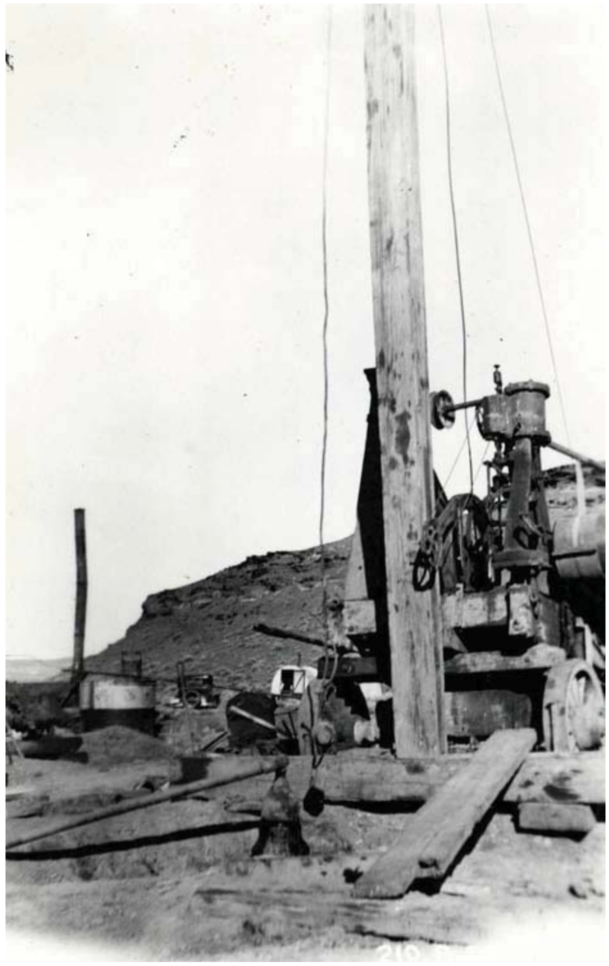
REASONABLE FORESEEABLE DEVELOPMENT SCENARIO FOR OIL AND GAS
BIGHORN BASIN PLANNING AREA, WYOMING



56 Petroleum Co. Government #1 well, west of Oregon Basin Field circa 1933 (Bureau files)

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UNITED STATES DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

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WYOMING STATE OFFICE
RESERVOIR MANAGEMENT GROUP

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Bighorn Basin Planning Area, Wyoming

November 8, 2010

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Figure List

Table List

INTRODUCTION

The Bighorn Basin Planning Area (Planning Area) represents the combined lands managed by the Cody and Worland, Wyoming Bureau of Land Management (Bureau) field offices. The Planning Area lies within north-central Wyoming, east of Yellowstone National Park (Figure 1). The Planning Area includes part of Hot Springs, and all of Park, Washakie, and Big Horn counties, Wyoming.

A Resource Management Plan Revision and associated Environmental Impact Statement are currently being prepared for the Planning Area. In support of the Resource Management Plan Revision, this reasonable foreseeable development projection technically analyzes the oil and gas resource known to occur and potentially occurring within the Planning Area and projects future development potential and activity levels for the period 2008 through 2027. Historic and present oil and gas related development areas are presented for all lands within the Planning Area (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, and State and Private managed lands are included in the base line projection for those lands assessed for future development. Certain other federally managed lands within the Planning Area are not assessed for the potential for future reasonable foreseeable 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 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 (see Glossary) technology research and development, geophysical activity, and limitations on access and infrastructure. It must be emphasized that the reasonable foreseeable development projections presented are 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 7,815,981 surface acres of all oil and gas mineral ownership types. The Planning Area contains about 6,367,924 acres of Federal oil and gas mineral ownership, or about 81.5 percent of total acres. The remaining 1,448,057 acres (18.5 percent) is managed by state and private interests. The Bureau manages most of the Federal oil and gas mineral lands in the Planning Area (4,039,336 acres, or about 63.4 percent). We assume that about 836,903 acres of state and private surface lands within Planning Area boundaries overlie Bureau managed oil and gas mineral lands. All Bureau managed oil and gas mineral lands will be covered by decisions made in the associated Resource Management Plan EIS.

The U.S. Forest Service manages about 2,144,188 acres or 33.7 percent of Federal oil and gas mineral lands within the Planning Area. The remaining 2.9 percent is managed by the Bureau of Reclamation (84,337 acres), Department of Defense (84,221 acres), and National Park Service (15,842 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 for the important contributions that she has 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 (see Glossary) are explored and then developed. The sequence begins when initial exploratory activity begins, and ends when projects are abandoned.

EXPLORATORY ACTIVITY AND OPERATIONS

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

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

Exploratory activity includes:

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

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

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

1. The major structural elements (anticlines and faults) of the Planning Area (Figure 4) define areas were there has been the greatest historical interest in exploring for and developing oil and gas fields (Figure 5). The largest part of the Planning Area lies within the Bighorn Basin, an asymmetric intermontane basin of the Rocky Mountain foreland (see Glossary). It is located in north-central Wyoming and south-central Montana. This basin is defined by fault-bounded Laramide uplifts that surround it (Fox and Dolton, 1995). These include the Absaroka Volcanic Plateau to the west, the Beartooth Mountains to the northwest, and Bighorn Mountains to the east. The Owl Creek Mountains bound the Bighorn Basin to the south, just south of the Planning Area boundary. The Bighorn Basin contains all the productive sedimentary formations found within the Planning Area (Figure 6).
2. Thick accumulations of sandstones, carbonates, and shales (potential source and reservoir rocks) exist, with coals present in some areas. Figure 6 presents a stratigraphic chart for the Planning Area showing nomenclature used for these accumulations in our report.
3. Burial and thermal histories that could promote the development and preservation of diagenetic pore-throat traps (see Glossary) and extensive oil and gas generation in the center of the Bighorn Basin.
4. Structure traps (see Glossary) that have played a large role in localizing oil and gas accumulations, especially when coupled with stratigraphy.
5. Stratigraphic traps (see Glossary), which have had a smaller role in exploration and development.
6. Pressure regimes, ranging from slightly under-pressured to highly over-pressured, could be important in the center of the basin. In areas of abnormally high pressures, productive capacity can be greatly increased. Over-pressuring also creates problems in drilling and completion, increasing the cost of both.
7. Secondary porosity, produced by the dissolution of unstable grains (see Glossary) and rock fragments, is important in local accumulations.

We believe that those components are also important in exploring for and developing new oil and gas resources in the Planning Area. Almost all recent (since 1998) Planning Area drilling activity (exploratory and development) has been occurring in the vicinity of existing fields (Figure 7), with only about seven percent of new wells drilled as wildcats. Smaller amounts of exploration activity have occurred in the deeper parts of the basin and additional exploration is planned over the next few years.

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

1. Tight Sands Gas – formed in sandstone or carbonate (called tight gas sands) with low permeability, which prevents the gas from naturally flowing to a borehole.
2. Coalbed Natural Gas – formed in coal deposits and adsorbed (see Glossary) by coal particles.
3. Fractured 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. In the Planning area this could include gas in the Mowry Shale (U.S. Geological Survey, 2010).

In addition, there is some potential for unconventional oil reservoirs. Specifically, fractured shale oil reservoirs, formed in fine-grained shale rock with low permeability could be present in the Planning Area in the Mowry Shale (U.S. Geological Survey, 2010).

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

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

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

Of the 547 boreholes (see Glossary), including directional and horizontal boreholes, spudded (see Glossary) in the most recent 10-year period (January 1, 1999 to December 31, 2008) initial classifications, as defined by IHS Energy Group (2009) were:

• Core Hole	16 boreholes	2.93 percent,
• Development	354 boreholes	64.72 percent,
• Development Deepening	37 boreholes	6.76 percent,
• Development Redrill	75 boreholes	13.71 percent,
• Injection	14 boreholes	2.56 percent,
• Injection Deepening	4 boreholes	0.73 percent,
• Stratigraphic Test	4 boreholes	0.73 percent,

- Service 1 borehole 0.18 percent,
- Service Deepening 2 boreholes 0.37 percent,
- Deeper Pool Wildcat 1 borehole 0.18 percent,
- New Field Wildcat 24 boreholes 4.39 percent,
- Wildcat Outpost 14 boreholes 2.56 percent, and
- Wildcat Outpost Redrill 1 borehole 0.18 percent.

Locations of these boreholes are shown in Figure 7. Total wildcats and stratigraphic tests were 44, or 8.0 percent of the total. Of the 547 boreholes drilled, 119 (21.75) were drilled on existing locations that were deepened or redrilled. The redrilled boreholes were classified either as horizontal or directional in trajectory.

Of the boreholes drilled in the last 10 years (January 1, 1999 through December 31, 2008), more than 73 percent were drilled in 14 fields:

- Elk Basin 72 boreholes,
- Oregon Basin 66 boreholes,
- Silver Tip 59 boreholes,
- Spring Creek South 46 boreholes,
- Greybull 29 boreholes,
- Hamilton Dome 21 boreholes,
- Garland 19 boreholes,
- Cottonwood Creek 15 boreholes,
- Byron, Five Mile, Grass Creek, and Murphy Dome 13 boreholes each, and
- Red Springs and Sunshine North 11 boreholes each.

Of the 466 development wells drilled during this period, their final classification (IHS Energy Group, 2009) ended up as:

- Drilled and Abandoned 24 boreholes,
- Drilled and Abandoned – Coalbed natural gas 13 boreholes,
- Development – Gas or Gas Shut-In 89 boreholes,
- Development – Oil or Oil Shut-In 334 boreholes,
- Development – Spudded 1borehole, and
- Water Injection 5 boreholes.

Of the development boreholes completed, 92 percent were successful. This rate is quite high and is mainly due to the very high rates of successful drilling in and around the already existing major fields (Figure 7). Reservoirs in these field areas are oil prone and predominantly structural traps.

In the last 10 years (January 1, 1999 through December 31, 2008), 20 core holes or stratigraphic tests have been drilled at Greybull Field (Figure 7) the location of oil mining activity. Of the 23 injection wells drilled during this period, locations and type are:

- Elk Basin Field 3 gas injection wells,
- Pitchfork Field 1steam and 1 water injection well,
- Red Springs Field 8 steam and 2 water injection wells,
- Hamilton Dome Field 3 water injection wells,
- Garland and Spring Creek South 2 water injection wells in each, and

- Oregon Basin Field 1 water injection well.

Of the 40 wildcats drilled during this period (IHS Energy Group, 2009), their final classification ended up as:

- Drilled and Abandoned 22 boreholes,
- Gas 12 boreholes,
- Oil 4 boreholes, and
- Spudded 2 boreholes.

Of the wells completed, 42.1 percent were successful.

Fifty-two operators were responsible for the 547 boreholes drilled in the 10-year period from January 1, 1999 to December 31, 2008. The top seven operators [Marathon Oil Company – 163 boreholes, Fidelity Exploration & Production Company (including Voyager Exploration Incorporated) – 65 boreholes, Howell Petroleum Corporation – 63 boreholes, Phoenix Production Company – 29 boreholes, Rock Well Petroleum US Incorporated – 25 boreholes, Merit Energy Company – 24 boreholes, and Continental Resources Incorporated – 22 boreholes] are responsible for the drilling of 71.5 percent of these wells. Nineteen operators were responsible for the drilling of only one well each.

New hydrocarbon production has come from 17 intervals during the last 10 year period of January 1, 1999 to December 31, 2008. Only the Fort Union Formation (two wells), produces from Tertiary aged sediments. Five intervals (Lance Formation – 32 wells, Meeteetse Formation – 7 wells, Mesaverde Formation – 12 wells, Frontier Formation – 117 wells, and Mowry Shale – 6 wells) produce from Upper Cretaceous aged sediments. In addition, two intervals (Muddy/Dakota Sandstone – 14 wells and Cloverly Formation – 3 wells) produce from Lower Cretaceous aged sediments, two intervals (Morrison Formation – 1 well and Sundance – 2 wells) produce from Jurassic aged sediments, and two intervals (Crow Mountain Sandstone – 3 wells and Chugwater Formation – 12 wells) produce from Triassic aged sediments. Finally, the Permian aged Phosphoria Formation produces from 77 wells, the Pennsylvanian aged Tensleep Sandstone produces from 120 wells, the Lower Pennsylvanian aged Amsden Formation produces from 12 wells, and the Mississippian aged Madison Limestone produces from 42 wells. The Frontier Formation and Tensleep Sandstone each produce in 25 percent of wells with a reported completion interval, the Phosphoria Formation is productive in almost 17 percent, and the Madison Limestone in nine percent. The other 13 intervals account for the remaining 23 percent of productive wells.

Drilling depths for all wells drilled in the last 10-year period from January 1, 1999 to December 31, 2008 have ranged from 205 to 12,292 feet. Twenty-seven of these wells (4.9 percent) were deeper than 10,000 feet. The deepest well was a new field wildcat drilled near the center of the basin in section 15 of township 50 north, range 97 west as a dry hole (Figure 7). Seven wells in this depth range have been drilled and abandoned, nine were completed as gas productive, 10 were completed as oil productive and one has been spudded but not completed. Eleven boreholes were completed as directional or horizontal wells (41 percent) and the rest were vertical.

In the 5,000 to 9,999 foot range, 129 wells (23.6 percent) were drilled. Eleven wells in this depth range have been drilled and abandoned, 39 were completed as gas productive, 127 were completed as oil productive, two were completed as water injectors, and two were service wells. Fifty-four boreholes were completed as directional or horizontal wells (42 percent) and the rest were vertical. Silver Tip Field (Figure 7) had the greatest number of boreholes drilled in this depth range: 41 wells or almost 32 percent.

For depths less than 5,000 feet, 390 wells (71.4 percent) were drilled. Fifty-four wells in this depth range have been drilled and abandoned, 53 were completed as gas productive, 258 were completed as oil productive, 21 were completed as injectors, two were service wells, and two wells were spudded but have not been completed. One hundred ninety-two boreholes were completed as directional or horizontal wells (49.2 percent) and the rest were vertical. Elk Basin (70 boreholes), Oregon Basin (65 boreholes), and Spring Creek South (45 boreholes) fields account for 46 percent of wells drilled in this depth range.

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

From the early 1990's to present, activity has focused 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 occurred and will continue to occur is expected in:

- computer processing capability and speed;
- remote sensing and image-processing technology;
- developments in global positioning systems;
- advances in geographical information systems;
- three-dimensional and four-dimensional time-lapse imaging technology that permits better interpretation of subsurface traps and characterization of reservoir fluid;
- improved borehole logging tools that enhance our understanding of specific basins, plays (see Glossary), and reservoirs; and
- advances in drilling that allow more cost-efficient tests of undepleted zones in mature fields, testing deeper zones in existing fields, and exploring new regions.

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

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

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

FEDERAL DEVELOPMENT CONTRACTS

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

FEDERAL OIL AND GAS UNIT AGREEMENTS

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

A need to conserve oil and gas resources in the United States was identified early in the 20th century and was reinforced by national security issues surrounding the importance of petroleum in fighting the First World War (Avery and Miller, 1934). Congress in 1930 enacted temporary legislation providing for participation in unit operations or cooperative development among lessees of public lands (46 Stat. 1007). The first unit approval in the United States was of the Little Buffalo Basin gas unit (Figure 8, unit #31), which was approved January 6, 1931. The Pitchfork Structure unit was the fifth United States unit (Figure 8, unit #43), which was approved November 30, 1932. In the following years thousands of units have been created in the United States. Many are still active while others have terminated.

Unit plans of operation where Federal oil and gas leases are incorporated, account for 58 active unit agreement areas that lie within or partly within the Planning Area boundary (Figure 8 and Table 1). Numerous other unit agreements have been approved in the 78 years since the first Planning Area approval, but they have since terminated. API/state units are established where Federal lands make up less than 10 percent of the proposed unit. API/state units (East Warm Springs and Torchlight) account for two of the 58 active units (Figure 8 and Table 1).

Active units encompass lands totaling approximately 250,707 acres, within the Planning Area. These units comprise a little more than 3.2 percent of the total Planning Area. Numerous units have been approved in all decades since their initiation in 1931. Numbers of still active units by decade are:

- 1930s – 7,
- 1940s – 13,
- 1950s – 9,
- 1960s – 6,
- 1970s – 9,
- 1980s – 4,
- 1990s – 5, and
- 2000s – 5.

Half of all still active units were initiated in the first thirty years of the program. From the 1980s to present, fewer units have been established and fewer still remain active.

Two exploratory units were approved in 2008 (Rocktober and Sundance). These units were initially approved as exploration tools to investigate non-producing parts of the Planning Area. They are both still in their exploration and development drilling phase and they cover about 19.2 percent of the total unit area. Neither unit has yet been established as productive. These units will likely contract to smaller developed unit areas once their productive limits are established.

Forty-one older exploratory units have contracted to their productive limits. These units are still producing oil and gas and cover 72.2 percent of the total unit area. Development drilling is continuing in some, while others are concentrating on obtaining maximum recovery with existing wells.

The 15 remaining unit agreements contain secondary oil recovery projects. Those with a formation name(s), in parenthesis, after the unit name in Table 1 are secondary oil recovery projects. Those formation names denote the formation(s) in which each secondary oil recovery project is active. Operators of these 15 units are working to obtain maximum oil recovery. They account for the remaining 8.6 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 14 different producing zones in the 28 units that are productive in secondary units or in Participating Areas within a unit. The numbers of units with production from each zone (from youngest age zone to oldest) are:

- Meeteetse – 1 unit,
- Mesaverde – 1 unit,
- Frontier (Torchlight) – 13 units,
- Muddy – 10 units,
- Cloverly (Dakota) – 5 units,
- Morrison – 1 unit,
- Sundance – 1 unit,
- Chugwater Group – 1 unit,
- Phosphoria (Embar) – 36 units,
- Tensleep – 26 units,
- Amsden – 5 units,
- Madison – 14 units,
- Bighorn – 1 unit, and
- Gros Ventre – 1 unit.

Twenty-four companies operate the 58 units within the Planning Area. Marathon Oil Company operates nine units, Saga Petroleum LLC operates seven units, Merit Energy Company operates six units, and Continental Resources Incorporated operates five units. St. Mary Land & Exploration Company, Whiting Petroleum Corporation, Citation Oil & Gas Corporation, and Encore Energy Partners Operating LLC/Encore Acquisitions Company each operate three units. Phoenix Production Company, Devon Energy Production Company LP, and Fidelity Exploration & Production Company each operate two units, while the remaining 13 companies each operate only one unit.

COMMUNITIZATION AGREEMENTS

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

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

At present, 40 active communitization agreements lie within the Planning Area (Figure 9). These agreements cover an area of about 9,870 acres. Areas covered by each agreement average:

- 40 acres – 4 agreements,
- 160 acres – 19 agreements,
- 320 acres – 13 agreements, and
- 640 acres – 4 agreements.

Other communitization agreements have been approved in all decades since the first Planning Area agreement effective in 1956. Numbers of still active agreements by decade are:

- 1950s – 1,
- 1970s – 12,
- 1980s – 17,
- 1990s – 4, and
- 2000s – 6.

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

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

- Frontier – 15 agreements,
- Muddy – 6 agreements,
- Chugwater – 1 agreement,
- Phosphoria (Embar) – 17 agreements, and
- Madison – 1 agreement.

Fourteen companies operate the 40 communitization units. Saga Petroleum LLC operates 13 agreements, Continental Resources Incorporated operates 11 agreements, Vernon E.

Faulconer Incorporated operates four agreements, and Wagner & Brown Incorporated operated two agreements. Ten other companies operate one agreement each.

TYPICAL DRILLING AND COMPLETION SEQUENCE

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

- constructing the well pad, associated reserve pits, and the access road prior to moving the drilling equipment on to the well location;
- using rotary equipment, hardened drill bits, weighted drill pipe/collars, and drilling fluids to cool and lubricate the drill bit, which all result in easier penetration of the earth's surface;
- for horizontal boreholes, geosteering (intentional directional control of the borehole based on the results of downhole geological logging measurements) the drill bit to maintain correct hole trajectory and keep a borehole in a particular reservoir to maximize economic production;
- inserting casing and cementing it in place to protect the subsurface and control the flow of fluids (oil, gas, and water) from the reservoir;
- perforating the well casing at the depth of the producing formation to allow flow of fluids from the formation into the borehole;
- hydraulically fracturing and propping fractures open with sized particles and/or acidizing the formation to increase permeability and the deliverability of oil and gas to the borehole;
- inserting tubing into each well to allow for controlled flow of fluids (oil, gas, and water) from the reservoir to the surface;
- installing a wellhead at the surface to regulate and monitor fluid flow and prevent potentially dangerous blowouts;
- reclaiming the portions of the well pad and access road that will not be used in the production phase of the well; and
- reclaiming the entire pad and access road after the well has ceased production and is plugged and abandoned.

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

- access to 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 (see Glossary) required. Environmental benefits of drilling and completion technology advances include:

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

DRAINAGE PROTECTION

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

HISTORICAL DRILLING AND COMPLETION ACTIVITY AND TECHNIQUES EMPLOYED

The existence of oil in Wyoming has been known for centuries. Within the Big Horn Basin, Thurman (1952) reported

> "the discovery, in 1884 of an oil spring near Bonanza. The first well drilled in the Basin was a dry hole completed in 1888. A few tests were drilled and rumors circulated that oil had been found in several localities prior to 1906. Such rumors were expressions of hope rather than statements of fact. In 1906, however, oil was found near Byron and in 1907 gas was found near Greybull."

The field near Byron is now known as Garland Field and that near Greybull is called the Greybull Field. Oil and gas activities, although quite variable over time, have continued from the first 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 Bighorn Basin structural province is a large intermontane syncline lying in the Rocky Mountains. The axis of the Bighorn Basin syncline trends in a northwest and southeast direction (Figure 4). It is bound by the Bighorn Mountains to the east, the Pryor Mountains to the northeast in Montana, the Owl Creek Mountains on the southwest, the Beartooth Mountains on the northwest, and Absaroka volcanics to the west.

The oil spring at Bonanza was discovered by Edward Loyd and the area was included in an oil placer claim staked in 1885 by A. A. Connant (Hares, 1947). The oil spring issued from Lower Cretaceous Thermopolis Shale. This oil was 36 degrees API gravity, and was locally used in lamps during a shortage of kerosene, latter in the century. The first well in the Planning Area was drilled only one and a quarter miles northeast of the spring. It was deep for its time at 1,200 feet, but was abandoned.

Two shallow holes were drilled and abandoned in the Torchlight Dome area in 1903. They were drilled in the vicinity of Torchlight Field (Figure 10), which was not discovered until latter. Hare (1947) reports that gas seeps were present at Byron and caused the drilling of the first productive oil well. The field is now designated as Garland Field (Figure 10). This early production was in Frontier Formation sandstone at about 400 feet and produced high grade light green oil. The earliest wells were drilled using cable tool rigs (see Glossary), which began to be converted to rotary drilling rigs (see Glossary) in 1926 at Oregon Basin Field.

Also, in 1907 gas was discovered at the Greybull Field where the first refinery was built. As previously stated, the first productive well was a gas producer completed in 1906. These discoveries inspired others to stake oil placer claims throughout the basin. By 1925 as many as 80 structures had been located within the Bighorn Basin (Bartlett and Maghee, 1925), although not all had been tested.

The earliest fields (Figure 10), prior to 1920 were discovered by surface mapping of geologic structures (Hewett and Lupton, 1917; Bartlett and Maghee, 1925; Espach and Nichols, 1941; Hares, 1947; Pierce, 1948; Rogers et al., 1948; Summerford, 1952; Wyoming Geological Association, 1957 and 1989; and Bureau Files). During this period fields were discovered on all sides of the basin. They are:

- Garland – a faulted asymmetric anticline probably caused by fault-propagation folding. It was initially called Byron Field. With the development of a new field a few miles northeast called Byron, the original was renamed Garland. The Cody Shale is exposed over much of the structure. It was discovered in 1906, producing light oil from the Frontier Formation. In 1915 sweet gas was found in the Cloverly Formation. In 1927 "sour gas" (hydrogen sulfide bearing) was discovered in the Phosphoria Formation, and deeper drilling recorded "sour gas" from the Tensleep Sandstone. Oil and gas was discovered in the Madison Limestone in 1930. Since 1940, additional discoveries were made in the Morrison, Sundance, Chugwater, Amsden, and Darby. The oil produced from

1907 to 1908 was used in development work; that produced from 1909 to 1912 was refined in a small plant at Cowley. Early gas production was piped to Lovell and Powell for domestic and industrial uses. From 1917 to 1921 most gas was used at a plant built in Cowley to make carbon black. In 1994, Garland was the fifth largest oil field in the Bighorn Basin, with 160 million barrels of oil in place (Demiralin et al., 1994).

- Greybull – an anticline with gas trapped structurally and oil confined to the north plunge and west flank, with trapping primarily attributed to pinchout of the producing sandstone and secondarily to faulting. The Cloverly Formation (Greybull sandstone) was discovered in July, 1907 and produced gas. The first well reportedly could not be controlled for a year and a half and gas escaped at about one million cubic feet per day. Oil was added from the Cloverly in October of 1908. The produced gas was initially used in the town of Greybull for lighting and heating. After 1940, the Frontier Formation was found to be productive.
- Shoshone – a faulted asymmetric anticline where oil was discovered in 1912 in the Muddy Sandstone. In 1929 oil was discovered in the Phosphoria Formation (locally called the Embar). After 1940, oil in the Tensleep Sandstone was discovered.
- Oregon Basin – two anticlinal structures (north dome and south dome). The discovery was a gas well near the south dome crest, drilled in 1912 and productive from the Cloverly Formation. Cloverly on the north dome was found to be productive of gas in 1916. In 1927 oil production was found in the Phosphoria (locally called the Embar) and Tensleep on the north dome. A Chugwater Group gas pool was found on the north dome in 1928 and a shallow (990 feet) gas discovery was made in the Frontier Formation in 1934. After 1940, oil was discovered in the Madison Limestone (1943) on the south and north domes, gas was found in the Flathead Sandstone (1957) on the south dome, gas was discovered in the Gros Ventre Formation (1973) on the south dome, gas was discovered in the Flathead Sandstone (1973) on the north dome, and gas was discovered in the Gros Ventre Formation (1977) on the north dome. Enhanced oil recovery began in 1960 in the Phosphoria and Tensleep. Gas storage into the Phosphoria Formation was approved in 2002.
- Lamb – an anticline with the Cody Shale at the surface. The first well on the anticline was drilled in 1907, with a little gas found and no other drilling occurred until the Frontier Formation (locally called the Peay sand) gas discovery was made in December, 1913. The gas was piped to Basin and Greybull for domestic use. In 1923 gas was discovered in the Muddy sand member of the Thermopolis Shale. After 1940, oil was discovered in the Tensleep Sandstone (1945), Phosphoria (1947), and Madison Limestone (1950).
- Torchlight – an anticline with a tilted water table and the upper part of the Frontier Formation at the surface. The first two wells were drilled in 1905 and encountered a little gas and no other drilling occurred until the Mowry Shale (locally called the Kimball and Octh Louie sands) oil discovery was made in 1913. After 1940, oil was discovered in the Tensleep Sandstone (1947), Madison Limestone (1948), and Bighorn Dolomite (1962) with gas discovered in the

Phosphoria Formation (1947). Supplemental water injection was started in 1957 to increase oil production (Willingham and Howald, 1965).

- Grass Creek – a fault bounded asymmetric anticline with Cody Shale at the surface. Drilling of the structure reportedly started in 1913, with the first oil discovery made in June of 1914 in the sandstones of the Frontier Formation. Gas was discovered in the Muddy Sandstone in 1915 and produced for several years. Oil in the Morrison Formation was discovered in 1920 (but not produced) and in the Phosphoria (Embar) and Tensleep Sandstone in 1922. Oil in the Crow Mountain Sandstone was discovered in 1926. After 1940, oil was also discovered in the Madison Limestone and Amsden Formation (1958).
- Little Buffalo Basin – two anticlinal domes separated by a saddle with Cody Shale at the surface. It was first tested in 1913 and in November of 1914 gas was discovered in the Frontier Formation. There was no immediate market for gas at that time, so the first wells were only drilled and shut-in. During the 1920's pipelines were laid to take the gas. The field was unitized in the Frontier Formation in 1931. After 1940, oil was discovered in the Phosphoria Formation and Tensleep Sandstone (1943) and in the Amsden Formation (1985). It is a sour, viscous, asphalt-base crude oil. Gas was also discovered in the Muddy Sandstone (1959) and Cloverly Formation (1956).
- Spence Dome – a small asymmetrical anticline with the Chugwater Group at the surface. Oil was discovered in the Phosphoria Formation (Embar) in 1914. The field appears to have been noncommercial until oil was discovered in the Madison Limestone in 1944 with oil production discovered in the Amsden Formation in 1957.
- Elk Basin – a highly faulted asymmetrical anticline with Cody Shale exposed along its axis. The northern part of the field lies in Montana. The discovery well completed in October of 1915 produced oil from the Frontier Formation (locally called the Torchlight and Peay sands). In 1920 gas was discovered in the Cloverly Formation. In 1927 a gas drive was started in the Peay sands by returning to the formation the gas produced with the oil. After 1940, oil was discovered in the Phosphoria Formation and Tensleep Sandstone (1942), the Madison Limestone (1946), and the Darby Formation/Bighorn Dolomite (1961). The deeper reservoirs were unitized in 1946. In 1949, inert gas injection began in the Phosphoria-Tensleep, in conjunction with a gasoline plant and sulfur plant.
- Big Polecat – a narrow thrust anticlinal closure with numerous cross faults. Frontier Formation gas was discovered in August of 1916. The gas was initially piped to Frannie and Deaver for domestic consumption. After 1940, oil was discovered in the Tensleep Sandstone (1954).
- Warm Springs – two small elongated domes on the Warm Springs anticlinal fold. The first well in the field was drilled in 1916 and the first discovery was of heavy black oil in the Phosphoria (Embar) Formation in the summer of 1917.
- Little Grass Creek – a small circular anticline, Cody Shale at the surface. Gas was discovered in the Frontier Formation in April of 1917. After 1940, gas was discovered in the Muddy Sandstone (1944). The productive area is between 800 and 900 acres.

- Hidden Dome – a narrow, elongated symmetrical anticline with Cody Shale at the surface. Gas was discovered in the Frontier Formation in September of 1917. Gas production was sold to the towns of Greybull and Basin. The gas producing zone is not now commercially productive. In 1932 oil in the Frontier Formation was discovered on the northwest part of the structure. After 1940, oil was discovered in the Tensleep Sandstone (1947).
- Hamilton Dome – a highly faulted asymmetrical anticline, with the Thermopolis Shale covering the crest. Prior to 1918 several shallow tests failed to find production on the anticline. The field was discovered in September of 1918 when oil was encountered in the Crow Mountain Sandstone. In 1919 oil was discovered in the Phosphoria Formation (Embar). In 1929 oil was discovered in the Tensleep Sandstone. After 1940, gas was discovered in the Muddy Sandstone (1941) and oil was discovered in the Amsden Formation (1959), Madison Limestone (1948), and Bighorn Dolomite (1953).
- Kirby Creek – an anticline with Cody Shale at the surface. Oil was discovered in the Frontier Formation in October of 1918. After 1940, oil was discovered in the Phosphoria Formation (1944).
- Byron – an asymmetrical faulted anticline with the Cody Shale exposed on the crest. The field was discovered in 1918 when a gas well was completed in the Frontier Formation (Torchlight sand). In 1929 oil was discovered in the Sundance Formation and no longer produces. In 1930 oil was discovered in the Phosphoria Formation (Embar) and Tensleep Sandstone. After 1940, oil was discovered in the Amsden Formation (1956).
- Golden Eagle – a small nearly symmetrical dome with the Fort Union Formation at the surface. The field was discovered in 1918 when a gas well was completed in the Mesaverde Formation. The field was considered to be depleted by 1937 and was abandoned. After 1940, gas was discovered in the Muddy Sandstone (1944) and oil was discovered in the Cloverly Formation (1945), Phosphoria Formation (1949), and Tensleep Sandstone (1949).
- Crystal Creek – a curved asymmetrical anticline with two structural highs and the Chugwater Group at the surface. The field was discovered in 1919 when an oil well was completed in the Tensleep Sandstone. Deeper wells drilled were non-commercial.
- Red Springs – a small faulted northwest plunging asymmetrical anticline, with the Phosphoria Formation exposed on the crest. An oil seep was reported to occur in a sandstone bed of the Chugwater Group. This field was discovered in 1919 when an oil well was completed in the Madison Limestone. The initial well produced a small amount of oil until 1934 and then was abandoned. Additional Madison Limestone production was established in 1938. After 1940, oil was discovered in the Tensleep Sandstone (1974) and Bighorn Dolomite.

In the 1920s and 1930s surface mapping of geologic structures continued to be the main method for discovering fields (Bartlett and Maghee, 1925; Espach and Nichols, 1941; Hares, 1947; Pierce, 1948; Rogers et al., 1948; Summerford, 1952; Wyoming Geological Association, 1957 and 1989; and Bureau Files). The fields discovered during this period are shown on Figure 11. No fields were discovered on the east side of the basin during this period. Those fields are:

- Little Polecat – a small elliptical dome with Lance Formation exposed at the surface. Gas in the Frontier Formation was discovered in April of 1922. After 1940, oil was discovered in the Tensleep Sandstone (1956).
- Black Mountain – a narrow asymmetric anticline with Mowry Shale exposed at the surface. Oil in the Tensleep Sandstone was discovered in November of 1922. Phosphoria Formation (Embar) oil production was discovered in 1925. After 1940, oil was discovered in the Amsden Formation (1946) and Madison Limestone (1961).
- Enos Creek – a small symmetrical fold with Cody Shale exposed at the surface. Gas in the Frontier Formation was discovered in November of 1924. After 1940, oil was discovered in the Phosphoria Formation (1950), Tensleep Sandstone (1948), and in the Crow Mountain Sandstone (1984).
- Lake Creek – a long narrow asymmetric anticline with extensive faulting in the producing horizons, with the Frontier Formation at the surface in the discovery well. Oil in the Phosphoria Formation (Embar) was discovered in October of 1925. It was not fully developed until the 1950's. After 1945, oil was discovered in the Tensleep sandstone (1949).
- Sunshine South – an elliptical anticline with the Morrison Formation exposed at the surface. Oil in the Phosphoria Formation (Embar) was discovered in November of 1926. The field was abandoned in 1986.
- Frannie – an asymmetrical anticline with the Cody Shale and Frontier Formation exposed at the surface. The first well on the structure was drilled in 1914 and recovered water in the Muddy Sandstone. Oil was discovered in the Tensleep Sandstone in August of 1928 and in the Madison Limestone in September of 1929. The first year's Tensleep production was sold to a refinery in Canada, since there was not a market for the heavy hydrogen sulfide rich crude oil. The northernmost part of the field lies in Montana.
- Sunshine North – a narrow anticline with the Mowry Shale exposed at the surface. A well drilled in 1922 had shows of oil in the Phosphoria Formation (Embar), but commercial quantities were not discovered until a test of the Tensleep Sandstone was completed in June of 1928. After 1940, oil was discovered in the Phosphoria Formation (1955).
- Fourbear – an anticline, with the Mowry Shale exposed on the crest. Oil was discovered in the Tensleep in December of 1928. After 1940, oil was discovered in the Amsden Formation and Madison Limestone (1948), Phosphoria Formation (1962), and Dinwoody Formation (1973). Extensive fracturing appears to have improved productivity.
- Walker Dome – a small dome shaped anticline, with the Mesaverde Formation exposed at the surface. A well to the Frontier Formation discovered gas in 1929, although it was not completed until 1934. It remained shut-in until 1953. After 1940, oil was discovered in the Phosphoria (1953) and a deeper Frontier Formation zone (1956).
- Spring Creek South – an anticline, with the Frontier Formation exposed at the crest. A well on the southeast end of the anticline was not productive in 1915.

Oil was discovered in the Phosphoria (Embar), Tensleep, and Amsden formations in September of 1930. After 1940, oil was discovered in the Madison Limestone (1946).

- Pitchfork – a narrow anticline, with the Mowry Shale exposed on the surface. Two early tests of the structure (1925 and 1928) drilled to the Muddy Sandstone and were plugged and abandoned. Oil was discovered in the Phosphoria Formation (Embar) and Tensleep Sandstone in November of 1930. After 1940, oil was discovered in the Madison Limestone (1948) and Amsden Formation (1962).
- Badger Basin – a small anticline, with the Fort Union exposed at the surface. Oil and gas was discovered in the Frontier Formation in July of 1931. After 1940, oil was discovered in the Cloverly Formation (1952).
- Waugh Dome – a long narrow anticline, with the Cody Shale exposed at the surface. Four wells tested the structure prior to 1923, with the Frontier Formation being the deepest drilled and no hydrocarbons encountered. Oil was discovered in the Phosphoria Formation (Embar) in December of 1934.
- Gooseberry – an anticline with two structural highs and the Cody Shale exposed at the surface of the discovery well. A non productive test in 1916 penetrated the Frontier Formation and one in 1927 went to the Morrison Formation. Oil was discovered in the Phosphoria Formation (Embar) and Tensleep Sandstone in September of 1937.

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

In the 1940s surface mapping of geologic structures continued to be the main method for discovering fields (Bartlett and Maghee, 1925; Espach and Nichols, 1941; Hares, 1947; Pierce, 1948; Rogers et al., 1948; Summerford, 1952; Wyoming Geological Association, 1957 and 1989; and Bureau Files). Some field discoveries were aided by the acquisition of seismic reflection data. The first trap discovered, in the Bighorn Basin, with a stratigraphic component was the South Fork Field in 1947. The fields discovered during this period are shown on Figure 12. During this period field discoveries were concentrated on the north and south ends of the Bighorn basin, with only a few new discoveries on west flank of the basin. Those fields are:

- Gebo – an asymmetric anticline, with the Cody Shale exposed at the surface. An initial well was completed in 1916, with a show in the Frontier Formation. Two additional non productive wells were drilled before the discovery oil well was completed to the Phosphoria Formation (Embar) and Tensleep Sandstone in December of 1943. Oil was discovered in the Crow Mountain Sandstone in 1961.
- Wagonhound – an asymmetric faulted anticline, with The Cody Shale exposed at the surface. At least six early wells on the structure unsuccessfully tested the

Frontier Formation and Muddy Sandstone. Oil was discovered in the Phosphoria Formation (Embar) in March of 1944.

- Elk Basin South – a faulted anticline with the Lance Formation exposed at the surface. Surface mapping and seismic reflection data led to the discovery. Oil was discovered in the Tensleep Sandstone in June of 1944. Additional discoveries were made in the Morrison Formation (gas in 1947), the Frontier Formation (oil in 1951), and Madison (oil in 1972)
- Half Moon – an asymmetric anticline, with Frontier Formation exposed at the surface. Well tests completed in 1920, 1928, and 1930 were not successful. Oil was discovered in the Phosphoria Formation (Embar) in September of 1944. The Tensleep Sandstone was found to be oil productive in 1945.
- Zimmerman Butte – an anticline, with the Cody Shale exposed at the surface. Oil was discovered in the Phosphoria Formation (Embar) in November of 1945. Oil was discovered in the Frontier Formation in 1946 and in the Tensleep Sandstone in 1981.
- Worland – an asymmetric anticline discovered using seismic reflection data. Oil was discovered in the Phosphoria Formation (Embar) in June of 1946. Oil was discovered in the Tensleep Sandstone in 1947 and oil and gas was discovered in the Frontier Formation in 1948. At a later date, this field became part of Cottonwood Creek Field.
- Corley – a small anticline, with the Cody Shale exposed at the surface. Oil was discovered in the Phosphoria Formation in 1946 and the field was abandoned in 1949.
- Neiber Dome – a faulted anticline, with the Fort Union Formation exposed at the surface. Surface mapping and latter on, seismic reflection data lead to the discovery. The first well test occurred in 1915 and at least six tests followed, with no success. Oil was discovered in the Phosphoria in February of 1947 and in the Tensleep in 1954.
- South Fork – a stratigraphic and structural trap (see Glossary for both terms), with Tertiary sediments at the surface. Seismic reflection data was used to discover the field. Oil was discovered in the Phosphoria Formation in April of 1947.
- Sand Creek – an anticline with a stratigraphic permeability limit that was discovered using seismic reflection data. Oil was discovered in the Frontier Formation in September of 1947. The field was abandoned in 1984 with 21 percent of the original oil-in-place (see Glossary for in-place) recovered.
- Shoshone South – a faulted anticline, with the Cloverly Formation exposed at the surface. Oil was discovered in the Phosphoria Formation in December of 1948 and the field was abandoned soon after.
- Frank's Fork – a small monoclinal trap with closure, discovered using surface geology. Oil was discovered in the Dinwoody and Phosphoria formations in March of 1948. The field was abandoned in 1982.
- Silver Tip – a faulted anticline, with the Fort Union Formation at the surface. Seismic reflection data was used to make the field discovery. Oil, with hydrogen sulfide gas was discovered in the Phosphoria Formation in May of 1948. Oil in the Frontier Formation was discovered soon after. Oil was discovered in the

Tensleep in 1949 and in the Madison Limestone in 1961. Gas was discovered in the Lance Formation in 1965 and in the Mesaverde Formation in 1977.

- Sage Creek – a faulted anticline with stratigraphic variations. Testing of this anticline began as early as 1914 and at least eight unsuccessful wells were drilled before discovery. Surface mapping and latter on, seismic reflection data led to the discovery. Oil was discovered in the Madison Limestone in June of 1948 and in the Tensleep Sandstone in 1952.
- Heart Mountain – a fault bounded asymmetrical anticline, with Mesaverde Formation and Cody Shale exposed at the surface. A well drilled between 1918 and 1920 was a dry hole. Gas was discovered in the Frontier Formation in September of 1948. Gas in the Cloverly Formation was discovered in 1956.
- Wildhorse Butte – an anticline, with the Chugwater Group exposed at the surface. A well drilled in 1919 had a show of oil in the Phosphoria Formation, but the well was not completed as productive. The well was re-entered and completed as an oil discovery in the Phosphoria Formation in September of 1948. The field was abandoned in 1994.
- North Danker – a fault bounded asymmetrical anticline, with surface mapping leading to discovery. Gas was discovered in the Frontier Formation in December of 1948. Oil was discovered in the Phosphoria Formation and Tensleep Sandstone in 1961.
- Little Sand Draw – a small asymmetric anticline, with the Cody Shale exposed at the surface. One dry hole was completed in 1928. Oil was then discovered in the Tensleep Sandstone in February of 1949 and soon after in the Phosphoria Formation.
- South Frisby – an anticline discovered using seismic reflection data. Oil was discovered in the Phosphoria Formation in July of 1949. At a later date, this field became part of Cottonwood Creek Field.
- Murphy Dome – an anticline, with the Cody Shale exposed at the surface. Ten wells were completed on the anticline between 1916 and 1945. Two of these tests (one in 1919 and one in 1927) reported gas from the Frontier Formation, but as no market was available, neither appears to have been hooked up for production. Oil was discovered in the Tensleep Sandstone in October of 1949 and in the Crow Mountain Sandstone in 1961.

During the first 43 years of exploration in the Planning Area (1906 through 1939) 54 fields were discovered. During the 1950s an additional 29 fields were added, with most discovered using seismic reflections techniques. Surface mapping was still useful in aiding the discovery of additional fields. Subsurface geologic mapping began to be used during this period, with five fields discovered that used this method at least to partly help in making the discovery.

Discovery rates of fields with more than one producing well declined sharply between 1960 and the present. Those field discovery rates were:

- 1960s – 13 fields,
- 1970s – 12 fields,
- 1980s – 9 fields, and

- 1990s – 2 fields.

Field discoveries with only one productive well became more common from 1960 to the present. One-well field discovery rates were:

- 1960s – 3 fields,
- 1970s – 10 fields,
- 1980s – 10 fields, and
- 1990s – 2 fields.

Fields discovered between the 1950s and the present are shown on Figure 13.

Subsurface stratigraphic mapping has been little used in the Planning Area because most fields in the Bighorn Basin are structurally trapped. Stratigraphic variations rarely contribute to trap limits within the basin. The major exception to this generality is the Cottonwood Creek Field, where the Phosphoria Formation trap is controlled by stratigraphy and has the largest areal extent of all fields within the Bighorn Basin.

The Bighorn Basin has always been remote from major industrial markets, which has been an adverse factor in its development. Oil pipelines began to be built within the Bighorn Basin in 1916. No oil pipelines were built out of the basin until 1944 when an eight inch line was built from Elk Basin Field to Billings (Hares, 1947). A twelve inch line was also built to Casper in that year, which also connected it to Eastern markets. Prior to that, shipments outside the basin had been by tank car or truck. Gas production was of little interest outside the Bighorn Basin in the earliest period of activity. The Greybull Field gas was used as early at 1907 to heat local homes. This gas was also burned at the Greybull refinery beginning in 1916 (Hares, 1947).

Producing Zones

There are 137 named fields (Figure 5) and one unnamed field located within the Planning Area (DeBruin, 2006). Oil and gas occurs in the Planning Area in numerous geologic formations, and members of formations which range in age from the oldest producing formation, the Flathead Sandstone of Cambrian age, upward in time to the Fort Union 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 Group (2009). In some wells, more than one zone produces. Those variations are presented in Table 2. Total wells (8,845 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 to 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 never produced before being plugged and abandoned at a later date.

Cumulative production (through 2008) within the Planning Area has been more than two trillion cubic feet of gas and almost 2.87 billion barrels of oil (Table 2). The most prolific oil productive formations have been the Phosphoria Formation and Tensleep Sandstone. The Madison has produced the third largest quantity of oil. A significant amount of gas production has also been associated with the Phosphoria Formation and

Tensleep Sandstone, and also with the Frontier Formation. The Phosphoria Formation is productive in about 42 percent of the active wells within the Planning Area and the Tensleep Sandstone is productive in about 37 percent, while the Madison Limestone and Frontier Formation are each productive in about 10 percent. Other formations have contributed smaller amounts of oil and gas from fewer wells than the four best producing formations.

Source rocks for hydrocarbons occurring within the Planning Area (Roberts et al., 2008) are:

1. Oil was sourced from the Permian aged Phosphoria Formation to the west in the Idaho-Wyoming thrust belt. It then migrated into reservoirs older than the Cretaceous in the basin. There is potential for some of this oil to have cracked to gas.
2. Oil was sourced from the Cretaceous aged Thermopolis and Mowry shales and trapped in some of the Cretaceous aged reservoirs in the basin.
3. Gas was sourced from the Cretaceous aged Thermopolis and Mowry shales; from the Cretaceous aged Frontier, Cody, Mesaverde, and Meeteetse formations; and the Tertiary aged Fort Union Formation. The generated gas was then trapped in some of the Cretaceous and younger aged reservoirs.

Technology Development

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

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

Unconventional gas has become a significant potential component of future production within the Planning Area if reserves can be established in the central part of the Bighorn Basin. 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. Costs have leveled out and in some cases decreased in recent months, due to decreases in oil and gas demand and in price. We do not expect costs to increase significantly in the near future. Once oil and gas demand and prices begin to increase again, then costs will also begin to rise.

The National Petroleum Council (1999) suggested that access restrictions can add 25 thousand dollars to the average cost of drilling a well in the Rocky Mountains. They also suggested that access restrictions can delay drilling activity by an average of two years. Access restrictions on Bureau managed lands in the Planning Area have been rare in recent years.

Drilling and Completion Activity

There have been 9,928 surface well locations spudded or completed in the Planning Area through March 3, 2009 (Wyoming Oil and Gas Conservation Commission, 2009). Of the 9,928 wells spud or drilled in the Planning Area, 6,133 wells, or 61.8 percent, appear to have been on Bureau managed oil and gas lands. There are 25 wells (0.25 percent) that appear to have been drilled on Forest Service managed lands. An additional 3,770 wells (38 percent) appear to have been drilled on private and state owned oil and gas mineral ownership.

Figure 14 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, 2009) as of March 2, 2009. Of these wells, their present well class and status is:

- Gas – Spudded 6 wells
- Gas – Producing 354 wells
- Gas – Flowing 13 wells
- Gas – Dormant 4 wells
- Gas – Shut-In 30 wells
- Gas – Temporarily Abandoned 9 wells
- Gas – Notice of Intent to Abandon 10 wells
- Oil – Spud 12 wells
- Oil – Drilled 6 wells
- Oil – Producing 2,421 wells
- Oil – Flowing 2 wells
- Oil – Pumping 85 wells
- Oil – Dormant 39 wells
- Oil – Shut-In 140 wells
- Oil – Temporarily Abandoned 285 wells
- Oil – Notice of Intent to Abandon 43 wells.

A total of 18 wells have been spud and not completed. Of the 3,441 completed wells, 420 wells (12.2 percent) are classed as gas wells, and 3,021 wells (87.8 percent) are classed as oil wells.

Figure 15 presents the locations of all wells that are being used for enhanced oil recovery purposes and for disposal, monitoring, and source wells (Wyoming Oil and Gas Conservation Commission, 2009) as of March 2, 2009. Of these 1,044 wells, their present well class and status is:

- Injector – Active Injector 811 wells
- Oil – Active Injector 9 wells
- Injector – Dormant 7 wells
- Injector – Drilled 2 wells
- Injector – Shut-In 43 wells
- Injector – Temporarily Abandoned 69 wells
- Injector – Notice of Intent to Abandon 5 wells
- Disposal – Active Injector 39 wells
- Disposal – Shut-In 6 wells
- Disposal – Temporarily Abandoned 1 well
- Monitor – Active Monitor 24 wells
- Monitor – Shut-In 5 wells
- Monitor – Temporarily Abandoned 8 wells
- Monitor – Notice of Intent to Abandon 1 well
- Source – Active Injector 1 well

- Source – Water Source	6 wells
- Source – Shut-In	3 wells
- Water Source – Temporarily Abandoned	4 wells.

The 4,503 active wells (as of March 2, 2009) that are shown in Figures 14 and 15 account for about 45.4 percent of all the 9,928 wells spudded or completed within the Planning Area. The above information shows that of the active wells in the Planning Area, 18 wells (0.4 percent) have been spud but not completed, 3,441 wells (76.4 percent) are oil and gas well types, 947 wells (21 percent) are being used as injectors for enhanced oil recovery type projects, 46 (1 percent) are being used for oil and gas related disposal purposes, 38 (0.8 percent) are being used for oil and gas related monitoring purposes, and 13 (0.3 percent) are being used for oil and gas related source purposes.

About 54.6 percent (5,425 wells) of the 9,928 spudded and completed 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 16. Starting in 1940, the graph shows an overall increase in well spuds thru 1953 when spuds reached their peak. Overall, spuds then declined through 1964. Spuds then showed a small overall increase between 1964 and 1984. Since 1984 spuds have mostly been at a rate of less than 100 per year. Spuds reached a low of 50 in 2003.

A map of the Planning Area shows locations of all wells spud to February 17, 2009 (Figure 2). This map shows that drilling has been spread out across the Planning Area. The largest drilling concentrations have been around the basin margins, where anticlinal traps are the most common. See Figure 4 for the locations of the most prominent anticlinal structures. The center of the basin has historically received little drilling activity, although there are now proposals to begin testing some of these areas. The Bighorn Mountains, Absaroka Volcanic, and Beartooth Mountains (Figure 4) have seen little or no drilling activity. Only 25 wells have been drilled on Forest Service managed lands (Figure 2).

Drilling Rigs and Rig Counts

The Land Rig Newsletter (2008) reported that in 2007, onshore areas of the U.S. achieved more than 68 million feet of hole drilled: a record year. Drilling footage in the Rocky Mountains alone was close to 15.5 million feet. They also reported that while conventional vertical footage dropped, non-vertical footage increased, with directional and horizontal footage both exceeding 11.5 million feet. Since then drilling activity and footage drilled has declined in the U.S. and in the Rocky Mountains. This has been due primarily to reduced demand and price for oil and gas. Within the Planning Area, the last active rig was used to drill a Roctober Unit well (see Figure 8 for unit location) between the weeks of December 19, 2008 to January 8, 2009. Since then no drilling rigs have been reported to be active within the Planning Area (Rocky Mountain Oil Journal, 2009).

Figure 17 presents footage drilled within the Planning Area on a yearly basis and cumulatively. Rates were at their lowest, at less than 200,000 feet drilled per year, between 1920 and 1941. Overall footage rates increased from 1942 through 1981 and peaked at more than 1.4 million in 1980. From 1982 to the present, overall footage rates (with one large spike in 1997) have dropped significantly. The most recent minor spike in footage drilled (2005) appears to be tied to a large number of horizontal boreholes drilled that year.

Production

Data from IHS Energy Group (2009) was used to compile historic cumulative production by field and by reservoir. Table 3 lists the fields in the Planning Area and itemizes the number of producing zones, hydrocarbon production through 2008, and well activity (wells actively producing and wells with historical production but not producing). There are eight major producing oil fields in the Planning Area (by volume), with production of 130 to 590 million barrels of cumulative oil production. In descending order, they are Oregon Basin, Elk Basin, Hamilton Dome, Grass Creek, Garland, Little Buffalo Basin, Frannie, and Byron (Figure 5). There are six major producing gas fields in the Planning Area (by volume), with production of 151 to more than 408 billion cubic feet of cumulative gas production. In descending order, they are Worland, Elk Basin, Oregon Basin, Hamilton Dome, Garland, and Little Buffalo Basin (Figure 11). At the close of 2008, there were 4,301 actively producing oil and gas wells and a cumulative production of 2,869,788,177 barrels of oil and 2,168,185,301,000 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 2008, and the respective well activity (wells actively producing and wells with historical production but not producing). The Phosphoria Formation (1855 wells) and Tensleep Sandstone (1,593 wells) have by far the largest numbers of active producing wells and are followed by the Frontier Formation (444 wells) and Madison Limestone (455 wells). Other zones produce from only a limited number of active wells (fewer than 100 wells productive from any formation).

Yearly (Figure 18) and cumulative (Figure 19) graphs of oil and gas production illustrate historical volume rates and cumulative volumes of oil and gas as a function of time from 1974 through 2008 (IHS Energy Group, 2009). Figure 18 illustrates the historical annual rate change in the production of hydrocarbons within the Planning Area. The rate of oil production has declined steadily from its high in 1978, with only a few short periods when production flattened. The rate of gas production declined from 1974 to 1983 and essentially flattened until 1989. The overall rate then increased until 1998 and has since declined. In 2008, oil production was at its lowest rate for the 1974 through 2008 period and gas production was near its lowest rate.

The change and trend in the annual oil production curve (Figure 18) is mainly due to the lack of newly discovered traps and reservoirs in the 1974 through 2008 period. More than 80 percent of all fields in the Planning Area were discovered before 1974. As previously discussed, only 10 new fields were discovered in the 1980s and 1990s and none have been discovered in this century. Market forces have had only a minor impact on production in the Planning Area. Production of oil, in association with the development of enhanced oil recovery projects at older oil fields, has only slowed the annual decline in oil production.

The minor increases in annual gas production from 1983 through 1998 appear to have been due to additional in-fill drilling in already discovered fields such as Oregon Basin, Manderson, Five Mile, and Meeteetse.

Starting in 1979, cumulative oil production increased, but at a constantly decreasing rate and the decrease has slowed in recent years (Figure 18). Gas however, has increased at a fairly steady rate between 1974 and present, with a decrease in the rate during the 1980s.

An historical 5-year epoch oil production graph (Figure 20) shows that oil wells completed from 1910 through 1974 still account for more than 43 percent of present production. The 1975 through 1984 period produces about 20 percent, 1985 through 1994 produces about 11 percent, 1995 through 2004 produces about 14 percent, and the most recent period (2005 through 2008) produces about 12 percent.

An historical 5-year epoch gas production graph (Figure 21) shows that oil wells completed from 1910 through 1974 still account for more about 35 percent of present production. The 1975 through 1994 period produces about 19 percent, 1995 through 1999 produces about 9 percent, 2000 through 2004 produces about 20 percent, and the most recent period (2005 through 2008) produces about 17 percent.

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 22. Water volumes produced were highest between 1981 and 1985 and in the last two years. Increases in water production in recent years appear to be at least partly tied to increased waterflooding activity during that time. Cumulative water produced through 2008 was more than 27,500,000,000 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 23. The highest yearly injection rates have occurred since 1997. Locations of injection and disposal wells are shown on Figure 15. Cumulative water injected through 2008 was more than 15,000,000,000 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.

In 2007, Oregon Basin Field (Figure 10) was ranked 92nd in the U.S. by liquids production (Energy Information Administration, 2009a).

Coalbed Natural Gas Activity

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 borehole, and
- artificial lift techniques and software are promoting rapid and efficient dewatering.

According to the Wyoming Geological Survey (2009) the Bighorn Basin contains the third largest coal field in the state of Wyoming. In the Wyoming portion of the Bighorn Basin, the coal field occurs in outcrop and at minable depths around the margins of the basin (Figure 24). These Tertiary Fort Union Formation coals, as well as the deeper (unminable) Cretaceous Meeteetse-Mesaverde Formation coals, are broadly classified as bituminous to sub-bituminous and are estimated to contain 116 billion cubic feet of coalbed natural gas as undiscovered resources (Roberts and Rossi, 1999 and U.S. Geological Survey, 2008a). The extents of these potential coalbed natural gas bearing zones are shown in Figure 25.

Only 14 coalbed natural gas wells have been drilled within the Planning Area, 13 of which have subsequently been plugged, with the remaining well being currently shut-in (IHS Energy Group, 2009) (Figure 24). Thirteen of the wells were completed in 2005 by Big Horn Basin Development, Incorporated at depths averaging 1,500 feet (IHS Energy Group, 2009). They are called North Danker Coal by the operator (Wyoming Oil and Gas Conservation Commission, 2009). The 13 wells were completed as two test pods of eight and five wells separated on the surface by approximately one mile. Only four wells of the pod of eight wells in township 57 north, range 98 west have production data indicating a test of the viability of the play. Three of the four wells show one month of water production, but not in sufficient quantities to indicate a concerted effort at dewatering. The remaining well in the pod produced 4,985 barrels of water from February through May, 2006 with no gas production reported. These wells were all abandoned in early 2008 (Wyoming Oil and Gas Conservation Commission, 2009).

The other coalbed natural gas well in the Planning Area is located in township 50 north, range 92 west. Drilled by Loemwal, Incorporated in 1991 on fee mineral ownership, this well reached a total depth of 38 feet in Fort Union Formation coal. It was drilled on a coal mine near the town of Manderson. According to Wyoming Oil and Gas Conservation Commission records, casing with perforations was placed, but no production data has been submitted. The well's status as of this writing is shut-in.

Oil Mining Activity

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

Oil Mining is a form of enhanced oil recovery whereby a mine is tunneled beneath the reservoir and a series of wells are drilled upward into the producing formation and gravity drainage is used to extract the oil (Rock Well Petroleum, 2009). Due in part to the limitations on depths at which underground mining techniques are economic to pursue, only a limited number of mature oil fields will be viable candidates for this technique. One such field, the Greybull Field, is located just west of the town of Greybull (Figure 10).

The Greybull oil mining project, operated by Rock Well Petroleum, is an active oil mining project on fee mineral lands. The project includes an inclined access tunnel mined several hundred feet deep underneath a Peay Sandstone oil reservoir (locally named sandstone within the Frontier Formation), initially discovered in 1955. Initial field development ceased in the late 1980s, and production steadily declined until Rock Well Petroleum began the oil mining project in 2005. The Greybull Field produced 1,703 barrels of oil in 2005, and by 2007 was producing over 34,000 barrels annually almost exclusively (97.5 percent) from the five boreholes drilled up to the Peay Sandstone from the central mining tunnel and then extended horizontally (IHS Energy Group, 2009). The remaining oil production is from marginal (traditional) oil wells still producing from original development efforts.

Rock Well Petroleum has similar projects around the country, including two more in Wyoming (Jones Draw and Poison Spider projects), but none within the Planning Area. The viability of future oil mining projects in the Planning Area is unknown. Rock Well states that, "Target fields are generally large, shallow, depressurized oil fields that are often in 'stripper production,' which is generally described as wells producing less than 10 [barrels of oil per day] (Rock Well Petroleum, 2009)." The most likely future candidate in the Planning Area, Spence Dome Field, while shallow, still has relatively stable production. Any other field candidates would necessarily be around the margins of the basin where production is from more shallow reservoirs. However, Rock Well Petroleum recently scaled back their operations in Wyoming and elsewhere in late 2008. Currently, the Greybull project is in the production phase and no plans for further expansion or future projects are known.

Marginal Wells

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

Producing oil or natural gas wells are considered to be “marginal” when their producing rate is at the limit of profitability. The Interstate Oil and Gas Compact Commission (2008) defines marginal or stripper wells as wells that are producing 10 or fewer barrels of oil per day and no more than 60,000 cubic feet per day of natural gas.

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

In 2007 Wyoming ranked 11th of the 29 major producing states in the number of marginal oil wells (Interstate Oil and Gas Compact Commission, 2008). In that year there were 12,572 marginal oil wells that produced 8,263,340 barrels of oil in the state, and marginal well production amounted to approximately 15.3 percent of total Wyoming crude oil production (Interstate Oil and Gas Compact Commission, 2008). Many of the oil wells in the oldest fields shown on Figures 10, 11, and 12 now qualify as marginal oil wells. From 2004 to 2007 the number of marginal oil wells in Wyoming increased by 229 wells to 12,572 wells.

In 2007, Wyoming ranked 5th of the 28 major producing states in the number of marginal gas wells (Interstate Oil and Gas Compact Commission, 2008). According to the Interstate Oil and Gas Compact Commission, in 2007 there were 29,614 marginal gas wells that produced 103.9 billion cubic feet of gas which amounted to about 5.4 percent of total Wyoming gas production (Interstate Oil and Gas Compact Commission, 2008). The Planning Area contains only a small portion of the marginal gas wells in Wyoming. Most gas wells in the Planning Area are older and more likely to be marginal gas producers. From 2004 to 2007 the number of marginal gas wells in Wyoming increased by 9,944 wells to 29,614 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 March 2, 2009 the Wyoming Oil and Gas Conservation Commission (2009) indicated that there had been 19 wells drilled to depths of more than 15,000 feet in the Planning Area and they are located near the Bighorn basin axis in a northwest-southwest trend (Figure 26). Well class and present status of these wells is:

- Gas– Producing Gas or Shut-in 4 wells
- Gas – Permanently Abandoned 1 well
- Oil – Producing Oil or Shut-in 1 well
- Oil – Permanently Abandoned 13 wells.

Only five wells continue to be active and the remaining wells 14 wells have been abandoned. Two of the still active gas wells lie in the recently formed Rocktober Unit (see Figure 8 for unit location). The other two lie in Seller Draw and Heart Mountain fields, while the only active oil well lies in the South Fork Field. Twelve of these wells (including the two Rocktober Unit wells) were drilled as wildcat wells and the other seven were drilled within named fields.

The deepest well drilled was the Loch Katrine Unit #1 in section 2 of township 51 north, range 100 west. It bottomed in Devonian aged sediments. The deepest producing zone is in the Sellers Draw Unit II #1 drilled in section 21 of township 48 north, range 98 west. This is a one well gas field completed in 1997. The Bill Barrett Corporation well was initially drilled to 23,081 feet, and the deepest producing zone in this well is from 16,095 – 16,154 feet in the Cretaceous Mesaverde Formation (IHS Energy Group, 2009; Wyoming Oil and Gas Conservation Commission, 2009).

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

There have been 550 known wells in the Planning Area that have drilled to the 10,000- to 15,000-foot depth range as of March 2, 2009 (Wyoming Oil and Gas Conservation Commission, 2009). As Figure 26 shows, most wells in this depth range are located on the northeast side of the Bighorn Basin, and are most concentrated on its southeastern part. Well class and present status of these wells is:

- Disposal – Active Injector or Shut-in 5 wells
- Disposal – Permanently Abandoned 3 wells
- Injector – Active Injector 2 wells
- Injector – Permanently Abandoned 2 wells
- Gas– Producing Gas, Flowing, or Shut-in 55 wells
- Gas– Producing Oil 1 well
- Gas - Temporarily Abandoned or Dormant 4 wells
- Gas – Notice of Intent to Abandon 3 wells

- Gas – Permanently Abandoned 24 wells
- Oil – Producing Oil or Shut-in 150 wells
- Oil – Notice of Intent to Abandon 15 wells
- Oil – Producing Gas 3 wells
- Oil – Temporarily Abandoned 11 wells
- Oil – Permanently Abandoned 267 wells
- Unknown – Permanently Abandoned 4 wells
- Water Supply – Temporarily Abandoned 1 well.

Forty-five percent of these well locations (250 wells) continue to be active and the remaining wells (300 wells) have been abandoned or a subsequent report of abandonment has been filed. The majority of the still active wells in this depth range (79 percent) lie in:

- Frisby South Field 38 wells
- Cottonwood Creek Field 34 wells
- Rattlesnake Field 31 wells
- Worland Field 28 wells
- Slick Creek Field 25 wells
- Five Mile Field 21 wells
- Nowater Field 20 wells.

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

There have been 2,280 known wells in the Planning Area that have drilled to the 5,000- to 9,999-foot depth range (Wyoming Oil and Gas Conservation Commission, 2009). As Figure 26 shows, wells in this depth range are located around the Bighorn Basin synclinal limbs, with more wells located on the northeast and southeast limbs of the syncline. Few wells in this depth range are drilled along the Bighorn Basin axis or on the east and west sides of the Planning Area. Well class and present status of these wells is:

- Disposal – Active Injector or Shut-in 13 wells
- Disposal – Permanently Abandoned 3 wells
- Injector – Active Injector or Shut-in 208 wells
- Injector – Temporarily Abandoned or Dormant 32 wells
- Injector – Oil Producer 1 well
- Injector – Notice of Intent to Abandon 2 wells
- Injector – Permanently Abandoned 65 wells
- Gas– Producing Gas, Flowing, or Shut-in 108 wells
- Gas– Producing Oil 13 wells
- Gas - Temporarily Abandoned or Dormant 5 wells
- Gas – Notice of Intent to Abandon 2 wells
- Gas – Permanently Abandoned 47 wells
- Oil – Producing Oil, Flowing, or Shut-in 679 wells
- Oil – Dormant or Notice of Intent to Abandon 16 wells
- Oil – Producing Gas 33 wells
- Oil – Active Injector 2 wells

- Oil – Temporarily Abandoned 92 wells
- Oil – Drilled but not completed 1 well
- Oil – Permanently Abandoned 937 wells
- Monitor – Active 6 wells
- Monitor – Temporarily Abandoned 1 well
- Monitor – Notice of Intent to Abandon 1 well
- Unknown – Permanently Abandoned 3 wells
- Stratigraphic Test – Permanently Abandoned 1 well
- Source – Active Injector 1 well
- Source – Water Source 3 wells
- Source – Permanently Abandoned 5 wells.

About 53.5 percent of these well locations (1,219 wells) continue to be active and the remaining wells (1,061 wells) have been abandoned or a subsequent report of abandonment has been filed. The majority of the still active wells in this depth range (71.5 percent) lie in:

- Elk Basin Field 238 wells
- Cottonwood Creek Field 232 wells
- Byron Field 114 wells
- Little Buffalo Basin Field 109 wells
- Gebo Field 62 wells
- Silver Tip Field 60 wells
- Manderson Field 59 wells.

Shallowest Well Drilling: Less than 5,000 feet

The greatest number of wells drilled (6,883) in the Planning Area have been to less than 5,000 feet (Wyoming Oil and Gas Conservation Commission, 2009). As Figure 26 shows, wells in this depth range are spread out across all flanks of the Bighorn Basin, with few drilled near the axis of the basin or on the easternmost and westernmost side of the Planning Area. Well class and present status of these wells is:

- Disposal – Active Injector 23 wells
- Disposal – Oil Producer 1 well
- Disposal – Shut-in 3 wells
- Disposal – Temporarily Abandoned 1 well
- Disposal – Permanently Abandoned 12 wells
- Injector – Active Injector or Shut-in 639 wells
- Injector – Oil Producer 4 wells
- Injector – Drilled 1 well
- Injector – Dormant or Temporarily Abandoned 44 wells
- Injector – Notice of Intent to Abandon 3 wells
- Injector – Permanently Abandoned 221 wells
- Monitor – Active Monitor or Shut-in 23 wells
- Monitor – Temporarily Abandoned 7 wells
- Monitor – Permanently Abandoned 6 wells

- Gas – Producing Gas, Flowing, or Shut-in 127 wells
- Gas – Producing Oil 1 well
- Gas – Drilled 1 well
- Gas – Dormant or Temporarily Abandoned 4 wells
- Gas – Notice of Intent to Abandon 6 wells
- Gas – Permanently Abandoned 140 wells
- Oil – Producing Oil, Flowing, or Shut-in 1,762 wells
- Oil – Drilled 9 wells
- Oil – Dormant or Temporarily Abandoned 211 wells
- Oil – Active Injector 7 wells
- Oil – Producing Gas 71 wells
- Oil – Notice of Intent to Abandon 20 wells
- Oil – Permanently Abandoned 3,446 wells
- Stratigraphic Test – Dormant or Temp. Aban. 4 wells
- Stratigraphic Test – Drilled 1 well
- Stratigraphic Test - Permanently Abandoned 22 wells
- Source – Water Source or Shut-in 6 wells
- Source – Temporarily Abandoned 3 wells
- Source – Permanently Abandoned 15 wells.

Only about 43.3 percent of these well locations (2,982 wells) continue to be active and the remaining 3,901 wells have been abandoned or a subsequent report of abandonment has been filed. The majority of the still active wells in this depth range (74 percent) lie in:

- Oregon Basin Field 597 wells
- Grass Creek Field 351 wells
- Garland Field 327 wells
- Hamilton Dome Field 307 wells
- Little Buffalo Basin Field 149 wells
- Elk Basin Field 104 wells
- Pitchfork Field 100 wells
- Warm Springs Field 96 wells
- Spring Creek South Field 90 wells
- Frannie Field 85 wells.

Summary of Current Drilling Techniques

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

Directional and Horizontal Drilling and Completion Activity

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

Drilling and completion costs for directional and horizontal wells are typically significantly higher than for conventional vertical boreholes, even when the cost savings associated with reduced need for surface disturbance is taken into account. Eustes (2003) and Fritz et al., (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 almost 10,000 wells drilled in the Planning Area (IHS Energy Group, 2009), only 507 boreholes were drilled directionally and 106 were drilled horizontally (IHS Energy Group, 2009). The vertical wells producing in the Planning Area are completed in a variety of formations for both gas and oil. Vertical well depths range from a number of dry holes drilled only a few tens of feet deep, to over 23,000 feet.

Figures 27 and 28 show the locations of directional and horizontal boreholes drilled within the Planning Area through February 17, 2009 (IHS Energy Group, 2009). Of the 507 directional boreholes, 22 are either service or injection wells. Of the remaining directional oil and gas boreholes, directional boreholes that have been spud and not completed and all boreholes still capable of producing oil and gas as of February 17, 2009 account for 455 of the 487 directional boreholes, providing a 93 percent success rate. About 93 percent of these successful boreholes are oil, and 7 percent are gas. Only 32 directional boreholes drilled in the Planning Area were dry holes or junked and abandoned.

The earliest known directional borehole drilled in the Planning Area is the Howell Petroleum, Unit #172 well in the Elk Basin Field completed in 1959 (IHS Energy Group, 2009). This oil well was a successful completion in the Tensleep Formation, and is currently in use as an injection well. The most recent productive directional borehole drilled was the Encore Operating, LLC Gooseberry B #32-22 well at Gooseberry Field, spud September 16, 2008 and currently producing oil and gas from the Mowry Shale.

Directional wells have been drilled in various fields along the basin margin; however, the following five fields contain the majority of the directional wells drilled in the Planning Area:

- Cottonwood Creek (79 boreholes),
- Oregon Basin (65 boreholes),
- Spring Creek South (45 boreholes),
- Garland (43 boreholes), and
- Elk Basin (39 boreholes).

Directional wells at Cottonwood Creek Field have predominantly been completed in the Phosphoria Formation, at Oregon Basin and Spring Creek fields in the Tensleep Formation, at Garland Field in the Madison, and at Elk Basin Field completions have been in the Frontier Formation.

Two operators have drilled the majority of the directional boreholes in the Planning Area: Marathon Oil Company has drilled 213 boreholes, and Bass Petroleum has drilled 79 boreholes representing together over 57 percent of all directional oil and gas boreholes.

Horizontal boreholes have been used with less frequency in the Planning Area, with only 106 drilled as of February, 2009 (Figure 28). Only one of the 106 boreholes (at Oregon Basin Field) was drilled and abandoned. Of the 105 active boreholes; 101 were drilled for oil, one for gas, and three as injectors (IHS Energy Group, 2009). The majority of these have produced from the following formations:

- Tensleep Sandstone – 42 boreholes,
- Phosphoria Formation – 37 boreholes,
- Madison Formation – 156 boreholes.

The earliest known horizontal borehole, the Conoco May #4 well in Sunshine North Field, was completed in 1987 (IHS Energy Group, 2008). This oil well was a successful completion in the Phosphoria Formation. The most recent productive horizontal borehole drilled was the Saga Petroleum, LLC Ainsworth #13-35 well at Manderson Field, spud August 9, 2008 and currently producing oil and gas from the Mowry Shale.

While several fields contain horizontal boreholes, the majority (61) have been drilled in the Oregon Basin Field (Figure 28). Pitchfork and Cottonwood Creek fields are the only other fields with five or more horizontal boreholes.

Fourteen different companies drilled the 106 horizontal boreholes, with Marathon Oil Company drilling the majority (76 boreholes) (IHS Energy Group, 2009). The only other companies that have drilled multiple horizontal boreholes in the Planning Area are Continental Resources, Inc. (13 boreholes), Howell Petroleum Corporation (3 wellbores), Phoenix Production Company (3 boreholes), and Texaco Exploration and Production, Inc (2 boreholes). The nine other operators only drilled one horizontal borehole 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). This drilling method has not yet been reported to be used in the Planning Area.

Slimhole Drilling and Coiled Tubing

Slimhole drilling—a technique used to tap into reserves in mature fields—has not yet been used much in the Rocky Mountain Area. At Madden Field, south of the Planning Area, 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. Almost 7,000 wells in the Planning Area have been drilled to depths less than 5,000 feet (Figure 26). Future wells drilled in this depth range would be amenable to coiled tubing rigs. A review of coiled tubing drilling and intervention (well work during the life of a well) and its advantages, disadvantages, and limitations was presented for the U.S. Department of Energy (2005). Most likely, future applications may be for drilling shallow development wells (including coalbed natural gas wells), reservoir data monitoring holes, shallow re-entry wells, and deeper exploration holes (Spears & Associates, Inc., 2003). Brown (2006) has reported that slimhole drilling with coiled tubing may soon begin to replace conventional rotary drilling in the shallow depths across the United States. He reported that cost savings can range from 25 to 35 percent per hole, and other advantages include:

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

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

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

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 in the Planning Area is not likely in the near future. Other Rocky Mountain plays (western Wyoming, western Colorado, and North Dakota) have a higher priority for new rigs since more prolific reservoirs are being developed in those locations than reservoirs are capable of within the Planning Area.

Light modular rigs also have potential for use in situations where pad drilling is being used. Pad drilling refers to the drilling of multiple directional boreholes from one surface location. Pads are the flat graded land surfaces that serve as the foundation for the drilling rig. Since modular rigs allow quicker breakdown and movement to new locations, they reduce time to drill and rig costs. 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 could occur in the future.

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). Additional improvements have continued to be made to enable faster drilling. Environmental benefits of improved bits include:

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

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

Summary of Current Completion Techniques

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

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

Drilling and Completion Costs

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

The National Petroleum Council (2003) reported drilling and completion costs for vertical wells in the 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 249 thousand dollars,
- 5,000 to 10,000 feet 578 thousand dollars,
- 10,000 to 15,000 feet 1.390 million dollars, and
- 15,000 to 20,000 feet 5.412 million dollars.

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

- 0 to 5,000 feet 273 thousand dollars,
- 5,000 to 10,000 feet 513 thousand dollars,
- 10,000 to 15,000 feet 1.314 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 145 thousand dollars,
- 5,000 to 10,000 feet 338 thousand dollars,
- 10,000 to 15,000 feet 1.196 million dollars, and
- 15,000 to 20,000 feet 3.392 million dollars.

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

SUMMARY OF 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 nine to 15 dollars per barrel of oil equivalent in the 1980's to an average of about five to nine dollars per barrel of oil equivalent in 1999.

Operating costs in the U.S. have been rising in recent years. Rocky Mountain operating costs rose to about 55,000 dollars per 12,000 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.

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

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

The search for oil and gas in the Planning Area has been successful in finding some additional oil and gas production (Figure 7) in the past 10 years. Gas production additions have predominantly been in and around existing fields or near existing fields. Fields with the most new productive gas bore holes (including well re-entries) have been:

- Silver Tip 38 wells
- Oregon Basin 14 wells
- Five Mile 8 wells
- Elk Basin 8 wells
- Terry 6 wells
- Worland 6 wells.

Of the 101 new gas boreholes drilled, only nine were completed as wildcats (eight as outpost extensions and one as a deeper pool discovery). The rest were completed as development wells.

Oil production additions have been almost entirely from development within existing fields (Figure 7). Fields with the most new productive oil boreholes (including well re-entries) have been:

- Elk Basin 53 wells
- Oregon Basin 50 wells
- Spring Creek South 43 wells
- Silver Tip 21 wells
- Hamilton Dome 17 wells
- Garland 15 wells
- Cottonwood Creek 14 wells
- Grass Creek 13 wells
- Murphy Dome 13 wells
- Byron 12 wells
- Sunshine North 11 wells.

Of the 338 new oil boreholes drilled, only four were completed as wildcats (one as an outpost extension and three as deeper pool discoveries). The rest were completed as development wells.

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:

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

According to the U.S. Department of Energy, as much as 90 percent of the oil originally in place in an oil reservoir is left behind once primary recovery methods are completed (U.S. Department of Energy, 2008a). In other words, the recovery factor (the percent of original oil in place removed from a reservoir) for primary recovery can be as low as 10 percent. However, the primary recovery factor varies depending on oil and reservoir characteristics, but as a general rule 15-20 percent is considered the norm (Sandrea and Sandrea, 2007). Primary recovery relies on the natural pressure found in the reservoir to bring hydrocarbons to the surface for production. Once that pressure is depleted, the reservoir must either be abandoned or other methods for recovering additional hydrocarbons must be employed. Historically, many of 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 large 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 Bighorn Basin 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 only Elk

Basin Field (Figure 10) has a gas injection program into the Phosphoria Formation and Tensleep Sandstone. Gas is injected for pressure maintenance.

There are presently 46 active secondary recovery projects, 24 inactive projects, and three terminated projects in 37 total units/fields. Locations of these injection wells are shown on Figure 15. Brief summaries of these projects (Wyoming Oil and Gas Conservation Commission, 2009) are presented below.

1. Alkali Anticline Field/Unit contains one active Tensleep Formation water flood approved in 1979 and operated by Prima Exploration Co. The Phosphoria-Tensleep is the water source for the three active injectors.
2. Badger Basin Field/Unit contains one inactive Frontier Formation water flood project approved in 1984 and operated by Beartooth Oil & Gas Company.
3. Bearcat Field/Unit contains one active Phosphoria Formation water flood project approved in 2005 and operated by Qualmay Development LLC. The Mesaverde Formation is the water source for the single active injector.
4. Black Mountain Field/Unit contains one active Tensleep Sandstone water flood project approved in 1989 and operated by Phoenix Production Co. The Madison Limestone is the water source for the five active injectors.
5. Byron Field/Unit contains one active Madison Limestone water flood project approved in 2001and operated by Marathon Oil Co. The Phosphoria-Tensleep-Madison is the water source for the 33 active injectors.
6. Cody Field/Unit contains two active water floods (Phosphoria Formation approved in 1981 and Tensleep Sandstone approved in 1983) operated by Merit Energy Co. A number of different formations provide water for the 15 active injection wells.
7. Cottonwood Creek Field/Unit contains one active (Tensleep Sandstone approved in 2000) and two inactive (Phosphoria approved in 1961 and 1974) water flood projects operated by Continental Resources Inc. The Tensleep Sandstone and Madison Limestone provide water for the four active injection wells.
8. Elk Basin Field/Unit contains two active (Madison Limestone approved in 1961 and Phosphoria-Tensleep approved in 1962), one inactive (Frontier Formation approved in 1966), and one terminated (Phosphoria-Tensleep approved in 1967) water flood projects operated by Howell Petroleum Corp. A number of different formations provide water for the 64 active injection wells.
9. Fourbear Field/Unit contains one active Phosphoria-Tensleep water flood project approved in 1993 and operated by St. Mary Land & Exploration. The Madison-Amsden-Tensleep provides water for 23 active injection wells.
10. Frannie Field/Unit contains one active Phosphoria-Tensleep water flood project operated by Merit Energy Co. The Phosphoria-Tensleep provides water for 38 active injection wells.
11. Garland Field/Unit contains three active (Phosphoria Formation approved in 1966, Madison Limestone approved in 1982, and Phosphoria-Tensleep approved in 1999) and two inactive (Sundance Formation approved in 1990 and Morrison-Cloverly approved in 1971) water flood projects operated by Marathon Oil Co. The Phosphoria-Tensleep-Madison provides water for 40 active injection wells.

12. Gooseberry Field/Unit contains one active Phosphoria Formation water flood project operated by Oncore Operation LP. The Phosphoria-Tensleep provides water for 11 active injection wells.
13. Grass Creek Field/Unit contains five active [Chugwater Group (Curtis) approved in 1960, Amsden Formation (Darwin) approved in 1966, Frontier Formation approved in 1974, Phosphoria-Tensleep approved in 1974, and Cloverly Formation (Lakota) approved in 2007] water flood projects operated by Marathon Oil Co. A number of different formations provide water for the 125 active injection wells.
14. Greybull Field contains one active Frontier Formation (Peay) water flood project operated by Rockwell Petroleum Inc. The Frontier provides water for one active injection well.
15. Half Moon Field contains one active Phosphoria Formation water flood project operated by Merit Energy Co. The Phosphoria-Tensleep provides water for three active injection wells.
16. Hamilton Dome Field/Unit three active (Tensleep Sandstone approved in 1983 and 2006 and Phosphoria Formation approved in 1972), five inactive [Amsden approved in 1983, Chugwater Group (Curtis) approved in 1970 and 1976, Phosphoria Formation approved in 1985, and Tensleep Sandstone approved in 1986], and one terminated (Chugwater Group approved in 1986) water flood projects operated by Merit Energy Company. A number of different formations provide water for the 76 active injection wells.
17. Hidden Dome Field contains one active (Tensleep Sandstone approved in 1976) and one inactive [Amsden Formation (Darwin) approved in 2000] water flood projects operated by Phoenix Production Co. The Tensleep-Sundance provides water for the nine active injection wells.
18. Kirby Creek Field/Unit contains two active water flood projects approved to the Phosphoria Formation in 1968 and 1997 and operated by St. Mary Land & Exploration. The Phosphoria-Tensleep provides water for 13 active injection wells.
19. Little Buffalo Basin Field/Unit contains three active (Tensleep Sandstone approved in 1966, Phosphoria-Tensleep approved in 1971, and Phosphoria approved in 1972) and one inactive (Frontier approved in 1993) water flood projects operated by Citation Oil & Gas Corp. The Phosphoria-Tensleep provides water for 74 active injection wells.
20. Little Sand Draw Field contains one inactive water flood project approved to the Phosphoria Formation in 1991 and operated by Citation Oil & Gas Corp. No injection wells are presently located in the field.
21. Manderson Field/Unit contains one inactive water flood project approved to the Phosphoria Formation in 1999 and operated by KCS Mountain Resources Inc. No injection wells are presently located in the field.
22. Murphy Dome Field contains one active water flood project approved to the Tensleep Sandstone in 2007 and operated by St. Mary Land & Exploration. The Tensleep Sandstone provides water for one active injection well.

23. North Danker Field/Unit contains one inactive water flood project approved to the Tensleep Sandstone in 1985 and operated by Merit Energy Co. No injection wells are presently located in the field.
24. Nowood Field contains one inactive water flood project approved to the Tensleep Sandstone in 1992 and operated by J&J Production LLC. No injection wells are presently located in the field.
25. Oregon Basin Field/Unit contains one active (Phosphoria-Tensleep approved in 1958) and two inactive [Madison Limestone approved in 1958 and Amsden Formation (Darwin) approved in 1984] water flood projects operated by Marathon Oil Co. A number of formations provide water for 177 active injection wells.
26. Packsaddle Field/Unit contains one inactive water flood project approved to the Phosphoria Formation in 2001 and operated by Gas Ventures Inc. One active injection well is presently located in the field.
27. Prospect Creek Field contains one inactive water flood project approved to the Crow Mountain Formation in 1971 and operated by KCS Mountain Resources Inc. No injection wells are presently located in the field.
28. Pitchfork Field/Unit contains two active water floods (Phosphoria Formation approved in 1987 and Tensleep Sandstone approved in 1984) operated by Marathon Oil Co. The Phosphoria-Tensleep provides water for 41 active injection wells.
29. Prospect Creek Field contains one inactive water flood project approved to the Crow Mountain Formation in 1971 and operated by KCS Mountain Resources Inc. No injection wells are presently located in the field.
30. Sage Creek Field/Unit contains one inactive water flood project approved to the Tensleep Sandstone in 1971 and operated by Whiting Oil & Gas Corp. No active injection wells are presently located in the field.
31. Shoshone Field/Unit contains two active water floods (Phosphoria Formation approved in 1983 and Tensleep Sandstone approved in 1986) operated by Merit Energy Co. The Phosphoria-Tensleep provides water for six active injection wells.
32. Silver Tip Field/Unit contains one terminated water flood project approved to the Frontier Formation in 1971 and operated by True Oil Co. No injection wells are presently located in the field.
33. Spence Dome Field/Unit contains one active water flood project approved to the Madison Limestone in 1989 and operated by Endeavor Energy LLC. The Madison Limestone provides water for two active injection wells.
34. Spring Creek South Field contains one active water flood project approved to the Madison-Phosphoria-Tensleep in 2000 and operated by Marathon Oil Co. A number of formations provide water for 21 active injection wells.
35. Sunshine North Field contains one active water flood project approved to the Tensleep Sandstone in 1997 and operated by Phoenix Production Co. The Tensleep Sandstone provides water for three active injection wells.
36. Torchlight Field/Unit contains two active (Tensleep Sandstone, both approved in 1958) and one inactive (Madison Limestone approved in 1970) water floods operated by Whiting Oil & Gas Corp. The Tensleep-Madison provides water for two active injection wells.

37. Walker Dome Field/Unit contains one active (Phosphoria Formation approved in1989) and one inactive [Frontier Formation (Torchlight) in 1965] water flood project and operated by Natural Gas Processing. The Phosphoria-Mesaverde provides water for three active injection wells.
38. Warm Springs Field contains three active Phosphoria Formation water flood projects approved in 1974, 1975, and 1983 with Continental Operating, Cork Petroleum and Morning Star Oil Company each operating one project. A number of formations provide water for 22 active injection wells.

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. One active steamflooding injection project is located at Garland Field (Figure 10). It was approved to the Madison Limestone in 1986 and is operated by Marathon Oil Company. Steam was used for past projects at Pitchfork Field (Figure 11) in the Tensleep Sandstone, at Red Springs Field (Figure 10) in the Tensleep Sandstone, and at Cloverly Field (Figure 14) in the Phosphoria Formation.

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; Byron (Phosphoria-Tensleep, Figure 10), Deaver (Tensleep, Figure 13), Elk Basin (Phosphoria-Tensleep, Figure 10), Enigma (Tensleep, Figure 13), Frannie (Phosphoria-Tensleep, Figure 11), Garland (Tensleep, Figure 10), Garland (Cloverly), Grass Creek (Phosphoria-Tensleep, Figure 10), Hamilton Dome (Phosphoria), Hamilton Dome (Tensleep, Figure 10), and Oregon Basin (Phosphoria-Tensleep, Figure 10).

Surfactant Flooding

Adding surfactants to injected water can enhance oil production. A type of surfactant flood called a micellar flood uses a two-step enhanced oil recovery process in which a small quantity of surfactant is injected into the well followed by a larger quantity of water containing a high-molecular-weight polymer which pushes the chemicals through the field and improves mobility and sweep efficiency. These types of projects are expensive and have not often used. This type of flood has been used at Torchlight Field (Figure 10) and was approved in 1976.

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 approved at Willow Draw Field (Figure 10) in 1975, but is now terminated.

Carbon Dioxide Injection

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

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

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

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

The carbon dioxide "huff and puff" method has been tested at Bonanza (Tensleep, Figure 13), Elk Basin (Madison-Bighorn, Figure 10), Gebo (Phosphoria, Figure 12), Little Buffalo Basin (Frontier-Phosphoria-Tensleep, Figure 10), and Sunshine North (Tensleep, Figure 11). 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 and all projects have been terminated.

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. To the south of the Planning Area, 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 Murphy Dome, Cottonwood Creek, Bonanza, Worland, Hamilton Dome, Grass Creek, Little Buffalo Basin, Pitchfork, Spring Creek, Oregon Basin, Garland, Byron, Big Polecat, Frannie, and Elk Basin (Figures 10, 11, 12, or 13).

Advanced Resources International (2006) identified and evaluated 13 large Planning Area oil reservoirs for Carbon Dioxide enhanced oil recovery. Those fields and the formation of interest are:

- Big Polecat – Tensleep Sandstone,
- Byron – Phosphoria-Tensleep,
- Elk Basin – Phosphoria-Tensleep,
- Elk Basin South – Phosphoria-Tensleep,
- Frannie – Phosphoria-Tensleep,
- Gebo – Tensleep Sandstone,
- Grass Creek – Tensleep Sandstone,
- Murphy Dome – Tensleep Sandstone,
- Garland – Tensleep Sandstone,
- Hamilton Dome – Tensleep Sandstone,
- Little Buffalo Basin – Tensleep Sandstone,
- Oregon Basin North – Tensleep Sandstone, and
- Oregon Basin South – Tensleep Sandstone.

Hydrogen Sulfide Occurrence

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

Oil and gas reservoirs in the Bighorn Basin commonly contain hydrogen sulfide gas. The Phosphoria Formation, a known source rock for many of the oil and gas reservoirs, contains high-sulfur oil (Wyoming Geological Association, 1989 and Watson, 1980). The sulfur and associated sulfate compounds are converted through inorganic and organic processes to hydrogen sulfide during the burial and maturation process (Levorsen, 1967). Several established fields and point fields (single wells) in the Planning Area are known hydrogen sulfide production. Figure 29 shows the location of all oil and gas fields in the Planning Area which are known to contain hydrogen sulfide. These fields (not including the point fields) are:

- Black Mountain,
- Cottonwood Creek,
- Elk Basin,
- Five Mile,
- Fourteen Mile,
- Kirby Creek,
- Lake Creek,
- Little Buffalo Basin,
- Manderson,
- Marshall,
- Oregon Basin,
- Silver Tip,
- Torchlight, and
- Whistle Creek.

<u>Acid Gas Removal and Recovery</u>

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. Plants in the Planning Area that process this sour gas include:

- Oregon Basin Gas Plant operated by Marathon Oil Company,
- Hiland Gas Plant operated by Hiland Partners L.L.C., and
- Oregon Basin Wellfield operated by Marathon Oil Company.

Waste gas (carbon dioxide and some hydrogen sulfide) is either vented or flared. Gas disposal wells are located at Garland, Golden Eagle, Grass Creek, and Hamilton Dome fields (Wyoming Oil and Gas Conservation Commission, 2009).

<u>Artificial Lift Optimization</u>

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

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

Produced Water Management

Coproduction of a variable amount of water with oil and gas is unavoidable at most locations. Wyoming allows water produced with oil and gas to be disposed of by injection in a permitted disposal or enhanced recovery well, evaporation in an approved pond, or discharge into a surface water source through an outfall permit. The Planning Area presently has 36 active and two shut-in disposal wells (Wyoming Oil and Gas Conservation Commission, 2009).

Figure 30 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 (2008b) database of water quality samples. Water quality information is available for 2,186 samples and total dissolved solids range from 0 to 220,200 milligrams per liter. Water quality sample distribution is:

- less than 5,000 milligrams per liter – 1,094 samples,
- 5,000 to 9,999 milligrams per liter – 615 samples,
- 10,000 to 49,999 milligrams per liter – 444 samples, and
- Greater than 50,000 milligrams per liter – 33 samples.

The Bureau considers total dissolved solids concentrations of less than 10,000 milligrams per liter to be fresh water. Over 78 percent of these water quality samples fall within this range. Oil and gas fields (Figure 30) with at least 20 samples (and formations sampled) recording total dissolved solids of less than 10,000 milligrams per liter are:

- Alkali Anticline – 22 samples – Amsden, Madison Limestone, Phosphoria, and Tensleep Sandstone;
- Byron – 58 samples – Amsden, Frontier, Madison Limestone, Morrison, Phosphoria, and Tensleep Sandstone;
- Elk Basin – 26 samples – Cloverly, Frontier, Lance, Madison Limestone, Phosphoria, and Tensleep Sandstone;
- Frannie – 25 samples – Bighorn Dolomite and Tensleep Sandstone;
- Garland – 178 samples – Amsden, Bighorn Dolomite, Cloverly, Frontier, Lakota, Madison Limestone, Phosphoria, and Tensleep Sandstone;
- Gebo – 25 samples – Chugwater Group (formation not specified), Flathead Sandstone, Morrison, Phosphoria, and Tensleep Sandstone;
- Golden Eagle - 26 samples -- Frontier, Mesaverde, Muddy Sandstone, Phosphoria, and Tensleep Sandstone;

- Grass Creek – 124 samples – Amsden, Bighorn Dolomite, Devonian (formation not specified), Flathead Sandstone, Frontier, Gallatin Limestone, Gros Ventre, Madison Limestone, Morrison, Muddy, Phosphoria, and Tensleep Sandstone;
- Hamilton Dome – 95 samples -- Amsden, Bighorn Dolomite, Chugwater Group (formation not specified), Cloverly, Flathead Sandstone, Madison Limestone, Morrison, Phosphoria, and Tensleep Sandstone;
- Little Buffalo Basin – 62 samples – Amsden, Bighorn Dolomite, Cloverly, Darby, Frontier Madison Limestone, Phosphoria, and Tensleep Sandstone;
- Neiber Dome – 31 samples – Amsden, Cody Shale, Frontier, Mesaverde, and Phosphoria;
- Oregon Basin – 238 samples – Bighorn Limestone, Cloverly, Devonian (formation not specified), Flathead Sandstone, Frontier, Madison Limestone, Phosphoria, and Tensleep Sandstone; and
- Sage Creek – 24 samples – Tensleep Sandstone.

Only about 22 percent of water quality samples have a total dissolved solids concentration of greater than 10,000 milligrams per liter. Oil and gas fields (Figure 30) with at least 15 samples (and formations sampled) recording total dissolved solids greater than 10,000 milligrams per liter are:

- Elk Basin – 16 samples – Amsden, Frontier, Madison Limestone, and Tensleep;
- Gebo – 15 samples -- Phosphoria;
- Grass Creek – 76 samples – Chugwater Group (formation not specified), Madison Limestone, Morrison, Phosphoria;
- Hamilton Dome – 38 samples – Chugwater Group (formation not specified), Morrison, Phosphoria, and Tensleep Sandstone;
- Neiber Dome – 26 samples – Amsden, Chugwater Group (formation not specified), and Phosphoria; and
- Oregon Basin – 39 samples – Amsden, Chugwater Group (formation not specified), Flathead Sandstone, Madison Limestone, Phosphoria, and Tensleep Sandstone.

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

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

Leak Detection and Low-bleed Equipment

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

Downhole Water Separation

At least some water is produced along with the hydrocarbons in most wells within the Planning Area. It is most often stored, at least temporarily, in tanks on the well site. It is then transported via pipeline or truck to approved disposal pits, or it may be injected into approved subsurface zones. Emerging technology to separate oil and water could cut produced water volumes by as much as 97 percent in applicable wells (U.S. Department of Energy, 1999). By separating the oil and water in the borehole and injecting the water directly into a subsurface zone, only the oil needs to be brought to the surface. This new technology could help to minimize environmental risks associated with bringing water to the surface where it then has to be handled, treated, and then disposed of. It would also reduce the costs of lifting and disposing of produced water. In addition, surface disturbance could be reduced, oil production could be enhanced and marginal or otherwise uneconomic wells could become economic. Although trials of downhole water separation have occurred at other locations within Wyoming (Veil and Quinn, 2004), there do not appear to presently be any ongoing projects in 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. No record of use of this equipment is available for the Planning Area.

PLANT SITES

Nine active plants that process natural gas or liquids are located within the Planning Area (Wyoming Oil and Gas Conservation Commission, 2009). Brief summaries of these projects are presented below.

1. Badger Basin – Has received from 20 wells at Badger Basin Field and is operated by Beartooth Oil & Gas Company. In February, 2009 the plant received 5,366,000 cubic feet of gas.
2. Elk Basin – Has received from 22 wells at Elk Basin, Elk Basin South, and Bearcat fields and is operated by Howell Petroleum Corporation. In February, 2009 the plant received 391,670,000 cubic feet of gas.
3. Fourteen Mile – Has received gas from four wells at Fourteen Mile Field and is operated by Saga Petroleum LLC. In February, 2009 the plant received 246,000 cubic feet of gas.
4. Heart Mountain – Has received gas from eight wells at Heart Mountain Field and us operated by Encana Energy Resources Incorporated. In February, 2009 the plant received 18,860,000 cubic feet of gas.
5. Hiland – Has received gas from 38 wells at Frisby South, No Water Creek, Rattlesnake, and Slick Creek fields and is operated by Hiland Partners LLC. In February, 2009 the plant received 62,116,000 cubic feet of gas.
6. Little Buffalo Basin – Has received gas from 24 wells at Little Buffalo Basin and Sellers Draw fields and is operated by Marathon Oil Company. In February, 2009 the plant received 24,262,000 cubic feet of gas.
7. Oregon Basin – Has received gas from 342 wells at Oregon Basin Field and is operated by Marathon Oil Company. In February, 2009 the plant received 113,588,000 cubic feet of gas.
8. Silvertip – Has received gas from 71 wells at Silvertip Field and is operated by Fidelity Exploration & Production Company. In February, 2009 the plant received 146,433,000 cubic feet of gas.
9. Worland – Has received gas from 52 wells at Worland, Dobie Creek, and Five Mile fields. In February, 2009 the plant received 269,036,000 cubic feet of gas.

UNDERGROUND GAS STORAGE

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

- Elk Basin – This active project was approved in 1950, stores gas in the Cloverly Formation, and is operated by Williston Basin Interstate Pipeline.
- Garland – This inactive project was approved in 1964, stored gas in the Cloverly Formation, and is operated by Marathon Oil Company.
- Oregon Basin – This active project was approved in 2002, stores gas in the Phosphoria Formation, and is operated by Marathon Oil Company.
- Worland – This inactive project was approved in 1983, stored gas in the Frontier Formation, and is operated by Devon Energy Corporation.

ASSESSMENTS OF OIL AND GAS RESOURCES

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

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

- The Energy Information Administration (2003) uses a natural gas resource base of 383 trillion cubic feet for the Rocky Mountain region.
- The Potential Gas Committee (2003) estimated 288 trillion cubic feet of natural gas; including 50 trillion cubic feet of proved reserves (see Glossary).
- As part of a study done in compliance with the Energy Policy and Conservation Act Amendments of 2000 (U.S. Departments of Interior, Agriculture, and Energy, 2003) the U.S. Geological Survey estimated the technically recoverable gas resource for five basins in the Rocky Mountain region at 226 trillion cubic feet. Of that total, they estimated a conventional gas resource of 13 trillion cubic feet, tight gas sand and shale gas resources of 127 trillion cubic feet, 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, 2007b). Our domestic production rose from 17.7 to 19.7 trillion cubic feet (11.3 percent increase) for the 1990 to 2000 period (Curtis and Montgomery, 2002) and then dropped to 18.3 trillion cubic feet in 2005. It is expected to rise to 20.6 trillion cubic feet in 2030 (Energy Information Administration, 2007b). North American producing areas are expected to provide 75 percent of long-term United States gas needs, but they will be unable to meet the entire projected demand (National Petroleum Council, 2003). The gap between consumption and production has necessitated a rise in imports and concern about our future United States energy supply.

Oil and gas produced within the Planning Area to date, has helped supply a portion of this countries demand. The Planning Area will also continue to help meet rising national demand by supplying additional oil and gas that has not yet been discovered. A recent oil and gas resource assessment has been prepared that covers most of the Planning Area. This assessment provides an indication of the range of undiscovered resource volumes that could be available for exploration, development, and production through the year 2027.

We will present below only the results of the latest (and most current) U.S. Geological Survey assessment, which covers most of the Planning Area (with the exception of smaller areas of the Bighorn Mountains on the northeast and southeast and the Absaroka Volcanic Field on the west). Combined, the most current assessment provides an idea of the range of oil and gas resources that may be available for exploration and development in the Planning Area through 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. The Bighorn Basin Province assessed at that time covered the Planning Area.

As part of a study prepared in compliance with the Energy Policy and Conservation Act Amendments of 2000 (U.S. Departments of Interior, Agriculture, and Energy, 2003) the U.S. Geological Survey prioritized oil and gas assessment studies for certain basins. An initial updated analysis covering the Bighorn Basin Province in the Planning Area has been prepared in response to their new priorities. The report for the Bighorn Basin Province is titled "Assessment of undiscovered oil and gas resources of the Bighorn Basin Province, Wyoming and Montana, 2008" (U.S. Geological Survey, 2008). In this report the U.S. Geological Survey updated their quantitative estimates of the undiscovered oil and gas resources for the province. The U.S. Geologic Survey (2010) recently updated their analysis with "Petroleum systems and Geologic Assessment of oil and gas in the Bighorn basin province, Wyoming and Montana."

The Bighorn Basin Province occupies most of the Planning Area (Figure 31). 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 the majority 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. The Sub-Absaroka play (see Glossary), which was projected beneath Eocene-age volcanic rocks trapped in Laramide structures was considered under the earlier assessment of the Bighorn Basin Province in the western part of the Planning Area (Beeman et al., 1996: Charpentier et al., 1996: Gautier et al., 1996), but was not included in the most recent assessment.

In their newest assessment, the U.S. Geological Survey (2008 and 2010) divided the Bighorn Basin Province into "total petroleum systems" and "assessment units" (see Glossary definitions) rather than "plays." All Planning Area fields lie within the Bighorn Basin Province and its assessment units.

Two total petroleum systems and eight assessment units have been identified in the Bighorn Basin Province and all assessment units in each total petroleum system lie wholly or at least partly within the Planning Area. Conventional oil and gas resources are defined by the Phosphoria and Cretaceous-Tertiary Composite total petroleum systems, with each having one assessment unit (Figures 32 and 33). 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. Continuous oil and gas resources are defined by the Cretaceous-Tertiary Composite total petroleum system, which contains six assessment units (Figures 34 through 39). With their newest report, the U.S. Geological Survey (2010) has made available detailed information for all eight of the assessment units within the Planning Area.

The U.S. Geological Survey (2008) estimated undiscovered technically recoverable resource (see Glossary) quantities of oil and gas that could be added to the proved reserves within each assessment unit, using a forecast span of 30 years. A 30-year forecast span affects the minimum undiscovered accumulation 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 all the assessment units, which lie wholly or at least partly within the Planning Area.

In Table 4, the U.S. Geological Survey resource estimates for three types of hydrocarbons [oil, gas, and natural gas liquids (see Glossary)] 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 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 about 62.05 million barrels of oil, about 913.23 billion cubic feet of gas, and 12.05 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 16.51 to 124.99 million barrels, the gas resource could range from 293.61 to 1,879.61 billion cubic feet, and the natural gas liquids resource could range from 2.63 to 25.95 million barrels** (assuming fractile data used has a perfect positive correlation).

It appears that the Muddy-Frontier Sandstone and Mowry Fractured Shale Gas assessment unit (Figure 34) has the greatest potential undiscovered resource of the eight assessment units. Operators in the Planning Area have expressed interest in exploring the rocks of this assessment unit in the future.

Dyman et al. (1997) showed that the Bighorn 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. The U.S. Geological Survey has not made a recent estimate of the potential petroleum resource at these depths. The Potential Gas

Committee (2003) did estimate that traditional resources of natural gas below 15,000 in the Bighorn Basin were 2.81 trillion cubic feet.

DEPARTMENTS OF INTERIOR, AGRICULTURE, AND ENERGY RESOURCE ASSESSMENTS

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

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

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

RAND SCIENCE AND TECHNOLOGY ASSESSMENT

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

- review existing resource assessment methodologies and results,
- evaluate recent studies of federal land access restrictions in the Intermountain West,
- consider a set of criteria that can be used to define the “viable” hydrocarbon resource, with particular attention to issues relevant to the Intermountain West,
- develop a more comprehensive assessment methodology for the viable resource, and
- employ this methodology to assess the viable resource in Intermountain West basins.

The report by LaTourrette et al (2003) indicated that the details of their spatial analysis and other data were available on request. We contacted the lead author and asked for this information in order to see the details of how the methodology was applied.

Unfortunately, that information had been lost and was no longer available. Therefore, their analysis methodology has not been used to analyze the Planning Area.

OIL AND GAS OCCURRENCE POTENTIAL

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

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

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

Using the above criteria, we consider that Planning Area lands have either high or low potential for the occurrence of oil and gas (including coalbed natural gas) as shown in Figure 40. All areas within the Bighorn Basin Province are contained within specific assessment units designated by the U.S. Geological Survey (2008a) so are considered to have high potential. All areas outside the province 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 Muddy-Frontier Sandstone and Mowry Fractured Shale continuous assessment unit and oil and gas in plays associated with the Paleozoic-Mesozoic and Cretaceous-Tertiary conventional assessment units of the Bighorn Basin Province (as discussed in more detail above).

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.

<u>Gas Prices</u>

Data for Figure 41 (historical and projected future natural gas prices) were obtained from the Energy Information Administration (2009b). The Energy Information Administration price projection data is an average for Lower 48 Wellhead Prices and is made in 2007 dollars. Historical prices are in nominal dollars.

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

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

The Energy Information Administration projects that natural gas prices will fall sharply in 2009 from the recent spike in prices which began in 2003 and likely culminated in 2008. Prices are then expected to begin a gradual and linear rise from $3.99 per thousand cubic feet (2007 dollars) in 2009 to $8.01 per thousand cubic feet in 2030 (Energy Information Administration , 2008c). They also predict that the current high natural gas prices (relative to 2003 and older prices) will stimulate development of new gas supplies and constrain growth in natural gas consumption (Energy Information Administration, 2009b). 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.

Historically, oil exploration has been predominant in the Planning Area, outpacing gas exploration by a factor of five. In the previous ten year period, gas wells have been predominantly drilled as infill wells in existing fields (Figure 42). Outside of existing fields, several isolated dry holes have been drilled along the basin margin as well as toward the center of the basin. Production was also recently established in new fields in township 48 north, range 93 west, as well as in township 58 north, range 103 west. Much of the recent 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 have dropped sharply from their 2008 high. Prices are expected to only fall, on average in 2009, to 2003 levels; the 2003 prices were more than 170 percent the average Wyoming wellhead acquisition price from the previous ten year period. 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 2009 Annual Energy Outlook, U.S. demand for natural gas in 2008 was 23.0 trillion cubic feet. Demand is expected to decrease by approximately five percent to 21 trillion cubic feet in 2014, and begin a continual increase through 2027. Increases in future natural gas production, to accommodate projected increased 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 fields, and from exploration for plays associated with the Muddy-Frontier Sandstone and Mowry Fractured Shale gas, Paleozoic-Mesozoic conventional oil and gas, and Cretaceous-Tertiary conventional oil and gas assessment units.

Oil Prices

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

Data for Figure 43 (historical and projected crude oil prices) were obtained from the Energy Information Administration (2009b). The data are projected averages of imported Low Sulfur Light Crude Oil prices and are made in 2007 dollars. Historical prices are in nominal dollars and show the historic volatility that has occurred in crude oil prices in Wyoming. In general, the trends seen in wellhead gas prices in Wyoming have been mirrored in Wyoming crude oil prices. Prices began declining in the early 1980's from a high of $32.30 in 1981 to a low of $10.70 in 1998. The significant climb seen in natural gas prices since 1999 is mirrored in crude oil wellhead acquisition prices in the Planning Area. The rise from a low of $10.70 per barrel to the most recent average high of nearly $100 per barrel represents over an order of magnitude increase in prices in just eleven years.

The Energy Information Administration (2009b) projection of future prices predicts that world oil price projects are higher for 2006-2030 than those presented in previous Annual Energy Outlook reports. Domestic petroleum-based liquids consumption is expected to remain flat through 2030 (approximately 20 million barrels per day) due to increased use of and reliance on biofuels. However, worldwide demand will continually increase during the same time, driving world oil prices to higher levels. The Energy Information Administration reference case projects that world oil prices will sharply decline from current levels to about $40 per barrel in 2009, and start rising again as production in non-OPEC regions peaks, and continue rising to nearly $130 per barrel in 2030 (all prices in 2007 dollars). However, as stated in their 2009 projections, "recent volatility in crude oil prices demonstrates the uncertainty inherent in the projections" (Energy Information Administration, 2009b). Such uncertainty is demonstrated in their low- and high-price case projections. These cases reflect a wide band of potential world oil price paths, ranging from $45-50 per barrel in the low case to $200 per barrel in the high case in 2030 (Energy Information Administration, 2009b).

Most of the recent oil exploration in the Planning Area, like that for gas, has been as infill drilling in existing fields around the basin margin (Figure 42). If the current Energy Information Administration crude oil price projection is accurate, future oil drilling and production will likely continue at levels similar to those seen in recent years as operators continue with in-fill drilling programs and entertain secondary and enhanced recovery projects in older fields. Barring any significant new discoveries, however, it is unlikely that drilling activity will increase significantly beyond the recent peak. Any new discoveries would most likely come from plays associated with Paleozoic-Mesozoic conventional oil and gas, and Cretaceous-Tertiary conventional oil and gas assessment units.

LEASING

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

Leases on lands where the 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 44 presents the locations of leased and unleased Federal oil and gas minerals within the Planning Area. Excluding lands under Forest Service wilderness areas and Bureau wilderness study areas, there were about 1,488,000 acres of leased Federal oil and gas minerals as of January 1, 2009 and about 4,800,000 acres of unleased Federal oil and gas minerals. About 24 percent of Federal oil and gas minerals available for lease were leased at that 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 1,865 wells will be drilled in the Planning Area. Up to 150 of these wells could be coalbed natural gas wells (to be discussed latter). As many as 175 of the conventional wells could be deep wells (greater than 15,000 feet in depth) located in the central portion of the Bighorn Basin. These deep wells are part of a high-risk play in the early exploratory stage. Such activity assumes that operators not currently exploring deep targets will show interest in doing so during the Planning Period. As such development is at this point hypothetical, no provisions were made in our calculations to include additional disturbance from deep wells (all conventional wells were treated the same for surface disturbance calculations).

The estimated conventional oil and gas development potential and drilling densities within the Planning Area during the planning period are shown in Figure 45. Estimated acres, number of townships, and percentage of the Planning Area within each development potential classification type shown in Figure 45 are summarized in Table 5.

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 1,715 conventional wells (not including coalbed natural gas wells) projected within the Planning Area, the majority (1,681) are projected in areas of moderate or low potential. No operators responded indicating areas of high activity during the Planning Period, nor did a review of the geology or historical drilling trends suggest such levels. Drilling activity is likely to be concentrated in the following areas:

- In and around Elk Basin and Garland fields on the northern portion of the Planning Area, in and around and east of Oregon Basin Field near the town of Cody and around Fritz Field in the east-central portion of the Planning Area and in and around several isolated smaller fields around the margins of the basin in additional scattered townships where moderate levels of activity are projected. Most of these fields are already relatively densely drilled. Many new wells in these areas 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. Exploratory activities and development of new discoveries are projected in areas of moderate and low in the center of the Bighorn Basin. The main target in this area will be sedimentary rocks in the Muddy-Frontier Sandstone and Mowry Fractured Shale assessment unit that has been identified by the U.S. Geological Survey (2010). Well spacing in most of the basin is projected to be variable, in the 160 to 20 acre range.
- 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 the potential for an increase in drilling density.

The remaining 34 conventional wells could be drilled in areas of very low potential and are projected for areas generally not proven productive by historical drilling, but which still may contain hydrocarbons based on U.S. Geological Survey assessment data. Most of these townships will not receive any drilling at all. If new field discoveries are made in any of these areas of very low development potential, subsequent drilling density could increase in those specific areas. However, predicting a well density for such areas is not possible at this time.

Figure 26 shows historic well distributions by depth. We anticipate that future drilling depths will on average be deeper than they have been historically, with possible increases in deep wells greater than 15,000 feet. Nineteen deep wells have been drilled in the Planning Area, though 14 of those were dry holes. Of the remaining five deep wells, only four have been productive from their deepest formations (IHS Energy Group, 2008). We project that up to 175 additional deep wells may be drilled in the Planning Area during the planning period, though such activity will rely heavily on the results of initial exploration in the center of the basin. Most conventional wells drilled will be to depths similar to those drilled in the past (7,500 feet or less).

As stated earlier, the majority of the anticipated activity in the Planning Area will be infill drilling of conventional wells to increase proved recoverable reserves and as exploratory drilling to further explore for conventional resources and potential continuous resources identified by the U.S. Geological Survey (2008a and 2010) in the Bighorn Basin province. Initial estimates of the ultimate size of new oil or gas fields are usually too low, and over time, newer estimates of the size and ultimate recovery contribute to growth in the reserve estimate (Central Region Energy Resources Team, 1996). Factors that could contribute to increases in reserve growth in the Planning Area include:

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

Projected Coalbed Natural Gas Drilling

The U.S. Geological Survey has identified the Mesaverde-Meeteetse Formation and Fort Union Formation coalbed gas assessment units as potentially productive within the Planning Area. Only limited exploratory drilling for coalbed natural gas has occurred in the Planning Area (see previous discussion). Responses to our request for future drilling projections suggest there are no current plans for coalbed natural gas development in the Planning Area. However, since there has been limited coalbed natural gas exploration in the recent past (though unsuccessful) and the Planning Area includes the two above mentioned U.S. Geological Survey coalbed gas assessment units, it should be assumed that future exploration and development may occur during the Planning Period.

Figure 45 shows areas of low and very low coalbed natural gas development potential. These areas correspond with the two identified U.S. Geological Survey assessment units. Where these units overlap, we have assigned a value of low development potential. Where only one assessment unit is present a very low potential was assigned, and all areas outside the units were assumed to have no potential for development.

It is within the areas of very low and low potential that the 150 coalbed natural gas wells are projected to be drilled. Such development will likely occur as test pods of 16 to 25 wells per pod. Projected activity includes these types of tests and initial development if economic reserves are encountered. If successful, future coalbed natural gas development could increase significantly, though the currently available data from operator input, published research, and historical activity does not suggest anything beyond the potential for additional exploratory test pods.

As stated earlier, the majority of the anticipated activity in the Planning Area will be infill drilling of conventional wells to increase proved recoverable reserves and as exploratory drilling to further explore for conventional resources and potential continuous resources identified by the U.S. Geological Survey in the Bighorn Basin province (U.S. Geological Survey; 2008 – fact sheet and assessment references). 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.

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 BASE LINE OIL AND GAS PRODUCTION

As indicated above, we projected 1,865 wells would be drilled within the analysis period of 2008 through 2027. These wells were assumed to be drilled at an average rate of 85 wells per year for the first 10 years of the Planning Period, 100 wells per year for the next five years, and 103 wells per year for the final five years. Table 6 presents a base line forecast of oil and gas production for the 20-year period beyond the year 2008. Gas and oil production are projected to decline over the period, even with the new additional wells. Oil production would not decline as rapidly if carbon dioxide flood operations are used in the future to enhance production. Gas production could flatten in the future if significant reserves are discovered in the center of the Bighorn Basin. The cumulative oil and gas values are for the 20 year planning period and ignore the historical production.

Future coalbed natural gas production, for the base line analysis, was included in Table 6. We estimate that coalbed natural gas wells will be more likely drilled in the second half of the Planning Period. If any coalbed natural gas production does come online during the 20-year assessment period it will only be minor part of the total gas production shown in Table 6.

OTHER POTENTIAL FUTURE OIL AND GAS ACTIVITIES

Resource Plays

We use the term Resource Play to describe accumulations of hydrocarbons known to exist over a large areal extent and/or thick vertical section, may be self sourcing, may be developed with horizontal well completions, and are driven by development efficiencies rather than geologic risk. Within the Planning Area, resource plays could include continuous resource assessment units identified by the U.S. Geological Survey (2008, and 2010). Those assessment units could include the:

- Muddy-Frontier Sandstone and Mowry Fractured Shale (Figure 34),
- Mowry Fractured Shale Oil (Figure 35),
- Cody Sandstone Gas (Figure 36), and
- Mesaverde Sandstone Gas (Figure 37).

Coalbed natural gas assessment units could be included as a resource play, but are not included here since their potential for future development has already been discussed.

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. The U.S. Geological Survey (2008, 2010) identified the Muddy-Frontier Sandstone and Mowry Fractured Shale as a potential gas play (Figure 34). A recent report prepared for the American Clean Skies Foundation (Navigant Consulting, 2008) also identified the Mowry Shale as a potential shale gas resource in the Planning Area. While the only current production in the Planning Area from the Mowry is oil, this important future gas source could become viable and result in additional drilling activity before the end of the planning cycle.

The four assessment units listed above have little or no drill-stem tests and little production data in the Bighorn Basin Province, so the U.S. Geological Survey (2008 and 2010) used geologic analogs from similar nearby basins to infer production potentials. They identified the Mowry Fractured Shale Oil assessment unit as hypothetical since there are no wells producing oil from fractured reservoirs nor any wells know to have been tested for fracture oil.

When and if a shale gas play is fully 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. Most existing plays in the Planning Area are around the basin margins. A continuous-resource shale gas play would more likely include the deeper portions of the basin (Figure 36) which have as yet seen only limited conventional development.

If a shale gas play aerially overlaps an existing play, existing wellbores may also be utilized in addition to new wells drilled specifically for the shale gas. However, the nature of shale gas plays would likely require drilling of horizontal wells, so the existing 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. 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 or larger for horizontal wells.

The hypothetical Mowry Fractured Shale Oil assessment unit (Figure 35) has the lowest potential for development during the planning period. The U.S. Geological Survey (2010) also has also projected this assessment unit as having the lowest undiscovered resource quantity. If a discovery was made, it is likely that development would also require horizontal drilling technology. Well spacing should be expected to be at 80- to 160-acre spacing or larger.

The three assessment units with potential for continuous-resource sandstone reservoirs will likely include the deeper portions of the basin (Figures 34, 36, and 37). Exploration and future production activities will likely be dominated by vertical or directional drilling.

Although there has not been a lot of past interest in exploration of these four assessment units, some operators have indicated an interest in exploring plays associated with some of them during the planning period. Their projections were used to assist in preparing the development potential map (Figure 45) and projection of 1,715 wells for the planning period. The development potential in parts of the Planning Area underlain by the four assessment units (Figures 34, 35, 36, and 37) is thus predominantly tied to operator identified plays associated with these assessment units or our projections of potential for development of these U.S. Geologic Survey (2010) described assessment units. Consequently, our projections of the number of future wells in these areas are predominantly tied to the above described indications of potential for exploration and development of these four assessment units.

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 value. The limiting factor in depth would be potential reduced permeability of the coal and the ability to efficiently inject and produce the gas.

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

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. 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, carbon dioxide is produced in association with natural gas production at Elk Basin (Tensleep Sandstone), Hamilton Dome (Madison Limestone), Oregon Basin (Frontier Formation) and Spence Dome (Tensleep Sandstone) (Bentley, 2009; Wyoming Geological Association, 1989; and U.S. Department of Energy, 2008b). Of these fields, the greatest concentrations of carbon dioxide gas have been noted at Hamilton Dome (96.4 percent) and Oregon Basin (58 percent) (Bentley, 2009; Wyoming Geological Association, 1989). All of the above are primarily oil producing reservoirs with associated produced gas.

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

- Oil and gas reservoirs – These reservoirs have hosted natural accumulations of oil and/or gas and could, in the future, be used to store carbon dioxide. The entrapment of hydrocarbons indicates that a containment seal is present and any associated water is assumed to be nonpotable. Larger oil and gas reservoirs in the Planning Area could be considered for sequestration. Carbon dioxide injected into a mature oil reservoir can enable incremental oil to be recovered. An additional 10 to 15 percent of original oil in place can be recovered when carbon dioxide is injected. There are currently no carbon dioxide injection enhanced recovery projects in the Planning Area, or a pipeline for carbon dioxide transportation.
- Unminable coal seams – Unminable coal seams are considered to be those that are too deep or too thin to be economically mined. The majority of the Tertiary

and Cretaceous coals in the Planning Area meet these criteria. If methane contained in Planning Area coal beds becomes economically producible then there could be a future opportunity to inject carbon dioxide, which could sweep additional methane from the coalbeds and allow adsorption by the coals of the carbon dioxide. Since coal beds preferentially adsorb carbon dioxide, they provide excellent storage sites.

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

REASONABLY FORESEEABLE DEVELOPMENT SCENARIOS FOR RESOURCE MANAGEMENT PLAN ALTERNATIVES A, B, C, AND D

The Environmental Impact Statement for the Bighorn Basin Resource Management Plan presently contains four management alternatives. Each alternative contains management imposed restrictions that may negatively affect oil and gas development. These restrictions can effectively decrease the base line estimated number of well locations in areas of Federal oil and gas ownership. For each alternative, we have analyzed the restrictions and estimated the number of resulting well locations that could be reduced from the base line total.

PROCEDURES USED TO DETERMINE WELL LOCATION REDUCTIONS

Well location reductions from the base line reasonably foreseeable development scenario, for each alternative, are due to proposed management restrictions. Restrictions applied to each alternative can affect oil and gas development activities by not allowing leasing, not allowing surface occupancy, controlling surface use, or placing restrictive stipulations on conditions of approval of Federal applications to drill. Reduced oil and gas activities result in increased exploration and development costs, fewer drilled wells, and reduced production. For reasonably foreseeable development scenario analysis purposes, the restrictions for the five alternatives analyzed were separated into four categories designated A, B, C, and D. Restrictions on drilling are progressively more limiting from restriction category A to restriction category D and are:

- Restriction Category A - These areas are open to leasing. Restrictions are relatively minor and result in standard lease terms and conditions that are applied to every Federal oil and gas lease sold in Wyoming. These restrictions are considered to have no affect on the number of well locations or production for any alternative.

- Restriction Category B – These areas are open to leasing subject to relatively minor constraints. These restrictions can have a moderate effect such as multiple, consecutive timing restrictions for protection of wildlife values such as; crucial winter range or raptor nesting habitat. We also considered restrictions such as avoidance of areas near wetlands, riparian areas, or perennial waters that could have a moderate effect on the potential locations of wells and cumulative production.
- Restriction Category C – These areas are open to leasing, subject to major constraints. These restrictions can have a moderate to severe effect on the location of wells; such as no surface occupancy stipulations on an area more than 40 acres in size or requirements that view sheds be protected, thus requiring that well locations and production facilities not be visible from areas such as historic trails. Restrictions tied to sage grouse core areas would also be within this restriction category. Overlapping minor constraints may also severely limit the development of oil and gas resources.
- Restriction Category D areas are closed to leasing. These are areas where a determination is made that other land uses or resource values cannot be adequately protected with even the most restrictive lease stipulations. This category has the most severe restrictions on oil and gas activity and production.

Reductions in well locations from the base line reasonably foreseeable development projection were determined as described below:

- An estimate of the number of well locations/township that could be drilled in each development potential category over the 20-year life of the Resource Management Plan was made for conventional oil and gas development activity (Table 5) and for coalbed natural gas development activity (Table 7).
- The acres of Federal oil and gas ownership for each area of non-coalbed gas development potential (Figure 45) was determined using GIS software. Acres of non-Federal oil and gas minerals were not included because proposed Resource Management Plan decisions will only apply to Federal oil and gas minerals. We assumed development on non-Federal minerals will occur as estimated in the base line foreseeable development projection.
- The acres of Federal oil and gas ownership for each area of coalbed natural gas development potential (Figure 46) was determined using GIS software. Acres of non-Federal oil and gas minerals were not included because proposed Resource Management Plan decisions will only apply to Federal oil and gas minerals. We assumed development on non-Federal minerals will occur as estimated in the base line foreseeable development projection.
- Next, the area covered by each category of restriction (B, C, or D category) within the moderate, low, or very low development potential areas (for non-coalbed gas and coalbed natural gas potential) was calculated using GIS software. The area within category A was not calculated, since we previously determined that this type of restriction would have no affect on the number of well locations for any

alternative. As an example, the Alternative A acreage calculations for each potential area are presented in Table 8.

- After the acres of Federal oil and gas were calculated for each alternative in each restriction category, the percent reduction in well locations for each alternative in each category of restriction was estimated. This estimate is a percent of the well locations which would not be drilled in each area due to the specific category of restriction. As an example, the results of our calculations for conventional oil and gas under Alternative A, Category C restrictions are shown in Table 9 below. Category C restrictions for Alternative A were calculated to reduce non-coalbed oil and gas wells by 161 wells and coalbed natural gas wells by 16 wells. The number of townships was calculated by dividing the Federal acres by 23,040 acres per township.
- The percent reduction for each alternative, each category of restriction, and each development potential combination was determined. Potential well reduction determinations were made for each of these additional restrictions. The estimates of reduction in well locations were then summed for both non-coalbed oil and gas and for coalbed natural gas for each alternative. The results of these calculations are shown in Table 10.
- Because reductions in well locations were calculated only for Federal wells, the percent of Federal wells projected to be drilled for each alternative is different. The percentage of Federal wells projected to be drilled for each alternative is presented in Table 10.

ESTIMATED FUTURE OIL AND GAS PRODUCTION

Future oil production and gas production for 2009 through 2028 was estimated for each alternative using the projected well counts from Table 10. The statistical methods used to project production for each alternative were the same as those used to project production for the base line scenario (see above). Cumulative production for Alternative A was projected to be 255,775,043 thousand cubic feet of gas and 128,041,197 barrels of oil (Table 11). Cumulative production for Alternative B was projected to be 158,441,721 thousand cubic feet of gas and 79,316,055 barrels of oil (Table 12). Cumulative production for Alternative C was projected to be 278,288,661 cubic feet of gas and 139,311,536 barrels of oil (Table 13). Cumulative production for Alternative D was projected to be 243,079,392 thousand cubic feet of gas and 121,685,745 barrels of oil (Table 14).

POTENTIAL SURFACE DISTURBANCE

Table 15 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 4,510 active wells in March of 2009, industry will abandon 1,043wells (23 percent) by December 2027,

- of the existing 2,966 active Federal Minerals wells in March of 2009, industry will abandon 697 wells (23 percent) by December 2027,
- the success rate of new coalbed natural gas wells will be 90 percent, and
- the success rate for new conventional wells (excluding coalbed natural gas wells) will be 80 percent.

Table 15 shows our projection of new exploratory and development wells (1,865 wells with 1,354 of those wells managed by the Bureau) that could be drilled in the Planning Area from 2008-2027. There are an additional 4,510 existing active wells (Wyoming Oil and Gas Conservation Commission, 2009), as of March 2, 2009. New wells plus existing wells will total of 6,375, with 4,320 of those wells located on Bureau managed oil and gas minerals. Table 15 calculates associated acres of total surface disturbance (short-term disturbance) directly associated with all new wells and existing active wells (as of March 2, 2009). Approximately 5,595 acres of new short-term surface disturbance (4,062 acres of disturbance on Bureau managed oil and gas minerals) could occur if all projected wells are drilled. Total short-term surface disturbance (for all well types) would be 12,360 acres, with 8,511 of those acres on Bureau managed oil and gas minerals.

Table 15 also calculates new producing wells remaining in production after all new exploratory and development wells are drilled and all dry holes are abandoned and reclaimed (1,507 total new producing wells with 1,094 of those new producing wells on Bureau managed oil and gas minerals). There are an additional 3,467 existing wells (2,269 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 15 calculates unreclaimed associated acres of total surface disturbance (long-term disturbance) directly associated with all remaining wells. Approximately 2,261 acres of new unreclaimed surface disturbance (1,641 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 7,461 acres, with 5,044 of those acres on Bureau managed oil and gas minerals.

For all alternatives, the same methods of calculating surface disturbance (short-term and long-term) were used. Projections of future wells for each alternative were brought forward and used in these calculations. The resulting short-term and long-term surface disturbance figures for each alternative are presented in Tables 16, 17, 18, and 19.

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 1,865 wells could be drilled for this period. As many as 150 of these new drilled wells could be completed as coalbed natural gas wells. Table 10 shows the forecasts for future wells for the base line and all alternatives. Our forecast of annual and cumulative oil and gas production for 2008 through 2027 for the newly drilled wells is presented in Table 6 and for the alternatives in Tables 11, 12, 13, and 14. Short-term and long-term surface disturbance associated with existing wells and future projected wells for the base line is presented in Table 15 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. Tables 16, 17, 18, and 19 show the projections of disturbance for the four alternatives.

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GLOSSARY

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

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

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

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

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

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

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

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

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

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

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.

Rocky Mountain Foreland. That area of the Rocky Mountains bounded on the west by the fold and thrust belt an on the east by the undeformed craton.

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

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

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

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

Total petroleum system. A total petroleum system consists of all genetically related petroleum generated by a pod or closely related pods of mature source rocks. Particular emphasis is placed on similarities of the fluids of petroleum accumulations. These fluids are closely associated with the generation and migration of petroleum. It is characterized by: 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.

Unstable grains. Said of mineral grains within a sedimentary rock, that do not resist chemical change after deposition.

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FIGURES

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Figure 1.

The Bighorn Basin Planning Area and its location within Wyoming.

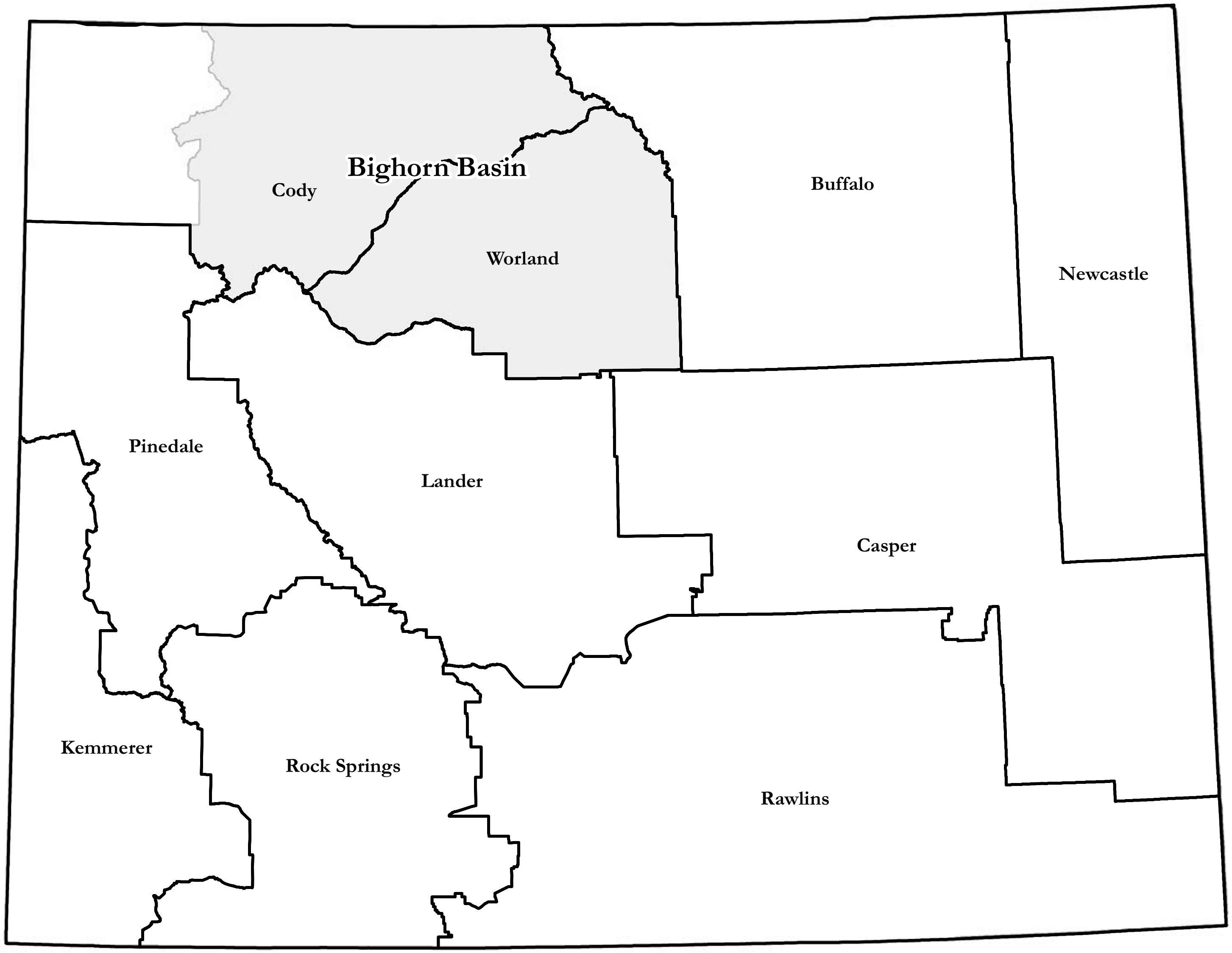

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Figure 2.

Location and initial status of all wells drilled within the Bighorn Basin Planning Area. Data from IHS Energy Group (2009).

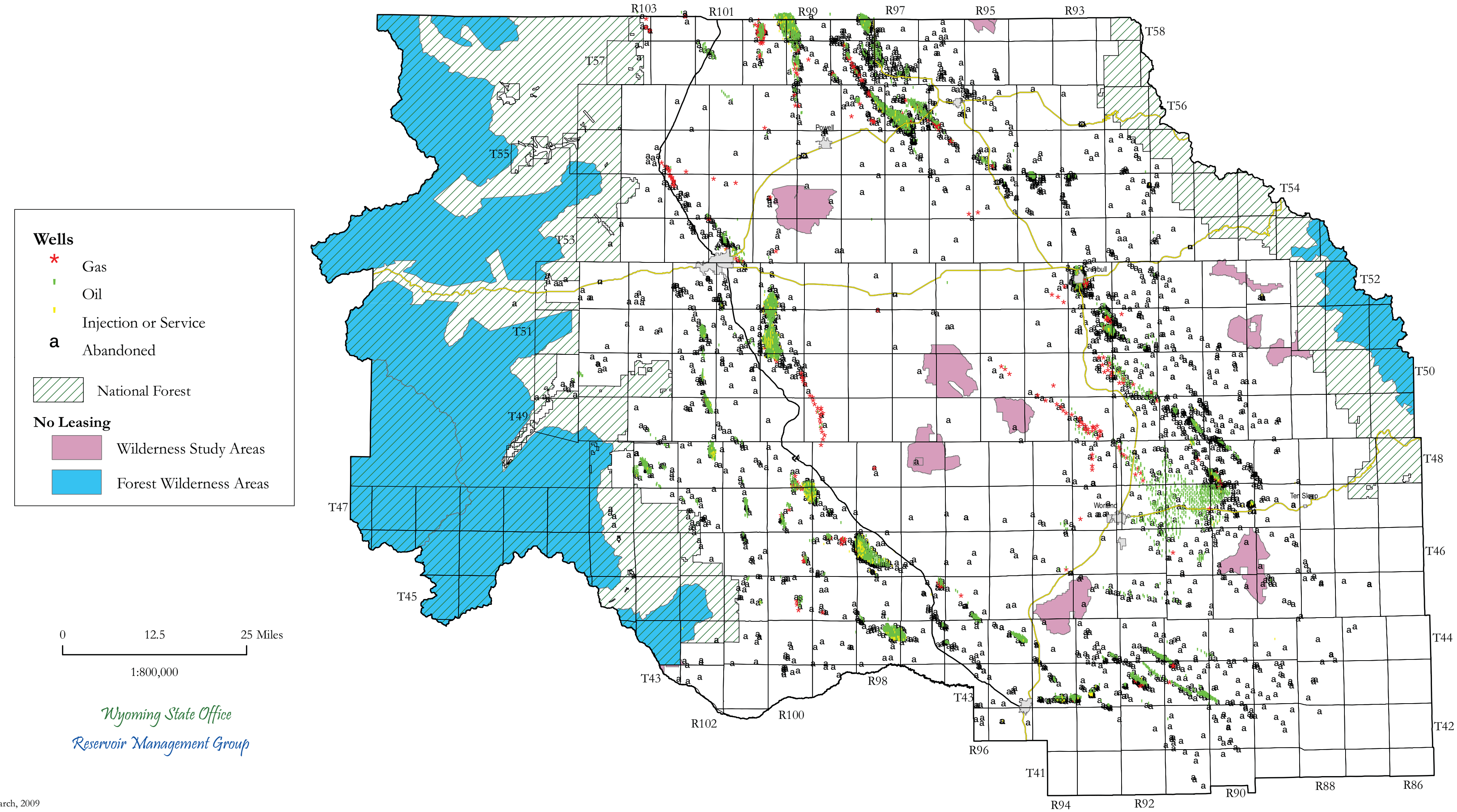

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Figure 3.

Bighorn Basin Planning Area with National Forest, National Forest wilderness and Bureau managed wilderness study areas.

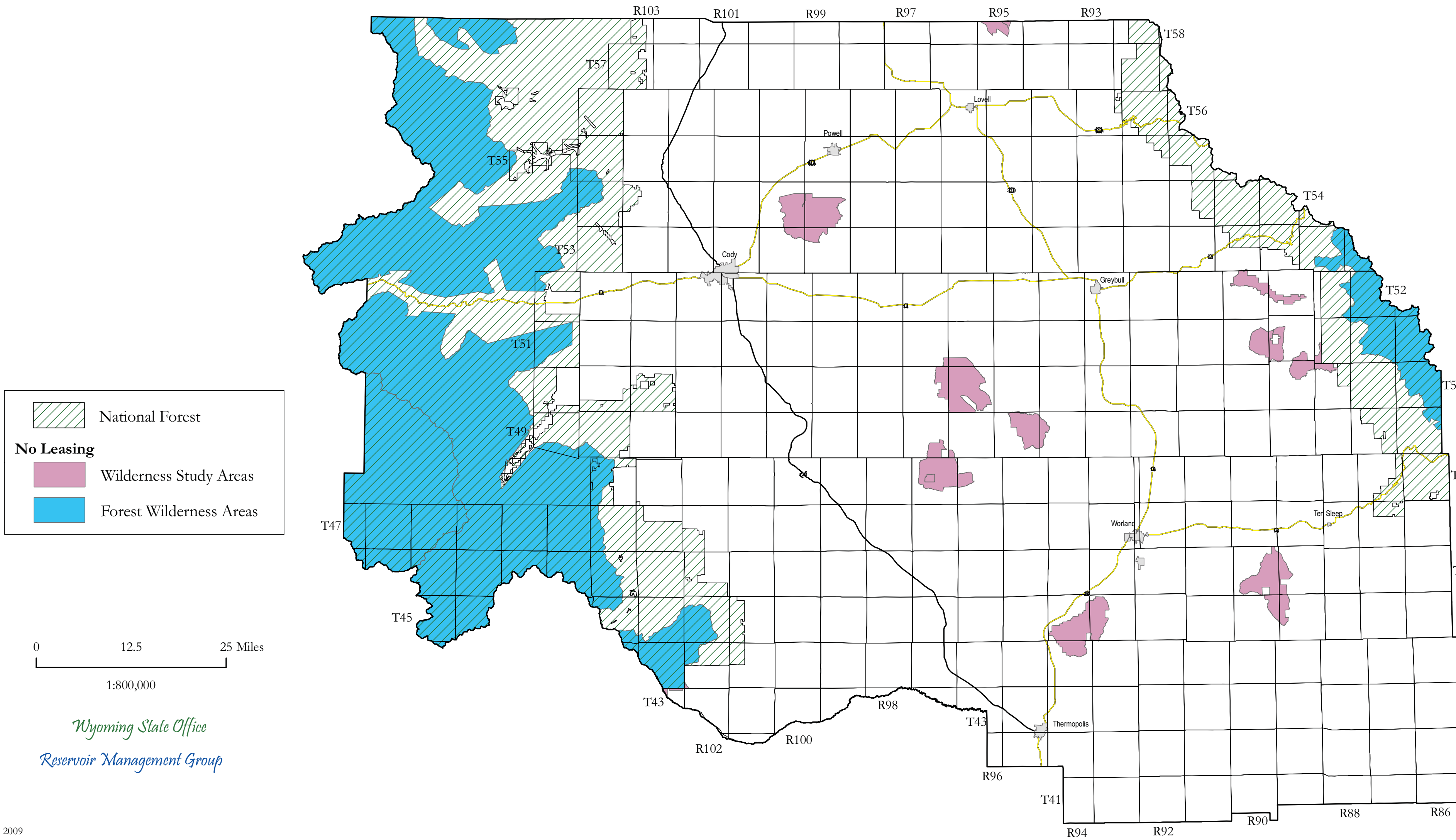

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Figure 4.

Major structural elements of the Bighorn Basin Planning Area. Modified from Zapp (1956) and Blackstone (1993).

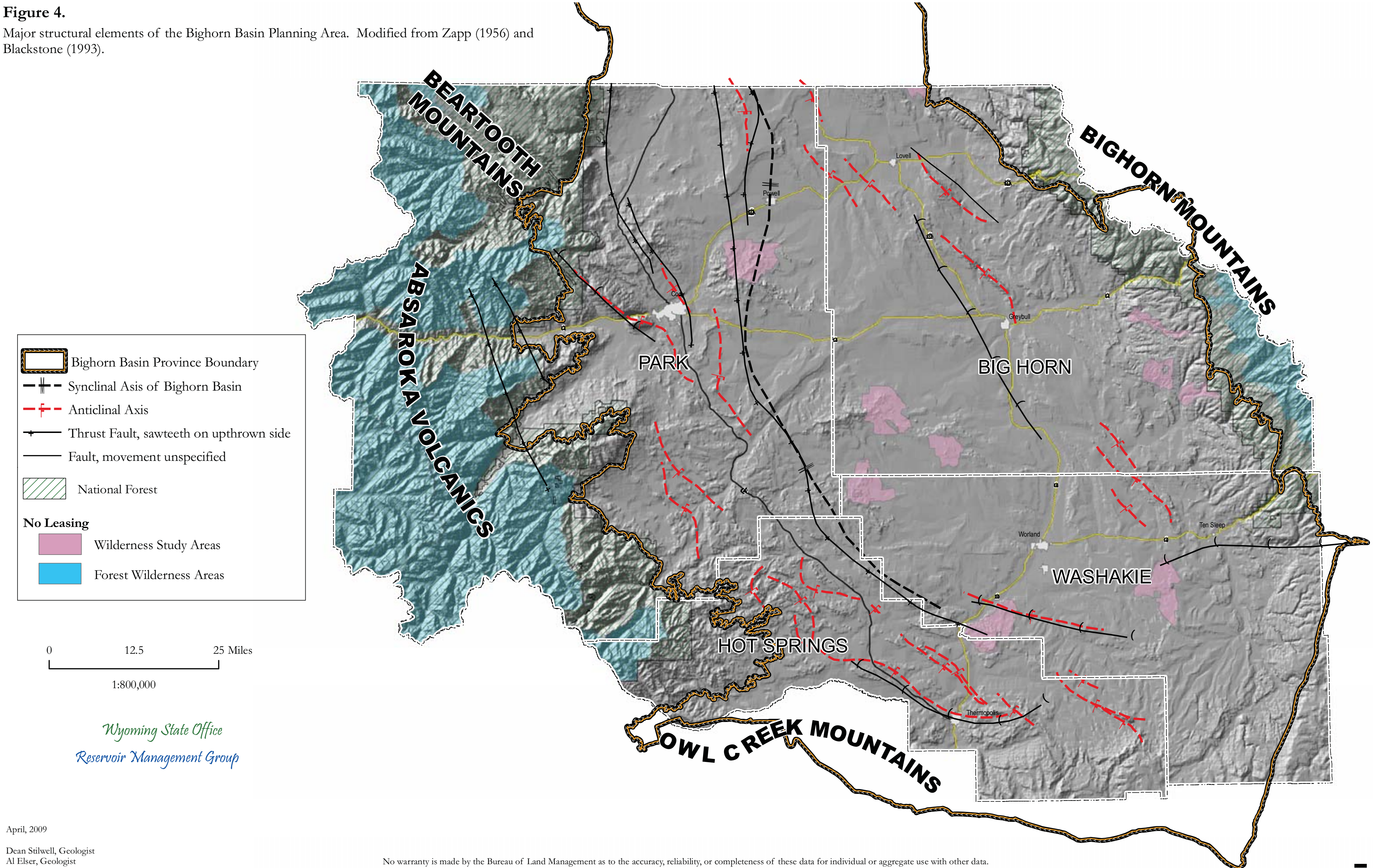

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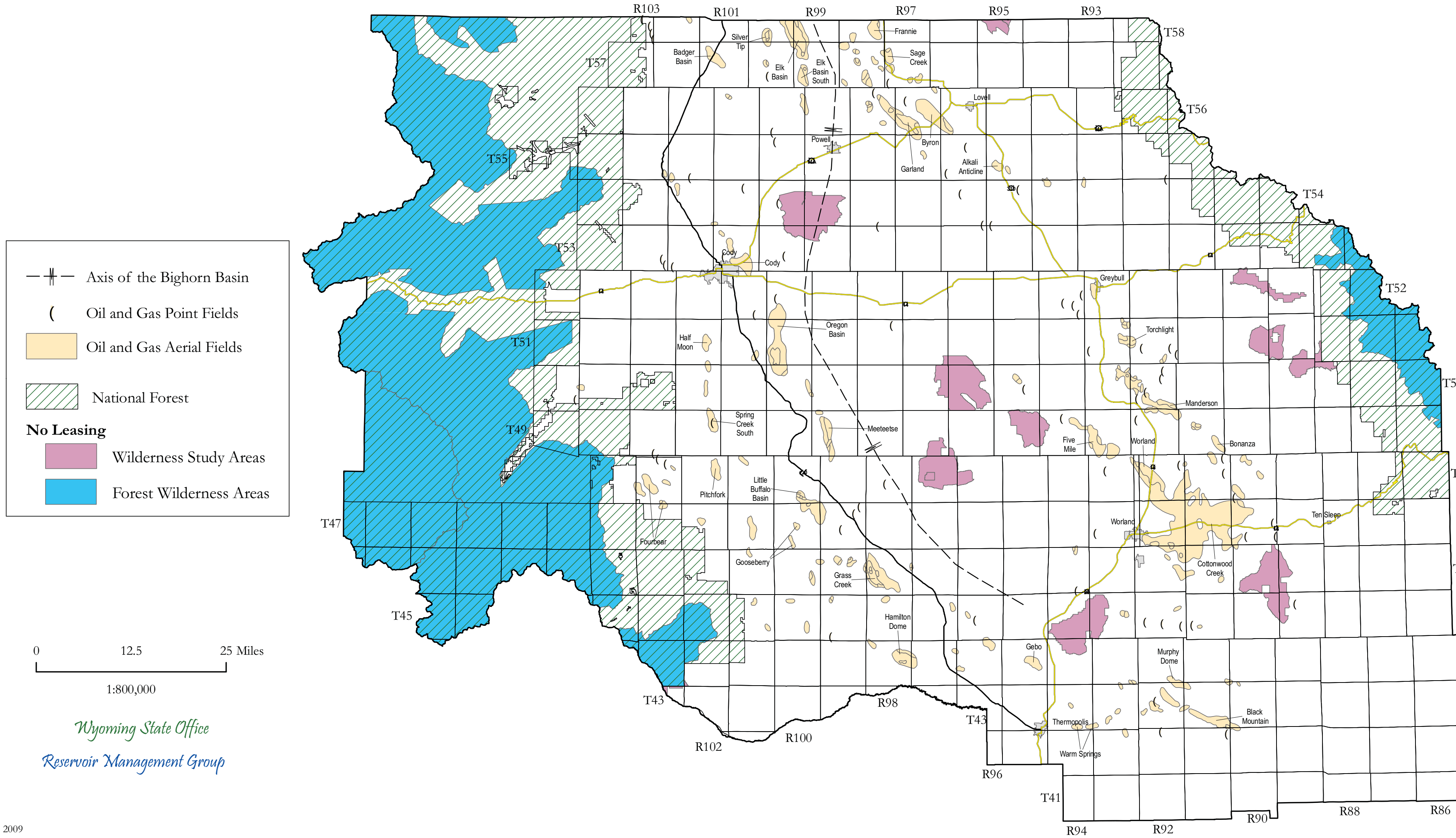
Figure 5.

Field boundaries within the Bighorn Basin Planning Area. Field data from DeBruin (2006).



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Era	Age		Group	Formation/Rock Member	Hydrocarbons
Cenozoic	Tertiary	Eocene		Wapiti Fm / Aycross Formation	
				Tatman Formation	
				Willwood Formation	
		Paleocene		Fort Union Formation	Gas
Mesozoic	Cretaceous	Upper		Lance Formation	Gas Oil
				Meeteetse Formation / Lewis Shale	Gas Oil
			Mesaverde	Teapot Sandstone	
				Mesaverde Formation	Gas Oil
				Cody Shale	Gas Oil
			Colorado	Frontier Formation	Gas Oil
				Mowry Shale	Oil
		Lower	Dakota	Muddy Sandstone	Gas Oil
				Thermopolis Shale	
				Cloverly Formation	Gas Oil
	Jurassic	Upper		Morrison Formation	Gas Oil
		Middle		Sundance Formation	Gas Oil
				Gypsum Spring Formation	
		Lower		Nugget Sandstone	Gas Oil
	Triassic	Upper	Chugwater	Popo Agie Formation	
				Crow Mountain Sandstone	Gas Oil
				Alcova Limestone	
		Lower		Red Peak Formation	
				Dinwoody Formation / Goose Egg Formation	Oil (Dinwoody)
Paleozoic	Permian			Phosphoria Formation / Goose Egg Formation	Gas Oil (Phosphoria)
	Pennsylvanian	Upper		Tensleep Sandstone	Gas Oil
		Lower			
	Mississippian	Upper		Amsden Formation	Gas Oil
		lower	Madison	Madison Limestone	Gas Oil
	Devonian	Upper		Darby Formation	
		Lower		Beartooth Butte Formation	
	Ordovician	Upper		Bighorn Dolomite	Gas Oil
	Cambrian	Upper		Gallatin Limestone	
		Middle		Gros Ventre Formation	
				Flathead Sandstone	Gas Oil

Figure 6. Generalized stratigraphic chart of the Bighorn Basin Planning Area with oil and gas bearing zones (modified from Love et al., 1993).

Figure 7.

Location and status of Bighorn Basin Planning Area wells drilled between January 1, 1999 and December 31, 2008. Data from IHS Energy Group (2009).

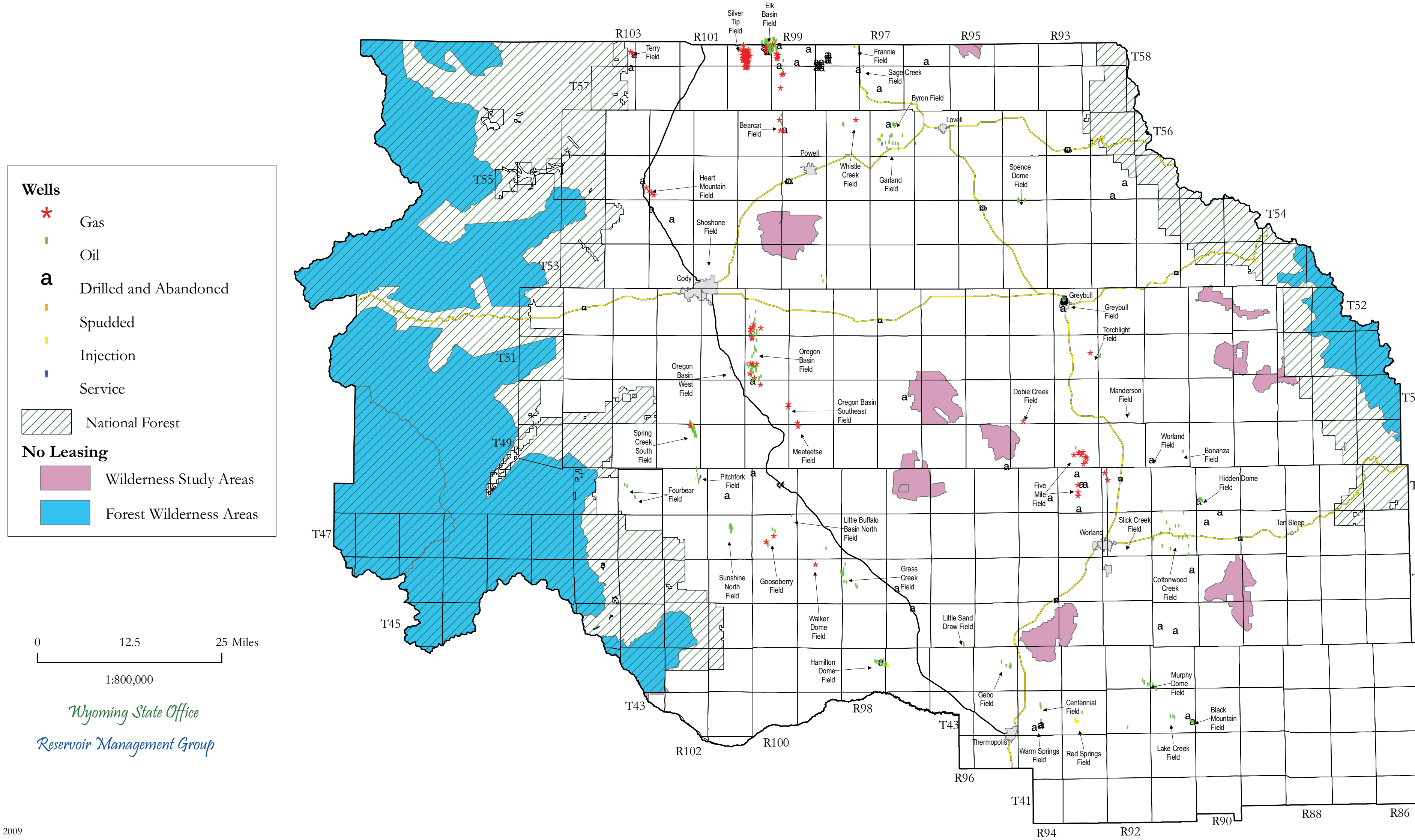

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Figure 8.

Location of oil and gas unit agreements within Bighorn Basin Planning Area. Data from Bureau files.

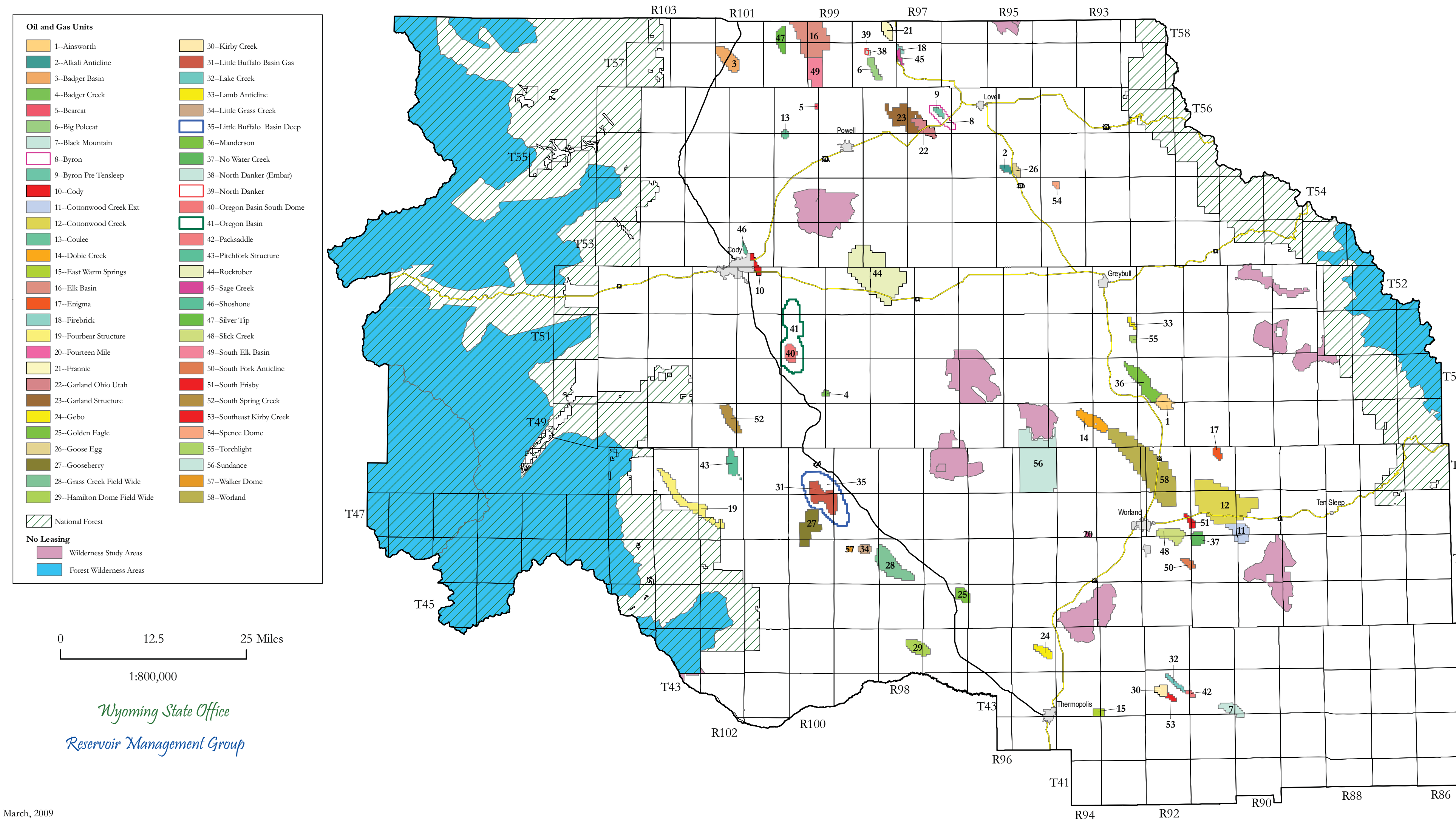

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Figure 9.

Location of communitization agreements within Bighorn Basin Planning Area. Data from Bureau files.

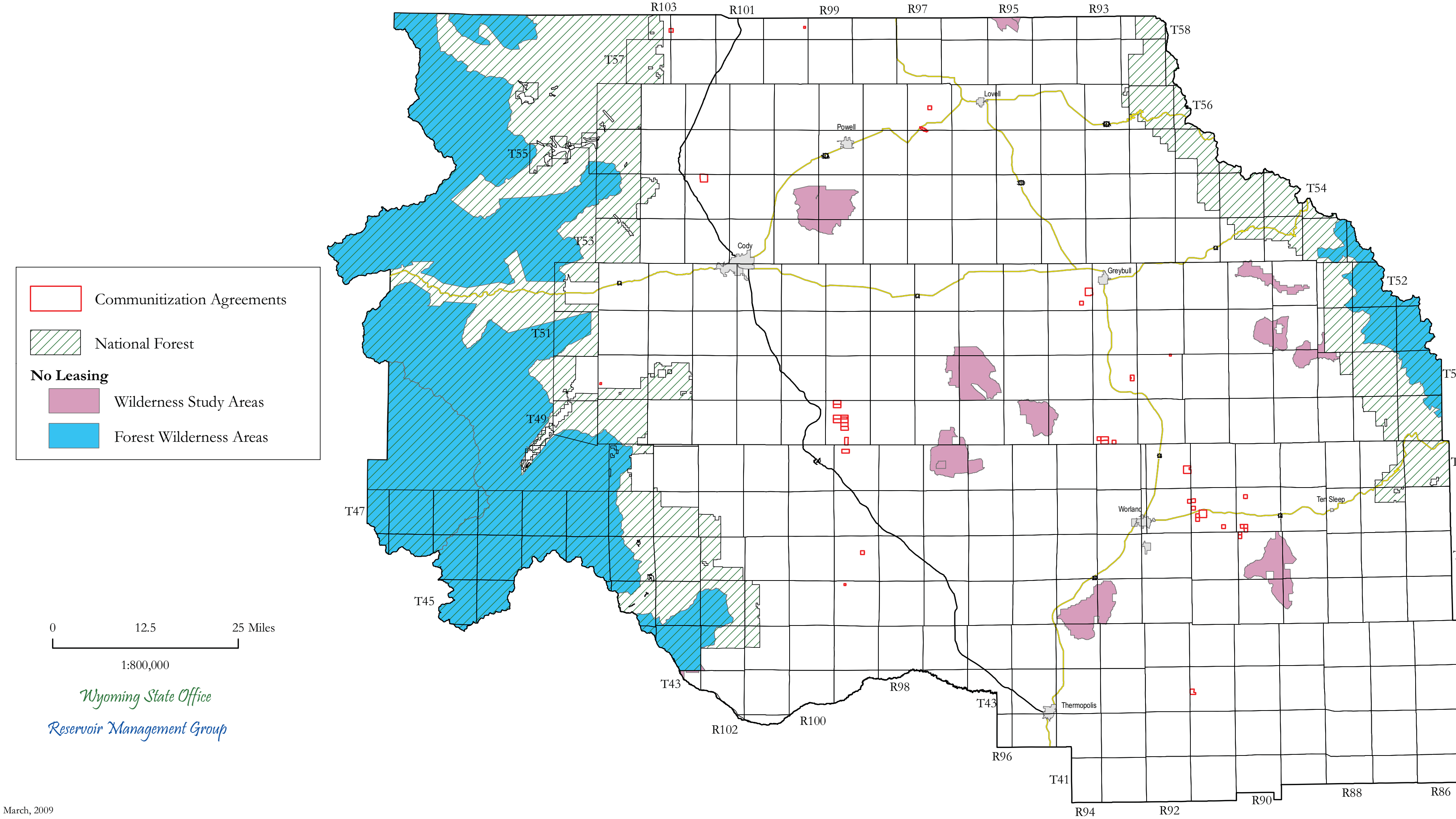

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Figure 10.

Locations of fields discovered within the Bighorn Basin Planning Area prior to 1920. Locations from DeBruin (2006).

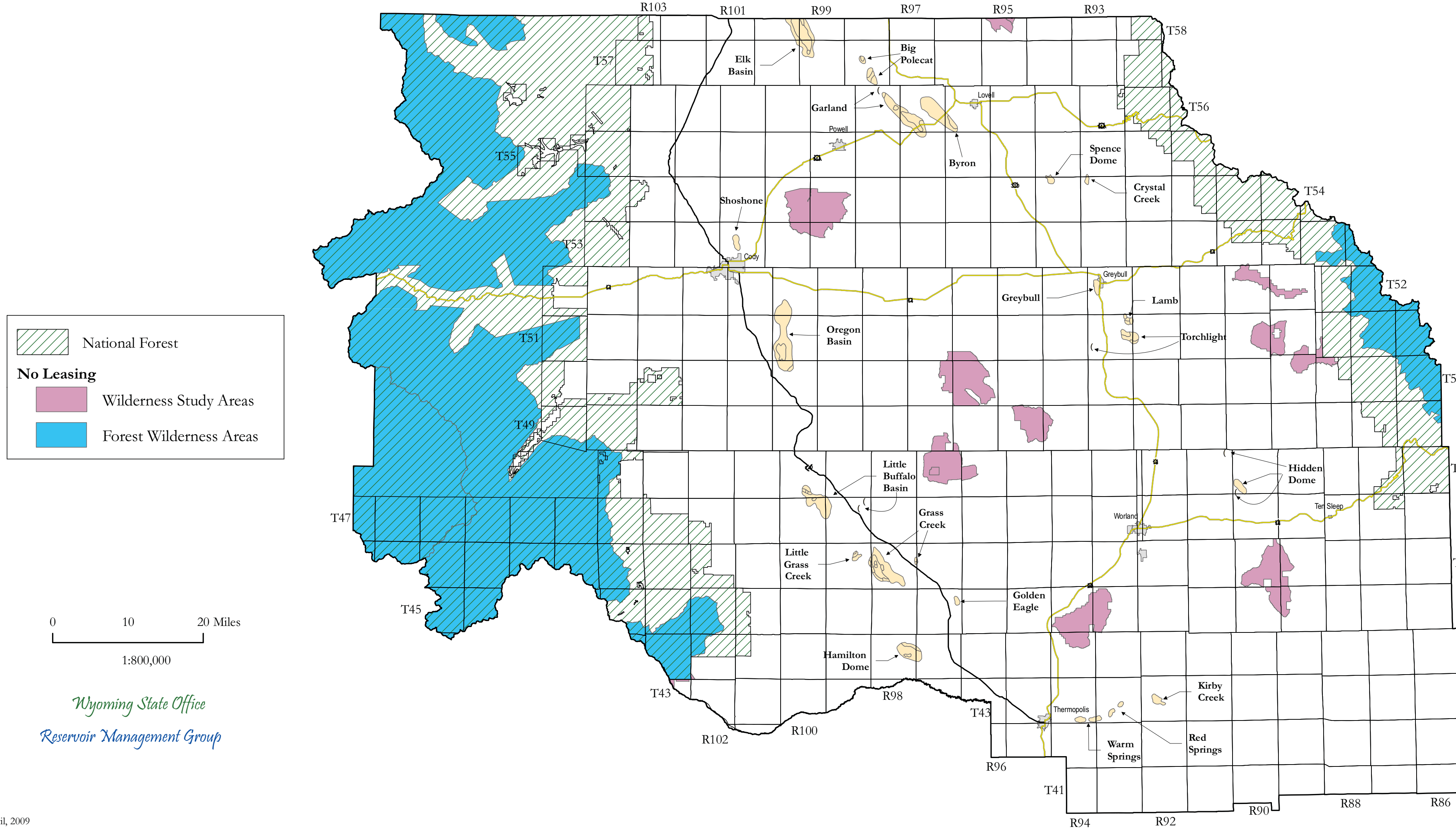

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Figure11.

Locations of fields discovered within the Bighorn Basin Planning Area in the 1920s and 1930s. Locations from DeBruin (2006).

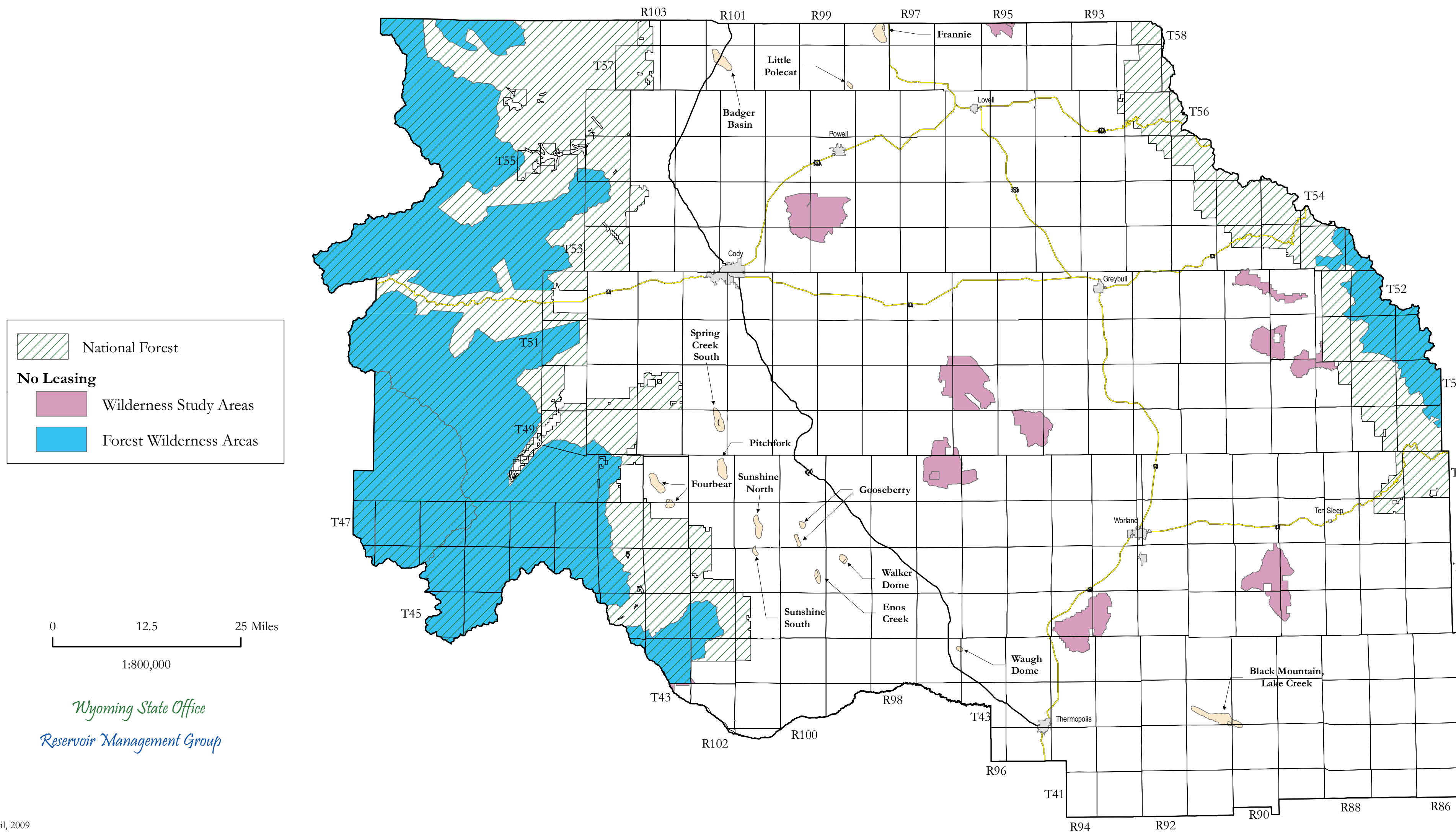

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Figure 12.

Locations of fields discovered within the Bighorn Basin Planning Area in the 1940s. Locations from DeBruin (2006) and Bureau files.

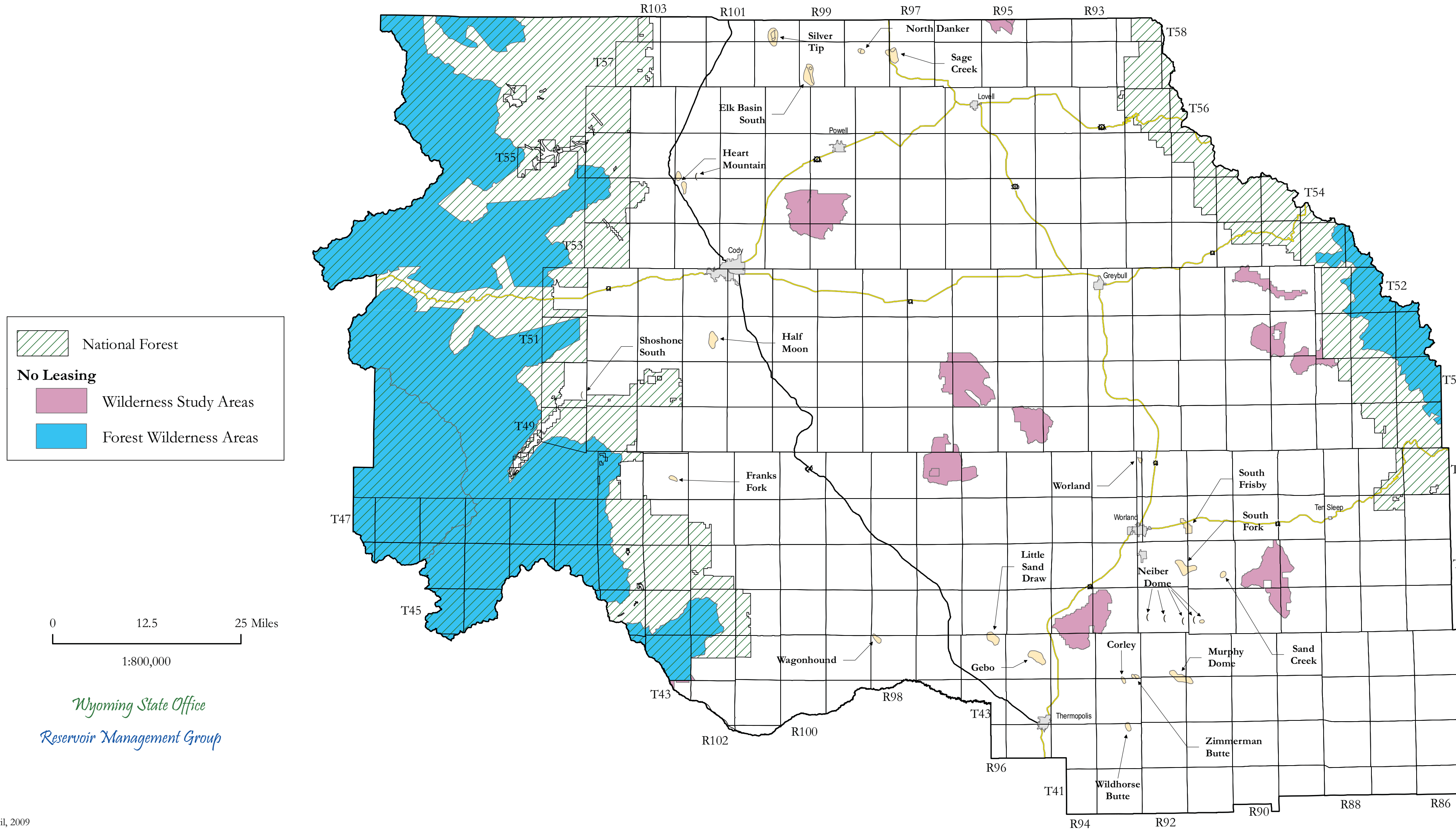

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Figure 13.

Locations of fields discovered within the Bighorn Basin Planning Area from 1950 to the present. Locations from DeBruin (2006).

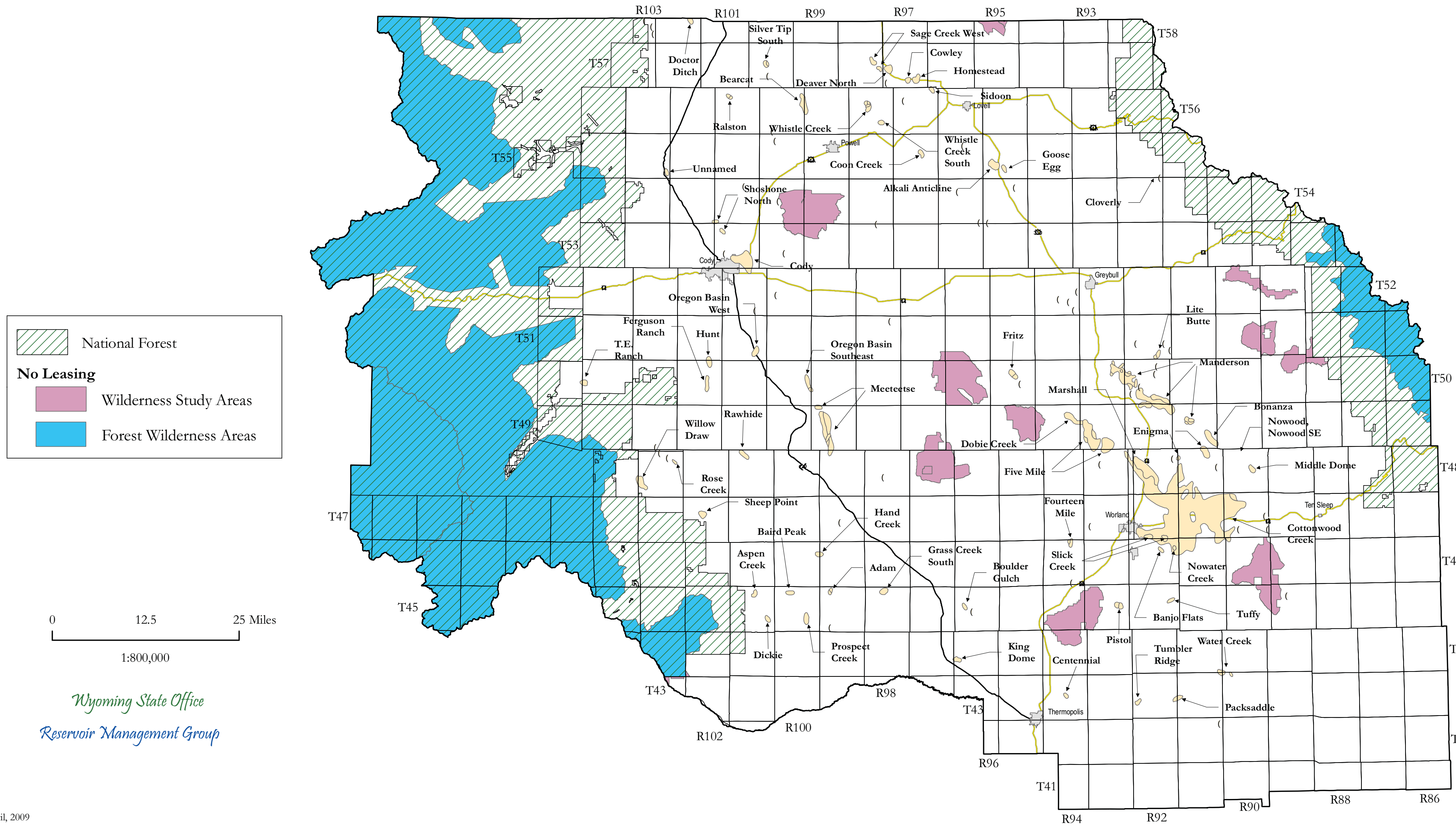

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Figure 14.

Bighorn Basin Planning Area locations of all wells that have been spudded and not completed and those still capable of producing oil and gas.

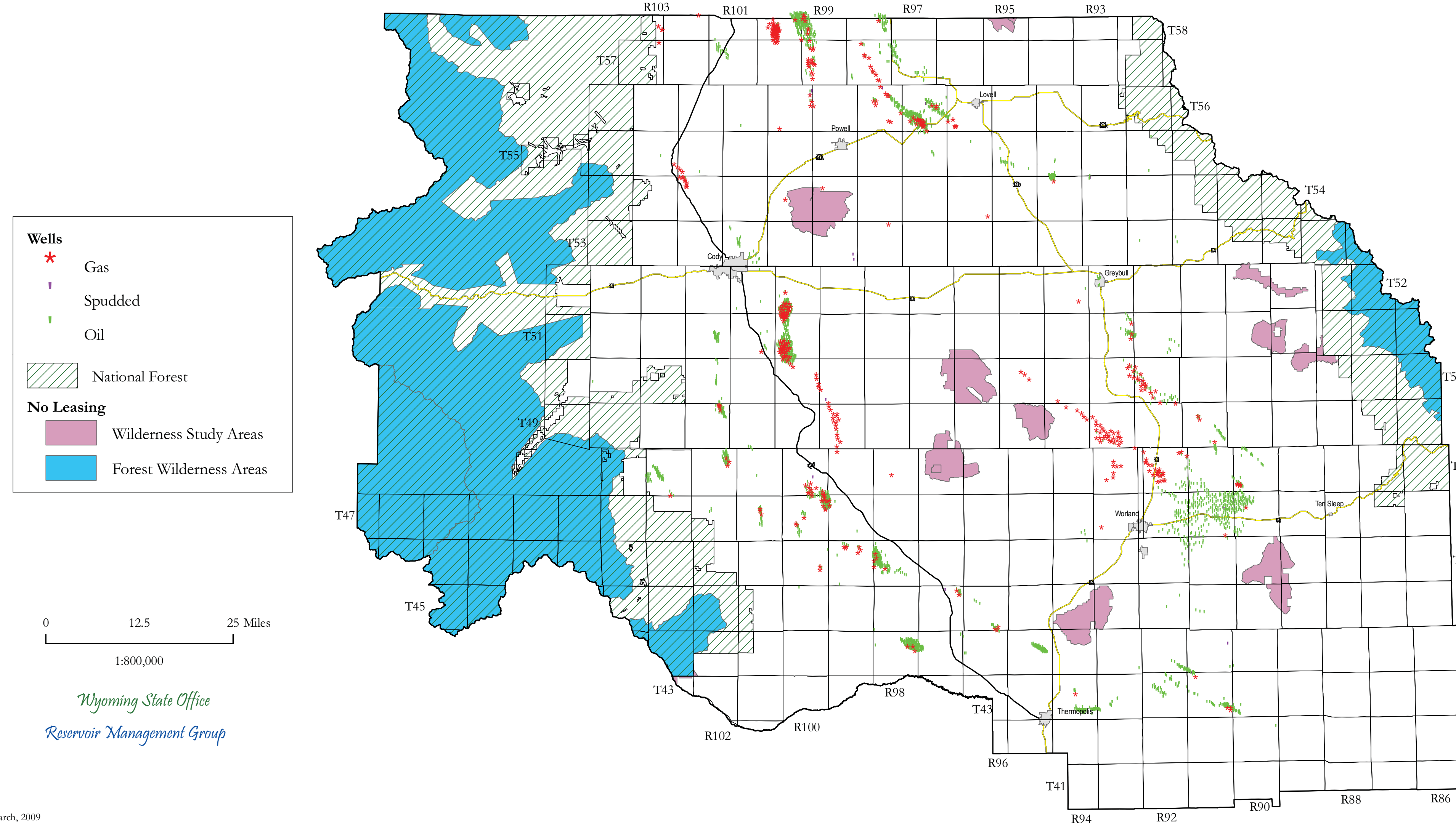

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Figure 15.

Bighorn Basin Planning Area locations of all wells being used for enhanced oil recovery purposes (steam injection, water injection, polymer-enhanced flooding, surfactant flooding, and carbon dioxide injection, for disposal (acid gas and water disposal), monitoring, and as source wells.

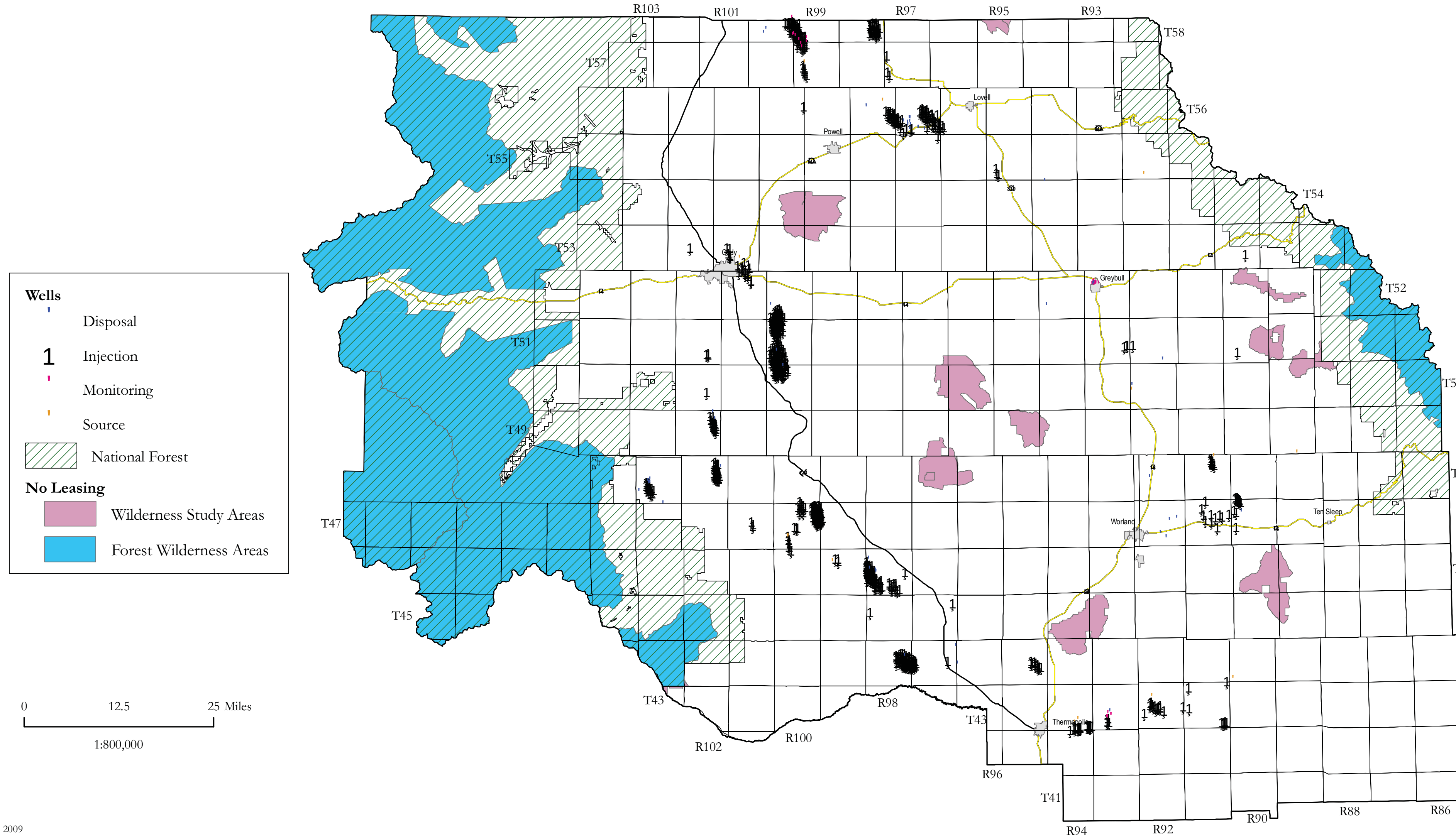

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Figure 16. Annual wells spud and cumulative wells spud within Bighorn Basin Planning Area from 1940 through 2008. Data from IHS Energy Group (2009).

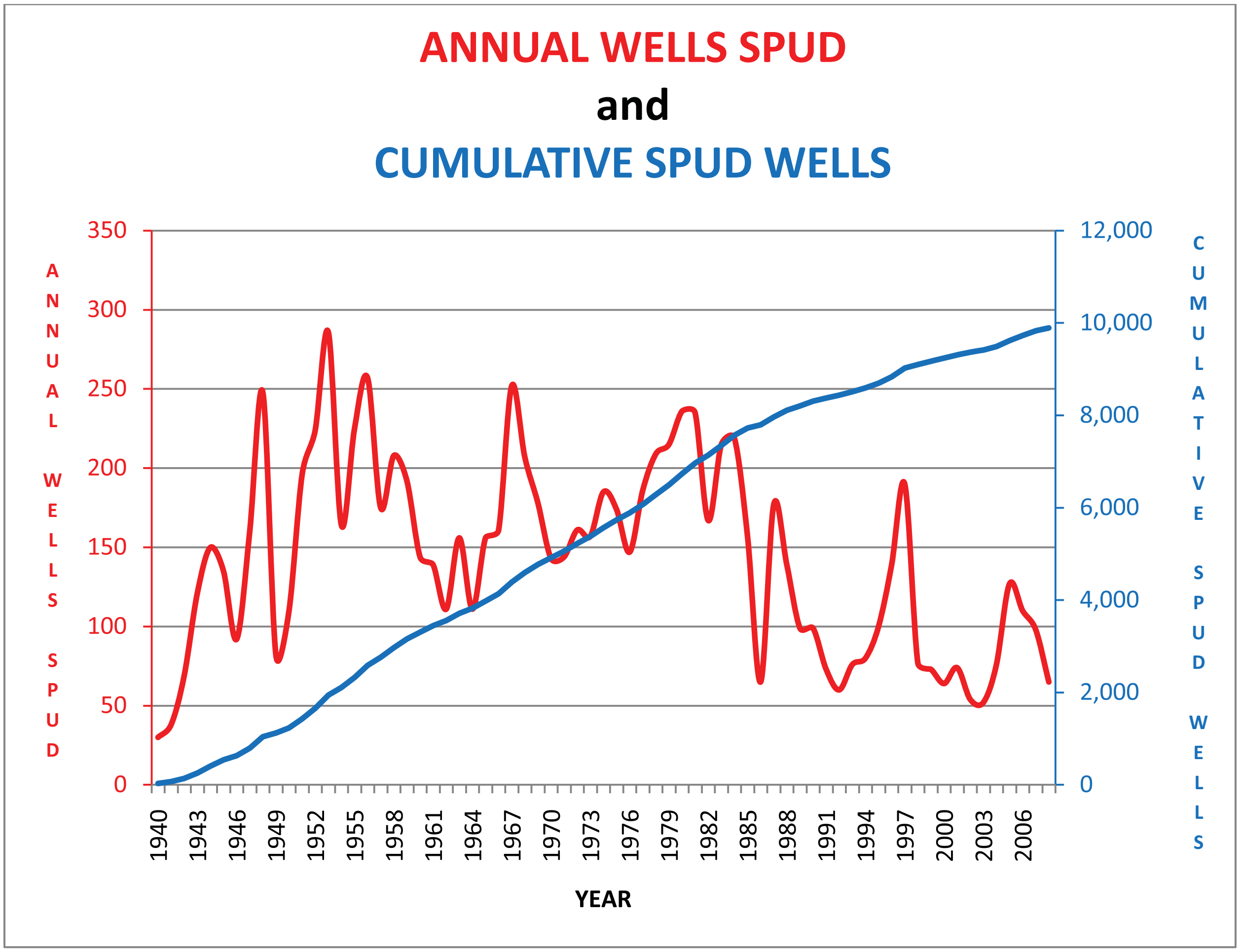


Figure 17. Footage drilled within the Bighorn Basin Planning Area on a yearly basis and cumulatively. Data from IHS Energy Group (2009).

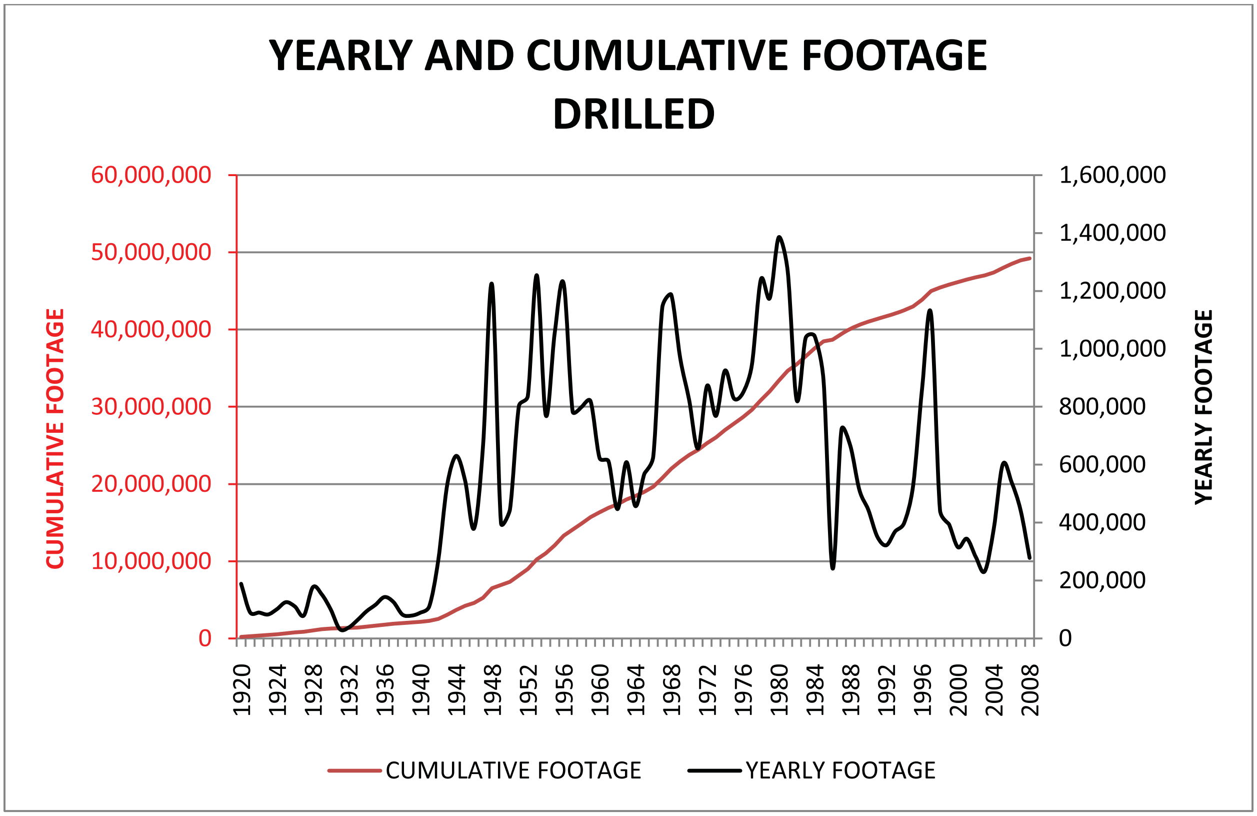
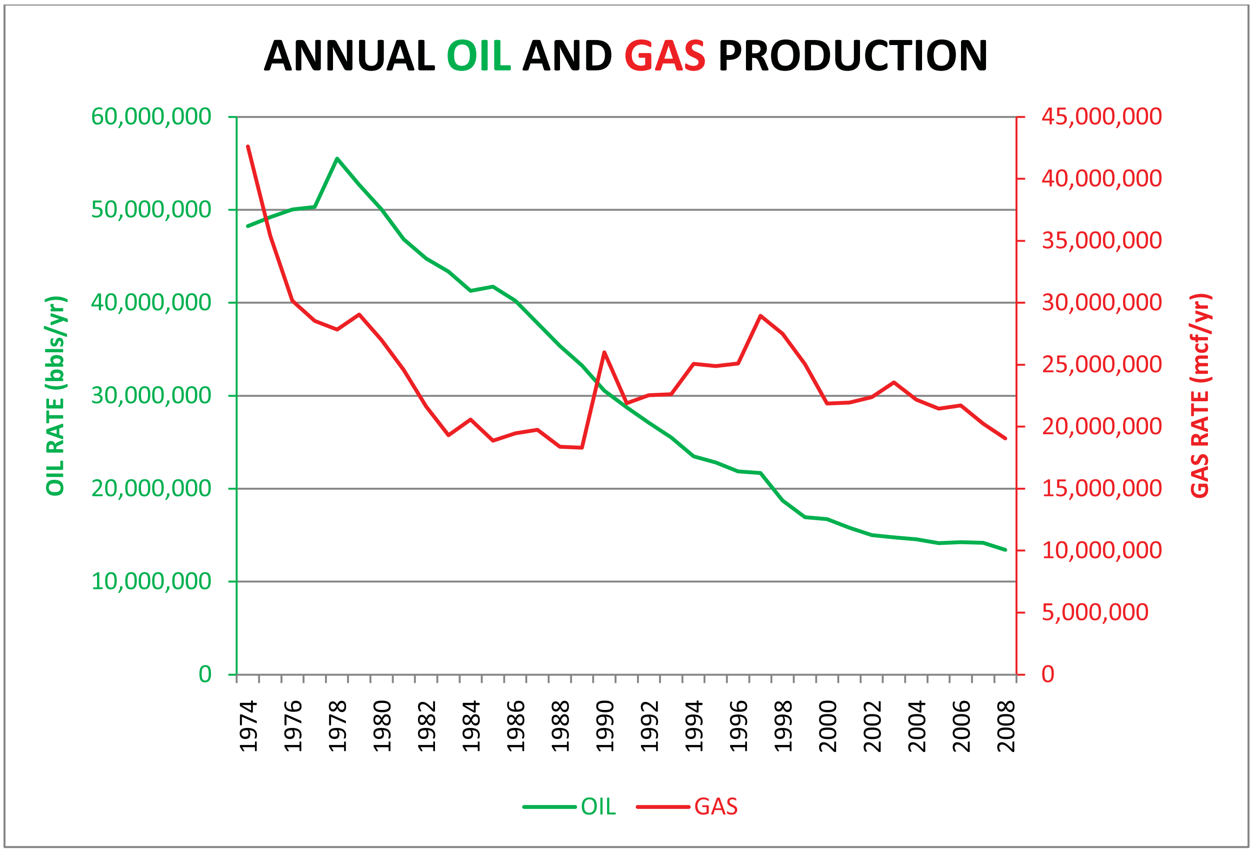


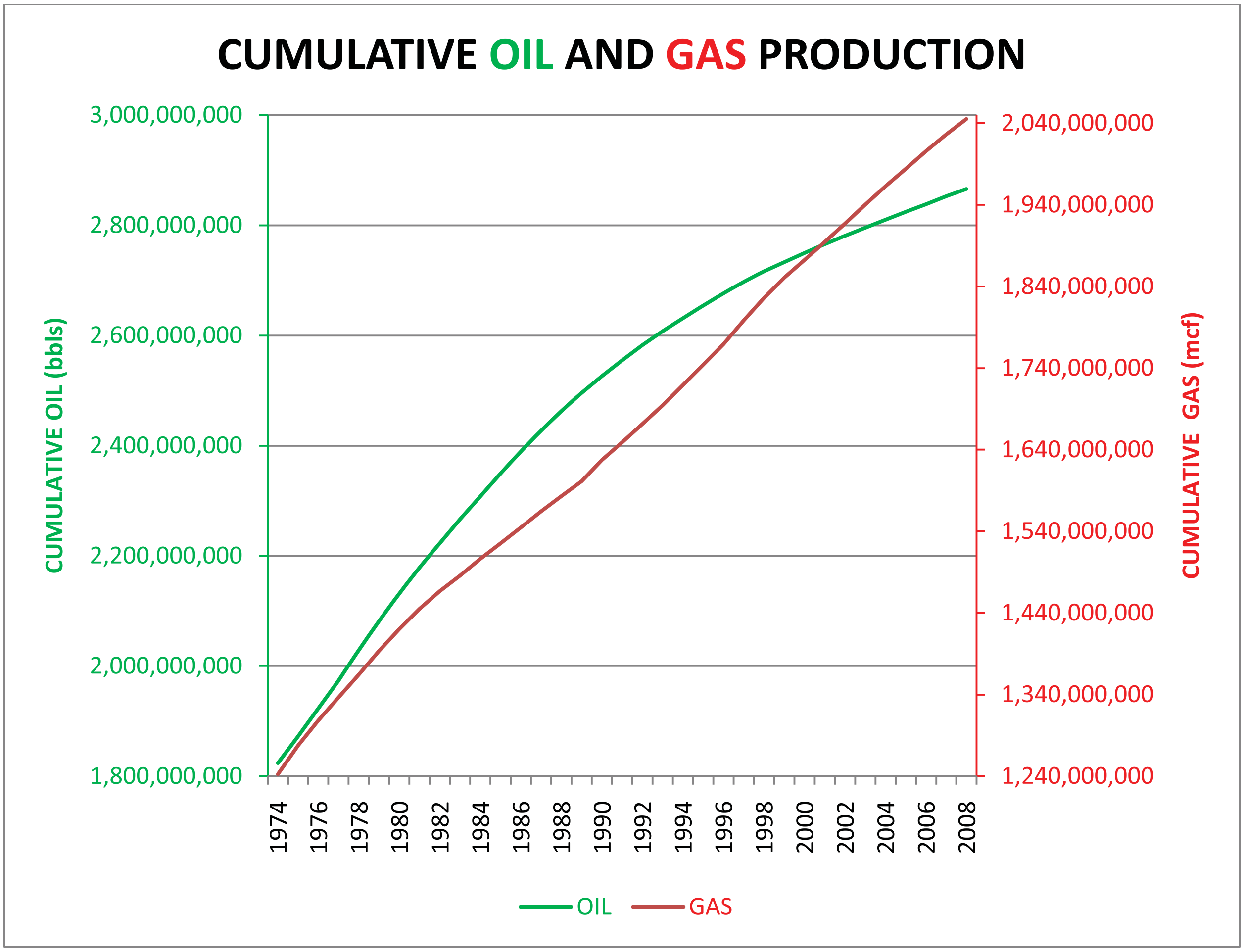
Figure 18. Oil and gas yearly production rates from Federal, private, and state wells in the Bighorn Basin Planning Area. Data from IHS Energy Group (2009).



bbls/yr = barrels per year

mcf/yr = thousand cubic feet per year

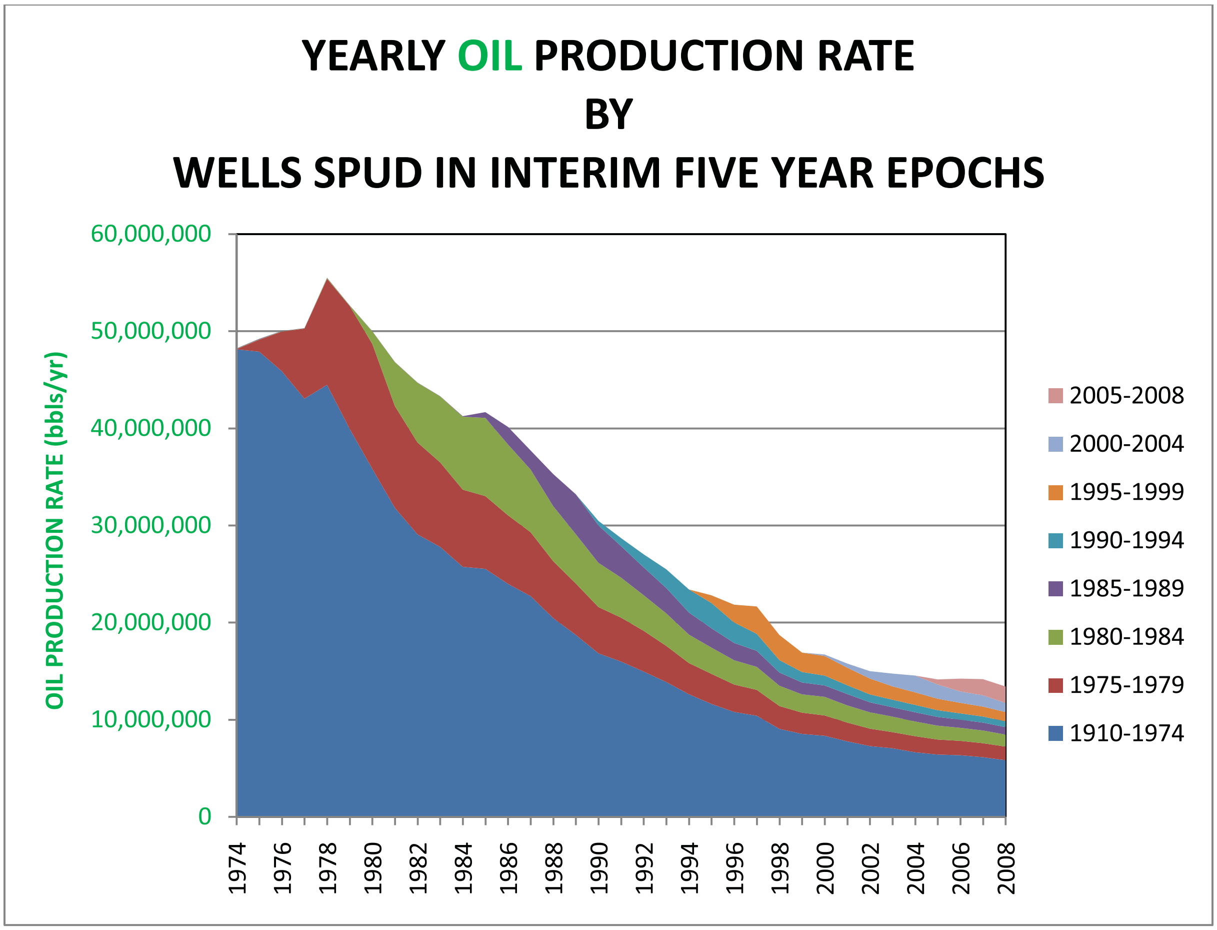
Figure 19. Oil and gas cumulative production rates from Federal, private, and state wells in the Bighorn Basin Planning Area. Data from IHS Energy Group (2009).



bbls = barrels of oil

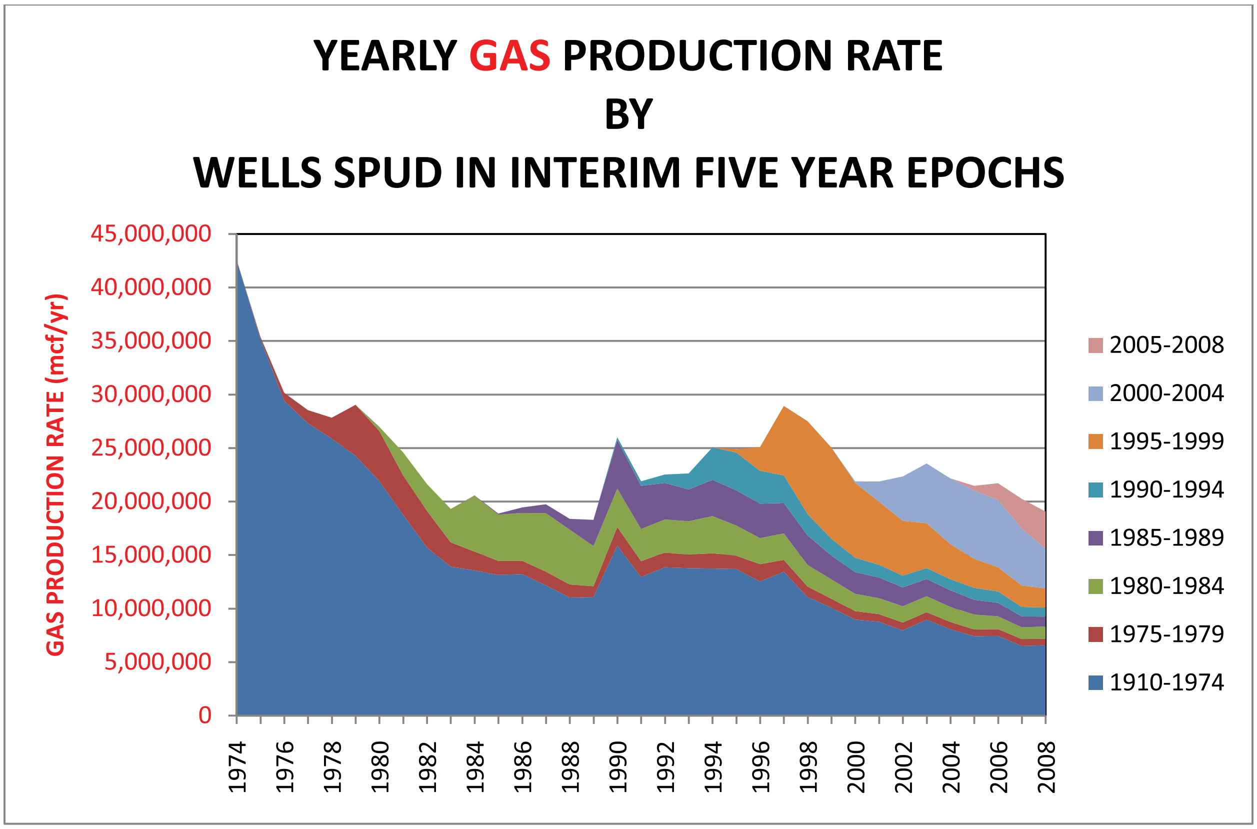
mcf = thousand cubic feet of oil

Figure 20. Historical five year epoch oil production data from Bighorn Basin Planning Area. Data from IHS Energy Group (2009).



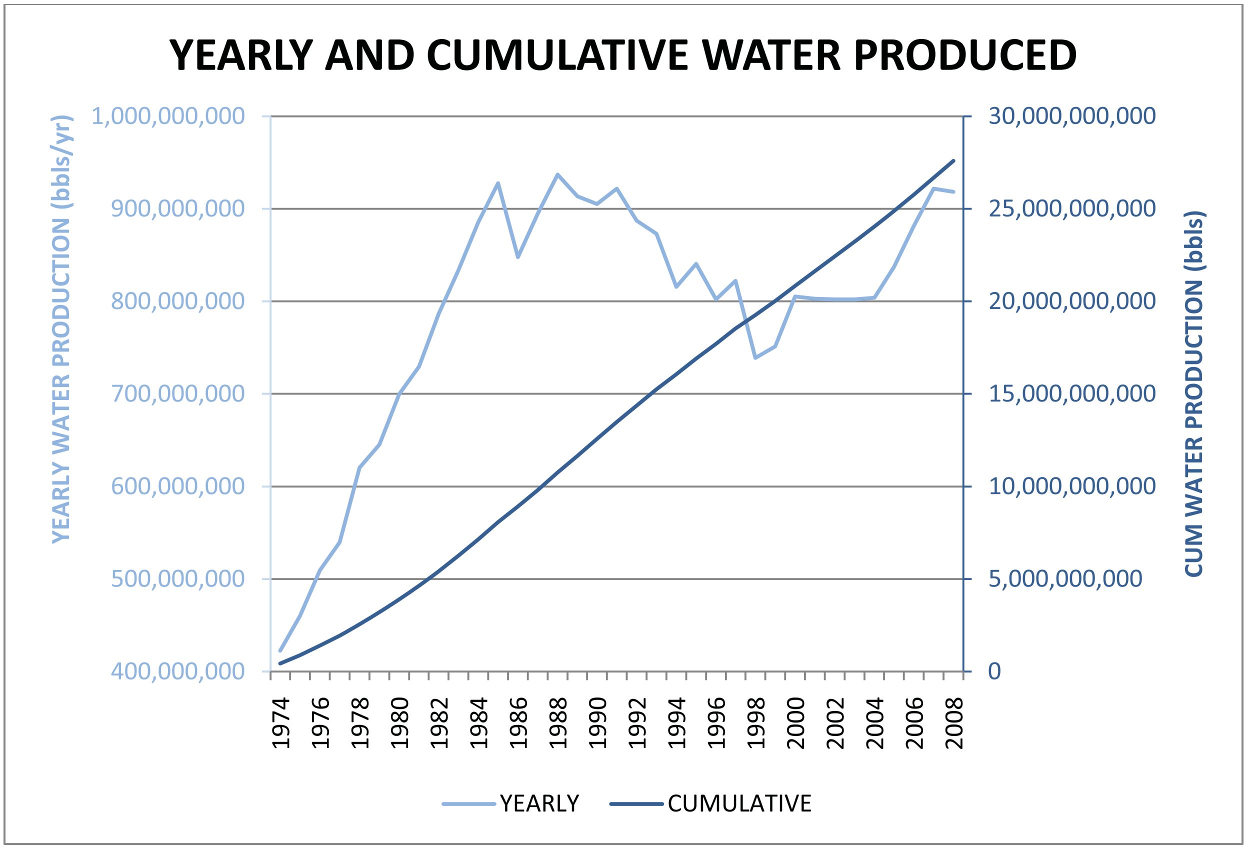
bbls/year = barrels per year

Figure 21. Historical five year epoch gas production data from Bighorn Basin Planning Area. Data from IHS Energy Group (2009).



mcf/yr = thousand cubic feet per year

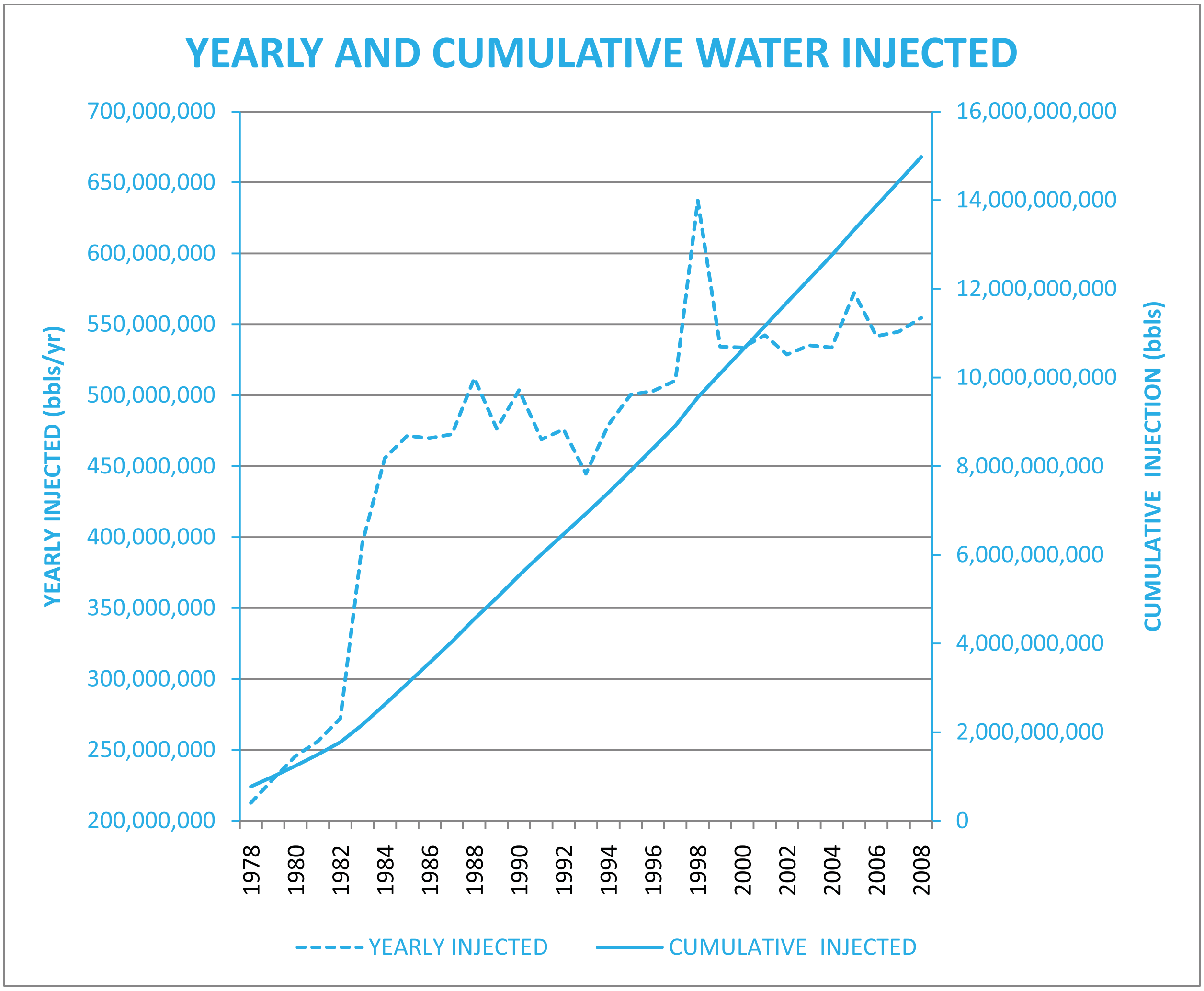
Figure 22. Yearly and cumulative water production rates within the Bighorn Basin Planning Area. Data from IHS Energy Group (2009).



bbls = barrels

bbls/yr = barrels per year

Figure 23. Yearly and cumulative water injection rates within the Bighorn Basin Planning Area. Data from IHS Energy Group (2009).



bbls = barrels

bbls/yr = barrels per year

Figure 24.
Fort Union Formation outcrops and coalfields within the Bighorn Basin. Data from Roberts and Rossi (1999).

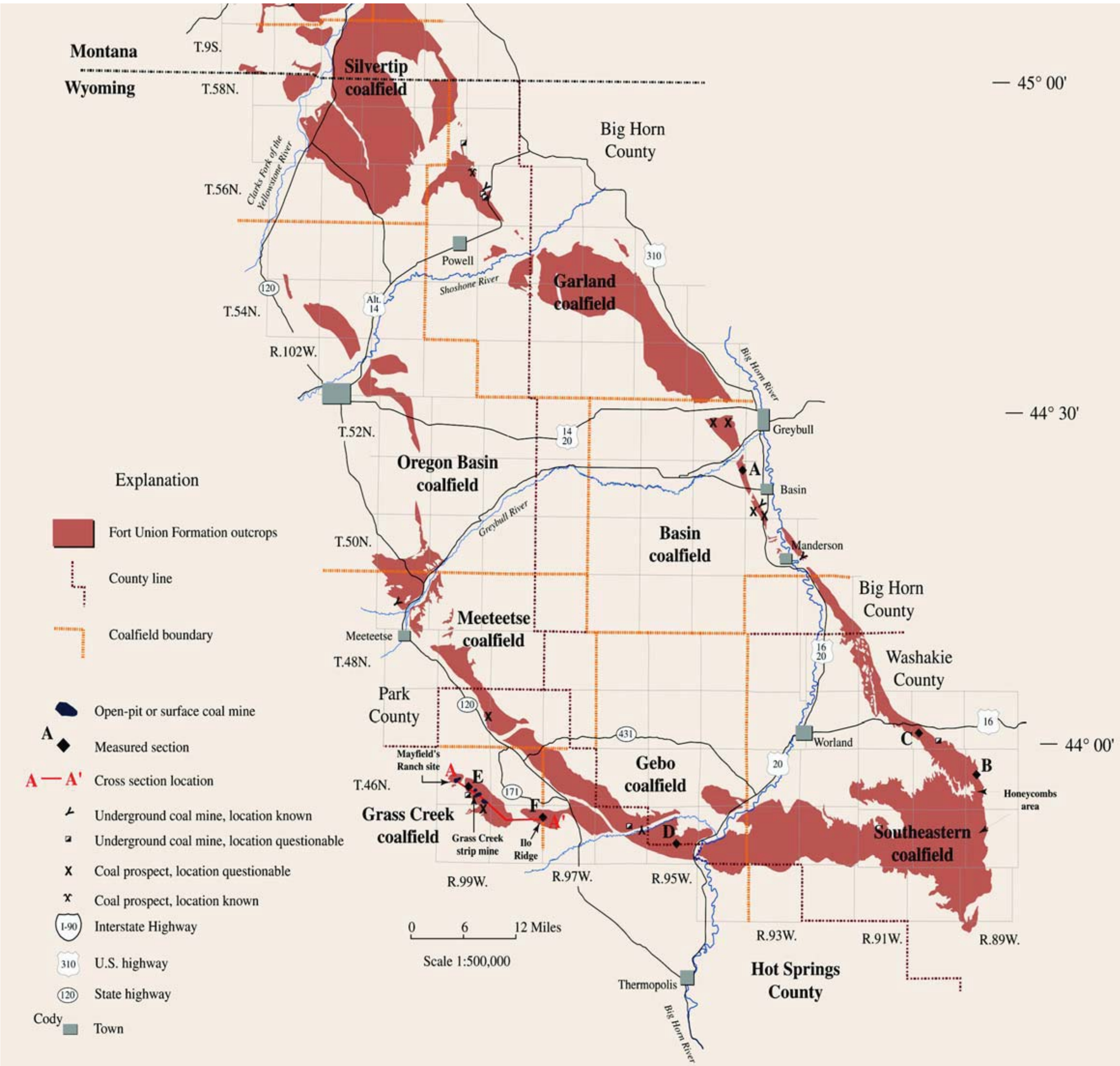


Figure SB-4. Map showing locations of coalfields, abandoned coal mines, and measured stratigraphic sections, Bighorn Basin, Montana and Wyoming. Abandoned mine locations and coalfield boundaries modified from Luhr and Jones (1985).

Figure 25.

Distribution of coalbed natural gas wells and Tertiary and Cretaceous coals in outcrop and the subsurface. Data from U.S. Geological Survey (2008a) and IHS Energy Group (2009).

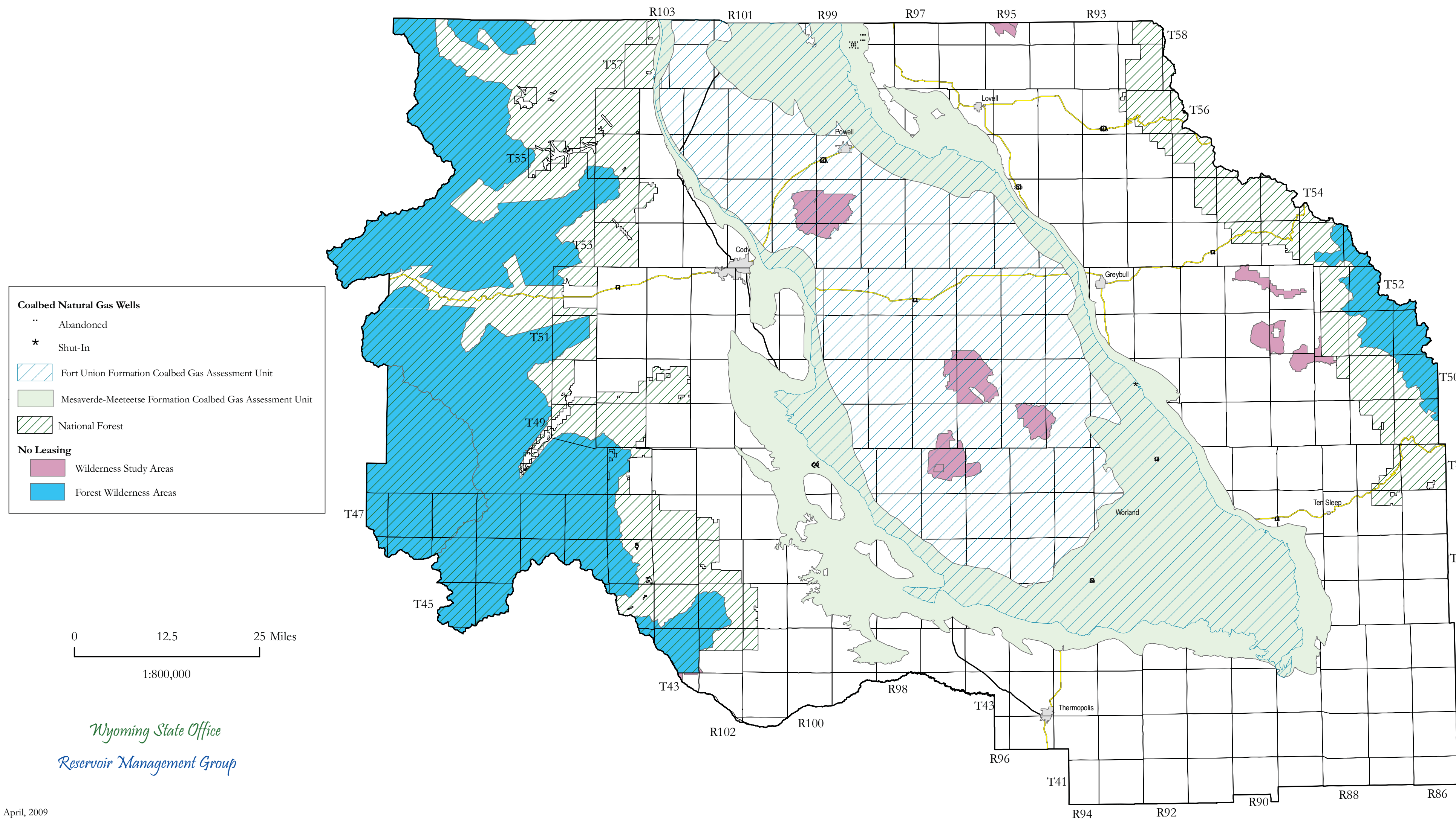


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Figure 26.

True vertical depths of vertical, directional, and horizontal wells drilled within the Bighorn Basin Planning Area. Data from Wyoming Oil and Gas Conservation Commission (2009).

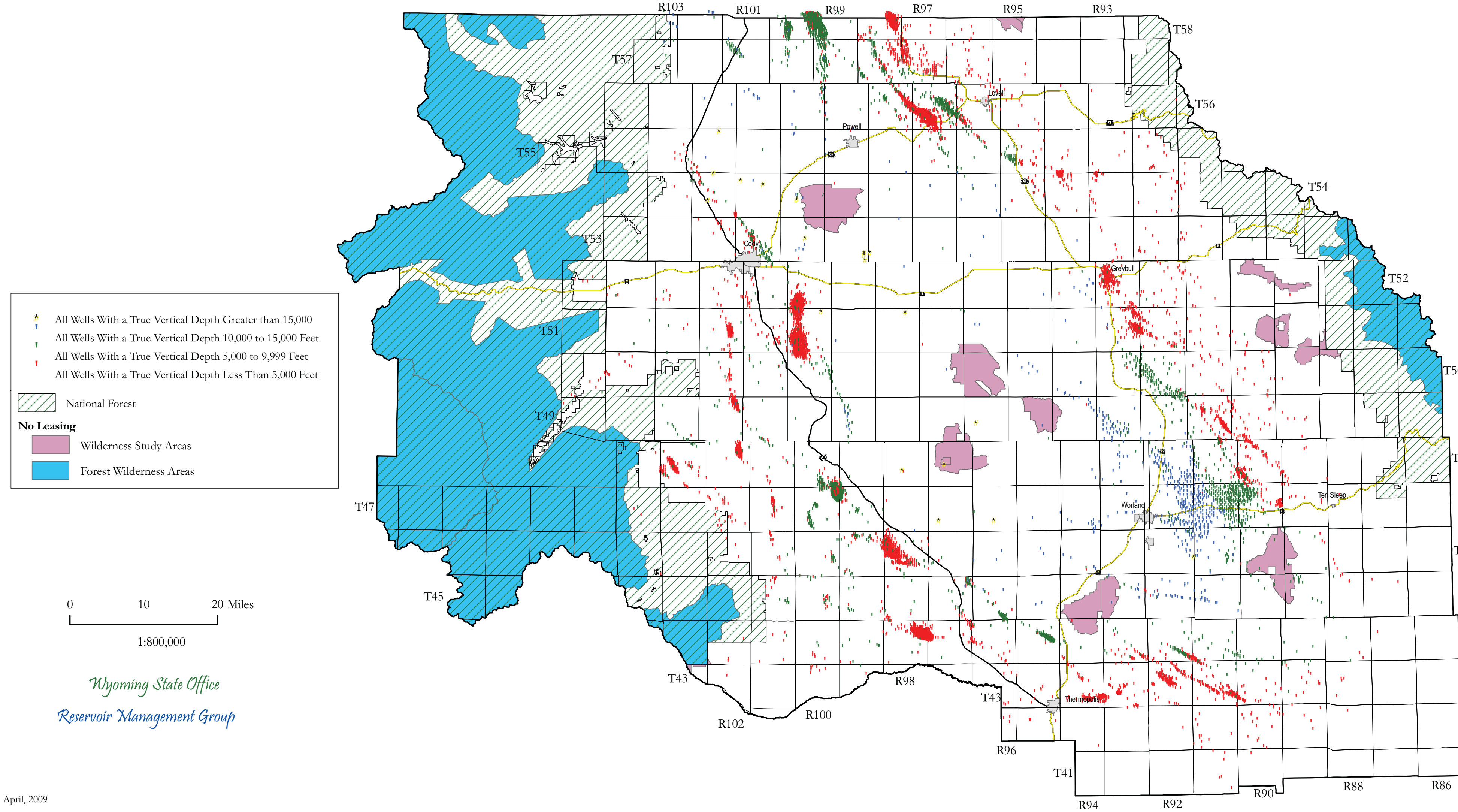

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Figure 27.

Directional borehole locations within the Bighorn Basin Planning Area. Data from IHS Energy Group (2009) and DeBruin (2006).

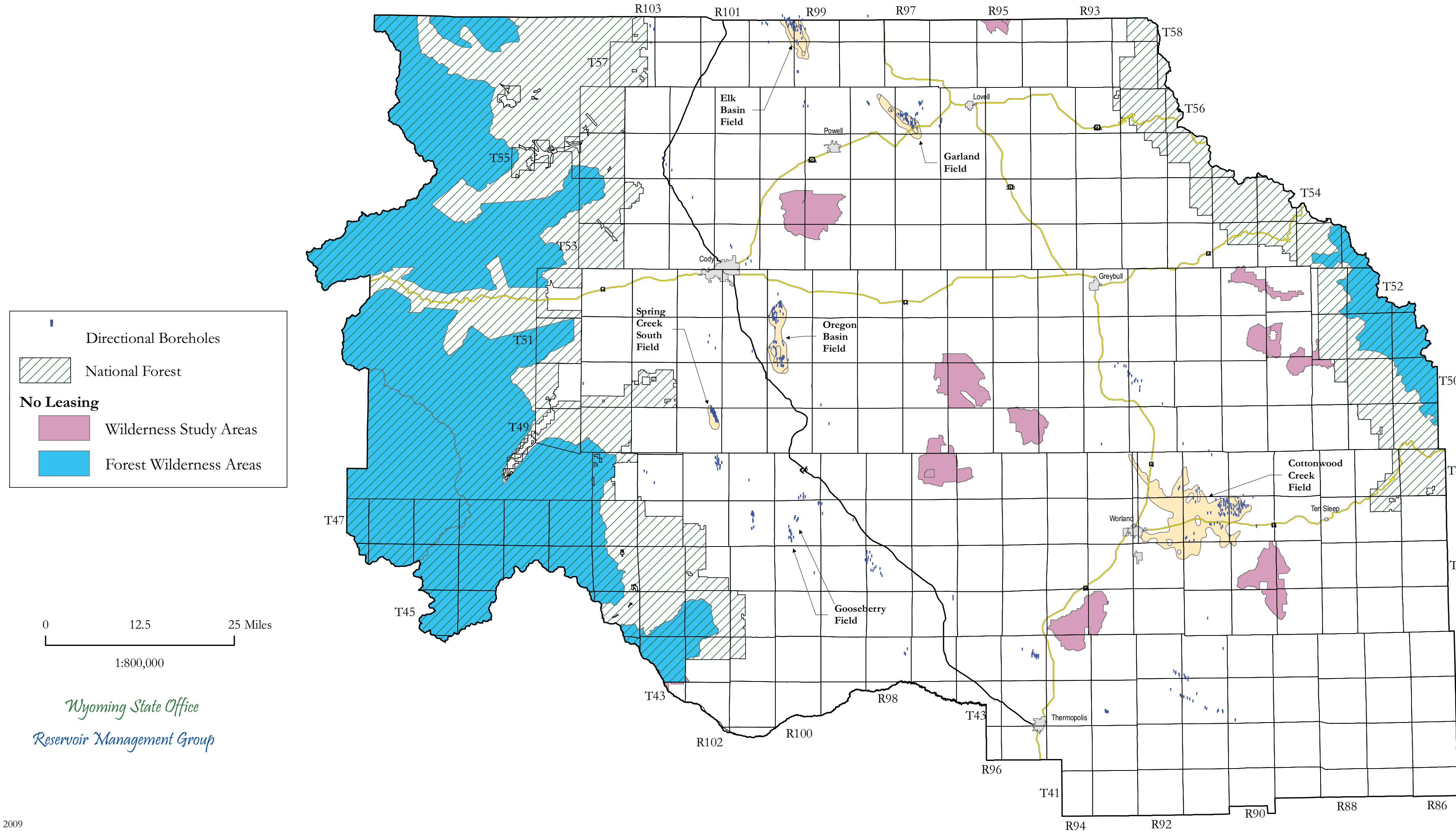

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Figure 28.

Horizontal borehole locations within the Bighorn Basin Planning Area. Data from IHS Energy Group (2009) and DeBruin (2006).

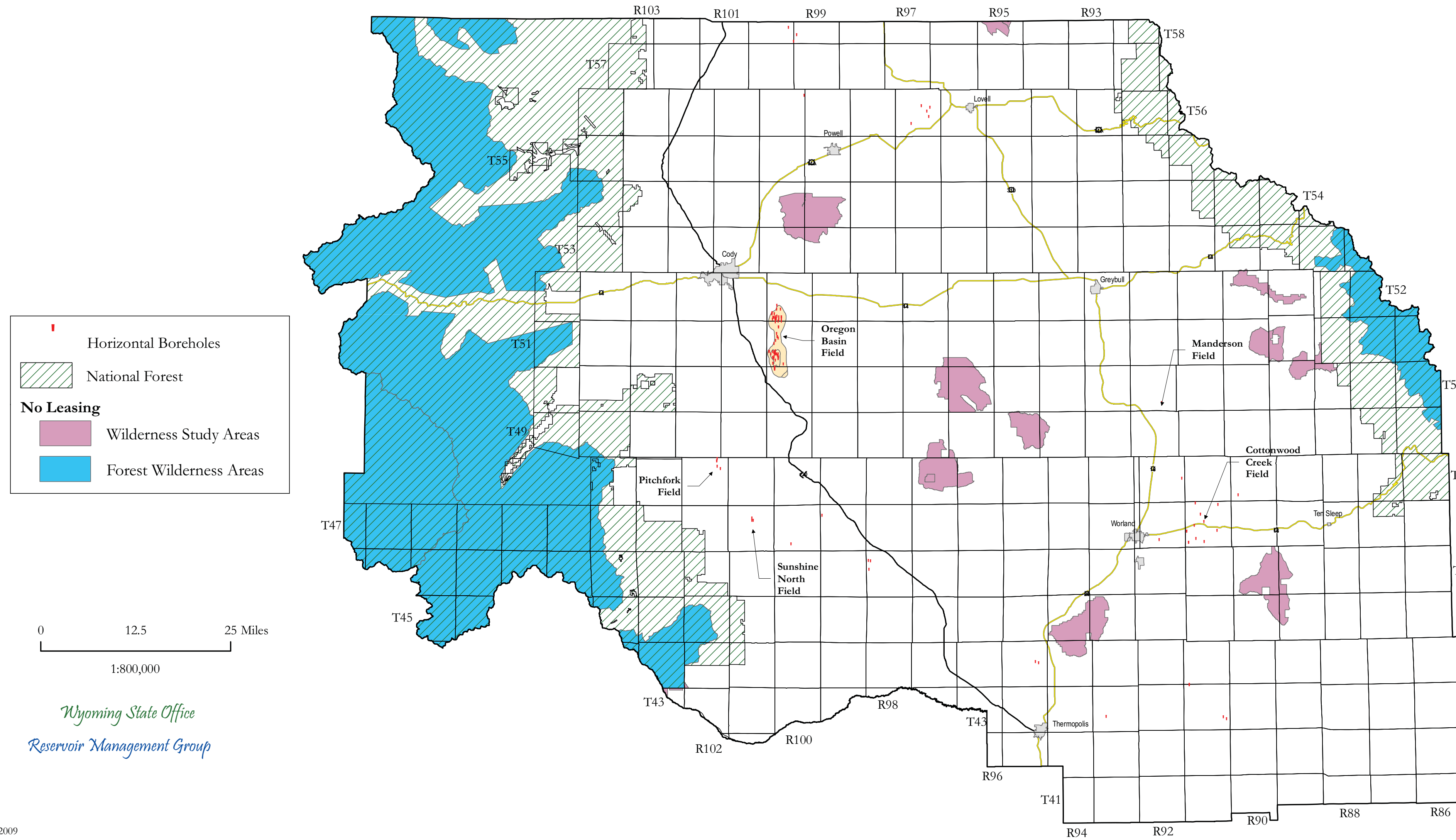

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Figure 29.

Fields within the Bighorn Basin Planning Area known to contain hydrogen sulfide gas. Data from DeBruin (2006).

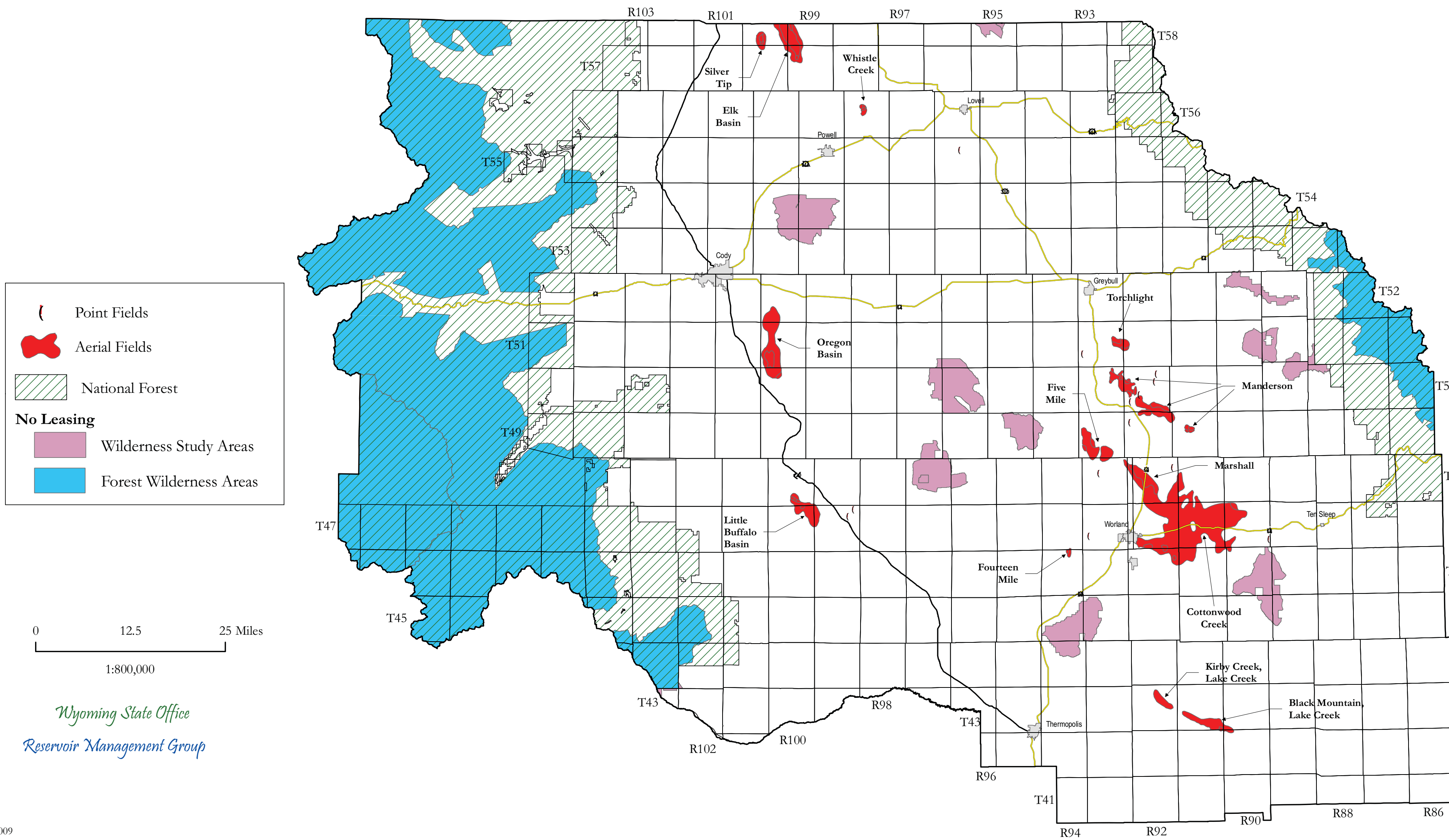

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Figure 30.

Geographic distribution of water quality samples across the Bighorn Basin Planning Area and distribution of sample salinity. Data from U.S. Geological Survey (2008b) and DeBruin (2006).

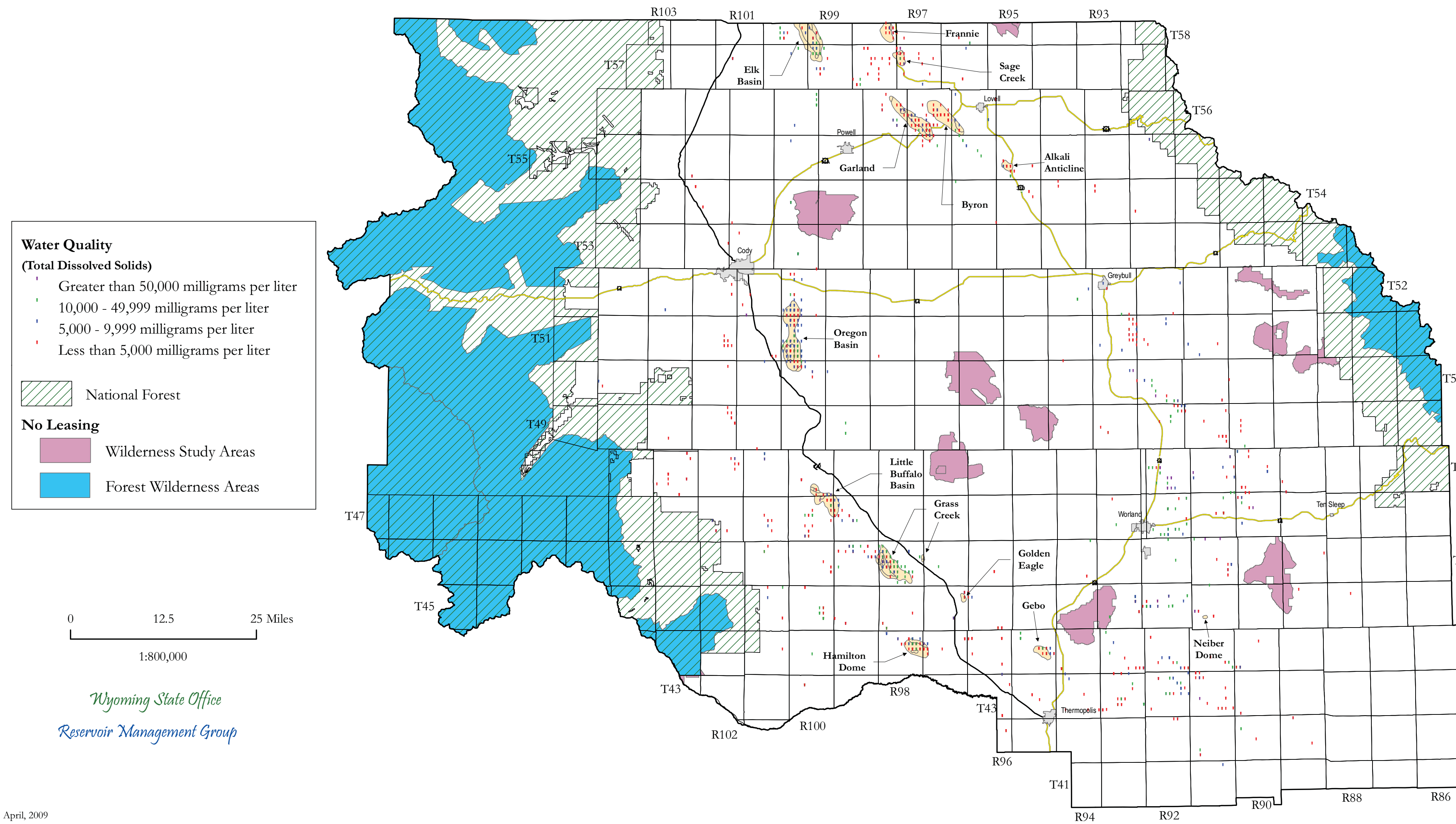

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Figure 31.
Location of the Bighorn Basin Province within the Bighorn Basin Planning Area (U.S. Geological Survey, 2008).

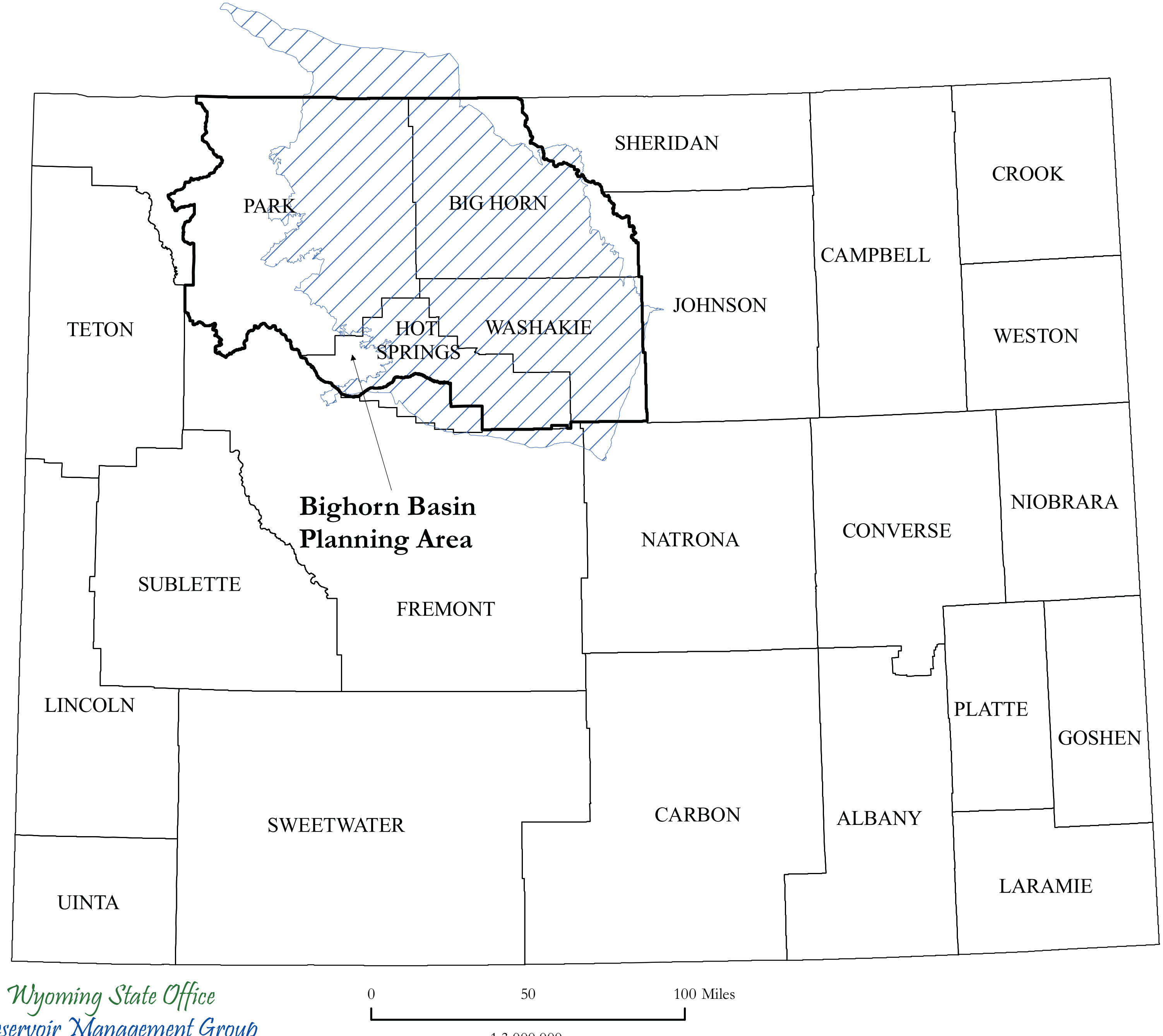

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Figure 32.
Location of the Bighorn Basin Province, Phosphoria total petroleum system, Paleozoic-Mesozoic conventional oil and gas assessment unit with respect to Bighorn Basin Planning Area boundary (U.S. Geological Survey, 2009).

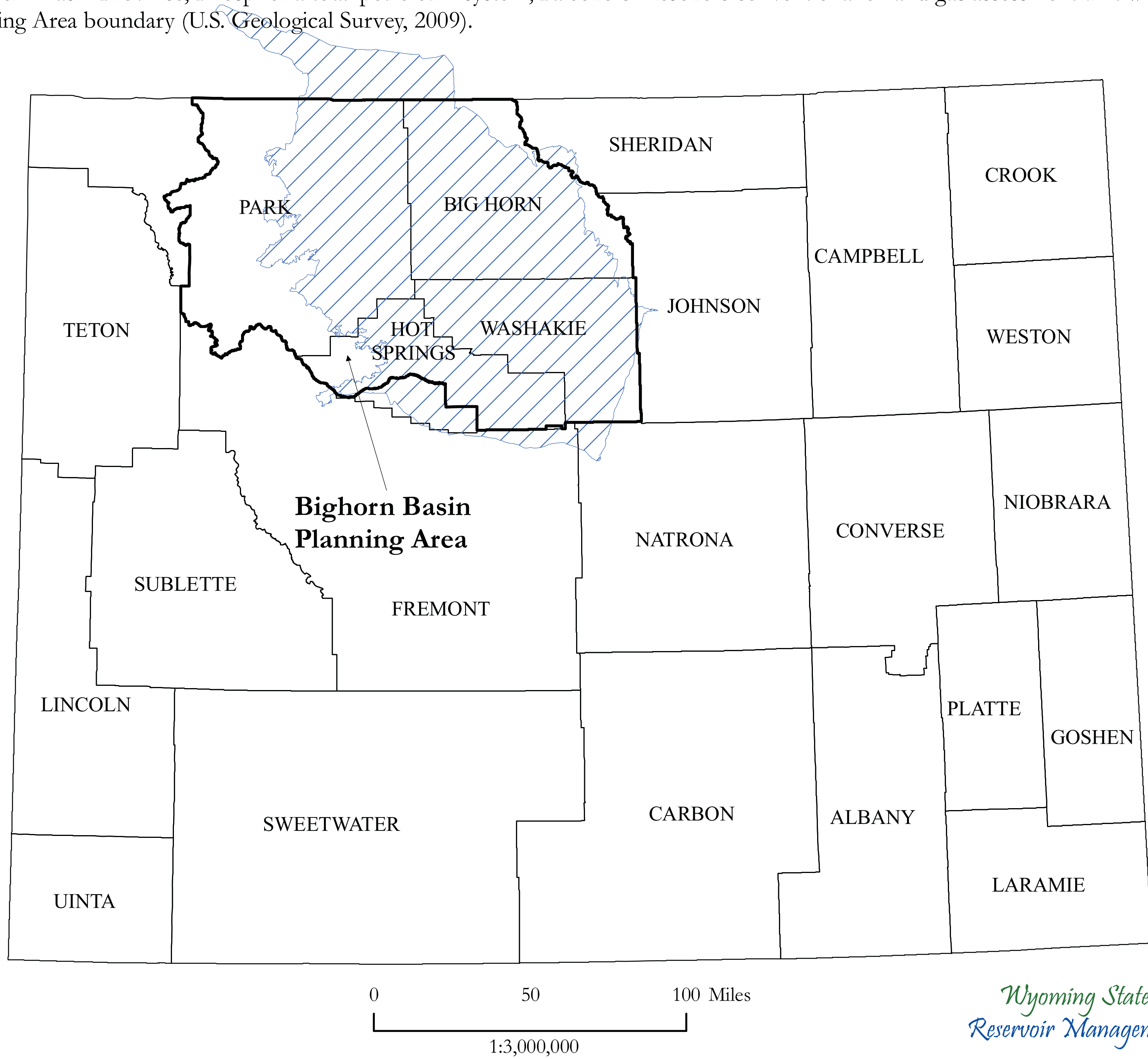

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Figure 33.
Location of the Bighorn Basin Province, Cretaceous-Tertiary Composite total petroleum system, Cretaceous-Tertiary conventional oil and gas assessment unit with respect to Bighorn Basin Planning Area boundary (U.S. Geological Survey, 2009).

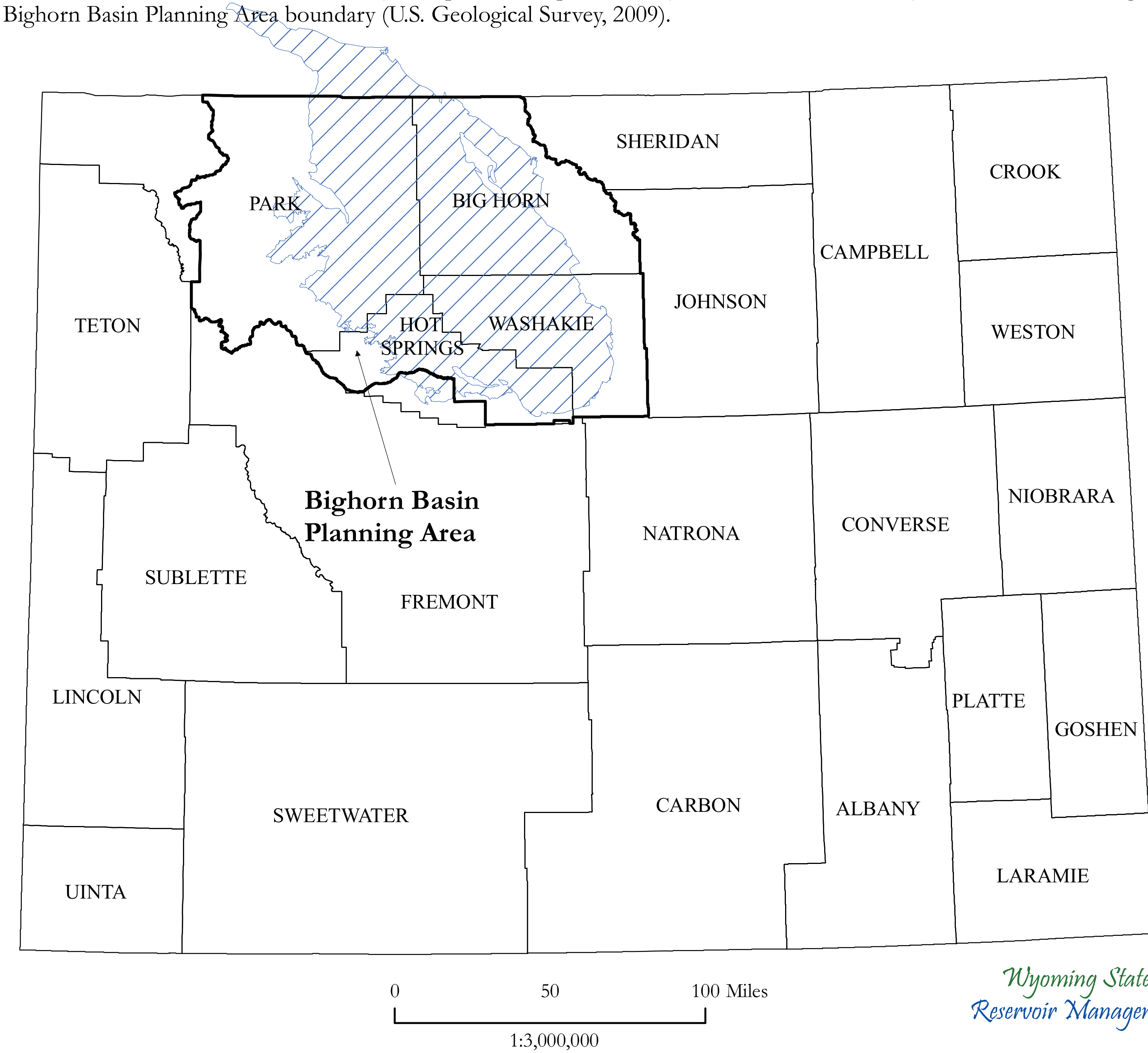

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Figure 34.
Location of the Bighorn Basin Province, Cretaceous-Tertiary Composite total petroleum system, Muddy-Frontier Sandstone and Mowry Fractured Shale continuous gas assessment unit with respect to Bighorn Basin Planning Area boundary (U.S. Geological Survey, 2009).

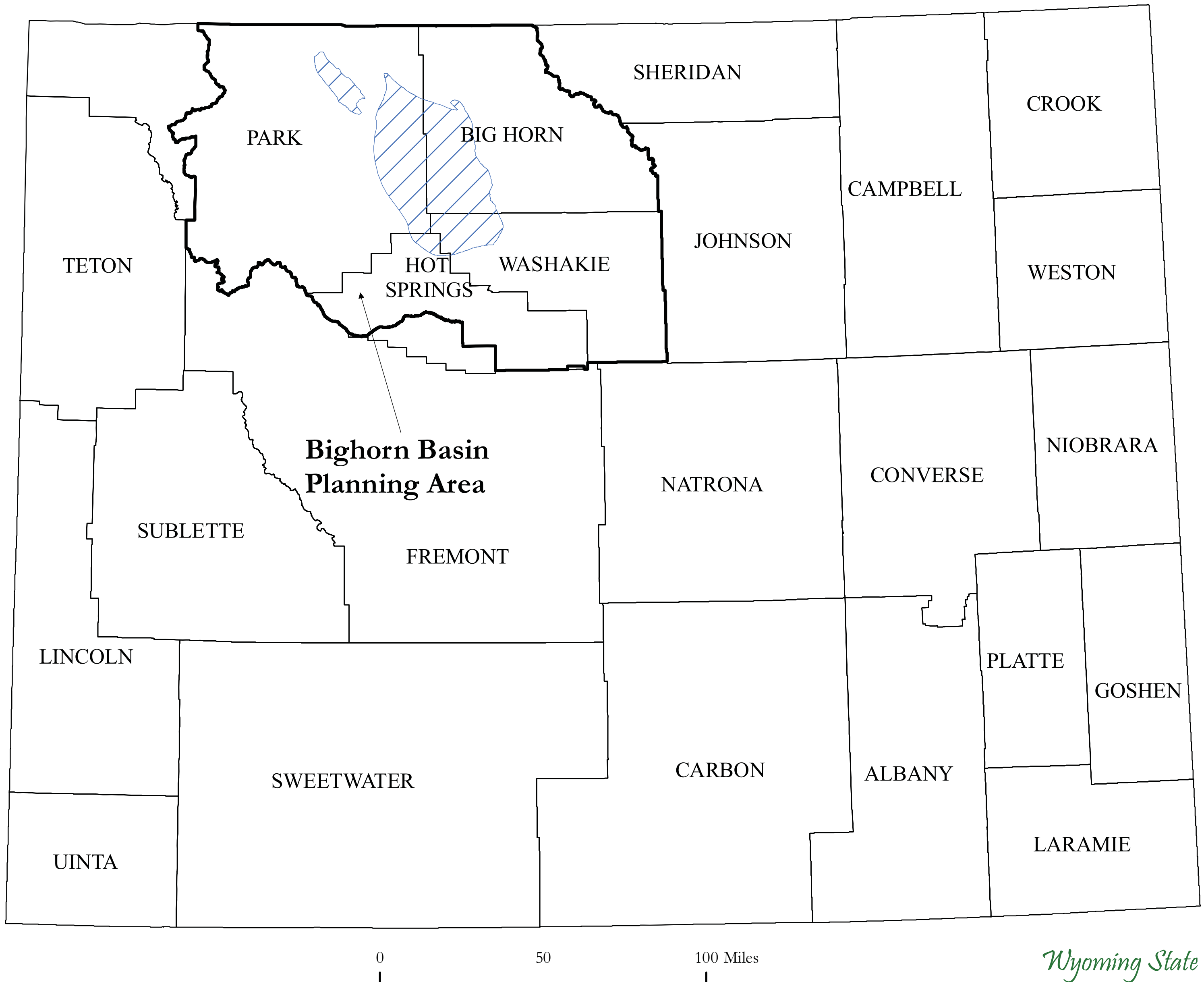

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Figure 35.
Location of the Bighorn Basin Province, Cretaceous-Tertiary Composite total petroleum system, Mowry Fractured Shale continuous oil assessment unit with respect to Bighorn Basin Planning Area boundary (U.S. Geological Survey, 2009).

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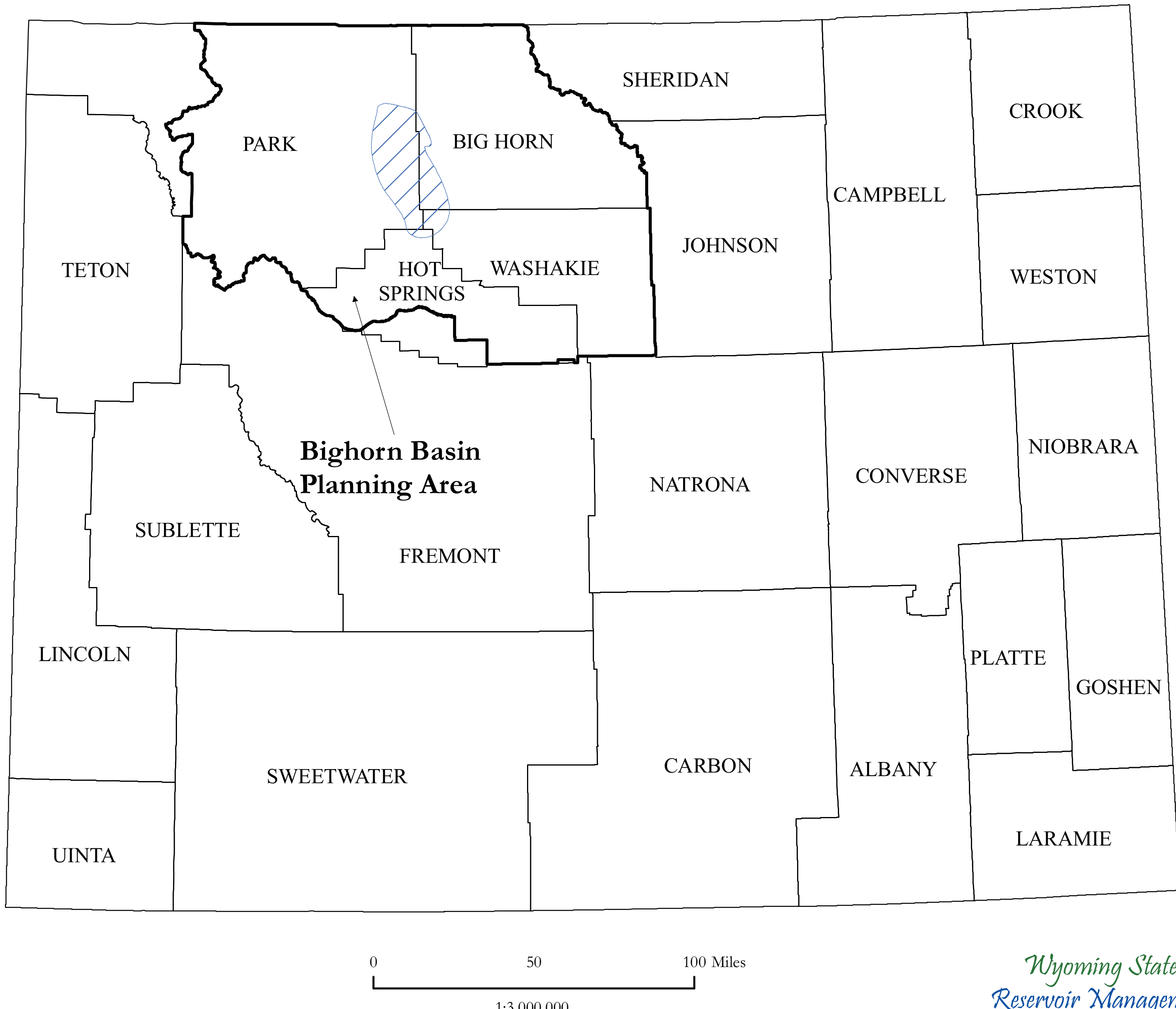
Figure 36.
Location of the Bighorn Basin Province, Cretaceous-Tertiary Composite total petroleum system, Cody Sandstone continuous gas assessment unit with respect to Bighorn Basin Planning Area boundary (U.S. Geological Survey, 2009).



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Dean Stilwell, Geologist
Al Elser, Geologist
Stan Lawrence, Petroleum Engineer

Figure 37.
Location of the Bighorn Basin Province, Cretaceous-Tertiary Composite total petroleum system, Mesaverde Sandstone continuous gas assessment unit with respect to Bighorn Basin Planning Area boundary (U.S. Geological Survey, 2009).

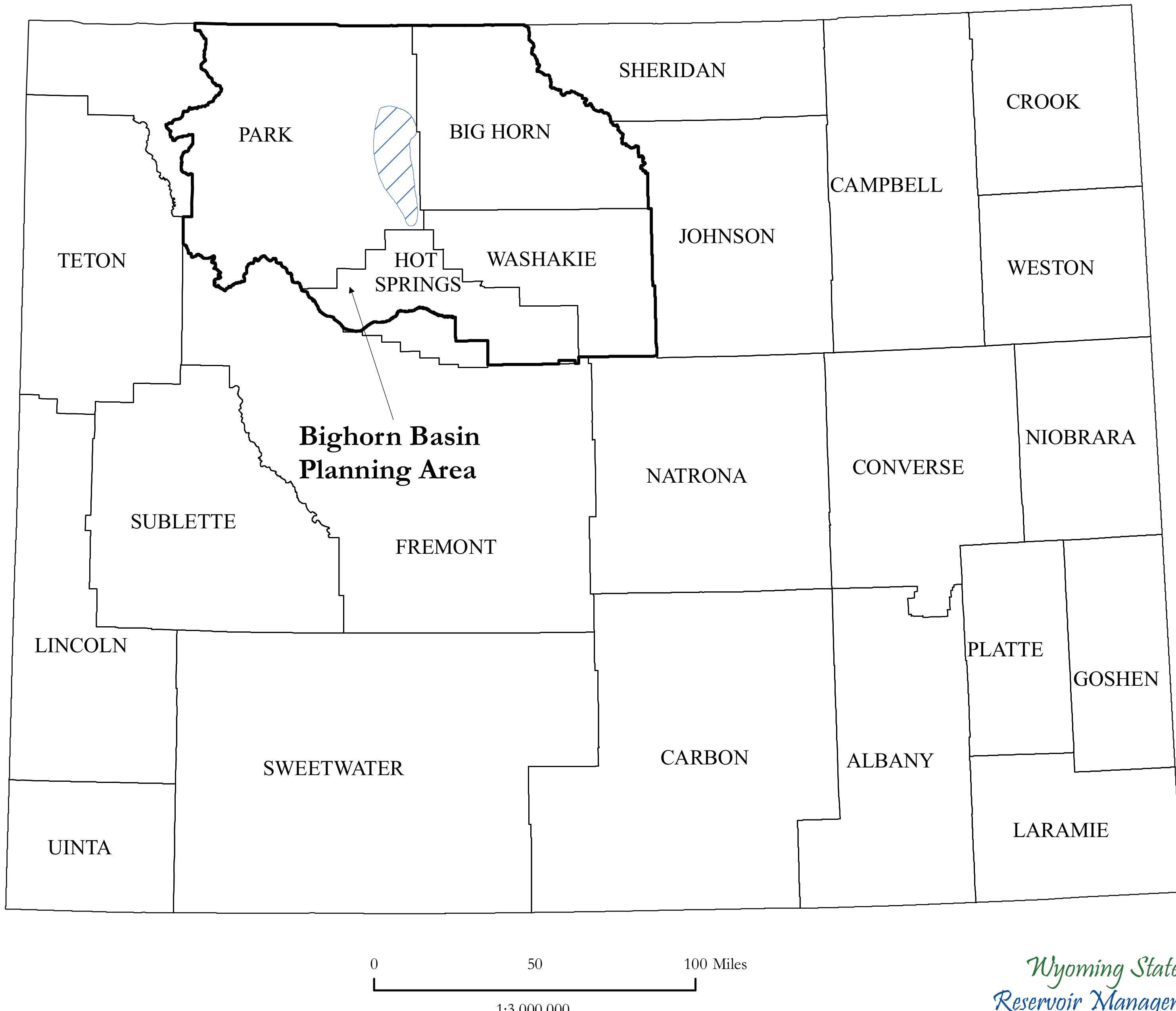

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Figure 38.
Location of the Bighorn Basin Province, Cretaceous-Tertiary Composite total petroleum system, Mesaverde-Meeteetse Formation continuous coalbed gas assessment unit with respect to Bighorn Basin Planning Area boundary (U.S. Geological Survey, 2009).

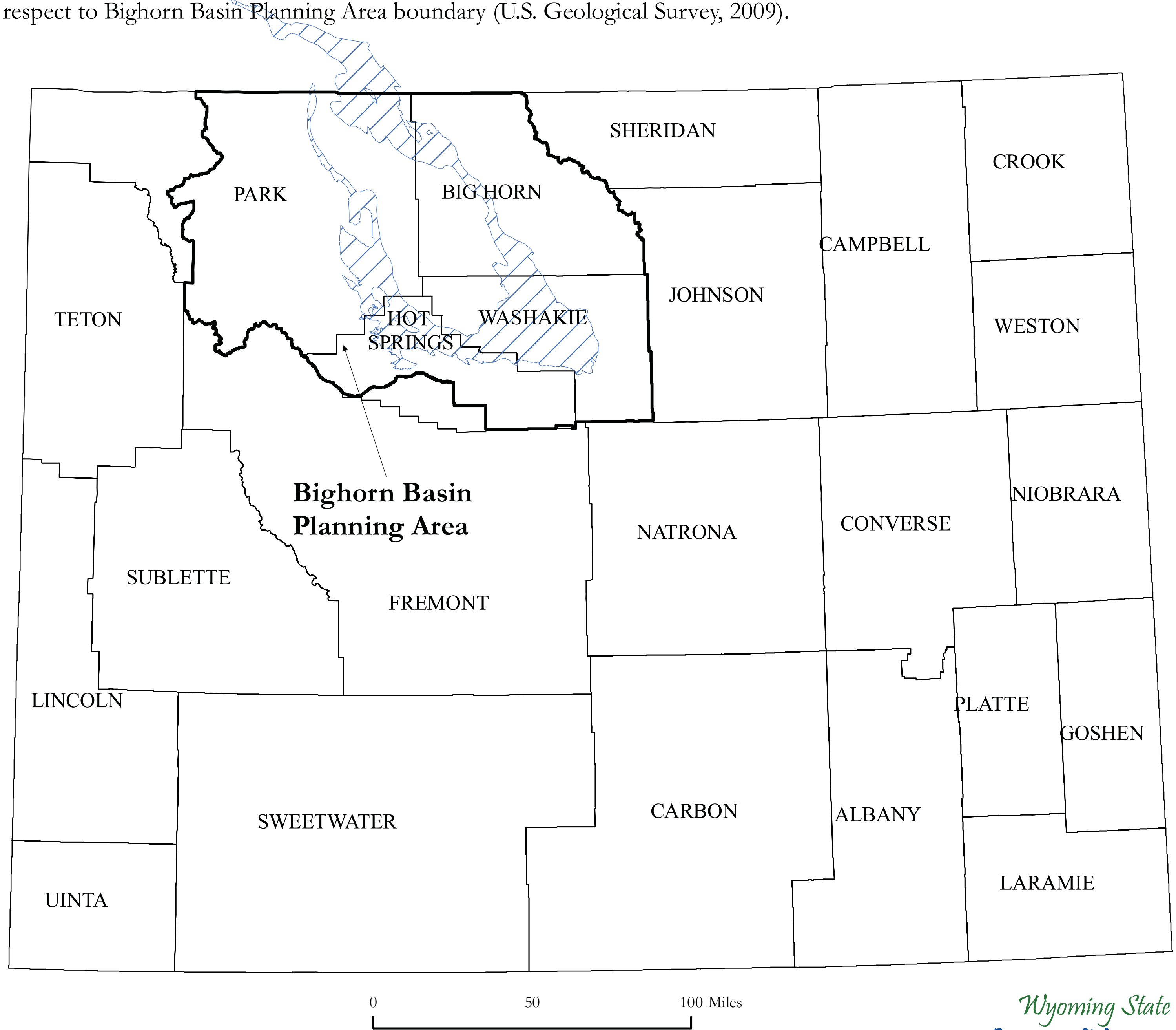

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Figure 39.
Location of the Bighorn Basin Province, Cretaceous-Tertiary Composite total petroleum system, Fort Union Formation continuous coalbed gas assessment unit with respect to Bighorn Basin Planning Area boundary (U.S. Geological Survey, 2009).

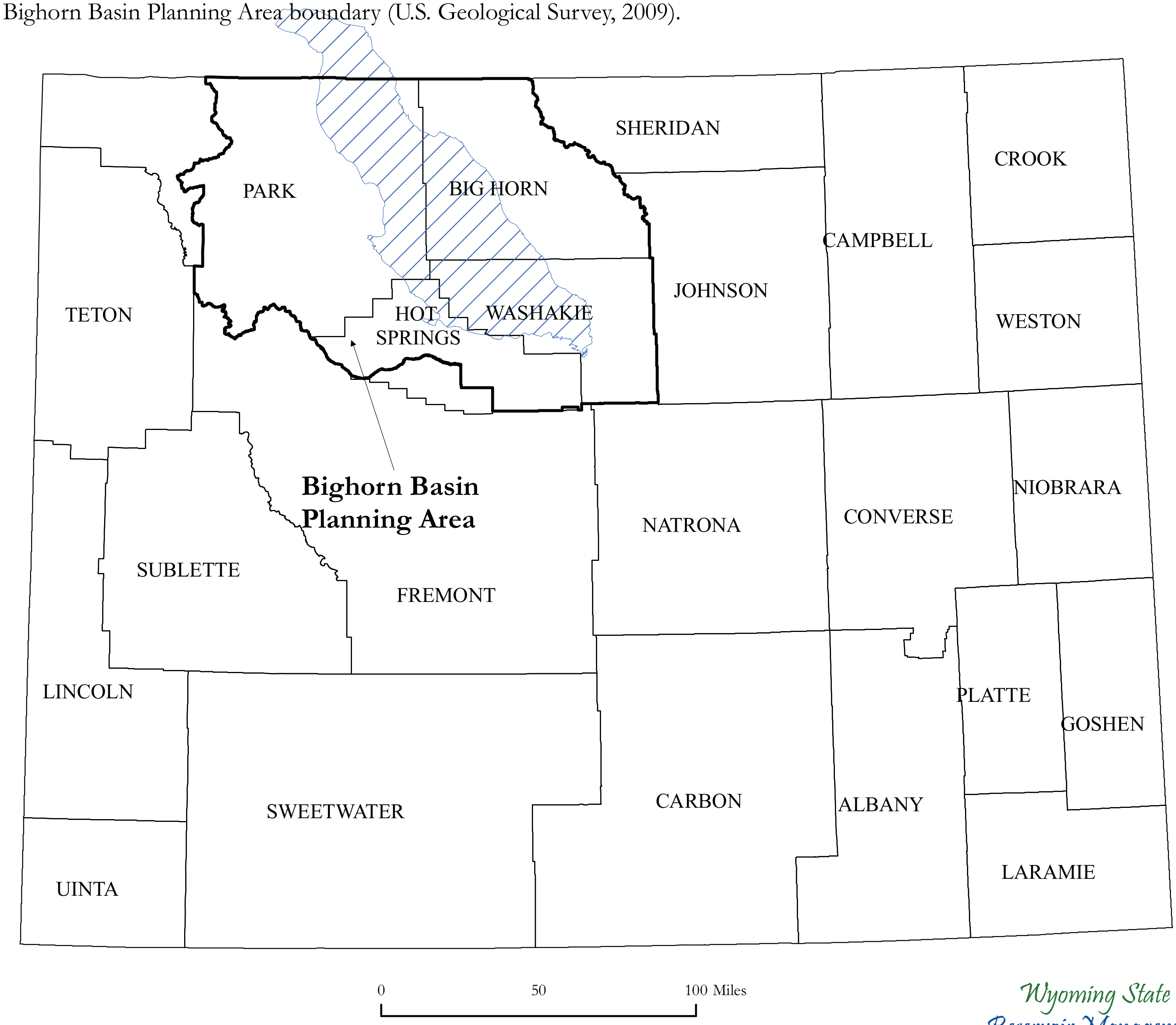

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Figure 40.

Potential for occurrence of oil and gas within the Bighorn Basin Planning Area.

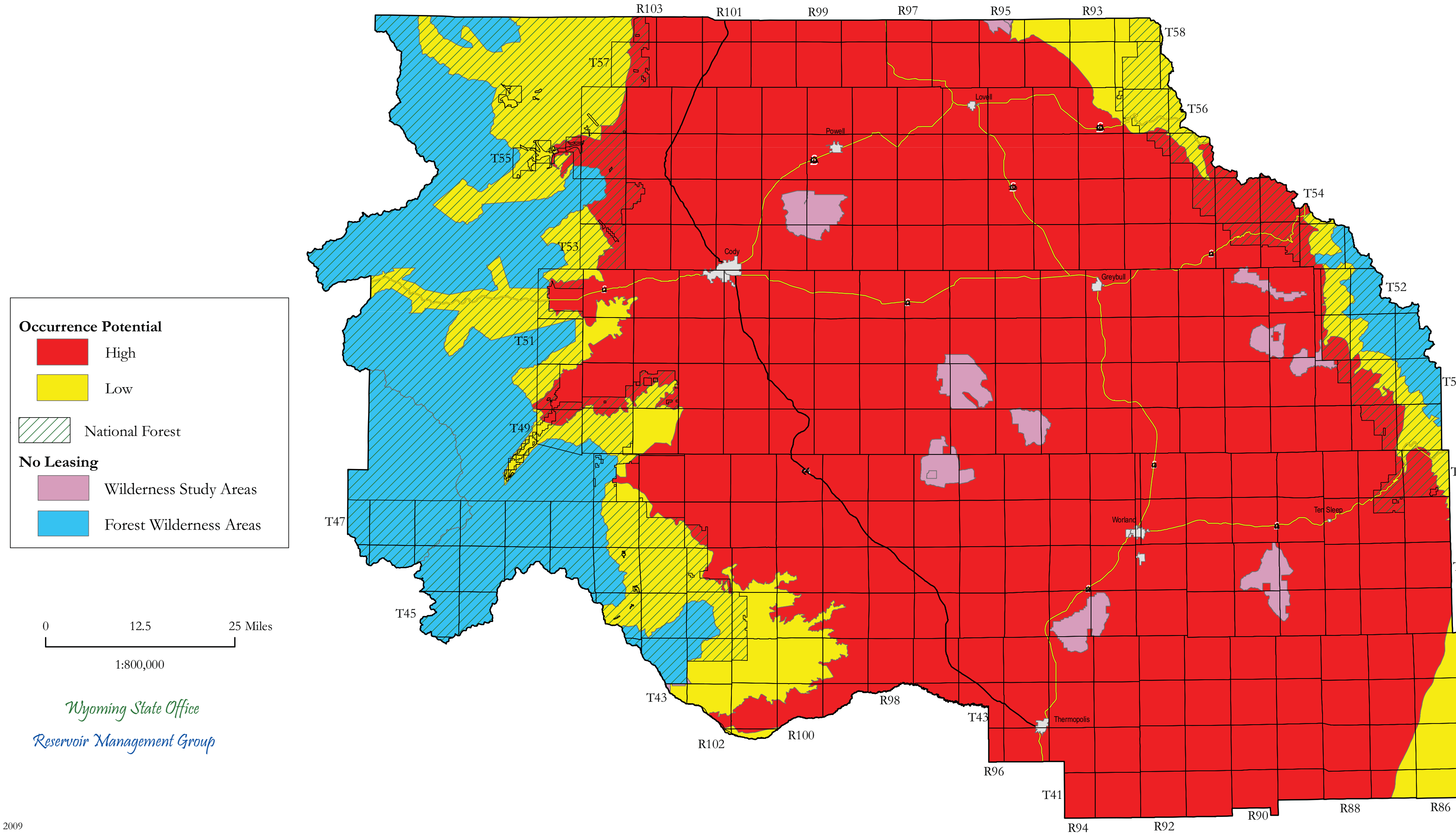

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Figure 41. Wyoming historical natural gas prices with future natural gas price projections (Energy Information Administration, 2009b).

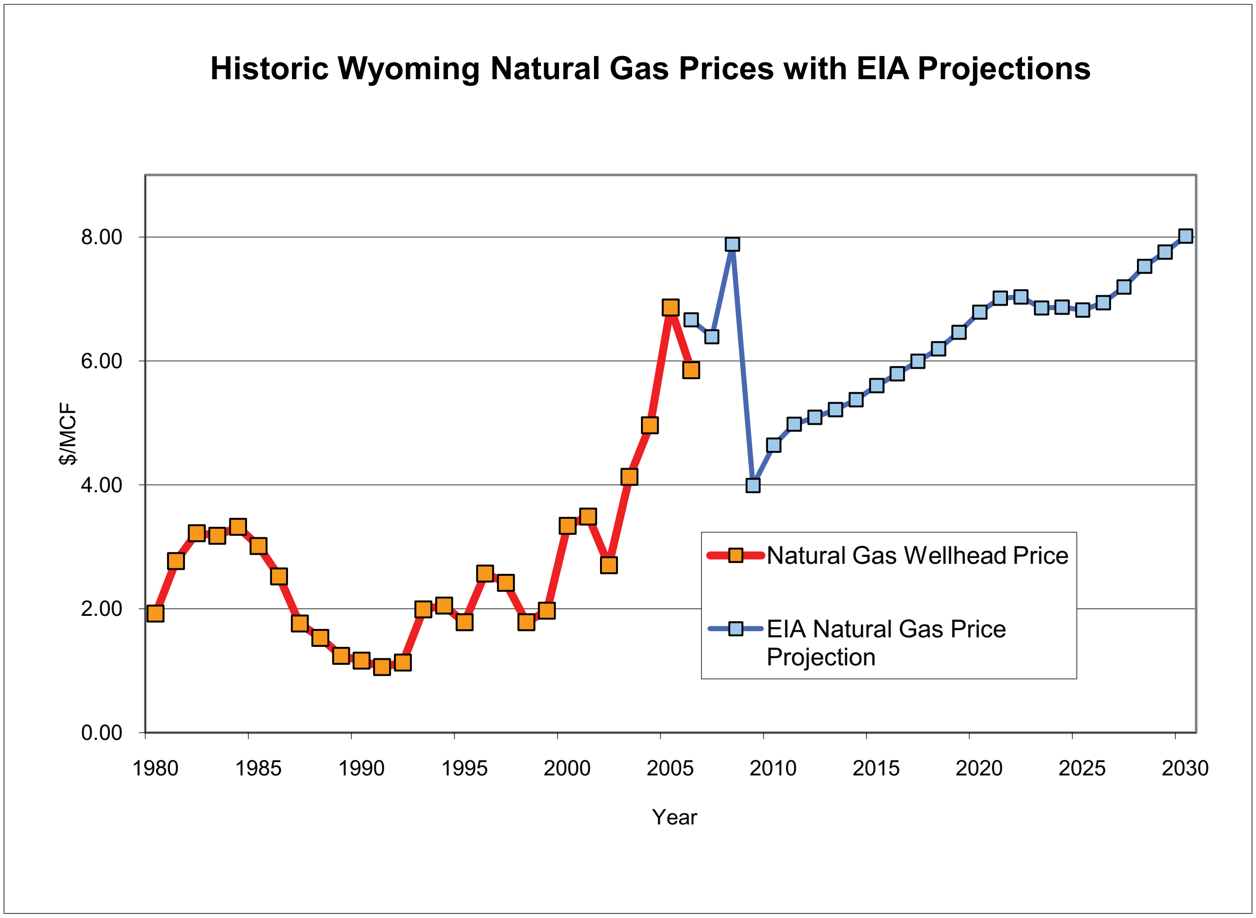

Figure 42.

Wells drilled in the Bighorn Basin Planning Area during 1999 - 2008, by two-year period (IHS Energy, 2009).

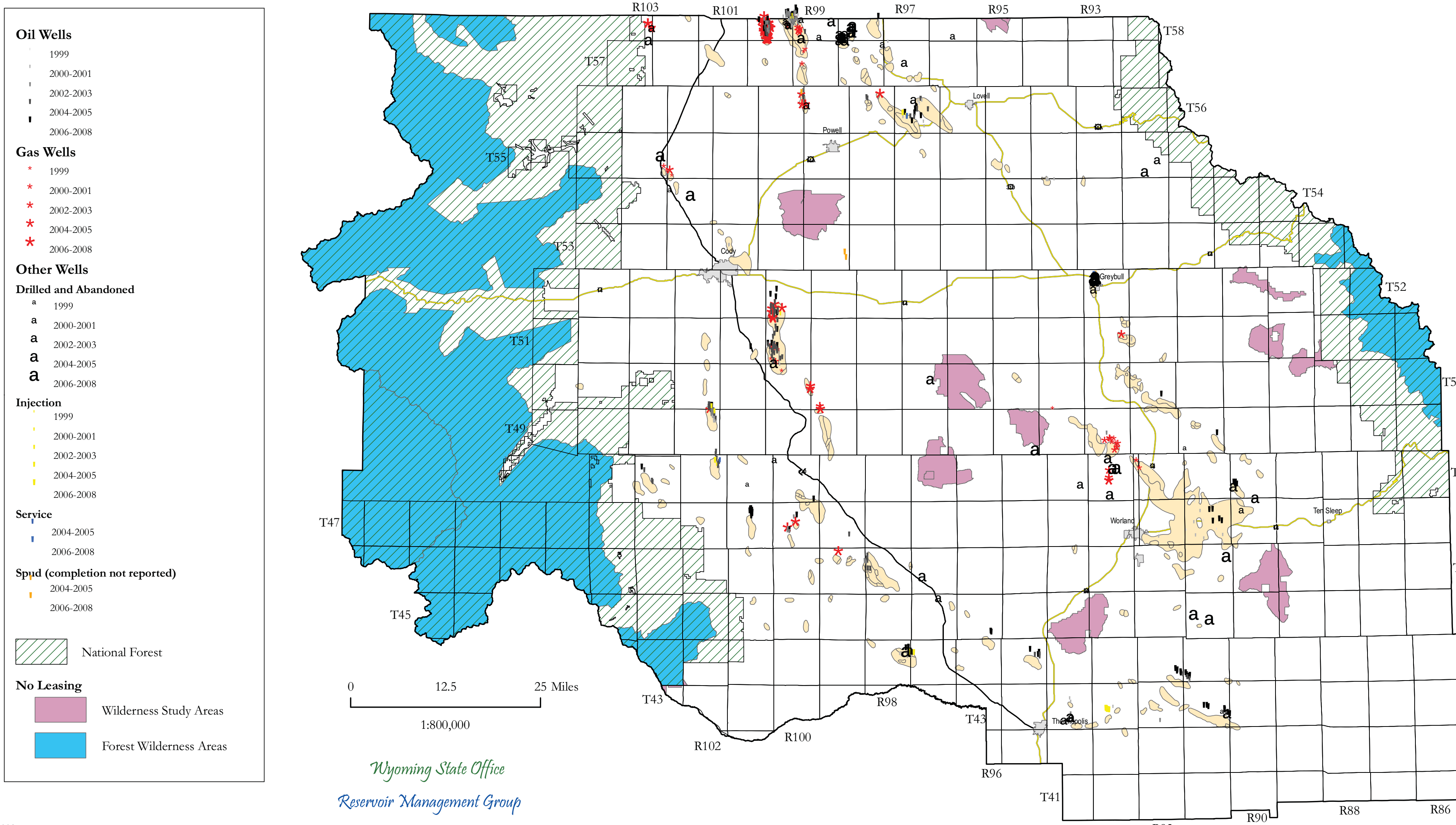

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Figure 43. Wyoming historical crude oil prices with future crude oil price projections (Energy Information Administration, 2009b).

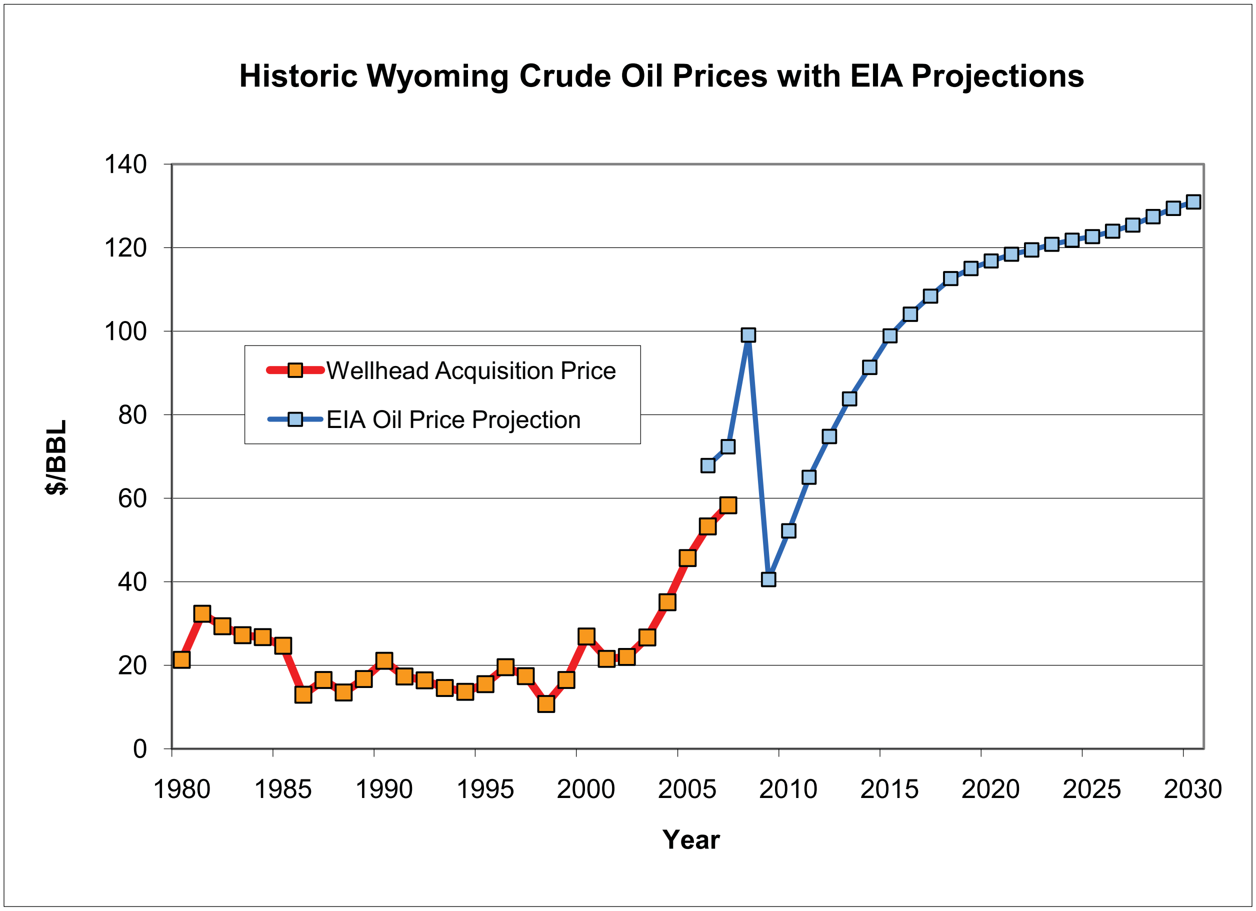

Figure 44.

Leased and unleased Federal oil and gas minerals within the Bighorn Basin Planning Area. Data from Bureau files.

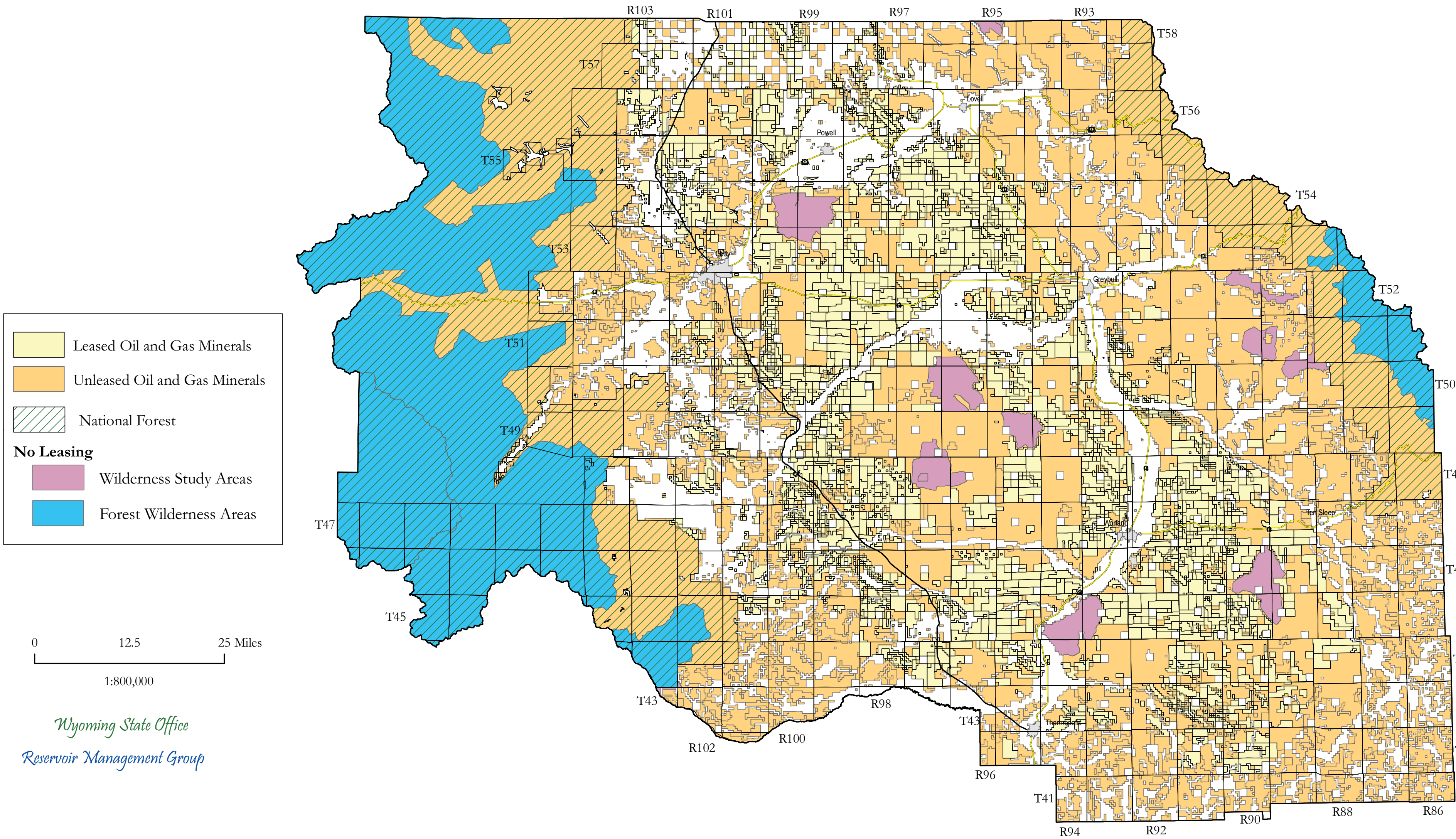

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Figure 45.
Oil and gas (excluding coalbed natural gas) development potential and projected drilling densities within the Bighorn Basin Planning Area for 2008 through 2027.

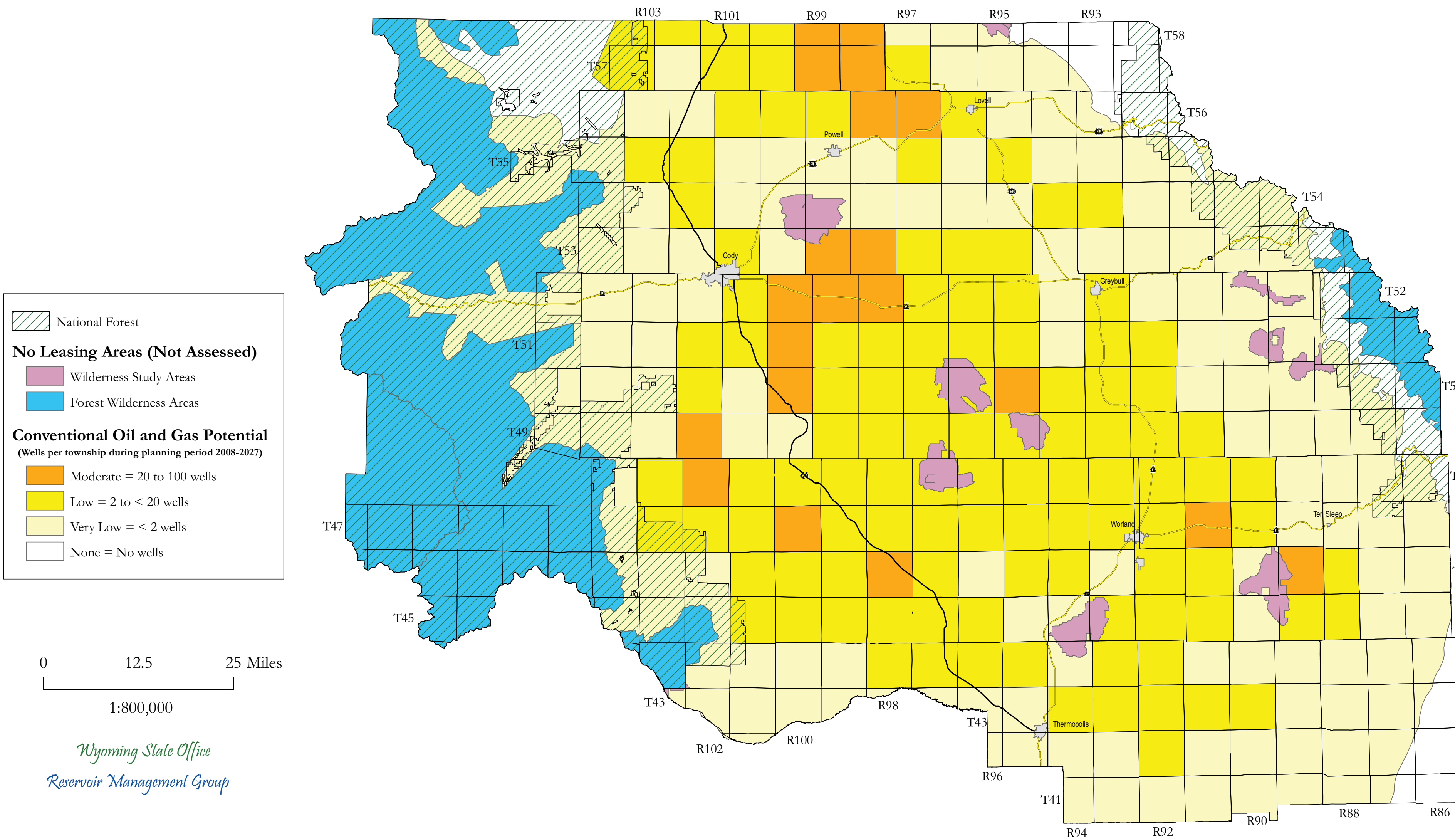

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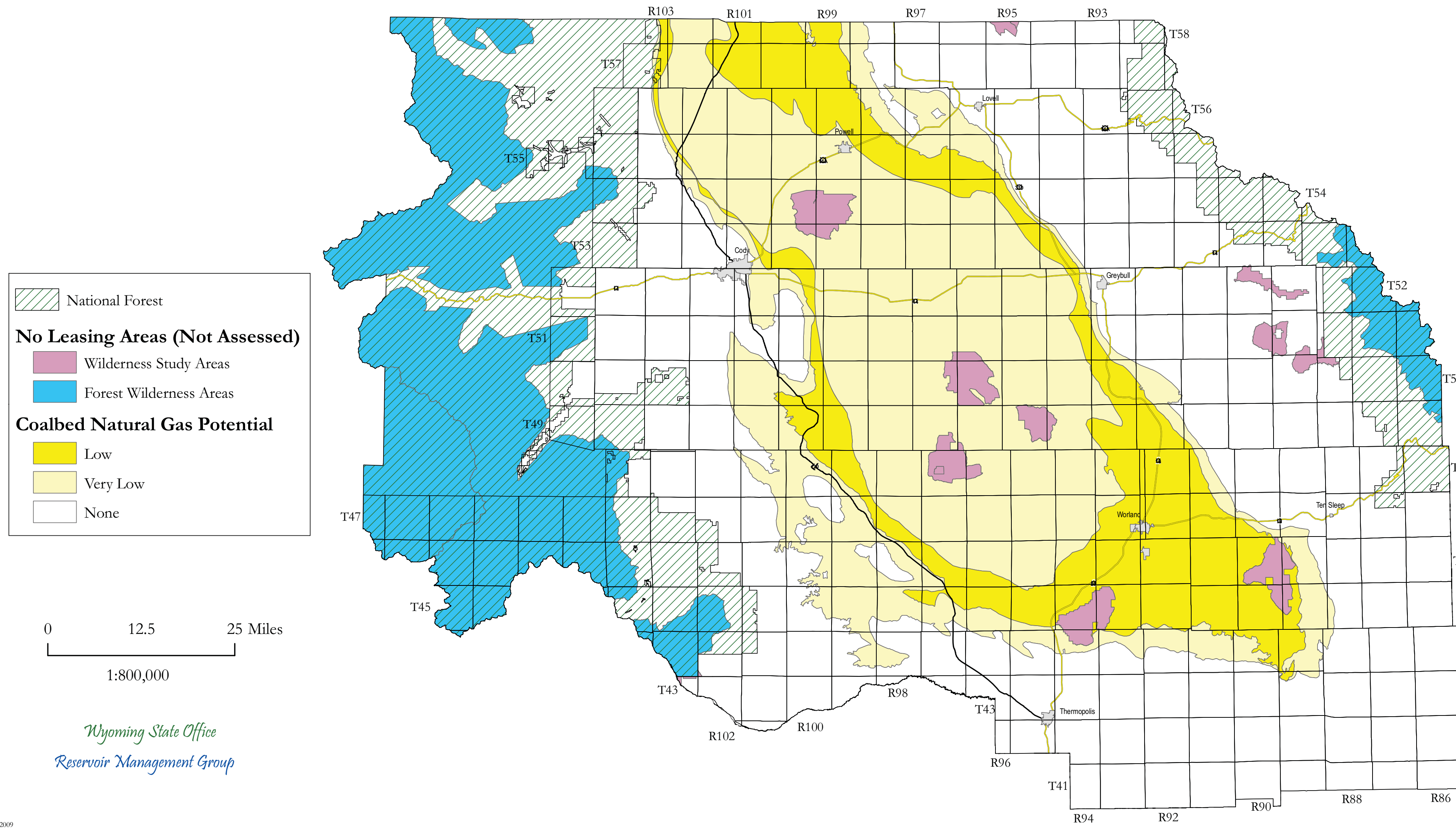
Figure 46.

Coalbed natural gas development potential within the Bighorn Basin Planning Area for 2008 through 2027.



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TABLES

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Table 1

Active units within or partly within Bighorn Basin Planning Area. Data from Bureau files and Wyoming Oil and Gas Conservation Commission (2009).

Unit Name	Operator	Acres	Effective Date	Participating Area Productive Formation(s)
AINSWORTH	Saga Petroleum LLC	2,330.50	1/1/1955	Muddy/Phosphoria
ALKALI ANTICLINE	Prima Exploration Inc.	920.00	4/14/1953	Phosphoria/Tensleep/Darwin(Amsden)/ Madison
BADGER BASIN (FRONTIER)	Beartooth Oil & Gas Co.	4,147.64	4/1/1985	
BADGER CREEK	Saga Petroleum LLC	529.01	8/28/1981	Muddy
BEARCAT (PHOSPHORIA)	Qualmay Development LLC	240.00	12/30/2006	
BIG POLECAT	Cline Production Co.	1,854.19	5/27/1954	Phosphoria/Tensleep
BLACK MOUNTAIN	Phoenix Production Co.	2,522.12	4/1/1946	Embar[1]/Tensleep
BYRON (EMBAR[1]/TENSLEEP)	Marathon Oil Co.	3,480.08	4/1/1973	
BRYON PRE TENSLEEP	Marathon Oil Co.	774.37	11/30/1955	Amsden/Madison
CODY	Merit Energy Co.	1,416.65	10/25/1977	Phosphoria/Tensleep
COTTONWOOD CREEK	Continental Resources Inc.	21,417.04	2/1/1953	Phosphoria/Tensleep
COTTONWOOD CREEK EXTENSION (PHOSPHORIA)	Continental Resources Inc.	3,718.87	5/1/1974	
COULEE	Chaco Energy Co.	639.67	1/25/1978	Frontier
DOBIE CREEK	Devon Energy Production Co. LP	4,037.01	6/9/1978	Frontier/Muddy
EAST WARM SPRINGS (PHOSPHORIA)	Ramco Oil & Gas Inc.	943.56	1/1/1976	
ELK BASIN	Encore Energy Partners Operating LLC	11,968.08	5/1/1946	Sundance/Embar[1]/Tensleep/Madison/Bighorn
ENIGMA (TENSLEEP)	Citation Oil & Gas Corp.	1,035.65	5/1/1995	
FIREBRICK	Whiting Petroleum Corp.	395.78	1/17/1996	Madison
FOURBEAR STRUCTURE	St. Mary Land & Exploration Co.	7,548.27	9/19/1934	Tensleep/Amsden/Madison
FOURTEEN MILE	Saga Petroleum LLC	320.00	2/28/1997	Dakota (Cloverly)
FRANNIE (PHOSHORIA/TENSLEEP)	Merit Energy Co.	1,888.34	9/1/1969	
GARLAND STRUCTURE/KINNEY COASTAL	Marathon Oil Co.	6,964.52	8/1/1936	Frontier/Phosphoria/Tensleep/Madison
GARLAND OHIO UTAH	Marathon Oil Co.	3,047.98	8/1/1935	Embar[1]/Tensleep/Madison
GEBO	Phoenix Production Co.	1,743.56	9/1/1943	Embar[1]/Tensleep
GOLDEN EAGLE	Saga Petroleum LLC	2,039.08	7/1/1946	Muddy/Cloverly/Embar[1]/Tensleep
GOOSE EGG	Underwood O&G	1,015.03	4/12/1977	Phosphoria
GOOSEBERRY	Encore Acquisitions Co.	5,957.67	5/1/1937	Embar[1]/Tensleep
GRASS CREEK FIELD WIDE	Marathon Oil Co.	7,458.11	8/1/2000	
HAMILTON DOME FIELD WIDE	Merit Energy Co.	3,111.79	11/1/1996	
KIRBY CREEK (PHOSPHORIA)	St. Mary Land & Exploration Co.	940.66	11/1/1968	
LAKE CREEK	Fidelity Exploration & Production Co.	1,124.16	11/19/1948	Embar[1]/Tensleep
LAMB ANTICLINE	Saga Petroleum LLC	640.00	10/26/1954	Muddy/Tensleep/Madison
LITTLE BUFFALO BASIN FRONTIER GAS	Citation Oil & Gas Corp.	4,806.40	1/6/1931	Frontier
LITTLE BUFFALO BASIN DEEP SAND	Citation Oil & Gas Corp.	17,651.50	10/1/1943	Muddy/Dakota (Cloverly)/Embar[1]/Tensleep
LITTLE GRASS CREEK	Saga Petroleum LLC	1,240.00	7/1/1943	Frontier/Muddy
MANDERSON	Saga Petroleum LLC	5,992.07	10/17/1952	Frontier/Muddy/Phosphoria
NO WATER CREEK	Continental Resources Inc.	1,933.85	8/7/1967	Phosphoria
NORTH DANKER	Merit Energy Co.	200.00	11/10/1948	Frontier
NORTH DANKER (EMBAR[1]/TENSLEEP)	Merit Energy Co.	360.00	6/1/1986	
OREGON BASIN	Marathon Oil Co.	14,234.00	3/1/1948	Chugwater/Embar[1]/Tensleep/Madison/Gros Ventre
OREGON BASIN SOUTH DOME (CLOVERLY)	Marathon Oil Co.	2,202.14	11/1/1971	
PACKSADDLE (UPPER PHOSPHORIA)	Gas Ventures LLC	418.27	12/31/2001	
PITCHFORK STRUCTURE	Marathon Oil Co.	2,563.95	1/1/1932	Phosphoria/Tensleep/Amsden/Madison
ROCKTOBER	Bill Barrett Corp.	23,677.13	12/28/2008	Non-productive
SAGE CREEK	Whiting Petroleum Corp.	956.46	11/21/1947	Tensleep/Madison
SHOSHONE (PHOSPHORIA/TENSLEEP)	Merit Energy Co.	457.47	9/1/1988	
SILVER TIP	Fidelity Exploration & Production Co.	2,404.05	11/1/1953	Meeteetse/Mesaverde/Peay(Frontier)
SLICK CREEK	Continental Resources Inc.	3,675.31	7/14/1950	Frontier/Muddy/Phosphoria
SOUTH ELK BASIN	Encore Energy Partners Operating LLC	4,782.14	12/1/1944	Frontier/Cloverly/Morrison/Embar[1]/Tensleep
SOUTH FORK ANTICLINE	Black Hills Exploration & Production Co.	1,056.35	11/1/1947	Embar[1]
SOUTH FRISBY	Continental Resources Inc.	1,018.05	1/12/1973	Phosphoria
SOUTH SPRING CREEK	Marathon Oil Co.	3,453.09	3/15/1938	Phosphoria/Tensleep/Amsden/Madison
SOUTHEAST KIRBY CREEK (PHOSPHORIA)	St. Mary Land & Exploration Co.	643.65	1/28/1997	
SPENCE DOME	Endeavor Energy LLC	520.00	9/19/1969	Madison
SUNDANCE	Exco Resources Inc.	24,546.84	9/11/2008	Non-productive
TORCHLIGHT (TENSLEEP/MADISON)	Whiting Petroleum Corp.	758.66	9/1/1962	
WALKER DOME (TORCHLIGHT[2])	Natural Gas Processing Co.	360.00	12/1/1965	
WORLAND	Devon Energy Production Co. LP	24,625.80	8/1/1945	Frontier/Muddy/Embar[1]/Tensleep
	Total Unit Acres	**250,706.57**		

[1]Embar is equivalent to the Phosphoria [2]Torchlight is equivalent to Frontier

Table 2.
Bighorn Basin Planning Area productive zones, number of producing fields, cumulative oil production, cumulative gas production, and wells (through December, 2008). Data modified from IHS Energy Group (2009).

SEQ	PRODUCTION ZONE	FIELDS	CUM GAS (thousand cubic feet)	CUM OIL (barrels)	INACTIVE WELLS	ACTIVE WELLS	TOTAL WELLS
1	AMSDEN	15	5,446,804	17,239,333	55	47	102
2	AMSDEN-MADISON	3	63,250	7,704,323	22	9	31
3	AMSDEN / PHOSPHORIA	1	0	90	1	0	1
4	BIG HORN	2	328,738	7,887,032	10	4	14
5	CHUGWATER	3	111,136,829	208,143	17	52	69
6	CLOVERLY	30	37,091,000	1,458,953	50	28	78
7	CLOVERLY / MOWRY	1	58,357	39,133	0	1	1
8	CODY	4	417,958	100,119	7	1	8
9	CROW MOUNTAIN	1	12,829	287,645	13	0	13
10	CROW MOUNTAIN-PHOSPHORIA-TENSLEEP	1	0	2,081	1	0	1
11	DARBY	3	3,734	30,257	4	1	5
12	DEVONIAN	1	18,203	119,266	4	0	4
13	DINWOODY	2	0	628,973	49	0	49
14	DINWOODY / PHOSPHORIA / TENSLEEP / AMSDEN / MADISON	1	0	3,220,368	10	33	43
15	DINWOODY-PHOSPHORIA	3	13,784	2,464,787	16	8	24
16	DINWOODY-PHOSPHORIA-TENSLEEP	1	0	25,866	2	1	3
17	FLATHEAD	1	2,464,282	40,192	3	2	5
18	FORT UNION	4	791,051	0	7	1	8
19	FORT UNION-LANCE	2	75,379	0	0	2	2
20	FRONTIER	88	677,344,620	88,171,606	793	428	1,221
21	FRONTIER-CLOVERLY	1	130,560	11,425	2	0	2
22	FRONTIER / MUDDY	3	29,561,414	234,612	3	12	15
23	GROS VENTURE	1	4,687,895	36,530	1	2	3
24	LANCE	3	452,241	5,658	2	2	4
25	LEWIS / MESAVERDE	1	3,250	0	1	0	1
26	MADISON	21	152,110,544	359,644,999	360	392	752
27	MADISON / AMSDEN	1	0	20,469	0	1	1
28	MADISON / AMSDEN / TENSLEEP	4	5,036	373,837	1	4	5
29	MADISON / TENSLEEP	4	1,119	1,049,110	7	7	14
30	MEETEESEE	3	1,262,763	1,228	1	9	10
31	MESAVERDE	6	5,089,224	99,028	9	16	25
32	MORRISON	5	955,610	148,735	10	1	11
33	MOWRY	6	1,474,326	276,963	24	15	39
34	MOWRY / FRONTIER	3	1,626,429	167,008	0	3	3
35	MUDDY	25	118,716,719	1,509,001	52	64	116
36	MUDDY / CLOVERLY	2	385,731	21,085	1	1	2
37	MUDDY / FRONTIER	1	133,703	7,805	0	1	1
38	PHOSPHORIA	120	559,517,419	976,280,423	1,443	1,543	2,986
39	PHOSPHORIA / TENSLEEP	27	19,848,843	260,501,835	248	226	474
40	PHOSPHORIA / TENSLEEP / AMSDEN	2	8,335	123,550	1	1	2
41	PHOSPHORIA / TENSLEEP / AMSDEN / MADISON	2	36,625	451,433	0	7	7
42	PHOSPHORIA / TENSLEEP / MADISON	1	47,575	232,637	1	2	3
43	PRECAMBRIAN	1	31,234	0	1	0	1
44	SUNDANCE	16	8,341,739	73,371,516	209	62	271
45	TEAPOT	1	0	163	1	0	1
46	TENSLEEP	62	428,077,091	1,063,488,792	1,098	1,307	2,405
47	TENSLEEP / AMSDEN	4	14,655	412,160	1	5	6
48	TENSLEEP / PHOSPHORIA / DINWOODY	1	0	22	1	0	1
49	UNKNOWN	2	398,403	1,689,986	2	0	2
	TOTAL		**2,168,185,301**	**2,869,788,177**	**4,544**	**4,301**	**8,845**

Table 3.

Producing fields within the Bighorn Basin Planning Area, with their number of producing zones, cumulative gas production, cumulative oil production, and well activity (through December, 2008). Data from IHS Energy Group (2009).

FIELD NAME	PRODUCING ZONES	CUMULATIVE GAS (thousand cubic feet)	CUMULATIVE OIL (barrels)	INACTIVE WELLS	ACTIVE WELLS	TOTAL WELLS
ADAM	2	0	119,588	1	1	2
ALKALI ANTICLINE	4	159,893	2,862,004	28	12	40
ASPEN CREEK	1	0	341,678	4	0	4
BADGER BASIN	2	7,253,556	3,699,785	12	9	21
BAIRD PEAK	1	0	469,211	1	1	2
BANJO FLATS	1	3,808	34,696	1	0	1
BEARCAT	7	1,649,457	846,138	4	9	13
BIG POLECAT	4	16,221,497	6,236,269	18	10	28
BLACK MOUNTAIN	6	104,512	21,925,035	24	52	76
BLUE SPRINGS	1	525	1,636	1	0	1
BONANZA	2	0	43,899,199	25	16	41
BOULDER GULCH	1	148,987	84,485	4	0	4
BUD	1	0	13,863	1	0	1
BUFFALO RIM	1	0	3,373	1	0	1
BYRON	9	10,004,560	130,898,136	143	115	258
BYRON SOUTH	1	4,434,390	42,519	1	0	1
BYRON SOUTHEAST	2	655,689	135,520	4	0	4
CENTENNIAL	1	0	84,116	1	4	5
CITY	1	0	311	1	0	1
CODY	3	279,412	8,626,740	28	29	57
COON CREEK	2	159,840	168,353	3	4	7
COTTONWOOD CREEK	6	66,892,025	60,028,218	109	198	307
COTTONWOOD CREEK SOUTH	1	0	14	1	0	1
COULEE	2	279,422	18,329	2	1	3
COWLEY	1	0	931,755	3	2	5
CRYSTAL CREEK	3	0	20,532	6	1	7
DANKER NORTH	5	2,819,760	1,149,009	9	4	13
DEAVER NORTH	1	146	1,566,094	3	9	12
DICKIE	1	0	36,340	2	0	2
DOBIE CREEK	3	17,970,481	359,120	6	7	13
DOCTOR DITCH	2	794,669	49,391	2	0	2
ELK BASIN	18	387,899,398	499,334,538	245	283	528
ELK BASIN SOUTH	9	36,197,273	24,973,266	41	29	70
EMBLEM	1	542,230	5,651	1	1	2
ENIGMA	1	0	3,432,292	2	20	22
ENOS CREEK	4	402,225	289,810	10	1	11
FERGUSON RANCH	2	31	5,186,274	5	12	17
FIVE MILE	7	52,325,845	1,364,026	14	26	40
FLASHLIGHT	1	0	98,202	1	0	1
FOSTER GULCH	2	0	17,315	2	0	2
FOURBEAR	7	279,989	40,526,593	179	64	243
FOURTEEN MILE	4	1,581,228	175,767	3	4	7
FRANKS FORK	1	0	2,081	1	0	1
FRANNIE	5	1,091,967	136,543,590	136	81	217
FREEDOM	1	0	27,694	0	1	1
FRISBY SOUTH	2	5,855,515	7,379,642	22	24	46
FRITZ	2	1,522,500	94,090	2	1	3
GARLAND	26	163,580,431	205,015,262	344	321	665
GARLAND SOUTH	2	1,343,934	6,460,395	4	0	4
GEBO	4	1,018,991	34,426,393	135	49	184
GOLDEN EAGLE	9	1,255,225	9,028,188	18	7	25
GOOSE EGG	1	13,372	131,089	2	4	6
GOOSEBERRY	4	215,076	12,927,564	29	33	62
GRASS CREEK	23	15,503,950	269,309,750	761	370	1,131
GRASS CREEK SOUTH	1	0	10,808	1	0	1
GREYBULL	2	293	640,359	48	5	53
GREYBULL WEST	3	1,237,718	68,543	1	2	3
HALF MOON	3	744,477	13,001,587	72	27	99

Table 3.

Producing fields within the Bighorn Basin Planning Area, with their number of producing zones, cumulative gas production, cumulative oil production, and well activity (through December, 2008). Data from IHS Energy Group (2009).

FIELD NAME	PRODUCING ZONES	CUMULATIVE GAS (thousand cubic feet)	CUMULATIVE OIL (barrels)	INACTIVE WELLS	ACTIVE WELLS	TOTAL WELLS
HAMILTON DOME	14	265,434,111	293,140,149	278	307	585
HAND CREEK	1	0	181,254	1	2	3
HEART MOUNTAIN	2	51,657,553	113,866	5	14	19
HIDDEN DOME	7	414,718	9,987,965	39	26	65
HOMESTEAD	1	30	1,953,450	10	4	14
HUNT	3	0	842,423	6	3	9
KING DOME	3	1,274	391,351	9	1	10
KIRBY CREEK	2	554,782	1,720,414	9	29	38
KIRBY CREEK EAST	1	0	1,291	1	0	1
LAKE CREEK	4	31,282	7,640,419	18	23	41
LAMB	5	521,093	1,221,804	16	3	19
LITE BUTTE	2	0	465,493	1	3	4
LITTLE BUFFALO BASIN	8	151,557,087	168,629,557	318	233	551
LITTLE GRASS CREEK	5	13,092,748	213,499	3	4	7
LITTLE POLECAT	4	1,307,425	819,003	8	3	11
LITTLE SAND DRAW	5	396,802	12,110,782	41	13	54
LOVELL DRAW	1	0	860	1	0	1
MANDERSON	7	47,603,392	4,007,116	82	53	135
MARSHALL	1	24,779	701,148	4	5	9
MCCULLOCH PEAK	2	749,788	1,867	2	0	2
MEETEETSE	5	35,109,102	465,097	10	16	26
MIDDLE DOME	2	2,811	389,284	4	2	6
MURPHY DOME	3	26,881	38,381,717	28	39	67
NEIBER DOME	6	238,073	702,770	7	4	11
NO WATER CREEK	2	481,939	4,162,667	25	10	35
NORTHLINE	2	27,768	3,401	2	0	2
NOWOOD	2	8	999,210	11	3	14
NOWOOD SOUTHEAST	1	7,238	242,836	2	6	8
OREGON BASIN	16	304,132,678	590,084,882	362	954	1,316
OREGON BASIN SOUTH	2	0	0	2	0	2
OREGON BASIN SOUTHEAST	4	8,808,554	2,814	4	4	8
OREGON BASIN WEST	2	143,610	802,410	2	4	6
PACKSADDLE	1	260,596	418,158	1	2	3
PENNEY GULCH	1	204	0	1	0	1
PISTOL	1	5,918	9,069	2	0	2
PITCHFORK	5	2,341,961	54,912,466	39	122	161
PROSPECT CREEK	1	12,829	287,645	13	0	13
PULLIUM	3	8,372	5,117	3	0	3
RALSTON	2	318,404	100,705	3	0	3
RATTLESNAKE	1	6,490,144	6,897,674	28	24	52
RAWHIDE	1	0	121,879	0	4	4
RED SPRINGS	3	0	21,185	13	7	20
ROSE CREEK	2	0	99,624	5	0	5
SAGE CREEK	2	50	13,526,646	14	24	38
SAGE CREEK WEST	1	54,469	1,316,421	8	6	14
SAGEBUSH	1	0	16,517	1	1	2
SAND CREEK	2	0	438	2	0	2
SELLER DRAW	2	3,385,929	1,938	1	1	2
SHEEP POINT	1	9,846	590,046	3	3	6
SHOSHONE	4	38,268	4,832,776	30	17	47
SHOSHONE NORTH	5	6,990	308,553	10	0	10
SIDDON	1	0	60,151	3	0	3
SILVER TIP	9	32,880,103	5,540,377	30	69	99

Table 3.

Producing fields within the Bighorn Basin Planning Area, with their number of producing zones, cumulative gas production, cumulative oil production, and well activity (through December, 2008). Data from IHS Energy Group (2009).

FIELD NAME	PRODUCING ZONES	CUMULATIVE GAS (thousand cubic feet)	CUMULATIVE OIL (barrels)	INACTIVE WELLS	ACTIVE WELLS	TOTAL WELLS
SILVER TIP SOUTH	5	640,245	176,514	11	1	12
SKELTON DOME	1	57,850	2,159	1	0	1
SLICK CREEK	4	9,620,887	6,340,130	41	15	56
SOUTH FORK	3	136,626	1,428,697	9	2	11
SPENCE DOME	2	2,352	1,060,644	27	50	77
SPRING CREEK	1	959	80,410	0	1	1
SPRING CREEK SOUTH	16	3,535,202	29,872,887	74	96	170
SUNSHINE NORTH	5	0	4,332,341	16	33	49
SUNSHINE SOUTH	3	0	628,870	6	0	6
T E RANCH	3	1	217,007	5	1	6
TERRY	2	766,513	22,180	1	2	3
TORCHLIGHT	7	6,412,788	16,474,302	80	32	112
TRENCH	1	0	40	1	0	1
TUFFY	2	91,168	98,920	2	1	3
TUMBLER RIDGE	1	0	6,989	4	0	4
UNNAMED	10	1,684,786	210,095	10	5	15
WAGONHOUND	2	9,521	317,490	3	1	4
WALKER DOME	5	1,251,818	5,051,159	17	11	28
WARM SPRINGS	1	3,950	4,815,107	89	92	181
WATER CREEK	1	0	210,723	3	0	3
WAUGH	1	0	355,393	1	3	4
WHISTLE CREEK	6	3,430,583	4,818,206	25	2	27
WHISTLE CREEK SOUTH	2	1,124,597	741	3	0	3
WILDHORSE BUTTE	1	0	508	3	0	3
WILEY	1	153,745	81,127	1	3	4
WILLOW DRAW	4	13,783	2,417,118	18	8	26
WORLAND	7	408,660,331	5,525,268	39	44	83
ZIMMERMAN BUTTE	5	3,690	672,742	5	1	6
TOTALS		**2,168,185,301**	**2,869,788,177**	**4,301**	**4,544**	**8,845**

Table 4.
U.S. Geological Survey undiscovered conventional and continuous resources of assessment units
within Bighorn Basin Province and Bighorn Basin Planning Area

	Estimated Undiscovered Bighorn Basin Province Resource Quantities at Probabiities of Occurrence of 95 and 5 Percent and for the Mean Case										Estimated Undiscovered Planning Area Resource Quantities at Probabilities of Occurrence of 95 and 5 Percent and for the Mean Case [1]								
	Oil (MMBO)			Gas (BCFG)			NGL (MMBNGL)				Oil (MMBO)			GAS (BCFG)			NGL (MMBNGL)		
Assessment Unit	95%	5%	Mean	95%	5%	Mean	95%	5%	Mean	% of Unit Lying Within Field Office	95%	5%	Mean	95%	5%	Mean	95%	5%	Mean
Paleozoic-Mesozoic Conventional Oil and Gas	13	110	54	55	449	218	1	18	9	84.10	10.93	92.51	45.41	46.26	377.61	183.34	0.84	15.14	7.57
Cretaceous-Tertiary Conventional Oil and Gas	4	24	13	62	436	221	2	10	5	89.52	3.58	21.48	11.64	55.50	390.31	197.84	1.79	8.95	4.48
Muddy-Frontier Sandstone and Mowry Fractured Shale Continuous Gas				119	743	348	0	1	0	100.00				119.00	743.00	348.00	0.00	1.00	0.00
Mowry Fractured Shale Continuous Oil	2	11	5	1	6	2	0	0	0	100.00	2	11	5	1.00	6.00	2.00	0.00	0.00	0.00
Cody Sandstone Continuous Gas				14	80	38	0	0	0	100.00				14.00	80.00	38.00	0.00	0.00	0.00
Mesaverde Sandstone Continuous Gas				13	63	32	0	0	0	100.00				13.00	63.00	32.00	0.00	0.00	0.00
Mesaverde-Meeteetse Formation Continuous Coalbed Gas				38	196	98	0	1	0	85.52				32.50	167.62	83.81	0.00	0.86	0.00
Fort Union Formation Continuous Coalbed Gas				14	59	32	0	0	0	88.26				12.36	52.07	28.24	0.00	0.00	0.00
Total Undiscovered Resources	**19**	**145**	**72**	**316**	**2,032**	**989**	**3**	**30**	**14**		**16.51**	**124.99**	**62.05**	**293.61**	**1,879.61**	**913.23**	**2.63**	**25.95**	**12.05**

MMBO = Million Barrels of Oil

BCFG = Billion Cubic Feet of Gas

MMNGL = Million Barrels of Natural Gas Liquids

[1] Potential resource is assumed to be evenly distributed across each assessment unit.

Table 4.

U.S. Geological Survey undiscovered conventional and continuous resources of assessment units within Bighorn Basin Province and Bighorn Basin Planning Area

Table 5. Estimated oil and gas (excluding coalbed natural gas) development potential classification acres, number of townships, projected average drilling densities, and percentage of the Bighorn Basin Planning Area within each development potential classification type for the period 2008 through 2027.

Development Potential	Acres (thousands)	Area (townships)	Average new wells per township	% of Planning Area
High	0	0	0	0
Moderate	441,988	19.18	60	5.63
Low	2,473,989	107.37	5	31.53
Very Low	3,191,666	138.53	0.25	40.68
None	428,517	18.60	0	5.46
Not Assessed	1,309,745	56.85	0	16.69
Totals	**7,845,905**	**340.53**		

Table 6. Forecast of Bighorn Basin Planning Area base line annual and cummulative oil and gas production for 2009 through 2028.

Year	Annual Gas (Thousand Cubic Feet)	Cummulative Gas (Thousand Cubic Feet)	Annual Oil (Barrels)	Cummulative Oil (Barrels)
2009	18,888,943	18,888,943	11,350,700	11,350,700
2010	18,345,137	37,234,080	10,780,278	22,130,978
2011	17,816,987	55,051,067	10,238,521	32,369,499
2012	17,304,042	72,355,109	9,723,991	42,093,490
2013	16,805,864	89,160,973	9,235,318	51,328,808
2014	16,322,029	105,483,002	8,771,203	60,100,011
2015	15,852,123	121,335,125	8,330,411	68,430,422
2016	15,395,746	136,730,871	7,911,772	76,342,194
2017	14,952,507	151,683,378	7,514,171	83,856,365
2018	14,522,030	166,205,408	7,136,551	90,992,916
2019	14,103,945	180,309,353	6,777,908	97,770,824
2020	13,697,897	194,007,250	6,437,288	104,208,112
2021	13,303,539	207,310,789	6,113,786	110,321,898
2022	12,920,535	220,231,324	5,806,542	116,128,440
2023	12,548,557	232,779,881	5,514,738	121,643,178
2024	12,187,288	244,967,169	5,237,598	126,880,776
2025	11,836,420	256,803,589	4,974,386	131,855,162
2026	11,495,654	268,299,243	4,724,401	136,579,563
2027	11,164,698	279,463,941	4,486,979	141,066,542
2028	10,843,270	290,307,211	4,261,489	145,328,031

Table 7. Estimated coalbed natural gas development potential classification acres, number of townships, projected average drilling densities, and percentage of the Bighorn Basin Planning Area within each development potential classification type for the period 2008 through 2027.

Development Potential	Acres (thousands)	Area (townships)	Average new wells per township	% of Planning Area
Low	787,607	34.18	3.6	10.04
Very Low	1,815,572	78.80	0.27	23.14
None	3,933,084	170.71	0	50.13
Not Assessed	1,309,745	56.85	0	16.69
Totals	**7,846,008**	**340.54**		

Table 8. Alternative A summary of the number of acres in each restriction category for each development potential type within the Bighorn Basin Planning Area.

Development Potential	Category D Federal Acres	Category C Federal Acres	Category B Federal Acres
Non-Coalbed Gas			
High	0	0	0
Moderate	0	94,762	153,929
Low	0	536,858	810,237
Very Low	9,376	687,528	700,179
Coalbed Natural Gas			
High	0	0	0
Moderate	0	0	0
Low	0	180,479	236,234
Very Low	0	364,623	706,599

Table 9. Bighorn Basin Planning Area analysis results showing the calculated reduction in Federal non-coalbed oil and gas wells and Federal coalbed natural gas wells for Alternative A due to Category C restrictions. This calculation indicates there would be a reduction of 161 non-coalbed oil and gas well locations and 16 coalbed natural gas well locations on Federal lands.

Development Potential	Well Locations per Township	Federal Acres (thousand)	Federal Townships	Percent Reduction in Well Locations	Reduction in Well Locations
Non-Coalbed Oil and Gas					
Moderate	60	94,762	4.11	40%	98.71
Low	5	536,858	23.30	50%	58.25
Very Low	0.25	687,528	29.84	55%	4.10
Coalbed Natural Gas					
Low	3.6	180,479	7.83	50%	14.10
Very Low	0.27	364,623	15.83	55%	2.35

Table 10. Total wells projected to be drilled within the Bighorn Basin Planning Area for the base line and each alternative for the period 2008 through 2027. The projections of the percent of Federal wells drilled for this period is also presented.

Alternative	Coalbed Natural Gas Wells	Non-coalbed Oil and Gas Wells	Total Wells	Percent Federal
Base Line	150	1,715	1,865	72.6
Alternative A	130	1,511	1,641	68.9
Alternative B	84	936	1,020	49.9
Alternative C	124	1,644	1,768	71.1
Alternative D	98	1,436	1,534	66.7

Table 11. Forecast of Bighorn Basin Planning Area Alternative A annual and cummulative oil and gas production for 2009 through 2028.

Year	Annual Gas (Thousand Cubic Feet)	Cummulative Gas (Thousand Cubic Feet)	Annual Oil (Barrels)	Cummulative Oil (Barrels)
2009	16,642,095	16,642,095	10,000,529	10,000,529
2010	16,162,975	32,805,070	9,497,959	19,498,488
2011	15,697,649	48,502,719	9,020,644	28,519,132
2012	15,245,719	63,748,438	8,567,318	37,086,450
2013	14,806,799	78,555,237	8,136,773	45,223,223
2014	14,380,517	92,935,754	7,727,865	52,951,088
2015	13,966,506	106,902,260	7,339,505	60,290,593
2016	13,564,415	120,466,675	6,970,663	67,261,256
2017	13,173,900	133,640,575	6,620,357	73,881,613
2018	12,794,628	146,435,203	6,287,655	80,169,268
2019	12,426,275	158,861,478	5,971,673	86,140,941
2020	12,068,526	170,930,004	5,671,570	91,812,511
2021	11,721,077	182,651,081	5,386,548	97,199,059
2022	11,383,632	194,034,713	5,115,851	102,314,910
2023	11,055,901	205,090,614	4,858,758	107,173,668
2024	10,737,605	215,828,219	4,614,583	111,788,251
2025	10,428,473	226,256,692	4,382,681	116,170,932
2026	10,128,241	236,384,933	4,162,431	120,333,363
2027	9,836,652	246,221,585	3,953,251	124,286,614
2028	9,553,458	255,775,043	3,754,583	128,041,197

Table 12. Forecast of Bighorn Basin Planning Area Alternative B annual and cummulative oil and gas production for 2009 through 2028.

Year	Annual Gas (Thousand Cubic Feet)	Cummulative Gas (Thousand Cubic Feet)	Annual Oil (Barrels)	Cummulative Oil (Barrels)
2009	10,309,067	10,309,067	6,194,901	6,194,901
2010	10,012,273	20,321,340	5,883,580	12,078,481
2011	9,724,023	30,045,363	5,587,904	17,666,385
2012	9,444,072	39,489,435	5,307,088	22,973,473
2013	9,172,180	48,661,615	5,040,383	28,013,856
2014	8,908,116	57,569,731	4,787,082	32,800,938
2015	8,651,654	66,221,385	4,546,510	37,347,448
2016	8,402,576	74,623,961	4,318,028	41,665,476
2017	8,160,669	82,784,630	4,101,029	45,766,505
2018	7,925,726	90,710,356	3,894,934	49,661,439
2019	7,697,547	98,407,903	3,699,196	53,360,635
2020	7,475,937	105,883,840	3,513,295	56,873,930
2021	7,260,707	113,144,547	3,336,737	60,210,667
2022	7,051,674	120,196,221	3,169,051	63,379,718
2023	6,848,659	127,044,880	3,009,793	66,389,511
2024	6,651,488	133,696,368	2,858,537	69,248,048
2025	6,459,994	140,156,362	2,714,884	71,962,932
2026	6,274,013	146,430,375	2,578,449	74,541,381
2027	6,093,386	152,523,761	2,448,870	76,990,251
2028	5,917,960	158,441,721	2,325,804	79,316,055

Table 13. Forecast of Bighorn Basin Planning Area Alternative C annual and cummulative oil and gas production for 2009 through 2028.

Year	Annual Gas (Thousand Cubic Feet)	Cummulative Gas (Thousand Cubic Feet)	Annual Oil (Barrels)	Cummulative Oil (Barrels)
2009	18,106,952	18,106,952	10,880,788	10,880,788
2010	17,585,659	35,692,611	10,333,981	21,214,769
2011	17,079,374	52,771,985	9,814,652	31,029,421
2012	16,587,665	69,359,650	9,321,423	40,350,844
2013	16,110,111	85,469,761	8,852,981	49,203,825
2014	15,646,307	101,116,068	8,408,080	57,611,905
2015	15,195,854	116,311,922	7,985,537	65,597,442
2016	14,758,371	131,070,293	7,584,229	73,181,671
2017	14,333,482	145,403,775	7,203,089	80,384,760
2018	13,920,826	159,324,601	6,841,102	87,225,862
2019	13,520,050	172,844,651	6,497,307	93,723,169
2020	13,130,812	185,975,463	6,170,788	99,893,957
2021	12,752,780	198,728,243	5,860,679	105,754,636
2022	12,385,632	211,113,875	5,566,155	111,320,791
2023	12,029,054	223,142,929	5,286,431	116,607,222
2024	11,682,741	234,825,670	5,020,764	121,627,986
2025	11,346,399	246,172,069	4,768,449	126,396,435
2026	11,019,741	257,191,810	4,528,814	130,925,249
2027	10,702,486	267,894,296	4,301,221	135,226,470
2028	10,394,365	278,288,661	4,085,066	139,311,536

Table 14. Forecast of Bighorn Basin Planning Area Alternative D annual and cummulative oil and gas production for 2009 through 2028.

Year	Annual Gas (Thousand Cubic Feet)	Cummulative Gas (Thousand Cubic Feet)	Annual Oil (Barrels)	Cummulative Oil (Barrels)
2009	15,816,048	15,816,048	9,504,143	9,504,143
2010	15,360,709	31,176,757	9,026,518	18,530,661
2011	14,918,480	46,095,237	8,572,896	27,103,557
2012	14,488,982	60,584,219	8,142,071	35,245,628
2013	14,071,849	74,656,068	7,732,896	42,978,524
2014	13,666,725	88,322,793	7,344,284	50,322,808
2015	13,273,265	101,596,058	6,975,201	57,298,009
2016	12,891,132	114,487,190	6,624,667	63,922,676
2017	12,520,000	127,007,190	6,291,749	70,214,425
2018	12,159,554	139,166,744	5,975,561	76,189,986
2019	11,809,484	150,976,228	5,675,263	81,865,249
2020	11,469,493	162,445,721	5,390,056	87,255,305
2021	11,139,290	173,585,011	5,119,182	92,374,487
2022	10,818,594	184,403,605	4,861,921	97,236,408
2023	10,507,130	194,910,735	4,617,588	101,853,996
2024	10,204,633	205,115,368	4,385,534	106,239,530
2025	9,910,845	215,026,213	4,165,142	110,404,672
2026	9,625,516	224,651,729	3,955,825	114,360,497
2027	9,348,400	234,000,129	3,757,027	118,117,524
2028	9,079,263	243,079,392	3,568,221	121,685,745

Table 15.
Bighorn Basin Planning Area surface disturbance associated with wells projected for the base line development scenario for the 2008 through 2027 period and for existing active wells.

Disturbance Associated With All New Drilled Wells and Existing Active Wells (Short-Term Disturbance)						
	Wells			Acres of Surface Disturbance		
	Type	All Lands	BLM Managed	Well Pad + Access Roads + Facilities	All Lands	BLM Managed
New Wells	Oil and Gas	1,715	1,249	3	5,145	3,747
	Coalbed gas	150	105	3	450	315
	Wells/Disturbance	**1,865**	**1,354**		**5,595**	**4,062**
Existing Wells	Oil and Gas	4,510	2,966	1.5	6,765	4,449
	Coalbed gas	0	0	1.5	0	0
	Wells/Disturbance	**4,510**	**2,966**		**6,765**	**4,449**
	Total Wells/Disturbance	**6,375**	**4,320**		**12,360**	**8,511**

Disturbance Associated With All New Producing Wells and Existing Active Wells Less Abandonments (Long-Term Disturbance)						
	Wells			Acres of Surface Disturbance		
	Type	All Lands	BLM Managed	Well Pad + Access Roads + Facilities	All Lands	BLM Managed
New Wells	Oil and Gas	1,372	999	1.5	2,058	1,499
	Coalbed gas	135	95	1.5	203	142
	Wells/Disturbance	**1,507**	**1,094**		**2,261**	**1,641**
Existing Wells	Oil and Gas	3,467	2,269	1.5	5,201	3,404
	Coalbed gas	0	0	1.5	0	0
	Wells/Disturbance	**3,467**	**2,269**		**5,201**	**3,404**
	Total Wells/Disturbance	**4,974**	**3,363**		**7,461**	**5,044**

Table 16

Bighorn Basin Planning Area surface disturbance associated with wells projected for the Alternative A development scenario for the 2008 through 2027 period and for existing active wells.

Disturbance Associated With All New Drilled Wells and Existing Active Wells (Short-Term Disturbance)						
	Wells			**Acres of Surface Disturbance**		
	Type	**All Lands**	**BLM Managed**	**Well Pad + Access Roads + Facilities**	**All Lands**	**BLM Managed**
New Wells	Oil and Gas	1,511	1,045	3	4,533	3,135
New Wells	Coalbed gas	130	85	3	390	255
New Wells	**Wells/Disturbance**	**1,641**	**1,130**		**4,923**	**3,390**
Existing Wells	Oil and Gas	4,510	2,966	1.5	6,765	4,449
Existing Wells	Coalbed gas	0	0	1.5	0	0
Existing Wells	**Wells/Disturbance**	**4,510**	**2,966**		**6,765**	**4,449**
	Total Wells/Disturbance	**6,151**	**4,096**		**11,688**	**7,839**

Disturbance Associated With All New Producing Wells and Existing Active Wells Less Abandonments (Long-Term Disturbance)						
	Wells			**Acres of Surface Disturbance**		
	Type	**All Lands**	**BLM Managed**	**Well Pad + Access Roads + Facilities**	**All Lands**	**BLM Managed**
New Wells	Oil and Gas	1,209	836	1.5	1,813	1,254
New Wells	Coalbed gas	117	77	1.5	176	115
New Wells	**Wells/Disturbance**	**1,326**	**913**		**1,989**	**1,369**
Existing Wells	Oil and Gas	3,467	2,269	1.5	5,201	3,404
Existing Wells	Coalbed gas	0	0	1.5	0	0
Existing Wells	**Wells/Disturbance**	**3,467**	**2,269**		**5,201**	**3,404**
	Total Wells/Disturbance	**4,793**	**3,182**		**7,189**	**4,772**

Table 17

Bighorn Basin Planning Area surface disturbance associated with wells projected for the Alternative B development scenario for the 2008 through 2027 period and for existing active wells.

	Disturbance Associated With All New Drilled Wells and Existing Active Wells (Short-Term Disturbance)					
	Wells			Acres of Surface Disturbance		
	Type	All Lands	BLM Managed	Well Pad + Access Roads + Facilities	All Lands	BLM Managed
New Wells	Oil and Gas	936	470	3	2,808	1,410
New Wells	Coalbed gas	84	39	3	252	117
New Wells	Wells/Disturbance	1,020	509		3,060	1,527
Existing Wells	Oil and Gas	4,510	2,966	1.5	6,765	4,449
Existing Wells	Coalbed gas	0	0	1.5	0	0
Existing Wells	Wells/Disturbance	4,510	2,966		6,765	4,449
	Total Wells/Disturbance	5,530	3,475		9,825	5,976

	Disturbance Associated With All New Producing Wells and Existing Active Wells Less Abandonments (Long-Term Disturbance)					
	Wells			Acres of Surface Disturbance		
	Type	All Lands	BLM Managed	Well Pad + Access Roads + Facilities	All Lands	BLM Managed
New Wells	Oil and Gas	749	376	1.5	1,123	564
New Wells	Coalbed gas	76	35	1.5	113	53
New Wells	Wells/Disturbance	824	411		1,237	617
Existing Wells	Oil and Gas	3,467	2,269	1.5	5,201	3,404
Existing Wells	Coalbed gas	0	0	1.5	0	0
Existing Wells	Wells/Disturbance	3,467	2,269		5,201	3,404
	Total Wells/Disturbance	4,291	2,680		6,437	4,020

Figure 18

Bighorn Basin Planning Area surface disturbance associated with wells projected for the Alternative C development scenario for the 2008 through 2027 period and for existing active wells.

Disturbance Associated With All New Drilled Wells and Existing Active Wells (Short-Term Disturbance)							
	Wells			Acres of Surface Disturbance			
	Type	All Lands	BLM Managed	Well Pad + Access Roads + Facilities	All Lands	BLM Managed	
New Wells	Oil and Gas	1,644	1,178	3	4,932	3,534	
New Wells	Coalbed gas	124	79	3	372	237	
New Wells	**Wells/Disturbance**	**1,768**	**1,257**		**5,304**	**3,771**	
Existing Wells	Oil and Gas	4,510	2,966	1.5	6,765	4,449	
Existing Wells	Coalbed gas	0	0	1.5	0	0	
Existing Wells	**Wells/Disturbance**	**4,510**	**2,966**		**6,765**	**4,449**	
	Total Wells/Disturbance	**6,278**	**4,223**		**12,069**	**8,220**	

Disturbance Associated With All New Producing Wells and Existing Active Wells Less Abandonments (Long-Term Disturbance)						
	Wells			Acres of Surface Disturbance		
	Type	All Lands	BLM Managed	Well Pad + Access Roads + Facilities	All Lands	BLM Managed
New Wells	Oil and Gas	1,315	942	1.5	1,973	1,414
New Wells	Coalbed gas	112	71	1.5	167	107
New Wells	**Wells/Disturbance**	**1,427**	**1,014**		**2,140**	**1,520**
Existing Wells	Oil and Gas	3,467	2,269	1.5	5,201	3,404
Existing Wells	Coalbed gas	0	0	1.5	0	0
Existing Wells	**Wells/Disturbance**	**3,467**	**2,269**		**5,201**	**3,404**
	Total Wells/Disturbance	**4,894**	**3,283**		**7,341**	**4,924**

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Figure 19

Bighorn Basin Planning Area surface disturbance associated with wells projected for the Alternative D development scenario for the 2008 through 2027 period and for existing active wells.

Disturbance Associated With All New Drilled Wells and Existing Active Wells (Short-Term Disturbance)						
	Wells			**Acres of Surface Disturbance**		
	Type	**All Lands**	**BLM Managed**	**Well Pad + Access Roads + Facilities**	**All Lands**	**BLM Managed**
New Wells	Oil and Gas	1,436	979	3	4,308	2,937
	Coalbed gas	98	53	3	294	159
	Wells/Disturbance	**1,534**	**1,032**		**4,602**	**3,096**
Existing Wells	Oil and Gas	4,510	2,966	1.5	6,765	4,449
	Coalbed gas	0	0	1.5	0	0
	Wells/Disturbance	**4,510**	**2,966**		**6,765**	**4,449**
	Total Wells/Disturbance	**6,044**	**3,998**		**11,367**	**7,545**

Disturbance Associated With All New Producing Wells and Existing Active Wells Less Abandonments (Long-Term Disturbance)						
	Wells			**Acres of Surface Disturbance**		
	Type	**All Lands**	**BLM Managed**	**Well Pad + Access Roads + Facilities**	**All Lands**	**BLM Managed**
New Wells	Oil and Gas	1,149	783	1.5	1,723	1,175
	Coalbed gas	88	48	1.5	132	72
	Wells/Disturbance	**1,237**	**831**		**1,856**	**1,246**
Existing Wells	Oil and Gas	3,467	2,269	1.5	5,201	3,404
	Coalbed gas	0	0	1.5	0	0
	Wells/Disturbance	**3,467**	**2,269**		**5,201**	**3,404**
	Total Wells/Disturbance	**4,704**	**3,100**		**7,056**	**4,650**

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