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RESERVOIR MANAGEMENT GROUP

DRAFT

Reasonable Foreseeable Development Scenario for Oil and Gas

Buffalo Field Office Planning Area, Wyoming

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INTRODUCTION

The Buffalo Planning Area (Planning Area) represents the lands managed by the Buffalo Field Office of the Wyoming Bureau of Land Management (Bureau). The Planning Area lies within north-central Wyoming (Figure 1). The Planning Area includes part of Campbell, Johnson, and Sheridan counties, Wyoming.

A Resource Management Plan Revision and associated Environmental Impact Statement are currently being prepared for the Planning Area. In support of the Resource Management Plan Revision, this reasonable foreseeable development projection technically analyzes the oil and gas resource known to occur and potentially occurring within the Planning Area and projects future development potential and activity levels for the period 2009 through 2028.

Hydrocarbon activities and projections of future development will be discussed separately for coalbed natural gas and for all other types of oil and gas (hereafter known as conventional oil and gas). When both types of hydrocarbon are being referenced, we will hereafter refer to them as oil and gas. Figure 2a presents historic and present conventional oil and gas related development areas for all lands within the Planning Area. Figure 2b presents historic and present coalbed natural gas related development areas for all lands within the Planning Area.

Our analysis makes a base line projection that assumes future conventional oil and gas and coalbed natural gas related activity levels on all assessed lands within the Planning Area will not be constrained by management-imposed conditions (Rocky Mountain Federal Leadership Forum, 2004). National Forest lands, other Federal agency lands, and State and Private managed lands are included in the base line projection for those lands assessed for future development. Certain other federally managed lands within the Planning Area are not assessed for the potential for future reasonable foreseeable conventional oil and gas and coalbed natural gas related development. Those lands with legislatively imposed restrictions (no leasing) are not included in this base line projection since activities will not be allowed in the foreseeable future. Those restricted lands are National Forest wilderness areas and Bureau wilderness study areas (Figure 3).

The reasonable foreseeable development evaluation and projections presented below review and analyze past, present, and potential future exploratory, development, and production operations and activities. It also presents occurrence potential for conventional oil and gas, coalbed natural gas, and deep conventional oil and gas (at depths greater than 15,000 feet) as well as available estimates of the hydrocarbon resources that may be present within the Planning Area. Additional factors used to project future activities include (but are not limited to) a review of published resource information (including a number of on-line databases) for the area, a call for data from conventional oil and gas and coalbed natural gas operators, a review of petroleum (see Glossary) technology research and development, geophysical activity, and limitations on access and infrastructure. It must be emphasized that the reasonable foreseeable development projections presented are possible and/or likely to happen and should not be considered to be worst-case scenarios, but reasonable and science based projections of the anticipated activity that use logical and technically based assumptions to make those projections (Rocky Mountain Federal Leadership Forum, 2004). Finally, projections of future activity levels for each resource management plan alternative are presented.

The Planning Area contains about 7,356,589 surface acres of all oil and gas mineral ownership types. The Planning Area contains about 4,202,737 acres of Federal oil and gas mineral ownership, or about 57.1 percent of total acres. The remaining 3,153,852 acres (42.9 percent) is managed by state and private interests. The Bureau manages most of the Federal oil and gas mineral lands in the Planning Area (3,369,997 acres, or about 80.2 percent of the 4,202,737 acres). We assume that about 2,592,687 acres of state and private surface lands within Planning Area boundaries overlie Bureau managed oil and gas mineral lands. All Bureau managed oil and gas mineral lands will be covered by decisions made in the associated Resource Management Plan EIS.

The U.S. Forest Service manages about 828,574 acres or 19.7 percent of Federal oil and gas mineral lands within the Planning Area. We assume that about 60,570 acres of Bankhead Jones Federal oil and gas mineral lands and about 717,114 acres of Grasslands Federal oil and gas mineral lands are managed by the Forest Service. The remaining 0.1 percent is managed by the Department of Defense (4,166 acres). Decisions made as part of the Resource Management Plan EIS for the Planning Area will not be made for these lands.

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EXPLORATORY AND PRODUCTION ACTIVITY AND OPERATIONS

The following discussion brings together known information on past and present exploratory and production operations and activity for the Planning Area. Information is presented in the approximate sequence that occurs when project areas or fields (see Glossary) are explored and then developed. The sequence begins when initial exploratory activity begins, and ends when projects are abandoned.

EXPLORATORY ACTIVITY AND OPERATIONS

The petroleum industry in the U.S. has historically relied on continual improvements in technology to better understand the oil and gas resource locked in the earth and to find and produce it. Some of the biggest breakthroughs have been:

- the anticlinal theory (1885) that oil and gas tend to accumulate in anticlinal structures, which allowed drillers to locate better drilling spots with improved opportunities to find oil and gas;
- rotary drilling rigs (1900s), which became the chief method of drilling deeper wells;
- seismograph (1914), which allowed one dimensional subsurface imaging;
- well logging (1924), which allowed measurement of subsurface rock and fluid properties;
- offshore drilling (1930s), which allowed drillers to access new areas and basins;
- digital computing (1960s), which allowed two dimensional imaging of data;
- directional drilling (1970s), which allowed more cost efficient management of reservoirs;
- three dimensional seismic (1980s), which allowed more accurate subsurface imaging;
- three dimensional modeling and four dimensional seismic (1990s), which allowed the prediction of fluid movement in the subsurface;
- identification of new types of reservoirs and improved exploitation methods (1990s to present) allowed development of heavy oil, tight gas, shale gas, coalbed natural gas, and the use of carbon dioxide in the flooding process to increase recoveries; and
- multi-discipline collaboration (2000s), which allows for better drilling decisions, higher success rates, improved risk assessment, and enhanced reservoir development.

Exploratory activity includes:

- the study and mapping of surface and subsurface geologic features to recognize potential oil and gas traps,
- determining a geologic formations potential for containing economically producible oil and gas,
- pinpointing locations to drill exploratory wells to test all potential traps,
- drilling additional wells to establish the limits of each discovered trap,

- testing wells to determine geologic and engineering properties of geologic formation(s) encountered, and
- completing wells that appear capable of producing economic quantities of oil and gas.

A number of components can control and characterize potential oil and gas accumulations (see Glossary) in the Planning Area. Those major components of accumulations can be:

1. The major structural elements (basin boundary, basin axis, anticline, and faults) and Precambrian aged rock outcrops of the Planning Area are shown on Figure 4. The largest part of the Planning Area lies within the Powder River Basin, a major intermontane basin of the northern Rocky Mountains, which occupies northeastern Wyoming and a small part of southeastern Montana. Dolton and Fox (1996) define the basin as

    > "a deep, northerly trending, asymmetric, mildly deformed trough, approximately 250 miles long and 100 miles wide. Its structural axis is close to its western margin, which is defined by reverse and thrust faults and by hogbacks of steeply dipping and overturned strata along the Bighorn Mountains uplift and by the Casper Arch. It is bounded on the south by reverse or thrust faults along the Laramie and Hartville Uplifts, and on the east by the Black Hills where strata are mildly folded and locally faulted along monoclines associated with the Black Hills Uplift. The northern margin is described by the structurally subtle northwest-trending Miles City Area."

    Only the western boundary of the Powder River Basin lies within the Planning Area (Figure 4). The Bighorn Mountains lie west of the Powder River Basin boundary and contain a significant component of Precambrian aged rocks that outcrop at the surface.
2. The Powder River Basin contains more than 18,000 feet of sediments in the basin axis (Dolton and Fox, 1996). Thick accumulations of Mesozoic and Tertiary aged sandstones and shales (potential source and reservoir rocks) exist, with thick and thin coals present under most of the Powder River Basin. Carbonate rocks (potential reservoir rocks) are predominant in older formations (formations of Paleozoic age) within the basin. The Paleozoic section of carbonates, along with sandstones and shales, rarely exceeds 2,200 feet in thickness (Dolton and Fox, 1996). Figure 5 presents a stratigraphic chart for the Planning Area showing nomenclature used for these accumulations in our report. The Powder River Basin contains all the productive sedimentary formations found within the Planning Area. Figure 6a shows all conventional oil and gas fields. These fields help define areas were there has been the greatest historical interest in exploring for and developing the conventional oil and gas resource within the Planning Area. Figure 6b shows all coalbed natural gas fields. These Fields help define areas were there has been the greatest historical interest in exploring for and developing the coalbed natural gas resource within the Planning Area.

3. Burial and thermal histories that could promote the development and preservation of diagenetic pore-throat traps (see Glossary) and extensive oil and gas generation in the center of the Powder River Basin.
4. Structure traps (see Glossary), have played a small role in localizing oil and gas accumulations within the Planning Area.
5. Stratigraphic traps (see Glossary), which have had a large role in exploration and development within the Planning Area, especially when coupled with stratigraphic variation.
6. Pressure regimes, ranging from slightly under-pressured to highly over-pressured, could be important in the center of the Powder River Basin. In areas of abnormally high pressures, productive capacity can be greatly increased. Over-pressuring also creates problems in drilling and completion, increasing the cost of both.
7. Secondary porosity, produced by the dissolution of unstable grains (see Glossary) and rock fragments, is important in local accumulations.

We believe that these components are also important in exploring for and developing new oil and gas resources in the Planning Area. Most recent (since 1998) Planning Area conventional oil and gas drilling activity (exploratory and development) has been occurring in the vicinity of existing fields (Figure 7), with only about 30 percent of new wells spudded as wildcats. Most recent (since 1998) Planning Area coalbed natural gas activity has been occurring within existing developed areas or as westward extensions from existing areas of development.

Potential unconventional gas resources (see Glossary) make up a portion of hydrocarbon resource that will be explored for and developed in the Planning Area in the future. Unconventional gas is a potentially large resource, although it is technically challenging to develop. Three types of unconventional gas have potential for future development within the Planning Area.

1. Tight Sands Gas – formed in sandstone or carbonate (called tight gas sands) with low permeability, which prevents the gas from naturally flowing to a borehole.
2. Coalbed Natural Gas – formed in coal deposits and adsorbed (see Glossary) by coal particles.
3. Shale Gas – formed in fine-grained shale rock (called gas shales) with low permeability in which gas has been adsorbed by clay particles or is held within minute pores and microfractures.

U. S production from the above types of unconventional reservoirs has increased from 15 percent in 1990 to 41 percent in 2004 (Boswell, 2006) and 43 percent in 2006 (Kuuskraa, 2007a). It accounted for more than half of the reported 196 trillion cubic feet of proved natural gas (see Glossary) in the lower 48 states in 2006 (Kuuskraa, 2007b). The tight sands gas and shale gas types of reservoirs have a lower drilling, completion, and operating risk, lower finding costs, and lower reserve decline rates. Technological advances needed to produce these types of reservoirs have been in:

- Reservoir knowledge,
- Hydrofracing,

- Stimulation,
- Horizontal drilling,
- Drilling fluids, and
- Three-dimensional seismic.

Commonly these types of unconventional gas resources have lower reserves (see Glossary) per well and many wells are required to develop the resource. There is a need for well cost and environmental footprint control when developing these resources.

Of the 491 conventional oil and gas boreholes (see Glossary), including directional and horizontal boreholes, spudded (see Glossary) in the most recent 10-year period (January 1, 1999 to December 31, 2008) initial classifications, as defined by IHS Energy Group (2009) were:

• Development	305 boreholes	62.12 percent,
• Development-Deepening	1 borehole	0.20 percent,
• Development Redrill	9 boreholes	1.83 percent,
• Injection	17 boreholes	3.46 percent,
• Injection-Deepening	1 borehole	0.20 percent,
• Injection-Redrill	1 borehole	0.20 percent,
• Injection-Water	2 boreholes	0.41 percent
• Pilot	1 borehole	0.20 percent,
• Stratigraphic Test	2 boreholes	0.41 percent,
• Unclassified	3 boreholes	0.61 percent,
• Deeper Pool Wildcat	1 borehole	0.20 percent,
• New Field Wildcat	86 boreholes	17.52 percent,
• New Field Wildcat-Redrill	2 boreholes	0.41 percent
• Wildcat Outpost	55 boreholes	11.20 percent,
• Wildcat Outpost Redrill	3 boreholes	0.61 percent,
• New Pool Wildcat	1 borehole	0.20 percent, and
• Shallower Pool Wildcat	1 borehole	0.20 percent.

Locations of these boreholes are shown in Figure 7. Total wildcats and stratigraphic tests were 151, or 30.8 percent of the total. Of the 491 boreholes drilled, 18 (3.7) were drilled on existing locations that were deepened or redrilled. All of the redrilled boreholes were classified either as horizontal or directional in trajectory.

Of the conventional oil and gas boreholes drilled in the last 10 years (January 1, 1999 through December 31, 2008), over 40 percent were drilled in five units (Figure 7):

• House Creek (Sussex) and House Creek North	48 boreholes,
• Hartzog Draw Shannon	50 boreholes,
• Savageton (Lower Parkman)	65 boreholes, and
• Central Hilight	13 boreholes.

All other units or fields contained fewer than 10 boreholes, or the boreholes were not drilled within named fields.

Of the 310 conventional oil and gas development wells completed (excluding five spudded wells that are not completed) during this period, their final classification (IHS Energy Group, 2009) ended up as:

- Drilled and Abandoned or Junked and Abandoned 49 boreholes,
- Development – Gas 3 boreholes,
- Development – Oil 239 boreholes, and
- Injection 19 boreholes.

Of the development boreholes completed, about 84 percent were successful.

Of the 141 conventional oil and gas wildcats completed (excluding seven spudded wells that are not completed and one well that is still confidential) during this period (IHS Energy Group, 2009), their final classification ended up as:

- Drilled and Abandoned 69 boreholes,
- Oil 65 boreholes,
- Gas 5 boreholes, and
- Injection 2 boreholes.

Of the wells completed, 48.3 percent were successful.

Of 491 conventional oil and gas boreholes drilled in the 10-year period from January 1, 1999 to December 31, 2008 there were 111 operators that drilled at least one well. The top five operators [Medicine Bow Operating – 62 boreholes, Ballard Petroleum – 47 boreholes, Trend Exploration – 40 boreholes, ExxonMobil – 35 boreholes, and El Paso Exploration and Production – 32 boreholes] are responsible for the drilling of 44 percent of these wells. Thirty-seven operators were responsible for the drilling of only one well each.

New conventional oil and gas production has come from 12 intervals during the last 10 year period of January 1, 1999 to December 31, 2008. Seven intervals (Lewis Shale – 1well, Parkman Sandstone – 69 wells, Sussex Sandstone – 57 wells, Shannon Sandstone – 53 wells, Niobrara Shale – 1 well, Turner Sandstone – 1 well, Frontier Formation – 6 wells, and Mowry Shale – 5 wells) produce from Upper Cretaceous aged sediments. In addition, two intervals (Muddy/Dakota Sandstone – 41 wells and Lakota Formation – 1 well) produce from Lower Cretaceous aged sediments and two intervals (Tensleep Sandstone – 3 wells and Minnelusa Formation – 78 wells) produce from Permian aged sediments. The Minnelusa Formation produces in 25 percent of wells with a reported completion interval, the Parkman Sandstone is productive in almost 22 percent, the Sussex Sandstone produces in more than 18 percent, the Shannon Sandstone produces in almost 17 percent, and the Muddy/Dakota Sandstone in almost 13 percent. The other 7 intervals account for the remaining five percent of productive wells.

Drilling depths for all conventional oil and gas wells drilled in the last 10-year period from January 1, 1999 to December 31, 2008 have ranged from 60 to 16,425 feet. Three wells were deeper than 15,000 feet. The deepest well was a new field wildcat drilled near the center of the basin in section 3 of township 44 north, range 81 west as a dry hole (Figure 7).

There are 53 conventional oil and gas wells drilled to depths between 10,000 and 15,000 feet. Sixteen wells in this depth range have been drilled and abandoned, 26 were completed as oil productive, three were completed as gas productive, three were completed as injection wells, four have been spudded but not completed, and one is still confidential. Eighteen boreholes were completed as directional or horizontal wells (34 percent) and the rest were vertical.

In the 5,000 to 9,999 foot range, 415 conventional oil and gas wells (84.5 percent) were drilled. In this depth range there were 96 wells that were drilled and abandoned or junked and abandoned, five that were completed as gas productive, 278 that were completed as oil productive, 30 that were completed as injectors, and six that were spudded but not completed. There were 122 boreholes that were completed as directional or horizontal wells (29 percent) and the rest were vertical.

For depths less than 5,000 feet, only 20 conventional oil and gas wells were drilled. In this depth range there were eight wells that were drilled and abandoned or junked and abandoned, five that were completed as oil productive, three that were completed as injectors, and four wells that were spudded but have not been completed. Only three boreholes were completed as directional or horizontal wells and the rest were vertical.

Innovative drilling and completion techniques have enabled the industry to drill fewer dry holes and to recover more oil and gas reserves per well. Smaller accumulations once thought to be uneconomic can now also be produced. Improvements have also allowed downspacing to occur in some cases. Increased drilling success rates have cut the number of both wells drilled and dry holes (U.S. Department of Energy, 1999). The Energy Information Administration (2007b) has projected the increase in percentage of wells drilled successfully will be 0.2 percent per year to 2030.

From the early 1990’s to present, activity has focused predominantly on very low risk development drilling in and around known field areas, which helped to improve the overall success rate. During the last 10 years, more exploratory activity has occurred in the Planning Area when compared to most other parts of Wyoming. Additional future exploratory drilling will be required to discover new resources in the Planning Area. Since the risk of failure is higher for these types of activities, the success rates could decline slightly in the future.

Advances in technology have boosted exploration efficiency, and additional future advances will continue this trend. Significant progress that has and will continue to occur is expected in:

- computer processing capability and speed;
- remote sensing and image-processing technology;
- developments in global positioning systems;
- advances in geographical information systems;
- three-dimensional and four-dimensional time-lapse imaging technology that permits better interpretation of subsurface traps and characterization of reservoir fluid;

- improved borehole logging tools that enhance our understanding of specific basins, plays (see Glossary), and reservoirs; and
- advances in drilling that allow more cost-efficient tests of undepleted zones in mature fields, testing deeper zones in existing fields, and exploring new regions.

New technologies will allow companies to target higher-quality prospects and improve well placement and success rates. As a result, fewer drilled wells will be needed to find a new trap, and total production per well will increase (U.S. Department of Energy, 1999). Also, drilling fewer wells will reduce surface disturbance and volumes of waste, such as drill cuttings and drilling fluids. An added benefit of improved remote sensing technology is the ability to identify oil and gas "seeps" so that they can be cleaned up. These seeps can also help pinpoint undiscovered oil and gas.

Technology improvements have also cut the average cost of finding oil and gas reserves in the United States. Finding costs are the costs of adding proven reserves of oil and natural gas via exploration and development activities and the purchase of properties that might contain reserves. U.S. Department of Energy (1999) estimated finding costs were approximately 2 to 16 dollars per barrel of oil equivalent in the 1970's. Finding costs dropped to 4 to 8 dollars per barrel of oil equivalent in the 1993 to 1997 period. Since that time finding costs have fluctuated around the higher end of this range. During the 2003 to 2005 period, finding costs were 7.05 dollars per barrel of oil equivalent and they increased by 60.9 percent to 11.34 dollars per barrel for the 2004 to 2006 period (Energy Information Administration, 2007a). Most of this increase was reported to have come from a rise in exploration and development spending, which was amplified by a drop in reserves found. Producers have been willing to spend more to find oil and gas since prices received during this period had been higher.

Once hydrocarbons have been found, acquired, and developed for production the expense of operating and maintaining wells and related equipment and facilities is tracked. This cost is referred to as a lifting or production cost. During 2006, lifting costs in the U.S. were 9.09 dollars per barrel of oil equivalent, which was an increase of 20.0 percent from a 2005 cost of 7.57 dollars per barrel (Energy Information Administration, 2007a). Lifting costs have increased in recent years because more producers are willing to spend more to produce oil and natural gas when their selling prices are higher.

FEDERAL DEVELOPMENT CONTRACTS

The United States approves development contracts between companies and a number of oil and gas leases sufficient to justify operations for discovery, development, or production on the oil or gas resource. Contracts are approved when the United States determines that conservation of oil and gas products or the public convenience, necessity, or interests of the United States is best served. This program is intended to stimulate exploration on Federal lands. Contracts are usually approved for large, relatively unexplored areas of Federal lands. The contract normally calls for definite exploratory objectives, a timetable for accomplishing those objectives, significant financial expenditures, and it may require a definite drilling obligation. No development contracts presently lie within the Planning Area.

FEDERAL OIL AND GAS UNIT AGREEMENTS

A Federal unit agreement is a contract between the Federal Government and lessees that hold leases over a potential oil and gas reservoir or over oil reservoirs which are candidates for enhanced recovery. Federal units are intended to facilitate the orderly and timely exploration, development, and operation of multiple leases under a single operator. Units may overlie a portion of, or an entire geologic structure. An approved agreement establishes performance obligations, promotes the exploration of unproven acreage or logical enhanced recovery procedures, and permits controlled development of the unit. This process stimulates exploration and/or development of Federal lands and encourages the drilling of the optimum number of wells needed to maximize resource recovery.

A need to conserve oil and gas resources in the United States was identified early in the 20^{th} century and was reinforced by national security issues surrounding the importance of petroleum in fighting the First World War (Avery and Miller, 1934). Congress in 1930 enacted temporary legislation providing for participation in unit operations or cooperative development among lessees of public lands (46 Stat. 1007). The first unit approval (January 6, 1931) in the United States was of the Little Buffalo Basin gas unit in the Bighorn Basin of Wyoming. Billy Creek Unit (Figure 8a) was the first Planning Area unit and the fourth approved in the Unites States (April 11, 1932). In the following years thousands of units have been created in the United States. Many are still active while others have terminated.

Conventional Oil and Gas Unit Agreements

Unit plans of operation where Federal conventional oil and gas leases are incorporated account for 161 active unit agreement areas that lie within or partly within the Planning Area boundary (Figure 8a). Numerous other unit agreements have been approved in the 77 years since the first Planning Area approval, but they have since terminated.

Active units (excluding coalbed natural gas units) encompass lands totaling approximately 413,020 acres, within the Planning Area. These units comprise a little more than 5.6 percent of the total Planning Area. Numerous units have been approved in all decades since the first in 1932.

API/state units are established where Federal lands make up less than 10 percent of the proposed unit. API/state units account for 21 of the 161 active units and 5.8 percent of unit acres.

One exploratory unit was approved in September of 2008 (Wild West). Exploratory units are initially approved as exploration tools to investigate non-producing parts of the Planning Area. This unit is still in its exploration and development drilling. This unit has not yet been established as productive. Wild West Unit will likely contract to a smaller developed unit area once its productive limit is established. Seventeen older exploratory units have contracted to their productive limits and are still producing conventional oil and gas. Development drilling is continuing in some, while others are concentrating on obtaining maximum recovery with existing wells. Exploratory units account for 18 of the 161 active units and 14 percent of unit acres.

The 122 remaining unit agreements contain secondary oil recovery projects. Operators of these 122 units are working to obtain maximum oil recovery. These units account for the remaining 80.2 percent of the total unit area.

Seventy companies operate the 161 units within the Planning Area. Osborn Heirs Company Limited operates the most units at 19. All other companies operate 10 or fewer units. There are 42 companies that only operate one unit.

<u>Coalbed Natural Gas Unit Agreements</u>

Unit plans of operation where Federal oil and gas leases are incorporated account for 44 active coalbed natural gas unit agreement areas that lie within the Planning Area boundary (Figure 8b). These 44 active units encompass lands totaling approximately 647,371 acres within the Planning Area. These units comprise almost 8.8 percent of the total Planning Area. The oldest coalbed natural gas unit in the Planning Area is the Williams Draw Unit approved in May of 1999.

API/state units are established where Federal lands make up less than 10 percent of the proposed unit. There are no API/state units set up to develop coalbed natural gas. All 44 units have been approved as exploratory units. Exploratory units are initially approved as exploration tools to investigate non-producing parts of the Planning Area. Exploratory drilling is continuing in some units, while others are in a development drilling stage.

Ten companies operate the 44 coalbed natural gas units within the Planning Area. Anadarko Petroleum Corporation and its subsidiary Lance Oil and Gas Company Incorporated operate 18 of the units, Williams Production operates 10 units, Devon Energy operates four units, Pennaco Energy Incorporated and Petro Canada each operate three units, St. Mary Land & Exploration operates two units, and four companies (Bill Barrett Corporation, Black Diamond Energy, Kennedy Oil, and Citation oil & Gas Corporation) each operate only one unit.

COMMUNITIZATION AGREEMENTS

Communitization Agreements may be authorized when a Federal lease cannot be independently developed and operated in conformity with an established well-spacing or well-development program. In Wyoming, the following circumstances can constitute good reason for communitization to occur.

- Communitization is required in order to form a drilling unit that conforms to acceptable spacing patterns established by State or Bureau order.

- Adequate engineering and/or geological data is presented to indicate that communitizing two or more leases or unleased Federal acreage will result in more efficient reservoir management of an area.
- Communitization is required when the logical spacing for a well includes both unit and nonunit land.

Conventional Oil and Gas Communitization Agreements

At present, 515 active conventional oil and gas communitization agreements lie within the Planning Area (Figure 9a). These agreements cover an area of about 102,438 acres (1.4 percent of the Planning Area). Agreements by an agreement average are:

- 20 acres – 2 agreements,
- 40 acres – 8 agreements,
- 120 acres – 10 agreements,
- 160 acres – 302 agreements,
- 200 acres – 1 agreement,
- 320 acres – 81 agreements, and
- 640 acres – 30 agreements.

Other communitization agreements have been approved in all decades since the first Planning Area agreement made effective in July of 1960. Numbers of still active agreements by decade are:

- 1960s – 63,
- 1970s – 259,
- 1980s – 110,
- 1990s – 29, and
- 2000s – 54.

Most of these agreements were initiated in the 1970s and 1980s when drilling in the Planning Area occurred at a higher rate than it has in recent years. From the 1990s to present, fewer agreements have been established and fewer still remain active.

Communitization agreements have been established, and are still active, in 11 different productive zones. They are:

- Parkman Sandstone – 57 agreements,
- Sussex Sandstone – 73 agreements,
- Shannon Sandstone – 86 agreements,
- Niobrara Formation – 1 agreement,
- Turner – 31 agreements,
- Frontier Formation – 11 agreements,
- Mowry Shale – 3 agreements,
- Muddy Sandstone – 191 agreements,
- Cloverly Formation (Dakota) – 19 agreements,
- Tensleep Sandstone – 2 agreements,
- Minnelusa Formation – 39 agreements, and
- All formations – 2 agreements.

Sixty-three companies operate the 515 communitization agreements. XTO Energy Incorporated operates the largest number with 67 total agreements and is followed by El Paso Exploration & Production Company with 62 agreements, Resolute Wyoming Incorporated with 58 agreements, Devon Energy with 57 agreements, and M&K Oil Company with 30 agreements. Twenty-five companies only operate one agreement.

Coalbed Natural Gas Communitization Agreements

At present, 1,825 active coalbed natural gas communitization agreements lie within the Planning Area (Figure 9b). These agreements cover an area of about 151,661 acres (2.1 percent of the Planning Area). Most agreements (about 95 percent) cover an average area of about 80 acres, while the remainder average about 160 acres.

Communitization agreements have only been approved since the first Planning Area agreement was made effective in September of 1998. Most agreements have been established in Fort Union Formation coals, with a minor number in Wasatch Formation coals.

Only 44 companies operate the 1,825 communitization agreements. The eight largest operators are:

1. Williams Production 349 agreements,
2. Lance Oil & Gas Company 242 agreements,
3. Pennaco Energy Incorporated 227 agreements,
4. Yates Petroleum Corporation 143 agreements,
5. Devon Energy 131 agreements,
6. Bill Barrett Corporation 105 agreements,
7. Patriot Energy Resources 101 agreements, and
8. JM Huber Corporation 101 agreements.

There are 24 companies that operate two to 59 agreements and 12 that only operate one agreement.

TYPICAL DRILLING AND COMPLETION SEQUENCE

Before an oil or gas well is drilled, an Application for Permit to Drill must be approved by the Wyoming Oil and Gas Conservation Commission http://wogcc.state.wy.us/. If the well will be located on Federal lands, an Application for Permit to Drill must also be approved by the Bureau. Not every approved application is actually drilled. The drilling and completion sequence for a targeted reservoir in the Planning Area generally involves:

- constructing the well pad, associated reserve pits, and the access road prior to moving the drilling equipment on to the well location;
- using rotary equipment, hardened drill bits, weighted drill pipe/collars, and drilling fluids to cool and lubricate the drill bit, which all result in easier penetration of the earth's surface;
- for horizontal boreholes, geosteering (intentional directional control of the borehole based on the results of downhole geological logging measurements) the

drill bit to maintain correct hole trajectory and keep a borehole in a particular reservoir to maximize economic production;

- inserting casing and cementing it in place to protect the subsurface and control the flow of fluids (oil, gas, and water) from the reservoir;
- perforating the well casing at the depth of the producing formation to allow flow of fluids from the formation into the borehole (many horizontal well completions do not contain casing in the horizontal part of the borehole);
- hydraulically fracturing and propping fractures open with sized particles and/or acidizing the formation to increase permeability and the deliverability of oil and gas to the borehole;
- inserting tubing into each well to allow for controlled flow of fluids (oil, gas, and water) from the reservoir to the surface;
- installing a wellhead at the surface to regulate and monitor fluid flow and prevent potentially dangerous blowouts;
- reclaiming the portions of the well pad and access road that will not be used in the production phase of the well; and
- reclaiming the entire pad and access road after the well has ceased production and is plugged and abandoned.

The cost of developing conventional deposits of oil and gas in the Rocky Mountain region is higher than the average for the onshore 48 contiguous states (Cleveland, 2003). Factors that may contribute to higher costs in the Planning Area could be:

- access to some well sites can be more difficult when they are remote from the main activity areas and when they are located in steep terrain,
- harsh environments (particularly cold temperatures),
- changes in rig availability,
- changes in development priority as industry focus on certain plays evolves with new discoveries and changes in oil and gas price,
- labor market conditions, and
- restrictions (many of them environmental restrictions of some type) on land use.

Drilling improvements have occurred in new rotary rig types, coiled tubing, drilling fluids, and borehole condition monitoring during the drilling operation. Improvements in technology are allowing directional and horizontal drilling use in many applications. New bit types have boosted drilling productivity and efficiency. New casing designs have reduced the number of casing strings (see Glossary) required. Environmental benefits of drilling and completion technology advances include:

- smaller footprints (less surface disturbance),
- reduced noise and visual impact,
- less frequent maintenance and workovers of producing wells with less associated waste,
- reduced fuel use and associated emissions,
- enhanced well control for greater worker safety and protection of groundwater resources,
- less time on site with fewer associated environmental impacts

- lower toxicity of discharges, and
- better protection of sensitive environments and habitat.

DRAINAGE PROTECTION

Producing oil and gas wells may cause drainage (migration of hydrocarbons toward the borehole) from nearby lands. This drainage will result in the loss of oil and gas from those lands and result in loss of royalty revenues for landowners. Drainage is most often avoided or reduced by the drilling of a protective well. By protecting Federal lands from drainage the Federal Government may stimulate drilling and development activity in an area and help to insure timely and more efficient management of the producing reservoir.

HISTORICAL DRILLING AND COMPLETION ACTIVITY AND TECHNIQUES EMPLOYED FOR CONVENTIONAL OIL AND GAS

The existence of oil in Wyoming has been known for centuries. Earliest interest in the Powder River Basin was focused on the Jackass oil spring south of the Planning Area in Natrona County. Oil claims near what was to become the Shannon and Salt Creek fields were first staked in 1883. The Shannon Field was discovered in 1893 and the Salt Creek Field in 1908. A number of additional Powder River Basin field discoveries were made to the east, southeast, and south of the Planning Area before the first actual Planning Area discovery was made at Billy Creek Field in 1923 (Figure 6a). The history of coalbed natural gas activities in the Planning Area are presented in Appendix 1.

Early Exploration and Development Activity

Information on exploration and development of the conventional oil and gas fields within the Planning Area is available from Espach and Nichols (1941), Biggs and Espach (1960), Wyoming Geological Association (1957, 1961, 1989, and 2000), and Bureau Files.

There were probably a number of tests drilled before 1902. The only record of a test found was for an 1886 well drilled on the Tisdale structure near what later became North Tisdale Field (Biggs and Espach, 1960) in the southwest part of the Planning Area (Figure 5). IHS Energy Group (2009) shows that at least 30 wells are known to have been drilled and abandoned in the Planning Area between 1902 and 1923 when the first field discovery was made at Billy Creek in 1923 (Figure 6a). Two wells had tested the Billy Creek anticlinal structure in 1916 and 1921 without success. The discovery well was found to be gas productive in the Second Wall Creek Sandstone of the Frontier Formation. The field was discovered by surface mapping of geologic structure. Gas production did not begin until 1930, when an 8-inch pipeline was laid to Buffalo and Sheridan. The field was converted to gas storage in 1941.

Seventeen of the first 30 drilled wells drilled were in the vicinity of North Tisdale Field (Figure 6a) which was not discovered until 1952. Most of the remaining wildcat wells were drilled to the northwest and northeast of North Tisdale Field. Two other wildcat wells were drilled near the town of Gillette.

An additional 40 wells (some with hydrocarbon shows) are known to have been drilled in the Planning Area before the next discoveries was made at Adon and Sussex fields (Figure 6a) in 1948. Adon Field is an anticlinal trap discovered with seismic information. It produces oil from the Pennsylvanian Minnelusa Formation. The Sussex Field is a combination structural-stratigraphic trap discovered with surface and seismic information. It has produced conventional oil and gas from nine zones (Lakota Formation; Teapot, Parkman, Sussex, and Shannon Sandstones; Frontier and Sundance formations; Tensleep Sandstone; Gypsum Springs Formation).

Exploration of surface geologic structures (anticlines, faulted anticlines, and domes) was the most successful method of discovering new reservoirs in Wyoming through the earliest periods of exploration. Since there were few of these types of structures present within the Planning Area part of the Powder River Basin, few discoveries were made in the earliest period of Wyoming exploration. Once subsurface geologic techniques and acquisition of seismic reflection data began to be employed in the late 1940s, additional discoveries began to be made. Fields most often are considered to be stratigraphic traps, but structural and combination structural/stratigraphic trap types are also common. Most fields are considered to be oil fields. Gas fields were rarely discovered within the Planning Area until coalbed natural gas exploration began in recent years (see below for a discussion of historical coalbed natural gas exploration and development activity).

Producing Zones

The Wyoming State Geological Survey (DeBruin, 2007) recognizes 137 named fields that have had more than one producing well, 69 fields that have contained only one producing well, and 15 unnamed fields in the Planning Area (Figure 6a). DeBruin (2007) shows that 32 of the fields that have had more than one producing well and nine fields that have contained only one producing well are now abandoned.

Conventional oil and gas occurs in the Planning Area in numerous geologic formations, and members of formations. Fourteen formations or members have been productive in more than six wells in the Planning Area (IHS Energy Group, 2009). From youngest to oldest (see Figure 5) they are:

- Wasatch/Fort Union formations 22 wells,
- Parkman Sandstone 372 wells,
- Sussex Sandstone 500 wells,
- Shannon Sandstone 1,045 wells,
- Niobrara Formation 14 wells,
- Turner Sandstone 91 wells,
- Frontier Formation 143 wells,
- Mowry Shale 45 wells,
- Muddy Sandstone/Newcastle 1,945 wells,
- Cloverly Formation (Dakota) 75 wells,

- Lakota Formation 65 wells,
- Crow Mountain Sandstone 48 wells,
- Tensleep Sandstone 169 wells, and
- Minnelusa Formation 1,464 wells.

Table 1 presents information on all producing zones within the Planning Area, as obtained from IHS Energy Group (2009). Cumulative production (through 2008) within the Planning Area has been almost 1.4 trillion cubic feet of gas and over 1.2 billion barrels of oil.

The most prolific oil productive formations have been the Minnelusa Formation (40.5 percent) and the Muddy Sandstone (20.9 percent). The Shannon Sandstone produced the third largest quantity of oil (16.7 percent). All other zones produced five percent or less of the cumulative oil. Oil, gas, and water production rates (since January of 1974) are presented for the top 10 oil productive zones (Figures 10, 11, 12, 13, 14, 15, 16, 17, 18, and 19) from most to least productive. Figure 20 shows how the oil production rate compares for the top 10 oil productive zones during the 1974 through 2008 year period. Figure 21 shows how these 10 productive zones compare by percentage of production for the same period.

A significant amount of gas production has also been associated with the Muddy Sandstone (66.2 percent), the Shannon Sandstone (9.8 percent), and the Dakota (7.9 percent). All other zones produced less than five percent of the cumulative gas. Oil, gas, and water production rates (since January of 1974) are presented for the top 10 gas productive zones (Figures 11, 12, 17, 18, 22, 13, 19, 10, 16, and 23) from most to least productive. Figure 24 shows how the gas production rate compares for the top 10 gas productive zones during the 1974 through 2008 year period. Figure 25 shows how these 10 productive zones compare by percentage of production for the same period.

Source rocks for hydrocarbons occurring within the Planning Area (Dolton and Fox, 1996) are:

1. Paleozoic reservoirs such as the Minnelusa Formation (Figure 5) are potentially sourced by Pennsylvanian black shales, and possibly organic rich rocks of the Phosphoria Formation west of the Powder River Basin.
2. Most Cretaceous aged shale zones in the Powder River Basin could also be source rocks for Cretaceous aged reservoirs. Source rocks in the Mowry Shale and Niobrara Formation appear to have been the principle source of hydrocarbons for Cretaceous aged reservoirs (Figure 5).

Technology Development

"Technology has historically contributed significantly to the ability of the petroleum industry to find, develop, and produce natural gas resources" (National Petroleum Council, 2003). Reeves et al. (2007) noted strong levels of industry investment in oil and gas recovery research and development during the 1980s and early 1990s and a decline after that. The National Petroleum Council (2003) postulated that technology improvements would play a lesser role in gas resource enhancement in the 2003-2008 time periods. They also assumed that technology improvements would play a greater role after 2008 when higher gas prices would motivate industry to invest more in development of technology. Future average improvement rates for certain types of technology were assumed to be:

- Exploration well success rate 0.53% annual improvement
- Development well success rate 0.46% annual improvement
- Estimated ultimate recovery per well 0.87% annual improvement
- Drilling cost reduction 1.81% annual improvement
- Completion cost reduction 1.37% annual improvement
- Initial production rate 0.74% annual improvement
- Infrastructure cost reduction 1.18% annual improvement
- Fixed operation cost reduction 1.00% annual improvement.

Unconventional gas has become a significant potential component of future production within the Planning Area if reserves can be established. Initial exploration will most likely be in the southeast part of the Planning Area. The Energy Policy Act of 2005 established funding for unconventional gas research and development and selected the Research Partnership to Secure Energy for America to oversee and manage new projects (Reeves et al., 2007). The goals of this organization are to:

- Increase the volume of the technically recoverable unconventional gas resource base by 30 trillion cubic feet,
- Convert 10 trillion cubic feet of technically recoverable unconventional gas to economically recoverable gas,
- Develop technologies for developing unconventional resources with minimum environmental impact, and
- Emphasize science-building capacity and effective technology dissemination.

Technologies that will be required to tap currently undeveloped unconventional gas resources (Reeves et al., 2007) may be:

- Detection methods to find where the highly productive, naturally fractured “fairways” of a play exist,
- Improving reservoir characterization in order to identify the entire productive pay interval,
- Advanced well stimulation methods to establish the low-end of reservoir quality for using well stimulation to yield economic results, and
- Enhanced recovery technology using injection of nitrogen and/or carbon dioxide to accelerate and increase gas recovery from coals, shales, and possibly tight sands.

With the rise in well drilling and well stimulation costs in recent years there had been concerns that much of the unconventional resource may become uneconomic to pursue. Gobec et al. (2007) have projected that the pursuit of efficiencies and technology improvements will at least partially offset the recent increases in costs. Costs have leveled out and in some cases decreased in recent months, due to decreases in oil and gas demand and in price. We do not expect costs to increase significantly in the near future. Once oil and gas demand and prices begin to increase again, then costs will also begin to rise.

The National Petroleum Council (1999) suggested that access restrictions can add 25 thousand dollars to the average cost of drilling a well in the Rocky Mountains. They also suggested that access restrictions can delay drilling activity by an average of two years.

Drilling and Completion Activity

There have been 13,250 surface well locations spudded or completed in the Planning Area through March 1, 2009 (Wyoming Oil and Gas Conservation Commission, 2009). Of the 13,250 wells spud or drilled in the Planning Area, 6,555 wells, or 49.5 percent, appear to have been on Bureau managed oil and gas lands.

Figure 26 presents the locations of all wells that have been spud and not completed and all wells still capable of producing conventional oil and gas (Wyoming Oil and Gas Conservation Commission, 2009) as of March 2, 2009. Of these 3,009 wells, their present status is:

- Confidential 13 wells
- Gas – Spudded 3 wells
- Gas – Producing 214 wells
- Gas – Flowing 3 wells
- Gas – Gas Lift 1 well
- Gas – Pumping Rods 2 wells
- Gas – Shut-In 42 wells
- Gas – Temporarily Abandoned 2 wells
- Gas – Notice of Intent to Abandon 2 wells
- Oil – Spudded 19 wells
- Oil – Producing 2,196 wells
- Oil – Gas Lift 6 wells
- Oil – Pumping 26 wells
- Oil – Plunger Lift 2 wells
- Oil – Dormant 75 wells
- Oil – Shut-In 195 wells
- Oil – Temporarily Abandoned 150 wells
- Oil – Notice of Intent to Abandon 58 wells.

A total of 22 wells have been spud and not completed and the status of the 13 confidential wells is unknown. Of the remaining 2,974 completed wells, 266 wells (8.9 percent) are classed as gas wells, and 2,708 wells (91.1 percent) are classed as oil wells.

Figure 27 presents the locations of all wells that are being used for enhanced oil recovery purposes and for disposal, monitoring, and source wells (Wyoming Oil and Gas

Conservation Commission, 2009) as of March 2, 2009. Of these 1,137 wells, their present well status is:

- Injector – Spudded 2 wells
- Injector – Active Injector 854 wells
- Injector – Dormant 6 wells
- Injector – Shut-In 109 wells
- Injector – Temporarily Abandoned 41 wells
- Injector – Notice of Intent to Abandon 23 wells
- Disposal – Dormant 1 well
- Disposal – Shut-In 8 wells
- Disposal – Temporarily Abandoned 2 wells
- Disposal – Unknown 1 well
- Monitor – Active Monitor 9 wells
- Monitor – Shut-In 10 wells
- Source – Active 1 well
- Source – Dormant 2 wells
- Source – Shut-In 7 wells
- Source – Temporarily Abandoned 3 wells
- Water Source – Spudded 2 wells
- Water Source – Active 34 wells
- Water Source – Dormant 1 well
- Water Source – Shut-In 16 wells
- Water Source – Temporarily Abandoned 4 wells
- Water Source – Notice of Intent to Abandon 1 well.

The 4,146 active conventional oil and gas wells (as of March 2, 2009) that are shown in Figures 26 and 27, account for about 31.3 percent of all the 13,250 conventional oil and gas wells spudded or completed within the Planning Area. The above information shows that of the active wells in the Planning Area, 26 wells (0.6 percent) have been spud but not completed, 13 wells (0.3 percent) are confidential and their final status is not yet known, 2,974 wells (71.7 percent) are oil and gas well types, 1,033 wells (24.9 percent) are being used as injectors for enhanced oil recovery type projects, 12 (0.3 percent) are being used for oil and gas related disposal purposes, 19 (0.5 percent) are being used for oil and gas related monitoring purposes, and 69 (1.7 percent) are being used for oil and gas related source purposes.

About 68.7 percent (9,104 wells) of the 13,250 spudded and completed conventional oil and gas wells have been plugged and abandoned and their surface locations have been reclaimed or are in the process of final reclamation. Wells have been abandoned because:

- they were "dry"--no hydrocarbons were encountered, hydrocarbons were not present in economic quantities, or mechanical difficulties within a borehole prevented economic oil and gas production;
- they were considered to be just stratigraphic tests drilled to obtain information about subsurface geologic horizons and their depths; or

- they initially were capable of producing hydrocarbons but they became uneconomic to produce at a later date or they were used in enhanced oil recovery projects, as disposal wells, or as source wells and were no longer needed for those purposes.

A graph of the historical conventional oil and gas drilling activity in the Planning Area, as related to wells spudded annually and cumulatively is presented in Figure 28. Starting in 1960, the graph shows an overall increase in well spuddings thru 1969 when spuddings reached their historical peak at 779. Overall, spuddings then declined through 1973. Spuddings then showed a small overall increase between 1974 and 1984, with a high of 405 spuds in 1977. From 1984 to 1995 they dropped to historical lows. In 1995 and 1996 they increased slightly, but since then spuddings have been at a rate of less than 100 per year and only averaged 40 spuds for 2007 and 2008. Spuds reached a low of 21 in 2003.

Drilling Rigs and Rig Counts

The Land Rig Newsletter (2008) reported that in 2007, onshore areas of the U.S. achieved more than 68 million feet of hole drilled: a record year. Drilling footage in the Rocky Mountains alone was close to 15.5 million feet. They also reported that while conventional vertical footage dropped, non-vertical footage increased, with directional and horizontal footage both exceeding 11.5 million feet. Since then drilling activity and footage drilled has declined in the U.S. and in the Rocky Mountains. This has been due primarily to reduced demand and price for oil and gas. Within the Planning Area, the last active conventional oil and gas drilling rig was used to spud the EOG Resources #2-16M in section 2 of township 45 north, range 69 west. This has been the only conventional oil and gas well spudded in 2009.

Figure 29 presents conventional oil and gas well footage drilled within the Planning Area on a yearly basis and average annual well depth. Annual footage closely mirrors wells spudded for the same time period. The highest annual footage drilled occurred in 1969, when 6.059 million feet were drilled. Only 187,572 feet were drilled in 2003. From 1973 to present, average annual well depths have been between 8,500 and 9,500 feet. The highest annual average well depth reached its high in 1984 at an average of 9,441 feet per well drilled.

Production

Data from IHS Energy Group (2009) was used to compile historic cumulative production by reservoir and by field. Table 1 lists cumulative oil, gas, and water production by producing zone or combinations of multiple productive zones where production has been commingled. Details have been previously discussed above.

Table 2 lists all fields in the Planning Area with reported conventional oil and gas production. It itemizes hydrocarbon production through 2008, and well activity (wells actively producing and wells with historical production but not producing). There are 426 fields with hydrocarbon production recognized by IHS Energy Group (2009).

There are six major producing oil fields in the Planning Area (by volume), with production of 38.59 to more than 114 million barrels of cumulative oil production. In descending order and percent of cumulative production, they are:

- Hartzog Draw (9.35 percent),
- Sussex (6.26 percent),
- Hilight (6.26 percent),
- Raven Creek (3.66 percent),
- House Creek (3.25 percent), and
- Meadow Creek (3.16 percent).

Locations of these six fields are shown on Figure 6a.

There are seven major producing gas fields in the Planning Area (by volume), with production of 68.58 to more than 279.4 billion cubic feet of cumulative gas production. In descending order and percent of cumulative production, they are:

- Hilight (20.21 percent),
- Kitty (9.00 percent),
- Recluse (8.56 percent),
- Buck Draw North (6.52 percent),
- Meadow Creek (5.94 percent),
- Porcupine (5.71 percent), and
- Amos Draw (4.96 percent).

Locations of these seven fields are shown on Figure 6a.

At the close of 2008, there were 3,090 actively producing oil and gas wells, as classified by IHS Energy Group (2009). At that time cumulative production was 1,222,757,562 barrels of oil and 1,382,632,515,000 cubic feet of gas.

Yearly (Figure 30) and cumulative (Figure 31) graphs of oil and gas production illustrate historical volume rates and cumulative volumes of oil and gas as a function of time from 1974 through 2008 (IHS Energy Group, 2009). Figure 30 illustrates the historical annual rate change in the production of oil and cumulative oil production within the Planning Area. The rate of oil production has shown an overall decline from its high point in the initial year graphed (1974). Two periods showed increased production (1977 through 1978 and 1983 through 1989). Since 1989 decline in oil production has been steady, with only a few short periods when production flattened.

Figure 31illustrates the historical annual rate change in the production of gas and cumulative gas production within the Planning Area. The rate of gas production has shown an overall decline from its high point in the initial year graphed (1974). Two periods showed increased production (1983 through 1986 and 1998 through 2000). Since 2000 decline in gas production has been steady.

Water is often produced in conjunction with the production of oil and gas from most reservoirs. Waterflooding projects also cause an increase in associated water production. Water production by field is shown on Table 2. There are eight major water producing fields in the Planning Area (by volume), with production of 95.04 to more than 564.9 million barrels of cumulative production. In descending order and percent of cumulative water production, they are:

- Rocky Point (16.19 percent),
- Hilight (11.59 percent),
- North Fork (6.96 percent),
- Sussex (5.30 percent),
- Raven Creek (5.02 percent),
- Gas Draw (3.88 percent),
- Rozet (2.96 percent), and
- Meadow Creek (2.72 percent).

Locations of these eight fields are shown on Figure 6a.

Volumes of annual and cumulative water produced are shown on Figure 32. Produced water volumes reached peaks in 1981, 1985, and 2006. Increases in water production appear to be at least partly tied to periods of increased waterflooding activity. Cumulative water produced through 2008 was 3,489,209,732 barrels.

Oil Mining Activity

Traditional oil and gas development involves drilling wells from the surface to the target formation at depth and bringing the product to the surface using natural formation pressures or by means of artificial lift. In some oil fields, however, a mature, depressurized reservoir located at shallow depths may have a portion of the remaining oil extracted via a process known as "oil mining."

Oil mining is a form of enhanced oil recovery whereby a mine is tunneled beneath the reservoir and a series of wells are drilled upward into the producing formation and gravity drainage is used to extract the oil (Rock Well Petroleum, 2009). Due in part to the limitations on depth of underground mining techniques, only a limited number of mature oil fields are viable candidates for this technique. One such field, North Tisdale, is located in the southwestern part of the Planning Area (Figure 6a).

The North Tisdale field produces oil from several zones, including the Pennsylvanian Tensleep Sandstone, the Triassic Crow Mountain Sandstone (Curtis Formation), the Jurassic Morrison Formation, and the Cretaceous Lakota Formation. The first well was drilled in the field in 1886, but only water from the Sundance Formation was reported (Biggs and Espach, 1960). It wasn't until 1952 that oil was discovered in the Crow Mountain Sandstone (Curtis Formation), and the following year in the Lakota Formation. The area was initially unitized in 1953 (Bureau records). In 1984, New Tech Oil Company began an oil mining operation in the Lakota Sand Participating Area of the unit. At the time, Conoco, Inc. was the operator of the North Tisdale Unit, and was producing from traditional oil wells to the Crow Mountain Sandstone (Curtis Formation) and Lakota Formation. As stated in Conoco's application for designation of a sub-operator, New Tech "would apply certain techniques and methods which they have developed to further develop Lakota Oil production" (Bureau records).

New Tech mined the Lakota Formation oils through the use of a central horizontal mine adit, 984 feet in length which entered the field from a nearby canyon. At the end of the adit, a 300 foot deep vertical shaft entered the Lakota, from which several horizontal well bores were drilled into the formation. Oil was mined through gravity drainage into the horizontal well bores which directed the oil to the central shaft for production.

Production from the Lakota Formation increased with the onset of oil mining from approximately 15,000 barrels of oil in 1983 to over 66,000 barrels of oil in 1987 (IHS Energy, 2009). Lakota Formation production from both oil mining and traditional means has since been in a gradual decline. In 2008, oil mining produced the majority (6,903 barrels) of the 7,267 barrels of reported Lakota Formation oil production from North Tisdale Field (IHS Energy, 2009).

The North Tisdale Unit, including the Lakota Sand Participating Area, is currently operated by Hilcorp Energy Company. Oil mining production continues to the present with oil that drains to the central borehole/shaft brought to the surface by the use of traditional pumping methods (Spicer, 2009). The Lakota Formation also still produces via traditional vertical boreholes, though field development has ceased and a secondary water flood has been implemented in the Lakota.

In addition to the North Tisdale project, the Greybull project, operated by Rock Well Petroleum, is currently producing oil from an oil mine in Greybull Field. The field is located in the east-central Big Horn Basin, and lies outside the Planning Area boundary. The viability of future oil mining projects in the Planning Area is unknown. Rock Well states that, "Target fields are generally large, shallow, depressurized oil fields that are often in 'stripper production,' which is generally described as wells producing less than 10 [barrels of oil per day] (Rock Well Petroleum, 2009)." Any field candidates would necessarily be around the margins of the basin where production is from more shallow reservoirs. As of this writing, operators have not expressed interest in developing new oil mining projects in any other field within the Planning Area.

Marginal Wells

Low-volume oil and gas wells, known as "marginal" or "stripper" wells contribute an important percentage of the hydrocarbons produced in the U.S. In 2005, about 29 percent of crude oil production and more than 10 percent of natural gas production was credited to marginal wells (Duda and Covatch, 2005). In 2007, the oil contribution had decreased to approximately 28 percent and the gas contribution increased to 11 percent – an important contribution to the nation's supply (Interstate Oil and Gas Compact Commission, 2008).

Producing oil or natural gas wells are considered to be “marginal” when their producing rate is at the limit of profitability. The Interstate Oil and Gas Compact Commission

(2008) defines marginal or stripper wells as wells that are producing 10 or fewer barrels of oil per day and no more than 60,000 cubic feet per day of natural gas.

The majority of marginal wells are owned, maintained, and produced by independent operators rather than integrated exploration and production firms which operate globally. They account for a large proportion of the jobs and corresponding economic growth associated with the petroleum industry in this country (Duda and Covatch, 2005). The Interstate Oil and Gas Compact Commission (2008) estimated that in 2007 the industry created almost 10 jobs for every million dollars of marginal oil and gas production. In addition, as long as these wells remain productive there are additional opportunities to use advanced technology to enhance recovery. The Interstate Oil and Gas Compact Commission (2008) also reported on development of technologies being pursued to improve production performance of the nation's marginal wells.

In 2007, Wyoming ranked 11th of the 30 major producing states in the number of marginal oil wells, and 5th of the 28 major gas producing states (Interstate Oil and Gas Compact Commission, 2008). In that year there were 12,572 marginal oil wells that produced 8,263,340 barrels of oil in the state of Wyoming, and 29,614 marginal gas wells which produced 103,854,785 million cubic feet of gas (data for 2008 was not available at the time of this writing). These totals represent 15.3 and 5.4 percent of the total production of oil and gas for the state, respectively (Interstate Oil and Gas Compact Commission, 2008, and Energy Information Administration, 2008a).

As of February 2009, 602 marginal oil wells and 1,453 marginal gas wells were located within the Planning Area (IHS Energy, 2009). Of these, 301 marginal oil wells and 709 marginal gas wells were located on Bureau managed minerals. According to the Interstate Oil and Gas Compact Commission (2008), the average daily production for marginal oil and gas wells in Wyoming in 2007 was 1.80 barrels of oil and 9.6 million cubic feet of gas. Assuming these averages have not changed significantly since the 2007 data was analyzed, annual production from marginal wells within the Planning Area may account for as much as 395,514 barrels of oil and 5,091,312 million cubic feet of gas (197,757 barrels of oil and 2,484,336 million cubic feet of gas from wells on Bureau managed lands).

Deep Well Drilling: Greater than 15,000 feet

Dyman et al. (1990, 1993a, 1993b, and 1997) characterized deep wells as those drilled to depths greater than 15,000 feet. Drilling and completing deep gas wells are very costly due to the extremely high temperatures and variable pressures and hard rock encountered. Through May 11, 2009, the IHS Energy Group (2009) database shows that there have been 66 wells drilled to depths of more than 15,000 feet in the Planning Area, and they are located near the Powder River Basin axis in a northwest-southwest trend (Figure 33). These wells were split between drilled and abandoned (30 wells), oil (35 wells) and injectors (one well). All productive wells were completed in the Minnelusa Formation, and all but two wells were completed through perforations deeper than 15,000 feet. The two shallower completions were perforated within 100 feet of the 15,000 foot depth.

The first deep well was drilled in 1964 and the last one in 2001. The deepest was a 16,240 foot drilled and abandoned wildcat located in section 3 of township 44 north, range 81 west that was spudded in 2001 and completed in 2002. It bottomed in the Minnelusa Formation.

The deepest producing zone was is in the Reno Federal #32-19 drilled at Reno Field (Figure 33). The Minnelusa Formation was productive between 15,478 and 15,552 feet in this well. Twenty-one deep wells (32 percent) have been drilled at Reno Field. Five fields (Fourmile, Hub, Pheasant, Reno, and Reno East) have proven to be oil productive at depths below 15,000 feet (Figure 33).

Deep Well Drilling and Completion Activity: 10,000 to 15,000 feet

There have been 2,060 known boreholes in the Planning Area that have drilled to the 10,000- to 15,000-foot depth range as of May 11, 2009 (IHS Energy Group, 2009). As Figure 33 shows, most wells in this depth range are located in the southeast quarter of the Planning Area and most are concentrated to the south and northwest of Gillette, and along the southeast Planning Area border. Completion status of these wells has been split between drilled and abandoned or junked and abandoned (1,267 wells or 61.5 percent), oil (692 wells or 33.6 percent), gas (54 wells or 2.6 percent), and other well types (47 wells or 2.3 percent).

Fields with the most wells drilled in this depth range are:

- Maysdorf Field 59 wells
- Big Hand Field 58 wells
- Amos Draw Field 53 wells
- Pine Tree Field 52 wells
- Bone Pile Field 45 wells
- Hilight Field 41 wells
- Porcupine Field 35 wells
- Dry Gulch Field 32 wells
- School Creek Field 32 wells.

Most of the gas wells (69 percent) are productive in the Muddy Sandstone, with a minor contribution from the Turner and Shannon sandstones. Of the oil wells the formations with the largest productive well percentage are:

- Minnelusa Formation 38 percent
- Muddy Sandstone 24 percent
- Shannon Sandstone 13 percent
- Dakota Sandstone (Cloverly) 6 percent
- Frontier Formation 5 percent.

Shallower Well Drilling: 5,000 to 9,999 feet

The greatest number of wells drilled (9,990) in the Planning Area have been drilled to the 5,000- to 9,999-foot depth range (IHS Energy Group, 2009). As Figure 33 shows, wells in this depth range are located across the Planning Area, but concentrated in its eastern portion. Completion status of these wells has been split between drilled and abandoned or junked and abandoned (5,185 wells or 51.9 percent), oil (4,476 wells or 44.8 percent), gas (69 wells or 0.7 percent), and other well types (260 wells or 2.6 percent).

Fields with the most wells drilled in this depth range are:

- Hilight Field 426 wells
- Hartzog Draw Field 388 wells
- House Creek Field 387 wells
- Kitty Field 274 wells
- Rozet Field 209 wells
- Meadow Creek Field 195 wells
- Recluse Field 181 wells
- Sussex Field 139 wells
- Springen Ranch Field 131 wells
- Gas Draw Field 119 wells
- Ute Field 109 wells.

Most of the gas wells are productive in the Muddy Sandstone (59 percent) and Turner Sandstone (32 percent). Of the oil wells the formations with the largest productive well percentage are:

- Muddy Sandstone 36 percent
- Minnelusa Formation 25 percent
- Shannon Sandstone 13 percent
- Sussex Sandstone 9 percent
- Parkman Sandstone 7 percent
- Tensleep Sandstone 3 percent
- Frontier Formation 2 percent.

<u>Shallowest Well Drilling: Less than 5,000 feet</u>

There have been 1,331 known boreholes in the Planning Area that have drilled to the less than 5,000 feet as of May 11, 2009 (IHS Energy Group, 2009). As Figure 33 shows, most wells in this depth range are located in the southwest part of the Planning Area with minor concentrations in the northeast, north and south of the town of Gillette and north and south of the town of Sheridan. Completion status of these wells has been split between drilled and abandoned or junked and abandoned (571 wells or 42.9 percent), oil (527 wells or 39.6 percent), gas (62 wells or 4.7 percent), and other well types (171 wells or 12.8 percent).

Fields with the most wells drilled in this depth range are:

- Meadow Creek Field (including East and North) 218 wells
- Tisdale Field (including East and North) 174 wells
- Sussex Field 130 wells
- Sussex West Field 129 wells

- Dugout Creek Field 82 wells.

Most of the 62 gas wells are productive in the Fort Union (27 percent), Shannon Sandstone (18 percent), and Frontier Formation (11 percent) with a minor contribution from the Turner and Shannon sandstones. Of the oil wells the formations with the largest productive well percentage are:

- Shannon Sandstone 62 percent
- Sussex Sandstone 15 percent
- Crow Mountain Sandstone 9 percent
- Tensleep Sandstone 6 percent
- Lakota Formation 2 percent.

Summary of Current Drilling Techniques

Most oil and gas wells have been drilled vertically throughout the Planning Area, with directional and horizontal wells mostly being drilled in recent years. Developments in drilling techniques have allowed for more widespread use of directional and horizontal drilling technology. Directional drilling has many benefits, but also some limitations. For instance, directional drilling may be employed to avoid sensitive or inaccessible surface features, increase the area that a borehole contacts a producing formation, and when multiple directional wells are drilled from the same vertical borehole or from the same surface location, reduce drilling time, associated waste volumes and emissions, and provide greater protection of sensitive environments. Most of this technology will be tested first in other regions where economic returns on investment are higher than in the Planning Area. Where technology is shown to provide significant cost benefits, local operators will begin to apply those methods when appropriate.

Directional and Horizontal Drilling and Completion Activity

In addition to the benefits of directional and horizontal drilling outlined above, such boreholes will often be allowed to “drift” updip along the flanks of geologic structures (e.g., along the axis of a plunging anticline), thereby naturally contacting more of the producing formation. Depending on subsurface geology, technology advances now allow operators to deviate boreholes by anywhere from a few degrees to completely horizontal. Deviation allows operators to reach reservoirs that are not located directly beneath the drilling rig, or to allow the borehole to contact more of the reservoir. In some cases directional drilling may be used specifically for avoidance of unfavorable surface locations. Directional wells also have the benefit of providing the operator with the option of drilling multiple wells from the same location, substantially reducing the surface disturbance and potentially avoiding environmentally sensitive areas.

Drilling and completion costs for directional and horizontal wells are typically significantly higher than for conventional vertical boreholes, even when the cost savings associated with reduced need for surface disturbance is taken into account. Eustes (2003) and Fritz and others (1991) identified the following specialized requirements and risk factors unique to horizontal and directional drilling that can affect drilling and completion costs for these types of wells:

- specialized equipment (e.g., mud motors, measurement while drilling tools) and specially trained personnel,
- a larger drilling rig and associated equipment,
- casing and drilling string modifications to address problems associated with ovality and bending stresses,
- increased risk of borehole damage due to unique tectonic stresses,
- slower penetration rates lengthens overall drilling time on location, and/or
- increased torque and drag on borehole equipment.

In addition to increased costs, the risk of losing the well due to geologic and/or mechanical failures is also greater in directional and especially horizontal boreholes than in conventional vertical boreholes. As a result of these increased costs and risk, operators tend to prefer vertical over directional or horizontal boreholes unless special circumstances exist that make such drilling a necessity or economically attractive. As an example, the geology of a reservoir may be such that a vertical borehole may only contact a few feet of the productive horizon, while a horizontal borehole may be able to contact tens to thousands of feet depending on factors such as how the well is completed and the areal extent of the pool. In a case such as this, the operator must make the determination that the increased potential for productivity outweighs the inherent risks involved in directional and horizontal drilling.

The majority of oil and gas wells in the Planning Area have traditionally been drilled vertically. Of the more than 13,000 wells drilled in the Planning Area, only 205 boreholes were drilled directionally and 105 were drilled horizontally (IHS Energy Group, 2009). The vertical wells producing in the Planning Area are completed in a variety of formations for both gas and oil. Vertical well depths range from a number of dry holes drilled only a few tens of feet deep to over 16,000 feet. Horizontal wells in the Planning Area have boreholes as long as 14,505 feet (vertical depth plus horizontal lateral distance), though the deepest (true vertical depth) horizontal well was drilled to 12,748 feet, and contained a horizontal lateral of 1,267 feet. Similarly, directional wells in the Planning Area have boreholes (vertical depth plus horizontal lateral distance) as long as 16,425 feet. Since most directional well bores are S-shaped, the true vertical depth and measured depths (borehole lengths) are usually within a few percent of each other.

Figure 34 shows the locations of directional and horizontal wells drilled within the Planning Area through May 11, 2009 (IHS Energy, 2009). Of the 205 directional wells, 11 were completed as either service or injection wells, 84 were abandoned (81 dry wells, three junked), four were temporarily abandoned, two were in drilling status, and there was one producing gas well and 103 producing oil wells.

The earliest known directional well drilled in the Planning Area is the Marlin Oil Company’s Ollie #8-11 well in an unnamed field completed in 1982 (IHS Energy, 2009). This oil well was completed in the Minnelusa Formation, though it only produced 387 barrels of oil from December 1982 through February 1983, and is currently in use as a water injection well. The most recent productive directional well drilled was Ballard Petroleum's Geis Federal #43-29HP well in the Gaither Draw Field (Figure 34), spud October 21, 2008, and currently producing oil and gas from the Parkman Sandstone of the Mesaverde Formation.

Directional wells have been drilled to various formations throughout the basin margin; however, the majority of the directional wells drilled in the Planning Area have tested the Minnelusa Formation (171 of 205 wells). Most of these are located in various small fields in the eastern portion of the Planning Area (Figure 34).

Seventy-five different operators have drilled the 205 directional wells in the Planning Area. Those operators that have each drilled 10 or more wells are Lario Oil & Gas Company (20 wells), and Trend Exploration, Limited (18 wells). The majority (167 wells) have been drilled by companies who each have drilled less than 10 directional wells in the Planning Area.

Horizontal boreholes have been used with less frequency in the Planning Area with only 105 drilled as of May, 2009 (Figure 34). Twelve of the 105 boreholes were abandoned (10 dry and 2 junked), four were completed as water injection wells, 86 as producing oil wells, and 3 are in drilling status (IHS Energy, 2009). There are no horizontal gas wells in the Planning Area. The majority of the oil wells have produced from the following formations:

- Parkman Sandstone – 57 boreholes,
- Sussex Sandstone – 9 boreholes, and
- Minnelusa Formation – 8 boreholes.

The earliest known horizontal borehole, the Conoco North Tisdale #67 well in North Tisdale Field (Figure 34), was completed in 1990 (IHS Energy Group, 2009). This oil well was a successful completion in the Crow Mountain Sandstone (Curtis). Several other horizontal boreholes in this field are part of the oil mining operation of the Lakota Formation, though the North Tisdale #67 well is not and produces from a deeper reservoir. The most recent completed horizontal borehole drilled was the EOG Resources Crossbow #3-19H well in an unnamed field in section 19 of township 41 north, range 81 west. It was spudded April 27, 2008, and projected to test the Niobrara Formation. Its current status is unknown.

While several fields contain horizontal boreholes, nearly half (52) have been drilled in a recent westward extension of House Creek Field (Figure 34).

Twenty-three different companies drilled the 105 horizontal boreholes in the Planning Area, with El Paso Exploration & Production Company and Medicine Bow Operating Company drilling the majority (20 and 33 boreholes, respectively) (IHS Energy, 2009). Five other companies have drilled five or more horizontal boreholes in the Planning Area. Ballard Petroleum, Citation Oil & Gas, and DCD Incorporated have each drilled five, while ExxonMobil and Yates Petroleum have each drilled six.

While only 105 horizontal boreholes have been drilled in the Planning Area, it should be noted that as of May 11, 2009, there were 32 permitted but not yet spudded horizontal boreholes. Several formations could conceivably contain resource plays which generally lend themselves to horizontal completions. The U.S. Geological Survey's 2006 assessment of undiscovered oil and gas resources in the Powder River Basin identified the Mowry Shale and Niobrara Formation as two such potential plays, though others may exist as well.

Reverse Circulation Drilling

Reverse circulation drilling uses a dual-wall drill string. Drilling fluid is carried to the bit between the outer and inner wall of the drill pipe and cuttings and fluid are returned to the surface in the inner part of the pipe. Reverse circulation drilling appears to be an ideal system for drilling and producing tight low- or under-pressured formations that could be easily damaged by conventional drilling. K2 Energy of Calgary has applied this technology to successfully drill and test gas wells in the low-pressure (formation pressure estimated at 150 pounds per square inch) Bow Island Formation on the Blackfeet Indian Reservation and in the Montana Thrust Belt (Mackay, 2003). The method has also been used for water well drilling in Campbell County. This drilling method has not yet been reported to be used for oil and gas drilling projects in the Planning Area.

Slimhole Drilling and Coiled Tubing

Slimhole drilling—a technique used to tap into reserves in mature fields—has not yet been used much in the Rocky Mountain Area. At Madden Field, southwest of the Planning Area, some Lower Fort Union Formation wells have been drilled using slimhole drilling technology. Domain Energy drilled three slimhole wells in the Powder River Basin. It has the potential to improve efficiency and reduce costs of both exploration and development drilling. Coiled tubing—used effectively for drilling in reentry, underbalanced, and highly deviated wells—is often used in slimhole drilling. Most coiled tubing rigs are limited to relatively shallow drilling. They have been used at Teapot Dome Field just south of the Planning Area. More than 1,300 wells in the Planning Area have been drilled to depths less than 5,000 feet (Figure 33). Future wells drilled in this depth range would be amenable to coiled tubing rigs.

A review of coiled tubing drilling and intervention (well work during the life of a well) and its advantages, disadvantages, and limitations was presented for the U.S. Department of Energy (2005). Most likely, future applications may be for drilling shallow development wells (including coalbed natural gas wells), reservoir data monitoring holes, shallow re-entry wells, and deeper exploration holes (Spears & Associates, Inc., 2003). Brown (2006) has reported that slimhole drilling with coiled tubing may soon begin to replace conventional rotary drilling in the shallow depths across the United States. He reported that cost savings can range from 25 to 35 percent per hole, and other advantages include:

- good hole quality,

- improved safety,
- minimal cuttings, and
- reduced chance of damaging underpressured formations.

Coiled tubing will most likely be first used in some workover situations in the Planning Area. We expect both of these drilling and completion techniques to be used more often in the future. U.S. Department of Energy (1999) has identified the environmental benefits of using these techniques, which include:

- lower waste volumes,
- smaller surface disturbance areas,
- reduced noise and visual impacts,
- reduced fuel use and emissions, and
- protection of sensitive environments.

<u>Light Modular Drilling Rigs and Pad Drilling</u>

Now in production, new light modular drilling rigs can be more easily used in remote areas and are quickly disassembled and moved. Rig components are made with lighter and stronger materials and their modular nature reduces surface disturbance impacts. Also, these rigs reduce fuel use and emissions. Use of this type of rig in the Planning Area is not likely in the near future. Other Rocky Mountain plays (western Wyoming, western Colorado, and North Dakota) have a higher priority for new rigs since more prolific reservoirs are being developed in those locations than reservoirs are capable of within the Planning Area.

Light modular rigs also have potential for use in situations where pad drilling is being used. Pad drilling refers to the drilling of multiple directional boreholes from one surface location. Pads are the flat graded land surfaces that serve as the foundation for the drilling rig. Since modular rigs allow quicker breakdown and movement to new locations, they reduce time to drill and rig costs. Several formations could conceivably contain resource plays which generally lend themselves to horizontal completions and thus pad drilling. The U.S. Geological Survey's 2006 assessment of undiscovered oil and gas resources in the Powder River Basin identified the Mowry Shale and Niobrara Formation as two such potential plays, though others may exist as well.

<u>Pneumatic Drilling</u>

Pneumatic drilling is a technique in which boreholes are drilled using air or other gases rather than water or other drilling liquids. This type of drilling can be used in mature fields and formations with low downhole pressures and where formations are sensitive to the fluids commonly used in drilling. Some fields in the Planning Area meet these criteria. It is an important tool that can be used when drilling horizontal wells, so it could be used in those types of situations in the future. This type of drilling significantly reduces waste, shortens drilling time, cuts surface disturbance, and decreases power consumption and emissions.

Measurement-While-Drilling

Measurement-while-drilling systems measure borehole and formation parameters during the actual drilling process. These systems allow more efficient and accurate drilling. They can reduce costs, improve safety of operations, reduce time on site, and fewer wells may need to be drilled. At present, measurement-while-drilling would be critical for use in drilling horizontal boreholes within the Planning Area. In the future, use of this type of drilling system may become more widespread and may be used when drilling other types of directional boreholes.

Improved Drill Bits

Advances in materials technology and bit hydraulics have yielded tremendous improvement in drilling performance. Latest-generation polycrystalline diamond compact bits drill 150 to 200 percent faster than similar bits just a few years ago (U.S. Department of Energy, 1999). Additional improvements have continued to be made to enable faster drilling. Environmental benefits of improved bits include:

- lower waste volumes,
- reduced maintenance and workovers,
- reduced fuel use and emissions,
- enhanced well control,
- less time on site, and
- less noise.

Reducing time the rig is on the drill site reduces potential impacts on soils, groundwater, wildlife, and air quality.

Summary of Current Completion Techniques

Standard completion techniques for the Planning Area will be described below. Once the operator determines that a well should be completed for production, the first step is to place casing in the borehole and cement it in-place. Since the potential producing zones are then sealed off by the casing and cement, perforations (holes made through the casing and cement and into the formation) are made in order for the oil and/or gas to flow into the borehole. The casing also serves to protect sources of groundwater from contamination by oilfield fluids.

Some form of hydraulic fracturing is then usually used to improve hydrocarbon flow into the borehole. Hydraulic fracturing of reservoirs can enhance well performance, minimize drilling, and allow the recovery of otherwise inaccessible oil and gas resources. The flow of hydrocarbons is restricted in some low-permeability, tight formations and in nonconventional reservoirs (such as coalbed natural gas), but can be stimulated by hydraulic fracturing to produce economic quantities of hydrocarbons. Fluids are initially pumped into the formation at pressures high enough to cause fractures to open in the reservoir rock. Sand slurry is pumped into the opened fractures, which keeps the fractures propped open, allowing hydrocarbons in the reservoir to more easily enter the borehole. Improvements such as carbon dioxide-sand fracturing, new types of additives, and fracture mapping, promise more effective fractures and greater ultimate hydrocarbon recovery.

A limited number of horizontal wells have been drilled to date. New types of horizontal fracturing technology will likely be used to stimulate these types of wells in the future. Development could be similar to that used to stimulate the Bakken Formation Middle Member in North Dakota. For horizontal boreholes, multi-stage fracture stimulations could be used. The Energy Information Administration (2006b) has reported that once the Bakken Formation has been fractured an uncemented pre-perforated liner is installed in the borehole.

The final completion step is to place production tubing in the borehole to carry the hydrocarbons to the surface. At the surface it is connected to a Christmas tree (a collection of valves) used to control the well's production.

Drilling and Completion Costs

Expenditures for exploration and development in the U.S. onshore increased 30 percent from 2005 to 29 billion dollars in 2006 (Energy Information Administration, 2007c). This was more than three times the average annual expenditure level in the 1990s and the highest amount since 1982. Most of the expenditures in 2006 were for development (26 billion dollars).

The National Petroleum Council (2003) reported drilling and completion costs for vertical wells in the Powder River Basin region. All cost components such as permitting, location construction, mobilization, rentals and services, tangible items, and stimulations were assumed to be included in these costs. They reported that the average gas well cost for wells in four depth ranges. Those costs were:

- 0 to 5,000 feet 83 thousand dollars,
- 5,000 to 10,000 feet 1,061 thousand dollars,
- 10,000 to 15,000 feet 1.871 million dollars, and
- 15,000 to 20,000 feet 5.412 million dollars.

The National Petroleum Council (2003) also reported an average drilling and completion cost for oil wells. Those costs were:

- 0 to 5,000 feet 159 thousand dollars,
- 5,000 to 10,000 feet 710 thousand dollars,
- 10,000 to 15,000 feet 1.238 million dollars, and
- 15,000 to 20,000 feet 3.334 million dollars.

Reported dry hole well costs were estimated to be:

- 0 to 5,000 feet 159 thousand dollars,
- 5,000 to 10,000 feet 378 thousand dollars,
- 10,000 to 15,000 feet 1.935 million dollars, and
- 15,000 to 20,000 feet 2.444 million dollars.

Since 2003, operators in the Rocky Mountain region had been faced with increases in drilling and completion costs. Drilling rates had increased 20-50 percent (Rocky Mountain Oil Journal, 2005) and service costs had also increased. Drilling rates and service costs continued to increase into 2008 and rig shortages affected most of the Rocky Mountain region. Costs have since declined to some extent and rigs are now available, at least in the short-term.

SUMMARY OF CONVENTIONAL OIL AND GAS PRODUCTION AND ABANDONMENT TECHNIQUES

Once production begins application of reservoir management procedures are needed to ensure the maximum hydrocarbon production at the lowest possible cost, with minimal waste and environmental impact. In earlier days, recovery was only about 10 percent of the oil-in-place in a given field, and sometimes, the associated natural gas was vented or flared. Newer recovery techniques have allowed the production of up to 50 percent of the oil-in-place. Also, 75 percent or more of the natural gas-in-place in a typical reservoir is now recovered. Operators have also taken significant steps in reducing production costs. U.S. Department of Energy estimated that costs of production had decreased from a range of nine to 15 dollars per barrel of oil equivalent in the 1980's to an average of about five to nine dollars per barrel of oil equivalent in 1999.

Operating costs in the U.S. have been rising in recent years. Annual Rocky Mountain operating costs rose to about 55,000 dollars per 12,000 foot well in 2005, as reported by Kim (2007).

Since 1990, most reserve additions in the United States (89 percent of oil reserve additions and 92 percent of gas reserve additions) have come from finding new reserves in old fields (U.S. Department of Energy, 1999). Our review indicates that most recent reserve additions in the Planning Area have come from existing oil fields. The U.S. Department of Energy (1999) reports that about half of new reserve additions in the United States are from more intensive development within the limits of known reservoirs. They report that the other half of reserve additions has come from finding new reservoirs in old fields and extending field limits.

The Energy Information Administration (2006c) has shown that the cost of equipping and operating gas wells in the Rocky Mountains is higher than the average for onshore 48 contiguous states. Cleveland (2003) indicated a number of reasons why Rocky Mountain gas wells may be more expensive to equip and operate. Reasons for extra costs that may apply to the Planning Area are:

- remoteness and cold temperatures which often requires dehydrators and line heaters, more expensive types of steel casing, and insulation of surface equipment; and
- workovers and preventive maintenance is more frequent which minimizes shut-in days in the winter when well site access is difficult.

Recovering oil and gas from a geologic reservoir often occurs in a staged process using different recovery techniques (or a combination of techniques) as the reservoir is drained. Traditionally, processes were referred to as primary, secondary, or tertiary depending on when the process was applied. However, as technology has improved and the price of oil and gas has increased, reservoirs that had previously been bypassed are now being tapped using secondary or tertiary processes from the outset. Therefore, the terms "secondary" and "tertiary" are seeing less usage, or are more narrowly defined. "Secondary recovery" has become synonymous with water flooding and gas (not carbon dioxide) injection and "enhanced recovery" broadly encompasses any recovery techniques that are not part of primary recovery or waterflooding. The following definitions will be used in this report:

- Primary Recovery - Primary recovery produces oil, gas, and/or water using the natural pressure in the reservoir. Wells may be stimulated to improve the flow of oil and gas to the borehole. Other techniques, including artificial lift, pumping, and gas lift, help extend productive life when a reservoir's natural pressure dissipates.
- Secondary Recovery – Stimulation of reservoir production via injection of water into the producing formation thereby driving oil to production wells, or via injection of gas to expand the gas cap and/or regulate the reservoir pressure.
- Enhanced Oil Recovery - Injection of fluids (e.g., water, surfactants, polymers, or carbon dioxide) or sources of heat (steam or hot water) to stimulate hydrocarbon flow and move hydrocarbons that were bypassed in earlier recovery phases.

According to the U.S. Department of Energy, as much as 90 percent of the oil originally in-place in an oil reservoir is left behind once primary recovery methods are completed (U.S. Department of Energy, 2008a). In other words, the recovery factor (the percent of original oil in place removed from a reservoir) for primary recovery can be as low as 10 percent. However, the primary recovery factor varies depending on oil and reservoir characteristics, but as a general rule 15-20 percent is considered the norm (Sandrea and Sandrea, 2007). Primary recovery relies on the natural pressure found in the reservoir and artificial lift (generally some type of pumping method) to bring hydrocarbons to the surface for production. Once that pressure is depleted, the reservoir must either be abandoned or other methods for recovering additional hydrocarbons must be employed. Historically, many of the methods used to recover additional hydrocarbons were cost prohibitive and a large percentage of the oil or gas in any given reservoir was left behind until cost effective methods off recovery could be developed.

As newly discovered volumes of oil and gas decline and demand, and consequently price, for oil and gas continues to climb, methods for removing additional oil and gas that was previously left behind in reservoirs by primary recovery methods are becoming increasingly utilized. These secondary and enhanced recovery methods all involve some form of artificial stimulation of the reservoir either through the regulation of reservoir pressure or gas cap, or by injecting into wells to physically "push" the oil toward production wells.

Secondary Oil Recovery

The secondary recovery methods most widely used both historically and today, are waterflooding and gas injection (Sandrea and Sandrea, 2007; Williams and Pitts, 1997). In waterflooding, water is injected into the oil-bearing formation and physically displaces the oil down a pressure gradient toward the production wells. Waterflooding is an economical way to recover additional volumes left behind in the primary recovery process and is usually the first method considered after primary methods have ceased to be effective. Gas injection (as a secondary recovery method) is used to expand the gas cap and regulate the reservoir pressure of an oil reservoir or to displace oil immiscibly, i.e., physically pushing the oil toward production wells (Green and Whillhite, 1998). Once secondary recovery is no longer effective in improving recovery factors (or, if they were deemed inappropriate due to reservoir and hydrocarbon characteristics) enhanced recovery methods must then be considered.

Enhanced Oil Recovery

Enhanced oil recovery projects are initiated because of the limited production efficiency of primary and secondary recovery projects (Williams and Pitts, 1997). Green and Whillhite (1998) identified five general enhanced oil recovery categories: mobility-control, chemical, miscible, thermal, and "other" processes (e.g., microbial). With the exception of "other" methods (which is generally a catch-all used for methods that do not fit the other categories) these methods all involve the injection of fluids (e.g., water, surfactants, polymers, or carbon dioxide) or sources of heat (steam or hot water) to stimulate hydrocarbon flow and move hydrocarbons that were bypassed in earlier recovery phases. As with secondary recovery injection methods, enhanced recovery injection causes an increase in pressure gradient between injection wells and production wells, increasing the tendency of oil in the reservoir to flow toward the production wells. Many injection fluids also have additional chemical or physical effects that help mobilize the oil and allow it to be swept towards production wells (Nummedal et al., 2003).

Williams and Pitts (1997) reported that reservoir location can also be important in enhancing an oil recovery project's feasibility. For example, proximity to a carbon dioxide source is a factor in choosing a carbon dioxide injection project. A nearby source of fresh or treatable water is needed for waterflood projects and for use in steamflood or chemical injection projects. Oil and gas prices play a very important role in determining whether the additional costs associated with an enhanced oil recovery project will allow it to be viable economically. Oil and gas prices may also play a part in deciding the specific type of recovery project would be appropriate. There are a large number of small and large sized oil fields within the Planning Area, and a number of different types of enhanced oil recovery projects have been used to increase production from many of these fields. Waterflood injection projects have historically been the predominate method of increasing oil recovery in the Planning Area and fewer floods of different types have been used.

Secondary and Enhanced Recovery Projects in Buffalo Field Office Planning Area

Waterflooding and Gas Injection

In waterflooding the injected fluid is water. Waterflooding typically yields an extra 10 to 25 percent of the original oil in place (Nummedal et al., 2003). Many Wyoming oil reservoirs are good candidates for waterflooding, and waterfloods have been the predominate method used to recover additional oil reserves in the Planning Area.

Gas injection typically refers to the re-injection of produced natural gas into a producing oil formation (as opposed to disposal injection into another formation). In today's market, most produced natural gas is sold rather than re-injected. Currently there are no active secondary recovery gas re-injection projects in the Planning Area.

There have been 208 secondary recovery projects in the Planning Area. Presently, of those 208 projects, two are abandoned, 136 are active, 48 are inactive, 12 have been terminated, and eight have moved into enhanced recovery (Wyoming Oil and Gas Conservation Commission, 2009). There are also two proposed secondary recovery projects which have not yet commenced injection.

Of the active secondary recovery projects, the majority (101) are waterfloods of small Minnelusa Formation fields in the eastern portion of Campbell County (Figure 35). Most of these projects (86) use water from the Cretaceous Fox Hills Sandstone, and/or coproduced water from the Minnelusa Formation as the injected fluid. The active secondary projects in the Planning Area are run by 49 different operators.

Steamflooding

Steamflooding uses heat to mobilize oil and is especially applicable to heavy (viscous) oils that are not easily produced just by pumping. Steam injection into an oil reservoir under pressure thins the oil (lowering viscosity) and increases pressure which helps push the oil toward nearby producing wells. There are no active steamflooding projects in the Planning Area.

Polymer-Enhanced Waterflooding

Polymer-enhanced waterflooding is used to control mobility of injected water. It improves volumetric sweep efficiency and reduces channeling and breakthrough hence it improves overall recovery. The majority of all enhanced recovery projects (54 of 58 projects) in the Planning Area are polymer enhanced waterfloods. Most of these (48) are floods of the Minnelusa Formation in smaller fields located in eastern Campbell County (Figure 35). All but two of the polymer-enhanced waterflood projects in the Planning Area were still active at the end of 2008. There is one active polymer-enhanced waterflood project flooding the Cretaceous Muddy Sandstone. It is of similar size to the aforementioned Minnelusa projects, and also resides in eastern Campbell County. The remaining five projects are either Sussex or Shannon Sandstone floods and are significantly larger than the Minnelusa projects. The locations of these fields and/or units are also shown on Figure 35.

Surfactant Flooding

Adding surfactants to injected water can enhance oil production. A type of surfactant flood called a micellar flood uses a two-step enhanced oil recovery process in which a small quantity of surfactant is injected into the well followed by a larger quantity of water containing a high-molecular-weight polymer which pushes the chemicals through the field and improves mobility and sweep efficiency. These types of projects are expensive and are not often used, and no such projects exist within the Planning Area.

In-Situ Combustion (High Pressure Air Injection)

The terms in-situ combustion and high pressure air injection are used synonymously to describe the process by which pressurized air is injected into hot and deep reservoirs causing spontaneous oxidation/combustion of the oil (Manrique, et al., 2006). The term "thermal process" is also a catch-all sometimes used to describe these as well as hot-water and steam floods (Green and Willhite, 1998), but will not be used here as each recovery method is discussed separately. During in-situ combustion, oxygen (as atmospheric air or in a partially purified mixture) is continuously injected under pressure either by itself (dry) or with water (wet) into the reservoir where spontaneous or artificially initiated combustion causes the lighter hydrocarbons to vaporize and be pushed away from the high pressure injection site toward the producing wells. While not nearly as effective as carbon dioxide injection (another method wherein a gas, in this case carbon dioxide, is injected into the reservoir) in-situ combustion is much more cost effective since the injected gas (usually atmospheric air) would be free. There are presently no active in-situ combustion enhanced recovery projects in the Planning Area.

Carbon Dioxide Injection

At sufficiently high pressures carbon dioxide is miscible with oil, and once dissolved, it:

- Causes oil to swell, and so lowers the oil's viscosity significantly, making it flow more easily and
- Under miscible conditions it reduces forces causing oil to stick to the reservoir rock, again allowing for more oil flow.

Carbon dioxide enhanced recovery processes are typically employed in one of four ways:

- the "huff and puff" method whereby the carbon dioxide is injected, allowed time to react with the oil, followed by pumping in three separate stages,
- injection of a small amount of carbon dioxide, called a "slug," which is followed by water injection and then pumping,
- pulses of carbon dioxide alternated with water pulses (so-called water-alternating-gas method), or
- continuous carbon dioxide injection with concurrent pumping.

The carbon dioxide “huff and puff” method has been effectively used in the Planning Area in three different projects. All three were initially approved in 1990. One is located in the Hartzog Draw Field located in the south-central portion of the Planning Area (Figure 35). The Hartzog Draw project enhances oil production from the Shannon Sandstone in a field which spans several townships. The remaining two projects are both pilot projects in the Sussex and West Sussex units in southeastern Johnson County (approximately 25 miles southwest of Hartzog Draw) (Figure 35). The West Sussex project targeted oil production in the Shannon Sandstone. It was approved in 1990, and has since terminated as a unit (though an exploratory unit of the same name operated by Anadarko Exploration & Production is currently active in the area). The remaining unit, the Sussex Unit, was also approved in 1990 and continues to date as a successful carbon dioxide "huff and puff" enhanced recovery project.

In addition to the "huff and puff" method, there is one "slug" injection project within the Planning Area. Approved in 1980, the Dillinger Ranch Unit injects water and carbon dioxide into the Minnelusa Formation in a small secondary recovery unit in west-central Campbell County (Figure 35).

Carbon dioxide enhanced oil recovery in the U.S. has been constrained by economics, technology, carbon dioxide supply, and pipeline infrastructure. Continuous carbon dioxide injection into the reservoir (miscible flooding method) displaces the oil from the rock and sweeps it toward producing wells. Most of the injected carbon dioxide stays in the reservoir and is sequestered. Some carbon dioxide may move into producing wells where it is separated, recovered, and reinjected. Depending on the efficiency of this flooding process, it can recover an additional five to 20 percent of the original oil-in-place (Nummedal et al., 2003). This flooding process has been working well at a number of fields in other parts of Wyoming (Lost Soldier, Wertz, Salt Creek, and Monell). To date the carbon dioxide gas used in continuous flooding has been coming from the Shute Creek processing plant in southwest Wyoming. To the southwest of the Planning Area, Madden Field contains a large resource of carbon dioxide and could be tapped for future injection projects in the area. Green Rock LLC has proposed a carbon dioxide enhanced oil recovery project that will use carbon dioxide gas from the Lost Cabin Gas Plant at Madden Field to flood at Dillinger Ranch Field. Facilities construction and field redevelopment is expected to start in the fourth quarter of 2009 and pipeline construction is expected to start in 2010.

Nummedal et al. (2003) listed a number of carbon dioxide enhanced oil recovery candidate fields in the Planning Area (Figure 36). Those candidate fields and formations of interest, several of which are already undergoing carbon-dioxide "huff and puff" enhanced recovery (see discussion above), are:

- Gas Draw – Muddy Sandstone,
- Hartzog Draw – Shannon Sandstone,
- Hilight – Muddy Sandstone; Minnelusa Formation,
- House Creek – Sussex Sandstone,
- Kitty – Muddy Sandstone,

- Meadow Creek – Shannon Sandstone,
- Recluse – Muddy Sandstone, and
- Rozet – Muddy Sandstone.

Advanced Resources International (2006) identified and evaluated six large Planning Area oil reservoirs for carbon dioxide enhanced oil recovery in addition to those identified above (Figure 36). Those fields and the formation of interest are:

- Ash Creek – Shannon Sandstone,
- Ash Creek South – Shannon Sandstone,
- Meadow Creek North – Sussex Sandstone,
- Sussex – Shannon, Sussex, and Tensleep sandstones, and
- Timber Creek – Minnelusa Formation.

Hydrogen Sulfide Occurrence

Hydrogen sulfide is a colorless, flammable gas that occurs naturally in most crude oil and many natural gas reservoirs (Levorsen, 1967). Hydrogen sulfide is toxic to humans and animals, and a single breath may provide enough exposure to be fatal (International Programme on Chemical Safety, 1994). It has a characteristic foul, or "rotten egg" odor, and is heavier than air, so it tends to accumulate in low-lying areas. Hydrogen sulfide is an impurity that must be removed from oil or natural gas through desulfurization in oil refineries and natural gas "sweetening" plants (natural gas containing hydrogen sulfide is commonly referred to as "sour gas") (Skrtic, 2006). The presence of hydrogen sulfide in hydrocarbons is problematic not only because it is an impurity that must be removed in processing, but also because it is corrosive to metals both as a free gas and in solution, and because of its toxicity to personnel, wildlife, and the public. On Federal lands, operators are required by law to follow specific safety practices and have public protection plans in place where hydrogen sulfide can "reasonably be expected to be present in concentrations of 100 parts per million or more in the gas stream" (43 CFR 3160).

The Wyoming Oil and Gas Conservation Commission (2009) catalogs all fields known to contain hydrogen sulfide. To date, no fields in the Planning Area have been identified as containing hydrogen sulfide gas.

Acid Gas Removal and Recovery

Before natural gas or oil can be transported safely, any hydrogen sulfide or carbon dioxide gas must be removed. Special plants are needed to recover these unwanted gases and sweeten the hydrocarbon product for sale. Improvements in the removal process have made it possible to produce sour natural hydrocarbon resources, almost eliminate noxious emissions, and recover almost all of the elemental sulfur and carbon dioxide for later sale or disposal. There is only one natural gas processing plant in the Planning Area (Hilight Plant in Campbell County); however, this plant is not designed to remove elemental sulfur or carbon dioxide. Presently producing oil and gas formations within the

Planning Area do not produce hydrogen sulfide or carbon dioxide, or they produce in such minor amounts that removal is not required.

Artificial Lift Optimization

Artificial lift is used to produce oil once reservoir pressure declines and natural processes can no longer push the oil to the surface. Improvements in artificial lift have enhanced production, lowered costs, and lowered power consumption, which reduce air emissions. Artificial lift is used to recover oil from some many of the older fields in the Planning Area.

Glycol Dehydration

In the Planning Area, dehydration systems use Glycol to remove water from wet natural gas before the gas can be directed to a pipeline. During operation, these dehydration systems may vent methane, other volatile organic compounds, and hazardous air pollutants. Improvements to these systems have allowed increased gas recovery and have reduced unwanted emissions.

Produced Water Management

Coproduction of a variable amount of water with oil and gas is unavoidable at most locations. Figure 32 shows the annual volume of produced water from wells in the Planning Area. Wyoming allows water produced with oil and gas to be disposed of by injection in a permitted disposal or enhanced recovery well, evaporation in an approved pond, or discharge into a surface water source through an outfall permit.

Figure 37 documents the geographic distribution of water quality samples across the Planning Area and shows the distribution of sampled salinity, expressed as total dissolved solids, in those water samples. This information is from a U.S. Geological Survey (2008a) database of water quality samples. Water quality information is available for 1,337 samples and total dissolved solids range from 0 to 307,713 milligrams per liter. Water quality sample distribution is:

- less than 5,000 milligrams per liter – 343 samples,
- 5,000 to 9,999 milligrams per liter – 249 samples,
- 10,000 to 49,999 milligrams per liter – 563 samples, and
- Greater than 50,000 milligrams per liter – 182 samples.

The Bureau considers total dissolved solids concentrations of less than 10,000 milligrams per liter to be fresh water. Approximately 44 percent of these water quality samples fall within this range. Seventy one of these samples are from wells in unnamed fields. Oil and gas fields (Figure 37) with at least 15 samples (and formations sampled) recording total dissolved solids of less than 10,000 milligrams per liter are:

- Ash Creek and Ash Creek South – 46 samples – Bighorn Dolomite, Cody Shale, Madison Limestone, Teapot Sandstone, Parkman Sandstone, Shannon Sandstone, and Steele Shale (Ash Creek sand member);

- Dead Horse Creek – 16 samples – Fort Union Formation, Fox Hills Sandstone. Lance Formation, and Parkman Sandstone;
- Meadow Creek (including Meadow Creek, and Meadow Creek East, West, and North fields) – 58 samples – Frontier Formation, Lakota Formation, Shannon Sandstone, Sussex Sandstone, and Tensleep Sandstone;
- Rocky Point – 16 samples – Madison/Pahasapa Limestone, Minnelusa Formation, and Muddy Sandstone;
- Sussex – 32 samples – Amsden Formation, Frontier Formation, Madison Limestone, Parkman Sandstone, Shannon Sandstone, Sussex Sandstone, and Tensleep Sandstone;
- Tisdale North – 20 samples – Bighorn Dolomite, Lakota Formation, Curtis Sandstone (Crow Mountain Sandstone), and Tensleep Sandstone; and
- Ute – 24 samples – Muddy Sandstone, and Fox Hills Sandstone.

Approximately 56 percent of water quality samples have a total dissolved solids concentration of greater than 10,000 milligrams per liter. Oil and gas fields (Figure 37) with at least 15 samples (and formations sampled) recording total dissolved solids greater than 10,000 milligrams per liter are:

- Dead Horse Creek– 48 samples – Mesaverde Formation, Parkman Sandstone, Pierre Shale, and Tensleep Sandstone;
- Halverson – 22 samples – Minnelusa Formation;
- Hilight – 18 samples – Muddy Sandstone, and Teapot Sandstone;
- Meadow Creek (including Meadow Creek, and Meadow Creek East, West, and North fields) – 85 samples – Cloverly Formation, Frontier Formation, Lakota Formation, Shannon Sandstone, and Tensleep Sandstone;
- Raven Creek – 29 samples – Minnelusa Formation;
- Rozet (including Rozet, and Rozet East, West and South fields) – 57 Samples – Minnelusa Formation, Muddy Sandstone, and Newcastle Formation;
- Sandbar West – 17 samples – Muddy Formation and Newcastle Formation;
- Sussex – 27 samples – Frontier Formation, Lakota Formation, Shannon Sandstone, Sundance Formation, and Sussex Sandstone;
- Timber Creek – 17 samples – Minnelusa Formation, Muddy Formation, and Newcastle Formation; and
- Ute – 23 samples – Muddy Sandstone.

A new freeze-thaw/evaporation process has been shown to be useful in separating out dissolved solids, metals, and chemicals that are contained in water produced along with the oil and gas production of wells. In 1998, this type of produced water facility was determined to be successful in southwestern Wyoming (PTTC, 2002). It could probably be successfully used in the cold climate of the Planning Area, in locations where production of poor quality water cannot be disposed of by other means.

The Gas Technology Institute tested the performance and costs associated with the application of electrodialysis to produced water management (Hayes, 2004). A pilot was set up south of the Planning Area at a conventional-well site in the Wind River Basin near Lysite, Wyoming. The produced water at this site contained about 8,300 to 10,000 milligrams per liter of total dissolved solids. This pilot showed that the electrodialysis process was capable of demineralizing a conventional gas produced water stream from 9,000 milligrams per liter to 1,000 milligrams per liter for only three cents per 42 gallon barrel, and one cent per barrel to reach 2,500 milligrams per liter. The pilot has yet to be replicated or expanded upon in the Planning Area; however, the process appears viable and could reasonably be expected to be implemented at sites within the Planning Area during the analysis period.

Leak Detection and Low-bleed Equipment

New technology is facilitating the detection of hydrocarbon leaks in equipment. The replacement of equipment that bleeds significant gas allows for increased worker safety and reduced emissions of methane. Not allowing gas to bleed from equipment increases recovery rates and usage of this valuable resource. No record of use of this equipment is available for the Planning Area.

Downhole Water Separation

At least some water is produced along with the hydrocarbons in most wells within the Planning Area. It is most often stored, at least temporarily, in tanks on the well site. It is then transported via pipeline or truck to approved disposal pits, or it may be injected into approved subsurface zones. Emerging technology to separate oil and water could cut produced water volumes by as much as 97 percent in applicable wells (U.S. Department of Energy, 1999). By separating the oil and water in the borehole and injecting the water directly into a subsurface zone, only the oil needs to be brought to the surface. This new technology could help to minimize environmental risks associated with bringing water to the surface where it then has to be handled, treated, and then disposed of. It would also reduce the costs of lifting and disposing of produced water. In addition, surface disturbance could be reduced, oil production could be enhanced and marginal or otherwise uneconomic wells could become economic. Although trials of downhole water separation have occurred at other locations within Wyoming (Veil and Quinn, 2004), there do not appear to presently be any ongoing projects in the Planning Area.

Vapor Recovery Units

Vapor recovery can reduce a lot of the fugitive hydrocarbon emissions that vaporize from crude oil storage tanks, mainly from tanks associated with high-pressure reservoirs, high vapor releases, and large operations. The emissions usually consist of 40 to 60 percent methane, along with other volatile organic compounds, and hazardous air pollutants (U.S. Department of Energy, 1999). Where useable, this technology can capture over 95 percent of these emissions. No record of use of this equipment is available for the Planning Area.

PLANT SITES

One active plant that processes natural gas and so liquids is located within the Planning Area (Wyoming Oil and Gas Conservation Commission, 2009). Western Gas Resources operates the Hilight Plant in section 26 of township 45 north, range 71 west (Campbell County). In April, 2009 the plant received 719,473,000 cubic feet of gas.

UNDERGROUND GAS STORAGE

Produced gas can be stored in some existing good quality reservoirs that have already been depleted of their native gas content. The objective of gas storage is to allow lands to be used to store natural gas during periods of excess production so that those supplies can be made available to meet peak gas demands and to maximize the efficiency of the gas delivery system. At present there is one active and one inactive gas storage projects within the Planning Area (Wyoming Oil and Gas Conservation Commission). They are:

- Billy Creek – This active project was approved in 1941, stores gas in the Frontier Formation, and is operated by Williston Basin Interstate Pipeline.
- Meadow Creek North – This inactive project was approved in 1967, stored gas in the Frontier Formation, and was operated by Conoco, Incorporated.

ASSESSMENTS OF OIL AND GAS RESOURCES

The Energy Information Administration has recently provided forecasts of United States energy supply (Energy Information Administration, 2008b). Technically recoverable (see Glossary) United States oil resources (as of January 1, 2006) were estimated to be 178 billion barrels. The technically recoverable natural gas resource was estimated to be 1,531 trillion cubic feet. The Rocky Mountains account for about 37 percent of the natural gas and 17 percent of the oil projections of the technically recoverable resource base on public lands in the lower 48 states (Humphries, 2004).

A number of recent assessments of technically recoverable (see Glossary) gas resources have been made for the Rocky Mountain region. Each estimate has been prepared using somewhat different assumptions. They all show a large natural gas resource for the Rocky Mountain region.

- The Energy Information Administration (2003) uses a natural gas resource base of 383 trillion cubic feet for the Rocky Mountain region.
- The Potential Gas Committee (2003) estimated 288 trillion cubic feet of natural gas; including 50 trillion cubic feet of proved reserves (see Glossary).
- As part of a study done in compliance with the Energy Policy and Conservation Act Amendments of 2000 (U.S. Departments of Interior, Agriculture, and Energy, 2003) the U.S. Geological Survey estimated the technically recoverable gas resource for five basins in the Rocky Mountain region at 226 trillion cubic feet. Of that total, they estimated a conventional gas resource of 13 trillion cubic feet, tight gas sand and shale gas resources of 127 trillion cubic feet, 43 trillion cubic feet of coalbed natural gas, and 43 trillion cubic feet of proved reserves.
- The National Petroleum Council (2003) estimated 284 trillion cubic feet of natural gas for the Rocky Mountain region. The Council also presented a

The National Petroleum Council (2003) has divided remaining natural gas resources into proved natural gas reserves, proved growth reserves, and undiscovered resources (see Glossary for descriptions of each). They further divided undiscovered resources into conventional and nonconventional (also known as unconventional) resource types (see Glossary for descriptions of each).

As of January 1, 2002, the National Petroleum Council (2003) estimated Rocky Mountain region proved natural gas reserves to be 50 trillion cubic feet. The Energy Information Administration (2004) was able to separately assess proved tight sand gas reserves (26.8 trillion cubic feet) and proved coalbed natural gas reserves (14.8 trillion cubic feet) for the Rocky Mountain region. Growth of proved gas reserves in the Rockies was estimated at 26 trillion cubic feet (National Petroleum Council, 2003). Finally, undiscovered resources for conventional gas were estimated to be 173 trillion cubic feet, while unconventional gas resources were estimated to be 209 trillion cubic feet (National Petroleum Council, 2003).

The U.S. Department of Energy (2003) has reported that "as geologic knowledge and technology for finding and producing natural gas have improved, the estimated volume of natural gas resources in the Rocky Mountain States has grown." They assumed that as long as investment continued towards expanding the geologic knowledge base and technology progress, then there would be a continued upward trend in future resource assessment volumes and recovery would be expected to continue to increase, at least through 2015. These reserve additions will be needed in the future to replace those that are being depleted due to production and consumption.

"The importance of natural gas as a primary energy source in the United States has grown considerably during the past decade" (Curtis and Montgomery, 2002). Rising demand in this country will result in a 1.1 percent average annual increase in our consumption of energy to 2030 (Energy Information Administration, 2007a). During that period natural gas consumption will rise from 21.08 trillion cubic feet in 2005 to 26.9 trillion cubic feet in 2030 (Energy Information Administration, 2007b). Our domestic production rose from 17.7 to 19.7 trillion cubic feet (11.3 percent increase) for the 1990 to 2000 period (Curtis and Montgomery, 2002) and then dropped to 18.3 trillion cubic feet in 2005. Domestic production is expected to rise to 20.6 trillion cubic feet in 2030 (Energy Information Administration, 2007b). North American producing areas are expected to provide 75 percent of long-term United States gas needs, but they will be unable to meet the entire projected demand (National Petroleum Council, 2003). The gap between consumption and production has necessitated a rise in imports and concern about our future United States energy supply.

Oil and gas produced within the Planning Area to date, has helped supply a portion of this countries demand. The Planning Area will also continue to help meet rising national demand by supplying additional oil and gas that has not yet been discovered. A recent oil and gas resource assessment has been prepared that covers most of the Planning Area. This assessment provides an indication of the range of undiscovered resource volumes that could be available for exploration, development, and production through the year 2028.

We will present below only the results of the latest (and most current) U.S. Geological Survey assessment, which covers the entire Planning Area. Combined, the most current assessment provides an idea of the range of oil and gas resources that may be available for exploration and development in the Planning Area through 2028. In addition, we will present information about how the departments of Interior, Agriculture, and Energy used these resource estimates in their inventory of Federal lands and the critique of assessment prepared by RAND Science and Technology.

U.S. GEOLOGICAL SURVEY RESOURCE ASSESSMENTS

The U.S. Geological Survey is responsible for preparing the National Oil and Gas Resource Assessment for all provinces within the United States. Their "1995 National Assessment of United States Oil and Gas Resources" (Beeman et al., 1996: Charpentier et al., 1996: Gautier et al., 1996) presents information about potential undiscovered accumulations of oil and gas in 71 geologic or structural provinces within the United States. The Powder River Basin Province assessed at that time covered the Planning Area.

As part of a study prepared in compliance with the Energy Policy and Conservation Act Amendments of 2000 (U.S. Departments of Interior, Agriculture, and Energy, 2003) the U.S. Geological Survey prioritized oil and gas assessment studies for certain basins. Initial updated analyses covering the Powder River Basin Province in the Planning Area have been prepared in response to their new priorities (Anna and Cook, 2008; and U.S. Geological Survey, 2006a, 2003, and 2002). In these reports the U.S. Geological Survey has updated their quantitative estimates of the undiscovered oil and gas resources for the province.

The Powder River Basin Province occupies the entire Planning Area (Figure 38). The Powder River Basin Province is a major Laramide (Late Cretaceous through Eocene) intermontane structural-sedimentary basin covering more than 34,000 square miles in northeastern Wyoming and a small part of southeastern Montana (Dolton and Fox, 1996), with a large part lying within the Planning Area. The basin is an asymmetric syncline with an axis along the westernmost margin and a northwest to southeast orientation (Figure 4). It is flanked by the Bighorn Mountains on the west, the Casper Arch-Laramie Range on the southwest and south, the Hartville Uplift on the southeast, the Black Hills on the east, and the Miles City Arch on the northeast. The Powder River Basin contains a thick sequence of Phanerozoic strata that exceeds 18,000 feet in thickness near the basin axis (Dolton and Fox, 1996).

In their newest assessments, the U.S. Geological Survey (2006a, 2003, and 2002) divided the Powder River Basin Province into "total petroleum systems" and "assessment units" (see Glossary definitions) rather than "plays." All Planning Area fields lie the within Powder River Basin Province.

Six total petroleum systems and 14 assessment units have been identified in the Powder River Basin Province and all assessment units in each total petroleum system lie wholly or at least partly within the Planning Area. Conventional oil and gas resources are defined by the following total petroleum systems and associated assessment units:

- Pennsylvanian-Permian Composite total petroleum system – Minnelusa-Tensleep-Leo assessment unit (Figure 39, not available),
- Mowry total petroleum system – Fall River-Lakota Sandstone (Figure 40, not available) and Muddy Sandstone (Figure 41, not available) assessment units,
- Niobrara total petroleum system – Frontier-Turner Sandstones (Figure 42, not available), Sussex-Shannon Sandstones (Figure 43, not available), and Mesaverde-Lewis Sandstones (Figure 44, not available) assessment units,
- Tertiary-Upper Cretaceous Coalbed Methane total petroleum system –Eastern Basin Margin Upper Fort Union Sandstone assessment unit (Figure 45), and
- Paleozoic-Mesozoic total petroleum system – Basin Margin (Figure 46, not available) assessment unit.

Continuous oil and gas resources are defined by the following total petroleum systems and associated assessment units:

- Tertiary-Upper Cretaceous Coalbed Methane total petroleum system – Wasatch Formation (Figure 47), Upper Fort Union Formation (Figure 48), and Lower Fort Union-Lance Formation (Figure 49) assessment units,
- Mowry total petroleum system – Mowry Continuous Oil (Figure 50) assessment unit,
- Niobrara total petroleum system – Niobrara Continuous Oil (Figure 51) assessment unit, and
- Cretaceous Biogenic Gas total petroleum system – Shallow Continuous Biogenic Gas (Figure 52) assessment unit.

The U.S. Geological Survey has only made available a limited amount of information for the 14 assessment units within the Planning Area. In addition, map data is not presently available for seven of the 14 assessment units and will be included in a latter version of this report.

The U.S. Geological Survey (2006a) estimated undiscovered technically recoverable resource (see Glossary) quantities of oil and gas that could be added to the proved reserves within each assessment unit, using a forecast span of 30 years. A 30-year forecast span affects the minimum undiscovered accumulation (see Glossary) size, the number of years in the future that reserve growth is estimated, economic assessments, the accumulations chosen for consideration, and the assessment of risk. Below, we summarize the estimated hydrocarbon volumes in the 14 conventional and continuous assessment units, which lie wholly or at least partly within the Planning Area.

Hydrocarbon volumes are not presently available for seven of the 14 assessment units. A full discussion of estimated hydrocarbon volumes will be included in a latter version of this report.

Dyman et al. (1997) showed that the Powder River Basin Province contains sedimentary rocks at depths greater than 15,000 feet. Productive reservoir sediments are known in these rocks at depths below 15,000 feet (see previous discussion). The U.S. Geological Survey has not made a recent estimate of the potential petroleum resource at these depths. The Potential Gas Committee (2003) did estimate that traditional resources of natural gas below 15,000 in the Powder River Basin were one trillion cubic feet.

DEPARTMENTS OF INTERIOR, AGRICULTURE, AND ENERGY RESOURCE ASSESSMENTS

The U.S. Departments of Interior, Agriculture, and Energy (2003, 2006, and 2008) have contributed to three publications that inventoried oil and gas resources in parts of the Rocky Mountains. Only the most recent report included information for the Bighorn Basin part of the region. In addition, the reports discussed restrictions to development of oil and gas resources in these areas.

The Energy Information Administration (2007b) projected a crude oil technically recoverable resource for the Rocky Mountains of 19.92 billion barrels. They also projected natural gas technically recoverable resources for the Rocky Mountains of 249.41 trillion cubic feet. The projected natural gas resource was further subdivided into several categories which are:

- Undiscovered nonassociated conventional gas – 14.68 trillion cubic feet
- Inferred reserves of nonassociated conventional gas – 15.74 trillion cubic feet
- Unconventional tight gas – 149.47 trillion cubic feet
- Unconventional shale gas - 14.11 trillion cubic feet
- Unconventional coalbed natural gas – 55.41 trillion cubic feet.

RAND SCIENCE AND TECHNOLOGY ASSESSMENT

The William and Flora Hewlett Foundation funded an assessment of natural gas and oil resources of the Greater Green River Basin, in Wyoming by RAND Science and Technology, a research unit of RAND. A number of reports were published as a result of the RAND Science and Technology study (LaTourrette et al, 2002a; LaTourrette et al, 2002b; LaTourrette et al, 2003; and Vidas et al, 2003). The LaTourrette et al (2002a and 2002b) reports were prepared to:

- review existing resource assessment methodologies and results,
- evaluate recent studies of federal land access restrictions in the Intermountain West,
- consider a set of criteria that can be used to define the "viable" hydrocarbon resource, with particular attention to issues relevant to the Intermountain West,

- develop a more comprehensive assessment methodology for the viable resource, and
- employ this methodology to assess the viable resource in Intermountain West basins.

The report by LaTourrette et al (2003) indicated that the details of their spatial analysis and other data were available on request. We contacted the lead author and asked for this information in order to see the details of how the methodology was applied. Unfortunately, that information had been lost and was no longer available. Therefore, their analysis methodology has not been used to analyze the Planning Area.

OIL AND GAS OCCURRENCE POTENTIAL

The Bureau has established criteria to use in rating the oil and gas occurrence potential of lands studied for planning documents such as the Resource Management Plan to be prepared for the Planning Area. This rating is based on guidance outlined in Bureau of Land Management Handbook H-1624-1 which states:

"Due to the nearly ubiquitous presence of hydrocarbons in sedimentary rock... the following [is used] for classifying oil and gas [occurrence] potential:

- HIGH: Inclusion in an oil and gas play as defined by the USGS [United States Geological Survey] national assessment, or, in the absence of play designation by the USGS, the demonstrated existence of: source rock, thermal maturation, and reservoir strata possessing permeability and/or porosity, and traps. Demonstrated existence is defined by physical evidence or documentation in the literature.
- MEDIUM: Geophysical or geological indications that the following may be present: source rock, thermal maturation, and reservoir strata possessing permeability and/or porosity, and traps. Geologic indication is defined by geological inference based on indirect evidence.
- LOW: Specific indications that one or more of the following may not be present: source rock, thermal maturation, reservoir strata possessing permeability and/or porosity, and traps.
- NONE: Demonstrated absence of (1) source rock, (2) thermal maturation, or (3) reservoir rock that precludes the occurrence of oil and/or gas. Demonstrated absence is defined by physical evidence or documentation in the literature."

Using the above criteria, we consider that all Planning Area lands have a high potential for the occurrence of oil and gas (including coalbed natural gas). All areas within the Powder River Basin Province are contained within specific assessment units designated by the U.S. Geological Survey (2006a) so are considered to have high potential.

PROJECTIONS OF FUTURE OIL AND GAS ACTIVITY 2009-2028

The Energy Information Administration (2005) estimates that over the next two decades:

- U.S. energy demand will grow at an average annual rate of 1.4 percent
- energy efficiency of the economy will increase at an average annual rate of 1.5 percent
- future natural gas supply growth will depend on unconventional domestic production, natural gas from Alaska, and liquefied natural gas imports
- U.S. oil imports will grow from 56 percent to 68 percent
- price of oil and natural gas will be higher than in the past
- carbon dioxide emissions will grow at an average annual rate of 1.5 percent.

The above projected increases in demand and in oil and gas prices indicate continued industry emphasis on increasing oil supplies and searching for additional natural gas supplies in the Planning Area. Much of the Planning Area oil and gas supply growth is expected to come from production from existing reservoirs, with most of the new reservoir discoveries potentially coming from exploration for nonconventional plays in the continuous assessment units identified by the U.S. Geological Survey (2006a, 2003, and 2002) as previously discussed in greater detail.

OIL AND GAS PRICE ESTIMATES

Anticipated oil and gas prices are the single most important factor controlling the amount of future oil and gas drilling and production activity in the Planning Area. Boswell (2006) reported that “in today’s market the average unconventional resource play breaks even at $4 per thousand cubic feet of gas and requires in excess of $7 per thousand cubic feet to achieve 20 percent rate of return at the wellhead.” The National Petroleum Council (2003) has projected that through 2025 “supply and demand will balance at higher price ranges than historical levels” in the United States.

Gas Prices

Data for Figure 53 (historical and projected future natural gas prices) were obtained from the Energy Information Administration (2009a). The Energy Information Administration price projection data is an average for Lower 48 Wellhead Prices and is made in 2007 dollars. Historical prices are in nominal dollars.

Beginning in 1985, wellhead gas prices in Wyoming began to decline from a high of $3.32 per thousand cubic feet seen in 1984. By 1991, gas prices had decreased to less than a third of the 1984 prices ($1.06 per thousand cubic feet). 1992 marked the beginning of a general increases in natural gas prices in Wyoming. Several peaks and valleys in prices have occurred since that time, but by 2005, prices had increased to an average of $6.86 per thousand cubic feet, up nearly 650 percent from their 1991 low.

Sieminski (2007) predicts that U.S. natural gas prices will average 7 dollars per thousand cubic feet for the next five years. Petak (2007) projected that Henry Hub (near the town of Erath in southern Louisiana) prices will average between 6 and 8 dollars per thousand cubic feet in the long-term (to 2025).

The Energy Information Administration projects that natural gas prices will fall sharply in 2009 from the recent spike in prices which began in 2003 and likely culminated in 2008. Prices are then expected to begin a gradual and linear rise from $3.99 per thousand cubic feet (2007 dollars) in 2009 to $8.01 per thousand cubic feet in 2030 (Energy Information Administration , 2009b). They also predict that the current high natural gas prices (relative to 2003 and older prices) will stimulate development of new gas supplies and constrain growth in natural gas consumption. The combination of a growing demand and limited supply has created market tightening and led to higher gas prices and price volatility (National Petroleum Council, 2003). However, the Energy Information Administration projects that in the long-term, growth in domestic production will outpace growth in domestic demand leading to a decline in net imports. Most of this growth is expected to come from nonconventional sources, in particular from gas shale production.

The National Petroleum Council anticipates that price ranges will be determined by response to “increased efficiency, conservation, and alternate fuel use, the ability to increase conventional and unconventional supplies from North American… and increasing access to world resources through LNG imports" (National Petroleum Council, 2003). It is not known if liquefied natural gas imports will meet expectations nor if new pipelines will connect gas supplies in northern Canada and Alaska with U.S. markets. While both scenarios would not happen for years, they could decrease future gas prices. Consequently, the projection of future natural gas prices should be considered speculative.

The natural gas price projections allow for some generalizations concerning future gas drilling and production activity in the Planning Area. If the Energy Information Administration gas price scenario is accurate, the recent increase in drilling activity to current levels will likely continue, even though prices have dropped sharply from their 2008 high. Prices are expected to only fall, on average in 2009, to 2003 levels; the 2003 prices were more than 170 percent the average Wyoming wellhead acquisition price from the previous ten year period. Since conventional gas reservoirs in the Planning Area are relatively uncommon compared to oil reservoirs, and if future gas price predictions hold true, it is likely that natural gas development will continue at a pace similar to the previous ten year period, with only several gas wells drilled on average per year during the analysis period.

Gas prices are tied to the demand for the gas resource. According to the Energy Information Administration's 2009 Annual Energy Outlook, U.S. demand for natural gas in 2008 was 23.0 trillion cubic feet (Energy Information Administration, 2009b). Demand is expected to decrease by approximately five percent to 21 trillion cubic feet in 2014, and begin a continual increase through 2028. Increases in future natural gas production, to accommodate projected increased demand, are anticipated to come partly from the Rocky Mountain area. Relatively little anticipated new gas production (not including coalbed natural gas) is expected to come from reservoirs in the Planning Area. According to the U.S. Geological Survey, less than two-fifths of one percent of the total U.S. undiscovered conventional gas resource is attributed to the Powder River Basin, and much of the current gas production from the basin lies outside of the Planning Area (U.S. Geological Survey, 2008b). Any additional gas produced from Planning Area plays is expected to come mainly from the addition of incremental production from existing fields, and from exploration for plays associated with the Minnelusa-Tensleep Formations, Fall River-Lakota Sandstone, Muddy Sandstone, and Cretaceous Biogenic gas U.S. Geological Survey assessment units. If such new plays are discovered, gas drilling will likely increase beyond the most recent rates, but projecting future gas drilling rates following hypothetical new discoveries with the available existing data is not possible at this time.

Oil Prices

Sieminski (2007) recently reported that West Texas Intermediate crude oil prices averaged 19.7 dollars per barrel in the 1990s. In documentation submitted in support of his testimony before the U.S. House of Representatives Select Committee on Energy Independence and Global Warming, Sieminski (2008) stated that "our [Deutsche Bank] forecast for next year is that oil prices should average about $105/barrel," and that "for the longer term... prices will settle toward the cost of marginal supply, or $85/barrel..." While recent world events have seen oil prices fall from a high of over $146 per barrel (NYMEX light sweet crude futures price) in July, 2008 to a low of less than $45 per barrel in February, 2009, it is likely that Sieminski's averages will approximate actual trends. Indeed, even with the volatility seen in prices throughout 2008, the average price for light sweet crude in 2008 was approximately $100 per barrel (Energy Information Administration, 2009b).

Data for Figure 54 (historical and projected crude oil prices) were obtained from the Energy Information Administration (2009a). The data are projected averages of imported Low Sulfur Light Crude Oil prices and are made in 2007 dollars. Historical prices are in nominal dollars and show the historic volatility that has occurred in crude oil prices in Wyoming. In general, the trends seen in wellhead gas prices in Wyoming have been mirrored in Wyoming crude oil prices. Prices began declining in the early 1980's from a high of $32.30 in 1981 to a low of $10.70 in 1998. The significant climb seen in natural gas prices since 1999 is mirrored in crude oil wellhead acquisition prices in the Planning Area. The rise from a low of $10.70 per barrel to the most recent average high of nearly $100 per barrel represents over an order of magnitude increase in prices in just eleven years.

The Energy Information Administration (2009b) projection of future prices predicts that world oil price projects are higher for 2006-2030 than those presented in previous Annual Energy Outlook reports. Domestic petroleum-based liquids consumption is expected to remain flat through 2030 (approximately 20 million barrels per day) due to increased use of and reliance on biofuels. However, worldwide demand will continually increase during the same time, driving world oil prices to higher levels. The Energy Information Administration reference case projects that world oil prices will sharply decline from current levels to about $40 per barrel in 2009, and start rising again as production in non-OPEC regions peaks, and continue rising to nearly $130 per barrel in 2030 (all prices in 2007 dollars). However, as stated in their 2009 projections, "recent volatility in crude oil prices demonstrates the uncertainty inherent in the projections" (Energy Information Administration, 2009b). Such uncertainty is demonstrated in their low- and high-price case projections. These cases reflect a wide band of potential world oil price paths, ranging from $45-50 per barrel in the low case to over $180 per barrel in the high case in 2030 (Energy Information Administration, 2009b).

Most of the recent oil exploration in the Planning Area has been as infill drilling in existing fields (80 percent), though several new fields have also been discovered through wildcat drilling, notably in an unnamed field producing from the Parkman Sandstone between the House Creek and Hartzog Draw fields in Townships 45-46 North, Ranges 74-75 West (Savageton Unit). If the current Energy Information Administration crude oil price projection is accurate, future oil drilling and production will likely continue at levels similar to those seen in recent years as operators continue with in-fill drilling programs and entertain secondary and enhanced recovery projects in existing fields. Barring any significant new discoveries; however, it is unlikely that drilling activity will increase significantly beyond the recent peak. Any new discoveries would most likely come from plays associated with U.S. Geological Survey's Mowry Total Petroleum System including the Fall River-Lakota Sandstone and Muddy Sandstone conventional oil and gas assessment units, and the Mowry and Niobrara continuous oil and gas assessment units.

LEASING

After initial fieldwork, research, and subsurface mapping (which frequently includes use of seismic data), leasing is often the next step in oil and gas development. Leasing may be based on speculation, with leases within high risk prospects usually purchased for the lowest prices.

Leases on lands where the Unite States owns the oil and gas rights are offered via oral auction at least quarterly. Starting in 2010 these auctions will be held on the first Tuesday of the second month in each quarter. A list of parcels that will be offered for lease, plus their associated environmental stipulations, is published in a "Notice of Competitive Oil and Gas Lease Sale" which is posted at least 45 days prior to the date of each sale. Leasing is a discretionary act of the Secretary of Interior. Parcels offered for lease may be withdrawn at any time prior to lease issuance.

Maximum lease size is 2,560 acres and the minimum bid is two dollars per acre. A 365 dollar per parcel administrative fee is charged and the successful bidder must meet citizenship and legal requirements. In addition to the lease bonus, a 1.50 dollar per acre rental is charged for the first five years of the lease and two dollar per acre is charged thereafter. Leases are issued for a ten-year term and a 12.5 percent royalty on any production is required. Leases that become productive are held-by-production and normally do not terminate until all wells on the lease have ceased production. Many private oil and gas leases contain a "Pugh clause," which allows only the developed portion of the lease to be held by production. However, Federal leases have no such clause, allowing one well to hold an entire lease.

In Wyoming, past Federal oil and gas lease sales have been held on even numbered months, usually in Cheyenne, Wyoming. Since August 1996, only lands nominated by industry have been offered for lease. Before that date, virtually all Federal lands available for competitive leasing were offered at each sale. Each new lease is reviewed for resource conflicts and contains restrictive stipulations which protect potentially affected, mainly surface, resource values.

Oil and gas prices and exploration success will, to a great extent, determine the amount of acreage leased and bonus bids received. Forty-nine percent of the money earned from oil and gas leases on public domain minerals goes to the State of Wyoming. The rest stays with the Federal treasury, where it is split between the conservation fund and the general fund on a 4:1 ratio, respectively.

Figure 55 presents the locations of leased and unleased Federal oil and gas minerals within the Planning Area. Excluding lands under Forest Service wilderness areas and Bureau wilderness study areas, there were about 2,494,000 acres of leased Federal oil and gas minerals (about 2,434,000 Bureau managed acres) as of April 1, 2009 and about 1,710,000 acres of unleased Federal oil and gas minerals (about 938,000 Bureau managed acres). About 59 percent of Federal oil and gas minerals available for lease were leased at that time.

Leasing often can be one of the first indications of a developing play in a region. After initial scientific investigations and perhaps preliminary drilling has occurred, leasing over a relatively large area is the next logical step in development of an oil and gas play. Figures 56 and 57 show the amount of acreage that has been leased and the amount of bonus money received annually from competitive oil and gas leasing in the Planning Area from 1990 through 2008. Lease sales in 1998 were almost entirely connected to rapid development of the coalbed natural gas play in the Planning Area. Lease sales in 1998 produced 49 percent of the total revenue and leased 30 percent of the total acreage for the 18 year period shown in Figures 56 and 57. During this period a total of 2.38 million acres (average 125,000 acres per year) was leased competitively and $95.9 million was received in lease bonuses. Figures 56 and 57 do not include acreage leased noncompetitively. Federal acreage in an area totaling approximately 235 townships has not been available since March 2003 due to a U.S. District Court decision (Weaver, 2009, personal communication). That acreage will not be available until the completion of the ongoing Buffalo Field Office Resource Management Plan.

Anticipated future leasing activity will be less than the average during 1990 through 2008 and acres leased will probably be unevenly distributed among lease sales during the next 20 years. Competitive lease sales averaging about 50,000 acres per year are anticipated.

The percent distribution is estimated to be about 55-35-10 for Campbell, Johnson, and Sheridan counties, respectively. Average revenue receipts are estimated to be about $2.5 million per year with percent distribution approximately 75-20-5 for Campbell, Johnson, and Sheridan counties, respectively. There are many factors that affect future leasing and the numbers given here should be used as only a general guideline

PROJECTIONS OF FUTURE OIL AND GAS DRILLING ACTIVITY

It is difficult to predict what will occur a few years into the future, but it is even more difficult to predict 20 years ahead. In an attempt to gain more insight as to what may occur in the Planning Area, geologists and engineers in the oil and gas industry were approached for their input. Major oil and gas companies operating in the Planning Area were contacted by letter and asked what development activity they anticipated during the next 20 years. The Bureau also contacted many of these companies by telephone, either a few days after the letters were sent, or in order to clarify information after replies were received. In addition, the Wyoming State Geologic Survey was contacted to get their ideas and input. Information obtained was compiled and used to help predict locations and amounts of future drilling activity within the Planning Area. A review of available technical data was also used to help make these predictions. Much of the data reviewed has been summarized above. Projections of future coalbed natural gas drilling activity are presented in Appendix 1.

Projected Oil and Gas Drilling Activity

For a base line, unconstrained reasonable foreseeable development projection (Rocky Mountain Federal Leadership Forum, 2002, page 13) we estimate that during the 20-year planning cycle of 2009 to 2028, as many as 1,359 wells will be drilled in the Planning Area. Only six deep wells (greater than 15,000 feet in depth) were drilled in the last 20 years and there are currently no proposals to drill additional deep wells. We expect that as many as 15 to 25 of the 1,359 wells could be deep wells located near the Powder River Basin axis on the west side of the Planning Area. As such development is at this point hypothetical, no provisions were made in our calculations to include additional disturbance from deep wells (all conventional wells were treated the same for surface disturbance calculations).

The estimated conventional oil and gas development potential and drilling densities within the Planning Area during the Analysis period are shown in Figure 58. Estimated acres, number of townships, and percentage of the Planning Area within each development potential classification type shown in Figure 58 are summarized in Table 4.

Conventional oil and gas development potential is defined as very high, high, moderate, low, very low, and none. We estimate that **average** drilling densities per township (one township is about 36 square miles) during the Analysis period will be:

- Very High: more than 30 wells
- High > 20 to 30 wells
- Moderate: >10 to 20 wells

- Low: > 5 to 10 wells
- Very Low: 1 to 5 wells
- Negligible less than 1 well
- None no wells.

Forest Service wilderness lands and Bureau wilderness study areas were not assessed for future development potential since those areas cover Federal lands that are removed from oil and gas leasing and thus, oil and gas development cannot occur.

A limit number of wells could be drilled in areas of very low potential and are projected for areas generally not proven productive by historical drilling, but which still may contain hydrocarbons based on U.S. Geological Survey assessment data. Most of these townships will not receive any drilling at all. If new field discoveries are made in any of these areas of very low development potential, subsequent drilling density could increase in those specific areas. However, predicting a well density for such areas is not possible at this time.

Figure 29 shows historic conventional well distributions by depth. We anticipate that future drilling depths will be on average between 8,000 and 9,500 feet, which has been the standard since 1970.

The majority of the anticipated activity in the Planning Area is expected to be infill drilling of conventional wells to increase proved recoverable reserves and as exploratory drilling to further explore for conventional resources and potential continuous resources identified by the U.S. Geological Survey (2006a, 2003, and 2002) for the Powder River Basin province. Initial estimates of the ultimate size of new oil or gas fields are usually too low, and over time, newer estimates of the size and ultimate recovery contribute to growth in the reserve estimate (Central Region Energy Resources Team, 1996). Factors that could contribute to increases in reserve growth in the Planning Area include:

- Physical expansion of fields by areal extensions and development of new producing intervals,
- Improved recovery resulting from application of new technology and engineering methods (i.e. carbon dioxide enhanced oil recovery), and
- Upward revisions of reserve calculations based on production experience and changing relations between price and cost.

PROJECTIONS OF FUTURE OIL AND GAS PRODUCTION

Natural gas production from the Rocky Mountains has grown steadily since 1992 (National Petroleum Council, 2003). The Rockies are currently the largest producing region in the onshore lower 48 states. Much of this growth has been from unconventional resources, although conventional production has also been increasing.

When the Energy Information Administration (2004) looked at past U.S. gas production they found that "Just a few years ago, it was believed that natural gas supplies would increase relatively easily in response to an increase in wellhead prices because of the large domestic natural gas resource base. This perception has changed over the past few years. While average natural gas wellhead prices since 2002 have generally been higher than during the 1990's and have led to significant increases in drilling, the higher prices have not resulted in a significant increase in production. With increasing rates of production decline, producers are drilling more and more wells just to maintain current levels of production. A significant increase in conventional natural gas production is no longer expected. Drilling deeper wells in conventional reservoirs is expected to slow the overall decline." More recent analysis has confirmed this trend. Foss (2007) found that gas production in the U.S. has been lower than the recent high of 20.5 trillion cubic feet reported in 2001. This decline in total production for the U.S. has occurred even while drilling has reached an all-time high. Foss (2007) indicated that the U.S. resource base (conventional oil and gas reservoirs) is maturing and unconventional plays are increasingly the target of drilling. Since unconventional plays tend to have a lower ultimate oil and gas recovery, overall production from new wells does not match historical results, nor is it expected to in the future. In general, we expect that new gas wells drilled within the Planning Area will follow this trend of reduced production per well from new wells completed, unless a new gas play develops.

Onshore oil production in the lower 48 states has been declining since the late 1980s and is expected to continue into the future (Energy Information Administration (2006a). New oil reservoir discoveries in the Planning Area are likely to be smaller, more remote, and increasingly costly to exploit. Coalbed natural gas production will be discussed in Appendix 1.

ESTIMATED FUTURE CONVENTIONAL OIL AND GAS PRODUCTION

As indicated above, we projected 1,359 conventional oil and gas wells could be drilled within the analysis period of 2009 through 2028. Table 5 presents a forecast of conventional oil and gas production for the 20-year period beyond the year 2008. Gas and oil production are projected to decline over the period, even with the projected new additional wells. Oil production may not decline as rapidly as projected in Table 5 if future carbon dioxide flood operations are used to enhance production from oil fields within the Planning Area. Gas production is not projected to decline as rapidly as oil production during the analysis period since we assume some additional contribution could come from as yet undeveloped plays in the Mowry Shale and Niobrara Formation. If these formations become more productive with time, their production could cause the projected decline in gas production to flatten and possibly increase slightly.

OTHER POTENTIAL FUTURE OIL AND GAS ACTIVITIES

Shale Gas

The Mowry Shale has been identified as a potential shale gas resource in the Planning Area (Tyson, 2008). While the only current production in the Planning Area from the Mowry is oil with associated gas, this important future gas source could become viable before the end of the planning cycle. Most existing plays are concentrated in the eastern and southern parts of the Planning Area. A continuous-resource shale gas play would most likely begin to develop in the southeastern part of the Planning Area.

If a shale gas play aerially overlaps an existing play, existing boreholes may also be utilized in addition to new wells drilled specifically for the shale gas. However, the nature of shale gas plays would likely require drilling of horizontal wells, so the existing boreholes would likely still have to be re-entered and a horizontal lateral drilled into the zone of interest using the existing borehole as a pilot. Shale has very low permeability and large hydraulic fracture stimulations will probably be necessary to liberate the gas (Bereskin and Mavor, 2003). Production may be accompanied by significant volumes of water. Well spacing may be dense; one well per 40 acres should be expected for vertical wells and 80- to 160-acre spacing for horizontal wells. Opportunities for development of an extensive shale gas resource in the Planning Area appear to be low for the planning analysis period.

Coal Gasification

Underground coal gasification may be a potential future process that is applied to coal deposits within the Planning Area. This process burns the coal in-situ producing a combustible gas with a low heating value that can be used in industrial processes, in gas turbines, and can be converted to electrical power. Air or oxygen commingled with steam is injected into the coal seam resulting in the coal being burned outward from the injection well. The combustion products react with the non-burned coal to form hydrogen, carbon monoxide, and pyrolysis products that are produced at a production well. There is evidence that combustion gases preferentially absorb to the coal cleat faces and displace coalbed natural gas from the coal, which increases the heating value of the produced gas. The heat of reaction of the burned coal heats up the unburned coal in front of the combustion front and drives off the hydrocarbon volatile matter contained in the coal. The removal of volatile matter is essentially the same process that coal goes through in the geologic process of changing lignite to anthracite by adding geothermal heat (increasing burial depth) and geologic time.

Underground coal gasification is usually at depths too deep to be economically mined (generally greater than 500 feet). Depth is a positive factor in the gasification process as the higher pressures at depth appear to give better reaction results and a gas with a higher heating value. The limiting factor in depth would be potential reduced permeability of the coal and the ability to efficiently inject and produce the gas.

Underground coal gasification uses essentially the same injection/production process that is utilized in water flooding oil reservoirs and in the carbon dioxide tertiary oil recovery process. Because the coal is burned and removed, subsidence may be a problem but the thin zones, greater depths, and strong cap rocks in the Planning Area should limit this.

At present there is only one demonstration project planned in the United States. GasTech Incorporated, BP America Incorporated, and Link Energy Group have combined to begin work on a demonstration project to be located on State lands near Gillette. Work on the project is expected to begin in the summer of 2009. If the demonstration project is able to show that proposed underground gasification technology involving deep coal beds is economic then additional projects could be proposed at other locations within the Planning Area. Any projects on Bureau managed minerals would not likely occur before 2014 and then only if the process is first proved to be economic.

Carbon Dioxide Sequestration

Carbon dioxide sequestration is a method of storing captured carbon dioxide gas, a greenhouse gas. The primary industrial sources of carbon dioxide include electrical power plants, oil refineries, chemical refineries, agricultural processing plants, cement works, and iron and steel production. Power and industrial plants, agricultural processing, chemical processing, and petroleum and natural gas processing (including refineries and sources associated with pipeline infrastructure) have been identified as the major industrial sources of carbon dioxide (United States Department of Energy, 2007). Of these sources, electrical power plants produce the most carbon dioxide by a substantial margin.

Within the Planning Area the only known source of carbon dioxide is from output of the electrical generation plant near the town of Gillette. Other carbon dioxide sources are the carbon dioxide pipeline that ends just south of the Planning Area in the Salt Creek Field area and at Madden Field, to the southwest in eastern Fremont County

Capturing and storing carbon dioxide has been proposed to reduce the environmental effects caused by releasing the gas to the atmosphere. Three types of geologic formations have been identified as potential carbon dioxide sequestrations sites, each occurring in the Planning Area (United States Department of Energy, 2008b). Those formation types are:

- Oil and gas reservoirs – These reservoirs have hosted natural accumulations of oil and/or gas and could, in the future, be used to store carbon dioxide. The entrapment of hydrocarbons indicates that a containment seal is present and any associated water is assumed to be nonpotable. Larger oil and gas reservoirs in the Planning Area could be considered for sequestration. Carbon dioxide injected into a mature oil reservoir can enable incremental oil to be recovered. An additional 5 to 20 percent of original oil in place can be recovered when carbon dioxide is injected. Pilot tests have occurred within the Planning Area (see previous discussion under enhanced oil recovery section). Larger projects have been proposed at Meadow Creek and Sussex fields, but a source of carbon dioxide has not been secured to justify extending the pipeline from the Salt Creek Field to the south into the Planning Area.
- Unminable coal seams – Unminable coal seams are considered to be those that are too deep or too thin to be economically mined. The majority of the Tertiary and Cretaceous coals in the Planning Area meet these criteria. If methane contained in Planning Area coal beds becomes economically producible then there could be a future opportunity to inject carbon dioxide, which could sweep

additional methane from the coalbeds and allow adsorption by the coals of the carbon dioxide. Since coal beds preferentially adsorb carbon dioxide, they provide excellent storage sites. Feasibility studies have looked at coal beds in the Planning Area (Robertson, 2009 and Zoback et al., 2006), but no pilot projects have been approved.

- Saline formations – Saline formations suitable for carbon sequestration were defined in the United States Department of Energy (2008b) atlas as porous and permeable rocks containing water with total dissolved solids greater than 10,000 milligrams per liter, which have the capacity to store large volumes of carbon dioxide. They are much more extensive than coal seams or oil- and gas-bearing rock, and thus have a large potential for carbon dioxide storage. Many of these potential formations are made up of reactive carbonate rocks that could potentially react with and convert the carbon dioxide into compounds for storage in the host rock. Currently, there are no projects known to be evaluating this process in saline formations within the Planning Area.

Additional carbon dioxide sequestration projects are ongoing within the Wyoming State Geological Survey (2009). Their projects include:

- evaluating the suitability of depleted oil and gas fields around the state for enhanced oil recovery and carbon dioxide sequestration activities to be used in conjunction with clean coal technology and carbon capture, and
- investigation and inventory of potential carbon sequestrations sites in Wyoming.

POTENTIAL OIL AND GAS SURFACE DISTURBANCE

Only disturbance associated with conventional oil and gas activity is presented here. Disturbance associated with coalbed natural gas activity is presented in Appendix 1. Table 6 projects short-term and long-term disturbance associated with existing conventional oil and gas wells and projected drilling activity for 2009 through 2028. The method used to determine the number of new wells drilled during this period has been previously discussed. In addition, we assumed that:

- of the existing active wells in March 2009,
  - all dormant, shut-in, temporarily abandoned, or wells with notices of intent to abandon (758 wells, 483 on Bureau managed minerals), and
  - all marginal wells (see previous discussion) not in potential carbon dioxide enhanced oil recovery fields will be abandoned by December 2028.
- the success rate of new oil and gas wells will average 75 percent based on historical trends.

Table 6 also shows our projection of new exploratory and development wells (1,359 wells with 629 of those wells managed by the Bureau) that could be drilled in the Planning Area from 2009 through 2028. There are an additional 4,133 existing active wells (Wyoming Oil and Gas Conservation Commission, 2009), as of March 2009, for a total of 5,492 existing and projected oil and gas wells. Of those 5,492 existing and projected wells; 2,818 will lie on Bureau managed oil and gas minerals. Table 6 also calculates associated acres of total surface disturbance (short-term disturbance) directly associated with all new wells and existing active wells (as of March 2009). Approximately 3,737 acres of new short-term surface disturbance (1,730 acres of disturbance on Bureau managed oil and gas minerals) could occur if all 1,359 projected wells are drilled. Total short-term surface disturbance (for all well types) would be 12,003 acres, with 6,108 of those acres on Bureau managed oil and gas minerals.

Table 6 also includes our projection of new producing wells remaining in production after all new exploratory and development wells are drilled and all dry holes are abandoned and reclaimed (1,019 total new producing wells with 472 of those new producing wells on Bureau managed oil and gas minerals). As stated previously, we assume an average success rate of 75 percent for new wells drilled during the analysis period. There are an additional 2,524 existing wells (1,307 projected active wells will lie on Bureau managed oil and gas minerals) that will remain active after some formerly existing active and producing wells are abandoned. Finally, Table 6 shows the calculated unreclaimed acres of total surface disturbance (long-term disturbance) directly associated with all remaining wells. Approximately 2,039 acres of new unreclaimed surface disturbance (944 acres of unreclaimed Bureau managed oil and gas minerals) from new wells drilled during the Analysis period could remain in the long-term. Total unreclaimed long-term surface disturbance (for all well types) would be 7,087 acres, with 3,558 of those acres on Bureau managed oil and gas minerals.

SUMMARY

For our base line projection we analyzed the oil and gas resource within the Planning Area, discussed types of future development that may occur, estimated the development potential for each type of resource, and projected base line activity levels for the analysis period 2009 through 2028. We projected that as many as 1,359 conventional oil and gas wells and 13,803 coalbed natural gas wells could be drilled during this period. Our forecast of annual and cumulative conventional oil and gas production for 2009 through 2028 for the newly drilled conventional oil and gas wells is presented in Table 5. Coalbed natural gas production is presented in Table A1-15. Short-term and long-term surface disturbance associated with existing conventional oil and gas wells and future projected conventional oil and gas wells is presented in Table 6 for all lands and for Bureau managed lands. Short-term and long-term surface disturbance associated with existing coalbed natural gas wells and future projected coalbed natural gas wells is presented in Table A1-3 for all lands and for Bureau managed lands. For our analysis of the base line projection, we assumed that the only land use restrictions on future oil and gas resource development would be those that have been legislatively imposed.

APPENDIX 1

Reasonably Foreseeable Development Scenario for Coalbed Natural Gas in the Buffalo Field Office Area, Wyoming

Origins, Historical Summary, and Discovery

Coalbed natural gas is commonly called coalbed methane. “Coalbed methane” is a misnomer because nitrogen and carbon dioxide are usually present in significant quantities. The more correct term is coalbed natural gas, which is the term that will be used in this document.

Coal is formed by burial of organic (mostly woody) material. Methane is a natural byproduct of coal formation. It is generated by anaerobic bacteria early in the coal forming process. As burial increases temperature increases. At approximately 50 degrees Celsius most of the biogenic methane has been generated. As burial depth continues to increase, carbon dioxide, nitrogen and water are also released. Maximum carbon dioxide generation occurs at about 100 degrees Celsius. Methane associated with coal has been observed in nearly all coal bearing areas in Wyoming (DeBruin and Jones, 1989).

In the Buffalo Field Office area coalbed natural gas contains small quantities (generally less than ten percent) of nitrogen and carbon dioxide. Hydrocarbon gasses other than methane are seldom present in quantities above one percent. Flores et al. (2008) found 90 percent of the wells contained between 78 percent and 97 percent methane, with the average being 85 percent. Seventy eight percent of the samples contained less than 22 per cent nitrogen plus carbon dioxide.

Little Interest -- Before 1987

The earliest suspected coalbed natural gas production in the Powder River Basin occurred in 1916, perhaps earlier, from a well in the southeast quarter Section 30, township 58 north, range 75 west. Natural gas was produced from coal beds and/or adjacent sandstones in at least 11 other locations in the Buffalo Field Office area (DeBruin and Jones, 1989). All these instances were inadvertent or for limited domestic use of coalbed natural gas. DeBruin and Jones (1989) have an excellent historical summary and list of references.

Commercial coalbed natural gas development in the planning area can be divided into four time periods. These are summarized in Table A1-1. Data from the Wyoming Oil and Gas Conservation Commission indicate before 1987 only 12 wells specifically targeting coalbed natural gas were drilled. The first modern wells drilled specifically to develop coalbed natural gas resources are located near Meade Creek, ten miles southeast of Sheridan, Wyoming. Two wells were drilled in December 1979. An additional well was drilled two years later. Average depth was 345 feet and average cumulative gas recovery was 24 million cubic feet per well. None of the three wells is currently productive. The producing interval was the Wasatch Formation. By the end of 1986 a total of 12 coalbed gas wells had been drilled mostly in three scattered locations in Campbell and Sheridan counties.

<u>The Developing Play – 1987 through 1998</u>

Years 1987 through 1998 saw drilling rates increase from 19 wells in 1987 to 653 wells in 1998. Wells were drilled in proximity to coal mines to take advantage of dewatering done by the mines. Also, stratigraphic tests were drilled to gain geologic data so that wells could be located on small anticlines. These anticlines were often small local features caused by compaction of underlying geologic layers. The practice of "blanket drilling" was not yet a dominant method of coalbed gas development. During the 11 year period 1,642 wells were drilled. The drilling pattern was dominantly one well per quarter section (40 acres).

Although drilling activity increased substantially from the early years, well depths and average well recovery increased only slightly (see Table A1-1). Monthly gas production however increased one-hundred fold, from one million cubic feet of gas per day in January 1987 to 118 million cubic feet of gas per day in December 1998. By the end of 1998 a significant number of coalbed gas wells had been drilled in Johnson and Sheridan counties, Wyoming and Big Horn County, Montana.

<u>The Play Explodes – 1999 through 2008</u>

Starting in 1999 coalbed gas development exploded. IHS Energy Inc. data indicate that 2,507 coalbed gas wells were drilled in 1999, more than during all previous years combined. Blanket drilling clearly became the dominant method of development. Use of stratigraphic tests had nearly disappeared by the end of 1999. IHS Energy Inc. data show that during 1998, 95 percent of the coalbed gas wells drilled were in Campbell County, Wyoming. That number declined to 86 percent in 1999 and to 47 percent by 2008 as drilling expanded to nearly the entire play area. However, IHS Energy Inc. data indicate that 96 percent of all the wells drilled in the coalbed gas play in the Powder River Basin are in the Buffalo Field Office area, and 97 percent of the cumulative coalbed gas production is from the Buffalo Field Office area.

There was considerable debate before the Wyoming Oil and Gas Conservation Commission concerning the appropriate well spacing. After listening to a great deal of technical testimony, the commission decided that one well per 80 acres was the appropriate pattern. In March 2001 the Wyoming Oil and Gas Conservation Commission rules were changed to require a drilling pattern of one well per 80 acres for all future coalbed natural gas development in the Powder River Basin.

Development in the basin proceeded generally from east to west, from relatively shallow areas to deeper areas. Well depths reflected this trend (Figure A1-1). As development proceeded generally westward mineral ownership changed. Initially most wells were drilled on private or state owned minerals. Further west the ownership was predominantly Federal. From about 2003 through 2008, the coalbed gas play in the Buffalo Field Office area was controlled by the availability of Federal drilling permits. As more Federal permits became available, drilling rates increased, other factors being equal.

Except for Sheridan and northwest Campbell counties, development has mostly been limited to the Wyodak-Anderson coal zone. The Wyodak-Anderson zone is the thickest and most continuous coal interval in the Powder River Basin. It is slightly lower stratigraphically but generally continuous with the Big George coal. The Big George coal is the main producing coal in the central part of the Powder River Basin and will almost certainly produce a larger amount of coalbed natural gas than any other coal in the basin. Figure A1-2 is a map showing the locations of deep and shallow wells. Deep wells are defined as those wells which have production from at least one coal below the main producing interval (the Wyodak-Anderson coal zone). Shallow wells are defined as wells with production from above the main producing interval. Many of the shallow wells produce from Wasatch Formation coals. A comparison of Figure A1-2 with Figure 2b reveals how few wells were drilled to deeper horizons in the southern part of the field office area. Note that south of Interstate 90 there has been little development of deeper coals. This may be due to low gas contents in the deeper coals although much of the area appears to be untested.

Limited gas content data gathered by the U.S. Geological Survey with assistance by the BLM (Stricker et al., 2006) indicate that coals below the Wyodak-Anderson zone have very low gas contents in some parts of the basin. Samples from one deep coal indicated a very high gas content.

Future Development - General Comments

It is difficult to predict the method and location of future development more than a few years into the future. A few general speculations are reasonable however. Future development from 2009 through 2028 will initially occur in undrilled areas as Federal drilling permits become available and gas prices become more favorable. Successful application of multiple completion technology will be key to development in some areas, especially in Sheridan County. Limited down-spacing should be expected in a few areas.

A gradual change away from blanket drilling should be expected during the next five to ten years as development of the Wyodak-Anderson coal zone becomes mature. Future development probably will include multiple thin coals and deep (below the Wyodak-Anderson zone) locally thick coals. To a lesser extent, shallow coals (above the Wyodak-Anderson zone) of the Wasatch Formation will be developed.

Development will become more localized and will require more geologic and engineering analysis. Stratigraphic tests will again become more useful. Gas content, under-saturation, and permeability data from coals will be required to determine economic viability. Seismic data may become more useful.

Localized development of deeper coals will occur as prospective coals are identified. Development of specific coals may cover as much as a few townships but will not cover hundreds of square miles as occurred during 1999 – 2008. Well completion techniques will control development in some areas as thinner coals will require multiple completions of several coals in one wellbore. Economics may require spacing of one well per quarter section in some areas. Development will be driven to some extent by expiring leases as depleted coalbed gas wells are abandoned, and leases will expire unless new production can be established.

In summary, coalbed natural gas development will continue as in the past for about five years, if the gas price is adequate. Eventually, development will change toward deeper coals and there will probably be an increased application of geologic, seismic, and engineering sciences to develop the remaining coalbed natural gas resources in the Buffalo Field Office area. The pace of development will almost certainly be significantly slower than during 1999-2008. As in the past, 95 percent of the coalbed gas development activity will be within the Buffalo Field Office area.

Seismic

Reflection seismic information is obtained by transmitting energy into the ground then recording, mathematically processing, and interpreting the seismic waves which return to the surface. The goal is to map subsurface rock layers. Seismic information has been used very little in coalbed gas development. If as anticipated, the play becomes more fragmented and specific local coals are targeted, seismic data may become more valuable. Structure, depth, and thickness data about specific coals could be obtained from a seismic survey. Areas where coal is present and possibly the presence of cleats (fractures) could be mapped. These data would allow identification of potential coalbed gas targets (prospects) and help locate well sites for optimum efficient recovery.

Seismic surveys targeting coalbed natural gas development would be on a much smaller scale than those done for conventional oil or gas exploration. Targeted coals would be only 1,000 to 4,000 feet below the surface. Crew sizes would be small, probably not more than seven or eight people. Energy sources could be vibrations (vibroseis), weight drops, or light charges of dynamite. Field equipment would also be relatively small. Data processing could be done on location, in real time, and used as a guide to ongoing seismic acquisition.

Estimated future seismic activity

It is impossible to accurately estimate how many miles of shallow seismic surveys are likely during the next 20 years, or in which parts of the Buffalo Field Office Area the activity would occur. Seismic activity will probably be more common during the last half of the planning cycle. Associated surface disturbance is expected to be minimal.

Drilling

Review of Past Well Estimates

This review is a brief attempt to show how rapidly the coalbed gas play developed and how inadequate early well estimates were. One of the earliest coalbed gas drilling estimates was in about 1990 when an estimated 1,000 coalbed gas wells was anticipated in a 1,000 square mile area in western Campbell and eastern Johnson counties. An Environmental Impact Statement was initiated, however the project was not drilled. In 1992 Betop Inc. proposed a 32 well project of mostly fee wells in Rawhide Field about 20 miles west of Gillette. In 1993 a 40 well project within a 26 square mile area south of Gillette, the Marquiss project, was predicted. In 1994 this project was expanded by 200 additional wells in the Lighthouse area and became the Marquiss-Lighthouse project. Further expansion occurred when 640 wells were predicted for the south Gillette area.

The South Gillette Environmential Impact Statement was completed in 1997. A 250 well project was predicted for an area north of Gillette. The Gillette North Environmental Assessment was completed in 1996. These projects were followed closely by a request from industry for 2,250 additional coalbed gas wells. This request resulted in the Wyodak Coalbed Methane Development Project Environmental Impact Statement, which initially covered 2,400 square miles in the eastern part of the Buffalo Field Office. A Draft Environmental Impact Statement was issued in May 1999. BLM expanded the project to 3,600 square miles and 5,000 wells to be drilled over five years. The Record of Decision was signed in November 1999. By November 2000 a total of slightly over 7,700 coalbed natural gas wells had been drilled based on data compiled from the IHS Energy Inc. well database. Faced with the potential loss of $26 million in Federal royalties over two years due to drainage of Federal leases, an additional 2,500 wells was authorized through an environmental assessment. The Decision Record was signed on March 26, 2001. A BLM (Wyoming Reservoir Management Group) study completed in February 2001 revised estimated future drilling upward to 50,000 wells. Additional National Environmental Policy Act analysis was completed covering 51,000 wells to be completed by 2013. The Record of Decision was signed on April 30, 2003.

Review of Drilling Activity

Data from the Wyoming Oil and Gas Conservation Commission indicate that at least 29,716 coalbed natural gas wells had been drilled in the Buffalo Field Office area through 2008. Figure A1-3 shows how these wells are proportioned based on mineral ownership. Drilling rates were very low until 1996, increased sharply in 1999, peaked in 2001, then declined erratically through 2008. Figure A1-4 shows the relative proportion of wells drilled on Federal, fee, and state minerals from 1990 through 2008. The relative proportion of Federal wells has increased from about 20 percent in 2000 to about 60 percent during 2006 through 2008. The distribution of Federal minerals suggests the proportion of Federal wells will remain high for the foreseeable future.

Not all wells drilled are productive. Since 2000 the failure rate has averaged 0.9 percent. Some wells are designed only to provide scientific data and some do not encounter economic thickness of coal. Almost all of the failures since 2000 were due to a lack of coal thickness or were caused by mechanical failure. Figure A1-5 shows the number of productive wells drilled by county during 1995 through 2008. Note the relatively large proportion of wells drilled in Campbell County (see also Figure A1-6).

Coal beds dip westward in the eastern 90 percent of the coalbed gas play area. Development progressed generally from east to west, therefore average well depths became greater over time. Figure A1-7 shows the increase in average well depth by year. Well depths are slightly over 4000 feet for the deepest wells.

<u>Methodology used to Calculate Future Well Numbers</u>

Future drilling was estimated using a combination of factors and assumptions including:

1. Responses from letters to coalbed natural gas operators requesting drilling estimates. Operators which cumulatively drilled 84 percent of all the coalbed gas wells between January 2007 and February 2009 provided written responses.
2. A series of east-west cross sections constructed by the U.S. Geological Survey (Flores et al., in preparation).
3. Coalbed gas desorption data (Stricker, 2009 and Stricker et al., 2006).
4. Data from the Wyoming Oil and Gas Conservation Commission and IHS Energy Inc. production and well databases.
5. Estimated ultimate recovery calculations for approximately 18,000 coalbed gas wells.
6. The assumptions that multiple completions will be a viable method of developing multiple, thin coal zones, and that in some areas future well spacing may be one well per quarter section.
7. The assumption that gas prices will be sufficient to justify development of multiple thin coals.
8. Professional judgment.

The data were compiled and reviewed on a township by township basis. Two of the drilling estimates from operators were for less than 20 years (5 years and 8 years). Well numbers were estimated on a township-by-township basis. If well cumulative estimates from industry did not appear to be sufficient in an area, then additional wells were added to the number predicted by responding coalbed natural gas operators. Drilling densities were rated based on the estimated number of wells to be drilled per township over the life of the land use plan. A development potential map was then constructed. Table A1-2 lists the ranges used for the development potentials mapped. A total of 13,803 wells is predicted to be drilled during 2009 through 2028.

Figure A1-8 shows the projected number of wells expected to be drilled annually. Annual well numbers were calculated using statistical analysis. Annual well numbers generally follow the same trend as projected gas prices shown in Figure 53.

After a well reaches the end of its economic life it is usually abandoned. Well abandonments are increasing rapidly, as shown by Figure A1-8. Abandonments appear to increase about five to nine years after a group of wells is drilled. More data are needed to estimate the delay with precision. The estimated number of future abandonments was calculated for each year and is also shown in Figure A1-8. Approximately ten percent of the coalbed gas wells which would normally be abandoned will be used by local land owners (Gonzales, 2009). The wells will be used mostly for livestock water and will probably not be abandoned in a predictable manner. Projected abandonments shown in Figure A1-8 account for 90 percent of the wells drilled.

Estimated future drilling activity

Estimates of future drilling activities predict 13,803 wells will be drilled between 2009 and 2028. Figure A1-9 shows estimated coalbed natural gas development potential on a township by township basis. This includes all wells regardless of mineral ownership. Figure A1-9 shows townships with low development potential adjacent to townships with high and very high development potential. Large contrasts in development potential result when one township has a high density of existing wells and an adjacent township has a much lower density of existing wells.

Annual drilling estimates shown in Figure A1-8 should be used only as a general guideline. Future drilling activity depends on many factors, most importantly gas price and the availability of Federal drilling permits. As mentioned above, the coalbed gas play in the Powder River Basin will probably change. As deeper coals are explored and exploited, more scientific information will be needed. The coalbed gas play may appear slightly more like a conventional gas play. More wells will be drilled to determine gas content and permeability. Seismic data will probably be used to help map coals.
Data do not allow well abandonments to be precisely estimated. Preliminary data suggest that about five years after a group of wells is drilled abandonment of some wells begins. Remaining wells will be abandoned over the next several years. For planning purposes ninety percent of the wells drilled are assumed to be abandoned 14 years after initial well completion. As more data become available abandonment rates can be more precisely determined.

Surface disturbance resulting from projected drilling and abandonments is listed in Table A1-3. Estimates of disturbance for roads and well pads were provided by Hunter (2009) and are listed in Table A1-3.

Coalbed Natural Gas and Associated Water Production

Although coalbed gas production for local or domestic use dates from 1916 or earlier (DeBruin and Jones, 1989) the Wyoming Oil and Gas Conservation Commission and IHS Energy Inc. list commercial production starting in 1987 and 1981 respectively.

Cumulative production for the entire coalbed gas play area in the Powder River Basin through 2008 is 3,213 billion cubic feet of coalbed gas and 699 thousand acre feet (5.42 billion barrels) of water. Ninety-seven percent of the coalbed gas and 96 percent of the associated water production are from the Buffalo Field Office area. Over 90 percent of the gas and water produced outside the Buffalo Field Office area is from Big Horn County, Montana.

Annual coalbed natural gas production from the Buffalo Field Office area increased ten-fold from 1999 through 2008. Figure A1-10 shows annual coalbed gas production graphically by county. Proportional gas production from the three counties in the Buffalo Field Office area has changed substantially since 2002. Campbell County had the highest production rate until 2007 when Johnson County became the dominant gas producing county in the Buffalo Field Office area. This change resulted from development of the Big George coal. The Big George coal is part of the Wyodak-Anderson coal zone, and is the most prolific coalbed natural gas producing coal in the Buffalo Field Office area. As production from wells on the east side of the field office area (Campbell County) declined, production increased from wells further west. Overall, annual coalbed natural gas production from the field office area increased an average of 16 percent per year from 2005 through 2008.

Well efficiency, as measured by well productivity, is markedly different for each county. Data from the IHS Energy Inc. production database indicates that during 2008 the average coalbed gas well in Campbell County produced 40 thousand cubic feet of gas per day, the average well in Sheridan County produced 69 thousand cubic feet of gas per day, and the average well in Johnson County produced 362 thousand cubic feet of gas per day (Figure A1-11). During 2008 only 16 percent of the producing coalbed gas wells were in Johnson County, although 58 percent of the produced coalbed gas was from Johnson County.

Figure A1-12 shows gas production by mineral/surface ownership. Federal coalbed gas production increased from 29 percent of the total in 2005 to 61 percent of the total in 2008. During the same time period, production from fee minerals decreased from 62 percent of total to 33 percent of total gas production. The increase in gas production from Federal minerals is due to a number of factors, most important is the increase in proportion of Federal mineral acreage as the play has progressed from the eastern part of the Buffalo Field Office area to the deeper central part of the area. Other factors being equal, the deeper a coalbed gas well the greater the gas content in the coal. As Figure A1-12 suggests, the coalbed natural gas play in the Buffalo Field Office area is now controlled to a large extent by the availability of Federal drilling permits.

As production from Federal minerals increased, the average productivity of individual Federal wells also increased. This was probably caused in part to deeper drilling depths with the resultant higher gas contents in the coal. Currently, the average Federal well produces 145 thousand cubic feet of gas per day compared to 59 thousand cubic feet of gas per day for nonfederal wells.

Production history from a "typical" coalbed gas well is shown in Figure A1-13. The ramp-up, flat, and decline portions of the gas curve are typical, and are the result of pressure changes within the coalbed. Ramp-up and flat portions may be very short (a few months). The decline portion is usually the longest part of the curve. Water production usually begins at high rates and gas production usually ramps up gradually from a low initial rate. Exceptions are not uncommon, especially in areas where pressure in the coal has been reduced by water production before a well is drilled. Water production generally begins at relatively high rates then declines over the life of the well. Gas production builds up, then remains flat for a period of time which may be very short, and then declines. The well shown in Figure A1-13 recovered 223 million cubic feet of coalbed natural gas. This is a typical recovery for a coalbed natural gas well. The well also produced 3.48 million barrels of water (449 acre feet) which is higher than average but not unusual.

Water produced from coalbed gas wells in the Buffalo Field Office area during 2008 totaled 664 million barrels (86,000 acre feet). Water production by county is shown in Figure A1-14. Campbell County continues to have the largest proportion of produced water with 54 percent of the 2008 total. Cumulative associated water production from 1981 through 2008 was 5.42 billion barrels (699 thousand acre feet). In an attempt to put these numbers in perspective, 699 thousand acre feet of water is enough to fill Keyhole Reservoir (in Crook County) to 110 percent of capacity or Pathfinder Reservoir (in Natrona and Carbon counties) to 70 percent of capacity.

Water production per thousand cubic feet of produced coalbed gas has declined substantially since 2000. Associated water production in the Buffalo Field Office area decreased from 2.5 barrels of water (106 gallons) per thousand cubic feet of gas in 2000, to 1.2 barrels of water (53 gallons) per thousand cubic feet of gas in 2008. Water production from wells on Federal leases decreased from 1.7 barrels (70 gallons) of water per thousand cubic feet of gas in 2000 to an average of 0.9 barrels of water (36 gallons) per thousand cubic feet of gas during 2008.

Estimated Future Coalbed Natural Gas and Associated Water Production

Although percentages may change slightly with time, geologic criteria (mainly coal thickness and depth) suggest that it is unlikely more than five percent of the cumulative gas or water production from the entire coalbed natural gas play in the Powder River Basin will come from outside the Buffalo Field Office area.

Although the average daily productive rate per well for Johnson County has increased each year since production was first established in 1999, it is unlikely the average rate will increase much further because an increasing number of wells will enter the decline stage.

Estimated coalbed natural gas recovery during 2009 through 2028 from wells projected to be drilled during 2009 through 2028 is 3,160 billion cubic feet. Estimated coalbed gas recovery during 2009 through 2028 from wells drilled before 2009 is 2,005 billion cubic feet. Estimated cumulative recovery from all coalbed gas wells, including those drilled before 2009, in the Buffalo Field Office area through 2028 is 8,378 billion cubic feet.

Figure A1-15 shows historical and projected coalbed gas production through the year 2028. Future production for coalbed gas wells existing on December 31, 2008 was calculated using a 10 percent nominal decline rate for years 2009 and 2010 then a 34 percent nominal decline rate for 2011 through 2028. A decline rate of 10 percent was used for two years to account for the flat portion of individual well decline curves. A decline rate of 34 percent was used because 34 percent is the average annual nominal decline rate for 4,882 wells used to model coalbed natural gas production through the year 2028. Estimated gas production for wells drilled during 2009 through 2028 was calculated using a type well with an estimated ultimate recovery of 0.28 billion cubic feet of gas and a well life of nine years.

Ultimate recovery of coalbed gas resources from the Buffalo Field Office area has been estimated to be approximately 25,000 billion cubic feet of gas (Finley and Goolsby, 2000; Crockett et al., 2001; and Potential Gas Committee, 2003). A more recent analysis by the U.S. Geological Survey (2004) estimated 14,300 billion cubic feet of recoverable coalbed gas remaining as of 2003. Limited gas desorption data published by Stricker et al. (2006) suggest coals below the Wyodak-Anderson coal zone, the main producing coal interval, may have very low gas contents over a large area. Future gas production rates estimated in this study suggest that 14,300 billion cubic feet may be closer to reality than the 25,000 billion cubic feet of earlier estimates.

Recent analysis by Stricker (2009) suggests that coalbed natural gas production from the Buffalo Field Office area may have peaked, and will begin declining with decline rates averaging about 15 percent per year for the first ten years. If this occurs, ultimate recovery from the Buffalo Field Office area may be substantially less than estimated. Stricker (2009) also indicates coalbed gas production from the San Juan and Black Warrior basins has peaked and is in the early stages of decline. IHS Energy Inc. production data for those basins indicates decline rates are averaging four to five percent per year.

Water production has declined by half relative to gas production since 2000. During 2009 through 2028 this decline is expected to continue but at a slower rate.
In summary, coalbed natural gas production from the Buffalo Field Office area is expected to decline substantially from approximately 2009 through 2018, then begin increasing only to be followed by another decline in response to changes in the number of estimated coalbed gas wells drilled. Associated water production will also decline.

Induced Insitu Methanogenesis – Gas Farming

Induced insitu methanogenesis is literally gas farming. Coal in the Powder Basin contains naturally occuring anerobic bacteria which produce methane as part of their metabolic process. Gas farming involves providing the nuterients in the appropriate amounts sufficiently dispersed through the coal to cause the bacteria to become more active and produce methane (Ulrich and Bower, 2008). The process has been demonstrated in the laboratory and in a pilot project by Luca Technologies (DeBruyn, 2009). Currently a commercial scale project is in its early stages. If the project is successful, coalbed gas wells that have declined to their economic limit can be used to recover methane generated from methanogenesis. Nutrients are pumped into the coal then allowed to soak for about a month. Wells which have little or no gas production can be stimulated to produce an average of about 30 thousand cubic feet of gas per day, with production sustained on an intermitant basis for several years and perhaps for several tens of years. No water discharge results from gas farming (DeBruyn, 2009). A small amount of additional surfase disturbance may be required. Potentially several thousand wells could be used for gas farming. If large scale gas farming occurs then the amount of reclaimed acreage in 2028 will probably be significantly less than previously estimated.

Surface Disturbance Estimates for Coalbed Natural Gas

Some of the information used to estimate surface disturbance was obtained from BLM staff in the Buffalo Field Office (Brus, 2009, Hunter, 2009, and Gonzales, 2009). Historical data from the Wyoming Oil and Gas Conservation Commission website and the IHS Energy Inc. production and well databases was also used extensively. Estimated surface disturbance due to coalbed natural gas operations was calculated based, in part, on the inputs and assumptions listed below:

1. Reclamation will not be completed until two years after well abandonment.
2. Ten percent of the coalbed natural gas wells which reach their economic limit will be converted to water wells. BLM managed wells will be released via a signed agreement. Surface disturbance will no longer be credited to coalbed natural gas activity.
3. Only 50 percent of the roads will be reclaimed after well abandonment, this applies to both Federal and nonfederal surface. Unreclaimed roads are not used for coalbed natural gas operations.
4. Constructed well pads are 0.9 acres with initial reclamation to 0.5 acres in two years (constructed well pads are built by using earth moving equipment).
5. Nonconstructed well pads are 0.9 acres with initial reclamation to 0.3 acres in two years (nonconstructed well pads are established by simply driving on top of the natural surface).
6. Federal wells include both public domain and split estate.
7. Flowlines follow roads and do not add additional long term (over two years) surface disturbance.
8. The area in acres disturbed initially by roads and flow lines for an undrilled location is 2.07 acres, after initial reclamation it is 0.92 acres.

9. Approximately 25 percent of the wells drilled before 2008 had constructed pads and approximately 70 percent of the wells drilled after 2008 will have constructed pads.
10. For wells drilled before 2009, 9.18 percent were on a pad with another well, and for wells drilled after 2008, 18.96 percent will be on a well pad with another well.
11. During 1990-2008, 24.13 percent of all the wells drilled were on Federal surface (public domain).
12. During 2009-2028, 59.55 percent of the wells drilled will be on Federal minerals, and 27.89 percent will be on Federal surface.
13. At the end of 2028, there will be an estimated 10,460 active coalbed natural gas wells in the Buffalo Field Office area. This is based on calculated abandonment rates.

Wells pads and roads

Results of surface disturbance calculations are listed in Table A1-3. An estimated 30,182 acres (10,166 acres due to wells on Federal minerals) of unclaimed surface disturbance due to well pads and roads existed at the end of 2008. In addition, an estimated 33,962 acres (20,224 on Federal minerals) will be disturbed during 2009-2028 for a total disturbance of 64,144 acres (31 thousand acres due to wells on Federal minerals). Unreclaimed surface disturbance is estimated to be 13,639 acres (8,122 on Federal minerals) at the end of 2028. Calculated disturbance figures shown in Table A1-3 are based on averages, estimates, and projections from numerous sources, some of which are listed above. Table A1-3 does not include an extended well life for wells which may be used in gas farming. If a large number of wells are converted to gas farm wells, actual disturbed acreage due to unreclaimed wells and roads at the end of 2028 (long term disturbance) would be much larger. It is important to remember the acreage and well numbers listed in Table A1-3 are estimates and actual numbers will almost certainly be at least slightly different.

Unreclaimed acreage

When production from coalbed natural gas wells declines to a level which no longer pays for operating expenses, the wells are considered to have reached their economic limits. In most cases, the well bores are plugged and surface disturbance is reclaimed. This usually occurs within a few years after the economic limit is reached. However, coalbed natural gas wells in the Buffalo Field Office area are not all abandoned when the economic limit occurs. Some wells with associated surface disturbance and roads are retained as water wells, usually for livestock use. Ownership is usually transferred via a signed water well release agreement. On Federal minerals these agreements are mandatory. Surface disturbance associated with these water wells is not required for coalbed natural gas development; therefore it is not considered part of coalbed natural gas development. It is estimated that between 2009 and 2028 ten percent (2,635 wells) of the coalbed natural gas wells which would otherwise be abandoned and reclaimed, will be retained for water supply wells (Gonzales, 2009).

In addition to water supply wells, 50 percent of the roads associated with wells that will be plugged and abandoned will be retained to provide better access for ranchers and other surface users (Hunter, 2009). This amounts to an estimated 18,401 acres (6,816 acres of Federal surface) of roads that will remain after the wells are abandoned and reclaimed. None of this unreclaimed acreage is considered necessary for coalbed natural gas production.

Water impoundments

Water impoundments are small reservoirs used to hold water produced with coalbed natural gas. At the beginning of 2008, total estimated disturbance due to water impoundments was approximately 19,548 acres (1,827 acres of Federal surface) in the Buffalo Field Office area. During 2009-2028 an estimated total of 29,900 acres (2,946 acres of Federal surface) will be disturbed at some time due to water impoundments. At the end of 2028 there will be an estimated 7,566 acres (817 acres of Federal surface) of unreclaimed disturbance due to active water impoundments in the Buffalo Field Office area. These impoundments will be used to retain associated water production from coalbed natural gas wells. Construction of new impoundments during 2009-2028 may be less than in years prior to 2008 (Brus, 2009). If this occurs, the acreage estimates above may be too high. Gas farming will have no affect on water impoundments (DeBruyn, 2009).

When wells reach their economic limit and are abandoned, water impoundments are also abandoned, except that some are retained by nonfederal surface owners. In the Buffalo Field Office area estimated reclaimed acreage is about 50 percent of total disturbed acreage on nonfederal surface (Brus, 2009). On Federal surface all impoundments are required to be completely reclaimed, therefore none of the unreclaimed acreage will include Federal surface. Acreage remaining unreclaimed at the end of 2028 is estimated to be 16,839 acres (no Federal surface). None of the unreclaimed water impoundments are considered necessary for coalbed natural gas production operations.

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GLOSSARY

Accumulation. An accumulation is one or more pools or reservoirs of petroleum that make up an individual production unit and is defined by trap, charge, and reservoir characteristics. Two types of accumulations are recognized, conventional and continuous.

Adsorbed (adsorption). The adherence of gas molecules to the surface of solids (coal or shale particles) with which they are in contact.

Analysis period. January 1, 2009 through December 31, 2028.

Associated water. Water that is produced from a well that also produces coalbed natural gas.

Assessment unit. A mappable volume of rock within a total petroleum system that encompasses accumulations (discovered and undiscovered) that share similar geologic traits and socio-economic factors. Accumulations within an assessment unit should constitute a sufficiently homogenous population such that the chosen methodology of resource assessment is applicable. A total petroleum system might equate to a single assessment unit. If necessary, a total petroleum system can be subdivided into two or more assessment units in order that each unit is sufficiently homogeneous to assess individually. An assessment unit may be identified as conventional, if it contains conventional accumulations (see Glossary), or as continuous, if it contains continuous accumulations (see Glossary).

Blanket Drilling. Continuous drilling until every spacing area contains at least one well.

BTU. Brittish Thermal Unit. A measure of heat energy. One million BTU's is the heating value of one thousand cubic feet of methane.

Borehole. Any narrow shaft drilled in the earth, either vertically or horizontally, to explore for or release oil, gas, water, etc.

Cable tool rigs. A type of drilling rig that employed a heavy chisel-lie bit, which was suspended on a heavy cable and dropped repeatedly into the rock at the bottom of the hole.

Casing string. An assembled length of steel pipe configured to suit a specific borehole. The sections of pipe are connected and lowered into a borehole, then cemented in place. Casing is run to protect or isolate formations next to the borehole.

Coalbed natural gas. The gas that is produced from coalbeds. It is mostly biogenic and may include nitrogen and carbon dioxide. Coalbed natural gas is used inerchangeably with coalbed gas.

Continuous accumulation. Common geologic characteristics of a continuous accumulation include occurrence down dip from water-saturated rocks, lack of obvious trap and seal, pervasive oil or gas charge, large aerial extent, low matrix permeability, abnormal pressure (either high or low), and close association with source rocks. Common production characteristics include a large in-place petroleum volume, low recovery factor, absence of truly dry holes, dependence on fracture permeability, and sweet spots within the accumulation that have generally better production characteristics but where individual wells still have serendipitous hit or miss production characteristics (Schmoker, 2003).

Conventional accumulation. The U.S. Geological Survey has defined conventional accumulations "by two geologic characteristics: (1) they occupy limited, discrete volumes of rock bounded by traps, seals, and down-dip water contacts, and (2) they depend upon the buoyancy of oil or gas in water for their existence" (Schmoker and Klett, 2003).

Diagenetic pore-throat trap. A stratigraphic configuration of the reservoir and/or its sealing units formed by post depositional processes that cause variations in pore-throat aperture sizes (constricted openings connecting pore spaces between sediment grains) that create the trap boundaries between the reservoir and seal.

Field. A production unit consisting of a collection of oil and gas pools that when projected to the surface form an approximately contiguous area that can be circumscribed.

HBP. Held by production. This usually refers specifically to oil and gas leased that are productive and are held beyond their primary term because they are producing oil or gas in economic quantities.

Infill drilling. Additional wells drilled between existing wells in an effort to increase the recovery of oil or gas from a reservoir.

In-place. The total volume of oil and/or gas thought to exist (both discovered and yet-to-be discovered) without regard to the ability to either access or produce it. Although the in-place resource is primarily a fixed, unchanging volume, the current understanding of that volume is continually changing as technology improves.

Natural gas. Any gas of natural origin that consists primarily of hydrocarbon molecules producible from a borehole.

Natural gas liquids. Hydrocarbons found in natural gas that are liquefied at the surface in field facilities or in gas processing plants. Natural gas liquids are commonly reported separately from crude oil.

Petroleum. A collective term for oil, gas, natural gas liquids, and tar.

Play. A set of known or postulated oil and gas accumulations sharing similar geologic, geographic, and temporal properties, such as source rock, migration pathway, timing, trapping mechanism, and hydrocarbon type. A play may differ from an assessment unit; an assessment unit can include one or more plays.

Play area. An area where productive oil or gas wells may be drilled based on a specific geologic concept

Proved growth reserves or reserve growth. The increases in known petroleum volume that commonly occur as oil and gas accumulations are developed and produced, synonymous with field growth.

Proved reserves. The volume of oil and gas demonstrated, on the basis of geologic and engineering information, to be recoverable from known oil and gas reservoirs under present-day economic and technological conditions.

Public domain. Minerals that have been owned continuously by the United States.

Reserves. Oil and gas that has been proven by drilling and is available for profitable production.

Rotary drilling rig. A modern drilling unit capable of drilling a well with a bit attached to a rotating column of steel pipe.

Spacing pattern. The pattern of well locations, usually one well location per 80 acres for coals in the Buffalo Planning Area. More than one coalbed natural gas well may be drilled on a location.

Spudded. To break ground with a drilling rig at the start of well-drilling operations.

Stratigraphic test. A well drilled to obtain geologic and/or engineering data about the coal.

Stratigraphic trap. A trap (any barrier to the upward movement of oil or gas, allowing either or both to accumulate) that is the result of lithologic changes rather than structural deformation.

Structure trap. A trap (any barrier to the upward movement of oil or gas, allowing either or both to accumulate) that is the result of folding, faulting, or other deformation.

Technically recoverable resources. The volume of hydrocarbons which are recoverable using current exploration and production technology without regard to cost, which is a proportion of the estimated in-place resource.

Total petroleum system. A total petroleum system consists of all genetically related petroleum generated by a pod or closely related pods of mature source rocks. Particular emphasis is placed on similarities of the fluids of petroleum accumulations and is therefore closely associated with the generation and migration of petroleum. The geologic elements of a total petroleum system, include (1) source-rock distribution, thickness, organic richness, maturation, petroleum generation, and migration; (2) reservoir-rock type (conventional or continuous), distribution, and quality; and (3) character of traps and time of formation with respect to petroleum generation and migration.

Nonconventional gas (Unconventional gas). Nonconventional gas is generally thought of as gas that is created in formations without the permeability necessary to allow significant migration. It is generally described as those gas accumulations that are hard to discover, characterize, and commercially produce by common exploration and production technologies. It may include coalbed natural gas, tight sand, tight carbonates, shale, or deep gas.

Undiscovered technically recoverable resource. A subset of the in-place resource hypothesized to exist on the basis of geologic knowledge, data on past discoveries, or theory, and that is contained in undiscovered accumulations outside of known fields. Estimated resource quantities are producible using current recovery technology but without reference to economic viability. These resources are therefore dynamic, constantly changing to reflect our increased understanding of both the in-place resource as well as the likely nature of future technology. Only accumulations greater than or equal to 1 million barrels of oil or 6 billion cubic feet of gas were included in the earlier 1995 assessment.

Unstable grains. Said of mineral grains within a sedimentary rock, that don't resist chemical change after deposition.

Vibroseis. A method of putting energy into the earth for a seismic survey. It ususlly involves a hydraulic vibrator mounted on a mobil base.