
No existing regulation	43 CFR 3162.3-3(a) through (j)	This proposal would add provisions addressing well stimulation operations, would require disclosure of well stimulation fluids, and would require approval of well stimulation operations. The proposed rule

		would also require that mechanical integrity tests be conducted before well stimulation activities are conducted and would require full reporting of the results of the well stimulation activity within thirty days of its completion. This proposal would also add a section allowing the authorized officer to grant a variance to specific conditions of these rules if the operator can demonstrate that alternative procedures would meet or exceed the intent of the minimum standards in this rule. This variance language is consistent with that found in the BLM's Oil and Gas Onshore Orders.
43 CFR 3162.5-2(d) Protection of fresh water and other minerals	43 CFR 3162.5-2(d) Protection of fresh water and other minerals	This proposal removes the definition of usable water from this section. The new definition of usable water would be placed in 43 CFR 3160.0-5.

The proposed rule would remove the terms "nonroutine fracturing jobs," "routine fracturing jobs," and "acidizing jobs" from 43 CFR 3162.3-2(a) and 43 CFR 3162.3-2(b). It would add a new section, 43 CFR 3162.3-3, for well stimulation activities. In the proposed rule, there would be no distinction drawn between what was previously considered nonroutine or routine well stimulations. Prior approval would be required for well stimulation activities, generally in connection with the prior approval process that already is in place for general well drilling activities through the Application for Permit to Drill (APD) process. Operators also will be required to submit cement bond logs before fracturing operations begin. The running of cement bond logs on surface casing, which is currently an optional practice, would now be required for new wells. Existing wells would require mechanical integrity testing prior to hydraulic fracturing.

The proposed rule would include six new definitions for technical terms used in the proposed rule. These definitions will improve readability and clarity of the regulations.

The proposed rule intends to add the following definitions:

• Annulus means the space around a pipe in a wellbore, the outer wall of which may be the wall of either the borehole or the casing; sometimes also called the annular space.

• Bradenhead means a heavy, flanged steel fitting connected to the first string of casing that allows suspension of intermediate and production strings of casing, and supplies the means for the annulus to be sealed off.

 Proppant means a granular substance (most commonly sand, sintered bauxite, or ceramic) that is carried in suspension by the fracturing fluid and that serves to keep the cracks open when fracturing fluid is withdrawn after a hydraulic fracture treatment.

• Stimulation fluid means the liquid or gas, and any accompanying solids, used during a treatment of oil and gas wells, such as the water, chemicals, and proppants used in hydraulic fracturing.

• Usable water means water containing up to 10,000 ppm of total dissolved solids.

• Well stimulation means those activities conducted in an individual well bore designed to increase the flow of hydrocarbons from the rock formation to the well bore by modifying the permeability of the reservoir rock. Examples of well stimulation operations are acidizing and hydraulic fracturing. The proposed rule would delete the definition of "fresh water." The BLM has maintained a definition of fresh water in its oil and gas operating regulations since 1988. However, in its onshore orders, the BLM has sought to protect all usable waters during drilling operations, not just fresh water. This distinction has led to confusion in the regulations. Usable water includes fresh water and water that is of lower quality than fresh water. The BLM intends to be more protective when it seeks to protect all usable water during drilling operations, not just fresh water. Therefore, the BLM proposes to delete the definition of fresh water.

Revised section 3162.3-2(a) would remove the phrase "perform nonroutine fracturing jobs" from the current 43 CFR 3162.3-2(a). The phrase "routine fracturing jobs or acidizing jobs, or" would also be removed from existing section 3162.3-2(b). Well stimulation activities would be addressed under the new proposed 43 CFR 3162.3-3.

Proposed section 3162.3-3(a) would make it clear that this section applies only to well stimulation activities and that all other injection activities must comply with section 3162.3-2. This language is necessary to make the distinction between well stimulation activities and other well injection activities, such as secondary and tertiary recovery operations.

Proposed section 3162.3-3(b) would require the BLM's approval of all well stimulation activity. For new wells, the operator has the option of applying for the BLM's approval in its application for permit to drill (APD). For wells permitted prior to the effective date of this section or for wells permitted after the effective date of this section, the operator would submit a Sundry Notice and Report on Wells (Form 3160-5) for the well stimulation proposal for the BLM's approval before the operator begins the stimulation activity. This section would supersede and replace existing section 3162.3-2(b) that states that no prior approval is required for routine fracturing. This reference in the existing section would be deleted. Also, an operator must submit a Sundry Notice prior to well stimulation activity if the BLM's previous approval for well stimulation is more than five years old, or if the operator becomes aware of significant new information about the relevant geology, the stimulation operation or technology, or the anticipated impacts to any resource. The five-year period is consistent with common state practices, including those of Montana, Wyoming, and Colorado, which require that operators reconfirm well integrity for fracturing operations through a pressure test every five years.

The BLM understands the time sensitive nature of oil and gas drilling and well completion activities and does not anticipate that the submittal of additional well stimulation-related information with APD applications will impact the timing of the approval of drilling permits. The BLM believes that the additional incremental information that would be required by this rule would be reviewed in conjunction with the APD and within the normal APD processing time frame. Also, the BLM anticipates that requests to conduct well stimulation activities on existing wells that have been in service more than five years will be reviewed promptly. The BLM understands that delays in approvals of operations can be costly to operators and the BLM intends to avoid delays whenever possible.

Proposed section 3162.3-3(c)(1) would require a report that includes the geological names, a geological description, and the depth of the top and the bottom of the formation into which well stimulation fluids would be injected. The report is needed so that the BLM may determine the properties of the rock layers and the thickness of the producing formation and identify the confining rocks above and below the zone that would be stimulated.

Proposed section 3162.3-3(c)(2) would require the operator to submit information in the form of a cement bond log, which will help the BLM in its efforts to make sure that water resources are protected. A cement bond log is a tool used to gauge the extent to which water bearing formations are isolated from the casing string. The log is a document that reports the data from a probe of the wellbore that uses sonic technology to detect gaps or voids in the cement and the casing. This log would be used to verify that the operator has taken the necessary precautions to prevent migration of fluids in the annulus from the fracture zone to the usable water horizons.

The proposed regulation would allow for the use of other evaluation tools acceptable to the BLM in order to allow the substitution of equally effective tools or procedures. For example, an operator could request a variance from the requirements of proposed section 3162.3-3(c)(2) that it submit cement bond logs to prove that the occurrences of usable water have been isolated to protect them from contamination. The BLM could grant a variance to allow for the use of logs other than cement bond logs (e.g., slim array sonic tool, ultrasonic imager tool) if it was satisfied that the alternative logs would meet or exceed the objectives of section (c)(2).

The BLM recognizes that the cement bond log would not be available prior to drilling a well. Therefore, when the operator takes advantage of the option to submit its well stimulation information as part of its APD, the cement bond log would be required after approval of the permit to drill and prior to commencing well stimulation activities. Many operators routinely perform cement bond logs for the zones of interest, so the BLM does not expect this step to be a burden for operators. The best available means for the BLM to help ensure that well stimulation activities do not contaminate aquifers is to require cement bond logs for the cement behind the pipe along all areas intersecting useable water, including running cement bond logs on the surface casing.

Proposed section 3162.3-3(c)(3) would require reporting of the measured depth to the perforations in the casing and uncased hole intervals (open hole). This proposed section would also require the operator to disclose specific information about the water source to be used in the fracturing operation, including the location of the water that would be used as the base fluid. The BLM needs this information to determine the impacts associated with operations and the need for any mitigation applicable to Federal and Indian lands. This section would also require the operator to disclose the type of materials (proppants) that would be injected into the fractures to keep them open and the anticipated pressures to be used in the well stimulation operation.

Proposed section 3162.3-3(c)(4), consistent with protecting public health and safety and preventing unnecessary or undue degradation to the public lands, would require operators to certify in writing that they have complied with all applicable Federal, tribal, state, and local laws, rules, and regulations pertaining to proposed stimulation fluids.

The BLM will use this information to make an informed decision on the proposed action. This section also would require the operator to certify that it has complied with all necessary permit and notice requirements. The BLM acknowledges that other Federal, state, tribal, and local agencies may have regulatory requirements that would apply to chemical handling, injecting fluids into the subsurface, and the protection of groundwater.

It remains the responsibility of the operator to be aware of and comply with these regulatory requirements. The BLM will rely on the operator's certification that it has complied with all of the laws and regulations that apply to its operation.

Proposed section 3162.3-3(c)(5) would require the operator to submit a detailed description of the well stimulation engineering design to the BLM for approval. This information is needed in order for the BLM to be able to verify that the proposed engineering design is adequate for safely conducting the proposed well stimulation.

Proposed section 3162.3-3(c)(5)(i) would require the operator to submit to the BLM an estimate of the total volume of fluid to be used in the stimulation.

Proposed section 3162.3-3(c)(5)(ii) would require the operator to submit to the BLM a description of the range of the surface treating pressures anticipated for the stimulation. This information is needed by the BLM to verify that the maximum wellbore design burst pressure will not be exceeded at any stage of the well stimulation operation.

Proposed section 3162.3-3(c)(5)(iii) would require the operator to submit to the BLM the proposed maximum anticipated injection pressure for the stimulation. This information is needed by the BLM to verify that the maximum allowable injection pressure will not be exceeded at any stage of the well stimulation operation.

Proposed section 3162.3-3(c)(5)(iv) would require the operator to submit to the BLM the estimated or calculated fracture length and height anticipated as a result of the stimulation, so that the BLM can verify that the intended effects of the well stimulation operation will remain confined to the petroleum-bearing rock layers and will not have unintended consequences on other rock layers, such as aquifers.

Proposed section 3162.3-3(c)(6) would require the operator to provide information pertaining to the handling of recovered fluids that will be used for the stimulation activities for approval. This information is being requested so that the BLM has all necessary information regarding chemicals being used in the event that the information is needed to help protect health and safety or to prevent unnecessary or undue degradation of the public lands.

Proposed section 3162.3-3(c)(6)(i) would require the operator to submit to the BLM an estimate of the volume of fluid to be recovered during flow back, swabbing, and recovery from production facility vessels. This information is required to ensure that the facilities needed to process or contain the estimated volume of fluid will be available on location.

Proposed section 3162.3-3(c)(6)(ii) would require the operator to submit to the BLM the proposed methods of managing the recovered fluids. This information is needed to ensure that the handling methods will adequately protect of public health and safety.

Proposed section 3162.3-3(c)(6)(iii) would require the operator to submit to the BLM a description of the proposed disposal method of the recovered fluids. This is currently required by existing BLM regulations (i.e., Onshore Order Number 7, Disposal of Produced Water, (58 FR 47354). This information is requested so that the BLM has all necessary information regarding disposal of chemicals used in the event it is needed to protect the environment and human health and safety and to prevent unnecessary or undue degradation of the public lands. The BLM specifically requests comments on whether the operator should be required to submit as part of the Sundry Notice application additional information about how it will dispose of waste streams not specifically addressed in this proposal.

Proposed section 3162.3-3(c)(7) would require the operator to provide, at the request of the BLM, additional information pertaining to any facet of the well stimulation proposal. For example, the BLM may require new or different tests or logs in cases where the original information submitted was inadequate, out of date, or incomplete. Any new information that the BLM may request will be limited to information necessary for the BLM to ensure that operations are consistent with applicable laws and regulation. Such information may include, but is not limited to, tabular or graphical results of a mechanical integrity test, the results of logs run, the results of tests showing the total dissolved solids in water proposed to be used as the base fluid, and the name of the contractor performing the stimulation.

This provision would allow the BLM obtain additional information about the proposed well stimulation activities. For example, after initial cementing activities, an operator may be asked to perforate the well casing and squeeze cement into the areas with inadequate cement bonding. In this case, the BLM may ask for additional information to show that the corrective action was successful and to ensure that the corrective work addressed any cement bonding deficiencies. The BLM wants to ensure that any additional information requested under this provision is the least burdensome to operators as possible while still accomplishing the goal of protecting the public lands and resources; therefore, the BLM is specifically requesting public comment on how this may be best achieved. Proposed section 3162.3-3(d) would require the operator to perform a successful mechanical integrity test before beginning well stimulation operations.

This requirement is necessary to help ensure the integrity of the wellbore under anticipated maximum pressures during well stimulation operations.

Proposed section 3162.3-3(d)(1) would require the mechanical integrity test to emulate the pressure conditions that would be seen in the proposed stimulation process. This test would show that the casing is strong enough to protect water and other subsurface resources during well stimulation activities.

The proposed section 3162.3-3(d)(2) would establish the engineering criteria for using a fracturing string as a technique during well stimulation. The requirement to be 100 feet below the cement top would be imposed to ensure that the production or intermediate casing is surrounded by a competent cement sheath as required by Onshore Order Number 2. The 100 foot requirement is required by some state statutes (e.g., Montana Board of Oil and Gas Conservation, section 36.22.1106, Hydraulic Fracturing) and is a generally accepted standard in the industry. Testing would emulate the pressure conditions that would be seen in the proposed stimulation process in order to ensure that the casing used in the well would be robust enough to handle the pressures.

Proposed section 3162.3-3(d)(3) would require the use of the pressure test time requirement of holding pressure for 30 minutes with no more than 10 percent pressure loss. This requirement is the same standard applied in Onshore Order Number 2, Drilling, (53 FR 46790) Section III.B.h., to confirm the mechanical integrity of the casing. This language does not set a new standard in the BLM's regulations. This test, together with the other proposed requirements, would demonstrate if the casing is strong enough to protect water and other subsurface resources during well stimulation activities.
The BLM believes that all of these tests are important to show that reasonable precautions have been taken to ensure the protection of other resources during well stimulation activities.

Proposed section 3162.3-3(e)(1) would require the operator to continuously monitor and record the pressure(s) during the well stimulation operation. The pressure during the stimulation should be contained in the string through which the stimulation is being pumped. Unexpected changes in the monitored and recorded pressure(s) would provide an early indication of the possibility that well integrity has been compromised. This information is needed by the BLM to ensure that well stimulation activities are conducted as designed. This information would also show that stimulation fluids are going to the formation for which they were intended.

Proposed section 3162.3-3(e)(2) would require the operator to orally notify the BLM as soon as possible, but no later than 24 hours following the incident, if during the stimulation operation the annulus pressure increases by more than 500 pounds per square inch over the annulus pressure immediately preceding the stimulation. Within 15 days after the occurrence, the operator must submit a Subsequent Report Sundry Notice (Form 3160-5, Sundry Notices and Report on Wells) to the BLM containing all details pertaining to the incident, including corrective actions taken. This information is needed by the BLM to ensure that stimulation fluids are going into the formation for which they were designed. The BLM also needs to obtain reasonable assurance that other resources are adequately protected. An increase of pressure in the annulus of this amount could indicate that the casing had been breached during well stimulation.

Consistent with the BLM's Onshore Order Number 2, Drilling Operations, the operator must repair the casing should a breach occur.

Proposed section 3162.3-3(f) would require the operator to store recovered fluids in tanks or lined pits. This provision grants flexibility for the operator to choose using either a lined pit or a storage tank, whichever the operator determines is the least burdensome or costly option for the storage of flowback fluid. The BLM is proposing this requirement because flowback fluids could contain hydrocarbons from the formation and could also contain additives and other components that might degrade surface and ground water if they were to be released without treatment. This provision is consistent with existing industry practice and American Petroleum Institute (API) recommendations for handling completion fluids (including hydraulic fracturing fluids) (see Section 6.1.6 of API Recommended Practice 51R, Environmental Protection for Onshore Oil and Gas Production Operations and Leases, First Edition, July 2009). Section 302(b) of the Federal Land Policy and Management Act (43 U.S.C. 1732(b)) states that "In managing the public lands, the Secretary shall, by regulation or otherwise, take any action necessary to prevent unnecessary or undue degradation of the public lands." In addition, existing BLM regulations at 43 CFR 3161.2 requires that "all operations be conducted in a manner which protects other natural resources and the environmental quality." Because the use of lined pits or tanks for the storage of recovered fluids are methods that best and reasonably protect the public lands from spills or leaks of recovered fluids, the BLM believes that this provision is in keeping with FLPMA's mandate to prevent unnecessary or undue degradation of the public lands and the BLM regulation's requirement to protect environmental quality.

Additional conditions of approval for the handling of flowback water may be placed on the project by the BLM if needed to ensure protection of the environment and other resources. The BLM specifically requests comments on whether this rule should impose additional requirements that would require tanks or lined pits for drilling fluids and any other fluids associated with well stimulation operations. The BLM recognizes the ongoing efforts of states to regulate hydraulic fracturing operations. In implementing this rule, the BLM intends to avoid duplication of existing state requirements and will continue to engage states in cooperative efforts to avoid duplication. Please comment on whether this proposed provision would be duplicative of provisions of state rules and whether it is unnecessarily burdensome.

Proposed section 3162.3-3(g) would require the operator to submit to the BLM the post-operation data on a Subsequent Report Sundry Notice (Form 3160-5, Sundry Notices and Report on Wells) following the completion of the stimulation activities. The BLM would determine if the well stimulation operation was conducted as approved. This information would be retained by the BLM as part of the individual well record and would be available for use when the well has been depleted and the plugging of the well is being designed.

Proposed section 3162.3-3(g)(1) would require reporting of the actual measured depth to the perforations and open hole interval. This information identifies the producing interval of the well and will be available for use when the well has been depleted and plugging of the well is being designed. Specific information as to the actual source of water, including location of the water being used as the base fluid, is required because the BLM needs the information to determine the impacts associated with operations and the need for any mitigation applicable to Federal and Indian lands.

Proposed section 3162.3-3(g)(2) would require the operator to submit to the BLM the actual total volume of fluid used, including water, proppants, chemicals, and any other fluid used in the stimulation(s) in order for the BLM to maintain a record of the stimulation operation as actually performed.

Proposed section 3162.3-3(g)(3) would require the operator to submit to the BLM a report of the surface pressure at the end of each stage pumped and the rate at which the fluid was pumped at the completion of each stage (i.e., just prior to shutting down the pumps). In addition to the information provided for the individual stages, the pressure values for each flush stage must also be included. This information is needed by the BLM for it to ensure that the maximum allowable pressure was not exceeded at any stage of the well stimulation operation.

Proposed sections 3162.3-3(g)(4) and (5) would require the operator to identify to the BLM the stimulation fluid by additive trade name and additive purpose, the Chemical Abstracts Service Registry Number, and the percent mass of each ingredient used in the stimulation operation. This information is needed in order for the BLM to maintain a record of the stimulation operation as performed. The information is being required in a format that does not link additives (required by 3162.3-3(g)(4)) to chemical composition of the materials (required by 3162.3-3(g)(5)) to minimize the risk of disclosure of any formulas of additives.

This approach is similar to the one the State of Colorado adopted in 2011 (Colorado Oil and Gas Conservation Commission Rule 205A.b2.ix – xii). The BLM intends to place this information on a public web site and is working with the Ground Water Protection Council in an effort to integrate this information into the existing website known as FracFocus.org. The disclosure of the fluids used in hydraulic fracturing would only be required after the fracturing operation has taken place.

Proposed section 3162.3-3(g)(6) would require the actual, estimated, or calculated fracture length and height of the stimulation(s) to be reported to the BLM so that it can verify that the intended effects of the well stimulation operation remain confined to the petroleum-bearing rock layers and will not have unintended consequences on other rock layers or aquifers. This section would require the operator to show that the well stimulation activity was successfully implemented as designed and that the integrity of the well was maintained during stimulation.

Proposed section 3162.3-3(g)(7) would allow the operator flexibility to report online the information listed in proposed sections 3162.3-3(g)(1) through 3162.3-3(g)(6) by attaching a copy of the service company contractor's job log or report, provided the information required is adequately addressed. The operator is responsible for ensuring the accuracy of any information provided to the BLM, even if originally drafted by a third party.

Proposed section 3162.3-3(g)(8), would require operators to certify they have complied with all applicable Federal, state, tribal, and local laws, rules, and regulations pertaining to the stimulation fluids that were actually used during well stimulation operations. The proposed section would also require that the operator certify that it has complied with all necessary permit and notice requirements. This information would be retained by the BLM as part of the well record and be available for use when the well has been depleted and closure of the well is being designed. The information is also needed for the BLM to fulfill its obligation to prevent unnecessary or undue degradation of the public land.

Proposed section 3162.3-3(g)(9) would require operators to certify that wellbore integrity was maintained throughout the operation. This information is needed because the BLM has a mandate to protect human health and safety and prevent contamination of the environment.

Proposed section 3162.3-3(g)(10) would require the operator to provide information describing the handling of the fluids used for the stimulation activities, flow-back fluids, and produced water. The operator must also report how it handled those fluids after operations were completed Proposed section 3162.3-3(g)(10)(i) would require the operator to report the volume of fluid recovered during flow back, swabbing, or recovery from production facility vessels.

Proposed section 3162.3-3(g)(10)(ii) would require the operator to report the methods of managing the recovered fluids.

Proposed section 3162.3-3(g)(10)(iii) would require the operator to report the disposal method of the recovered fluids. This section also makes it clear that the fluid disposal methods must be consistent with Onshore Order Number 7, Disposal of Produced Water (58 FR 47353). This information is needed so that the BLM can help protect human health and safety and prevent the contamination of the environment. The BLM also needs to confirm that the disposal methods used are those that were approved and conform to the regulations.

Proposed section 3162.3-3(g)(11) would require the operator to submit documentation and an explanation if the actual operations deviated from the approved plan. Understanding the complexities

of well stimulation, the BLM expects there to be slight differences between the proposed plan and the actual operation.
Proposed sections 3162.3-3(h) and (i) would notify the operator of procedures it needs to follow to identify information required to be submitted under this section that the operator believes to be exempt, by law, from public disclosure. If the operator fails to specifically identify information as exempt from disclosure by Federal law, the BLM will release that information. The BLM may also release information which the operator has marked as exempt if the BLM determines that public release is not prohibited by Federal law after providing the operator with no fewer than 10 business days' notice of the determination. All other information submitted by the operator will become a matter of public record.

Proposed section 3162.3-3(j) would provide the operator with a process for requesting a variance from the minimum standards of this regulation. Variances apply only to operational activities and do not apply to the actual approval process. The proposed regulation would make clear that the BLM has the right to rescind a variance or modify any condition of approval due to changes in Federal law, technology, regulation, field operations, noncompliance, or other reasons. The BLM must make a determination that the variance request meets or exceeds the objectives of the regulation. For example, an operator could request a variance from the requirements of proposed section 3162.3-3(c)(2) that it submit cement bond logs to prove that the occurrences of usable water have been isolated to protect them from contamination. The BLM could grant a variance to allow for the use of logs other than cement bond logs if it was satisfied that the alternative logs would meet or exceed the objectives of section (c)(2). This variance provision is consistent with existing BLM regulation such as Onshore Order Number 1 (see section X. of Onshore Oil and Gas Operations; Federal and Indian Oil and Gas Leases; Onshore Oil and Gas Order Number 1, Approval of Operations (72 FR 10308, 10337).

Revised section 3162.5-2(d) would remove the references to fresh water and remove the phrase "containing 5,000 ppm or less of dissolved solids." This revision would require the operator to isolate all usable water. This language does not set a new standard in the BLM's regulations.

Since 1988, Onshore Order Number 2, Drilling Operations, (53 FR 46790) Section II.Y. has defined usable water and Onshore Order Number 2, Drilling Operations, Section III.B. has required the operator to "protect and/or isolate all usable water zones." Section 3162.5(d) was not revised when Onshore Order Number 2, Drilling Operations, was promulgated, which has led to some confusion in implementing and interpreting the regulations.

IV. Procedural Matters

Federal and Indian Oil and Gas Leasing Activity

To understand the context of costs and benefits of the proposed rule, background information concerning the BLM's leasing of Federal oil and gas, and management of Federal and Indian leases may be helpful and is included here. This discussion is provided to explain the basis for the conclusions related to the procedural matters sections that follow. The BLM Oil and Gas Management program is one of the most important mineral leasing programs in the Federal Government. There were 49,173 Federal oil and gas leases covering 38,463,410 acres at the end of fiscal year (FY) 2011. For FY 2011, there were 90,452 producible and service drill holes and 96,606 producible and service completions on Federal leases.

For FY 2011, onshore Federal oil and gas leases produced about 98 million barrels of oil, 2.97 billion Mcf of natural gas, 2.55 billion gallons of natural gas liquids, and approximately $2.7 billion in royalties. The production value of the oil and gas produced from public lands exceeded $23 billion. Oil and gas production from Indian leases was almost 20 million barrelsof oil, 255 million Mcf of natural gas, and 143 million gallons of natural gas liquids, with a production value of $2.7 billion and generating royalties of $433 million.

Estimating Benefits and Costs

This analysis attempts to capture the potential benefits and costs that would result if the BLM implemented the proposed rule. As such, the current operating environment is the reference point from which the change is measured.

Current regulations require operators conducting a "non-routine" well stimulation operation to submit a Notice of Intent Sundry and all operators, regardless of the type of well stimulation, to submit a Subsequent Report Sundry. The proposed rule would require BLM approval for all hydraulic fracturing events. For each event, operators would obtain the BLM's approval prior to the event and submit a Subsequent Report Sundry within 30 days of the event. The operator, if it so chooses, may seek approval for the stimulation operation at the same time that it submits the APD. Other information would be required if an incident occurs during a fracturing operation or if the BLM determines that there is a need for additional information. For example, the BLM may require new or different information in cases where the original information submitted in the Subsequent Report was inadequate or incomplete.

Potential costs and benefits rely on the number of well stimulation events estimated to occur in the future. Those estimates depend on a number of factors, including, but not limited to, future oil and gas prices, the number of applications to drill, the number of wells completed, and the portion of wells that are stimulated. Expected costs and benefits are anticipated to increase in the future because the number of wells drilled and well stimulation activities are expected to increase in the future, considering projected commodities prices and production.

Administrative costs include only the additional burden posed by the requirements. For operators, this burden includes the submission of forms and supporting documentation that are not currently required. The reporting requirements would also pose an additional burden on the BLM, since it would review an additional number of sundry forms and additional information per form. The efficiency of processing applications could also be impacted if operators submit incomplete or inadequate information, thereby requiring additional communication between the BLM and the operators.

The proposed rule seeks to achieve benefits by making more information available to the public about the chemicals injected in well stimulation fluids, while protecting trade secrets and confidential business information. The information that would be submitted to the BLM under this section would generally be made available to the public. The proposed rule, however, would allow an operator to identify specific information that it believes is protected from disclosure by Federal law, and to substantiate those claims of exemption. Under existing law, the BLM may nonetheless make that information available to the public, but only if it determines that the information is not protected by Federal law, and provides not less than 10 business days notice to the operator before releasing the information.
Furthermore, the disclosure mechanism in the proposed rule would require a table of the additives by trade name and the purpose for which they are included in the well stimulation fluid. It would also require a separate table listing all the chemicals used by the Chemical Abstracts Service Registry Number. This design will inhibit reverse-engineering of specific additives.

Potential costs include those to perform tests or take other actions that might not have been conducted otherwise. Operational costs include the cost of any additional logs, tests, or other requirements needed to prepare all documents required by the proposed rule that are not currently required. Depending on the well and the operator, these tests or other requirements currently may be conducted or practiced pursuant to other permits, general well testing, etc.

New wells, where operators are conducting hydraulic fracturing operations, should already comply with many of the standards provided in this proposed rule, with the exception of running cement bond logs on the surface casing. Typically, an operator will assume that the casing is fully cemented if cement circulates to the surface during the cementing process. However, circulation to the surface does not confirm that there is appropriate or proper bonding. A cement bond log will provide confirmation that there is proper bonding by providing a graphical representation that proper bonding has occurred. Old vertical wells that are converted to horizontal wells already require a deepening sundry, a separate process that addresses some of the requirements in this proposed rule.

The potential benefits of the proposed regulations include reduced surface and subsurface contamination. The analysis assumes that, absent this regulation, a certain number of well stimulation events may result in contamination and pose a cost to society. The proposed rule is designed to identify potential issues regarding wellbore integrity and the design of the operations, thereby reducing the likelihood of contamination events.

Estimating the benefits of the proposed regulation is uncertain and subject to assumptions about the number of deficiencies, likelihood of contamination if a deficiency was present, and costs of remediation. One way to measure this benefit is by estimating the cost of internalizing the contamination, which for a subsurface event may include restoring a source of drinking water or remediation of an aquifer.

There are other benefits that are difficult to quantify in monetary terms though they exist. The disclosure requirements might encourage operators to use fewer or safer chemicals in the hydraulic fracturing fluid. The public would benefit from increased knowledge about the fluids used. Increased transparency is also likely to benefit scientists, state and Federal agencies, and other organizations that study the potential impacts of hydraulic fracturing operations, and the BLM would have more information with which to make resource management decisions or respond to incidents.

Methodology

This analysis presents costs and benefits expected to occur over the next 10 years, from 2013 to 2022. This period of analysis was chosen because 10 years is the length of the primary lease term on BLM-managed lands. Net benefits are discounted using 7 and 3 percent discount rates. The analysis presents a range of expected outcomes since the number of well stimulation events occurring in the future is highly variable and subject to future conditions.

The proposed regulation is designed to reduce the risk that well stimulation events may pose to the environment. Any contamination event that occurs is expected to require remediation. Since the remediation costs are uncertain, the analysis makes assumptions about remediation costs which may underestimate the true costs of remediation. The analysis assumes two scenarios: a low remediation cost – low environmental risk scenario and a high remediation cost – high environmental risk scenario. The benefits, while representing the value of risk reduction, will underestimate or overestimate the true benefits if the true risk of well stimulation operations varies from the assumptions.

Discounted Present Value

There is a time dimension to estimates of potential benefits and costs. The potential events described, if they occur at all, may be in the distant future. The further in the future the benefits and costs are expected to occur, the smaller the present value associated with the stream of costs and benefits. As such, future costs and benefits must be discounted (the discount factor equals $1/(1+r)_t$ where r is the discount rate and t is time measured in years during which benefits and costs are expected to occur). The discount factor is then used to convert the stream of costs and benefits into “present discounted values.” When the estimated benefits and costs have been discounted, they can be added to determine the overall value of net benefits.

The OMB’s basic guidance on the appropriate discount rate to use is provided in OMB Circular A-94. The OMB’s Circular A-94 states that a real discount rate of 7 percent should be used as a base-case for regulatory analysis. The OMB considers the 7 percent rate as an estimate of the average before-tax rate of return to private capital in the U.S. economy. It is a broad measure that reflects the returns to real estate and small business capital as well as corporate capital. It approximates the opportunity cost of capital, and it is the appropriate discount rate whenever the main effect of a regulation is to displace or alter the use of capital in the private sector.

OMB Circular A-4 also states that a 3 percent discount rate should be used for regulatory analyses and explains the use of that discount rate as follows: “The effects of regulation do not always fall exclusively or primarily on the allocation of capital. When regulation primarily and directly affects private consumption (e.g., through higher consumer prices for goods and services), a lower discount rate is appropriate. The alternative most often used is sometimes called the ‘social rate of time preference.’ This simply means the rate at which "society" discounts future consumption flows to their present value.”

Uncertainty

The benefits and costs provided in this analysis are indeed estimates and come with uncertainty. Estimated costs and benefits rely on the number of well stimulation events occurring in future years and those estimates are uncertain. This analysis estimates the number of future well stimulation events using regression models and future projections of commodity prices.

Assuming the number of well stimulation events is known, though administrative costs are more easily estimated, the operational costs required by producers to comply with the regulations are subject to assumptions about the number of wells that would require such expenditures.

Further uncertainty lies in the estimation of benefits and remediation costs. For the purposes of this analysis, a range of assumed average costs of remediating both subsurface and surface contaminations are used. This assumption may be too low or too high in the real world, depending on the location, severity, consequences, duration of the contamination, and if a causal link between the source and contamination can be made.

This analysis does not quantify other benefits that are undoubtedly relevant, such as the benefit that disclosing the components of fracturing fluids will have for public health research and the remediation of contamination events. It is also uncertain what additional benefits, if any, would result from the disclosure requirements, for instance, if companies find safer substitutes for the chemicals in the fracturing fluids.

Results

The analysis estimates the effects of the proposed regulations over a baseline scenario, where no action is taken. The BLM considered an alternative to the proposed regulation which would remove

the requirement for operators to use lined pits if they choose to use pits to store hydraulic fracturing fluids.
A summary of the results appears in Table 2 and Table 3, with the entire results available in the full Economic Analysis and Initial Regulatory Flexibility Analysis available at the address listed in the ADDRESSES section of this rule.

Results for the Proposed Regulations (Preferred Approach)

Benefits: Under the proposed regulations, it is assumed that the regulations would remove much of the risk associated with potential wellbore integrity issues and unlined pits. The change in social benefits from the baseline scenario is positive. If you assume that there is low environmental risk posed by wellbore integrity issues and storage of hydraulic fracturing fluids in unlined pits and the costs of surface and subsurface remediation is low (on the range assumed), then the change in social benefit as a result of the proposed regulation is positive and ranges between \$11.70MM and \$13.79MM per year using a discount rate of 7% and between \$11.74MM and \$13.85MM per year using a discount rate of 3%. If you assume that environmental risks are high and remediation costs are high (on the range assumed), then the social benefits of the proposed regulation is positive and ranges between \$42.67MM and \$50.27MM per year using a discount rate of 7% and between \$42.79MM and \$50.49MM per year using a discount rate of 3%. Tables 7 and 8 (below) show the annual change in benefits over the baseline.

Note that the figures for the estimated benefits of the proposed rule do not include such benefits as avoiding harm to water users that cannot be compensated by later providing alternative water sources. The increase in information about additives could aid water users when they consider the potential effects of well stimulation operations and constituent chemicals.

Costs: The costs include both costs to the industry and the BLM under this alternative. Costs include operational tests that demonstrate wellbore integrity and those associated with lining open pits in the instances where operators use pits instead of storage tanks. The change in costs over the baseline ranges between \$37.34MM and \$43.99MM per year using a discount rate of 7% and between \$37.44MM and \$44.18MM per year using a discount rate of 3%, assuming low remediation costs and low environmental risks. The change in costs ranges between \$37.34MM and \$43.99MM per year using a discount rate of 7% and between \$37.44MM and \$44.18MM per year using a discount rate of 3%, assuming high remediation costs and high environmental risks. Tables 7 and 8 (below) show the annual change in costs over the baseline.

Net Benefits: The change in net benefits for the proposed regulations varies depending on the amount of environmental risk associated with wellbore integrity issues and unlined pits and the level of remediation costs associated with contamination events. Assuming low remediation costs and low environmental risks, the change in net benefits from the baseline is negative and ranges from -\$25.63MM and -\$30.20MM per year using a discount rate of 7% and between -\$25.70MM and -\$30.33MM per year using a discount rate of 3%. Assuming high remediation costs and high environmental risks, the change in net benefits is positive and ranges between \$5.33MM and \$6.28MM per year using a discount rate of 7% and between \$5.35MM and \$6.31MM per year using a discount rate of 3%.

Given the assumptions made and the fact that certain benefits were not quantified, the range of estimated outcomes could underestimate the actual net benefits, i.e., where net benefits are estimated to be negative, the net benefits would be greater (or less negative).

This analysis also does not capture the potential benefits associated with the disclosure of fracturing fluids. For example, disclosure might encourage operators to use fewer or safer chemicals in the hydraulic fracturing fluid. The public would benefit from increased knowledge about the fluids used. This transparency is also likely to benefit scientists, state and Federal agencies, and other organizations that study the potential impacts of well stimulation operations. The BLM would be able to make more informed resource decisions and respond effectively to events where environmental resources have been compromised.

Also, the variance language might also enable operators to reduce costs, in which case, these estimates may overestimate the actual costs and underestimate the change in net benefits.
It should be noted that the low cost and risk scenario results in negative net benefits while the high cost and risk scenario results in positive net benefits. The primary difference is not a result of the administrative or operational costs changing between the scenarios. Instead, the difference is due to the valuation of social benefits. If the assumed risk of contamination is greater and the costs of remediation are higher, then benefits of the proposed rule would be greater and offset the compliance costs.

The annual cost per well stimulation does not vary greatly between the cost and risk scenarios, but the benefits do. The average annual cost per well (including administrative and operational costs) is estimated to be about $11,833. However, the average annual benefit ranges more widely, between $3,754 and $13,688. The uncertainty about risk and damages causes this variability. The net benefit ranges from -$8,079 to $1,855 on a per well stimulation basis.

Note that the figures for the estimated benefits of the proposed rule do not include such benefits as avoiding harm to water users that cannot be compensated by later providing alternative water sources. The increase in information about additives could aid water users when they consider the potential effects of well stimulation operations and constituent chemicals.

Economic Impact Analysis and Distributional Assessments
Energy System Impact Analysis

Executive Order 13211 provides that agencies prepare and submit to the Administrator of the Office of Information and Regulatory Affairs (OIRA), OMB, a Statement of Energy Effects for certain actions identified as significant energy actions. Section 4(b) of Executive Order 13211 defines a "significant energy action" as "any action by an agency (normally published in the Federal Register) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of proposed rulemaking, and notices of proposed rulemaking: 1)(i) that is a significant regulatory action under Executive Order 12866 or any successor order, and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or 2) that is designated by the Administrator of OIRA as a significant energy action."

This analysis estimates the additional cost burden per well stimulation event and finds that the average burden per stimulation is about $11,833 in 2013.

The BLM believes that the additional cost per well stimulation resulting from this proposed rule is insignificant when compared with the drilling costs in recent years, the production gains from hydraulically fractured well operations, and the net incomes of entities within the oil and natural gas industries.

Table 4 presents drilling costs per well for a range of wells from 1998 to 2007. The data clearly show that drilling costs increased during this time. Using the estimates for the average burden per well

stimulation and the average cost of drilling wells in 2007, the annual costs of this proposed rule represent about 0.3% of the drilling cost of a well.
As such, the proposed regulations are unlikely to have an effect on the investment decisions of firms, and the rule is unlikely to affect the supply, distribution, or use of energy.

Employment Impact Analysis
Executive Order 13563 reaffirms the principles established in Executive Order 12866, but calls for additional consideration of the regulatory impact on employment. It states, “Our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and job creation.” An analysis of employment impacts is a standalone analysis and the impacts should not be included in the estimation of benefits and costs.

This analysis seeks to inform the discussion of labor demand and job impacts by providing an estimate of the employment impacts of the proposed regulations using labor requirements for the additional administration and operational needs.

This proposed rule would require operators who have not already done so to conduct one-time tests on a well or make a one-time installation of a mitigation control feature. In addition, operators would be required to perform administrative tasks related to a one-time event. Compliance with the operational requirements would shift resources within the industry from the operators to firms providing the services or supplies. For example, the requirement for a cement bond log represents an additional cost to the operator, but a benefit to the company running the log.

In 2013, the BLM estimates that the labor requirements for operators to meet additional administrative and operational needs are estimated to be about 15 to 18 full time equivalents in each of the next three years. According to the U.S. Census Bureau, employment in the related sectors was 257,302 persons in 2007. Note that these impacts are only for the regulated sector. The BLM cannot predict the net national employment impact, i.e., whether the increased employment in the regulated sector comes from previously unemployed workers or is displaces workers actively employed in other sectors.

Another area of interest is the extent to which the financial burden is expected to change operators’ investment decisions. If the financial burden is not significant and all other factors are equal, then one would expect operators to maintain existing levels of investment and employment. As with the results in the earlier discussion, the BLM believes that the proposed rule would result in an additional cost per well stimulation that is small and would not alter the investment or employment decisions of firms. Therefore, considering the labor requirements and those operators would not likely reduce investment, the BLM anticipates an overall net gain in employment in the sectors.

Executive Order 12866, Regulatory Planning and Review

In accordance with the criteria in Executive Order 12866, the Office of Management and Budget has determined that this rule is a significant regulatory action.

The rule will not have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or state, local, or tribal governments or communities. However, the rule may raise novel policy issues because of the proposed requirement that operators provide to the BLM information regarding well stimulation activities that they are not currently providing to the BLM.

This proposed rule would not create inconsistencies or otherwise interfere with an action taken or planned by another agency. This proposed rule would not change the relationships of the oil and gas operations with other agencies. These relationships are included in agreements and memoranda of understanding that would not change with this rule. In addition, this proposed rule would not materially affect the budgetary impact of entitlements, grants, loan programs, or the rights and obligations of their recipients. Please see the discussion of the impacts of the proposed rule as described earlier in this section of the preamble.

Regulatory Flexibility Act

Congress enacted the Regulatory Flexibility Act of 1980 (RFA), as amended, 5 U.S.C. 601–612, to ensure that Government regulations do not unnecessarily or disproportionately burden small entities. The RFA requires a regulatory flexibility analysis if a rule would have a significant economic impact, either detrimental or beneficial, on a substantial number of small entities. For the purposes of this analysis, we will assume that all entities (all lessees and operators) that may be affected by this proposed rule are small entities, even though that is not actually the case.

The proposed rule deals with well stimulation on all Federal and Indian lands (except those excluded by statute). There would be some increased costs associated with the proposed enhanced recordkeeping requirements and some new operational requirements. However, the BLM expects that these costs would be minor in comparison to overall operations costs. Therefore, the BLM has determined under the RFA that the proposed rule would not have a significant economic impact on a substantial number of small entities. Please see the discussion earlier in this section of the preamble for a discussion of the impacts of the rule.

Small Business Regulatory Enforcement Fairness Act

The Regulatory Flexibility Act as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute, unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small governmental jurisdictions, or small not-for-profit enterprises.

The BLM reviewed the Small Business Administration (SBA) size standards for small businesses and the number of entities fitting those size standards as reported by the U.S. Census Bureau in the 2007 Economic Census. Using the Economic Census data, the BLM concludes that about 99% of the entities operating in the relevant sectors are small businesses in that they employ fewer than 500 employees. Also, small firms account for 74% of the total value of shipments and receipts for services, 86% of the total cost of supplies, 78% of the total capital expenditures (excluding land and mineral rights), and 67% of the paid employees.

Small entities represent the overwhelming majority of entities operating in the onshore crude oil and natural gas extraction industry. As such, the proposed rule is likely to affect a significant number of small entities. To examine the economic impact of the rule on small entities, the BLM performed a screening analysis for impacts on a sample of expected affected small entities by comparing compliance costs to entity net incomes.

Under the cost and risk scenarios, the average cost per entity in 2013 is estimated to represent between 0.002% and 0.22% of the 2010 net incomes of the sampled companies, depending on the

U.S. Energy Information Administration's Annual Energy Outlook commodity price forecasts. The proportions do not change substantially over the outlook period.
After considering the economic impact of the proposed rule on these small entities, the screening analysis indicates that this proposed rule would not have a significant economic impact on a substantial number of small entities. Please see the discussion earlier in this section of the preamble for a discussion of the impacts of the rule.

Unfunded Mandates Reform Act

This proposed rule does not contain a Federal mandate that may result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate, or to the private sector in any one year. Thus, the proposed rule is also not subject to the requirements of Sections 202 or 205 of the Unfunded Mandates Reform Act (UMRA).

This proposed rule is also not subject to the requirements of Section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments; it contains no requirements that apply to such governments nor does it impose obligations upon them.
Executive Order 12630, Governmental Actions and Interference With Constitutionally Protected Property Rights (Takings)

Under Executive Order 12630, the proposed rule would not have significant takings implications. A takings implication assessment is not required. This proposed rule would establish recordkeeping requirements for hydraulic fracturing operations and some additional operational requirements on Federal and Indian lands. All such operations are subject to lease terms which expressly require that subsequent lease activities be conducted in compliance with subsequently adopted Federal laws and regulations. The proposed rule conforms to the terms of those Federal leases and applicable statutes, and as such the proposed rule is not a governmental action capable of interfering with constitutionally protected property rights. Therefore, the proposed rule would not cause a taking of private property or require further discussion of takings implications under this Executive Order.
Executive Order 13352, Facilitation of Cooperative Conservation
Under Executive Order 13352, the BLM has determined that this proposed rule would not impede facilitating cooperative conservation and would take appropriate account of and consider the interests of persons with ownership or other legally recognized interests in land or other natural resources. This rulemaking process will involve Federal, State, local and tribal governments, private for-profit and nonprofit institutions, other nongovernmental entities and individuals in the decision-making. The process would provide that the programs, projects, and activities are consistent with protecting public health and safety.

Executive Order 13132, Federalism

Under Executive Order 13132, this proposed rule would not have significant Federalism effects. A Federalism assessment is not required because the proposed rule would not have a substantial direct effect on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government. The proposed rule would not have any effect on any of the items listed. The proposed rule would affect the relationship between operators, lessees, and the BLM, but would not impact states. Therefore, under Executive Order 13132, the BLM has determined that the proposed rule would not have sufficient Federalism implications to warrant preparation of a Federalism Assessment.

Executive Order 13175, Consultation and Coordination With Indian Tribal Governments

Under Executive Order 13175, the President's memorandum of April 29, 1994, ''Government-to-Government Relations with Native American Tribal Governments'' (59 FR 22951), and 512 Departmental Manual 2, the BLM evaluated possible effects of the proposed rule on federally recognized Indian tribes. The BLM approves proposed operations on all Indian onshore oil and gas leases (except those excluded by statute). Therefore, the proposed rule has the potential to affect Indian tribes. In conformance with the Secretary's policy on tribal consultation, the Bureau of Land Management held four tribal consultation meetings to which over 175 tribal entities were invited. The consultations were held in:

• Tulsa, Oklahoma on January 10, 2012;

• Billings, Montana on January 12, 2012;

• Salt Lake City, Utah on January 17, 2012; and

• Farmington, New Mexico on January 19, 2012.

The purpose of these meetings was to solicit initial feedback and preliminary comments from the tribes. Comments from tribes will be received and consultation will continue as this rulemaking proceeds. To date, the tribes have expressed concerns about the BLM's Inspection and Enforcement program's ability to enforce the terms of this rule; previously plugged and abandoned wells being potential conduits for contamination of ground water; and the operator having to provide documentation that the water used for the fracturing operation was legally acquired. The BLM will further address these concerns during the drafting of the final rule.

Executive Order 12988, Civil Justice Reform

Under Executive Order 12988, the Office of the Solicitor has determined that the proposed rule would not unduly burden the judicial system and meets the requirements of Sections 3(a) and 3(b)(2) of the Order. The Office of the Solicitor has reviewed the proposed rule to eliminate drafting errors and ambiguity. It has been written to minimize litigation, provide clear legal standards for affected conduct rather than general standards, and promote simplification and avoid unnecessary burdens.

Paperwork Reduction Act

The Paperwork Reduction Act (PRA) (44 U.S.C. 3501 – 3521) provides that an agency may not conduct or sponsor, and a person is not required to respond to, a "collection of information," unless it displays a currently valid control number. Collections of information include requests and requirements that an individual, partnership, or corporation obtain information, and report it to a Federal agency (44 U.S.C. 3502(3); 5 CFR 1320.3(c) and (k)).

In accordance with the PRA, the BLM is inviting public comment on its request that OMB assign a new control number for proposed new uses of Form 3160-5 (Sundry Notices and Reports on Wells). The BLM is proposing that these new uses would replace certain existing uses of Form 3160-5 for well-stimulation operations.

OMB has approved the use of Form 3160-5 under control number 1004-0137, Onshore Oil and Gas Operations (43 CFR part 3160) to collect information on a number of operations, including some well-stimulation operations. Once the BLM is authorized to collect well-stimulation information in accordance with finalized new section 3162.3-3 and a new control number, the BLM will request revision of control number 1004-0137 to:

• Add the new well-stimulation uses and burdens of Form 3160-5 to control number 1004-0137, and

• Remove the existing well-stimulation uses and burdens from the existing approval of Form 3160-5.

The new collection of information would be required to obtain or retain a benefit for the operators of Federal and Indian (except on the Osage Reservation, the Crow Reservation, and certain other areas) onshore oil and gas leases, units, or communitization agreements that include Federal leases. The BLM has requested a 3-year term of approval for the new control number.

The information collection request for this proposed rule has been submitted to OMB for review under 44 U.S.C. 3504(h) of the Paperwork Reduction Act. A copy of the request can be obtained from the BLM by electronic mail request to Barbara Gamble at barbara_gamble@blm.gov or by telephone request to 202-912-7148. The BLM requests comments to:

• Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;
• Evaluate the accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;
• Enhance the quality, utility, and clarity of the information to be collected; and
• Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, e.g., permitting electronic submission of responses.

Comments on the information collection requirements should be sent to both OMB and the BLM as directed in the **ADDRESSES** section of this preamble. OMB is required to make a decision concerning the collection of information contained in this proposed rule between 30 to 60 days after publication of this document in the Federal Register.

Therefore, a comment to OMB is best assured of having its full effect if OMB receives it by [INSERT DATE 30 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER].

Summary of Information Collection Requirements

The proposed rule is intended to increase transparency for the public regarding the fluids and additives used in well stimulation. The proposed provisions that include information collection requirements are amendments to 43 CFR 3162.3-2 new 43 CFR 3162.3-3.

OMB has approved the use of Form 3160-5 under control number 1004-0137 for the operations listed in existing section 3162.3-2. As amended, section 3162.3-2 would no longer include well stimulation jobs (i.e., nonroutine fracturing, routine fracturing, and acidizing) on the list of operations for which prior approval and subsequent reports would be required. Other categories of operations would remain subject to the information collection requirements in section 3162.3-2. Once the BLM is authorized to collect well-stimulation information under new section 3162.3-3 and a new control number, the BLM will request revision of control number 1004-0137 by removing the well-stimulation burdens from the existing approval of Form 3160-5. New section 3162.3-3 would require operators to use Form 3160-5 both to seek prior BLM approval of well stimulation operations, and to submit a report on subsequent actual well stimulation operations. It would also encourage operators to use Form 3160-5 if they want to request a variance from the requirements of new section 3162.3-3.
Request for Prior Approval (i.e., Notice of Intent Sundry)

New section 3162.3-3(b) would require operators to seek and obtain prior approval by the BLM for proposed well stimulation operations. Submission of the information, called a Notice of Intent (NOI)

Sundry in the proposed rule, would be required at least 30 days before the date the operator wants to begin well stimulation operations. The information to be included in this Notice of Intent Sundry, and the reasons for requiring it, are listed in the following table:

Proposed Regulation 43 CFR	**Regulatory Text**	**Rationale**
§ 3162.3-3(c)(1)	The geological names, a geological description, and the proposed measured depth of the top and the bottom of the formation into which well stimulation fluids are to be injected.	The BLM would use the information to determine the properties of the rock layers and the thickness of the producing formation, and identify the confining rocks above and below the zone that would be stimulated.
§ 3162.3-3(c)(2)	The proposed measured depths (both top and bottom) of all occurrences of usable water and the Cement Bond Logs (or another log acceptable to the authorized officer) proving that the occurrences of usable water have been isolated to protect them from contamination.	The BLM would use the information to help protect water resources.
§ 3162.3-3(c)(3)	The proposed measured depth of perforations or the open-hole interval, the source and location(s) of the water used in the stimulation fluid or trade name of the base fluid (if other than water), type of proppants, and estimated pump pressures. Information concerning water supply, such as rivers, creeks, springs, lakes, ponds, and wells, which may be shown by quarter-quarter section on a map or plat, or which may be described in writing. The NOI Sundry must also identify the source, access route, and transportation method for all water	The BLM would use the information to determine the impacts associated with operations and the need for any mitigation applicable to Federal and Indian lands
§ 3162.3-3(c)(4)	A certification signed by the operator that the proposed treatment fluid complies with all applicable permitting and notice requirements as well as all applicable Federal, tribal, state, and local laws, rules, and regulations;	The BLM would use the information to make an informed decision on the proposed well stimulation..
§ 3162.3-3(c)(5)	A detailed description of the proposed well stimulation design, including: (i) the estimated total volume of fluid to be used; (ii) The anticipated surface treating pressure range; (iii) The maximum injection treating pressure; and (iv) the estimated or calculated fracture length and fracture height.	The information would enable the BLM to verify that the proposed engineering design is adequate for safely conducting the proposed well stimulation, that the maximum wellbore design burst pressure will not be exceeded at any stage of the well stimulation operations, and that the intended effects of the well stimulation operation will remain confined to the petroleum-bearing rock layers

		and will not have unintended consequences for other rock layers, such as aquifers.
§ 3162.3-3(c)(6)	The following information concerning the handling of recovered fluids: (i) the estimated volume of fluid to be recovered during flow back, swabbing, and recovery from production facility vessels; (ii) The proposed methods of handling the recovered fluids, including, but not limited to, pit requirements, chemical composition of the fluid, pipeline requirements, holding pond use, re-use for other stimulation activities, or injection; and (iii) The proposed disposal method of the recovered fluids, including, but not limited to, injection, hauling by truck, or transporting by pipeline.	The BLM would use the information to ensure that the facilities needed to process or contain the estimated volume of fluid will be available on location, that the handling methods will adequately ensure protection of public health and safety, and that the BLM has all necessary information regarding disposal of chemicals used in the event it is needed to protect the environn health and safety and to prevent unnecessary or degradation of the public lands.
§ 3162.3-3(c)(7)	Additional information, as requested by the authorized officer.	The information would allow the BLM to make an informed decision about the proposed well stimulation if special circumstances exist

Subsequent Report (i.e., Subsequent Report Sundry Notice)

Within 30 days after the completion of well stimulation operations, section 3162.3-3(f) of the proposed rule would require operators to submit a Subsequent Report Sundry Notice on Form 3160-5 (Sundry Notices and Report on Wells). The information to be included in this Subsequent Report, and the reasons for requiring it, are listed in the following table.

Proposed Regulation 43 CFR	**Proposed Regulatory Text**	**Rationale**
3162.3-3(e)(1)	A continuous record of the annulus pressure must be submitted with the required Subsequent Report Sundry Notice (Form 3160-5, Sundry Notices and Reports on Wells) identified in paragraph (g) of this section.	The BLM would use the information to ensure that well stimulation activities are conducted as designed. The information would also show that stimulation fluids are going to the formation for which they were intended.
3162.3-3(e)(2)	If during the stimulation the annulus pressure increases by more than 500 pounds per square inch as compared to the pressure immediately preceding the stimulation, the operator must orally notify	The BLM would use the information to ensure that stimulation fluids are going into the formation for which they were designed. The BLM

	the	also needs to obtain reasonable assurance that
authorized officer as soon as practicable, but no later than 24 hours following the incident. Within 15 days after the occurrence, the operator must submit a report containing all details pertaining to the incident, including corrective actions taken, as part of a Subsequent Report Sundry Notice (Form 3160-5, Sundry Notices and Reports on Wells).		other resources are adequately protected.
§ 3162.3-3(g)(1)	The actual measured depth of perforations or the open-hole interval, the source and location(s) of the water used in the stimulation fluid or trade name of base fluid (if other than water), type of proppants, and estimated pump pressures. Information concerning water supply, such as rivers, creeks, springs, lakes, ponds, and wells, which may be shown by quarter-quarter section on a map or plat, or which may be described in writing. It must also identify the source, access route, and transportation method for all water used in stimulating the well.	The BLM would use the information to determine the impacts associated with operations and the need for any mitigation applicable to Federal and Indian lands.
§ 3162.3-3(g)(2)	The actual total volume of the fluid used.	The BLM would use the information to maintain a record of the stimulation operation as actually performed.
§ 3162.3-3(g)(3)	The actual surface pressure and rate at the end of each fluid stage, and the actual flush volume, rate, and final pump pressure.	The BLM would use the information to ensure that the maximum allowable pressure has not been exceeded at any stage of the well stimulation operation.
§ 3162.3-3(g)(4) and (5)	(4) A report (table) that discloses all additives of the	The BLM would use the information to maintain a

	actual stimulation fluid, by additive trade name and purpose (such as, but not limited to, acid, biocide, breaker, brine, corrosion inhibitor, crosslinker, demulsifier, friction reducer, gel, iron control, oxygen scavenger, pH adjusting agent, proppant, scale inhibitor, or surfactant); and (5) A report (table) that discloses the complete chemical makeup of all materials used in the actual stimulation fluid without regard to original source additive (see paragraph (g)(4) of this section). For each chemical, the operator must provide the Chemical Abstracts Service Registry Number as well as the percentage by mass. The percent mass value is the mass value for each component (Mc) divided by the value of the entire fluid mass (Mt) times 100. (Mc/Mt)*100 = percent value. The percent mass values should be for the entire stimulation operation, not for the individual stages.	record of the stimulation operation as performed.
§ 3162.3-3(g)(6)	The actual, estimated, or calculated fracture length and fracture height.	The BLM would use the information to verify that the intended effects of the well stimulation operation remain confined to the petroleum-bearing rock layers and will not have unintended consequences on other rock layers or aquifers.
§ 3162.3-3(g)(7)	The Subsequent Report Sundry Notice (Form 3160-5, Sundry Notices and Reports on Wells) may be completed in whole or in part, as applicable, by attaching the service contractor's job log or other report, so long as the information required in paragraphs (g)(1) through (g)(6) of this section is complete and readily apparent.	This provision would allow the operator the flexibility to submit a copy of the service company contractor's job log or other report in lieu of all or part of the data described above, so long as the required information is complete

		and readily apparent.
§ 3162.3-3(g)(8)	A certification signed by the operator that the treatment fluid used complies with all applicable permitting and notice requirements as well as all applicable Federal, tribal, state, and local laws, rules, and regulations.	The BLM would use the information to help protect public health and safety and obtain the operator's self-certification of compliance with all necessary permits and notice requirements.
§ 3162.3-3(g)(9)	A certification signed by the operator that wellbore integrity was maintained throughout the operation, as required by paragraphs (d), (e)(1), and (e)(2) of this section.	The BLM would use the information to help protect public health and safety and obtain the operator's self-certification that wellbore integrity was maintained throughout the operation.
§ 3162.3-3(g)(10)	The following information concerning the handling of recovered fluids: (i) The volume of fluid recovered during flow back, swabbing, or recovery from production facility vessels; (ii) The methods of handling the recovered fluids, including, but not limited to, pipeline requirements, holding pond use, re-use for other stimulation activities, or injection; and (iii) The disposal method of the recovered fluids, including, but not limited to, injection, hauling by truck, or transporting by pipeline. The disposal of fluids produced during the flow back from the well stimulation process must follow the requirements set out in Onshore Order Number 7, Disposal of Produced Water, Section III. B.	The BLM would use the information to help protect human health and safety and prevent the contamination of the environment. The BLM also needs to confirm that the disposal methods used are those that were approved and conform to the regulations
§ 3162.3-3(g)(11)	If the actual operations deviate from approved plan, the deviation(s) must be documented.	The BLM would use the information to maintain a record of any deviations of the operation from the approved plan in the event such information is needed to protect health and safety and prevent undue degradation of the environment

Requesting a Variance

Proposed 43 CFR 3162.3-3(j) would encourage operators to use Form 3160-5 to request a variance from the requirements under proposed section 3162.3-3. Any request for a variance, whether filed on Form 3160-5 or not, would have to specifically identify the regulatory provision of this section for which the variance is being requested, explain the reason the variance is needed, and demonstrate how the operator would satisfy the objectives of the regulation for which the variance is being requested.

Estimated Annual Hour and Cost Burdens

The estimated annual hour and costs burdens of each aspect of this information collection are shown in the following table;

A. **Type of Response**	**B.** **Number of Responses**	**C.** **Hours Per Response**	**D.** **Total Hours (Column B x Column C)**
Sundry Notices and Reports on Wells / Well Stimulation / Notice of Intent Sundry (43 CFR 3162.3-3) Form 3160-5	1,700	8	13,600
Sundry Notices and Reports on Wells / Well Stimulation / Subsequent Report Sundry Notice (43 CFR 3162.3-3) Form 3160-5	1,700	8	13,600
Sundry Notices and Reports on Wells / Well Stimulation / Variance Request (43 CFR 3162.3-3) Form 3160-5	170	8	1,360
Totals	**3,570**		**28,560**

National Environmental Policy Act

The BLM has prepared an environmental assessment (EA) that concludes that the proposed rule would not constitute a major Federal action that may result in a significant adverse effect on the human environment under section 102(2)(C) of the National Environmental Policy Act (NEPA), 42 U.S.C. 4332(2)(C). A detailed statement under NEPA would not be required if the proposed amendments were promulgated as regulations. The BLM has placed the EA and the draft Finding of No Significant Impact on file in the BLM Administrative Record at the address specified in the ADDRESSES section.

Data Quality Act

In developing this rule, we did not conduct or use a study, experiment, or survey requiring peer review under the Data Quality Act (Pub. L. 106–554).

Executive Order 13211,
Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

In accordance with Executive Order 13211, the BLM has determined that the proposed rule will not have substantial direct effects on the energy supply, distribution, or use, including a shortfall in supply or price increase. Please see the discussion earlier in this section of the preamble for a discussion of the impacts of the rule.

Clarity of the Regulations

Executive Order 12866 requires each agency to write regulations that are simple and easy to understand. We invite your comments on how to make these proposed regulations easier to understand, including answers to questions such as the following:

1. Are the requirements in the proposed regulations clearly stated?
2. Do the proposed regulations contain technical language or jargon that interferes with their clarity?
3. Does the format of the proposed regulations (grouping and order of sections, use of headings, paragraphing, etc.) aid or reduce their clarity?
4. Would the regulations be easier to understand if they were divided into more (but shorter) sections?
5. Is the description of the proposed regulations in the **SUPPLEMENTARY INFORMATION** section of this preamble helpful in understanding the proposed regulations? How could this description be more helpful in making the proposed regulations easier to understand?

Please send any comments you have on the clarity of the regulations to the address s specified in the ADDRESSES section.

Authors
The principal authors of this rule are: Michael Worden of the BLM Washington Office; Nicholas Douglas of BLM Washington Office; Adrienne Brumley of the BLM New Mexico State Office; Donato Judice of the BLM Great Falls, Montana Oil and Gas Field Office, assisted by Ian Senio and Joe Berry of the BLM's Division of Regulatory Affairs and the Department of the Interior's Office of the Solicitor.

List of Subjects
43 CFR Part 3160
Administrative practice and procedure; Government contracts; Indians-lands; Mineral royalties; Oil and gas exploration; Penalties; Public lands-mineral resources; Reporting and recordkeeping requirements.

43 CFR Chapter II
For the reasons stated in the preamble, and under the authorities stated below, the Bureau of Land Management proposes to amend 43 CFR part 3160 as follows:

PART 3160 – ONSHORE OIL AND GAS OPERATIONS

The authorities citation for part 3160 is revised to read as follows: **Authority:** 25 U.S.C. 396d and 2107; 30 U.S.C. 189, 306, 359 and 1751; 40 U.S.C. 4332, and 43 U.S.C. 1732(b), 1733, and 1740.

Subpart 3160—Onshore Oil and Gas Operations: General
§3160.0-3 [AMENDED]

2. In section 3160.0-3 add “the Federal Land Policy and Management Act (43 U.S.C. 1701 et seq.),” after “the Mineral Leasing Act for Acquired lands, as amended (30 U.S.C. 351-359),”.

3. Amend § 3160.0-5 by adding definitions of “annulus,” “bradenhead,” “proppant,” “stimulation fluid,” “usable water,” and “well stimulation” in alphabetical order and by removing the definition of “fresh water”:
The additions read as follows:

§ 3160.0-5 Definitions.
*** * * * ***
Annulus means the space around a pipe in a wellbore, the outer wall of which may be the wall of either the borehole or the casing; sometimes also called annular space.
* * * * *

1. Bradenhead means a heavy, flanged steel fitting connected to the first string of casing that allows suspension of intermediate and production strings of casing and supplies the means for the annulus to be sealed off.
2. Proppant means a granular substance (most commonly sand, sintered bauxite, or ceramic) that is carried in suspension by the fracturing fluid that serves to keep the cracks open when fracturing fluid is withdrawn after a hydraulic fracture treatment.
3. * * * * *
4. Stimulation fluid means the liquid or gas, including any associated solids, used during a treatment of oil and gas wells, such as the water, chemicals, and proppants used in hydraulic fracturing.
5. * * * * *
6. Usable water means generally those waters containing up to 10,000 ppm of total dissolved solids.
7. * * * * *
8. Well stimulation means those activities conducted in an individual well bore designed to increase the flow of hydrocarbons from the rock formation to the well bore through modifying the permeability of the reservoir rock. Examples of well stimulation operations are acidizing and hydraulic fracturing.
9. * * * * *

Subpart 3162—Requirements for Operating Rights Owners and Operators

Amend § 3162.3-2 by revising the first sentence of paragraph (a) and revising paragraph (b) to read as follows:

§ 3162.3-2 Subsequent well operations a) A proposal for further well operations shall be submitted by the operator on Form 3160–5 for approval by the authorized officer prior to commencing operations to redrill, deepen, perform casing repairs, plug-back, alter casing, recomplete in a different interval, perform water shut off, commingling production between intervals and/or conversion to injection. * * *

(b) Unless additional surface disturbance is involved and if the operations conform to the standard of prudent operating practice, prior approval is not required for recompletion in the same interval; however, a subsequent report on these operations must be filed on Form 3160–5. * * * * *
5. Add a new § 3162.3-3 to read as follows:

§ 3162.3-3 Subsequent well operations; Well stimulation.

(a) This section applies to well stimulation activities. All other injection activities must comply with section 3162.3-2.

(b) When an Operator Must Submit Notification for Approval of Well Stimulation.
A proposal for well stimulation must be submitted by the operator and approved by BLM before commencement of operations. The proposal may be submitted in one of the following ways:

For new wells, the operator may submit with its Application for Permit to Drill the information required in paragraph (c) of this section, except for the cement bond log required by paragraph (c)(2). The approved permit to drill will require submission and approval of the cement bond log required by paragraph (c)(2) prior to conducting well stimulation activities; (a) A proposal for further well operations shall be submitted by the operator on Form 3160–5 for approval by the authorized officer prior to commencing operations to redrill, deepen, perform casing repairs, plug-back, alter casing, recomplete in a different interval, perform water shut off, commingling production between intervals and/or conversion to injection. * * *
(b) Unless additional surface disturbance is involved and if the operations conform to the standard of prudent operating practice, prior approval is not required for recompletion in the same interval; however, a subsequent report on these operations must be filed on Form 3160–5. * * * * *
5. Add a new § 3162.3-3 to read as follows:
§ 3162.3-3 Subsequent well operations; Well stimulation.
(a) This section applies to well stimulation activities. All other injection activities must comply with section 3162.3-2.
(b) When an Operator Must Submit Notification for Approval of Well Stimulation.
A proposal for well stimulation must be submitted by the operator and approved by BLM before commencement of operations. The proposal may be submitted in one of the following ways:

(i)For new wells, the operator may submit with its Application for Permit to Drill the information required in paragraph (c) of this section, except for the cement bond log required by paragraph (c)(2). The approved permit to drill will require submission and approval of the cement bond log required by paragraph (c)(2) prior to conducting well stimulation activities; (ii) For wells permitted prior to the effective date of this section or for wells permitted after the effective date of this section, if the application for permit to drill a well did not include the information required in paragraph (c) of this section, the operator must submit a proposal for well stimulation operations on Form 3160-5 (Sundry Notices and Reports on Wells) as a Notice of Intent Sundry for approval by the authorized officer prior to well stimulation. If there is additional surface disturbance, the proposal must include a surface use plan of operations; and

(iii) If an operator has received BLM approval for well stimulation activities, it must submit a new Notice of Intent Sundry if either: (A) Well stimulation activities have not commenced within five years after the effective date of approval of the well stimulation activity; or (B) The operator has significant new information about the geology of the area, the stimulation operation or technology to be used, or the anticipated impacts of the stimulation activity to any resource.
(c) What the Notice of Intent Sundry Must Include. The authorized officer may prescribe that each proposal contain all or a portion of the information set forth in § 3162.3-1 of this title. The Notice of Intent Sundry must include the following:
(1) The geological names, a geological description, and the proposed measured depth of the top and the bottom of the formation into which well stimulation fluids are to be injected;
(2) The proposed measured depths (both top and bottom) of all occurrences of usable water and the cement bond logs (or another log acceptable to the authorized officer) proving that the occurrences of usable water have been isolated to protect them from contamination;

(3) The proposed measured depth of perforations or the open-hole interval, the source and location(s) of the water used in the stimulation fluid or trade name of the base fluid (if other than water), type of proppants, and estimated pump pressures. Information concerning water supply, such as rivers, creeks, springs, lakes, ponds, and wells, which may be shown by quarter-quarter section on a map or plat, or which may be described in writing. It must also identify the source, access route, and transportation method for all water anticipated for use in stimulating the well;

(4) A certification signed by the operator that the proposed treatment fluid complies with all applicable permitting and notice requirements as well as all applicable Federal, tribal, state, and local laws, rules, and regulations;

(5) A detailed description of the proposed well stimulation design, including:
(i) The estimated total volume of fluid to be used;
(ii) The anticipated surface treating pressure range;
(iii) The maximum injection treating pressure; and
(iv) The estimated or calculated fracture length and fracture height;

(6) The following information concerning the handling of recovered fluids:
(i) The estimated volume of fluid to be recovered during flow back, swabbing, and recovery from production facility vessels; (ii) The proposed methods of handling the recovered fluids, including, but not limited to, pit requirements, chemical composition of the fluid, pipeline requirements, holding pond use, re-use for other stimulation activities, or injection; and
(iii) The proposed disposal method of the recovered fluids, including, but not limited to, injection, hauling by truck, or transporting by pipeline.

(7) The authorized officer may request additional information under this subsection prior to the approval of the Notice of Intent Sundry.

(d) Mechanical Integrity Testing Prior to Well Stimulation. Prior to the well stimulation, the operator must perform a successful mechanical integrity test (MIT) of the casing.
(1) If well stimulation through the casing is proposed, the casing must be tested to not less than the maximum anticipated treating pressure.
(2) If well stimulation through a fracturing string is proposed, the fracturing string must be inserted into a liner or run on a packer-set not less than 100 feet below the cement top of the production or intermediate casing. The fracturing string must be tested to not less than the maximum anticipated treating pressure minus the annulus pressure applied between the fracturing string and the production or intermediate casing.
(3) The MIT will be considered successful if the pressure applied holds for 30 minutes with no more than a 10 percent pressure loss.
(e)(1) Monitoring and Recording During Well Stimulation. During the well stimulation operation, the operator must continuously monitor and record the annulus pressure at the bradenhead. If an intermediate casing has been set on the well that is being stimulated, the pressure in the annulus between the intermediate casing and the production casing must also be continuously monitored and recorded. A continuous record of the annulus pressure during the well stimulation must be submitted with the required Subsequent Report Sundry Notice (Form 3160-5, Sundry Notices and Reports on Wells) identified in paragraph (f) of this section.
(e)(2) If during the stimulation the annulus pressure increases by more than 500 pounds per square inch as compared to the pressure immediately preceding the stimulation, the operator must orally notify the authorized officer as soon as practicable, but no later than 24 hours following the incident. Within 15 days after the occurrence, the operator must submit a report containing all details

pertaining to the incident, including corrective actions taken, as part of a Subsequent Report Sundry Notice (Form 3160-5, Sundry Notices and Reports on Wells).

(f) Storage of all recovered fluids must be in either tanks or lined pits. The authorized officer may require additional measures to protect the mineral resources, other natural resources, and environmental quality from the release of recovered fluids.

(g) Information that Must be Provided to the Authorized Officer After Completed Operations. The following information must be provided to the authorized officer in the required Subsequent Report Sundry Notice (Form 3160-5, Sundry Notices and Reports on Wells) within 30 days after the operations are completed (see subpart 3160.0-9(c)(1)):

(1) The actual measured depth of perforations or the open-hole interval, the source and location(s) of the water used in the stimulation fluid or trade name of base fluid (if other than water), type of proppants, and actual pump pressures. Information concerning water supply, such as rivers, creeks, springs, lakes, ponds, and wells, which may be shown by quarter-quarter section on a map or plat, or which may be described in writing. It must also identify the source, access route, and transportation method for all water used in stimulating the well;
(2) The actual total volume of the fluid used;
(3) The actual surface pressure and rate at the end of each fluid stage, and the actual flush volume, rate, and final pump pressure;
(4) A report (table) that discloses all additives of the actual stimulation fluid, by additive trade name and purpose (such as, but not limited to, acid, biocide, breaker, brine, corrosion inhibitor, crosslinker, demulsifier, friction reducer, gel, iron control, oxygen scavenger, pH adjusting agent, proppant, scale inhibitor, or surfactant);
(5) A report (table) that discloses the complete chemical makeup of all materials used in the actual stimulation fluid without regard to original source additive (see paragraph (f)(4) of this section). For each chemical, the operator must provide the Chemical Abstracts Service Registry Number as well as the percentage by mass. The percent mass value is the mass value for each component (Mc) divided by the value of the entire fluid mass (Mt) times 100. (Mc/Mt)*100 = percent value. The percent mass values should be for the entire stimulation operation, not for the individual stages.
(6) The actual, estimated, or calculated fracture length and fracture height;
(7) The Subsequent Report Sundry Notice (Form 3160-5, Sundry Notices and Reports on Wells) may be completed in whole or in part, as applicable, by attaching the service contractor's job log or other report, so long as the information required in paragraphs (g)(1) through (g)(6) of this section is complete and readily apparent; (8) A certification signed by the operator that the treatment fluid used complied with all applicable permitting and notice requirements as well as all applicable Federal, tribal, state, and local laws, rules, and regulations;
(9) A certification signed by the operator that wellbore integrity was maintained throughout the operation, as required by paragraphs (d), (e)(1), and (e)(2) of this section;
(10) The following information concerning the handling of recovered fluids:
(i) The volume of fluid recovered during flow back, swabbing, or recovery from production facility vessels;
(ii) The methods of handling the recovered fluids, including, but not limited to, pipeline requirements, holding pond use, re-use for other stimulation activities, or injection; and
(iii) The disposal method of the recovered fluids, including, but not limited to, injection, hauling by truck, or transporting by pipeline. The disposal of fluids produced during the flow back from the well stimulation process must follow the requirements set out in Onshore Order Number 7, Disposal of Produced Water, Section III. B. (October 8, 1993, 58 FR 47354). (11) If the actual operations deviate from the approved plan, the deviation(s) must be documented and explained.

(h) Identifying Information Claimed to be Exempt from Public Disclosure. At the time of submission of any information required under this section, operators must:
(1) Specifically identify particular information claimed to be exempted from public disclosure by a Federal statute or regulation;

(2) Identify the Federal statute or regulation that prohibits the public disclosure of each piece of particular information, and explain in detail why the information is subject to the prohibition of the identified Federal statute or regulation; and

(3) Inform the BLM whether the particular information is available to the public through other means, such as disclosures required by state law.
(i) Any information that is provided in accordance with this section for which the operator does not substantiate a reason for withholding under paragraph (h) of this section shall be deemed not to be protected by the Trade Secrets Act or other Federal law and shall be released to the public. If an operator identifies information as exempt from disclosure, the BLM may nonetheless release that information if it determines that the information is not prohibited from disclosure by Federal law, after providing the operator with no fewer than 10 business days notice of the BLM's determination.
(j) Requesting a Variance from the Requirements of this Section. The operator may make a written request to the authorized officer to request a variance from the requirements under this section. The BLM encourages submission using a Sundry Notice (Form 3160-5, Sundry Notices and Reports on Wells). (1) A request for a variance must specifically identify the regulatory provision of this section for which the variance is being requested, explain the reason the variance is needed, and demonstrate how the operator will satisfy the objectives of the regulation for which the variance is being requested.
(2) The authorized officer, after considering all relevant factors, may approve the variance, or approve it with one or more conditions of approval, only if the BLM determines that the proposed alternative meets or exceeds the objectives of the regulation for which the variance is being requested. The decision whether to grant or deny the variance request is entirely within the BLM's discretion.
(3) A variance under this section does not constitute a variance to provisions of other regulations, laws, or orders.

(4) Due to changes in Federal law, technology, regulation, BLM policy, field operations, noncompliance, or other reasons, the BLM reserves the right to rescind a variance or modify any conditions of approval. The authorized officer must provide a written justification if a variance is rescinded or a condition of approval is modified.

6. Amend § 3162.5-2 by revising the first sentence of paragraph (d) to read as follows:
§ 3162.5-2 Control of wells.
* * * * *
(d) Protection of usable water and other minerals. The operator shall isolate all usable water and other mineral-bearing formations and protect them from contamination. Tests and surveys of the effectiveness of such measures shall be conducted by the operator using procedures and practices approved or prescribed by the authorized officer. * * *

_________________________________ ______________

Acting Assistant Secretary Date
Land and Minerals Management