REASONABLE FORESEEABLE DEVELOPMENT SCENARIO FOR OIL AND GAS LANDER FIELD OFFICE, WYOMING

Derby Dome Field

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INTRODUCTION

The Lander Field Office Planning Area (Planning Area) lies within west-central Wyoming (Figure 1). The main goal of this reasonable foreseeable development projection is to technically analyze the oil and gas resource known to occur and potentially occurring within the Planning Area and to project future development potential and activity levels for the period 2008 through 2027. Historic and present oil and gas related development areas (fields) are presented for all lands, including Indian Reservation lands (Figure 2).

Our analysis makes a base line projection that assumes future oil and 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, 2002). National Forest lands, other Federal agency lands, Indian Reservation lands, and State and Private managed lands are included in the base line projection for those lands assessed for future development (Figure 3). Certain other federally managed lands within the Planning Area are not assessed for the potential for future reasonable foreseeable oil and gas related development. Those lands with legislatively imposed restrictions (no leasing) are not included in this base line projection since oil and gas activities will not be allowed. Those restricted lands are National Forest wilderness areas and Bureau of Land Management (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 oil and gas, coalbed natural gas, and deep 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 oil and gas resource information (including a number of on-line databases) for the area, a call for data from oil and gas operators, a review of petroleum technology research and development, geophysical activity, and limitations on access and infrastructure. It must be emphasized that the reasonable foreseeable development projections presented are not worst-case projections, but reasonable and science based projections of the anticipated oil and gas activity and they use logical and technically based assumptions to make those projections. Finally, projections of future activity levels for each resource management plan alternative are presented.

The Planning Area contains about 6,486,835 surface acres of all oil and gas mineral ownership types. Total Federal oil and gas mineral ownership, in the Planning Area, amounts to about 3,670,521 acres, or about 57 percent of total acres. Reservation tribes own about 1,762,005 acres of oil and gas minerals, or about 27 percent of total acres. The oil and gas resource on these lands are managed for the tribes by the Bureau of Indian Affairs. The remaining 1,060,508 acres (16 percent) is owned by state and private interests.

The Bureau of Land Management (Bureau) manages most of the Federal oil and gas mineral lands in the Planning Area (about 2,785,627 acres, or 76 percent). We assume that about 401,663 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.

Smaller amounts of Federal oil and gas mineral lands within the Planning Area are managed by the U.S. Forest Service (878,029 acres or 24 percent), Bureau of Reclamation (5,412 acres), Department of Defense (1,341 acres) and Fish & Wildlife (112 acres). Decisions made as part of the Resource Management Plan EIS for the Planning Area will not be made for these lands.

We would like to thank Cathy Stilwell of the Bureau of Land Management Wyoming State Office Reservoir Management Group staff and Stuart Cerovski of the Bureau of Land Management Lander Field Office for the important contributions that they have made to this reasonable foreseeable development analysis.

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 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.

Hendricks (1995) studied the components that control and characterize potential gas accumulations in the Great Divide and Washakie basins. The Great Divide portion of this area extends into the southern portion of the Field Office area (Figures 4 and 5). He reported that the major components of accumulations "are:

1. Thick accumulations of sandstones and shales (potential source and reservoir rocks) exist, with coals present in some areas. Figure 6 presents a stratigraphic chart for the Lander Planning Area showing nomenclature used for these accumulations in our report.
2. Burial and thermal histories promoted the development and preservation of diagenetic pore throat traps and extensive gas generation.
3. Although the centers of basins are completely gas saturated, production is controlled by stratigraphy. Both basin-wide and local stratigraphic variations are important in creating traps and reservoirs (local compartments).
4. Structure also plays a role in localizing gas accumulations, especially when coupled with stratigraphy.
5. Pressure regimes, ranging from slightly under-pressured to highly over-pressured, are important. 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.
6. The presence of fractures, both tectonic and produced by gas generation, is important to overall productivity.
7. Secondary porosity, produced by the dissolution of unstable grains and rock fragments, is important in both basin-wide and local accumulations."

We believe that those components are also important in exploring for and developing new gas resources in the Wind River Basin portion of the Field Office (Figures 4 and 5). Almost all Field Office area drilling activity (exploratory and development) has been occurring in the eastern Wind River Basin and eastern portions of the Wind River Indian Reservation, with additional exploratory activity in the Great Divide Basin portion of the Field Office (Figure 7). New drilling activities in the western part of the Wind River Indian Reservation and northwestern portion of the Wind River Basin have been rare in recent years.

Potential unconventional gas resources (see Glossary) make up a significant 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 wellbore.
2. Coalbed Natural Gas – formed in coal deposits and adsorbed 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 these 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 in the lower 48 states in 2006 (Kuuskraa, 2007). 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 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 834 wells spud in the most recent 10-year period (September 1, 1998 to September 1, 2008) initial classifications, as defined by IHS Energy Group (2008) were:

- Development 719 wells 86.2 percent,
- Injection 2 wells 0.2 percent,
- Stratigraphic Test 4 wells 0.5 percent,
- Deeper Pool Wildcat 6 wells 0.7 percent,
- New Field Wildcat 72 wells 8.6 percent,
- Wildcat Outpost 29 wells 3.5 percent,
- New Pool Wildcat 1 well 0.1 percent, and
- Shallower Pool Wildcat 1 well 0.1 percent.

Total wildcats and stratigraphic tests were 113 wells, or 13.5 percent of the total.

New wells drilled in the last 10 years are concentrated within the northeast part of the Lander Planning Area (mainly at Madden, Frenchie Draw, Fuller Reservoir, and Beaver Creek Fields) and within the southeastern part of the Wind River Indian Reservation (at Muddy Ridge, Pavillion, and Riverton Dome Fields), with a few new oil wells drilled in the northwest and occasional new wells scattered across the south (Figure 7).

Of the 719 development wells drilled during this period, their final classification (IHS Energy Group, 2008) ended up as:

- Dry (including Temporarily Abandoned) 45 wells,
- Development – Gas 598 wells,
- Development – Oil 52 wells,
- Development – Gas Shut-In 12 wells,

- Development – Spud 8 wells, and
- Water Injection 4 wells.

Of the wells completed, 93.7 percent were successful. This rate is quite high and is mainly due to the very high rates of successful drilling around the already existing major fields (Figure 7). Reservoirs in these field areas are gas prone and predominantly stratigraphic traps. In these areas, gas production is more ubiquitous than in other parts of the Planning Area (western part of the Wind River Indian Reservation and scattered small fields in the south) where oil production has predominated in the past (Figure 2). In that part of the Planning Area from township 32 north and southward, only 28 development wells have been spud within the last 10 years.

Of the two injection wells, one was completed as a water injection well while the other was spud and has not yet been completed. Of the 113 wildcats and stratigraphic tests drilled during this period (IHS Energy Group, 2008), their final classification ended up as:

- Dry (including Temporarily Abandoned) 45 wells,
- Gas 63 wells,
- Oil 2 wells,
- Spud 2 wells, and
- Service 1 well.

Of the wells completed, 59.5 percent were successful.

Fifty-two operators were responsible for the 834 wells drilled in the 10-year period (September 1, 1998 to September 1, 2008). The top three operators (EnCana Oil & Gas (USA) Incorporated, Burlington Resources Oil and Gas Company, and Devon Energy Corporation) are responsible for the drilling of more than 75 percent of these wells. Twenty-four operators were responsible for the drilling of only one well each.

New production has come from 16 intervals during the last 10 years. Three intervals (Wind River Formation – 79 wells and Fort Union Formation – 449 wells) produce from Tertiary aged sediments, six intervals (Lance Formation – 35 wells, Meeteetse Formation – 9 wells, Lewis Shale – 1 well, Mesaverde Formation – 25 wells, Cody Shale – 13 wells, and Frontier Formation – 38 wells) produce from Upper Cretaceous aged sediments, only the Muddy Sandstone (11 wells) produces from Lower Cretaceous aged sediments, two intervals (Morrison Formation – 1 well and Lower Jurassic Nugget Sandstone – 4 wells) produce from Jurassic aged sediments, only the Crow Mountain Formation (1 well) of the Chugwater Group produces from Triassic aged sediments, two intervals (Phosphoria Formation – 13 wells and Tensleep Sandstone – 15 wells) produce from Permian aged sediments, and only the Madison Limestone (7 wells) produces from Mississippian aged sediments. In addition, 10 wells were completed to coal beds. The Fort Union Formation is productive in 63 percent of wells with a reported completion interval, the Wind River Formation is productive in 11 percent, and the Frontier and Lance formations are productive in five percent. The other 12 intervals account for the remaining 16 percent of productive wells.

Drilling depths for all wells drilled in the 10-year period (September 1, 1998 to September 1, 2008) have ranged from 60 to 25,830 feet. Seventeen of these wells (two percent) were deeper than 15,000 feet, with 16 lying in the Madden Field area (Figure 5). None of these deep Madden Field wells have been abandoned, although one is still in a testing status and two are temporarily abandoned, while the rest have been completed as producing gas wells. Of the completed wells, all but one well were completed in horizons deeper than 15,000 feet. The remaining deep well was a 16,168 foot wildcat that was drilled and abandoned in the northeast part of the Wind River Indian Reservation.

In the 10,000 to 15,000 foot range, 154 wells were drilled (18.5 percent). Thirty-six of these wells (23 percent) were drilled on the Wind River Indian Reservation. All were drilled in the gas rich eastern part of the Reservation, with two-thirds drilled at Muddy Ridge Field. Only one well was drilled and abandoned and two are temporarily abandoned, while the rest were completed as gas wells. Almost, all produce in the interval between 10,000 and 15,000 feet. Only six wells were drilled from township 32 north and southward in this depth range. The remaining 112 wells (73 percent) in this depth range lie in the northeast part of the Field Office. Almost half of these wells lie in Madden Field, with another quarter in Frenchie Draw and Beaver Creek fields and the remainder scattered across the area.

In the 5,000 to 10,000 foot range, 486 wells were drilled (58 percent). Eighty of these wells (16.5 percent) were drilled on the Wind River Indian Reservation. The three main producing fields in this depth range are Pavillion and Riverton Dome (gas wells) and Steamboat Butte (oil wells). Only nine wells were drilled from township 32 north and southward in this depth range. The remaining 397 wells (82 percent) in this depth range lie in the northeast part of the Field Office. More than half of these wells lie in Madden Field, with another 30 percent in Frenchie Draw, Fuller Reservoir, and Beaver Creek field and the remainder scattered across the area.

Only 173 wells were drilled to depths less than 5,000 feet (21 percent). One hundred and two wells (59 percent) were drilled on the Wind River Indian Reservation. Two thirds of these wells were gas wells drilled at Pavillion Field, with another 20 percent drilled at Riverton Dome (gas wells) and Lander (oil wells) fields. Thirty-one wells (18 percent) were drilled from township 32 north and southward in this depth range. About 40 percent were oil wells drilled at Bison Basin Field and the remainder were scattered across this area. The remaining 40 wells (23 percent) in this depth range lie in the northeast part of the Field Office. Almost half of these wells were drilled in Madden and Beaver Creek fields, with the remainder scattered across the area.

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). Industry is drilling fewer dry holes and reducing the number of wells needed to fully develop each

reservoir. 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 almost entirely on very low risk development drilling in and around known field areas, which helped to improve the overall success rate. More future exploratory drilling will be required to discover new resources in the Planning Area and to determine whether its potential coalbed natural gas resource is economic to produce. 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, 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 have 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 Lander 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.

Federal oil and gas leases are incorporated into 35 active unit agreement areas that lie within or partly within the Lander Planning Area boundary (Figure 8 and Table 1). Two of these units (Lander and Rolff Lake) lie within reservation boundaries, but are not shown on Figure 8. These two units are tied to fields of the same name, and the locations of the fields are shown on Figure 5. Numerous other unit agreements have been approved in the Planning Area but have since terminated. API/state units are established where Federal lands make up less than 10 percent of the proposed unit. No API/state units lie within the Planning Area.

Active units encompass lands totaling approximately 421,960 acres, with about 344,725acres lying entirely within the Planning Area. These units comprise a little more than 5.3 percent of the total Lander Planning Area. The oldest still active unit in the

Planning Area is the Big Sand Draw Gas unit established in 1934. Fifteen exploratory units (including the three coalbed natural gas units) have been approved in the last 10 years. These units were initially approved as exploration tools to investigate non-producing parts of the Planning Area. They are still in their exploration and development drilling phase and they cover about 73 percent of the total unit area. Seven of the 15 (including the three coalbed natural gas units) are still considered to be non productive. These units will likely contract to smaller developed unit areas once their productive limits are established.

Fourteen older units have contracted to their productive limits. These units are still producing oil and gas and cover 23 percent of the total unit area. Development drilling is continuing in some, while others are concentrating on obtaining maximum recovery with existing wells.

The six remaining unit agreements (Beaver Creek, Bison Basin, Crooks Gap, Happy Springs, Lander Phosphoria, and Rolff Lake units) contain secondary oil recovery projects. Operators of these six units are working to obtain maximum oil recovery. They account for the remaining five percent of the total unit area.

Some units produce oil and/or gas from only one zone, while others produce from multiple zones (Table 1). At present, there are 17 different producing zones in the 28 units that are presently productive. The numbers of units with production from each zone (from youngest age zone to oldest) are:

- Fort Union – 11 units
- Lance – 8 units
- Lewis – 1 unit
- Meeteetse – 1 unit
- Mesaverde – 3 units
- Cody/Shannon – 3 units
- Frontier – 6 units
- Muddy – 6 units
- Cloverly (locally called the Dakota) – 2 units
- Cloverly (locally called the Lakota) – 2 units
- Morrison – 2 units
- Nugget – 2 units
- Crow Mountain of the Chugwater Group – 2 units
- Phosphoria – 4 units
- Tensleep – 3 units
- Madison – 1 unit
- Paleozoic – 1 unit.

Twenty-one companies operate the 35 units within the Lander Planning Area. EnCana Oil & Gas (USA) Incorporated operates six units, St. Mary Land & Exploration Company operates five units, Richardson Operating Company and the Hudson Group

LLC each operate three units, and Noble Energy Incorporated operates two units, while the remaining 16 companies each operate only one unit.

COMMUNITIZATION AGREEMENTS

Communitization Agreements may be authorized when a Federal or Tribal 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 or Tribal 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.

At present, only 2 active communitization agreements lie within the Lander Planning Area and outside the reservation (Figure 9). Each 640-acre communitization agreement is permitted to the Frontier Formation. Additional communitization agreements lie on reservation lands but information is not available to the public.

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 or Wind River Indian Reservation 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 Lander 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 well bores, geostearing the drill bit to maintain correct hole trajectory;
- inserting casing 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;
- hydraulically fracturing 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.

Data was retrieved from IHS Energy Resources (2008) and Wyoming Oil and Gas Conservation Commission (2008) for wells spud since January, 2003. Data for time from spud date to the final drill date (or date total depth was reached) was used to determine the average time required to drill a vertical well within certain depth ranges. A data base of 488 wells was reviewed. The data shows that 86 percent of 49 wells drilled to depths up to 5,000 feet (average drill depth 2,903 feet) were completed in six days or less and those wells averaged almost five days to drill. Of 261 wells drilled to depths of 5,000 to 9,999 feet (average drill depth 7,374 feet), most wells (82 percent) were completed in 19 days or less and those wells averaged almost 9.5 days to drill. Of 43 wells drilled to depths of 10,000 to 14,999 feet (average drill depth 11,584 feet), most wells (81 percent) were completed in 55 days or less and those wells averaged over 31 days to drill. Of nine wells drilled to depths of more than 15,000 feet (average drill depth 17,470 feet), most wells (89 percent) were completed in 130 days or less and those wells averaged over 101 days to drill.

The average time required to drill directional and coalbed natural gas wells were analyzed separately. Only one directional well was drilled to a depth shallower than 5,000 feet (4,615 feet) and it was completed in seven days. Of 82 directional wells drilled to depths of 5,000 to 9,999 feet (average drill depth 6,896 feet), most wells (80 percent) were completed in 29 days or less and those wells averaged over 10 days to drill. Directional wells had a large range of days required to drill to total depth when compared to vertical wells (29 days for directional wells and 19 days for vertical wells), but the average number of days to total depth was closer (9.4 days for vertical compared to 10.3 days for directional). The result is that directional well rig costs would be slightly higher in this depth range. Of 23 wells drilled to depths of 10,000 to 14,999 feet (average drill depth 11,420 feet), most wells (83 percent) were completed in 59 days or less and those wells averaged over 28 days to drill. Directional wells in the 10,000 to 14,999 had a similar range in days to total depth and average days when compared to vertical wells, indicating that there was little cost difference in drill rig costs for these two types of wells in this depth range. No directional wells greater than 15,000 feet were drilled in the time period analyzed.

Nineteen vertical coalbed natural gas wells were spud and reached total depth since January, 2003. Depth ranges for these wells have been 4,310 to 7,130 feet. Of the 19 wells drilled, most wells (83 percent) were drilled in nine days or less and those wells averaged 6.5 days to drill.

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 Lander Planning Area are could be:

- access to well sites is generally more difficult due to remoteness from the main activity areas and sometimes 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 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 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 and tribal 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

The existence of oil in Wyoming has been known for centuries. Native Americans used the “Great Tar Spring,” 10 miles southeast of Lander, to provide horse liniment. Captain Bonneville reported on this spring in 1832 and pioneers used this oil as axle grease for their wagons. Activity, although quite variable over time, has continued from its discovery in the Planning Area more than 100 years ago to the present, with constant improvements being made in exploration and development techniques.

Early Exploration and Development Activity

The "Great Tar Spring" had been known by early trappers in the region and was first reported by Captain Bonneville in 1832 as part of a War Department expedition. The first oil well in the state was drilled in 1884, near this spring and within the Planning Area. That well was drilled by Mike Murphy and his brother. They found oil at 300 feet in what is now known as the Chugwater Group. Their well was the discovery well for the Dallas Field (see Figure 10), which still produces today. Later, two additional wells were drilled on the same structure to a depth of 750 feet and produced oil from the Phosphoria Formation. The produced oil was marketed to the railroad in southern Wyoming but was eventually shut in as a result of competition from eastern suppliers. Later, a combination of a rail spur, pipeline, and foreign investment resulted in the drilling of 53 additional wells, all producing oil from the Phosphoria Formation. Shortly after this surge in drilling activity, a well was drilled in 1930 to a depth of 1,150 ft and produced oil from the Tensleep Sandstone. This resulted in the extension of a number of the previously drilled Phosphoria Formation wells also into the Tensleep Sandstone.

This discovery inspired others to stake oil placer claims throughout the state. Additional natural oil seeps were discovered at a number of sites northwest of Dallas Field on Reservation lands. Oil fields were later developed on most of these sites.

Exploratory and development activities continued throughout Wyoming, but no additional discoveries were made within the Lander Planning Area until after the turn of the next century. Most of the earliest fields (Figure 10), prior to 1947 were discovered by surface observation of oil seeps and/or surface mapping (Espach and Nichols, 1941; Biggs and Finnegan, 1952; and Wyoming Geological Association, 1957 and 1989) and are:

- Lander – a thrust faulted anticline discovered in 1909 and initially producing oil from the Phosphoria Formation, with Tensleep Sandstone oil production added in 1926;
- Plunkett – a stratigraphic trap (associated oil seep) discovered in 1909 and producing oil from the Mowry Shale, with all wells now abandoned;
- Sage Creek Anticline - an anticline (associated oil seep) discovered in 1909 and producing oil from the Tensleep Sandstone, with Phosphoria Formation oil production added in 1916, Sundance Formation oil production added in 1928, and all wells now abandoned;
- Pilot Butte – a faulted dome-shaped anticline (associated oil seeps) discovered in 1916 and producing oil from the Cody Shale, with Tensleep Sandstone oil production added in 1942, Phosphoria Formation oil production added in 1944, Muddy Sandstone oil and gas wells added in 1949, and Frontier Formation gas wells added in 1951;
- Winkleman – a thrust and normal faulted anticline discovered in 1917 and producing gas from the Cloverly (locally called the Lakota), with Tensleep Sandstone oil production added in 1944 and Phosphoria Formation oil production added in 1948;

- Maverick Springs – an anticline discovered in 1918 and producing oil from the Phosphoria Formation, with Tensleep Sandstone oil production added in 1952;
- Big Sand Draw – a thrust faulted anticline discovered in 1918. Gas was first produced from the Frontier Formation in 1920. Beginning in 1922 some gas was piped to an absorption gasoline plant in Riverton, Wyoming. Once gasoline was separated the remaining residue was burned in a carbon-black plant. The gasoline plant was moved to the field in 1928 Cloverly Formation (locally called the Lakota) gas production was added in 1937 and Morrison Formation gas production was added in 1939. During these early years a combination of high pressure, no market for the gas, dipping anticlinal axis, and the inability to map at depth a southern closure on the structure preempted significant development until drilling technology progressed. Later, weighted mud in combination with rotary methods enabled operators to test deeper formations for a much more sought after hydrocarbon, oil. The discovery of oil in the Tensleep Sandstone in 1944 resulted in the flaring of a huge amount of gas as was typical of the industry during this time period. Eventually pipelines were constructed to Riverton, Lander, and Casper as a market for the gas. Phosphoria Formation gas production was added in 1948 and the Madison Limestone was eventually tested and only produced water;
- Alkali Butte – a faulted anticline discovered in 1920 and producing gas from the Frontier Formation, with Muddy Sandstone oil and gas production added in 1928 and Morison Formation gas production added in 1933;
- Derby – a thrust and strike/slip faulted anticline with thrust and strike/slip faulting discovered in 1921 and producing oil from the Phosphoria Formation, with Tensleep Sandstone oil production added in 1922;
- Circle Ridge – a thrust faulted anticline discovered in 1923 and producing oil from the Phosphoria Formation and Tensleep Sandstone, with Madison Limestone oil production added in 1946 and Darwin Sandstone Member of the Amsden Formation oil production added in 1955;
- Bison Basin – a faulted anticline discovered in 1923 and producing oil and gas from the Frontier Formation. The first well in the field had been drilled and abandoned in 1919. In 1923 a well to the Frontier Formation produced gas. With no market for the gas, it was utilized to drill additional wells in the field. During the fields first phase of development nine wells were drilled, two were shut-in and the others were abandoned. Interest in the area didn't pick up until shortly after World War II. Thirteen cable tool wells were drilled between 1946 and 1955, with 10 producing oil from six distinct sand zones in the Frontier Formation. In 1956, 50% interest of this operation was purchased by a major operator and a seismic survey was shot for field development. Additional wells were drilled with the intent of looking for deeper production, but none was found;
- Crooks Gap – a faulted anticline discovered in 1925 and producing oil from the Frontier Formation, with Cloverly Formation (locally called the Lakota) oil production added in 1944, Muddy Sandstone oil production added in 1947, and Nugget Sandstone oil production added in 1955;
- Sheep Creek – an anticline discovered in 1935 and producing oil from the Phosphoria Formation;

- Muskrat – a faulted plunging anticline discovered in 1928 when the field discovery well blew out at an estimated 49 million cubic feet of gas per day. Gas from this well was transported to Casper, Wyoming via a then existing nearby pipeline. In 1937, Cloverly Formation gas was discovered. Additional Frontier, Muddy, and Phosphoria formation production was discovered latter in the fields history;
- Muskrat East – an anticline discovered in 1945 and producing gas from the Frontier Formation in section 16 of township 33 north and range 91 west, with all wells now abandoned; and
- Dubois – a faulted anticline discovered in 1946 and producing oil from the Phosphoria Formation.

Exploration of the above types of surface geologic structures (anticlines, faulted anticlines, and faulted domes) was the most successful method of discovering new reservoirs in the Lander Planning Area during this earliest period of activity. These structures display variations in size, shape, and amount of structural relief. Surface methods (areal and structural mapping) as well as the presence of oil seeps have been used to recognize these types of structures.

Over time, additional exploratory methods were added to help explore for and locate additional new traps. Seismic was used to delineate Quealy Dome in 1933 (in the Laramie Basin of south-central Wyoming) which resulted in the first discovery as a result of seismic in the Rockies. In the Lander Planning Area, additional methods included using a combination of mapping of surface geologic structures, the development of geophysical methods (seismic surveys), and/or some subsurface mapping. The earliest use of these types of methods was in the 1938 through 1959 period. Many of these types of discoveries were found at greater depths than those from the earliest period of discovery. In the Planning Area, these discovered fields are located on Figure 10 and geologic summaries (Wyoming Geological Association; 1957, 1961, and 1989) include:

- Beaver Creek – a thrust and normal faulted anticline discovered in 1938 and producing gas from the Cloverly Formation (locally called the Lakota). Development of the field ceased until a market opened up for the gas in 1944. Frontier Formation and Muddy Sandstone gas production was added in 1947, Tensleep Sandstone oil wells were added in 1948, Mesaverde Formation oil wells were added in 1951, and Madison Limestone oil wells were added in 1953;
- Steamboat Butte – a faulted anticline discovered in 1943 and producing oil from the Nugget Sandstone, with Cloverly (locally called the Lakota) and Tensleep Sandstone oil production added in 1944, Frontier Formation gas wells added in 1945, and Phosphoria Formation oil wells added in 1948;
- Sheldon – a thrust and normal faulted anticline discovered in 1945 and producing oil from the Phosphoria Formation and Tensleep Sandstone;
- Sand Draw South – a thrust faulted anticline discovered in 1946 using reflection seismic and producing gas from the Frontier Formation, with Phosphoria Formation and Tensleep Sandstone oil production added in 1953 and Muddy Sandstone gas production added in 1956;

- Antelope Springs East – a faulted anticline discovered in 1947 and producing gas from the Wind River Formation;
- Longs Creek – a thrust faulted anticline discovered in 1948 and producing gas and oil from the Phosphoria Formation;
- Riverton Dome – an anticline discovered in 1949 and producing oil from the Tensleep Sandstone, with Phosphoria Formation oil production added in 1951;
- Happy Springs – a faulted anticline discovered in 1950 and producing oil in the Frontier Formation and Muddy Sandstone, with Cloverly Formation (locally called the Dakota) oil production added in 1951, Cloverly Formation (locally called the Lakota) oil production added in 1952, and Phosphoria Formation oil production added in 1953;
- Sand Draw North – a thrust faulted plunging anticline discovered in 1953 and producing oil from the Tensleep Sandstone;
- Kirby Draw – a faulted plunging anticline discovered in 1954 and producing gas from the Frontier Formation and the Cloverly (locally called the Lakota);
- Grieve – a stratigraphic trap discovered in 1954 and producing oil from the Muddy Sandstone;
- Kirk – a thrust faulted anticline discovered in 1954 and producing oil from the Phosphoria Formation;
- Sheldon Northwest – a faulted anticline discovered in 1954 and producing oil from the Crow Mountain Formation of the Chugwater Group;
- Mt. Rogers Unit – an anticline discovered in 1955 and producing gas from the Cloverly Formation, with all wells now abandoned;
- Lost Cabin – an anticline discovered in 1957 and producing gas from the Lance Formation, with Wind River Formation oil and gas production added in 1958. This field latter became part of the larger Madden Deep Unit;
- Castle Garden – a thrust faulted anticline discovered in 1957 and producing gas from the Shannon Sandstone Member of the Cody Shale;
- Rolff Lake – a thrust faulted anticline discovered in 1957 and producing oil from the Crow Mountain Formation of the Chugwater Group and the Phosphoria Formation;
- Little Dome – an anticline discovered in1958 and producing gas from the Crow Mountain Formation of the Chugwater Group, with all wells now abandoned; and
- Dolis Hills – a stratigraphic trap discovered in 1959, with the first well completed for oil and gas in the Lance Formation and lying in section 23 of township 39 north and range 91 west. All wells are now abandoned. Dolis field latter became part of the larger Madden Deep Unit.

With increasing data obtained from drilled wells, subsurface stratigraphic mapping began to contribute to exploration for new production. In the Lander Planning Area, the earliest use of subsurface stratigraphic mapping appears to have aided in the discovery of the Frenchie Draw and Dinty Moore Reservoir fields in 1961, the Bonneville Field in 1968, and the Madden Field in 1968 (Wyoming Geological Association, 1989). The locations of these four fields are shown in Figure 5. The first producing formation in each of these fields was the Fort Union. This method was also used in combination with geophysical methods (seismic surveys) in three of the four above discovery cases.

Producing Zones

There are 88 named fields (Figure 5) and seven unnamed fields located within the Planning Area (DeBruin, 2006). Oil and gas occurs in the Lander Planning Area in numerous geologic formations, and members of formations which range in age from the oldest producing formation (Flathead Sandstone of Cambrian age), upward in time to the Wind River Formation of Tertiary age. The range of producing oil and gas zones is shown in the stratigraphic chart presented in Figure 6. Table 2 presents information on all producing zones within the Planning Area, as obtained from IHS Energy (2008). Some producing zones are reported under more than one name. Those equivalent zones are presented in parenthesis in Table 2. In some wells, more than one zone actually produces. Those variations are also presented in Table 2. Total wells (3,172 wells) include those presently producing, shut-in wells, and those wells that produced at some time in the past but have since been plugged and abandoned due lack of economic production. These well totals do not include wells that were drilled and abandoned, junked and abandoned, or those that were completed as productive wells but then were never productive before being plugged and abandoned at a later date.

Cumulative production (through 2007) within the Lander Planning Area has been almost four trillion cubic feet of gas and more than 500 million barrels of oil (Table 2). The most prolific oil productive formations have been the Phosphoria Formation and Tensleep Sandstone. A significant amount of gas production has also been associated with these two formations. Almost all of the fields producing from these two formations are located within the Wind River Indian Reservation, with some additional productive fields to the south and southeast of the Reservation. Both formations have been productive in 1,467 of the 3,172 total productive wells (46 percent) within the Planning Area.

The Fort Union Formation and Madison Limestone, at Madden Field have been the most prolific gas producers within the Lander Planning Area. A moderate amount of oil has been produced in association with the gas in the Fort Union Formation wells while associated oil production in the Madison Limestone has been moderate from other fields such as Beaver Creek. Most of the Fort Union Formation producing gas fields are concentrated in the northeast part of the Planning area, with Madden Field (Figure 5) containing more than one third of the total wells. The Fort Union Formation has been productive in 737 (23 percent) of the total productive wells in the Planning Area. Only 61 wells have produced from the Madison Limestone (less than 2 percent of all producing wells), with most wells located at Circle Ridge and Beaver Creek Fields (Figure 5). Even though only 8 Madison Limestone wells produce at Madden Field, that field has produced more than 98 percent of all Madison Limestone gas production.

Two source rock and associated oil and gas reservoir systems appear to be responsible for most of the hydrocarbons found in the Lander Planning Area. Permian aged Phosphoria source rocks (Kirschbaum et al., 2005) appear to have sourced most of the pre-Cretaceous aged reservoirs in the Planning Area. These older formations have

predominately produced oil with smaller amounts of gas: the Madison Limestone, which has produced mostly gas in the Madden Field, is the exception. Tertiary and Cretaceous aged source rocks appear to have been the source of hydrocarbons in most Tertiary and Cretaceous aged reservoirs. Finn (2007) showed that the lower shaly member of the Cody Shale is a fair to excellent source rock for both oil and gas, and it is the most organic-rich and oil-prone of all potential hydrocarbon source rocks in Cretaceous strata in the Wind River Basin. In the Tertiary and Cretaceous aged reservoirs, gas production tends to predominate, although there is usually a significant oil component produced along with the gas.

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 component of production within the Planning Area and could become the most significant portion in the future. 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 have 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.

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. Access restrictions on Bureau managed lands in the Planning Area have been rare in recent years.

Drilling and Completion Activity

There have been 4,481 surface well locations spud or completed in the Planning Area through October 23, 2008 (Wyoming Oil and Gas Conservation Commission, 2008). Of this total, 24 have been sidetracked once and one well has been sidetracked twice (IHS Energy Group, 2008). In addition, 520 wells have been plugged back once, 94 have been plugged back twice, 30 have been plugged back three times, and 11 have been plugged back four times (IHS Energy Group, 2008).

Of the 4,481 wells spud or drilled in the Planning Area, 1,900 wells, or 42.4 percent, appear to have been on Bureau managed oil and gas lands. There are 1,867 wells (41.7 percent) that lie within the boundary of the Wind River Indian Reservation; 1,415 of those wells (31.5 percent of total wells) are managed by the Bureau of Indian Affairs, while the remaining wells (452 wells) have private oil and gas mineral ownership. There are an additional 1,114 wells (24.9 percent) that appear to have been drilled on private and state owned oil and gas mineral ownership.

Figure 11 presents the locations of all wells that have been spud and not completed and all wells still capable of producing oil and gas (Wyoming Oil and Gas Conservation Commission, 2008) as of October 23, 2008. Of these wells, their present well class and status is:

- Confidential – Spud 1 well

- Gas – Spud 37 wells
- Gas – Producing 891 wells
- Gas – Flowing 16 wells
- Oil – Producing Gas 21 wells
- Gas – Plunger Lift 1 well
- Gas – Pumping Rods 2 wells
- Gas – Shut-in 137 wells
- Gas – Temporarily Abandoned 25 wells
- Gas – No Report 3 wells
- Gas – Notice of Intent to Abandon 12 wells
- Oil – Spud 14 wells
- Oil – Producing 542 wells
- Oil – Pumping Submersible 16 wells
- Oil – Pumping Rods 42 wells
- Gas – Producing Oil 8 wells
- Oil – Flowing 3 wells
- Oil – Gas Lift 1 well
- Oil – Shut-in 122 wells
- Oil – Dormant 24 wells
- Oil – Temporarily 80 wells
- Oil – Unknown 6 wells
- Oil – Notice of Intent to Abandon 18 wells.

A total of 55 wells have been spud and not completed, 862 wells are classed as oil wells or are producing oil, and 1,108 wells are classed as gas wells.

Figure 12 presents the locations of all wells that are being used for enhanced oil recovery purposes, for disposal, monitoring, and as source wells (Wyoming Oil and Gas Conservation Commission, 2008) as of October 23, 2008. Of these 242 wells, their present well class and status is:

- Injector – Active Injector 162 wells
- Oil – Active Injector 9 wells
- Injector – Shut-in 20 wells
- Injector – Temporarily Abandoned 7 wells
- Injector – Notice of Intent to Abandon 1 well
- Disposal – Active Injector 25 wells
- Disposal – Shut-in 2 wells
- Monitor – Active Injector 2 wells
- Monitor – Active Monitor 3 wells
- Monitor – Shut-in 2 wells
- Monitor – Dormant 1 well
- Source – Flowing 1 well
- Source – Water Source 4 wells
- Source – Unknown 1 well
- Water Source – Shut-in 2 wells.

The wells shown in Figures 11 and 12 account for about 50 percent of the wells completed (as of October 23, 2008) within the Planning Area. The above information shows that 55 wells (2.4 percent) have been spud but not completed, 4,184 wells (86.9 percent) are oil and gas well types, 199 wells (8.8 percent) are being used as injectors for enhanced oil recovery type projects, 27 (1.2 percent) are being used for oil and gas related disposal purposes, eight (0.4 percent) are being used for oil and gas related monitoring purposes, and 8 (0.4 percent) are being used for oil and gas related source purposes.

About 50 percent (2,217 wells) of the 4,426 completed (minus spud wells) 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 drilling activity in the Planning Area, as related to wells spud annually and cumulatively is presented in Figure 13. Starting in 1920, the graph shows a steady decline in spuds up to the beginning of WWI. Beginning in 1940, and continuing up through 1955, annual spuds increased at an average rate of 5 wells per year and peaked at 128 wells in 1956. From 1956 to 1986, spud activity decreased at an average rate of 1.5 wells year and bottomed out in 1986 with only 27 wells spud. The major shifts in this decline occurred at the beginning and end of this interval. From 1956 to 1957 drilling dropped from 128 to 67 spud wells, and again from 1979 to 1986 where drilling dropped from 119 to 15 spud wells, for an average decline of 15 wells spud per year. Activity picked back up beginning in 1993 at 30 wells spud and increased steadily through 2001 and topped out at 120 wells spud. Spuds then declined to 47 wells in 2002, then increased to 166 in 2006 and declined back to 86 in 2007.

A map of the Planning Area shows locations of all wells spud to October 23, 2007 (Figure 2). This map shows that drilling has been spread out across the Planning Area. The largest gas drilling concentrations have been in the northeast portion of the Planning Area and in the southeast portion of the Wind River Indian Reservation. Oil drilling has been mostly concentrated along a northwest/southeast trend on the western edge of the main drilled area. Even with the large number of wells drilled in the Planning Area, many townships have received little or no drilling activity.

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. The Land Rig Newsletter (2008) also projects that the rig count in the U.S. will stay flat, but there will be an increase in footage (as much as 16 million additional feet) drilled due to greater productivity per rig. Most of this footage increase is expected to be due to non-vertical wells and pad drilling, neither of which is common within the Planning Area at present. The Land Rig Newsletter (2008) reports that capacity constraints for equipment were a factor that tended to restrain activity in 2005 and 2006, while in 2007 an industry wide bottleneck was tied to a lack of people at every level of the workforce.

The Land Rig Newsletter (2008) reports that additional new-built rigs have been moving into the U.S. market, with almost four dozen moved in during an 18 month period ending in December 2007 and additional new rigs planned for the market in 2008. They report that these new rigs tend to be advanced technology fast moving units, including some coil drilling rigs, or they feature increased use of automation.

Rig shortages have affected most areas of the Rocky Mountain region. Rig utilization rates approached 96 percent in 2006 (Kim, 2007).

Nationwide, rig counts have been increasing since late 2002 (Smith Technologies, 2008). In the Planning area more rigs work during the winter months than during the summer months. Weekly rig counts for the Fremont County portion of the Planning Area have varied from one rig to six rigs in the past year (the week of November 23, 2007 through the week of November 21, 2008). The percentage of weeks in the past year with rigs working has been:

- 1 rig 25 percent,
- 2 rigs 11.5 percent,
- 3 rigs 28.8 percent,
- 4 rigs 23.1 percent,
- 5 rigs 3.8 percent, and
- 6 rigs 7.7 percent.

Production

Data from IHS Energy Group (2008) was used to compile historic cumulative production by field and by reservoir. Table 3 lists the fields in the LFO and itemizes the number of producing zones, hydrocarbon production through 2007, and well activity (wells actively producing and wells with historical production but not producing). The major producing gas fields in the Planning Area (by volume), in descending order, are Madden, Beaver Creek, Pavillion, and Big Sand Draw (Figure 11). The major producing oil fields, in descending order, are Winkleman, Steamboat Butte, Beaver Creek, Big Sand Draw, and Circle Ridge (Figure 11). At the close of 2007, there were 1,566 actively producing oil

and gas wells and a cumulative production of 506,101,136 barrels of oil and 3,876,634,353,000 cubic feet of gas.

Table 2, as previously discussed, lists all the Planning Area's producing formations/zones, the number of fields they produce from, hydrocarbon production through the end of 2007, and the respective well activity (wells actively producing and wells with historical production but not producing). The most prolific producing gas formations are the Fort Union, Madison (at Madden Field), and Frontier. At Madden Field, the Madison Limestone produces from the deepest onshore reservoir in the world. The most prolific producing oil formations are the Tensleep, Phosphoria, and the Madison (at fields other than Madden Field). The producing formations with the largest numbers of active wells are the Fort Union, Phosphoria, and Tensleep.

Yearly (Figure 14) and cumulative (Figure 15) 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 2007 (IHS Energy Group, 2008). Figure 14 illustrates the historical annual rate change in the production of hydrocarbons within the Planning Area. The rate of oil production declined steadily for a decade starting in 1982 and has been flat since 1993. The rate of gas production was flat up through 1994, but has since increased sharply, then began to decline in 2006.

The various changes or trends in the shapes of the annual oil production curve (Figure 14) are partly the result of the same market forces that have impacted all production everywhere in the world. The only difference between the Planning Area and the rest of the world would be the magnitude of the numbers. Historically, producers primarily only had an interest in oil. The 1973 Oil Crisis raised consciousness of the impact of oil on the environment. The Arab members of the Organization of Arab Exporting Countries, reduced oil supply which created a worldwide oil shortage. As a result, exploration activity increased in the United States, and after a lag of several years, production began to increase. In the Planning Area, increased drilling allowed oil production to remain at a fairly stable rate. Conservation, alternative energies, and numerous other interacting factors eventually resulted in a glut of oil that is reflected in the decline in annual oil production between 1982 and 1993. In the Planning Area little new oil production was added during this period and overall production from existing fields was allowed to decline. With the glut of oil came a sharp market correction in oil price from a high of about 80 dollars per barrel in the early 1980s to about 20 dollars per barrel in 1987. Production of oil in association with the development of additional gas resources (especially at Beaver Creek) and improvements in enhanced oil recovery at older oil fields halted the annual decline in oil production since 1993.

The increase in annual gas production since 1994 has been tied to additional drilling activity tied mostly to developments at Madden, Frenchie Draw, Muddy Ridge/Pavillion, Beaver Creek, Fuller Reservoir, and Riverton Dome fields (Figure 7).

The cumulative oil and gas production graph (Figure 15) exhibits an inverse relationship between the total gas and oil produced over time. Starting in 1974, cumulative gas

increased at a constant rate for 10 years then slowed for a few years, but has increased steadily up until the last few years. Oil however, increased steadily until 1984 then gradually decreased up till 1993 and has been steady ever since, but at a lower rate.

An historical 5-year epoch oil production graph (Figure 16) shows that oil wells completed from 2000 through 2007 (eight years) account for about 47 percent of present production. Wells completed from 1985 through 1999 (15 years) have not contributed significantly to cumulative production and are now only producing about 26 percent of the today's total production. Wells completed from 1975 through 1984 (10 years) are now producing about nine percent and remaining wells completed before 1975 have contributed the most to cumulative oil production and are still producing about 18 percent of present production.

An historical 5-year epoch gas production graph (Figure 17) shows that gas wells completed from 1990 through 2004 (15 years) account for about 81 percent of present production and the largest portion of cumulative production. During the periods prior to 1985 and the last 3-year epoch (2005 through 2007) larger percentages of production contributed to annual production rates, but wells completed during these epochs have significantly declined in their share of production and combined they now account for most of the remaining 19 percent of production. The 1985 through 1989 period (five years) has historically and presently contributed very little to gas production.

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. Volumes of annual water produced are shown on Figure 18. Increases in water production in recent years are mainly tied to increased gas production during that time (Figure 14). Cumulative water produced through August, 2007 was 4,389,859,424 barrels.

Water is injected into oil reservoirs as part of waterflooding projects or the water produced in conjunction with oil and gas production may be disposed of (injected) into the subsurface. The volumes of water injection (for waterflooding and water disposal), on a yearly basis, are shown on Figure 18. Locations of injection and disposal wells are shown on Figure 12. Cumulative water injected through August, 2007 was 1,408,250,055 barrels. Produced water that is not injected is disposed of in evaporation ponds and in a limited number of ponds managed under National Pollutant Discharge Elimination System permits managed by the State of Wyoming.

Figure 18 shows that water injection (mostly for waterflooding purposes) was highest during the 1982 through 1992 period and then dropped off for a number of years when oil prices were very low and there was little incentive to produce oil. Water injection began to increase again in 1999 and peaked in 2006, at more than 50 million barrels (IHS Energy Group, 2008). With higher oil prices in recent years, there has been added incentive to bear the additional costs of waterflooding to obtain additional oil production. Since 1982, the water production curve has tended to mirror the water injection curve, but at higher rates.

In 2006, Madden Field (Figure 11) was ranked 10th in the U.S. by gas proved reserves and 12th by gas production (Energy Information Administration, 2007c).

Coalbed Natural Gas

Advanced technology has helped in the exploitation of coalbed natural gas (Garbutt, 2004). Improvements have been made in:

- new logging measurements and sampling devices that enhance evaluation of coal deposits,
- light cements and additives to minimize damage to sensitive reservoirs,
- nondamaging fracture-stimulations fluids and innovative hydraulic fracture designs are being used to improve gas and water flow to the wellbore, and
- artificial lift techniques and software are promoting rapid and efficient dewatering.

There currently is little coalbed natural gas activity in the Planning Area. Three coalbed natural gas units have been designated in the southern portion of the Planning Area (Figure 8). There are presently no producing coalbed natural gas wells within any of these units. Coalbed natural gas production started in late 1990 with one well in Riverton Dome Field (Figure 19) located in the southeastern corner of the Wind River Indian Reservation. This well was drilled by Arco and plugged back and completed in three coal intervals between 3,270 and 3,869 feet. The produced water from this well was very high in dissolved solids. Coalbed natural gas production from the well continued through October, 1992 and then ceased until November, 1999 when it produced for eight days and then ceased again until May, 2006. The well is currently producing.

Table 4 presents cumulative production and information on all active coalbed gas wells since the first producing well was completed in 1990. As discussed above, only one well periodically produced from 1990 through 1999. In November 1999, production started in one well and increased to four wells in May of 2000 and continued through July, 2001 when production ceased again until 2005 when nine to 16 wells produced that year. Producing wells ranged from 15 to 19 in 2006 and decreased to 11 in 2007. During the first 10 months of 2008, 10 to 11 wells produced. Cumulative coalbed gas production within the Planning Area has been more than 5.026 billion cubic feet and cumulative water production has been more than 13.7 million barrels. While wells were in production, gas production has averaged 278,813 cubic feet per day and water production has averaged 762 barrels per day. As water is a major component of natural gas produced from cleats in coal, the issue of water quality and the method required for disposal will impact the economics of future coalbed gas activity within the Planning Area.

Present coalbed gas producing zones are coals in the Mesaverde Formation. Three areas have produced coalbed gas within the Planning Area. Two areas are located on the southeastern fringe of the Wind River Indian Reservation and the third is located just four miles south of the Reservation boundary, at Beaver Creek Field.

The Beaver Creek Field lies south of the Wind River Indian Reservation (Figure 19) and contains nine coalbed natural gas wells. Four coalbed natural gas wells were initially operated by Santa Fe Snyder Corp., and now the Devon Energy Production Company. These wells produced gas and water continuously from June, 2000 to July, 2001 (Table 5). All four are presently shut in. Five additional wells went into production in early 2008 and have continued to produce through October (Table 5). Total cumulative coalbed natural gas production for the field is 186,156,000 cubic feet and 5,960,870 barrels of water. All production is from the Shipton Top Coal through the Signor Base Coal of the Mesaverde Formation. The mean (average) subsea depth of the top perforations in the wells is +3,820 feet and the mean thickness perforated is 560 feet.

The Riverton Dome Field is located seven miles south-southeast of Riverton, Wyoming on the Wind River Indian Reservation (Figure 19). The coalbed natural gas wells in this field are drilled on 80-acre spacing and the current operator is Devon Energy Production Company. The first well in the field was drilled to a depth of 6,080 feet and reached total depth on October 11, 1990. On October 19, the well was plugged back to 4,530 ft and perforated from a depth of 3,545 to 3,839 feet in six intervals. The initial potential for the well was 147,000 cubic feet per day and 240 barrels of water from coal layers in the Mesaverde Formation. It was the only producing coalbed natural gas well in the field until July, 2005. Producing wells soon increased to 11 and have remained at that level. Through October, 2008 there has been production of 1,698 barrels of oil from six of these wells, with one of the wells producing 1,131 barrels. The ground elevation over the field varies from a high of 5,377 feet on the south end to a low of 5,272 ft. on the north end. Production is from one to three intervals at a depth of 3,000 to 4,000 feet.

The third area of coalbed gas production has occurred at an unnamed field located eight miles south-southwest of Riverton Wyoming on the Wind River Indian Reservation in township 2 south, range 3 east (Figure 19). There are a total of eight wells on 80-acre spacing and the operator is Wolverine Gas and Oil Company of Wyoming, LLC. All of these wells produced gas and water from July, 2005 to November, 2006 or 17 months. These wells have been plugged and abandoned and a Subsequent Report of Abandonment was submitted to the State of Wyoming on all these wells in November of 2007. Cumulative production amounted to 3,270,000 cubic feet of gas and 623,558 barrels of water from Mesaverde Formation coals. The average ground elevation of the field is 5,232 feet and the mean subsea depth of the production perforations is +1,114 feet.

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 2006, 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 2006, their contribution had decreased to approximately 18 and nine percent, respectively – still an important contribution to the nation's supply (Interstate Oil and Gas Compact Commission, 2007).

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 (2007) 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 (2007) estimated that in 2006, the industry created nine jobs for every 1.26 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.

In 2006 Wyoming ranked 11th of the 29 major producing states in the number of marginal oil wells (Interstate Oil and Gas Compact Commission, 2007). In that year there were 12,464 marginal oil wells that produced 8,245,343 barrels of oil in the state, and marginal well production amounted to approximately 15.6 percent of total Wyoming crude oil production (Interstate Oil and Gas Compact Commission, 2007, and Wyoming Oil and Gas Conservation Commission, 2008). Many of the oil wells in the oldest fields shown on Figure 10 now qualify as marginal oil wells.

In 2006, Wyoming ranked 5th of the 28 major producing states in the number of marginal gas wells (Interstate Oil and Gas Compact Commission, 2007). According to the Interstate Oil and Gas Compact Commission, in 2006 there were 27,249 marginal gas wells that produced 99.65 billion cubic feet of gas which amounted to about five percent of total Wyoming gas production (Interstate Oil and Gas Compact Commission, 2007, and Energy Information Administration, 2008). From 2003 to 2006 the number of marginal gas wells in Wyoming increased by 10,729 wells to 37,978 wells.

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 October 23, 2008 the Wyoming Oil and Gas Conservation Commission (2008) indicated that there had been 105 well bores drilled to depths of more than 15,000 feet and two wells spud that proposed to drill deeper than 15,000 feet (Figure 20). Well class and present status of these wells is:

- Disposal – Active Injector 3 wells
- Injector – Shut-in 1 well
- Gas – Spud 2 wells
- Gas– Producing Gas or Shut-in 64 wells
- Gas– Producing Oil 1 well
- Gas– Temporarily Abandoned 2 wells
- Gas – Subsequent Report of Abandonment 2 wells

- Gas – Permanently Abandoned 25 wells
- Oil – Permanently Abandoned 7 wells.

Sixty-eight percent of these well locations (73 wells) continue to be active and the remaining wells (34 wells) have been abandoned or a subsequent report of abandonment has been filed. Seventy-one of the still active wells lie in the northeast part of the Planning Area, in and near Lysite and Madden fields. Only two deep wells are still active on Wind River Indian Reservation lands.

Twenty-one wells have been drilled to 20,000 feet or deeper. The deepest well drilled was a gas producing well that went to 25,830 feet at Madden Field. The deepest well drilled on the Wind River Indian Reservation was a dry hole drilled to 24,818 feet. The oldest formation encountered was the Cambrian Flathead Sandstone.

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

There have been 494 known wellbores in the Planning Area that have drilled to the 10,000- to 15,000-foot depth range (Wyoming Oil and Gas Conservation Commission, (2008). These include 24 spud wells with a proposed total depth within this range. As Figure 20 shows, wells in this depth range are concentrated in the northeast part of the Planning Area, the southeast part of the Wind River Indian Reservation, and along the southern part of the Planning Area. Well class and present status of these wells is:

- Disposal – Active Injector or Shut-in 11 wells
- Injector – Active Injector or Shut-in 14 wells
- Gas or Oil – Spud 24 wells
- Gas– Producing Gas, Flowing, or Shut-in 229 wells
- Gas– Producing Oil 2 wells
- Gas - Temporarily Abandoned 3 wells
- Gas – Notice of Intent to Abandon or No Report 5 wells
- Oil – Producing Oil or Shut-in 37 wells
- Oil – Active Injector 2 wells
- Oil – Notice of Intent to Abandon 1 well
- Oil – Producing Gas 5 wells
- Gas – Subsequent Report of Abandonment 7 wells
- Gas – Permanently Abandoned 49 wells
- Oil – Permanently Abandoned 104 wells
- Disposal – Permanently Abandoned 1 well.

Sixty-seven percent of these well locations (333 wells) continue to be active and the remaining wells (161 wells) have been abandoned or a subsequent report of abandonment has been filed. The majority of the still active wells in this depth range (77 percent) lie in:

- Beaver Creek Field 79 wells
- Madden Field 77 wells
- Frenchie Draw Field 42 wells
- Muddy Ridge Field 33 wells
- Riverton Dome Field 26 wells.

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

There have been 1,395 known wellbores in the Planning Area that have drilled to the 5,000- to 9,999-foot depth range (Wyoming Oil and Gas Conservation Commission, (2008). These include 17 spud wells with a proposed total depth within this range. As Figure 20 shows, wells in this depth range are spread out across the Planning Area. Well class and present status of these wells is:

- Disposal – Active Injector or Shut-in 9 wells
- Injector – Active Injector or Shut-in 22 wells
- Injector – Temporarily Abandoned 2 wells
- Gas or Oil – Spud 17 wells
- Gas– Producing Gas, Flowing, or Shut-in 600 wells
- Gas– Producing Oil 7 wells
- Gas - Temporarily Abandoned 16 wells
- Gas – Notice of Intent to Abandon 6 wells
- Oil – Producing Oil, Flowing, or Shut-in 145 wells
- Oil – Dormant or Notice of Intent to Abandon 8 wells
- Oil – Producing Gas 9 wells
- Oil – Temporarily Abandoned 26 wells
- Gas – Subsequent Report of Abandonment 13 wells
- Oil – Subsequent Report of Abandonment 12 wells
- Injector – Permanently Abandoned 9 wells
- Gas – Permanently Abandoned 75 wells
- Oil – Permanently Abandoned 417 wells
- Strat test – Permanently Abandoned 1 well
- Water Source – Permanently Abandoned 1 well.

Sixty-two percent of these well locations (868 wells) continue to be active and the remaining wells (527 wells) have been abandoned or a subsequent report of abandonment has been filed. The majority of the still active wells in this depth range (75 percent) lie in:

- Madden Field 229 wells
- Frenchie Draw Field 97 wells
- Steamboat Butte Field 81 wells
- Pavillion Field 66 wells
- Beaver Creek Field 47 wells
- Muddy Ridge Field 43 wells
- Big Sand Draw Field 42 wells
- Fuller Reservoir Field 26 wells.

Shallowest Well Drilling: Less than 5,000 feet

The greatest number of wells drilled (2,366) in the Planning Area have been in to less than 5,000 feet (Wyoming Oil and Gas Conservation Commission, (2008). These include 11 spud wells with a proposed total depth within this range. As Figure 20 shows,

wells in this depth range are spread out across the Planning Area. Well class and present status of these wells is:

- Disposal – Active Injector 4 wells
- Injector – Active Injector or Shut-in 135 wells
- Injector – Temporarily Abandoned 3 wells
- Injector – Notice of Intent to Abandon 1 well
- Monitor – Active Monitor or Shut-in 5 wells
- Monitor – Dormant 1 well
- Monitor – Active Injector 2 wells
- Gas or Oil – Spud 11 wells
- Gas– Producing Gas, Flowing, or Shut-in 148 wells
- Gas– Producing Oil 1 wells
- Gas - Temporarily Abandoned 4 wells
- Gas – Notice of Intent to Abandon 4 wells
- Oil – Producing Oil, Flowing, or Shut-in 517 wells
- Oil – Dormant or Notice of Intent to Abandon 31 wells
- Oil – Active Injector 7 wells
- Oil – Producing Gas 7 wells
- Oil – Temporarily Abandoned 52 wells
- Water Source – Active or Shut-In 7 wells
- Injector – Subsequent Report of Abandonment 10 wells
- Gas – Subsequent Report of Abandonment 13 wells
- Oil – Subsequent Report of Abandonment 11 wells
- Disposal – Permanently Abandoned 1 well
- Injector – Permanently Abandoned 29 wells
- Gas – Permanently Abandoned 85 wells
- Oil – Permanently Abandoned 1,254 wells
- Strat test – Permanently Abandoned 18 wells
- Water Source – Permanently Abandoned 5 wells.

Only about 40 percent of these well locations (940 wells) continue to be active (the lowest active percentage of any depth range) and the remainder (1,426 wells) have been abandoned or a subsequent report of abandonment has been filed. The majority of the still active wells in this depth range (82 percent) lie in:

- Winkleman Field 160 wells
- Circle Ridge Field 147 wells
- Lander Field 123 wells
- Pavillion Field 74 wells
- Dallas Field 65 wells
- Maverick Springs Field 59 wells
- Bison Basin Field 38 wells
- Beaver Creek Field 36 wells
- Fuller Reservoir Field 35 wells
- Derby Field 31 wells.

Summary of Current Drilling Techniques

Most oil and gas wells have been drilled vertically throughout the Lander 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 limitations. For instance, directional drilling may be employed to avoid sensitive or inaccessible surface features, increase the area that a well bore contacts a producing formation, and, when multiple directional's are drilled from the same vertical well bore 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 wellbores 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 4,481 surface well locations spud or completed in the Planning Area through October 23, 2008 (Wyoming Oil and Gas Conservation Commission, 2008), only 230 wellbores were drilled directionally and 17 were drilled horizontally (IHS Energy Group, 2008). 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 25,830 feet. The deepest productive vertical well drilled to date was the Burlington Resources Oil & Gas Company, Big Horn 6-27 well, a shut-in gas well capable of producing from the Pennsylvanian Darwin Sandstone and Mississippian Madison Limestone in Madden Field (Figure 11). The well reached a total depth in the Cambrian Gallatin Group at 25,830 feet.

Figures 21 and 22 show the locations of directional and horizontal wellbores drilled within the Planning Area through October 23, 2008 (Wyoming Oil and Gas Conservation Commission, 2008). Directional wellbores that have been spud and not completed and all wellbores still capable of producing oil and gas as of October 23, 2008 account for 212 of the 230 directional boreholes, or 92 percent success rate. About 71 percent of these wells are gas wells, 18 percent are oil wells, 7 percent are temporarily abandoned, 2 percent are injection wells, and 1 percent were spud but are not yet completed. The majority of wells have been drilled at three fields:

- Madden (116 wellbores or 50 percent),
- Beaver Creek (28 wellbores or 12 percent), and
- Steamboat Butte (20 wellbores or 9 percent).

Directional wellbores at Madden Field (Figure 21) have predominantly been completed in the Tertiary Fort Union Formation, at Beaver Creek Field they have been completed in the Frontier Formation, and at Steamboat Butte Field completions have been in the Permian Phosphoria Formation, Pennsylvanian Tensleep Sandstone, and Lower Jurassic Nugget Sandstone.

Four operators have drilled the majority of the directionally drilled boreholes within the Planning Area. These operators were:

- Burlington Resources Oil & Gas Company and its precursors – 115 wellbores,
- Devon Energy Production Company LP and its precursors – 25 wellbores,
- Marathon Oil Company – 21 wellbores, and

- EnCana Oil and Gas (USA) Inc. and its precursor – 18 wellbores.

Horizontal wellbores have been rarely used in the Planning Area, with only 17 drilled as of October of 2008 (Figure 22). Only one of the 17 wellbores (at Sand Draw North Field) was drilled and abandoned. Twelve wellbores were completed for oil production and four for gas production. Producing formations have been:

- Tensleep Sandstone – 9 wellbores,
- Phosphoria Formation – 3 wellbores,
- Fort Union Formation – 2 wellbores,
- Frontier Formation – 1 wellbore, and
- Nugget Sandstone – 1 wellbore.

The earliest known horizontal wellbore, the Cenex Federal 4-28H in Sand Draw North Field, was completed in 1995 (IHS Energy Group, 2008). This oil well was a successful completion in the Tensleep Sandstone. The last horizontal well drilled was the Devon Energy Production Company LP, Beaver Creek Unit #141H at Beaver Creek Field, spud May 19, 2008 and currently producing oil and gas from the Phosphoria Formation.

Ten different companies drilled the 17 horizontal boreholes, with Camwest Limited Partnership (now operated by Wesco Operating Incorporated) drilling six of the wellbores (at Winkleman and Lander fields) and Marathon Oil Company drilling the three wellbores at Steamboat Butte Field. The eight other operators only drilled one horizontal well each.

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).

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, most Lower Fort Union Formation wells have been drilled using slimhole drilling technology. It has the potential to improve efficiency and reduce costs of both exploration and production 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. Slightly more than half of all Planning Area wells have been drilled to depths less than 5,000 feet (Figure 20). Future wells drilled in this depth range would be amenable to coiled tubing rigs. A review of coiled tubing intervention and

drilling 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.

Light Modular Drilling Rigs and Pad Drilling

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 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. Shallower drilling targets in the Planning Area are not conducive to the use of significant amounts of directional drilling so pad drilling would only be likely where deeper drilling is occurring within the Planning Area.

Pneumatic Drilling

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). 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 Lander 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.

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

unconventional 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 use 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 producing 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 Wind 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 250 thousand dollars,
- 5,000 to 10,000 feet 796 thousand dollars,
- 10,000 to 15,000 feet 1.902 million dollars, and
- 15,000 to 20,000 feet 8.244 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 224 thousand dollars,
- 5,000 to 10,000 feet 495 thousand dollars,
- 10,000 to 15,000 feet 1.170 million dollars, and
- 15,000 to 20,000 feet 3.553 million dollars.

Reported dry hole well costs were estimated to be:

- 0 to 5,000 feet 136 thousand dollars,
- 5,000 to 10,000 feet 317 thousand dollars,
- 10,000 to 15,000 feet 1.010 million dollars, and
- 15,000 to 20,000 feet 6.770 million dollars.

Operators in the Rocky Mountain region have recently been faced with increases in drilling and completion costs. Drilling rates have increased 20-50 percent (Rocky Mountain Oil Journal, 2005) and service costs have also increased. Rig shortages have affected most areas of the region. Reasons why new Planning Area wells may be more expensive to equip and operate are:

- remoteness and cold temperatures, which often requires dehydrators and line heaters, more expensive types of steel casing, and insulation of surface equipment;
- workovers and preventive maintenance is more frequent, which minimizes shut-in days in the winter when well site access is difficult; and
- lack of rig availability due to competition with other more high profile plays.

SUMMARY OF PRODUCTION AND ABANDONMENT TECHNIQUES

Once production begins application of reservoir management procedures are needed to ensure 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 9 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. Rocky Mountain operating costs rose to about 55,000 dollars per12,000 foot well in 2005 (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 gas 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. Both types of reserve addition have occurred in

areas such as the Madden Field area on the eastern edge of the Planning Area, and at Muddy Ridge and Pavillion fields on the Wind River Indian Reservation (Figure 5).

The Energy Information Administration (2006c) has shown that 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;
- workovers and preventive maintenance is more frequent – which minimizes shut-in days in the winter when well site access is difficult; and
- lack of rig availability due to its lower drilling priority in the Rockies.

The search for oil and gas in the Planning Area has been successful in finding mostly new gas production (Figure 7) in the past 10 years. This new gas production has predominantly been on the edges of existing fields or near existing fields. Few successful new gas producing wells away from existing fields have been discovered. Very few oil wildcats have been drilled indicating the mature nature of oil plays within the Planning Area. Only one new field wildcat oil discovery was made in the past 10 years. That was the Frontier Formation oil well at Kirby Draw Federal 1-4 in section four of township 32 north, range 95 west (South Kirby Draw Field, see Figure 7). There was one successful outpost extension well drilled (Government Federal Meadows 33-7) in section 7 of township 30 north, range 94 west (Figure 7).

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 gone up 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:

- <u>Primary Recovery</u> - 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.
- <u>Secondary Recovery</u> – 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, 2008). 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 to bring hydrocarbon 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 such methods were cost prohibitive and a large percentage of the oil or gas in any given reservoir was left behind for future recovery.

As new discovery volumes decline and demand, and consequently price, for oil and gas continues to climb, methods for removing more of the oil and gas left behind 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 physically "pushing" 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 locale can also be important in enhancing oil recovery projects. For example, proximity to a carbon dioxide source is a factor in choosing a carbon dioxide project. A source of fresh or treatable water is needed for steamflood or chemical projects. Oil and gas prices play a very important role in determining whether an enhanced oil recovery project will be viable, and deciding what type of recovery project would be appropriate. There are a number of older oil fields within the Planning Area, and a number of different types of enhanced oil recovery projects have been used to increase production. Water floods have been the predominate method of increasing oil recovery and fewer floods of different types have been used.

Secondary and Enhanced Recovery Projects in Lander 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 an oil producing formation (as opposed to disposal injection into another formation). In today's market, most produced natural gas is sold rather than re-injected. Currently Circle Ridge Field has a lean gas injection program into the Tensleep Sandstone and Phosphoria Formation within the Planning Area. Also, a nitrogen gas pilot was reportedly tried at Circle Ridge Field (Figure 10).

A number of waterflooding projects are located in older oil fields in the Planning Area (Wyoming Oil and Gas Conservation Commission, 2008). There are presently 11 active secondary recovery projects, seven inactive projects, and one terminated project in 11 total units/fields. Locations of these injection wells are shown on Figure 12. Brief summaries of these projects are presented below. In addition, Big Sand Draw Unit has one injector that was approved in November 2007 and has not initiated water flooding to date.

1. Beaver Creek Field/Unit contains four water flood projects operated by Devon Energy Corporation. Injection into the Madison Limestone is the only active secondary unit project and it was approved in 1959. The Madison Limestone

presently contains seven active and two shut-in injectors. The source of injection water is the Madison Limestone. The operator converted the Madison Limestone water flooding project to carbon dioxide injection 2008.

Two inactive water floods were for the First Cody (approved 1988) and the Tensleep Sandstone (approved 1985). A Second Cody water flood was approved in 1966 and is now terminated.

2. Bison Basin Field/Unit contains one active water flood operated by Richardson Operating Co. It was approved in 1959 and water from the Frontier Formation and Tensleep Sandstone is injected into the Frontier Formation. There are presently eight active injectors in the Frontier Formation.

3. Circle Ridge Field contains two active water flood projects operated by Marathon Oil Co. Injection into the Amsden Formation was approved in 1976 while Phosphoria Formation (locally called the Embar) and Tensleep Sandstone injection was approved in 1986. There are presently 13 active water injectors in the field with one shut-in and one temporarily abandoned injector. Some polymer injection has occurred in the past.

4. Crooks Gap Field/Unit contains one inactive water flood operated by Richardson Operating Co. It was approved in 1966 and is there is presently one shut-in injector. Water from the Cloverly Formation (locally called the Dakota and Lakota) was used to inject into the Muddy Sandstone.

5. Happy Springs Field/Unit (Figure 5) contains two inactive water floods operated by Richardson Operating Co. The Cloverly (locally called the Dakota) water flood was approved in 1973 and the Frontier Formation water flood was approved in 1983. Wells previously used for water injection have since been abandoned.

6. Lander Field/Unit contains one active water flood operated by Wesco Operating Inc. It was approved in 1965 and water from the Tensleep Sandstone is injected into the Phosphoria Formation. There are presently 38 active injectors and one temporarily abandoned injector to the Phosphoria Formation.

7. Rolff Lake Field/Unit contains one active water flood operated by Phoenix Production Co. It was approved in 1975 and water from the Crow Mountain Formation of the Chugwater Group and Frontier Formation is injected into the productive part of the Crow Mountain Formation. There are presently two active injectors in the Crow Mountain.

8. Sand Draw South Field contains one inactive water flood operated by Thorofare Resources Inc. It was approved in 1986 and water from the Frontier Formation was injected into the producing portion of the Frontier Formation. There is presently one temporarily abandoned injector to the Frontier Formation.

9. Sheldon Northwest Field contains one inactive water flood operated by Pioneer Oil & Gas Co. It was approved in 1969 and water from the Crow Mountain Formation of the Chugwater Group was injected into the producing portion of the Crow Mountain. There are presently three shut-in injectors to the Crow Mountain. Wesco Operating Inc., filed notices of intent to convert to wells to Crow Mountain water injectors in their portion of the field in 2007. Those wells are reported as shut-in at this time.

10. Steamboat Butte Field contains three active water floods operated by Marathon Oil Co. The Tensleep Sandstone was approved in 1952, the Phosphoria Formation was approved in 1962, and the Lower Jurassic Nugget Sandstone approval date is unknown. There are presently 18 total active water injectors servicing the three water floods.

11. Winkleman Field contains three active water floods operated by Wesco Operating Inc. The Phosphoria Formation was approved in 1962 and the Tensleep Sandstone was approved in 1967. The other active flood is in the Lower Jurassic Nugget Sandstone, but its approval date is unknown. There are presently 18 total active water injectors servicing the three water floods. Each formation supplies injection water for injection into the producing portion of its formation. There are presently 57 active injectors, four shut-in injectors, and one temporarily abandoned injector.

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. No active steamflooding injection projects are located in the Planning Area, although Winkleman Field (Figure 5) used steam for a Lower Jurassic Nugget Sandstone recovery project in the past.

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. Fields within the Planning Area that have used polymer-enhanced waterflooding include; Circle Ridge, Lander, Maverick Springs, and Steamboat Butte (Figure 10).

Surfactant Flooding

Adding surfactants to injected water can enhance oil production. These types of projects are expensive and have not been reported 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. An air injection pilot was reportedly tried at Circle Ridge Field (Figure 10).

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 carbon dioxide "slug" 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 tested at Beaver Creek, Crooks Gap, Lander, and Steamboat Butte, and Winkleman (Figure 10). In this technique, the operator injects carbon dioxide into a well for several days or weeks and then converts that well back to production. This method has not proved effective in recovering additional oil in the Planning Area.

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 of 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 flooding has been coming from the Shute Creek processing plant in southwest Wyoming. The Planning Area's Madden Field contains a large resource of carbon dioxide and could be tapped for future injection projects in the area.

Nummedal et al. (2003) listed a number of carbon dioxide enhanced oil recovery candidate fields in the Planning Area. Those candidate fields include Beaver Creek, Big Sand Draw, Circle Ridge, Pilot Butte, Steamboat Butte, and Winkelman (Figure 10). Devon Energy Corporation has proposed a carbon dioxide flood for the Beaver Creek Unit in the Planning Area. Devon has converted its Madison Limestone waterflood to a carbon dioxide flood and began injection on July 1, 2008 (Merrill, 2008). The carbon dioxide is being purchased from the Shute Creek processing plant and is carried to the field via pipeline. It is projected that the life of the field will be extended by 20 years due to the initiation of this new flood.

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 the unwanted gases and sweeten the hydrocarbon product for sale. Improvements in the 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. Devon Energy Corporation operates the Beaver Creek Phosphoria Gasoline Plant, processing liquids from Beaver Creek and Riverton Dome Fields (Figure 10). The acid gas is injected into one well. Devon will update this process by combining hydrogen sulfide with carbon dioxide, to dispose of the unwanted bi-product. ConocoPhillips (Burlington Resources Oil and Gas Company) processes hydrogen sulfide and carbon dioxide rich natural gas at its Lost Cabin Gas Plant. It receives Madison Limestone produced gas from the Madden Field (Figure 5) and recovers hydrocarbon gas and sulfur. Waste gas (carbon dioxide and some hydrogen sulfide) is either vented or flared. In addition, St. Mary Land & Exploration Company operates one shut-in acid gas disposal well at Muskrat Field (Figure 10), which is set up to dispose in the Frontier Formation.

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 of the older fields in the Planning Area.

Glycol Dehydration

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. 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 pit, or discharge into a surface water source through an outfall permit. The Planning Area presently has 26 active and two shut-in disposal wells (Wyoming Oil and Gas Conservation Commission, 2008).

Figure 23 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 1,523 samples and salinity ranges from 1,009 to 220,219 milligrams per liter. Water quality sample distribution is:

- less than 5,000 milligrams per liter – 704 samples,
- 5,000 to 9,999 milligrams per liter – 440 samples,
- 10,000 to 49,999 milligrams per liter – 345 samples, and
- Greater than 50,000 milligrams per liter – 34 samples.

The Bureau considers total dissolved solids concentrations of less than 10,000 milligrams per liter to be fresh water. Over 75 percent of these water quality samples fall within this range. Oil and gas fields (Figure 23) with at least 20 samples (and formations sampled) recording total dissolved solids of less than 10,000 milligrams per liter are:

- Beaver Creek – 103 samples-Mesaverde, Cody, Frontier, Morrison, Tensleep, Madison, and Flathead;
- Winkleman – 76 samples-Muddy, Sundance, Phosphoria, Tensleep, Madison, and Bighorn;
- Steamboat Butte – 68 samples-Muddy, Cloverly, Sundance, Dinwoody, Phosphoria, Tensleep, Amsden, Madison, and Bighorn;
- Maverick Springs – 63 samples-Chugwater, Sundance, Phosphoria, Tensleep, and Madison;
- Pilot Butte – 51 samples-Frontier, Muddy, Cloverly, Phosphoria, Tensleep, and Madison;
- Lost Cabin – 50 samples-Wind River, Fort Union, and Lance;
- Happy Springs - 39 samples-Frontier, Muddy, Morrison, Phosphoria, Tensleep, and Madison;
- Riverton Dome – 37 samples-Wind River, Fort Union, Mesaverde, Cody, Frontier, Muddy, Phosphoria, Tensleep, and Madison;

- Sand Draw South – 35 samples-Frontier, Muddy, Morrison, Sundance, Phosphoria, and Tensleep;
- Frenchie Draw – 30 samples-Wind River and Fort Union;
- Big Sand Draw – 28 samples-Frontier, Sundance, Phosphoria, Tensleep, and Madison;
- Alkali Butte – 26 samples-Mesaverde, Cody, Frontier, Muddy, Phosphoria, and Tensleep;
- Madden – 22 samples-Fort Union, Lance, and Muddy;
- Sheldon – 21 samples-Mesaverde, Frontier, Muddy, Chugwater, Phosphoria, Tensleep, and Madison; and
- Crooks Gap – 20 samples-Frontier, Muddy, Cloverly, Sundance, Phosphoria, and Tensleep.

Only about 25 percent of water quality samples have a total dissolved solids concentration of greater than 10,000 milligrams per liter. Oil and gas fields (Figure 23) with at least 15 samples (and formations sampled) recording total dissolved solids greater than 10,000 milligrams per liter are:

- Steamboat Butte – 61 samples-Chugwater, Sundance, Phosphoria, Tensleep, and Madison;
- Riverton Dome – 43 samples-Cloverly, Frontier, Muddy, Morrison, Sundance, and Phosphoria;
- Beaver Creek – 38 samples-Mesaverde, Cody, Frontier, Muddy, Phosphoria, Tensleep, and Madison;
- Sheldon – 27 samples-Chugwater, Sundance, Phosphoria, and Tensleep;
- Pilot Butte – 22 samples-Chugwater, Dinwoody, Phosphoria, and Tensleep;
- Alkali Butte – 17 samples-Frontier, Muddy, Morrison, Sundance, and Phosphoria; and
- Sheldon Northwest – 16 samples-Chugwater, Phosphoria, and Tensleep.

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 at a conventional-well site in the Wind River Basin near Lysite, Wyoming. The produced water at this sit e 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.

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.

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 or near 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.

PLANT SITES

Four active plants that process natural gas or liquids are located within the Planning Area. Beaver Creek Gasoline Plant is operated by Devon Energy Corporation. It handles liquids produced from Beaver Creek and Riverton Dome Field (Figure 10). Devon Energy Corporation also operates the Beaver Creek Phosphoria Gasoline Plant, processing liquids that contain hydrogen sulfide from Beaver Creek and Riverton Fields. ConocoPhillips (Burlington Resources Oil and Gas Company) processes hydrogen sulfide and carbon dioxide rich natural gas at its Lost Cabin Gas Plant. It receives Madison Limestone produced gas from the Madden Field (Figure 5) and recovers hydrocarbon gas and sulfur. As much as 46 million cubic feet per day of carbon dioxide, from this plant, could be available for enhanced oil recovery projects (Steidtmann, 2007). EnCana Oil and Gas (USA) Inc., operates the EnCana Oil and Gas Pavillion Station gas

plant. It processes gas and liquids from Pavillion, Muddy Ridge, Sand Mesa, and Fuller Reservoir fields.

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 are two active gas storage projects within the Planning Area. The Bunker Hill Field gas storage project is located within Bunker Hill Field in the southeast corner of the Planning Area (Figure 5). Kinder Morgan operates this project, which is set up to store gas in the Cody Shale (Shannon Sandstone Member). The Kirk Ranch gas storage project lies within the Kirk Field (Figure 10). Source Gas operates this project, which is set up to store gas within the Cloverly Formation.

ASSESSMENTS OF OIL AND GAS RESOURCES

The Energy Information Administration has recently provided forecasts of United States energy supply (Energy Information Administration, 2007a). Technically recoverable (see Glossary) United States oil resources (as of January 1, 2005) were estimated to be 168.8 billion barrels. The technically recoverable natural gas resource was estimated to be 1,341 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 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.
- 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, and 43 trillion cubic feet each of coalbed natural gas and 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 comparative analysis of their estimates with those of the Energy Information

Administration, Potential Gas Committee and U.S. Geological Survey to better understand the factors that influenced the differences among each estimate.

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 unconventional (also known as nonconventional) 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. Energy Information Administration (2004) was able to split out 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. 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, 2007a). 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. It is expected to rise to 20.6 trillion cubic feet in 2030 (Energy Information Administration, 2007a). 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 number of recent oil and gas resource assessments have been prepared that cover all or portions

of the Planning Area. These assessments provide an indication of the range of undiscovered resource volumes that could be available for exploration, development, and production through the year 2027.

We will present below only the results of the latest three (and most current) U.S. Geological Survey assessments, which cover the entire Planning Area (with the exception of smaller areas of predominately igneous rock of little future hydrocarbon potential). Combined, the three assessments provide an idea of the range of oil and gas resources that may be available for exploration and development in the Planning Area through 2027. 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. Three of those assessed provinces are the Wind River Basin, Southwestern Wyoming, and Bighorn Basin provinces. Each province lies partly within 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. Updated analyses covering the Wind River Basin, Southwestern Wyoming, and Bighorn Basin provinces in the Planning Area have been prepared in response to their new priorities. The reports for these provinces are titled "Assessment of undiscovered oil and gas resources of the Wind River Basin Province, 2005" (U.S. Geological Survey, 2005a), " Petroleum systems and geologic assessment of oil and gas in the Wind River Province, Wyoming" (U.S. Geological Survey, 2008b), "Assessment of undiscovered oil and gas resources of the Southwestern Wyoming Province, 2002" (U.S. Geological Survey, 2002), "Petroleum Systems and Geologic Assessment of Oil and Gas in the Southwestern Wyoming Province, Wyoming, Colorado, and Utah(U.S. Geological Survey, 2005b), and Assessment of undiscovered oil and gas resources of the Bighorn Basin Province, Wyoming and Montana, 2008 (U.S. Geological Survey, 2008c). In these reports the U.S. Geological Survey updated their quantitative estimates of the undiscovered oil and gas resources for each province. A more complete discussion of these assessments, their locations, and estimates of the oil and gas resource volumes is presented in Appendix 1.

For the Wind River Basin, Southwestern Wyoming, and Bighorn Basin provinces assessments, the U.S. Geological Survey estimated undiscovered technically recoverable resources (see Glossary definition) for each play or assessment unit (Tables A1-3, A1-6, and A1-7). When preparing estimates of resource quantities for each province, the U.S.

Geological Survey used geology-based, well-documented estimates of quantities of oil and gas having the potential to be added to reserves. In addition, they used a future time frame—forecast span—of 30 years when estimating quantities of the potential oil and gas resource.

For each type of hydrocarbon, a mean (average) estimated undiscovered resource volume was recorded for each assessment unit and a calculation of the portion lying within the Planning Area was made (Tables A1-3, A1-6, and A1-7). We estimate that all portions of assessment units, in all provinces, lying within the Planning Area contain a mean (average) undiscovered volume of **35.39 million barrels of oil, 3.13371 trillion cubic feet of gas, and 54.55 million barrels of natural gas liquids**. In addition, we estimate that the Planning Area's oil resource could **range from 9. 51 to 76.12 million barrels, the gas resource could range from 1.5389 to 5.49116 trillion cubic feet, and the natural gas liquids resource could range from 19.55 to 93.62 million barrels.**

Dyman et al. (1997) showed that the Wind 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. No recent assessment of the potential volume of resource in this area has been made.

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, including parts of the Planning Area. These publications studied the Southwestern Wyoming Province and Wind River Basin Province, which cover almost all of the Planning Area. 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 Lander Field Office. 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 [United States Geological Survey] national assessment, or, in the absence of play designation by the [United States Geological Survey], the demonstrated existence of: source rock, thermal maturation, <u>and</u> 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 Planning Area lands have either high or low potential for the occurrence of oil and gas (including coalbed natural gas) as shown in Figure 24. All areas within the Wind River Basin, Southwestern Wyoming, and Bighorn Basin provinces are contained within specific plays or assessment units designated by the U.S. Geological Survey (Beeman et al., 1996: Charpentier et al., 1996: Gautier et al., 1996 and U.S. Geological Survey; 2002, 2005a, 2005b, 2008b, 2008c, and 2008c) so are considered to have high potential. All areas outside these provinces are designated as low occurrence potential since one or more specific indicators of the presence of hydrocarbons (source rock, thermal maturation, reservoir strata possessing permeability and/or porosity, and traps) may not be present.

PROJECTIONS OF FUTURE ACTIVITY 2008-2027

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 and gas 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 gas in plays associated with the Lance-Fort Union Sandstone, Frontier-Muddy, and Mesaverde-Meeteetse Sandstone continuous assessment units of the Wind River Province (as discussed in more detail in Appendix 1).

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 25 (historical and projected future natural gas prices) were obtained from the Energy Information Administration (2008c). 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 $5.73 per thousand cubic feet (2007 dollars) in 2009 to $8.39 per thousand cubic feet in 2030 (Energy Information Administration , 2008c). They also predict that the current high natural gas prices will stimulate development of new gas supplies and constrain growth in natural gas consumption (Energy Information Administration, 2008a). 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.

Oil exploration was historically predominant, but in recent years gas exploration has increased and oil exploration is now minimal in the Planning Area. Most activity has been focused in the northeast part of the Planning Area, in the southeast part of the Wind River Basin, and on the southern part of the Planning Area, where coalbed natural gas exploration is included in the mix. Most of this increased activity has likely been

influenced by the spike in natural gas prices. If future gas price predictions hold true, it is likely that development of these areas will continue, though most known fields have already been fairly densely drilled and future activity will not likely continue at the current pace for more than a few years, unless additional reservoirs can be identified.

The natural gas price projections allow 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 are expected to drop sharply from their 2008 high. Prices are expected to only fall, on average in 2009, to 2006 levels; the 2006 prices were more than double the average Wyoming wellhead acquisition price from the previous ten year period. At no time are prices projected to drop below 2004 levels. Furthermore, it is likely that gas production will continue to be mainly a function of the ability of industry to discover and economically develop gas accumulations, and their ability to increase drilling, production, processing, and transportation efficiency.

According to the Energy Information Administration's 2008 Annual Energy Outlook, U.S. demand for natural gas in 2007 was 22.9 trillion cubic feet. Demand is expected to continually increase through 2030. Increases in future natural gas production, to accommodate projected demand, are anticipated to come partly from the Rocky Mountain area. Anticipated new production in the Planning Area is expected to come mainly from the addition of incremental production from existing natural gas fields, exploration for tight gas sands, and exploration for coalbed natural gas reservoirs.

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 less than $65 per barrel in November, 2008, it is likely that Sieminski's averages will approximate actual trends. Indeed, even with the volatility seen in prices throughout 2008, through the first week of November, 2008, the average price for light sweet crude in 2008 has been approximately $108 per barrel (Energy Information Administration, 2008b).

Data for Figure 26 (historical and projected crude oil prices) were obtained from the Energy Information Administration (2008c). 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 has been just as prevalent 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 over $108 per barrel represents over a one thousand percent increase in prices in just eleven years.

The Energy Information Administration (2008c) projection of future prices predicts that world oil price projects are higher for 2006-2030 than those presented previously. Domestic petroleum-based liquids consumption is expected to remain be 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 $60 per barrel in 2009, and start rising again as production in non-OPEC regions peaks, and continue rising to $130 per barrel in 2030 (all prices in 2007 dollars). However, as stated in their 2008 projections, "recent volatility in crude oil prices demonstrates the uncertainty inherent in the projections" (Energy Information Administration 2008b). 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 $40-50 per barrel in the low case to over $180 per barrel in the high case in 2020 (Energy Information Administration, 2008c).

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 since in recent years as operators continue with in-fill drilling programs and entertain secondary and enhanced recovery projects in older fields. Barring any significant new discoveries, however, it is unlikely that drilling activity will increase significantly beyond the recent peak.

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 U.S. owns the oil and gas rights are offered via oral auction at least quarterly. Maximum lease size is 2,560 acres and the minimum bid is two dollars per acre. A 75 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 and two dollar per acre thereafter. Leases are issued for a ten-year term and a 12.5 percent royalty on 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, Federal oil and gas lease sales are held on even numbered months, usually in Cheyenne, Wyoming. Since August 1996, only lands nominated by industry are 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 27 presents the locations of leased and unleased Federal oil and gas minerals within the Planning Area. Excluding lands under Forest Service wilderness areas, Bureau wilderness study areas, and within the Wind River Indian Reservation there were about 1,049,222 acres of leased Federal oil and gas minerals as of December 1, 2007 and about 2,110,489 acres of unleased Federal oil and gas minerals. About 33 percent of Federal oil and gas minerals available for lease were leased at that time.

SEISMIC SURVEYS

Seismic surveys are a critical part of exploration for oil and gas resources. They are authorized on Bureau managed surface by approval of Notices of Intent to Conduct Geophysical Operations. Seismic surveys on surface not managed by the Bureau do not have to be permitted with the Bureau even though the surveys cover federal minerals.

The energy sources utilized to create the transmission of acoustical waves in the subsurface are either dynamite in shotholes, dropped weights, or a number of vibroseis trucks working in tandem simultaneously. There are also two modes of acquiring the data and those modes are referred to in the literature as two-dimensional or three-dimensional seismic. All three energy sources may be used in the two modes of acquiring seismic exploration data. With respect to the seismic acquired in Wyoming, some of the programs used just dynamite in shotholes, others used just vibroseis or dropped weights, and still others have utilized both dynamite in shotholes and vibroseis. Two-dimensional seismic data is a regional exploration tool and is acquired through a grid of intersecting seismic lines. Three-dimensional seismic generates an almost continuous acoustic image of the subsurface. The anticipated or inferred relief of the target structures at depth determines the lateral limits of the seismic program along with the grid size. A seismic program is designed via acquisition and processing parameters that will spatially image the target horizons at depth correctly.

Historically, two-dimensional seismic surveys have been acquired over large parts of the Planning Area. The Wind River Mountains along the western side and the Absaroka Range on the northwest side have not had recent seismic surveys. Three-dimensional

surveys have been less widespread within the Planning Area. Recent three-dimensional surveys have been acquired in the central part of the Planning Area. Seismic surveys of both types will continue to be run in the Planning Area and will generally be in or near areas where past activities have occurred. We anticipate that the number of seismic surveys in the Planning Area will decrease with time.

PROJECTIONS OF FUTURE 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.

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 2008 to 2027, as many as 3,427 wells may be drilled in the Planning Area. Seventy-five of these wells could be deep wells (greater than 15,000 feet in depth). Up to 861 of these 3,427 wells could be coalbed natural gas wells (to be discussed latter).

The estimated development potential and drilling densities within the Planning Area during the planning period are shown in Figure 28. Estimated acres, number of townships, and percentage of the Planning Area within each development potential classification type shown in Figure 28 are summarized in Table 8.

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

- High: 100+ wells
- Moderate: 20 to 100 wells
- Low: 2 to <20 wells
- Very Low: <2 wells
- 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.

Of the 2,566 wells (not including coalbed natural gas wells) projected within the Planning Area, the majority (2,542) are projected in areas of high, moderate, or low potential and drilling activity will be concentrated in certain areas :

- In and around Madden and Frenchie Draw fields on the northeastern portion of the Planning Area and in and around Muddy Ridge Field on the Wind River Indian Reservation high levels of activity are projected. Most of these townships marked high already are relatively densely drilled. Many new wells in these townships will likely be drilled as infill or fringe wells in existing fields, or as re-entries into existing well bores. Some minor exploratory activity could occur just beyond field boundaries. Well spacing is projected to be variable, in the 160 to 20 acre range.
- In the northeastern part of the planning area, in and around Sand Mesa Field, in the Beaver Creek Field area, and on the southern end of the Planning Area moderate levels of activity are projected. Infill field drilling, fringe wells in existing fields, or wildcat wells looking to discover entirely new fields are all possible. As with areas of projected high density drilling, well spacing in areas of moderate potential is likely to be variable depending on the characteristics of the play(s) driving development.
- In areas of projected low potential activity future drilling will be to either improve enhanced oil production projects, to add wells in and around existing oil and gas fields that are maturely developed and have limited opportunities to develop the existing reservoirs or additional deeper reservoirs, or to explore for new oil and gas reservoirs away from existing developed areas. Well densities will remain similar to what they are at present, with isolated townships having a low potential for an increase in drilling density.

The remaining 23 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 moderately. However, predicting a well density for such areas is not possible at this time.

Figure 20 shows historic well distributions by depth. We anticipate that future drilling depths will on average be deeper than they have been historically, with increases in the number of wells in the 5,000 to 10,000 and 10,000 to 15,000 foot depth ranges and a reduction in wells with depths of 5,000 feet or less. More than 100 deep wells (greater than 15,000 feet in true vertical depth) have been drilled in the Planning Area and many have been productive from their deepest formations (IHS Energy, 2008). We project that additional deep wells will be drilled in the Planning Area during the planning period at about 125 percent of the rate they were drilled in the past 20 years, 75 new deep wells. Most oil wells drilled will be to depths of 5,000 feet or less.

As stated earlier, the majority of the anticipated activity in the Planning Area will be infill drilling to increase proved recoverable reserves and as exploratory drilling to further

explore the potential of continuous resources identified by the U.S. Geological Survey in the Wind River Basin and Southwestern Wyoming provinces (U.S. Geological Survey; 2002, 2005a, 2005b, 2008b). 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, and
- Upward revisions of reserve calculations based on production experience and changing relations between price and cost.

Projected Coalbed Natural Gas Drilling

The estimated coalbed natural gas development potential and drilling densities within the Planning Area during the planning period are shown in Figure 29. Estimated acres, number of townships, and percentage of the Planning Area within each development potential classification type shown in Figure 29 are summarized in Table 9.

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

- Moderate: 20 to 100 wells
- Low: 2 to <20 wells
- Very Low: <2 wells
- 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, coalbed natural gas development cannot occur.

Areas with coalbed natural gas activity or proposed future activity and lying within U.S. Geological Survey (U.S. Geological Survey; 2002, 2005a, 2005b, 2008b) designated coalbed gas assessment units were designated as moderate development potential. All other areas within designated coalbed gas assessment units, but where no activity has occurred and no activity is presently proposed, were assigned a low development potential. Remaining parts of the Planning Area that contain Cretaceous sediments with potential coalbeds at depths greater than 6,000 feet were assigned a very low potential. Areas assigned no potential are not within coalbed gas assessment units and are not known to contain coalbeds in Tertiary or Cretaceous sediments.

It is anticipated that approximately 844 or the new coalbed natural gas wells will be drilled somewhere in the areas of moderate or low potential between 2008 and 2027

(Figure 29). Coalbed natural gas wells drilled during the first 10 years of the planning period (2008 through 2017) will most likely be in areas of moderate potential were activity is currently taking place or is proposed. The remaining 17 wells, of the 861 total wells, could be drilled within the area of very low potential.

Results from coalbed natural gas pilot drilling projects in other parts of Wyoming suggest that often too few wells have been drilled to adequately evaluate the economic viability of a particular area. Past history indicates that pilots should contain 16 (four interior wells) to 25 (nine interior wells) wells to adequately evaluate an area (Cook, 2002, and Likwartz, 2002). History suggests that fewer than 16 to 25 wells may not adequately reduce pressure over a sufficient area and allow subsequent gas production. Also, heterogeneity in the coal may preclude the one interior well in a normal five or nine well pilot from providing the data necessary to adequately evaluate economic viability. Therefore, we assume that any coalbed natural gas pilots in the Planning Area will contain 16 to 25 wells. This should provide a better chance of obtaining adequate data and thus avoiding duplicate projects. Spacing for coalbed natural gas is likely to range from 40 to 160 acres per well.

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.

ESTIMATED FUTURE OIL AND GAS PRODUCTION

As indicated above, we projected 3,427 wells would be drilled within the analysis period of 2008 through 2027. These wells were assumed to be drilled at an average rate of 171 wells per year during the period with 178 wells drilled in the last year. Table 10 forecasts oil and gas production for the 20-year period beyond the year 2007. Gas production is projected to increase and oil production is projected to be somewhat flat. The cumulative values are for the 20 year planning period and ignore the historical production. The values were arrived at by noting local operator's interest in finding and producing gas over oil. It is inferred that coalbed natural gas drilling activity will increase, which will contribute to increased gas production.

OTHER POTENTIAL FUTURE OIL AND GAS ACTIVITIES

Shale Gas

Carbonaceous shale is expected to be an important future source of natural gas in the United States. At present, there is little information available to characterize any shale gas plays that may be present within the Planning Area. However, this important future gas source could become viable before the end of the planning cycle.

When and if a shale gas play is characterized for the Planning Area and technology and well completion methods are developed, this energy source could become important. If adjacent to or overlapping existing plays, development would likely commence at a faster rate than if found to be geographically separated from such areas. This is the most likely scenario as some parts of the Planning Area have already been developed with an existing infrastructure already in place.

Existing wellbores may also be utilized if the plays overlap aerially. However, the nature of shale gas plays would likely require drilling of horizontal wells, so the existing wellbores would likely still have to be re-entered and a horizontal lateral drilled into the zone of interest using the existing wellbore as a pilot. Additional new horizontal wells would also likely be drilled. 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 any shale gas resource in the Planning Area appear to be very low for the planning 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 and gas turbines. 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. 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. 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 should limit this.

Presently, the underground gasification technology involving deep coal beds does not appear to be economic and there is no known research activity into future development in the Planning Area. There are coal beds in the Planning Area at depths too deep for mining but good candidates for underground gasification however, considering the relatively experimental status of underground coal gasification and the abundant coal found elsewhere in the region, there is a low probability that this process will be utilized in the Planning Area during the planning period.

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 carbon dioxide produced in association with natural gas production at Madden Field is the largest source. 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, 2007). 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 10 to 15 percent of original oil in place can be recovered when carbon dioxide is injected. An enhance oil recovery project using carbon dioxide went on line at Beaver Creek Field during the summer of 2008.
- Unmineable coal seams – Unmineable coal seams are considered to be those that are too deep or too thin to be economically mined. Most 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.
- Saline formations – Saline formations suitable for carbon sequestration were defined in the United States Department of Energy (2007) 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. This process is being evaluated at the Lost Soldier oil and gas field just southeast of the Planning Area.

POTENTIAL SURFACE DISTURBANCE

Table 11 projects short-term and long-term disturbance associated with existing wells and projected drilling activity for 2008 through 2027. 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 October 2008, 63 completed as exploratory wells, 400 completed as development wells, 12 completed as coalbed natural gas wells, and 13 completed as deep wells will be abandoned by December 2027,
- the success rate of new coalbed natural gas wells will be 90 percent,
- the success rate for new exploratory wells will be 60 percent, and
- the success rate for new development wells and new deep wells will be 80 percent.

Table 11 shows our projection of new exploratory and development wells (3,427 wells with 2,367 of those wells managed by the Bureau) that could be drilled in the Planning Area from 2008-2027. There are an additional 2,264 existing active wells (Wyoming Oil and Gas Conservation Commission, 2008), as of October 2008, for a total of 5,691 existing and projected oil and gas wells. Of those 2,264 existing and projected wells; 887 total wells (113 non-coalbed exploratory wells, 722 non-coalbed development wells, 5 coalbed natural gas wells and 47 deep wells) will lie on Bureau managed oil and gas minerals. Table 11 calculates associated acres of total surface disturbance (short-term disturbance) directly associated with all new wells and existing active wells (as of October 2008). Approximately 23,075 acres of new short-term surface disturbance (16,014 acres of disturbance on Bureau managed oil and gas minerals) could occur if all 3,247 projected wells are drilled. Total short-term surface disturbance (for all well types) would be 34,021 acres, with 20,407 of those acres on Bureau managed oil and gas minerals.

Table 11 calculates new producing wells remaining in production after all new exploratory and development wells are drilled and all dry holes are abandoned and reclaimed (2,760 total new producing wells with 1,897 of those new producing wells on Bureau managed oil and gas minerals). There are an additional 1,777 existing wells (675 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. Table 11 calculates unreclaimed associated acres of total surface disturbance (long-term disturbance) directly associated with all remaining wells. Approximately 12,026 acres of new unreclaimed surface disturbance (8,318 acres of unreclaimed Bureau managed oil and gas minerals) could remain in the long-term. Total unreclaimed long-term surface disturbance (for all well types) would be 20,638 acres, with 11,682 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 period 2008 through 2027. We projected that as many as 3,427 wells could be drilled for this period. As many as 861 of these wells could be drilled as coalbed natural gas wells. Our forecast of annual and cumulative oil and gas production for 2008 through 2027 is presented in Table 10. Short-term and long-term surface disturbance associated with existing wells and future projected wells is presented in Table 11 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.

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APPENDIX 1 - U.S. GEOLOGICAL SURVEY ASSESSMENTS OF UNDISCOVERED OIL AND GAS RESOURCES WITHIN THE LANDER FIELD OFFICE AREA

INTRODUCTION

The U.S. Geological Survey has published a number of resource assessments of undiscovered oil and gas resources that cover parts of the Lander Planning Area. Their "1995 National Assessment of United States Oil and Gas Resources" (Beeman et al., 1996: Charpentier et al., 1996: and Gautier et al., 1996) scientifically estimated the amount of crude oil, natural gas, and natural gas liquids that could be added to proved reserves in the United States, assuming existing technology. It presented information about potential undiscovered accumulations of oil and gas in 71 geologic or structural provinces within the United States. Three of those provinces, the Wind River Basin, Southwestern Wyoming, and Bighorn Basin provinces, lie partly within the Planning Area.

Recently the U.S. Geological Survey revised their methods of preparing oil and gas resource assessments. They have updated their quantitative estimates of undiscovered oil and gas resources for the Wind River Basin, Southwestern Wyoming, and Bighorn Basin provinces, (U.S. Geological Survey; 2002, 2005a, 2005b, 2008b, 2008c and Roberts et al., 2008) using the revised methods. In the following analysis, we will use the newest assessment to describe the potential undiscovered technically recoverable oil and gas resources lying within all three provinces. Figure A1-1 shows the location of each of these three provinces and their relation to the Planning Area. The three areas not assessed for the three provinces (southwestern edge, northwestern boundary, and southeastern boundary of Planning Area) contain predominantly igneous rock types with low potential for occurrence of hydrocarbons, so the U.S. Geological Survey has not prepared an analysis for these areas

WIND RIVER BASIN PROVINCE ASSESSMENT

The Wind River Basin Province (Figure A1-1) encompasses about 4.7 million acres in central Wyoming and about 80 percent of the province, or 3,916,897 acres, lies within the Lander Planning Area. It lies in the Wind River Basin, a west-east-trending asymmetrical intermontane basin of the Rocky Mountain Foreland and occupies the largest and central part of the Planning Area. Province boundaries include the Owl Creek Mountains on the north, the Wind River Mountains to the west, the Casper Arch on the east, and the Sweetwater Uplift on the south. The Wind River Basin Province is about 200 miles long and 100 miles wide and covers about 11,700 square miles. A summary of past oil and gas related activities in the Planning Area portion of the province is presented in the main body of this report.

Assessment Unit Summaries

In their newest assessment, the U.S. Geological Survey (2005a and 2008b) divided the Wind River Basin Province into "total petroleum systems" and "assessment units" (see Glossary definitions) rather than "plays" as they had done in previous assessments. "The total petroleum system approach is designed to focus the geologic studies on the hydrocarbon source rocks, processes that create hydrocarbons, migration pathways, reservoirs, and trapping mechanisms" (U.S. Departments of Interior, Agriculture, and Energy, 2003). Most of the older fields within the Planning Area portion of the province can be classified as conventional accumulations of hydrocarbons. Continuous accumulations can include tight reservoirs, shale reservoirs, unconventional reservoirs, basin-centered reservoirs, fractured reservoirs, coalbeds, oil shales, and shallow biogenic gas. Most of the more recent gas developments in this part of the Planning Area have been considered to be part of continuous accumulations. Three total petroleum systems and 12 assessment units have been identified in the Wind River Basin Province, all of which lie at least partly within the Planning Area.

Conventional oil and gas resources are defined by the Phosphoria, Cretaceous-Tertiary, and Waltman Shale total petroleum systems, with each system containing one conventional assessment unit (Figures A1-2, A1-3, and A1-4). These three conventional accumulations (see Glossary definitions) are:

- Tensleep-Park City conventional oil and gas assessment unit,
- Cretaceous-Tertiary conventional oil and gas assessment unit, and
- Upper Fort Union Sandstone conventional oil and gas assessment unit.

The U.S. Geological Survey has made available some statistical information for the three conventional assessment units (Table A1-1). Some small quantities of carbon dioxide, hydrogen-sulfide and nitrogen can be expected to be produced with any gas discovered in the Tensleep-Park City assessment unit and carbon dioxide and nitrogen can be expected with any gas discovered in the Cretaceous-Tertiary assessment unit.

Continuous oil and gas resources are defined within the Cretaceous-Tertiary (eight assessment units) and Waltman Shale (one assessment unit) total petroleum systems (Figures A1-5 through A1-13). Continuous accumulations can include tight reservoirs, shale reservoirs, unconventional reservoirs, basin-centered reservoirs, fractured reservoirs, coalbeds, oil shales, and shallow biogenic gas. The continuous accumulations are:

- Frontier-Muddy continuous gas assessment unit,
- Cody Sandstone continuous gas assessment unit,
- Cody Fractured Shale continuous oil assessment unit,
- Mesaverde-Meeteetse Sandstone gas assessment unit,
- Lance-Fort Union Sandstone gas assessment unit,
- Mesaverde coalbed gas assessment unit,
- Meeteetse coalbed gas assessment unit,
- Fort Union coalbed gas assessment unit, and
- Waltman Fractured Shale continuous oil assessment unit.

Again, the U.S. Geological Survey has made available some statistical information for these continuous assessment units (Table A1-2). The Cody Fractured Shale and the Waltman Fractured Shale continuous oil assessment units are hypothetical and only limited data is available.

Assessment Unit Resource Results

The U.S. Geological Survey (2005a and 2008b) estimated undiscovered technically recoverable resource 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 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 three conventional and seven continuous assessment units, which both lie at least partly within the Planning Area.

In Table A1-3, the U.S. Geological Survey resource estimates for three types of hydrocarbons (oil, gas, and natural gas liquids) are shown for the conventional and continuous assessment units in the Wind River Basin Province, together with our projection of the amount of those hydrocarbons that could be present within the Lander Planning Area. To determine the potential resource within the Planning Area we:

- assumed a homogenous distribution of each hydrocarbon type within each assessment unit,
- calculated the percent of each assessment unit that lies within the Planning Area, and
- multiplied that percentage by the U.S. Geological Survey resource value estimates for each entire assessment unit to calculate Planning Area resource values.

Our estimates of recoverable resources for each assessment unit area within the province and within the Planning Area are presented as a range of possibilities: a low case having a 95 percent probability of that amount or more occurring, a high case having a 5 percent probability of that amount or more occurring, and a mean case representing an arithmetic average of all possible outcomes. We estimate that the Planning Area contains a **mean undiscovered volume of almost 31.06 million barrels of oil, almost 1,823 billion cubic feet of gas, and 22.89 million barrels of natural gas liquids, in the 10 assessment units with projected hydrocarbon volumes.**

In addition, we estimate that the Planning Area's oil resource could **range from 7.56 to 68.35 million barrels, the gas resource could range from 757.3 to 3,446.52 billion cubic feet, and the natural gas liquids resource could range from 4.08 to 37.36 million barrels** (assuming fractile data used has a perfect positive correlation).

SOUTHWESTERN WYOMING PROVINCE ASSESSMENT

A small part of the Southwestern Wyoming Province occupies the southern part of the Planning Area (Figure A1-1). Its full extent includes the Green River, Hoback, Great Divide, Washakie, Hanna, Carbon, Sand Wash, and Laramie basins. The province covers about 40,500 square miles in parts of Wyoming, Colorado, and Utah, with only about 3.18 percent or 480,585 acres lying within the Planning Area.

Assessment Unit Summaries

In their newest assessment, the U.S. Geological Survey (2002 and 2005b) divided the Southwestern Wyoming Province into "total petroleum systems" and "assessment units" (see Glossary definitions) rather than "plays." Most of the older fields within the Planning Area portion of the province can be classified as conventional accumulations of hydrocarbons. Continuous accumulations can include tight reservoirs, shale reservoirs, unconventional reservoirs, basin-centered reservoirs, fractured reservoirs, coalbeds, oil shales, and shallow biogenic gas. Most of the more recent gas developments in this part of the Planning Area have been considered to be part of continuous accumulations.

Nine total petroleum systems and 23 assessment units have been identified in the Southwestern Wyoming Province, but only seven total petroleum systems and 13 assessment units lie at least partly within the Planning Area. Conventional oil and gas resources are defined by the Phosphoria, Mowry Composite, Hilliard-Baxter-Mancos, Mesaverde, Lewis, and Lance-Fort Union Composite total petroleum systems, with each system containing one conventional assessment unit (Figures A1-14 through A1-19). These six conventional accumulations (see Glossary definitions) are:

- Sub-Cretaceous conventional oil and gas assessment unit,
- Mowry conventional oil and gas assessment unit,
- Hilliard-Baxter-Mancos conventional oil and gas assessment unit,
- Mesaverde conventional oil and gas assessment unit,
- Lewis conventional oil and gas assessment unit, and
- Lance-Fort Union conventional oil and gas assessment unit.

The U.S. Geological Survey has made available some statistical information for the three conventional assessment units (Table A1-4). Some small quantities of carbon dioxide and nitrogen can be expected to be produced with any gas discovered in any of the above assessment units. No hydrogen sulfide would be expected to occur in any of these assessment units.

Continuous oil and gas resources within the Planning Area are defined within the Mowry Composite, Niobrara, Hilliard-Baxter-Mancos, Mesaverde, and Lewis total petroleum systems (Figures A1-20 through A1-26). Continuous accumulations can include tight reservoirs, shale reservoirs, unconventional reservoirs, basin-centered reservoirs, fractured reservoirs, coalbeds, oil shales, and shallow biogenic gas. The continuous accumulations lying at least partly within the Planning Area are:

- Mowry continuous gas assessment unit,

- Niobrara continuous oil assessment unit,
- Hilliard-Baxter-Mancos continuous gas assessment unit,
- Rock Springs continuous gas assessment unit,
- Lewis continuous gas assessment unit,
- Lance-Fort Union continuous gas assessment unit, and
- Fort Union coalbed continuous gas assessment unit.

Again, the U.S. Geological Survey has made available some statistical information for these continuous assessment units (Table A1-5).

Assessment Unit Resource Results

The U.S. Geological Survey (2002 and 2005b) estimated undiscovered technically recoverable resource 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 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 six conventional and seven continuous assessment units, which both lie at least partly within the Planning Area.

In Table A1-6, the U.S. Geological Survey resource estimates for three types of hydrocarbons (oil, gas, and natural gas liquids) are shown for the conventional and continuous assessment units in the Southwestern Wyoming Province, together with our projection of the amount of those hydrocarbons that could be present within the Lander Planning Area. To determine the potential resource within the Planning Area we:

- assumed a homogenous distribution of each hydrocarbon type within each assessment unit,
- calculated the percent of each assessment unit that lies within the Planning Area, and
- multiplied that percentage by the U.S. Geological Survey resource value estimates for each entire assessment unit to calculate Planning Area resource values.

Our estimates of recoverable resources for each assessment unit area within the province and within the Planning Area are presented as a range of possibilities: a low case having a 95 percent probability of that amount or more occurring, a high case having a 5 percent probability of that amount or more occurring, and a mean case representing an arithmetic average of all possible outcomes. We estimate that the Planning Area contains a **mean undiscovered volume of almost 2.97 million barrels of oil, almost 1,297 billion cubic feet of gas, and 31.29 million barrels of natural gas liquids, in the 13 assessment units with projected hydrocarbon volumes.**

In addition, we estimate that the Planning Area's oil resource could **range from 1.58 to 5.12 million barrels, the gas resource could range from 777.84 to 2,017.35 billion**

cubic feet, and the natural gas liquids resource could range from 15.36 to 55.53 million barrels (assuming fractile data used has a perfect positive correlation).

BIGHORN BASIN PROVINCE ASSESSMENT

The Bighorn Basin Province occupies the northernmost and smallest part of the Planning Area (Figure A1-1). The Bighorn Basin is a large Laramide (Late Cretaceous through Eocene) structural-sedimentary basin covering about 7,500 square miles in north-central Wyoming and south-central Montana (Roberts et al., 2008), with only about 325,933 acres lying within the Planning Area. Adjacent mountain ranges include the Beartooth Mountains to the northwest, the Absaroka Mountains to the west, the Owl Creek Mountains to the south, and the Bighorn Mountains to the east.

Assessment Unit Summaries

In their newest assessment, the U.S. Geological Survey (2008c) divided the Bighorn Basin Province into "total petroleum systems" and "assessment units" (see Glossary definitions) rather than "plays." No Bighorn Basin Province fields lie within the Planning Area portion of the province.

Two total petroleum systems and eight assessment units have been identified in the Bighorn Basin Province, but only one assessment unit in each total petroleum system lies at least partly within the Planning Area. Conventional oil and gas resources are defined by the Phosphoria and Cretaceous-Tertiary Composite total petroleum systems (Figures A1-27 through A1-28). The two accumulations (see Glossary definitions) are the Paleozoic-Mesozoic conventional oil and gas assessment unit and the Cretaceous-Tertiary conventional oil and gas assessment unit. The U.S. Geological Survey has not yet made available any statistical information for the assessment units.

Assessment Unit Resource Results

The U.S. Geological Survey (2008c) estimated undiscovered technically recoverable resource 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 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 two conventional assessment units, which both lie at least partly within the Planning Area.

In Table A1-7, the U.S. Geological Survey resource estimates for three types of hydrocarbons (oil, gas, and natural gas liquids) are shown for the conventional and continuous assessment units in the Bighorn Basin Province, together with our projection of the amount of those hydrocarbons that could be present within the Lander Planning Area. To determine the potential resource within the Planning Area we:

- assumed a homogenous distribution of each hydrocarbon type within each assessment unit,
- calculated the percent of each assessment unit that lies within the Planning Area, and
- multiplied that percentage by the U.S. Geological Survey resource value estimates for each entire assessment unit to calculate Planning Area resource values.

Our estimates of recoverable resources for each assessment unit area within the province and within the Planning Area, are presented as a range of possibilities: a low case having a 95 percent probability of that amount or more occurring, a high case having a 5 percent probability of that amount or more occurring, and a mean case representing an arithmetic average of all possible outcomes. We estimate that the Planning Area contains a **mean undiscovered volume of almost 1.36 million barrels of oil, about 13.71 billion cubic feet of gas, and 0.37 million barrels of natural gas liquids, in the two assessment units with projected hydrocarbon volumes.**

In addition, we estimate that the Planning Area's oil resource could **range from 0.37 to 2.65 million barrels, the gas resource could range from 3.76 to 27.29 billion cubic feet, and the natural gas liquids resource could range from 0.11 to 0.73 million barrels** (assuming fractile data used has a perfect positive correlation).

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.

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, or as continuous, if it contains continuous accumulations.

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).

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.

Geologic province. A U.S. Geological Survey-defined area having characteristic dimensions of perhaps hundreds to thousands of miles encompassing a natural geologic entity (for example, sedimentary basin, thrust belt, delta) or some combination of contiguous geologic entities.

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.

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.

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

Total petroleum system. The total petroleum system includes: 1) identification and mapping the extent of the major hydrocarbon source rocks; 2) understanding the thermal evolution of each source rock, the extent of mature source rock, and the timing of hydrocarbon generation, expulsion, and migration; 3) estimating migration pathways and all forms of hydrocarbon trapping; 4) modeling the timing of structural development and the timing of trap formation relative to hydrocarbon migration; 5) determining the sequence stratigraphic evolution of reservoirs, and the presence of conventional or continuous reservoirs, or both; and 6) modeling the burial history of the basin and the effect burial and uplift has had on the preservation of conventional and continuous hydrocarbons.

Unconventional gas. Unconventional 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.