UtahStateUniversity

REPORT

USU Regional Development

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The Regulatory Road Map for Oil & Gas Exploration, Development & Production in Utah

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Acronym Guide

ACA	Air Conservation Act
AMS	Analysis of Management Situation
AO	Approval Order
APD	Application for Permit to Drill
API	American Petroleum Institute
ARPA	Archaeological Resources Protection Act of 1979
BACT	Best Available Control Technology
BAT	Best Available Technology
BIA	Bureau of Indian Affairs
BIA *Handbook*	BIA Fluid Mineral Estate Procedural Handbook
BLM	Bureau of Land Management
BMP	Best Management Practice
BPCT	Best Practical Control Technology
CAA	Clean Air Act
CEQ	Council on Environmental Quality
CWA	Clean Water Act
CX (CE)	Categorical Exclusion
DAQ	Utah Division of Air Quality
DEMD	Division of Energy and Mineral Development
DEQ	Utah Department of Environmental Quality
DERR	Utah Division of Environmental Response & Remediation
DNA	Documentation of NEPA adequacy
DOGM	Utah Division of Oil, Gas, and Mining
DSHW	Utah Division of Solid and Hazardous Waste
DWQ	Utah Division of Water Quality
EA	Environmental Assessment
EDA	Exploration and Development Agreement
EIS	Environmental Impact Statement
EOI	Expression of Interest
EPA	Environmental Protection Agency
ESA	Endangered Species Act of 1973
FAN	Final Abandonment Notice

Acronym Guide

FLPMA	Federal Land Policy Management Act
FOGRMA	Federal Oil and Gas Royalties Act
FONSI	Finding of No Significant Impact
FOOGLRA	Federal Onshore Oil & Gas Leasing Reform Act
FWS	US Fish and Wildlife Service
GAO	General Approval Order
HAP	Hazardous Air Pollutant
IDCR	Interdisciplinary Consistency Review
IDPR	Interdisciplinary Parcel Review
IMDA	Indian Mineral Development Act
LRMP	Land Resource Management Plan
LUDP	Land Use Development Plan
MDP	Master Development Plan
MLA	Mineral Leasing Act of 1920
MLP	Master Leasing Plan
MMS	Minerals Management Service
MOA	Memorandum of Agreement
MOU	Memorandum of Understanding
NAA	Non-Attainment Area
NAAQS	National Ambient Air Quality Standard
NAGPRA	Native American Graves Protection & Repatriation Act
NEPA	National Environmental Policy Act
NESHAP	National Emission Standard for Hazardous Air Pollutants
NFMA	National Forest Management Act
NHPA	Natural Historic Preservation Act
NIA	Notice of Intent to Abandon
NMFS	National Marine Fisheries Service
NOA	Notice of Availability
NOI	Notice of Intent
NOS	Notice of Staking
NPDES	National Pollutant Discharge Elimination System
NPS	National Park Service

Acronym Guide

NSPS	New Source Performance Standard
NSR	New Source Review
OED	Utah Governor's Office of Energy Development
ONRR	Office of Natural Resources Revenue
OST	Office of the Special Trustee for American Indians
PM	Particulate Matter
POTW	Publically Owned Treatment Works
PSD	Prevention of Significant Deterioration
RMP	Resource Management Plan
ROD	Record of Decision
ROW	Right-of-Way Use Permit
SDWA	Safe Drinking Water Act
SHPO	State Historic Preservation Officer
SITLA	School and Institutional Trust Lands Administration
SPCC	Spill Prevention Control & Countermeasures
SRA	Subsequent Report Plug and Abandon
SUA	Surface Use Authorization
SUPO	Surface Use Plan of Operations
TAR	Tribal Authority Rule
TERA	Tribal Energy Resource Agreement
TMDL	Total Maximum Daily Load
UDC	Ute Distribution Corporation
UIC	Underground Injection Control
UPA	Utah Petroleum Association
UPA	Ute Partition Act
USFS	US Forest Service
UST	Underground Storage Tank
USU	Utah State University
WQA	Water Quality Act
WQS	Water Quality Standards

Executive Summary

As Utah's land-grant research institution, Utah State University (USU) has a vested interest in the issues that impact our local, state, and regional economies. This interest ensures that every Utah citizen has access to the collective assets of the university and benefits from its collaborative partnerships with industry, government, and other research institutions. USU's comprehensive education, technology, and research programs not simply attract but also support and expand economic opportunity. One such opportunity vital to Utah's economic portfolio is the development of the state's vast energy resources.

According to the Utah Governor's Office of Energy Development (OED),

> Energy is a $20.9 billion industry in Utah, generating $656 million in state and local revenues (including $77 million directly for education through the Utah School and Institutional Trust Lands Administration in 2013). There are more than 10,000 direct energy jobs in the state, a total that expands to almost 40,000 when indirect employment is included. Over 98% of the energy produced in Utah is derived from oil, gas, and coal, but unconventional and renewable energy resources provide potential for growth (http://energy.utah.gov/resource-areas/energy-information).

Energy development is a key economic driver for the state, and our abundant and diverse resources are essential to regional and national energy strategies. But our energy industry is not immune to the capricious global oil market, whose price cycles are influenced by complex factors such as weather, inventory, investor speculation, geopolitical events, policies of the Organization of the Petroleum Exporting Countries (OPEC), and other occurrences that can negatively impact the economy, the severity of one or more of which can dictate the duration and intensity of a particular pricing cycle.

As of this writing, crude oil prices that a short time ago exceeded $100 per barrel now sit at $40-$45, and while some laud the small respite at the pump, our local and state economies have been negatively impacted. Unemployment has risen because costs associated with production are higher relative to the revenue generated from exploration and production. The point at which an energy company will cease new production depends on the region or country and the associated cost of production. Producing a barrel of oil in the Middle East, for example, costs approximately $27, but in the Arctic the cost rises to around $75.

In Utah, cutbacks due to weak oil prices are having a profound effect, particularly in the Uintah Basin where the energy industry accounts for more than 60% of the area's economy. State and local governments have also been forced to cut numerous jobs that are linked to energy production revenues. On January 29, 2015, speaking before the state legislature, Utah's Geological Survey reported a loss of 16 full-time positions and a $1.4 million shortfall in mineral revenue due to falling oil prices. Infrastructure and other government services tied to mineral revenues are also being negatively affected.

Another factor currently impacting energy exploration, development, and production is the regulatory and legal framework imposed on energy producers. State laws, regulations, and policies apply to non-federally controlled lands with some exceptions and are discussed in this document. Federal laws, regulations, and policies dictate land access and use on public lands and continue to be a focus of debate, litigation, and legislative proposal for management reform. As of this writing, the U.S. Department of the Interior (DOI) introduced new hydraulic fracturing rules that the energy industry says will curtail its activity on federal public land. The industry claims that states already regulate this activity, that fracking has been used for more than 40 years with no negative environmental incidents, and that implementing the new regulations will average $97,000 per well.

The largest agency responsible for leasing and permitting federally controlled land in Utah is the Bureau of Land Management (BLM). The BLM sets the legal requirements, establishes the action timetables, and ensures the regulatory compliance that determine access to energy resources and the pace at which exploration, development, and production may occur.

USU has launched the Energy Policy Studies Initiative to provide stakeholders and the public with a coherent synthesis of current public energy development policy. Since policies and procedures for energy development often change and impact revenue at the state and local levels, this Initiative will help interested parties stay abreast of current developments. The Initiative will also promote government and industry collaboration to maximize responsible development of energy resources.

This first document under the Initiative describes the regulatory process for oil and gas exploration and development and details chronologically the requirements to access, explore, and produce oil and gas. For example, after a potential oil and gas resource has been identified, the first critical step is to determine ownership of the land surface and the mineral subsurface. Ownership determines the environmental reviews and analyses required for access. Once access is approved, exploration and production permits must be obtained. After permits are issued, production can begin, subject to environmental requirements and reporting procedures.

The regulatory overview here forms the groundwork for discussions about improving efficiency and effectiveness, avoiding redundancies, and incorporating scientific advances. Also included are stakeholder recommendations for improving the regulatory framework and best practices for achieving energy production goals. Subsequent publications under the Energy Policy Studies Initiative will address wind, solar, geothermal, oil shale, oil sands, coal, and other energy resources. All publications will be updated periodically to reflect the most current regulations and procedures. ■

Introduction

The Regulatory Roadmap for Oil and Gas Exploration, Development, and Production in Utah is a resource guide that provides stakeholders with an overview of oil and gas regulations across various land and mineral ownerships. Beginning just after a company has determined with high probability that oil and gas resources exist in a specific geological formation, the guide adopts a regulatory chronology for its seven chapters and appendix.

- **Chapter 1** describes the complex weave of land and mineral ownership in Utah and discusses the unique regulatory requirements of each ownership type (i.e., federal, state, tribal, and private).
- **Chapter 2** addresses the major legal requirements for environmental review at the federal and state levels, including such laws as the National Environmental Policy Act (NEPA) that concern oil and gas access and operations. Laws not covered in the chapter are noted in the appendix, as is access information for additional research.
- **Chapter 3** focuses on federal land use planning, particularly on the processes of the Bureau of Land Management (BLM), the largest federal agency in Utah with responsibility to provide oil and gas access and leasing. Not only does the BLM administer leases of its own lands but also of lands managed by other federal agencies such as the U.S. Forest Service (USFS) and the Bureau of Indian Affairs (BIA). Results of the BLM land use planning process, in turn, determine what lands are available for oil and gas exploration and development and under what conditions.
- **Chapter 4** illuminates the process of leasing surface land and subsurface minerals from federal, state, tribal, and private landlords and owners. Differences in each ownership are discussed, and required steps are detailed.
- **Chapter 5** unravels the permitting process. Successful energy company are expert in securing required permits, but since various land and mineral landlords and owners have distinct permit requirements, and since those requirements often undergo amendment or alteration, the process can be daunting.
- **Chapter 6** concerns exploration, development, and production. The regulatory requirements of the production phase, such as periodic inspections and compliance measures, are outlined.
- **Chapter 7** recounts the challenges and opportunities identified during interviews with individuals who are responsible for either overseeing, implementing, or complying with the regulatory framework of the oil and gas industry. Interviews were given in good faith, with each participant expressing a desire to affect positive change.

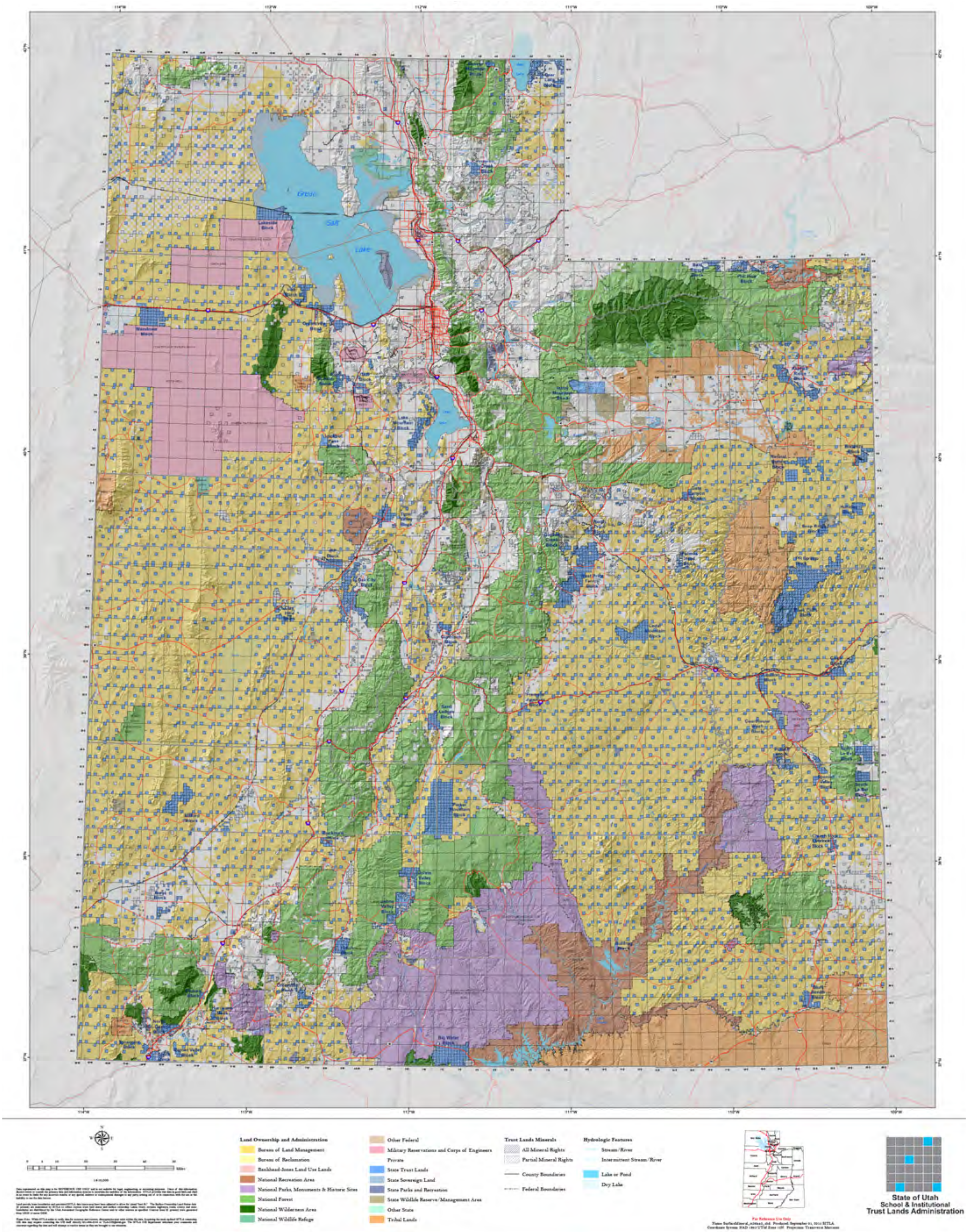
Each chapter, where appropriate, engages in two basic questions:

- What is the specific law or regulation at issue?
- Why is the specific law or issue important to oil and gas exploration, development, and production?

Document Updates

This guide will be updated periodically to reflect changes to current regulations, laws, and/or policies (upon jurisdictional verification). The document (and subsequent updates) may be downloaded in digital format at **rd.usu.edu**.

UTAH LAND STATUS & AREAS OF RESPONSIBILITY



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CHAPTER 1: OWNERSHIP AND MANAGEMENT

After a determination has been made that oil and gas resources are likely to exist in a particular location, the next step in the exploration and development process is to identify the area's land and mineral ownership. Each ownership type has distinct regulatory requirements related to environmental review, resource access, and energy production. This chapter describes the various land and mineral owners and management agencies engaged in oil and gas leasing in Utah, with particular attention to the Uintah Basin.

Major Leasable Land & Mineral Estates in Utah (and key regulatory agencies)	
Federal	Bureau of Land Management U.S. Forest Service
State	School & Institutional Trust Lands Administration Utah Division of Oil, Gas, and Mining Division of Forestry, Fire, and State Lands
Tribal	Bureau of Indian Affairs Bureau of Land Management
Private	Utah Division of Oil, Gas, and Mining

Lands and Minerals in Utah

FEDERAL

Bureau of Land Management (BLM)

- *BLM Public Lands in Utah: 23 million acres*[1]
- *BLM Subsurface Mineral Acres: 32 million acres*[2]

The BLM was established in 1946 following the consolidation of the General Land Office and the U.S. Grazing Service to manage public land resources for such activities as recreation, livestock grazing, mineral development, et al. Approximately 94 percent of BLM-managed lands are located west of the Mississippi River.

The BLM federal mineral estate underlies lands that are managed by such agencies as the U.S. Forest Service, the U.S. Park Service, the Bureau of Reclamation, and the U.S. Fish and Wildlife Service; moreover, this estate, in some cases, includes the subsurface that underlies private surface ownership. Since BLM is the largest land manager in Utah and is the lead agency for oil and gas leasing, this handbook focuses predominately on the BLM's regulatory processes for oil and gas exploration and development.

The BLM also provides technical assistance related to mineral development on tribal lands in cooperation with the Bureau of Indian Affairs (BIA) and tribal governments, as part of the federal government's trust responsibilities to Native American tribes.

U.S. Forest Service (USFS)

- *Surface Acres in Utah: 8.2 million*[3]
- *Subsurface Acres in Utah: 0*[4]

Established in 1905, the USFS manages surface forest lands in 44 states and Puerto Rico. Its mission is "to sustain the health, diversity, and productivity of the Nation's forests and grasslands to meet the needs of present and future generations."[5]

Though it is the BLM's responsibility to manage the mineral resources of forest lands, the USFS nevertheless plays an important role in the extraction of oil, gas, and other energy resources because it participates in managing the surface impacts related to mineral development. This guide, then, describes the BLM/USFS relationship as it relates to oil and gas exploration and development.

STATE

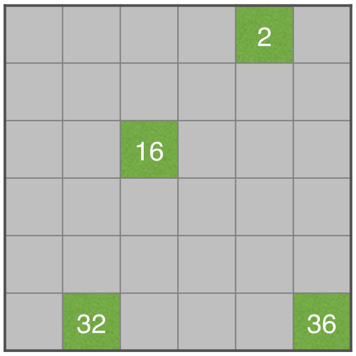
Utah School and Institutional Trust Lands Administration (SITLA)

- *Surface Acres: 3.4 million*[6]
- *Subsurface Oil/Gas Acres: 4.4 million*

When Utah became a state in 1894, it was granted 7,475,297 acres of trust land (about one-ninth of the total land in the state). Since then, over half of that land has been sold to private parties (approximately 30% of private land in Utah was once state trust land). SITLA, established in 1994, manages remaining trust lands for twelve beneficiaries that, among others, include public schools and institutions of higher education. These lands generate revenue from oil and gas development, lumber production, livestock grazing, and other activities. Under the guidance of various Utah legal authorities, SITLA's oil and gas leasing program (described in chapter 4) accounts for nearly half of agency revenue.[7]

In FY2014, SITLA generated $138.9 million from the management of trust lands, pushing its total trust fund value over $1.6 billion. That year, $40.4 million was distributed to public schools, a $2.6 million increase over 2013, and $14.6 million more than in 2012.

Land Swaps



The checkerboard appearance of state trust lands on the map beginning this chapter is due to the method by which lands were initially given to the state. As with other western states, all land in Utah was divided into 6x6-mile (36 mi^2) land parcels called "townships," and each township was subdivided into mile-square sections. Of each 36-section township grid, the state was given parcels 2, 16, 32, and 36 as a means to provide funding for public schools.

Other state institutions were given quantity grants from the remaining public land domain, but not under the same pattern.[8] Some counties, such as Salt Lake County, have very little trust land while rural counties may have large amounts.

Because Trust lands are often surrounded by federal lands, access can prove challenging; in fact, nearly 326,000 acres of state trust land are within federally-designated wilderness study areas. SITLA, as a result, has difficulty in leasing such trust lands for profit.[9] A land swap can occur with the federal government, either congressionally or administratively, as long as the lands to be exchanged have similar value, whether derived from land, cash, or other rights.

Utah Division of Forestry, Fire, and State Lands (FFSL)

- *Surface Acres: 1.45 million*[10]
- *Subsurface Acres: 0*

The FFSL manages state sovereign lands and state lands or mineral estates that are not SITLA trust lands. Sovereign lands are commonly called "submerged" lands because they include river and lake beds. Sovereign land areas in Utah are the Great Salt Lake, Utah Lake, Bear Lake, Bear River, Jordan River, and portions of the Colorado and Green rivers.

While most oil and gas exploration and production on state land occurs through SITLA, the FFSL also offers parcels for oil and gas leasing (described briefly in Chapter 4). Permitting, production, and reclamation processes of sovereign and non-SITLA state lands fall under the same regulations and requirements of SITLA trust lands. DOGM is the regulatory authority for all drilling-related activities on FFSL lands.

TRIBAL

Ute Indian Tribal Land

- *Surface Acres: 1.2 million (4 million acre jurisdictional boundary)*[11]
- *Subsurface Acres: 400,000*

Bureau of Indian Affairs (BIA)

The BIA was established in 1824 to "enhance the quality of life, to promote economic opportunity, and to carry out the responsibility to protect and improve the trust assets of American Indians, Indian tribes, and Alaska Natives."[12] As will be discussed in subsequent chapters, the BIA is integral to the development of oil and gas resources on tribal lands.

In the Uintah Basin (Utah's main oil and gas exploration and development area), three types of tribal lands (described below) fall under BIA trust responsibility. Because information is not available at this time, these lands will not be discussed individually in this version of the handbook; instead, general BIA standards and regulations will be referenced when discussing oil and gas development on tribal lands. Please note, however, that individual tribes have independent jurisdictional authority in management of their resources, so additional procedures beyond those discussed here may be required for oil and gas development on Utah tribal lands.

Northern Ute Indian Tribe

In 1861, Abraham Lincoln issued the executive order that created the original Uintah Valley Reservation in what is now northeastern Utah. In 1886, this land was merged with the adjacent Uncompahgre Reservation, and the resulting area was designated as the Uintah and Ouray Indian Reservation. Today, the Northern Ute Indian Tribe (comprised of the Whiteriver, Uintah, and Uncompahgre bands) manages reservation lands, in cooperation with the BIA.[13]

Case Study: Recent Land/Mineral Estate Swaps

A 2014 law that entitles SITLA and Ute Tribe to exchange mineral estates is helping to protect culturally sensitive reservation lands near Grand County in exchange for mineral estates with greater energy development potential in the northern part of the reservation. The Tribe prefers the southern reservation area to remain undeveloped due to cultural significance. SITLA will acquire the mineral estate known as the Hill Creek Extension (managed by BLM) for energy leasing purposes.

In 2013, SITLA swapped land near Book Cliffs, Colorado River Valley, and Nine Mile Canyon for federal land in Uintah, Grand, and San Juan counties with valuable mineral reserves. The land SITLA traded had environmental and recreational value that would have been compromised had it gone to lease. BLM's multiple use mission is more aligned with conservation area management than is SITLA's directive, which mandates that the agency profit from its land management.

Individual Tribal Members

In 1887, the U.S. Congress adopted the General Allotment Act, which authorized the allotment of tribal trust lands to individual tribal members. Unlike non-tribal private lands, individual tribal lands are held in trust with the federal government, and the responsibility to uphold this trust rests with the BIA. The BIA also oversees oil and gas activities and ensures that resources are developed in a responsible manner and generate the maximum benefit to individual mineral owners.[14]

Ute Distribution Corporation (UDC)

Simply put, the 1954 Ute Partition and Termination Act (UPA) resulted in the division and distribution of all tribal assets between members of full and of mixed ancestries.[15] With federal oversight, these assets were to be managed jointly by the Tribal Business Committee and by the authorized representatives of the mixed ancestry group. Under the UPA, the mixed ancestry group received 27.5% of all tribal assets defined as "any property of the tribe, real, personal or mixed, whether held by the tribe or by the United States in trust for the tribe." To manage its assets and distribute revenue, the mixed ancestry group established the UDC, a private corporation located in Roosevelt, Utah.

PRIVATE

Individual Land Owners

- *Surface Acres in Utah: 11.4 million*[16]

Utah lands became the public domain of the United States of America through the signing of the Treaty of Guadalupe Hidalgo in 1848. After acquiring the land now known as Utah, the Federal government began transferring land portions to private owners through purchase agreements, preemption, and homestead rights established by the Homestead Act of 1862.[17] Today, private surface and subsurface acres are scattered throughout Utah. The DOGM manages nearly all oil and gas development on private lands in Utah.

Split Estates

In the United States, landowners do not automatically own the rights to the minerals that lie beneath the surface of their land. Just after the Revolutionary War, the federal government began selling its land, but it wasn't until the early 1900s that congress enacted a legal distinction between ownership of the surface land (i.e., surface estate) and ownership of the minerals beneath that land (i.e., mineral estate). Federal land sales since have typically included only the rights to the land's surface estate, while the government has either retained ownership of the mineral estate for itself or sold those rights to some other party. Today, surface rights and mineral rights today are most often held separately (i.e., not owned by the same entity), a situation known as a "split estate," and because so many of these rights have been purchased or traded multiple times throughout the years, surface and subsurface ownerships are often quite complex.[18]

In Utah, a split estate's mineral rights have precedence over its surface land rights, so mineral owners are allowed access to surface lands for purposes of resource extraction. Over time, state and federal laws have been passed to address the conflicts inherent to this surface land use and the impacts characteristic of mineral exploration and development. The Energy Policy Act of 2005 includes a provision to compensate a surface land owner for damages resulting from mineral development[19], and the Utah Surface Owner Protection Act of 2012 requires the surface land owner and the mineral owner to negotiate a surface use agreement detailing the use of the surface land and specifying the damages (e.g., loss of crops, loss of value to existing surface improvements, potential permanent damages, et al.) that would be owed to the surface land owner as a result of the mineral owner's use of the land. The agreement is between the mineral and surface owners, and enforcement is not regulated by any government agency.[20] ■

Chapter 1 Notes

[1] http://www.blm.gov/ut/st/en/prog/energy.html.

[2] BLM Public Land Statistics 2013.

[3] http://extension.usu.edu/utahrangelands/files/uploads/RRU_Section_Two.pdf.

[4] BLM manages subsurface acres for all federal agencies in Utah.

[5] From the USFS website, http://www.fs.fed.us/about-agency.

[6] From SITLA at http://trustlands.utah.gov/our-agency/what-are-trust-lands.

[7] SITLA financial data at http://trustlands.utah.gov/our-agency/financial-reports-statistics.

[8] From SITLA's 2013 Annual Report at http://trustlands.utah.gov/download/financial/fy2013/SITLA %20FY2013%20Annual%20Report%20Email.pdf.

[9] From the 2011 Annual Report: http://trustlands.utah.gov/download/financial/fy_2011/ 2011%20annual %20report.pdf.

[10] "Land Ownership of Utah" by Ellie I. Leydsman McGinty (USU) at http://extension.usu.edu/ utahrangelands/files/uploads/RRU_Section_Two.pdf.

[11] http://www.bia.gov/cs/groups/xieed/documents/document/idc1-022549.pdf.

[12] http://bia.gov/WhoWeAre/index.htm.

[13] http://www.utetribe.com/memberServices/publicRelations/publicRelations.html.

[14] 25 CFR Subchapter I 211.1(d).

[15] UPA defines assets as "any property of the tribe, real, personal or mixed, whether held by the tribe or by the United States in trust for the tribe." UPA Id. 677a(f).

[16] http://extension.usu.edu/utahrangelands/files/uploads/RRU_Section_Two.pdf.

[17] http://archives.utah.gov/research/guides/land-original-title.htm#purchase.

[18] More information at http://www.blm.gov/bmp/split_estate_docs/Split%20Estate%20Presentation %202006.pdf.

[19] Energy Policy Act of 2005, Sec 1835.

[20] Utah's Surface Owner Protection Act 2012: http://www.utahsurfaceowners.org/uploads/ 9/8/4/7/9847022/split_estate_brochure_finall.pdf.

Shots of the Uintah Basin oilfield, courtesy of Howard Shorthill, USU

CHAPTER 2: ENVIRONMENTAL REVIEW

Photo courtesy of Jordan Evans, USU

The demands and complexity of environmental review vary by land and mineral ownership. The federal government, for example, must ensure that all actions on federal land comply with the National Environmental Policy Act (NEPA), but state, tribal, and private entities are under no such obligation in managing actions on their land and mineral jurisdictions, and instead employ environmental review processes of their own. Given its extensive application in Utah, however, NEPA is the primary focus of the chapter, but other laws that impact oil and gas operations (figure below) are discussed in the Appendix.

Major Environmental Legislation

- National Environmental Policy Act*
- Endangered Species Act
- Clean Air Act
- Clean Water Act
- Air Conservation Act♦
- Water Quality Act♦
- Archaeological Resource Protection Act
- Native American Graves Protection & Repatriation Act*
- National Historic Preservation Act
- The Antiquities Act

* = Federal only, ♦ = State only

The chapter describes major environmental legislation, identifies legislative and regulatory authority, and provides agency-specific environmental checkpoints.

The National Environmental Policy Act

WHAT IS NEPA?

Despite common perception, NEPA is not an environmental statute; rather, it is a procedural statute that requires federal agencies[1] to identify and consider the environmental impacts of and potential alternatives to any proposed action on federal lands* (surface or mineral estate) before that action can be authorized. In requiring informed decisions, however, NEPA does not obligate federal agencies to elevate environmental concerns over valid social or economic concerns.[2]

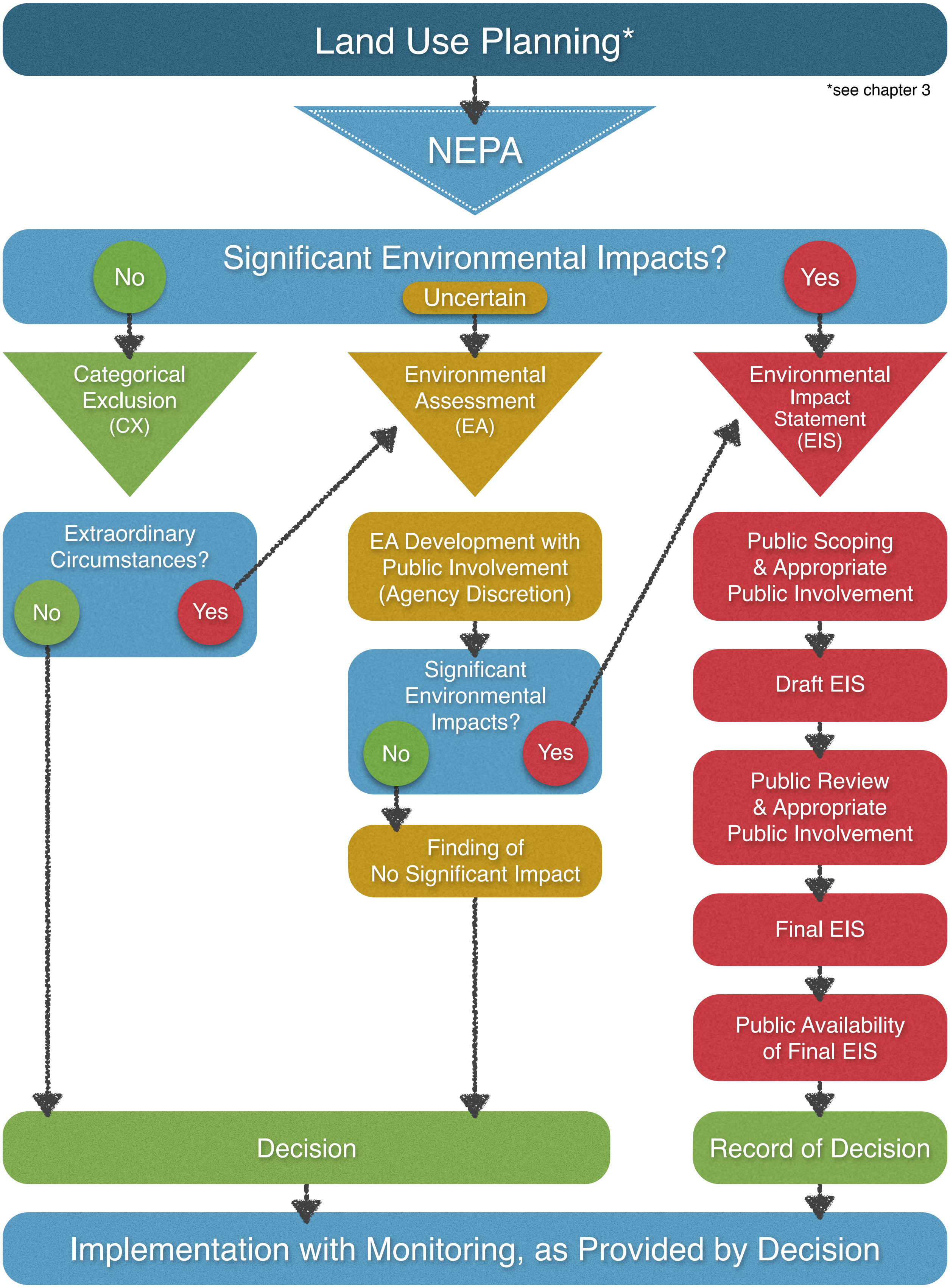
WHY IS NEPA IMPORTANT?

NEPA is the benchmark for the environmental review processes and mitigation measures demanded at each stage of oil and gas development on federal land. NEPA requirements can be extremely time consuming and expensive, but they are crucial since they often form the basis of federal land litigation.

HOW DOES NEPA AFFECT OIL AND GAS DEVELOPMENT?

Before authorizing any action on federal surface lands or subsurface mineral estates, the agency must go through the NEPA process to determine the environmental effects to the quality of the human environment. Note that NEPA only applies to federal agencies and federal lands, or if there is a demonstrated federal nexus to a given undertaking on non-federal land. The figure below maps the NEPA process, and step descriptions follow.

THE NEPA PROCESS



Categorical Exclusion (CX)

In this category, the agency has made a determination that the proposed action will not significantly impact the human environment as a single action or as an action that can have a cumulative impact. A CX is used when there has been analysis conducted previously on the affected land area, and no significant impact was identified. If the agency official determines that the previous analysis is legally defensible and remains sufficient to make an informed decision without conducting further analysis, then approval of the action can occur without further analysis. This step minimizes duplication of information and bureaucratic effort and provides an efficient approach for final decisions when there are negligible environmental impacts. (The Energy Policy Act of 2005 added five circumstances where CX would apply.[3])

Environmental Assessment (EA)

An EA is prepared when the significance of the environmental impacts of a project proposal is uncertain. At its most basic, an EA briefly discusses a project's need and environmental impact, considers alternative actions and their impacts, and lists authorities consulted. The information assists in determining whether a Finding of No Significant Impact is issued or an Environmental Impact Statement is required. In the former, it is determined that the proposed action will not result in significant impacts to the quality of the human environment. In the latter, there is a finding of significant impacts, and the agency official determines that an EIS is necessary. An EA can be finalized in as little as six months; however, depending on the complexity and opposition to the proposed action, the final decision can take several years and often results in litigation.

Environmental Impact Statement (EIS)

An EIS is a detailed document required when a proposed action has been determined to significantly affect the quality of the environment. The EIS describes the environmental effects of a proposed action and contains alternative actions that may be chosen, including the decision not to proceed with the proposed action, known as the No-Action Alternative. An EIS allows for extensive input from the public and is designed to involve cooperating agency partners, e.g., local government, state and federal officials. While NEPA indicates completion in two to three years, most EISs today require a five- to ten-year timeline.

After an agency (or agencies) has prepared a draft EIS, the Environmental Protection Agency (EPA) reviews, comments on, and rates the adequacy of the analysis and the proposed action's impact to the environment, according to the following scale:

Adequate

This rating indicates that the draft EIS adequately discloses the impacts of the alternatives proposed, and no further analysis or data collection is required.

Insufficient Information

This rating denotes that the draft EIS lacks sufficient information to properly "assess environmental impacts that should be avoided in order to fully protect the environment," and/or that the draft fails to include "new reasonably available alternatives that are within the spectrum of alternatives analyzed in the draft EIS, which could reduce the environmental impacts of the proposal."[4] In giving this rating, EPA suggests that the draft EIS be revised to include information adequate to fully support the agency's analysis.

Inadequate

This rating indicates that the draft EIS,

> does not adequately assess the potentially significant environmental impacts of the proposal, or the reviewer has identified new, reasonably available alternatives that are outside of the spectrum of alternatives analyzed in the draft EIS, which should be analyzed in order to reduce the potentially significant environmental impacts.[5]

EPA requires the agency to either revise the draft EIS and/or supplement the document with information, data, or analysis so that the document fulfills the NEPA requirements. If the agency disagrees with the EPA's rating, the matter is taken up with United States Council on Environmental Quality (CEQ).

EPA receives all EISs (draft, final, and supplemental) prepared by federal agencies and is responsible for publishing the Notices of Availability (NOA) in the Federal Register. Once a notice appears in the Federal Register, the official clock starts for authorized public review, comment, and wait periods.

PROGRAMMATIC VS. SITE-SPECIFIC NEPA ANALYSIS

Programmatic Analysis

A programmatic NEPA analysis evaluates land use planning and new policies for broad geographic areas and assesses the potential cumulative environmental effects of the proposed actions. At the programmatic level, multiple objectives and alternatives are evaluated. Mitigation measures and stipulations to address environmental impacts are generic at this stage. Examples of previously conducted programmatic analyses include Greater Sage Grouse, oil shale, and oil sands.

Site-Specific Analysis

In contrast to a programmatic analysis, a site-specific analysis is conducted when a specific action is proposed on federal land. For oil and gas, this may be drilling a well or constructing a production facility. Site-specific analyses explore different ways of achieving the specific objective. The geographic area of the analysis is limited, and potential environmental impacts are examined for that specific area. Any mitigation measures are specific and are included in the proposal of the action.

Case Study: Greater Sage-Grouse*

On September 22, 2015, the Department of the Interior announced that the Greater Sage-grouse does not warrant protection under the Endangered Species Act (ESA) because of the restrictions that have been approved in the BLM and USFS land use plans. The 98 land use plans cover ten Western States including Utah where 50% of the bird's occupied range is managed by the federal government. The planning efforts were at the state and federal levels. The state identified 11 Sage-grouse Management Areas in Utah (~7.5 million acres). The state plan addresses major threats to the bird such as wildfire and invasive species, and called for voluntary conservation measures to achieve conservation goals on private and trust lands. The federal plans focus on three categories of protection. First, the 228,500 acre Sagebrush Focal Areas (SFA) require the highest level of protection due to presence and activity of the bird population. The federal government proposes to withdraw lands to prevent mineral development (e.g., metallic, nonmetallic minerals). Second is the 2.7 million acre Priority Habitat Management Areas (PHMA) which limit energy and mineral development. Third is the 583,000 acre General Habitat Management Areas (GHMA) where the restrictions for land use are less stringent but still require measures to avoid, mitigate, and minimize impacts from any activity (e.g., energy and mineral development, grazing, and recreation).

Addressing the needs of Greater Sage-grouse is one of numerous examples where NEPA and the Endangered Species Act connect to impact oil and gas development on public lands.

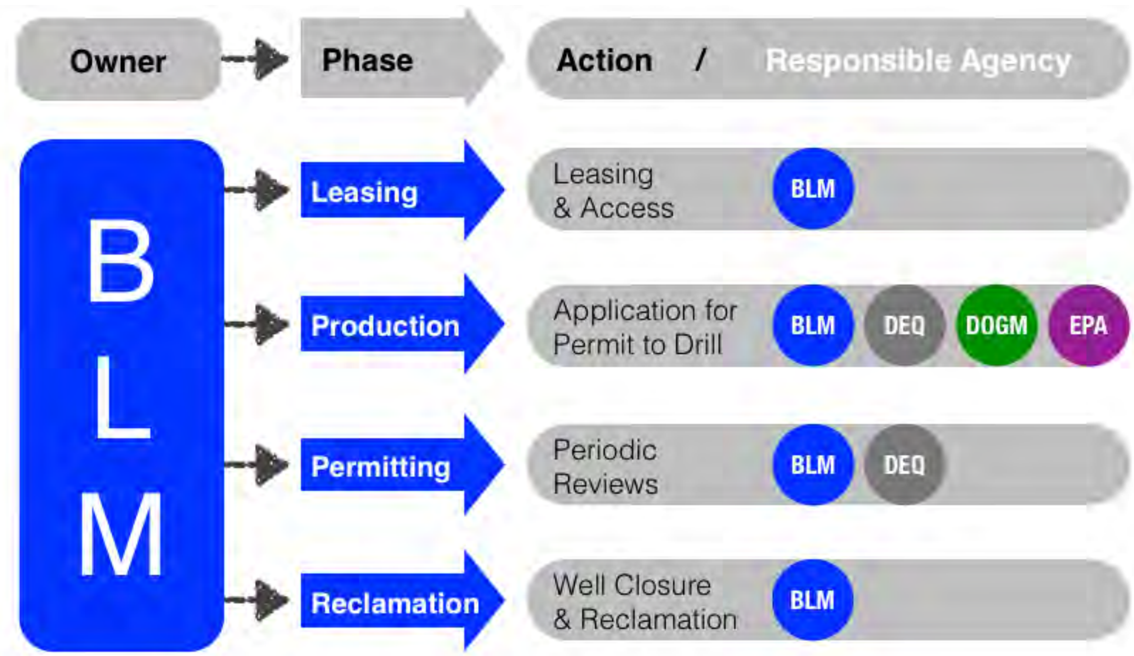
**Source: BLM Fact Sheet for Greater Sage-Grouse Conservation Strategy in Utah.*

Key Environmental Regulatory Checkpoints by Lead Agency

FEDERAL

Since each federal agency is permitted to create its own procedures for implementing NEPA, this section illustrates agency-specific NEPA procedures at various stages of oil and gas activity on federal lands. Also identified are the points at which environmental reviews (i.e., NEPA, Clean Air Act) intersect with federal, state, tribal, and private ownerships. Each step lists the responsible agency.

The Bureau of Land Management (BLM)



Leasing/Access (BLM)

A programmatic EIS is completed during the creation of a Resource Management Plan (RMP) and is used to determine which lands will be open to oil and gas development. This EIS may impose restrictions on lands leased. After nomination, the land parcel undergoes a site-specific EA prior to being leased. If the EA finds that significant environmental impacts are likely to occur due to leasing, nominations may be withdrawn from auction and deferred for further environmental analysis.

Permitting (BLM, DOGM, DEQ or EPA)

A site-specific NEPA analysis is required prior to any drilling or surface disturbance on federal land. Approval of full development projects (projects with multiple wells) has recently taken more than seven years. The Surface Use Plan of Operations (SUPO) portion of the Application Permit to Drill (APD) must also be in compliance with environmental regulations and stipulations of the lease. The operator is required to obtain all necessary environmental permits from DOGM and Department of Environmental Quality (DEQ) prior to the approval of the APD. If the project is in Indian country, the EPA has jurisdiction for air and water permits.

Periodic Reviews (BLM and DEQ)

Periodic environmental inspections certify compliance with the various environmental regulations and air and water quality permits, and ensure adherence to the terms of the lease and APD. BLM's high priority sites are inspected at least once a year, while low priority sites are inspected when possible. DEQ inspects sites to ensure compliance with issued water and air permits.

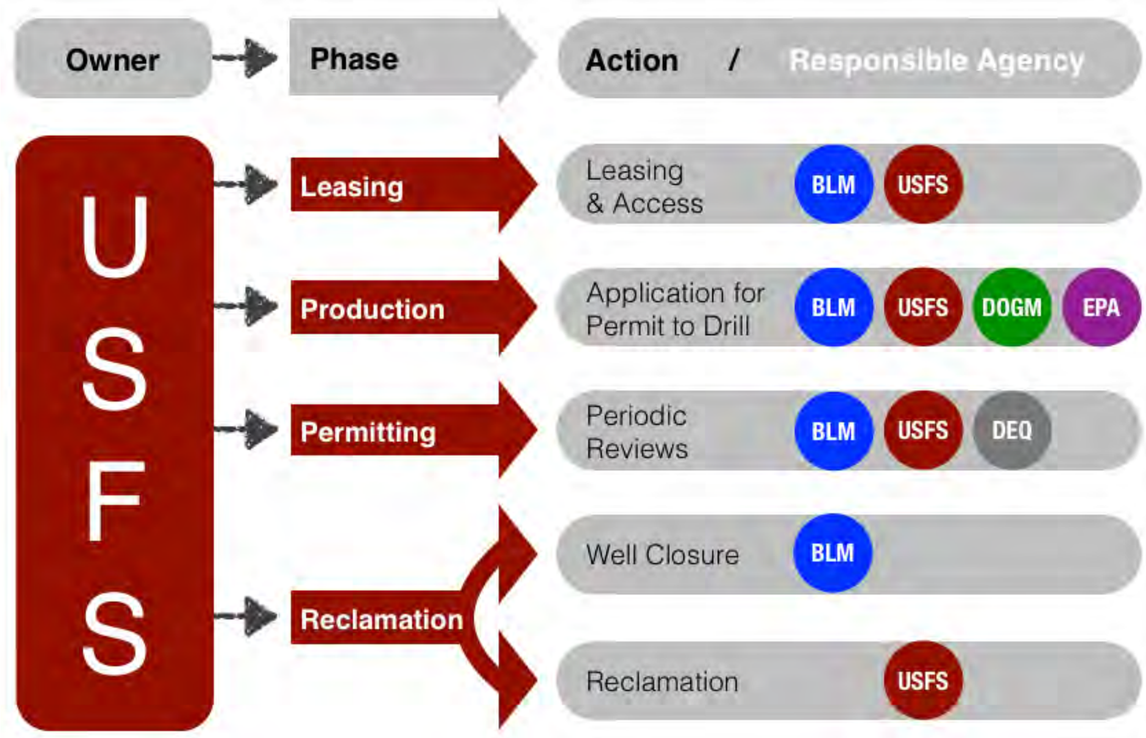
Well Closure (BLM)

The well closure process must be carried out in accordance with environmental requirements set forth in the lease terms and prior NEPA analyses. In cases of emergency or well failure, closure may occur with verbal approval from the BLM.

Reclamation (BLM)

Reclamation plans are included in the SUPO portion of an APD. Reclamation may be completed during the development of the lease (interim reclamation) or after production has ceased (final reclamation). The ultimate goal of reclamation is to "set the course for eventual ecosystem restoration."[6]

The US Forest Service (USFS)



Leasing/Access (USFS and BLM)

A programmatic EIS is completed with the land use plans created by the USFS. As with BLM land, nominated parcels undergo a site-specific EA to determine the adequacy of environmental protections in the land use plan. If additional environmental analyses are required, the lands will be withdrawn from consideration.[7] BLM performs the leasing.

Permitting (USFS, BLM, DEQ, or EPA)

A site-specific NEPA analysis is required prior to any drilling or surface disturbance on USFS land. The USFS approves the SUPO submitted with the APD, while the rest of the APD is approved by the BLM, including the drilling plan. The operator is also required to obtain all necessary environmental permits from DOGM and DEQ prior to APD approval. If the well is in Indian country, the EPA has jurisdiction over air and water permits, not DEQ or DOGM.

Periodic Reviews (BLM, USFS, and DEQ or EPA)

The BLM and the USFS have joint responsibility for inspections of wells on USFS land. During the drilling, production, and reclamation phases, the BLM conducts inspections of all drilling, down-hole operations, production, and environmental compliance; and the USFS is responsible for the inspection of surface use operations. DEQ also conducts periodic reviews to ensure compliance with water and air permits (EPA performs this review if the well is in Indian country).

Well Closure (BLM)

The operator must contact the BLM to gain approval and coordinate the witnessing of plugging operations. Plugging must be carried out in accordance with the environmental requirements set forth in the lease and prior NEPA analyses. In cases of emergency or well failure, plugging may occur with verbal approval from the BLM.

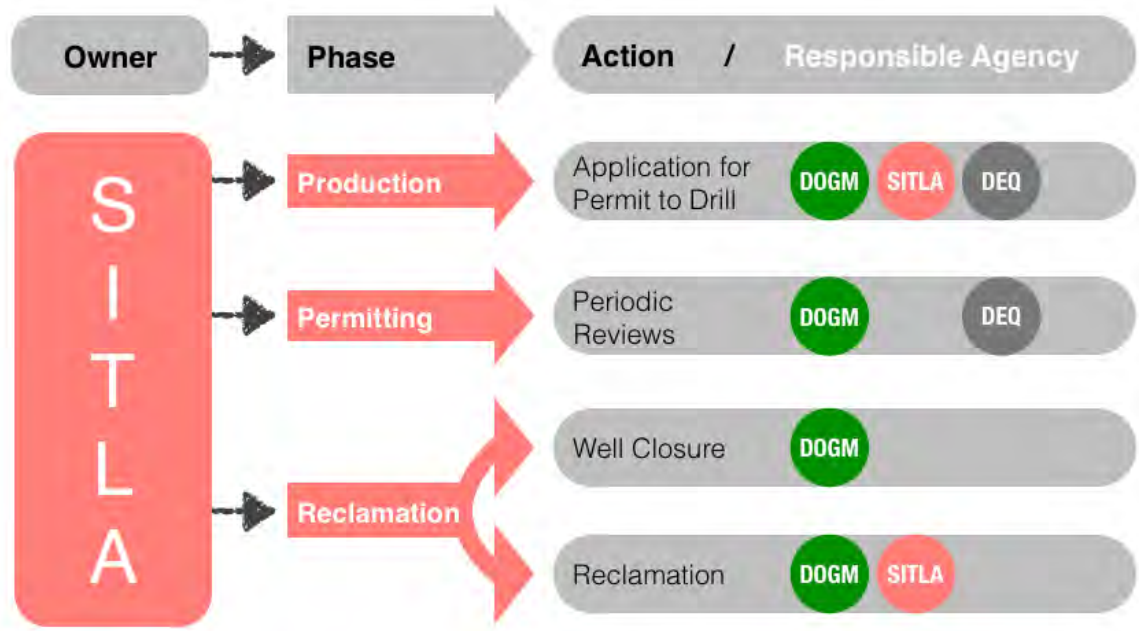
Reclamation (USFS)

Reclamation plans are included in the SUPO portion of an APD. Reclamation may be completed during the development of the lease (interim reclamation) or after production has ceased (final reclamation). The ultimate goal of reclamation is to "set the course for eventual ecosystem restoration."[8] The USFS is responsible to ensure that reclamation meets the necessary standards.

STATE

While not subject to NEPA, oil and gas development on state trust or privately owned lands must comply with other federal environmental laws (e.g., CAA, CWA, ESA, etc.) and other laws and regulations determined by the states. The DEQ is the umbrella agency that determines environmental regulations within the state of Utah. Utah's environmental regulations can be found in Title 19 of the Utah Code. The following are environmental checkpoints on trust land.

State Trust Lands



Leasing

The School and Institutional Trust Lands Administration (SITLA) has an environmental compliance program to ensure that development on its land is consistent with existing regulations. SITLA itself is not a regulatory agency but is committed to managing trust lands for the interests of its beneficiaries. SITLA also has a Wildlife Advisory Board to review impacts on wildlife. If trust land is found to have a high conservation value, SITLA works to trade that land with agencies that are able to encourage conservation efforts.[9]

Permitting (DOGM, SITLA, and DEQ)

APDs include site impact assessments, reclamation plans, and mitigation steps to reduce the environmental impact of a well. Prior to issuing an APD, a pre-site inspection is conducted by DOGM, the surface owner, and the operator to address any restrictions or stipulations that may be necessary during the life of the well. Appropriate air and water permits must also be obtained through the DEQ. If the APD is on SITLA land, copies must be submitted to SITLA for review. DOGM will not approve any APD on SITLA land without SITLA's approval. SITLA ensures that a paleontological and/or archaeological review of the land has been completed.

Periodic Reviews (DOGM and DEQ)

DOGM inspects all natural gas and oil wells on trust land to ensure compliance with the terms of the lease and other regulations. DEQ is responsible for the periodic review of various air and water permits. The majority of inspections for wells on trust land are environmental.[10]

Well Closure (DOGM)

The operator must submit to DOGM a notice of intent to plug and abandon before a well is closed. This notice includes a description of and pertinent information about the well, and indicate when the well closure will occur. In cases of emergency only, a verbal approval must be given, but proper forms should be submitted within five days of the emergency closure. Within 30 days after a well closure, a report of how, when, and by whom a well was closed must be submitted.

Reclamation (DOGM and SITLA)

The reclamation of well sites on trust land is done according to the lease between SITLA and the operator. Within 30 days of well closure, DOGM, SITLA, and the operator will inspect the site to establish minimum reclamation requirements. Reclamation should be completed within one year of well plugging, though extensions may be granted. Compliance with reclamation standards is necessary for the release of DOGM and SITLA bonds.

Air Quality in the Uintah Basin

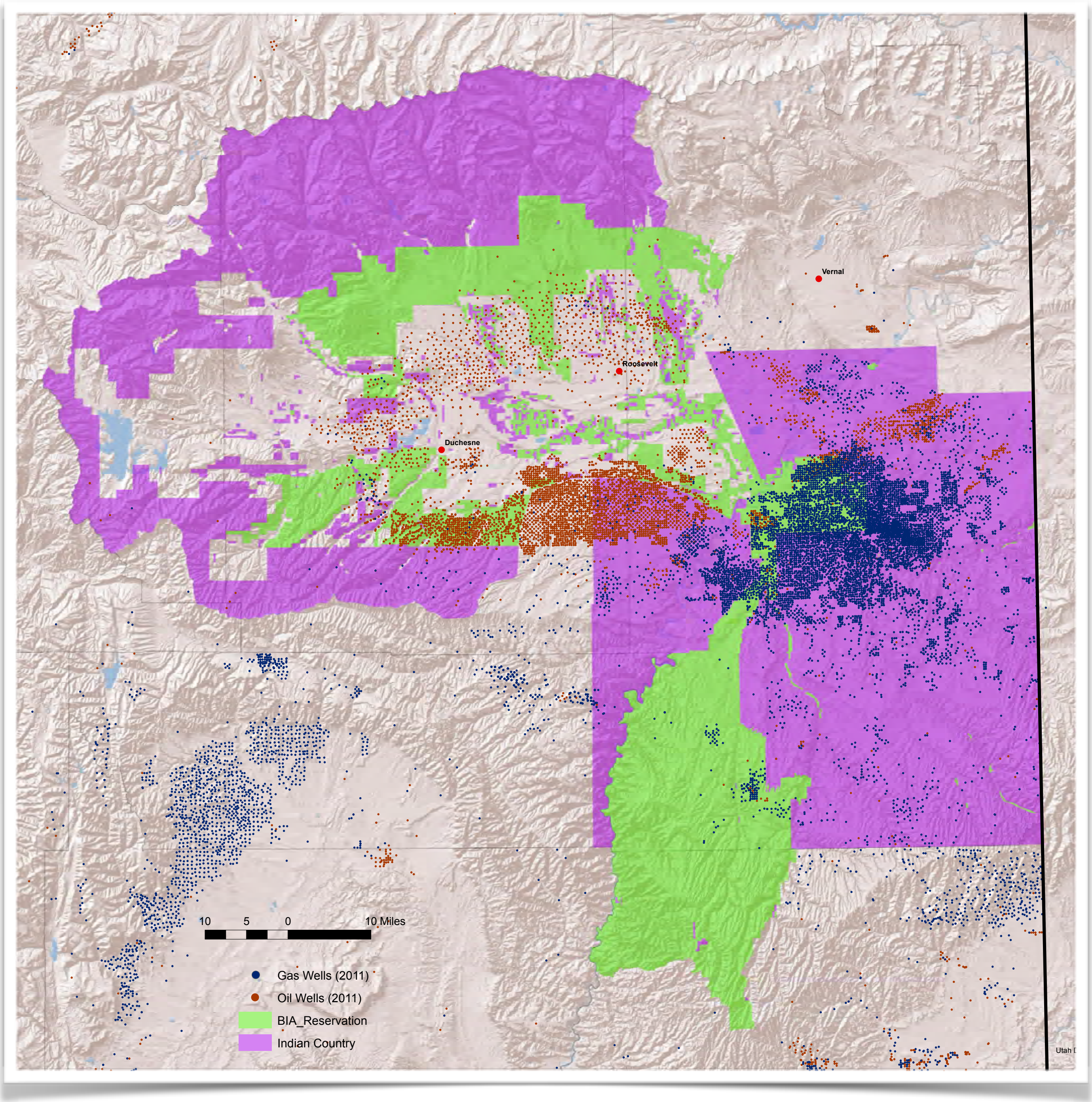
The Clean Air Act is especially relevant in the Uintah Basin where air quality can be a concern during those winters when the area experiences high ozone concentrations. This rural wintertime phenomenon contrasts in many ways with the ozone pollution typically experienced during summer in many urban areas of the United States. Oil and gas production is the greatest contributor of ozone-forming pollutants in the Basin.

Air quality in the Uintah Basin is being addressed in multiple ways. First, Utah has opted into the Ozone Advance program that promotes emissions reductions in areas of high ozone that are not yet in non-attainment. New EPA standards for hydraulically fractured wells aim to reduce nearly a quarter of oil and gas emissions. Soon to be implemented on tribal lands, the Tribal Minor Source Permitting Program will document sources not previously accounted for and will require minor sources to meet EPA standards. The BLM also includes CAA considerations in its NEPA analyses.

Utah State University is an active partner in monitoring and modeling air quality in the Uintah Basin. A 2014 MOU between the BLM and USU formalized an air quality modeling partnership aimed at strengthening the computer simulations that inform policy decisions and industry improvements.

TRIBAL

Tribal authority over oil and gas activities varies through the Uintah Basin. Tribal lands are not subject to state environmental regulations, but instead are subject to federal requirements and any regulations adopted by the tribe. BLM Land in Indian Country is managed by the BLM and treated like other federal land, with the exception of air and water quality, which is regulated by the EPA in behalf of the tribe. The map below shows the different tribal jurisdictions in relation to environmental review for oil and gas.



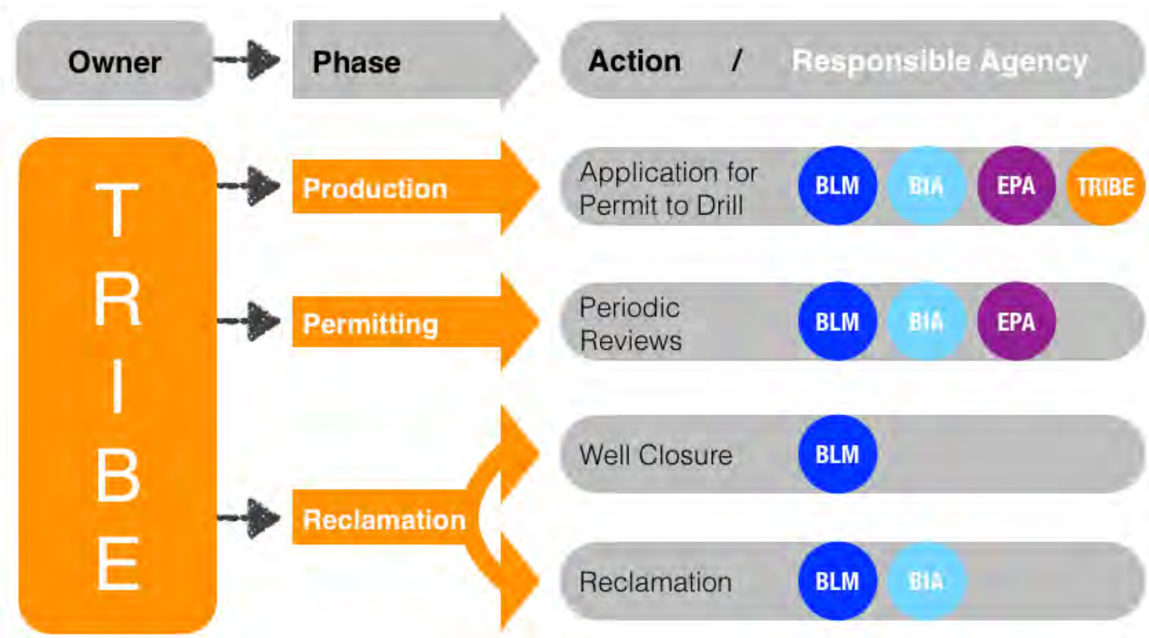
BIA Reservation

The tribe and the EPA have regulatory authority for environmental quality on the BIA reservation (i.e., the sovereign nation of the tribe). The tribe receives royalties from oil and gas development on tribal land. The following information is for tribal land only.

Indian Country

In Indian Country, the EPA monitors air and water quality and permits for the tribe. For wells on federal land in Indian Country, oil and gas leasing and production is managed by the BLM. For lands within the purple area, therefore, environmental review (except for air and water quality permitting) does not fall under tribal and EPA jurisdiction, but rather that of the BLM. For environmental checkpoints on federal land in Indian Country, please see the BLM and USFS sections above.

Tribal Lands



Permitting (BIA, Tribe, BLM, and EPA)

As part of the APD, a site-specific NEPA analysis is conducted by the BLM and the BIA. In addition to the APD, the operator must obtain all necessary air or water permits from the EPA.

Periodic Reviews (BLM, BIA, and EPA)

Once production is underway, the BLM performs periodic environmental compliance reviews. The BIA may also conduct inspections and report non-compliance to the BLM.[11] The EPA is responsible for air and water compliance, which may include inspections.

Well Closure (BLM)

The operator must contact the BLM to receive approval and coordinate the witnessing of well closure operations. The well closure must be carried out in accordance with environmental requirements set forth in the lease and prior NEPA analyses. In cases of emergency or well failure, closure may occur with verbal approval from the BLM.[12]

Reclamation (BLM and BIA)

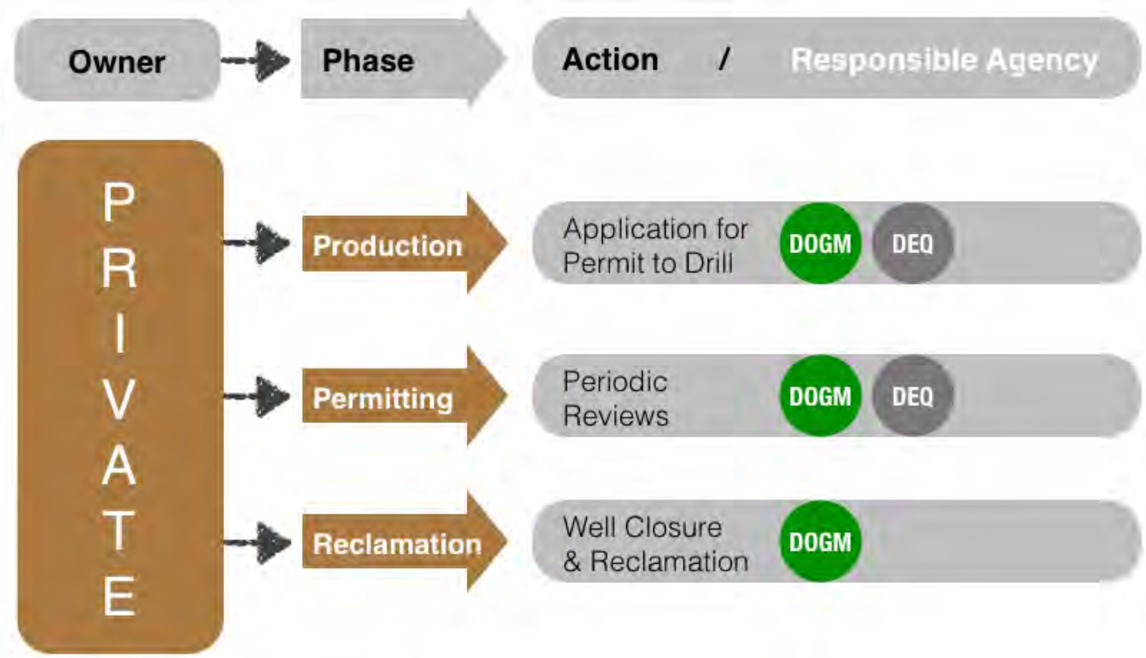
The BIA has jurisdiction over surface estate matters and is, therefore, the regulatory authority for reclamation actions. The BIA gives final approval, while BLM supervises the work.[13]

Fort Duchesne area, courtesy of Howard Shorthill, USU

PRIVATE

Oil and gas access and production on private land must go through state regulatory authorities, primarily through DOGM.

Private Lands



Land and mineral owner Leasing/Access

Access to and production of oil and gas on private land is determined by the surface and mineral owners and the operator.

Permitting (DOGM and DEQ)

Prior to drilling on private land, an operator must submit an APD to DOGM. The APD includes a reclamation plan and mitigation steps to reduce the well's environmental impact, to which the surface owner and operator assent in a surface use agreement. Onsite inspection is conducted by DOGM, the surface owner, and the operator to address any necessary restrictions on surface activities. Appropriate air and water permits must be obtained from the DEQ. Once DOGM has given its approval, an APD is valid for one year.

Periodic Reviews (DOGM and DEQ)

DOGM inspects all natural gas or oil wells on state land to ensure compliance with the terms of the lease and relevant regulations. The DEQ conducts periodic review of various air and water permits. The majority of inspections are environmental.[14]

Well Closure (DOGM)

The operator of a well must submit a notice of intent to plug and abandon before any well closure operations occur. This notice will include a description of and pertinent information about the well, and indicate when the well closure will occur. The well will be closed in accordance with Utah Code R649-3-24, unless otherwise approved by DOGM. In cases of emergency only, a verbal approval must be given, but proper forms should be submitted within five days of the emergency closure. Within 30 days after a well closure, a report of how, when, and by whom a well was closed must be submitted.

Operator and Surface Owner Reclamation

Any reclamation requirements are between the operator and the surface owner, as agreed to in the surface use agreement. ■

Chapter 2 Notes

[1] The President, Congress, and Federal Courts are exempt from NEPA.

[2] E.g., Park County Resource Council v. USDA 1987; Robertson v. Methow Valley Citizens Council 1989.

[3] http://www.gpo.gov/fdsys/pkg/BILLS-109hr6enr/pdf/BILLS-109hr6enr.pdf.

[4] More information on EPA's ratings: http://www.epa.gov/compliance/nepa/comments/ratings.html.

[5] Ibid.

[6] BLM *Gold Book*, p. 49.

[7] http://www.fs.fed.us/geology/MOU_BLM_Oil_Gas.pdf.

[8] BLM *Gold Book*, p. 49.

[9] For more on SITLA land swaps, see Chapter 1.

[10] In 2013, DOGM conducted 9,726 inspections, of which more than 7,000 were production or environmental inspections (other inspection types include plugging, production and royalty compliance, pre-site operations, and audits (statistics provided by DOGM).

[11] BIA Fluid Mineral Estate Procedural Handbook 2012 (BIA *Handbook*), pp. 65-6. http://www.bia.gov/cs/groups/xraca/documents/text/idc-020740.pdf. For additional information, see Chapter 5.

[12] BIA *Handbook*, p. 24. For additional information, see Chapter 5.

[13] BIA *Handbook*, p. 2. For additional information, see Chapter 6.

[14] In 2013, DOGM conducted 9,726 inspections, of which more than 7,000 were production or environmental inspections (other inspection types include plugging, production and royalty compliance, pre-site operations, and audits (statistics provided by DOGM).

CHAPTER 3: LAND USE PLANNING

The federal land use planning process determines which lands are available for oil and gas leasing and stipulates how activities on the leases are to occur. The BLM is the lead management agency for leasing oil and gas resources on lands managed by federal agencies, including the BIA and the USFS. The land use planning process differs slightly for each federal agency, but this chapter focuses mainly on the BLM process since most oil and gas operations on federal lands in Utah occur on BLM-managed public lands.

Authorized by the National Forest Management Act (NFMA), the USFS conducts land use planning through its Land Resource Management Plan (LRMP). Because oil and gas exploration and development occur less frequently on forest lands than on BLM lands, and since the BLM is the lead agency for leasing USFS lands, less detail is provided here about the land use planning process required under the NFMA. Additional information about the USFS planning process is available.[1] Note that through its own planning process, the USFS performs leasing analyses and identifies lands available for oil and gas leasing. The BLM will only lease oil and gas underlying USFS lands after the USFS has given its authorization. Specific USFS land leasing steps are discussed in Chapter 4.

Trust lands under SITLA jurisdiction are intended to generate revenue for public schools and other state institutions. Under Rule R850-100, SITLA has the discretion to participate in joint planning with other land management agencies if its director determines "trust management obligations will be facilitated." Additionally, SITLA complies with laws protecting endangered species and cultural resources, but beyond these considerations, the trust lands are to be managed primarily for oil and gas leasing, real estate transactions with development potential, and land exchanges and sale.[2]

The Ute Tribe Business Committee, the main governing body of the Ute Indian Tribe, determines which tribal lands are available for oil and gas leasing. The Ute Tribe receives administrative and technical support from the BIA, as part of the federal government's trust responsibility.

Finally, privately held lands are not required to go through a land use planning process, but they must comply with local zoning ordinances and pertinent environmental regulations.

Federal Land Policy and Management Act (FLPMA)

WHAT IS FLPMA?

Passed in 1976, FLPMA is a landmark law that changed the way federal lands are managed. Prior to this act, the federal government had moved a significant portion of its land and mineral holdings into state and private hands. FLPMA largely ended this practice and established a mission for the BLM of accommodating multiple uses of federal land such as development, conservation, and/or recreation. FLPMA requires the BLM to engage in a formal land use planning process to ensure that land uses and land resource values are maintained and that changing conditions of the land and resources are accounted for periodically, usually every 15 to 20 years.[3]

WHY IS FLPMA IMPORTANT?

The land use planning process is a comprehensive review and inventory of land and resource values that responds to changing conditions and planning issues of a particular planning area for the BLM. The result of this process is a Resource Management Plan (RMP) that outlines land management decisions for the planning area.

The land use planning process can take several years. RMPs completed by the BLM in Utah in 2008, for example, took five to seven years to complete. The six plans included Vernal and Moab, sites of high interest in oil and gas activity.[4] The decisions outlined in RMPs provide energy companies with information about what lands are open to oil and gas exploration and production, and about the conditions or stipulations under which lands will be leased. (The leasing process is discussed in chapter 4.)

Land use planning is separate from the National Environmental Policy Act (NEPA), but the NEPA process supports decisions in land use plans. As part of the land use planning process, agencies will prepare an environmental analysis, as required by NEPA. For more information about NEPA, see chapter 2.

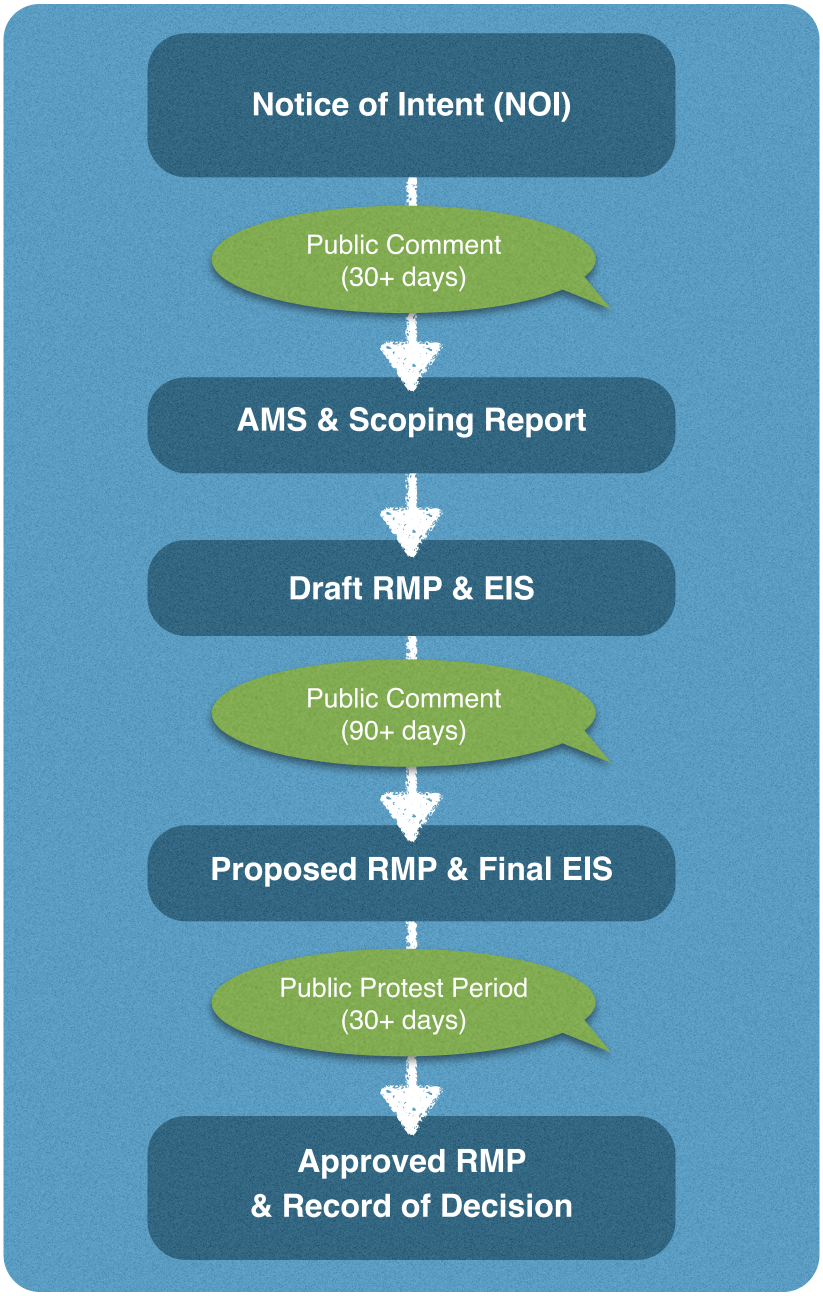
HOW DOES FLPMA APPLY TO OIL AND GAS EXPLORATION AND DEVELOPMENT?

As mentioned previously, RMPs determine which lands are open or closed to oil and gas leasing, and under what conditions. Land allocation decisions in the proposed RMPs are analyzed against one another to best balance possible uses and minimize negative impacts. As a result of the environmental analysis, restrictions on oil and gas activities in RMPs may include seasonal concerns for wildlife, visual impact mitigation, cultural resource conservation, and/or surface footprint reduction.

BLM's Land Use Planning Process

One of the key components of land use planning is the involvement of the public, which includes the opportunity to comment and provide input throughout RMP development. The diagram below highlights milestones in land use planning and identifies points in the process where the public may be involved. RMPs must be consistent with local county and state planning documents. The figure below shows the BLM's RMP process.[5]

THE RMP PROCESS



EXPLANATION OF THE MAJOR LAND USE PLANNING STEPS

Notice of Intent (NOI)

The BLM must notify the public, Native American tribes, other federal agencies, and state and local governments about its intent to engage in land use planning for a given area. Prior to scoping (obtaining public input for planning), the BLM must publish a NOI in the Federal Register to announce its decision to prepare an EIS and associated planning documentation.[6] Publication in the Federal Register formally initiates the RMP development process. Along with the Federal Register NOI, the BLM simultaneously submits a scoping notice to federal agencies, state agencies, heads of county boards, other local government units, Tribal leaders, and any other entity or person who has requested such notice or who the BLM reasonably believes would be concerned with the planning effort.[7]

Analysis of Management Situation (AMS) and Scoping Report[8]

An AMS is an internal examination of the current conditions that should be considered in the development of an RMP, while a scoping report is an external examination of the current conditions. An AMS requires the BLM to compile and analyze an inventory of all land resources and other pertinent data to characterize the planning area. The information gathered during this examination gives land managers the opportunity to identify land uses that could be adjusted or changed, to address resource values such as the need to open or close lands to a particular use, and to identify management strategies. The scoping process gives the public an opportunity to identify issues to be addressed in the planning process. Public comment provides BLM information about community priorities. This input often involves disputes or controversies about existing and potential land uses and resource allocations, existing management practices, and opportunities to protect resources from development.

Draft RMP/EIS

The draft RMP describes the purpose of and need for the land use plan, the affected environment, available alternatives for managing public lands within the planning area (including preferred alternative as determined by BLM), the environmental impacts of the available alternatives, and the consultation and coordination in which the BLM engaged during plan development. A companion document, the draft EIS includes a detailed environmental analysis of alternatives identified in the draft RMP.

The BLM must allow a minimum 90-day public comment period on the draft RMP (including amendments or revisions) and the draft EIS. The comment period officially starts when the

EPA publishes the Notice of Availability (NOA) for the document in the Federal Register.[9] Public comments may be written, made orally, or submitted electronically. The EPA's role in determining the adequacy of documents required by NEPA is discussed more in Chapter 2.

Proposed RMP/Final EIS

The proposed RMP and final EIS include appropriate responses to public comments on the RMP and EIS drafts. They also corrects errors that were identified through public comment and internal BLM review. Issuance of the proposed RMP/final EIS officially occurs with the EPA's publication of a Notice of Action (NOA) for the document in the Federal Register. Individuals and entities have 30 days from the publication of EPA's NOA to file a protest with the BLM Director. The protest period cannot be extended. The BLM must resolve any protests of a proposed RMP/final EIS before issuing a record of decision.

Approved RMP and Record of Decision (ROD)

The Approved RMP and Record of Decision (ROD) serve as the final planning decision documents for land managers and stakeholders. The ROD provides the rationale and basis for decisions in the approved RMP, with which it is issued simultaneously. An RMP is officially approved when the State Director or other authorizing official signs a ROD adopting the RMP.[10] The ROD, RMP, and accompanying EIS comprise several hundred printed pages. The chapter notes provide links to additional information about the Moab and Vernal RMPs.

Land Use Planning in Utah

The BLM in Utah is organized by district offices, and within each district are the field offices that conduct land use planning. Each field office may have one or more RMPs. In 2008, the BLM completed a revision and improvement of six RMPs, including the consolidation of the two RMPs by which the Vernal Planning Area had been managed into one plan with updated information and decisions.

Land managed by the Vernal Field Office produces the highest volume of oil and gas exploration and development of any field office in Utah. While the Moab Field Office also has a high potential for oil and gas, the BLM is currently engaged in a planning process that may reduce the potential for leasing in that area.

VERNAL RMP

The Vernal Field Office RMP guides the management of over 1.7 million acres of public land and 3.9 million acres of federal mineral estate administered by the BLM in Daggett, Duchesne, Uintah, and a small portion of Grand counties in northeast Utah. The Vernal RMP identifies the lands that are open to oil and gas development and specifies the restrictions or stipulations under which oil and gas leasing is allowed. Some lands, for example, are subject to "No Surface Occupancy," which stipulates that oil and gas resources can only be accessed without impacts to the surface land (via horizontal drilling techniques). Also, oil and gas activities on some lands are restricted at certain times of the year to allow for seasonal changes in wildlife behavior and to protect visual resources and sensitive soils.

Photo courtesy of Howard Shorthill, USU

Several land and mineral owners are involved in the leasing of BLM managed lands in Vernal, such as USFS land and Tribal land (including cases where the Ute Tribe owns the surface land, but subsurface minerals are federally owned). Of the 1.7 million acres of BLM surface land open to oil and gas leasing, approximately 750,000 acres are open to exploration and development with standard lease terms (i.e., with restrictions less inflexible than those of leases with rigid time controls and surface use stipulations) for oil and gas operations. Another 890,280 acres are available for oil and gas exploration and development with restrictions for wildlife and visual considerations. Nearly 87,000 acres are open to oil and gas leasing with restrictions to surface disturbance.

Although the RMP establishes the possibility of oil and gas leasing on these lands, there is no guarantee that they will actually be leased. Whether the lands are leased depends on a number of factors, not the least of which includes whether the BLM chooses to offer the lands for lease and whether energy companies choose to lease the lands. Chapter 4 provides information about the leasing process.

Chapter 3 Notes

[1] For more information, see http://www.fs.fed.us/emc/nfma/model.html.

[2] http://www.rules.utah.gov/publicat/code/r850/r850-100.htm#T1.

[3] See Appendix for more information regarding FLPMA.

[4] Time for RMP completion varied across field offices. The Moab field office completed its RMP in ~five years, while the Vernal office needed about seven. RMP timelines are found at http://www.blm.gov/ut/st/en/fo/moab/planning/moab_rmp_schedule.html, and http://www.blm.gov/pgdata/etc/medialib/blm/ut/vernal_fo/planning/supplement_eis/rmp_schedule.Par.80679.File.dat/RMP%20Process.pdf.

[5] http://www.blm.gov/wo/st/en/prog/planning/nepa/webguide/document_pages/land_use_planning.html.

[6] 40 CFR 1501.7.

[7] 43 CFR 1610.3-1(d).

[8] 43 CFR 1610.2 and 43 CFR 1610.4-1.

[9] 43 CFR 1610.2(e).

[10] 40 CFR 1506.1(a).

CHAPTER 4: LEASING

The leasing process is the next important step in the oil and gas development process. A lease may be obtained through a competitive or non-competitive process. Once a lease is secured, the lease holder is required to follow the terms of the lease, which include rental fees, royalties and other payments, and all contractual obligations. This chapter describes the leasing process for the various jurisdictions that make oil and gas resources available for exploration, development, and production.

Major Legislation for Oil & Gas Leasing

- Mineral Leasing Act*
- Federal Onshore Oil and Gas Leasing Reform Act*
- School and Institutional Trust Lands Management Act♦
- Indian Mineral Development Act∞

* = Federal only, ♦ = State only, ∞ = Tribe only

Leasing Process by Land Jurisdiction

FEDERAL

When developing RMPs[1], the BLM determines whether sections of land will be open for oil and gas exploration and development. If open for energy development, the land may be developed through leases. As mentioned, the BLM administers all leases of federal land even if the surface owner is another federal agency, such as USFS or the Department of Defense.

Leasing Reform[2]

In 2010, the BLM made several significant changes to the federal lands leasing process. The reform affected existing land use plans, introduced Master Leasing Plans (MLP), and changed the parcel review process.

Resource Management Plan (RMP)

The 2010 leasing reforms mandated periodic RMP review to ensure adequate protection of valuable resources in light of changing circumstances. Now should changes in circumstances warrant updates to an RMP, the state BLM offices may call for an additional review before determining whether a parcel is open for oil and gas development and/or what restrictions may be applied. This requirement ensures that plans are amended and/or revised at a more frequent and time consuming basis.

Interdisciplinary Consistency Review (IDCR) teams were implemented by each field office to ensure that the stipulations assigned to oil and gas development are written according to the national BLM office criteria and that the stipulations are consistent across state offices for similar resources and situations.

An adaptive management approach was also implemented, requiring BLM staff to use the best available science in decision making and to adapt management strategies to changing resource conditions. In some circumstances, this adaptive approach may lead to an increase in the level of environmental protection.

Master Leasing Plan

MLPs essentially are amendments to existing RMPs that take into account changes in available science, resource conditions, and environmental protections since implementation of the RMP. MLPs are developed when there is (1) a large area of unleased federal lands of which the federal government owns a majority of the mineral rights, (2) industry interest in developing the lands, and (3) a warranted need for additional analysis and insight into the impacts of leasing.

A MLP may address but is not limited to air or water quality, a land's significance to a Native American tribe, public health and safety, recreation area effects, and wilderness characteristics. MLPs may institute phased leasing, phased development, surface disturbance caps, best management practices, or other stipulations that affect development.

Parcel Review

Another impact of leasing reform is the expanded parcel review coinciding with the BLM's NEPA review of land nominated for leasing. The parcel review has four goals: (1) to determine parcel availability, (2) to evaluate the conditions to oil and gas development as prescribed in RMPs, MLPs, or other pertinent documents, (3) to identify stipulations (i.e., restrictions) on development that may be necessary, and (4) to allow public comment.

An Interdisciplinary Parcel Review (IDPR) team comprised of experts from the BLM or other applicable government agencies conducts the review to ensure adequate stipulations and considerations are attached to each parcel. The IDPR team gathers information about the site proposed for lease, ensures that the lease proposal complies with the RMP, evaluates conformity with other necessary programs or plans, and determines the appropriate stipulations. The IDPR team also conducts on-site inspections and utilizes specialists from external agencies or groups, as needed, to ensure a complete review. Public participation in the parcel review process is the same as in the NEPA review of a parcel.

Currently, the Moab and Monticello field offices are in the process of amending their RMPs as part of the MLP policy.

Competitive Leasing Process: Federal

1. *Land Use Plan*

As Chapter 3 indicates, the Federal Land Policy and Management Act (FLPMA) requires the BLM and the USFS to develop land use plans to efficiently manage federal lands. A land parcel closed to development is not available for lease unless an amendment is made to the land use plan.

Public Comment

The public can make written or verbal comments to the BLM throughout the development of an RMP. Commonly included are requests that stipulations or other conditions be applied to a certain area or activity. Comments may also be made on the thoroughness of the NEPA analysis. Public influence is most effective at this stage because once an RMP is complete, changes must be made through amendment or legal action.

2. Nomination of Lease Parcels

Land parcels that are designated available for oil and gas development by the applicable RMP may be nominated for auction by private parties or the BLM. Private parties may nominate lands by sending an Expression of Interest (EOI) to the appropriate BLM office at least 11 months prior to an auction to ensure the *potential* availability of the parcel. In truth, nomination is no guarantee that the desired parcel actually will be made available. The submission of a non-competitive lease offer for a land parcel also constitutes a nomination. The BLM Utah State Office posts all EOIs on its website.

Forest Service

EOIs for parcels located on U.S. Forest Service land are also submitted to the BLM. The BLM cannot offer any such parcels for lease without first obtaining USFS consent. USFS reviews the parcels and may attach additional stipulations for the protection of surface resources.

3. Notice of Lease Sale

Based on EOIs received, the BLM determines which lands that will be available at auction. An IDPR team conducts a brief review of the NEPA analysis in the land use plan to identify "significant new information" and finalize any lease stipulations. If the review results in a recommendation of further evaluation, the parcels may be withdrawn from auction. Parcels may also be withdrawn from auction at the discretion of the U.S. Secretary of the Interior. Posting of nominated lands will occur at least 90 days prior to auction.

Public Comment/Protest

No lease may be offered for sale without first undergoing an Environmental Assessment (EA). The EA ensures a 30-day public comment period that takes place approximately two months prior to the posting of a Notice of Lease Sale. The public may formally oppose the leasing of a parcel, but must submit its protest to the BLM within 30 days following the

Notice of Lease Sale. Objections may concern adequacy of the NEPA analysis, compliance with the Endangered Species Act of 1973 (ESA), and/or other pertinent regulations. After considering the protest, the BLM decides whether to allow or withdraw the parcel in question.

4. Oral Auction

Oral auctions are held quarterly and rotate between BLM district offices, as required by law. To secure a lease, a party or its agent must be present at the auction (mailed bids are not accepted). To bid for a lease, a party or its agent must have prepared (1) the official lease bid form, (2) the administrative fee, (3) the first year's rent, and (4) the minimum bonus bid of $2 per acre of land available for lease.

The lease bid form is a legally binding document that agrees to the terms of the lease. The administrative fee for Utah is $155, and the first year's rent is $1.50 per acre. The bonus bid is the amount above what is required that a company is willing to pay for the right to develop the oil and gas reserves. The highest bonus bid for a parcel of land will secure the lease. (Note that a bonus bid in excess of $2 per acre may be paid within 10 days of auction.) Upon receipt of all fees, including the bonus bid, the BLM has 60 days to decide whether to issue the lease. Land parcels that receive no qualifying bid are available for non-competitive lease for the next two years.

Normal Terms of a Lease

Length: 10 Years
Royalty Rate: 12.5%
Rent: $1.50 per acre for years 1-5 and $2 per acre for years 6-10 (plus bonus bid).

After the initial 10-year term, the lease may continue provided that paying quantities of oil or gas are being produced. "Paying quantities" indicates that production revenue exceeds operating costs.

Non-Competitive Leasing Process: Federal

On the business day following a competitive lease auction (and for a period of up to two years), any land parcel that failed to receive a qualifying bid is made available as a non-competitive lease. On that day, and through the end of that same month, the configuration of the land parcel must remain as described originally at competitive auction, and any lease offer must refer to its desired parcel by the same number used originally at auction to designate the land. After the month ends during which the competitive auction took place, a parcel for lease is no longer constrained to the same configuration as it had during the competitive process.

Required at submission of the lease form is a $400 filing fee and the first year's rent of $1.50 per acre. All offers for the same land received on the first day of availability will have an equal opportunity to win the lease. In this instance, a random public drawing determines lease priority. If no offers are made on the first day, the BLM bases priority on the order of receipt.

STATE

Utah state rule R850-21 provides the regulatory framework for the leasing of SITLA land for oil and gas development[3]. While leasing is carried out entirely by SITLA, the DOGM assumes regulatory authority once the lease has been granted.

Competitive Leasing Process: State

1. Nomination of Land Parcels

If it determines that a parcel has a strong potential for profitability, SITLA may choose to offer that land for lease. SITLA also reviews EOIs submitted via mail or email by other parties interested in a tract of land. If approved, SITLA will make the land available for lease at its next sale.

2. Notice of Sale

SITLA posts on its website quarterly notice of lands it intends to make available for lease. The announcements include descriptions of parcels and timeframes for bid submission.

3. Submission of Applications

Sealed applications received prior to the deadline will be evaluated with equal priority for the lease. Only one application per envelope is accepted. Each application requires a non-refundable $30 fee. The minimum bonus bid is $40, or $2 per acre, whichever is greater, and must be included in a separate check with the application (this is the first year's rental). Applications are opened at 10 a.m. on the first business day after the closing date.

4. Review of Offers

The lease will be awarded to the qualified bidder who submits the highest bonus bid. If two or more bids are identical, an auction or drawing will be held. If an auction is selected, a minimum bid may be established.

SITLA may reject a bid if it determines that the proposed activity could negatively impact higher priority operations, that other operations on the land would be impacted, and/or that the proposed action is not in the best interest of SITLA's beneficiaries.

Non-Competitive Leasing Process: State

As with the federal approach, state lands offered at competitive auction that do not receive a qualifying bid may be made available for lease through a non-competitive process. Non-competitive state parcels, however, may only be offered for a period of three months from the date of competitive auction.

The non-competitive lease is still held to a minimum annual rental of $40, or $2 per acre, whichever is greater. The bidding is online through SITLA's website. Notice of non-competitive oil and gas leases are posted online and at the SITLA office. If an application is missing required information, the applicant has 15 days to address the deficiency and thereby retain the original submission date and time.

Other Business Arrangements (OBA)

OBAs are agreements between SITLA and a developer that include special negotiated terms intended to bring trust lands into production more quickly than competitive leasing. All OBAs must be approved by the SITLA Board of Trustees. Terms may vary between agreements but could include royalty increases, shorter lease lengths, larger bonuses, required seismic commitments, or other unique terms.

Terms of the Lease

Leases can include no more than 2,560 acres (four sections). Unless some exception is made, all acres in a lease must be located within the same township. The minimum annual rental of any lease, regardless of size, cannot be less than $40. The term of the lease can be no longer than 10 years but can be renewed as long as paying quantities of oil and gas are produced.

State-Division of Forestry, Fire, and State Lands (FFSL)[4]

The FFSL offers leases for sovereign and non-SITLA state lands through a competitive bidding process. The FFSL posts the available land for at least 15 days, during which time it also accepts bids. Sealed applications are submitted with three items: the official FFSL oil and gas lease application[5], a $40 filing fee, and the bid, which also constitutes the first year's rent. The highest bid will be offered the lease.

The minimum annual rent amount is $1.10 per acre, or $20, whichever is greater. All leases are offered with a no surface occupancy stipulation. The royalty rate for most leases is 12.5%, and the primary lease term is 10 years. The FFSL, as part of the lease, may require cultural, paleontological, or biological surveys to be completed.

In the following chapters, the processes and regulations for FFSL lands are essentially the same as those for SITLA land. The FFSL does serve as the surface management agency and is involved throughout the process where other surface management agencies are involved.

TRIBAL

The Indian Mineral Development Act (IMDA) outlines requirements for competitive and non-competitive leases on Tribal land. A tribe can enter into a minerals agreement, such as an Exploration and Development Agreement (EDA), with an oil and gas company, but it must have the approval of the Secretary of the Interior to do so. 25 CFR 211 (tribal) and 212 (allotted) set how lease sales are administered.[6]

The BIA and the tribe of concern (the Business Committee carries out this function for the Ute Indian Tribe) determine the leasing process, which can be either competitive bidding or non-competitive negotiation.[7] The Ute Indian Tribe and the allottees no longer have lease sales. The tribe reviews EDAs proposed by the energy operators who wish to drill on trust land.

The BIA also offers assistance to allotted tribal mineral owners. Stakeholder involvement in the leasing process depends on whether mineral ownership is tribal trust lands or individually allotted lands. If the land is tribal trust land, more stakeholders will likely be involved.[8]

Tribal Energy Resource Agreement (TERA)

Tribes can enact TERAs that "allow the BIA to accept an overall plan by the tribe to be responsible for all leasing, environmental, and Right-of-Way Use Permits (ROWs) as designated in the plan."[9] TERAs were authorized by the Energy Policy Act of 2005. Tribes are not required to have a TERA, but if they choose to do so, the BIA must review the plan.

When a tribe expresses interest in developing a TERA, the BIA's Office of Indian Energy and Economic Development (IEED) contacts the BLM and other affected government agencies to arrange a consultation with the tribe. The tribe then submits an application, which the IEED reviews and deems complete or deficient. Once the proposed TERA has passed IEED review, it is reviewed by the Department of the Interior and undergoes a public comment period before it is approved.[10]

Once a TERA is in place, the BIA only becomes involved in oil and gas leasing if a complaint is lodged against the tribe regarding the TERA plan or if the tribe has failed to follow the terms of the plan.[11] The Ute Indian Tribe does not currently have a TERA in place.

Tribal Minerals

Tribal minerals are those minerals held in trust with the Federal Government. Before the competitive or non-competitive leasing of tribal minerals can take place, the following prefatory steps must be taken:

1. ***Identification of Lands for Lease***

   The BIA conducts land use planning and determines which tribal lands are available for oil and gas development. Mineral assessments are key to identifying the oil and gas resources of tribal lands. The BIA provides the BLM with a list of leasable lands.

2. ***Verification of Land and Mineral Ownership***

   BLM and BIA verify land and mineral ownership and ensure that all appropriate entities are involved in the leasing process. Split estates are also identified during this step.[12]

3. ***Determination of Leasing Method***

   In accordance with the IMDA, a tribe determines the method by which a competitive lease is awarded. Methods may include oral auction, sealed bid, traditional negotiation, or some combination of the three.[13] If the method is negotiation, the BIA may be involved.

4. ***Mineral Valuation Request***

   During this step, the BIA and tribe solicit BLM assistance in conducting a mineral valuation to determine the potential royalty value, bonus amount, and annual lease rental.[14] The process takes 30 to 60 days.

5. Notification of Sale

The BIA notifies the mineral owner that the lease sale has been approved.

After the five prefatory steps are complete, tribal minerals can be leased through a competitive or non-competitive process.

Competitive Leasing Process: Tribe

1. Competitive Sale

The authorizing officials follow the procedure selected in prefatory step 3 to award the bid and ensure the maximum economic return.[15]

2. Lease Packet Review

To meet leasing requirements, the lessee packet must include, at minimum, the legal description, parcel information, a license to do business in that state, a statement verifying payment capacity, and contact information.[16]

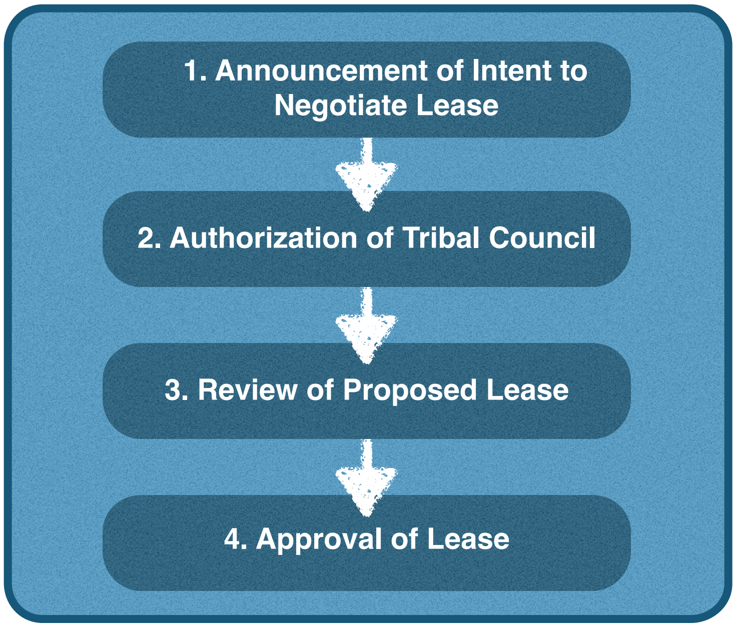
3. NEPA Implementation (when required)

Whether the lease is through the authority of a TERA or an EDA, NEPA requirements must be met. Because the BLM and the BIA do not always conduct NEPA analyses, energy companies often contract with other agencies to secure a more timely completion than would otherwise be possible. The NEPA analysis must ensure that potential impacts are evaluated and mitigation measures are recommended.

4. *Lease Approval*

The law requires the BIA to provide a 30-day notice before approving any lease so that a tribe has time to reconsider or modify the lease agreement. If a change is made, the 30-day notice period is void, and more time is allowed for review. If a change does not gain tribe approval, the local BIA attempts to mediate tribal and lessee concerns. If mediation is unsuccessful, the case moves to the BIA Central Office, where the Assistant Secretary for Indian Affairs is responsible to make the final decision regarding the lease.[17]

Non-Competitive Leasing Process: Tribe



1. *Announcement of Intent to Negotiate Lease*

The first step in the non-competitive leasing process is a notice of a tribe's intent to consider energy industry interest in a certain tract of land.

2. *Authorization of Tribal Council*

The tribal council authorizes its agents to engage in lease negotiations with energy companies. Without proper authorization, any negotiations would be illegitimate and subject BIA action to prevent the lease.

3. Review of Proposed Lease

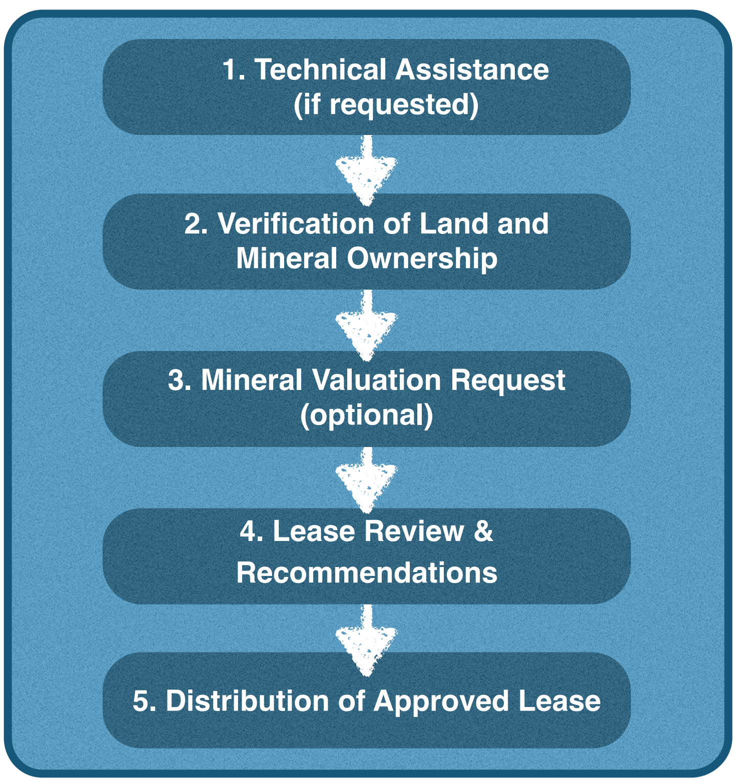
Once a tribe and an energy company have reached a tentative agreement, a lease proposal is sent to the BIA for review. Considerations include the best interests of the tribe, economic return, and environmental and cultural impacts. The BIA also ensures that mechanisms are in place to resolve disputes and comply with federal regulations.[18]

4. Approval of Lease

The law requires the BIA to provide a 30-day notice before approving any lease so that the tribe has time to reconsider or modify the lease agreement. If a change is made, the 30-day notice period is void, and more time is allowed for review.[19] If a change does not gain tribe approval, the local BIA attempts to mediate tribal and lessee concerns. If mediation is unsuccessful, the case moves to the BIA Central Office, where the Assistant Secretary for Indian Affairs is responsible to make the final decision regarding the lease.[20]

Allotted Minerals

In the past, certain mineral resources were allotted to individual tribal members and, therefore, are not held in trust with the federal government. The BIA still offers assistance to these individual tribal landowners, but neither EDAs nor TERAs are required to lease their lands. The only permanent role the BIA has in this process is lease approval. Any other BIA involvement will occur only if requested by the mineral owner.



1. ***Technical Assistance (If Requested)***

   When its assistance is requested, the BIA can help to establish that a lease is "reasonable and approvable." Mineral owners should be aware that their local BIA office may have area-specific or other preferred lease forms. A tribe's Division of Energy and Mineral Development (DEMD) also provides owners with additional guidance.[21]

2. ***Verification of Land and Mineral Ownership***

   The individual mineral owner must have the appropriate documentation to verify ownership of the mineral rights to be leased. This step also identifies split estates, but due to its informal nature, the process may not involve any government agencies.[22]

3. ***Request Mineral Valuation (Optional)***

   At the request of the mineral owner, the BIA and the BLM provides assistance in the valuation of the mineral estate, which can help shape the terms of the lease, particularly with regard to royalty rate or annual rent amount.[23]

4. ***Review Lease and Make Recommendations***

   Once the individual mineral owner has come to a lease agreement with an energy company through either a competitive or negotiated process, the proposed lease is submitted to the BIA for review. The BIA makes sure that the lease is beneficial to the individual owner based on the economic return and environmental or cultural impacts. It also makes sure all proper mechanisms are in place for resolving disputes and protecting the individual mineral owner, who may not have an expertise in the field.[24] The BIA will work with the individual Native American mineral owner(s) and the potential lessee to resolve issues that hinder approval of the agreement.[25]

5. ***Distribute Approved Lease***

   The BIA distributes the approved lease to lessee, the BLM, and the beneficiary (generally an individual tribal member).

PRIVATE

The individual landowner works with the energy company to conduct private leasing. There are no regulations specific to this process. Oil and gas development on private land is discussed in greater depth in chapters 5 and 6. ■

Chapter 4 Notes

[1]See Chapter 2 for more about RMPs.

[2] For more information about BLM leasing reform, see BLM Instruction Memorandum No. 2010-117 or the BLM website: http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas.html.

[3] See Appendix for more on R850-21 Oil, Gas and Hydrocarbon Resources.

[4] Rules for FFSL mineral leases: http://www.rules.utah.gov/publicat/code/r652/r652-020.htm.

[5] Oil and gas lease application: http://forestry.utah.gov/images/statelands/leasing/forms/OilGasHyLeaseAppForPdf-fillablesave.pdf.

[6] http://www.bia.gov/idc/groups/xieed/documents/text/idc010756.pdf.

[7] 25 CFR Part 162.

[8] For more information on types of tribal land ownership see Chapter 1.

[9] The BIA Fluid Mineral Estate Procedural Handbook (BIA *Handbook*), p. 44. http://www.bia.gov/cs/groups/xraca/documents/text/idc-020740.pdf.

[10] TERA approval process: http://teeic.indianaffairs.gov/documents/docs/TERA_flowchartTEEIC.pdf.

[11] BIA *Handbook*, p. 44.

[12] For more information on split estates see Chapter 1.

[13] BIA *Handbook*, p. 26.

[14] Ibid.

[15] BIA *Handbook*, p. 33.

[16] Entire checklist is found in the BIA Handbook, attachment 10. http://www.bia.gov/WhatWeDo/Knowledge/Directives/Handbooks/index.htm.

[17] BIA *Handbook*, p. 39.

[18] BIA *Handbook*, p. 29.

[19] BIA *Handbook*, p. 39.

[20] Ibid.

[21] BIA *Handbook*, p. 28.

[22] For more information on split estates see Chapter 1.

[23] BIA *Handbook*, p. 26.

[24] BIA *Handbook*, p. 29.

[25] Ibid.

CHAPTER 5: PERMITTING

After a lease is finalized, the leaseholder or operator must apply for drilling permits before production can begin. The Application for Permit to Drill (APD) is the underlying document that must be approved in advance of any site activity. The APD requires the applicant to submit a number of documents that describe the plan of operations and reclamation. In addition, the APD includes a requirement that all necessary permits must be obtained before it can be approved. The permits required vary by land and mineral ownership, scope of operations, and environmental stipulations, but the State of Utah demands certain permits for all land and mineral jurisdictions. This chapter reviews the details of the APD and the major permits that are required.

Major Legislation for Oil & Gas Permitting

- Mineral Leasing Act of 1920*
- Federal Onshore Oil and Gas Leasing Reform Act*
- Onshore Oil and Gas Order No 1*
- Utah Oil and Gas Conservation Act (Title 40-6)♦
- Utah Administrative Code R649♦
- Clean Air Act
- Clean Water Act
- Safe Drinking Water Act

* = Federal only, ♦ = State only

Permits by Jurisdiction

The chart below illustrates the permits (color-coded jurisdiction) required by each management agency (left column) to develop oil and gas resources on its land. As part of a BLM-managed lease, for example, a company must obtain separate federal and state APDs; State of Utah permits for water quality, air quality, hazardous waste, and underground storage tanks; and any applicable county permits. by jurisdictional authority (color-coded)

Later, the federal section examines the contents of and approval process for federal APDs and rights-of-way permits. The state section covers requirements for APDs and air, water, hazardous waste, and storage tank permits, which are all also required for wells on federal land under the state process. The tribal section discusses right-of-way, air, and water permits for both tribal land and Indian Country (note that wells on tribal land also require APDs as detailed in the federal and state sections). Finally, Duchesne and Uintah county permits are examined and private rights of way are discussed.

LAND AGENCY	REQUIRED PERMITS* FEDERAL	STATE	TRIBE	COUNTY	PRIVATE
BLM	APD, ROW	APD, H_2O, AIR, HAZ, UST		PERM	
USFS	APD, ROW	APD, H_2O, AIR, HAZ, UST		PERM	
SITLA		APD, H_2O, AIR, HAZ, UST, ROW		PERM	
BIA	APD	APD	ROW, H_2O, AIR		
PRIVATE		APD, H_2O, AIR, HAZ, UST			ROW

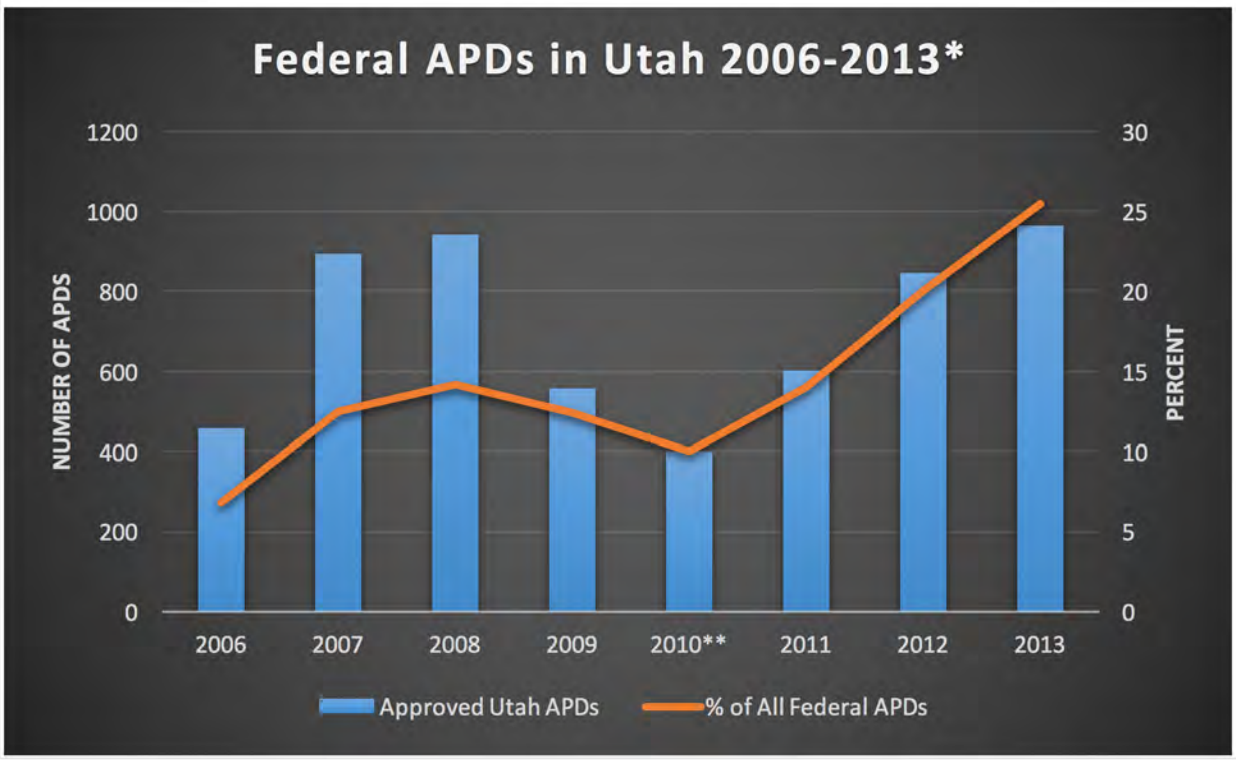
***Permit Type:** **APD** = Application for Permit to Drill, **ROW** = Right of Way, **H_2O** = Water Quality, **AIR** = Air Quality, **UST** = Underground Storage Tank, **HAZ** = Hazardous Waste, **PERM** = County Permits.

FEDERAL

Leases on federal land require several permits before surface-disturbing activities can begin. The operator must obtain an approved APD from the BLM (in conjunction with the USFS if the lease is on USFS land), in addition to a separate APD approved by DOGM. For APD approval, the operator must have obtained all other necessary permits, which may include right-of-way, water, air, hazardous waste, underground storage tank, and any applicable county permits. This section describes the APD and right-of-way permits that are managed primarily by the BLM (with assistance from other federal agencies in certain situations).

Application for Permit to Drill (APD)

The leaseholder or authorized operator must obtain an APD before drilling or conducting any surface-disturbing operation. The APD includes information about well location, drilling plans, a Surface Use Plan of Operations (SUPO), a plan for interim and final reclamation, proof of adequate bond coverage, and proof that the operator has obtained the proper permits from other agencies. The figure below shows the annual number of BLM-approved APDs in Utah and indicates the state's percentage of total APDs awarded nationally by the BLM.



*Information obtained from the BLM. **The anticipation and implementation of the 2010 BLM leasing reform is likely responsible for the sharp decrease of federal APDs in 2009 and 2010.

The BLM oversees the APD process for all federal lands, including USFS, split-estate, and BIA lands. USFS and BIA involvement in the APD process is discussed later in the section.

Components of an APD[1]

All components of an APD do not need to be submitted at the same time. Any part may be developed with help from federal and/or state agencies and then submitted separately, which may help avoid the request for extensive revision. In addition to a $6500 fee, the APD includes[2]:

1. Form 3160-3, Application for Permit to Drill or Reenter,
2. Certified Well Plat,
3. Drilling Plan,
4. Surface Use Plan of Operations,
5. Evidence of Bond Coverage,
6. Operator Certification and Signature,
7. On-Site Inspection, and
8. Other Information.

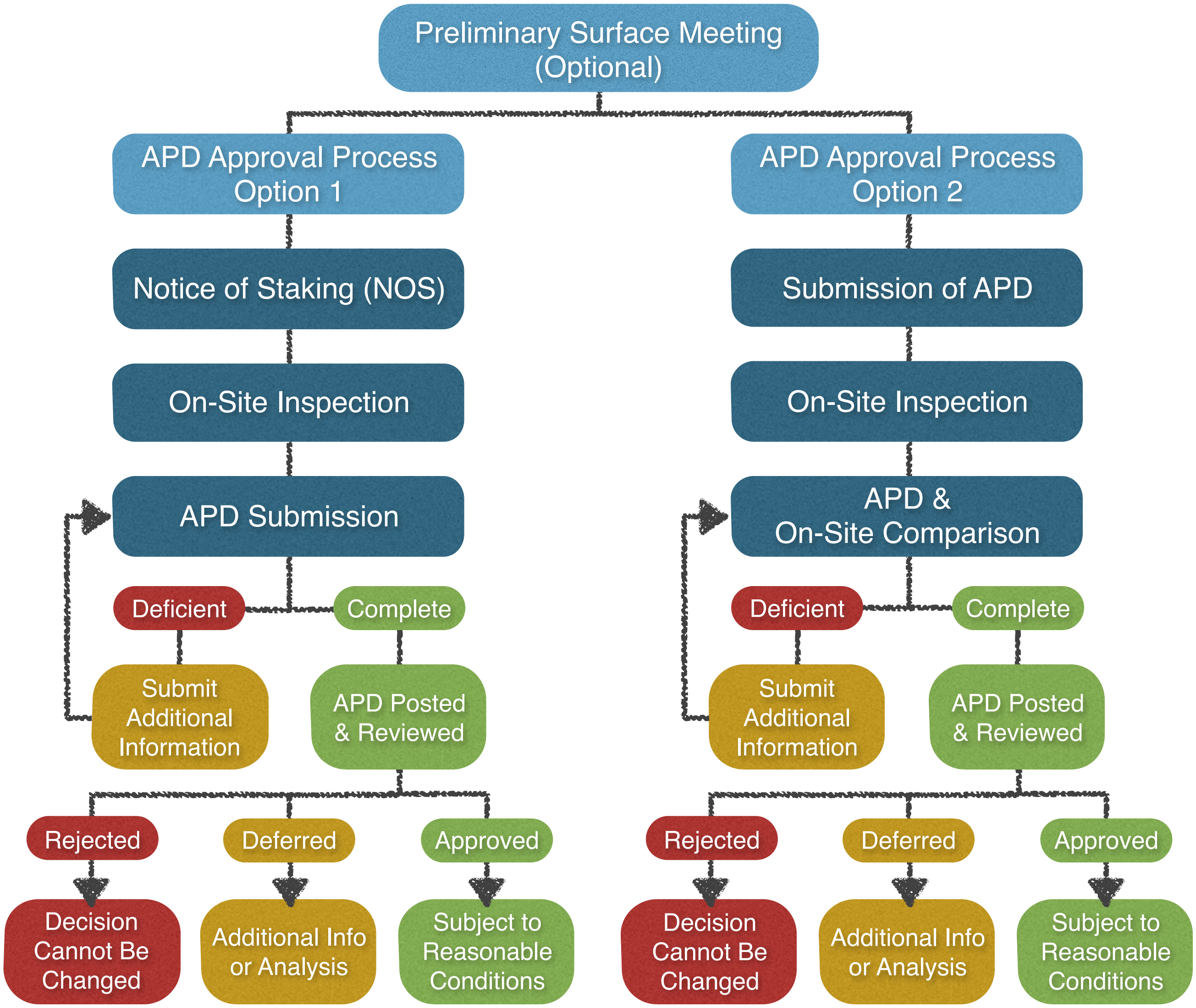
APD Approval Process

The approval process can be initiated in one of two ways: filing a Notice of Staking (NOS) or submitting a formal APD. While the time frame and regulations are the same, each option has distinct advantages.

A NOS may be filed with the BLM in lieu of a complete APD and provides notice that initial staking has been completed. The NOS initiates the BLM's on-site invitation to other involved federal or state agencies or private surface owners. By conducting the on-site inspection prior to APD submission, the operator may be better prepared to identify potential resource impacts that may require stipulations, Best Management Practices (BMP), and/or Conditions of Approval (COA) from other agencies, very helpful information when assembling a complete APD. A NOS is not recommended, however, for initial development of a lease where a working relationship has not been established between the operator and the BLM. For infill wells or in cases where a master development plan has been agreed to, submitting an APD would be more efficient.

NOS requirements include staking the proposed well and ancillary facilities locations, new or existing access routes (generally without cut and fill measurements), and reference points for the drill pad. After receiving the results of the on-site inspection, the operator has 60 days to affect the noted changes and submit the complete APD package, otherwise the NOS is returned. It is important, therefore, to file a NOS only if the APD can be completed in time.

Major Steps of the APD Approval Process[3]



APD Approval Process Option 1

1. Preliminary Surface Meeting (Optional)

It is recommended that the operator contact the BLM and surface management agency/owner prior to submitting a NOS. A solid working relationship with the involved federal agencies can be helpful throughout the APD preparation process and may increase the likelihood of timely approval. Federal agencies can address operator concerns and provide recommendations about environmentally sensitive areas.

2. Notice of Staking

A NOS form is prepared by the operator and includes well location, estimated well depth, proposed well information (e.g., horizontal, directional, or vertical well), lease information, and a map that indicates approximate well site locations. The BLM provides a sample format in its *Gold Book*[4], but it may be altered if site specifics warrant. A complete submission includes the original NOS, a copy of the NOS, and a map. Submission of a NOS initiates an on-site inspection.

3. On-Site Inspection

Conducted by the BLM, the on-site inspection also includes the operator, surface management agency if separate from the BLM, private surface or mineral owner if applicable, and other agencies as needed to address specific concerns. The inspection provides the BLM with site-specific conditions and potential resource mitigation concerns necessary to conduct a review of the proposed action. The BLM must give the results of the inspection to the operator within seven days.

4. APD Submission

The BLM reviews the submitted materials for completeness. If the application is incomplete, the operator is notified of the deficiencies. At this stage, the BLM may also request additional information it deems important.

5a. APD Posted and Reviewed

Once the complete APD (including any requested information and/or revision) is received, the BLM either approves the APD, defers action on the APD, or denies the proposal. A proposal is only denied if the APD is deficient and neither the BLM nor the USFS is able to determine what actions could be taken to make it acceptable.

The BLM (and/or other federal surface management agencies) must post the APD (excluding personal information) for at least 30 days before approval can be given. The posting is merely for information purposes and is neither appealable nor open for public comment. APDs submitted for leases on tribal land are exempt from being posted.

5b. Submit Additional Information

If the APD is incomplete, the operator is notified of any deficiencies or requests for more information. Any issues that arise from the on-site inspection not covered in the APD must be resolved before the APD is considered complete. After notification from BLM (and/or other cooperating agencies) of any deficiencies or requests, the operator has 45 days to provide the revisions or additional information, otherwise the APD may be returned to the operator.

6a. Approved

An approved APD may include BMPs attached as COAs that the operator must implement. The USFS may place other conditions on the operator if the lease is located on USFS land. Other stipulations included in the resource management plan may be determined based on completed analyses to ensure compliance with any federal laws.

In accordance with the Energy Policy Act of 2005, approval of APDs must occur within 30 days of receiving all information that comprises a complete APD. This goal, unfortunately, is rarely achieved, with only 6% of APDs being approved within the required time frame. BLM statistics show that it takes an average of 228 days to approve an APD, including the time the operator needs to provide additional information and the time BLM takes to review the additional information and process the APD. Statistics vary widely across BLM field offices based on workload and staffing.[5]

6b. Deferred

If a permit is deferred, the BLM (or the USFS with regards to a SUPO) provides the operator with requirements necessary for APD approval. These actions may include (but are not limited to) gathering more data or information on aspects of the drilling plan or SUPO.

6c. Rejected

When an APD is rejected, no additional information or actions can change the decision. Rejection occurs only when the BLM determines that no possible changes can salvage the APD. The documents are returned to the applicant.

APD Approval Process Option 2

1. Preliminary Surface Meeting (Optional)

It is recommended that the operator contact the BLM and surface management agency/owner prior to developing the APD. A solid working relationship with the involved federal agencies can be helpful throughout the APD preparation process and may increase the likelihood of timely approval. Federal agencies can address operator concerns and provide recommendations about environmentally sensitive areas.

2. Submission of APD

Within ten days of receiving an APD, the BLM reviews the submitted materials to determine whether the application is complete. The operator is notified of any deficiencies and/or requests for more information.

3. On-Site Inspection

Conducted by the BLM, the on-site inspection also includes the operator, surface management agency if separate from the BLM, private surface or mineral owner if applicable, and other agencies as needed to address specific concerns. The inspection provides the BLM with site-specific conditions and potential resource mitigation concerns necessary to conduct a review of the proposed action. If the on-site inspection is for a NOS, the operator will have a better understanding of the issues that must be addressed in the APD. The BLM is required to provide the operator with the results of the inspection within seven days.

4. APD and On-Site Comparison

BLM determines whether the APD addresses and resolves the issues identified during the on-site inspection. The BLM (and/or other federal agencies) may request additional information not included in the APD but deemed necessary as a result of the on-site inspection.

5a. APD Posted and Reviewed

Once the complete APD (including any requested information and/or revision) is received, the BLM either approves the APD, defers action on the APD, or denies the proposal. A proposal is only denied if the APD is deficient and neither the BLM nor the USFS is able to determine what actions could be taken to make it acceptable.

The BLM (and/or other federal surface management agencies) must post the APD (excluding personal information) for at least 30 days before approval can be given. The posting is merely for information purposes and is neither appealable nor open for public comment. APDs submitted for leases on tribal land are exempt from being posted.

5b. Submit Additional Information

If an APD is incomplete, the operator is notified of any deficiencies or requests for more information. Any issues that arise from the on-site inspection not covered in the APD must be resolved before the APD is considered complete. After notification from BLM (and/or other cooperating agencies) of any deficiencies or requests, the operator has 45 days to provide the revisions or additional information, otherwise the APD may be returned to the operator.

6a. Approved

An approved APD may include BMPs attached as COAs that the operator must implement. The USFS may place other conditions on the operator if the lease is located on USFS land. Other stipulations included in the resource management plan may be determined based on completed analyses to ensure compliance with any federal laws.

In accordance with the Energy Policy Act of 2005, approval of APDs must occur within 30 days of receiving all information that comprises a complete APD. This goal, unfortunately, is rarely achieved, with only 6% of APDs being approved within the required time frame. BLM statistics show that it takes an average of 228 days to approve an APD, including the time the operator needs to provide additional information and the time BLM takes to review the additional information and process the APD. Statistics vary widely across BLM field offices based on workload and staffing.[6]

6b. Deferred

If a permit is deferred, the BLM (or the USFS with regards to a SUPO) provides the operator with requirements necessary for APD approval. These actions may include (but are not limited to) gathering more data or information on aspects of the drilling plan or SUPO.

6c. Rejected

When an APD is rejected, no additional information or actions can change the decision. Rejection occurs only when the BLM determines that no possible changes can salvage the APD. The documents are returned to the applicant.

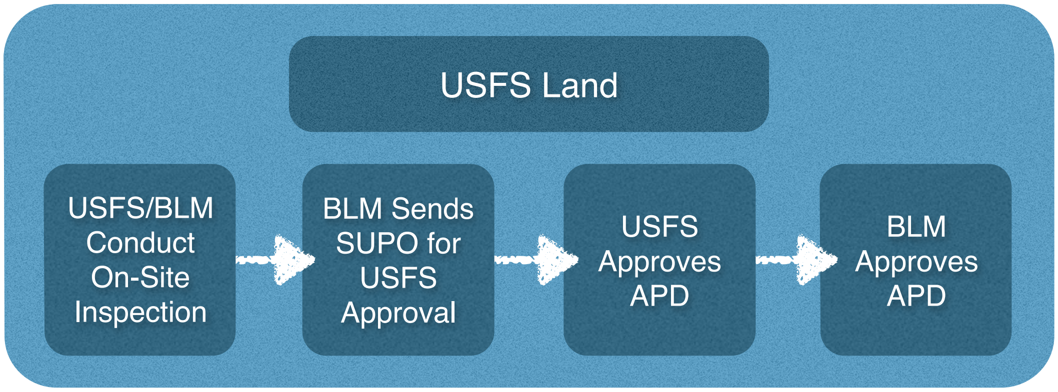
Master Development Plans

Operators may also submit a Master Development Plan (MDP) to serve as an APD for multiple well sites. While the MDP requires more information from the operator, it relieves the need to develop multiple similar individual APDs. MDPs can be beneficial to reviewers (the BLM and/or surface management agencies) because the potential cumulative environmental effects can better be determined through an MDP than through the submission of multiple individual APDs. MDPs do pose a challenge to the BLM, however, because despite being much larger and more complex, their review and approval or denial must still occur within the same 30-day time limit.

United States Forest Service

The USFS assumes responsibilities for assessing potential surface impacts to its lands in the processing and approval of an APD. The BLM retains administrative duties in processing and issuing the APD, as well as review and approval of all downhole activities in the drilling plan. The USFS and the BLM work jointly in several functions through the APD process.

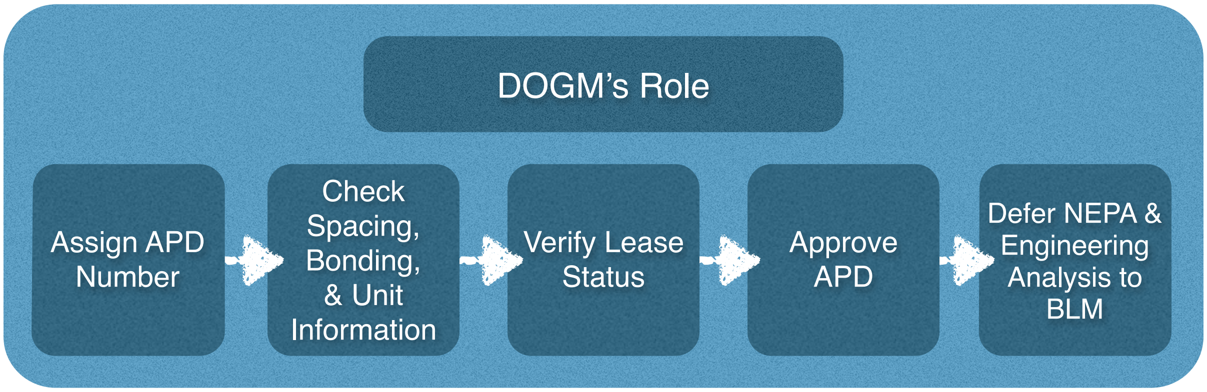
- When an APD is submitted, both the BLM and the USFS review the APD within 10 days to determine whether it is complete.
- A complete APD is posted by both the BLM and the USFS to initiate the 30-day public notification period.
- The USFS takes the lead in scheduling the on-site inspection and is involved in the inspection.
- The BLM and the USFS work jointly on any National Environmental Policy Act (NEPA) or other analysis that is performed.
- Right-of-way issues associated with USFS lands may require a USFS Special Use Authorization (SUA).
- The SUPO portion of the APD must be approved by the USFS, while the rest of the APD is processed and approved by the BLM.
- Wells on USFS land may require additional bonding above the BLM requirements.



DOGM's Role

Operators must submit an APD to both the BLM and DOGM if the lease is located on federal land in Utah. A state-issued APD through DOGM must be obtained regardless of land ownership, tribal lands and Indian Country included. DOGM's review process for federal lands is generally completed within a few days. DOGM's procedure for approving an APD:

1. The APD is assigned a number and map.
2. Unit spacing and information is verified.
3. Bonding is verified.
4. Lease status is verified.
5. The APD is reviewed and approved.



Right-of-Way (ROW)

In some cases, a ROW use permit may be required by the BLM, or a SUA may be required by the USFS. A ROW is not required if all pipelines, roads, facilities, or power lines remain on the lease. If any of these extend beyond the lease, however, a ROW is necessary. The BLM informs the operator of the necessity of a ROW within 10 days after receiving an APD, or during the on-site inspection if the operator submitted a NOS.

The most efficient means of obtaining a ROW is to include the necessary information in the SUPO portion of the APD, whereupon ROW approval can occur concurrently with the APD rather than after the APD has been approved. ROW information that is required in the SUPO includes a detailed map of the entire ROW project and specifics regarding the construction and reclamation of projects on and off lease. Including the ROW information with the APD has a negligible effect on the time frame of APD approval.

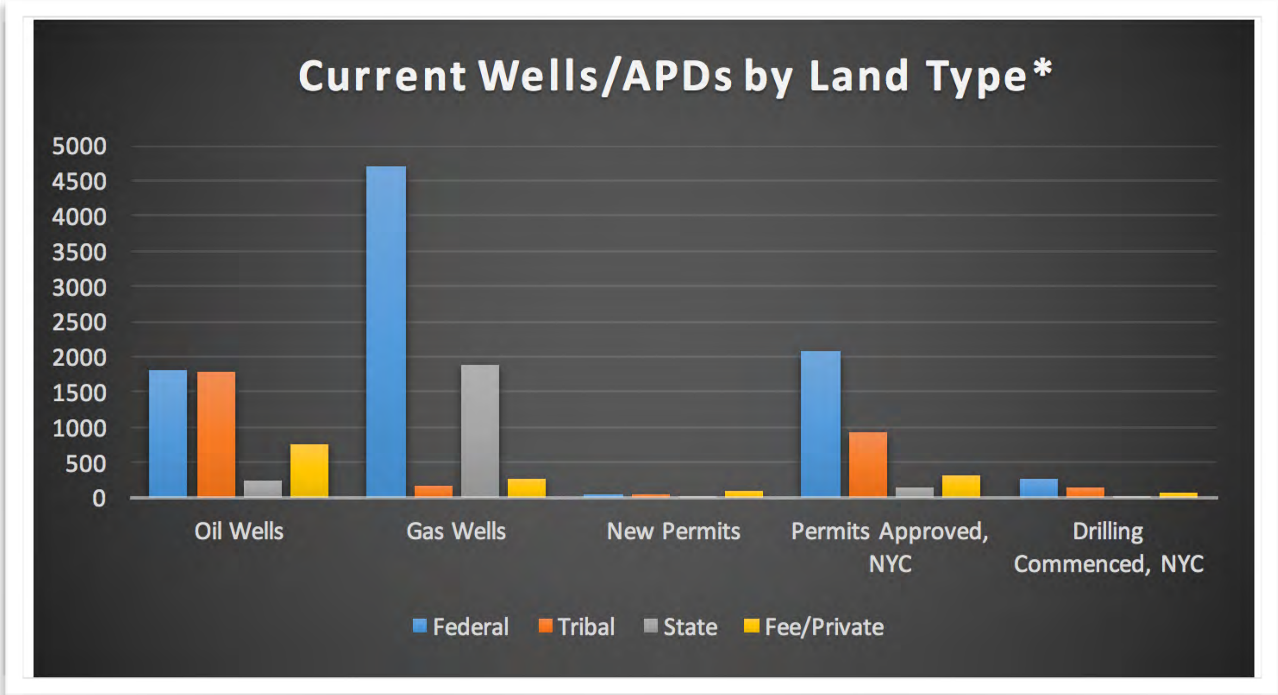
Prior to Mineral Leasing Act (MLA) amendment, BLM was responsible for any on-lease activity and USFS was responsible for off-lease activity. This split responsibility required an operator to obtain both an APD and a SUA. Today, USFS regulates all project surface-disturbing activities, whether on or off lease, and approves the SUA via the SUPO. As with the BLM's ROW, the operator should include detailed information for both on- and off-lease operations.

In some cases, a SUA must be obtained through the USFS in addition to the SUPO approved in the APD, e.g., when facilities or pipelines are not directly related to the drilling activities on lease or are operated by third parties.

STATE

If the well is located on school trust or private surface and minerals, DOGM has full regulatory authority. DOGM conducts the on-site inspection, the APD approval, and all compliance inspections. In addition to a state APD, an operator of a well on trust land may also be required to obtain permits for air and water quality, hazardous waste, underground storage tanks, and ROW use. All applicable county permits must also be obtained.

The chart below shows, by land type, the total number of oil and gas producing wells in the state of Utah. "New Permits" indicates the number of permits submitted that are still awaiting approval. "Permits Approved, NYC" is the number of permits that have been approved but not completed, and "Drilling Commenced, NYC" indicates the number of wells that are currently being constructed. The majority of active oil and gas wells and approved permits are on BLM and tribal land.



*Data obtained through DOGM. NYC = Not Yet Completed.

The following section examines the state APD, air permits through the Utah Division of Air Quality (DAQ), water permits through the Utah Division of Water Quality (DWQ) and Division of Drinking Water (DDW), hazardous waste permits, and underground storage tank permits. Each of these permits is also required for wells on federal land.

Application for Permit to Drill

DOGM requires an APD for any well within the state of Utah prior to any drilling or surface disturbance. Components of the state APD are similar to those of the federal APD, but with several important processing differences, the greatest of which is environmental review. While the federal APDs follow the NEPA process, state APDs rely on a pre-site evaluation for environmental considerations. The pre-site evaluation assesses the unique circumstances of the well and the environmental protections that are necessary. The evaluation also includes a SUPO, waste management plan, the location of future reserve pits, a reclamation plan, and other appropriate environmental considerations.

The following is the process for approving APDs for wells located on state- or privately-owned surface and minerals. The process is similar to DOGM's approval for federal wells, but with steps 5 and 6 applying uniquely to wells on state- or privately-owned land.

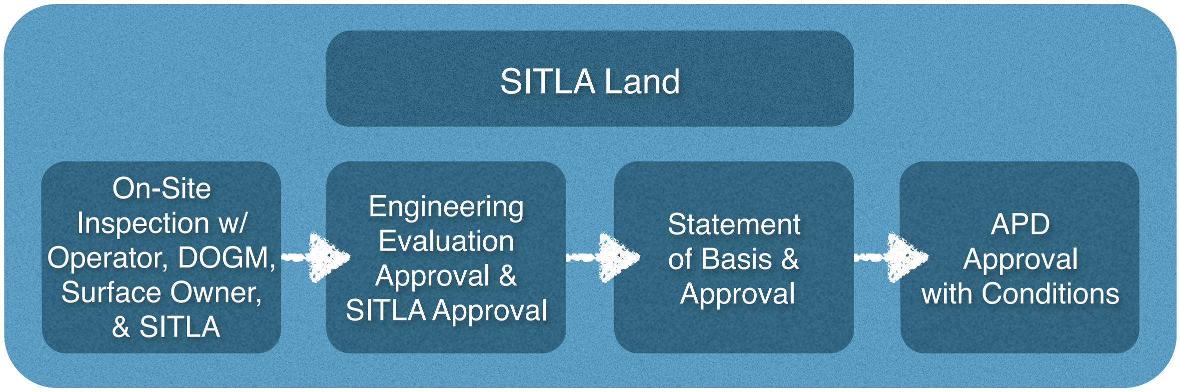
1. The APD receives an American Petroleum Institute (API) number and map.
2. Unit spacing[7] and information is verified.
3. Bonding is verified.
4. Lease status is verified.
5. DOGM reviews the engineering/drilling plan.
6. The pre-site environmental analysis is completed.
7. The APD is reviewed and approved.

SITLA's Role

APDs for wells on trust land require SITLA involvement and may require additional analyses. DOGM forwards a copy of the APD to SITLA for approval. (DOGM can approve no APD that has not first received SITLA approval.) SITLA's involvement with the APD process:

1. SITLA participates as the surface management agency in the pre-site evaluation.
2. SITLA determines whether paleontological or archaeological surveys must be completed for APD approval.[8]
3. SITLA reviews and approves the APD to ensure consistency with lease stipulations.
4. SITLA may require bonding in addition to that required by DOGM.[9]

5. SITLA works with DOGM to ensure the success of reclamation efforts.



Right-of-Way (ROW) Permit

A right-of-way permit is required if any road, pipeline, or surface disturbance will occur on state land (SITLA or FFSL), regardless of whether the well itself is on state land. This type of permit may also be called an easement.

SITLA

SITLA's Surface Business Group issues easements. With the easement application, the operator must also submit a cover letter, map, and legal description prepared by a surveyor. The cost of the easement depends on the type of access necessary and the value of the land. At this point, an on-site meeting may be necessary with the operator. The operator is notified of application acceptance or rejection within 15 days. If accepted, a $750 filing fee is due in addition to the determined easement fee. Once fees are paid, the application is approved by the director.

Additional requirements may be necessary before an easement application is approved. During the initial application review, it will be determined whether the Resource Development Coordinating Committee (RDCC) must review the easement prior to approval. If so, the 30-day review process involves local governments and other state agencies. SITLA may also require a survey of cultural and/or paleontological resources.

Utah Division of Forestry, Fire, and State Lands (FFSL)

The FFSL requires an easement application that includes the location of the proposed easement, a $150 filing fee, and, if applicable, a platted survey. The FFSL reviews the application and will approve or deny the easement.

Water Permits

There are two categories of water permits required for oil and gas development: class II injection wells and associated facilities (e.g., reserve pits, treatment facilities, etc.). Enforced by the DWQ and DOGM on federal, state, and private land, the permits ensure compliance with the Clean Water Act (CWA) and Safe Drinking Water Act (SDWA). The EPA has jurisdiction over wells located on Indian Country (including tribal).

Class II Injection Wells[10]

Class II injection wells are most commonly used in oil and gas development for hydraulic fracturing and are administered by DOGM (Class I and III-V wells are regulated by DWQ). A Class II injection well application is submitted to DOGM with the following information:

- UIC Form 1.
- Well plat with nearby active or abandoned wells.
- Bond logs associated with the well.
- Casing description.
- Injection fluid and pressure details.
- Sub-surface layer geology and hydrology.
- Mechanical state of nearby wells.
- All surface owners within half a mile of the well.
- Proof that injection well application has been submitted.

DOGM reviews the application for accuracy and completeness. Once the application has been through an engineering review by DOGM, it is approved if technically adequate.

Associated Facilities

According to Utah Rule 317-6, oil and gas water pits, waste facilities, and reserve pits are "permit by rule." As long as the associated facilities are constructed and operated in compliance with applicable state law, they do not require discharge permits. The facilities must, however, comply with the standards set in the CWA and SDWA. If pollutant levels around the oil and gas facilities rise above water quality standards, additional protections are necessary.

Air Permits

The majority of the equipment and processes associated with oil and gas development and production are minor air pollution sources.[11] Minor sources are regulated by the New Source Performance Standards (NSPS) and the National Emission Standards for Hazardous Air Pollutants (NESHAP). Were areas of Utah to receive a non-attainment designation, one likely result would be the more stringent regulation of minor sources.

Some sources, such as low producing tank batteries (not including all tank batteries), do require an actual permit from DAQ if the source emits more than five tons of pollutants. Operators may use either the State's Approval Order (AO) or General Approval Order (GAO) process when applying for permits.

New Source Performance Standards

States are required to enforce the EPA's NSPS. The NSPS sets operational standards for equipment or processes, based on the emissions emitted. Well completions and storage tank and compressor station emissions, for example, fall under the authority of the NSPS. These standards apply only to new facilities, not to existing or older facilities.

Separate from the NSPS, Utah DAQ has recently approved standards specifically for existing and new pneumatic controllers (frequently used in oil and gas development). These standards require all high-bleed[12] controllers to be retrofitted or replaced with low-bleed controllers. Pneumatic controllers in Uintah and Duchesne counties need to meet the standard by the end of 2015, but controllers in the rest of the state have until 2017. Utah DAQ has also adopted standards for combustion devices and truck loading.

Permits for equipment regulated by the NSPS are approved through either the Approval Order (AO) or General Approval Order (GAO) process.

National Emission Standards for Hazardous Air Pollutants (NESHAP)

States are required to enforce NESHAP, which regulates criteria pollutants of both new and existing sources. These regulations identify a particular process, such as a dehydrator, and determine an appropriate level of control, with an emissions threshold for the process as a whole rather than for individual equipment.

Permitting Process

All DAQ permits are required before any construction or operation can begin. The following is the basic permitting process for DAQ.

1. First is an optional pre-submission meeting between the operator and DAQ. The meeting is recommended for operators who are not familiar with the requirements for obtaining an air permit, or if the project has special circumstances.
2. The operator submits an application to DAQ that includes source location, equipment specifications, modeling, a Best-Available-Control-Technology (BACT), and emissions estimates.
3. DAQ reviews the application to ensure that the information is complete and accurate. If information is missing, the operator is notified.
4. An engineering review is drafted. The permit and any conditions that apply to the source are included.
5. Applicant signs the proposed permit.
6. The permit is posted for a 30-day public comment period.
7. DAQ reviews and responds to any comments. Changes may be made to the permit at this point, based on the comments.
8. The permit is issued.

The process takes an average of 120 days from the time the information is received by DAQ. If construction or operation does not begin within 18 months after the permit is issued, approval may expire. An extension to this time frame may be obtained.

General Approval Order

DAQ's GAO is an alternative route for permitting minor sources. It establishes conditions for similar new or modified sources within a source category and specific types of equipment.

To qualify under a GAO, an operator is required to meet all existing rules (including NESHAP and NSPS), comply with various BMPs established by DAQ, and meet specific operational limitations. Once a GAO is adopted for a particular source category, a new or modified source can apply to be covered under the permit if it meets the specified criteria. The rule requires review of the GAO at least once every three years to ensure periodic opportunities for public review and comment.[13]

Time is GAO's advantage over the traditional permitting process, usually taking only a couple of weeks to be approved. A GAO is, however, only applicable to state or private land.

Hazardous Waste Permits

The operator must make sure that the transportation and disposal of hazardous waste associated with oil and gas production is carried out in accordance with the CWA, Clean Air Act (CAA), SDWA, and the Oil Pollution Act (an amendment to the CWA). The Utah Division of Solid and Hazardous Waste (DSHW) is the regulatory agency over the transportation and disposal of waste.

Any operator who generates hazardous waste is required to work with DSHW to determine proper waste storage, transportation, and disposal. Many wastes associated with oil and gas development are exempt (e.g., drilling fluids, waste water, sludge, and hydrocarbon-bearing soil), but they still must be disposed of in accordance with general waste regulations; they are not, however, subject to additional regulations. Some wastes are non-exempt and may require permits or special requirements for disposal or storage. These non-exempt wastes include unused fracturing fluids, acids, chemicals, and used oil.

The DSHW requires operators to report the transportation of generated wastes and forwards the information to the EPA. Any facilities that store, treat, or dispose waste must obtain a permit from DSHW.

Underground Storage Tank (UST) Permits

The Utah Division of Environmental Response and Remediation (DERR) is the regulatory agency over USTs. The operator must notify DERR at least 10 days prior to beginning installation operations on a UST. An installation permit and $200 per tank fee are required before completion of the installation. An installation permit requires:

- A certified UST installer.
- Installation company name, address, and permit number.
- Date of installation.
- Tank owner information.
- Facility information.
- Complete description of planned installation.
- Integrity testing.

The UST must meet the standards set for new tanks, which include spill protection, secondary containment features, and corrosion protection for both tank and piping. The installation must also be done properly according to the standards set for the industry. The UST must also be registered with the EPA.

TRIBAL

Though having no authority over Native American lands, State of Utah oil, gas, and minerals divisions and commissions may manage the rules for orderly spacing under the jurisdiction of the tribe to assure maximum recovery and provide a forum for dispute resolution if the BIA and the tribe adopt their recommendations. If the state does not provide the service, the responsibility rests with the BLM, unless the tribe and/or the BIA have assumed responsibility.

Application for Permit to Drill

An APD for a well located on tribal land is submitted to the BLM, who then forwards it to the BIA. The two major parts of the APD are the drilling plan and the SUPO.[14] The BIA is the surface management agency and functions in this instance much like the USFS does when a well is on USFS land. The on-site inspection consists of the BIA, BLM, lessee, and other surface or mineral owners. The BIA provides the BLM with any surface use stipulations required for APD approval.[15] The contents of a tribal APD are the same as a federal APD. See the federal section for more information.

Right of Way

ROW permits may be obtained by the operator at the time of APD submission. The contents of the ROW permit are the same described for federal land. ROW permits must be applied for individually, even if they are part of a common use corridor. ROW permits are necessary to ensure that surface use is carried out according to the established rules of the surface management agency. ROW permits are necessary for operations such as transmission lines, pipelines, and roads.[16]

Water Permits

A general water permit must be obtained from the EPA for each well drilled on tribal land. The permit costs $175 and allows use of water for all drilling-related operations.[17]

In addition to the general permit, the operator is required to obtain a permit through the EPA's Underground Injection Control (UIC) program. The requirements for obtaining a UIC permit are similar to those listed in the state “Water Permits” section, with the major difference being that the EPA issues the permit. The permit may be issued as a site-specific permit or as an area permit. An area permit can be issued for multiple wells if they have the same owner, are located within the same geologic formation, and the action on the wells are the same.

Under the CWA and SDWA, tribes may assume regulatory responsibility for water quality from the EPA. To gain this authority, a tribe must be federally recognized, have a governing body, and have a regulatory body deemed capable of enforcing EPA water standards.

Air Permits[18]

Wells on tribal land are required to obtain the same permits and adhere to the same regulations as wells on federal, state, or private lands. The major difference is that the EPA is in charge of the permitting, rather than the state. Tribes can apply for air quality primacy under the Tribal Authority Rule (TAR)[19], but the Ute Tribe has not done so.[20]

NSPS and NESHAP standards must be adhered to on tribal land, and operating permits are issued by the EPA rather than DAQ. See the state “Air Permits” section for more information. In addition to those permits and regulations, some oil and gas facilities on tribal land must comply with the Tribal New Source Review.

In 2011, the NSR program was expanded to include stationary minor sources; however, most minor oil and gas sources are not considered stationary and were not covered. After modification, a new rule covering NSR for oil and gas minor sources on Indian Country will soon be implemented. The EPA will be the primary permitting agency for minor sources.

COUNTY

Duchesne and Uintah counties have a number of permit requirements related to construction and development for the purposes of energy production.

Duchesne County[21]

All construction and development for energy production purposes in Duchesne County must comply with county regulations. If these statutes conflict with DOGM rules and statutes, DOGM has primacy.

Road Encroachment Permit

A road encroachment permit must be obtained from the County Public Works Department for new road approaches to a county road, for excavations within a county's road right of way associated with oil and gas drilling facilities/production, or for the placement of pipelines (surface or buried) within the county road right of way.

APD Requirements and Conditional Use Permits

Duchesne County requires a number of additional steps to be met before submitting an APD to DOGM if a well site, as measured from the wellhead, will be located 660 feet or closer to an existing primary or secondary dwelling or to any building open to the public. If the drill site owner is not the owner of all dwellings or buildings open to the public within 660 feet of the wellhead, the operator must notify, by certified mail, the off-site owner of the operator's intent to locate the well site. This notification must be sent at least 45 days prior to submitting an APD to DOGM. The operator must offer to discuss the well site location and potential mitigation measures with the off-site owner. If the off-site owner does not respond within 15 days of the date when the notice was mailed, the operator can file the APD for the proposed well site location.

If the off-site owner does respond, the operator must inform the County of the results of the consultation and whether an agreement regarding mitigation has been reached. If an agreement is reached, the operator may proceed to file the APD. If an agreement is not reached, the operator and off site owner are encouraged to mediate their differences.

On property that is zoned as A-2.5 (agricultural 2.5 acres minimum), R-1 (residential 1 acre minimum), and R-1/2 (residential ½ acre minimum) the operator must apply for an administrative conditional use permit that addresses the standards and mitigation discussed above. The county zoning administrator has the authority to grant or deny conditional use permits for oil and gas drilling facilities/production in A 2.5, R-1, and R ½ zones. If an operator's conditional use permit application complies, then the permit will be approved. If the conditional use permit application does not comply, then the administrator denies the conditional use permit or approves it with additional conditions to reasonably address the non-compliance. A decision is usually made within seven days after a notice is mailed to all property owners within 300 feet of the boundaries of the drill site owner's property.

Uintah

Road Encroachment Permit[22]

If an operator needs to use a county right-of-way and/or build a road, an encroachment permit is needed. This permit is obtained via application to the County Road Department.

Conditional Permit and Business License

If a wellhead is within 1,000 feet of a residence, operators are required to work with the surface owner in all phases of production. Conditional permits are necessary if a wellhead is on private land. A business license must also be obtained to drill in Uintah County.[23]

PRIVATE

Permits on private lands fall under the jurisdiction of state and county statutes and regulations. See above sections for more information.

Right of Way

Access to private lands will be granted by the private land owner; however, in the case where the surface owner is private but the subsurface minerals are federally-owned, access to private surface land must be granted. As discussed in Chapter 1, negotiated agreements between private surface and mineral subsurface owners should occur in advance to minimize conflict and disruption of surface land uses.

Chapter 5 Notes

[1] Please see Onshore Oil and Gas Order No. 1 at http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas/Onshore_Order_no1.html.

[2] For more information on the components of an APD, see the appendix.

[3] Please see the Appendix for a chart of average APD processing time.

[4] BLM *Gold Book*, Appendix 2, pg. 61-2.

[5] "Onshore Oil and Gas Permitting, U.S. Department of the Interior," Office of Inspector General, June 2014. http://www.doi.gov/oig/reports/upload/CR-EV-MOA-0003-2013Public.pdf.

[6] Ibid.

[7] A spacing unit is a legal boundary of a common oil & gas source. The leased mineral acreage as a percentage of the total source acreage is used to determine royalty payments due to the land owner. Spacing units also allow for more efficient recovery of oil and gas resources.

[8] For a map showing lands that are subject to paleontological review, see ftp://lands-ftp.state.ut.us/pub/download/data/PaleoSensitivityMap.pdf.

[9] E.g., SITLA's 20/20 rule states that if >20 feet are cut out of the surface or >20 tons of earth are moved, extraordinary bonding will be required. Other situations may require additional bonding.

[10] "Permitting a Class II Injection Well", Utah Division of Oil, Gas and Mining, April 2004 https://oilgas.ogm.utah.gov/pub/Publications/Handbooks/guideUIC1.pdf.

[11] A major source emits more than 100 tons per year of any air pollutants or 10 tons per year of specific hazardous air pollutants. Minor sources are those that fall below these thresholds.

[12] The bleed rate is the amount of natural gas that is released into the environment from the device.

[13] For more information, see http://www.deq.utah.gov/Permits/GAOs/gaos.htm.

[14] See the "Federal APD" section and the Appendix for information on a drilling plan and SUPO.

[15] BIA *Handbook*, p. 31.

[16] 25 CFR § 169.25. BIA *Handbook*, p. 8.

[17] BIA *Oil and Gas Sample Lease*, p. 12. http://www.bia.gov/cs/groups/xieed/documents/text/idc010987.pdf

[18] http://www.epa.gov/tribalcompliance/airresources/arairdrill.html.

[19] http://www.epa.gov/ttnamti1/files/2006conference/farsitar.pdf.

[20] http://www.epa.gov/tribalcompliance/airresources/arairdrill.html.

[21] Duchesne County Ordinance #12-308 Oil and Gas Wells, p. 2.

[22] Uintah Co. Encroachment Permit application: http://www.co.uintah.ut.us/roads/encroachment/ENCROACHMENTPERMITAPP5-10-07.pdf.

[23] Complete list of Uintah County Permit fees: http://www.co.uintah.ut.us/UCfeeSchedule.pdf.

6. EXPLORATION, DEVELOPMENT, & PRODUCTION

After a lease has been purchased and all permits are secured, oil and gas exploration, development, and production can begin according to the terms of the lease and permits. The operator can apply for modification to, waiver of, or exemption from the stipulations of the lease or permits throughout the life of the lease, if applicable.

Major Legislation for Oil & Gas Production

- Mineral Leasing Act of 1920*
- Onshore Oil and Gas Orders No 1-7*
- Federal Oil and Gas Royalty Management Act*
- Utah Administrative Code R649, Section 3♦
- School and Institutional Trust Lands Management Act♦

* = Federal only, ♦ = State only

Construction and Drilling Activities

The construction and drilling activities that are necessary for a well site must be completed in compliance with the drilling plan and surface use plan of operations (SUPO) portions of the application for permit to drill (APD). The operator's representative should be in contact with the surface management agency and have access to the approved APD to ensure that all drilling and construction activities are done properly.

The key principle of all construction activities is to minimize surface disturbance on the lease site. The top soil that is displaced throughout construction should be stored separately for purposes of interim and final reclamation.

The main areas of construction that are regulated include reserve pits, roads, drainage ditches or culverts, pipelines, and drilling activities. In addition, a number of individual county ordinances may affect operations on the site.

RESERVE PITS

The BLM *Gold Book* states that reserve pits are "used for storage of water, drilling mud, and cuttings during drilling operations."[1] The location of the reserve pit is specified in the approved APD and must be constructed at the approved location. Reserve pits should not be constructed where shallow ground water or other natural water sources exist. If the well site is on uneven terrain, the reserve pit should not be located in the fill.[2]

It is usually required that reserve pits be lined with an impermeable liner to prevent leakage. If the area is known to contain shallow groundwater, the BLM requires that at least a semi-closed loop drilling system be used. Reserve pits should also be fenced or netted to keep out birds and wildlife. Additional requirements for reserve pits may be implemented by the surface management agency or state regulatory agency.

It is necessary to use a closed loop or semi-closed loop drilling system if oil-based muds will be used during drilling. Hydraulic fracturing and other completion fluids are circulated through tanks, into the wellbore, and then recycled but not placed in the reserve pit.

ROADS

In most cases, it will be necessary to construct a road to access the well site. The requirements that accompany the construction and maintenance of roads will vary based on the surface management agency and environmental sensitivity of the site. The following provides some basic information on the construction and maintenance of roads, but should not be seen as a comprehensive guide.

Plans for new roads are included in the SUPO and include the following information: road width, grade, crown design, turnouts, ditches, bridges, culverts, erosion control, any cuts, storage of top soil, and surfacing materials.[3] The reclamation plan should include how roads will be reclaimed unless an agreement is made with the surface management agency to preserve the roads for future use. Road planning and construction must be done in an environmentally responsible manner due to potential environmental harm.

The BLM *Gold Book* states that transportation planning must consider future road use, the effects on the environment, and ensure that unnecessary development doesn't take place.[4] Existing roads and transportation routes should be considered before making the decision to construct a new road. The location of a new road should be chosen in order to minimize environmental impacts. The surface management agency may already have a transportation plan in place for the land that identifies the best transportation routes and takes into account the environmental sensitivities of the area.[5]

When the land is managed by the BLM or the USFS, road construction must comply with the current transportation and land use plans. The *Gold Book* provides specifics for BLM and USFS land, based on whether the road is local, collector, or arterial.[6] If SITLA owns the land, surface activities should not interfere with other approved land uses. If the land is privately owned, the operator should involve the surface owner in determining road locations.

A maintenance plan for all roads that will be used or constructed should be submitted to the surface management agency. Some examples of activities that may be included in a maintenance plan are monitoring, surface replacement, dust abatement, repairs, slide removal, weed control, ditch or culvert cleaning, and snow removal.[7]

DRAINAGE DITCHES AND CULVERTS

The construction and maintenance of drainage ditches and culverts in conjunction with roads is a vital part of minimizing the environmental impacts of oil and gas development. It is necessary to ensure that water does not remain on the roadway or pad. Proper drainage combines the use of many techniques, e.g., ditches, culverts, crowning, water bars, bridges.

PIPELINES

When possible, pipelines should follow roads in order to limit surface disturbance. Pipelines should avoid "steep hillsides and water courses"[8] due to erosion potential. If the pipeline follows the road, steps should be taken to ensure protection of the pipeline. The topsoil that is removed during pipeline construction should be stored and not mixed with subsurface material. The pipeline should be tested for leaks before the trench is filled. Pipelines should not block or change the course of any drainage or natural water courses. Gathering lines do not need to be buried and may be laid across the surface to reduce disturbance.

DRILLING ACTIVITIES

Reporting

The drilling of the actual well should be done in accordance with the approved APD. A daily drilling report is required by both the BLM and DOGM during the drilling of a well. When a well is completed, a well completion report should be submitted to the managing agency (the BLM or DOGM) within 30 days. A sundry notice is required when production begins on any lease site on the date of first production report.

Periodic repairs or servicing operations usually do not require prior approval by the managing agency as long as there is no additional surface disturbance. If the well is going to be deepened, plugged, or changed in a significant way, then a sundry notice is required. A supplemental SUPO for the proposed action may be required. On USFS land, the operator must seek approval from the USFS for any surface operations.

Water Disposal

The disposal of any produced water must comply with Onshore Order No. 7 and other applicable federal and state regulations. Permits typically are required from either the EPA or DWQ, based on land jurisdiction. The BLM must also approve of disposal operations on federal lands.

Waste or Pollution Control

The BLM and DOGM mandate the reporting of major undesirable events in cases where any spills, leakages, blowouts, fires, or injuries occur. Operators are empowered to take actions to prevent further contamination or to stop the undesirable event, but they should consult the required agencies within 24 hours. Any chemicals or hydrocarbons that are used in the fracturing of wells must be reported to FracFocus, according to Utah Rule 649-8.[9]

Dust Control

Operators of oil and gas drilling and production facilities are required to control dust at each individual well site and along well access roads when there is traffic associated with drilling or operations.[10]

COUNTY ORDINANCES

Painting of Well Production Facilities and Location of Well Site Equipment

Duchesne County requires well production facilities such as pumps, tanks, separators, and appurtenances to be painted to blend with the natural surroundings. The color choice must be made from the standard BLM color palette with drill site owner concurrence. When possible, production equipment should be clustered.

Lighting

Duchesne County requires all site lighting to be oriented and or installed with shielded fixtures so that light is directed toward the work area in accordance with safety standards but reduces glare on nearby roads or on lands used for residential purposes.

Noise

Duchesne County requires well site production facility motors to be powered by electricity when located within 660 feet of a primary or secondary dwelling or a building open to the public, provided that the power company has adequate capacity and availability of easements to supply the power. Engines located at well sites where the wellhead is within 660 feet of a primary or secondary dwelling or building open to the public that are not served by electricity must be muffled or situated to mitigate noise impacts.

Inspections and Enforcement

Throughout the life of a well, the managing agency will conduct inspections to ensure compliance with the approved APD and applicable regulations. The inspections are performed by different agencies depending on land and mineral ownership. The majority of inspections at both the federal and state level are to ensure compliance with environmental regulations and proper production reporting.

While federal and state agencies perform inspections, well operators are expected to implement their own inspection programs to identify issues or noncompliance and to take corrective actions rather than relying solely on federal or state inspections.

FEDERAL

The Bureau of Land Management

The BLM is the primary agency that conducts inspections of wells on federal land. This authority was granted to the BLM through the Department of Interior in the Mineral Leasing Act of 1920, and FOGRMA expanded the BLM's authority. Any oil or gas well that is expected to produce significant quantities or whose operator has a history of non-compliance is required to be inspected annually by the BLM. Wells that do not fit into the high priority category are inspected when possible. When determining well site inspection priority, considerations are made based on environmental concerns, resource conflicts, or public health and safety issues. The following are the types of inspections conducted by the BLM.

- ***Production***

  Ensures production equipment and practices are consistent with regulations and that metering and gauging measurements are accurate. Production accountability ensures that proper royalties are paid.

- ***Drilling***

  Conducted when a well is being drilled to ensure compliance with the approved procedures of cementing and casing. Drilling inspections can also include blow out prevention equipment tests, formation psi, and rig compliance.

- ***Abandonment***

  Conducted when a well is plugged to ensure proper placement of cement and plugs.

- ***Work Over***

  Conducted when work over operations (usually plugging back or recompletions) are conducted on an existing well.

- ***Environmental***

  Typically conducted by natural resource specialists to examine environmental concerns such as pad construction, erosion, interim reclamation, waste disposal methods, surface hazards, and final reclamation, including reseeding success.

- ***Records Verification***

  Conducted to examine production records to ensure accuracy of the information submitted to the Office of Natural Resources Revenue.

- *Major Undesirable Event*

  Conducted when spills or accidents occur.

- *Alleged Theft*

  Conducted to investigate alleged theft or under-reporting of sales of oil or gas.

The U.S. Forest Service

In addition to the inspections listed above, wells located on USFS land are subject to annual inspections by the USFS. The primary focus of these inspections is to ensure compliance of surface activities with the approved conditions in the SUPO.

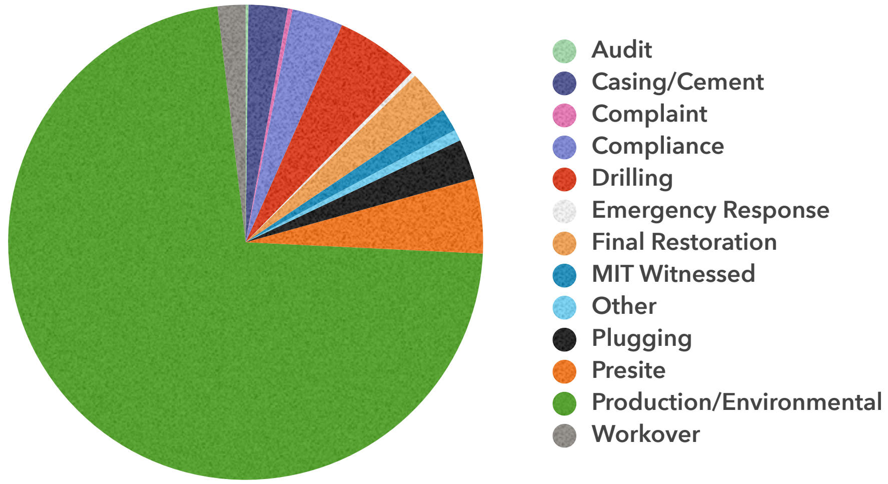
STATE

Division of Oil, Gas and Mining

DOGM is the primary agency that conducts inspections of oil and gas wells on state and private land. Section R649-3-17 provides the legal guidance for the inspections of wells and mandates that DOGM conduct inspections to ensure regulatory compliance, that inspections not interfere with production operations, and that no inspection be conducted that may cause a safety hazard.

DOGM "routinely inspects field operations to verify that natural resources are not wasted and the environment is protected."[11] As shown in the figure below, production/environmental inspections account for nearly 70% of all inspections in 2013.

DOGM Inspections 2013



The Division of Air Quality

The DAQ's minor source compliance section has two full-time oil and gas inspectors. These inspectors conduct compliance inspections, investigate complaints, and initiate enforcement action as necessary to ensure that federal and state regulations are being followed.

The Division of Water Quality (DWQ)

Most oil and gas equipment/facilities regulated by the CWA or the Safe Drinking Water Act (SDWA) are permit-by-rule and do not require inspections. The Underground Injection Control (UIC) program is administered by DOGM, so compliance is checked during the agency's inspections.

TRIBAL[12]

Once the lease comes into production, the BIA and the BLM monitor operations to ensure compliance with the terms and conditions of the lease and protection of the environment according to the findings of the NEPA documentation. The field monitoring responsibility continues for the BIA and the BLM throughout the life of the operations.

The BIA conducts lease compliance inspections, and though it has no regulatory authority over the actual production process, the BIA still may inspect wells and report non-compliance issues to the BLM.[13] A standard inspection will include checking the equipment and ensuring compliance with environmental regulations and the APD.[14]

PRIVATE

Private lands are under the same jurisdiction as state lands for inspections and enforcement (unless split estate). Please refer to the above section "State" for more information.

Royalties

FEDERAL

Royalties from federal and tribal leases are collected by the Office of Natural Resources Revenue (ONRR). The royalty rate for onshore oil and gas is usually set at 12.5% of the production value. There may be circumstances where some leases may pay less or on a sliding scale, as in cases of declining production or if the lease originated prior to current royalty regulations. For more information on how royalties are calculated, please see the *Oil and Gas Payor Handbook* published by the ONRR.[15]

Royalties from federal and tribal leases are split between the federal government (52%) and the state (48%) where the lease is located. The revenue received by Utah is put into its Mineral Lease Account within its General Fund. Utah Code 59-21 provides the legal basis for the disbursement of funds. Revenue from the Mineral Lease Account is disbursed in pre-determined percentages.[16]

Mineral Lease Account

RECIPIENT	PERCENTAGE
Utah Department of Transportation	40%*
Permanent Community Impact Fund	32.5%*
County Government	52¢ per acre leased*
Dept. of Community & Economic Development	5%*
Utah Geological Survey	2.25%
State Board of Education	2.25%
USU Water Research Lab	2.25%

*Mineral revenues go to special districts and/or the county of origination.

STATE

Leases administered by SITLA are also subject to royalties. Lands east of Range 6w West are leased at a 1/6 royalty rate, while lands west are leased at a 1/8 royalty rate. The royalties from leases located in the Grand Staircase-Escalante National Monument are split 6.25% between the state of Utah and SITLA. SITLA receives 3% for administrative costs, and the rest is deposited as follows:

SITLA Revenue Disbursement

RECIPIENT	PERCENTAGE
Land Grant Management Fund	50%
Land Exchange Distribution Account	50%

The Land Exchange Distribution Account is further divided among several state agencies including the Constitutional Defense Restricted Fund, State Board of Education, Utah Geological Survey, and others.

Case Study: Duchesne and Uintah Counties

Land ownership within a county strongly influences how royalty revenue is distributed. Utah's Duchesne and Uintah counties are prime examples of the royalty disparity that can exist between two adjoining counties of similar industrial base. The difference is that while over half of the oil and gas production in Duchesne County occurs on state or private land, the majority of production in Uintah County occurs on federal land. Uintah County, as a result, receives much more funding at the local level than Duchesne County. For example, Uintah County's largest city, Vernal, has nearly 10 times the budget of Duchesne County's largest, Roosevelt, despite having a population only twice as large.

The majority of the revenue that Duchesne County receives from oil and gas development must be allocated to road maintenance due to heavy industry use. Because little funding remains for community or educational development, the relationship between the energy companies and county citizens can suffer.

TRIBAL

Tribal royalties are usually higher than those on federal land. All royalties from wells located on tribal land are paid to the ONRR, and the operator must report royalty amounts monthly. There may be some situations where special requirements or stipulations with royalties take place, for example with shut-in wells.[17] Royalties are then disbursed by the ONRR according the terms of the lease and the BIA instructions for distribution.[18]

Beyond traditional royalties, other types of compensation may be identified in the lease conditions, e.g., a bonus paid to the mineral estate owner or contributions to scholarship or environmental preservation funds.[19]

PRIVATE

No royalties are paid to the federal or state governments if the mineral rights are privately owned. In this case, the operator and private owner negotiate the terms of the lease, including any royalties that will be paid.

Royalties may also be paid to private surface owners who do not own the mineral rights. Surface owners may be compensated for lost revenue that is caused by drilling activities on the surface. For example, if the surface land is used for farming, the surface owner is compensated for the lost crops caused by the surface disturbances.

Well Plugging and Reclamation

FEDERAL

Reclamation

Oil and gas production is not a permanent use of the land, and as such reclamation efforts seek to return the well site to its original condition. Interim and final reclamation plans are a key portion of the SUPO that is submitted with the APD. Interim reclamation is done throughout the life of the well and contributes to the success of long term reclamation.

Utah State University reclamation test site, courtesy of Colleen Jones, USU

According to the BLM, "the long-term objective of final reclamation is to set the course for eventual ecosystem restoration."[20] The operator is not responsible for achieving a full restoration of the natural ecosystem, but is responsible to take the short term measures necessary for full reclamation to occur over time through natural processes.

The operator must submit a Notice of Intent to Abandon (NIA) when preparing to abandon wells or production facilities. The NIA should include any revisions to the reclamation plan in the SUPO. The USFS reviews these changes or additions if the well is located on USFS land.

Plugging the Well

Prior to any abandonment operations, the operator must have obtained approval via the Sundry Notices and Reports on Wells, Form 3160-5. The BLM usually witnesses the plugging operations to ensure they are done properly.

All earthwork operations necessary for final reclamation should occur within six months of plugging the well, if possible. All areas of surface disturbance should be contoured to match the surrounding topography, and the original top soil should be redistributed. Native vegetation should be reintroduced once all the appropriate reclamation measures have been conducted. The methods for re-vegetation and plant species used should be determined by the surface management agency and included in the SUPO. Multiple seeding attempts may be necessary to achieve the reclamation standards set by the surface management agency.

Pit Reclamation

All reserve pits must be reclaimed to match the surrounding environment. They must be free of any hydrocarbons and trash and allowed to mostly dry before being back-filled. Any liner materials must be removed and taken to an approved landfill. Based on the reclamation plan, pits may be mounded to allow for settling and reduce the impacts of drainage.

Pipeline and Road Reclamation

When roads and pipelines are "co-located," as suggested during construction activities, it reduces the reclamation measures that must be taken. Pipelines that are above surface, buried close to the surface, or may become exposed due to water erosion must be removed by the operator. Deeply buried pipelines may be decommissioned and remain in place if authorized by the BLM and other proper authorities.

Roads should be reclaimed unless the surface management agency requests that they remain for other uses. Reclamation of roads includes returning the road surface to the natural contour of the area, introducing native vegetation, and minimizing potential erosion hazards.

Release of Bonding

The operator must file a Final Abandonment Notice (FAN) once all reclamation operations are complete and the standards set by the surface management agency are complete. Once a FAN has been submitted, the surface management agency conducts an inspection of the site to ensure that the reclamation efforts have been successful.

Individual lease bonds will be released once the final abandonment has obtained the approval of all necessary agencies. If the site was covered by a nationwide or statewide bond, it will not be released until all liabilities have been addressed.

STATE

Reclamation efforts on SITLA trust land should "meet the well site restoration requirements of the appropriate surface management agency."[21] The lease between SITLA and the operator requires the land to be returned to its pre-drilling state, or as close as possible. Release of a company bond is predicated on SITLA's approval of the reclamation effort.

Within 30 days of receiving an NIA, DOGM schedules an on-site inspection with the operator and surface management agency to determine necessary reclamation measures and what will be required for the final release of the bond. DOGM has the authority to release the bond even if the operator has not fully met the reclamation requirements in the surface use agreement.

Reclamation on SITLA trust land should be completed as quickly as possible, though circumstances may require reclamation efforts for more than a year. Reclamation goals are essentially the same as presented in the federal section. For more information on the specifics of what should be reclaimed, see the federal section.

TRIBAL

The BIA works with the BLM to approve the lessee's plan of plugging and abandonment and ensure that the lessee's reclamation plan is appropriate and successful at the end of the life of the well.[22] Requirements for complete reclamation are given in the federal section.

The BLM monitors and approves plugging of the wellbore and restoration of the surface. Final abandonment will not be approved by the BLM until the surface reclamation work required by the APD, NIA, or Subsequent Report Plug and Abandon has been completed and the required reclamation is acceptable to the BIA. The BIA ensures that the reclamation is successful, which may require several years of monitoring, and only then is the BLM released from its primary responsibility for the well.[23]

PRIVATE

Private or fee land "shall meet the well site restoration requirements of the private landowner or the minimum well site restoration requirements established by the division [DOGM]."[24] The operator is required to make a reasonable effort to establish a surface use agreement with the owner of the land prior to drilling a new well, reentering an abandoned well, or assuming operation of existing wells. Though rare, if a surface use agreement cannot be obtained, then the minimum reclamation standards are set by DOGM.

Within 30 days of receiving a NIA, DOGM schedules an on-site inspection with the operator and surface owner to determine necessary reclamation measures and what will be required for the final release of the bond. DOGM has the authority to release the bond even if the operator has not fully met the reclamation requirements in the surface use agreement.

Reclamation on private or fee land should be completed within one year if possible. ■

Chapter 6 Notes

[1] BLM *Gold Book*, p. 16.

[2] Drill pads should always be located on a flat surface. For uneven terrain, it may be necessary to construct a cut-away section that allows a flat location.

[3] See the SUPO components in the Appendix permitting section. Also see Federal Onshore Oil and Gas order No. 1 or the BLM *Gold Book* for more information.

BLM *Gold Book*, p. 21.

BLM *Gold Book*, p. 22.

[6] See BLM *Gold Book* chapter 4 for these specific requirements. The *Gold Book* is available at http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas/best_management_practices/gold_book.html.

BLM *Gold Book*, p. 30.

BLM *Gold Book*, p. 36.

[9] FracFocus (http://fracfocus.org/) is a searchable multi-state database that shows chemical composition and amount used in hydraulic fracking.

[10] Utah Administrative Code R307-205, Fugitive Dust Rule.

[11] See DOGM website: http://oilgas.ogm.utah.gov/Statistics/INSPECT_annual.cfm.

[12] BIA *Handbook*, pp. 65-6.

[13] BIA *Handbook*, p. 65.

[14] BIA *Handbook*, p. 66.

[15] The handbook may be found at http://www.onrr.gov/ReportPay/PDFDocs/ogphb3.pdf.

[16] Utah Code R59-21, Mineral Lease Account fund information http://le.utah.gov/lfa/reports/cobi2014/fundinfo/fund_1326.pdf.

[17] BIA *Handbook*, p. 77

[18] BIA *Handbook*, p. 4

[19] BIA *Handbook* p. 77

[20] BLM *Gold Book*, p. 43.

[21] Utah Code R649-3-34.

[22] BIA *Handbook*, p. 24.

[23] BIA *Handbook*, p. 2.

[24] Utah Code R649-3-34.

CHAPTER 7: INTERVIEWS & STAKEHOLDER INPUT

USU conducted interviews with private landowners, energy industry leaders, and federal, state, and local government officials to understand their experiences with and perspectives on the regulatory process, as well as to gain insight into potential improvements. Stakeholders' comments and opinions are distilled below into possible solutions to the challenges facing the development of oil and gas in Utah. The objective of this chapter is to provide information that leads to improvement of the oil and gas regulatory process.

As described in the preceding chapters, the federal regulatory process is the most complex and cumbersome. From land use to final production, the federal process can take 10 to 15 years. Operators invest significant amounts of time and capital to access the energy resources, and because the process takes years to complete, they hold an inventory of leases at various stages of the regulatory process (e.g., some just beginning, a few moving forward, others delayed or rejected).

One suggestion made frequently during stakeholder interviews is that since state processes are more efficient, the federal government might reasonably delegate to the states its authority to process permits, conduct inspections, and oversee compliance. Since precedent exists with the EPA for this type of deputation, interviewees suggested legislative reform to accomplish similar delegations of authority for oil and gas activities.

Photo courtesy of Howard Shorthill, USU

Challenges and Opportunities

During their interviews, stakeholders identified key challenges and encouraged several improvements to the regulatory framework in Utah. Most concerns focused on the federal process due to its dominant presence, but some state and local issues were also addressed.

1. The federal regulatory framework is highly complex, time consuming, and costly. All respondents agree that protecting the environment is vital, but the increasingly burdensome regulatory framework may limit flexibility in achieving environmental protection goals that could be accomplished through more innovative and efficient management practices.

Possible Solution to Challenge 1

States could be given full control to manage energy resources within the state regulatory framework. One proposal includes congressional action, such as legislation sponsored by Senator Jim Inhofe. The Federal Land Freedom Act of 2013 would authorize a state to establish a program for leasing and permitting regulatory requirements on federal lands. Under the Act, state programs would be required to satisfy applicable requirements of federal laws and regulations for NEPA, ESA, and NHPA. It would also prohibit drilling in National Parks, National Wildlife Refuges, and congressionally designated wilderness areas.

2. The timeframe for policy changes at the federal level is not compatible with the oil and gas industry's business planning processes. Great uncertainty regarding federal rules changes hinders industry evolution.

Possible Solution to Challenge 2

The Utah Public Lands Initiative, spearheaded by Congressman Rob Bishop, is another proposal to deal with these challenges. According to Congressman Bishop, the Initiative seeks to strike "a real balance between conservation and responsible development, and to establish greater certainty about the way our public lands may be used." Bishop is including participation from stakeholders across the landscape, including federal, state, county officials, conservation groups, industry, and the public.

3. The BLM's 2010 leasing reform policy is viewed as a "political tool" rather than an improvement to the leasing process. Environmental review and analysis already occur during land use planning, and they occur again during leasing, and again before APDs are issued. Some believe the 2010 leasing reform adds an unnecessary step and is outside the scope of regulatory authority. The reform was intended to reduce public protest, but instead may have had the opposite effect.

Possible Solution to Challenge 3

The Utah Transfer of Public Lands Act is state legislation signed into law that would transfer certain federal lands back into state ownership. The law is based on historic federal land policy in place at the time of Utah's statehood.

4. Many regulatory requirements overlap or are duplicated by federal and state governments. For example, a rule regulating hydraulic fracturing already exists at the state level, and many stakeholders feel that federal plans to further regulate hydraulic fracturing are duplicative and unnecessary.

Possible Solution to Challenge 4

Developing legislation that would give states the authority for oil and gas permitting and compliance activities on both federal and state jurisdictions. States have been delegated the authority for other federal responsibilities. Allowing states the authority to issue all permitting and compliance requirements for oil and gas activities can address timeliness and efficiency.

5. The BLM's Resource Management Plans have become so prescriptive as to limit operational flexibility.

Possible Solution to Challenge 5

Land exchanges have already occurred and have helped achieve federal and state priorities. The recent land exchange between SITLA and the federal government resulted in the state acquiring a number of energy-rich lands held previously by the federal government in exchange for lands the federal government was seeking for conservation purposes.

6. Energy resources in Utah face access problems that limit development.

Three Possible Solutions to Challenge 6

6.1 The state legislature established the Uintah Basin Energy Zone in Daggett, Uintah, and Duchesne counties to maximize "efficient and responsible development of energy and mineral resources." The designation calls for a cooperative management approach among all governmental entities to achieve production goals in the zone. A cooperative and collaborative approach is key to a predictable and efficient path for energy and mineral development. (http://le.utah.gov/~2012/bills/static/sb0083.html).

6.2 The Governor's 10-year energy strategy includes several recommendations that address energy resource access and acknowledge and support research universities and regional colleges, the energy industry, and other technical and scientific entities. Technological innovation and application ensure ongoing environmentally responsible development of energy resources. In the Uintah Basin, Utah State University's Bingham Research Center is the leader in comprehensive ongoing environmental studies and instrument development for enhanced monitoring, data collection, and computer modeling. (http://energy.utah.gov/download/reports/10%20Year%20Strategy_2.0_03042014.pdf).

6.3 A recent Utah Department of Transportation report considers energy resource infrastructure in the Uintah Basin, particularly "(1) whether the volume of Uinta Basin oil and gas production in Duchesne and Uintah counties over the next three decades is likely to be constrained by limitations in the capacity of transportation infrastructure; and (2) the economic costs associated with lost oil and gas production due to any such constraints." Transportation infrastructure is a consideration vital to the overall strategic planning process for long term energy production and business goals. (http://www.utssd.utah.gov/documents/ubetsreport.pdf).

7. Litigation dramatically increases the time and expense required for federal decision making.

Possible Solution to Challenge 7

Potential abuses of the litigation process could be analyzed to verify the integrity of the Equal Access to Justice Act. Reforming processes for legal recourse will likely require legislative action.

8. Local federal land managers lack authority, resources, and personnel to review proposed energy projects in a timely manner.

Possible Solution to Challenge 8

The Energy Pilot Offices, which were established by the 2005 Energy Policy Act, should be permanent to reduce permitting backlogs. As of December, 2014, legislation was signed into law to make this program permanent. These offices were established to add additional personnel to BLM offices that manage major energy activities. Additionally, the pilot offices were designed to enhance coordination among all the agencies responsible for reviewing and approving permits. The BLM field office in Vernal is a designated pilot office.

9. Split Estate issues create conflicts between surface and subsurface land owners.

Three Possible Solutions to Challenge 9

9.1 Surface land owners should be educated about their rights and the rights of the subsurface mineral owner. Successful negotiation of a surface owner agreement is key, but an enforcement mechanism is likely necessary to ensure compliance throughout the period of surface land use.

9.2 Ongoing collaboration between surface land owners and subsurface mineral owners is key to minimizing conflicts. Understanding the concerns of each party is critical. State legislation and local ordinances have been passed to address conflicts in split estate cases.

9.3 The Utah Surface Owner Protection Act was signed into law in 2012. The law requires a surface use agreement to be negotiated by the surface land owner and the oil and gas operator. The agreement addresses use and reclamation of surface land and stipulates compensation for damages, both interim and permanent, of the oil and gas operations. Recent federal policy also addresses this concern, and other states have passed laws similar to Utah's.

10. Revenue to mitigate impacts from oil and gas operations is often lacking at the local level. Local governments receive a portion of the revenue generated from federal mineral estates, but in counties with few exploitable federal minerals but abundant private and/or

tribal minerals, revenue to mitigate impacts may be inadequate to address local needs such as road repair and other public services.

Possible Solution to Challenge 10

State and local officials and legislative representatives could explore legislative options and opportunities to address shortfalls in communities that have inadequate revenue to mitigate impacts from oil and gas operations.

11. Public policy goals in oil and gas producing communities are often at odds with the goals of urban communities or of the state as a whole.

Four Possible Solutions to Challenge 11

11.1 Greater collaboration between rural and urban communities could occur through existing meetings and conferences.

11.2 A targeted, locally-based collaborative group could be established that would include representatives from local, tribal, state, and federal governments, and also include industry and other stakeholders. This group could discuss and develop solutions for conflicts in each entity's policy agenda.

11.3 Utah's energy zone legislation "calls upon Congress to establish an intergovernmental standing commission among federal, state, and local governments to guide and control planning decisions and management actions in the Uintah Basin Energy Zone in order to achieve and maintain the goals, purposes, and policies [set forth for the Zone]."

11.4 Utah State University has a mandate to serve in the Uintah Basin and can convene county, state, tribal, private, and industry stakeholders to strategize action around energy interests and other issues of concern. Small-scale collaboration that addresses broader issues of common interest may be able to facilitate progress on contentious issues in ways that larger forums cannot.

APPENDIX

Air Conservation Act (ACA) – State only

WHAT IS THE ACA?

Utah was delegated the authority to regulate air quality in accordance with the federal CAA. The ACA sets up the Air Quality Board, the state's primary policy-making body in air quality.

WHY IS THE ACA IMPORTANT?

The Air Quality Board sets the acceptable air contaminant limits, air quality standards, emissions control regulations, reparations for violation of air quality regulations, and enforcement standards.[1] Regulations adopted by the Board are located in Utah Administrative Code R30. Regulations specific to the oil and gas industry are located in R307-500 series. Air operating permits, or approval orders, are issued through the DAQ in accordance with the federal CAA for federal, state, and private land within Utah.[2]

An operator emitting any air contaminant source must submit reports to DAQ to demonstrate the source is in compliance with federal and state air regulations.[3] Local political authorities (county, city, etc.) may enact and enforce ordinances within their jurisdiction that are consistent with the ACA. It is through the DAQ that the air requirements set by the EPA and the CAA are met on federal, state, or private land. The Air Quality Board may adopt new requirements as part of a State Implementation Plan (SIP) to attain or maintain any national ambient air quality standards (NAAQS).

The Antiquities Act Air

WHAT IS THE ANTIQUITIES ACT?

The Antiquities Act gives the President of the United States authority to set aside for protection"...historic landmarks, historic and prehistoric structures, and other objects of historic or scientific interest that are situated upon the lands owned or controlled by the Government of the United States," including tribal lands.[4]

WHY IS THE ANTIQUITIES ACT IMPORTANT?

The Antiquities Act can lead to restrictions to development in national monuments. This law impacts oil and gas development when the President designates an area as a national monument. National monument designation will result in no development activities except if existing valid rights exist and if those rights are not purchased or exchanged.

Archaeological Resource Protection Act (ARPA)

WHAT IS ARPA?

The ARPA is the federal regulatory framework mandating the protection and preservation of archaeological and cultural resources on federal land.

WHY IS ARPA IMPORTANT?

The ARPA is responsible for archaeological and cultural resource analyses conducted for resource management planning (RMP), NEPA analyses, and in pre-lease assessments. During the APD process, archaeological assessments are conducted to determine whether any artifacts or cultural resources are present on a proposed oil or gas development site. If archaeological or cultural resources or artifacts are discovered during development, the ARPA lays out the required steps to excavate and/or protect the artifacts or resources.

Photo courtesy of Jordan Evans, USU

Clean Air Act (CAA)

WHAT IS CAA?

The CAA is a federal law that regulates the discharge of pollutants into the air. The EPA is the lead regulatory authority for the CAA, but the EPA usually delegates the authority for compliance under the CAA to state agencies and can delegate that authority to Indian Tribes. The State of Utah's Division of Air Quality (DAQ) is charged with the responsibility to issue rules associated with air quality standards and other vital requirements to ensure compliance for land outside of tribal lands and Indian country.

WHY IS THE CAA IMPORTANT?

Programs that originate from the CAA and are applicable to oil and gas development include National Emission Standards for Hazardous Air Pollutants (NESHAP), New Source Performance Standards (NSPS), New Source Review (including Tribal New Source Review), and related operating permits.

The programs and standards of the CAA and associated rules require developers to obtain permits and meet environmental standards for equipment and processes. Air quality analyses are included in the NEPA analyses through the oil and gas leasing and development processes; including RMP development, pre-leasing analysis, and site-specific inspections.[5]

Clean Water Act (CWA)[6]

WHAT IS THE CWA?

The CWA is a regulatory framework for protecting the surface waters of the United States. The EPA is the lead regulatory authority for the CWA, has delegated authority to the Utah Department of Environmental Quality Division of Water Quality (DWQ) to ensure that Utah's surface waters meet the expectations set by the EPA and CWA.

WHY IS THE CWA IMPORTANT?

The CWA applies to point sources and non-point sources of water pollution. Point sources are discreet conveyances such as any pipe or man-made ditch that leads to surface waters, except for irrigation return flow which is exempt (Public Law 92-500, as amended). Non-point sources are all other sources not designated as point sources (i.e. rain runoff).

Oil and gas production facilities are usually exempt from the National Pollutant Discharge Elimination System (NPDES) permitting process. The two exceptions are: 1) when the facility has a spill of reportable quantity that could contaminate surface waters; or 2) if the storm water runoff violates water quality standards. If oil and gas development takes place in wetlands, then it is also subject to additional CWA regulations and permits. All oil and gas facilities are subject to Spill Prevention Control and Countermeasures (SPCC) regulations and must have site-specific spill prevention plans that meet the CWA standards.

Endangered Species Act (ESA)

WHAT IS ESA?

The ESA is a regulatory requirement that impacts uses of the federal, tribal, state and private lands. It was designed to protect and recover critically imperiled species from extinction.

WHY IS ESA IMPORTANT?

The ESA is administered by two federal agencies, the U.S. Fish and Wildlife Service (FWS) and the Commerce Department's National Marine Fisheries Service (NMFS). The ESA requires agencies to consult with FWS to ensure that the potential effects of actions they authorize, fund, or carry out are not likely to jeopardize the continued existence of listed species. During consultation an agency will receive a biological opinion (BO) from the FWS addressing the proposed action. If the FWS makes a jeopardy determination (meaning the proposed action could jeopardize an endangered species or its critical habitat), the proposing agency is required to offer reasonable and prudent alternatives that would minimize jeopardy.

The ESA also requires the designation of critical habitat for listed species when "prudent and determinable."[7] Critical habitat includes areas that contain essential physical or biological features for conservation of the species that may need special management or protection. Critical habitat designations affect Federal agency actions or federally funded or permitted activities.

Numerous plant and animal species occupy lands where oil and gas activity occurs and, if the species are not imperiled no regulatory actions are triggered. However, if the species are imperiled certain regulatory actions are initiated. For example, the Greater Sage-Grouse inhabits Utah and other western states. The FWS has issued a decision that the Greater Sage-Grouse should be protected under the ESA, but the agency has "determined that proposing the species for protection is precluded by the need to take action on other species facing more immediate and severe extinction threats."[8]

In the interim, agencies and others affected by the pending determination of the species undertake efforts to identify conservation measures that may prevent their permanent listing. For example, the BLM and the USFS are preparing an EIS to "address the effects of implementing proposed Greater Sage-Grouse conservation measures" on the lands they manage.[9] The decisions from this NEPA process will impact oil and gas activity on lands that are home to Greater Sage-Grouse.

Endangered Species in Utah

Common Name	Status	Counties Affected
Autumn Buttercup	E	Garfield
Barneby Reed-mustard	E	Emery, Wayne
Barneby Ridgecress	E	Duchesne
Black-Footed Ferret	EE	Most Counties
Bonytail	E	Carbon, Emery, Garfield, Grand, San Juan, Uintah, Wayne
California Condor	EE	Visits Southern Utah
Canada Lynx	T	Daggett, Duchesne, Summit, Uintah, Wasatch [*Cache, Morgan, Rich, Salt Lake, Utah, Weber*]*
Clay Phacelia	E	Utah
Clay Reed-mustard	T	Uintah
Colorado Pike Minnow	E	Carbon, Daggett, Emery, Garfield, Grand, San Juan, Uintah, Wayne
Coral Pink Sand Dunes Tiger Beetle	C	Kane
Deseret Milkvetch	T	Utah
Desert Tortoise	T	Washington
Dwarf Bearclaw-poppy	E	Washington
Frisco Buckwheat	C	Beaver
Frisco Clover	C	Beaver, Millard
Gierisch Mallow	C	Washington
Goose Greek Milkvetch	C	Box Elder
Graham Beardtongue	TP	Carbon, Duchesne, Uintah
Gray Wolf	E	All Counties
Greater Sage-Grouse	C	All Counties
Grizzly Bear	TX	All Counties
Gunnison Sage-Grouse	C	Grand, San Juan
Heliotrope Milkvetch	T	Sanpete, Sevier
Holmgren Milkvetch	E	Washington
Humpback Chub	E	Carbon, Emery, Garfield, Grand, San Juan, Uintah, Wayne
Jones Cycladenia	T	Emery, Garfield, Grand, Kane
June Sucker	E	Utah, Box Elder, Salt Lake, Weber

Common Name	Status	Counties Affected
Kanab Amber Snail	E	Kane
Kodachrome Bladderpod	E	Kane
Lahontan Cutthroat Trout	T	Box Elder
Last Chance Townsendia	T	Emery, Sevier, Wayne
Least Chub	C	Box Elder, Davis, Iron, Juab, Millard, Salt Lake, Tooele, Utah
Maguire Primrose	T	Cache
Mexican Spotted Owl	T	Emery, Garfield, Iron, Kane, San Juan, Washington, Wayne
Navajo Sedge	T	San Juan
Niles' Wild Buckwheat	C	Kane, Washington
Ostler Peppergrass	C	Beaver
Pariette Cactus	T	Duchesne, Uintah
Razorback Sucker	E	Carbon, Emery, Garfield, Grand, San Juan, Uintah, Wayne
Relict Leopard Frog	C	Washington
San Rafael Cactus	E	Emery, Wayne
Shem Milkvetch	E	Washington
Shrubby Reed-mustard	E	Duchesne, Uintah
Siler Pincushion Cactus	T	Kane, Washington
Southwestern Willow	E	Kane, San Juan, Washington
Uinta Basin Hookless Cactus	T	Carbon, Duchesne, Uintah
Utah Prairie-Dog	T	Beaver, Garfield, Iron, Kane, Millard, Piute, Sanpete, Sevier, Wayne
Ute Ladies'-tresses	T	Daggett, Duchesne, Juab, Garfield, Tooele, Uintah, Utah, Wasatch, Wayne
Virgin Chub	E	Washington
Welsh's Milkweed	T	Kane
White River Beardtongue	C	Uintah
Whooping Crane	EX	Passed through Eastern Utah
Winkler Pincushion Cactus	T	Emery, Wayne
Woundfin	E	Washington
Wright Fishhook Cactus	E	Emery, Sevier, Wayne
Yellow-billed Cuckoo	C	All Counties

T = Threatened, E = Endangered, C = Candidate, EE = Endangered Experimental, X = Extirpated.
[*] = Potential affected counties.

Federal Oil and Gas Royalty Management Act (FOGRMA) – Federal Only

WHAT IS FOGRMA?

FOGRMA is an amendment to the MLA that overhauled how royalties are managed from federal oil and gas leases as well has granting the BLM greater authority in monitoring and inspecting the accuracy of production reports, the reports from the operator detailing the amount of oil or gas recovered.

WHY IS FOGRMA IMPORTANT?

FOGRMA creates the criteria for evaluating, collecting, and auditing royalties from oil and gas development. During the life of a well, royalties are paid based on the FOGRMA. There are also reporting and accounting regulations set by FOGRMA.

Federal Onshore Oil & Gas Leasing Reform Act (FOOGLRA)[10] - Fed Only

WHAT IS FOOGLRA?

The Federal Onshore Oil and Gas Leasing Reform Act (FOOGLRA) is an amendment to the MLA that was passed to reform the leasing process for oil and gas on federal lands.

WHY IS FOOGLRA IMPORTANT?

There are two major components of FOOGLRA. First, it mandates that all federal lands be offered through a competitive process before non-competitive offers can be accepted. This was designed to eliminate unethical practices in leasing federal land. Second, FOOGLRA includes the USFS in the planning, leasing, and oversight processes for oil and gas production on USFS land. BLM still administers leases on the land, but with much greater input from and cooperation with the USFS than existed before.

FOOGLRA mandates competitive leasing for oil and gas development on federal land. Also, USFS now designates which areas are open for oil and gas development as part of their land use plans. They also may attach surface stipulations to the lease, regulate surface use, and set reclamation standards. The USFS must approve the Surface Use Plan of Operations (SUPO) for any application for permit to drill (APD) located on USFS land.

Indian Mineral Development Act (IMDA)[11] - Tribal Only

WHAT IS THE IMDA?

The Indian Mineral Development Act of 1982 (IMDA) gives tribes the ability to negotiate directly with companies. It empowers tribal governments to issue leases, or other production or exploration activities, for oil and gas. Any federal regulations that are applicable to Indian lands are administered by the Bureau of Indian Affairs.

WHY IS IMDA IMPORTANT?

The IMDA empowers tribal and individual Indian mineral owners to develop their energy resources according to their interests and provides for a systematic approach to achieve economic and cultural goals.

The IMDA outlines specific roles and responsibilities for each tribal and federal agency responsible for leasing and Exploration and Development Agreements (EDAs). An EDA is an agreement between an Indian tribe and an energy company to develop tribal land. IMDA requirements for the tribe, the BIA and the BLM to follow throughout the leasing, exploration and development processes. Within the confines of IMDA each tribe is free to create its own development process. The Ute Indian Tribe, through its Office of Energy and Minerals, has a specific outline for each of these steps.

Mineral Leasing Act (MLA)[12] - Federal Only

WHAT IS THE MLA?

Enacted in 1920 to replace the General Mining Act of 1872, the Mineral Leasing Act (MLA) provided a framework by which exploration, leasing, permitting, and production of oil and gas is regulated by BLM.

WHY IS THE MLA IMPORTANT?

The MLA provides the legal foundation for all oil and gas leasing on federal land. It is applicable to all federal lands open for oil and gas development, regardless of which agency owns the land. It sets the procedure for nominating lands for development, how lands are auctioned, and what stipulations are associated with leasing of lands. While additional regulations have altered the process, MLA is the foundation of the process. The MLA establishes the competitive lease process that is used for all federal oil and gas leases today.

It also sets the royalty rate at 12.5% of production value for most leases. It also provides the base legal authority for the BLM to regulate the exploration for, production of, and reclamation of oil and gas well sites on federal land.

National Historic Preservation Act (NHPA)

WHAT IS NHPA?

The NHPA governs the protection of cultural and historic resources in the United States.

WHY IS NHPA IMPORTANT?

The NHPA adds requirements for the oil and gas developer if the well is located on culturally or historically sensitive land. Under the NHPA Section 106 review process, federal agencies are required to consider whether actions such as oil and gas development operations on lands they manage will adversely affect cultural or historic resources. They are required to work with appropriate federal, state and tribal entities prior to approval of a project.[13]

Native American Graves Protection & Repatriation Act (NAGPRA) – Federal Only

WHAT IS NAGPRA?

The NAGPRA is an additional federal law dealing specifically with the protection of Native American cultural artifacts. It requires federal agencies and institutions that receive federal funding to return Native American cultural items to descendants and culturally affiliated Native American tribes. Cultural items include human remains, funerary objects, sacred objects, and objects of cultural patrimony.

WHY IS NAGPRA IMPORTANT?

The NAGPRA adds responsibilities for the oil and gas developer if the well is on Tribal land or non-Tribal land but culturally sensitive. The NAGPRA requires entities to report any Native American cultural items found on federal or tribal lands. For example, if cultural items are found during oil and gas exploration and development operations, the requirement to report the items found applies. While these provisions do not apply to discoveries or excavations on private or state lands, the collection provisions of the Act may apply to Native American cultural items if they come under the control of an institution that receives federal funding.

Onshore Oil and Gas Order #1 – Federal Only

WHAT IS ONSHORE ORDER NO. 1?

This order is an official rule originally published by the BLM in 1983. It has since been amended by FOOGLRA and the Energy Policy Act of 2005. The most recent version was published in 2007.[14]

WHY IS ONSHORE ORDER NO. 1 IMPORTANT?

Onshore Order No. 1 sets the process and requirements for oil and gas development on federal lands, including Tribal and USFS land. Onshore Oil and Gas Order No. 1 provides rules for drilling and construction operations, and regulations pertaining to reclamation. It also includes the requirements for a federal APD and the process of APD approval.

Safe Drinking Water Act (SDWA)[15]

WHAT IS THE SDWA?

The SDWA is a federal law that protects the water quality of surface water and underground aquifers that are drinking water sources.

WHY IS THE SDWA IMPORTANT?

The Underground Injection Control (UIC) program is under the SDWA. This program is responsible for regulating the construction, operation, permitting, and closure of injection wells that place fluids underground for storage or disposal. Also, geologic sequestration (GS), which is the process of injecting carbon dioxide (CO2) from a source through a well into the deep subsurface, has been the subject of regulatory action.

The UIC program has requirements for permitting, construction, operation, and plugging of injection wells. These requirements include cementing and casing standards, periodic inspections to ensure mechanical integrity, and specific plugging and abandonment practices. The EPA has delegated the permitting of Class II injection wells to DOGM, except for those in Indian country which EPA regulates. There are three types of Class II injection wells: 1) Enhanced Recovery Wells which inject brine, water, steam, polymers, or carbon dioxide into oil-bearing formations to recover residual oil, and in some limited applications, natural gas; 2) Disposal Wells inject brines and other fluids associated with the production of oil and natural gas or natural gas storage operations; and 3) Hydrocarbon Storage Wells which inject liquid hydrocarbons in underground formations (such as salt caverns) where they are stored, generally, as part of the U.S. Strategic Petroleum Reserve.

School & Institutional Trust Lands Management Act[16] - State Only

WHAT IS THE SCHOOL AND INSTITUTIONAL TRUST LANDS MANAGEMENT ACT?

This act created SITLA and established its administration and regulatory procedures. It provides the processes by which oil and gas leasing can be done through SITLA. SITLA's purpose is to act as trustee for their beneficiaries and to administer trust assets for the financial support of the beneficiaries. Approximately 96% of the revenue SITLA receives is deposited into the Permanent State School Fund for the benefit of K-12 education.

WHY IS THE SCHOOL & INSTITUTIONAL TRUST LANDS MANAGEMENT ACT IMPORTANT?

The School and Institutional Trust Lands Management Act is important because the dividends and interest of the Permanent School Fund are distributed to each school based on a state formula. The funds the schools receive are discretionary and allows schools to best meet the needs of their students.

SITLA leases school trust lands for oil and gas development among other uses. This act provides the process by which leases, both competitive and non-competitive, are granted. In addition, it details how revenues are allocated and distributed, what activities are allowed on trust lands, and provides the authority for land swaps to occur.

Utah Administrative Code R649[17] – State Only

WHAT IS CODE R649?

R649 is the administrative rule that prescribes the acceptable practices for oil and gas development in the state of Utah.

WHY IS CODE R649 IMPORTANT?

It covers all activities from the drilling of the well through reclamation. This section of the Utah Code regulates all applicable oil and gas activities, when developing an APD and throughout the life of the well. The APD that is submitted must be in compliance with the rules set forth in R649.

Utah Oil and Gas Conservation Act (Title 40-6)[18] – State Only

WHAT IS THE UTAH OIL AND GAS CONSERVATION ACT?

This act creates the Board of Oil, Gas, and Mining which is the policy making body over the Utah Division of Oil, Gas, and Mining (DOGM).

WHY IS THE UTAH OIL AND GAS CONSERVATION ACT IMPORTANT?

It is the legal authority for oil and gas development in Utah. It establishes the processes for exploration, permitting, and production. Section 9.5 provides the regulatory authority for DOGM to issue APDs for wells within the state of Utah. An APD must be submitted to and approved by DOGM regardless of land ownership.

Water Quality Act (WQA)– State only

WHAT IS THE WQA?

The WQA created the Water Quality Board to serve as the primary rule-makers regarding water quality in Utah. The state was delegated authority by EPA to ensure compliance with federal water legislation.

WHY IS THE WQA IMPORTANT?

The Water Quality Board ensures that Utah adequately implements the regulations necessary to comply with the CWA and the SDWA. The DEQ has regulatory authority for water permits, such as discharge permits, for all land and water in Utah, except on tribal land. The EPA delegated authority to the DOGM to regulate Class II injection wells which are used in oil and gas development.

National Environmental Policy Act (NEPA)

The BLM issued the NEPA Handbook (H-1790-1) to provide instructions for complying with the CEQ NEPA regulations. The handbook describes the following process for completing a decision in accordance with NEPA (the following is taken directly from the handbook):

1. Scoping the EIS

a. Publish a Notice of Intent in the Federal Register
b. Develop a preparation plan
c. Develop a strategy for public involvement and interagency/intergovernmental coordination and consultation
d. Define the proposed action
e. Identify the purpose and need, alternatives to be considered and impacts to be analyzed
f. Identify information and data needs
g. Identify cooperating agencies
h. Determine contracting needs
i. Determine staffing and budget needs and proposed schedule

2. Conduct the analysis and prepare the Draft EIS

a. Conduct the analysis
b. Select the preferred alternative
c. Prepare a Preliminary Draft EIS
d. Complete the Draft EIS

3. Issue the Draft EIS

a. Print the Draft EIS
b. File with EPA
c. Publish a Notice of Availability of the Draft EIS for review
d. Distribute the Draft EIS
e. Hold public meetings/hearings

4. Analyze comments and prepare the Final EIS

a. Evaluate and respond to public comments
b. Prepare a Preliminary Final EIS
c. Reevaluate and revise the preferred alternative or proposed action

5. Issue the Final EIS (publish a notice of action if actions have effects of national concern)

6. Reach and record the decision

a. Evaluate public comments
b. Document the decision
c. Publish an NOA regarding the availability of the Record of Decision[19]

Categorical Exclusion

Section 390 of the Energy Policy Act of 2005[20] provides circumstances which would qualify APDs for a categorical exclusion from a NEPA analysis:

1. Individual surface disturbances of less than 5 acres so long as the total surface disturbance on the lease is not greater than 150 acres and site-specific analysis in a document prepared pursuant to NEPA has been previously completed.
2. Drilling an oil or gas well at a location or well pad site at which drilling has occurred previously within 5 years prior to the date of spudding the well.
3. Drilling an oil or gas well within a developed field for which an approved land use plan or any environmental document prepared pursuant to NEPA analyzed such drilling as a

reasonably foreseeable activity, so long as such plan or document was approved within 5 years prior to the date of spudding the well.

4. Placement of a pipeline in an approved right-of-way corridor, so long as the corridor was approved within 5 years prior to the date of placement of the pipeline.
5. Maintenance of a minor activity, other than any construction or major renovation or a building or facility.

Components of an APD

1. Form 3160-3, Application for Permit to Drill or Reenter

This form is obtained from the BLM and provides basic information about the proposed well. Information includes but is not limited to the lease information, the location of the well, whether it is a request for new drilling or reentry, spacing information, estimated depth, and distance from property boundaries. Form 3160-3 is submitted after all other parts of the APD have been submitted.

2. Certified Well Plat

A well plat and associated geospatial database are required as part of the APD submittal. The well plate must be produced by a registered surveyor who signs off on the accuracy of the information. The well plat includes the geospatial coordinates and shows the proposed location of the well in conjunction with the boundaries of the lease, which is done to ensure that the proposed operations are within the boundaries of the lease.

3. Drilling Plan

The drilling plan provides the technical details about how the proposed wells would be drilled, casing and cement program, and what protections would be in place to prevent blow outs and other potential problems. OOGO No. 1 provides the guidelines for what to include in a drilling plan. There are 9 components to a complete drilling plan: a) names and estimated tops of all geologic groups, formations, members, or zones; b) estimated depth and thickness of formations, members, or zones potentially containing usable water, oil, gas, or prospectively valuable deposits of other minerals that the operator expects to encounter; c) the operator's minimum specifications for blowout prevention equipment and diverter systems to be used, including size, pressure rating, configuration, and the testing procedure and frequency; d) the operator's proposed casing program, including size, grade, weight, type of thread and coupling, the setting depth of each string, and its condition; e) the estimated amount and type(s) of cement expected to be used in the setting of each casing string; f) type and characteristics of the proposed circulating medium or mediums proposed for the drilling of each well bore section; g) the testing, logging, and coring procedures proposed, including drill stem testing procedures, equipment, and safety measures; h) the expected bottom-hole pressure and any anticipated abnormal pressures, temperatures, or potential hazards that the operator expects to encounter; and i) any other facets of the proposed operation that the operator would like the BLM to consider in reviewing the application

The more specific the drilling plan is, the more likely it would be approved. The operator submitting an APD is not always the same operator who ends up drilling the well. With this being the case, the drilling plan should have enough information so the new operator could use the APD's drilling plan to drill the well. Any part of the drilling that may differ from conventional industry practices should be fully explained.

A field-wide drilling plan may be submitted if drilling procedures would be the same for multiple wells. If this is the case, the drilling plan portion of an APD may reference the approved field-wide drilling plan.

4. Surface Use Plan of Operations

The SUPO is one of the more complex pieces of the APD. The OOGO No. 1 states that a SUPO must:

> Describe the access road(s) and drill pad, the construction methods that the operator plans to use, and the proposed means for containment and disposal of all waste materials; Provide for safe operations, adequate protection of surface resources, groundwater, and other environmental components; Include adequate measure for stabilization and reclamation of disturbed lands; Describe any best management practices (BMPs) the operator plans to use; Where the surface is privately owned, include a certification of Surface Access Agreement or an adequate bond.[21]

Operators must provide information about existing roads, plans for new roads or facilities, location of existing or planned wells, what building materials would be used, plans for how waste would be disposed of, and a reclamation plan that includes interim reclamation measures as well as the final reclamation. A SUPO contains appropriate maps, including a topographical map showing the locations of existing and planned roads, wells, buildings, facilities and may contain other surface occupancy information provided.

A key portion of the SUPO is the reclamation plan. A reclamation plan must include plans to re-contour the well pad and other disturbances to blend in with the natural landscape. Operators should stockpile and seed the excavated topsoil so that it may be used in interim reclamation efforts. Plans for the backfilling and closing of any pits, drainage ditches, or other disturbances must be included along with native vegetation re-seeding. SUPOs for the USFS lands are approved by the USFS, however drilling plans, approving all downhole operations are approved by the BLM.

5. Evidence of Bond Coverage

The APD must provide proof of adequate bond coverage (in the operator's name or the lessee's or sub-lessee's name). A bond is required for all oil and gas drilling and/or production on federal land. Additional bond amounts may be required by other federal or state agencies in addition to the BLM amount. For example, if the lease is on USFS land then the operator may be subject to bonds by both BLM (plugging and abandonment) and Forest Service (surface disturbance/pit closure). Bonds for leases on Indian land are subject to different regulations.

When determining the bond amount, BLM takes into account the history of bond violations by the operator, location and depth of wells, number of wells, producing capability of the field, and any unique environmental features or situations that could require additional bond coverage.[22]

6. Operator Certification and Signature

The operator and field representative must include their names along with contact information with the APD. The operator must provide a signed certification to be approved by BLM.

7. On-Site Inspection

If an on-site inspection has not already been conducted through a Notice of Staking (NOS), one is necessary for an APD to be considered complete. Within ten days of the submission of an APD, the BLM would set up an on-site inspection with the operator and surface management agency and/or owner. This would be scheduled as soon as is possible based on the schedules of those involved and weather conditions.

The purpose of an on-site inspection is to identify potential resource impacts from the proposed action that may require mitigation and attaching appropriate stipulations and/or conditions of approval (COAs) to the APD. Information gathered during the on-site inspection would be used when reviewing and approving the APD.

8. Other information required by regulation, rule, or notice

Information in addition to the above components may be required by BLM in order for an APD to be considered complete. This information may vary based on the location of the lease, or whether state, local, or tribal regulations are required. Identification of issues can be facilitated through early meetings with BLM and other involved agencies.

Components of a Drilling Plan

The following provides more information on the components of a Drilling Plan. Below are the exact descriptions provided in the Onshore Oil and Gas Order No 1, provided verbatim to preserve the technical integrity of each section.

Formation Tops - Names and estimated tops of all geologic groups, formations, members, or zones.

Resource Zones - Estimated depth and thickness of formations, members, or zones potentially containing usable water, oil, gas, or prospectively valuable deposits of other minerals that the operator expects to encounter, and the operator's plans for protecting such resources.

Pressure Control - The operator's minimum specifications for blowout prevention equipment and diverter systems to be used, including size, pressure rating, configuration, and the testing procedure and frequency. Blowout prevention equipment must meet the minimum standards outlined in Order 2.

Casing - The operator's proposed casing program, including size, grade, weight, type of thread and coupling, the setting depth of each string, and its condition. The operator must include the minimum design criteria, including casing loading assumptions and corresponding safety factors for burst, collapse, and tensions (body yield and joint strength). The operator must also include the lengths and setting depth of each casing when a tapered casing string is proposed. The hole size for each well bore section of hole drilled must be included. Special casing designs such as the use of coiled tubing or expandable casing may necessitate additional information.

Cement - The estimated amount and type(s) of cement expected to be used in the setting of each casing string. If stage cementing will be used, provide the setting depth of the stage tool(s) and amount and type of cement, including additives, to be used for each stage. Provide the yield of each cement slurry and the expected top of cement, with excess, for each cemented string or stage.

Circulating Medium - Type and characteristics of the proposed circulating medium or mediums proposed for the drilling of each well bore section, the quantities and types of mud and weighting material to be maintained, and the monitoring equipment to be used on the circulating system. The operator must submit the following information when air or gas drilling is proposed:

- Length, size, and location of the blooie (flow) line, including the gas ignition and dust suppression systems;
- Location and capacity of the compressor equipment, including safety devices, describe the distance from the well bore, and location within the drill site; and
- Anticipated amounts, types, and other characteristics as defined in this section, of the stand by mud or kill fluid and associated circulating equipment.

Testing, Coring, Logging - The testing, logging, and coring procedures proposed, including drill stem testing procedures, equipment, and safety measures.

Pressure and Temperatures - The expected bottom-hole pressure and any anticipated abnormal pressures, temperatures, or potential hazards that the operator expects to encounter, such as lost circulation and hydrogen sulfide (see Order 6 for information on hydrogen sulfide operations). A description of the operator's plans for mitigating such hazards must be included.

Miscellaneous Items - Any other facets of the proposed operation that the operator would like the BLM to consider in reviewing the application. Examples include, but are not limited to:

- Directional wells, proposed directional design, plan view, and vertical section in true vertical and measured depths;
- Horizontal drilling; and
- Coil tubing operations

Surface Use Plan of Operations (SUPO)

A complete SUPO consists of twelve components: existing roads, new or reconstructed access, location of existing wells, location of existing or proposed production facilities, location and type of water, construction materials, methods for handling of waste, ancillary facilities, well site layout, any plans for surface reclamation, surface ownership, and other information. The following can be shown on individual maps or combined onto single map as long as the required information is listed and designations are made.

Existing Roads - A map showing existing roads that provide access to the well or lease site in relation to a public reference point such as a town. The operator is responsible for ensuring that the existing roads remain in comparable or better condition than before drilling began. Please see BLM RMPs on how to maintain or improve existing roads.

New or Reconstructed Access - A map must also be submitted showing all proposed roads on the lease. Any bridges, culverts, low bridge crossings, etc for existing or proposed roads need to be noted as well as the length of the roads to the well site. If new roads are being constructed, information on the materials, maximum grade, width, turnouts, drainage ditches, reclamation plan, and fence cuts need to be included.

Location of Existing Wells - A map, and geospatial database if possible, that shows all wells (regardless of status) within a one mile radius of proposed well location.

Location of Existing or Proposed Production Facilities - A map showing the location of any facilities or lines (power, water, gas, etc) that are located on or off of the well pad. Distinctions between existing and proposed facilities and lines need to be shown on the map. The dimensions of any production facilities should also be included. If the operator does not have information regarding production facilities, the details of this portion may be deferred until a well is producing on the land. However, to ensure compliance with NEPA, some estimate of production facilities must be included in the SUPO.

Location and Type of Water - This portion may be done via map or in writing based. All sources of water on the lease site must be accounted for and protections that will be taken to prevent contamination. If a water well is going to be drilled the location and expected production information and time of completion should be included. The source and transportation of any water that is going to be used for production purposes should also be explained.

Construction Materials - Any materials that will be used on the well site should be described for what their purpose will be and where they will be obtained if from the lease area (such as soil or gravel).

Methods for Handling Waste - A written plan is required detailing how all types of waste produced through exploratory measures or drilling will be disposed of. If this requires the use of a reserve pit, a description of how the pit will be lined and the location is required.

Ancillary Facilities - The location, construction materials, and construction methods for any ancillary facilities located on the lease must be included.

Layout of Well-Site - This map must be submitted with a scale of no less than one inch being equal to fifty feet. The location of the well site, blooie (flow) line, reserve pits, storage of topsoil, access points, or any other applicable features should be included on the map.

Reclamation Plan - A reclamation plan is required to address all surface disturbances due to drilling operations. The plan should include interim reclamation measure which can be done throughout the life of the well. A complete plan will include the reshaped topography of the well site, the backfilling of any pits, what drainage systems will be in place that blend with the surroundings, the redistribution of topsoil, weed control, and what vegetation will be planted on the site. The reclamation plan may be amended at the time of abandonment.

Surface Ownership - Documentation is required as to who the surface owner is of the lease as well as the owners of any land where roads will be crossed or constructed to get to the well site. The surface owners should be given a copy of the proposed SUPO. Any surface agreements between the operator and the surface owner should also be included.

Other Information - Any other applicable information about surface use must be included in the plan. This information may be required by local or state regulations or requested by the surface managing agency or the BLM.

Appendix Notes

[1] Utah Code 19-2-103.

[2] Utah Code 19-2-109.1.

[3] Utah Code 19-2-120.

[4] Section 2 of the Antiquities Act http://www.cr.nps.gov/local-law/anti1906.htm.

[5] For more information on the MOU, see http://www.ksl.com/?nid=148&sid=30109965
For more information on air quality in the Uintah Basin, see the DAQ website at http://www.deq.utah.gov/locations/U/uintahbasin/index.htm.

[6] The act in its entirety can be viewed at http://www.epw.senate.gov/water.pdf.

[7] Endangered Species Act, § 424.12 Criteria for designating critical habitat.

[8] U.S. Fish and Wildlife Service, Greater Sage Grouse, ESA Protection.

[9] BLM, Sage-Grouse and Sagebrush Conservation, p.1.

[10] 30 U.S.C. § 181 et seq.

[11] 25 CFR 225, See later in Appendix for more information.

[12] 30 U.S.C. § 181 et seq. The MLA, FOGRMA, and FOOGLRA are found in their entirety at http://www.blm.gov/pgdata/etc/medialib/blm/ut/vernal_fo/lands___minerals.Par.6287.File.dat/MineralLeasingAct1920.pdf.

[13] http://www.nps.gov/archeology/tools/laws/NHPA.htm.

[14] For more on the Onshore Order #1, see http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas/Onshore_Order_no1.html.

[15] The act in its entirety may be found at http://www.epw.senate.gov/sdwa.pdf.

[16] See Title 53C of the Utah Code.

[17] The Utah Code can be found at http://www.rules.utah.gov/publicat/code/r649/r649-003.htm#T4.

[18] The Utah Oil and Gas Conservation Act can be found at http://oilgas.ogm.utah.gov/Rules/Conservation_act.htm.

[19] The NEPA process was taken from BLM's website and can be found at http://www.blm.gov/wo/st/en/prog/planning/nepa/nepa.html.

[20] The act in its entirety may be found at http://www.gpo.gov/fdsys/pkg/BILLS-109hr6enr/pdf/BILLS-109hr6enr.pdf.

[21] BLM and Forest Service, Onshore Oil and Gas Order No. 1, p.10331.

[22] BLM and Forest Service, Onshore Oil and Gas Order No. 1, p. 10333.