REASONABLE FORESEEABLE DEVELOPMENT SCENARIOS FOR OIL AND GAS ACTIVITIES ON FEDERAL LANDS IN THE PINEDALE FIELD OFFICE, WYOMING

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Reasonable Foreseeable Development Scenario for Oil and Gas
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INTRODUCTION

The Bureau of Land Management (Bureau) manages public lands in the Pinedale Field Office (Field Office) planning area, which lies within west-central Wyoming (Figure 1). Lands in Teton County are not included in these reasonable foreseeable development scenarios. The main goal of our evaluation is to technically analyze the oil and gas resource occurring within the Field Office area and to project future development potential and activity levels for the period 2001 through 2020. This analysis makes a base line projection that assumes future activity levels will not be constrained by management-imposed conditions (Rocky Mountain Federal Leadership Forum, 2002). Where legislatively imposed restrictions are applied to lands within the Field Office area, we have considered those restrictions when determining future activity levels and have constrained our base line projection to reflect those restrictions. Finally, projections of future activity levels for each resource management plan alternative are presented.

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 gas, and deep hydrocarbons (at depths greater than 15,000 feet) as well as available estimates of the hydrocarbon resources that may be present within the Field Office area. Additional factors used to project future activities include, but are not limited to review and analysis 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
- future oil and gas price estimates
- petroleum (see Glossary definition for *petroleum*) technology research and development
- geophysical activity
- bid performance at lease sales
- 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 uses logical and technically based assumptions to make those projections.

Total federal gas resource ownership in the Field Office planning area is about 2,526,640 acres (85 percent) of 2,965, 201 total acres. The Forest Service (53 percent) and the Bureau (46 percent) manage most of the federal mineral lands in the Field Office area. Smaller amounts of federal mineral lands are managed by the Bureau of Reclamation. State and private minerals lands amount to about 438,561acres, or about 15 percent of total acres within Field Office boundaries. Again, Teton County lands are not included as part of this analysis.

We would like to thank Dave Chase of the Bureau's Wyoming State Office Reservoir Management Group staff for updating the information on oil and gas prices, and Bill Lanning of the Bureau's Field Office for the update of surface disturbance assumptions and calculations. We would also like to thank Cathy Stilwell of the Bureau's Wyoming State Office Reservoir Management Group staff for the important contributions that she has made to this reasonable foreseeable development analysis.

REVIEW OF 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 Field Office area. Information is presented in the approximate sequence that occurs when project areas or fields (see Glossary definition for *field*) are explored and then developed. The sequence begins when initial exploratory activity begins, and ends when projects are abandoned

EXPLORATORY ACTIVITY AND OPERATIONS

Exploratory activity includes:

- the study and mapping of surface and subsurface geologic features to recognize potential hydrocarbon traps
- determining a geologic formation's potential for containing economically producible hydrocarbons
- 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
- completing wells that appear capable of producing economic quantities of hydrocarbons.

Hendricks (1995) studied the components that control and characterize potential gas accumulations (see Glossary definition for *accumulation and gas accumulation*) in the Great Divide and Washakie basins to the southeast of the Field Office area. He reported that the major components of accumulations "are:

1. Thick accumulations of sandstones, shales, and locally coal (potential source and reservoir rocks) exist.
2. Burial and thermal histories promoted the development and preservation of diagenetic pore throat traps and extensive gas generation.
3. Although the centers of basins are completely gas saturated, production is controlled by stratigraphy. Both basin-wide and local stratigraphic variations are important in creating traps and reservoirs (local compartments).
4. Structure also plays a role in localizing gas accumulations, especially when coupled with stratigraphy.
5. Pressure regimes, ranging from slightly under-pressured to highly over-pressured, are important. In areas of abnormally high pressures, productive capacity can be greatly increased. Over-pressuring also creates problems in drilling and completion, increasing the cost of both.
6. The presence of fractures, both tectonic and produced by gas generation, is important to overall productivity.

7. Secondary porosity, produced by the dissolution of unstable grains and rock fragments, is important in both basin-wide and local accumulations."

We believe that those components are also important in exploring for and developing new gas resources in the Greater Green River Basin and Wyoming Thrust Belt portions of the Field Office (Figure 2). Most of the exploratory interest in the Field Office area, in recent years, has been in the Greater Green River Basin portion. Almost all Field Office area drilling activity (exploratory and development) has been occurring in those parts of the Greater Green River Basin that do not cover Forest Service lands.

Innovative drilling and completion techniques have enabled the industry to drill deeper (with fewer dry holes) and to recover more hydrocarbon reserves per well. Smaller accumulations once thought to be uneconomic can now be produced. Improvements have also allowed downspacing to occur in some cases, such as at Jonah field and along the Pinedale Anticline, so that a greater percent of a field's gas-in-place (see Glossary definition for *in-place*) resource can be efficiently developed. Nationally, increased drilling success rates have cut the number of both wells drilled and dry holes (U.S. Department of Energy, 1999). Our review indicates that this observation also applies to western Wyoming. Barlow & Haun, Inc (1994) reported that in the Greater Green River Basin, one rig was capable of drilling four wells per year in 1973. By the early 1980's they found that the rate had increased to seven wells per year per rig and it increased again to 10 wells per year per rig by 1994. Since 1994 improvements in rig drilling rates have continued.

Barlow & Haun, Inc. (1994) also showed that successful gas well completions had gone from 30 percent in the early 1970's, to 45 percent in the early 1980's, to about 85 percent by 1993. Industry is drilling fewer dry holes and reducing the number of wells needed to fully develop each reservoir. During the early 1990's, activity was 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 Field Office area and to determine whether its potential coalbed gas resource will be economic to produce. Since the risk of failure is higher for these types of activities, the overall success rate could decline slightly in the future.

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

- computer processing capability and speed
- remote sensing, image-processing technology, and data visualization
- 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 definition for *play*), and reservoirs
- 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 hydrocarbon “seeps” so that they can be cleaned up. These seeps can also help pinpoint undiscovered hydrocarbons.

Technology improvements have also cut the average cost of finding oil and gas reserves in the United States. U.S. Department of Energy (1999) estimated finding costs were approximately \$12 to \$16 per barrel of oil equivalent in the 1970’s. Currently, finding costs have dropped to \$4 to \$8 per barrel.

FEDERAL DEVELOPMENT CONTRACTS

The United States approves development contracts between operating companies and a number of oil and gas lessees 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. Presently, two development contracts lie within or partially within the Field Office (Figure 3). They cover about 14 percent of the Field Office area. The Hoback Basin Development Contract is an approximately 396,246-acre area lying in the northwest part of the Greater Green River Basin. Forest Service managed lands abut the contract area on the north and northwest. This development contract was approved in August of 2002 with EOG Resources, Inc. and The Wolf Haven Corporation as parties to the contract.

The Tabernacle Butte Development Contract is an approximately 146,000-acre area straddling the southeast boundary of the Field Office. Only about 11,224 acres of this contract area actually lie within the Field Office. This development contract was approved in August of 2005 with Oxy USA WTP LP and EnCana Oil & Gas (USA) as parties to the contract. Financial information or information covered by the provisions of 43 CFR Part 2 and requested by the parties to the contract to be held confidential, are treated as proprietary.

FEDERAL OIL AND GAS UNIT AGREEMENTS

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

Federal oil and gas leases are incorporated into 45 active unit agreement areas that lie wholly or partly within the Field Office boundary (Figure 4). Numerous other unit agreements have been approved but have since terminated. API units are those in which federal leases comprise less than 10 percent of the total unit area. No API units lie within the Field Office boundary. Active units encompass lands totaling approximately 277,532 acres in area, or approximately nine percent of the total Field Office area. Most of these federal unit agreements were initially approved as exploration tools to investigate non-producing parts of the Field Office area. Some have found and developed oil and gas and are now considered to be producing units. Others are still in an exploratory stage of development. Seven of the 45 units were approved as secondary units to enhance the recovery of the oil resource. All secondary units are located within the Greater Big Piney-LaBarge area.

Companies operating more than one unit are; EOG Resources Incorporated (18 units), ExxonMobil (five units), EnCana Oil & Gas (USA) Incorporated (five units), Chevron USA Incorporated (two units), and McMurry Oil LLC (two units). Twelve other companies (Anschutz Pinedale Corporation, Beartooth Oil & Gas, BP America Production Company, Cimarex Energy Company, Gasco Production Company, Plains Exploration & Production Company, Questar Exploration & Production Company, Ultra Resources Incorporated, Wexpro Company, Wold Oil/Infinity Oil & Gas, XTO Energy Incorporated, and Yates Petroleum Corporation) operate one unit each.

The oldest producing unit was approved in 1940. Twenty-nine of the first 30 approved producing units are located in the Greater Big Piney-LaBarge area and its northeast flank (Figure 4). These units were approved between 1940 and 1993, with almost 75 percent now operated by EOG Resources Incorporated and ExxonMobil. These units are generally at a mature stage of development.

The first unit development outside of the Greater Big Piney/LaBarge area was The Mesa which was approved on the Pinedale Anticline in 1980. Additional unit developments were not approved in the Pinedale Anticline or adjacent Jonah areas until 1996. Ten of the 15 approved units between 1996 and the present are in this area. All 10 units were approved as exploratory units and all reflect increased exploratory and development interest and activity in this area in recent years. These newer units are in early stages of exploratory activity.

Of the remaining five units approved since 1996: two exploratory units and one secondary unit were approved in the Greater Big Piney/LaBarge area; Billy Canyon exploratory unit was approved in the center of the Field Office area in townships 31 and 32 north, range 112 west; and the South Rim exploratory unit was approved in the northwest part of the Field Office area on Forest Service and Bureau managed lands.

No coalbed gas units have been established within the Field Office area. Infinity Oil & Gas of Wyoming, Inc. established an initial Mesaverde Group coalbed gas participating area in the existing Riley Ridge Unit effective in May of 2002. Five coalbed gas wells were included in this participating area.

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 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, 41 active communitization agreements lie within the Field office area and cover approximately 7,370 acres. Companies operating more than one communitization agreement are; EOG Resources Incorporated (21 agreements), ExxonMobil (six agreements), BP America Production Company (three agreements), EnCana Oil & Gas (USA) Incorporated (three agreements), Infinity Oil & Gas (three agreements), and XTO Energy Incorporated (three agreements). Berco Resources and Whiting Oil & Gas Corporation each operate one agreement. Many other agreements have been approved but have since terminated.

The oldest producing communitization agreement was approved in 1966. Thirty-five agreements are located in the Greater Big Piney-LaBarge area and its northeast flank (Figure 2). These agreements were approved between 1966 and 2005, with 74 percent now operated by EOG Resources Incorporated and ExxonMobil.

Five communitization agreements have been approved in the Jonah field area (Figure 2) and one agreement has been approved in the center of the Field Office in township 34 north, range 111 west. All have been approved since December of 2003 and they reflect increased exploratory and development interest and activity in this area in recent years.

TYPICAL DRILLING AND COMPLETION SEQUENCE

The drilling and completion sequence for a targeted reservoir in the Field Office area generally involves:

- using rotary equipment, hardened drill bits, weighted drill pipe/collars, and drilling fluids to cool and lubricate, which all result in easier penetration of the earth's surface
- inserting casing and tubing into each well to protect the subsurface and control the flow of fluids (oil, gas, and water) from the reservoir
- cementing portions of casing to protect the potential groundwater resource from oil, gas, and poor quality water
- perforating the well casing at the depth of the producing formation to allow flow of fluids from the formation into the borehole
- hydraulically fracturing the formation to increase permeability and the deliverability of oil and gas to the borehole
- installing a wellhead at the surface to regulate and monitor fluid flow and prevent potentially dangerous blowouts.

Advanced Resources International (2001) used industry guidance to determine the average time required to drill and complete a well within certain depth ranges. They predicted an average time of 40 days to drill and complete a well of less than 10,000 feet, 65 days for wells between 10,000 and 14,000 feet, and 190 days for wells greater than 14,000 feet.

The cost of drilling a gas well in the Rocky Mountain region is higher than the average for the onshore 48 contiguous states (Cleveland, 2003). Factors contributing to this higher cost in the Field Office area are thought to be:

- costs increase with depth and most new wells are deeper than the average
- access to well sites is generally more costly due to remoteness and sometimes steep terrain
- wage rates are higher due to labor market conditions.

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

- smaller footprints (less surface disturbance)
- reduced noise and visual impact
- less frequent maintenance and workovers of producing wells with less associated waste

- reduced fuel use and associated emissions
- enhanced well control for greater worker safety and protection of groundwater resources
- less time on site with fewer associated environmental impacts
- lower toxicity of discharges
- better protection of sensitive environments and habitat.

DRAINAGE PROTECTION

Producing oil and gas wells may cause drainage (migration toward the borehole) from nearby lands. This drainage will result in the loss of oil and gas from those lands and result in loss of royalty revenues for landowners. Drainage is most often avoided or reduced by the drilling of a protective well. By protecting federal 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

McKinley (2003) reports that local ranchers and cowboys noted in 1892 that oil from a seep at Birch Creek, in the vicinity of the present-day LaBarge field area, was seen on horses' hooves. Schultz (1907) reported the discovery of oil in the summer of 1907, in section 34 of township 27 north, range 113 west (LaBarge field area). He reported "a sample collected from a shallow well about 3 feet square and 6 feet deep *** considerable oil was taken from this pit during the summer by various persons who visited *** at several points in the valley oil was encountered by sinking shallow wells a few feet into the soil." Numerous claims were staked in the vicinity. At this time drilling was occurring under placer mining laws. In 1920 the Federal Government changed to a leasing system for oil and gas development.

Wyoming Oil and Gas Conservation Commission (2006a) records show the earliest recorded drilling occurred in 1912 when two wells were drilled and abandoned in the LaBarge field area. The anticline on which these tests were drilled was first mapped by the United States Geological Survey in 1907 and published in 1914 (U.S. Geological Survey, 1920). In May of 1916, the Oil & Gas Journal reported that the driller "Lackey found that he had struck oil at a depth of 150 feet, and noting indications of gas, struck a match near the opening, and was surprised to see the flame shoot one hundred feet into the air." This well was drilled in the present-day Dry Piney field and appears to have been the first show of hydrocarbons while drilling. Lackey went on to drill the discovery well for the Dry Piney field, completing it in the fall of 1917 (Sawdon, 1925).

First production from the nearby LaBarge field was first obtained in the spring of 1924. By 1929 the Texas Production Company had acquired almost all of the Dry Piney and LaBarge field interest and was producing about 2,000 barrels per day ((Blevins et al., 2004). Acceleration of drilling activity has coincided with periods of increased demand. Those periods include World War Two (oil demand), the energy boom of the 1970s (oil and increasingly gas was developed) and the acceleration of gas drilling activity that has been occurring in recent years. This acceleration is at least partly in response to increased knowledge of the area, improved gas prices, and improvements in techniques used to drill and complete wells.

"Technology has historically contributed significantly to the ability of the petroleum industry to find, develop, and produce natural gas (see Glossary definition for *natural gas*) resources" (National Petroleum Council, 2003). Improved fracture stimulation and 3D seismic data and interpretation have had significant effects on natural gas production in Wyoming. Industry's efforts to search for better ways to find, develop, and operate fields has been clearly seen in the development of coalbed gas and tight sand formations in Wyoming. The National Petroleum Council (2003) postulates that technology improvements will play a lesser role in gas resource enhancement in the 2003-2008 time periods. New technology innovations currently being applied at Jonah Field and in the Pinedale Anticline area appear to be an exception to their postulate. Technology improvements will play a greater role after 2008 when higher gas prices will motivate industry to invest more in development of technology. Future average improvement rates for certain types of technology are:

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

The National Petroleum Council (1999) suggested that access restrictions add $25,000 to the average cost of drilling a well in the Rocky Mountains. The also suggested access restrictions delay drilling activity by an average of two years. Kunce et al, (2001) looked at the effects of environmental and land use regulation in the Wyoming Checkerboard in Southwest Wyoming for drilling in the 1987 through 1999 period. Their paper estimated the extra cost of drilling for oil and gas on federal land in comparison to private land. They determined that the characteristics of the Checkerboard allowed its study as a valid experimental control. For all wells, they determined that private wells cost $885,000 to drill and federal wells cost $1,086, 000. Average drilling costs on federal land were higher by $201,000 than on federal land.

Drilling and Completion Activity

A total of 4,038 wells, in five status categories, existed within the Field Office boundary on August 1, 2003 (Table 1). About 85 percent of all wells were drilled on federal lands, with the other 15 percent drilled on fee or state lands. Thirty-nine percent of all drilled wells had been abandoned. Wells are abandoned because:

- they were “dry”--no hydrocarbons were encountered, or hydrocarbons were not present in economic quantities
- they initially were capable of producing hydrocarbons, but they became uneconomic to produce at a latter date
- mechanical difficulties within a borehole prevented economic hydrocarbon production.

A map of the Field Office area shows locations of all wells drilled to August, 2006 (Figure 5). For this map we considered active wells to be those that the Wyoming Oil and Gas Conservation Commission determined to be in a drilling, dormant, notice of abandonment, or completed status. All other wells we considered to be abandoned. We also prepared a map of the Field Office area that shows all oil and gas fields, the synclinal axis of the Greater Green River Basin, the anticlinal axis of the Moxa Arch (locally called the LaBarge Anticline or LaBarge Platform), the Wind River Thrust Fault, and the leading edge of the Wyoming Thrust Belt (Figure 2). The location of the synclinal axis of the basin marks the thickest sequence of sedimentary rocks within that part of the Greater Green River Basin lying within the Field Office area. Both maps show that drilling activity has been concentrated in three regions. The first region is in the Greater Big Piney – LaBarge area. It is located in the southwest part of the Field Office area (along the Moxa Arch) and extends northward. This region has had the most historic activity and has produced most of the oil found in the Field Office area.

The second area of activity is in the Jonah field area, centered on township 29 north, and range108 west. In recent years, high levels of activity have occurred in the Jonah field area. High activity levels have also occurred to the north in a third area, along the Pinedale Anticline area. Exploratory activity is occurring and additional future activity is likely in areas lying between the Greater Big Piney-LaBarge area, Jonah field, the Pinedale Anticline area, and Merna field. Much of this exploratory activity appears to be targeting potential traps thought to be analogous to the trap that has created the Jonah field. Outside the areas discussed, little exploratory drilling and development activity has occurred. Many townships have not been tested at even one location.

The Greater Green River Basin has been a significant regional producer of gas (Barlow & Haun, Inc., 1994) for more than 75 years. The LaBarge field was discovered in the Field Office area in 1924. In 2005, the Field Office area contained seven of the top 25 producing gas fields in Wyoming and parts of two other fields (Wyoming Oil and Gas Conservation Commission, 2006b). Jonah, the second-most prolific gas-producing field in Wyoming (Figure 2), produced over 267 billion cubic feet of gas. The Pinedale Anticline area, the third-most prolific gas-producing area, produced almost 227 billion cubic feet of gas. Seven of the top producing fields (Fogarty Creek- 4th, Lake Ridge- 6th, Tip Top- 17th, part of Fontenelle- 18th, Hogsback – 21st, LaBarge- 23rd , and part of Green River Bend- 25th) lie in the Greater Big Piney-LaBarge area. A significant component of the over 243 million cubic feet of gas produced from two of these fields (Fogarty Creek and Lake Ridge fields) is carbon dioxide gas. In all, the nine fields produced over 804 billion cubic feet of gas in 2005. There are not any operating gas plants within the Field Office area.

Oil and gas fields in the Field Office area have made a smaller contribution to the state's oil production. Historically, the Greater Big Piney-LaBarge area has made most of the Field Office area's contribution to oil production. That dominance has recently changed. In 2005, the Jonah field produced the second highest amount of oil in the state (Wyoming Oil and Gas Conservation Commission, 2006b). Jonah field produced 2,415,251 barrels of oil in the form of natural gas liquids (see Glossary definition for *natural gas liquids*), along with the large amounts of gas also being produced. The Field Office area's only other top-25 oil field was Pinedale Anticline area, the 5th largest. It produced 1,761,303 barrels of oil in the form of natural gas liquids.

Nationally, the U.S. Department of Energy (2005) showed that the Field Office area had five of the top 100 U.S. fields by proved gas reserves (Pinedale Anticline-3rd, Jonah-6th, Fogarty Creek-18th, Lake Ridge-32nd, and Green River Bend-60th). They also report that only the Pinedale Anticline is ranked in the top 100 of U.S. fields by proved liquids reserves. Pinedale Anticline is ranked 84th for proved liquids reserves.

The rocks in the Field Office area range in age from Precambrian to Tertiary. In this part of the basin, the thickness of sedimentary rock above the Precambrian basement is as much as 32,000 feet (Law, 1995). Figure 6 presents the names of stratigraphic units recognized in the Greater Green River Basin. Those stratigraphic unit names presented for the "west" and "west-central" parts of the basin are those generally recognized and most often used within the Field Office area.

Producing well symbols on Figure 6 mark those stratigraphic intervals known to produce oil and gas within the Field Office area. Of the Tertiary aged stratigraphic units, oil and gas are produced from the Wasatch, Almy, and Fort Union formations in the Field Office area. Cretaceous aged stratigraphic units are the dominant producers within the Field Office area. Of the older stratigraphic units, only the Nugget Sandstone (producing mostly oil) and the Madison Limestone (producing gas) have been productive. Tests of many of the other older stratigraphic units have indicated the presence of hydrocarbons, but none have yet been determined to be economic to produce (Stilwell, 1989).

The Greater Big Piney-LaBarge area (Figure 2) has had the longest history of drilling activity within the Field Office area. Of the producing intervals marked on Figure 6, only the Lance Formation does not produce oil and gas in the Greater Big Piney-LaBarge area. Most recent drilling activity has been occurring in the Jonah field and Pinedale Anticline areas of the Field Office. In these areas, only the Fort Union and Lance formations and the Mesaverde Group have been determined to be economic to produce. The Lance Formation is presently the most prolific producer in the Jonah field and Pinedale Anticline areas.

Coalbed gas exploration and development is at a very early stage within the Field Office area. Only 11 wells had been drilled to test coalbed gas, as of August 3, 2006. CamWest Exploration LLC completed a Wasatch Formation coalbed gas test August 27, 2002 as a dry hole in section 24 of township 29 north, range 107 west and it was converted to a water supply well. This well was located on the southern end of the Pinedale Anticline (Figures 2 and 5) and it reached a total depth of 750 feet.

Infinity Oil and Gas has drilled 10 coalbed gas wells in the Riley Ridge field area on the northern end of the Greater Big Piney-LaBarge area (sections 1, 4, and 5 of township 29 north, range 114 west and section 6 of township 29 north, range 113 west). Five of these wells began to produce gas in May of 2002 as Mesaverde Group coalbed gas wells. Two additional wells began producing gas in January of 2003 and two others began producing in 2004 (one in October and one in December). The 10th well has not reported any gas production. Drilling depths have ranged from 3,460 to 4,100 feet. Cumulative production, as reported through May of 2006 (Wyoming Oil and Gas Conservation Commission, 2006a) was almost 209 million cubic feet of gas and 510,200 barrels of water. All wells have only been periodically in a production mode. In the latest month of reported production, only two wells were producing and the others were shut-in. The operator has reported 1,259 barrels of oil production from three of the wells. Infinity Incorporated (2005) estimates that there are 750 billion cubic feet of gas-in-place, with a recoverable resource potential of 248 billion cubic feet of gas.

Deep Well Drilling and Completion Activity

Dyman et al. (1990, 1993a, 1993b, and 1997) characterized deep wells as those drilled to depths greater than 15,000 feet. Wells drilled to these depths are not common in the Field Office area. According to IHS Energy records (2006) about 4,500 wells have been drilled in the Field Office area. Only 52 of those exceed 15,000 feet in depth. Figure 7 shows the location and classification of the deep wells in the Field Office area. Wells completed as producers in a deep formation are shown with a gas well symbol. All other deep wells have been assigned a drilled and abandoned symbol. About two thirds of the deep drilling to date has been centered in the Fogarty Creek, Lake Ridge, Riley Ridge, Tip Top, Graphite, and Hoback III fields (Figure 7) with the rest scattered across the Field Office area. Table 2 lists specific well data for the deep wells drilled through August 7, 2006.

Figure 7 also shows areas of the Field Office that may contain potential reservoir rocks below 15,000 feet and those that do not appear to contain potential deep reservoir rocks at those depths. About 80 percent of the Field Office area contains potential reservoir rocks below 15,000 feet. Those areas include the central part of the Field Office area, which lies in the northern part of the Greater Green River Basin and the Field Office area's western side, which lies within the Wyoming Thrust Belt (see Figure 2 for Wyoming Thrust Belt location). The northeastern border of the Field Office area appears to contain only igneous and metamorphic rocks below 15,000 feet. These types of rocks are not known to contain hydrocarbons in this part of Wyoming. Only one Wyoming well is known to have produced from these types of rocks. That well lies in Lost Soldier field, in the central part of Wyoming, where a small amount of gas has been produced from Precambrian aged rocks at less than 10,000 feet.

The Potential Gas Committee (2003) has projected large amounts of total undiscovered natural-gas resources in the onshore lower 48 states, at depths below 15,000 feet. For the entire Greater Green River Basin, the Potential Gas Committee estimated almost one third (8.359 of a total of 26.813 trillion cubic feet of gas) of the potential resource (coal-bed gas not included) lies below 15,000 feet. For the Wyoming-Utah-Idaho Thrust Belt, they estimated only about 15 percent (0.65 of a total of 3.70 trillion cubic feet of gas) of the potential resource lies below 15,000 feet. The potential resource estimates for the Greater Green River Basin and Wyoming-Utah-Idaho Thrust Belt were projected for much larger areas than the Field Office area, which only covers a relatively small portion of each of these two areas. Thus, we expect that a major portion of this potential resource will lie outside the area of the Field Office in other parts of the Greater Green River Basin and Wyoming-Utah-Idaho Thrust Belt. Information presented below will show that at least one significant deep gas reservoir does exist within the Field Office area and that there is potential for the discovery of additional reservoirs.

Of the 52 wells; 22 wells have been drilled between 15,000 and 16,000 feet, 20 have been drilled from 16,000 to 17,000 feet, six have been drilled between 17,000 and 18,000 feet, and four have been greater than 18,000 feet in depth. The deepest well drilled was the Telephone Pass No. 1 which was drilled to a total depth of 20,161 in township 35 north, range 116 west. It recovered high percentages of carbon dioxide gas in the Madison Formation and was abandoned in 1987.

Thirty-eight of the 52 deep wells (73 percent) were originally completed as gas wells. Twenty-nine of those 38 wells (76 percent) produce from zones deeper than 15,000 feet. With the exception of two recent Lance Formation gas wells all reported production in these deep wells has been gas from the Madison Limestone.

Moxa Arch Deep Wells

Most of the Field Office area deep wells (33) are concentrated in the Fogarty Creek, Lake Ridge, Riley Ridge, Tip Top, Graphite, and Hoback III fields (Table 2 and Figure7). These fields lie on and near the highest part of the Moxa Arch in the Greater Big Piney-LaBarge area. Most of these wells were drilled to test the Madison Limestone of Mississippian age.

In 1962, the first deep test in the Field Office portion of the Moxa Arch established the presence of gas in deep older formations, including the Madison Limestone (Stilwell, 1989). That deep test, the Tip Top Unit No. 22-19 (Table 2), recovered gas on tests of the Bighorn Dolomite and Madison Limestone. Only the younger Frontier Formation above 15,000 feet was ultimately completed for production in that well. In 1979, the industry began to develop the untapped resource in the Madison Limestone. The first Field Office area well to eventually produce deep gas from the Madison Limestone, the Riley Ridge No. 8-24, was completed in 1980. Madison development drilling mainly occurred in the 1979 to 1986 period, with the last well completed in 1994.

The Graphite Unit No. 215 (Table 2) produces gas from the deepest interval anywhere in the Field Office area. It produces from a thick section of the Madison Limestone in a 16,562 to 17,238-foot interval. Parts of the Madison Limestone on the highest structural part of the Moxa Arch actually lie above the 15,000-foot depth. Three deep wells (Federal No. 12-43, Tip Top No. T57-19 and Federal No. 17-34) produce gas from the Madison, but from depths slightly less than 15,000 feet.

The Madison Limestone produces gas from a thick, extensive section of carbonate sediments. It averages 850 feet thick on the highest part of the Moxa Arch and contains an alternating sequence of dolomite and limestone with dolomite the dominant rock type (Stilwell, 1989). The Madison Limestone appears to be potentially productive over an area of about 21 miles by 65 miles. Figure 7 shows the approximate outline of the Madison Limestone Reservoir (outline modified from De Bruin, 2001) and its relation to the Field Office boundary. It is a structural trap that appears to have some stratigraphic implications (Stilwell, 1989). As the outer limits of the Madison Limestone reservoir are approached, formations younger than the Madison Limestone will also be potential exploratory targets at depths of more than 15,000 feet.

The Madison Limestone reservoir contains an estimated 167 trillion cubic feet of gas-in-place (Matthews, 1988) and about 71 percent of the potential reservoir (containing about 119 trillion cubic feet of gas) lies within the Field Office boundary. Deep Madison Limestone production in the Field Office area has totaled 4.1782 trillion cubic feet of gas, or almost three percent of its total gas-in-place.

A significant percentage of non-hydrocarbon gas is produced from the Madison Limestone. Methane content averages about 20 percent. Carbon dioxide, nitrogen, hydrogen sulfide, and helium are other reservoir gases separated from the methane gas during processing at the Shute Creek Gas Plant. These products are marketed separately or are disposed of by flaring or injection.

Hydrocarbons and associated carbon dioxide gas have also been encountered in the Phosphoria Formation, Tensleep Sandstone, Amsden Formation, Darby Formation, and Bighorn Dolomite at various locations on the Moxa Arch (Stilwell, 1989). The presence of associated non-hydrocarbon gases does limit the future economic potential of these formations, due to the costs of removing and disposing of these constituents.

Other Deep Wells

Other deep wells are widely scattered across the Field Office area. The first deep test was the Unit No. 1 (Table 2) completed by Phillips Petroleum Company at a total depth of 16,531 feet in 1956. Upper Cretaceous sediments were tested below 15,000 feet, but only small quantities of gas were recovered and the well was abandoned. An additional 18 wells have been drilled; however, only the Cutlass Unit No. 1, Mesa No. 8-10, and Lovatt Draw State No. 36-55 were completed as producers at a depth of more than 15,000 feet. In 1981 the Cutlass well was completed in the Lower Cretaceous Frontier Formation over the 16,538 to 16,779-foot interval. Tests indicated that it could produce with an initial potential of 1.67 million cubic feet of gas per day. Unfortunately, this well never produced to a pipeline and was abandoned in 1988.

The Mesa No. 8-10 was completed as a Lance Formation producer, in the Pinedale Field, in December of 2003. It produced 2.797 million cubic feet of gas from zones that extend deeper than 15,000 feet. About 35 percent of the perforated interval in this well lies below 15,000 feet, so only a part of the reported production can be attributed to the deep interval. A subsequent report of abandonment of this well was approved in October of 2004.

The Lovatt Draw State No.36-66 was completed as a Lance Formation producer, in the Pinedale Field, in January of 2006. Through May of 2006, it has produced 119 million cubic feet of gas and 937 barrels of natural gas liquids from zones that extend deeper than 15,000 feet. Only two percent of the total productive perforated interval lies below 15,000 feet, so only a small part of the production can be attributed to the deep interval.

The Unit No. 5 and Wagon Wheel No. 1 were completed as productive wells in zones shallower than 15,000 feet. The Stewart Point #13-29 has been reported to be productive in the Lance Formation, but the productive depth of this well has not yet been reported.

Deep targets have been clastic (sandstone) sediments of Cretaceous age. Tests of the Upper Cretaceous section and the Lower Cretaceous Frontier Formation have indicated the presence of gas in these deep intervals and the potential for the future discovery of reservoirs with economically recoverable amounts of gas. Boswell et al. (2002b) estimated that about 587.7 trillion cubic feet of gas-in-place lies below 15,000 feet within the Greater Green River Basin (Figure A2-1). Assuming an even distribution of resources across the basin, about 68.245 trillion cubic feet of deep gas-in-place could be present in Cretaceous aged reservoirs within the Field Office area (Figure A2-1). An estimate of how much of this gas could be technically recoverable was not made.

Summary of Current Drilling Techniques

Improvements in drilling technique have allowed avoidance of sensitive surface features, recovery of additional oil and gas reserves, reduced drilling time, lower associated waste volumes, reduced emissions, and greater protection of sensitive environments.

Directional and Horizontal Drilling and Completion Activity

Oil and gas wells traditionally have been drilled vertically throughout the Field Office area, to depths ranging from less than a few hundred feet in the Greater Big Piney-LaBarge area to 19,000 feet in the Wagon Wheel No. 1 gas well on the Pinedale Anticline. Depending on subsurface geology, technologic advances now allow operators to deviate boreholes by anywhere from a few degrees to completely horizontal. Directional and horizontal drilling uses deviated boreholes to enable operators to reach reservoirs that are not located directly beneath the drilling rig, or to allow the borehole to contact more of the reservoir. Directional boreholes may be specifically deviated or allowed to "drift" naturally updip on the flanks of a geologic structure. In some cases directional drilling may be used specifically for avoidance of unfavorable surface locations.

Drilling and completion costs for directional and horizontal boreholes are higher than for conventional vertical boreholes. The risk of losing all or parts of the borehole due to technical drilling difficulties is also higher. Because of these factors, industry generally prefers not to drill directional or horizontal boreholes unless other concerns make this option necessary. An exception to this general rule can be made if industry can determine that reservoir conditions are suitable for using this type of borehole to contact more of the reservoir (increase drainage area) and increase productivity. In this case, the potential for increased productivity may offset the additional drilling costs and risks, making this type of borehole the preferable drilling option.

Eustes (2003) has identified a number of items that have the potential to raise drilling costs for these types of wells. Additional drilling costs can occur when:

- special directional drilling equipment (mud motor, measurement while drilling tools, and extra personnel) is required
- a larger rig is needed to drill, which would also require larger mud pumps
- casing and tubing design needs modification to overcome problems with ovality and bending stress
- borehole risk is higher due to tectonic stresses
- slower rate of penetration requires more drilling time on the location and/or
- torque and drag on borehole equipment is greater.

Figure 8 shows the locations of known directional wells and current applications to drill new directional wells, as reported by IHS Energy (2006). These locations are concentrated in three parts of the Field Office: the Greater Big Piney-LaBarge area, the Jonah field, and the Pinedale Anticline area. Only 16 directional wells have been drilled outside of these three areas. Table 3 shows how wells in each status category are distributed in each part of the Field Office area. According to HIS Energy (2006) industry has drilled 839 directional wells, is drilling and/or completing 205 directional wells and has filed applications to drill 173 additional directional wells in the Field Office area.

In the Greater Big Piney-LaBarge area, the successful productive completion rate (not including water injection wells) of directional boreholes has been 96 percent. The Jonah field has had a successful completion rate of 99 percent while the Pinedale Anticline area has been 98 percent. The high success rates in these areas are mainly due to the fact that almost all wells drilled have been field development wells. Industry prefers not to drill wildcat wells directionally, since details of geology and potential reservoir characteristics are not yet known and directional drilling adds an extra element of risk and increased costs. Four directional wells have had to be “junked and abandoned” due to borehole complications encountered during the drilling or completion process. The other abandoned wells have been nonproductive or not economic to produce.

The earliest known directional well was completed in 1975 in the Greater Big Piney-LaBarge area. Fewer than five directional wells were completed in any year until 1993, when 19 wells were completed. Since then, the pace of directional drilling has accelerated, with more wells drilled each year since 2002. A high of 242 directionally drilled wells occurred in 2005. That high is expected to be exceeded again in 2006, since 97 wells have already been completed and 205 other wells have been spud.

ExxonMobil Corporation, EOG Resources Inc., and ChevronTexaco operate most of the 263 directionally drilled wells in the Greater Big Piney-LaBarge area. To date, productive completions have been made in eight different stratigraphic units (Almy Formation, Mesaverde Group, Baxter Shale, Frontier Formation, Bear River Formation, Muddy Sandstone, Dakota Sandstone, and Madison Limestone). Of the gas completions, about 75 percent have been completed in the Frontier Formation, while 15 of the 21 oil completions have been made in the Mesaverde Group. The three directional water injection wells were completed in the Mesaverde Group in order to enhance oil production from that interval.

Directional drilling depths in the Greater Big Piney-LaBarge area have ranged from 740 to 17, 390 feet measured depth. Almy Formation and Mesaverde Group wells are relatively shallow in this area and have been drilled in the range of 740 to 4,900 feet true vertical depth. Most wells have been drilled in the 4,900 to 9,900-foot range. Wells completed at these depths produce from lower Cretaceous aged stratigraphic units (Baxter Shale, Frontier Formation, Bear River Formation, Muddy Sandstone, and Dakota Sandstone). The deepest directional well in the area produces carbon dioxide rich gas from the Madison Limestone.

In the Jonah field, the first two directional boreholes were completed in 1998. A small number of directional wells were drilled annually until 2004 (46 completed wells) and 2005 (111 completed wells) when completions increased significantly. Approximately the same number of wells will be completed again in 2006, since 63 have already been completed and 51 have been spud.

In the Jonah field area, most of the directional wells are operated by EnCanna Oil & Gas (USA) Incorporated and BP America Production Company. Productive completions are almost entirely in the Lance Formation, with a small number in the Mesaverde Group and Tertiary formations. All are considered to be gas wells. Drilling depths are mostly within the 9,800 to 13,700-foot range. The Lance pool is as much as 5,500 feet thick. Individual sandstones in the Lance pool are normally thin and have limited areal extents. Wellbores are S-shaped, and to prevent potential loss of the pay zone need intermediate casing. Due to drilling and completion difficulties in these types of well bores, the lowermost part of the potentially productive horizon could not be completed in nearly 10 percent of Jonah field directional wells.

In the Pinedale Anticline area, the first direction well was completed in 1998. A small number of directional wells were drilled annually until 2004 (76 completed wells) and

2005 (111 completed wells) when completions increased significantly. More directional completions are expected in 2006, since 29 have already been completed and 145 have been spud. All of these directional wells have an S-shaped wellbore and use intermediate casing.

In the Pinedale Anticline area, most of the directional wells are operated by Questar Exploration and Production Company, Anschutz Corporation, Shell Rocky Mountain Production LLC, and Ultra Resources Inc. Almost all (280 wells) productive completions are in the Lance Formation, with only a small number in the Mesaverde Group. All are considered to be gas wells. Drilling depths are mostly within the 11.300 to 14.700-foot range.

In the Jonah field and Pinedale Anticline areas the borehole should be vertical when it passes through the reservoir. An S-shaped borehole profile is used rather than the usual slant profile used in the Big Piney-LaBarge area. To drill an S-shaped borehole a well is started vertical, it is directed into a slant or angled portion until it reaches a position above the target reservoir, is brought back to vertical before the target reservoir is reached, and a vertical orientation is maintained through the target reservoir until total depth is reached. Most of the directional boreholes drilled in the Jonah field and on the Pinedale Anticline are being located to avoid sensitive surface features or areas of environmental concern, as identified in recent Environmental Impact Statements.

Industry does not use horizontal boreholes to avoid sensitive surface features or areas of environmental concern. Other types of directional boreholes are used to meet these concerns, as discussed above. Horizontal borehole drilling and completion costs are higher than those for a vertical or other type of directional borehole. A number of reasons to drill horizontal boreholes have been identified by Eustis (2003). They are:

- ability to intersect many fractures
- minimize premature entry of water or gas into the borehole
- increased drainage area
- ability to intersect layered reservoirs at high dip angles
- improve coal gas production
- increase productivity
- improve injection of water, steam, and etc.

The benefits from increased production can, in some cases, outweigh the added cost of drilling this type of well. Other reasons listed above, allow improved management of the reservoir, which may justify the increased drilling and completion costs.

Horizontal boreholes have not been commonly used within the Field Office area. Horizontal boreholes appear to have only been used to contact more of the reservoir (increase drainage area) and to increase productivity. Twelve horizontal wells have been drilled in the Field Office area (IHS Energy Group, 2006 and Wyoming Oil and Gas Conservation Commission, 2006a). Locations and status of these wells are shown in Figure 9.

In 1995 and 1996, Mobil Oil Corporation (now ExxonMobil Corporation) completed three productive horizontal Frontier Formation gas wells in the 6,000 to 7,000-foot depth range within the Tip Top field. In 2004 ExxonMobil Corporation came back and completed another Frontier Formation well and a combination Frontier/Muddy well. These five wells have a cumulative production of 5.2 billion cubic feet of gas and 10,216 barrels of oil.

In 1990, Texaco Exploration and Production Company (now ChevronTexaco) completed two productive horizontal Almy Formation oil wells at LaBarge field. These wells are productive in the 400 to 500-foot depth range in the same section. They have a cumulative production of 69,865 barrels of oil. One of the wells was a multilateral oil well. It contained three horizontal Almy Formation offshoots from one borehole. Recent advances in technology have encouraged multilateral drilling and completion, enabling multiple offshoots from a single borehole to radiate in different directions or contact resources at different depths. Multilateral drilling can increase well productivity and enlarge recoverable reserves, even in aging fields. Environmental benefits of horizontal and directional drilling can include:

- fewer wells and surface disturbance
- lower waste volume
- protection of sensitive environments.

In 2003 and again in 2005, EOG Resources Incorporated completed productive horizontal Frontier Formation gas wells at the Green River Bend Field. These wells are productive in the 7,000 to 8,000-foot range. They have a cumulative production of 366 million cubic feet of gas and 1,648 barrels of oils. EOG Resources Incorporated has filed an additional application for permit to drill a horizontal Frontier Formation test in this field.

Where Lance Formation and Mesaverde Group potential reservoirs are tested in the eastern part of the Field Office area (mainly the Jonah field/Pinedale Anticline area), horizontal drilling has not been considered to be a desirable option. In this area, reservoir targets are multiple thin sandstone lenses. Eberhard et al., (2000) indicated that single wells in the Jonah field, can have more than 30 individual five to 50 foot thick sandstones that can be completed over intervals of 2,000 to 3000 feet. In the Pinedale Anticline area, reservoir properties are similar to those of the Jonah field. In 2005, BP America Production Company completed two productive horizontal Lance Formation gas wells at Jonah Field. These wells are productive in the 9,000 to 10,000-foot range in the same section. After one year of production from one well and nine months from the other, cumulative production is 381 million cubic feet of gas and 4,610 barrels of oil. Shell Rocky Mountain Production LLC attempted a horizontal Lance Formation completion on the Pinedale Anticline in 2004. They found the horizontal section of the wellbore uneconomic to produce and plugged the well back to produce from the vertical portion.

Slimhole Drilling and Coiled Tubing

Slimhole drilling—a technique used to tap into reserves in mature fields—has not yet been used much in western Wyoming. 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. U.S. Department of Energy (1999) reported that a conventional 10,000-foot well in southwest Wyoming costing $700,000 could be drilled for $200,000 by using slimhole and coiled tubing. Most likely, future applications may be for drilling shallow development wells (including coalbed gas wells), reservoir data monitoring holes, shallow re-entry wells, and deep exploration holes (Spears & Associates, Inc., 2003). 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
- protection of sensitive environments.

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

Now in production, new light modular drilling rigs can be more easily used in remote areas and are quickly disassembled and moved. Rig components are made with lighter and stronger materials and their modular nature reduces surface disturbance impacts. Also, these rigs reduce fuel use and emissions.

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.

In pad drilling, more than one borehole is drilled from the same pad. A development plan is required for pad drilling to determine the layout of surface facilities that will be needed, the location and trajectory of each borehole to be drilled, and the sequence in which each borehole is drilled. Extra planning is required because pad drilling requires that each borehole will be a directional drilled well. Since each borehole is close to other boreholes, its near surface trajectory needs to be controlled so that it does not accidentally intersect those other boreholes.

Pad drilling can be used to avoid surface locations that would be difficult to reach due to topography and to reduce total surface disturbance where close-spaced infill drilling is proposed. Pad drilling is now being used in some parts of the Pinedale Anticline area and is being considered at a number of locations within the Field Office area, where future close-spaced infill drilling could occur.

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 parts of the Field Office area contain overpressured producing formations (Jonah field and Pinedale Anticline area) that will not be receptive to this type of drilling. 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, reduces 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 is most often used when drilling horizontal boreholes. In the future, use of this type of system may become more widespread and may find applications for 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). Peterson (2001) studied drill bit technology improvements in two areas of the Field Office. At Jonah field he studied the period from 1994 to 2000. During that period, rate of penetration increased from an average of 29.6 to 42.7 feet per hour and total drilling time was cut from 374.3 to 252.9 hours. Peterson estimated that this increased efficiency had reduced drilling costs by 31 percent.

Peterson (2001) also studied the Moxa Arch area. The north end of the Moxa Arch extends into the Field Office area in the Greater Big Piney-LaBarge area. During the 1993 to 2000 period, rate of penetration increased from an average of 47.9 to 72.7 feet per hour. Total drilling time was cut from 220.3 to 144.5 hours during that period. Peterson estimated that this increased efficiency had reduced drilling costs in this area by 39 percent.

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

- 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 Field Office 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 nonconventional reservoirs (such as coalbed 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.

The Jonah field is a model for reservoirs that became commercial using improvements in hydraulic fracturing technology (Eberhard and Mullen, 2001). The Lance pool in the Jonah field ranges from 2,200 to 5,500 feet with numerous potentially productive sandstone beds. The gas within each sandstone bed does not easily flow through that sandstone and into the borehole. Completion techniques have evolved that use hydraulic fracturing techniques to increase gas flow to the borehole and make these wells economic to produce. The successes at Jonah field have also stimulated the development of a similar gas reservoir in the Pinedale Anticline area.

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

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 as much as 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 (1999) estimated that costs of production had decreased from a range of $9 to $15 per barrel of oil equivalent in the 1980's to an average of about $5 to $9 per barrel of oil equivalent in 1999.

Since 1990, most reserve additions (see Glossary definition for *reserves*) 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 southwest Wyoming have come from existing fields. As an example, this type of reserve addition has been important in the old fields of the Big Piney-LaBarge area. 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. This type of activity is presently occurring at the Jonah field and Pinedale Anticline area where wells are being more closely spaced. They report that the other half of reserve additions has come from finding new reservoirs in old fields and extending field limits. Part of the increased drilling activity in the Pinedale Anticline area has come from extending field limits.

The Energy Information Agency (2006c) has shown that equipping and operating gas wells in the Rocky Mountains is higher than the average for the 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 Field Office area are:

- well depths are greater than the average - which is a major factor in the cost of down-hole repairs, amounts of chemicals used, and other maintenance costs
- remoteness and cold temperatures – which often requires dehydrators and line heaters, more expensive types of steel casing, and insulation of surface equipment
- workovers and preventive maintenance are more frequent – which minimizes shut-in days in the winter when well site access is difficult
- rig cost due to the more remote areas encountered
- the relative scarcity of labor.

The search for new gas fields in the Field Office area is predominantly for anomalously pressured reservoirs. Surdam et al. (2001) suggested that elements needed to evaluate these types of potential anomalously pressured gas prospects are:

- gas distribution
- gas migration conduits
- reservoir gas content
- microfracture swarm distribution
- linear fault orientation
- reservoir characterization attributes.

The oil and gas recovery process in a field may occur in the following sequence:

- 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 or gas lift) help extend productive life when a reservoir's natural pressure dissipates.
- Secondary Recovery – Secondary recovery uses methods like gas reinjection to maintain reservoir pressure and boost primary production, water flooding to energize the reservoir and displace hydrocarbons not produced in the primary recovery phase, or the first enhanced recovery method of any type applied to the reservoir to produce oil not recoverable by primary recovery methods. Enhanced oil recovery involves the injection of liquids or gases (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.

Secondary oil recovery projects are initiated because of the limited production efficiency of primary recovery and water-flood projects (Williams and Pitts, 1997). Primary depletion in most Rocky Mountain reservoirs is only 10 to 20 percent. Williams and Pitts (1997) reported that locale can 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 steam-flood or chemical projects. Accessibility of cheap natural gas is a consideration for gas injection 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 older oil fields within the Greater Big Piney/LaBarge area of the Field Office area, and a number of different types of secondary projects have been used to increase production.

In 2005, there were no active gas injection projects within the Field Office area to maintain reservoir pressures or to aid in secondary recovery of oil or for enhanced oil recovery. There were no air injection projects for pressure maintenance, or an in-situ combustion type project. No active hydrothermal injection projects for steam are in the Field Office area.

Secondary Recovery Fields

Secondary recovery is generally considered to be water flooding of a depleted reservoir. In 2005, the Wyoming Oil and Gas Conservation Commission (2006b) reported 13 active water flooding projects in five fields in the Greater Big Piney/LaBarge area. Brief summaries of these projects are presented below.

1. Big Piney field has six water flooding projects operated by EOG Resources Incorporated. The T-5 Sand was approved in the Green River Bend Unit in 1964, the Mesaverde water flood in the Mesaverde Unit was approved in 1967, the Mesaverde water flood in the Green River Bend Unit/Mesaverde Wasatch Unit

was approved in 1993, the Mesaverde water flood in the Mills Mesaverde Unit was approved in 1993, the Mesaverde water flood in the Burley Unit was approved in 1998, and the Birch Creek water flood was approved in the Green River Bend Unit in 1998.

2. Birch Creek field has a water flood in the Almy-Mesaverde. ChevronTexaco operates this project, which was approved in 1963-69.
3. Isenhour field has undergoing a water flood in the Almy M-42 Sand. EOG Resources Incorporated operates this project, which was approved in 1980.
4. LaBarge field has three water flooding projects. ChevronTexaco operates the Almy Sand water flood in the Almy Unit, which was approved in 1961. EOG Resources Incorporated operates a Mesaverde water flood in the Saddle Ridge Unit approved in 1967 and a Mesaverde water flood in the North LaBarge Shallow Unit approved in 1995, 6, and 8.
5. McDonald Draw field has two water flooding projects operated by EOG Resources Incorporated. The Almy M-20 Sand and Almy M-47 Sand were both approved in the Almy Unit in 1965.

Tertiary Projects

Tertiary projects use improved recovery methods that not only restore formation pressure but also improve oil displacement or fluid flow within the reservoir. They may include projects such as water-polymer floods, water-micellar floods, or water-carbon dioxide floods. In 2005, there were three active Tertiary projects within the Greater Big Piney/LaBarge area of the Field Office (Wyoming Oil and Gas Conservation Commission, 2006b). Brief summaries of these projects are presented below.

1. McDonald Draw field has a water-polymer injection project in the Peay-Almy Sand that is being operated by EOG Resources Incorporated. This project was approved in 1974.
2. Ruben field has a water-polymer injection project in the Almy-Stray 3-4 Sand that is being operated by EOG Resources Incorporated. This project was approved in 1970.
3. Tip Top field has a water-polymer injection project in the Mesaverde-Almy that is being operated by EOG Resources Incorporated. This project was approved in 1981.

Acid Gas (Sour Gas) Removal and Recovery

Before natural gas can be transported safely, carbon dioxide gas and/or hydrogen sulfide gas must be removed. Special plants are needed to recover the unwanted gases and sweeten gas for sale. Improvements in the process have made it possible to produce sour natural gas resources, almost eliminate noxious emissions, and recover almost all of the elemental sulfur and carbon dioxide for later sale or disposal. A significant percentage of non-hydrocarbon gas is produced from the Madison Limestone within the Greater Big Piney-LaBarge portion of the Field Office area. Carbon dioxide, nitrogen, hydrogen sulfide, and helium are separated from the methane gas during processing at the Shute

Creek Gas Plant, which lies to the south and outside of the Field Office area. Some of these products are sold while others are vented or re-injected into the subsurface.

Artificial Lift Optimization

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

Glycol Dehydration

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

Freeze-Thaw/Evaporation

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 constructed for McMurray Oil Company at Jonah field (PTTC, 2002). Over the first winter season (1998/1999), 17,300 barrels of water with a total dissolved solids content of 22,800 milligrams per liter was treated at this facility. The process yielded 9,500 barrels of treated water and 5,900 barrels of brine solution (1,900 barrels of water were lost to evaporation and sublimation). The treated water (1,210 milligrams per liter dissolved solids content) was suitable for reuse in drilling operations in the near-surface portion of other boreholes. The brine (66,900 milligrams per liter dissolved solids content) was suitable for reuse in drilling the deeper portions of other boreholes in the area. In each of the two following years progressively greater amounts of treated water have been produced at this facility.

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 provides increased worker safety and reduced methane emissions while increasing gas recovery rates and usage of this valuable resource.

Downhole Oil/Water Separation

At least some water is produced along with the hydrocarbons in most wells within the Field Office area. It is most often stored, at least temporarily, in dug pits on the well site.

Small amounts of water may be allowed to evaporate or percolate into the subsoil. Larger amounts may be trucked to bigger approved disposal pits, or it may be injected into approved subsurface zones in water disposal wells. 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.

Vapor Recovery Units

Vapor recovery can reduce much 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.

Site Restoration

Industry is turning to flexible Risk-Based Corrective Action as a process to ensure swift, efficient clean up of abandoned producing well sites and to restore these sites to near-original conditions. They are also using soil bioremediation and wetlands restoration to restore sites.

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. FMC Corporation obtained a gas storage approval in Chimney Buttes field in 1982. No activity has been reported for a number of years.

ASSESSMENTS OF OIL AND GAS RESOURCES

The Energy Information Administration (2005a) has recently provided a forecast of United States energy supply. Technically recoverable United States oil resources (as of December 31, 2004) were estimated to be 174.8 billion barrels and natural gas liquids were estimated to be 23.6 billion barrels. The technically recoverable natural gas resource was estimated to be 1,624 trillion cubic feet.

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

- The Energy Information Administration (2003) uses a natural gas resource base of 383 trillion cubic feet for the Rocky Mountain region.
- The Potential Gas Committee (2003) estimated 288 trillion cubic feet of natural gas; including 50 trillion cubic feet of proved reserves (see Glossary definition for *proved reserves*).
- As part of a study done in compliance with the Energy Policy and Conservation Act Amendments of 2000 (Cantey et al., 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 nonconventional (also known as unconventional) types (see Glossary for descriptions of each).

As of January 1, 2002, the National Petroleum Council (2003) estimated Rockies 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 gas reserves (14.8 trillion cubic feet) for the Rocky Mountain region. Growth to 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 nonconventional gas resources were estimated to be 209 trillion cubic feet (National Petroleum Council, 2003).

“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 has resulted in a 17 percent increase in our consumption between 1990 and 2004. During that period natural gas consumption rose from 18.7 (Energy Information Administration, 2001) to 22.4 trillion cubic feet (Energy Information Administration, 2006a). Our domestic production only rose from 17.7 to 19.7 trillion cubic feet (11.3 percent increase) for the 1990 to 2000 period (Curtis and Montgomery, 2002). Since then, annual production has dropped to 19.2 trillion cubic feet in 2004 (Energy

Information Administration, 2005a). 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 created a rise in imports and concerns about our future United States energy supply.

Significant amounts of oil and gas have been produced within the Field Office area to date, which helps supply a portion of this countries demand. The Field Office area also has significant potential for continuing to help meet rising national demand by supplying additional oil and gas that has not yet been discovered. A number of recent oil and gas resource assessments have been prepared that cover all or portions of the Field Office area. These assessments provide an indication of the range of undiscovered resource volumes that could be available for exploration, development, and production through the year 2020.

We will present below the results of a number of oil and gas resource assessments as they relate to the Field Office area. A discussion of gas-in-place estimates will be followed by estimates available for proved oil and gas reserves. Some estimates only describe potential gas resources because only relatively minor amounts of undiscovered oil are thought to be present in parts of the region when compared to the undiscovered potential gas resource. For example, recent estimates of oil-in-place were not available.

Finally, we will review recoverable resource estimates that have recently been made by the U.S. Geological Survey, the Department of Energy via sponsored work, and the Potential Gas Committee. The Department of Energy sponsored resource estimates prepared for the Greater Green River Basin significantly exceed estimates made by the U.S. Geological Survey. Those differences are a result of alternative methodologies used, dissimilar assumptions made, and the use of different geologic models that were designed to serve different analysis purposes. The Potential Gas Committee also uses different methods and assumptions to make their prediction of potential resources, and we present it as an additional estimate of resources. Combined, these studies provide an idea of the range of oil and gas resources that may be available for exploration and development in the Field Office through 2020.

GAS-IN-PLACE ESTIMATES

Gas-in-place estimates attempt to quantify the gas resource in an area without considering its economic or technical viability (Boswell et al., 2002a). Our review of additional resource estimates (see sections immediately following this discussion of gas-in-place estimates) will take the next step and attempt to determine what portion of the gas-in-place resource is proved and what portion is technically and economically recoverable.

Within the region, gas-in-place studies have been prepared for the Greater Green River Basin as a whole. Law et al. (1989) studied overpressured low-permeability Cretaceous and Lower Tertiary aged reservoirs in the basin. Five plays were assessed (Cloverly-Frontier, Mesaverde, Lewis, Fox Hills-Lance, and Fort Union). The reservoirs in these five plays produce the bulk of the basin's gas. They estimated that a mean gas-in-place volume of 5,063 trillion cubic feet could be present in these reservoirs. Law et al. (1989) found that two-thirds of this volume was contained within the various formations that make up the Mesaverde play. Assuming that the total resource is evenly distributed across the Greater Green River Basin, **about 608 trillion cubic feet of gas-in-place could be present in the analyzed reservoirs within the Field Office area**. The U.S. Geological Survey provided support for the subject analysis. It highlighted the concept and importance of basin-center gas formations and provided the data and information that the oil and gas industry could use to explore and develop these types of overpressured, low –permeability reservoirs. They also increased awareness of the very large volumes of gas existing in the Greater Green River and other basins.

The more recent review of Caldwell (1997) also studied Cretaceous and Tertiary aged tight gas formations in the Greater Green River Basin area. That review (sponsored by the Department of Energy) estimated that a mean gas-in-place volume of 1,968 trillion cubic feet could be present in these reservoirs. This study used a similar approach to that of Law et al. (1989), but added analysis of well logs to obtain more detail on typical porosity and water content within the potential reservoirs of each play. That additional data resulted in the lower gas-in-place estimate. Again, assuming that the resource is evenly distributed across the Greater Green River Basin, their data indicate that **about 236 trillion cubic feet of gas-in-place could be present in these reservoirs within the Field Office area**.

The most recent review (Boswell et al., 2002b) only studied certain of the most productive Cretaceous aged formations within the Greater Green River Basin area. That review (sponsored by the Department of Energy) updated the estimated gas-in-place that could be present in the seven units they analyzed. Six of the seven analyzed units lie at least partly within the Field Office area (Figure A2-1). They determined that 3,489 trillion cubic feet of gas-in-place could be present in the six units. Assuming an even distribution of resources within each analyzed unit, **about 421 trillion cubic feet of gas-in-place could be present in these reservoirs within the Field Office area** (Figure A2-1).

Boswell et al., (2002b) also determined that reservoirs below 15 thousand feet contain some of the above predicted 3,489 trillion cubic feet of gas-in-place. They projected that about 587.7 trillion cubic feet of that gas-in-place volume occurs below 15 thousand feet. Of the projected deep gas, we determined that **about 68.2 trillion cubic feet of gas-in-place could be present within the Field Office area**. A more complete discussion of the Boswell et al., (2002b) assessment is presented in Appendix 2.

The studies cited above have determined gas-in-place volumes for a portion of the potential gas bearing units known to lie within the Greater Green River Basin. Cretaceous aged units have been studied most intensely, because they are thought to contain a very large portion of the gas-in-place resource in the region. The only other known recent published projection of gas-in-place resources for the area was that of Matthews (1988). His projection was prepared only for the Madison Limestone, which we previously described in the section titled "Moxa Arch Deep Wells." Other younger and older units have potential to contain additional gas-in-place resources. We expect that additional studies of these other units would modestly increase the range of gas-in-place values presented above.

DuBois et. al., (2004) reported a gas-in-place estimate, for just the Jonah field, of more than 8.3 trillion cubic feet. Watford (2006) reported a gas-in-place at Jonah of 13.6 trillion cubic feet and more than 44 trillion cubic feet of gas-in-place on the Pinedale Anticline. Infinity Incorporated (2005) reported that their gas-in-place estimate for coalbed gas in the LaBarge Field area is 750 billion cubic feet.

PROVED OIL AND GAS RESERVES

In 2004, Wyoming ranked 6th in the United States for proved oil reserves and for production (Energy Information Administration, 2005a). Wyoming's proved oil reserves rose from 517 million barrels at the end of 2003, to 628 million barrels at the end of 2004 (an increase of 18 percent). Proved reserves have been rising from the 489 million barrels estimated for 2001 which was the lowest calculated for Wyoming in the 1977-2004 statistical period. The Energy Information Administration (2005a) estimated that 43 million barrels was produced in 2004, so an additional 154 million barrels of additional proved reserves were identified in 2004. Additional proved reserves were identified by enlarging proved areas of fields or reservoirs, revisions due to new information, and other adjustments. No new field or new reservoir discoveries of oil were made in Wyoming in 2004.

In 2004, Wyoming ranked 2nd in the United States for proved dry natural gas reserves (Energy Information Administration, 2005a). Wyoming's proved dry natural gas reserves rose from 21.744 trillion cubic feet at the end of 2003, to 22.632 trillion cubic feet at the end of 2004 (an increase of 4 percent). The 22.632 trillion cubic feet of dry natural gas proved reserves was the highest reported for Wyoming from 1977-2004 statistical period. Wyoming now accounts for 12 percent of the Nation's dry natural gas proved reserves. The Energy Information Administration (2005a) estimated that 1.524 trillion cubic feet of dry natural gas was produced in 2004 (a record for the 1977-2004 period), so an additional 2.412 trillion cubic feet of additional proved reserves were identified in 2004. Additional proved reserves were identified by making new field discoveries, making new reservoir discoveries in old fields, enlarging proved areas of fields or reservoirs, revisions due to new information, and other adjustments.

In 2004, Wyoming ranked 3rd in the United States for proved coalbed gas reserves and production, and its proved coalbed gas reserves accounted for 11.3 percent of all 2004 dry natural gas reserves (Energy Information Administration, 2005a). Wyoming's proved coalbed gas reserves dropped from 2.759 trillion cubic feet at the end of 2003, to 2.085 trillion cubic feet at the end of 2004 (a decrease of 24 percent). The 2003 proved coalbed gas reserve was the highest reported for Wyoming in the 2000-2004 period. The Energy Information Administration (2005a) estimated that 320 billion cubic feet of coalbed gas was produced in 2004. Very little of the proved coalbed gas reserve or production comes from the Field Office area. For the coalbed gas tests of Infinity Incorporated, no proved reserves had been identified as-of June 30, 2005 (Infinity Incorporated, 2005). The resource potential for the coalbeds in this area has been identified as 248 billion cubic feet of gas.

The only known recent attempt to estimate proved oil and gas reserves for an area covering the Field Office region was a report prepared by the U.S. Departments of the Interior, Agriculture, and Energy (Cantey et al., 2003). That report was prepared in compliance with the Energy Policy and Conservation Act amendments of 2000. In that report, the Energy Information Administration provided a detailed description of methods used to calculate proved oil and gas reserve estimates for the entire Greater Green River Basin, and for other western regions. The Greater Green River Basin occupies a large part, but not all of the Field Office area. Energy Information Administration detailed analysis of available data indicated that the Greater Green River Basin contains 177.362 million barrels of liquid reserves (both oil and natural gas liquids) and 10.082 trillion cubic feet of gas reserves. The Field Office area occupies about 12 percent of the Greater Green River Basin area. If the proved oil and gas reserves estimated by the Energy Information Administration is assumed to be evenly distributed across the basin, then **about 21.283 million barrels of proved liquid reserves and 1.210 trillion cubic feet of proved gas reserves lie within the Field Office area**.

The study by Cantey et al. (2003) did not include an estimation of any proved reserves for the Wyoming Thrust Belt province, which also lies partially within the Field Office area. Of the three Wyoming Thrust Belt province plays partly within the Field Office area, only the Moxa Arch Extension play has produced hydrocarbons. Present production is from porous dolomite and limestone units of the Madison Limestone (see section above titled “Moxa Arch Deep Wells” for additional discussion of the Madison Limestone reservoir). Deep Madison production in the Field Office area has totaled 3.4578 trillion cubic feet of gas and a small amount of liquid reserves. If an estimate of proved gas reserves were available for the Madison Limestone reservoir, the Cantey et al. (2003) estimate of proved gas reserves would be significantly increased above the figure of 1.210 trillion cubic feet of proved gas. We do not believe that a proved liquid reserve estimate for this reservoir would significantly increase their proved liquids estimate of 21.283 million barrels.

Watford (2006) reported that Jonah Field has a recoverable gas reserve of 8.5 trillion cubic feet and the Pinedale Anticline has a recoverable gas reserve of 25.8 trillion cubic feet.

U.S. GEOLOGICAL SURVEY RESOURCE ASSESSMENTS

Law et al. (1989) studied overpressured low-permeability Cretaceous and Tertiary aged reservoirs in the Greater Green River Basin. They estimated that recoverable gas in the reservoirs studied ranged from 189 to 816 trillion cubic feet, with 433 trillion cubic feet as the mean estimate. Assuming that the gas resource is evenly distributed across the

Greater Green River Basin, a range of 23 to 98 trillion cubic feet, with a mean estimate of 52 trillion cubic feet could be present in these reservoirs within the Field Office area.

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. Two provinces assessed were the Southwestern Wyoming, and Wyoming Thrust Belt provinces. Each province lies partly within the Field Office area.

As part of a study prepared in compliance with the Energy Policy and Conservation Act Amendments of 2000 (Cantey et al., 2003) the U.S. Geological Survey prioritized oil and gas assessment studies for certain basins. Updated analyses covering both provinces in the Field Office area were prepared in response to their new priorities. The resulting reports are titled "Assessment of Undiscovered Oil and Gas Resources of the Southwestern Wyoming Province, 2002" (U.S. Geological Survey, 2002), "Assessment of Undiscovered Oil and Gas Resources of the Wyoming Thrust Belt Province, 2003" (U.S. Geological Survey, 2004), "Petroleum Systems and Geologic Assessment of Oil and Gas in the Southwestern Wyoming Province, Wyoming, Colorado, and Utah" (U.S. Geological Survey, 2005), "Southwestern Wyoming, Province 5037" (U.S. Geological Survey, 2006a), and "Wyoming Thrust Belt, Province 5036 (U.S. Geological Survey, 2006b). In these assessments the U.S. Geological Survey updated their quantitative estimate of the undiscovered oil and gas resources for these provinces. A more complete discussion of these assessments, their locations, and estimates of the oil and gas resource volumes is presented in Appendix 1.

For the Wyoming Thrust Belt and Southwestern Wyoming province assessments, the U.S. Geological Survey estimated undiscovered technically recoverable resources (see Glossary definition for *undiscovered technically recoverable resource*) for each assessment unit (see Glossary definition for *assessment unit*) or play (Tables A1-2 and A1-5). When preparing estimates of resource quantities for each province, the U.S. Geological Survey used geology-based, well-documented estimates of quantities of oil and gas having the potential to be added to reserves within a future time frame—forecast span—of 30 years.

For each type of hydrocarbon, a mean estimated undiscovered resource volume was recorded for each assessment unit and a calculation of the portion lying within the Field Office area was made (Tables A1-2 and A1-5). We estimate that all assessment units lying within the Field Office area contain a mean undiscovered volume of **5.42 million barrels of oil, 8.086 trillion cubic feet of gas, and 352.59 million barrels of natural gas liquids**.

In addition, we estimate that the Field Office area's oil resource could **range from 1.38 to 12.45 million barrels, the gas resource could range from 4.748 to 12.791 trillion**

cubic feet, and the natural gas liquids resource could range from 173.08 to 622.73 million barrels.

DEPARTMENT OF ENERGY SPONSORED RESOURCE ASSESSMENTS

The Department of Energy has sponsored three resource assessments of the Greater Green River Basin area in recent years. Only potential for gas was studied in each of these assessments.

Caldwell Assessment

Caldwell (1997) studied Cretaceous and Tertiary aged tight gas formations in the Greater Green River Basin area. He determined that 608 trillion cubic feet of this potential gas resource was available for conversion to reserves that could be produced in the future; within no forecast span used. Assuming that the resource is evenly distributed across the Greater Green River Basin, **about 73 trillion cubic feet of gas could be present in these potential reservoirs within the Field Office area**.

Advanced Resources International Assessment

Advanced Resources International (2001) prepared an analysis of the gas resource in southern Wyoming and northwestern Colorado and focused on the Greater Green River Basin and adjacent areas. This analysis was part of a larger project planned by the Department of Energy. Advanced Resources International used the U.S. Geological Survey's 1995 assessment, supplemented by data from the Wyoming State Geologic Survey, and their own work, to estimate undiscovered, technically recoverable, natural gas resources for the area studied. They did not evaluate proved gas reserves or oil resources.

For all U.S. Geological Survey plays, Advanced Resources International assumed a homogenous distribution of resource within play boundaries. Using the three sources of data listed above, they predicted the undiscovered, technically recoverable, gas resource for the entire study area and for each township. Their results showed that there is about 160 trillion cubic feet of potential natural gas resources in the area studied. The **total predicted gas resource in the Field Office area is 30 trillion cubic feet**. Advanced Resources Internationals resource prediction is more optimistic than that of the U.S. Geological Survey mean value of 8.086 trillion cubic feet of gas.

The gas resource analysis of Advanced Resources International (2001) was used to produce Figure 10. We show undiscovered, technically recoverable, gas resources by township. Townships with zero gas resource are located in areas of Wind River Range Precambrian igneous and metamorphic rocks, where traps and hydrocarbons are not known to occur. Highest predicted volumes of gas are in the Jonah field area, along the Pinedale Anticline, at the north end of the Hoback Basin, and in a few townships between. Low predicted volumes of gas are located along the west flank of the Wind

River Range and in the southwest part of the Field Office area. Low volume predictions along the southwest flank of the Wind River Range are due to the presence of significant volumes of igneous and metamorphic rocks that would need to be drilled to encounter potential deep reservoirs. Low volume predictions in the southwest are in the area of the Greater Big Piney-LaBarge field complex where much of the potential gas resource has already been discovered and is being produced.

EG&G Services, Inc. and Advanced Resources International Assessment

The report by Boswell et al. (2002b), attempts to provide a better understanding of the size and nature of gas resources in the Greater Green River Basin and the potential of technology to convert those resources into economically recoverable resources. The study only reviewed the Cretaceous section in the Greater Green River Basin, which encompasses most of the basin's gas resources. A more complete discussion of this assessment, locations of units analyzed, data acquisition methods, analysis techniques, and estimates of gas resource volumes; is presented in Appendix 2.

Using the report of Boswell et al (2002b), we were able to estimate that **about 39.98 trillion cubic feet of technically recoverable gas, might be contained within the Field Office area**. This is significantly higher than the U.S. Geological Survey prediction of 8.002 trillion cubic feet of gas for the Southwestern Wyoming Province, which covers the same area as the Greater Green River Basin (see Appendix 1 for additional information). Analysis differences stem from the use of alternative methodologies, different geologic models, and different assumptions. For example, the U.S. Geological Survey estimates for continuous-type assessment units are based on extrapolating past production history to the assessment unit's remaining untested regions and therefore, is influenced by past economic decisions of operators. The Boswell et al. (2002b) assessment of technically recoverable resources is based on the reservoir geology modeled with current technology and assuming full resource development. In addition, the U.S. Geological Survey limits their analysis to a 30-year forecast span. Boswell et al. (2002b) do not place a time limit for discovery on their analysis. Thus, they can allow for additional discoveries to occur beyond the 30-year period.

The Wyoming Thrust Belt Province was not reviewed as part of the Boswell et al (2002b) assessment, so resource predictions were only made for that portion of the Field Office area within the Greater Green River Basin.

POTENTIAL GAS COMMITTEE ASSESSMENT

The Potential Gas Committee is a group of volunteer members from the oil and gas industry, government agencies, and academic institutions. Its objective is to provide periodic estimates, using expert knowledge, "of the potential supply of natural gas that may become available to the nation in addition to currently available proved recoverable reserves of natural gas" (Potential Gas Committee, 2003). The Committee estimates only gas volumes that can be expected to be producible in the future, with reasonable future prices and technological advances. Resource volumes estimated are probable (roughly equivalent to the concept of reserve growth, see Glossary definition for *reserve growth*), possible (not associated with known oil and gas fields, but in favorable areas), and speculative (in formations or areas that are not now productive) categories. The Potential Gas Committee (2003) made a most likely estimate for each of these three categories and a most likely total resource volume. We will refer to the most likely resource total in our following discussion.

Potential Gas Committee methodology uses expert estimates of the volume of potential reservoir rock, multiplying that volume by an expected yield, and then discounting the resulting volume for geologic risk. The committee lumps all types of gas resources (tight-gas and conventional) into one category called traditional resources. They did make a separate estimate for gas below 15,000 feet and for coalbed gas resources.

The Potential Gas Committee (2003) estimated that the most likely resource for the Greater Green River Basin was 18.454 trillion cubic feet of gas from 0 to a 15,000-foot depth and 8.359 trillion cubic feet of gas for depths below 15,000 feet. For the Wyoming-Utah-Idaho Thrust Belt they estimated that the most likely resource was 3.700 trillion cubic feet of gas from 0 to a 15,000-foot depth and only 650 billion cubic feet of gas for depths below 15,000 feet. Their most likely estimate of coalbed gas resource for the Greater Green River Basin area and Wyoming-Utah-Idaho Thrust Belt combined was 2.5 trillion cubic feet of gas. We estimate that the Field Office area occupies less than 10 percent of the Greater Green River Basin and Wyoming-Utah-Idaho Thrust Belt regions that the Potential Gas Committee has defined. If our estimate is accurate, then the resource estimates listed above would need to be reduced by at least 90 percent to represent the total resource that may be present in the Field Office area in each category. We do not have digital information available to make a more accurate estimate of the portion of each resource, predicted by the Potential Gas Committee (2003), which may be located within the Field Office area.

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 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
- employ this methodology to assess the viable resource in Intermountain West basins.

The initial reports of LaTourrette et al (2002a and 2002b) were used to establish a foundation for a method to use in defining the gas and oil resource by developing relationships among gas and oil deposit characteristics, technology options, infrastructure requirements, environmental impacts, various costs, and other variables to allow a quantitative assessment of the resources. They used this expanded set of criteria to estimate the quantity of gas resource "viable" that may actually be developed and produced. They called such a resource the "viable" resource. LaTourrette et al (2003) prepared an assessment of the Greater Green River to use as an example of their approach to assessments.

They applied their method by using data from the U.S. Geological Survey assessment of 1995 (Beeman et al., 1996: Charpentier et al., 1996: Gautier et al., 1996) and a National Petroleum Council assessment (1999). They added proved reserve data to the technically recoverable resource estimates from these two assessments and prepared an economic analysis that showed how much gas was economically recoverable at different gas price values in the Greater Green River Basin. Using the U.S. Geological Survey assessment data as a base they predicted that at a gas price of $5 per thousand cubic feet, there would be a reserve appreciation of 5.9 trillion cubic feet and a recoverable resource of 87 trillion cubic feet. At a gas price of $7 per thousand cubic feet, there would be a reserve appreciation of 7.2 trillion cubic feet and a recoverable resource of 100 trillion cubic feet. Finally, at a gas price of $10 per thousand cubic feet, there would be a reserve appreciation of 8.4 trillion cubic feet and a recoverable resource of 113 trillion cubic feet. The report by Vidas et al (2003) provides additional detail about how the economic analysis was prepared. Our gas price estimates (see below) indicate gas prices will be in the $5 to $7 dollar range for the next few years and the may increase to $8 dollars per thousand cubic feet.

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 use it to determine what portions of their estimated resource values could lay within the Field Office area. Unfortunately, that information had been lost and was no longer available. Consequently, we were unable to further break-out their estimated resource values so that we could determine what portions lie within the Field Office area.

OIL AND GAS OCCURRENCE POTENTIAL

We consider that most of the Field Office area has a high potential for the occurrence of oil and gas (Figure 11). This rating considers a variety of geologic characteristics, including:

- presence of hydrocarbon source rocks
- presence of reservoir rocks with adequate porosity/permeability
- potential for structural/stratigraphic traps to exist
- opportunity for migration from source to trap

- other conditions; such as temperature, depth of burial, and subsurface pressures.

All oil and gas play areas and assessment units, as defined by the U.S. Geological Survey, are considered as being in areas of high occurrence potential. Approximately 80 percent of the Field Office area falls within this category.

Approximately 20 percent of the Field Office area falls outside of play areas or assessment units designated by the U.S. Geological Survey. These areas are mostly located in parts of mountain ranges that are made up of Precambrian igneous and metamorphic rocks; where traps, reservoir strata, and hydrocarbons are not known to occur.

PROJECTIONS OF FUTURE ACTIVITY 2001-2020

The Energy Information Administration (2005b) 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 nonconventional 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 maintaining oil supplies and increasing gas supplies in the Field Office area. Much of the Field Office gas supply growth is expected to come from nonconventional production from reservoirs like those at Jonah Field and on the Pinedale Anticline.

OIL AND GAS PRICE ESTIMATES

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. They anticipate that price ranges will be determined by response to "increased efficiency, conservation, and alternate fuel use, the ability to increase conventional and nonconventional supplies from North American… and increasing access to world resources through LNG imports."

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 Field Office 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."

Oil and gas prices can be very volatile, as shown for natural gas in Figure 12 and for oil in Figure 13. Natural gas has shown the highest volatility of any commodity traded (Boswell, 2006). The three factors most affecting gas prices have been:

- demand for gas is dependent on weather
- market access/pipeline availability creates large regional differences in prices
- crude oil and fuel prices impact natural gas prices.

Gas Prices

Historical natural gas prices for Opal, Wyoming and projected future natural gas prices are shown in Figure 12. Historical prices are in nominal dollars and show the historic volatility that has occurred in natural gas prices in Wyoming. The Energy Information Administration (2006a) projection is an average for Lower 48 well head gas prices and is made in 2004 dollars. The estimated Opal Hub futures prices were derived from averaged, August 2006, New York Mercantile Exchange (NYMEX) futures prices. These futures prices were found on the Petrie and Parkman website http://ppcenergychannel.com/PetrieParkman&Co.htm. They have been reduced by $1.00 to account for gathering and compression costs. Estimated Opal Hub futures prices are in nominal dollars. NYMEX futures prices are for delivery at Henry Hub near the town of Erath in southern Louisiana. The $1.00, usually referred to as the differential, represents the difference between Opal and Henry Hub gas prices. During 1998-2003 the differential averaged $0.63. In the first seven months of 2006 the differential averaged $1.08. The differentials for Rockies gas are significantly higher than the differentials for gas flowing from the Mid-continent and Gulf Coast areas (Boswell, 2006). This higher differential makes Rockies gas less profitable than gas produced from other regions of the U.S.

The estimated Opal Hub futures prices and the Energy Information Agency projection predict that natural gas prices will decrease in 2007 from the relatively high prices enjoyed since late 2005. For analysis purposes, we believe that future natural gas prices will average $5.00 to $7.00 per thousand cubic feet of gas during the next few years, and may increase to $8.00 per thousand feet of gas. 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 estimate of future natural gas prices should be considered speculative.

These natural gas price estimates allow some generalizations concerning future gas drilling and production activity in the Field Office area. If the above gas price scenario is accurate, we expect a continued high level of gas exploration and production in the Field Office area. Gas prices are predicted to decrease until 2010 and remain flat until 2020 and then increase until 2030. Starting in 2007, gas production will be mainly a function of the ability of industry to discover and economically develop gas accumulations and the ability to increase drilling, production, processing, and transportation efficiency.

U.S. demand for natural gas is expected to increase about 50 percent by 2020. Increases in future natural gas production, are projected to come partly from the Rocky Mountain area. Anticipated production increases in Wyoming are expected to be mainly from unconventional energy sources such as coalbed gas and deep, basin-centered gas deposits.

Oil Prices

Historical oil prices for Wyoming Sweet (Powder River Basin/Other) and Wyoming Southwestern crude oil and projected future crude oil prices are shown in Figure 13. Historical prices are in nominal dollars and show the historic volatility that has occurred in crude oil prices in Wyoming. The Energy Information Administration (2006a) projection is an average imported Low Sulfur Light Crude Oil Price and is made in 2004 dollars. The differential between Wyoming Sweet (PRB) and Wyoming Southwestern has been almost $18 per barrel in 2006. The main reasons for the large differential and the lower price received by Wyoming Sweet (PRB) were summarized in a presentation by Wood Mackenzie in an article published by The Rocky Mountain Oil Journal (Volume 86 No. 33).

Wood Mackenzie states “no single factor can be identified to explain the onset of the recent price and differential volatility. Rather our analysis shows a complex interplay of a number but intrinsically linked factors. Three main factors – constraints on regional refining, constraints on pipeline export capacity and changing crude quality – each have to be viewed in the context of increasing total crude supply in the region, both within the Rocky Mountains from Montana, and as growing imports from Canada.”

Currently, Wyoming Southwestern crude oil enjoys one of the highest posted prices with Plains Marketing, L.P. There are no assurances that those high posted prices will continue in the future.

The Energy Information Agency (2006a) projection predicts that crude oil prices will steadily increase from approximately $60 per barrel to almost $100 per barrel in 2030. For analysis purposes, we believe that future crude oil prices will average between $60 per barrel to $80 per barrel during the next few years, and could increase to $90 per barrel with unforeseen world events. It should be remembered that much of the world’s crude oil comes from politically unstable areas. Consequently, the estimate of future crude oil prices should be considered very speculative.

It is unlikely that the projected future crude oil prices will significantly increase drilling and production activity in the Field Office area. The drilling and production activity will be exclusively related to the future price for natural gas.

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 the most risky leases 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 $2.00 per acre. A $75.00 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 per acre rental is charged for the first five years and $2.00 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 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. No lease sale was held in April 1996 due to the partial government shutdown. 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 contains restrictive stipulations which protect potentially affected, mainly surface, resource values.

Field Office Area Leasing

In June 2006, there were many federal oil and gas leases covering a total of 851,127 acres in the Field Office area (Figure 14). A summary of federal leased acreage is shown in Table 4. The 851,127 acres that are leased for oil and gas, is about 34 percent of the federal oil and gas mineral estate within the Field Office area. About 55 percent of the acreage leased is held by oil and/or gas production. Held-by-production leases do not expire until the last well on the lease ceases production.

There are about 915,231 acres of Bureau managed oil and gas mineral estate that will be covered by decisions made during this plan update. About 163,500 net leased acres have expired since April of 2003 and not been leased again. About 81 percent of these federal mineral lands are presently leased, which is a drop from about 99 percent leased in April of 2003. This drop in leased acreage is due to:

- Field Office placement of a leasing moratorium along the Wind River Front (east side of Field Office managed area) and along the northern end of the Field Office managed area
- Field Office case-by-case lease sale withholding of certain high value resource lands scattered across the Field Office area.

These lands will continue to be withheld from leasing until the EIS for the Pinedale Resource Management Plan revision is completed.

About 1.325 million acres of federal oil and gas mineral estate lies under Forest Service managed lands. Only about eight percent of these federal lands are presently leased. Approximately 11,000 net acres have expired since April of 2003 and not been leased again. About 37 percent of leases under Forest Service managed lands are held-by-production.

About 1,491 acres of federal oil and gas mineral estate lies under Bureau of Reclamation managed lands. Only 72 acres (5 percent) of these federal lands are presently leased. All of these leased lands are held by production.

As federal oil and gas leases expire the acreage may be nominated for leasing again. The number of federal acres in the Field Office area leased on an annual basis from 1996 through 2002 is shown in Figure 15. During the period studied, a total of 390,000 acres were offered for lease and 244,000 acres (62.5 percent) received the $2.00 per acre minimum bid. The average bonus bid for acreage leased was $92 per acre and total bonus received was $22 million. These data are shown in Figure 16. One-fourth of the total bonus amount was from a single, 142-acre lease in Section 1, T. 28 N., R. 109 W. that sold for $32,000 per acre. This per-acre bid is the largest ever received for a federal oil and gas lease in Wyoming. During the period studied, the average bid for acreage in the Field Office area was three times the statewide average.

<u>Disposition of Funds</u>

Half of the money earned from oil and gas leases on public domain minerals goes to the State of Wyoming. The other half stays with the federal treasury, where it is split between the conservation fund and the general fund on a 4:1 ratio respectively. In the Field Office area virtually all of the federal acreage leased has been public domain minerals.

Oil and gas prices and exploration success will, to a great extent, determine the amount of acreage leased and bonus bids received. We estimate the amount of Bureau managed oil and gas acreage under lease in the Field Office area between 2000 and 2020 will range between 0.75 and .9 million acres. The amount of federal acreage leased annually is projected to average between 10 thousand and 50 thousand acres. The amount of acreage held-by-production will probably increase beyond the current total.

If prospective acreage managed by the US Forest Service becomes available for oil and gas leasing without severely restrictive stipulations, then the average annual amount of acreage under lease could increase by as much as approximately 183,000 acres. Significant amounts of this acreage may receive substantially higher than average bonus bids. Based on a Department of Energy supported study (Advanced Resources International, 2001), approximately 7.6 trillion cubic feet of recoverable federal gas resources are present in parts of US Forest Service lands not presently leased.

Leasing in the Field Office area should generate a minimum of $10 million in bonus bids during 2001-2020. Average per acre bids will almost certainly vary substantially from year to year. If leasing activity remains similar to the 1997-2002 period, about $56 million will be received in bonus payments to 2020. If prospective acreage managed by the US Forest Service becomes available for leasing with reasonable access, bonus bids for some acreage in that area could be higher than average and an additional $33 million in lease bonuses could be received.

SEISMIC SURVEYS

Seismic surveys are a critical part of exploration for oil and gas resources. They are authorized on Bureau managed surface by approval of Notices of Intent to Conduct Geophysical Operations. Seismic surveys on surface not managed by the Bureau do not have to be permitted with the Bureau even though the surveys cover federal minerals. From 1990 through 2002 the number of approved Notices has averaged 3.1 per year within the Field Office area (see Figure 17).

De Bruin (2005) reported the number of seismic projects and miles permitted by the Wyoming Oil and Gas Conservation Commission (2001 through September, 2004). During the 45-month period reported, 20 projects were permitted for 790 miles of conventional 2D seismic surveys and 696 square miles of 3D seismic surveys. Permit approvals for this period have averaged 5.3 per year, with an average of 211 miles of 2D seismic and 186 miles of 3D seismic permitted each year.

The area covered by three-dimensional (3D) seismic surveys has increased substantially since the 1995-1998 period when the first 3D surveys were made in the Field Office. Seismic activity is expected to remain strong in the Field Office area. If seismic activities stay on pace with the 2001 through September, 2004 period, about 3,700 square miles of new 3D seismic surveys during 2001-2020 could be acquired. Based on recent activity, about 4,200 line miles of new 2D surveys could be acquired during the same period. We anticipate a gradual declining emphasis on both types of surveys to 2020. Historically, approximately 80 percent of the area covered by seismic surveys has been Bureau managed surface.

DRILLING OPERATIONS

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. If the well will be on federal lands, a federal application to drill must also be approved by the Bureau. Not every approved Application is actually drilled. Wyoming Oil and Gas Conservation Commission records indicate that 72 percent of the approved federal drilling applications and 65 percent of approved non-federal applications have actually been drilled. Federal wells were 85 percent of all wells drilled in the Field Office area from 1970-2002. Figure 18 shows the number of wells drilled per year in the Casper Field Office area since 1970. The graph does not include workovers, recompletions, or wells that were deepened. Oil and gas well records indicate that before 1970 only 428 wells had been drilled (IHS

Energy Group, 2002). There has been a gradual increase in the number of wells drilled per year since 1992. Much of this increased drilling activity is due to development of Jonah field and new drilling in the Pinedale Anticline area. The number of wells drilled and success rates are shown in Table 5. Since 1990 the overall success rate for all wells drilled in the Field Office area has been 94 percent.

Figures 19 and 20 show the number of new field wildcat wells and development wells in the Field Office area (1970-2002). New field wildcat wells are exploration wells that are drilled in an attempt to discover new oil and gas reserves. Development wells are drilled to extract the oil and gas from previously discovered fields. About ten times as many development wells are drilled as wildcat wells.

As additional wells are being drilled, some wells are being plugged and abandoned. The great majority of these are wells which are either unproductive (dry holes), or have become depleted and are not economic. Since 1990 approximately one well was plugged and abandoned for every four new wells that were drilled.

As the number of wells drilled has increased, the depth of the wells has also increased. Figure 21 shows the depth distribution for all wells drilled from 1990-2001. The average depth of wells in the Field Office area has increased from 6,500 feet in 1990 to 10,200 feet in 2001. This reflects the greater drilling depths in the Jonah and Pinedale Anticline areas where much of the drilling activity has been occurring. Drilling depths generally fall into three ranges: 2,000 to 4,000 feet; 7,000 to 9,000 feet; and 10,000 to 14,000 feet.

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 Field Office area, geologists and engineers in the oil and gas industry were contacted. Twenty oil and gas companies operating in the Field Office area were contacted by letter and asked what development activity they anticipate during the next 20 years. The Bureau contacted each company by telephone about five days after the letters were sent. Thirteen companies responded. Eleven provided information useful in constructing the development potential maps. Some companies requested that the information provided be held confidential. These data were compiled, and in some cases prorated to apply to the entire Field Office area. Due to time constraints, only a limited review of technical data from wells in the Field Office area was done by the authors. Structure contour maps drawn by the Rocky Mountain Map Company (2001) were used as base maps.

Projected Non-Coalbed Oil and Gas Drilling

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 2001 to 2020, as many as 9,150 wells will be drilled in the Field Office area. These wells are expected to be about 94 percent non-coalbed oil and gas wells and about six percent coalbed gas wells. The estimated location of non-coalbed oil and gas wells is shown on the Non-coalbed Oil and Gas Development Potential Map (Figure 22). Much of the anticipated drilling activity will be infill wells in the Jonah field area and the Pinedale Anticline and to a lesser extent in the Greater Big Piney/LaBarge area (Figure 2). Estimated acres, number of townships, and percentage of the Field Office area within each development potential classification type shown in Figure 22 are summarized in Table 6. Development potential is defined as very high, high, moderate, low, and none. Very high development potential indicates areas where we estimate **average** drilling density will exceed 500 well locations per township (one township is about 36 square miles) during 2001-2020. High indicates 100 to 500 wells per township; moderate indicates 20 to 100 well locations per township; and low is defined as fewer than 20 wells per township. In areas estimated to have no development potential, no wells are anticipated.

Very high-to-high development potential is anticipated for the area in and near Jonah field and the Pinedale Anticline area (Figure 22). We anticipate that areas marked very high will have intense, closely spaced drilling activity that will be nearly pervasive. In areas marked high, drilling activity will be localized but generally less closely spaced and will contain some areas that have relatively few wells. Drilling densities in the very high-to-high development potential areas may be one well location per 10 to 40 acres, with some of the very high potential areas in the Jonah field having densities as much as one well per five acres. We anticipate that drilling in the Jonah field and Pinedale Anticline area will comprise most of the projected drilling activity within the Field Office area. Again, these are hypothetical base line estimates based on no management-imposed restrictions.

The Jonah field area comprises 21,560 acres (DuBois, 2003). The reservoir is comprised of numerous discontinuous, vertically stacked, low- to medium-sinuosity, meander-belt, fluvial stream sandstones. Close well spacing is necessary to effectively extract oil and gas resources from this type of reservoir. Our draft RFD, dated May 2002, estimated 500 additional well locations for the Jonah field area. Since the draft RFD was written, EnCana Oil and Gas (U.S.A.) Inc. (the main operator in the Jonah field area) has estimated that ultimately as many as 3,100 additional well locations in the Jonah area may be needed in order to efficiently extract the gas resource and prevent waste. Some of the wells may be drilled to deeper or shallower horizons than those that are currently producing natural gas. Although numerous additional wells are predicted and gas production will increase substantially, we do not expect that new large gas compression facilities will be needed in the near term. The additional compression needed to move additional gas will be built by adding to current facilities.

In the Pinedale Anticline area the stratigraphic character of reservoir rocks is generally similar to those reservoir rocks in the Jonah field area. However, wells in the Pinedale Anticline area are deeper than wells in the Jonah area and produce more water. Initially, 900 well locations were projected for the Pinedale Anticline area based on 40-acre well spacing. It now appears that spacing may be 10 to 20 acres per well in parts of the productive area. We estimate that as many as 2,450 well locations will be drilled in the

Pinedale Anticline area during 2001-2020. This revision is based, in part, on well performance and additional drilling proposed for the Jonah field area, plus discussions with companies that operate wells in the Pinedale Anticline area. Oil and gas development in the Jonah field area is at a more advanced stage than in the Pinedale Anticline area and to some extent, can be used as an analog.

High development potential is also estimated for the Merna field area. Geologically, this area appears to be roughly similar to the Pinedale Anticline area, but it is much smaller. The Merna field area currently has very little gas production and there is considerable uncertainty that drilling will reach our estimated levels. The area of potential oil and gas reservoir is not well defined; therefore the high and moderate development potential areas outlined in Figure 22 are generalized. If development activity increases, we estimate that the wells will be located along a generally north-south trend with one well location per 20 to 40 acres. Locally, areas may have more closely spaced wells. If the Merna field area proves productive and oil and gas leases are available, development may extend onto National Forest lands.

Approximately 7.6 trillion cubic feet of undiscovered gas resources have been estimated in a report sponsored by the Department of Energy (Advanced Resources International, 2001) in a nine-township area of land managed by the National Forest lands. None of the land is currently under lease for oil and gas. Most of this projected resource is concentrated in T. 37 N., R. 110-113 W. and T. 38 N., R 111-112 W. Eight trillion cubic feet of natural gas is enough gas to supply Wyoming for 80 years, or to meet the entire household needs of the U.S. for about 1.5 years, based on 1998 usage. Access to these resources is problematic and there is significant uncertainty whether or not the resources are present in the quantities estimated by Advanced Resources International (2001). If this area becomes available for oil and gas leasing without severely restrictive stipulations and the gas resources are found, then areas of closely spaced wells should be anticipated. Based on the relatively large amount of natural gas estimated by Advanced Resources International (2001), numerous additional wells may be needed. These wells are not included in the projections listed above.

Moderate development potential is anticipated in a large area on the LaBarge Platform (located approximately in T. 25-29 N., R. 112-113 W.) and in the central and northern parts of the Field Office area (Figure 22). This moderate development potential area extends onto National Forest lands in the north end of the Field Office. Drilling activity on National Forest lands will depend mainly on industry ability to obtain access to surface locations. Drilling in this large area of moderate development potential will vary from relatively dispersed, as many as four well locations per square mile, to local areas of more intense drilling activity. There will also be extensive areas with little or no drilling activity. Some of the drilling in these moderate development potential areas will be for replacement and infill wells in areas where oil and gas production is ongoing. The oil and gas industry will also search diligently for other Jonah type fields in the central and northern parts of the Field Office area. If another field such as Jonah is found, drilling density may be as many as 16 to 32 well locations per square mile (possibly greater) in areas with the highest gas concentrations.

Low development potential is anticipated over large parts (48 percent) of the Field Office area. In these areas, drilling density may be scattered (mainly exploration wells) or locally intense, but the total number of wells will average fewer than 20 well locations per township. In much of the low development potential area there will be very little, to no drilling activity. Another Jonah type field is possible in this area. If this occurs, drilling activity could be intense locally. But, when averaged over the entire area, we expect activity to remain at a level below 20 well locations per township.

In the area rated none, we anticipate that drilling activity will not occur during 2001-2020. Some areas are closed to leasing because they are in wilderness study areas. There probably will never be much drilling activity in the great majority of this area, unless concepts of hydrocarbon generation and accumulation change significantly.

We anticipate that average well depths will continue to increase, with many wells being 12,000 to 14,000 feet deep. Deep wells, greater than 15,000 feet deep, will probably be much less common. We anticipate that about 30 deep well locations will be drilled to 2020. As many as 15 of these wells may be drilled in the area of deep Madison Limestone gas production, generally in or near T. 28-29 N., R. 114 W. The remainder will probably be scattered throughout the Field Office area.

Projected Coalbed Gas Drilling

Coalbed gas production in Wyoming has increased dramatically since 1997. Currently, coalbed gas accounts for about 17 percent of the gas produced in Wyoming.

The potential for coalbed gas in the Field Office area does not appear to be as large as in other parts of the state. The Potential Gas Committee (2003) estimated only 2.5 trillion cubic feet of undiscovered coalbed gas resources in the Greater Green River Basin. The U.S. Geological Survey (2002) estimated only 1.5 trillion cubic feet in the Greater Green River Basin. Based on surface area proportion of individual coalbed gas assessment units identified by the U.S. Geological Survey, only 54.09 billion cubic feet are in the Field Office area. By comparison, the Potential Gas Committee (2003) has estimated 26.7 trillion cubic feet of gas resources in the Powder River Basin and 6.1 trillion cubic feet in the Hanna Basin. If estimates by the Potential Gas Committee (2003) and the U.S. Geological Survey (2002) are accurate, the Field Office area has limited, but still significant coalbed gas resources when compared to other areas in Wyoming.

Coalbed gas exploration and development in the Field Office area is in the very early stages of development. Eleven wells have been drilled or have tested for coalbed gas in the Field Office area since 2002. Wyoming Oil and gas Conservation Commission records do not indicate any active coalbed gas drilling permits. One well is located on the southern end of the Pinedale Anticline (section 24 of township 29 north, range 107 west) and the other 10 wells are located in the Riley Ridge field area on the northern end of the Greater Big Piney-LaBarge area (sections 1, 4, and 5 of township 29 north, range 114 west and section 6 of township 29 north, range 113 west). Nine of the 10 Infinity wells have reported total production of almost 209 million cubic feet of gas, 1,259 barrels of oil, and 510,200 barrels of water through May of 2006 (Wyoming Oil and Gas Conservation Commission, 2006a). Most wells are presently shut-in.

Results from coalbed gas pilot projects in Wyoming suggest that often too few wells have been drilled to adequately evaluate the economic viability of the area. Past history indicates that pilots should contain 16 (four interior wells) to 25 (nine interior wells) wells to adequately evaluate an area (Lance Cook, 2002, Wyoming State Geologist, personal communication, and Don Likwartz, 2002, Wyoming Oil and Gas Supervisor, personal communication). History suggests that fewer than 16 to 25 wells may not adequately reduce pressure over a sufficient area. Also, heterogeneity in the coal may preclude the one interior well in a normal five or nine well pilot from providing the data necessary to adequately evaluate economic viability. It is recommended that coalbed gas pilots contain 16 to 25 wells. This should provide a better chance of obtaining adequate data and thus avoiding duplicate projects.

It is very difficult to estimate large-scale development based on the available information. We estimate that, as many as 600 coalbed gas well locations will be drilled during 2001-2020. This would account for about six percent of the total 9,150 wells projected. The estimated location of coalbed gas wells is shown on the Coalbed Gas Development Potential map (Figure 23). Estimated acres, number of townships, and percentage of the Field Office area within each development potential classification type shown in Figure 23 are summarized in Table 7. Development potential is defined as high, moderate, low, very low, and none. High coalbed gas development potential indicates areas where we estimate **average** drilling density will exceed 100 well locations per township (one township is about 36 square miles) during 2001-2020. Moderate indicates 20 to 100 well locations per township; low is defined as fewer than 20 well locations per township, and very low is defined as fewer than two well locations per township. In areas estimated to have no development potential, no coalbed gas wells are anticipated.

We anticipate that much of the coalbed gas drilling activity will be in the general area around the current wells (T. 29 N., R. 114 W), but a large amount of coalbed gas development may be in areas that have not yet been discovered. Much of the anticipated coalbed gas drilling may occur in only one or two townships. It will probably not be spread evenly over the Field Office area.

PRODUCTION

"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" (Energy Information Administration, 2004).

The Energy Information Administration (2006a) has recently published estimates of oil and gas production in the Rocky Mountain region and projected production out to 2030. Their estimates will be discussed below.

Oil production in the lower 48 onshore of the United States has been declining since the late 1980s and that decline is expected to continue into the future. New oil reservoir discoveries are likely to be smaller, more remote, and increasingly costly to exploit. Onshore lower 48 oil production is projected to decline from 2.9 million barrels per day in 2004 to 2.3 million barrels per day in 2030.

Estimates of Rocky Mountain natural gas production project an increase from 3.3 trillion cubic feet in 2002 to 4.6 trillion cubic feet in 2010 and 6.3 trillion cubic feet in 2025 (Energy Information Administration, 2004). The Rocky Mountain's share of United States production was 24 percent in 2002 and it will increase to 32 percent in 2010 and 39 percent in 2025 (Energy Information Administration, 2004).

Natural gas production estimates are divided between conventional and nonconventional sources. The share of conventional natural gas production is expected to decline between 2002 and 2025 (from a 68 percent share to a 57 percent share). Fewer and smaller new onshore conventional discoveries are expected. Reserve additions from conventional wells will add to total reserves, but at less than one billion cubic feet per well. Development of reservoirs below 10,000 feet are projected to slow the decline in the average finding rate from conventional sources, but at a higher average drilling cost for this type of well. Projected increases in the drilling of conventional wells will allow production to decline only slightly from its 2002 level of about 6 trillion cubic feet per year.

"Unconventional gas has become an increasingly important component of total lower 48 production over the past decade" (Energy Information Administration, 2004). It increased from 17 percent (3.0 trillion cubic feet) of total production in 1990 to 32 percent (5.9 trillion cubic feet) in 2002 (Energy Information Administration, 2004) and to 40 percent (7.5 trillion cubic feet) in 2004 (Energy Information Administration, 2006a). Unconventional gas production has offset recent declines in conventional gas production. It is expected to increase to 46 percent (9.5 trillion cubic feet) of total production by 2030 (Energy Information Administration, 2006a). Tight gas sand and coalbed gas production account for the largest portion of the undeveloped unconventional gas resource in the lower 48 onshore.

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 lower-48 onshore United States. Much of this growth has been from nonconventional resources, although conventional production has also been increasing.

The Rocky Mountain region of the United States produces the largest amount of gas from tight sands (39 percent) and it is expected to experience the most future growth.

United States production of coalbed gas is concentrated in the Rocky Mountain region. Overall coalbed gas growth in the Rocky Mountain region will average about one percent per year through 2025. New coalbed gas wells in the Field Office area will contribute to these projected production increases.

Oil

Oil production in the Field Office area is relatively minor compared to gas production. Ninety-three percent of the oil produced in the Field Office area is from federal minerals. Although oil production has increased sharply since 1994 (see Figure 24), it is only 4.7 percent of Wyoming's total oil production. Most of the increase in production shown in Figure 24 is due to natural gas liquids (condensate, see Glossary definition for *condensate*) production from the Jonah field.

Non-Coalbed Oil and Gas

Non-coalbed oil and gas production in the Field Office area has increased steadily since 1985 (see Figure 25). Ninety percent of the gas produced is from federal minerals. The abrupt increase in 1986 was due to start up of the Shute Creek gas plant. This plant processes gas from 17 deep wells (about 15,000 to 18,000 feet deep) that produce high volume, but poor quality gas from the Madison Limestone. This gas only contains about 24 percent methane. However, it also contains about 0.6 percent helium. The volume of gas production from these deep wells has remained relatively steady since 1986. From 1990-2002, gas production (excluding the Madison Limestone) increased at a nominal rate of 8.5 percent per year. Gas production from the Field Office area is currently 34 percent of all the natural gas produced in Wyoming, and two percent of our nation's natural gas consumption.

ESTIMATED FUTURE OIL AND GAS PRODUCTION

We estimate gas production in the Field Office area will continue to increase as development continues in the Jonah field and Pinedale Anticline areas. Additional oil and gas accumulations will almost certainly be discovered and developed to 2020. If the Shute Creek Gas Plant is expanded, an abrupt increase in gas production from the deep Madison Limestone reservoir should be expected. We estimate gas production from the Field Office area to be between 0.400 and 1.200 trillion cubic feet per year in 2010, and between 0.400 and 1.100 trillion cubic feet per year in 2020. We also estimate that cumulative gas production, including coalbed gas, will be as much as 17.402 trillion cubic feet from 2003 through 2020 (Table 8). These large production volumes assume continued significant rates of drilling and discovery of additional oil and gas. Additional gas production from coalbed gas activity is very difficult to predict. If this play proves viable, we estimate that cumulative coalbed gas production could be as much as 425 billion cubic feet by 2020.

Oil production (mostly condensate) will also increase but not as rapidly as natural gas production. Most oil production in the Field Office area is an associated byproduct of gas production and is more correctly called condensate or natural gas liquids. However, crude oil (oil not associated with gas production) is also produced in the Field Office area. Crude oil production will probably decline over the next 20 years and will continue to decrease as a proportion of total oil (crude oil plus condensate) production. Oil production (crude oil plus condensate), including oil from coalbed gas wells, is estimated to be between 4.3 and 10 million barrels per year in 2010 and between 4.3 and 8.7 million barrels per year in 2020. Cumulative oil production from 2003-2020 is estimated to be 144 million barrels (Table 8). We estimate cumulative oil plus condensate from coalbed gas wells could total as much as 0.21 million barrels by 2020.

Typically, in an oil and gas producing area, the maximum number of producing wells occurs several years after hydrocarbon production begins to decline. In the Field Office area this trend should be expected. The number of producing wells will probably continue to increase to 2020. The average depth of producing wells will probably continue to increase as development continues in the Jonah field and Pinedale Anticline areas, as well as in the Merna field area. However, the probability of oil and gas development in the Merna area (T. 35 N., R. 112 W.) is very uncertain. Deep (over 15,000 feet) producing wells may increase as a result of additional drilling in the area of deep Madison Limestone gas production. Additional deep wells should be anticipated in this productive area.

OTHER POTENTIAL FUTURE OIL AND GAS ACTIVITIES

Shale Gas

Natural gas resources are almost certainly present in shales in the Field Office area. PACE Global (PACE Global Energy Services, 2003, page 28) has stated "there are numerous carbonaceous shales in the GRB that are known to contain substantial gas resources that as of today have not been tested. *** Carbonaceous shales are the most unexplored, and potentially largest, gas resources in the Rocky Mountain region." These statements are clear. Carbonaceous shale is expected to be an important future source of natural gas. At present, technology and completion methods are not available to economically produce natural gas from shale in the Field Office area. However, this important future gas source could become viable before the end of the planning cycle.

When and if technology and well completion methods are developed, this energy source will become significant. Initial development will probably use existing boreholes. However, if sufficient reserves per well are present, additional wells may be drilled specifically to recover natural gas from shale. Shale has very low permeability and large hydraulic fracture stimulations will probably be necessary to liberate the gas (Bereskin and Mavor, 2003). This production may be accompanied by significant volumes of water. Also, well spacing may be dense; one well per 40 acres should be expected.

Coal Gasification

Underground coal gasification may be a potential future process that is applied to coal deposits within the Field Office area. This process burns the coal and produces a low heating value gas that may be used in industrial processes and gas turbines. Air or oxygen commingled with steam is injected into the coal seam and burns the coal 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 also evidence that combustion gases preferentially absorb to the coal cleat faces and displace coal bed methane gas from the coal, which would increase the heating value of the produced gas. The heat of reaction of the burned coal heats the unburned coal in front of the combustion front and drives off the hydrocarbon volatile matter contained in the coal. This volatile matter removal would be essentially the same process that coal goes through in the geologic process of changing lignite to anthracite by burial and geothermal heat. This geologic process could be the source of some of the deep basin gas located in the central part of the Field Office area.

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

To the southeast (in the Rawlins Field Office area) underground coal gasification has been tested in the Shamrock Hills area and to the northeast (Buffalo Field Office area) it has been tested at the Hoe Creek site. Coal gasification is 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, deep depths, and strong cap rocks should limit this. Currently, this technology does not appear to be economic and as a result there is little activity in the state. Considering the relatively experimental status of coal gasification and the abundant energy supplies from mineable coal in the Powder River Basin, there is a low probability that this process will be utilized in the Field Office area in the next 20 years. However, if it becomes economic to remove volatiles from coal beds, then there could be development activity in the Field Office area. We estimate one pilot project could be drilled by 2020.

Carbon Dioxide Sequestration

Carbon dioxide sequestration is a method of storing captured carbon dioxide gas. This gas is a greenhouse gas that is generated by power plants, oil refineries, cement works, and iron and steel production. In southwestern Wyoming, a significant volume of carbon dioxide is vented during natural gas production. Capturing and storing this gas has been proposed to reduce the environmental effects caused by releases of this gas. Currently, a number of fields in Wyoming have been approved for the use of carbon dioxide in the tertiary oil recovery process whereby it is injected into an oil reservoir to adsorb into the interstitial oil, reduce the oil viscosity, and allow increased oil recovery. This process also traps some of the carbon dioxide in the rock matrix as a free gas and in the interstitial water as dissolved carbon dioxide. The carbon dioxide used in this process currently comes from the Shute Creek processing plant just outside the Field Office area and it would otherwise be vented. There are also large coal fired power plants in Wyoming that could be a concentrated source of this gas for tertiary oil recovery. Tertiary oil recovery processes utilizing carbon dioxide have not been proposed for any of the oil fields within the Field Office area.

Carbon dioxide sequestration requires an oil reservoir that is isolated by an impermeable cap rock and has porosity and permeability characteristics that allow its efficient injection and storage. There are reservoirs in the Field Office area which are moderate in depth with reservoir characteristics that would allow efficient storage of this gas. Some of these reservoirs have limited oil reserves and sequestering carbon dioxide could improve the ultimate oil recovery from these fields.

In addition, the Department of Energy supports a test site at the Teapot Dome Field (Naval Petroleum Reserve No. 3 north of Casper, Wyoming) where a carbon dioxide sequestration test has been proposed. The environmental consequences of implementing this process would be much like the current tertiary oil recovery programs, except that injection wells and compressors would be the only necessary facilities. Carbon dioxide injection could begin in 2006 and continue for as many as 10 years. If successful, this type of project could be extended to other parts of Wyoming, including the Field Office area. On a regional basis, this process would be an environmental benefit by reducing acid rain and improving air quality.

PIPELINE INFRASTRUCTURE

In Wyoming, shortfalls in pipeline capacity have been common in recent years. These shortfalls appear to be the result of rapid growth in supply, which has outstripped new pipeline contracting. The National Petroleum Council (2003) projects that significant new infrastructure will be needed in the Rocky Mountain region through 2013 and then the need will decrease after that. The Federal Energy Regulatory Commission (2006) lists three major Wyoming pipeline projects that are at an early planning stage but have not been filed with the commission. They are:

- EnCanna Project Extension (Entrega Gas Pipeline Inc.)
- Painter Lateral Project (Overthrust Pipeline Company)
- Uinta Basin Exploration Project (Wyoming Interstate Co., Ltd.).

The Energy Information Administration (2005c) reported the 2004 completion of the Jonah Phase III Expansion, which added additional pipeline capacity in the Field Office area of 100 million cubic feet of gas per day. A regional 560 million cubic feet of gas per day extension of the Colorado Interstate Gas system was also added. It was designed to provide the expanding Wyoming/Colorado production an access to Midwestern markets. In 2005 (Energy Information Administration, 2006b), the only expansion was an additional 170 million cubic feet of gas per day capacity added to the Cheyenne Plains Pipeline. This expansion was also designed to bring Wyoming/Colorado production to Midwestern markets.

So far, two pipeline projects have been completed in 2006 (Energy Information Administration, 2006b). Kinder Morgan Energy Partners LP completed the Rockies Express Phase 1a pipeline that added an additional 750 million cubic feet of gas per day capacity. Jonah Gas Gathering Company completed Phase IV expansion, which added 400 million cubic feet of gas per day capacity. They also began construction of Phase V expansion which will add 300 million cubic feet of gas per day capacity. Windsor Energy Co. has begun construction of the Windsor Energy Gathering Lateral, which will add 300 million cubic feet of gas per day capacity.

A number of other pipeline projects in Wyoming have been approved or proposed (Energy Information Administration, 2006b). The Rendezvous Gas Services LLC, Kern River Lateral was approved and will add 300 million cubic feet of gas per day capacity. The Kinder Morgan Energy Partners LP, Rockies Express Phase 1b new pipeline was approved. Wyoming Interstate Company, LTD has proposed the Kanda Lateral, which is designed to add 225 million cubic feet of gas per day capacity. Questar Overthrust Pipeline Company has proposed the Wamsutter Expansion Project to add 750 million cubic feet of gas per day capacity. Questar Overthrust Pipeline Company has also proposed the Overthrust Extension, which will add 550 million cubic feet of gas per day capacity.

No major pipeline construction appears to be planned for the Field Office area in the near term.

REASONABLY FORESEEABLE DEVELOPMENT SCENARIOS FOR RESOURCE MANAGEMENT PLAN ALTERNATIVES 1, 2, 3, AND 4

The Environmental Impact Statement for the Field Office Resource Management Plan 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 four 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 future 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, raptor nesting habitat, or sage grouse strutting grounds. We also considered restrictions such as avoidance of areas within 500 feet of wetlands, riparian areas, or perennial waters could have a moderate effect on the potential locations of wells and cumulative production. Numerous overlapping Category B restrictions can lead to a greater negative affect on the number of future well locations or production for any alternative.
- 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 protect view sheds, thus requiring that well locations and production facilities are not visible from areas such as historic trails. Overlapping minor constraints may also severely limit the future 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. Because areas are closed to leasing, this category places the most severe restrictions on future oil and gas activity and production.

Estimates of future 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 non-coalbed oil and gas development activity (Table 9) and for coalbed gas development activity (Table 10).
- The acres of federal oil and gas ownership for each area of non-coalbed oil and gas development potential (Figure 22) 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 gas development potential (Figure 23) 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 areas covered by restriction categories (B, C, or D) within the high, moderate, low, or very low development potential areas for non-coalbed oil and gas and coalbed gas potential were calculated using GIS software. The area within category A was not calculated, because we previously determined that this type of restriction would have no significant affect on the number of well locations for any alternative. For example, Alternative 1 (No Action) acreage calculations for each potential area are presented in Table 11.
- 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. For example, the results of our calculations for non-coalbed oil and gas and coalbed gas under Alternative 1 (No Action), Category C restrictions are shown in Table 12 below. Category C restrictions for Alternative 1 were calculated and indicated that non-coalbed oil and gas wells would be reduced by 119 and coalbed gas wells would be reduced by 71. 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 estimated. The estimates of reduction in well locations were then summed for non-coalbed oil and gas and for coalbed gas for each alternative. The results of these calculations are shown in Table 13.
- Because reductions in well locations were only calculated 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 also presented in Table 13.

ESTIMATED FUTURE OIL AND GAS PRODUCTION

Future oil production and gas production was estimated for the base line scenario and each alternative. For oil production, Field Office wells were averaged together and an average estimated ultimate recovery for a type well was estimated using PowerTools Decline software. The resulting estimates of future yearly oil production and total oil production for the period 2001-2020, are presented in Table 14 for the base line and for each alternative. Gas production was determined using a procedure similar to that for our estimate of oil production. The resulting estimates of future yearly gas production and total gas production for the period 2001-2020, are presented in Table 15 for the base line and for each alternative.

SURFACE DISTURBANCE

The following assumptions and guidelines for roads, drill pads, pipelines, and ancillary facilities were used to determine acres of surface disturbance associated with oil and gas exploration and development drilling activities. The assumptions are based on existing oil and gas development across the Field Office.

Reasonably Foreseeable Development

- Approximately two-thirds of the projected wells would occur in the Jonah and Pinedale Anticline fields.
- The Pinedale Anticline area would be developed with multiple wells per pad on an average surface spacing of four to six well pads per square mile (160- to 120-acre surface spacing per pad).
- The Jonah field would predominantly be developed with single well pads at an average of 64 pads per square mile (10-acre surface spacing per pad).
- The greater Big Piney-LaBarge area, Castle Creek field, and the rest of the planning area would be developed with single well pads on an average surface spacing of 16 or fewer well pads per square mile (40-acre surface spacing per pad).
- The major collection and transportation pipeline system would double in Alternative 2 from the current level. Projected major pipeline development for the other Alternatives would be prorated based on the RFD projections. Current major pipeline systems in the Field Office area include the Anticline-Jonah System (approximately 36 miles long, 300 feet wide, involving 1300 acres), the Merna/Big Piney-LaBarge System (approximately 40 miles long, 150 feet wide, involving 720 acres), and the ExxonMobil system (approximately 24 miles long, 150 feet wide, involving 430 acres).

Access Roads

- Average initial 40 feet total width disturbance for 0.4 mile per well (1.9 acres).
- Average long-term 23.5 feet total width disturbance for 0.4 mile per well (1.14 acres).

Drill Pads

- Average initial disturbance of 3.7 acres per single-well pad.
- Average initial disturbance of 10 acres per well pad with multiple wells (projected size range: 4.0 acres for pads with two wells to 20 acres for pads with up to 32 wells).
- Average long-term disturbance of 1.5 acres per single-well pad.
- Average long term disturbance of five acres per pad with multiple wells (projected long term disturbance range: 1.5 acres per single well pad to eight acres for a pad with 32 wells).

- 100 percent of the coalbed gas wells would be vertical wells from single well pads.
- Approximately 65 percent of the non-coalbed oil and gas wells would be vertical wells from single well pads.
- Approximately 35 percent of the non-coalbed oil and gas wells would be directional wells from multiple-well pads. This assumption is based on vertical well development on the Pinedale Anticline Project Area that has by-and-large reached the number threshold for single well pads in each Management Area and that approximately 30 percent of the total RFD would occur in the Pinedale Anticline Project Area.
- An estimated average of seven wells would be developed from a multiple-well pad The Field Office currently has multiple-well pads with as few from two to 21 wells authorized from a single well pad.

Pipelines - Average initial disturbance of 1.5 acres per average single-well pad and 3.0 acres for multiple-well pads and stabilized after three years. Pipelines serving single well pads would average 0.4 miles in length per pad and have an average surface disturbance width of 30 feet. Pipeline disturbance associated with multiple-well pads would be double the disturbance for single-well pads (3.0 acres). These figures are based on four well pads per square mile.

Acres of projected surface disturbance are calculated using the guidelines above and the total number of well locations by alternative (Table 16). Projection period is from the base analysis year of 2001 through 2020 (note 560 wells have been developed from 2001 through July 2006). Tables 17 and 18 show the initial and long-term surface disturbance by alternative associated with the projected number of oil and gas wells in Table 16.

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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.

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

Condensate. Liquid hydrocarbon recovered by separation from natural gas.

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

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

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.

Gas accumulation. An accumulation with a gas-to-oil ratio (see Glossary definition for *gas-to-oil ratio*) of 20,000 cubic feet per barrel or greater.

Gas-to-oil ratio. Ratio of gas-to-oil (in cubic feet per barrel) in an accumulation. The gas to oil ratio is calculated using known gas and oil volumes at surface conditions.

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. Natural gas liquids are 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 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.

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

Reserve growth. The increases in estimated ultimate recovery that commonly occur as oil and gas accumulations are developed and produced, synonymous with field growth.

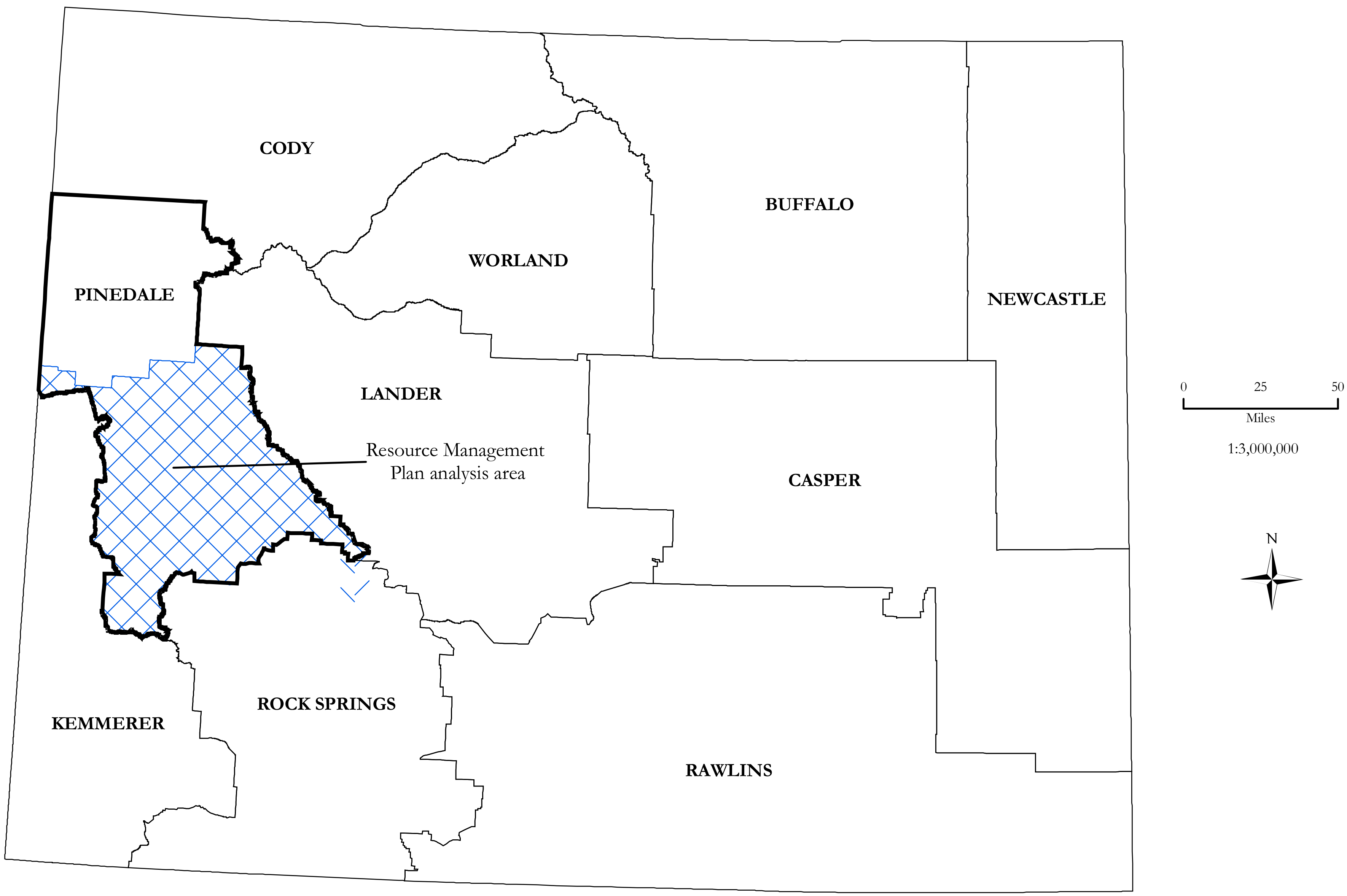
Reserves. Oil and gas that has been proven by drilling and is available for profitable production.

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

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 one million barrels of oil or 6 billion cubic feet of gas were included in the earlier 1995 assessment.

Figure 1.

Location of Pinedale Field Office management area and its relationship to other bureau management areas in Wyoming.



August, 2006

Fred Crockett, Geologist
Dean Stilwell, Geologist
Map generated by Cathy R. Stilwell

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Wyoming State Office
Reservoir Management Group

Figure 2.

Locations of oil and gas fields and major structural features within the Pinedale Field Office area. Field and structural data from DeBruin (2002).

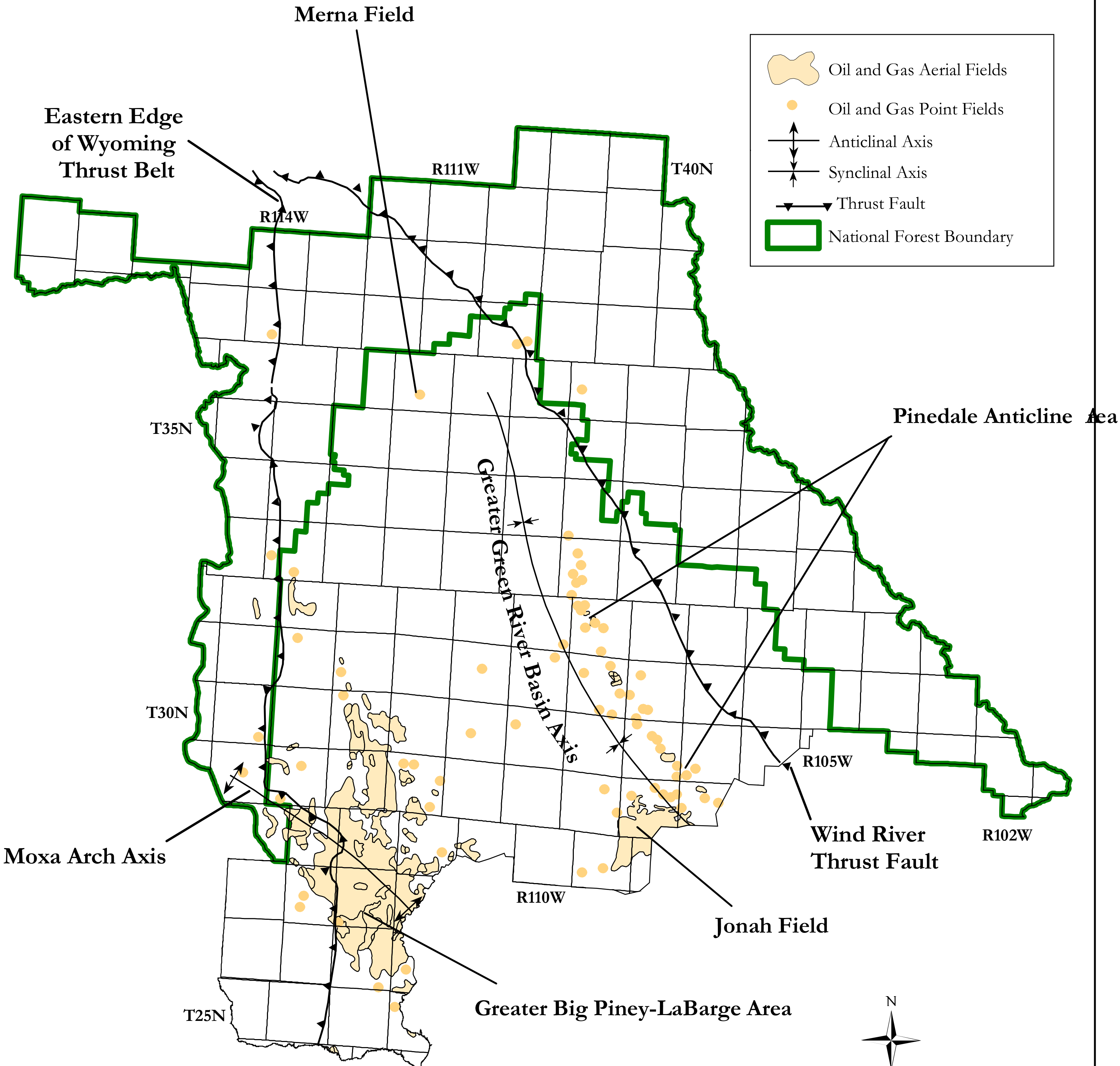

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Figure 3.

Federal development contracts within or intersecting Pinedale Field Office boundary. Development contract boundaries are from bureau files.

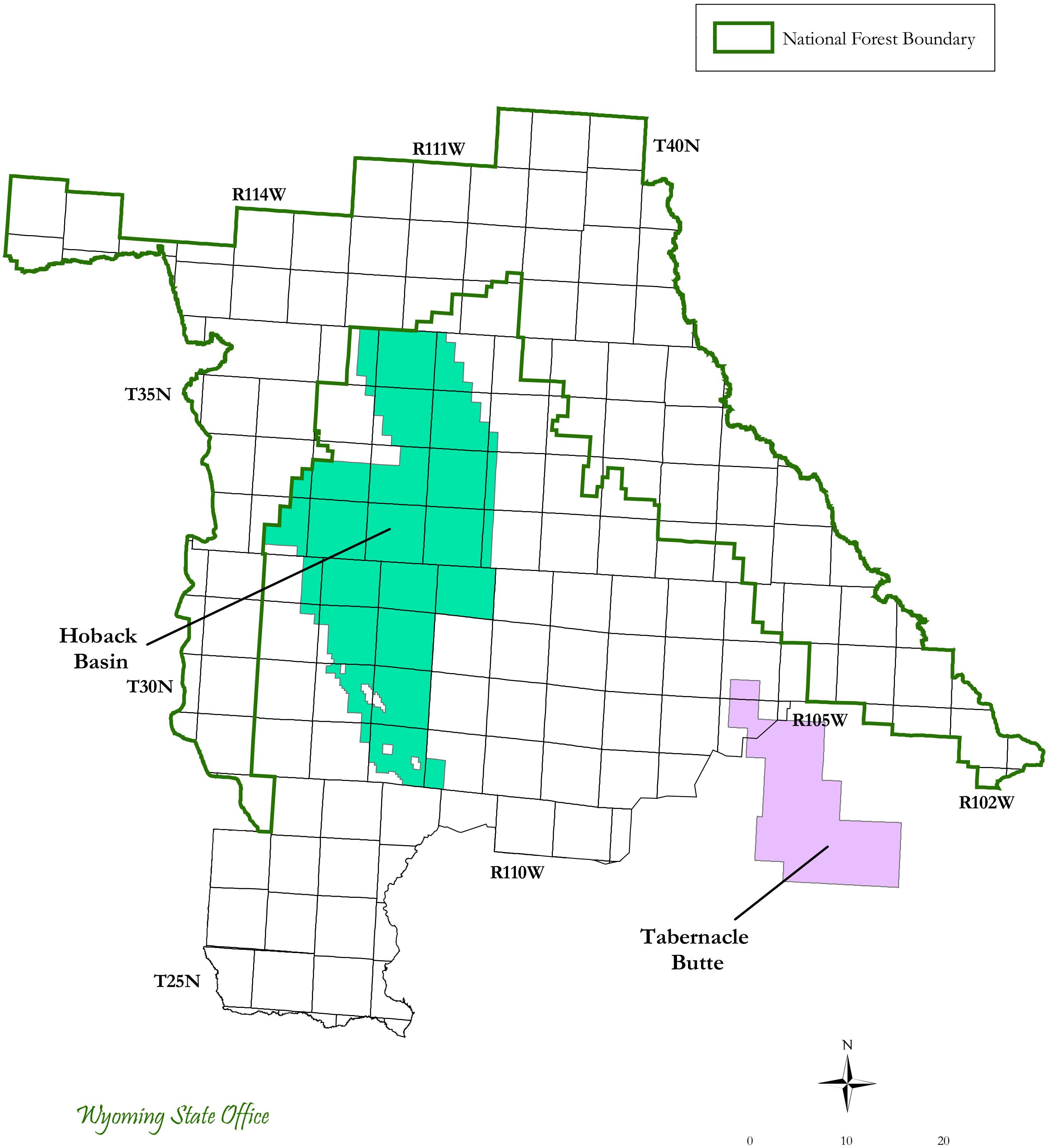

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Figure 4.

Federal oil and gas unit agreements within or intersecting Pinedale Field Office boundary.
Unit agreement boundaries are from bureau files.

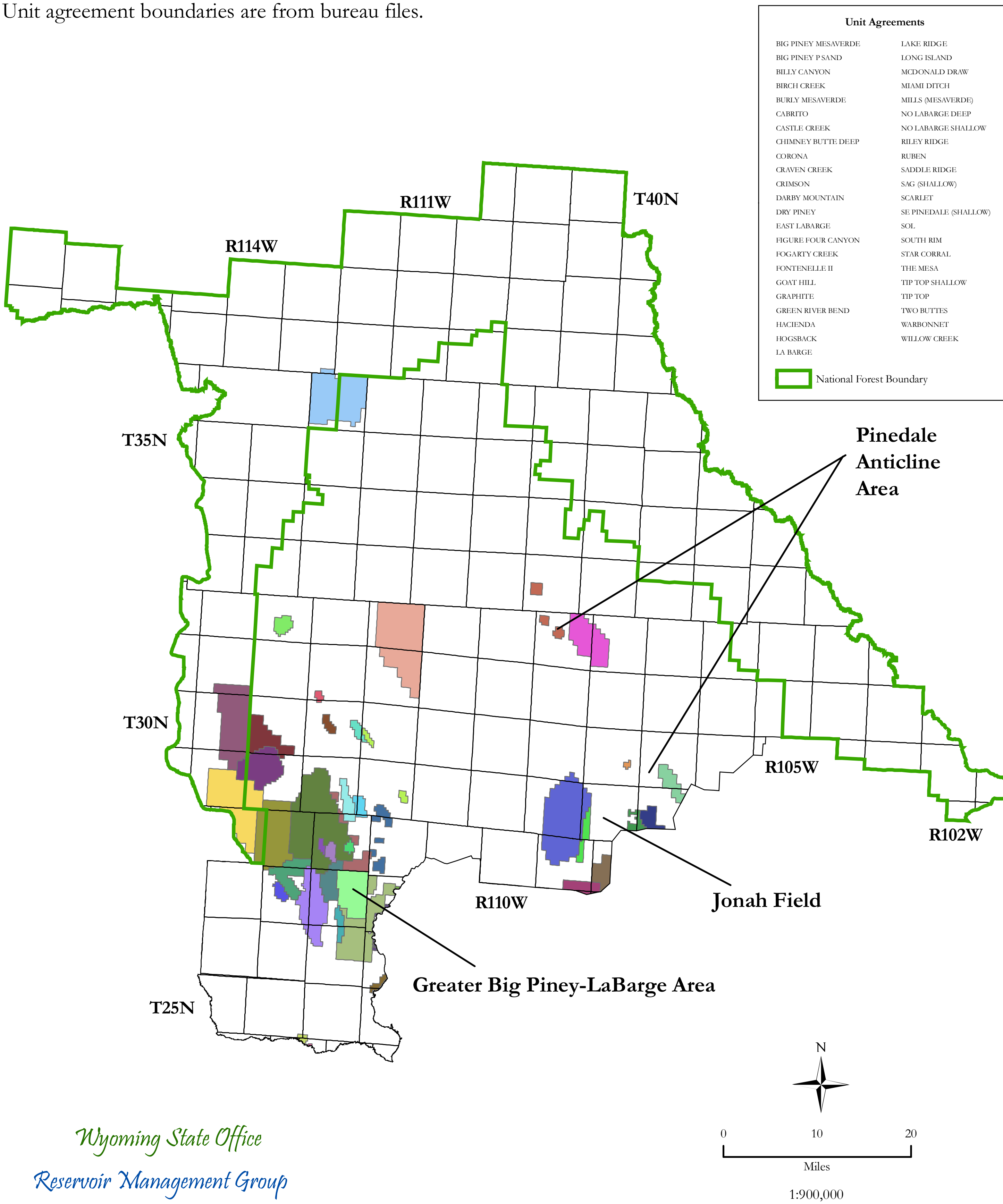

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Figure 5.

Locations of all wells drilled within Pinedale Field Office area. Well data from Wyoming Oil and Gas Conservation Commission (2006a).

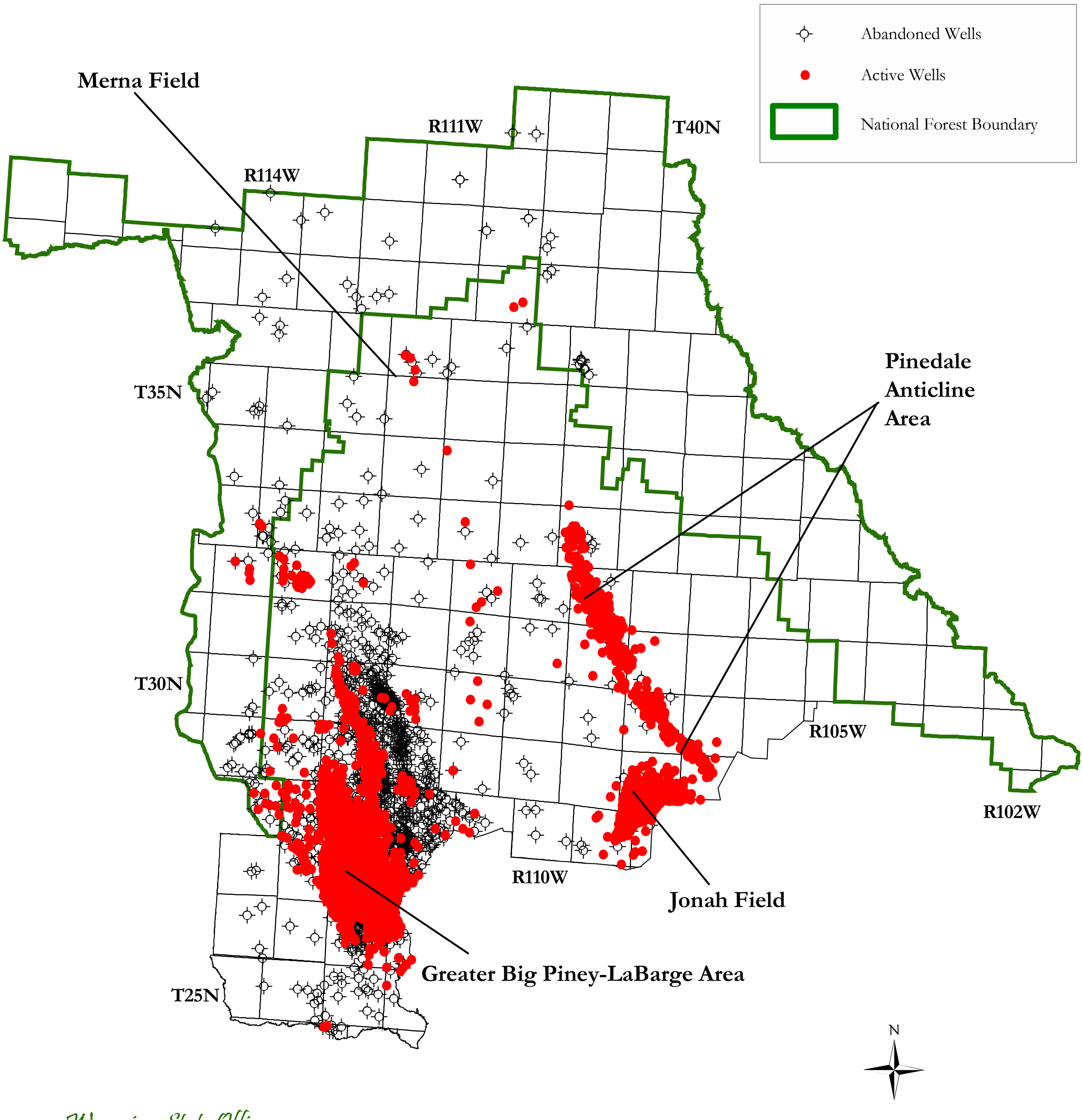

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Figure 6.
Stratigraphic nomenclature for Greater Green River Basin. Well symbols mark intervals known to produce oil and gas within the Pinedale Field Office. Stratigraphic units from Law (1995).

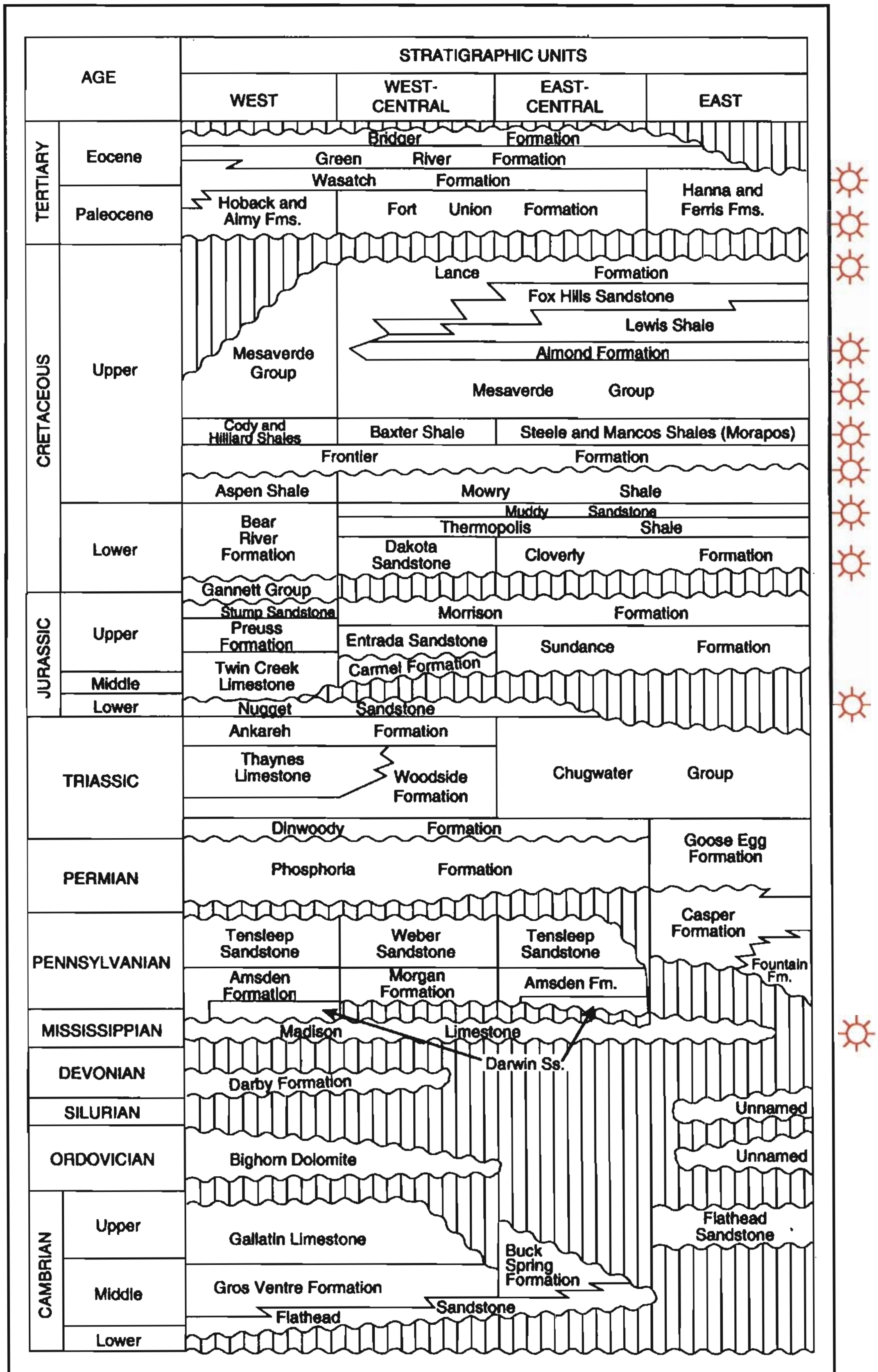

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Figure 7.

Potential deep (>15,000 feet) hydrocarbon resource, deep wells, and approximate location of deep Madison Limestone reservoir within Pinedale Field Office area. Well status as of August 7, 2006. Well data from IHS Energy (2006) and Wyoming Oil and Gas Conservation Commission (2006a).

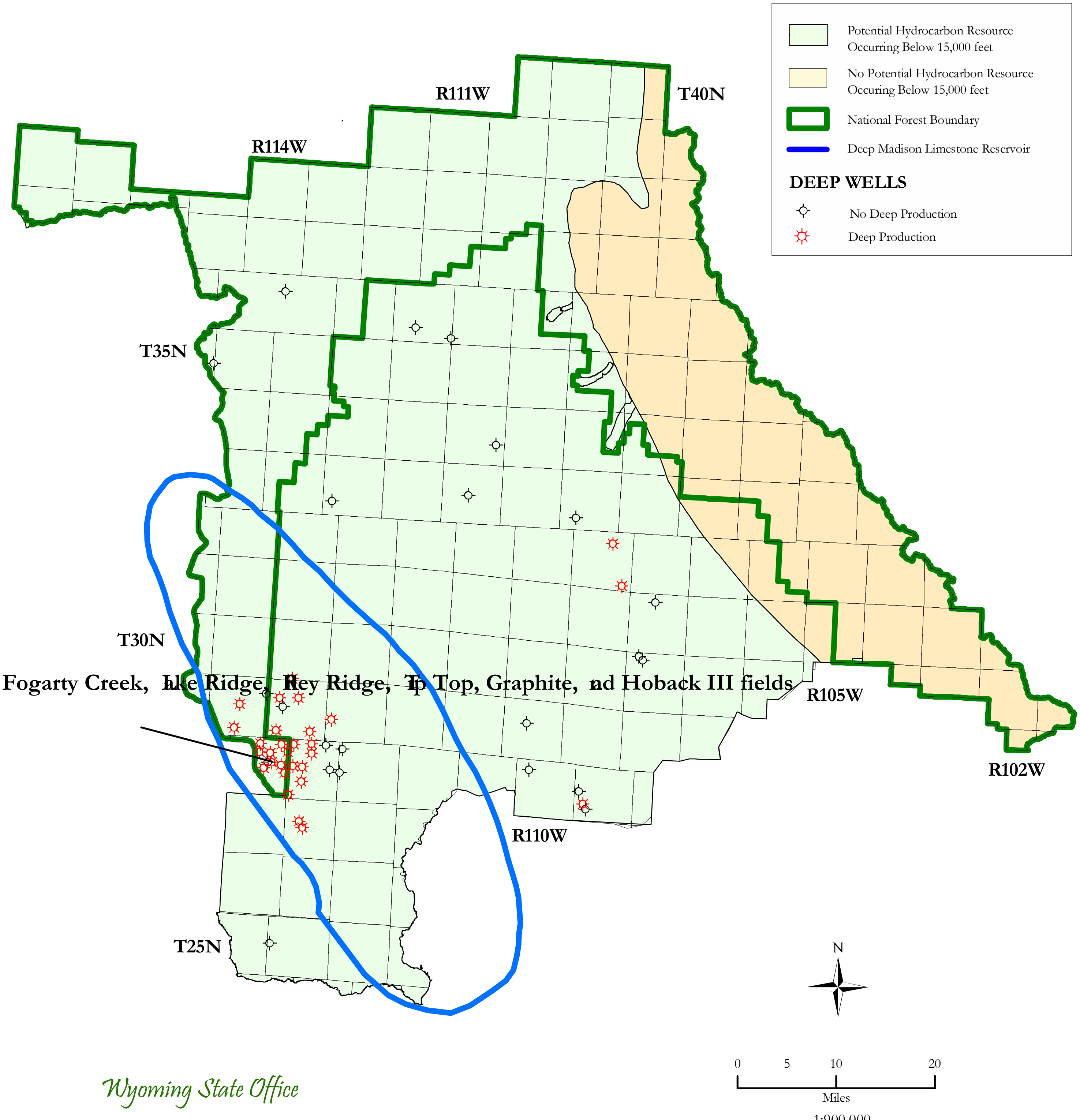

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Figure 8.

Location and status of directional wells within the Pinedale Field Office area. Well status as of August 8, 2006. Well data from IHS Energy (2006) and Wyoming Oil and Gas Conservation Commission (2006a).

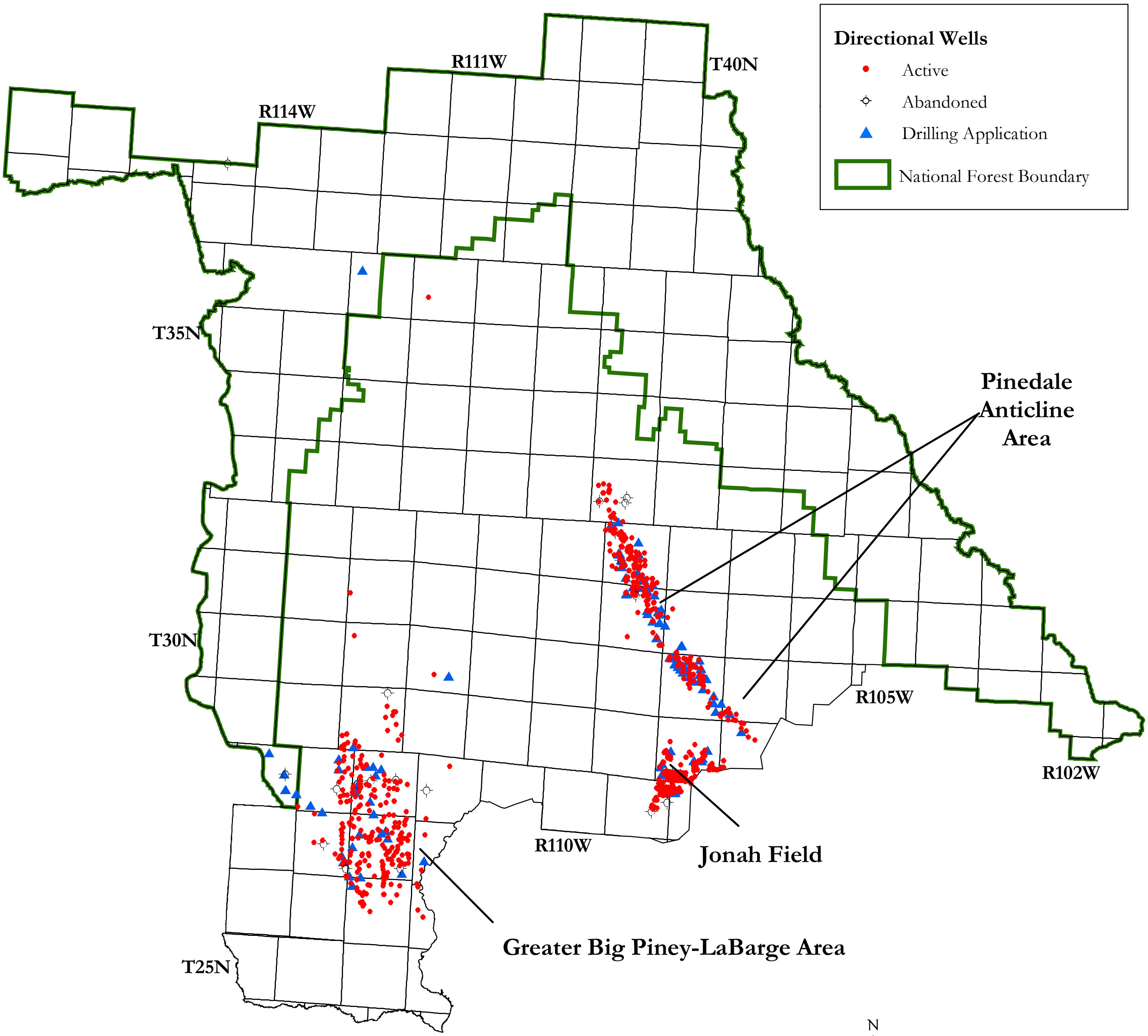

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Figure 9.

Location and status of horizontal wells within the Pinedale Field Office area. Well status as of August 8, 2006. Well data from IHS Energy (2006) and Wyoming Oil and Gas Conservation Commission (2006a).

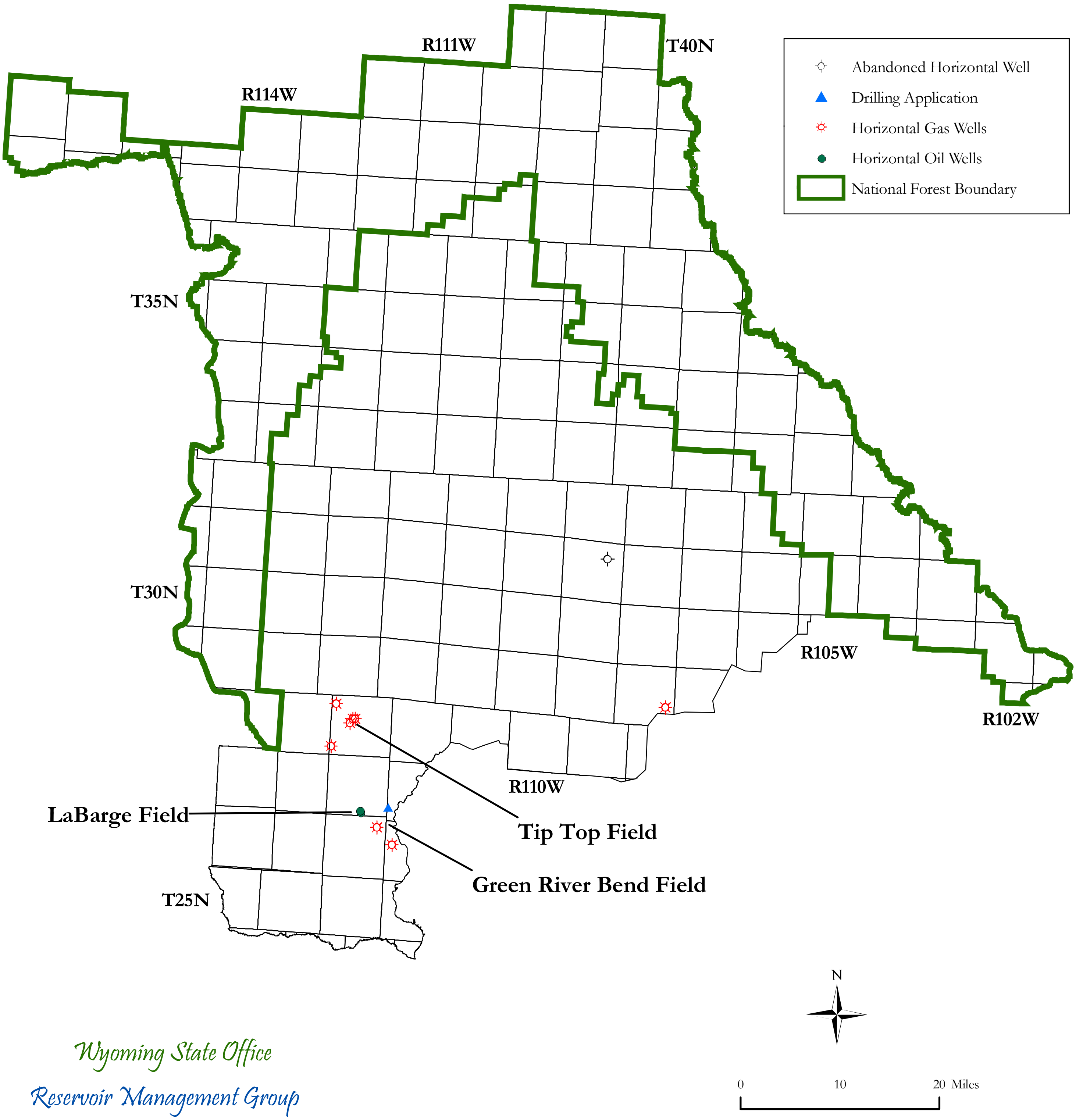

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Figure 10.

Undiscovered, technically recoverable, natural gas resources by township for the Pinedale Field Office area. Estimates of potential gas resources are modified from those of Advanced Resources International (2001).

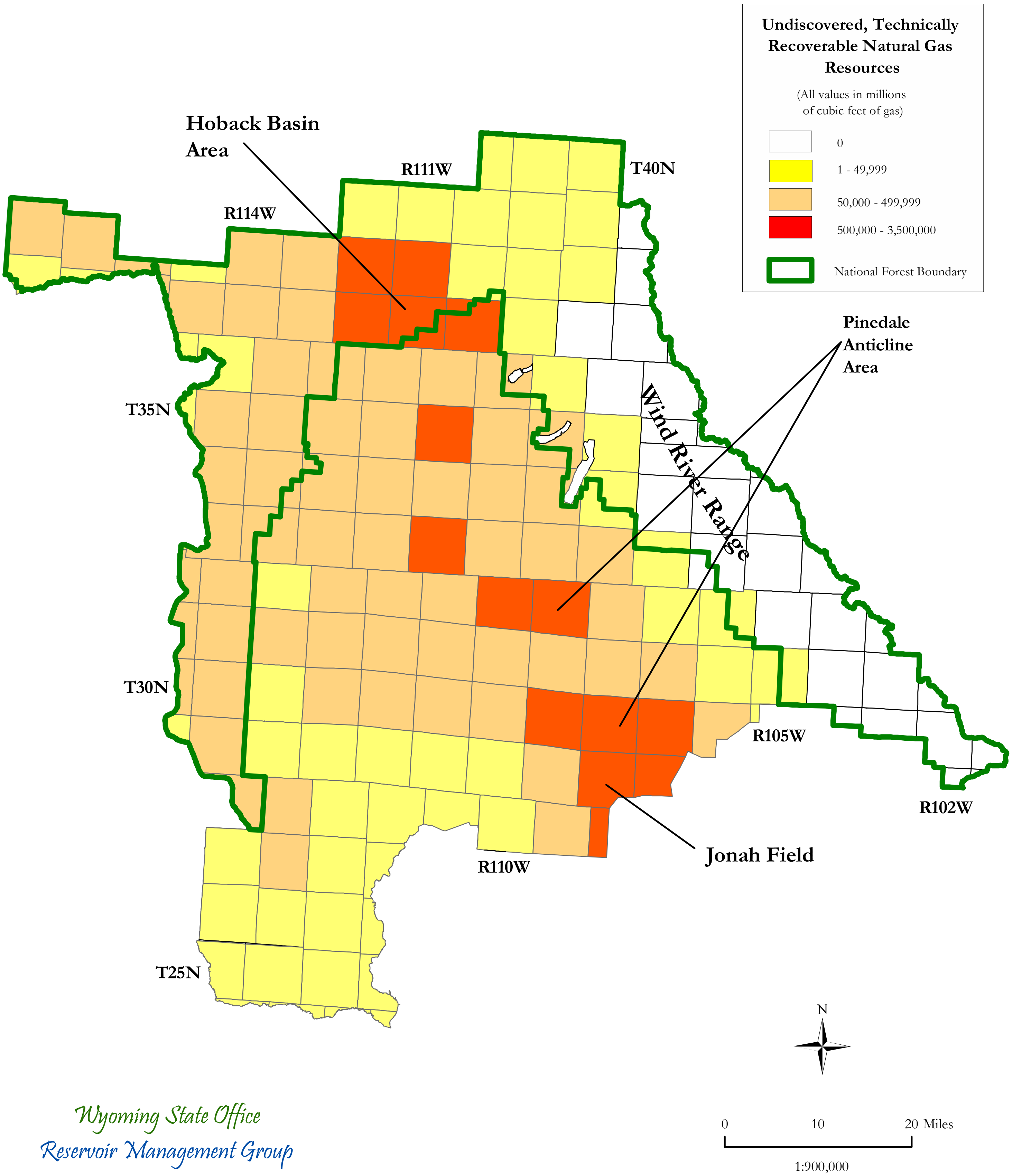

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Figure 11.

Potential for occurrence of oil and gas within the Pinedale Field Office area.

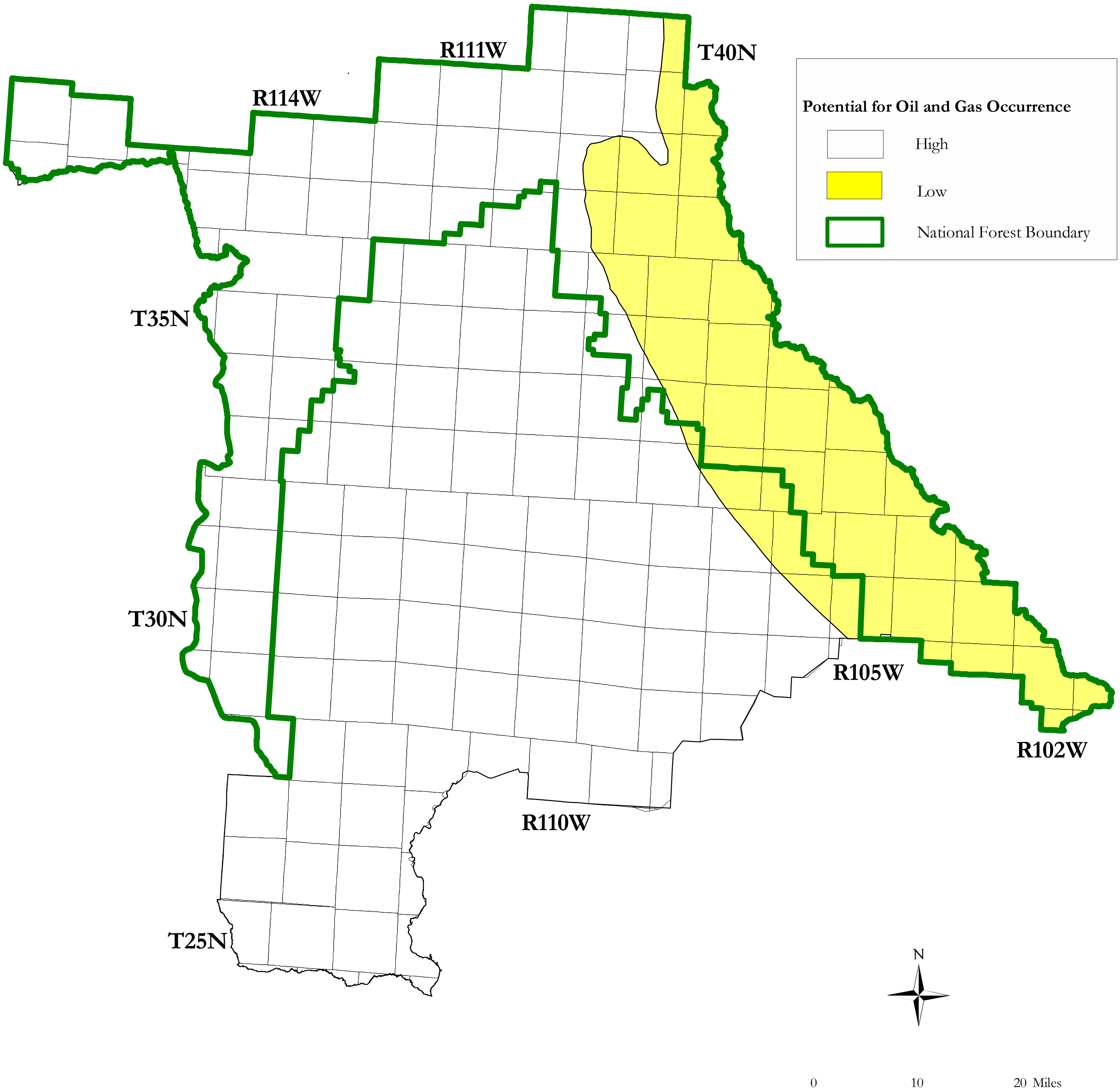

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Figure 12. Historical and projected natural gas prices. Historical Opal spot gas prices are for Northwest Pipeline at Opal, Wyoming and are in nominal dollars. Estimated Opal futures prices are derived from averaged August 2006 NYMEX gas futures, with a $1.00 differential, and are in nominal dollars. Energy Information Agency (2006a) projection is in 2004 dollars. Data are from Petrie and Parkman website, the Oil and Gas Journal, https://www.theice.com/marketdata/naNaturalGas/naIndex.jsp and the Energy Information Agency website. 1MMBTU equals 1,000 cubic feet of gas.

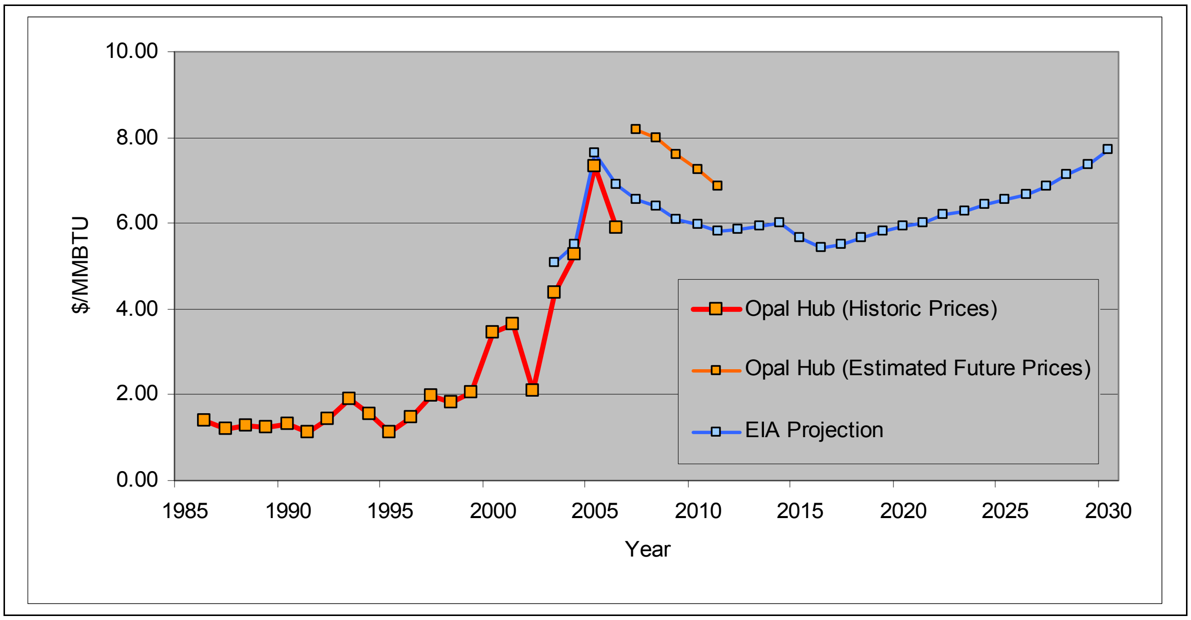

Figure 13. Historical and projected crude oil prices. Historical prices are for Wyoming Sweet (Powder River Basin/Other) (ConocoPhillips/Plains Marketing, L.P.) and Wyoming Southwestern (Plains Marketing, L.P.) and are in nominal dollars. Energy Information Agency (2006a) projection is in 2004 dollars.

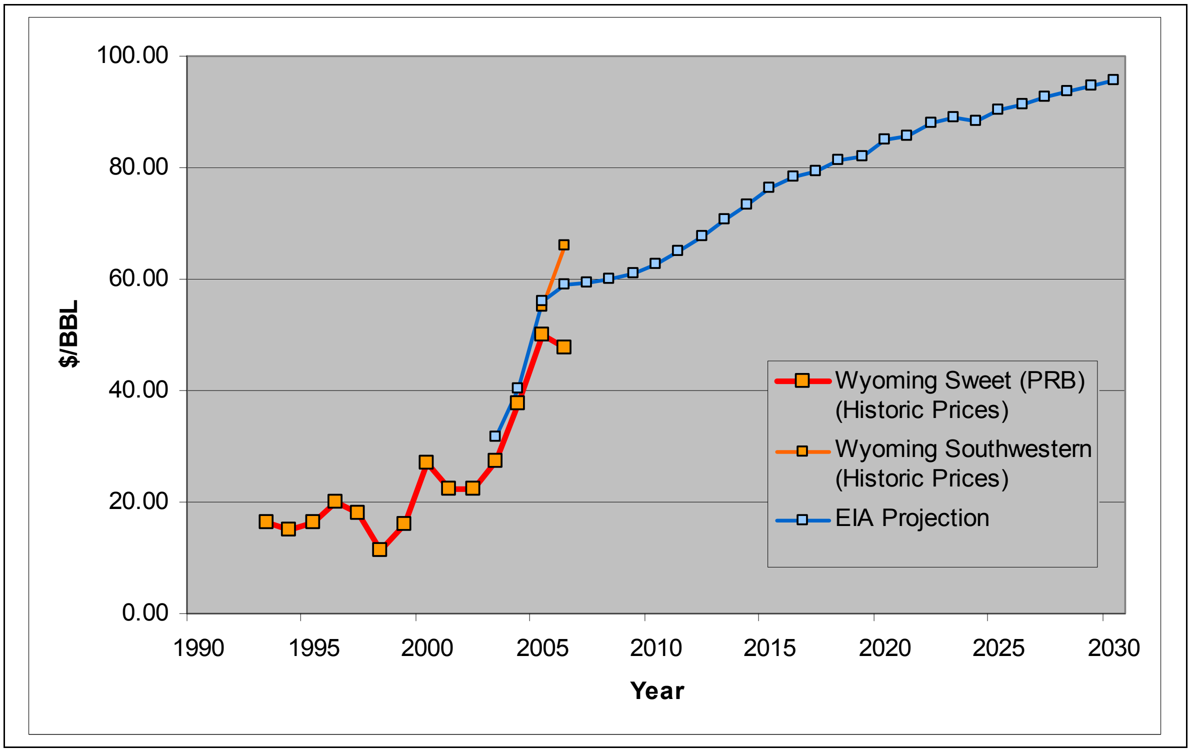

Figure 14.

Authorized federal oil and gas leases within Pinedale Field Office area.

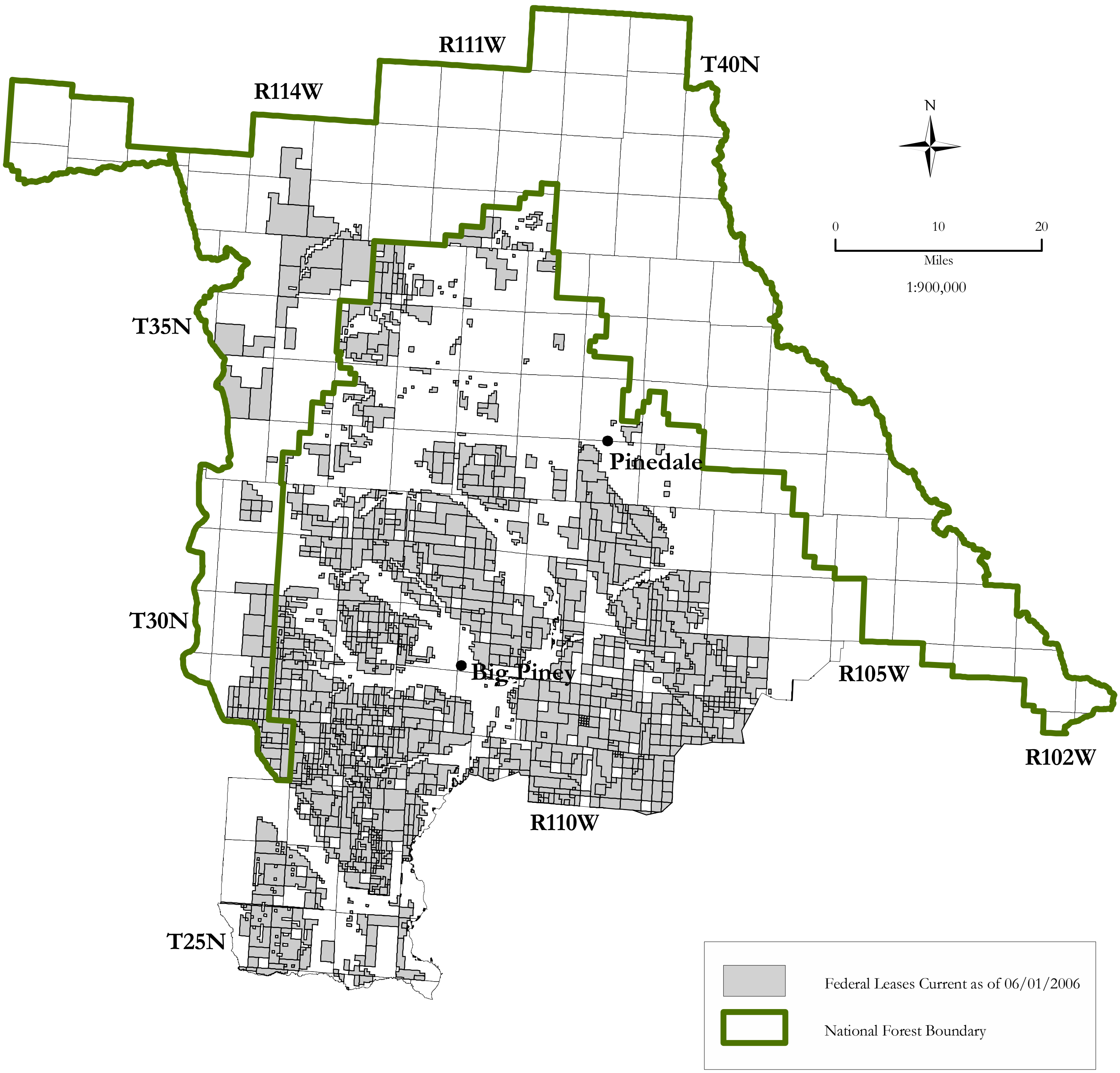

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Figure 15. Federal oil and gas lease sale results. Data are from bureau files.

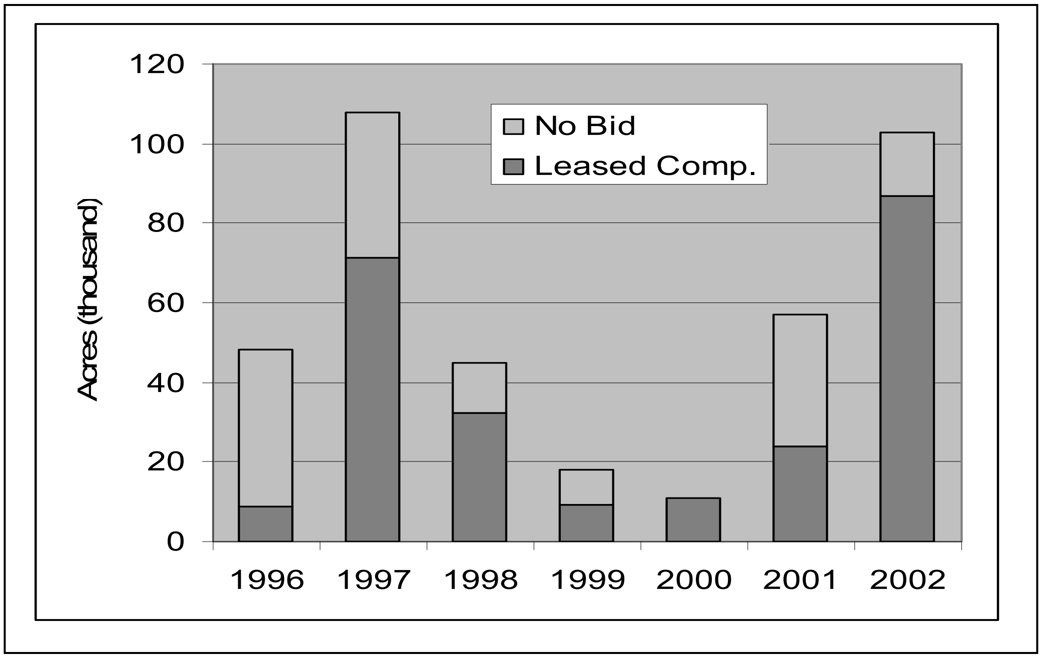

Figure 16. Total bonus and average per-acre bid data compiled from federal oil and gas lease sale results for lands in the Pinedale Field Office area.

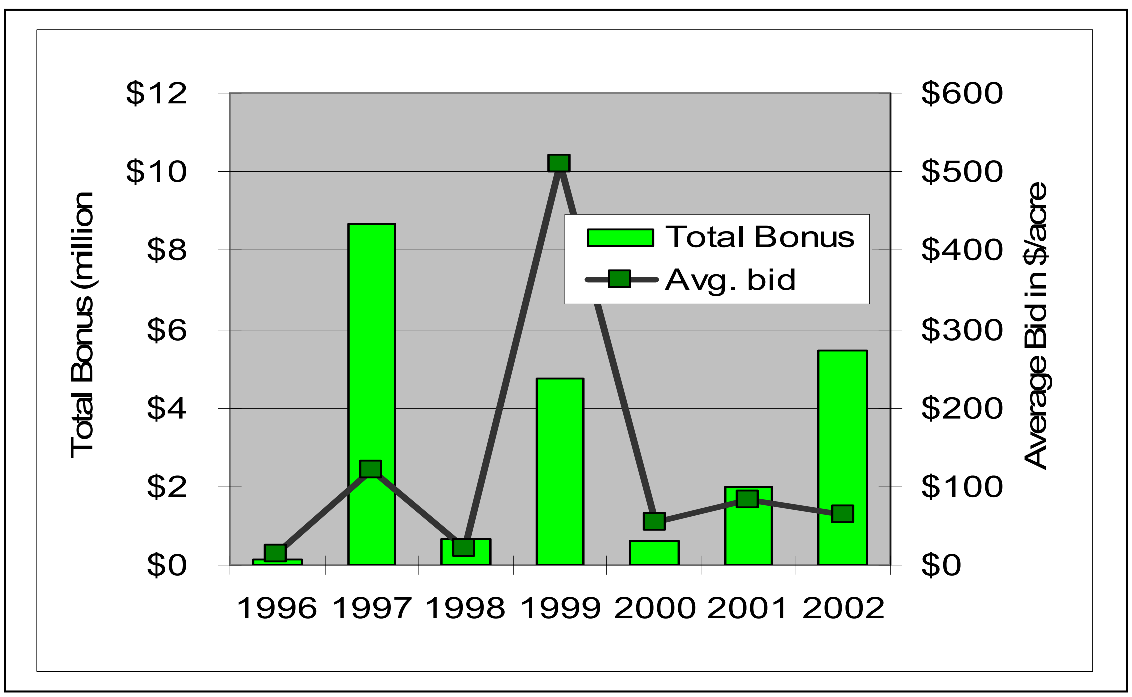

Figure 17. Approved seismic projects on bureau managed surface in the Pinedale Field Office area. Data are from bureau files.

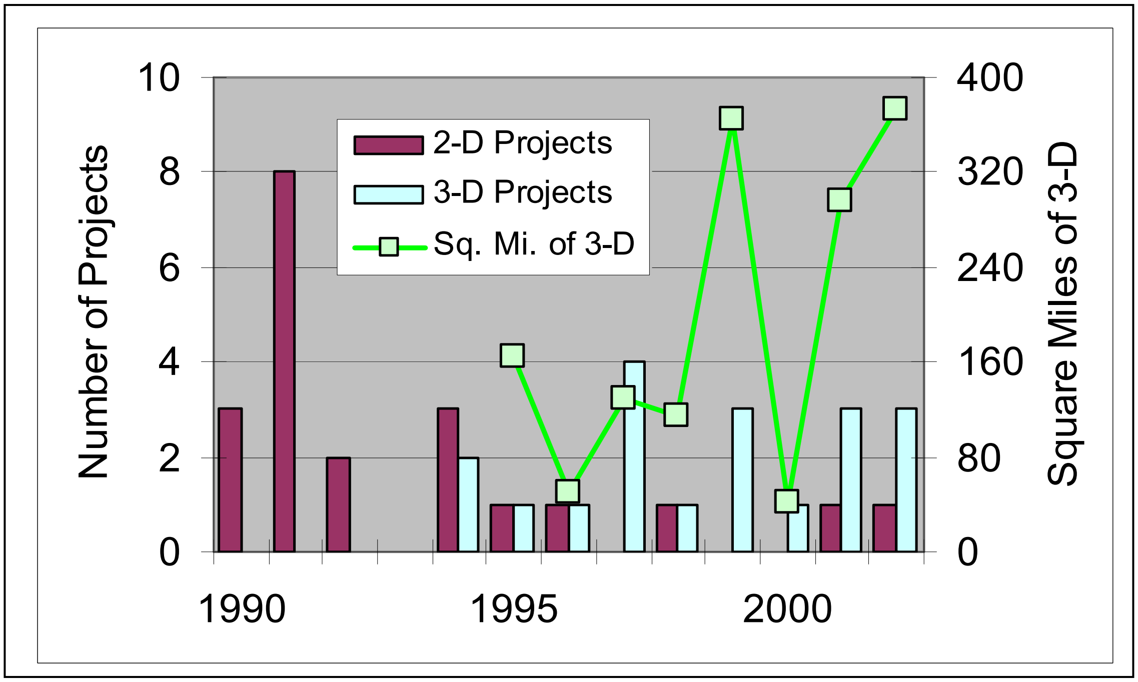

Figure 18. Wells drilled in the Pinedale Field Office area since 1970, by mineral ownership. Data are from Wyoming Oil and Gas Conservation Commission (2003) and IHS Energy Group (2002).

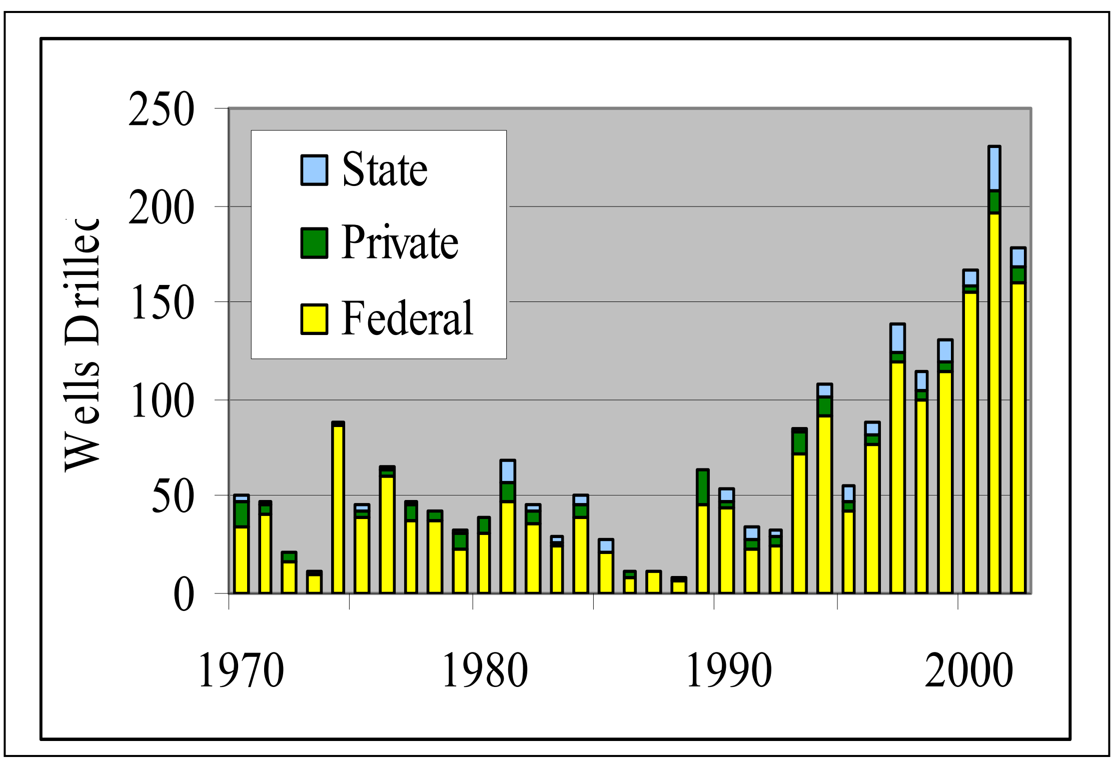

Figure 19. Exploration wells drilled in the Pinedale Field Office area (1970-2002). Note the increased success rate starting in 1996. Data for 2002 are incomplete. Data are from Wyoming Oil and Gas Conservation Commission (2003) and IHS Energy Group (2002).

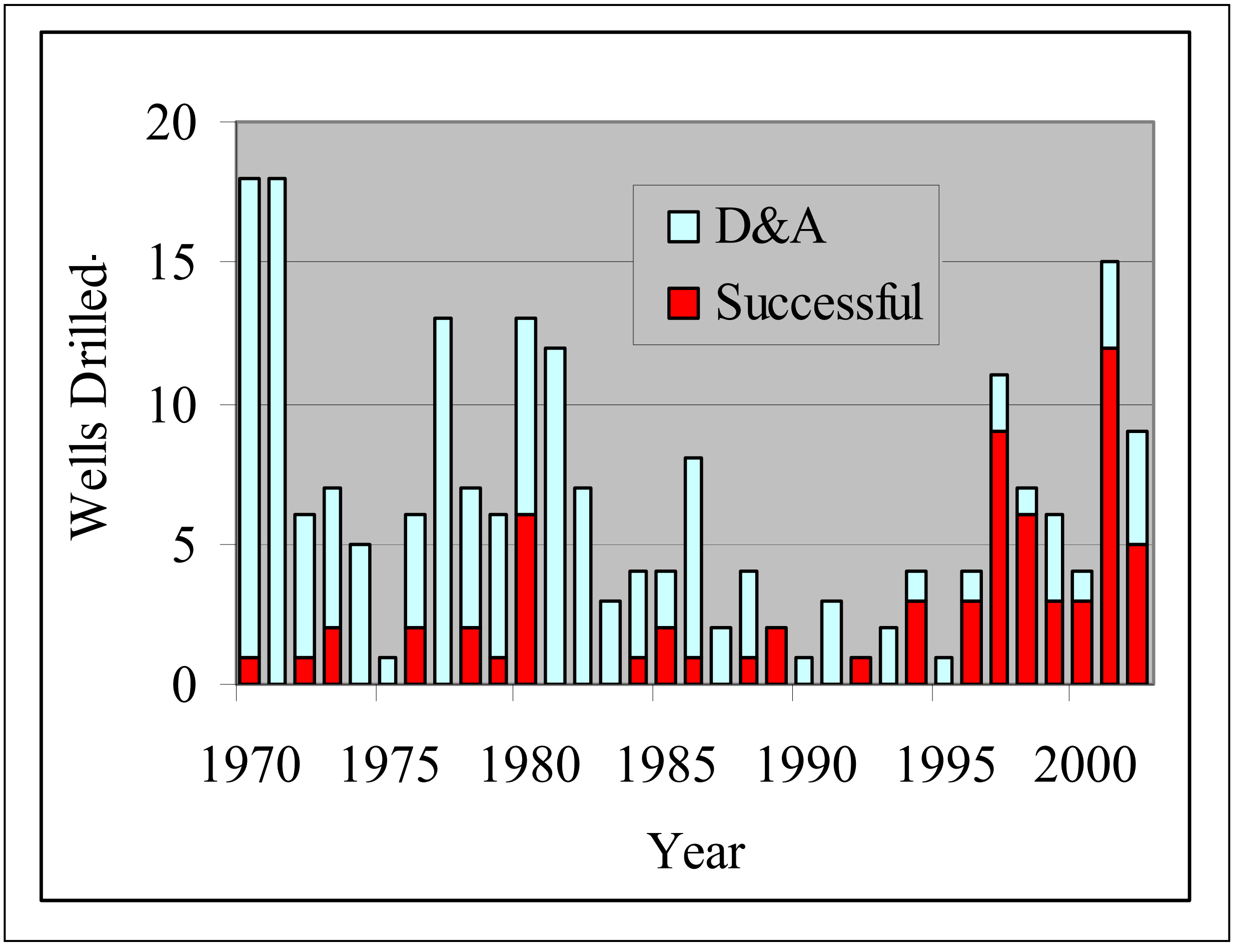

Figure 20. Development wells drilled in the Pinedale Field Office area (1970-2002). Note that both the number of development wells and success rate are much higher than for wildcat wells. Data for 2002 are incomplete. Data are from Wyoming Oil and Gas Conservation Commission (2003) and IHS Energy Group (2002).

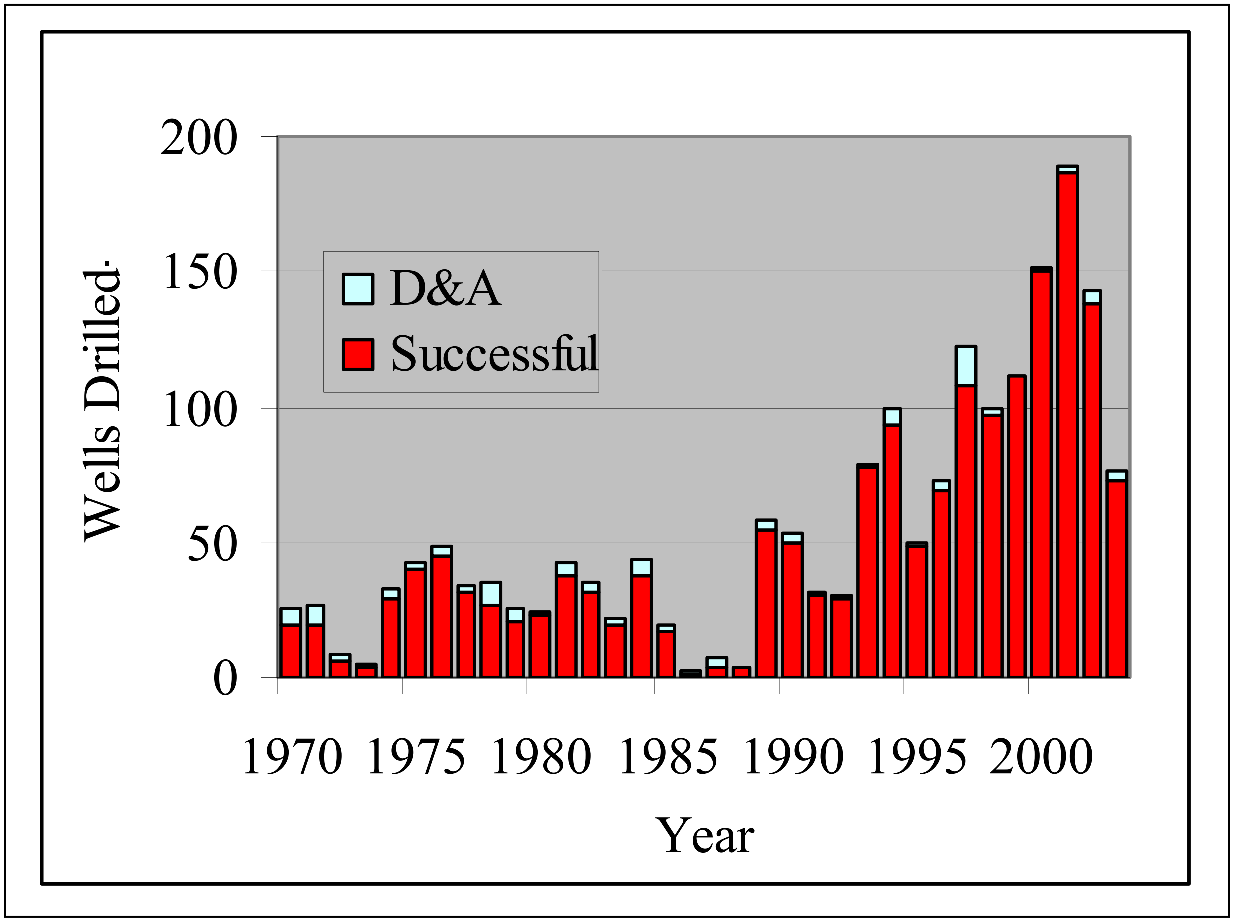

Figure 21. Depth distribution for wells drilled in the Pinedale Field Office area 1990-2001. Data are from the Wyoming Oil and Gas Conservation Commission (2003) and IHS Energy Group (2002).

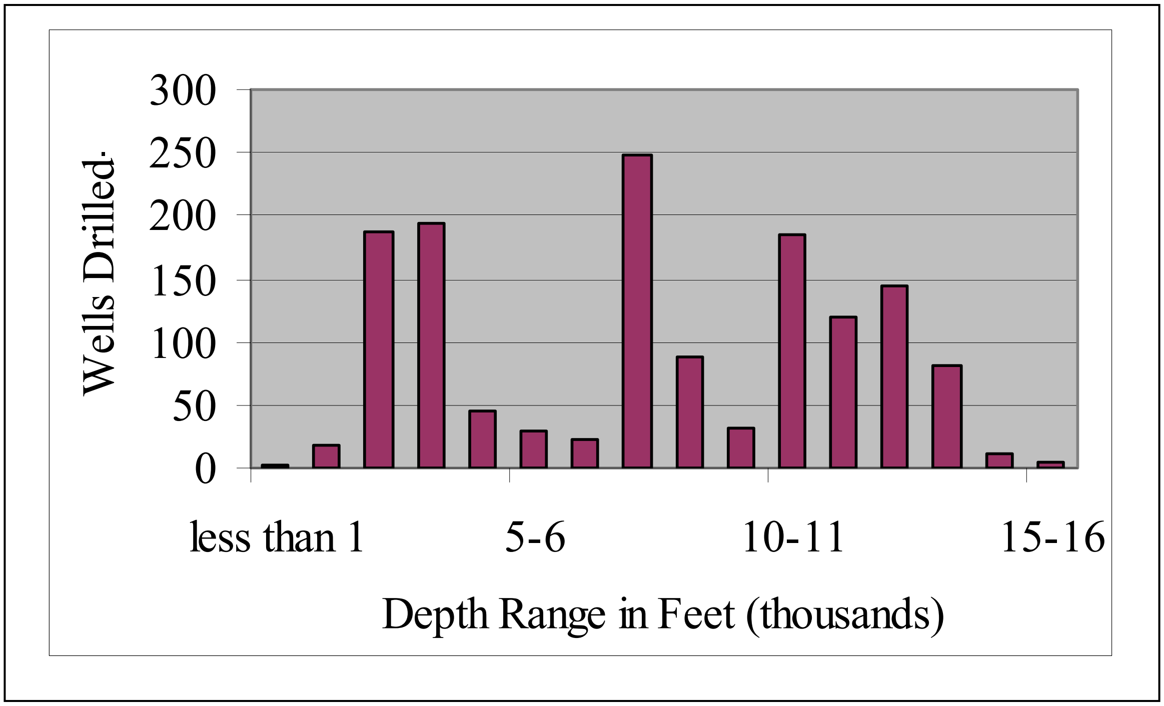

Figure 22.

Non-coalbed oil and gas development potential within Pinedale Field Office area.

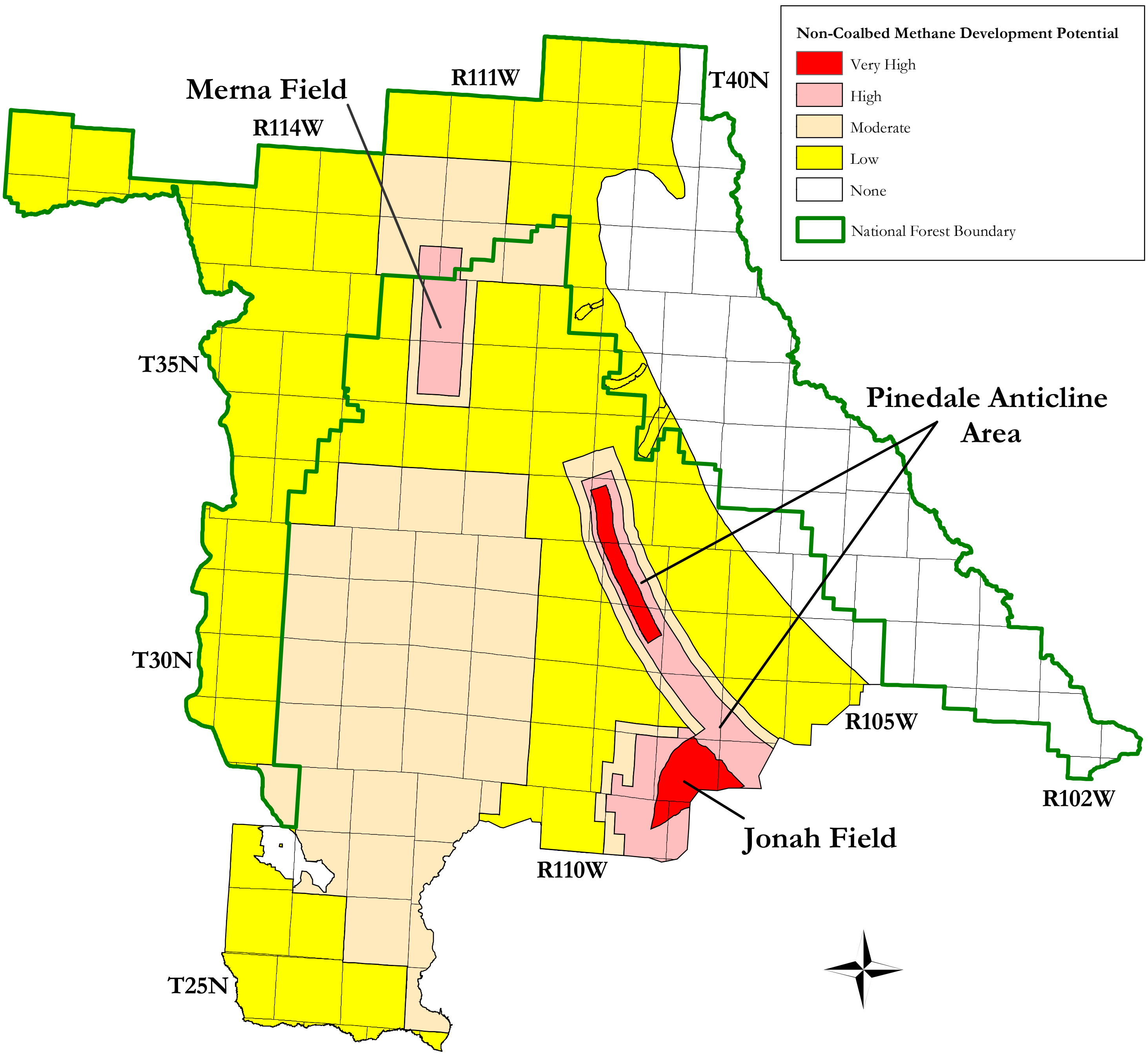

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Figure 23.

Coalbed gas development potential within Pinedale Field Office area.

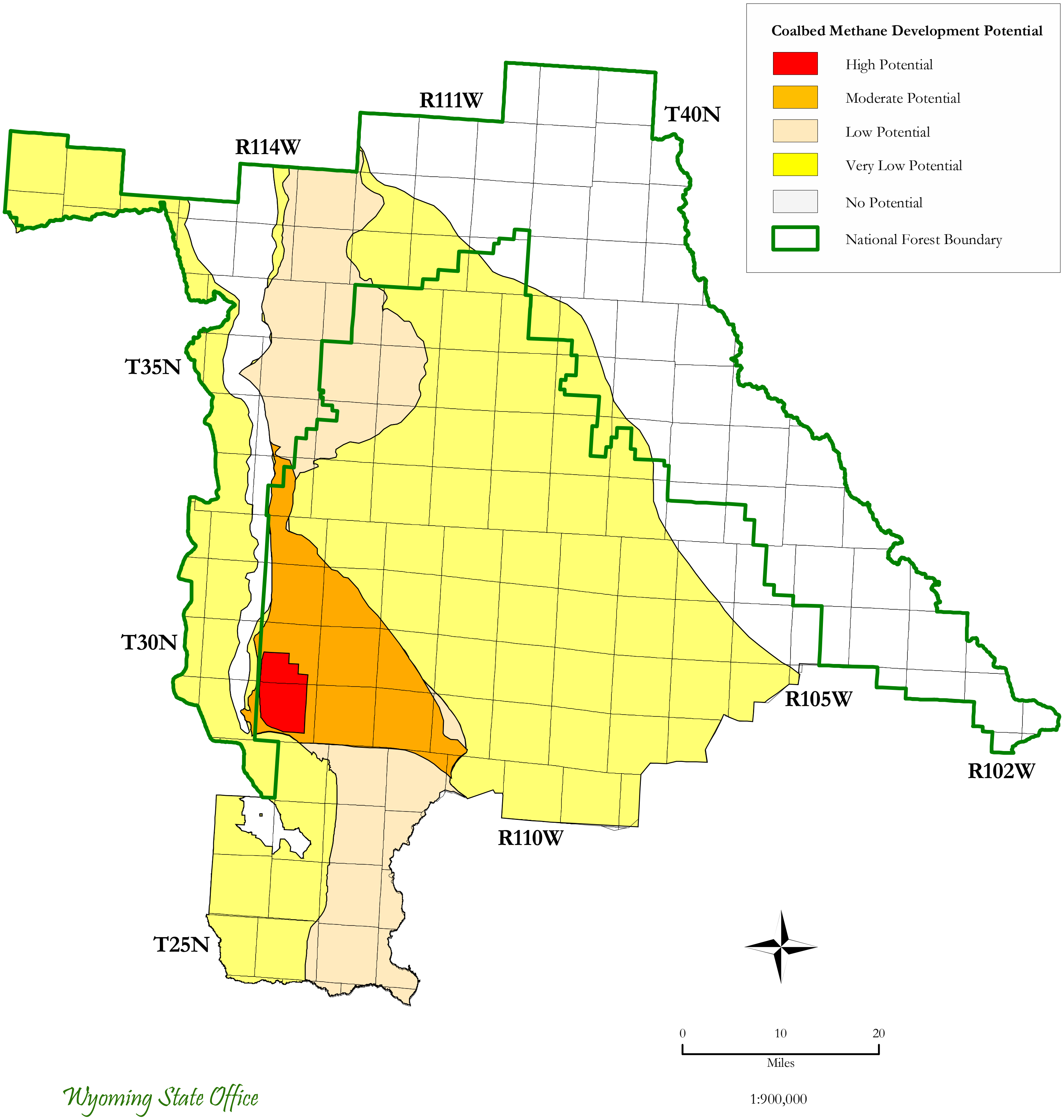

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Figure 24. Annual oil production from federal and non-federal wells in the Pinedale Field Office area. Data are from Wyoming Oil and Gas Conservation Commission (2003) and IHS Energy Group (2002).

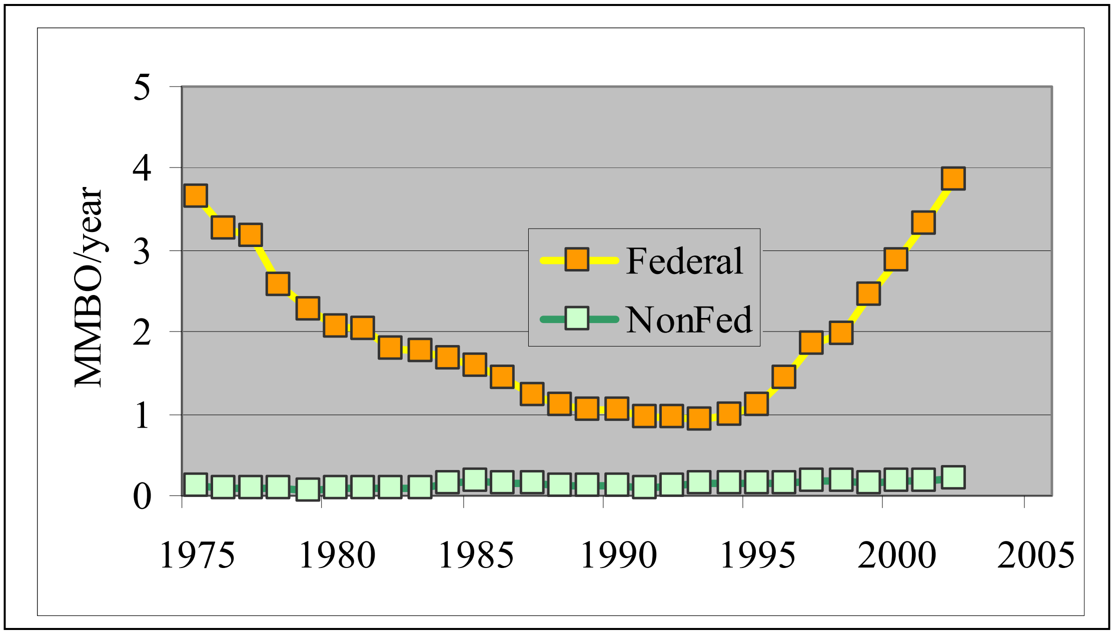


Figure 25. Annual natural gas production from federal and non-federal wells in the Pinedale Field Office area. The abrupt increase in 1986 is due to deep wells producing from the Madison Formation. Only hydrocarbon gas is shown. Data are from the Wyoming Oil and Gas Conservation Commission (2003) and IHS Energy Group (2002).

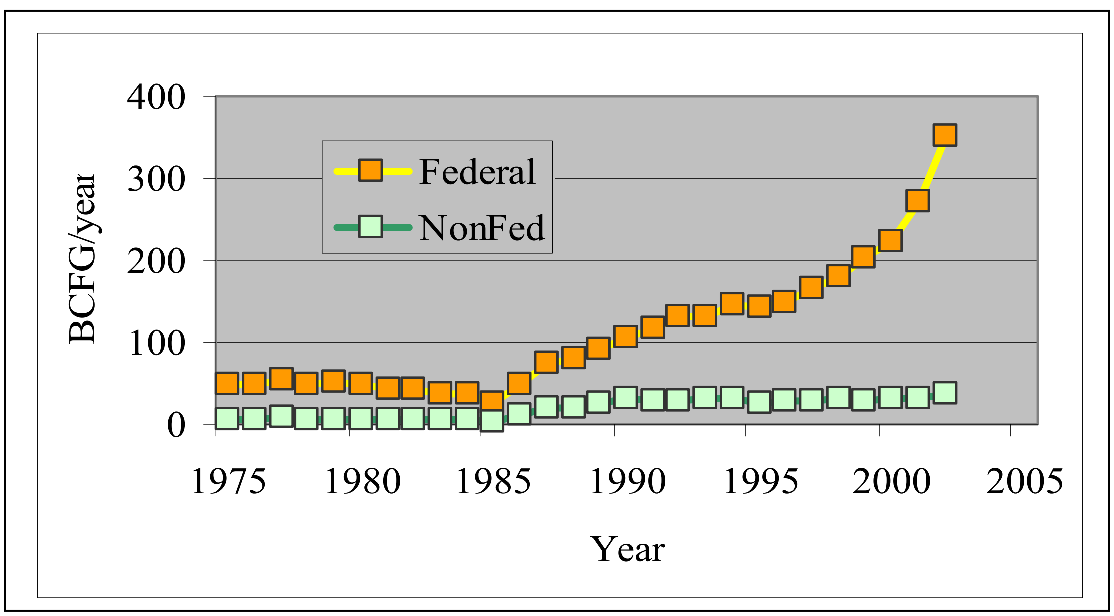


Table 1. Total number of wells within the Pinedale Field Office area, by status and ownership type (August 1, 2003). Completed well status includes those wells that are producing or temporarily shut-in. Drilling well status includes; wells actively drilling, waiting on completion activities to begin, testing for hydrocarbons, or waiting for hook-up to producing facilities and pipelines. Data was obtained from Wyoming Oil and Gas Conservation Commission (2003).

Well Status	Federal	Fee or State	Total Federal, Fee, and State
Plugged and Abandoned	1,327	263	1,590
Dormant	71	5	76
Completed	1,906	295	2,201
Notices of Abandonment	27	7	34
Drilling	112	25	137
Total Wells	**3,443**	**595**	**4,038**

Table 2
Summary of Data for all Deep Wells (>15,000 feet) Drilled in Pinedale Field Office Area

Well Name and Number	Location (Section, Township, & Range)	Operator Name	Field Name	Total Depth (feet)	Formation at Total Depth	Oldest Age Penetrated	Completion Date	Current Status	Deep Production	Initial Producing Formation	Cumulative Deep Production (BCFG)
Unit #5	5 30N 108W	El Paso Exploration	Pinedale	15,018	Mesaverde	Cretaceous	1956	P&A-Gas	No	Mesaverde	
Horse Creek 1-30X	30 33N 113W	EOG Resources Inc.		15,104	Frontier	Cretaceous	2001	D&A	No		
Fogarty Creek Unit #13-10	10 28N 114W	Exxon Mobil Oil Corp.	Fogarty Creek	15,160	Darby	Devonian	1984	Gas	Yes	Madison	290.5
Fogarty Creek Unit #2103	3 28N 114W	Exxon Mobil Oil Corp.	Fogarty Creek	15,172	Darby	Devonian	1986	Gas	Yes	Madison	238.4
Lovatt Draw State #36-55	36 32N 109W	Neilson & Assoc.	Pinedale	15,200	Lance	Cretaceous	2006	Gas	Yes	Lance	0.1
Fogarty Creek Unit #1935	35 29N 114W	Exxon Mobil Oil Corp.	Fogarty Creek	15,280	Darby	Devonian	1985	Gas	Yes	Madison	137.1
Fort Bonneville #13-24	24 34N 111W	Ultra Resources Inc.		15,350	Rock Springs	Cretaceous	1998	D&A	No		
Tip Top Unit #T22-19G	19 28N 113W	Exxon Mobil Oil Corp.	Tip Top	15,435	Cambrian	Cambrian	1962	Gas	No	Frontier	
Unit #1716	16 28N 114W	Exxon Mobil Oil Corp.	Fogarty Creek	15,451	Darby	Devonian	1985	Gas	Yes	Madison	346.8
Tip Top #27-6G	6 28N 113W	Exxon Mobil Oil Corp.	Tip Top	15,495	Madison	Mississippian	1982	TA	No		
Federal #12-43	12 29N 115W	Wold Oil Properties	Riley Ridge	15,550	Darby	Devonian	1982	TA	No	Madison	
Unit #3-15	15 29N 115W	Exxon Mobil Oil Corp.	Lake Ridge	15,552	Darby	Devonian	1986	P&A-Gas	Yes	Madison	0.0
Federal #1-7	7 36N 114W	Chevron USA Inc.		15,607	Frontier	Cretaceous	1981	D&A	No		
Tip Top Unit #T-54-2G	2 28N 114W	Exxon Mobil Oil Corp.	Tip Top	15,617	Nugget	Lower Jurassic	1987	Gas	No	Frontier	
Tip Top Unit #F14-13G	13 28N 114W	Exxon Mobil Oil Corp.	Tip Top	15,680	Bighorn	Ordovician	1979	Gas	No	Frontier	
Tip Top #T57-19G	19 29N 113W	Exxon Mobil Oil Corp.	Tip Top	15,700	Madison	Mississippian	1982	Gas	Yes	Madison	0.0
Mohr Federal #10-8	8 28N 110W	McMurry Oil Co.		15,832	Aspen	Cretaceous	1986	D&A	No		
Hogback III Unit #2-15	15 28N 115W	EOG Resources Inc.	Hoback III	15,896	Madison	Mississippian	1973	P&A-Gas	No	Bear River	
Boulder #15-4	4 31N 108W	Ultra Resources Inc.	Pinedale	15,910	Lance	Cretaceous	2004	D&A	No		
Fogarty Creek Unit #1817	17 28N 114W	Exxon Mobil Oil Corp.	Fogarty Creek	15,965	Darby	Devonian	1985	Gas	Yes	Madison	328.7
Fogarty Creek Unit #2312	12 28N 115W	Exxon Mobil Oil Corp.	Fogarty Creek	15,969	Madison	Mississippian	1994	Gas	Yes	Madison	185.4
Fogarty Creek Unit #1405	5 28N 114W	Exxon Mobil Oil Corp.	Fogarty Creek	15,982	Darby	Devonian	1985	Gas	Yes	Madison	249.1
Riley Ridge #8-24	8 29N 114W	Wold Oil Properties	Riley Ridge	16,000	Bighorn	Ordovician	1980	TA	Yes	Madison	0.0
Mesa #8-10	10 32N 109W	Anschutz Pinedale Corp.	Pinedale	16,000	Lance	Cretaceous	2003	P&A-Gas	Yes	Lance	0.0
Unit #2013	13 28N 115W	Exxon Mobil Oil Corp.	Fogarty Creek	16,155	Darby	Devonian	1986	Gas	Yes	Madison	293.8
Federal #10-14	10 29N 114W	Wold Oil Properties	Riley Ridge	16,215	Darby	Devonian	1981	TA	Yes	Madison	0.0
Unit #1528	28 28N 114W	Exxon Mobil Oil Corp.	Fogarty Creek	16,261	Darby	Devonian	1985	Gas	Yes	Madison	300.4
Unit #2201	1 28N 115W	Exxon Mobil Oil Corp.	Fogarty Creek	16,277	Darby	Devonian	1986	Gas	Yes	Madison	297.5
Lake Ridge Unit #5-32	32 29N 114W	Exxon Mobil Oil Corp.	Lake Ridge	16,316	Darby	Devonian	1986	Gas	Yes	Madison	161.8
Lake Ridge Unit #103	3 28N 115W	Exxon Mobil Oil Corp.	Lake Ridge	16,318	Madison	Mississippian	1981	P&A-Gas	Yes	Madison	0.0
Unit #6-14	14 28N 115W	Exxon Mobil Oil Corp.	Lake Ridge	16,332	Darby	Devonian	1986	Gas	Yes	Madison	268.7

Table 2
Summary of Data for all Deep Wells (>15,000 feet) Drilled in Pinedale Field Office Area

Well Name and Number	Location (Section, Township, & Range)	Operator Name	Field Name	Total Depth (feet)	Formation at Total Depth	Oldest Age Penetrated	Completion Date	Current Status	Deep Production	Initial Producing Formation	Cumulative Deep Production (BCFG)
Riley Ridge Federal #17-34	17 29N 114W	Wold Oil Properties	Riley Ridge	16,370	Bighorn	Ordovician	1984	TA	No	Madison	
Robins #36-1	36 36N 112W	Apache Corporation		16,480	Mesaverde	Cretaceous	1985	D&A	No		
North #33-24	33 30N 114W	Wold Oil Properties	Riley Ridge	16,505	Darby	Devonian	1982	Gas	Yes	Madison	0.0
Unit #811	11 28N 115W	Exxon Mobil Oil Corp.	Lake Ridge	16,523	Darby	Devonian	1986	Gas	Yes	Madison	294.7
Unit #1	21 33N 111W	Phillips Petroleum Co.		16,531	Mesaverde	Cretaceous	1956	D&A	No		
Granite Wash Unit #1	16 29N 110W	Davis Oil Co.		16,625	Cretaceous	Cretaceous	1977	D&A	No		
Unit #227	33 29N 115W	Exxon Mobil Oil Corp.	Lake Ridge	16,650	Darby	Devonian	1985	P&A-Gas	Yes	Madison	0.0
Lake Ridge Unit #710	10 28N 115W	Exxon Mobil Oil Corp.	Lake Ridge	16,740	Darby	Devonian	1986	Gas	Yes	Madison	292.1
Ferry Island #1	29 28N 109W	Home Petroleum Corp.	Cutlass	16,800	Frontier	Cretaceous	1979	D&A	No		
Unit #422	22 28N 115W	Exxon Mobil Oil Corp.	Lake Ridge	16,944	Darby	Devonian	1985	Gas	Yes	Madison	235.4
Cutlass Unit #1	29 28N 109W	Woods Petroleum Corp.	Cutlass	16,986	Mowry	Cretaceous	1981	P&A-Gas	Yes	Frontier	0.0
Unit #16-32	32 28N 114W	Exxon Mobil Oil Corp.	Fogarty Creek	17,132	Darby	Devonian	1985	Gas	Yes	Madison	107.5
Graphite #116	16 27N 114W	Exxon Mobil Oil Corp.	Graphite	17,317	Darby	Cambrian	1981	P&A-Gas	Yes	Madison	0.0
Fort A #1	18 25N 114W	Phillips Petroleum Co.		17,345	Nugget	Devonian	1963	D&A	No		
Federal #11-24	24 28N 115W	Exxon Mobil Oil Corp.	Fogarty Creek	17,368	Bighorn	Ordovician	1982	Gas	Yes	Madison	142.7
Graphite Unit #215	21 27N 114W	Exxon Mobil Oil Corp.	Graphite	17,390	Darby	Devonian	1985	Gas	Yes	Madison	7.7
Cutlass Unit #2	24 28N 110W	Woods Petroleum Corp.	Cutlass	17,700	Morrison	Upper Jurassic	1982	D&A	No		
Merna #3	28 36N 112W	EOG Resources Inc.	Merna	18,124	Cody	Cretaceous	1977	D&A	No		
Wagon Wheel #1	5 30N 108W	Burlington Resources	Pinedale	19,000	Cretaceous	Cretaceous	1971	Gas	No	Fort Union	
Stewart Point #15-29	29 33N 109W	Questar Explor. & Prod.	Pinedale	19,520	Phosphoria	Permian	2005	Gas	?	Lance	
Telephone Pass 1	25 35N 116W	Exxon Mobil Oil Corp.		20,161	Madison	Mississippian	1987	D&A	No		
Total Deep Production (Madison)											**4,178.3**

BCFG = Billion Cubic Feet of Gas
P&A-Gas = Gas well now plugged and abandoned
D&A = Drilled and Abandoned well
TA = Temporarily Abandoned well

Data from IHS Energy (2006) and Wyoming Oil and Gas Conservation Commission (2006a).
Production data current to August 7, 2006.

Wyoming State Office
Reservoir Management Group

Table 3. Status of directional wells drilled in the Pinedale Field Office area. Well status as of August 8, 2006. Data was obtained from IHS Energy (2006) and Wyoming Oil and Gas Conservation Commission (2006a).

Well Status	Greater Big Piney-La Barge Area Wells	Jonah Field Wells	Pinedale Anticline Area Wells	Other Wells	Total Wells
Gas Wells	228	260	288	9	785
Oil Wells	21	0	0	5	26
Water Injection Wells	3	0	0	0	3
Monitoring Wells	0	0	3	0	3
Abandoned Wells	10	1	5	2	18
Junked and Abandoned Wells	1	1	2	0	4
Total Wells Drilled	**263**	**262**	**298**	**16**	**839**
Spud Wells	9	51	145	0	205
Application to Drill	37	24	107	5	173

Table 4. Distribution of federal oil and gas leased acres in the Pinedale Field Office area. Held-by-production lease acres include all leases containing at least one producing well. Data were compiled from Bureau files as of June 1, 2006.

Surface Management	Held-by-Production Only Leased Acres	Total Leased Acres
BLM & Non-Federal	423,046	739,620
U.S. Forest Service	40,946	111,435
Bureau of Reclamation	72	72
Total acres	464,064	851,127

Table 5. Summary of wells drilled in the Pinedale Field Office area from 1970-2001. Data are from IHS Energy Group (2002) and Wyoming Oil and Gas Conservation Commission (2003).

Well Class	Dry	Successful	Total	Success Rate
New Field Wildcat Wells	143	60	203	30%
Other Wildcat Wells	28	70	98	71%
Development Wells	115	1933	2048	94%
Service Wells	9	98	107	92%

Table 6. Estimated non-coalbed oil and gas development potential classifications for the Pinedale Field Office area (2001-2020).

Development Potential	Acres (thousands)	Area (townships)	% of Pinedale Field Office
Very High	36	1.6	1.23
High	124	5.4	4.17
Moderate	767	33.3	25.85
Low	1,419	61.6	47.84
None	620	26.9	20.90
Totals	**2,966**	**128.8**	**99.99**

Table 7. Estimated coalbed gas development potential classifications for the Pinedale Field Office area (2001-2020).

Development Potential	Acres (thousands)	Area (townships)	% of Pinedale Field Office
High	21	0.9	0.72
Moderate	173	7.5	5.82
Low	368	16.0	12.39
Very Low	1,412	61.3	47.59
None	994	43.1	33.48
Total	2,968	128.8	100.00

Table 8. Summary of the cumulative production of oil and gas from 1974-2002, and estimated production based on hypothetical no-new-drilling and continued drilling scenarios for the period 2003-2021 (non-hydrocarbon gases are excluded from estimates). The difference between no drilling and continued drilling estimates is about 16 trillion cubic feet of natural gas and 113 million barrels of oil.

Producing Periods	Oil (million barrels)	Gas (Trillion Cubic Feet)
Cumulative 1974-2002	60	4.010
No New Drilling 2003-2020	31	1.504
Continued drilling 2003-2021	144	17.402

Table 9. Estimated well location densities and area in each non-coalbed oil and gas development potential category within the Pinedale Field Office area.

Development Potential	Acres (thousand)	Townships	Well Locations/Township
Very High	36	1.6	2,515
High	124	5.4	330
Moderate	766	33.3	65
Low	1,418	61.6	11
None	620	26.9	0

Table 10. Estimated well location densities and area in each coalbed gas development potential category within the Pinedale Field Office Area.

Development Potential	Acres (thousand)	Townships	Well Locations/Township
High	21	0.9	110
Moderate	173	7.5	60
Low	368	16.0	2
Very Low	1,426	61.9	0.4
None	978	42.4	0

Table 11. Alternative 1(No Action) summary of the number of acres in each restriction category for each development potential type within the Pinedale Field Office area.

Development Potential	Category D Federal Acres	Category C Federal Acres	Category B Federal Acres
Non-Coalbed Oil and Gas			
High	0	1,490	5,750
Moderate	5,130	5,020	21,990
Low	17,650	25,790	61,150
Very Low	86,010	18,250	145,430
Coalbed Gas			
High	0	14,300	1,170
Moderate	0	36,990	8,010
Low	4,860	18,250	23,920
Very Low	88,190	261,940	147,530

Table 12. Analysis results showing the calculated reduction in federal non-coalbed oil and gas wells and federal coalbed gas wells for Alternative 1 (No Action) due to Category C restrictions. This calculation indicates there would be a reduction of 119 non-coalbed oil and gas well locations and 71 coalbed 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					
High	2,515	1,490	0.06	30%	48.79
Moderate	330	5,020	0.22	40%	28.76
Low	65	25,790	1.12	50%	36.38
Very Low	11	18,250	0.79	55%	4.79
Coalbed Gas					
High	110	14,300	0.62	35%	23.90
Moderate	60	36,990	1.61	45%	43.35
Low	2	18,250	0.79	55%	0.87
Very Low	0.4	261,940	11.37	60%	2.73

Table 13. Total wells projected to be drilled within the Pinedale Field Office area for the base line and each alternative for the period 2001-2020. The projections of the percent of federal wells drilled for this period is also presented.

Alternative	Coalbed Gas Wells	Non-coalbed Oil and Gas Wells	Total Wells	Percent Federal
Base Line	600	8,550	**9,150**	86.38
Alternative 1 (No Action)	512	7,927	**8,439**	85.22
Alternative 2	586	8,465	**9,051**	86.22
Alternative 3	382	6,074	**6,456**	80.68
Alternative 4	547	7,836	**8,383**	85.12
Alternative				

Table 14. Historical (2001 through 2005) and future oil production (in millions of barrels) for the Pinedale Field Office area, estimated for the base line and each alternative.

Year	Base Line	Alternative 1 (No Action)	Alternative 2	Alternative 3	Alternative 4
2001	3.945	3.945	3.945	3.945	3.945
2002	4.468	4.468	4.468	4.468	4.468
2003	4.632	4.632	4.632	4.632	4.632
2004	4.737	4.737	4.737	4.737	4.737
2005	5.166	5.166	5.166	5.166	5.166
2006	6.901	6.741	6.901	6.325	6.723
2007	7.759	7.508	7.758	6.853	7.480
2008	8.423	8.085	8.422	7.238	8.079
2009	8.854	8.454	8.852	7.465	8.461
2010	9.171	8.722	9.169	7.617	8.737
2011	9.589	9.100	9.587	7.743	9.119
2012	9.942	9.409	9.937	7.864	9.432
2013	10.078	9.520	10.071	7.978	9.543
2014	10.372	9.774	10.361	8.196	9.798
2015	10.149	9.515	10.135	7.880	9.547
2016	9.267	8.603	9.252	7.044	8.634
2017	8.814	8.116	8.798	6.589	8.176
2018	8.555	7.833	8.540	6.302	7.902
2019	8.565	7.822	8.551	6.123	7.889
2020	8.195	7.435	8.044	5.606	7.384
Total	**157.582**	**149.586**	**157.324**	**129.772**	**149.853**

Table 15. Historical (2001 through 2005) and future gas production (in billions of cubic feet) for the Pinedale Field Office area, estimated for the base line and each alternative.

Year	Base Line	Alternative 1 (No Action)	Alternative 2	Alternative 3	Alternative 4
2001	496	496	496	496	496
2002	573	573	573	573	573
2003	659	659	659	659	659
2004	734	734	734	734	734
2005	818	818	818	818	818
2006	863	844	863	794	842
2007	964	934	964	856	932
2008	1046	1005	1046	903	1005
2009	1099	1050	1098	931	1052
2010	1137	1082	1137	950	1086
2011	1187	1127	1186	965	1131
2012	1229	1163	1228	980	1169
2013	1245	1177	1244	993	1182
2014	1280	1207	1279	1019	1213
2015	1258	1180	1256	985	1187
2016	1162	1080	1160	893	1087
2017	1113	1028	1112	843	1038
2018	1087	998	1085	813	1009
2019	1091	999	1089	794	1010
2020	1044	950	1024	729	946
Total	**20,084**	**19,104**	**20,052**	**16,730**	**19,168**

Table 16. Projected total number of well pads by alternative for federal surface and federal minerals (2001 to 2020) in the Pinedale Field Office area.

Alternative	Total Single Well Locations (coalbed gas)	Total Single Well Locations (non-coalbed oil and gas)	Total Multiple Well Locations (non-coalbed oil and gas)	**Total Well Pads**
Unrestricted Development	518	4,800	369 pads (2,585 wells)	**5,687 pads (7,903 wells)**
Alternative 1 (No Action)	430	4,732	290 pads (2030 wells)	**5,452 pads (7,192 wells)**
Alternative 2	504	5,110	310 pads (2190 wells)	**5,924 pads (7,804wells)**
Alternative 3	300	3,436	210 pads (1473 wells)	**3,946 pads (5,209 wells)**
Alternative 4	465	4,671	285 pads (2000 wells)	**5,421 pads (7,136 wells)**

Table 17. Initial surface disturbance from oil and gas activity on federal surface and federal minerals in the Pinedale Field Office area.

Alternative	Roads (acres)	Coalbed Gas Drill Pads (acres)	Non-coalbed Oil and Gas Single Well Pads (acres)	Multiple Well Pads (acres)	Well-Pad Related Pipelines (acres)	Collector/ Transportation Pipeline Trunk Lines (acres)	Total Surface Disturbance for Life of Plan (acres)
Alternative 1	10,360	1,191	17,508	2,900	8,613	2,450	**43,022**
Alternative 2	11,256	1,865	18,907	3,100	9,351	2,260	**46,739**
Alternative 3	7,497	1,110	12,713	2,100	6,084	1,635	**31,139**
Alternative 4	10,300	1,720	17,283	2,850	8,327	1,700	**42,180**

Table 18. Long-term surface disturbance from oil and gas activity in the Pinedale Field Office area.

Alternative	Roads (acres)	Coalbed Gas Drill Pads (acres)	Non-coalbed Oil and Gas Single Well Pads (acres)	Multiple Well Pads (acres)	Well-Pad Related Pipelines (acres)	Collector/ Transportation Pipeline Trunk Lines (acres)	Total Surface Disturbance for Life of Plan (acres)
Alternative 1	6,897	750	7,725	2,000	0	0	**17,372**
Alternative 2	7,434	900	8,250	2,105	0	0	**18,689**
Alternative 3	5,300	600	5,925	1,500	0	0	**13,325**
Alternative 4	6,890	825	7,650	1,965	0	0	**17,330**

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

INTRODUCTION

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

Recently the U.S. Geological Survey revised their methods of preparing oil and gas resource assessments. They used their new method to update their quantitative estimate of the undiscovered oil and gas resource for the Southwestern Wyoming and Wyoming Thrust belt provinces (U.S. Geological Survey; 2002, 2004, 2005, 2006a, and 2006b). In the following analysis, we will use the two newest assessments to describe the potential undiscovered technically recoverable oil and gas resources lying within the Field Office area. Figure A1-1 shows the location of each of these two provinces. The northeast side of the Field Office area is not presently located within a province. This area lies within a region of Wind River Range Precambrian igneous and metamorphic rocks, where traps and hydrocarbons are not known to occur. We have assigned this area a low oil and gas occurrence potential (Figure 11) and no development potential for coalbed gas or non-coalbed oil and gas hydrocarbons (Figures 22 and 23) for the 2001 to 2020 period

WYOMING THRUST BELT PROVINCE ASSESSMENT

The Wyoming Thrust Belt Province is an arcuate north-south-trending structural feature occupying the western-most part of the Field Office area and parts of Wyoming, Utah, and Idaho (Figure A1-1). Sediments have been strongly folded and thrust eastward into their present location. Four major thrust systems make up the province. Three of those thrust systems; the Absaroka, Prospect-Darby, and Hogsback thrusts lie at least partly within the Field Office area. These thrust faults are low-angle and moderately-to-highly overlapping. Productive traps have been found in complexly faulted folds and in anticlinal traps on the Moxa Arch where it lies beneath thrust-faulted sediments of the Hogsback thrust fault. Seismic exploration, drilling, and new field discoveries have been most heavily concentrated in the southern-most part of the province. In the northern part of the province occupied by the Field Office area, only minimal exploration and drilling activity has occurred.

Assessment Unit Summaries

In their newest assessment, the U.S. Geological Survey (2004 and 2006b) divided the Wyoming Thrust Belt province into "total petroleum systems" (see Glossary for *total petroleum system*) and "assessment units" (see Glossary definitions) rather than "plays" as they had done in previous assessments. "The total petroleum system approach is designed to focus the geologic studies on the hydrocarbon source rocks, processes that create hydrocarbons, migration pathways, reservoirs, and trapping mechanisms" (Cantey et al., 2003). Two total petroleum systems have been identified in the Wyoming Thrust Belt province (Mowry Composite and Frontier-Adaville-Evanston Coalbed Gas total petroleum systems). Each assessment unit falls within one of two types of potential undiscovered accumulation: conventional and continuous accumulations (see Glossary definition for *continuous accumulation*). One conventional accumulation (see Glossary definition for *conventional accumulation*), the Thrust Belt Conventional assessment unit, lies within the Mowry Composite total petroleum system. The older fields within the Field Office area can be classified as conventional accumulations of hydrocarbons.

Continuous accumulations can include tight reservoirs, shale reservoirs, unconventional reservoirs, basin-centered reservoirs, fractured reservoirs, coalbeds, oil shales, and shallow biogenic gas. One continuous accumulation (Frontier-Adaville-Evanston Coalbed Gas assessment unit) lies within the Frontier-Adaville-Evanston Coalbed Gas total petroleum system.

Both of the identified assessment units lie partly within the Field Office boundary (Figures A1-2 and A1-3). The U.S. Geological Survey has made available some statistical information for the Thrust Belt Conventional assessment unit (Table A1-1). The Frontier-Adaville-Evanston Coalbed Gas assessment unit is only hypothetical and only limited data is available. Supporting geologic studies for this assessment await formal publication.

Assessment Unit Resource Results

The U.S. Geological Survey (2004 and 2006b) estimated undiscovered technically recoverable resource quantities of oil and gas that could be added to the proved reserves within each assessment unit, using a forecast span of 30 years. A 30-year forecast span affects the minimum undiscovered accumulation size, the number of years in the future that reserve growth is estimated, economic assessments, the accumulations chosen for consideration, and the assessment of risk. Below, we summarize the estimated volumes of hydrocarbons in the Thrust Belt Conventional assessment unit and the Frontier-Adaville-Evanston Coalbed Gas assessment unit, which both lie at least partly within the Field Office area.

In Table A1-2, the U.S. Geological Survey resource estimates for three types of hydrocarbons (oil, gas, and natural gas liquids) are shown for the conventional assessment unit and the continuous assessment unit in the Wyoming Thrust Belt province, together with our projection of the amount of those hydrocarbons that could be present within the Field Office area. To determine the potential resource within the Field Office 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 Field Office area
- multiplied that percentage by the U.S. Geological Survey resource value estimates for each entire assessment unit to calculate Field Office area resource values.

Our estimates of recoverable resources for each assessment unit within the province and within the Field Office 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 Field Office area contains a **mean undiscovered volume of 1.99 million barrels of oil, 83.92 billion cubic feet of gas, and 2.94 million barrels of natural gas liquids, in the Wyoming Thrust Belt province assessment units.**

In addition, we estimate that the Field Office area's oil resource in the Wyoming Thrust Belt province could **range from 0.47 to 4.32 million barrels, the gas resource could range from 29.67 to 167.76 billion cubic feet, and the natural gas liquids resource could range from 0.66 to 6.49 million barrels**.

SOUTHWESTERN WYOMING PROVINCE ASSESSMENT

The Southwestern Wyoming Province occupies most of the Field Office area. Its full extent includes the Green River, Hoback, Great Divide, Washakie, Hanna, Carbon, Sand Wash, and Laramie basins. It also includes uplifts such as the Moxa, Sandy Bend, and Wamsutter arches as well as the Rock Springs uplift and Cherokee Ridge. The province covers about 40,500 square miles in parts of Wyoming, Colorado, and Utah. In the Field Office portion of the province the total sedimentary rock thickness is about 32,000 feet (Law, 1995). Oil and associated gas production in the Field Office portion of the province has been concentrated in the Greater Big Piney-LaBarge area. Drilling and production activity has only recently (since 1996) begun to concentrate in the Jonah field and Pinedale Anticline area.

<u>Assessment Unit Summaries</u>

In their newest assessment, the U.S. Geological Survey (2002, 2005, and 2006a) divided the Southwestern Wyoming Province into "total petroleum systems" and "assessment units" (see Glossary definitions) rather than "plays." "The total petroleum system approach is designed to focus the geologic studies on the hydrocarbon source rocks, processes that create hydrocarbons, migration pathways, reservoirs, and trapping mechanisms" (Cantey et al., 2003). Each assessment unit falls within one of two types of potential undiscovered accumulation: conventional and continuous accumulations (see Glossary definitions). Most of the older fields within the Field Office area can be classified as conventional accumulations of hydrocarbons. Continuous accumulations can include tight reservoirs, shale reservoirs, unconventional reservoirs, basin-centered reservoirs, fractured reservoirs, coalbeds, oil shales, and shallow biogenic gas. Most of the more recent discoveries of hydrocarbons in the Field Office area have been considered to be part of continuous accumulations.

The U.S. Geological Survey recognized seven conventional assessment units in the Southwestern Wyoming Province. Four of the seven identified assessment units lie partly within the Field Office boundary (Figures A1-4, A1-5, A1-6, and A1-7). The U.S. Geological Survey has made available some statistical information for these assessment units (Table A1-3), but the supporting geologic studies await formal publication.

The U.S. Geological Survey also recognized 16 continuous assessment units in the Southwestern Wyoming Province. Six of the 16 identified continuous assessment units, including two coalbed gas units, lie partly within the Field Office boundary (Figures A1-8, A1-9, A1-10, A1-11, A1-12, and A1-13). Again, the U.S. Geological Survey has made available some statistical information for these assessment units (Table A1-4), but the supporting geologic studies await formal publication. The Wasatch-Green River continuous gas assessment unit was not quantitatively assessed.

<u>Assessment Unit Resource Results</u>

The U.S. Geological Survey (2002, 2005, and 2006a) estimated undiscovered technically recoverable resource quantities of oil and gas that could be added to the proved reserves within each assessment unit, using a forecast span of 30 years. A 30-year forecast span affects the minimum undiscovered accumulation size, the number of years in the future that reserve growth is estimated, economic assessments, the accumulations chosen for consideration, and the assessment of risk. Below, we summarize the estimated volumes of hydrocarbons in the four conventional and six continuous assessment units lying partly within the Field Office area. The U.S. Geological Survey did not quantitatively assess the Wasatch-Green River continuous assessment unit, because it lacks sufficient supporting data to calculate resource estimates. If reserves are discovered within this assessment unit, resulting resource estimates would be greater than those presented below.

In Table A1-5, the U.S. Geological Survey resource estimates for three types of hydrocarbons (oil, gas, and natural gas liquids) are shown for the conventional and continuous assessment units in the Southwestern Wyoming Province, together with our projection of the amount of those hydrocarbons that could be present within the Field Office area. To determine the potential resource within the Field Office area we:

- assumed a homogenous distribution of each hydrocarbon type within each assessment unit area

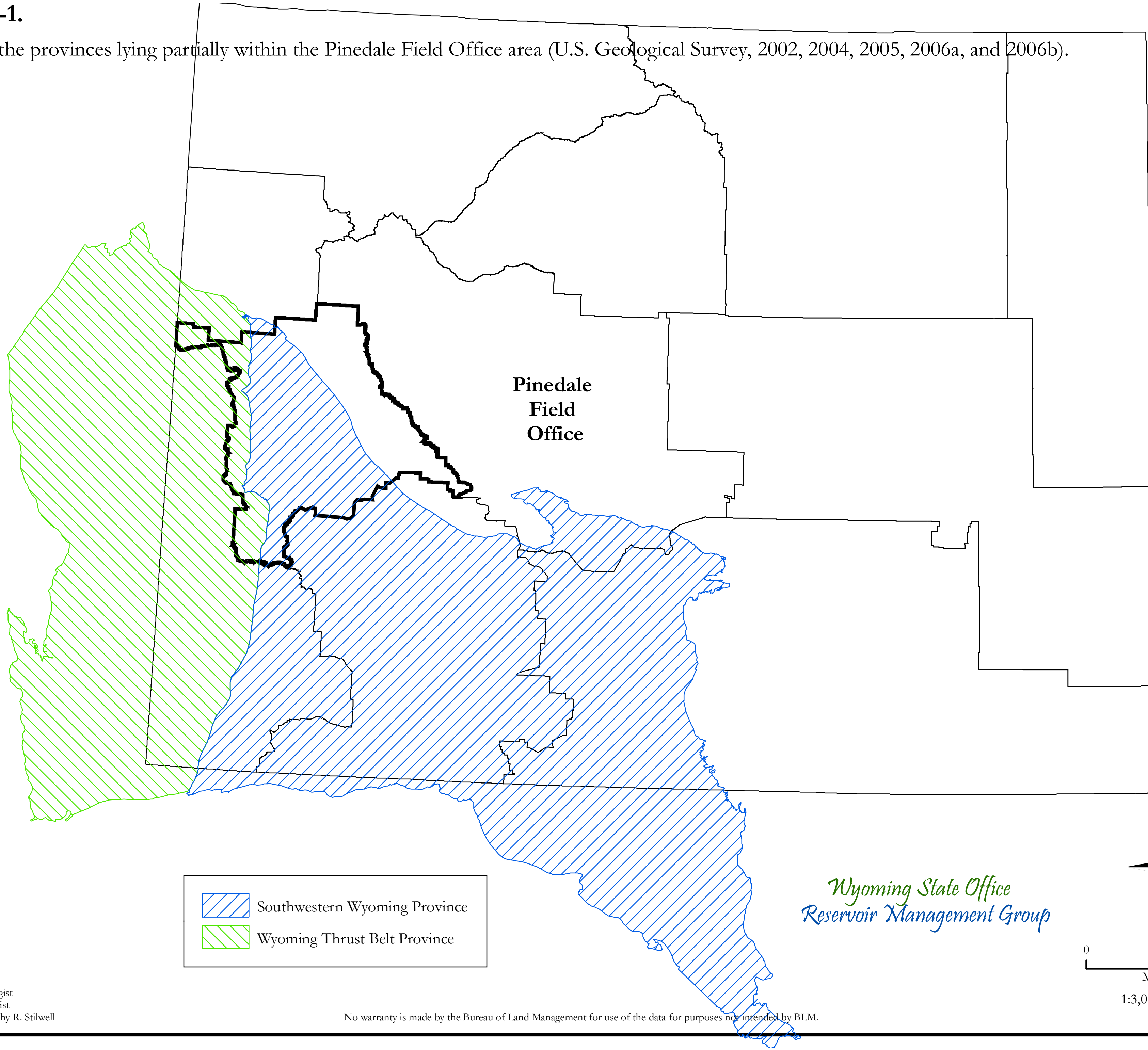
- calculated the percent of each assessment unit that lies within the Field Office area
- multiplied that percentage by the U.S. Geological Survey estimates for the entire assessment unit area to calculate Field Office area assessment unit resource values.

Our estimates of recoverable resources for each assessment unit within the province and within the Field Office 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 five percent probability of that amount or more occurring, and a mean case representing an arithmetic average of all possible outcomes. We estimate that the Field Office area contains a **mean undiscovered volume of 3.43 million barrels of oil, 8.002 trillion cubic feet of gas, and 349.65 million barrels of natural gas liquids, in the Southwestern Wyoming Province assessment units.**

In addition, we estimate (Table A1-5) that the Field Office area's oil resource in the Southwestern Wyoming province could **range from 0.91 to 8.13 million barrels, the gas resource could range from 4.718 to 12.623 trillion cubic feet, and the natural gas liquids resource could range from 172.42 to 616.24 million barrels**.

Figure A1-1.

Location of the provinces lying partially within the Pinedale Field Office area (U.S. Geological Survey, 2002, 2004, 2005, 2006a, and 2006b).



August, 2006

Fred Crockett, Geologist
Dean Stilwell, Geologist
Map generated by Cathy R. Stilwell

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Figure A1-2.

Location of Wyoming Thrust Belt Province, Thrust Belt Conventionial oil and gas assessment unit, with respect to Pinedale Field Office boundary.
Play boundary from U.S. Geological Survey (2006b).

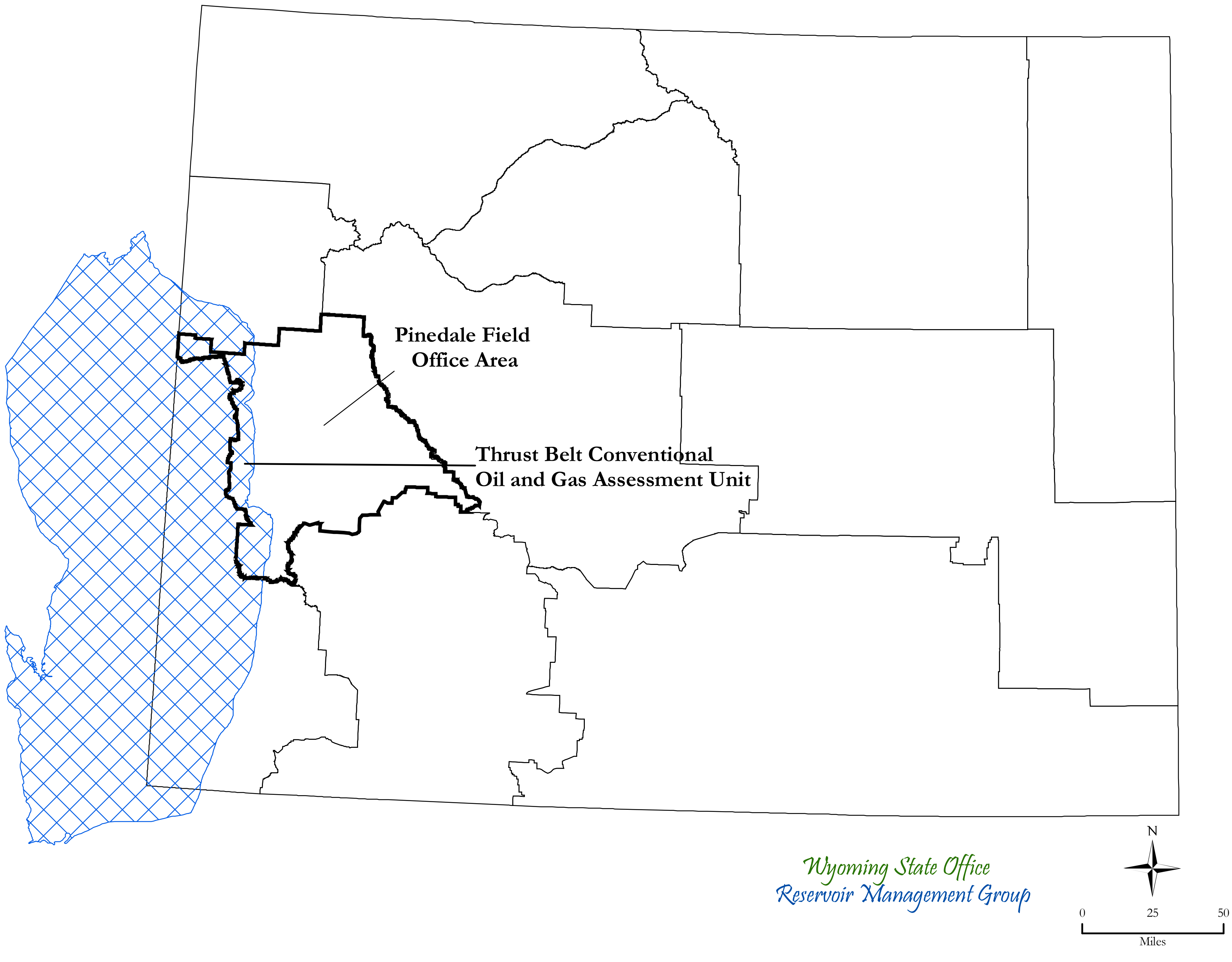

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Figure A1-3.

Location of Wyoming Thrust Belt Province, Frontier-Adaville-Evanston coalbed assessment unit, with respect to Pinedale Field Office boundary. Play boundaries from U.S. Geological Survey (2006b).

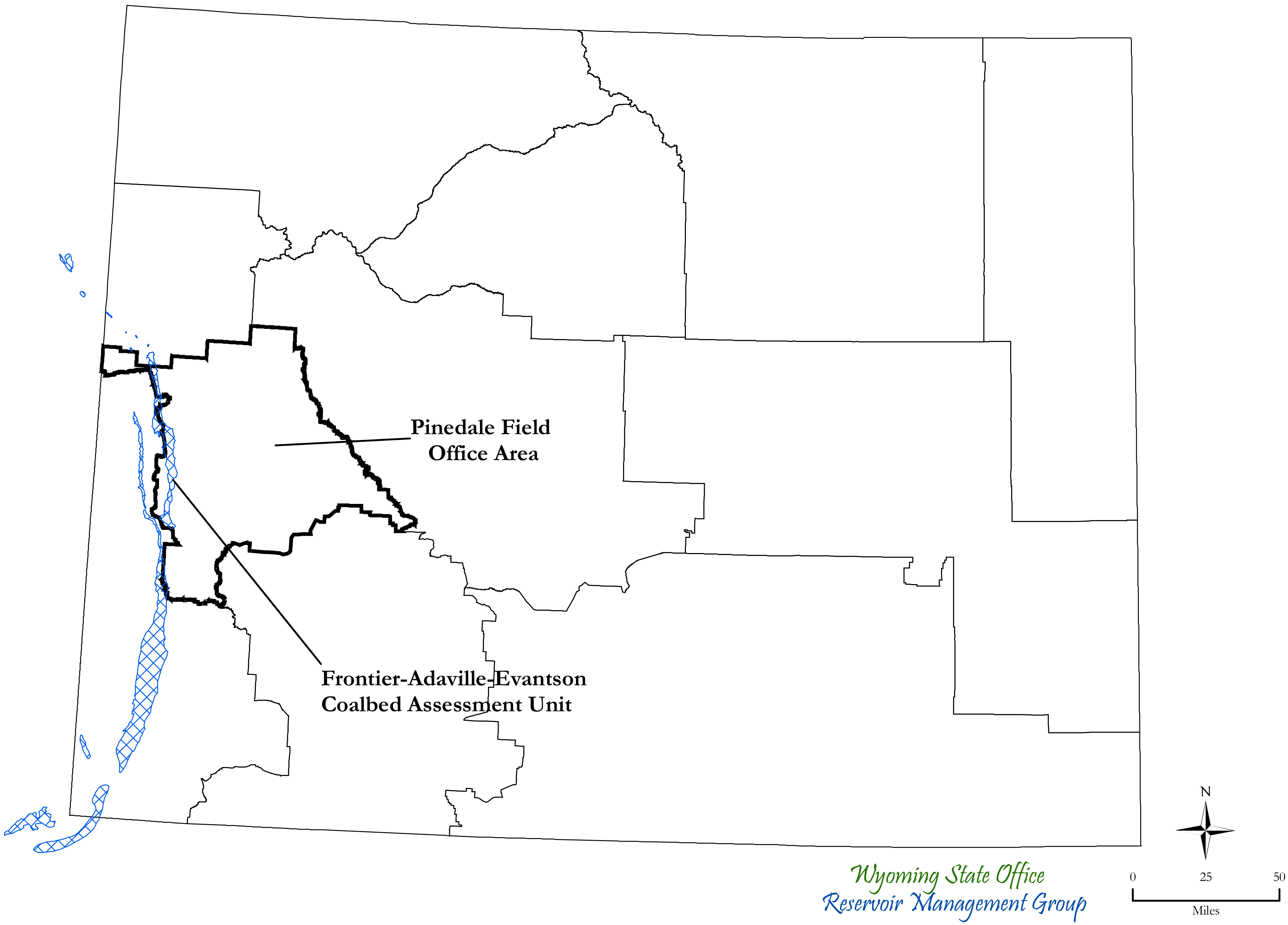

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Figure A1-4.

Location of Southwestern Wyoming Province, Sub-Cretaceous conventional oil and gas assessment unit, with respect to Pinedale Field Office boundary. Assessment unit boundary from Schenk (2003).

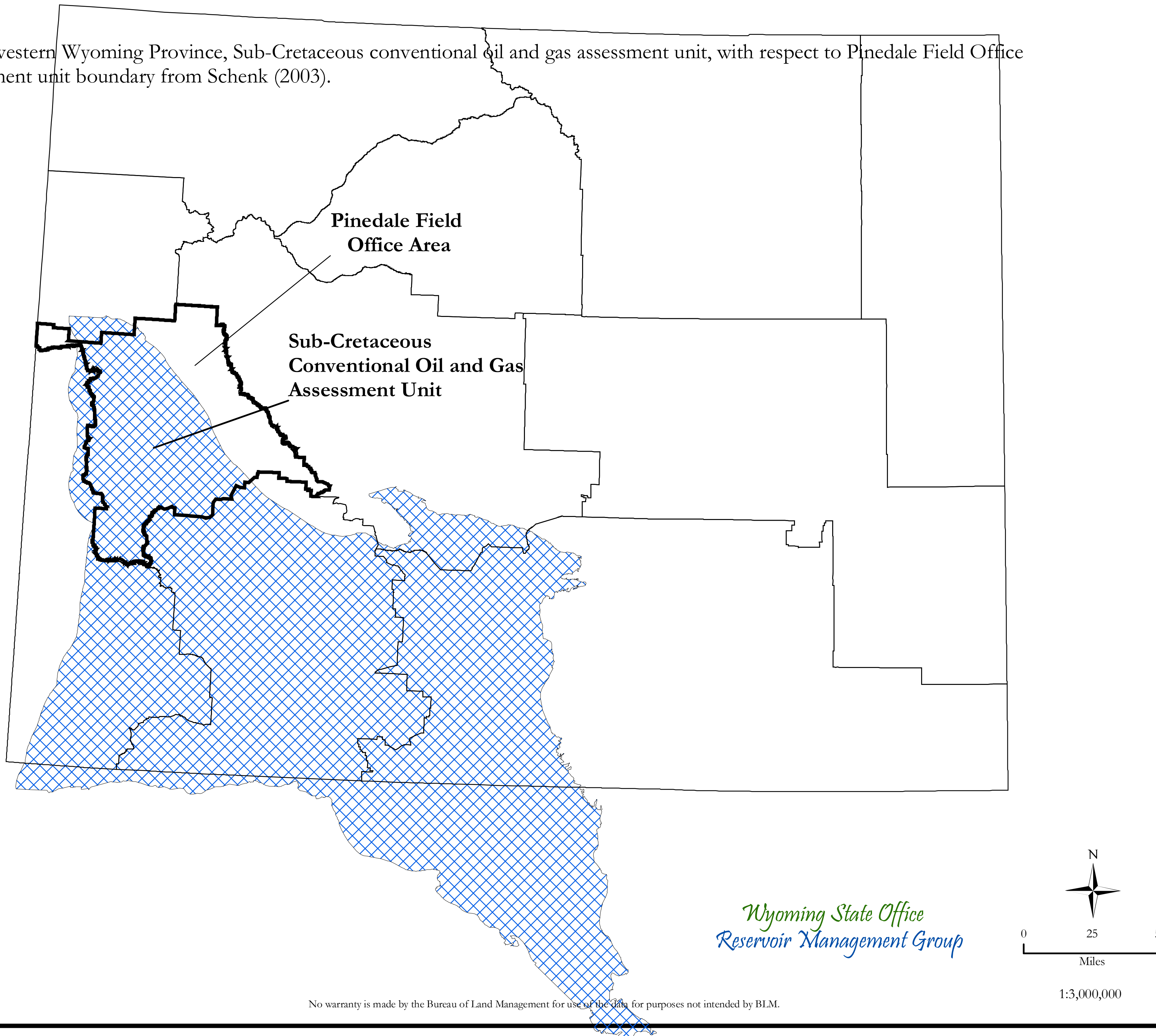

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Figure A1-5.

Location of Southwestern Wyoming Province, Mowry conventional oil and gas assessment unit, with respect to Pinedale Field Office boundary. Assessment unit boundary from Schenk (2003).

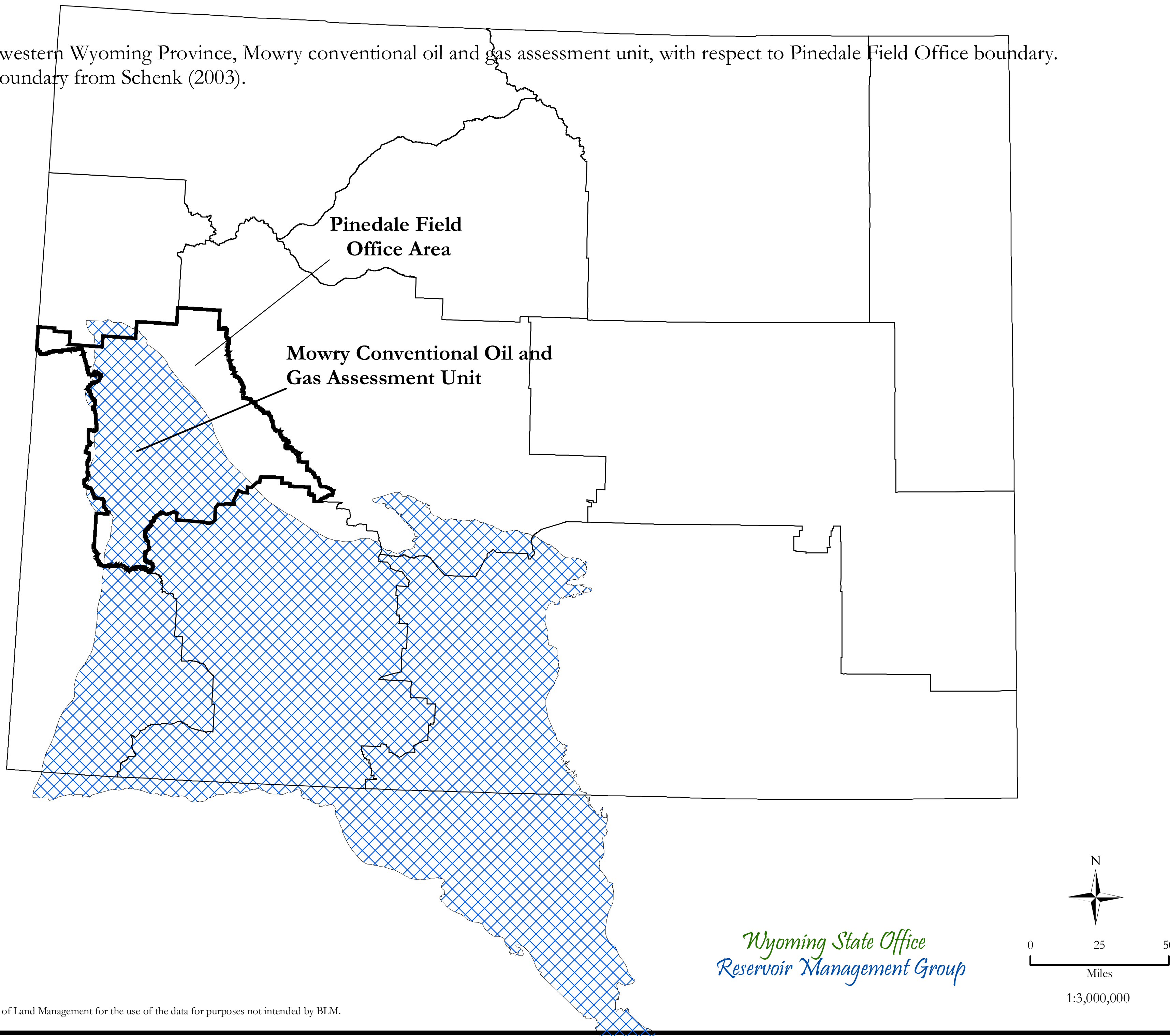

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Figure A1-6.

Location of Southwestern Wyoming Province, Hilliard-Baxter-Mancos conventional oil and gas assessment unit, with respect to Pinedale Field Office boundary. Assessment unit boundary from Schenk (2003).

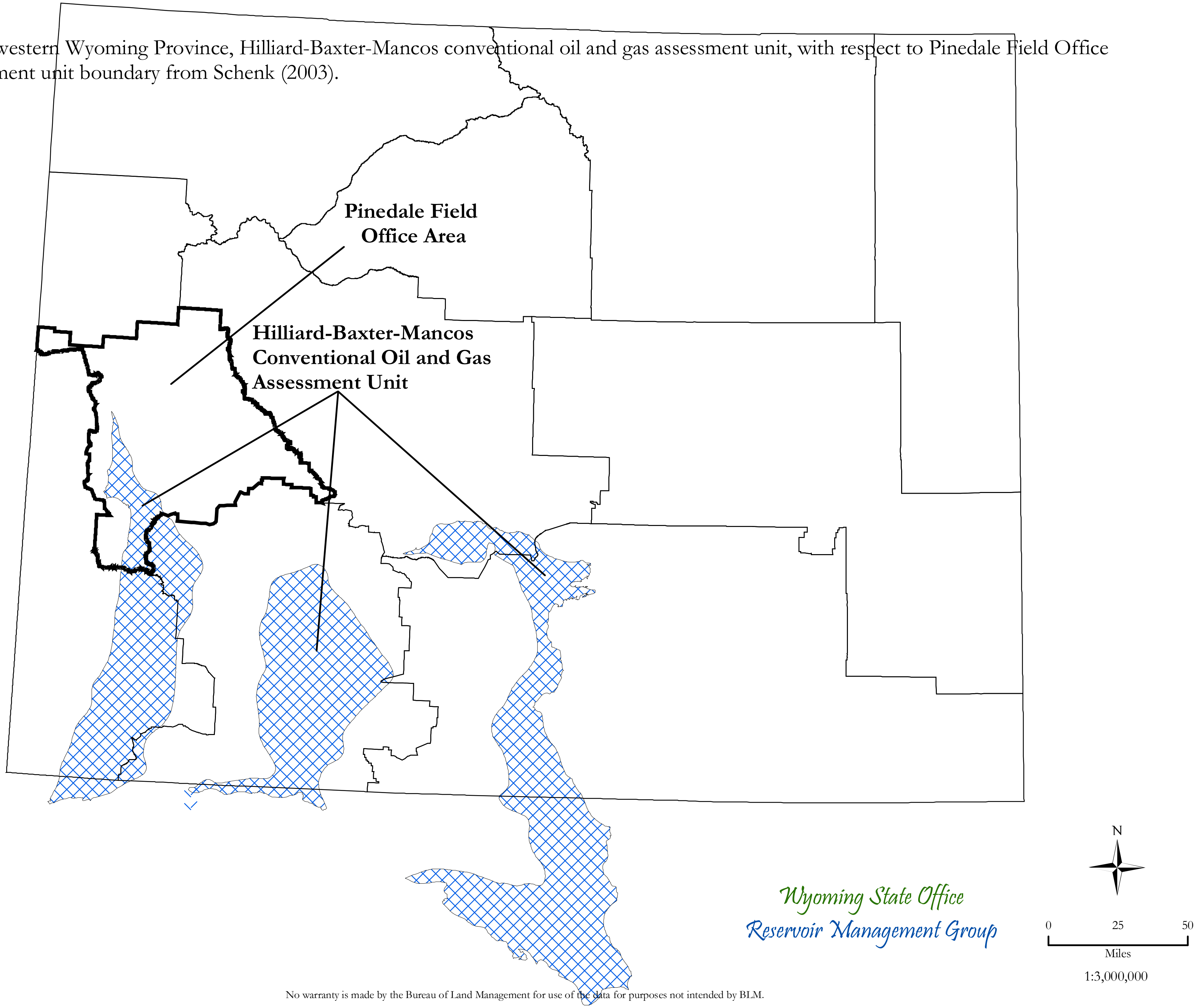

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Figure A1-7.

Location of Southwestern Wyoming Province, Mesaverde-Lance-Fort Union conventional oil and gas assessment unit, with respect to Pinedale Field Office boundary. Assessment unit boundary from Schenk (2003).

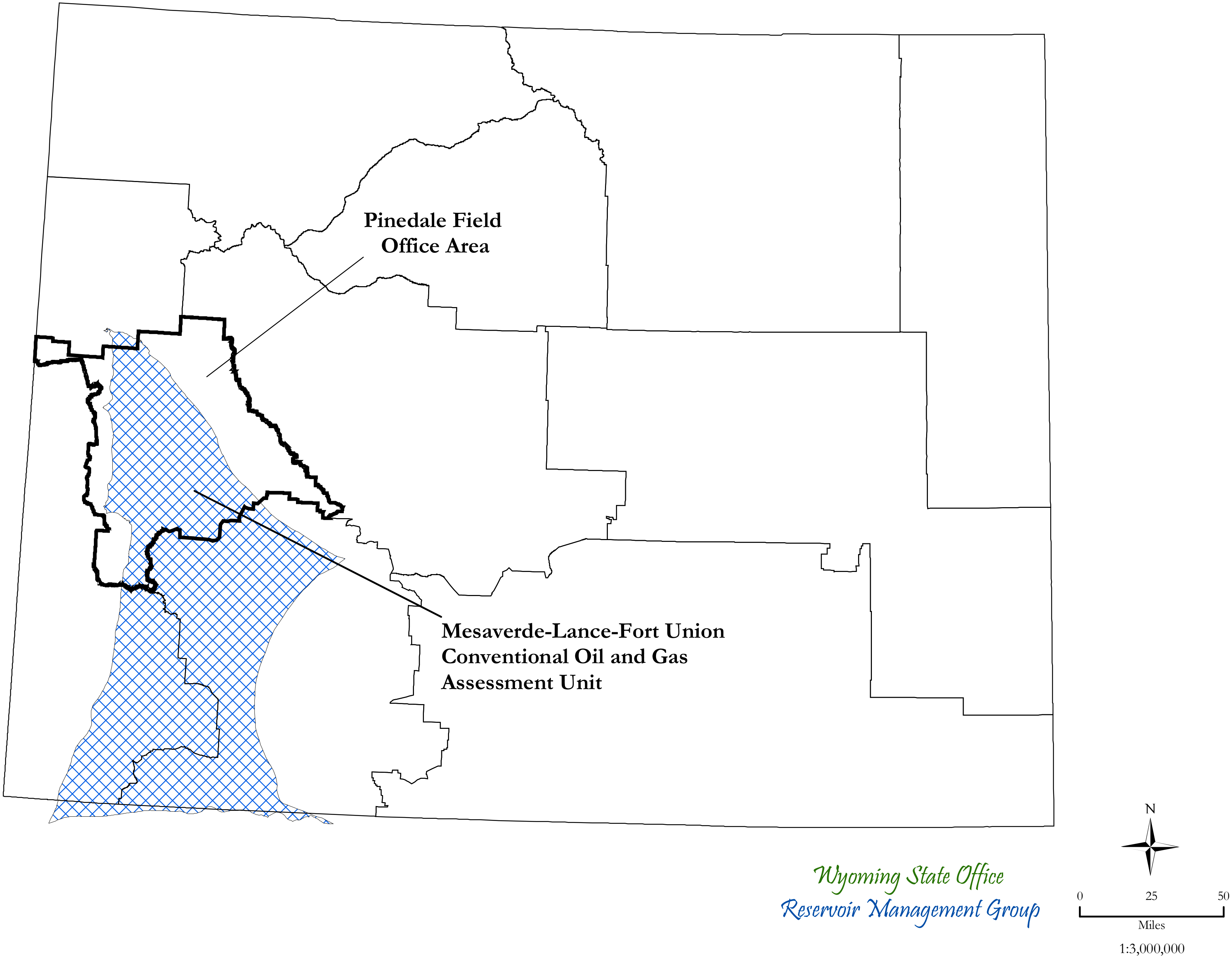

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Figure A1-8.

Location of Southwestern Wyoming Province, Mowry continuous gas assessment unit, with respect to Pinedale Field Office boundary. Assessment unit boundary from Schenk (2003).

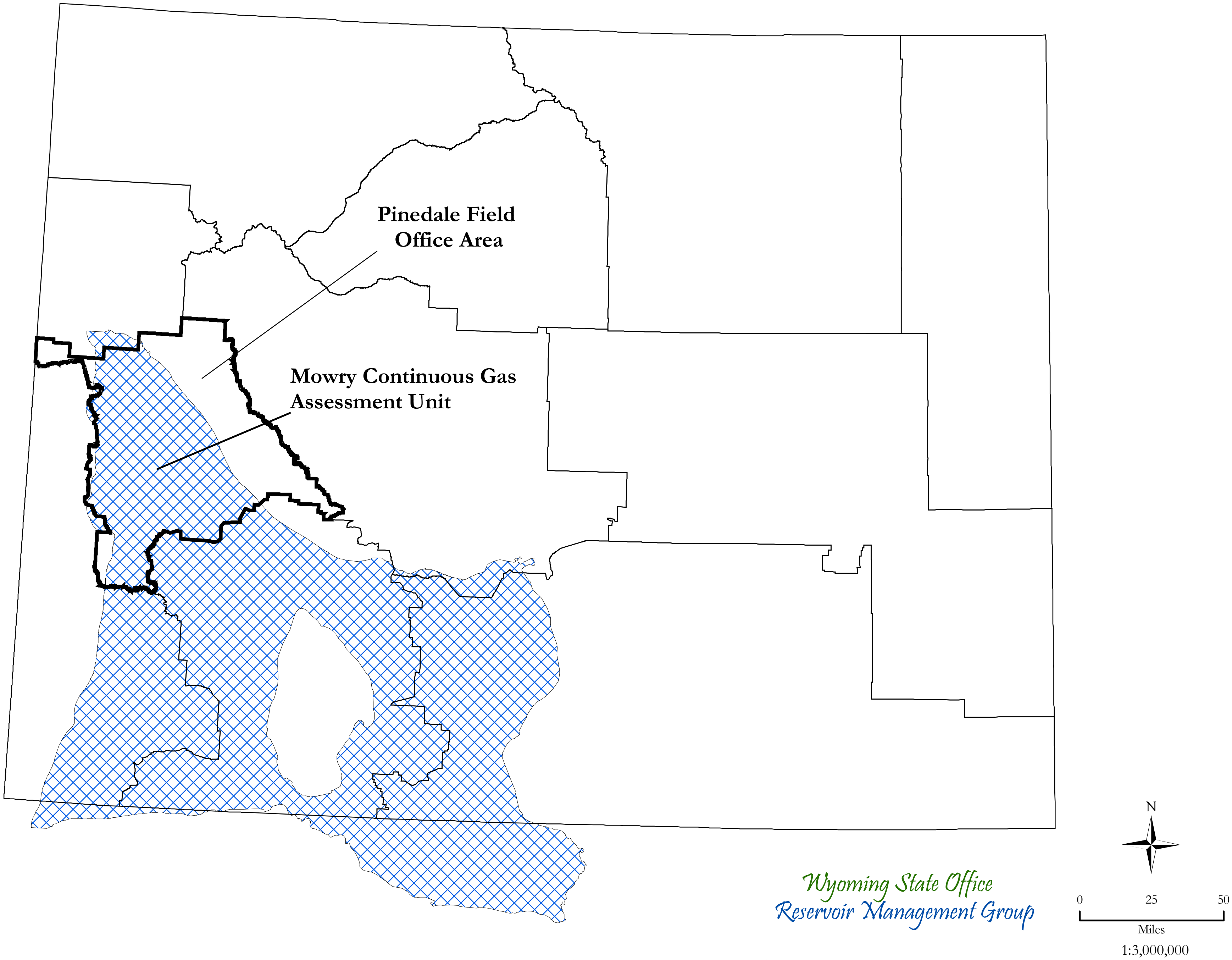

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Figure A1-9.

Location of Southwestern Wyoming Province, Hilliard-Baxter-Mancos continuous gas assessment unit, with respect to Pinedale Field Office boundary. Assessment unit boundary from Schenk (2003).

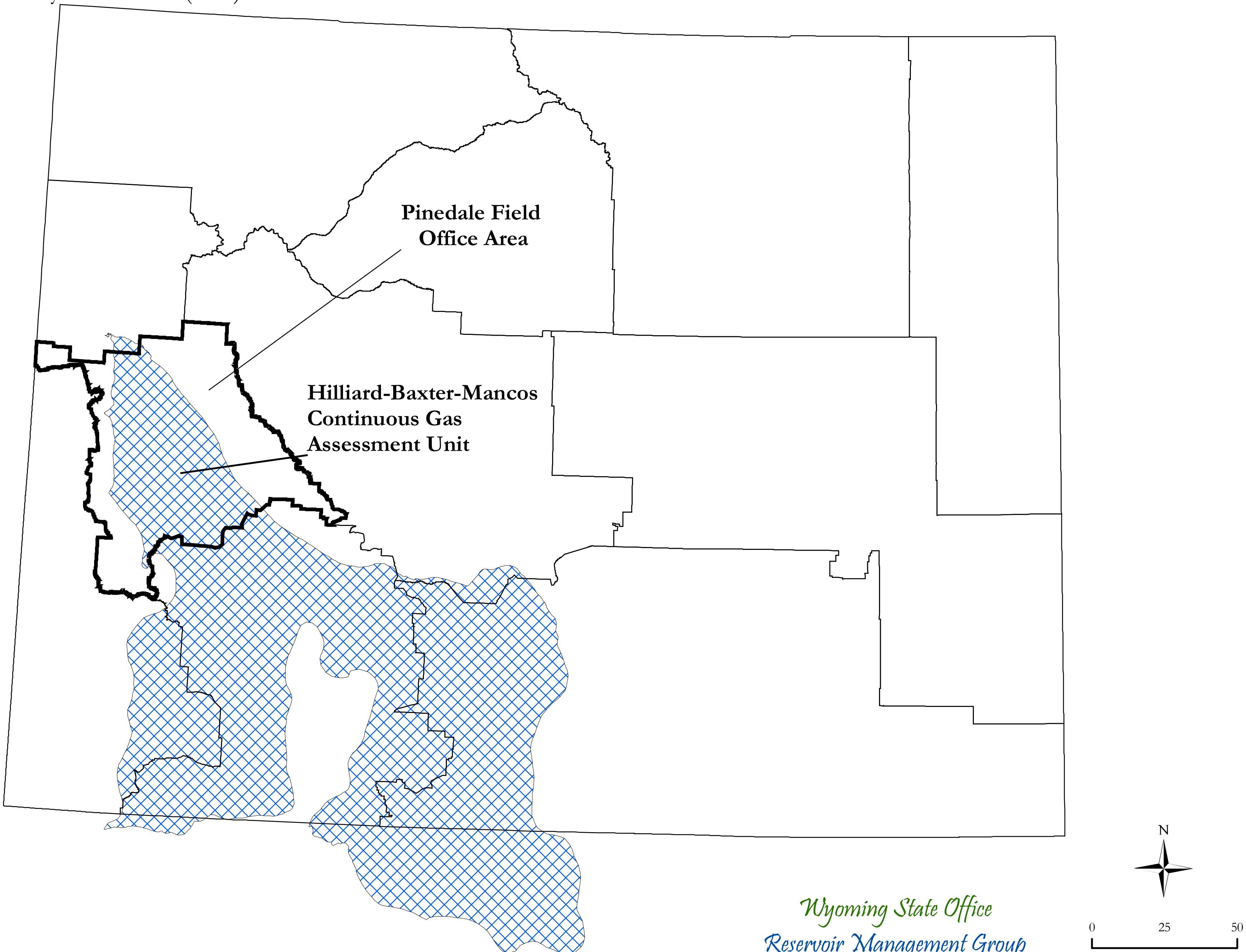

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Figure A1-10.

Location of Southwestern Wyoming Province, Mesaverde-Lance-Fort Union continuous gas assessment unit, with respect to Pinedale Field Office boundary. Assessment unit boundary from Schenk (2003).

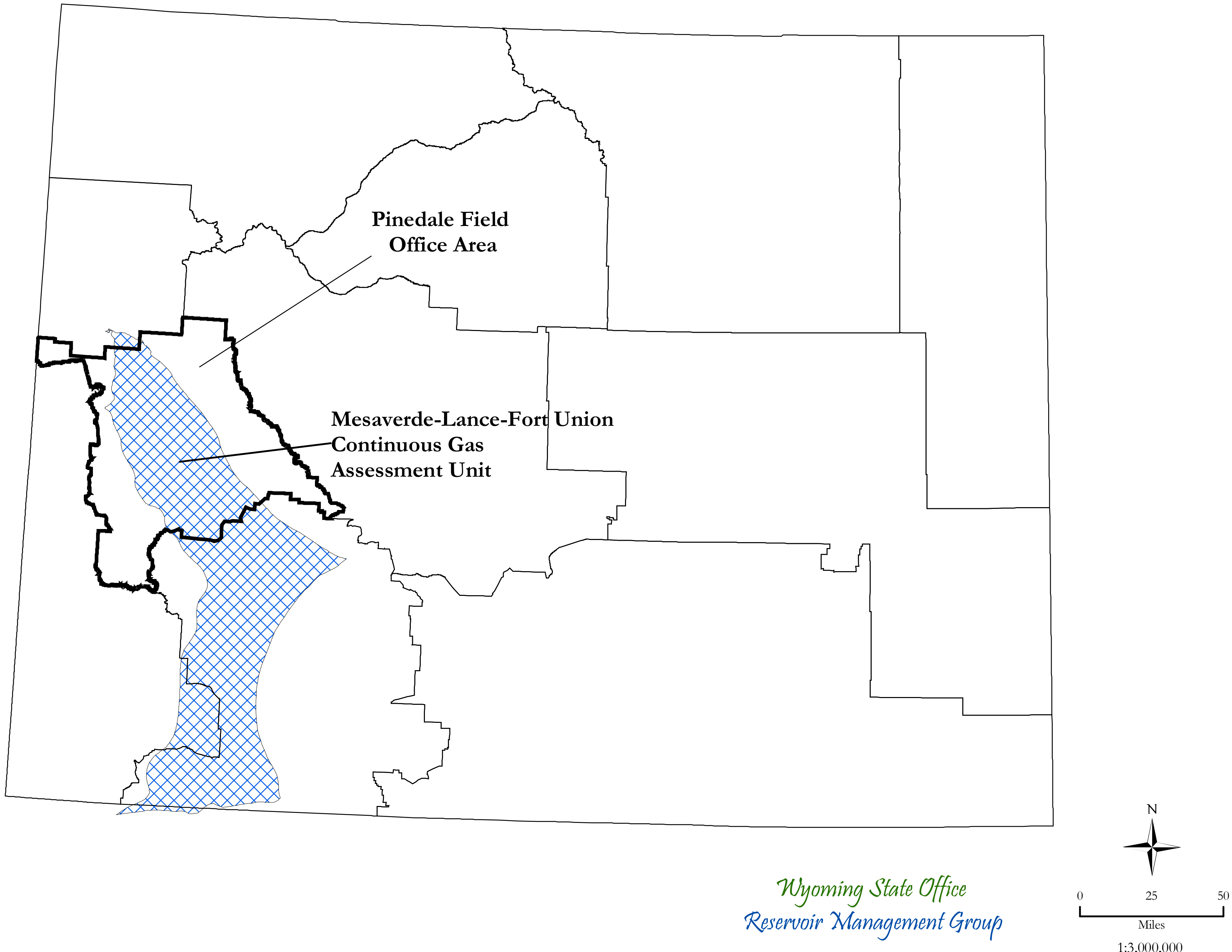

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Figure A1-11.

Location of Southwestern Wyoming Province, Wasatch-Green River continuous gas assessment unit, with respect to Pinedale Field Office boundary. Assessment unit boundary from Schenk (2003).

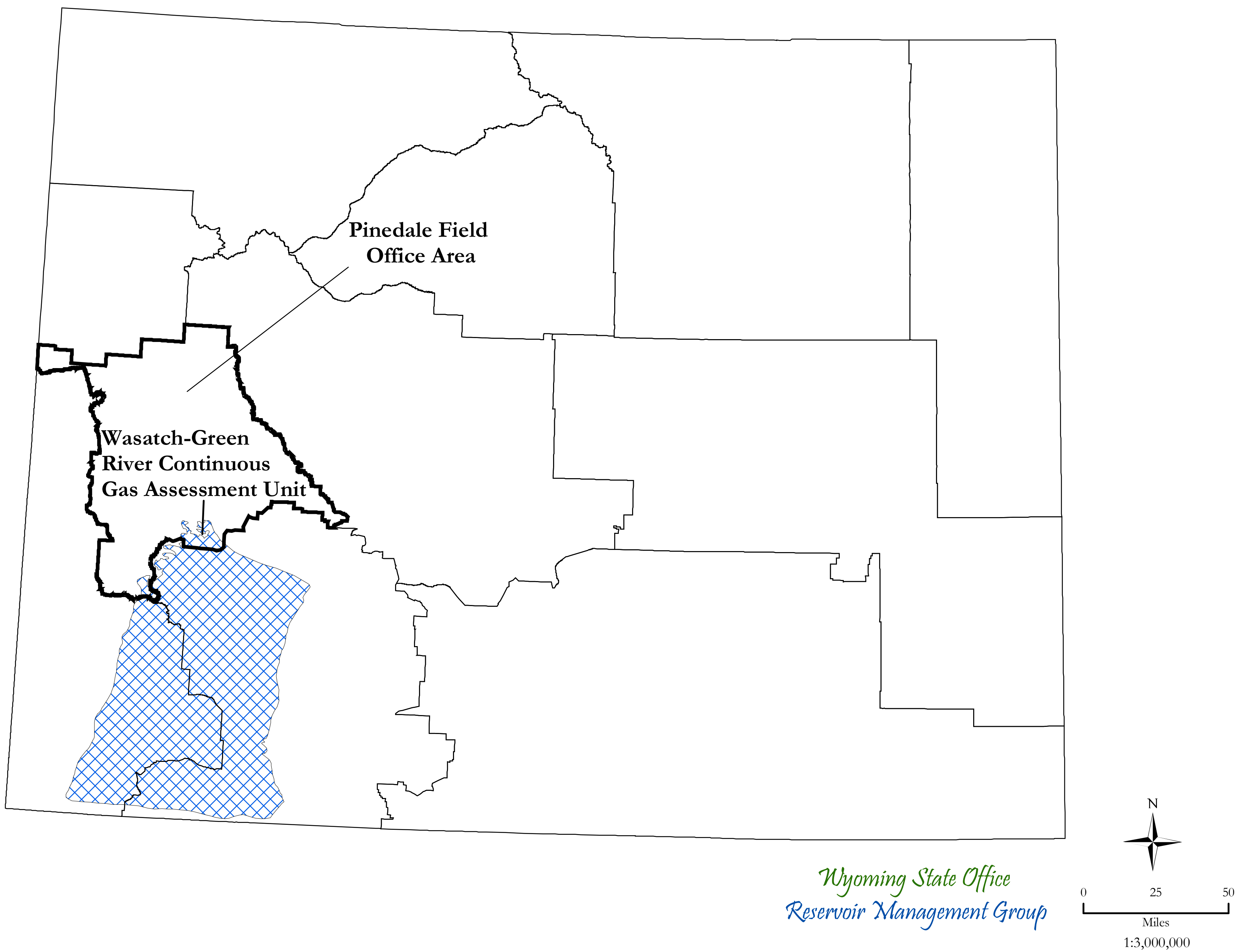

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Figure A1-12.

Location of Southwestern Wyoming Province, Mesaverde coalbed gas assessment unit, with respect to Pinedale Field Office boundary. Assessment unit boundary from Schenk (2003).

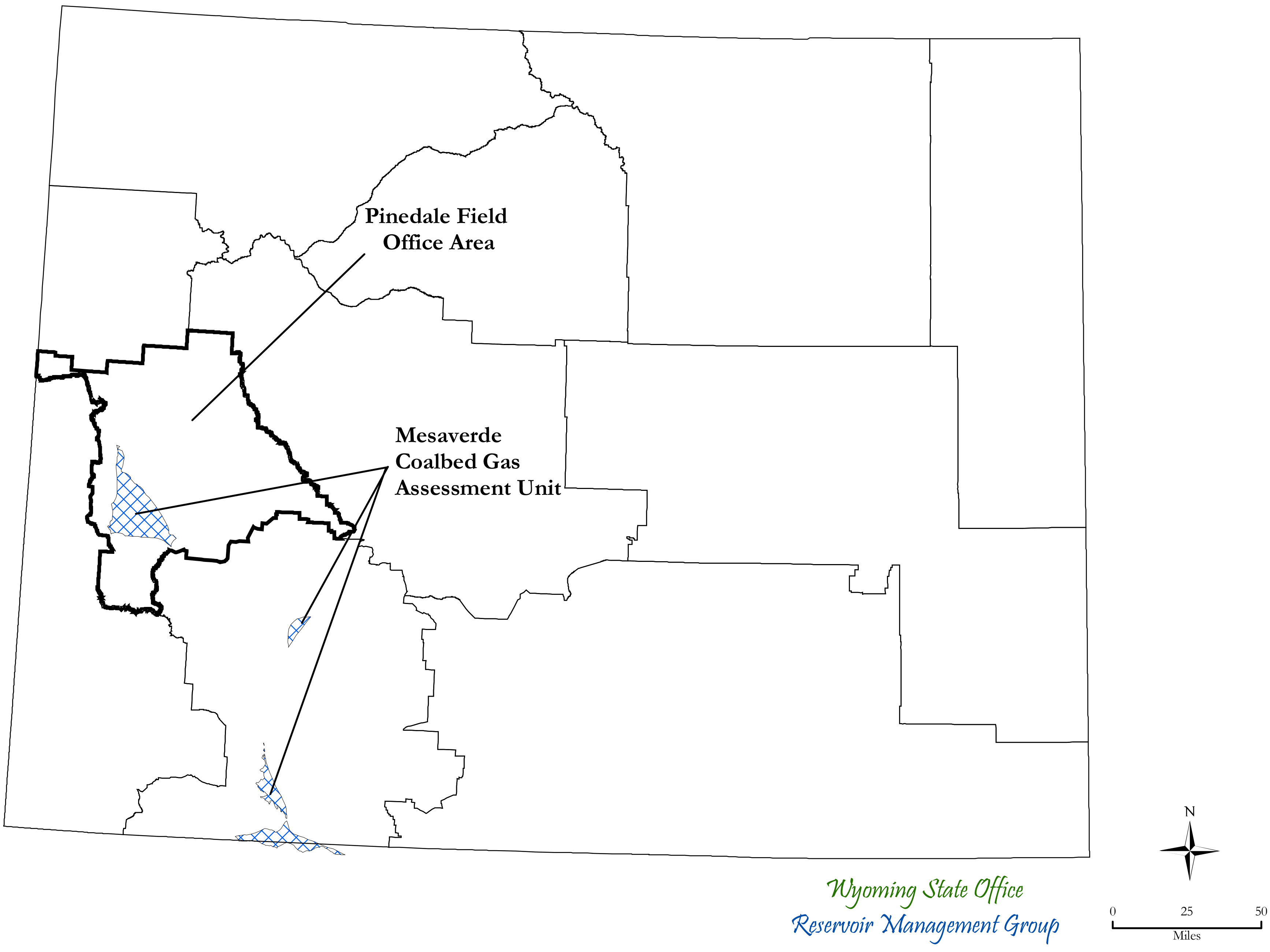

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Figure A1-13.

Location of Southwestern Wyoming Province, Fort Union coalbed gas assessment unit, with respect to Pinedale Field Office boundary. Assessment unit boundary from Schenke (2003).

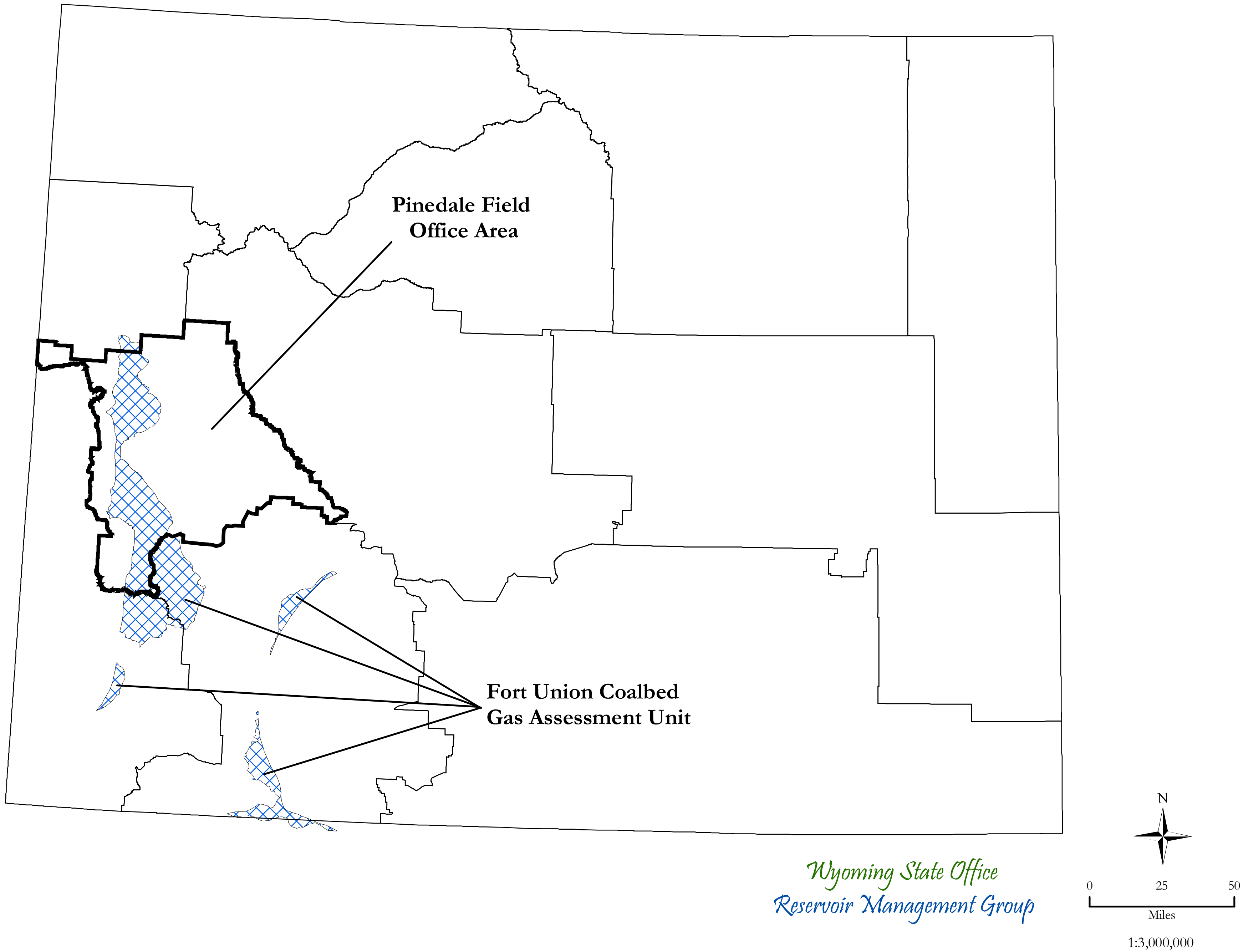

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Table A1-1
Data for Undiscoverd Accumulations in the Unconventional Thrust Belt Assessment Unit: Wyoming Thrust Belt Province, Pinedale Field Office Area

			Undiscovered Oil Accumulations (>0.5 MMBO)		Undiscovered Gas Accumulations (>3 BCFG)			Accumulation Producing Depths (m)		
Maturity	**Discovered Oil Accumulations**	**Discovered Gas Accumulations**	**Number Range**	**Size Range**	**Number Range**	**Size Range**	**Modal API Gravity (Degrees)**	**Maximum**	**Minimum**	**Median**
Established	7	12	1-16	0.5-80 MMBO	1-28	3-500 BCFG	46.5	1,525	5,500	3,000

MMBO = Million Barrels of Oil
BCFG = Billion Cubic Feet of Gas

Data from U.S. Geological Surfey (2006b).

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Table A1-2
U.S. Geological Survey Estimated Undiscovered Technically Recoverable Resource Quantities
Within Wyoming Thrust Belt Province and Pinedale Field Office Area

	Estimated Undiscovered Thrust Belt Province Resource Quantities at Probabilities of Occurrence of 95 and 5 Percent and for the Mean Case										Estimated Undiscovered Field Office 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)**		
Play Name	**95%**	**5%**	**Mean**	**95%**	**5%**	**Mean**	**95%**	**5%**	**Mean**	**% of Play Lying Within Field Office**	**95%**	**5%**	**Mean**	**95%**	**5%**	**Mean**	**95%**	**5%**	**Mean**
Conventional Thrust Belt Gas Fields				99.44	821.63	401.55	9.36	86.27	40.20	5				5.10	42.13	20.59	0.48	4.42	2.06
Conventional Thrust Belt Oil Fields	9.24	84.18	38.83	34.39	352.08	155.38	3.54	40.23	17.08	5	0.47	4.32	1.99	1.76	18.05	7.97	0.18	2.06	0.88
Continuous Frontier-Adaville-Evanston Coalbed Gas Fields				148.79	701.69	361.10	0.00	0.00	0.00	15	0.00	0.00	0.00	22.81	107.58	55.36	0.00	0.00	0.00
Total Undiscovered Resources	**9.24**	**84.18**	**38.83**	**282.62**	**1,875.40**	**918.03**	**12.90**	**126.50**	**57.28**		**0.47**	**4.32**	**1.99**	**29.67**	**167.76**	**83.92**	**0.66**	**6.49**	**2.94**

MMBO = Million Barrels of Oil
BCFG = Billion Cubic Feet of Gas
NGL = Natural Gas Liquids
MMBNGL = Million Barrels of Natural Gas Liquids
[1] Potential resource is assumed to be evenly distributed across each play area.

Table A1-3
Data for Undiscovered Conventional Accumulations in Assessment Units in the Southwestern Wyoming Province, Pinedale Field Office Area

		Undiscovered Oil Accumulations (>0.5 MMBO)					Undiscovered Gas Accumulations (>3 BCFG)				
Assessment Unit Name	**Exploration Status**	**Number Range**	**Size Range**	**Median API Gravity (Degrees)**	**Median Sulfur Content of Oil (%)**	**Drilling Depth Range (ft)**	**Number Range**	**Size Range**	**Median Carbon-dioxide Content (%)**	**Median Hydrogen-sulfide Content (%)**	**Drilling Depth Range (ft)**
Sub-Cretaceous	Established	2-8	0.5-90 MMBO	35	0.45	1,800-13,800	5-45	3-3,600 BCFG	5.2	0	3,000-20,000
Mowry	Established	1-7	0.5-20 MMBO	38	0.2	12,000-16,000	3-22	3-80 BCFG	0.6	0	2,100-19,000
Hilliard-Baxter-Mancos	Frontier	0-0	NA	NA	NA	NA	1-4	3-50 BCFG	0.4	0	1,000-7,900
Mesaverde-Lance-Fort Union	Frontier	1-3	0.5-5 MMBO	41.5	0.01	1,000-5,900	2-40	3-200 BCFG	0.5	0	2,000-8,900

MMBO = Million Barrels of Oil

BCFG = Billion Cubic Feet of Gas

Data from U.S.Geological Survey (2002, 2005, and 2006a)

Table A1-4
Data for Undiscovered Continuous Gas Accumulations in Assessment Units in the Southwestern Wyoming Province, Pinedale Field Office Area

Assessment Unit Name	Exploration Status	Assessment Unit Size-Median (acres)	Cell Size-Median (acres)	Total Cells-Median	Total Untested Cells-Median (%)	Untested Cells With Potential to Add Reserves-Median (%)	Projected Cell Success Ratio-Median (%)	Carbon-dioxide Content-Median (%)	Hydrogen-sulfide Content-Median (%)	Drilling Depth Range (ft)
Mowry	Established	11,458,000	120	95,483	96.0	9	76	1	0	6,900-17,100
Hilliard-Baxter-Mancos	Frontier	10,506,000	80	131,325	99.9	14	40	0.4	0	6,900-15,100
Mesaverde-Lance-Fort Union	Established	3,482,000	100	34,820	98.6	24	80	0.8	0	8,000-17,100
Wasatch-Green River	Not Quantitatively Assessed									
Mesaverde coalbed gas	Hypothetical	327,000	120	2,725	100.0	10	50	6.7	0	500-5,900
Fort Union coalbed gas	Hypothetical	1,185,000	80	14,813	100.0	4	70	5.4	0	4,000-6,000

Data from U.S.Geological Survey (2002, 2005, and 2006a)

Table A1-5
U.S. Geological Survey Estimated Undiscovered Technically Recoverable Resource Quantities Within Southwestern Wyoming Province and Pinedale Field Office Area

		Estimated Undiscovered Southwestern Wyoming Province Resource Quantities at Probabilities of Occurrence of 95 and 5 Percent and for the Mean Case										Estimated Undiscovered Field Office Area Resource Quantities at Probabilities of Occurrence of 95 and 5 Percent and for the Mean Case[2]								
		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[3]	95%	5%	Mean	95%	5%	Mean	95%	5%	Mean
Conventional Resources	Sub-Cretaceous[1]	3.80	43.60	16.60	212.90	3565.90	1382.90	6.10	110.40	41.80	12	0.46	5.23	1.99	25.55	427.91	165.95	0.73	13.25	5.02
	Mowry	1.70	14.80	6.60	88.50	327.30	206.30	1.90	10.40	5.50	12	0.20	1.78	0.79	10.62	39.28	24.76	0.23	1.25	0.66
	Hilliard-Baxter-Mancos				4.60	31.90	15.50	0.30	2.10	1.00	5				0.23	1.60	0.78	0.02	0.11	0.05
	Mesaverde-Lance-Fort Union	0.90	4.00	2.30	105.20	577.10	320.20	4.40	27.80	14.40	28	0.25	1.12	0.64	29.46	161.59	89.66	1.23	7.78	4.03
	Total Undiscovered Conventional Resources	**6.40**	**62.40**	**25.50**	**411.20**	**4502.20**	**1924.90**	**12.70**	**150.70**	**62.70**		**0.91**	**8.13**	**3.43**	**65.85**	**630.37**	**281.14**	**2.21**	**22.39**	**9.76**
Continuous Resources	Mowry				6,745.90	10,614.40	8,542.80	110.90	247.90	170.90	16				1,079.34	1,698.30	1,366.85	17.74	39.66	27.34
	Hilliard-Baxter-Mancos				4,895.10	22,703.40	11,753.20	286.50	1,525.20	752.20	13				636.36	2,951.44	1,527.92	37.25	198.28	97.79
	Mesaverde-Lance-Fort Union				8,320.10	20,695.40	13,635.20	329.20	1,016.90	613.60	35				2,912.04	7,243.39	4,772.32	115.22	355.92	214.76
	Wasatch-Green River	Not quantitatively assessed									2	Not quantitatively assessed								
	Mesaverde coal-bed				13.70	47.30	27.30				59				8.08	27.91	16.11			
	Fort Union coal-bed				35.30	151.90	80.80				47				16.59	71.39	37.98			
	Total Undiscovered Continuous Resources				**20,010.10**	**54,212.40**	**34,039.30**	**726.60**	**2,790.00**	**1,536.70**					**4,652.42**	**11,992.44**	**7,721.17**	**170.21**	**593.86**	**339.89**
	Total Undiscovered Resources	**6.40**	**62.40**	**25.50**	**20,421.30**	**58,714.60**	**35,964.20**	**739.30**	**2,940.70**	**1,599.40**		**0.91**	**8.13**	**3.43**	**4,718.27**	**12,622.80**	**8,002.30**	**172.42**	**616.24**	**349.65**

MMBO = Million Barrels of Oil
BCFG = Billion Cubic Feet of Gas
NGL = Natural Gas Liquids
MMBNGL = Million Barrels of Natural Gas Liquids

[1] Some pre-Cretaceous rocks may have a large non-flammable gas component.
[2] Potential resource is assumed to be evenly distributed across each assessment unit.
[3] Does not include lands that may lie in Teton County.

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APPENDIX 2 – EG&G SERVICES, INC. AND ADVANCED RESOURCES INTERNATIONAL, ASSESSMENT OF UNDISCOVERED OIL AND GAS RESOURCES IN THE GREATER GREEN RIVER AND WIND RIVER BASINS

INTRODUCTION

The subject assessment (Boswell et al, 2002b) of resources was prepared under a Department of Energy contract. It was prepared in response to recommendations made by the National Petroleum Council in their 1999 report, “Meeting the Challenges of the Nation’s Growing Natural Gas Demand”. The Greater Green River and Wind River basins were studied because past gas-in-place resource assessments indicated that these two areas contain the vast majority of the total tight-gas sandstone resource for the Rocky Mountain region. To obtain a portion of these resources, the oil and gas industry will need to apply “advanced exploration, drilling, completion, stimulation, and production technologies in order to produce gas economically and at reasonable prices” (Boswell et al., 2002b). Their report attempts to provide a better understanding of the size and nature of the gas resources that will be critical to future gas supply and the potential of technology to convert presently unrecoverable and sub-economic resources into economically recoverable resources.

The study of the Greater Green River Basin focused on deeper, unconventional gas resources. It reviewed the Cretaceous and older geologic sections to identify plays that encompass most of the basin’s gas resources, were dominated by deep and/or unconventional type accumulations, and had sufficient data available to use the proposed project methodology. They identified the section from the top of the Lance Formation to the base of sandstones within the Morrison Formation, and excluded the Fox Hills Sandstone and various stray sandstones within the Cody-Baxter-Hilliard-Steele shale interval (see Figure 5 for stratigraphic nomenclature). This interval was further divided into “units of analysis.” Each unit of analysis can be thought of as intervals with a common geologic condition that would likely be a target for individual wells. In the past the Mesaverde Group has commonly been assessed as one unit. Intervals of the Mesaverde were split out for this study because it has such a large stratigraphic thickness, industry would not likely target the entire interval in an individual well. The authors were able to divide the studied interval into seven units of analysis. Six of those units of analysis lie at least partially within the Field Office area. A description of each unit is described below, in order from youngest to oldest.

- The Lance unit of analysis (Figure A2-1) is comprised of multiple beds of fluvial sandstones, and interbedded siltstone, shales, and coal of the Lance Formation.
- The Lewis unit of analysis does not lie within the Field Office area.
- The Almond unit of analysis (Figure A2-2) includes Almond Formation sandstones of two distinct types. The first type is clean, blocky and coarsening-upwards sandstone that mark the migration of shorelines at the top of the Almond. The second type, are thinly bedded and highly lenticular sandstones of the lower

part of the delta plain that are interbedded with coals and shales. The Almond unit of analysis lies at the top of the Mesaverde Group.

- The Ericson unit of analysis (Figure A2-3) includes massive, quartz-rich sandstones of the Ericson Formation that lie in the middle of the Mesaverde Group.
- The Lower Mesaverde unit of analysis (Figure A2-4) contains two distinct intervals. At its base are thick, coarsening upward sequences of sandstone (the Blair Formation). Above that lie a thick section of highly lenticular fluvial sandstones and shales (the Rocks Springs Formation).
- The Frontier unit of analysis (Figure A2-5) includes five benches of the Lower Frontier Formation and sandstones within the Mowry Shale interval.
- The Muddy-Dakota-Morrison unit of analysis (Figure A2-5) includes the Muddy Sandstone, the Dakota Sandstone, and sandstones within the Morrison Formation. Those sandstones are interpreted to represent deposition during fluvial-dominated sedimentation.

The assessment attempted to produce a dataset from which recoverable resources could be appraised now, and as changes occur over time, with change in future conditions. A summary of the methodology used is described below.

- Obtain evenly distributed well log data.
- Subdivide stratigraphic section into units of analysis that will be modeled as separate drilling targets.
- Establish three-dimensional geometry of each unit of analysis.
- Establish the distribution of resource-bearing sandstone facies to improve extrapolation of parameters to areas of poor data control.
- Estimate unit of analysis values of porosity, drilling depth, resistivity, shale volume, and potential pay thickness for each well log suite.
- Estimate pressure and temperature gradients and water resistivity at township or quarter-township scale.
- Estimate expected matrix permeability and likely natural fracture overprint.
- Distribute scattered well data to regular grid filling unit of analysis area.
- Prepare data for model input and remove areas of significant historical production.
- Conduct analysis to determine gas-in-place, and the impact of technology/cost scenarios on economically- and technically-recoverable volumes.

The Wyoming Thrust Belt Province was not reviewed as part of the assessment, so resource predictions will only be made for that portion of the Field Office area within the Greater Green River Basin.

RESULTS

Table A2-1 presents the estimated gas-in-place for the six units of analysis that lie partially within the Field Office area. The Greater Green River Basin calculated volume of gas-in-place present within the six units of analysis totals 3,489 trillion cubic feet of gas. Of that total, 587.7 trillion cubic feet of gas is predicted to lie below 15,000 feet. To determine that portion of the gas that lies within the Field Office area; we assumed that the gas resource was evenly distributed across each unit of analysis, we determined the percent of each unit of analysis area that lies within the Field Office area, and we then multiplied that percentage by the basin-wide gas-in-place value for each unit of analysis. We determined that about 421.14 trillion cubic feet of gas-in-place, might be contained within the Field Office area. Of that total, we predict that 68.245 trillion cubic feet of gas lies below 15,000 feet. The Lower Mesaverde alone contains about one third of the total gas-in-place within the Field Office area. The Almond contains the smallest amount of gas-in-place (about three percent). The Muddy-Dakota-Morrison interval contains the most gas-in-place (37 percent) below 15,000 feet, while the Lance contains almost no gas (0.15 percent).

Some of the more important average reservoir parameters calculated for the subject analysis are also presented in Table A2-1. A log-analysis procedure was used to determine average "potential reservoir thickness". The reservoir within each assessment unit was equated with each interval that could be expected to produce under current circumstances. The Lance and Lower Mesaverde units of analysis contain the thickest amount of potential reservoir, while the Almond has the least.

The average porosity and water saturation were then calculated from well logs and those calculations were used to determine the reservoir thickness of each unit of analysis. Units with higher porosity and lower water saturation have more space to accommodate gas resources. Average porosity of all potential reservoirs is very uniform. Water saturation averages for the shallower units of analysis (Lance, Almond, Ericson, and Lower Mesaverde) are in the 53 to 62 percent range, while the two deeper units of analysis (Frontier and Muddy-Dakota-Morrison) have much lower water saturations. Even though the Ericson has more than twice the reservoir thickness of the Frontier and Muddy-Dakota-Morrison, it only has about the same range of gas-in-place. The higher water saturation of the Ericson is the main reason its gas-in-place value is so similar to the two thinner reservoirs.

Average drilling depth was calculated as the mid-point of the reservoir for each unit of analysis. The pressure data was obtained from individual pressure build-up tests on key wells and supplemented by drilling mud-weight data. Reservoir temperature data was based on existing databases and supplemented by temperatures recorded on well logs.

Boswell et al. (2002b) also analyzed resource recoverability for each unit of analysis within the Greater Green River Basin (Table A2-2). Their technically recoverable resource is defined as that part of the in-place gas resource that can be extracted given current technologies and drilling practices, without regard to price. They estimated that 330 trillion cubic feet of gas was recoverable from the six units of analysis. To determine that part of the technically recoverable gas that lies within the Field Office area; we assumed that the gas resource was evenly distributed across each unit of analysis, we determined the percent of each unit of analysis area that lies within the Field Office area, and we then multiplied that percentage by the basin-wide technically recoverable gas value for each unit of analysis. We determined that about **39.98 trillion cubic feet of technically recoverable gas**, might be contained within the Field Office area.

The Boswell et al. (2002b) assessment of technically recoverable gas is significantly higher than that of the U.S. Geological Survey (see Appendix 1). Differences stem from the use of alternative methodologies, different geologic models, and different assumptions. For example, the U.S. Geological Survey estimates for continuous-type assessment units are based on extrapolating past production history to the assessment unit's remaining untested regions and therefore, is influenced by past economic decisions of operators. The Boswell et al. (2002b) assessment of technically recoverable resources is based on the reservoir geology modeled with current technology and assuming full resource development. In addition, the U.S. Geological Survey limits their analysis to a 30-year forecast span that reduces their estimate further when compared to that of Boswell et al. (2002b).

Figure A2-1.

Location of the Lance unit of analysis with respect to Pinedale Field Office boundary. Analysis boundary from Boswell et al. (2003b).

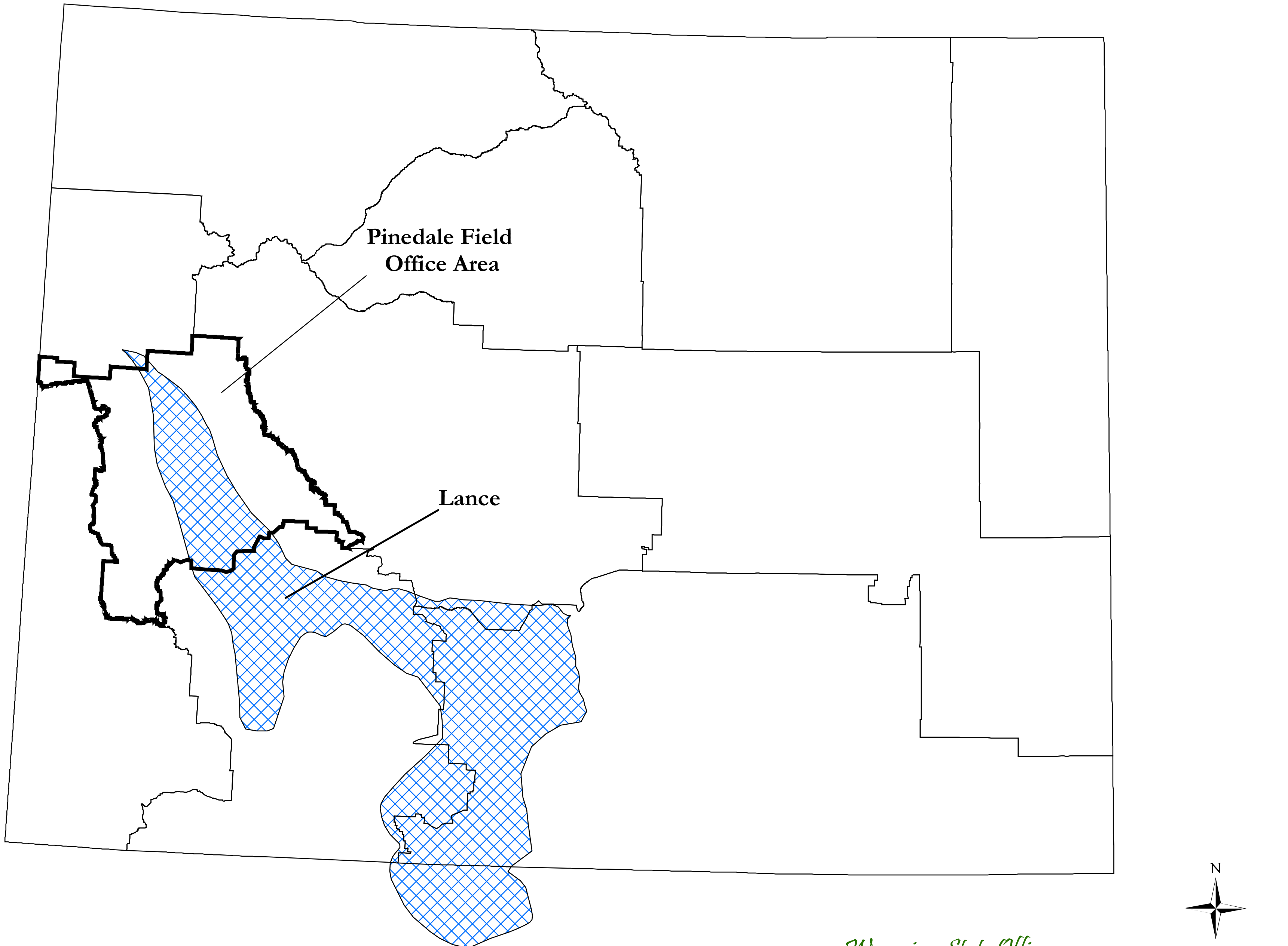

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Figure A2-2.

Location of the Almond unit of analysis with respect to Pinedale Field Office boundary. Analysis boundary from Boswell et al. (2003b).

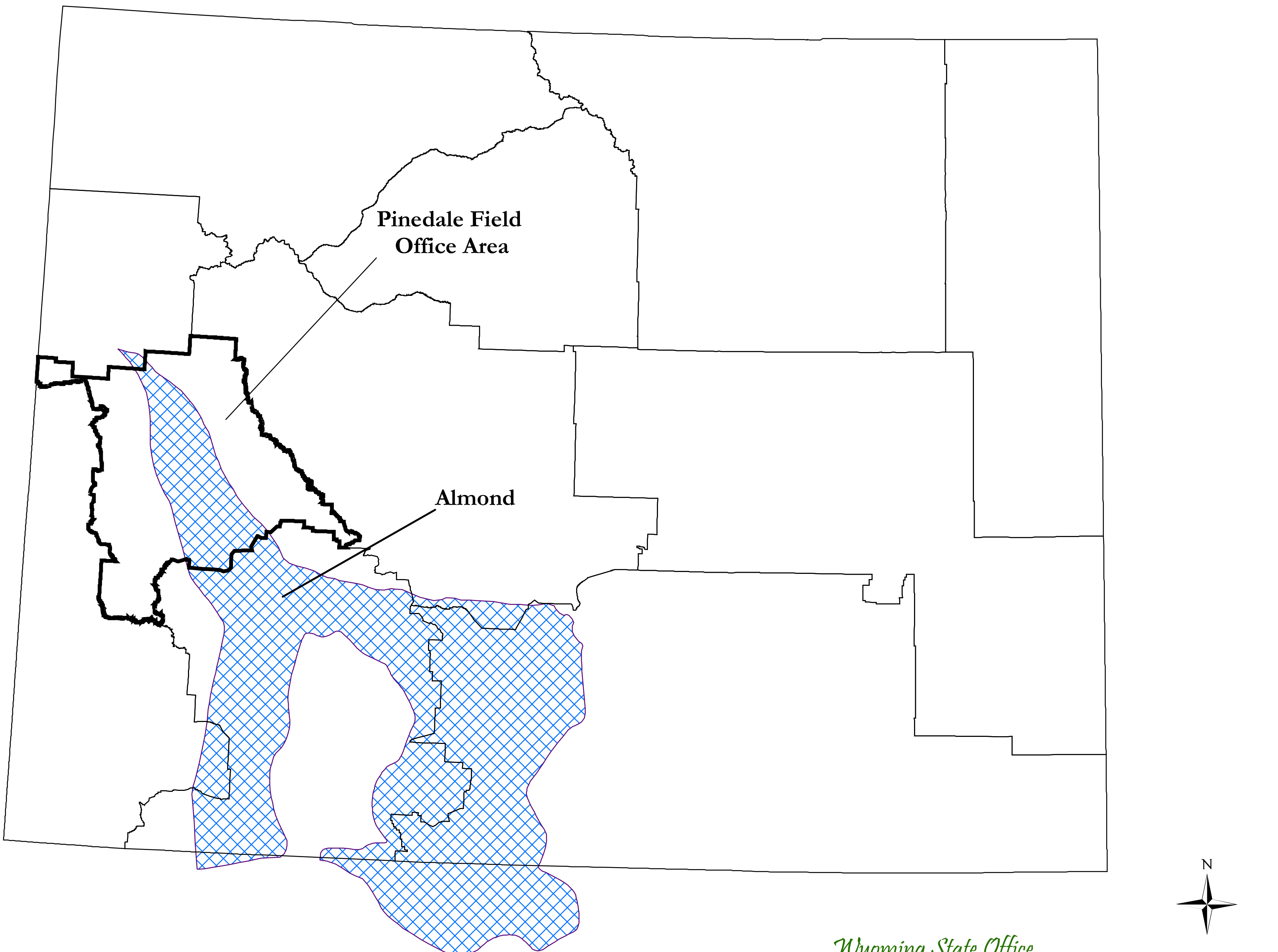

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Figure A2-3.

Location of the Ericson unit of analysis with respect to Pinedale Field Office boundary. Analysis boundary from Boswell et al. (2003b).

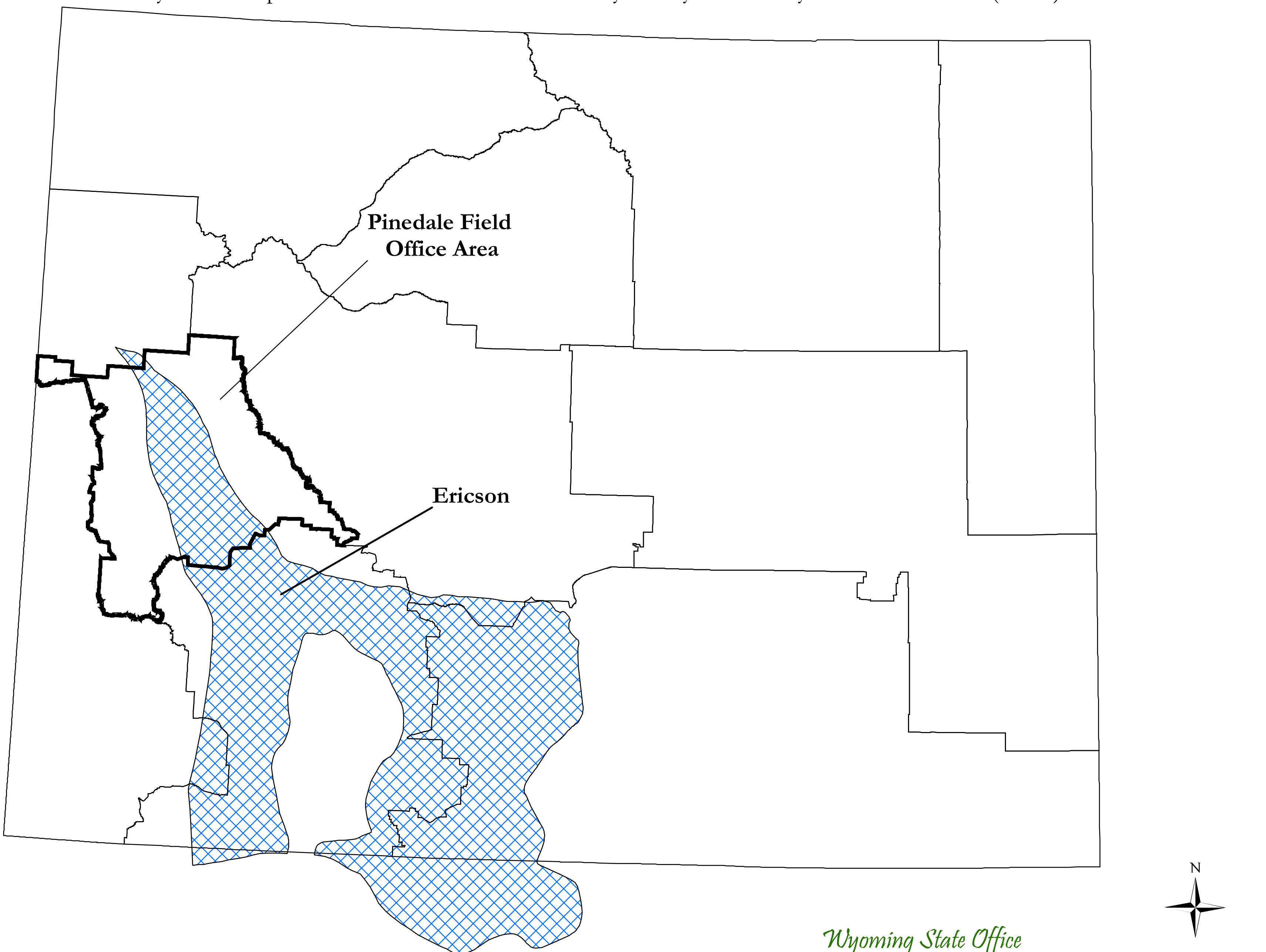

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Figure A2-4.

Location of the Lower Mesaverde unit of analysis with respect to Pinedale Field Office boundary. Analysis boundary from Boswell et al. (2003b).

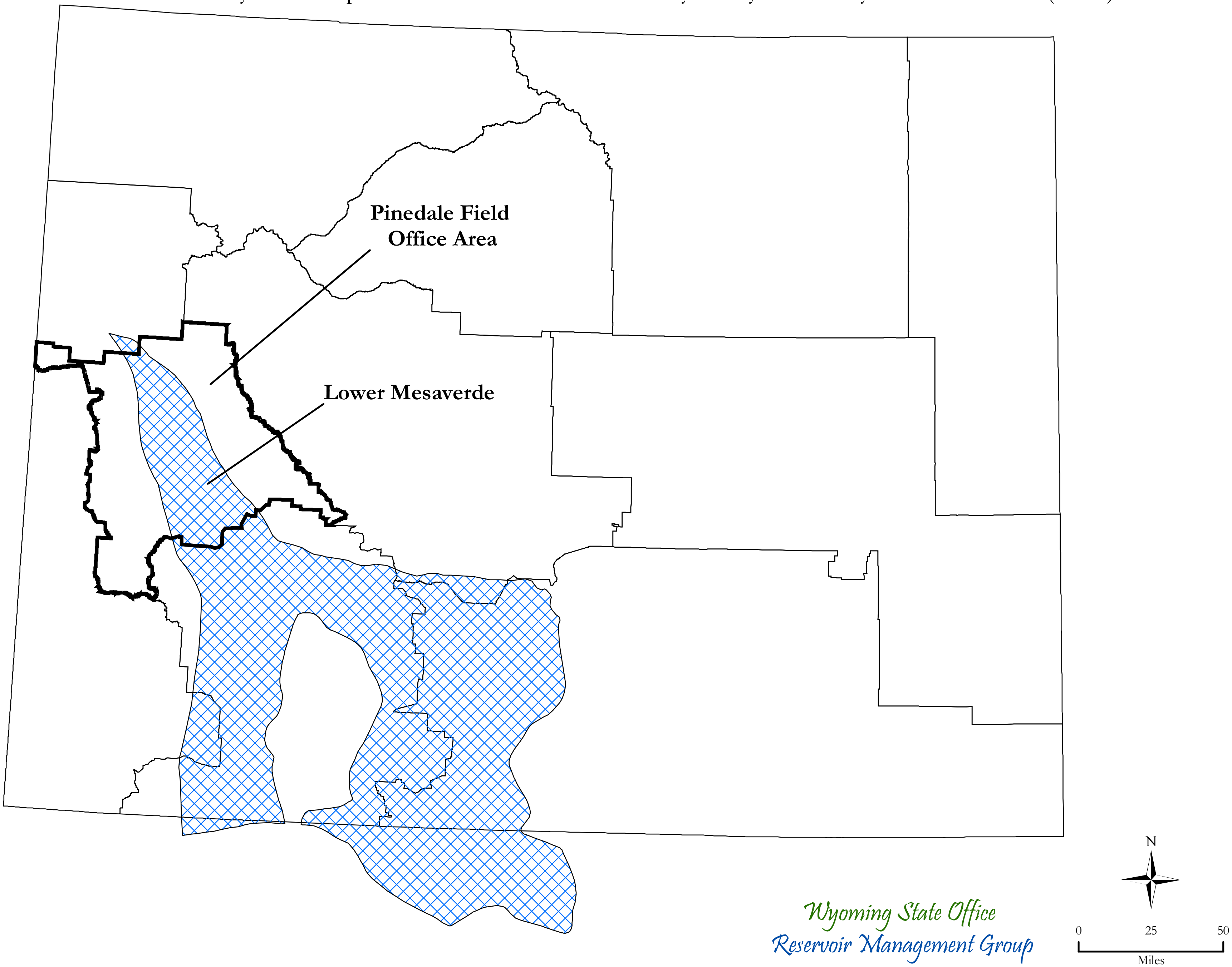

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Figure A2-5.
Location of the Frontier and Muddy-Dakota-Morrison units of analysis with respect to Pinedale Field Office boundary. Analysis boundary from Boswell et al. (2003b).

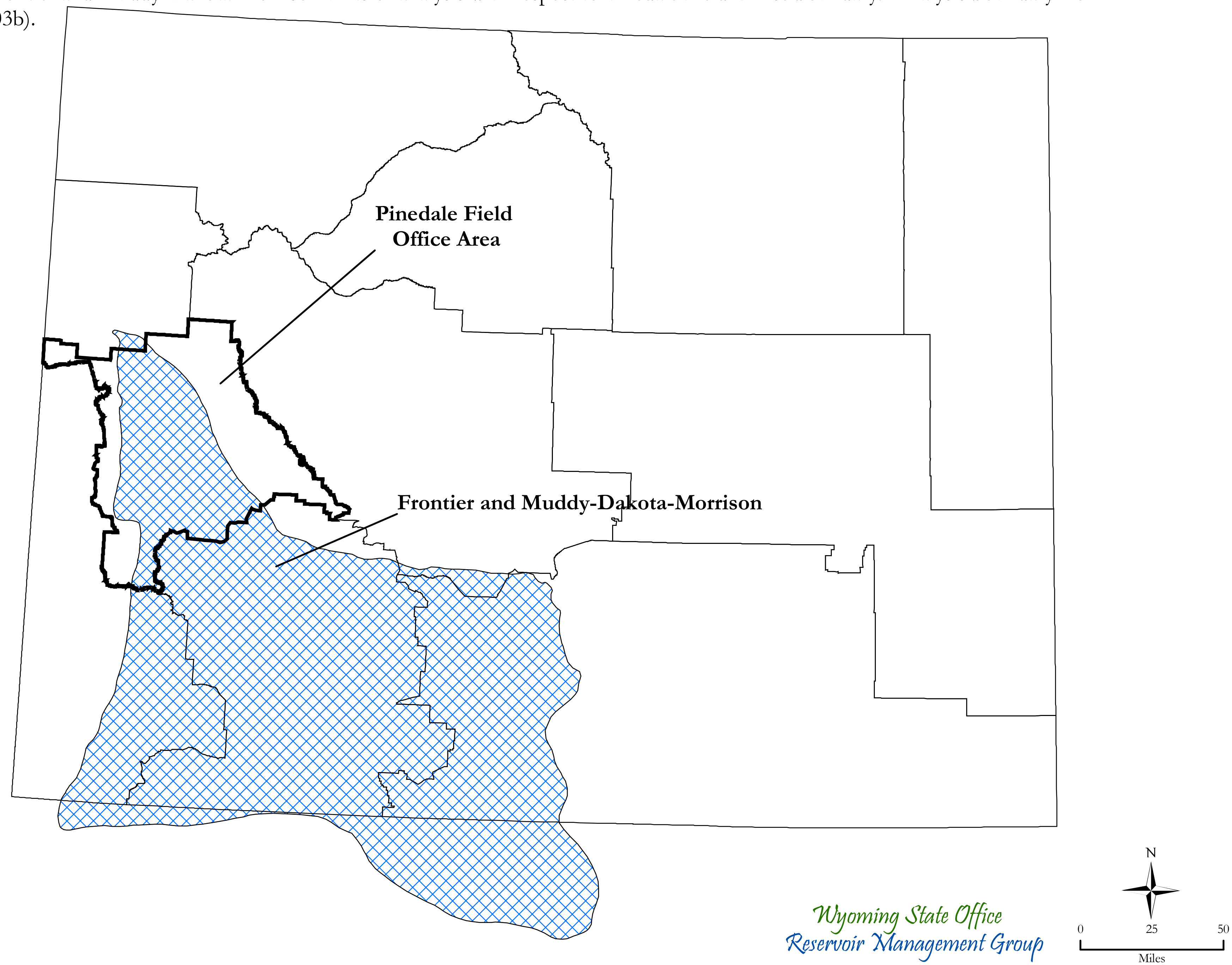

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Table A2-1
Gas-in-place and Average Reservoir Parameters for Each Unit of Analysis Area Within the Greater Green River Basin and the Pinedale Field Office Area

		Unit of Analysis Areas Within Pinedale Field Office Area						
		Lance	Almond	Ericson	Lower Mesaverde	Frontier	Muddy-Dakota-Morrison	Totals
Gas-in-place Resources	Greater Green River Basin In-place Resources (TCFG)	714	120	519	1,257	351	528	**3,489**
	Greater Green River Basin In-place Resources below 15,000' (TCFG)	0.7	5	24	201	145	212	**587.7**
	% of Unit of Analysis Area Lying within Pinedale Field Office Area	15	11	11	11	12	12	
	Field Office In-place Resources (TCFG)	**107.1**	**13.2**	**57.09**	**138.27**	**42.12**	**63.36**	**421.14**
	Field Office In-place Resources below 15,000' (TCFG)	**0.105**	**0.55**	**2.64**	**22.11**	**17.4**	**25.44**	**68.245**
Average Reservoir Parameters	Thickness (ft.)	341	27	119	305	46	55	
	Porosity (%)	8	9	9	8	8	8	
	Water Saturation (%)	58	62	53	58	39	35	
	Drilling Depth (ft.)	8,628	9,882	9,729	10,778	14,511	14,629	
	Pressure (psi)	4,322	5,430	5,322	5,739	8,498	9,592	
	Temperature (degrees F)	164	179	177	189	249	250	

ft. = feet
psi = pounds per square inch
TCFG = trillion cubic feet of gas

Data modified from Boswell et al., 2003b

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Table A2-2
Technically Recoverable Gas Resources for each Unit of Analysis
Within the Greater Green River Basin and the Pinedale Field Office Area

Unit of Analysis	Greater Green River Basin Technically Recoverable Gas (TCFG)	% of Unit of Analysis Area Lying within Pinedale Field Office Area	Pinedale Field Office Technically Recoverable Gas (TCFG)
Lance	68	15	10.2
Almond	27	11	2.97
Ericson	44	11	4.84
Lower Mesaverde	95	11	10.45
Frontier	59	12	7.08
Muddy-Dakota-Morrison	37	12	4.44
Total	**330**		**39.98**

TCFG = Trillion cubic feet of gas
Data modified from Boswell et al., 2003b