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BUREAU OF LAND MANAGEMENT

Reservoir Management Group
Wyoming State Office

FINAL

Reasonable Foreseeable Development Scenario for Oil and Gas
Casper Field Office, Wyoming
February 3, 2005

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INTRODUCTION

The Casper Field Office planning area lies within central and east-central Wyoming (Figure 1). The goal of this reasonable foreseeable development projection 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 is a base line projection and thus it assumes that 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 Casper Field Office area, we have considered those restrictions when determining future activity levels and have constrained the base line projection to reflect those restrictions.

The reasonable foreseeable development projection presented below reviews and analyzes 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. Factors used to project future activities include (but are not limited to) a review of published oil and gas resource information (including a number of on-line databases) for the area, a call for data from oil and gas operators, future oil and gas price estimates, a review of 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 projection presented is not a worst-case projection, but a reasonable and science based projection of the anticipated oil and gas activity that is based on information obtained and analyzed, and uses logical and technically based assumptions to make its projections.

Total Federal gas resource ownership in the Casper Field Office planning area amounts to more than 4,400,000 acres or about 52 percent of lands within the Field Office area. The Bureau of Land Management and Forest Service 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, Department of Defense, Fish and Wildlife Service, and National Park Service. State and private mineral lands make up the remaining 48 percent of lands within Field Office boundaries. The analysis prepared below includes data and information obtained from detailed research and makes future projections for all mineral land ownerships within the Field Office area.

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

EXPLORATORY AND PRODUCTION ACTIVITY AND OPERATIONS

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

EXPLORATORY OPERATIONS AND ACTIVITY

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, and
- completing wells that appear capable of producing economic quantities of hydrocarbons.

Hendricks (1995) studied the components that control and characterize potential gas accumulations in the Great Divide and Washakie basins to the southwest 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 Wind River and Powder River basin portions of the Field Office

(Figure 2). Most of the exploratory interest in the Field Office area, in recent years, has been in the Wind River Basin portion. Almost all Field Office area drilling activity (exploratory and development) has been occurring in both the Wind River and Powder River basins. Drilling activity in the Denver and Shirley basin parts of the Field Office area has been very rare in recent years.

Innovative drilling and completion techniques have enabled the industry to drill deeper (with fewer dry holes) and to recover more reserves per well. Smaller accumulations once thought to be uneconomic can now be produced. Nationally, increased drilling success rates have cut the number of both wells drilled and dry holes (U.S. Department of Energy, 1999). Industry is also drilling fewer dry holes and reducing the number of wells needed to fully develop each reservoir. During the 1990's, activity in the Powder River Basin portion of the Field Office area was focused almost entirely on very low risk development drilling in and around known field areas, which helped to improve the overall success rate. During that period, exploratory drilling occurred most frequently in the Wind River Basin portion of the Field Office area. More future exploratory drilling will be required to discover new resources and determine whether the coalbed gas resource in the Field Office area is economic to produce. Since the risk of failure is higher for this type of activity, 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 and image-processing technology;
- developments in global positioning systems;
- advances in geographical information systems;
- three-dimensional and four-dimensional time-lapse imaging technology that permits better interpretation of subsurface traps and characterization of reservoir fluid;
- improved borehole logging tools that enhance our understanding of specific basins, plays, and reservoirs; and
- advances in drilling that allow more cost-efficient tests of undepleted zones in mature fields, testing deeper zones in existing fields, and exploring new regions.

New technologies will allow companies to target higher-quality prospects and improve well placement and success rates. As a result, fewer drilled wells will be needed to find a new trap and total production per well will increase (U.S. Department of Energy, 1999). Also, drilling fewer wells will reduce surface disturbance and volumes of waste, such as drill cuttings and drilling fluids. An added benefit of improved remote sensing technology is the ability to identify 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 that 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, only the 740,000-acre Chinook Development Contract lies partially within the Casper Field Office. The contract area lies within Natrona and Fremont counties in the Wind River Basin. Other details of the contract are confidential and not available to the public.

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 56 unit agreement areas that lie wholly or partly within the Casper Field Office boundary (Figure 3). Three of these are API units in which Federal leases comprise less than 10 percent of the total unit area. The units encompass lands totaling approximately 345,757 acres in area, or approximately four percent of the total Field Office area. These unitized areas are located in the northern part of the Casper Field Office, generally within the Powder River and Wind River basin areas.

Most of the units in the Field Office area have been primarily oil-productive. As of December 17, 2003 the Wyoming Oil and Gas Conservation Commission (2003a) classified 34 as primary oil producers. The remaining units either primarily produce gas or substantial quantities of both commodities (six of the units are classified as primarily gas producers). Most of the oil units were established in the late 1950's through the early 1970's, and many of those have gone into secondary recovery and/or are in decline. Some of the early units that are not undergoing secondary recovery have contracted to the producing participating areas. The oldest unit, Salt Creek, was established in 1939.

Units established since the 1970's include oil, gas, and mixed production and are in varied stages of development. These newer units are also generally distributed across the northern half of the Field Office area in the Powder River and Wind River basin portions. Several major discoveries, including Cave Gulch and related fields, have been made since the mid-1980's. New units could be established at any time in response to evolving geological interpretations; improvements in exploration, drilling, and production technologies; or other factors. It is also possible that some of the units could undergo additional secondary or tertiary recovery operations.

No coalbed gas units have been established within the Casper Field Office area. Coalbed gas development in the Powder River Basin is beginning to expand into Converse County. Coalbed gas units may be established in the northern Field Office area as Powder River Basin development continues, but most likely not at the rate and extent that unitization has occurred farther north in the central part of the basin.

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, 341 active communitization agreements lie within the Casper Field office area.

TYPICAL DRILLING AND COMPLETION SEQUENCE

The drilling and completion sequence for a target reservoir in the Casper 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;
- 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; and

- 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.

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

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

DRAINAGE PROTECTION

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

Earliest recorded drilling activity within the Casper Field Office area according to Wyoming Oil and Gas Commission records was in the Shannon oil field 40 miles due north of Casper, Wyoming.

The following history of the Shannon Field and nearby Salt Creek Field is from Flores and others (2001), and was initially compiled by N. H. Whitehead (1986) and Art Randall (History of Salt Creek Area, unpublished).

Jackass Spring oil seep first created all of the exploration interest in the Shannon and Salt Creek oil fields. Jackass Spring is located in the Northeast 1/4, Southwest 1/4, Section 13, Township 40 North, Range 79 West, in Natrona County, Wyoming. The Shannon pool is located on the northeast flank of the Salt Creek anticline. Samuel Aughey, Territorial Geologist of Wyoming from 1885-1886, who coined names for all of his claims, named it Jackass.

The first man to attempt to acquire land in the Salt Creek area was Representative Stephen W. Downey, a delegate of Albany County (Wyoming). His first claim was made in 1883 and covered 160 acres of land near the northeast edge of the Salt Creek Field and other tracts, one of which contained a prolific oil seep (Jackass Spring). About 1884, A.T. Seymour took claims on the Shannon Field to the north.

In May of 1884, Aughey "jumped" Downey's Jackass Spring claim along with John Bothwell. Before the close of 1892, the team of Aughey and Bothwell and a group of New York men became owners of four quarters of the land, of which the Jackass claim was one. Land was not leased in those days but staked as petroleum placer claims. By 1892 the “interest” in Salt Creek had considerably widened. By this time the discovery well, the No. 1 Shannon, was completed in March of 1889. It was drilled to a total depth of about 1,000 feet and was able to produce 5 to 10 barrels of thick paraffin-based oil of about 24 Baume (specific weight of oil). It was located in the Shannon pool north of Jackass Spring oil seep.

One of the most colorful characters to enter the Salt Creek drama was Cy Iba. He learned prospecting in the California gold fields and brought his talents to Wyoming when he began locating and staking oil claims. He also founded the Casper Mountain Mining District, and it is in his district that the mining ghost towns of Copperopolis and Eadsville are located. Cy staked some 30 claims in Salt Creek and did the required assessment work. The law required that the assessment work be of the value not less than $100 per claim per year. The law also stated that a pit must be dug 6 x 8 feet to a depth of 10 feet. This was very easy to do at Salt Creek because of the soft clay (Cody Shale). Two men could do it in a short time of perhaps two hours.

In 1894 a refinery was built in Casper on a small site close to where Center Street crossed the Chicago and Northwestern Railroad tracks. As of the 4th of April 1895, 60 barrels of refined engine oil had been shipped from the refinery.

The drilling of No. 1 Salt Creek (or No. 1 Dutch) in October 1908 opened Salt Creek as one of the most significant fields in the Rocky Mountains. The discovery was made in the First Wall Creek (Frontier Formation) sand in Section 23, Township 40 North Range 79 West; the potential was for 150 barrels of oil per day (BOPD). By Dec 31, 1911, Salt Creek had already produced 66,798 BO. In the Great Depression year 1934, the cumulative production rose to 258,722,178 BO. The upper Cretaceous Frontier Formation has been the main

productive interval at Salt Creek, having produced in excess of 432,000,000 barrels of oil (as of 1979).

Based on data from the Wyoming Oil and Gas Conservation Commission, the Salt Creek oil field has produced about 671 million barrels of oil and 723 billion cubic feet of gas as of October 2003. During the "boom" years of Salt Creek, in the 1920s and 1930s, many business buildings were built in downtown Casper most of which are still standing today. The earliest recorded drilling in that portion of the Wind River Basin within the Casper Field Office area was a 2,155-foot deep dry hole one-half mile west of Pine Mountain and about 35 miles west of Casper. The Pine Mountain Field (cumulative production 139 thousand barrels of oil and 376 million cubic feet of gas to November 2003) was discovered two years later. The field produced 15 barrels of oil per day in October 2003.

"Technology has historically contributed significantly to the ability of the petroleum industry to find, develop, and produce natural gas resources" (National Petroleum Council, 2003). Improved fracture stimulation and 3D seismic 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. 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% annual improvement
- Development well success rate — 0.46% annual improvement
- Estimated ultimate recovery per well — 0.87% annual improvement
- Drilling cost reduction — 1.81% annual improvement
- Completion cost reduction — 1.37% annual improvement
- Initial production rate — 0.74% annual improvement
- Infrastructure cost reduction — 1.18% annual improvement
- Fixed operation cost reduction — 1.00% annual improvement.

Drilling and Completion Activity

A total of 12,932 wells, in five status categories, exist within the Casper Field Office boundary (Table 1). To date, 71 percent of all wells have been drilled on Federal minerals, with the other 29 percent drilled on fee or state lands. Fifty percent of all drilled wells have been abandoned. Wells have been 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; or
- mechanical difficulties within a borehole prevented economic hydrocarbon production.

A map of the Field Office area shows locations of all wells drilled (Figure 4). For this map we considered active wells to be those that the Wyoming Oil and Gas Conservation Commission (2003a) determined to be in a drilling, dormant, 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 major structural basins, and major synclinal axes (Figure 2). The location of the synclinal axis of each basin marks the thickest package of sedimentary rocks within that particular basin.

The Casper Field Office area contains parts of four sedimentary basins, the Powder River, Wind River, Denver, and Shirley basins. The portions of the Powder River and Wind River basins within the Casper Field Office area have produced large quantities of oil and gas (Table 2). Cumulative Field Office production from these two basins has been about 1,161 million barrels of oil and about 1,611 billion cubic feet of gas. Ninety-five percent of the oil and 59 percent of the gas was produced from the Powder River Basin portion. Only very small amounts of oil and gas have been produced by wells within the Casper Field Office portions of the Denver (262 thousand barrels of oil and 69 million cubic feet of natural gas) and Shirley (293 thousand barrels of oil and 0.6 million cubic feet of gas) basins. Oil and gas fields in the Casper Field Office area produced 10 percent of the state's oil and four percent of the state's gas in 2002.

Figure 4, is a map of the producing and abandoned oil and gas wells in the Casper Field Office area. It shows that the most heavily drilled region of the Field Office is the southern part of the Powder River Basin (northern part of the Field Office area) generally north of the cities of Douglas and Casper. The eastern Wind River Basin (western part of the Field Office area) also has numerous wells. The Casper Arch, a lightly drilled northwest-southeast trending geologic structure, separates the Powder River Basin from the Wind River Basin. The Denver Basin (southeastern part of the Field Office area) has had relatively little drilling and has very little current production. Several townships in the Denver Basin portion have had little or no drilling.

The southern Powder River Basin has been a large regional oil producer since about 1915. Salt Creek Field is the oldest and largest field in the southern Powder River Basin, and the largest sweet oil producing field in the world (Obert and Mather, 2000). Its oil production rate ranked it third in Wyoming for 2003 (Wyoming Oil and Gas Conservation Commission, 2003b). In other parts of the southern Powder River Basin large (over 50 million barrels of oil equivalent) fields include Big Muddy, South Glenrock, and Powell discovered in 1916, 1950, and 1954 respectively (Wyoming Oil and Gas Conservation Commission, 2003b). Powell Field produces mainly gas, the others mainly oil.

Rocks in the Field Office area range in age from Precambrian to Tertiary. The southeast part of the Wind River Basin contains the thickest section of sedimentary rock in the Field Office area. Precambrian crystalline basement rocks here are as much as 21,000 to 22,000 feet deep. In the southern Powder River Basin the Precambrian basement is as much as 18,000 feet deep, and in the portion of the Denver Basin that is within the Casper Field Office area the Precambrian basement is as much as 12,000 feet deep. The

stratigraphic intervals in the Denver, Powder River, and Wind River basins are shown in Figures 5, 6, and 7. The most prolific hydrocarbon producing intervals are identified on each figure. The Shirley Basin occupies only a small part of the Field Office area and produces only minor amounts of hydrocarbons; therefore no stratigraphic chart is shown.

The coalbed gas play in the Powder River Basin extends to the northern part of the Casper Field Office area. Coalbed gas exploration and development is at a very early stage within the Field Office area. As of January 4, 2005, Wyoming Oil and Gas Conservation Commission records indicated that 50 wells had been drilled. Nine of these wells had been plugged and abandoned and four wells were producing. One shut-in well was located in the Wind River Basin part of the Field Office and all the others were in the Powder River Basin part. The status of coalbed gas permits and wells is shown in Figure 8.

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 Casper Field Office area. According to IHS Energy records (2003) more than 13,300 wells have been drilled in the Field Office area. Only 37 of those exceeded 15,000 feet in depth, although 534 wells lacked depth data at the time the records were compiled. A limited corroborative review of Wyoming Oil and Gas Conservation Commission Records was conducted (January 2004) to compare their records with those of IHS Energy (2003). Some data discrepancies were corrected to reflect more current Commission data. Deep drilling to date has been confined to the Powder River and Wind River basins. Figure 9 shows the location and classification of the deep wells and the existing Federal unit areas in the Field Office area. Table 3 lists specific well data for the deep wells drilled through 2000.

Figure 10 shows areas of the Casper Field Office that may contain potential reservoir sediments below 15,000 feet and those that do not appear to contain potential deep reservoir sediments at those depths. Only about 28 percent of the Field Office area may contain potential reservoir sediments below 15,000 feet. Those areas are in deep parts of the Wind River and Powder River basins. The rest of the Field Office area (about 72 percent): the margins of the two deep basins, structural uplifts, and the shallow Denver and Shirley basin areas appear 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.

IHS Energy records show that deep drilling has occurred periodically in the Field Office area for the past 50+ years. The earliest reported deep well was drilled and abandoned in 1950. No additional deep drilling occurred until 1960. Deep well completions occurred in only 20 of the 50 calendar years from 1950 to 2000. According to the data available,

no more than four deep wells have been completed in any single year (four each in 1983, 1999 and 2000). Several intervening years have had two deep well completions.

IHS Energy records do not indicate any deep drilling following 2000, (exclusive of the 534 incomplete records discussed earlier). The Wyoming Oil and Gas Conservation Commission records indicate that three additional deep wells were completed in the Waltman Field during 2001. No additional deep drilling has occurred here since that time. A small portion of the Madden Deep Unit/Madden Field containing four deep wells occurs in the northwestern Field Office area. Most of this field lies within the Lander Field Office area. Several deep wells have been completed in the Madden area since the end of 2000, but none have been located in the Casper Field Office area. This activity suggests that deep drilling probably has not accelerated above historical levels between 2000 and 2004. Table 4 summarizes the deep well field distribution and completion status based on the IHS Energy records.

Out of 37 deep wells drilled to date (IHS Energy, 2003) in the Casper Field Office, 22 have been completed for production. Fourteen wells were abandoned or are otherwise non-productive. Seventeen wells were completed as gas wells. Only five deep wells are completed as oil producers. Based on the IHS Energy records, deep drilling has had an overall 62.2percent success rate in the Casper Field Office. All of the 11 deep wells drilled in the Waltman Field prior to 2001 were successful, however, suggesting that deep exploration targets and/or technologies are well-defined in this area.

Deep wells have been completed in nine fields in the Casper Field Office area; however, the Waltman Field has more deep well completions than any other. Waltman and the nearby related Tepee Flats, Bull Frog, and Hells Half Acre fields (IHS Energy classifications) include almost half of all directional wells (17 wells) in the Field Office area and two-thirds (14 of 22) of the producing deep wells.

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 Casper Field Office area, to depths ranging from less than 100 feet in the Salt Creek Field area to more than 21,000 feet in the Waltman Field area. Depending on subsurface geology, technology advances now allow operators to deviate boreholes by anywhere from a few degrees to completely horizontal. Directional and horizontal drilling use 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 wells may be specifically deviated or allowed to "drift" updip naturally 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 the borehole due to technical drilling difficulties is also higher. Because of these factors, industry generally prefers not to drill directional or horizontal wells unless other concerns make this option necessary. An exception to this general rule can be made if industry can determine 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 which would 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 stress,
- slower rate of penetration requires more drilling time on the location, and/or
- torque and drag on borehole equipment is greater.

Figure 11 shows the locations of known directional wells and current applications to drill new directional wells, as reported by IHS Energy (2003). Although directional and horizontal wells are generally distributed throughout Casper Field Office area, the Salt Creek, Bullfrog, Sand Dunes and Saddle Rock units contain more directional wells than any other specific locations. Most of the horizontal wells have been drilled outside these areas.

IHS Energy reports that 182 directional wells have been completed or applied for within the Field Office area. Nine wells have no reported completion status in the IHS database. Wyoming Oil and Gas Conservation Commission records (Jan. 2004) indicate that one of these wells has recently been completed as a gas producer and the others are currently in progress or in permit status. The total reported directional wells include 36 horizontal completions.

IHS Energy also reports that 107 of the 182 identified directional wells are (or were) productive of oil or gas. Six wells were completed as water injection wells. With the exception of the eight wells in progress, most of the remaining wells were drilled and abandoned, presumably due to non-productivity or uneconomic production. Several wells failed due to borehole complications encountered during the drilling and completion process ("Junked and Abandoned" classification).

The overall success rate of directional wells, including horizontal, in the Casper Field Office area is approximately 64 percent. This rate of success is lower than the directional drilling success rates recently reported elsewhere in Wyoming (Reasonable Foreseeable

Development Scenario for Oil and Gas, Pinedale Field Office Oct. 2003). Wells drilled within the Salt Creek and Waltman fields, where most of the directional drilling has occurred, experienced 85 and 92 percent success rates, respectively. Twenty-nine wells are classified as Wildcat. None of these were successful. Table 6 summarizes the productive fields (IHS Energy Field Name classification) and well completion status of the reported directional wells.

The earliest directional well reported by IHS Energy was drilled and abandoned in 1979. Directional wells have been completed during most years since the mid-1980's. The highest number of directional wells reported in a single year was 28, completed in 1990. Most of these were completed in the Salt Creek Field area. Since 1995, more than half of the directional drilling in the Field Office area has occurred in the Cave Gulch/Waltman Field area (48 of 92 total completed or applied for wells). Directional drilling has declined markedly in frequency since 2000, when 17 directional wells were drilled. Only three wells were drilled in 2001, five were drilled in 2002, and four in 2003. Directional drilling can be expected to continue at a low level, at least. Changes in exploration models or technologies, development technologies or other factors could result in an increase in the use of directional drilling at any time.

Directional wells (including horizontal wells) have been drilled to a variety of targets from Late Tertiary to Paleozoic aged formations (Table 7). Due to the recent discoveries and activity in the Cave Gulch/Waltman Field area, the most common directional completions have been in the Tertiary - age Fort Union/Lance Formations in this area (38 wells). Several of the wells currently in progress are also located in this vicinity. After the Cave Gulch area, the Wall Creek Formation in the Salt Creek Field is the second most common target for directional wells. In addition to the productive wells, three injection wells have also been completed in the Wall Creek Formation. The remaining wells target a variety of other formations. Mitchell and Rogers (1993) studied a part of the southern Powder River Basin that covers the northeastern part of the Field Office area (Figure 2). They found a system of faulting and fracturing in Cretaceous aged rocks in this area, and potential fractured, overpressured conventional, and unconventional reservoirs would be targets for the use of horizontal drilling techniques.

Slimhole Drilling and Coiled Tubing

Slimhole drilling—a technique used to tap into reserves in mature fields—has not yet been used much in 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, under balanced, 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, and
- protection of sensitive environments.

Light Modular Drilling Rigs

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 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.

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 (deeper parts of the Wind River and Powder River basins) 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 the Field Office area if additional horizontal boreholes are drilled. 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 three areas of southwestern Wyoming. He found that rate of penetration improved and drilling times were cut in all cases studied. Peterson estimated that this increased efficiency had reduced drilling costs by 31 to 43 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, and
- less noise.

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

Summary of Current Completion Techniques

Standard completion techniques for the 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. Improvements in hydraulic fracturing technology have encouraged the extensive development occurring in parts of the Wind River Basin lying within the Field Office area.

In the Powder River Basin portion of the Field Office the industry may want to access natural gas that is contained in numerous thin coal seams. Operators in the region are exploring the feasibility of multi-seam well completion techniques that have been used in other basins. "Recent study by DOE suggests that multi-seam completion technology, if properly modified and successful, could significantly increase resource recovery" (U.S. Department of Energy, 2003).

At Cave Gulch Field, in the Wind River Basin portion of the Field Office, some deep wells had initial high production rates of more than 5 million cubic feet of gas per day, but had to be shut in after a short time due to high water production (U.S. Department of Energy, 2003). Improving operator ability to better diagnose water-prone areas will be a factor in improving future production from tight-gas reservoirs.

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

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 reservoir and sometimes the associated natural gas was vented or flared. Newer recovery techniques have allowed the production of up to 50 percent of the oil-in-place. Also, 75 percent or more of the natural gas-in-place in a typical reservoir is now recovered. Operators have also taken significant steps in reducing production costs. U.S. Department of Energy (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 in the United States—89 percent of oil reserve additions and 92 percent of gas reserve additions—have come from finding new reserves in old fields (U.S. Department of Energy, 1999). Our review indicates that most recent reserve additions in the Powder River Basin portion of the Field Office area have come from old fields. In the Wind River Basin portion of the Field Office area reserve additions have come from infill drilling within the limits of older fields, discoveries of new fields and reservoirs, and step-out drilling from existing fields. Some of the newer

field discoveries in the Field Office area are anomalously pressured. 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, and 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 a large number of older oil fields within the Field Office area, and a number of different types of secondary projects have been used to increase production. There are presently no active hydrothermal injection projects within the Field Office area.

Secondary Recovery Fields

Secondary recovery is generally considered to be water flooding of a depleted reservoir. In 2002, there were 21 active water flooding projects in 11 fields (Wyoming Oil and Gas Conservation Commission, 2003b). Brief summaries of these projects are presented below.

1. Big Muddy Field has two water flooding projects operated by Bass Petroleum Incorporated. The Wall Creek (Frontier Formation) water flood was approved in 1957 and the Dakota Formation water flood was approved in 1960.
2. Brooks Ranch Field is undergoing a water flood in the Frontier Formation. Timberline Production operates this project, which was approved in 1966.
3. Burke Ranch East Field is undergoing a water flood in the Dakota Formation. Breck Operating Incorporated operates this project, which was approved in 1985.
4. Cole Creek South Field is undergoing a water flood in the Dakota formation. Continental Industries operates this project, which was approved in 1971.
5. Glenrock South Field has three water flooding projects operated by Continental Industries. The Upper Muddy Sandstone, Lower Muddy Sandstone, and Dakota Formation water floods were all approved in 1961.
6. Kaye Field is undergoing a water flood in the Teapot Sandstone. Ensign Operating Company operates this project, which was approved in 1998.
7. Mikes Draw Field is undergoing a water flood in the Teapot Sandstone. Matrix Production Company operates this project, which was approved in 1985.
8. Poison Spider Field is undergoing a water flood in the Sundance Formation. Timberline Production Company operates this project, which was approved in 1961.
9. Sage Spring Creek Field has two water flooding projects operated by Flying J Oil & Gas Incorporated. The Dakota Formation contains two separate water floods in the Dakota Formation. One was approved in 1972 and the second was approved in 1990.
10. Salt Creek Field has six water flooding projects operated by Howell Petroleum Corporation. The First Wall Creek (Frontier Formation) was approved at two locations in 1956 and1985, the Second Wall Creek (Frontier Formation) was approved in 1960 and 1967, the Third Wall Creek (Frontier Formation) was approved in 1969, and the Lakota Formation in 1983.
11. Teapot Dome Field has two water flooding projects operated by the Department of Energy. The Second Wall Creek (Frontier Formation) was approved in 1987 and the Third Wall Creek (Frontier Formation) was approved in 1997.

Gas Injection

In 2002, there were five active gas injection projects within the Field Office area (Wyoming Oil and Gas Conservation Commission, 2003b). Gas injection projects are used to maintain reservoir pressures or to aid in secondary recovery of oil or for enhanced oil recovery. Brief summaries of these projects are presented below.

1. Austin Creek Unit gas injection for pressure maintenance was approved in 1992. Wold Oil Properties has injected gas into the Muddy Sandstone at one injection site.
2. North Grieve Unit gas injection for pressure maintenance was approved in 1995. Nance Petroleum Corporation has injected gas into the Muddy Sandstone at two injection sites.

3. Saddle Rock Unit gas injection for pressure maintenance was approved in 1994. Merit Energy Company has injected gas into the Muddy Sandstone at one injection site.
4. North Sage Spring Creek Unit gas injection for a secondary recovery project was approved in 1987. Nance Petroleum Corporation has injected gas into the Dakota Formation.
5. Naval Petroleum Reserve #3 gas injection for pressure maintenance was approved in 1987. The Department of Energy operates this gas injection program into the Second Wall Creek Sandstone (Frontier Formation).

Air Injection

Air injection involves the injection of air into a reservoir for pressure maintenance, or an in-situ combustion type project. In 2002, there was one active air injection project operating within the Field Office area (Wyoming Oil and Gas Conservation Commission, 2003b). The Commission, in 2001, approved the injection project into the Sussex Sandstone at the Morton Field. Mtarri Incorporated operates this project and maintains one injection site.

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 2002, there were three active Tertiary projects within the Field Office area (Wyoming Oil and Gas Conservation Commission, 2003b). Brief summaries of these projects are presented below.

1. Burke Ranch East Field has a water-polymer injection project in the Dakota Formation that is being operated by Breck Operating Corporation. This project was approved in 1987.
2. Salt Creek Field has a water-micellar injection project in the Wall Creek (Frontier Formation) that is being operated by Howell Petroleum Corporation. This project was approved in 1972. A water-carbon dioxide flood test project began in 2003. The operator worked over 237 wells and drilled 14 new wells prior to initiating phase one in January of 2004 (Anadarko, 2004). Carbon dioxide is being initially injected into the second Wall Creek Formation at a rate of 65 million cubic feet per day and is expected to increase to 75 to 100 million cubic feet per day.
3. Teapot Dome Field has a water-polymer injection project in the Shannon Sandstone that is being operated by the Department of Energy. Date of project approval is unknown.

Acid Gas Removal and Recovery

Before natural gas can be transported safely, any hydrogen sulfide or carbon dioxide gas must be removed. Special plants are needed to recover the unwanted gases and sweeten 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. Fields known to contain hydrogen sulfide within the Field Office are Salt Creek East, Salt Creek West, Lost Dome, and Madden.

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 Field Office 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

In southwestern Wyoming 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. In the future, use of this technique could spread to parts of the Field Office area.

Leak Detection and Low-bleed Equipment

New technology is facilitating the detection of hydrocarbon leaks in equipment. The replacement of equipment that bleeds significant gas allows for increased worker safety and reduced emissions of methane. Not allowing gas to bleed from equipment increases recovery rates and usage of this valuable resource.

Downhole 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. 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 a lot of the fugitive hydrocarbon emissions that vaporize from crude oil storage tanks, mainly from tanks associated with high-pressure reservoirs, high vapor releases, and large operations. The emissions usually consist of 40 to 60 percent methane, along with other volatile organic compounds, and hazardous air pollutants (U.S. Department of Energy, 1999). Where useable, this technology can capture over 95 percent of these emissions.

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.

Teapot Dome Field Test Site

The Department of Energy supports a test site at the Teapot Dome Field (Naval Petroleum Reserve No. 3). The Department has supported oilfield research at this field with the following capabilities:

- Oil and gas production (artificial lift, operations, enhanced oil recovery)
- Drilling (oil and gas, geothermal, mining)
- Renewable energy (geothermal, solar, wind)
- Flow assurance
- Bioremediation
- Beneficial use of produced water (wetlands)
- Well completions
- Geology, petrophysics.

Future expansion of testing into new technological areas will consider coalbed gas development, produced water management, carbon dioxide flooding, and carbon sequestration.

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. No gas storage projects lie within the Field Office area and there are no proposals for underground gas storage.

ASSESSMENTS OF OIL AND GAS RESOURCES

The Energy Information Administration (2004) has recently provided a forecast of United States energy supply. Technically recoverable United States oil resources (as of January 1, 2002) are estimated to be 154 billion barrels. The technically recoverable natural gas resource as of January 1, 2002 was 1,279.5 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.
- 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 22 percent increase in our consumption between 1990 and 2000. During that period consumption rose from 18.7 to 22.8 trillion cubic feet (Energy Information Administration, 2001). Our domestic production only rose from 17.7 to 19.7 trillion cubic feet (11.3 percent increase) for that period (Curtis and Montgomery, 2002). North American producing areas are expected to provide 75 percent of long-term United States gas needs, but they will be unable to meet the entire projected demand (National Petroleum Council, 2003). The gap between consumption and production has necessitated a rise in imports and concern about our future United States energy supply.

Significant amounts of oil and gas have been produced within the Casper 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 since 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, no recent estimates of oil-in-place were 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 Wind River Basin significantly exceed the older 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 Casper Field Office area through 2020.

GAS-IN-PLACE ESTIMATES

Gas-in-place (see Glossary definition for *in-place*) estimates attempt to describe 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 of the Field Office, recent gas-in-place estimates are only known for the Wind River Basin as a whole. Coalbed gas-in-place estimates are available for the Powder River, Denver, and Wind River basins. Johnson et al. (1996) reported 995 trillion cubic feet of gas-in-place for Upper Cretaceous and Lower Tertiary sandstone reservoirs in the Wind River Basin. Twenty-three percent of the Wind River Basin province lies within Field Office boundaries. If the gas-in-place resource is assumed to be evenly distributed across the province, then **about 228.85 trillion cubic feet of gas-in-place may be located within that part of the Wind River Basin lying within the Field Office area.**

The most recent review (Boswell et al., 2002b) studied five of the most productive Tertiary and Cretaceous aged formations within the Wind River Basin area. That review (sponsored by the Department of Energy) updated the estimated gas-in-place that could be present in the five units they analyzed. They determined that 1,169 trillion cubic feet of gas-in-place could be present in the five units. Again, we assumed that about 23 percent of the gas-in-place resource lies within the Field Office. An even distribution of gas in the analyzed reservoirs yields a **gas-in-place estimate of 268.87 trillion cubic feet present in that part of the Wind River Basin lying within the Field Office area**.

Boswell et al., (2002b) also determined that reservoirs below 15 thousand feet contain some of the above predicted 1,169 trillion cubic feet of gas-in-place. They projected that about 314 trillion cubic feet of that gas-in-place volume occurs below 15 thousand feet. Again, using the above 23 percent assumption and an even distribution of gas yields a **deep gas-in-place estimate of 72.22 trillion cubic feet present within that part of the Wind River Basin lying within the Field Office area.**

The Gas Technology Institute (2001) estimated coalbed gas-in-place for the three basins lying partly within the Field Office area. Their basin-wide coalbed gas-in-place estimates were:

- Powder River Basin - 39 trillion cubic feet
- Wind River Basin - 6 trillion cubic feet
- Denver Basin - 2 trillion cubic feet.

Assuming an even distribution of the coalbed resource within each basin, the approximate portion of coalbed gas-in-place contained within the Casper Field Office area would be:

- Powder River Basin - 5.85 trillion cubic feet
- Wind River Basin - 1.38 trillion cubic feet
- Denver Basin - 0.13 trillion cubic feet.

Total coalbed gas-in-place is estimated to be about 7.36 trillion cubic feet for the entire Field Office area.

Advanced Resources International (2002) in a study of just the Powder River Basin coalbed gas resource, has estimated 61 trillion cubic feet of gas-in-place. Assuming an even distribution of the coalbed gas resource within the Powder River Basin, the approximate portion of coalbed gas-in-place contained within the Casper Field Office area would by 9.15 trillion cubic feet. The Gas Technology Institute (2001) and Advanced Resources International (2002) projections indicate a large volume of coalbed gas-in-place resource (5.85 to 9.15 trillion cubic feet) potentially available for future development.

The studies cited above have determined gas-in-place volumes for only portions of the potential gas bearing units known to lie within the three basins. Cretaceous aged units and coalbed gas have been studied most intensely, because they are thought to contain the largest portion of the potential gas-in-place resource in this region.

PROVED OIL AND GAS RESERVES

In 2002, Wyoming ranked 8th in the United States for proved oil reserves and for production (Energy Information Administration, 2003). Wyoming's proved oil reserves rose from 489 million barrels at the end of 2001, to 524 million barrels at the end of 2002 (an increase of 7 percent). The 489 million barrels of proved reserves for 2001 were the lowest calculated for Wyoming in the 1977-2002 statistical period. The Energy Information Administration (2003) estimated that 46 million barrels was produced in 2002, so an additional 81 million barrels of additional proved reserves were identified in 2002. 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 2002.

In 2002, Wyoming ranked 3rd in the United States for proved dry natural gas reserves (Energy Information Administration, 2003). Wyoming's proved dry natural gas reserves rose from 18.398 trillion cubic feet at the end of 2001, to 20.527 trillion cubic feet at the end of 2002 (an increase of 10 percent). The 20.527 trillion cubic feet of dry natural gas proved reserves was the highest reported for Wyoming from 1977 to 2002. Wyoming now accounts for 11 percent of the Nation's dry natural gas proved reserves. The Energy Information Administration (2003) estimated that 1.388 trillion cubic feet of dry natural gas was produced in 2002 (a record for the 1977-2002 period), so an additional 3.517 trillion cubic feet of additional proved reserves were identified in 2002. 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 2002, Wyoming ranked 3rd in the United States for proved coalbed gas reserves and production, and its proved coalbed gas reserves accounted for 11.5 percent of all 2002 dry natural gas reserves (Energy Information Administration, 2003). Wyoming's proved coalbed gas reserves rose from 2.297 trillion cubic feet at the end of 2001, to 2.371 trillion cubic feet at the end of 2002 (an increase of 3 percent). The 2.371 trillion cubic feet of proved coalbed gas reserves was the highest reported for Wyoming from 2000 to 2002. Wyoming now accounts for 12.8 percent of the Nation's proved coalbed gas reserves. The Energy Information Administration (2003) estimated that a record 302 billion cubic feet of coalbed gas was produced in 2002.

The only known recent attempts to estimate proved oil and gas reserves for areas covering the Field Office region were; a report prepared by the U.S. Departments of the Interior, Agriculture, and Energy (Cantey et al., 2003), and U.S. Geological Survey reports (Beeman et al., 1996: Charpentier et al., 1996: Gautier et al., 1996). The first 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 Powder River Basin, and for other western regions. The Powder River Basin occupies a large part (almost half) of the Field Office area. The Denver and Wind River basins cover the remainder. Energy Information Administration detailed analysis of available data indicated that the Powder River Basin contains 193.456 million barrels of liquid reserves (both oil and natural gas liquids) and 2.399 trillion cubic feet of gas reserves. The Field Office area occupies about 17.92 percent of the Powder River Basin area. If the proved oil and gas reserves estimated by the Energy Information Administration are assumed to be evenly distributed across the basin, then about 34.67 million barrels of proved liquid reserves and 0.43 trillion cubic feet of proved gas reserves lay within the Field Office area.

The older reports of the U.S. Geological Survey indicated that the Wind River Basin province had a proved reserve of 87 million barrels of liquid reserves (both oil and natural gas liquids) and 2.5 trillion cubic feet of gas as of year-end 1990. The Field Office area occupies about 23 percent of the Wind River Basin area. If the proved oil and gas reserves estimated by the U.S. Geological Survey authors are assumed to be evenly distributed across the basin, then about 20.01 million barrels of liquid reserves and 0.575 trillion cubic feet of proved gas reserves lay within the Field Office area.

In our review of proved reserves for that portion of the Denver Basin province within the Field Office area (Appendix 1) we estimated that the proved gas reserve is the already produced 68.6 million cubic feet. We estimated that the proved oil reserve will be no more than 620 thousand barrels.

When proved reserve estimates for the three provinces are combined, **total proved reserves within the Field Office area are about 55.3 million barrels of liquid reserves and 1.005 trillion cubic feet of gas reserves.**

U.S. GEOLOGICAL SURVEY RESOURCE ASSESSMENTS

The U.S. Geological Survey is responsible for preparing the National Oil and Gas Resource Assessment for all provinces within the United States. Their "1995 National Assessment of United States Oil and Gas Resources" (Beeman et al., 1996: Charpentier et al., 1996: Gautier et al., 1996) presents information about potential undiscovered accumulations of oil and gas in 71 geologic or structural provinces within the United States. Three provinces assessed were the Powder River, Denver, and Wind River basin 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 analysis covering parts of the Field Office area was prepared in response to their new priorities. The resulting reports are titled "Assessment of Undiscovered Oil and Gas Resources of the Powder River Basin province, 2002" (U.S. Geological Survey, 2002 and 2003b) and "2002 USGS Assessment of Oil and Gas Resource Potential of the Denver Basin province of Colorado, Kansas, Nebraska, South Dakota, and Wyoming" (U.S. Geological Survey, 2003a and 2003c). 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 Powder River, Denver, and Wind River basin province assessments, the U.S. Geological Survey estimated undiscovered technically recoverable resources (see Glossary definition) for each play or assessment unit (Tables A1-3, A1-5, and A1-7). When preparing estimates of resource quantities for the play areas, the U.S. Geological Survey assumed that those resource quantities would be producible using current recovery technology but they did not consider the economic viability of those estimated resources, nor the length of time it would take for those resources to be discovered. For the assessment units, 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 or play and a calculation of the portion lying within the Field Office area was made (Tables A1-3, A1-5, and A1-7). We estimate that **all plays and assessment units lying within the Field Office area contain a mean undiscovered volume of 388.77 million barrels of oil, 2.953 trillion cubic feet of gas, and 27.08 million barrels of natural gas liquids.**

In addition, we estimate that **all plays and assessment units lying within the Field Office area contain an undiscovered oil resource that could range from 101.84 to 845.78 million barrels, a gas resource that could range from 1.428 to 5.041 trillion cubic feet, and a natural gas liquids resource that could range from 5.54 to 54.08 million barrels.**

DEPARTMENT OF ENERGY SPONSORED RESOURCE ASSESSMENT (by EG&G Services, Inc. and Advanced Resources International)

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 only reviewed parts of the Tertiary and Cretaceous sections in the Wind River Basin, which encompasses most of that 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 the report of Boswell et al. (2002b).

Boswell et al. (2003b) estimated that about 122 trillion cubic feet of technically recoverable gas, might be contained within the entire Wind River Basin in the formations studied. This is significantly higher than the U.S. Geological Survey (Beeman et al., 1996: Charpentier et al., 1996: Gautier et al., 1996) mean prediction of 16.5 trillion cubic feet of technically recoverable gas for all the potential plays in the entire Wind River Basin province (see Table A1-7). 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. (2003b) assessment of technically recoverable resources is based on the reservoir geology modeled with current technology and assuming full resource development. They also estimated economically-recoverable resources of 33 trillion cubic feet of gas (assuming a gas price of $3.50 per thousand cubic feet, which is close to present prices). That estimate is still almost twice the mean estimate of the U.S. Geological Survey. Again, assuming that 23 percent of the Wind River Basin lies within the Field Office area and assuming that those resources are evenly distributed across the basin: we estimate that

28.06 trillion cubic feet of technically recoverable gas and 7.39 trillion cubic feet of economically-recoverable gas resources may lie in the Field Office area.

None of the Field Office areas in the Powder River or Denver basin provinces were reviewed for the Boswell et al (2003b) assessment.

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), 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 Powder River Basin area was 4.276 trillion cubic feet of gas from 0 to a 15,000-foot depth and 1.000 trillion cubic feet of gas for depths below 15,000 feet. We estimate that the Field Office area occupies about 18 percent of the Wind River Basin region, as defined by the Potential Gas Committee. Assuming that the Potential Gas Committee estimate is spread evenly across the basin, we estimate that the most likely resource for the Field Office portion of the Powder River Basin area is 0.770 trillion cubic feet of gas from 0 to a 15,000-foot depth and 0.180 trillion cubic feet of gas for depths below 15,000 feet. The Committee did not estimate potential coalbed gas resources for that part of the Powder River Basin that lies within the Field Office area. We estimate that the Field Office area contains a total likely resource of 0.950 trillion cubic feet of gas in the Powder River Basin area.

In the Potential Gas Committee (2003) estimate for the Denver Basin, Chadron Arch, Las Animas Arch area, they projected 2.437 trillion cubic feet of gas from 0 to a 15,000-foot depth. They also projected that no gas was recoverable below 15,000 feet in this area. Their estimate of mostly likely coalbed gas resources was 0.300 trillion cubic feet. We estimate that the Field Office area occupies about four percent of the Denver Basin

region, as defined by the Potential Gas Committee. Assuming that the Potential Gas Committee estimate is spread evenly across the basin, we estimate that the most likely resource for the Field Office portion of the Denver Basin area is 0.097 trillion cubic feet of gas from 0 to a 15,000-foot depth and 0.012 trillion cubic feet of coalbed gas. The gas resource left to find in this part of the Field Office would be relatively minor (0.109 trillion cubic feet of gas) in comparison to other portions of the Field Office area.

The Potential Gas Committee (2003) estimate of most likely resources for the Wind River Basin was 6.725 trillion cubic feet of gas from 0 to a 15,000-foot depth, 4.992 trillion cubic feet of gas for depths below 15,000 feet, and 2.450 trillion cubic feet of coalbed gas. We estimate that the Field Office area occupies about 23 percent of the Wind River Basin region, as defined by the Potential Gas Committee. Assuming that the Potential Gas Committee gas estimates are spread evenly across the basin, we estimate that the most likely resource for the Field Office portion of the Wind River Basin area is 1.547 trillion cubic feet of gas from 0 to a 15,000-foot depth, 1.148 trillion cubic feet of gas for depths below 15,000 feet, and 0.564 trillion cubic feet of coalbed gas. We estimate that the Field Office area contains a total likely resource of 3.259 trillion cubic feet of gas in the Wind River Basin area.

The Potential Gas Committee (2003) estimates for all three basins show that the Wind River Basin contains the largest amount of potential gas resources of the three basins partly within the Field Office area. **Total estimated likely gas resources for all lands within the Field Office area are 2.414 trillion cubic feet for depths of 0 to 15,000 feet, 1.328 trillion cubic feet for depths below 15,000 feet, and 0.576 trillion cubic feet for coalbed gas.**

OIL AND GAS OCCURRENCE POTENTIAL

We consider that most of the Casper Field Office area has a high potential for the occurrence of oil and gas (Figure 12). 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 96 percent of the Field Office area falls within this category.

Only about four 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 rock; where traps, reservoir strata, and hydrocarbons are not known to occur.

PROJECTIONS OF FUTURE ACTIVITY 2001-2020

OIL AND GAS PRICE ESTIMATES

Gas Prices

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 Casper Field Office area. These prices can be very volatile as shown in Figures 13 and 14.

Historical gas prices for Opal, Wyoming and estimated future gas prices are shown in Figure 13. Historical prices are in nominal dollars and show the historic volatility that has occurred in natural gas prices in Wyoming. The Energy Information Administration (2004) estimate is for average Rocky Mountain well head gas prices and is made in 2002 dollars. The estimated Opal futures prices were derived from averaged December 2003 New York Mercantile Exchange (NYMEX) futures prices, as found on the Petrie and Parkman website http://ppcenergychannel.com/PetrieParkman&Co.htm, minus $0.60 for gathering and compression. Estimated Opal futures prices are in nominal dollars. NYMEX futures prices are for delivery at Henry Hub near the town of Erath in southern Louisiana. The $0.60, usually referred to as the differential, represents the difference between Opal and Henry Hub gas prices. During 1998-2003 the differential averaged $0.63.

Futures prices and the Energy Information Agency estimate show obvious differences. Although the futures prices and the Energy Information Agency estimate show obvious differences, they both predict that gas prices will decrease from the relatively high prices enjoyed during 2003. We estimate that gas prices will decline to the $3.00 to $4.00 range during the next few years, and may decline below $3.00 if liquefied natural gas imports meet expectations and new pipelines connect gas supplies in northern Canada and Alaska with U.S. markets.

These price estimates allow some generalizations concerning future gas drilling and production activity in the Casper Field Office area. If the gas price scenario explained above is correct, it suggests future gas exploration and production in the Casper Field Office area will be driven by the currently high prices only during the next few years. From about 2005 to 2020, gas prices are expected to remain approximately flat. Starting in about 2005, 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

Anticipated oil prices are based on a combination of adjusted futures prices for West Texas Intermediate (WTI) crude oil, as found on the Petrie and Parkman website http://ppcenergychannel.com/PetrieParkman&Co.htm and the Energy Information Agency (2003) estimates for the Rocky Mountains. Figure 14 shows historical posted oil prices for Wyoming Sweet crude oil, West Texas Intermediate futures prices (adjusted downward $4.00 per barrel), and the Energy Information Agency estimated Rocky Mountain crude oil prices through 2025. The futures prices for West Texas Intermediate crude oil were adjusted to account for the differential between Wyoming Sweet crude oil and West Texas Intermediate crude oil prices. The historical differential is shown in Figure 15 and suggests $4.00 per barrel is a reasonable differential to use for the years 2004-2020.

Both the adjusted West Texas Intermediate futures prices and the Energy Information Agency estimates suggest Wyoming sweet crude oil prices will decrease from the relative high 2003 price of $27.32 per barrel to approximately $22 to $23 per barrel in 2006. Crude oil prices are then estimated to slowly increase to about $25 per barrel, in 2002 dollars, by 2020. In nominal dollars the estimated crude oil price would be about $40 to $45 per barrel in 2020. If this estimate is generally accurate, future drilling and production activity will be driven by industry's ability to discover and economically develop new oil deposits, and increase drilling, recovery, and transportation efficiency. It is unlikely that future oil and gas activity will be driven by significantly higher crude oil prices. It should be remembered however, that much of the world's crude oil comes from politically unstable areas. For both gas and crude oil, occasional, unforeseen, and abrupt price increases should be expected. As with the future gas price estimate, the estimate of future crude oil prices shown here should be considered very speculative. Actual prices may be much different than the estimates shown here.

LEASING

After initial field work, 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. Their maximum size is 2,560 acres and the minimum bid is $2.00 per acre. An administrative fee of $75.00 per parcel is charged and each 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 12.5percent royalty on production is required. Leases which 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.

Casper Field Office Area Leasing

In January 2003 there were numerous Federal oil and gas leases covering a total of 1,738,185 acres in the Casper Field Office area. A summary of Federal leased acreage is shown in Table 8. In total, 1.74 million acres was leased for oil and gas, which is about 39 percent of the Federal mineral estate within the Casper Field Office area. Twenty seven percent of the acreage leased is held by oil and/or gas production. The acreage leased for oil and gas is almost entirely in Natrona and Converse counties.

As Federal oil and gas leases expire the acreage may be nominated for leasing again. The number of Federal acres in the Casper Field Office area leased on an annual basis from 1996 through 2003 is shown in Figure 16. The amount of Federal acreage leased competitively from 1996 through 2003 has averaged 100 thousand acres per year and remained relatively constant. Sixty-nine percent of the acreage offered was leased competitively. From 1996 through 2001, over 1,236 leases in the Casper Field Office area were sold competitively. The average lease size was about 650 acres.

The total amount of money received from bonus bids on Federal oil and gas leasing in the Casper Field Office from 1996 through 2003 was $14.3 million. This is 7 percent of all the lease bonus revenue received for Wyoming during 1996-2003. The average bid was $17.81 per acre compared to $30.33 for the overall Wyoming average. The largest per-acre bid in the Field Office area was $410 per acre for a 586-acre tract in T. 36 N., R. 87 W. near Cave Gulch Field in western Natrona County. The largest bonus bid was $345,600 for a 1,920 acre tract in T. 38 N., R. 75 W. in the southern Powder River Basin. Half of the bonus dollars came from just 12 percent of the leased acreage. The amount received from bonus bids each year and the average dollar per-acre bid are shown in Figure 17. Thirteen percent of the Wyoming acreage offered was in the Casper Field Office area. During 1996-2003, about 12 percent of the oil and gas acreage leased competitively in Wyoming was in the Casper Field Office area.

Disposition of Funds

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 Casper Field Office area 96 percent of the leased acreage is public domain minerals.

Four percent of the Federal minerals under lease in the Casper Field Office area are acquired Federal minerals. Acquired Federal minerals were once private and were reacquired by the Federal government mostly under the authority of the Bankhead Jones Act. Within the Casper Field Office area acquired Federal minerals are almost all within the Thunder Basin National Grassland. A portion of the royalty and lease bonus money goes directly to counties with Thunder Basin National Grassland acreage.

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 Federal oil and gas acreage under lease in the Casper Field Office area between 2000 and 2020 will range between 1.0 and 2.0 million acres. The amount of Federal acreage leased annually is projected to average between 50 thousand and 150 thousand acres. The average size of Federal leases will continue to be relatively large, probably in excess of 500 acres. The amount of acreage held-by-production will probably increase beyond the current 0.47 million acres.

During the next 20 years several currently productive leases in parts of the southern Powder River Basin will probably cease production and expire. Most of the current held-by-production acreage which expires will be leased again as the oil and gas industry searches for deeper targets and more elusive targets in the highly petroliferous southern Powder River Basin. When producing leases cease producing and expire the overriding royalty interests are removed. This reduces the total royalty burden on the acreage and increases general economic viability.

Federal lease bonuses are estimated to average between $1.0 million and $2.0 million per year during 2004 and 2020. Average per acre bids will almost certainly vary substantially from year to year. These projections suggest a minimum of $20 million from lease bonuses will be received during the 2001-2020 planning cycle ($5.3 million was received during 2001-2003). If Federal oil and gas leasing is similar to 1996-2003, approximately $36 million will be received in bonus payments during the 20-year planning cycle of 2001-2020.

SEISMIC SURVEYS

Seismic surveys are a critical part of exploration for oil and gas resources. They are authorized on Bureau of Land Management managed surface by approval of Notices of Intent to Conduct Geophysical Operations. Seismic surveys on surface not managed by the Bureau do not have to be permitted with the Bureau even though the surveys cover Federal minerals. The number of approved Notices of Intent for the Casper Field Office

from 1995 through 2003 is shown in Figure 18. The surveys changed from mostly two dimensional linear surveys to dominantly three dimensional rectangular surveys. They were approximately evenly divided between dynamite and vibroseis.

The number of three dimensional seismic surveys on Bureau of Land Management administered surface in the Casper Field Office area is expected to average no more than about six per year during 2001-2020. The surveys will be mostly three dimensional surveys with occasional two dimensional surveys. We estimate that the amount of Bureau administered surface will average no more than 100 square miles per year, and will probably be much less. There will continue to be occasional two dimensional seismic surveys but they will be relatively insignificant compared to three dimensional surveys.

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 approve by the Bureau. Not every approved Application is actually drilled. Wyoming Oil and Gas Conservation Commission records indicate that 80 percent of the approved drilling applications from 1990-2000 were drilled. Federal wells were 71 percent of all wells drilled in the Casper Field Office area from 1970-2003. Figure 19 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. Wyoming Oil and Gas Conservation Commission records indicate that before 1970 there were 6,960 wells drilled in the Casper Field Office area.

As the number of wells drilled has increased, the depth of the wells has also increased. Figure 20 shows the depth distribution for all wells drilled during 1990-2003. A percentage was used because some wells did not have readily available depth information. From 1990-2001, the average depth of wells was 8,563 feet, however the average depth of Federal wells was 10,418 feet. This may be due in part to a disproportionate share of non-Federal coalbed gas wells being drilled. The average depth of coalbed gas wells is only a few hundred feet and could easily skew the overall depth ranges.

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 to the point of being uneconomic. Figure 21 shows the wells drilled and wells abandoned since 1970. Since 1970, the number of abandonments has been 71 percent of the total number of wells drilled. The number of abandoned wells is probably greater than shown in Figure 21 because from 1900 to 2003 there were 1,507 wells abandoned but there are no abandonment dates available.

Coalbed Gas Drilling

Fifty coalbed gas wells have been drilled in the Casper Field Office since 1999. The Wyoming Oil and Gas Conservation Commission has 103 active drilling permits. Figure 8 is a summary of active permits and well status for coalbed gas wells in the Casper Field Office area. Wyoming Oil and Gas Conservation Commission records indicate only 12 coalbed gas wells have produced at least some gas, although only four of these wells a presently producing. Eleven of the twelve wells are located in on the north edge of the Field Office, in Township 41 North, Range 71 West. The best producer (12.5 million cubic feet of gas) is located in section 31 of this township. The only coalbed gas well in the Wind River Basin portion of the Field Office produced 1.4 million cubic feet of gas and is now shut-in. Eleven wells have produced over 10,000 barrels of water (two of these more than 250,000 barrels of water) and 10 others have produced less than 10,000 barrels. All of the valid permits to drill and those waiting on approval are for wells in the Powder River Basin portion of the Field Office area. With only one well drilled in the Wind River Basin portion of the Field Office and no present proposals for additional drilling, the success and extent of any coalbed gas play that may develop in this area is very much an unknown at this time.

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.

Projections of Future Drilling Activity

It is difficult to predict what will occur a few years into the future. It is very difficult to predict 20 years ahead. In an attempt to get more insight as to what may occur in the Casper Field Office area, geologists and engineers in the oil and gas industry were contacted. Twenty-four oil and gas companies which operate in the Casper Field Office area were contacted by letter and asked their opinion of what development activity will occur during the next twenty years. The Bureau contacted 15 companies by telephone or email about a week later. Five companies provided information useful in constructing the development potential maps. Due to time constraints there was only a very limited review of technical data from wells in the Casper Field Office area by the authors of this report. Structure contour maps drawn by the Rocky Mountain Map Company were used as working base maps.

For a base line, unconstrained reasonable foreseeable development projection (Federal Leadership Forum, 2002, p. 13), we estimate that during the 20-year planning cycle of

2001 to 2020, between 1,400 and 2,800 wells (195 were drilled in 2001-2003) will be drilled in the Casper Field Office area. These wells are expected to be about 75 percent conventional wells and 25 percent coalbed gas wells. The estimated location of non-coalbed gas wells is shown on the Noncoalbed Gas Development Potential Map (Figure 22). Much of the anticipated drilling activity will be infill wells in existing fields. High development potential indicates areas where the average drilling density will be greater than 100 wells per township (36 square miles) during 2001-2020. Moderate indicates 20 to 100 wells per township; low is defined as fewer than 20 wells per township, and very low is defined as fewer than two wells per township. In areas estimated to have no development potential, no wells are anticipated. Well depths for conventional wells will probably continue to increase slightly as deeper reservoirs are developed. We estimate as many as two percent of the wells will be deep wells (15 thousand feet deep or greater). Thirty-seven deep wells were drilled in the Casper Field Office area from 1950 through 2003.

Clearly the Powder River Basin coalbed gas play will extend into the Casper Field Office area, however the play will be much less extensive with only a small fraction of the well numbers that are expected in the northern portion of the Powder River Basin. Although a viable coalbed gas play probably exists in the Casper Field Office area, it is very early in the life of that play, and there is very little available coalbed gas well or production data. In the Wind River Basin portion of the Field Office, there is even less information on potential coalbed gas development. Only two wells have been drilled in the Wind River Basin portion. Based on coal depths and thicknesses we estimate that about 700 coalbed gas wells (of the maximum 2,800 projected wells) will be drilled in the Casper Field Office area by 2020. The number of approved permits for coalbed gas wells will be higher. Historically, about 30 percent of the approved drilling permits for coalbed gas wells are not drilled (Rick Marvel, personal communication, 2004). The location of anticipated coalbed gas drilling is shown on the Coalbed Gas Well Development Potential map (Figure 23). Estimated depths for coalbed gas wells in the southern Powder River Basin will be a few hundred feet to a maximum of as much as 2,000 feet if coals near the base of the Tongue River Member of the Fort Union Formation are sufficiently thick. Although available data are limited, coals in the Lebo Shale and Tullock members of the Fort Union Formation appear to be too thin for a viable coalbed gas play (Flores, personal communication, 2004). Well spacing in the southern Powder River Basin will probably be the same as in the northern part of the basin, one well per 40 or 80 acres. Water and gas production will also be similar to wells in the northern part of the basin. Wyoming Oil and Gas Commission Records indicate an average productive well (Application for Permit to Drill approved before 1996) less than 1,000 feet deep has produced 688 thousand barrels of water (118 acre feet) and 0.21 billion cubic feet of gas.

A coalbed gas play in the eastern Wind River Basin is much more problematic. Shapurji (1978, p. 177) indicates that significant coals in the Mesaverde Formation are in the western part of the basin. If a viable coalbed gas play does develop in the eastern Wind River Basin, well depths will probably be from a few hundred feet to a few thousand feet. Well spacing will probably be one well per 80 or 160 acres. We estimate that few of the coalbed gas wells drilled in the Casper Field Office area during the planning cycle will be

in the eastern Wind River Basin. There are insufficient data to estimate expected well recoveries.

Figure 24 shows the number of producing wells in the Casper Field Office area. The number of producing wells is expected to continue to increase as new wells are drilled in the eastern Wind River Basin, Salt Creek Field, and for coalbed gas development, mostly in northern Converse County.

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 (2004) has recently published estimates of oil and gas production in the Rocky Mountain region and projected production out to 2025. 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. Onshore lower 48 oil production is projected to decline to 1.9 – 2.1 million barrels per day by 2025.

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. The Rocky Mountain share of United States production was 24 percent in 2002 and it will increase to 32 percent in 2010 and 39 percent in 2025.

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 1 billion cubic feet per well. Development of reservoirs below 10 thousand feet are projected to slow the decline in the average finding rate from conventional sources, but at a higher average drilling cost for these type of wells. 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 went from 17 percent (3.0 trillion cubic feet) of total production in 1990 to 32 percent (5.9 trillion cubic feet) in 2002. Unconventional gas production has offset recent declines in conventional gas production. This production is expected to account for 43 percent (9.2 trillion cubic feet) of total lower 48 natural gas production by 2025. Tight gas sand and coalbed gas production account for the largest portion of the undeveloped unconventional gas resource in the lower 48 states.

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 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, with the Wind River Basin projected to increase at the fastest rate (about 8 percent per year). In the Wind River Basin the tight gas production is projected to rise from 95 billion cubic feet in 2002, to 194 billion cubic feet in 2010, and 410 billion cubic feet in 2020. New Wind River Basin wells in the Field Office area will contribute to these projected production increases.

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 1 percent per year through 2025. In the Powder River Basin portion of the Rocky Mountain region coalbed gas production will continue to rise from 325 billion cubic feet in 2002, to 407 billion cubic feet in 2010, and 586 billion cubic feet in 2020. New Powder River Basin coalbed gas wells in the Field Office area will contribute to these projected production increases.

Oil

In 2002, the Casper Field Office area produced 10.4 percent of Wyoming's total oil production. Oil production in the Casper Field Office area was only 25 percent of oil production in 1974, a 4.8 percent average annual nominal decline rate. Oil production from Federal, State, and fee minerals is shown in Figure 25. Clearly the Casper Field Office area is a mature oil producing area. The short term reversals in the decline curves shown in Figure 25 are due to increased oil production from Sand Dunes Field (1992) and in part from Powell and Scott fields (1984 and 1985). Table 9 lists the top ten producing oil fields in the Casper Field Office area for 2002. Notice that Salt Creek Field produced more oil than the next nine fields combined. In 2002, Salt Creek Field produced 36 percent of the total oil produced in the Casper Field Office area and was the third largest oil producing field in the state. It is unlikely that discovery of any new oil fields will cause an intermediate to long term reversal in the decline curve for oil.

What is more likely is application of enhanced oil recovery technology in Salt Creek Field and other old oil fields in the Casper Field Office area. Well over half of the original oil-in-place in Salt Creek Field is still there. Currently the field is in the very early stages of enhanced oil recovery operations using carbon dioxide injection. This recovery method is currently unproven in the Salt Creek Field but shows promise. As of January 2004, over $150 million has been spent to implement carbon dioxide injection. If carbon dioxide injection works as well as anticipated, an additional 150 million barrels could be recovered from Salt Creek Field (Anadarko, 2003). The long term decline in oil production in the Casper Field Office area could reverse and increase by at least five million barrels per year. If carbon dioxide injection does not work as well as anticipated, the decline in oil production should still reverse but the increase may not be as large or as prolonged as hoped. Regardless, it appears that the long term decline in oil production will reverse for at least a few years. Oil production from fields not favorable for enhanced oil recovery will continue to decline.

Non-Coalbed Gas

In 2002, the Casper Field Office area produced 62.9 billion cubic feet of natural gas which was 3.6 percent of Wyoming's total gas production. Gas production in the Casper Field Office area was 39 percent more than in 1974, a 4.9 percent average annual nominal incline rate. Gas production from Federal, State, and fee minerals is shown in Figure 26. Clearly, gas production from the Casper Field Office area is increasing. The abrupt rise in gas production in 1984 was mainly caused by Powell Field in the southern Powder River Basin. The abrupt increase starting in 1995 is caused by Cave Gulch Field in the Wind River Basin. The production decline which started in 1999 is mainly the result of those two fields going into decline at the same time. Table 10 lists the top ten producing gas fields in the Casper Field Office area for 2002.

Although gas production in the Casper Field Office has declined from 100 to 63 billion cubic feet per year since 1999, drilling in the eastern Wind River Basin portion of the Field Office area may reverse or at least flatten the decline during the next few years. Also, the eastern portion of the Wind River Basin is prospective for additional discoveries of natural gas. The decline in gas production from the Casper Field Office area will slow and perhaps reverse during approximately 2004-2008 if gas remains near $4.00 per million British Thermal Unit and exploration and development in the Eastern Wind River Basin is favorable. If wells planed for this area do not find the gas anticipated, then the decline in gas production will probably continue.

Coalbed Gas

Most of the coalbed gas production will probably come from the southern Powder River Basin. The size of a possible coalbed gas play in the Wind River Basin is not known but does not appear to be large. Coalbed gas production in the Casper Field Office area is estimated to be only a minor part of the total gas production between 2001 and 2020.

Associated Water

Water produced in association with natural gas and oil is shown in Figure 27. Produced water increased 54 percent from 1974 to 2003 (average annual nominal increase of 1.5 percent per year). In 2002 about 80 percent of the water production was from Salt Creek Field, and 89 percent of the water production was from federal wells.

Future water production will be influenced by completion of new coalbed gas wells and reduction in water production associated with enhanced oil recovery in Salt Creek Field. Water production from coalbed gas wells could increase annual water production by about 20 percent. Enhanced oil recovery from Salt Creek Field could decrease water production by an unknown but significant amount. Depending on timing, water production could increase about 20 percent or decrease in the next three to eight years. Long term water production is expected to gradually decrease. Most water produced from Salt Creek Field will be reinjected, while most water from coalbed gas wells will be discharged on the surface. Water production per well for coalbed gas wells is expected to be about 800,000 barrels (103 acre feet) over a seven to eight year well life.

Hydraulic fracture of coalbeds has been identified as having a potential negative effect on the quality of underground sources of drinking water. The U.S. Environmental Protection Agency (2002) evaluated the potential danger and found "the threats posed by hydraulic fracturing of CBM wells to underground sources of drinking water are low and do not justify additional study." They did find that the occasional use of diesel fuel in fracturing fluids could introduce constituents of concern to underground sources of drinking water. Their suggestion to industry was to substitute water-based alternatives to "remove any threat whatsoever from injection fluids."

ESTIMATED FUTURE OIL AND GAS PRODUCTION

Enhanced oil recovery at Salt Creek Field, using carbon dioxide gas, is expected to increase from 5,300 barrels per day to a peak rate of 35,000 barrels per day over the next several years (Anadarko, 2003).

Well productivity in Wyoming can range dramatically. The U.S. Department of Energy (2003) reports that productivity can range from wells at Madden field (just west of the Field Office) with some individual wells having a reserve of nearly 1 trillion cubic feet, to exceptionally productive naturally fractured tight-gas wells, to the more common marginal/sub-economic tight-gas wells and thousands of other poor producers.

Estimates of future oil and gas production for the base line projection were determined. Those estimates will be discussed latter in this report (see discussion under "Reasonably Foreseeable Development Scenarios for Resource Management Plan Alternatives A, B, C, D, and E" along with estimates for all alternatives.

OTHER POTENTIAL FUTURE OIL AND GAS ACTIVITIES

Shale Gas

Significant natural gas resources are almost certainly present in shales in the Wind River Basin portion of the Casper Field Office area. PACE Global (PACE Global Energy Services, 2003, page 28) has stated "Carbonaceous shales are the most unexplored, and potentially largest, gas resources in the Rocky Mountain region." This statement is 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. However, this important future natural 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 is expected to use existing boreholes. However, if sufficient reserves per well are present, additional wells may be drilled specifically to develop natural gas from shale. Shale has very low permeability and large hydraulic fracture stimulations will probably be necessary to liberate the gas. 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 in the Wind River Basin, which is located in the western 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 south (in the Rawlins Field Office area) underground coal gasification has been tested in the Shamrock Hills area and to the north (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 and abundant energy supplies from mineable coal in the Powder River Basin, there is a low probability that this process will be utilized in the next 20 years. However, if it becomes economic to remove volatiles from coal beds, then there could be development activity in the Casper Field Office area. We estimate one or two pilot projects could be drilled by 2020.

Carbon Dioxide Sequestration

Carbon dioxide sequestration is a method of storing captured carbon dioxide gas. It is a greenhouse gas that is generated by power plants, oil refineries, cement works, and iron and steel production. In Wyoming, a sizable volume of carbon dioxide is vented during the production of natural gas. Capturing and storing this gas has been proposed to reduce the environmental effects caused by releases of this greenhouse gas. Currently, in the Casper Field Office area (Salt Creek Field), carbon dioxide has been approved for use in a tertiary oil recovery process whereby it is injected into an oil reservoir to adsorb into the interstitial oil, reducing the oil viscosity, and allowing increased recovery of the oil. 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 in southwestern Wyoming and it would otherwise be vented. The operator plans to inject about 7,200 tons per day of carbon dioxide and 24 million tons over the project life (Anadarko, 2003). There are also large coal fired power plants in Wyoming that could be a concentrated source of this gas for tertiary oil recovery.

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. The reservoir at Salt Creek Field is very large, has good reservoir injection characteristics, and has proven to be isolated by an effective cap rock. After the proposed tertiary flooding project is completed, it would be reasonable to fill this reservoir with carbon dioxide and sequester this greenhouse gas for geologic time. This process would also probably recover some extra oil as its saturation level would be reduced to the minimum by gravity segregation with the carbon dioxide gas. There are other large 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 should 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) 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 only injection wells and compressors would be the necessary facilities. In the case where the gas is sequestered in an oil reservoir, additional oil recovery wells may be used to recover the gravity displaced oil. On a regional basis, this process would be an environmental benefit by reducing acid rain and improving air quality. Carbon dioxide injection could begin in 2006 and continue for up to 10 years.

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 (2004) lists six major Wyoming pipeline projects that are at an early planning stage but have not been filed with the commission. They are:

- Kern River Expansion
- Advantage Southern Pipeline Project
- Piceance to Cheyenne Project
- Wheatland Expansion Project
- Bison Pipeline
- Western Frontier Pipeline Project.

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

A 125-mile pipeline carrying carbon dioxide gas was completed to the Salt Creek Field area at the end of 2003 (Anadarko, 2004). The 16-inch pipeline began transporting carbon dioxide, for enhanced oil recovery, to Salt Creek Field in January of 2004. The pipeline potentially could serve other enhanced oil recovery projects in Wyoming as well. No extension of the pipeline is presently proposed, but an extension to other potential project areas, to the north in the Powder River Basin, could be made before 2020.

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

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

PROCEDURES USED TO DETERMINE WELL LOCATION REDUCTIONS

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

- Restriction Category A - These areas are open to leasing. Restrictions are relatively minor and result in standard lease terms and conditions that are applied to every Federal oil and gas lease sold in Wyoming. These restrictions are considered to have no affect on the number of well locations or production for any alternative.
- Restriction Category B – These areas are open to leasing subject to relatively minor constraints. These restrictions can have a moderate effect such as multiple, consecutive timing restrictions for protection of wildlife values such as; crucial winter range, 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.
- Restriction Category C – These areas are open to leasing, subject to major constraints. These restrictions can have a moderate to severe effect on the location of wells; such as no surface occupancy stipulations on an area more than 40 acres in size or requirements that view sheds be protected, thus requiring that well locations and production facilities not be visible from areas such as historic trails. Overlapping minor constraints may also severely limit the development of oil and gas resources.
- Restriction Category D areas are closed to leasing. These are areas where a determination is made that other land uses or resource values cannot be adequately protected with even the most restrictive lease stipulations. This category has the most severe restrictions on oil and gas activity and production.

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

- An estimate of the number of well locations/township that could be drilled in each development potential category over the 20-year life of the Resource Management Plan was made for conventional oil and gas development activity (Table 11) and for coalbed gas development activity (Table 12).
- The acres of Federal oil and gas ownership for each area of non-coalbed 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 area covered by each category of restriction (B, C, or D category) within the high, moderate, low, or very low development potential areas (for non-coalbed gas and coalbed gas potential) was calculated using GIS software. The area within category A was not calculated, since we previously determined that this type of restriction would have no affect on the number of well locations for any alternative. As an example, the Alternative A acreage calculations for each potential area are presented in Table 13.
- After the acres of Federal oil and gas were calculated for each alternative in each restriction category, the percent reduction in well locations for each alternative in each category of restriction was estimated. This estimate is a percent of the well locations which would not be drilled in each area due to the specific category of restriction. As an example, the results of our calculations for conventional oil and gas under Alternative A, Category C restrictions are shown in Table 14 below. Category C restrictions for Alternative A were calculated to reduce non-coalbed oil and gas wells by 74 wells and coalbed gas wells by nine wells. The number of townships was calculated by dividing the Federal acres by 23,040 acres per township.
- The percent reduction for each alternative, each category of restriction, and each development potential combination was determined. A number of additional restrictions for certain alternatives were added for study at a latter date. Potential well reduction determinations were made for each of these additional restrictions. The estimates of reduction in well locations were then summed for both non-coalbed oil and gas and for coalbed gas for each alternative. The results of these calculations are shown in Table 15.
- Because reductions in well locations were calculated only for Federal wells, the percent of Federal wells projected to be drilled for each alternative is different. The percentage of Federal wells projected to be drilled for each alternative is presented in Table 15.

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, all Casper Field Office wells in the Powder River Basin, with a first production date after January 1, 1994, were averaged together and an average estimated ultimate recovery for a type well was estimated using PowerTools Decline software. This information was combined with projections for enhanced oil

recovery at Salt Creek Field (Anadarko, 2003). The resulting estimates of future yearly oil production and total oil production for the period 2001-2020, are presented in Table 16 for the base line and for each alternative.

Gas production was determined using a procedure similar to that for our estimate of oil production. Wells in the Wind River Basin were used to define a type well for gas production from non-coalbed gas wells. Since few coalbed wells have been drilled in the Casper Field Office area, coalbed gas wells just to the north of the Field Office boundary were used to define a type well for coalbed gas production. Information from the Wind River Basin gas well calculations and the coalbed gas well calculations was combined and the resulting estimates of future yearly gas production and total gas production for the period 2001-2020, are presented in Table 17 for the base line and for each alternative.

POTENTIAL SURFACE DISTURBANCE

Table 18 shows our projection of wells that could be drilled from 2001-2020 and calculates associated acres of total surface disturbance (short-term and long-term) directly associated with those wells. Approximately 24,620 acres of total short-term surface disturbance (17,480 acres of Federal disturbance) directly related to well drilling could occur if the 2,800 total wells are drilled. Including existing wells, short-term disturbance would be 44,256 acres (31,422 acres Federal).

In addition, Table 18 calculates unreclaimed associated surface disturbance (long-term disturbance) for the 2001-2020 period for wells that are successfully drilled. This assumes that some newly drilled wells will be abandoned because they are “dry” (no hydrocarbons are encountered, or hydrocarbons are not present in economic quantities when tested), they initially will be capable of producing some hydrocarbons and will became uneconomic to produce at a later date, or mechanical difficulties within the borehole will prevent economic hydrocarbon production. We used recent historical drilling data to determine success rates for each of the four types of wells. Those success rates are; 30 percent for non-coalbed exploratory wells, 90 percent for non-coalbed development wells, 93 percent for coalbed gas wells, and 60 percent for deep wells. Successful wells will total 2,361 (1,676 Federal wells). Unreclaimed (long-term) disturbance from drilling these successful wells will total 7,818 acres (5,551 acres Federal). Including existing wells, unreclaimed long-term disturbance would be 25,945 acres (18,421 Federal acres).

For all alternatives, the same methods of calculating surface disturbance (short-term and long-term) were used. Projections of future wells for each alternative were brought forward and used in these calculations. The resulting short-term and long-term surface disturbance figures for each alternative are presented in Tables 19, 20, 21, 22, and 23.

SUMMARY

For our base line projection we analyzed the oil and gas resource within the Casper Field Office planning area, discussed types of future development that may occur, estimated the development potential for each type of resource, and projected base line activity levels for the period 2001 through 2020. For our analysis of the base line projection, we assumed that the only land use restrictions on future oil and gas resource development would be those that have been legislatively imposed. Projections of future well numbers, oil and gas production, and surface disturbance for all alternatives were also prepared.

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 (conventional resource). 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.

Field growth. The increases in known petroleum volume that commonly occur as oil and gas fields are developed and produced; synonymous with reserve growth.

Gas accumulation. An accumulation with a 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.

Geologic 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.

Grown petroleum volume. Known petroleum volume adjusted upward to account for future reserve growth. Thirty years of reserve growth is considered for the U.S. Geological Survey assessments.

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.

Known petroleum volume. The sum of cumulative production and remaining reserves as reported in the databases used in support of the U.S. Geological Survey assessment. Also called total recoverable volume (sometimes called ultimate recoverable reserves or estimated ultimate recovery).

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.

Nonconventional (unconventional) resources. Include basin-centered gas, shale gas, and coalbed gas. This type of resource typically occurs in continuous accumulations that are larger in area than conventional discrete accumulations.

Oil accumulation. An accumulation with a gas to oil ratio of less than 20,000 (in cubic feet per barrel).

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

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

Proved growth reserves. The estimated technical resource remaining in a field above the current estimate of proved reserves.

Proved reserves (oil or natural gas). 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.

Reserve growth. The increases in known petroleum volume 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.

Technically recoverable resource. That quantity of oil or gas recoverable with current technology and without regard to the economics of doing so.

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 resource. The total volume of resource expected to be found in the future that is not due to growth of existing fields.

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

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APPENDIX 1 - U.S. GEOLOGICAL SURVEY ASSESSMENTS OF UNDISCOVERED OIL AND GAS RESOURCES WITHIN THE CASPER 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 Casper 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. Three of those provinces, the Powder River Basin, Denver Basin, and Wind River Basin, lie partly within the Field Office area. Figure A1-1 shows the location of each of the three provinces.

Recently the U.S. Geological Survey revised their methods of preparing oil and gas resource assessments. They used that new method to update their quantitative estimate of the undiscovered oil and gas resource for the Denver Basin province and updated a portion of the Powder River Basin province (U.S.G.S.; 2002, 2003a, 2003b, and 2003c). In the following analysis, we will use both Powder River Basin province assessments, the newer 2003 Denver Basin province assessment, and the older Wind River Basin assessment to describe the potential undiscovered technically recoverable oil and gas resources lying within the Field Office area.

POWDER RIVER BASIN PROVINCE ASSESSMENT

The Powder River Basin province occupies about half (the central part) of the Field Office area. It's a major basin in the northern Rocky Mountains, covering northeastern Wyoming and a small part of southeastern Montana (about 34,000 square miles). The province is a deep, northerly trending, asymmetric, mildly deformed syncline, about 250 miles long and 100 miles wide. Its southernmost end extends into the Field Office area (Figure A1-1). The province is bounded on the west by the Bighorn Mountains and the Casper Arch, on the south by the Laramie and Hartville Uplifts, and on the east by the Black Hills uplift. The Denver Basin province lies to the southeast, in the Field Office area, and the Wind River Basin province lies to the west. In the Field Office portion of the province, the total sedimentary rock thickness appears to be between 16,800 and 18,000 feet. Oil and gas production in the Field Office portion of the province has been most concentrated in the center of the basin, with few fields on the outer flanks.

Play Summaries

Parts of the "1995 National Assessment of United States Oil and Gas Resources" (Beeman et al., 1996: Charpentier et al., 1996: Gautier et al., 1996) were not updated with the latest U.S. Geologic Survey assessment of oil and gas resources within the Powder River Basin province. Their earlier resource assessments for 11 conventional oil and gas plays (Figures A1-2, A1-3, A1-4, A1-5, A1-6, A1-7, A1-8, A1-9, A1-10, A1-11, and A1-12) were carried forward into the updated assessments (U.S. Geological Survey, 2002 and 2003b). The earlier assessment divided the Powder River Basin province into "play" areas. Each play area is a set of discovered or undiscovered oil and gas accumulations or prospects that are geologically related. The U.S. Geological Survey defined a play "by the geological properties (such as trapping style, type of reservoir, nature of the seal) that are responsible for the accumulations or prospects." The eleven plays are defined as conventional type plays. A conventional play will contain oil and gas accumulations having hydrocarbon-water contacts (due to the buoyancy of hydrocarbons in water) and seals that hold or trap the hydrocarbons. The hydrocarbons in these plays can be recovered using traditional development and production practices. The U.S. Geological Survey has made available some statistical information for these plays (Table A1-1). Supporting geologic studies for these play areas are available at Gautier et al. (1996).

Assessment Unit Summaries

In their newest assessment, the U.S. Geological Survey (2002 and 2003b) divided the Powder River Basin 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). The previously discussed 11 conventional play areas now fall within the conventional accumulation category, and as previously noted the U.S. Geological Survey carried them forward into the new analysis with no modification. Most of the older fields within the Field Office area can be classified as conventional accumulations of hydrocarbons. A small portion of one new conventional assessment unit, Eastern Basin Margin Upper Fort Union Sandstone, (Figure A1-13) was identified as lying within the Field Office area and was included in the new study, with available statistical information for it shown in Table A1-1.

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. In their newest assessment, the U.S. Geological Survey (2002 and 2003b) redefined all continuous accumulations using their new methods. They recognized six continuous assessment units in the Powder River Basin province. All six of the identified continuous assessment units lie partly within the Field Office boundary (Figures A1-14, A1-15, A1-16, A1-17,

A1-18, and A1-19). Three of the assessment units are coalbed gas, two are oil, and the sixth is a gas unit. The U.S. Geological Survey has made available some statistical information for these assessment units (Table A1-2), but the supporting geologic studies await formal publication.

Assessment Unit and Play Resource Results

The U.S. Geological Survey (2002 and 2003b) 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. The U.S. Geological Survey (Beeman et al., 1996: Charpentier et al., 1996: Gautier et al., 1996) did not use a forecast span to estimate undiscovered technically recoverable resource quantities for the 11 play areas from their "1995 National Assessment of United States Oil and Gas Resources." Below, we summarize the estimated volumes of hydrocarbons in the 11 conventional plays, the one conventional assessment unit, and six continuous assessment units, which lie at least partly within the Field Office area.

In Table A1-3, the U.S. Geological Survey resource estimates for three types of hydrocarbons (oil, gas, and natural gas liquids) are shown for the conventional plays, a conventional assessment unit, and the continuous assessment units in the Powder River Basin 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 or play area,
- calculated the percent of each assessment unit or play area that lies within the Field Office area, and
- multiplied that percentage by the U.S. Geological Survey resource value estimates for each entire assessment unit or play area to calculate Field Office area resource values.

Our estimates of recoverable resources for each assessment unit or play area 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 345.24 million barrels of oil, 2.681 trillion cubic feet of gas, and 23.26 million barrels of natural gas liquids, in the Powder River Basin province assessment units and play areas.**

In addition, we estimate that the Field Office area's oil resource in the Powder River Basin province could **range from 97.51 to 750.04 million barrels, the gas resource**

could range from 1.403 to 4.467 trillion cubic feet, and the natural gas liquids resource could range from 5.26 to 48.54 million barrels.

DENVER BASIN PROVINCE ASSESSMENT

The Denver Basin province report was prepared as part of the U.S. Geological Survey's ongoing "National Oil and Gas Resource Assessment." The Denver Basin province occupies the southeastern part of the Field Office area, immediately southeast of the Powder River Basin province. It is a Laramide-aged structural basin located in eastern Colorado, southeastern Wyoming, the southwestern corner of South Dakota, and the Nebraska Panhandle. Productive traps have been primarily stratigraphic (mainly facies change and updip pinch-out of reservoir intervals). The Denver Basin province occupies a part of the Field Office area where only a small portion of the mineral estate is managed by the Bureau.

Assessment Unit Summaries

In their newest assessment, the U.S. Geological Survey (2003a and 2003c) divided the Denver Basin province into "total petroleum systems" and "assessment units" (see Glossary definitions) rather than "plays." Each assessment unit falls within one of two types of potential undiscovered accumulation: conventional and continuous accumulations (see Glossary definitions). Only five discovered fields lie within Field Office boundaries and within the Denver Basin province. The fields (Chugspring, Hawk Springs, Springer, Torrington, and Yoder) can be classified as conventional accumulations of hydrocarbons (Cretaceous aged stratigraphic traps). Fifty wells have been drilled within these fields, with only one well still producing. Cumulative production has been only 618,096 barrels of oil and 68.6 million cubic feet of gas (through October, 2003).

Continuous accumulations can include tight reservoirs, shale reservoirs, unconventional reservoirs, basin-centered reservoirs, fractured reservoirs, coalbeds, oil shales, and shallow biogenic gas. No Denver Basin discovery has been reported from this type of accumulation in the Field Office area.

The U.S. Geological Survey recognized five conventional assessment units in the Denver Basin province. Three of the five identified assessment units lie partly within the Field Office boundary (Figures A1-20, A1-21, and A1-22). Most Field Office area production has come from the Dakota Group and D Sandstone assessment unit. Only one well (at the Chugspring Field) appears to have produced 685 barrels (prior to abandonment) from the Fractured Niobrara Limestone Transitional assessment unit, although the U.S. Geological Survey did not recognize any discoveries in that assessment unit within the Field Office area. 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 U.S. Geological Survey also recognized seven continuous assessment units in the Denver Basin province. Two of the seven identified continuous assessment units lie partly within the Field Office boundary (Figure A1-23). The two assessment units (Denver Formation Coals and Laramie Formation Coals coalbed gas assessment units) occupy the same area. Neither assessment unit was quantitatively assessed, so no statistical information was available to include in this document.

Assessment Unit Resource Results

The U.S. Geological Survey (2003a and 2003c) 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 three conventional assessment units lying at least partly within the Field Office area. The U.S. Geological Survey did not quantitatively assess the Denver Formation Coals and Laramie Formation Coals coalbed gas continuous assessment units, because they lack sufficient supporting data to calculate resource estimates. In the future, if reserves are discovered within these two assessment units, 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 assessment units in the Denver Basin 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, and
- 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 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 3.96 million barrels of oil, 4.23 billion cubic feet of gas, and 1.34 million barrels of natural gas liquids, in the three Denver Basin province assessment units.**

In addition, we estimate that the Field Office area's oil resource in the Denver Basin province could **range from 1.19 to 7.86 million barrels, the gas resource could range**

from 1.22 to 8.76 trillion cubic feet, and the natural gas liquids resource could range from 0.08 to 0.65 million barrels.

Proved reserves (cumulative production plus remaining reserves) were also estimated by the U.S. Geological Survey, but we were unable to use their information to make an estimate for that part of the Field Office within the Denver Basin province. Our review of existing production shows that cumulative production has been only 618,096 barrels of oil and 68.6 million cubic feet of gas (through October, 2003). These numbers appear to be close to a proved reserve estimate for the Denver Basin province assessment units producing within the Field Office area, because only one well still produces. The only existing well still producing is an older well that has been producing for almost 22 years. This well was producing 1.3 barrels of oil per day in October, 2003 and no gas. With this information in mind, we estimate that the **proved gas reserve is the already produced 68.6 million cubic feet**. We estimate that the **proved oil reserve will be no more than 620,000 barrels**.

WIND RIVER BASIN PROVINCE ASSESSMENT

The Wind River Basin province occupies the western part of the Field Office area, immediately west of the Powder River Basin province. It's a west-east-trending asymmetrical intermontane basin located in central Wyoming, covering about 11,700 square miles. The province is bounded on the west by the Wind River Mountains, on the north by the Owl Creek Mountains, with Casper Arch to the east, and the Sweetwater Uplift to the south. The Wind River Basin province is about 200 miles long and 100 miles wide. Its southeastern end extends into the Field Office area. Oil and gas drilling and production has been spread across most of the province were it lies within the Field Office area.

Play Summaries

The "1995 National Assessment of United States Oil and Gas Resources" (Beeman et al., 1996: Charpentier et al., 1996: Gautier et al., 1996) was not updated with the latest U.S. Geologic Survey assessment of oil and gas resources. All of their 12 conventional oil and gas plays lie at least partly within Field Office boundaries (Figures A1-24, A1-25, A1-26, A1-27, A1-28, A1-29, A1-30, A1-31, A1-32, A1-33, and A1-34). Their assessment divided the Wind River Basin province into "play" areas. Each play area is a set of discovered or undiscovered oil and gas accumulations or prospects that are geologically related. The U.S. Geological Survey defined a play "by the geological properties (such as trapping style, type of reservoir, nature of the seal) that are responsible for the accumulations or prospects." The twelve plays are defined as conventional type plays. A conventional play will contain oil and gas accumulations having hydrocarbon-water contacts (due to the buoyancy of hydrocarbons in water) and seals that hold or trap the hydrocarbons. The hydrocarbons in these plays can be recovered using traditional development and production practices. The U.S. Geological Survey has made available some statistical information for these plays (Table A1-6). Supporting geologic studies for these play areas are available at Gautier et al. (1996).

Two unconventional plays were described in the Wind River Basin province. Only the basin-center gas play, a continuous-type play lies partially within the Field Office area (Figure A1-35). This play was determined to be hypothetical because there had been virtually no exploration at the time of publication. It is characterized by an extensive and continuous overpressured low permeability gas accumulation trapped in Tertiary and uppermost Cretaceous sandstone reservoirs in deep parts of the Wind River Basin. The play is distinguished by overpressuring due to active generation of gas. Due to its hypothetical nature, the play was not quantitatively assessed.

Play Resource Results

The U.S. Geological Survey ((Beeman et al., 1996: Charpentier et al., 1996: Gautier et al., 1996) estimated undiscovered technically recoverable resource quantities of oil and gas that could be added to the proved reserves within six of the 12 conventional play areas. No estimate of undiscovered technically recoverable resource was made for those conventional plays listed as not quantitatively assessed on Table A1-6, or for the unconventional basin-center gas play. In the future, if reserves are discovered within these play areas, resulting resource estimates would be greater than those that we present. Below, we summarize the estimated volumes of hydrocarbons in the six conventional plays, which lie at least partly within the Field Office area.

In Table A1-7, the U.S. Geological Survey resource estimates for three types of hydrocarbons (oil, gas, and natural gas liquids) are shown for the six conventional plays with available data in the Wind River Basin 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:

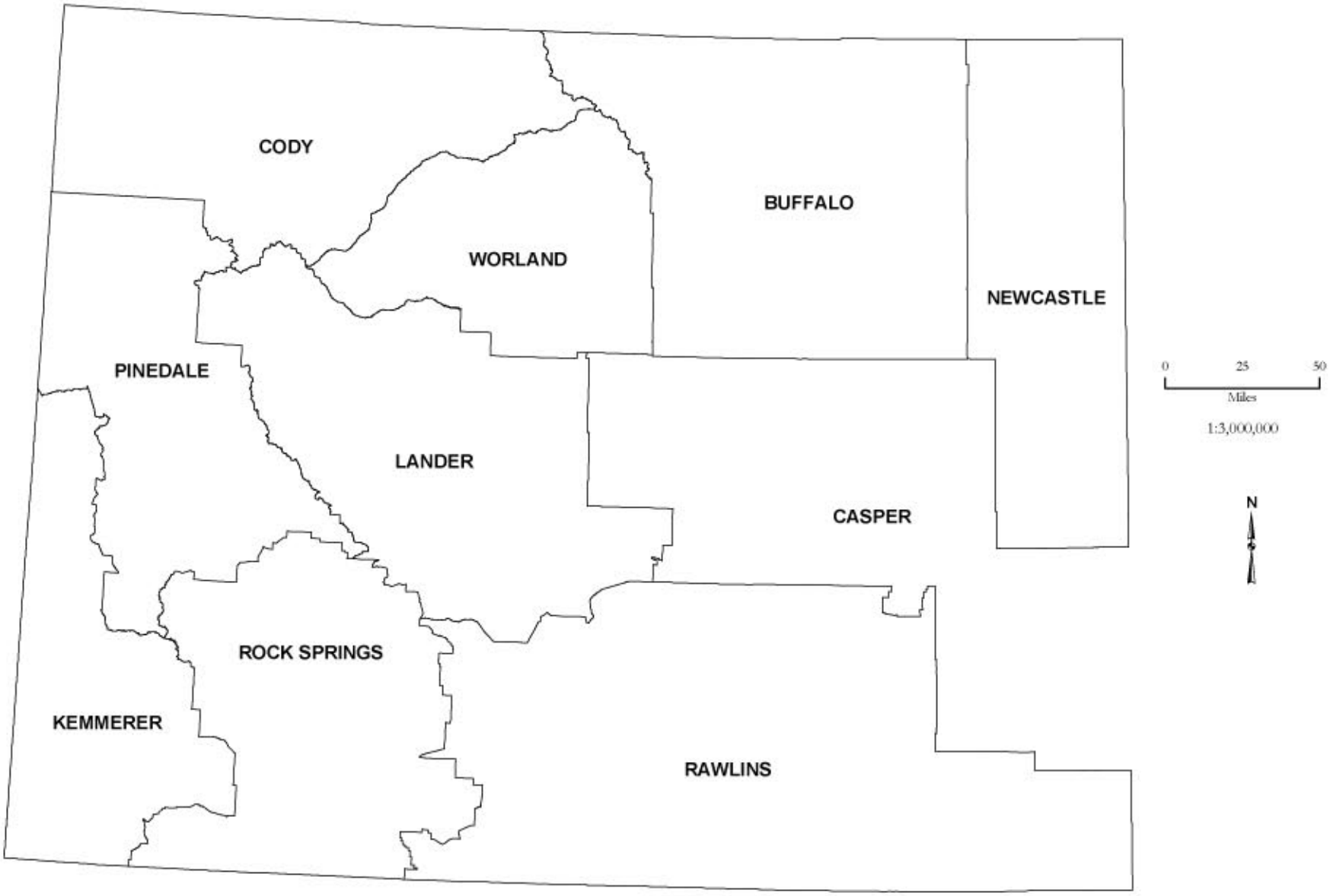
- assumed a homogenous distribution of each hydrocarbon type within each play area,
- calculated the percent of each play area that lies within the Field Office area, and
- multiplied that percentage by the U.S. Geological Survey resource value estimates for each entire play area to calculate Field Office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

Our estimates of recoverable resources for each of the six play areas 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 39.57 million barrels of oil, 0.268 trillion cubic feet of gas, and 2.48 million barrels of natural gas liquids, in the Wind River Basin province play areas.**

In addition, we estimate that the Field Office area's oil resource could **range from 3.14 to 87.88 million barrels, the gas resource could range from 0.023 to 0.565 trillion cubic feet, and the natural gas liquids resource could range from 0.20 to 4.89 million barrels.**

Figure 1.

Location of Casper Field Office management area and its relationship to other Bureau management areas in Wyoming.



May 18, 2004

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

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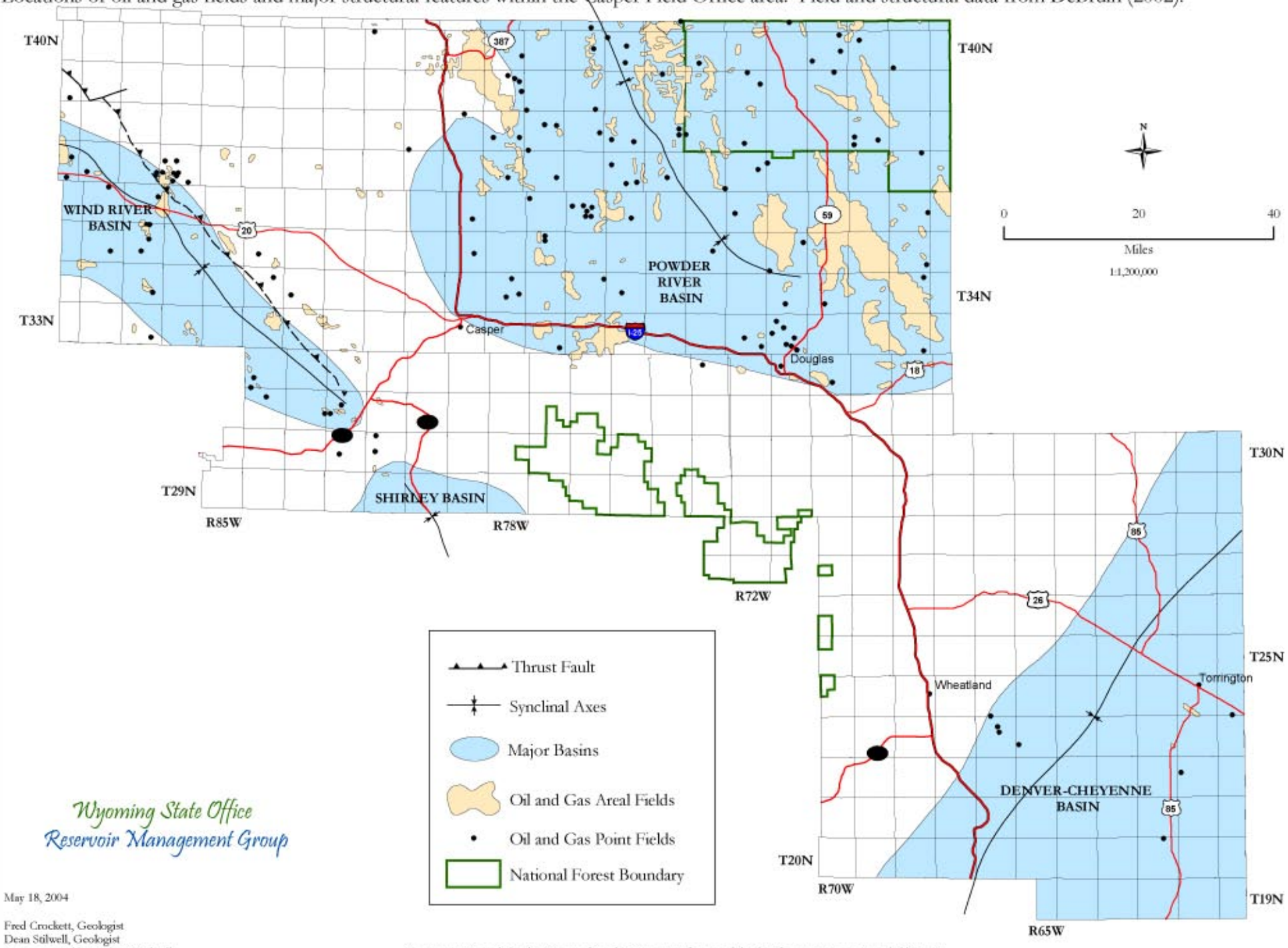
Wyoming State Office
Reservoir Management Group

Figure 2.

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



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

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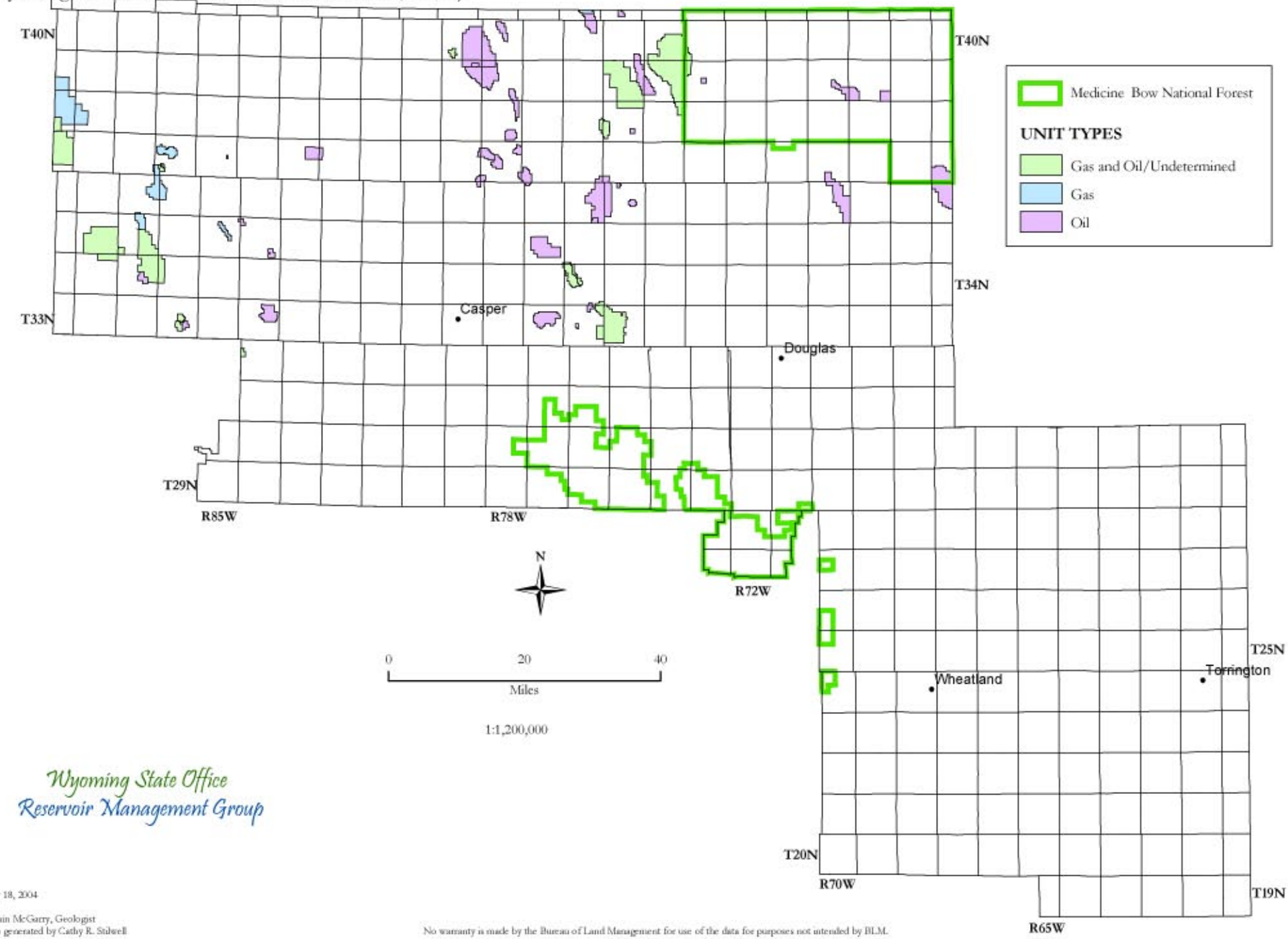
Figure 3.

Unit agreements within or intersecting Casper Field Office boundary. Boundaries from Bureau files. Unit types are as classified on December 17, 2003 (Wyoming Oil and Gas Conservation Commission, 2003a).



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Reservoir Management Group

May 18, 2004

Dwain McGarry, Geologist
Map generated by Cathy R. Stilwell

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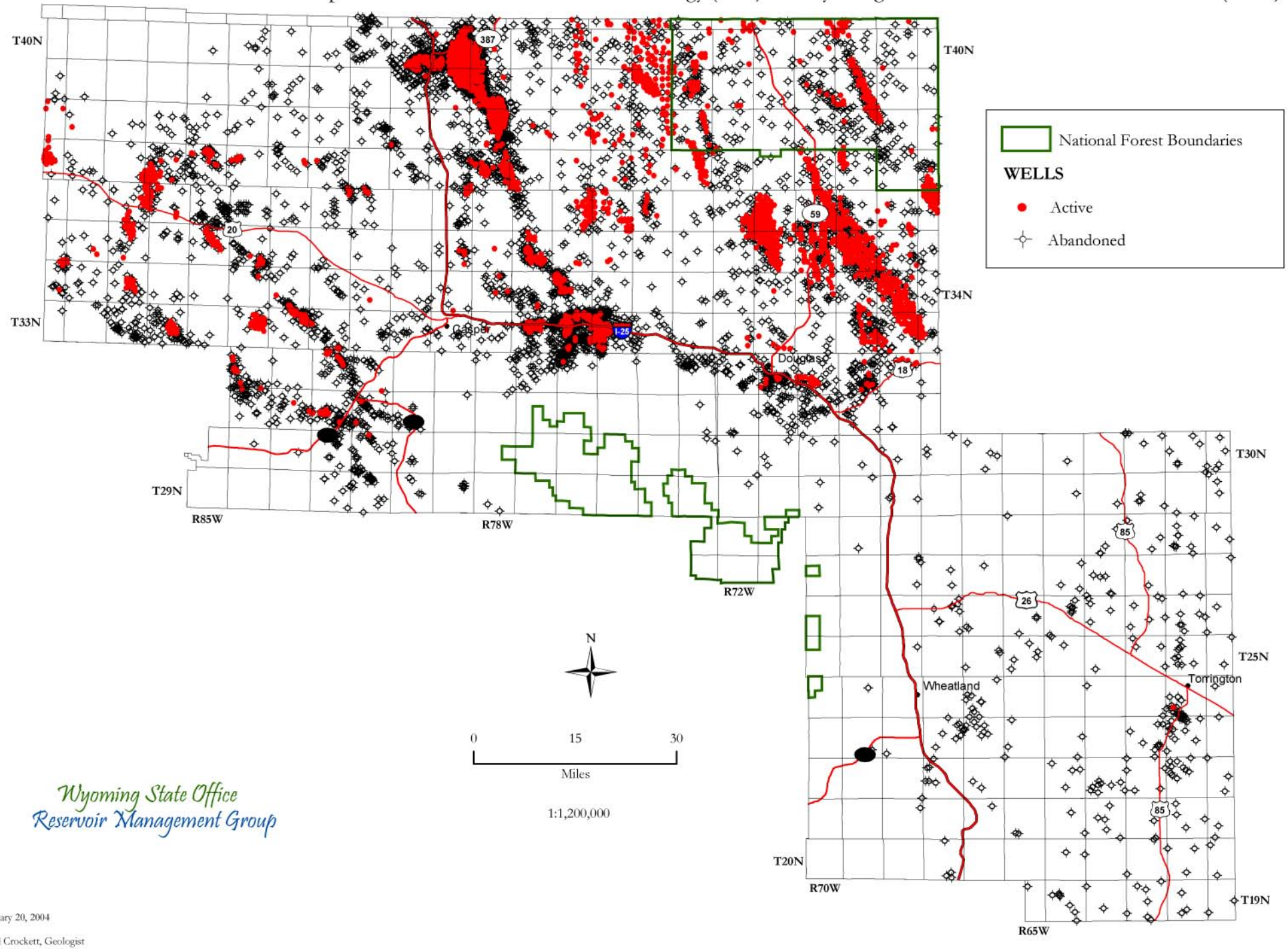
Figure 4.

Location of all wells drilled within the Casper Field Office area. Data from IHS Energy (2003) and Wyoming Oil and Gas Conservation Commission (2003a).



Wyoming State Office
Reservoir Management Group

January 20, 2004

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

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Figure 5. Stratigraphic nomenclature chart for the Denver Basin. The main productive intervals in the Casper Field Office are the Muddy (J) Sandstone and Codell Sandstone. Modified from Beeman et al. (1996).

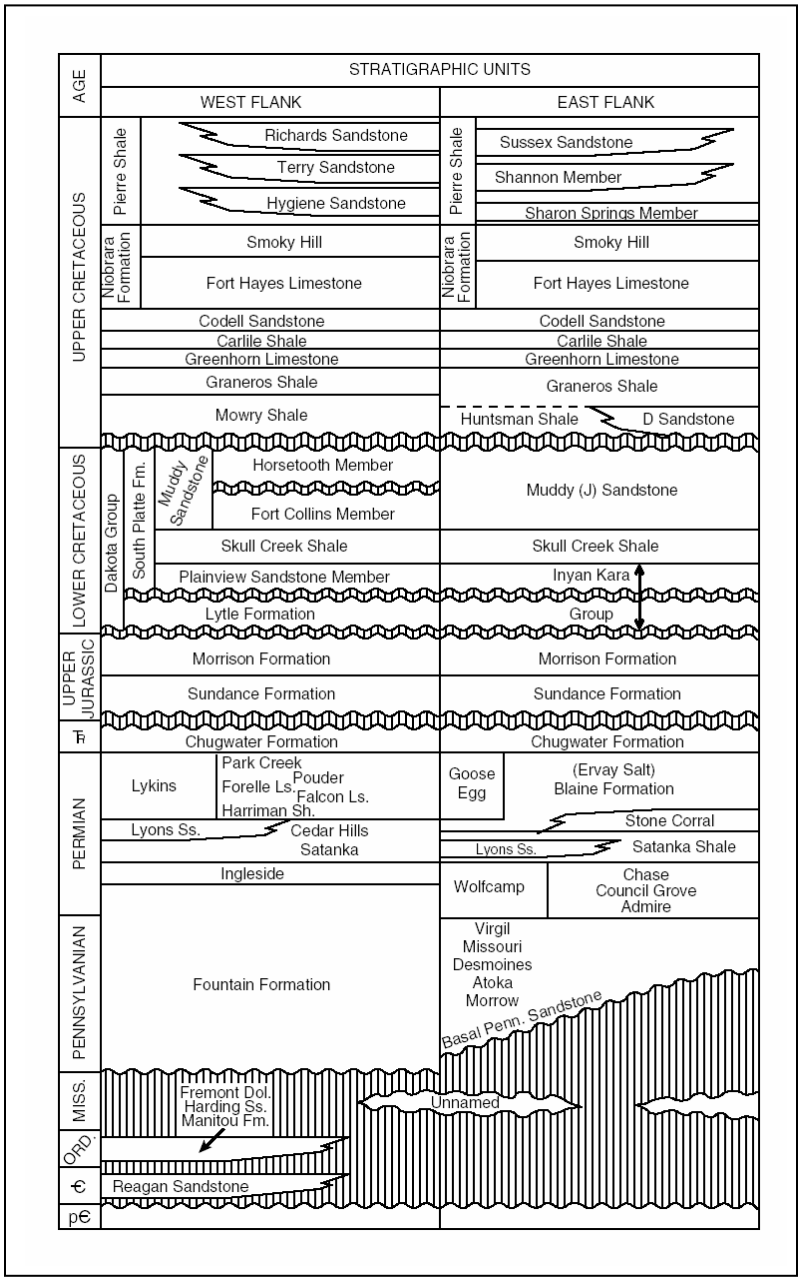


Figure 6. Stratigraphic nomenclature chart for the Powder River Basin. Hydrocarbon producing intervals are shown by black dots. Coalbed gas production is from the Tongue River member of the Fort Union Formation and is not identified on this chart. Modified from Beeman et al. (1996).

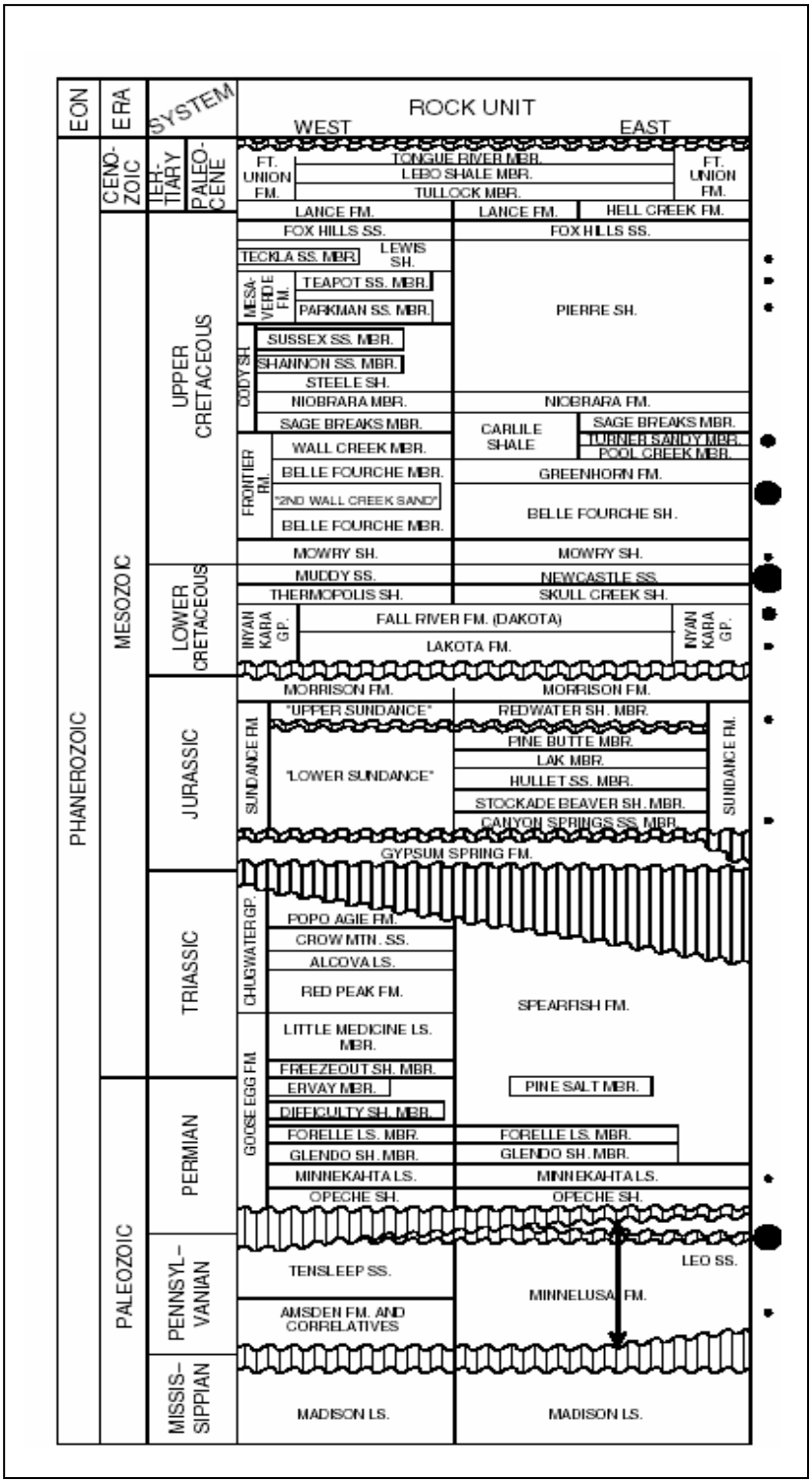


Figure 7. Stratigraphic nomenclature chart for the Wind River Basin. The most prolific producing Field Office intervals are the Tensleep Sandstone, Lance Formation, Fort Union Formation, Muddy Sandstone, and Mesaverde Formation. Modified from Beeman et al. (1996).

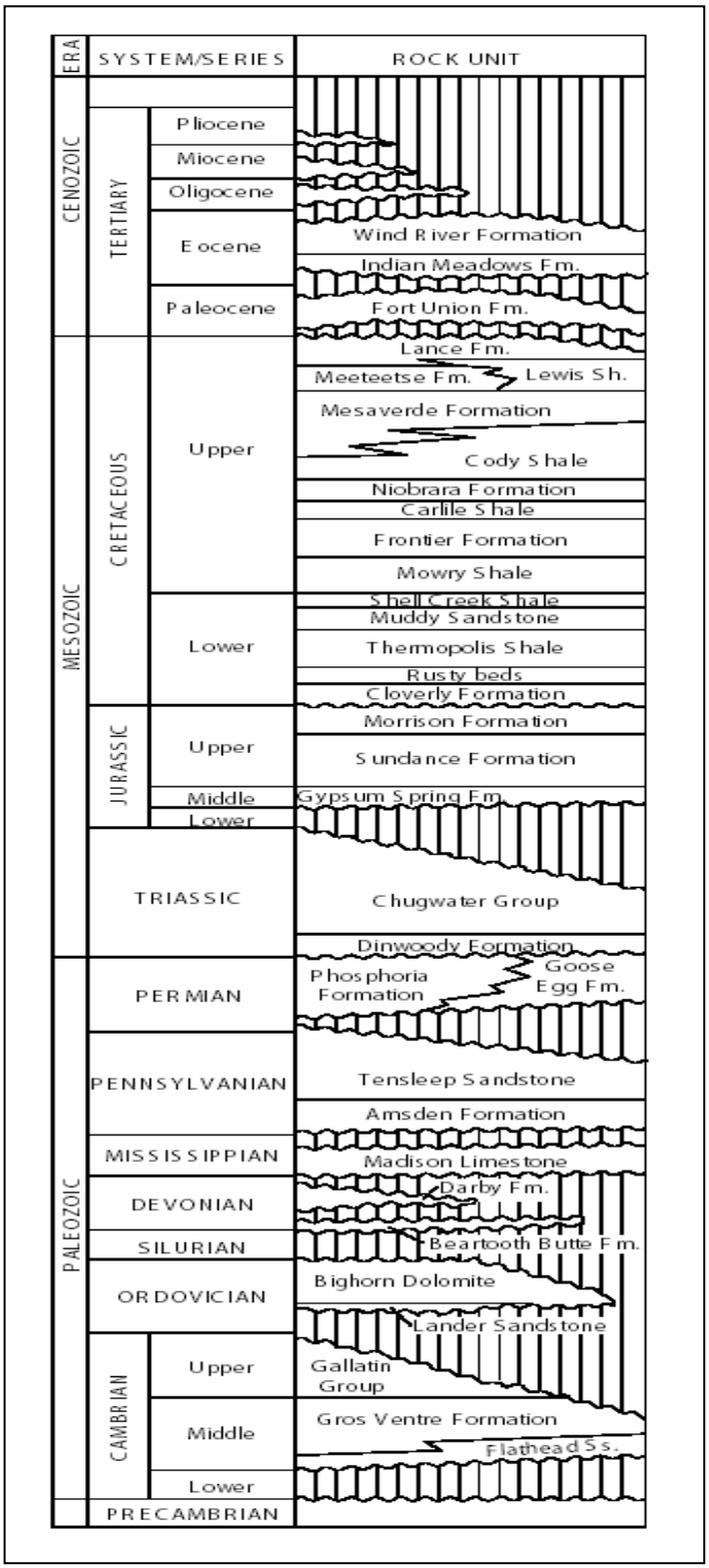


Figure 8. Status of coalbed gas applications to drill and well status, as of January 4, 2005. Data are from the Wyoming Oil and Gas Conservation Commission (2003a).

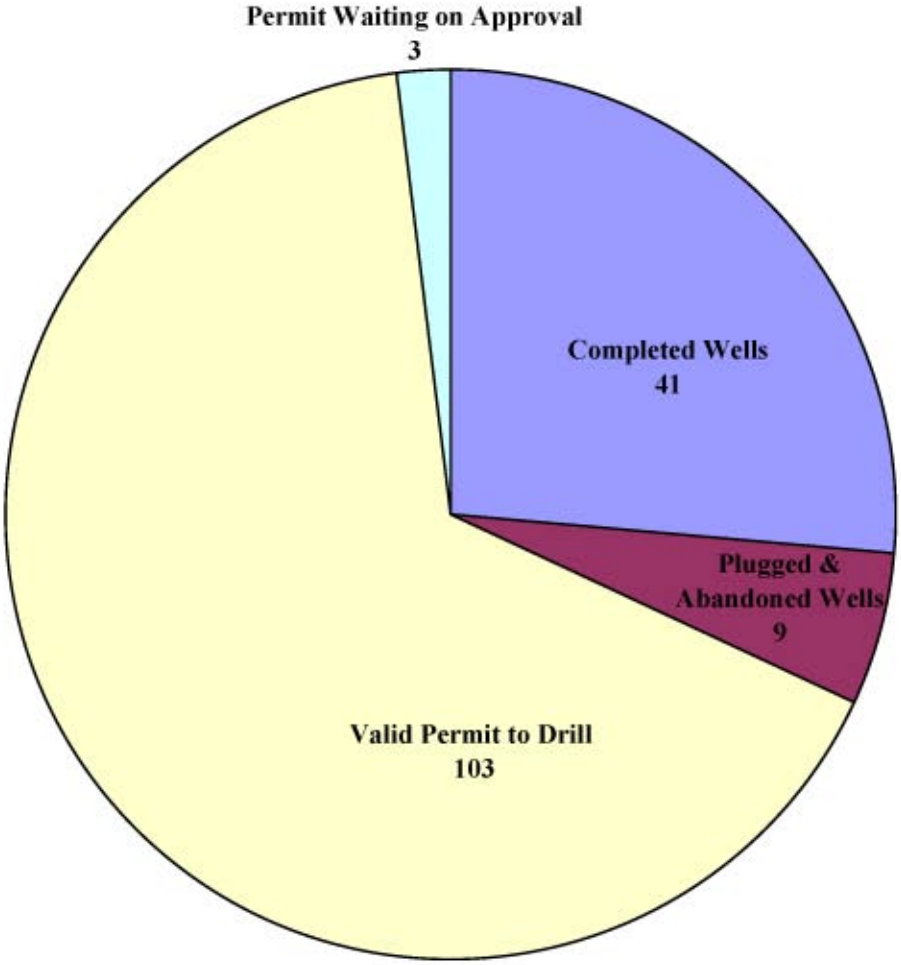
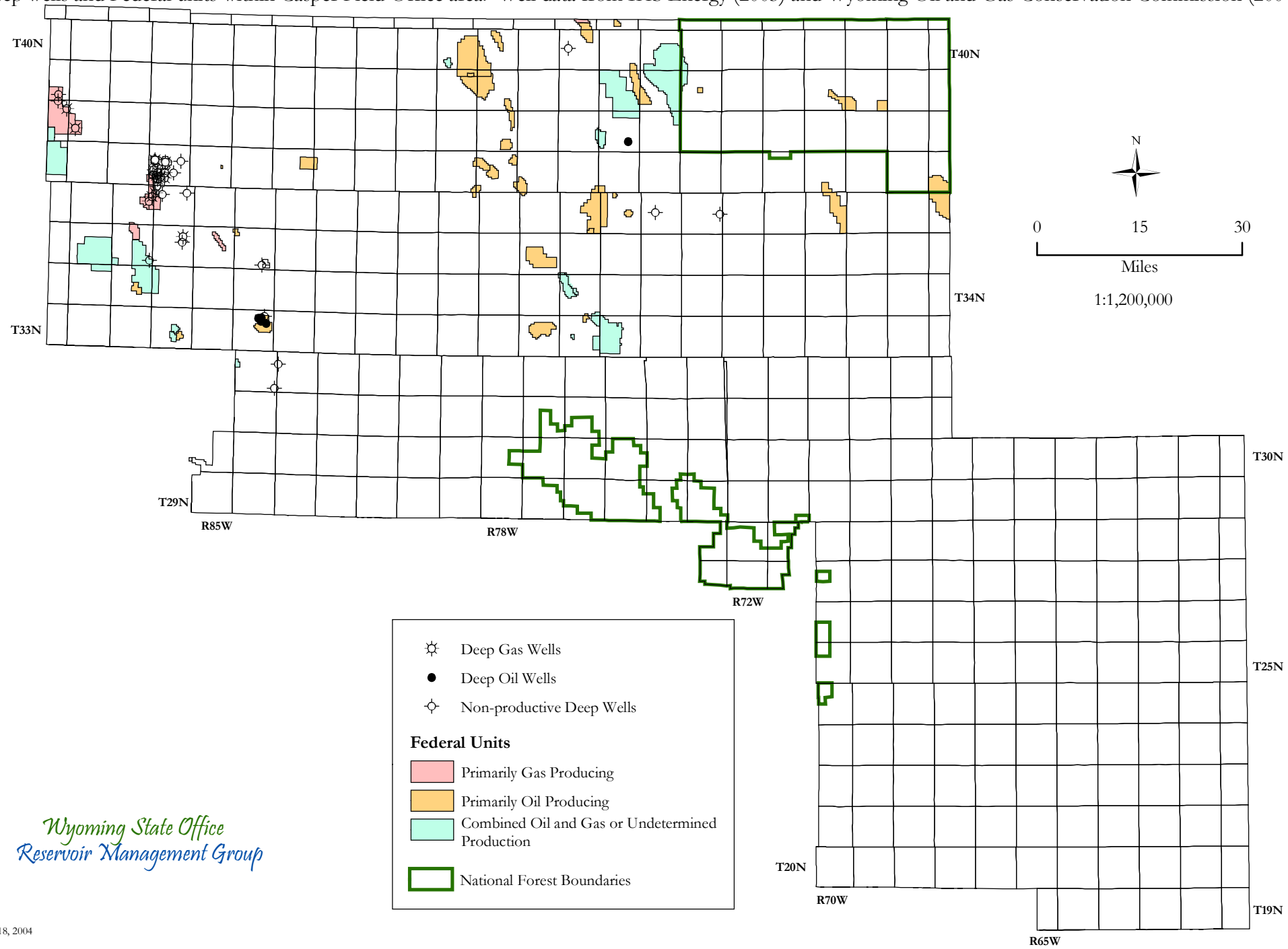


Figure 9.
Deep wells and Federal units within Casper Field Office area. Well data from IHS Energy (2003) and Wyoming Oil and Gas Conservation Commission (2004).



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Reservoir Management Group

May 18, 2004

Dwain McGarry, Geologist
Map generated by Cathy R. Stilwell

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Figure 10.

Deep hydrocarbon potential (>15,000 feet) within Casper Field Office area.

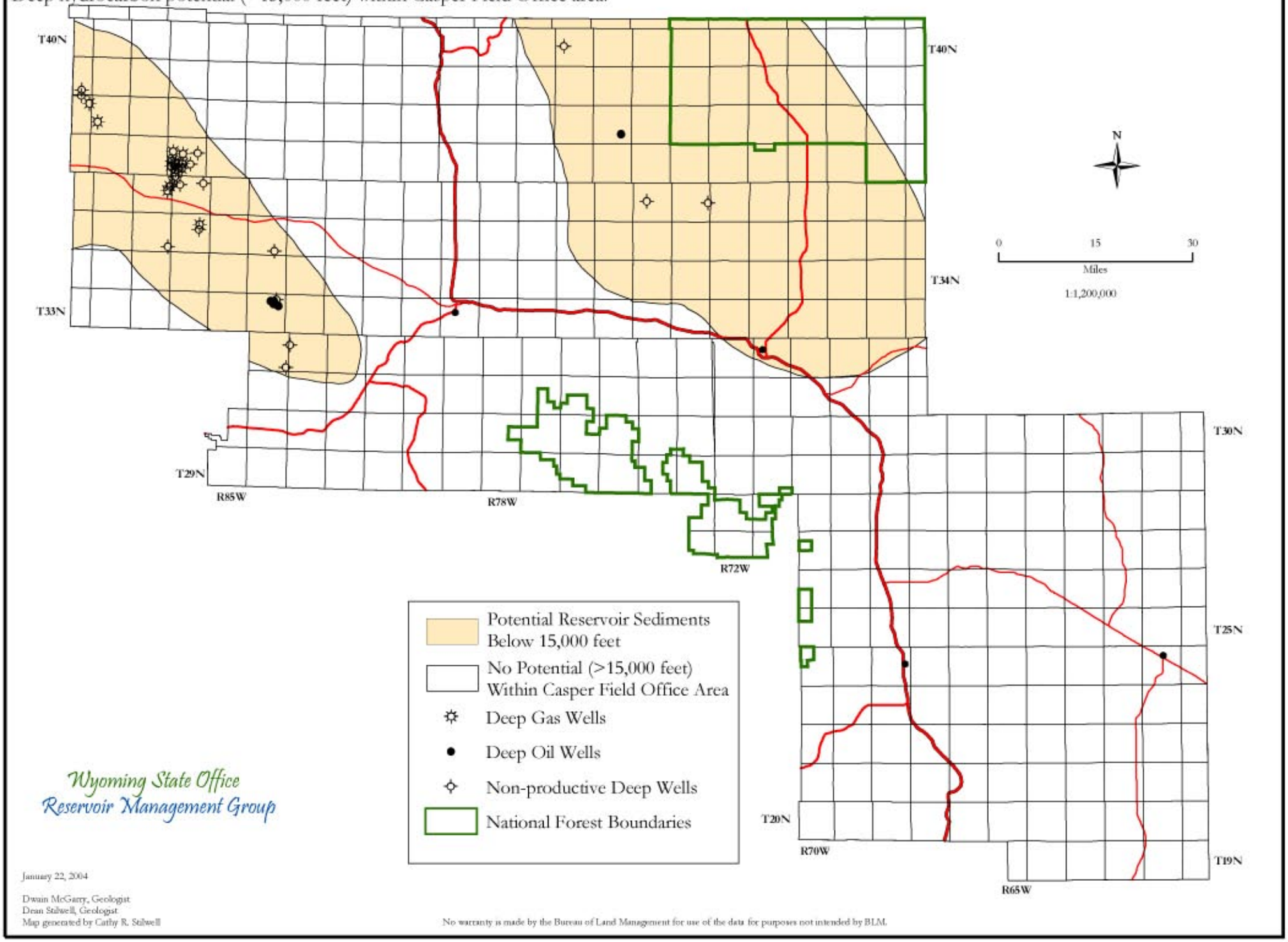
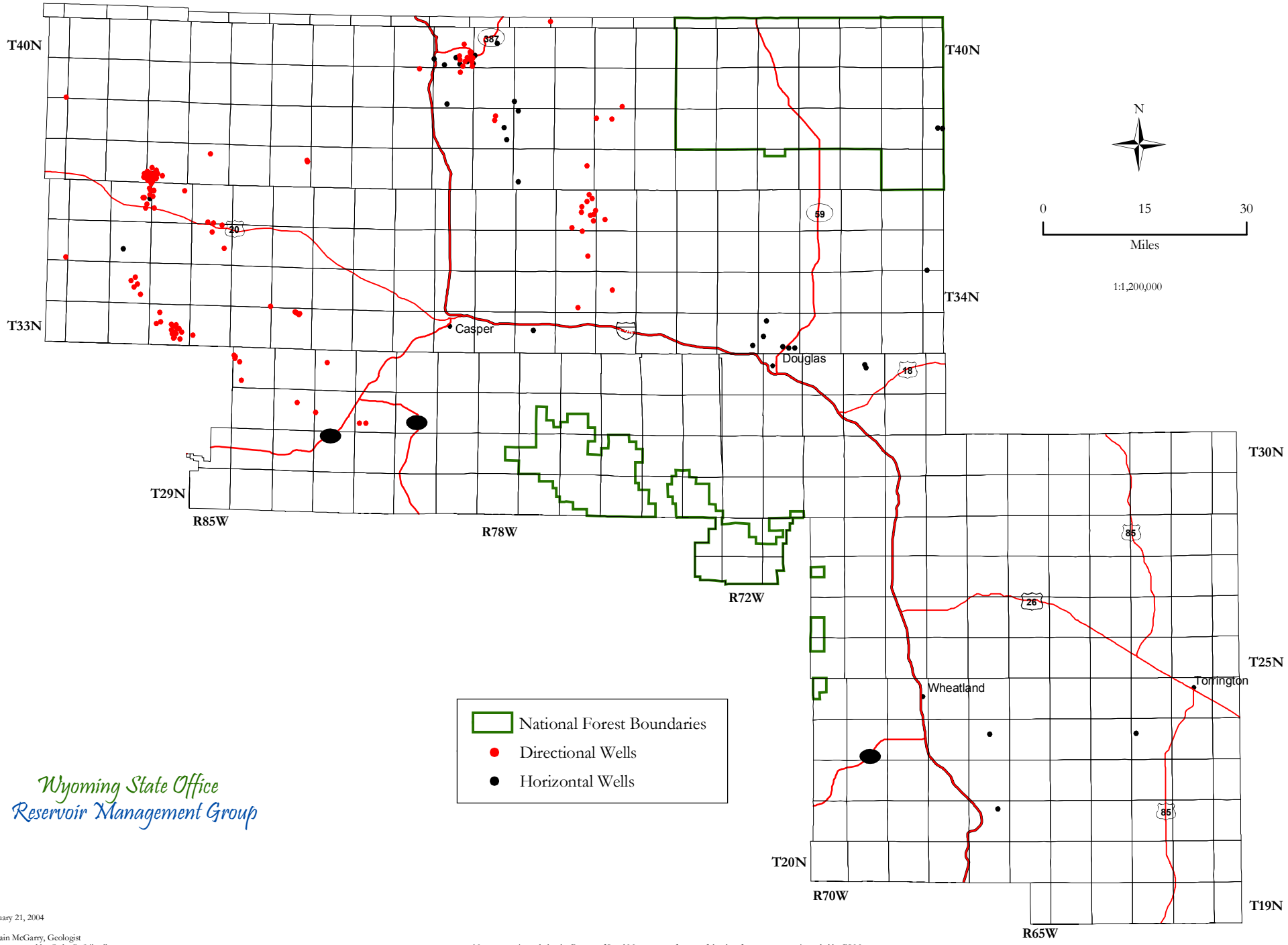


Figure 11.

Horizontal and directional well locations within Casper Field Office area. Well data from IHS Energy (2003).



Wyoming State Office
Reservoir Management Group

January 21, 2004

Dwain McGarry, Geologist
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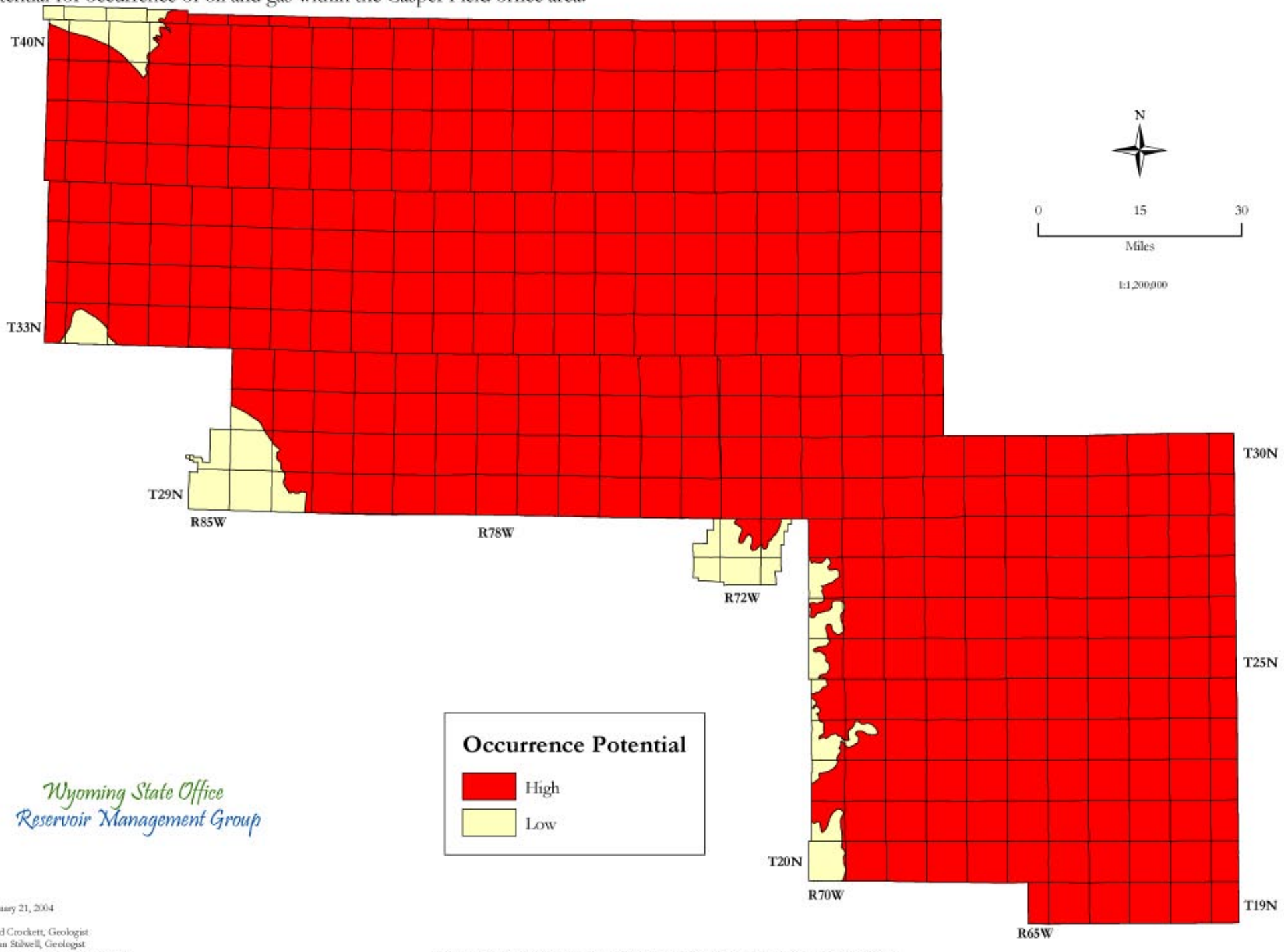
Figure 12.
Potential for occurrence of oil and gas within the Casper Field office area.



January 21, 2004

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

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Figure 13. 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 are derived from averaged December 2003 NYMEX gas futures with a $0.60 differential and are in nominal dollars. EIA (Energy Information Agency) Rocky Mountain estimates are in 2002 dollars. Data are from Petrie and Parkman website, http://www.enerfaxdaily.com, the Oil and Gas Journal, and Energy Information Agency website.

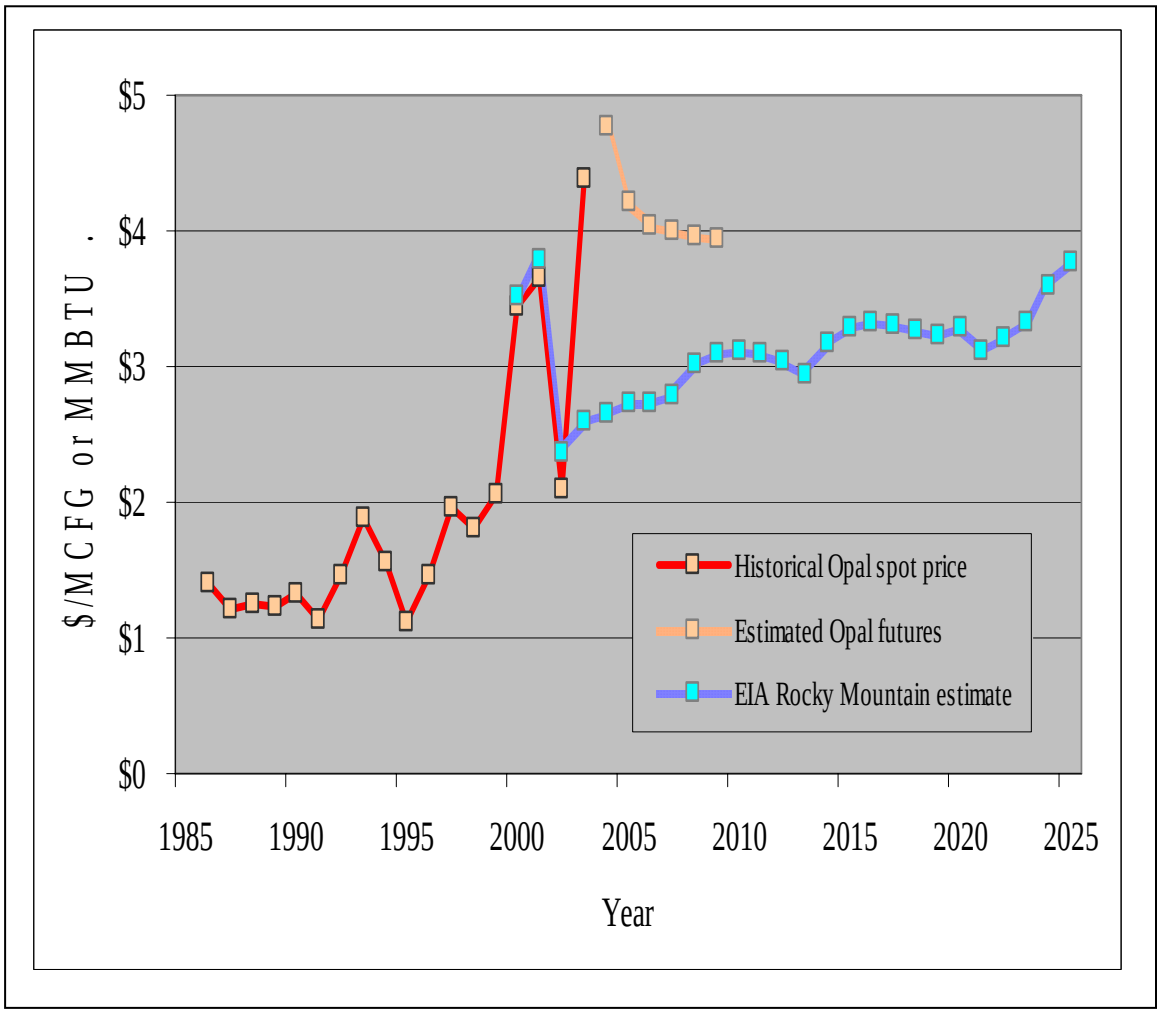


Figure 14. Historical and projected crude oil prices. Historical prices are for Wyoming Powder River Basin sweet crude oil, are in nominal dollars, and are from Marathon and ConocoPhilips. Adjusted West Texas Intermediate (WTI) crude oil futures prices are in nominal dollars, were adjusted downward $4/barrel, and are from Petrie and Parkman website. EIA (Energy Information Agency, 2003) Rocky Mountain estimates are in 2002 dollars.

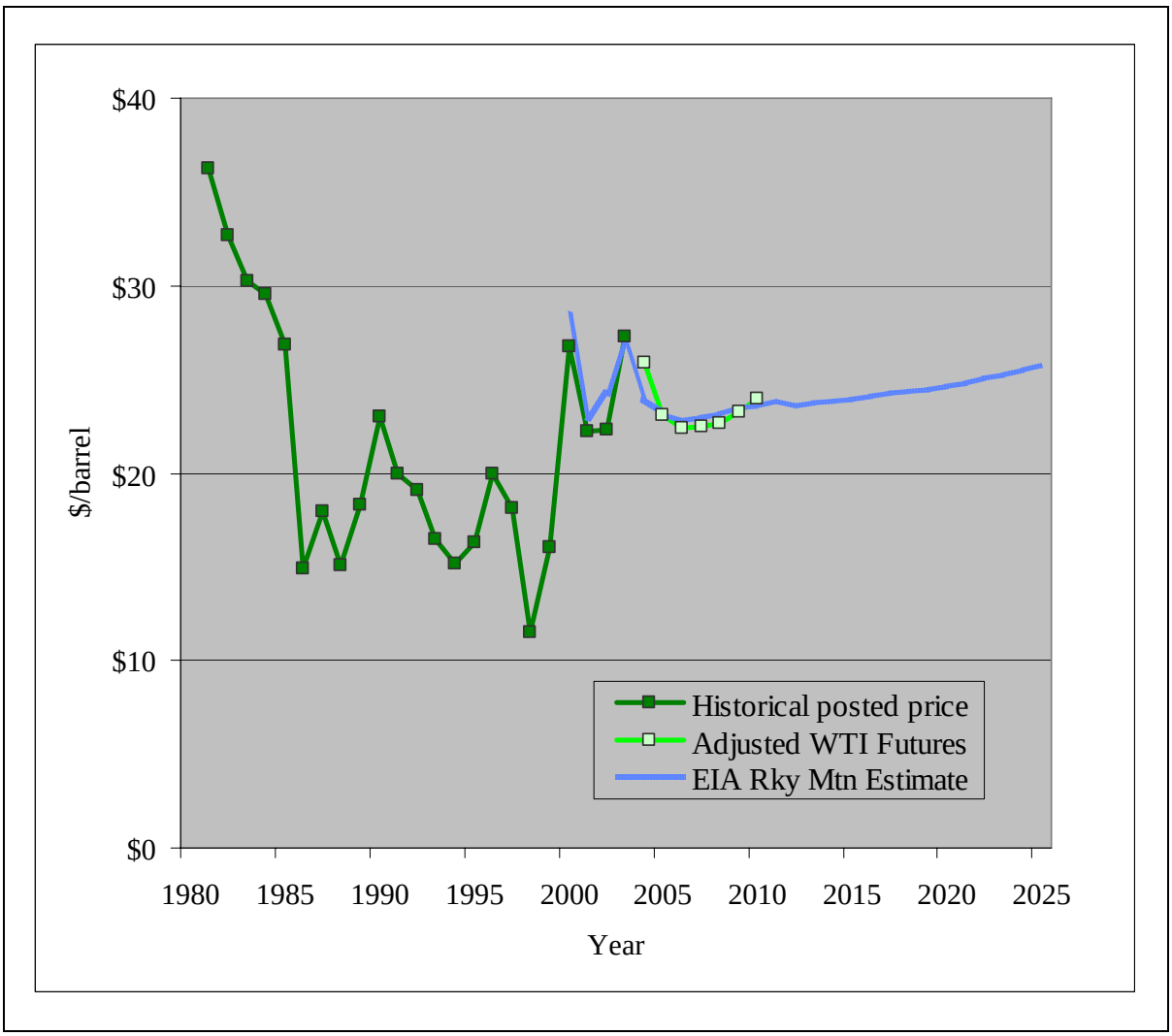


Figure 15. Annual price differential between West Texas Intermediate and Wyoming Sweet crude oil in nominal dollars. Wyoming Sweet crude oil was usually sold at a lower price than West Texas Intermediate and that differential is shown. In 1984 Wyoming Sweet Crude Oil had a higher posted price ($0.27 higher) than West Texas Intermediate Crude Oil, so the differential drops below the x-axis. Note the steady increase since 1984. Data are from ConocoPhilips, Marathon, Federal Reserve Bank of Dallas website, and http://www.economagic.com.

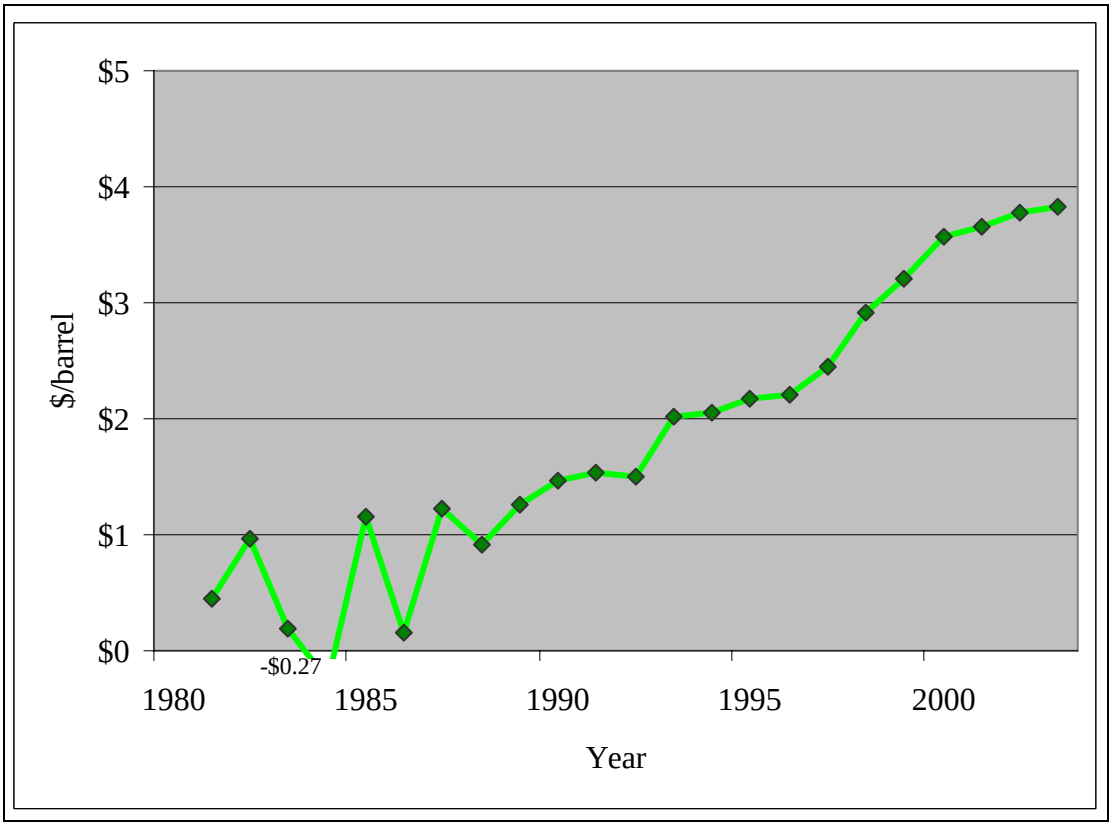


Figure 16. Federal oil and gas lease sale results. Acreage figures were compiled from lease sale results for lands in the Casper Field Office area only. Data are from BLM files.

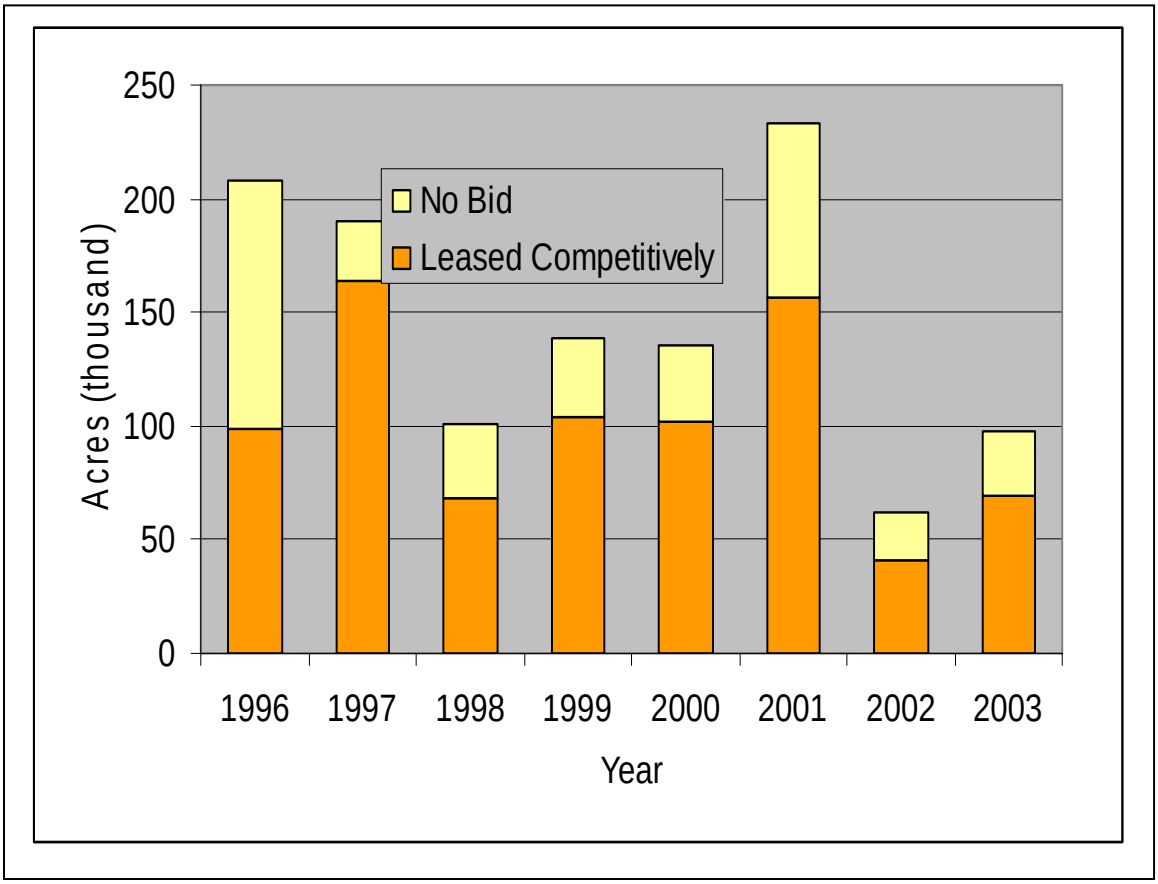


Figure 17. Total bonus and average per-acre bid data compiled from Federal oil and gas lease sale results for lands in the Casper Field Office area only. Data are from BLM files.

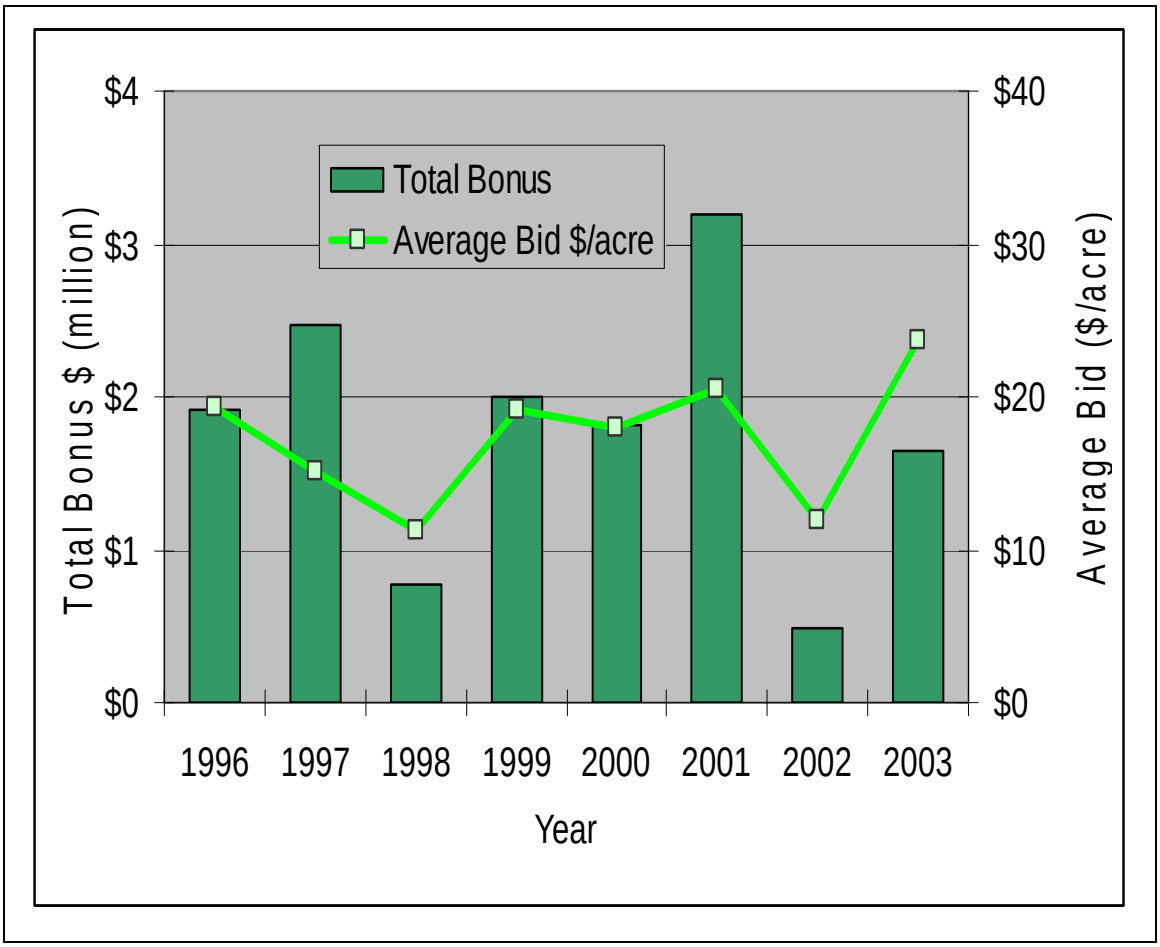


Figure 18. Approved seismic projects on BLM managed surface in the Casper Field Office area. Five other projects were canceled or withdrawn. Data are from BLM files, Casper Field Office.

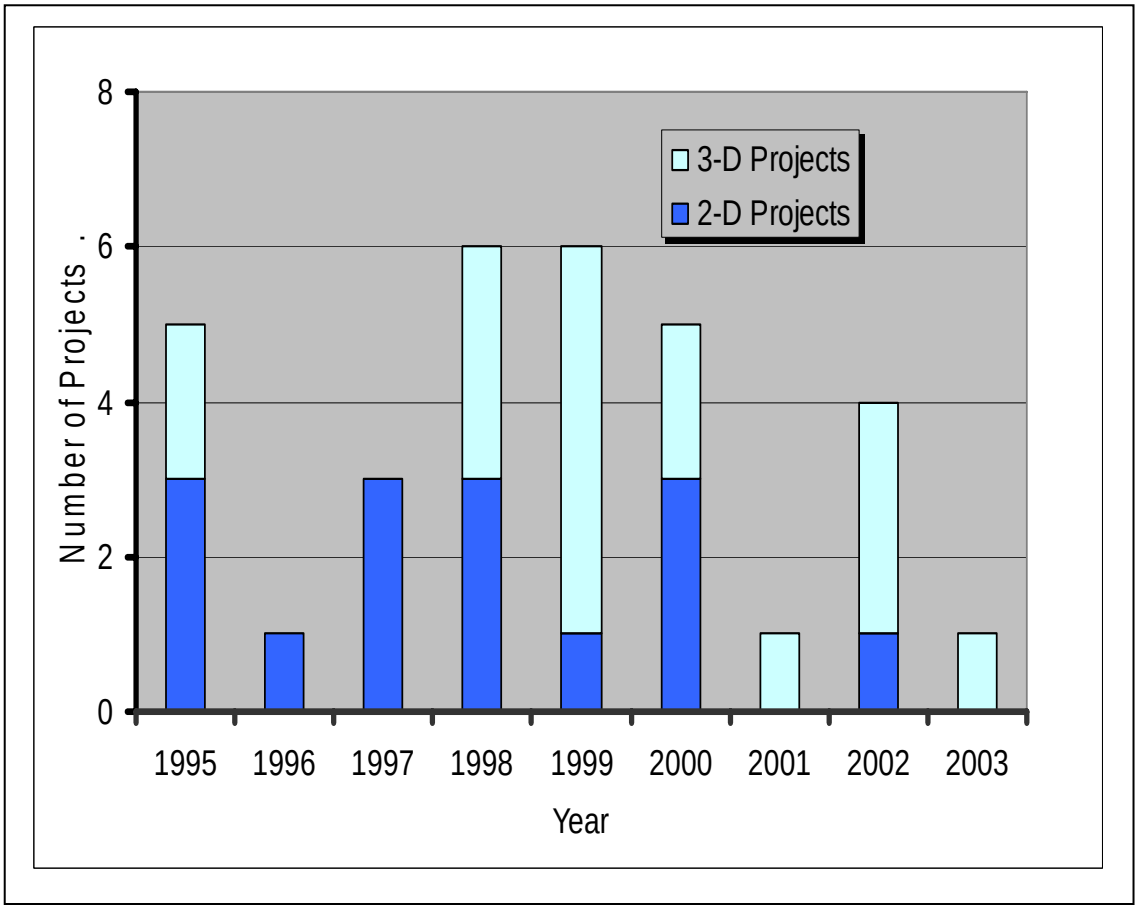


Figure 19. Wells drilled in the Casper Field Office area since 1975, by mineral ownership. From 1970 through 2003, 71 percent of the wells drilled were Federal. Data are from Wyoming Oil and Gas Conservation Commission (2003a) and IHS Energy (2003).

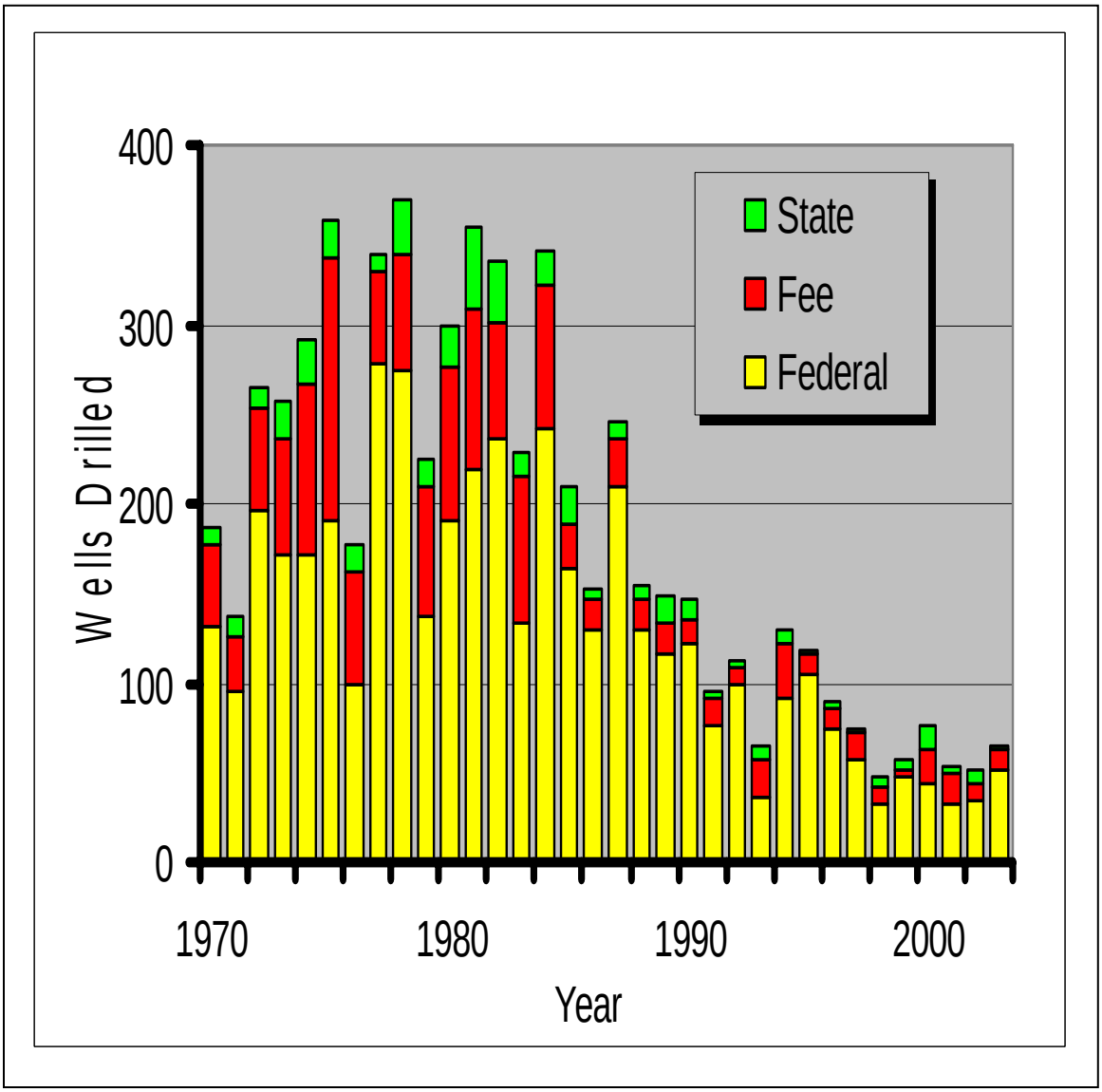


Figure 20. Depth distribution for wells drilled in the Casper Field Office area during 1990-2003. Data are from Wyoming Oil and Gas Conservation Commission (2003a) and IHS Energy (2003).

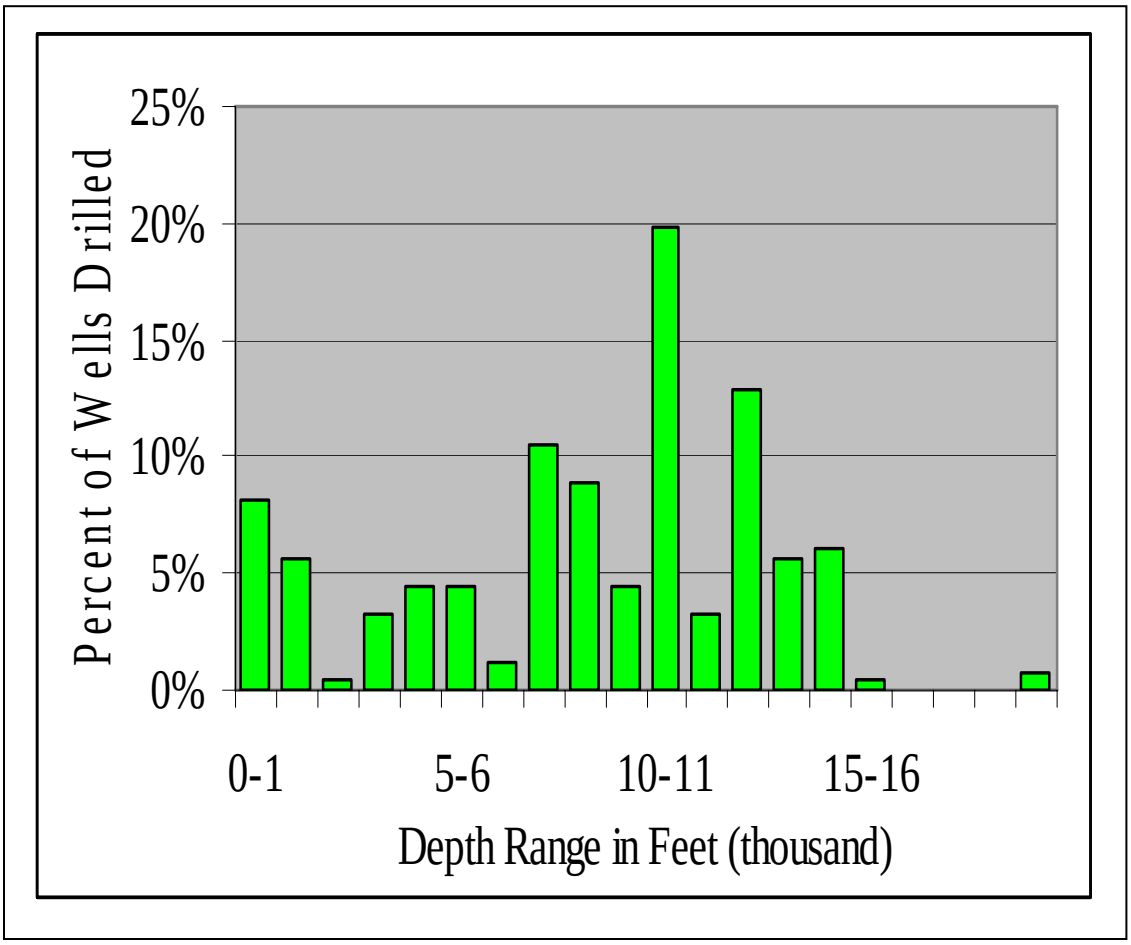


Figure 21. Wells drilled and wells abandoned in Casper Field Office area from 1970 to 2003. During this period, 71 percent as many wells were abandoned as were drilled. Many of the plugged and abandoned wells were in Salt Creek Field. These data do not include 1,507 abandoned wells (19 percent of wells abandoned from 1901-2003) which had insufficient data to determine an abandonment date. Data are from the Wyoming Oil and Gas Conservation Commission (2003a) and IHS Energy (2003).

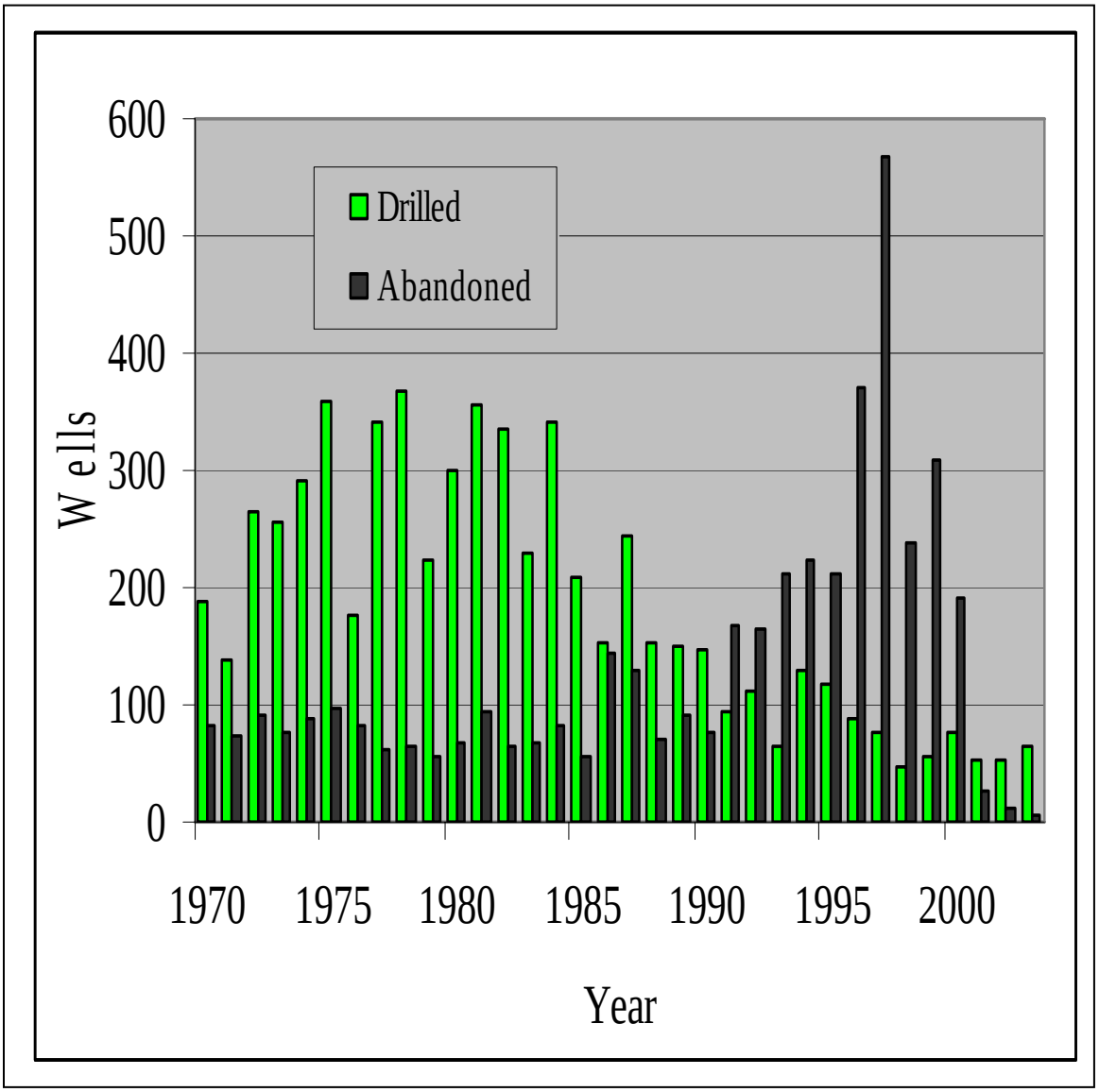
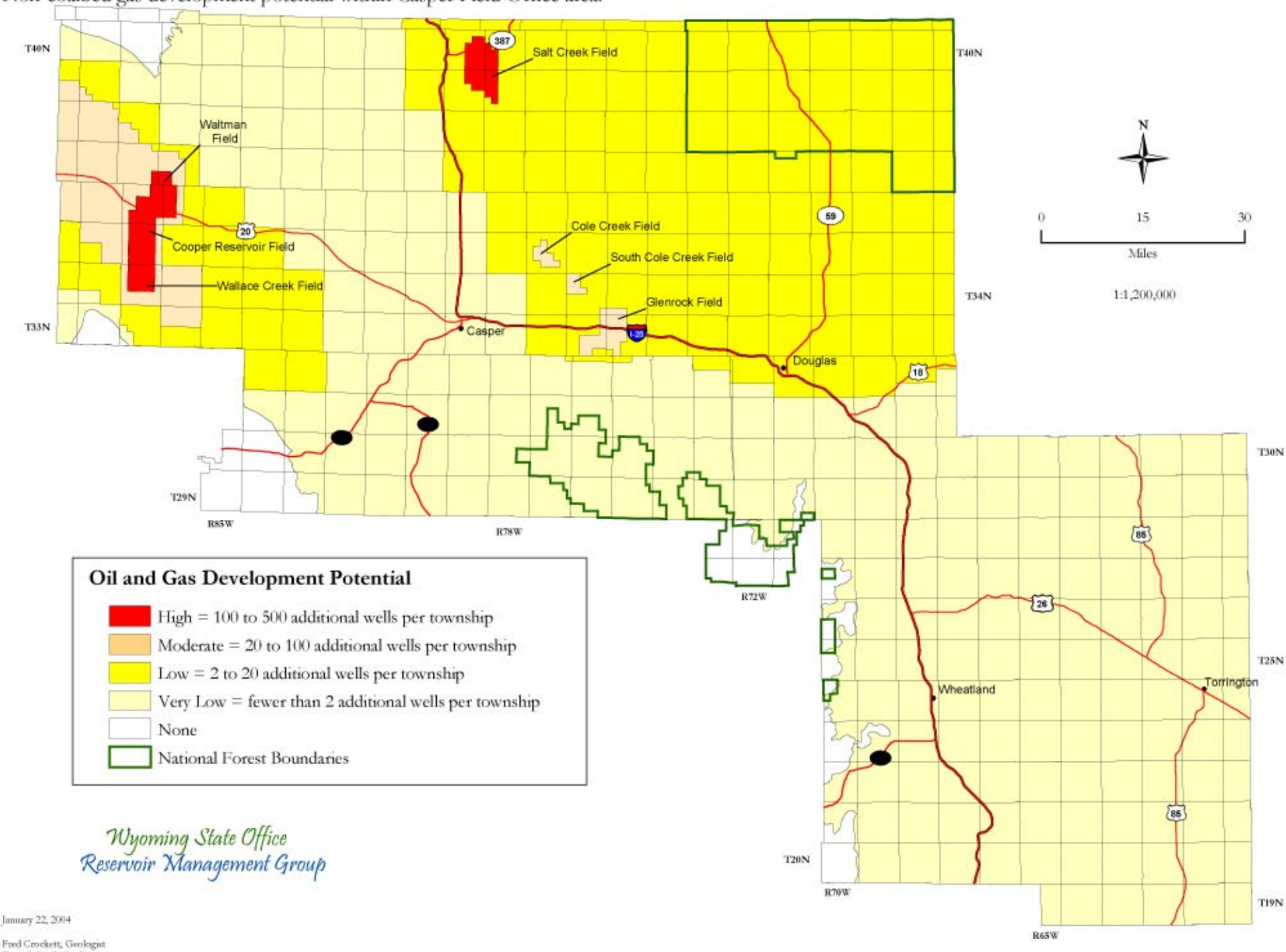


Figure 22.

Non-coalbed gas development potential within Casper Field Office area.



January 22, 2004

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

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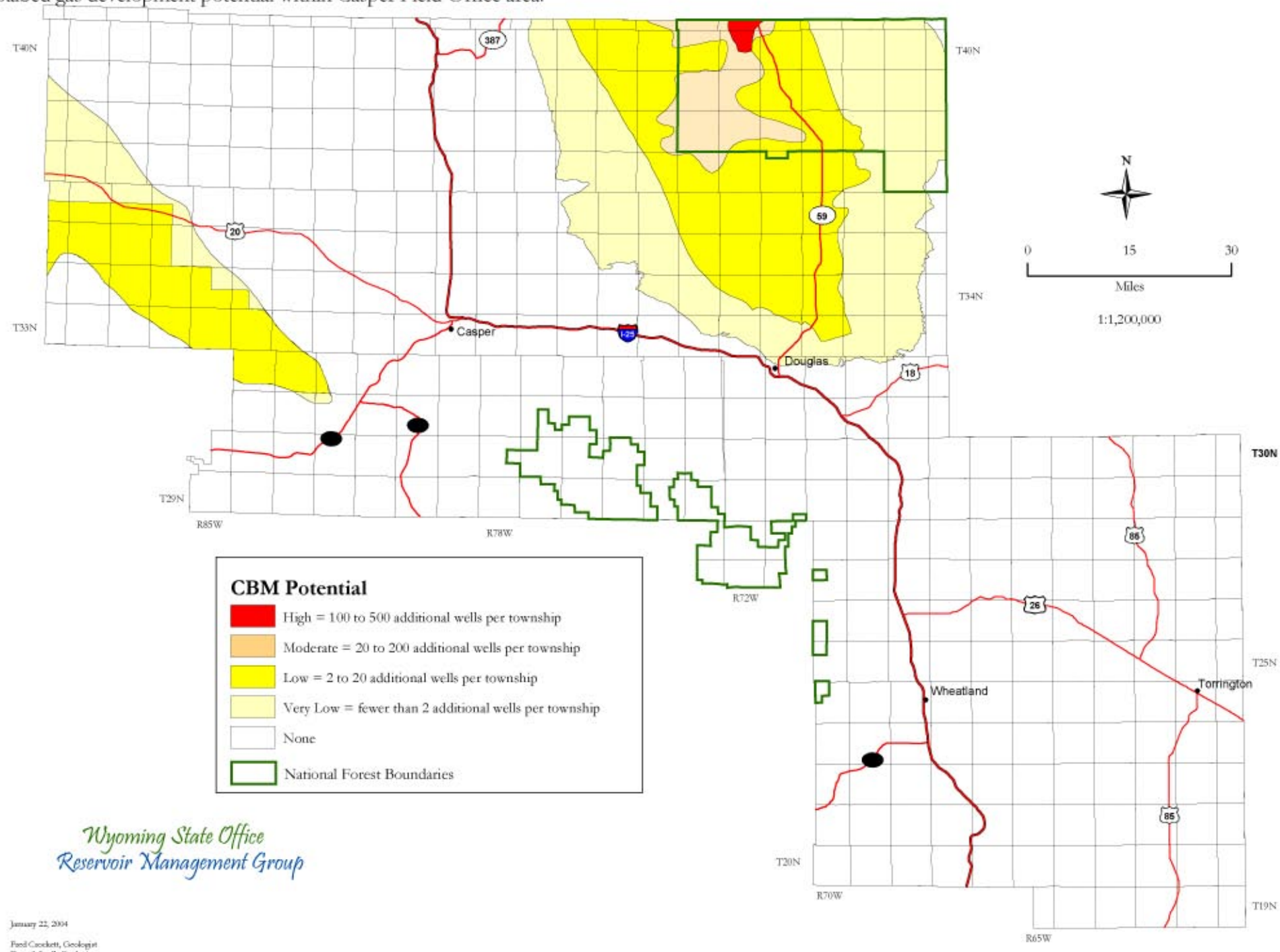
Figure 23.

Coalbed gas development potential within Casper Field Office area.



January 22, 2004

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

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Figure 24. Producing wells in the Casper Field Office area for the 1970 to 2003 period, by mineral ownership. Estimated drilling during 2004-2020 is expected to increase the number of producing wells substantially, probably above 4,000 wells. Data are from Wyoming Oil and Gas Conservation Commission (2003a) and IHS Energy (2003).

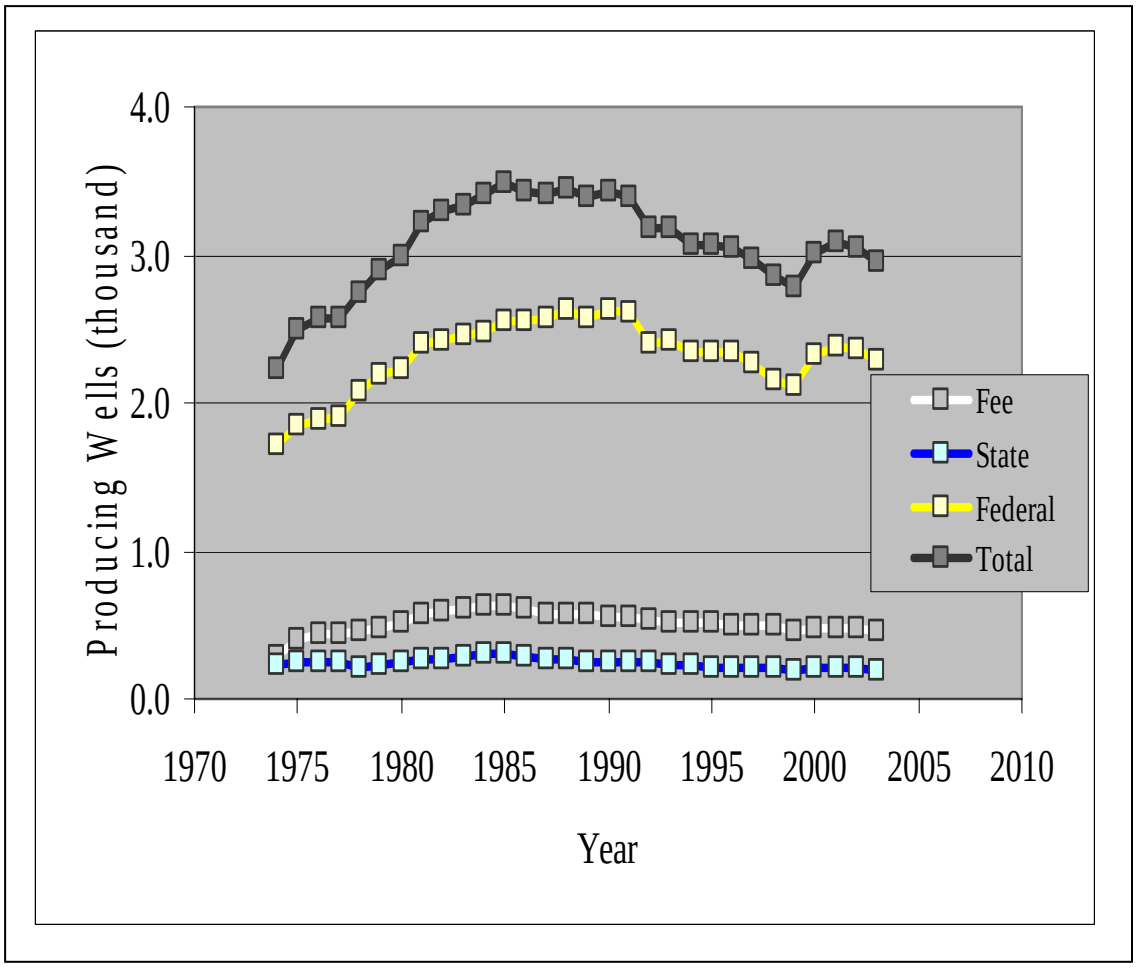


Figure 25. Annual oil production from Federal, private, and state wells in the Casper Field Office area. The average annual nominal decline rate was 2.1 percent from 1974-2003. Data are from Wyoming Oil and Gas Conservation Commission (2003a) and IHS Energy (2003).

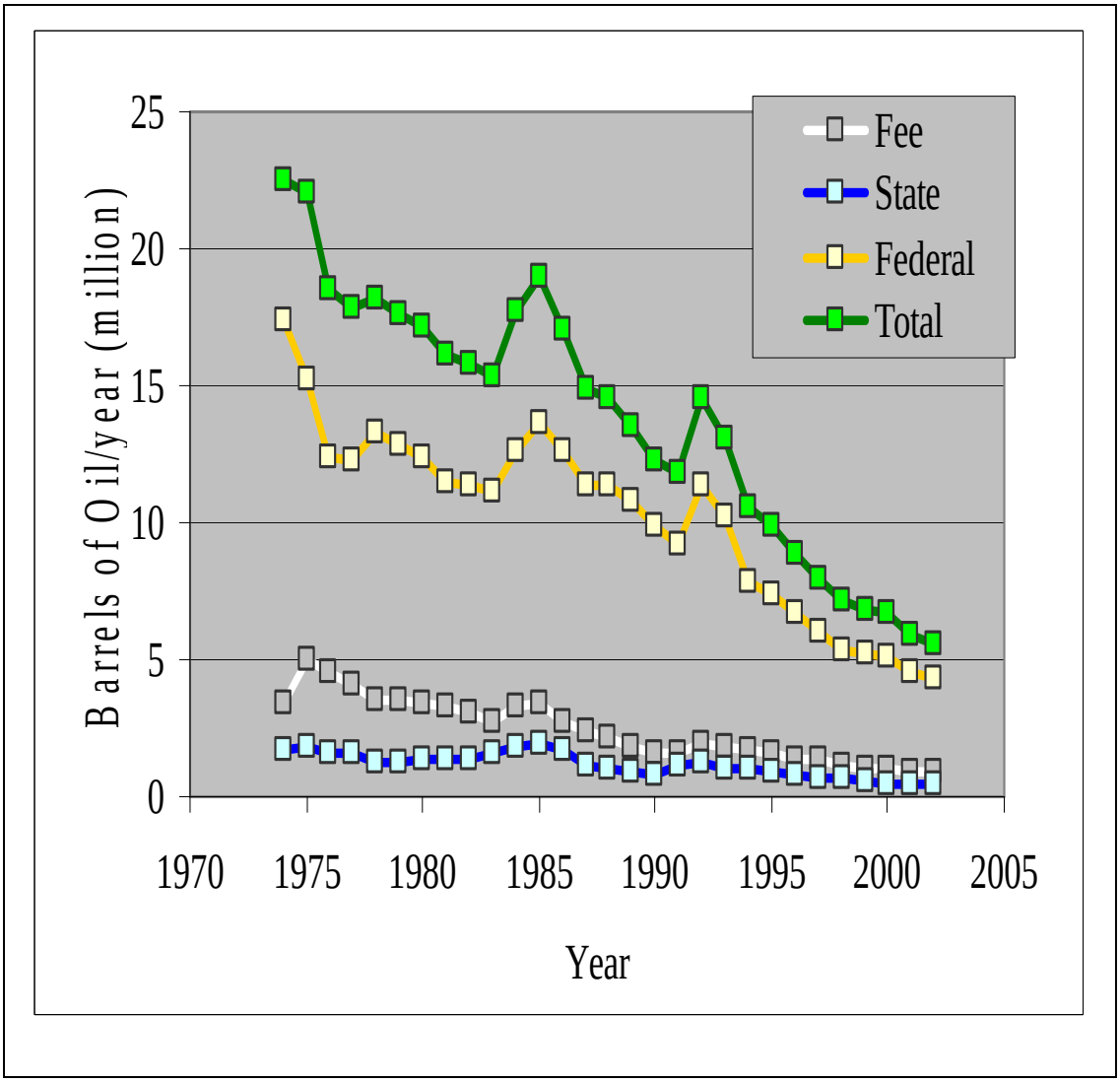


Figure 26. Annual gas production from Federal, private, and state wells in the Casper Field Office area. The abrupt increase in 1984 and 1994-1998 are due mainly to production increases from Powell field (Converse County) and Cave Gulch field (western Natrona County). Data are from Wyoming Oil and Gas Conservation Commission (2003a) and IHS Energy (2003).

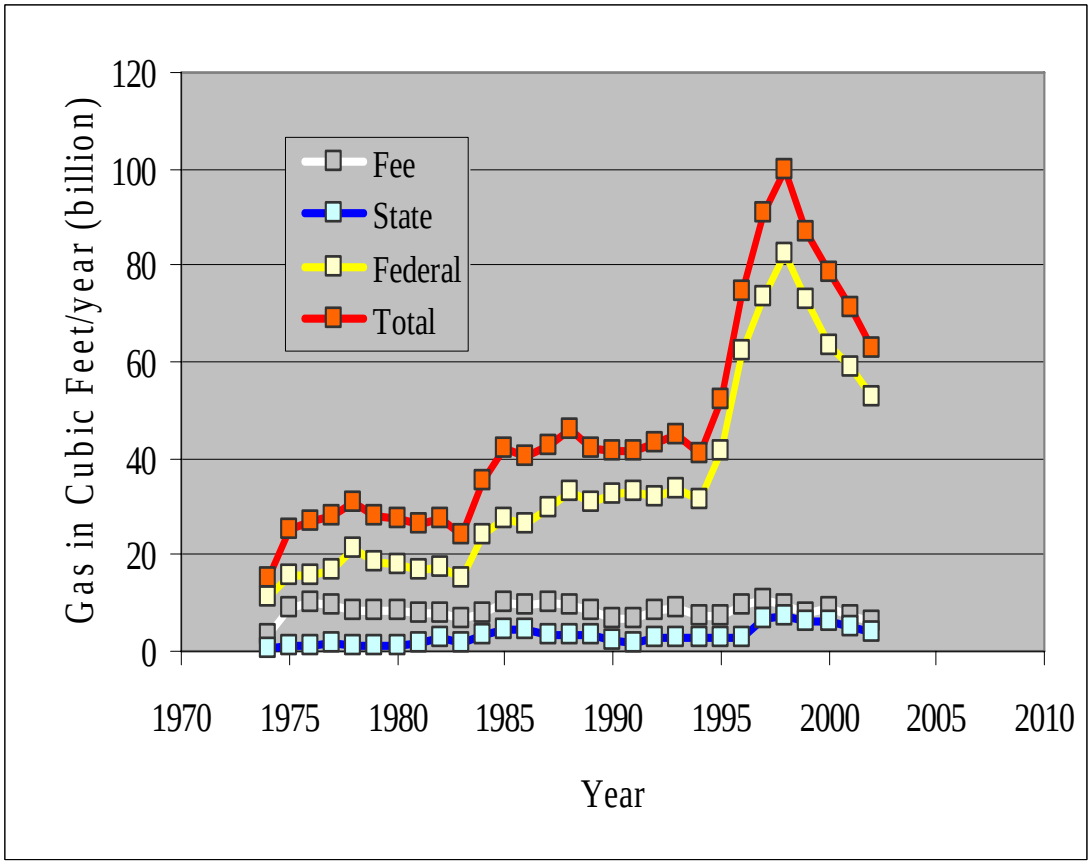


Figure 27. Annual water production from oil and gas wells in the Casper Field Office area, by mineral status. About 80 percent of the produced water is from Salt Creek Field. Water production from coalbed gas wells may comprise as much as 20 percent, possibly more, of the total produced water by 2010. Data are from Wyoming Oil and Gas Conservation Commission (2003a) and IHS Energy (2003).

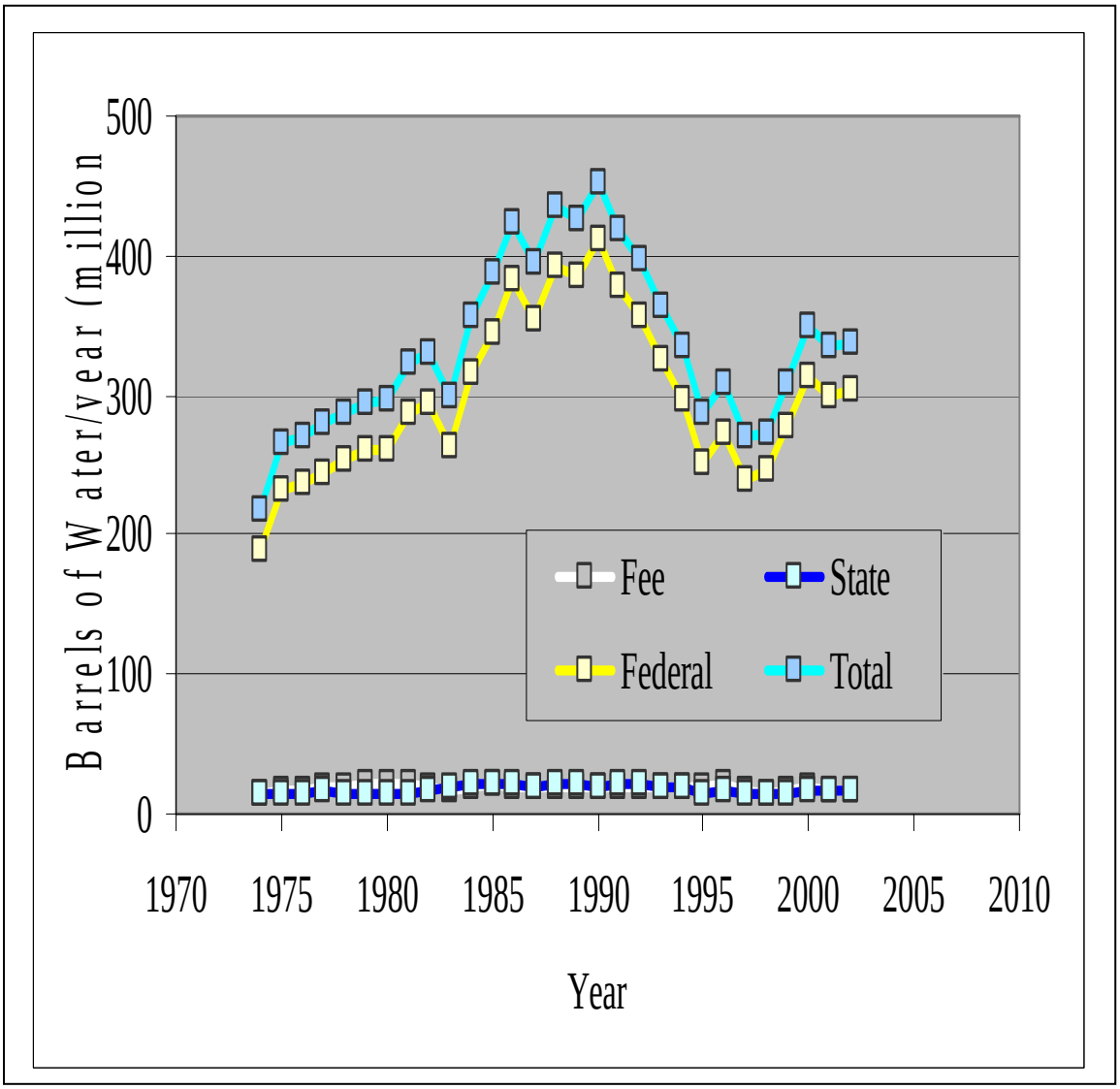


Table 1. Casper Field Office area wells by status and ownership type. Completed well status includes those wells that are producing or temporarily shut-in. Drilling well status includes; wells actively drilling, waiting on completion activities to begin, testing for hydrocarbons, or waiting for hook-up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

Wells Status	Federal	Fee or State	Total Federal, Fee, and State
Plugged and Abandoned	5,281	2,754	8,035
Unknown	21	3	24
Completed	3,227	865	4,092
Dormant	466	87	553
Drilling	62	39	101
Notice of Intent to Abandon	94	33	127
Total Wells	**9,151**	**3,781**	**12,932**

Table 2. Casper Field Office area cumulative oil and gas production separated by sedimentary basin. Productive wells include all wells which have produced at any time since 1974. Data were compiled from IHS Energy (2003) and are current to October 2003.

Sedimentary Basin	Oil Production in Barrels (million)	Natural Gas Production in Cubic Feet (billion)	Productive Wells
Denver Basin	0.3	0.1	16
Powder River Basin	1,101.0	950.8	8,072
Shirley Basin	0.3	0.0	19
Wind River Basin	59.6	659.7	734
Totals	**1,161.1**	**1,610.5**	**8,841**

Table 3.

Summary of data for all deep wells (>15,000 feet) drilled in Casper Field Office area.

Region of Field Office	Well Name and Number	Location (Section, Township, & Range)	Operator Name	Field Name	Total Depth (feet)	Formation at Total Depth	Completion Date	Current Status	Initial Producing Formation	Cumulative Deep Gas Production (MMCFG)	Cumulative Deep Oil Production (BO)
WIND RIVER BASIN	BADWATER UNIT 1	35 39N 89W	UNION OIL CO OF CALIFORNIA	BADWATER	17,034	MESAVERDE	June 20, 1950	D&A-G	MESAVERDE	65,061	
WIND RIVER BASIN	UNIT 2-A	2 38N 89W	PURE OIL	BADWATER	16,500	CODY	May 18, 1960	D&A-G			
POWDER RIVER BASIN	WIND CREEK 1	17 40N 76W	SINCLAIR OIL CORPORATION	WILDCAT	15,634	TENSLEEP	October 21, 1965	D&A			
POWDER RIVER BASIN	BEAR CREEK W-089382J 1	26 38N 75W	NORTH FINN LLC	BEAR CREEK	16,565	MADISON	May 7, 1966	OIL	MUDDY /SILT/ SH/ SD/	4,552,896	201,761
WIND RIVER BASIN	O T REILLY PS UNIT 8	11 33N 84W	QUICKSILVER RESOURCES INC	POISON SPIDER W	17,945	DINWOODY	June 5, 1968	OIL	CODY	1,508,457	137,345
POWDER RIVER BASIN	HORNBECK UNIT 1	16 36N 74W	HUMBLE OIL & REFINING	WILDCAT	16,800	MADISON	June 19, 1969	D&A-OG			
WIND RIVER BASIN	HELLS H ACRE UNIT II 1-K-11	11 35N 86W	RICHARDSON OPERATING CO.	HELLS HALF ACRE	22,431	MADISON	September 13, 1976	GAS	FRONTIER	128,324	
POWDER RIVER BASIN	HIGHLAND UNIT 1-24	24 36N 73W	GETTY OIL CO.	WILDCAT	16,044	MADISON	October 10, 1976	D&A			
WIND RIVER BASIN	BULLFROG UNIT 1-6-36-86	6 36N 86W	WILLIAMS PRODUCTION RMT CO.	WALTMAN	20,850	CHUGWATER	October 10, 1979	TAWG	MUDDY /SILT/ SH/ SD/	3,359,008	
WIND RIVER BASIN	DEEP UNIT W-045804E 1-29	29 38N 88W	BURLINGTON RESOURCES OIL & GAS CO.	MADDEN	22,674	SHANNON	December 4, 1979	GAS	SUSSEX		
WIND RIVER BASIN	UNIT PATENTED-FEE 35-D-11	11 33N 84W	QUICKSILVER RESOURCES INC	POISON SPIDER W	16,485	CHUGWATER (CROW MTN.)	December 11, 1980	OIL	MORRISON /JURASSIC/		
WIND RIVER BASIN	TEPEE FLATS 16-1	16 37N 86W	MONCRIEF W A JR	TEPEE FLATS	19,733	MUDDY	January 13, 1981	GAS	FRONTIER	6,264,758	40,471
WIND RIVER BASIN	CHEYENNE 073678 36-B10	10 33N 84W	QUICKSILVER RESOURCES INC	POISON SPIDER W	16,175	MORRISON	December 3, 1981	OIL	MORRISON /JURASSIC/	447,595	117,602
WIND RIVER BASIN	FEDERAL W-39420 27-1	27 37N 86W	MONCRIEF W A JR	WILDCAT	21,382	RED PEAK	October 20, 1982	D&A-G			
WIND RIVER BASIN	BULLFROG UNIT 2-7	7 36N 86W	CHEVRON USA INC	WALTMAN	20,847	LANCE	November 7, 1982	GAS	FRONTIER	2,979,496	1,088
WIND RIVER BASIN	KEY SPRING UNIT 1-F14	14 35N 86W	UNION OIL CO OF CALIFORNIA	HELLS HALF ACRE	20,000	CLOVERLY	January 3, 1983	D&A-OG			
WIND RIVER BASIN	WITTING FEE 1	2 33N 84W	APACHE CORPORATION	POISON SPIDER W	16,700	MORRISON	May 2, 1983	D&A-O	NIOBRARA	28,925	12,490
WIND RIVER BASIN	TEPEE FLATS 14-1	14 37N 86W	MONCRIEF W A JR	TEPEE FLATS	20,102	PRE-CAMBRIAN GRANITE	May 27, 1983	D&AW			
WIND RIVER BASIN	LOX 11-1	11 36N 86W	MONCRIEF W A JR	WILDCAT	22,780		May 30, 1983	D&A			
WIND RIVER BASIN	TEPEE FLATS 18-1	18 37N 86W	MONCRIEF W A JR	TEPEE FLATS	22,403	MADISON	February 20, 1984	GAS	FRONTIER 1	6,628,053	87
WIND RIVER BASIN	FEE 38-L11	11 33N 84W	QUICKSILVER RESOURCES INC	POISON SPIDER W	15,975	SUNDANCE	June 8, 1984	OIL	MORRISON /JURASSIC/	397,398	133,657
WIND RIVER BASIN	UNIT W-50081 3	8 36N 86W	COASTAL OIL & GAS CORPORATION	BULL FROG	20,100	MORRISON	May 16, 1985	D&A-G	LAKOTA	22,364	
WIND RIVER BASIN	PINE MOUNTAIN 35-1	35 35N 84W	MONCRIEF W A JR	WILDCAT	21,481	MORRISON	July 3, 1985	D&A			
WIND RIVER BASIN	EAGLE CREEK 1	36 32N 84W	EXXON MOBIL CORPORATION	WILDCAT	15,012		October 31, 1987	D&A			
WIND RIVER BASIN	BROAD MESA-STATE 1-36	36 35N 87W	BP EXPLORATION INC	WILDCAT	17,400		January 4, 1989	D&A			
WIND RIVER BASIN	CASPER CANAL W-98414 1-18	7 32N 83W	BP EXPLORATION INC	WILDCAT	15,577	MORRISON	February 13, 1989	D&A-O			
WIND RIVER BASIN	BADWATER CREEK 1	12 38N 89W	MONCRIEF W A JR	MADDEN	20,080	SHANNON	June 19, 1991	GAS-SI	LANCE		104
WIND RIVER BASIN	DEEP CAVE GULCH 16	32 37N 86W	BILL BARRETT CORPORATION	WALTMAN	19,104	CHUGWATER	August 11, 1997	GAS	FRONTIER	4,587,188	1,428
WIND RIVER BASIN	DEEP CAVE GULCH 3-29	29 37N 86W	BILL BARRETT CORPORATION	WALTMAN	21,965	FRONTIER	November 14, 1998	GAS	MUDDY /SILT/ SH/ SD/	13,412,542	11
WIND RIVER BASIN	DEEP CAVE GULCH 5-30	30 37N 86W	BILL BARRETT CORPORATION	WALTMAN	18,630	SUNDANCE	February 8, 1999	GAS	MUDDY /SILT/ SH/ SD/	3,175,238	15
WIND RIVER BASIN	DEEP CAVE GULCH 4-19	19 37N 86W	BILL BARRETT CORPORATION	WALTMAN	18,750	MORRISON	July 31, 1999	GAS-WO	FRONTIER/ MUDDY/ LAKOTA	1,245	
WIND RIVER BASIN	DEEP CAVE GULCH 1-29	29 37N 86W	BILL BARRETT CORPORATION	WALTMAN	18,274	MUDDY	October 9, 1999	GAS	MUDDY /SILT/ SH/ SD/	11,492,339	248
WIND RIVER BASIN	FEDERAL 28-1	28 37N 86W	MONCRIEF W A JR	WALTMAN	18,919	LAKOTA	December 2, 1999	GAS	MUDDY /SILT/ SH/ SD/	6,683,845	
WIND RIVER BASIN	CAVE GULCH LAK 6-29	29 37N 86W	BILL BARRETT CORPORATION	WALTMAN	19,125	SUNDANCE	January 9, 2000	GAS-SI	FRONTIER	2,306,872	3,601
WIND RIVER BASIN	DEEP CAVE GULCH LOOK 11-28	28 37N 86W	BILL BARRETT CORPORATION	UNNAMED	19,575	MORRISON	February 11, 2000	GAS	LAKOTA	2,279,826	215
WIND RIVER BASIN	BULLFROG UNIT 5-12	12 36N 87W	BILL BARRETT CORPORATION	WALTMAN	19,550	SUNDANCE	March 26, 2000	GAS	FRONTIER 1	1,984,393	267
WIND RIVER BASIN	BULLFROG 9-13	13 36N 87W	BILL BARRETT CORPORATION	WALTMAN	18,589	FRONTIER	November 29, 2000	GAS	FRONTIER	47,005	
Total Production										**53,018,308**	**139,633**

MMCFG = Million cubic feet of gas
BO = Barrels of oil
P&A-Gas = Gas well now plugged and abandoned
D&A = Drilled and abandoned well
TA = Temporarily abandoned well
SUS = Drilled and suspended well, waiting on completion activity

Wyoming State Office

Reservoir Management Group

Table 4. Deep well distribution and summary of completion status. Deep wells are shown by field area (IHS Energy, Field Name classification). Deep wells are defined as wells greater than 15,000 ft. deep. Productive wells include those that are shut-in. Non-productive wells include abandoned and other non-productive status classifications. Data are from IHS Energy, November, 2003 and Wyoming Oil and Gas Conservation Commission, January, 2004.

Field	Number Deep Wells	Gas Wells	Oil Wells	Non-productive Wells
Badwater	2			2
Bear Creek	1		1	
Bull Frog	1			1
Hells Half Acre	2	1		1
Madden	2	2		
Poison Spider W.	5		4	1
Teepee Flats	3	2		1
Unnamed	1	1		
Waltman	11	11		
Wildcat	9			9
Total Wells	**37**	**17**	**5**	**15**

Table 5. Deep well productive formations. Table shows the formations produced by deep wells. Productive wells include shut-in and abandoned producers. Data are from IHS Energy, November, 2003 and Wyoming Oil and Gas Conservation Commission, January, 2004.

Productive Formation	Productive Wells
Cody	1
Frontier (including multiple completions)	9
Lakota	1
Lance	1
Morrison	3
Muddy	5
Niobrara	1
Sussex	1
Total Wells	**22**

Table 6. Directional well distribution and summary of completion status. Directional wells are shown by field area (IHS Energy, Field Name classification). All directional wells, including horizontal wells, are shown. All unnamed fields and fields/locations with fewer than five wells are combined as all others. Data are from IHS Energy, November, 2003 and Wyoming Oil and Gas Conservation Commission, January, 2004.

Field	Number Directional Wells	Completed for Production	Drilling/ Permit Status	Percent Success
Casper Creek S.	5	5		100%
Cave Gulch	4		4	
Grieve North	5	3		60%
Saddle Rock	5	4		80%
Salt Creek*	26	22		84.6%
Sand Dunes	9	7		77.8%
Wallace Creek	5	1	1	25%
Waltman	50	44	2	91.7
Wildcat	29		1	0%
All Others	44	21	1	47.7%
Total Wells	**182**	**107**	**8**	

* Productive Salt Creek wells include 6 wells completed for water injection.

Table 7. Directional well productive formations. Table shows the formations produced by directional wells. All directional wells, including horizontal wells, are shown. Data are from IHS Energy, November, 2003 and Wyoming Oil and Gas Conservation Commission, January, 2004.

Productive Formation	Productive Wells
Directional (Non-horizontal) Wells	
Cody	1
Dual Fort Union/Lance	2
Fort Union	11
Frontier	4
Lakota	1
Lance	22
MesaVerde (including Teapot)	2
Meeteetsee	1
Muddy	20
Tensleep	8
Wall Creek	14
Horizontal Wells	
Fort Union/Lance	3
Frontier	2
Muddy	1
Niobrara	6
Sundance	1
Tensleep	2
Turner	2
Wall Creek	4
Total Wells	**107**

Table 8. Distribution of Federal oil and gas leased acres in the Casper Field Office area. HBP includes leased acres held by production from at least one well. Data were compiled from Bureau files as of January 2003.

Surface Management	Total Leased Acres (thousand)	HBP Only Acres (thousand)
BLM & NonFederal	1,558	431
U.S. Forest Service	137	34
State of Wyoming	43	5
Total acres	**1,738**	**471**

Table 9. The top ten producing oil fields in the Casper Field Office area for 2002. Salt Creek Field produced more oil than the next nine fields combined. Data are from the Wyoming Oil and Gas Conservation Commission (2003b).

Field Name	Producing Wells	Oil Produced (barrels)	Gas Produced (thousand cubic feet)
Salt Creek	1057	2,032,828	778,566
Scott	181	334,843	764,041
Lost Dome	6	289,316	0
Sand Dunes	22	262,470	9,848,081
Well Draw	255	216,526	844,543
Teapot Naval Reserve	714	205,127	1,111,035
Snake Charmer Draw	4	193,863	273,835
Notches	22	188,138	0
Casper Creek South	80	137,554	0
Mikes Draw	130	137,252	93,709

Table 10. The top ten producing gas fields in the Casper Field Office area for 2002. Data are from the Wyoming Oil and Gas Conservation Commission (2003b).

Field Name	Producing Wells	Oil Produced (barrels)	Gas Produced (thousand cubic feet)
Waltman	95	102,889	26,024,899
Sand Dunes	22	262,470	9,848,081
Powell	67	135,095	4,884,825
Derrick Draw	3	129,058	4,004,132
Cooper Reservoir	39	30,207	3,247,257
Frenchie Draw	17	17,919	1,790,895
African Swallow	2	74,462	1,624,646
Saddle Rock	6	5,954	1,501,769
Teapot Naval Reserve	714	205,127	1,111,035
Grieve North	5	8,182	1,053,526

Table 11. Estimated well location densities and area in each non-coalbed oil and gas development potential category within the Casper Field Office area.

Development Potential	Acres (thousand)	Townships	Well Locations/Township
High	73	3.2	110
Moderate	263	11.4	60
Low	2,769	120.2	11
Very Low	5,080	220.5	1
None	338	14.7	0

Table 12. Estimated well location densities and area in each coalbed gas development potential category within the Casper Field Office Area.

Development Potential	Acres (thousand)	Townships	Well Locations/Township
High	10	0.4	144
Moderate	143	6.2	60
Low	919	39.9	11
Very Low	965	78.3	1
None	6,486	256.4	0

Table 13. Alternative A summary of the number of acres in each restriction category for each development potential type within the Casper Field Office area.

Development Potential	Category D Federal Acres	Category C Federal Acres	Category B Federal Acres
Non-Coalbed Gas			
High	754	3,758	20,276
Moderate	0	29,151	94,676
Low	15,984	99,657	800,585
Very Low	20,445	595,392	1,503,439
Coalbed Gas			
High	0	0	2,847
Moderate	0	1,622	20,802
Low	0	24,133	278,674
Very Low	116	29,012	260,631

Table 14. Analysis results showing the calculated reduction in Federal non-coalbed oil and gas wells and Federal coalbed gas wells for Alternative A due to Category C restrictions. This calculation indicates there would be a reduction of 74 non-coalbed oil and gas well locations and 9 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	110	3,758	0.16	30%	5.4
Moderate	60	29,151	1.27	40%	30.4
Low	11	99,657	4.33	50%	23.8
Very Low	1	595,393	25.84	55%	14.2
Coalbed Gas					
High	144	0	0	35%	0
Moderate	60	1,622	0.07	45%	1.9
Low	11	24,133	1.05	55%	6.3
Very Low	1	29,012	1.26	60%	0.8

Table 15. Total wells projected to be drilled within the Casper 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	700	2,100	2,800	71
Alternative A (No Action)	677	1,965	2,642	69
Alternative B	343	655	998	19
Alternative C	642	1,841	2,483	67
Alternative D	678	1,931	2,609	69
Alternative E	679	1,949	2,628	69

Table 16. Future oil production (in millions of barrels) for the Casper Field Office area, estimated for the base line and each alternative.

Year	Base Line	Alternative A (No Action)	Alternative B	Alternative C	Alternative D	Alternative E
2001	8.646	8.646	8.646	8.646	8.646	8.646
2002	8.277	8.277	8.277	8.277	8.277	8.277
2003	7.478	7.478	7.478	7.478	7.478	7.478
2004	6.785	6.785	6.785	6.785	6.785	6.785
2005	8.651	8.638	8.511	8.625	8.638	8.633
2006	11.523	11.497	11.243	11.471	11.497	11.488
2007	16.303	16.262	15.905	16.224	16.266	16.254
2008	15.272	15.216	14.773	15.169	15.225	15.209
2009	14.315	14.248	13.730	14.193	14.261	14.242
2010	13.432	13.354	12.770	13.292	13.370	13.349
2011	12.611	12.524	11.881	12.456	12.543	12.520
2012	11.854	11.759	11.064	11.685	11.776	11.755
2013	11.154	11.053	10.311	10.973	11.067	11.049
2014	10.505	10.397	9.612	10.313	10.409	10.393
2015	9.904	9.790	8.967	9.702	9.801	9.787
2016	9.349	9.229	8.366	9.137	9.239	9.222
2017	8.838	8.714	7.814	8.618	8.722	8.702
2018	8.365	8.236	7.303	8.137	8.244	8.221
2019	7.924	7.795	6.831	7.694	7.802	7.777
2020	7.520	7.391	6.399	7.287	7.398	7.371
Total	**208.707**	**207.289**	**196.666**	**206.165**	**207.442**	**207.162**

Table 17. Future gas production (in billions of cubic feet) for the Casper Field Office area, estimated for the base line and each alternative.

Year	Base Line	Alternative A (No Action)	Alternative B	Alternative C	Alternative D	Alternative E
2001	56.84	56.84	56.84	56.84	56.84	56.84
2002	49.61	49.61	49.61	49.61	49.61	49.61
2003	52.34	52.34	52.34	52.34	52.34	52.34
2004	53.30	53.30	53.30	53.30	53.30	53.30
2005	54.97	54.13	47.55	53.56	54.13	54.13
2006	64.31	62.49	47.30	61.18	62.49	62.49
2007	72.82	70.18	47.95	68.27	70.18	70.18
2008	79.71	76.40	48.52	73.74	76.41	76.41
2009	85.26	81.34	48.95	78.03	81.41	81.13
2010	89.76	85.33	49.23	81.44	85.45	84.86
2011	93.43	88.59	49.39	84.19	88.73	87.89
2012	96.42	91.23	49.45	86.43	91.40	90.35
2013	98.80	93.32	49.39	88.17	93.50	92.27
2014	100.82	95.09	49.30	89.65	95.27	93.89
2015	102.26	96.59	48.90	90.90	96.71	95.21
2016	103.44	97.62	48.47	91.98	97.97	96.36
2017	104.48	98.43	48.10	92.91	99.06	97.36
2018	105.39	99.17	47.77	93.73	100.03	98.24
2019	106.19	99.81	47.47	94.43	100.87	99.01
2020	106.84	100.38	47.19	95.05	101.33	99.69
Total	1,677.00	1,602.20	987.02	1,535.74	1,607.03	1,591.56

Table 18.

Casper Field Office area surface disturbance associated with wells projected for the base line development scenario for the 2001-2020 period and for existing active wells.

	Disturbance Associated With All New Drilled Wells and Existing Active Wells (Short-Term Disturbance)							
	Wells			Acres of Surface Disturbance				
	Type	Total	Federal	Flow Lines[1]	Access Roads	Well Pad	Total	Federal
New Wells	Non-coalbed Exploratory	206		5	10	3	2,983	
	Non-coalbed Development	1,852		2	2	3	12,532	
	Coalbed gas	700		10	2.5	0.3	8,350	
	Deep	42		5	10	5	755	
	Wells/Disturbance	**2,800**	**1,988**				**24,620**	**17,480**
Existing wells	Non-coalbed Exploratory	478		0	7.5	2	4,541	
	Non-coalbed Development	4,250		0	1.5	2	14,875	
	Deep	22		0	7.5	2.5	220	
	Wells/Disturbance	**4,750**	**3,373**				**19,636**	**13,942**
	Total Wells/Disturbance	**7,550**	**5,361**				**44,256**	**31,422**

	Disturbance Associated With All New Producing Wells and Existing Active Wells Less Abandonments (Long-Term Disturbance)							
	Wells			Acres of Surface Disturbance				
	Type	Total	Federal	Flow Lines	Access Roads	Well Pad	Total	Federal
New Wells	Non-coalbed Exploratory	61		0	7.5	2	580	
	Non-coalbed Development	1,636		0	1.5	2	5,726	
	Coalbed gas	639		0	1.9	0.1	1,262	
	Deep	25		0	7.5	2.5	250	
	Wells/Disturbance	**2,361**	**1,676**				**7,818**	**5,551**
Existing wells	Non-coalbed Exploratory	443		0	7.5	2	4,209	
	Non-coalbed Development	3,931		0	1.5	2	13,759	
	Deep	16		0	7.5	2.5	160	
	Wells/Disturbance[2]	**4,390**	**3,117**				**18,127**	**12,870**
	Total Wells/Disturbance	**6,751**	**4,793**				**25,945**	**18,421**

[1]Flowline disturbance only calculated for new producing wells.

[2]360 existing wells abandoned (256 Federal) and 1,509 total acres reclaimed (1,071 acres Federal).

Table 19.

Casper Field Office area surface disturbance associated with wells projected for Alternative A (No Action) for the 2001-2020 period and for existing active wells.

	Disturbance Associated With All New Drilled Wells and Existing Active Wells (Short-Term Disturbance)							
	Wells			Acres of Surface Disturbance				
	Type	Total	Federal	Flow Lines[1]	Access Roads	Well Pad	Total	Federal
New Wells	Non-coalbed Exploratory	197		5	10	3	2,846	
	Non-coalbed Development	1,729		2	2	3	11,619	
	Coalbed gas	677		10	2.5	0.3	8,526	
	Deep	39		5	10	5	700	
	Wells/Disturbance	**2,642**	**1,823**				**23,691**	**16,347**
Existing wells	Non-coalbed Exploratory	478		0	7.5	2	4,541	
	Non-coalbed Development	4,250		0	1.5	2	14,875	
	Deep	22		0	7.5	2.5	220	
	Wells/Disturbance	**4,750**	**3,373**				**19,636**	**13,942**
	Total Wells/Disturbance	**7,392**	**5,195**				**43,327**	**30,288**

	Disturbance Associated With All New Producing Wells and Existing Active Wells Less Abandonments (Long-Term Disturbance)							
	Wells			Acres of Surface Disturbance				
	Type	Total	Federal	Flow Lines	Access Roads	Well Pad	Total	Federal
New Wells	Non-coalbed Exploratory	57		0	7.5	2	542	
	Non-coalbed Development	1,487		0	1.5	2	5,205	
	Coalbed gas	663		0	1.9	0.1	1,309	
	Deep	23		0	7.5	2.5	230	
	Wells/Disturbance	**2,230**	**1,539**				**7,286**	**5,027**
Existing wells	Non-coalbed Exploratory	443		0	7.5	2	4,209	
	Non-coalbed Development	3,931		0	1.5	2	13,759	
	Deep	16		0	7.5	2.5	160	
	Wells/Disturbance[2]	**4,390**	**3,117**				**18,127**	**12,870**
	Total Wells/Disturbance	**6,620**	**4,656**				**25,413**	**17,897**

[1]Flowline disturbance only calculated for new producing wells.

[2]360 existing wells abandoned (256 Federal) and 1,509 total acres reclaimed (1,071 acres Federal).

Table 20.

Casper Field Office area surface disturbance associated with wells projected for Alternative B for the 2001-2020 period and for existing active wells.

	Disturbance Associated With All New Drilled Wells and Existing Active Wells (Short-Term Disturbance)							
	Wells			Acres of Surface Disturbance				
	Type	Total	Federal	Flow Lines[1]	Access Roads	Well Pad	Total	Federal
New Wells	Non-coalbed Exploratory	66		5	10	3	978	
	Non-coalbed Development	576		2	2	3	3,870	
	Coalbed gas	343		10	2.5	0.3	4,320	
	Deep	13		5	10	5	235	
	Wells/Disturbance	**998**	**190**				**9,403**	**1,787**
Existing wells	Non-coalbed Exploratory	478		0	7.5	2	4,541	
	Non-coalbed Development	4,250		0	1.5	2	14,875	
	Deep	22		0	7.5	2.5	220	
	Wells/Disturbance	**4,750**	**3,373**				**19,636**	**13,942**
	Total Wells/Disturbance	**5,748**	**3,562**				**29,039**	**15,728**

	Disturbance Associated With All New Producing Wells and Existing Active Wells Less Abandonments (Long-Term Disturbance)							
	Wells			Acres of Surface Disturbance				
	Type	Total	Federal	Flow Lines	Access Roads	Well Pad	Total	Federal
New Wells	Non-coalbed Exploratory	24		0	7.5	2	228	
	Non-coalbed Development	495		0	1.5	2	1,733	
	Coalbed gas	336		0	1.9	0.1	664	
	Deep	8		0	7.5	2.5	80	
	Wells/Disturbance	**863**	**164**				**2,704**	**514**
Existing wells	Non-coalbed Exploratory	443		0	7.5	2	4,209	
	Non-coalbed Development	3,931		0	1.5	2	13,759	
	Deep	16		0	7.5	2.5	160	
	Wells/Disturbance[2]	**4,390**	**3,117**				**18,127**	**12,870**
	Total Wells/Disturbance	**5,253**	**3,281**				**20,831**	**13,384**

[1]Flowline disturbance only calculated for new producing wells.

[2]360 existing wells abandoned (256 Federal) and 1,509 total acres reclaimed (1,071 acres Federal).

Table 21.

Casper Field Office area surface disturbance associated with wells projected for Alternative C for the 2001-2020 period and for existing active wells.

	Disturbance Associated With All New Drilled Wells and Existing Active Wells (Short-Term Disturbance)							
	Wells			Acres of Surface Disturbance				
	Type	Total	Federal	Flow Lines[1]	Access Roads	Well Pad	Total	Federal
New Wells	Non-coalbed Exploratory	184		5	10	3	2,657	
	Non-coalbed Development	1,620		2	2	3	10,886	
	Coalbed gas	642		10	2.5	0.3	8,088	
	Deep	37		5	10	5	665	
	Wells/Disturbance	**2,483**	**1,664**				**22,296**	**14,938**
Existing wells	Non-coalbed Exploratory	478		0	7.5	2	4,541	
	Non-coalbed Development	4,250		0	1.5	2	14,875	
	Deep	22		0	7.5	2.5	220	
	Wells/Disturbance	**4,750**	**3,373**				**19,636**	**13,942**
	Total Wells/Disturbance	**7,233**	**5,036**				**41,932**	**28,880**

	Disturbance Associated With All New Producing Wells and Existing Active Wells Less Abandonments (Long-Term Disturbance)							
	Wells			Acres of Surface Disturbance				
	Type	Total	Federal	Flow Lines	Access Roads	Well Pad	Total	Federal
New Wells	Non-coalbed Exploratory	53		0	7.5	2	504	
	Non-coalbed Development	1,393		0	1.5	2	4,876	
	Coalbed gas	629		0	1.9	0.1	1,242	
	Deep	22		0	7.5	2.5	220	
	Wells/Disturbance	**2,097**	**1,405**				**6,841**	**4,584**
Existing wells	Non-coalbed Exploratory	443		0	7.5	2	4,209	
	Non-coalbed Development	3,931		0	1.5	2	13,759	
	Deep	16		0	7.5	2.5	160	
	Wells/Disturbance[2]	**4,390**	**3,117**				**18,127**	**12,870**
	Total Wells/Disturbance	**6,487**	**4,522**				**24,968**	**17,454**

[1]Flowline disturbance only calculated for new producing wells.

[2]360 existing wells abandoned (256 Federal) and 1,509 total acres reclaimed (1,071 acres Federal).

Table 22.

Casper Field Office area surface disturbance associated with wells projected for Alternative D for the 2001-2020 period and for existing active wells.

	Disturbance Associated With All New Drilled Wells and Existing Active Wells (Short-Term Disturbance)							
	Wells			Acres of Surface Disturbance				
	Type	Total	Federal	Flow Lines[1]	Access Roads	Well Pad	Total	Federal
New Wells	Non-coalbed Exploratory	193		5	10	3	2,784	
	Non-coalbed Development	1,699		2	2	3	11,417	
	Coalbed gas	678		10	2.5	0.3	8,548	
	Deep	39		5	10	5	700	
	Wells/Disturbance	**2,609**	**1,800**				**23,449**	**16,180**
Existing wells	Non-coalbed Exploratory	478		0	7.5	2	4,541	
	Non-coalbed Development	4,250		0	1.5	2	14,875	
	Deep	22		0	7.5	2.5	220	
	Wells/Disturbance	**4,750**	**3,373**				**19,636**	**13,942**
	Total Wells/Disturbance	**7,359**	**5,173**				**43,085**	**30,122**

	Disturbance Associated With All New Producing Wells and Existing Active Wells Less Abandonments (Long-Term Disturbance)							
	Wells			Acres of Surface Disturbance				
	Type	Total	Federal	Flow Lines	Access Roads	Well Pad	Total	Federal
New Wells	Non-coalbed Exploratory	55		0	7.5	2	523	
	Non-coalbed Development	1,461		0	1.5	2	5,114	
	Coalbed gas	665		0	1.9	0.1	1,313	
	Deep	23		0	7.5	2.5	230	
	Wells/Disturbance	**2,204**	**1,521**				**7,180**	**4,954**
Existing wells	Non-coalbed Exploratory	443		0	7.5	2	4,209	
	Non-coalbed Development	3,931		0	1.5	2	13,759	
	Deep	16		0	7.5	2.5	160	
	Wells/Disturbance[2]	**4,390**	**3,117**				**18,127**	**12,870**
	Total Wells/Disturbance	**6,594**	**4,638**				**25,307**	**17,824**

[1]Flowline disturbance only calculated for new producing wells.

[2]360 existing wells abandoned (256 Federal) and 1,509 total acres reclaimed (1,071 acres Federal).

Table 23.

Casper Field Office area surface disturbance associated with wells projected for Alternative E for the 2001-2020 period and for existing active wells.

	Disturbance Associated With All New Drilled Wells and Existing Active Wells (Short-Term Disturbance)							
	Wells			Acres of Surface Disturbance				
	Type	Total	Federal	Flow Lines[1]	Access Roads	Well Pad	Total	Federal
New Wells	Non-coalbed Exploratory	195		5	10	3	2,815	
	Non-coalbed Development	1,715		2	2	3	11,525	
	Coalbed gas	679		10	2.5	0.3	8,561	
	Deep	39		5	10	5	700	
	Wells/Disturbance	**2,628**	**1,813**				**23,601**	**16,285**
Existing wells	Non-coalbed Exploratory	478		0	7.5	2	4,541	
	Non-coalbed Development	4,250		0	1.5	2	14,875	
	Deep	22		0	7.5	2.5	220	
	Wells/Disturbance	**4,750**	**3,373**				**19,636**	**13,942**
	Total Wells/Disturbance	**7,378**	**5,186**				**43,237**	**30,226**

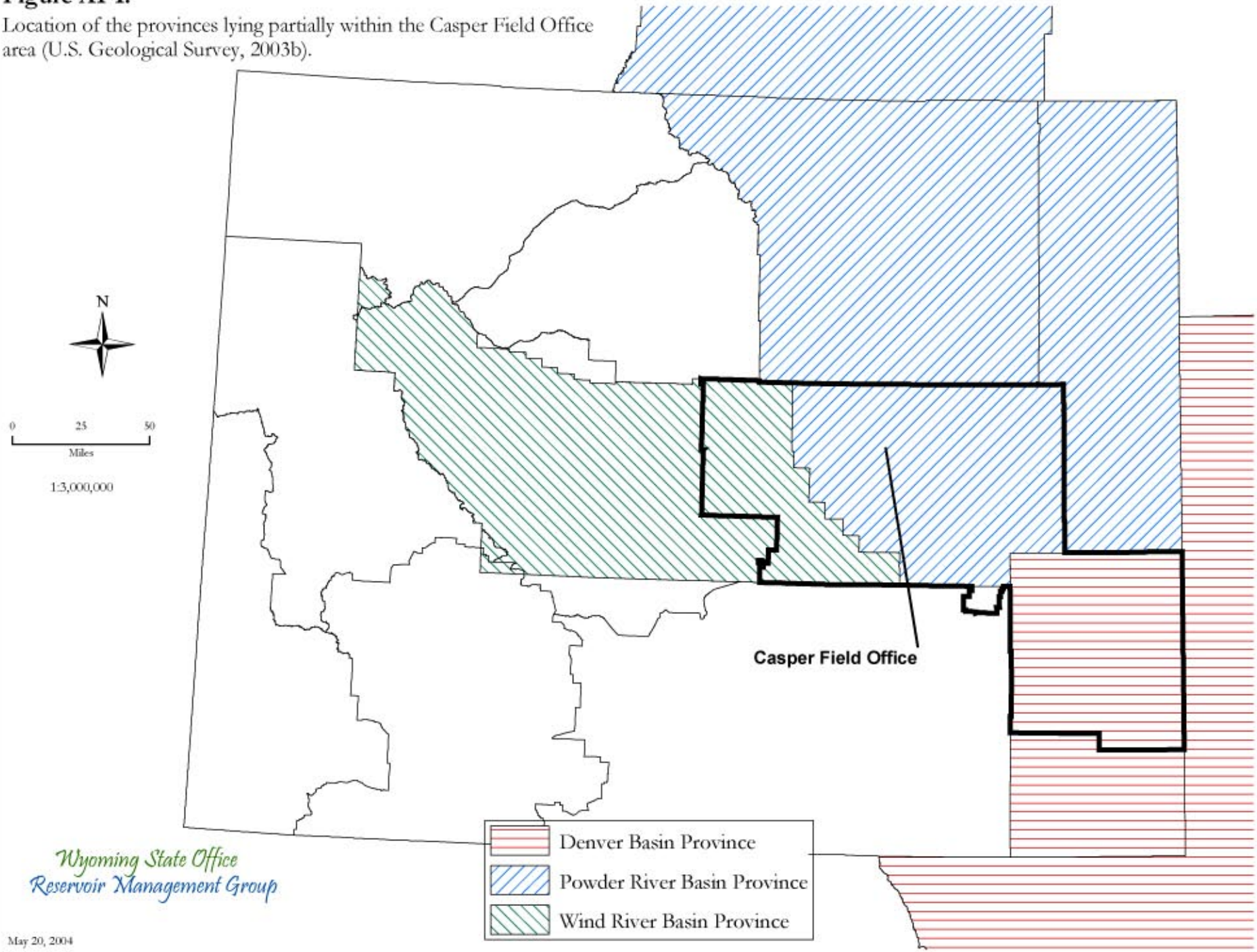
	Disturbance Associated With All New Producing Wells and Existing Active Wells Less Abandonments (Long-Term Disturbance)							
	Wells			Acres of Surface Disturbance				
	Type	Total	Federal	Flow Lines	Access Roads	Well Pad	Total	Federal
New Wells	Non-coalbed Exploratory	56		0	7.5	2	532	
	Non-coalbed Development	1,475		0	1.5	2	5,163	
	Coalbed gas	666		0	1.9	0.1	1,315	
	Deep	23		0	7.5	2.5	230	
	Wells/Disturbance	**2,220**	**1,532**				**7,240**	**4,996**
Existing wells	Non-coalbed Exploratory	443		0	7.5	2	4,209	
	Non-coalbed Development	3,931		0	1.5	2	13,759	
	Deep	16		0	7.5	2.5	160	
	Wells/Disturbance[2]	**4,390**	**3,117**				**18,127**	**12,870**
	Total Wells/Disturbance	**6,610**	**4,649**				**25,367**	**17,866**

[1]Flowline disturbance only calculated for new producing wells.

[2]360 existing wells abandoned (256 Federal) and 1,509 total acres reclaimed (1,071 acres Federal).

Figure A1-1.

Location of the provinces lying partially within the Casper Field Office area (U.S. Geological Survey, 2003b).



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Dean Stilwell, Geologist
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Figure A1-2.

Location of the Powder River Basin province, Basin Margin Subthrust conventional play area (U.S. Geological Survey, 2003b).

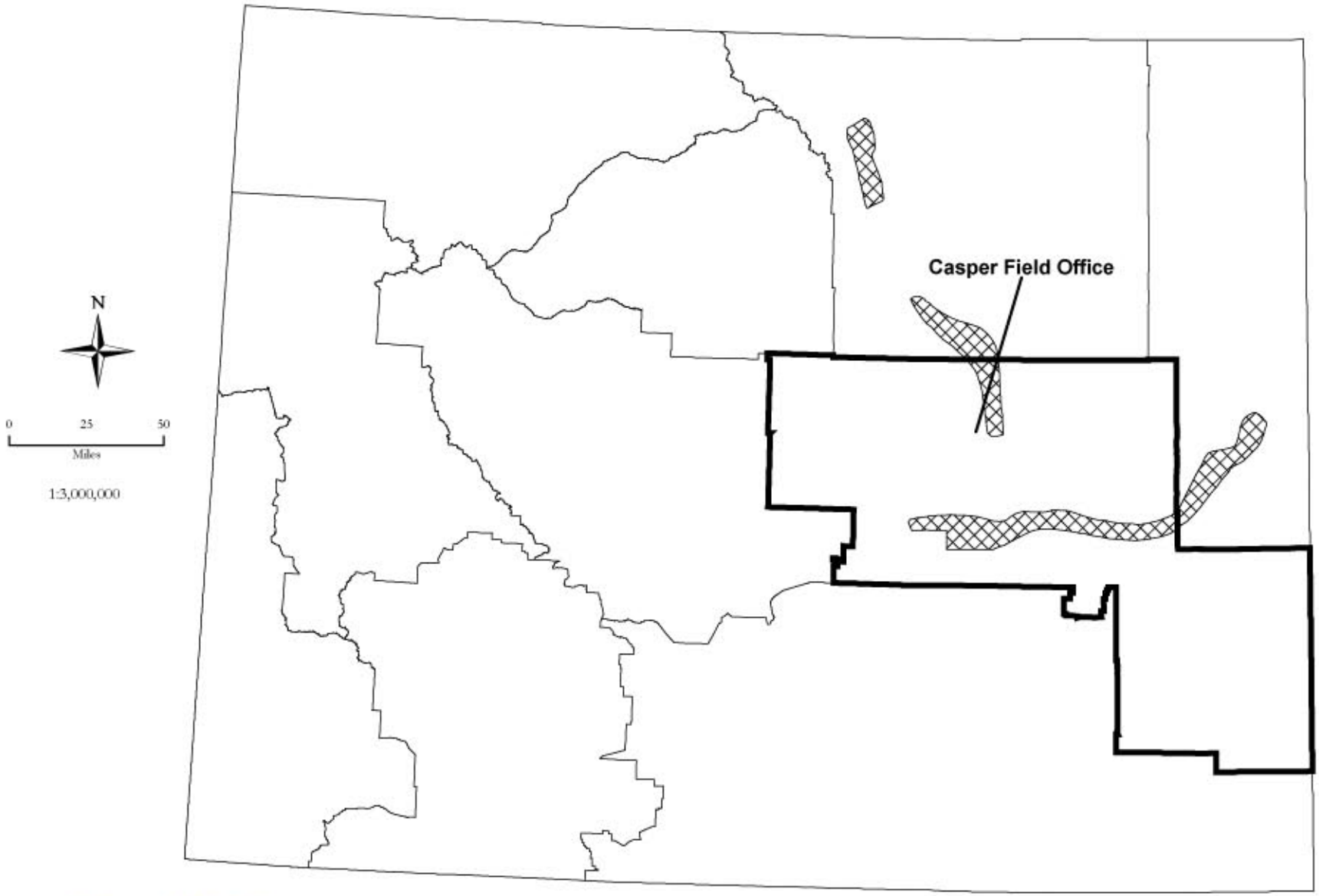

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Figure A1-3.

Location of the Powder River Basin province, Basin Margin Anticline conventional play area (U.S. Geological Survey, 2003b).

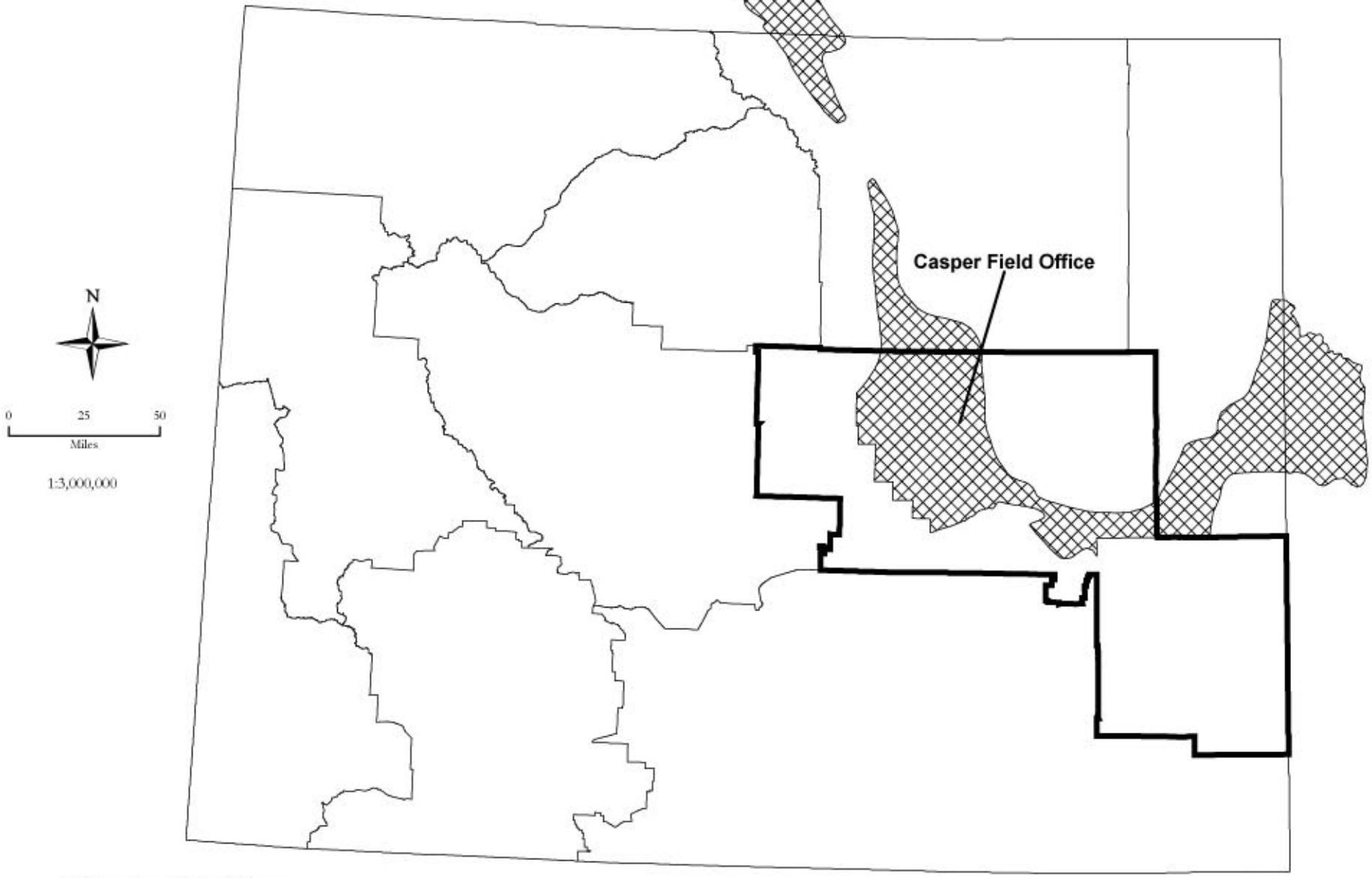

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Figure A1-4.

Location of the Powder River Basin province, Leo Sandstone conventional play area (U.S. Geological Survey, 2003b).

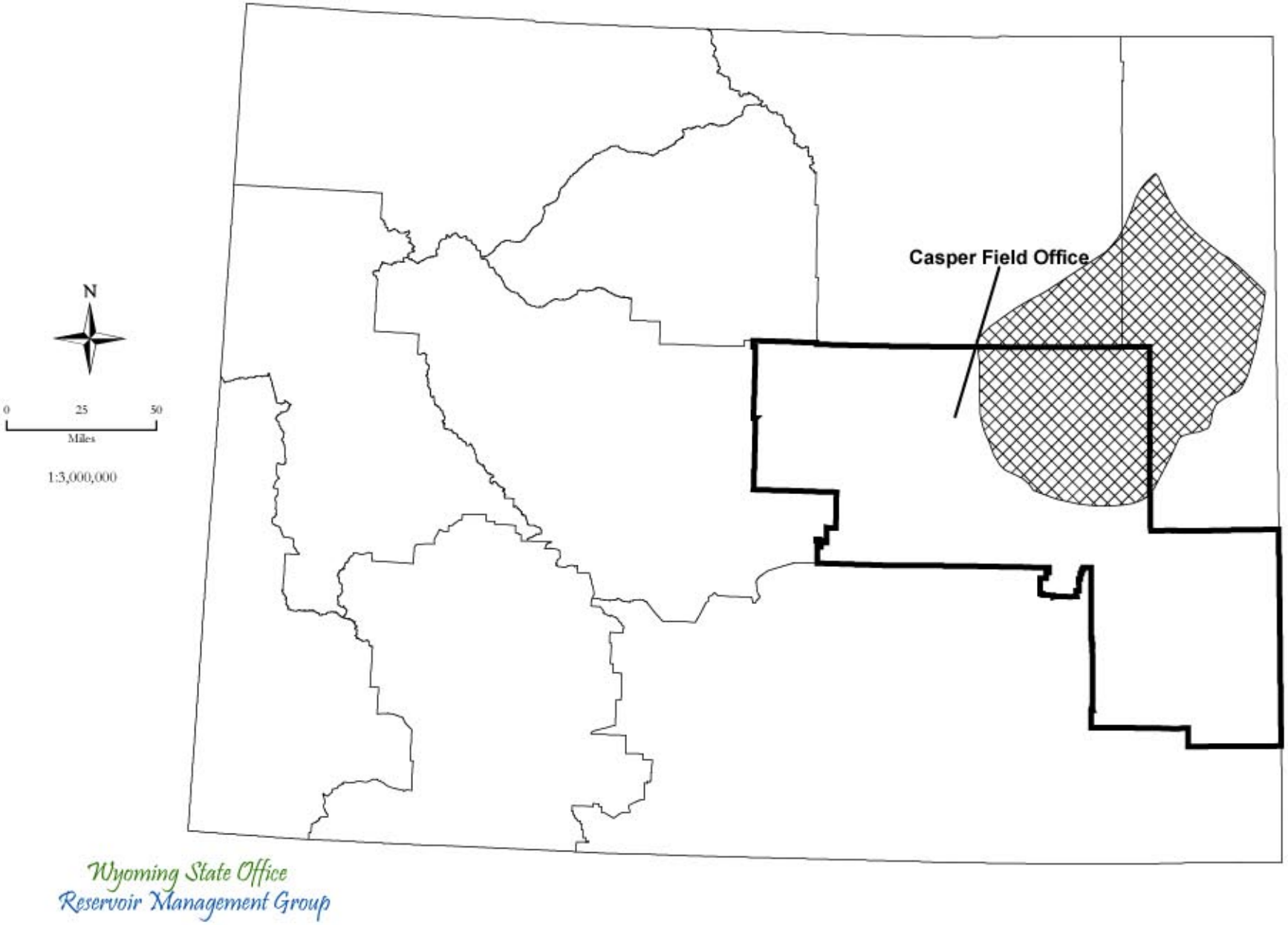

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Figure A1-5.

Location of the Powder River Basin province, Upper Minnelusa Sandstone conventional play area (U.S. Geological Survey, 2003b).

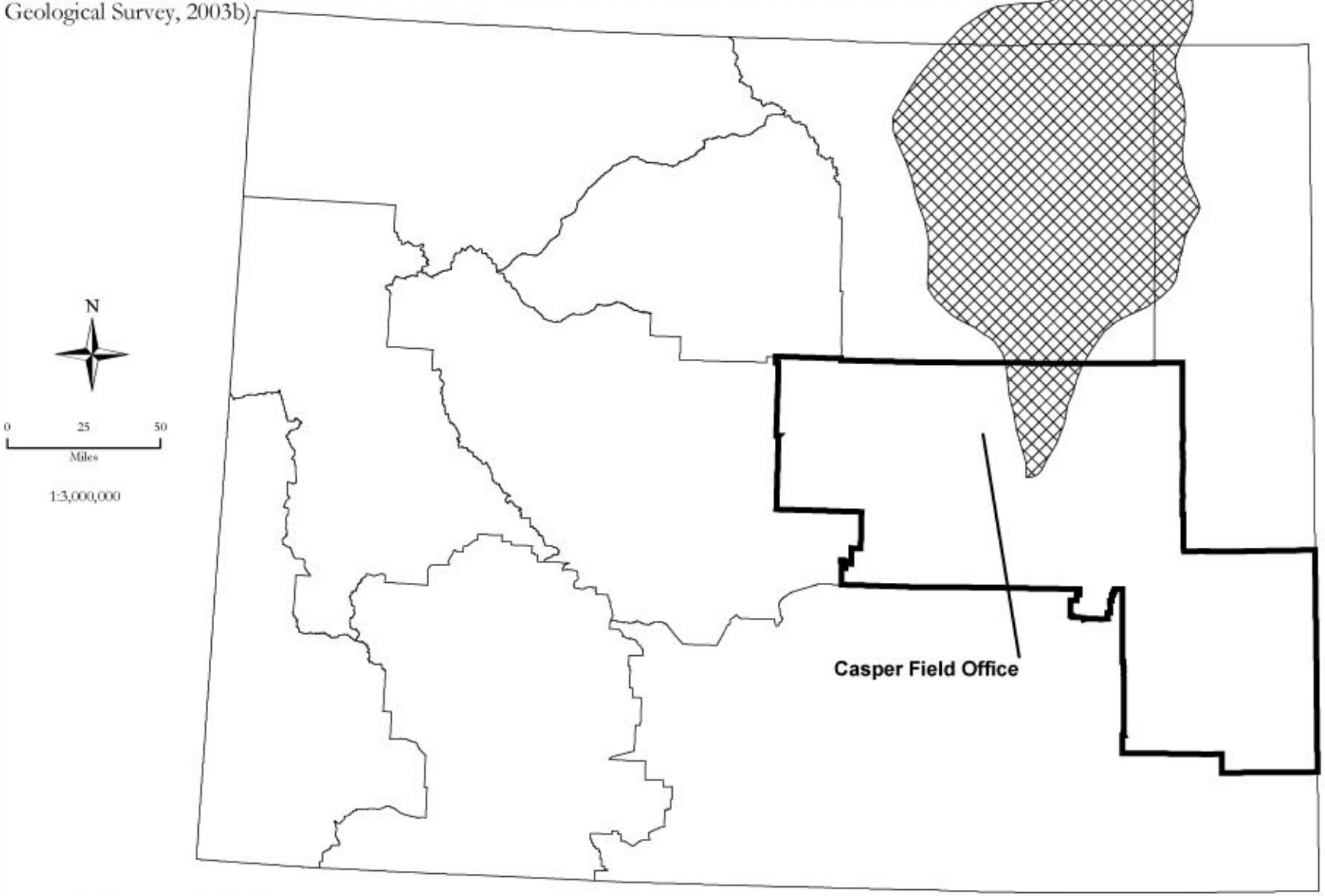

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Figure A1-6.
Location of the Powder River Basin province, Lakota Sandstone conventional play area (U.S. Geological Survey, 2003b).

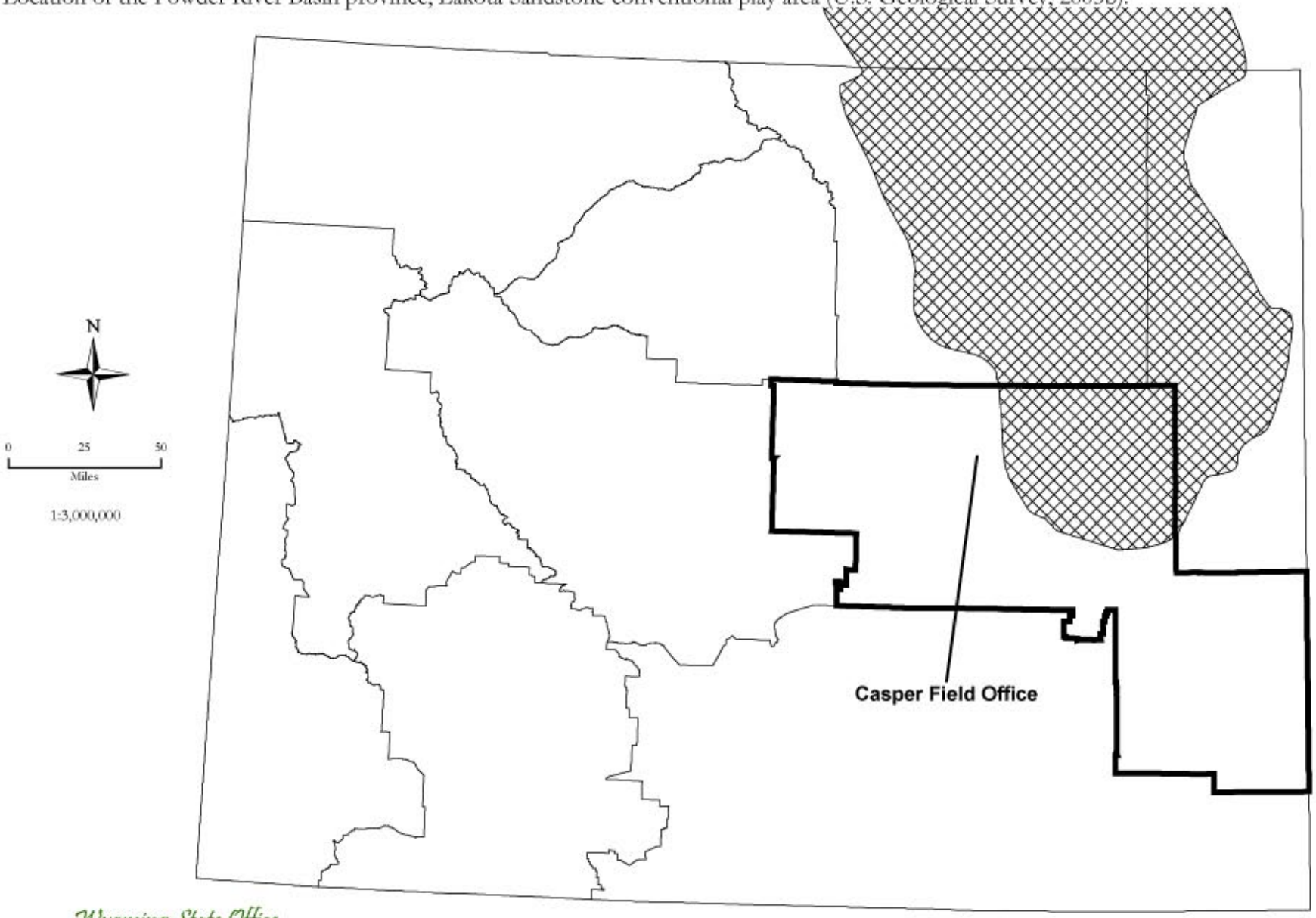

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Figure A1-7.

Location of the Powder River Basin province, Fall River Sandstone conventional play area (U.S. Geological Survey, 2003b).

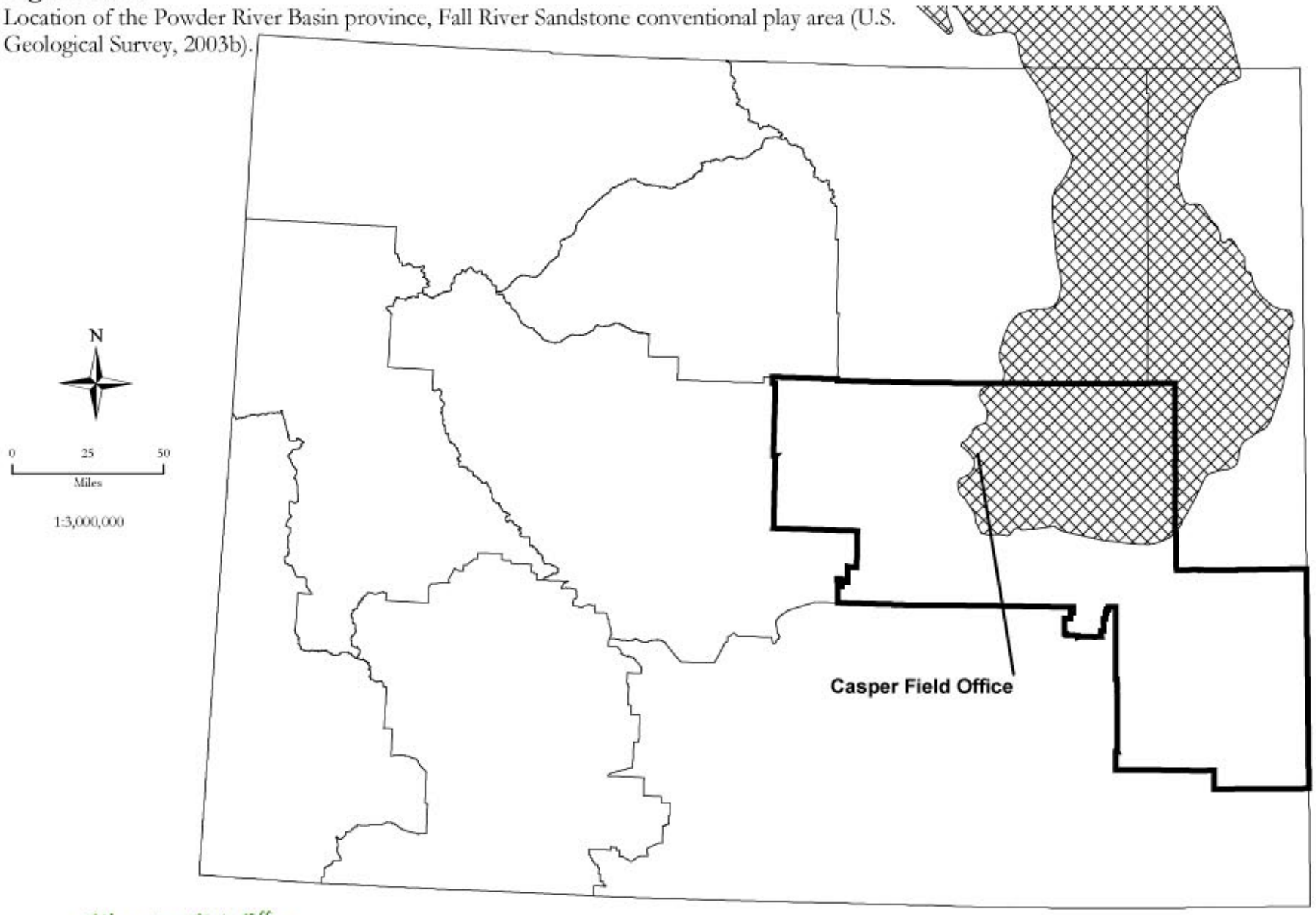

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Figure A1-8.
Location of the Powder River Basin province, Muddy Sandstone conventional play area (U.S. Geological Survey, 2003b).

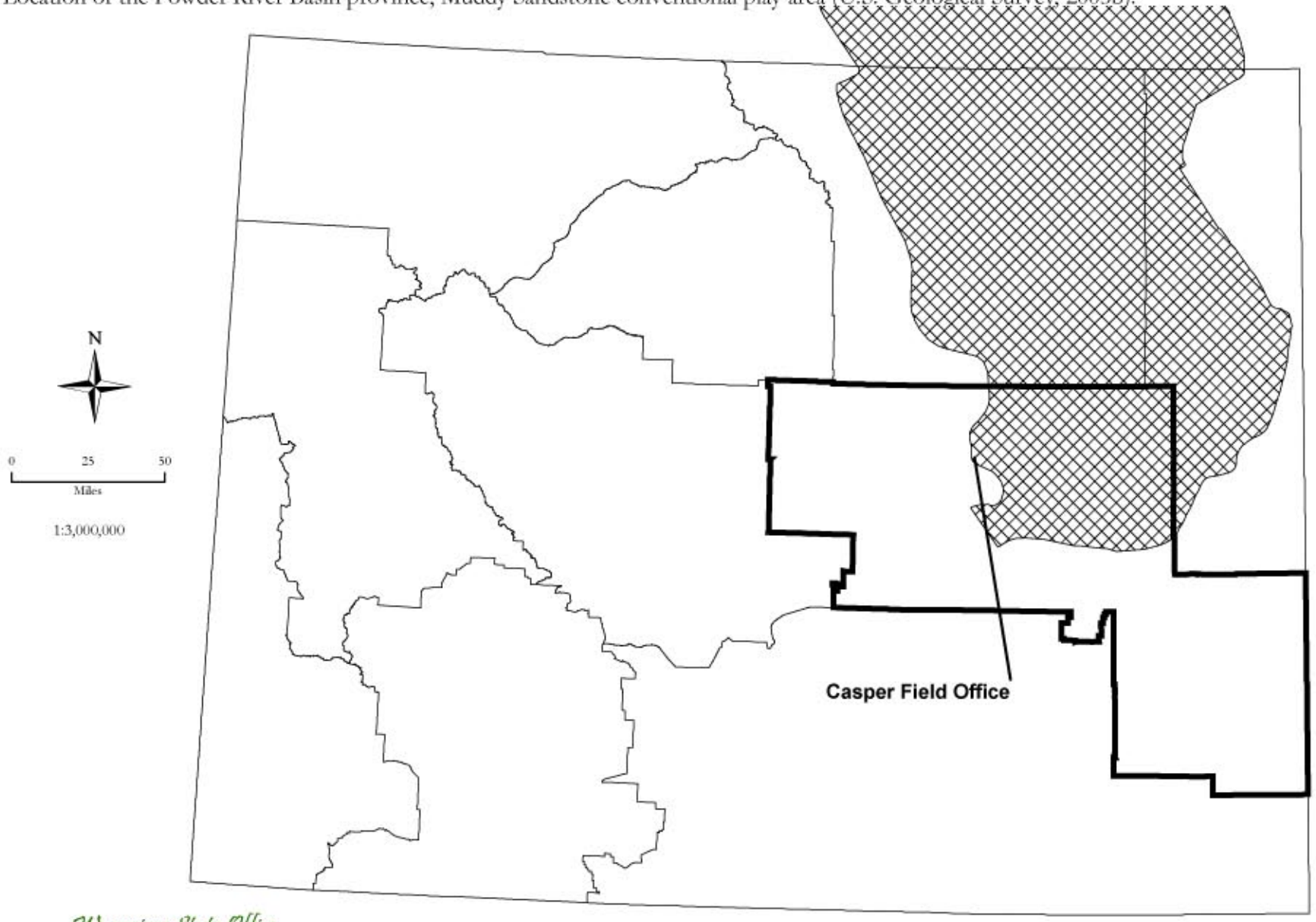

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Figure A1-9.
Location of the Powder River Basin province, Deep Frontier Sandstone conventional play area (U.S. Geological Survey, 2003b).

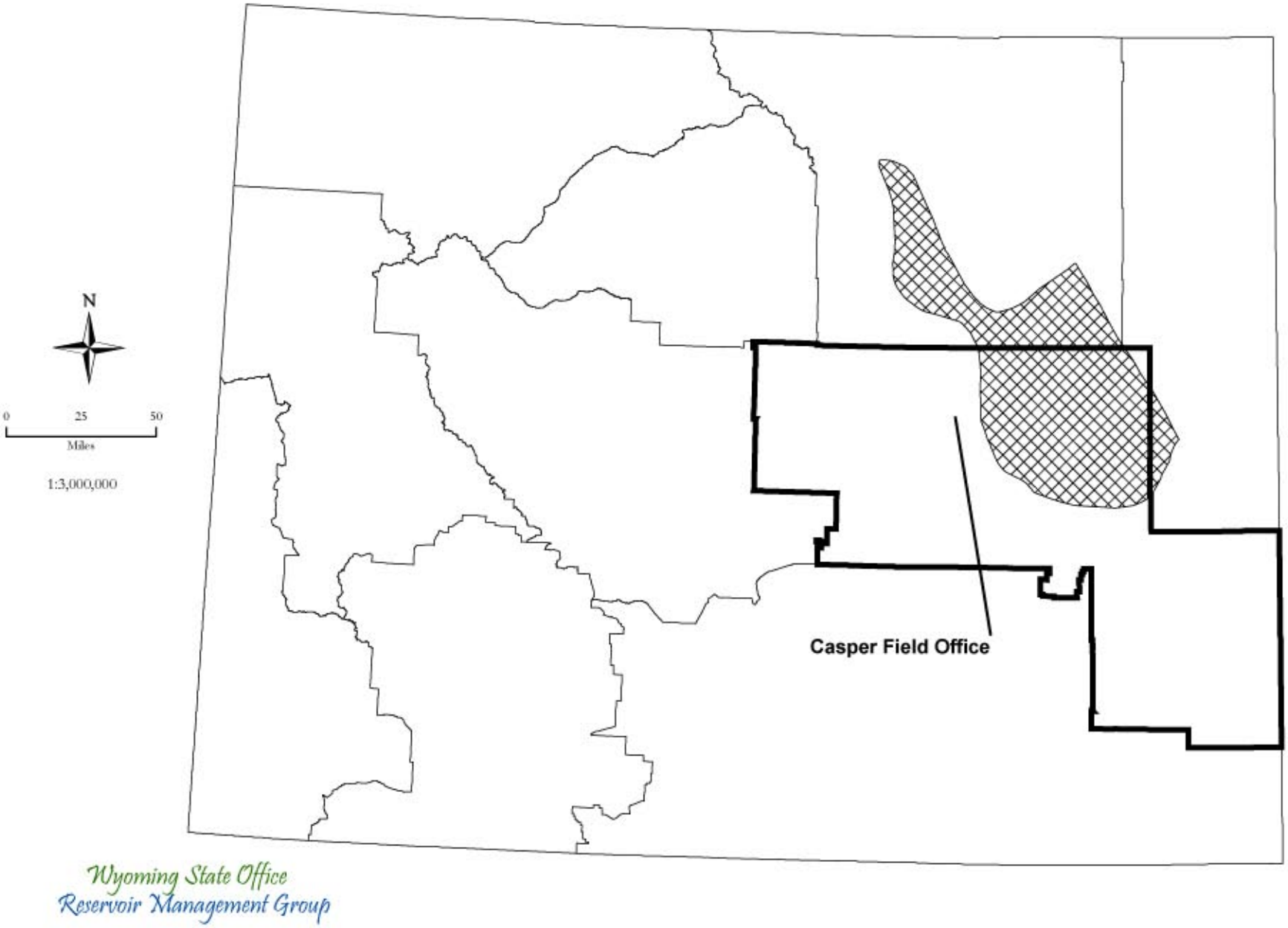

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Figure A1-10.
Location of the Powder River Basin province, Turner Sandstone conventional play area (U.S. Geological Survey, 2003b).

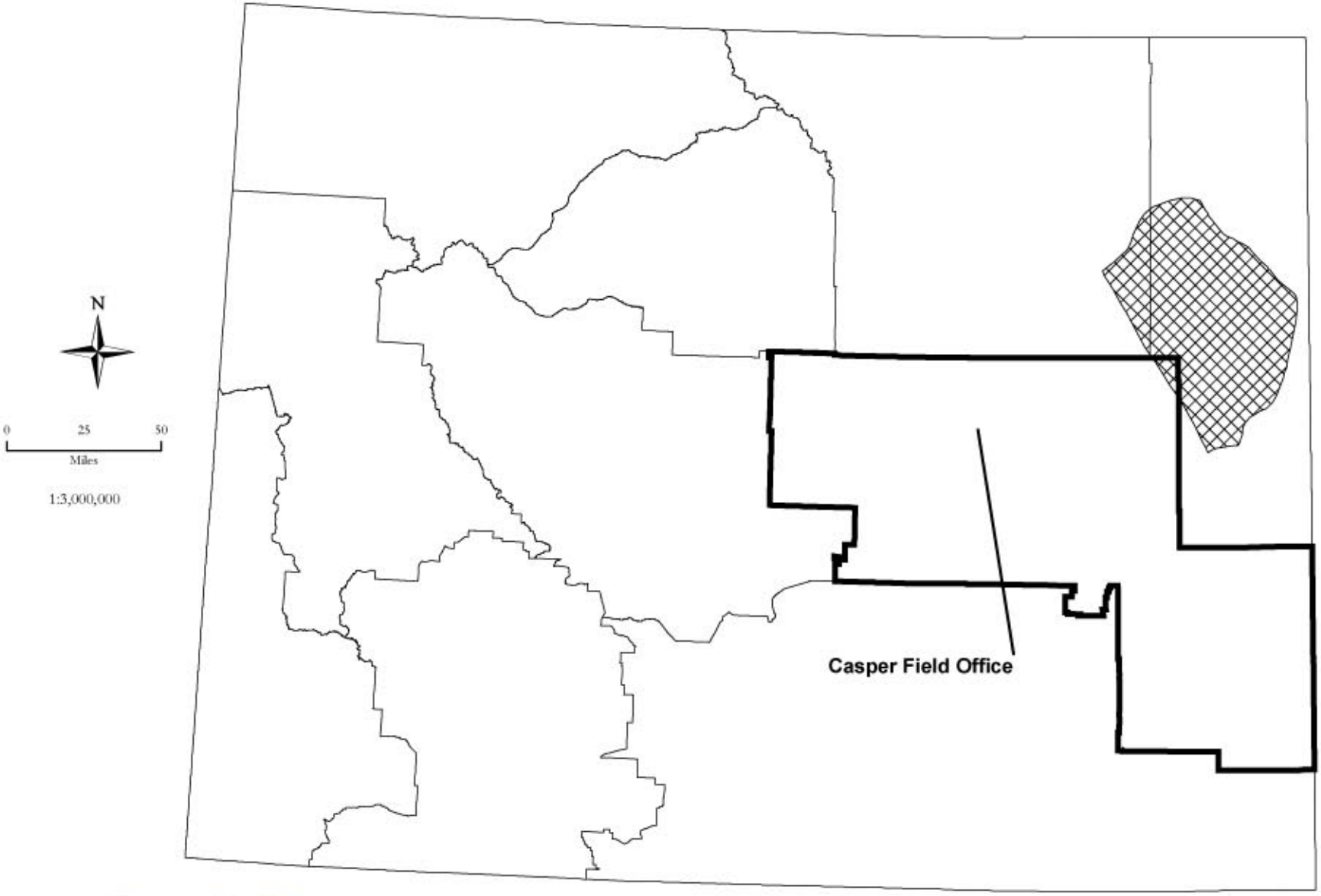

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Figure A1-11.
Location of the Powder River Basin province, Sussex-Shannon Sandstone conventional play area (U.S. Geological Survey, 2003b).

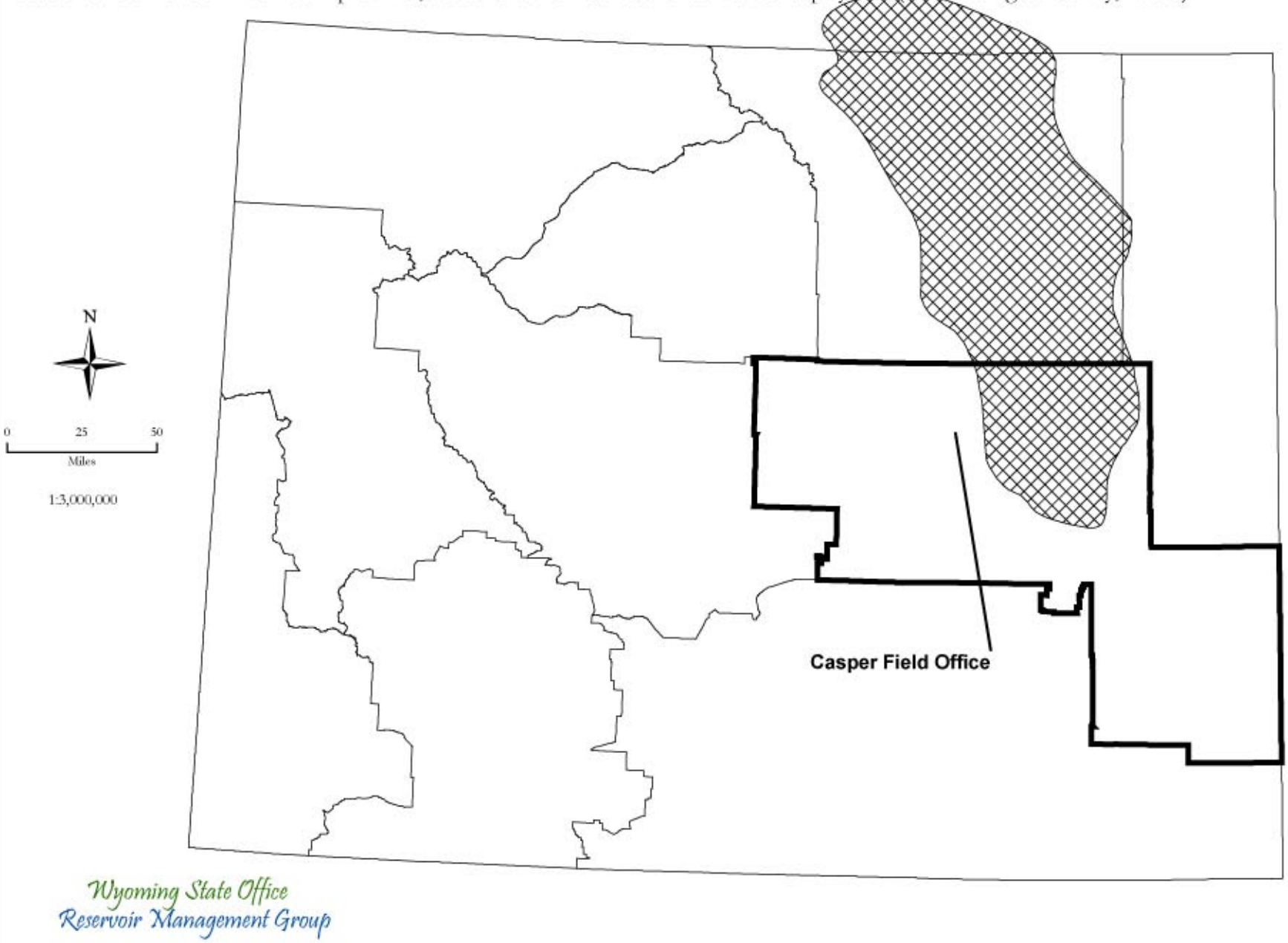

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Figure A1-12.
Location of the Powder River Basin province, Mesaverde-Lewis conventional play area (U.S. Geological Survey, 2003b).

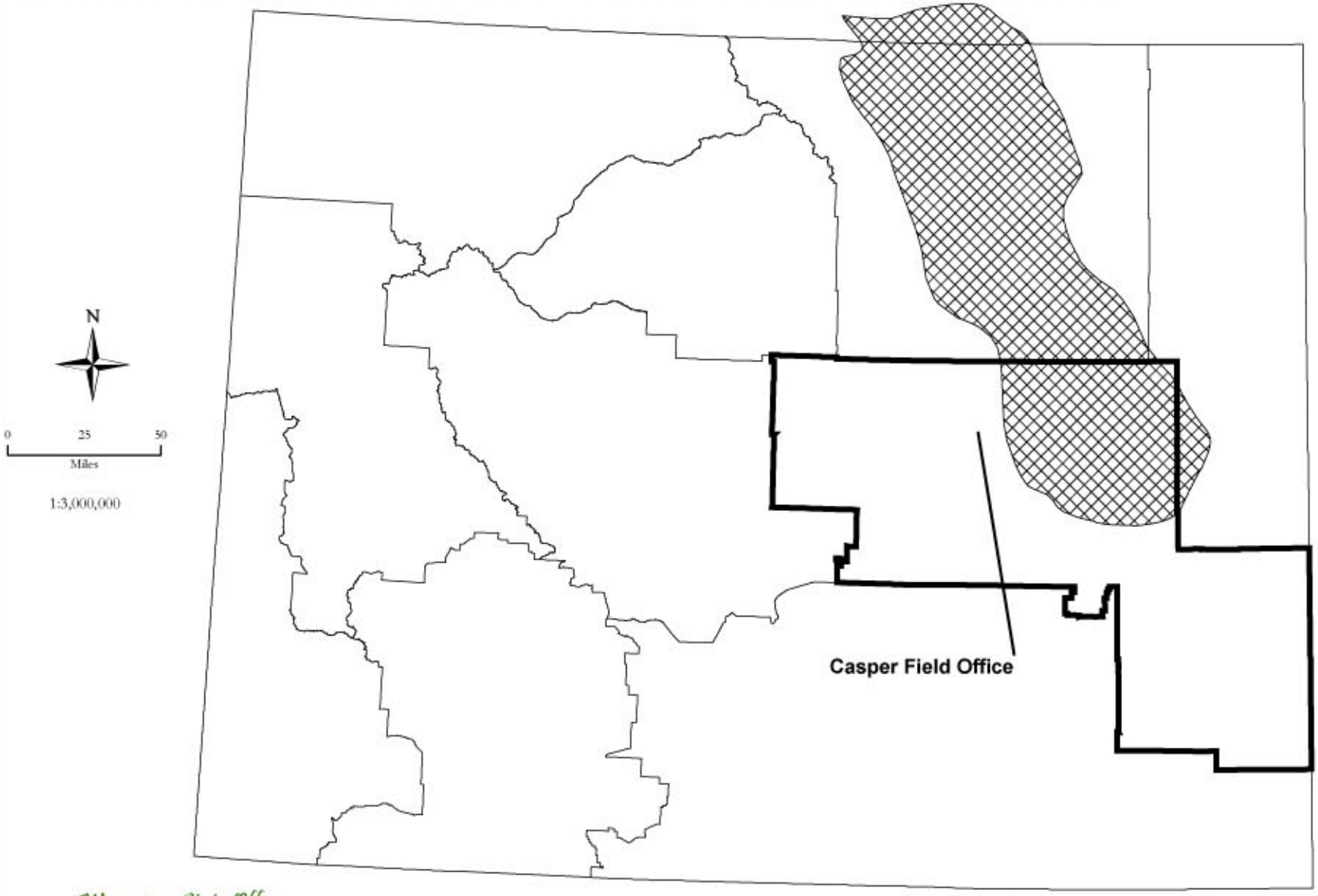

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Figure A1-13.
Location of the Powder River Basin province, Eastern Basin Margin Upper Fort Union Sandstone assessment unit area (U.S. Geological Survey, 2003b).

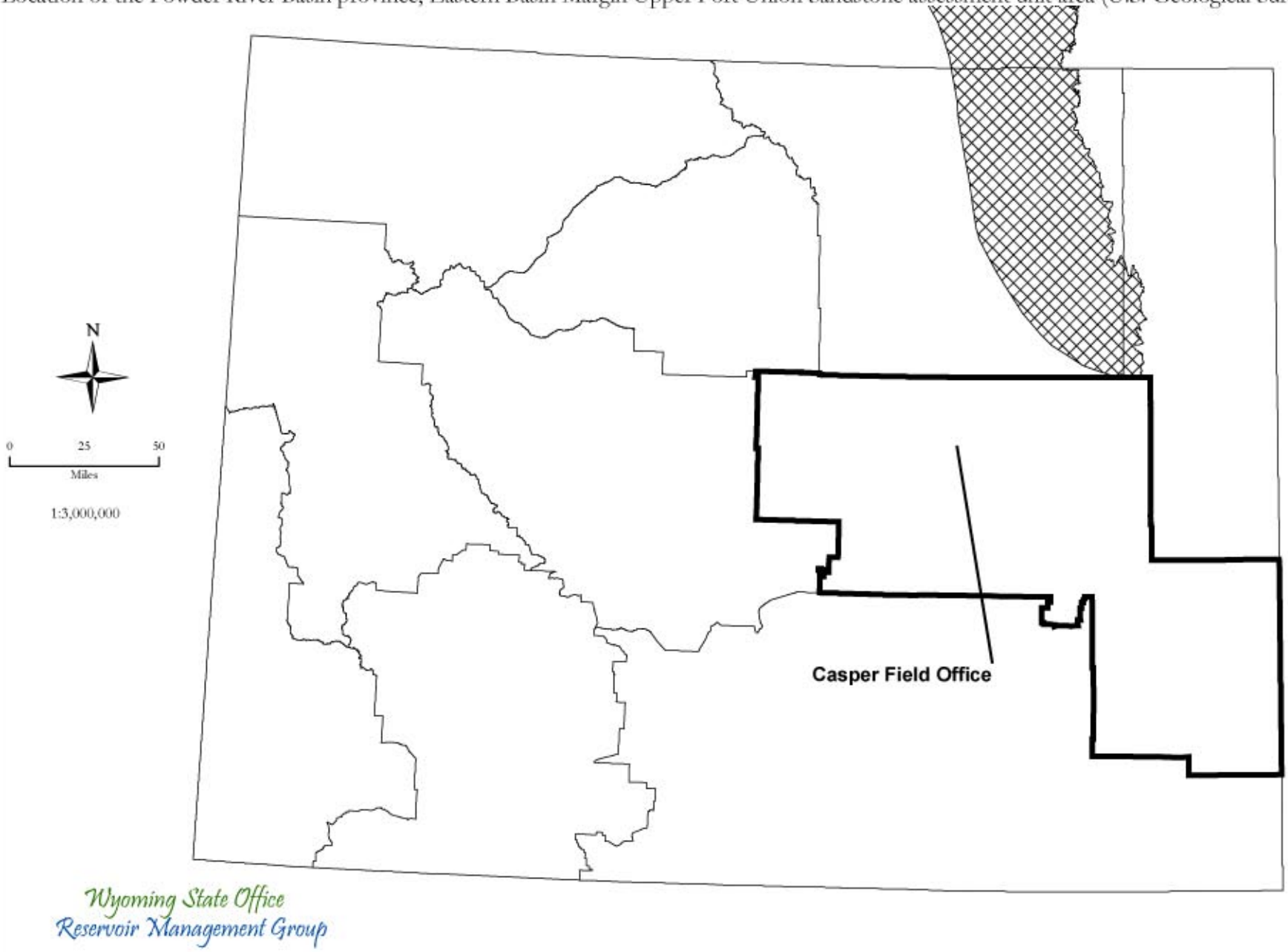

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Figure A1-14.
Location of the Powder River Basin province, Wasatch Formation coalbed gas continuous assessment unit area (U.S. Geological Survey, 2003b).

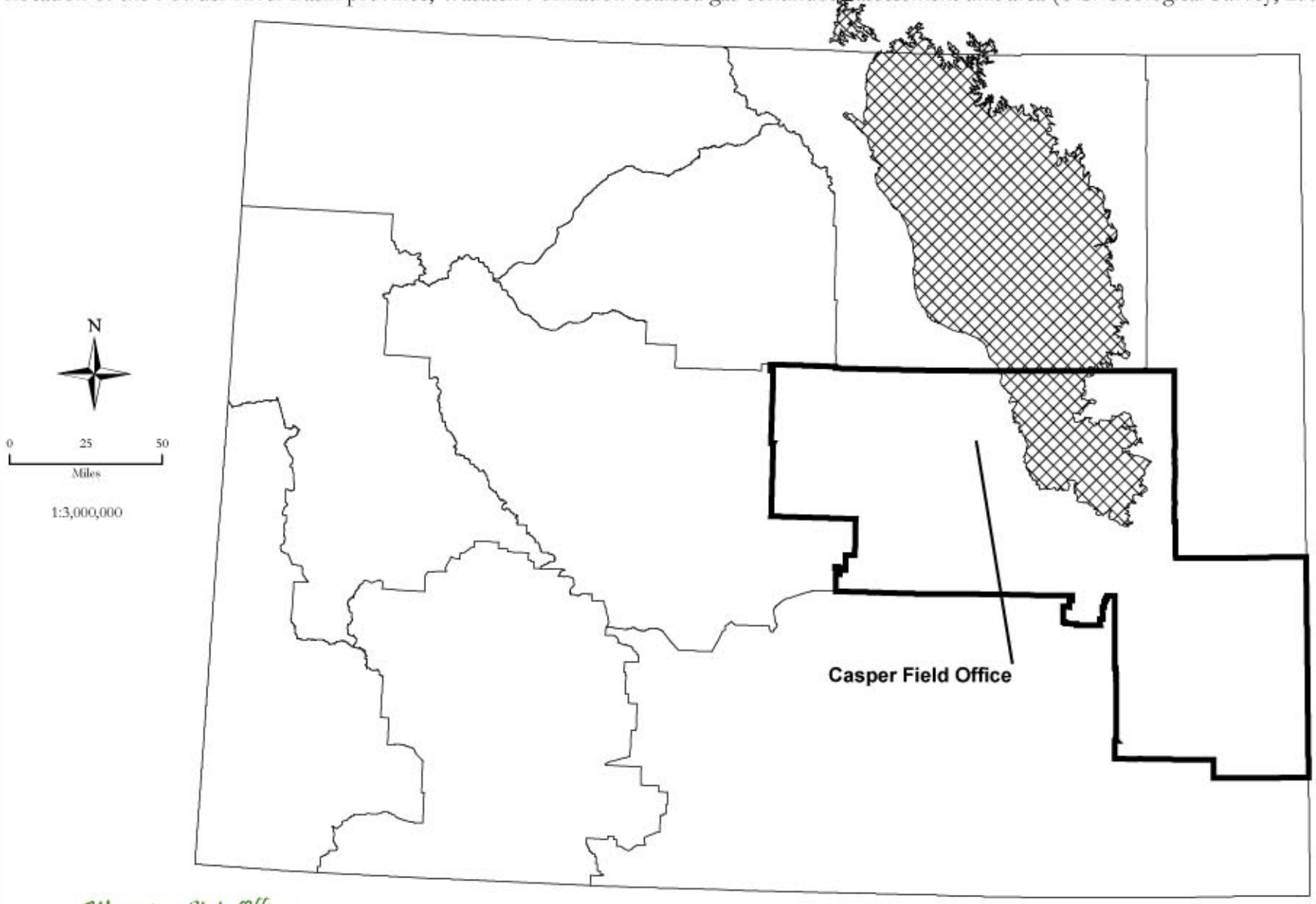

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Figure A1-15.
Location of the Powder River Basin province, Upper Fort Union Formation coalbed gas continuous assessment unit area (U.S. Geological Survey, 2003b).

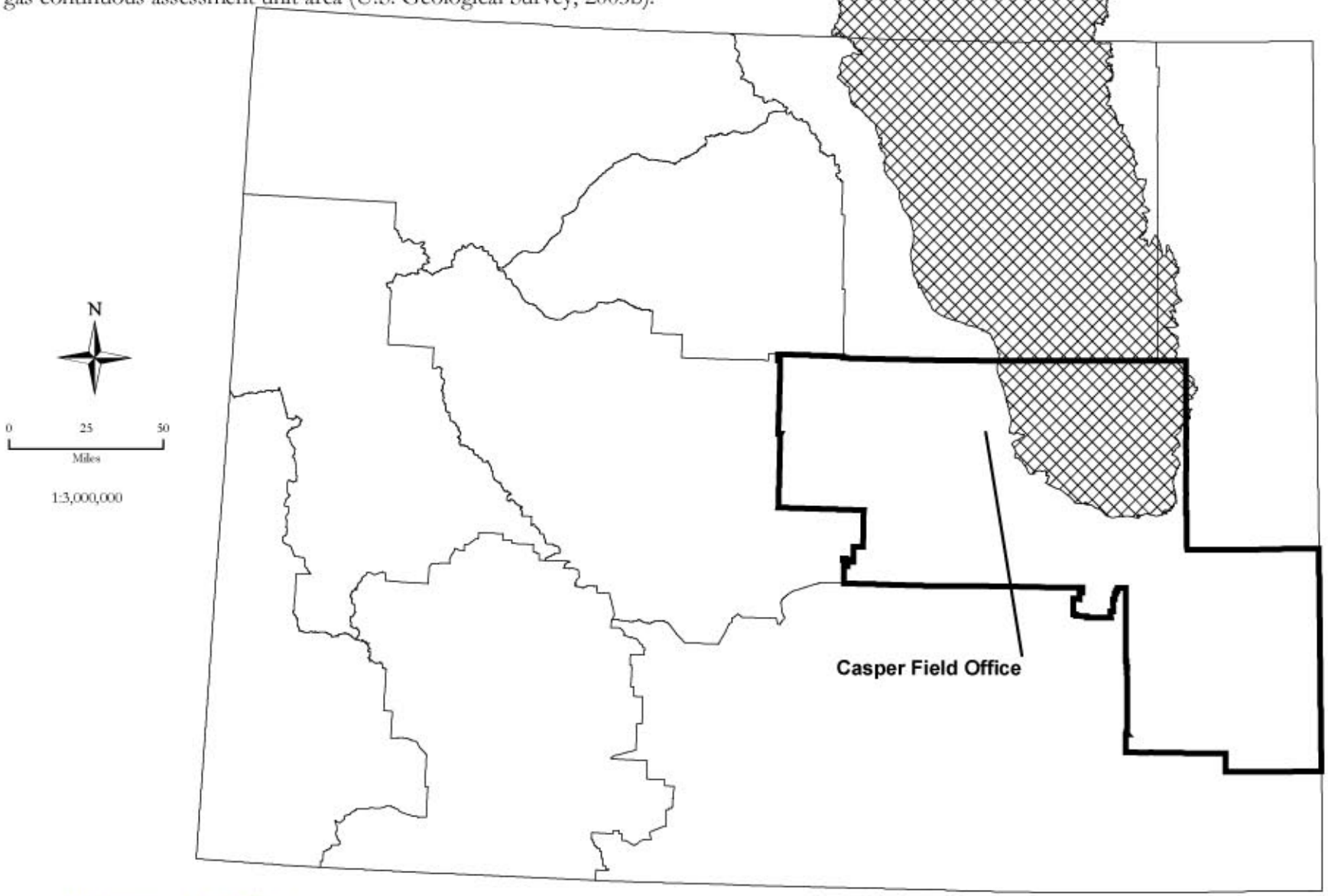

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Figure A1-16.
Location of the Powder River Basin province, Lower Fort Union-Lance Formation coalbed gas continuous assessment unit area (U.S. Geological Survey, 2003b).

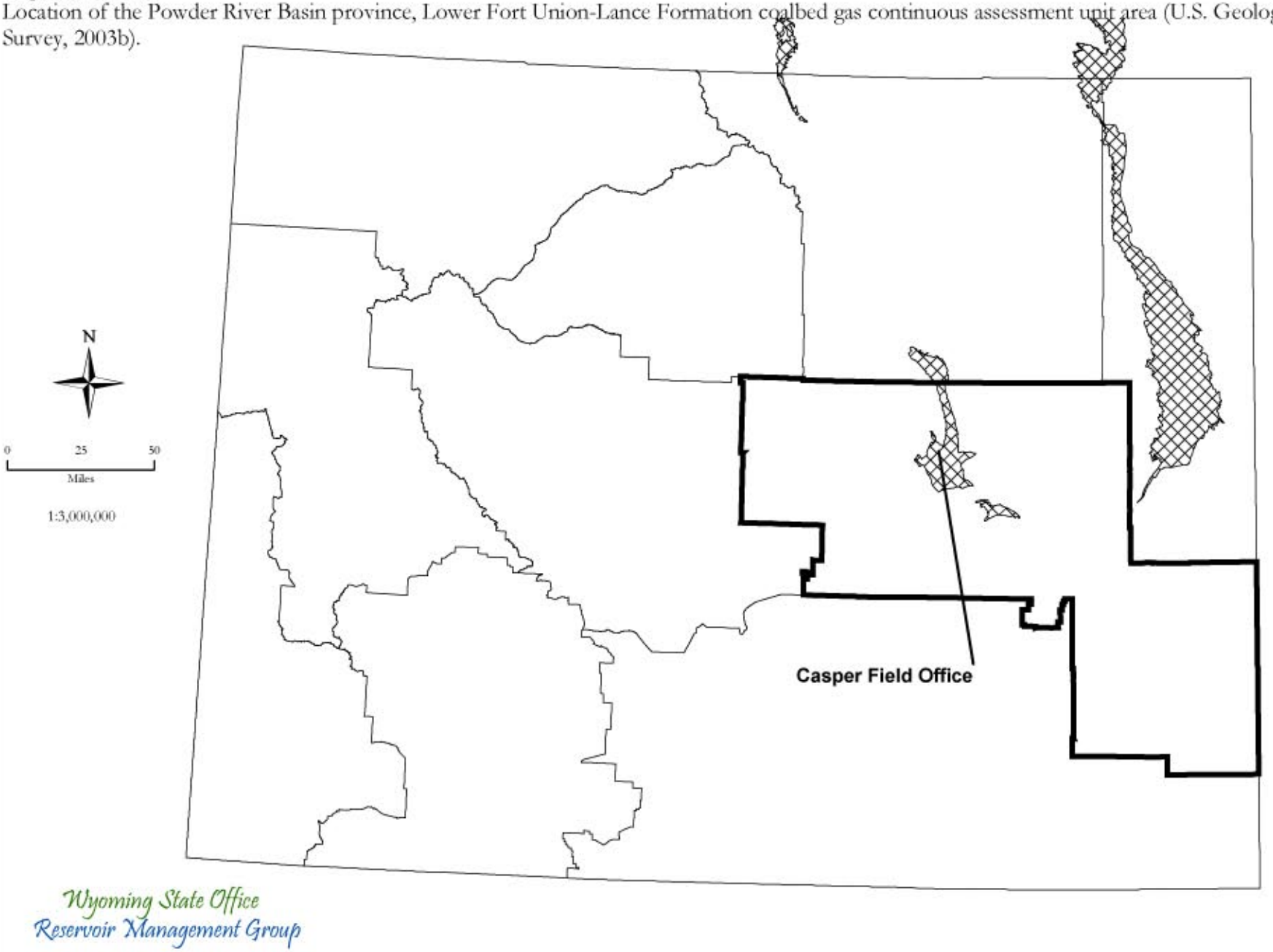

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Figure A1-17.
Location of the Powder River Basin province, Mowry continuous oil assessment unit area (U.S. Geological Survey, 2003b).

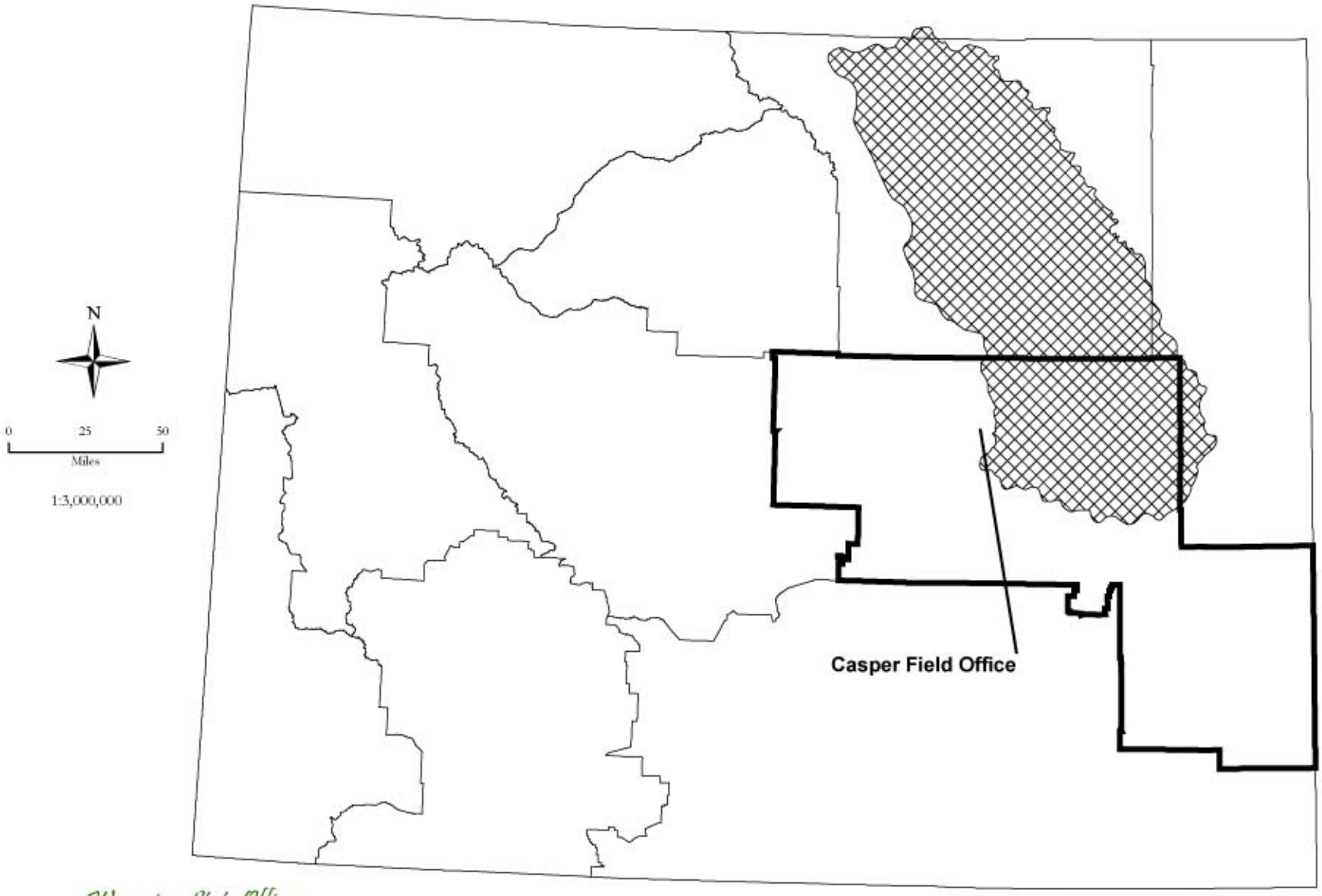

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Figure A1-18.
Location of the Powder River Basin province, Niobrara continuous oil assessment unit area (U.S. Geological Survey, 2003b).

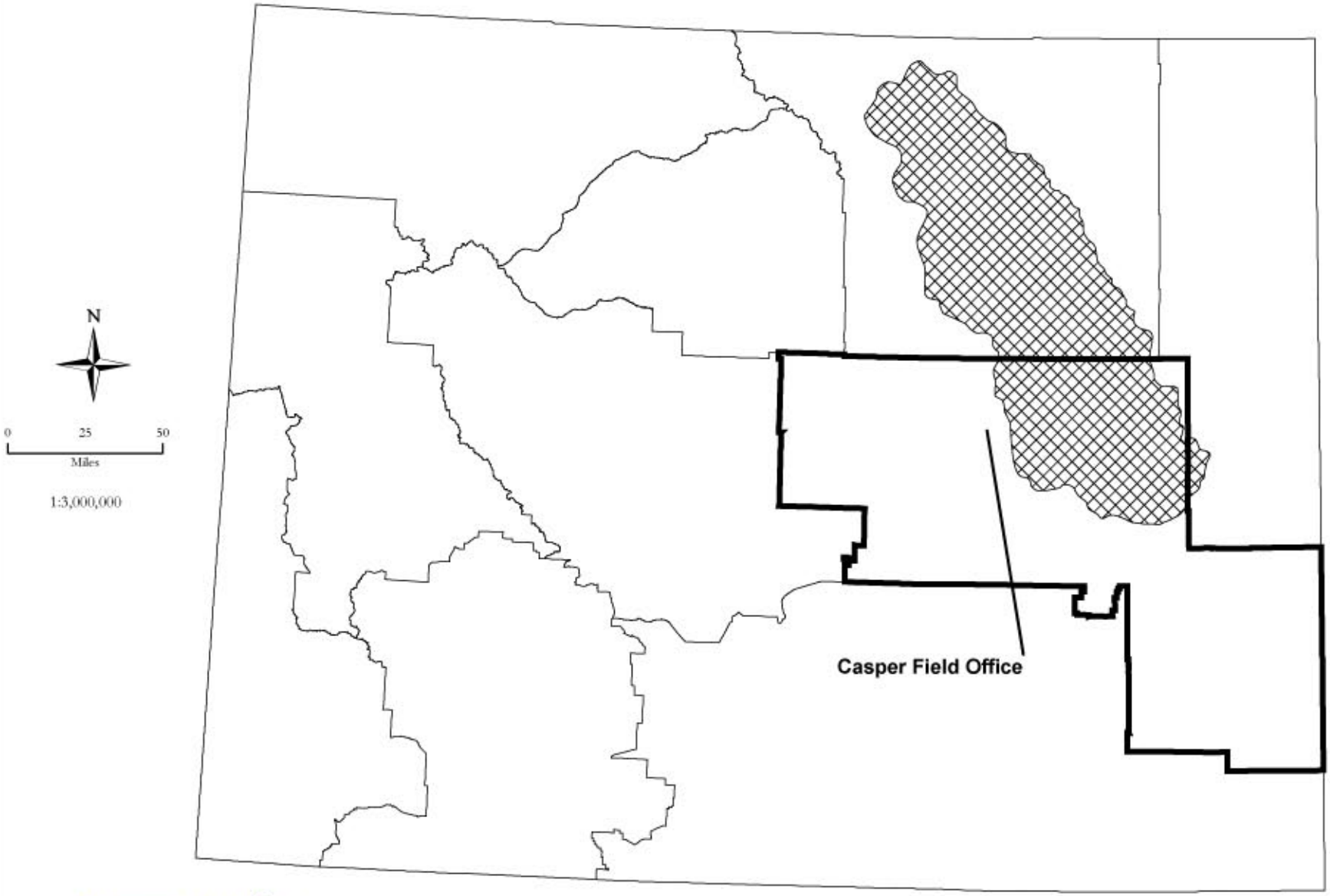

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Figure A1-19.
Location of the Powder River Basin province, Shallow Biogenic Gas continuous assessment unit area (U.S. Geological Survey, 2003b).

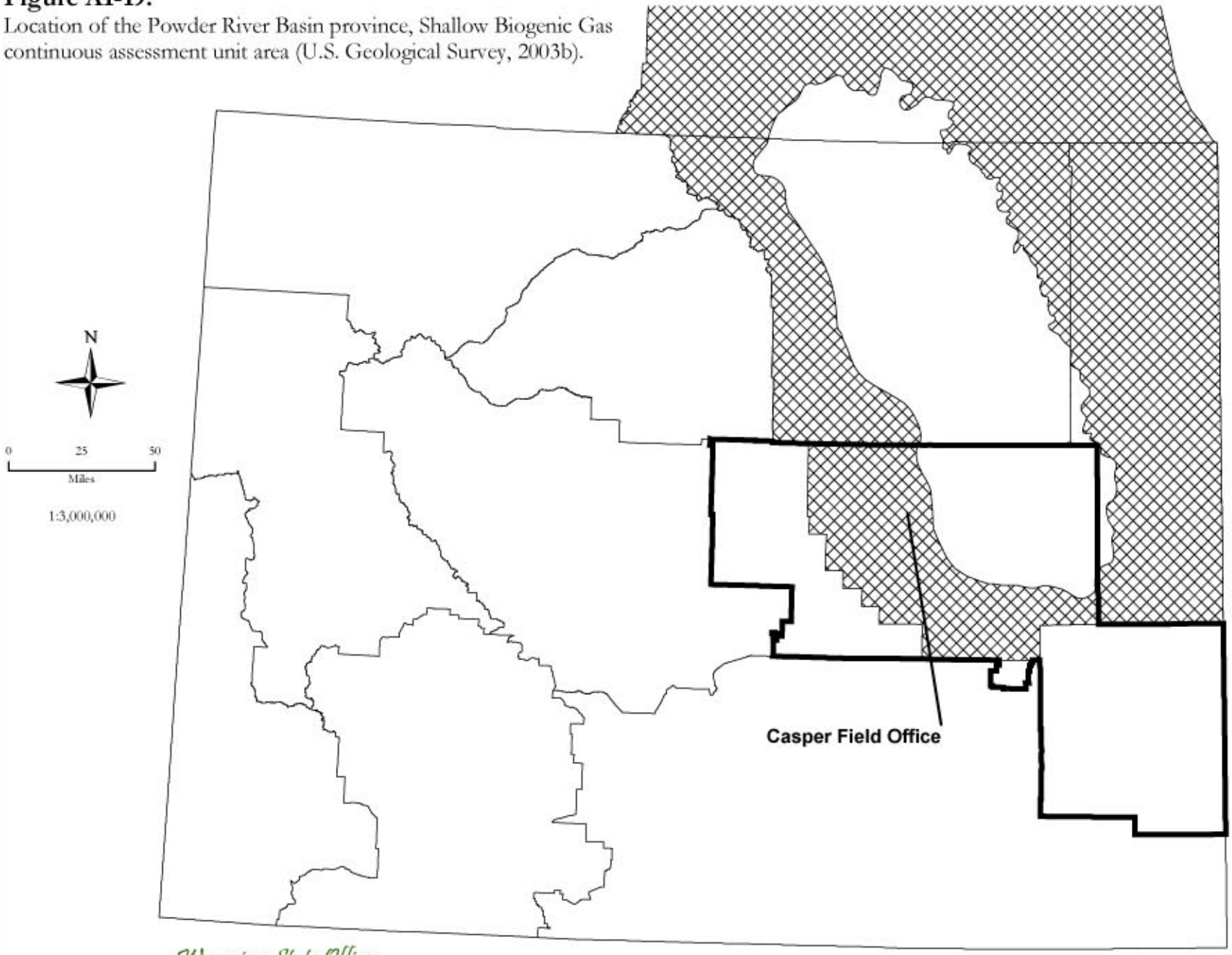

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Figure A1-20.

Location of Denver Basin province, Fractured Niobrara Limestone Transitional conventional assessment unit area (U.S. Geological Survey, 2003c).

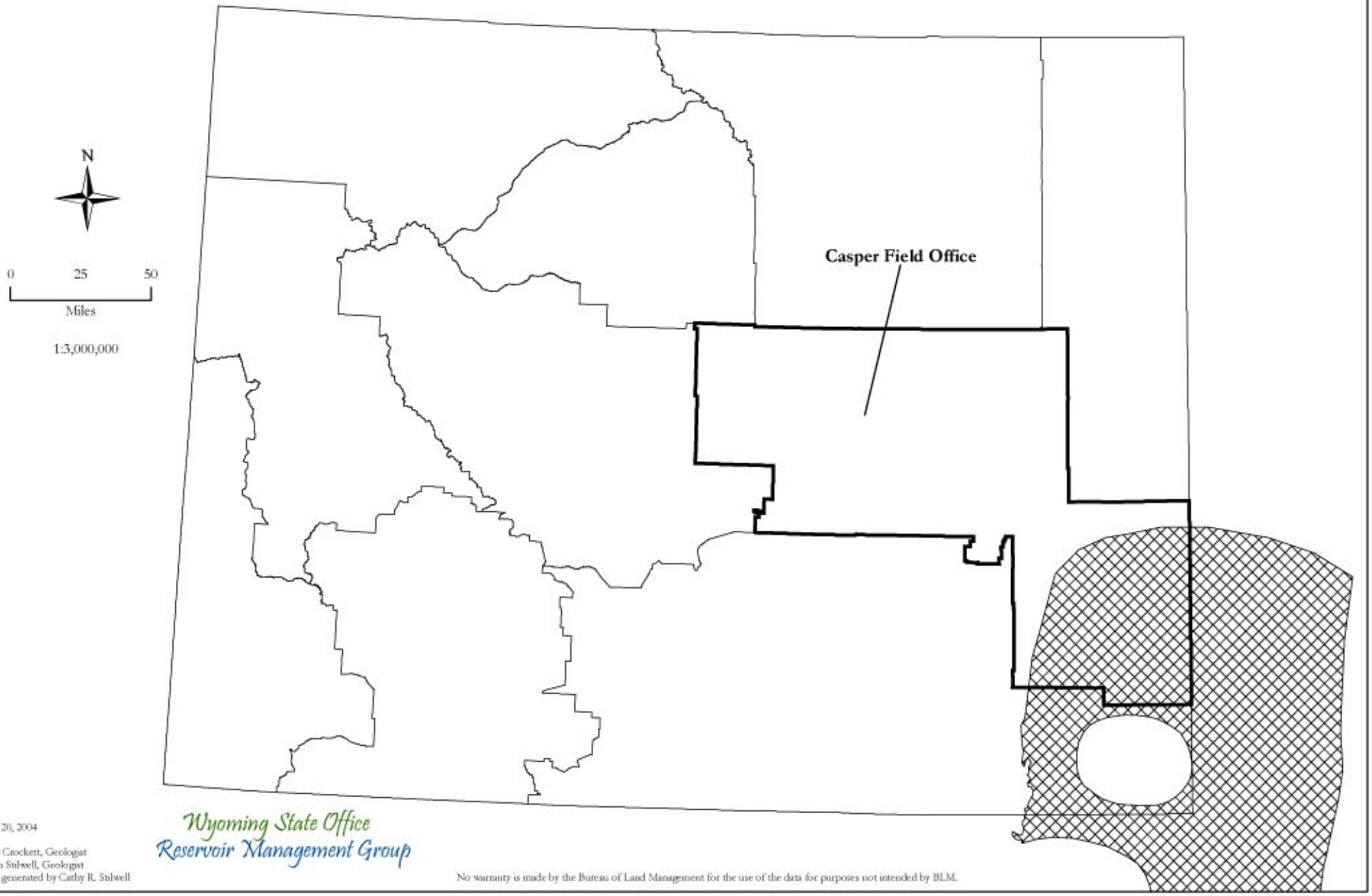

Figure A1-21.

Location of Denver Basin province, Dakota Group and D Sandstone conventional assessment unit area (U.S. Geological Survey, 2003c).

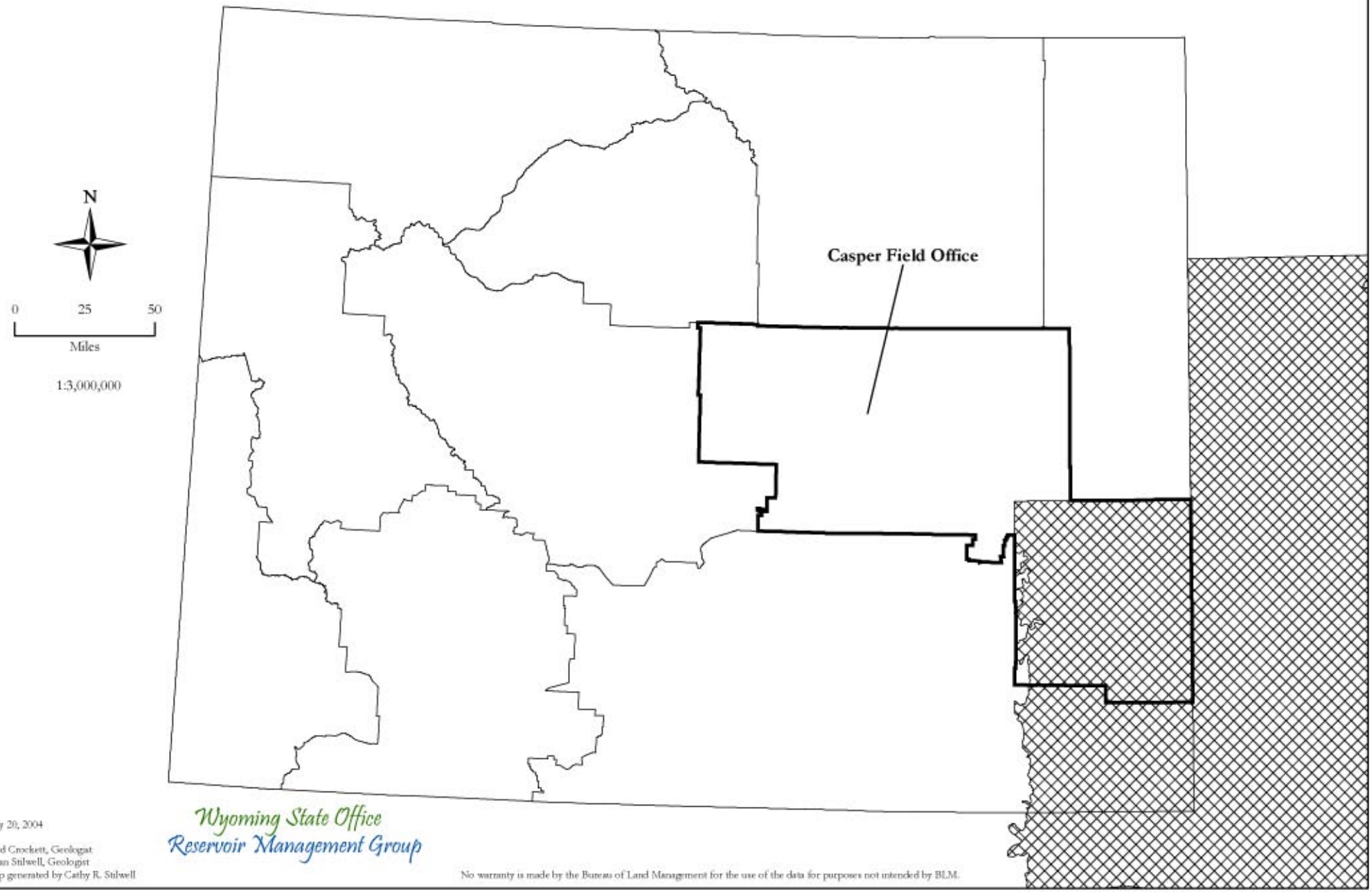

Figure A1-22.

Location of Denver Basin province, Permian-Pennsylvanian Reservoirs conventional assessment unit area (U.S. Geological Survey, 2003c).

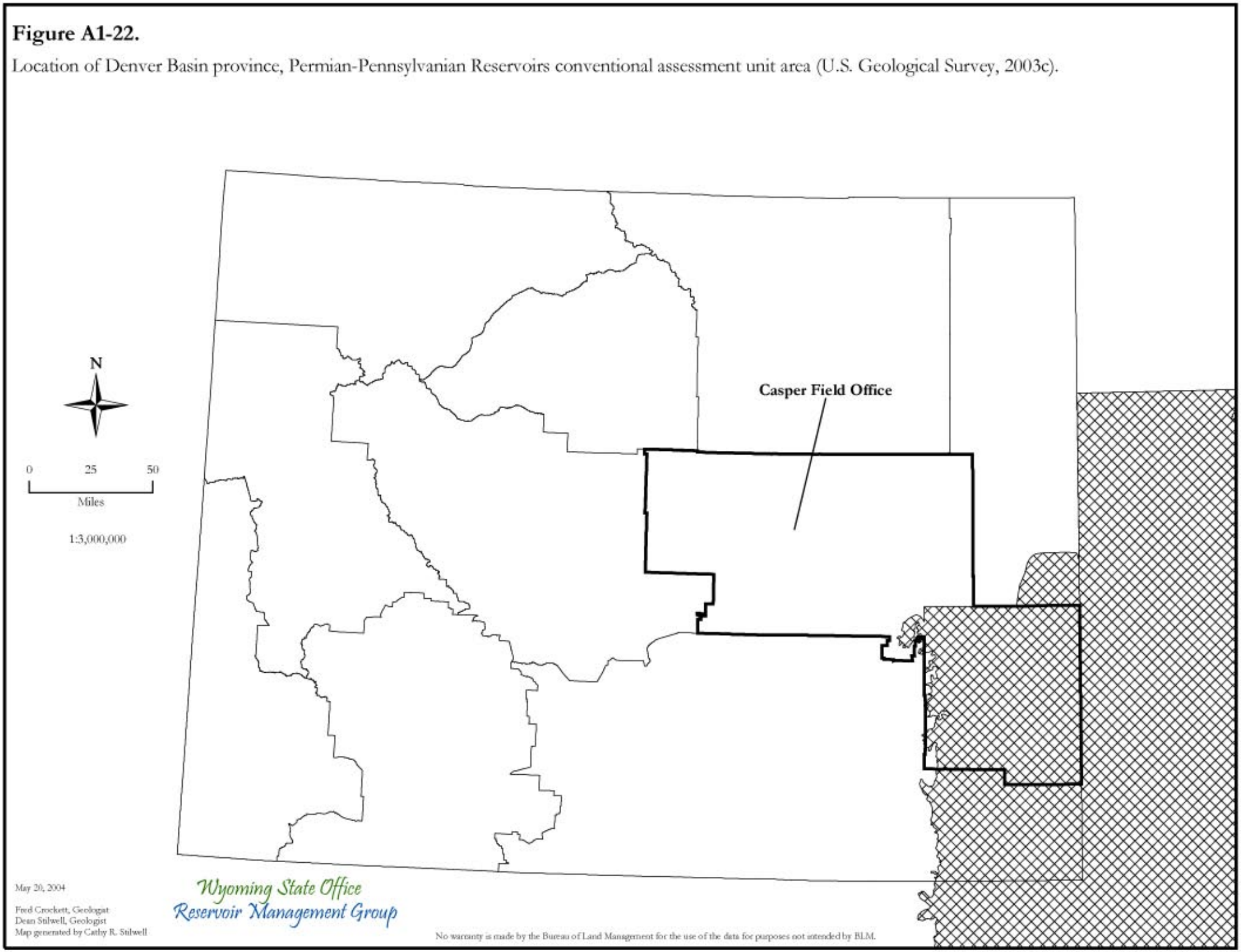

Figure A1-23.

Location of Denver Basin province, Denver Formation Coals and Laramie Formation Coals coalbed gas assessment units (U.S. Geological Survey, 2003c).

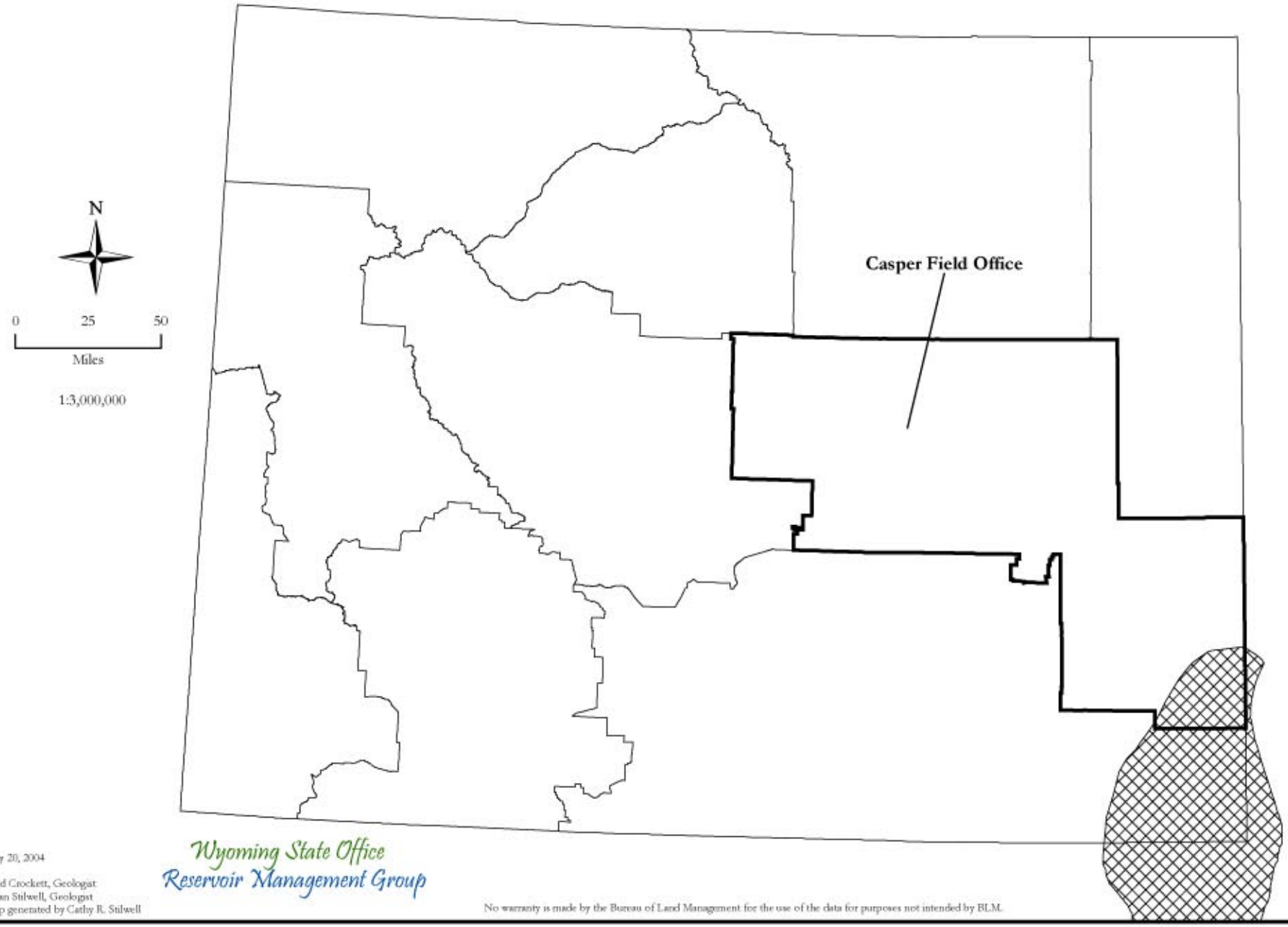

Figure A1-24.

Location of Wind River Basin province, Basin Margin Subthrust conventional play area (Beeman et al., 1996).

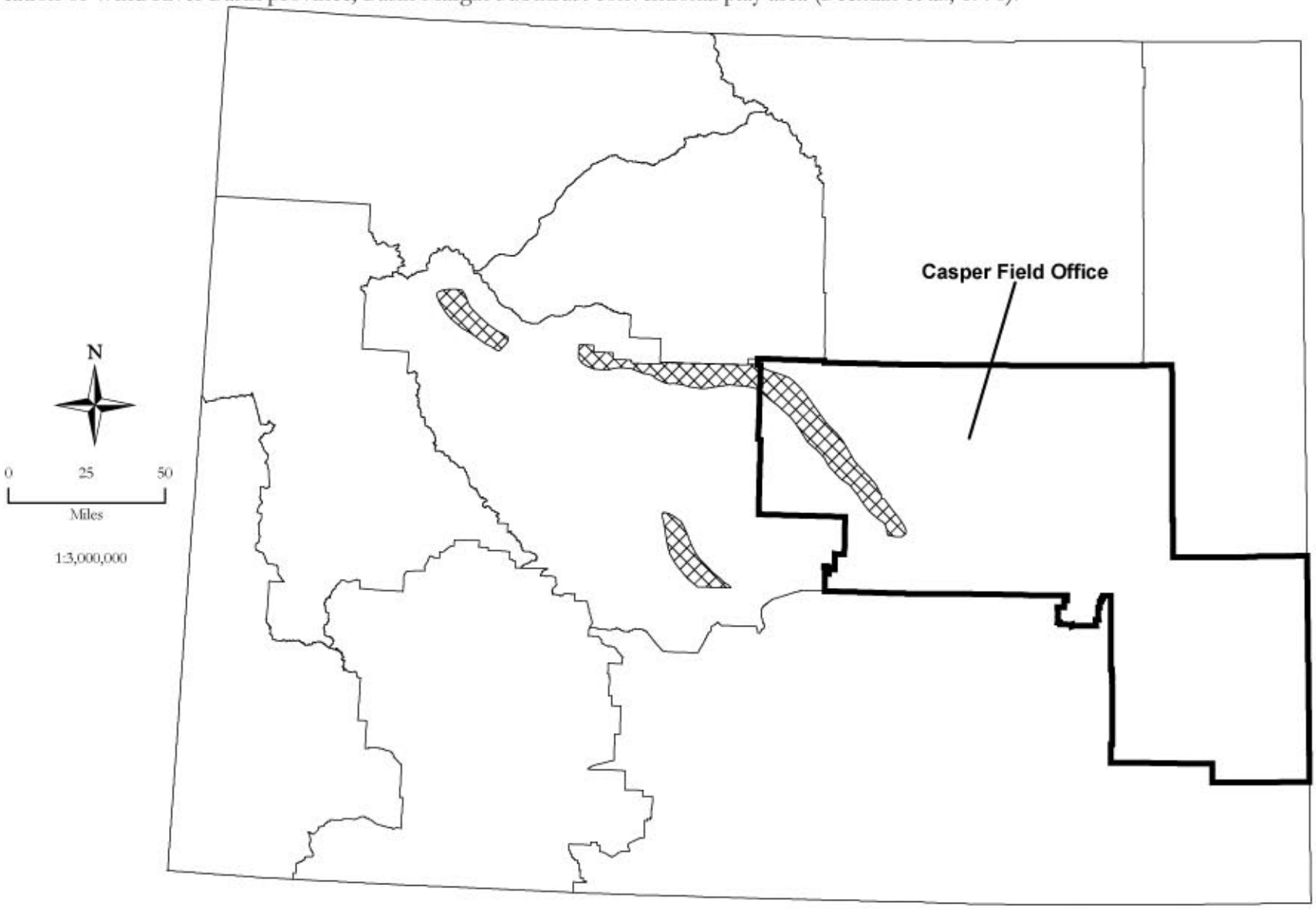

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Figure A1-25.

Location of Wind River Basin province, Basin Margin Anticline conventional play area (Beeman et al., 1996).

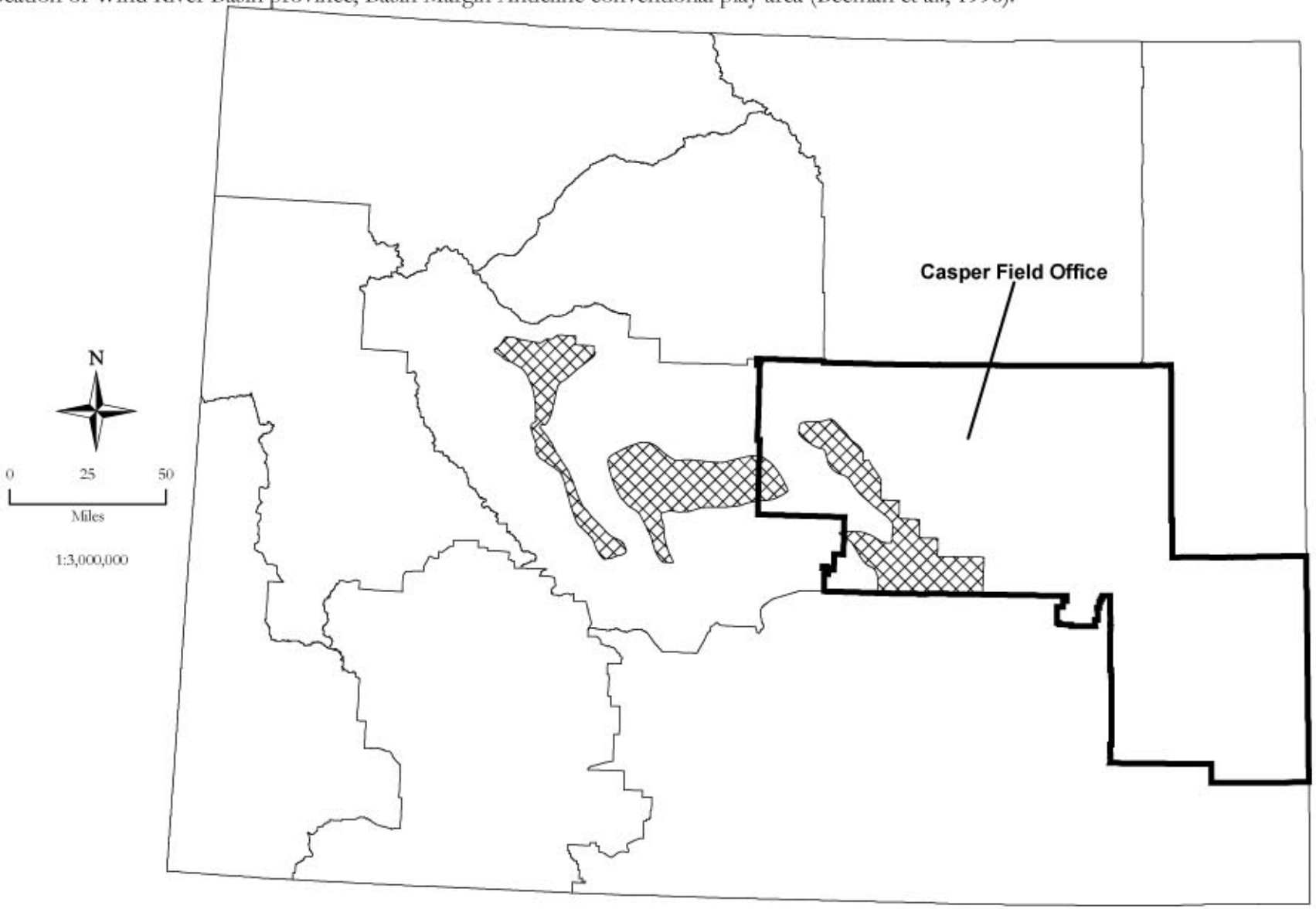

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Figure A1-26.

Location of Wind River Basin province, Deep Basin Structure conventional play area (Beeman et al., 1996).

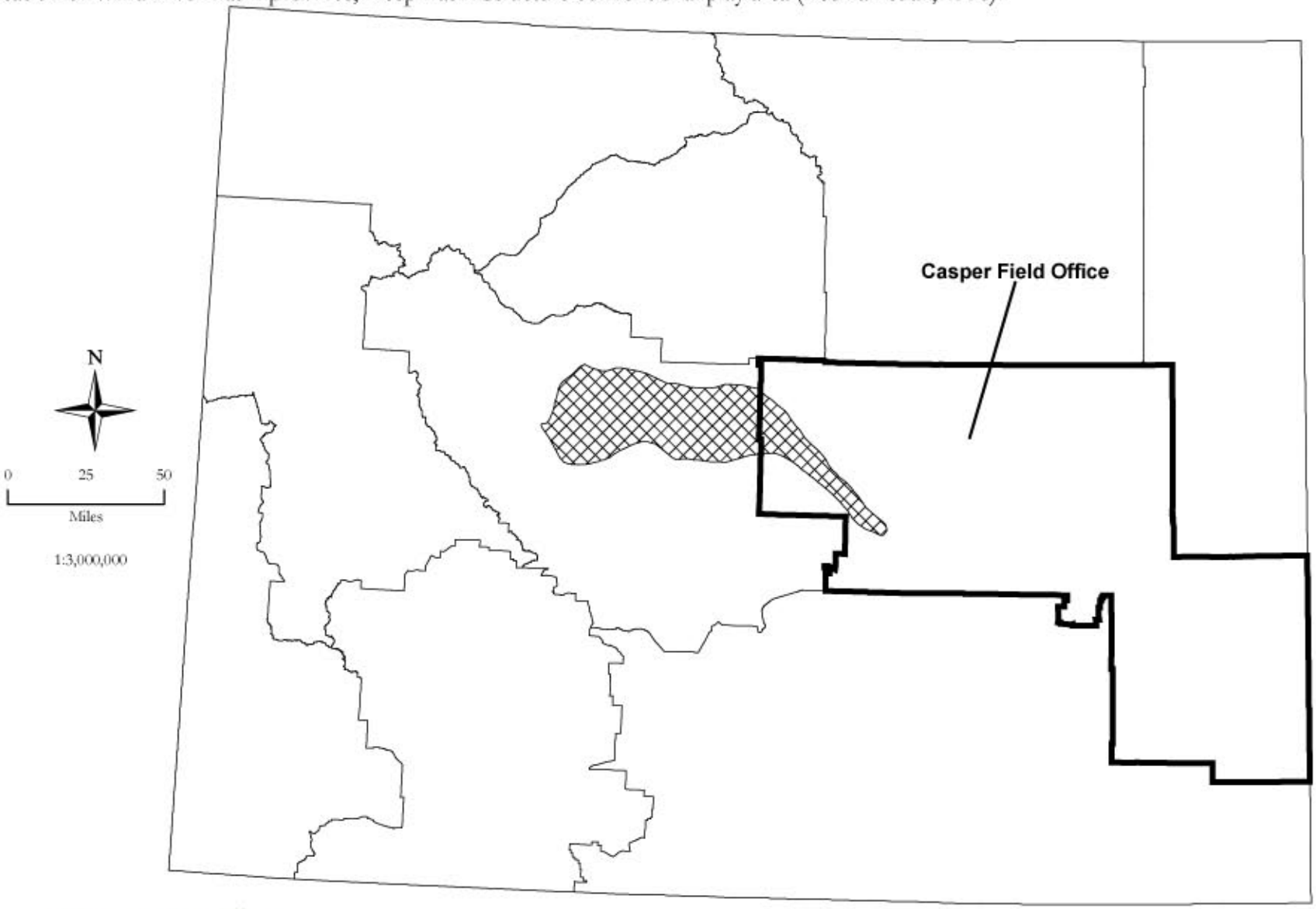

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Figure A1-27.

Location of Wind River Basin province, Muddy Sandstone conventional play area (Beeman et al., 1996).

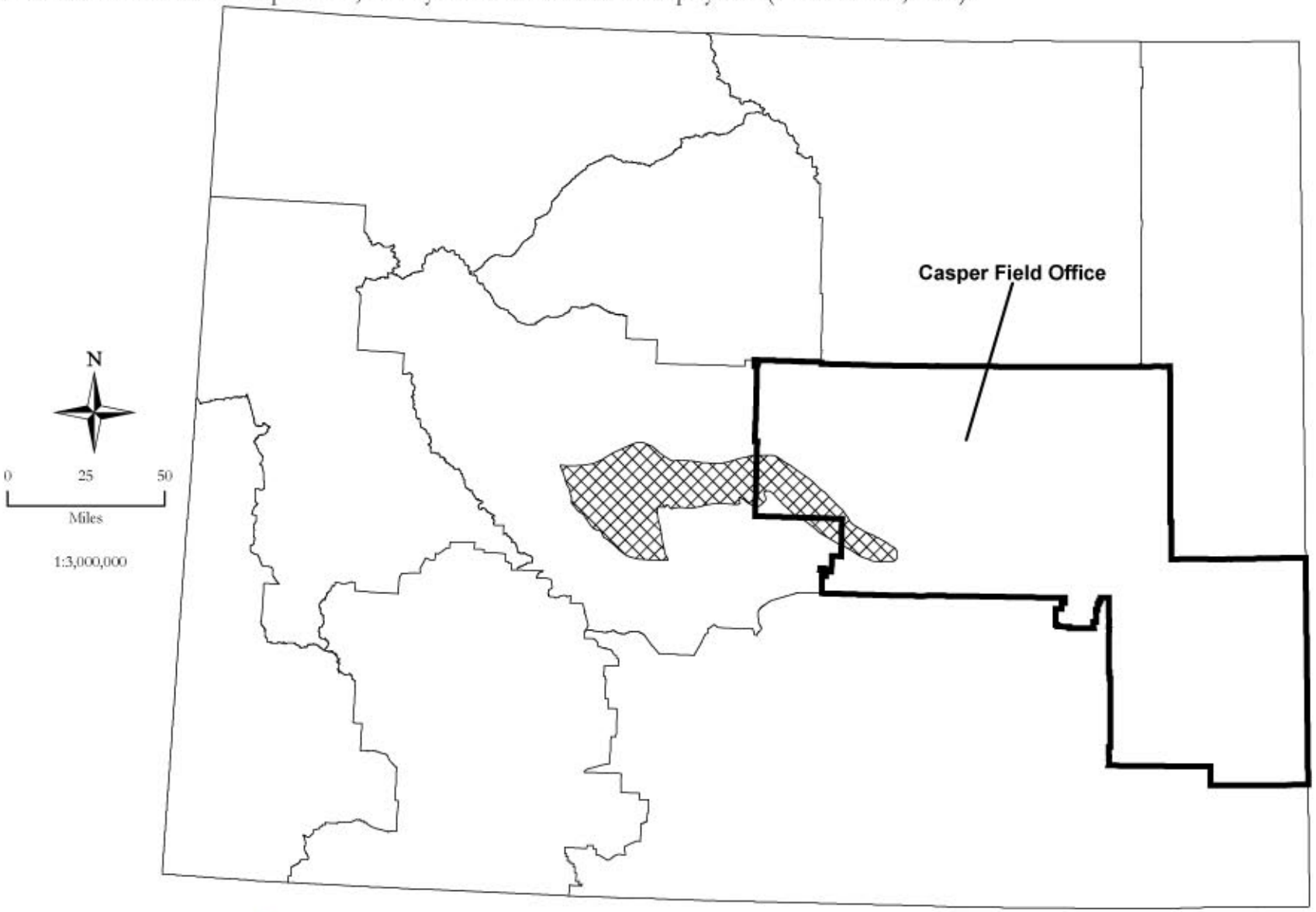

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Figure A1-28.

Location of Wind River Basin province, Phosphoria conventional play area (Beeman et al., 1996).

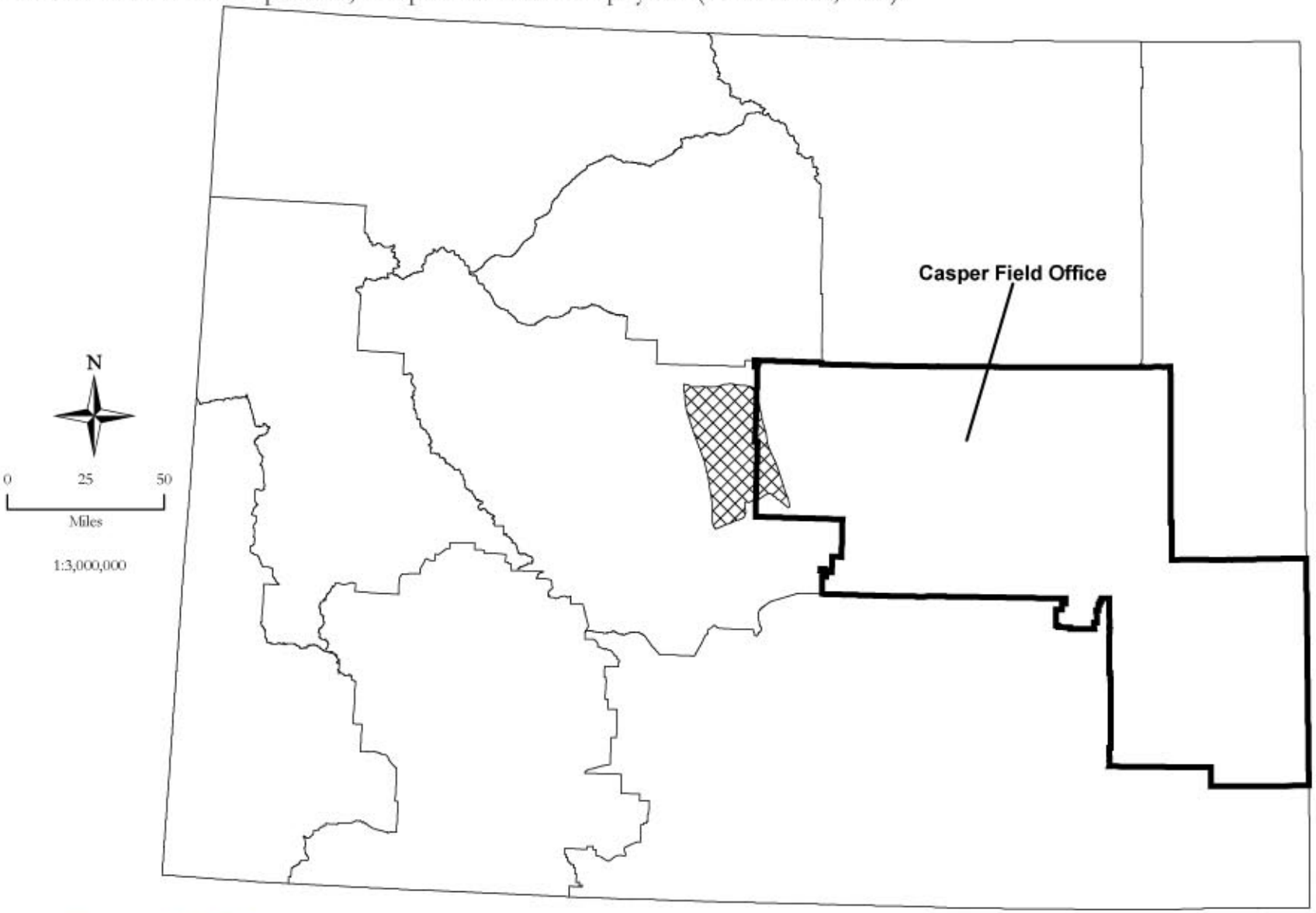

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Figure A1-29.

Location of Wind River Basin province, Bighorn Wedge-Edge Pinchout conventional play area (Beeman et al., 1996).

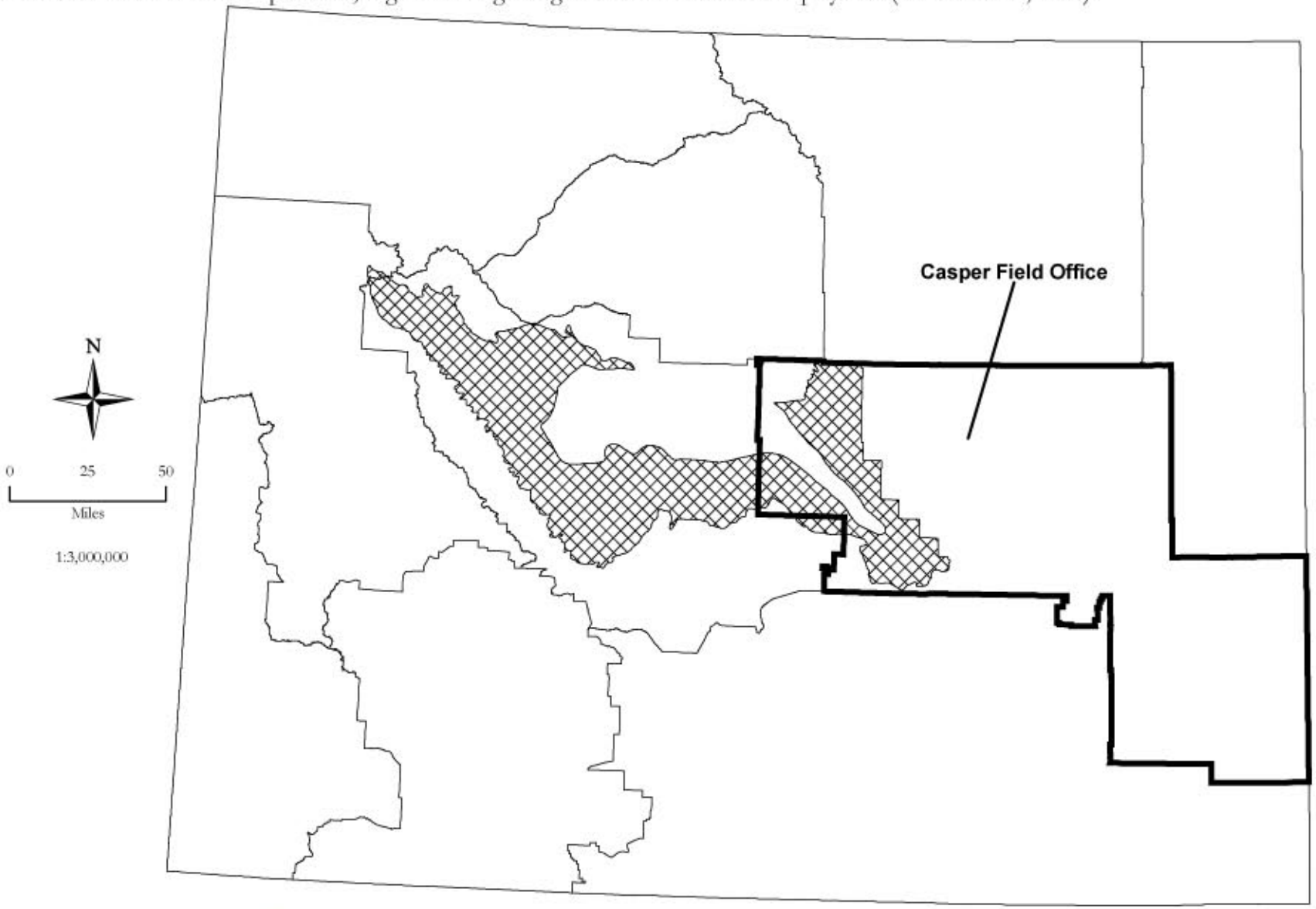

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Figure A1-30.

Location of Wind River Basin province, Flathead-Lander and Equivalent Sandstone conventional play area (Beeman et al., 1996).

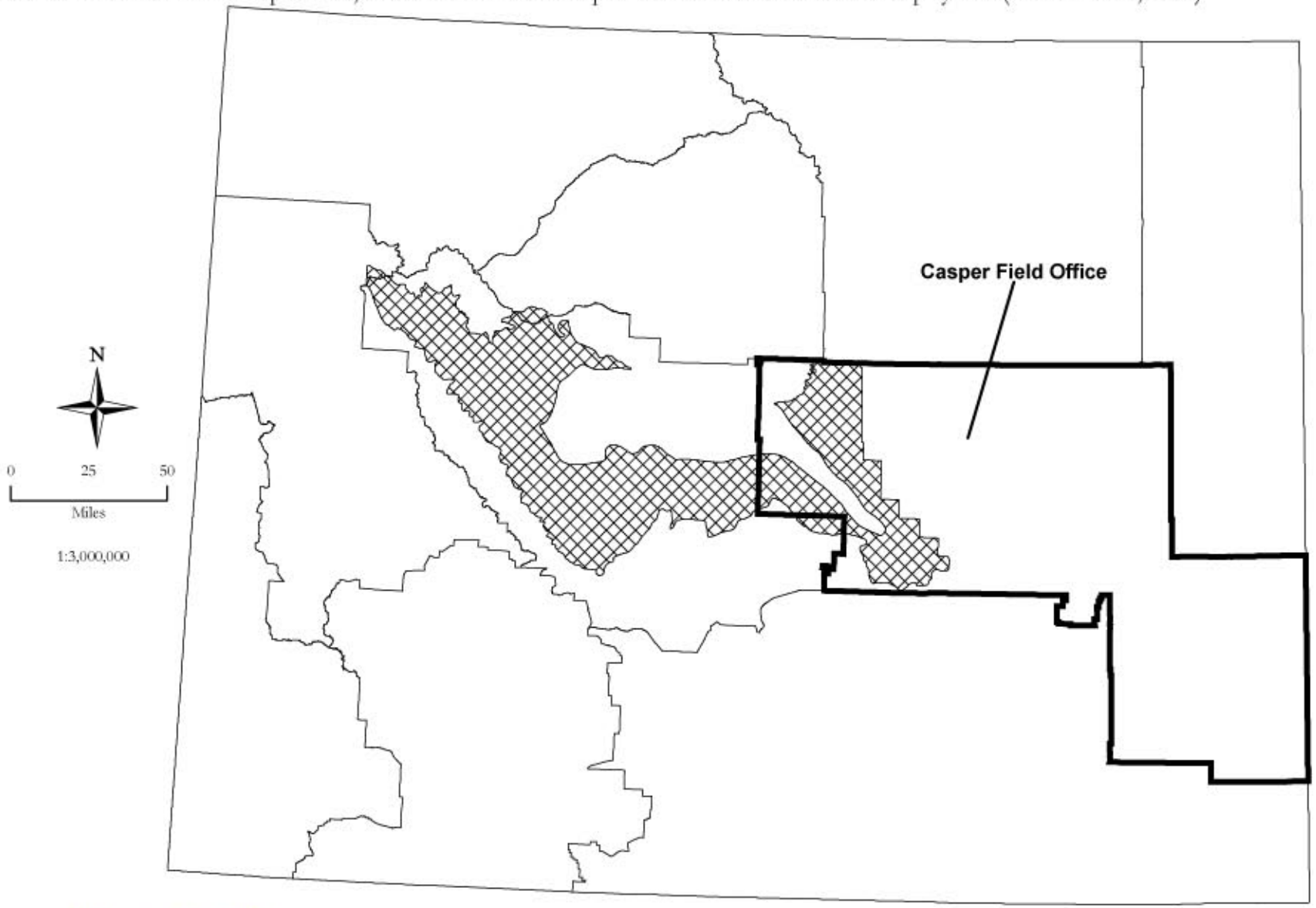

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Figure A1-31.

Location of Wind River Basin province, Madison Limestone and Darwin Amsden Sandstone conventional plays (Beeman et al., 1996).

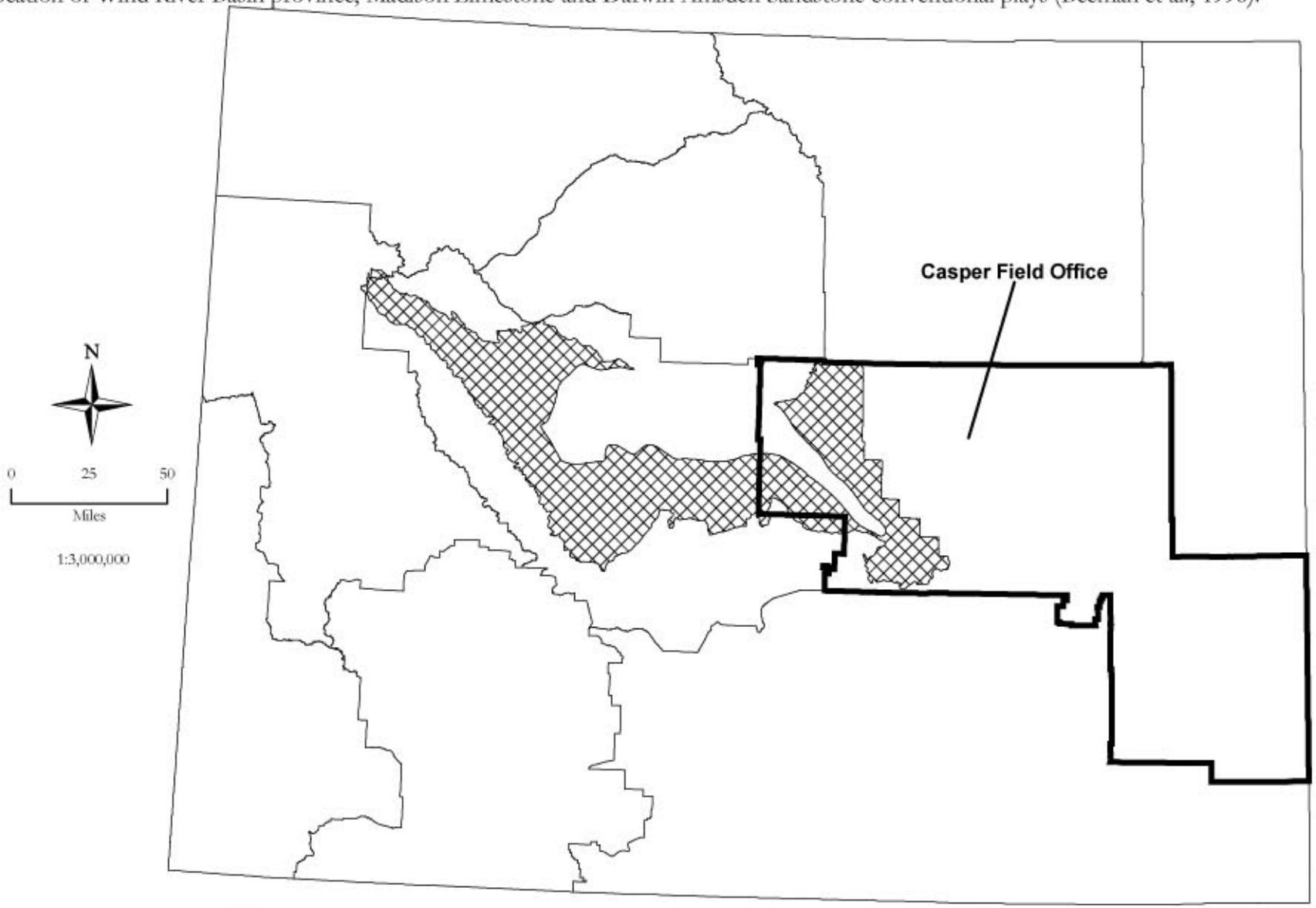

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Figure A1-32.

Location of Wind River Basin province, Triassic and Jurassic conventional plays (Beeman et al., 1996).

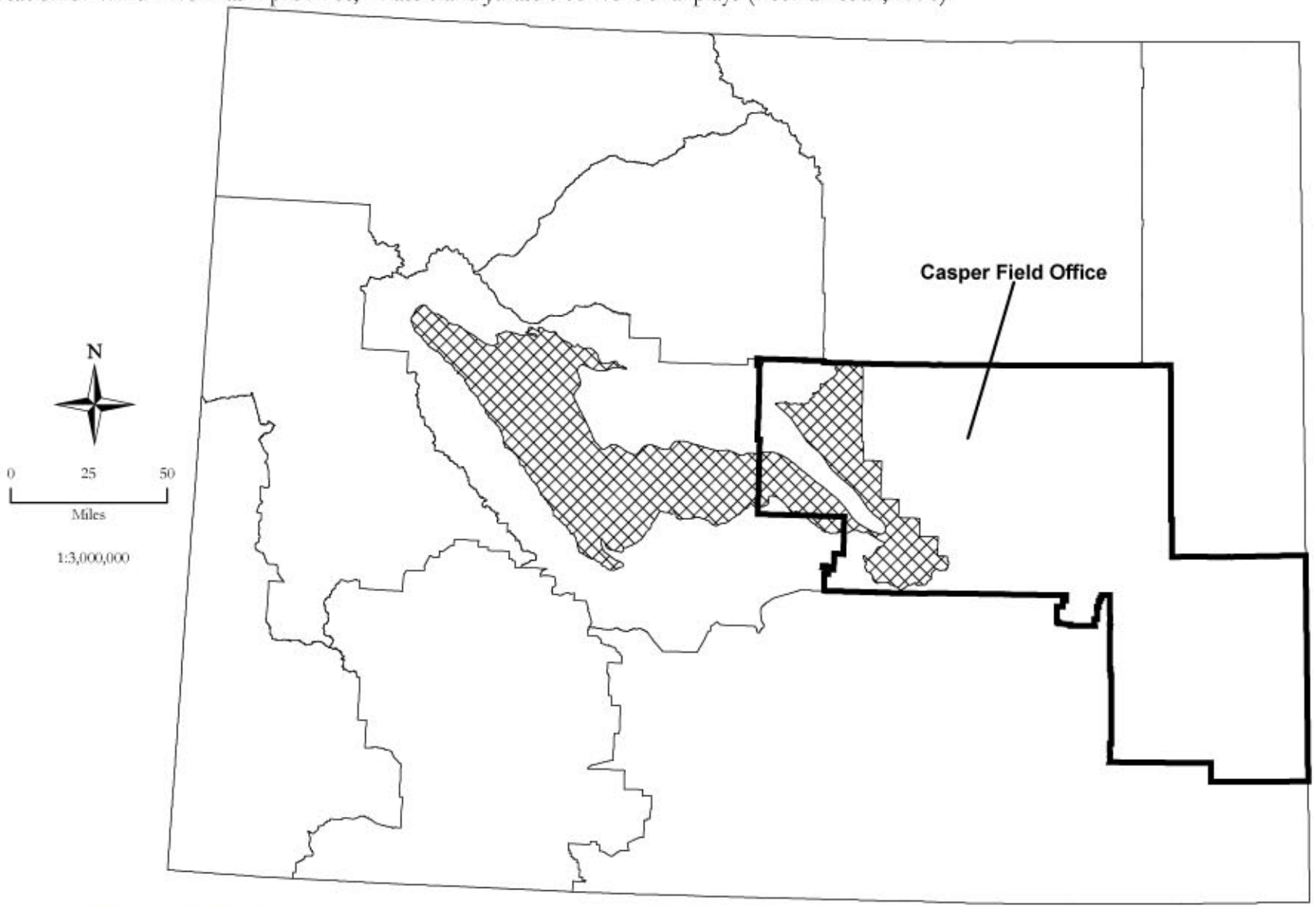

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Figure A1-33.

Location of Wind River Basin province, Shallow Tertiary-Upper Cretaceous conventional play (Beeman et al., 1996).

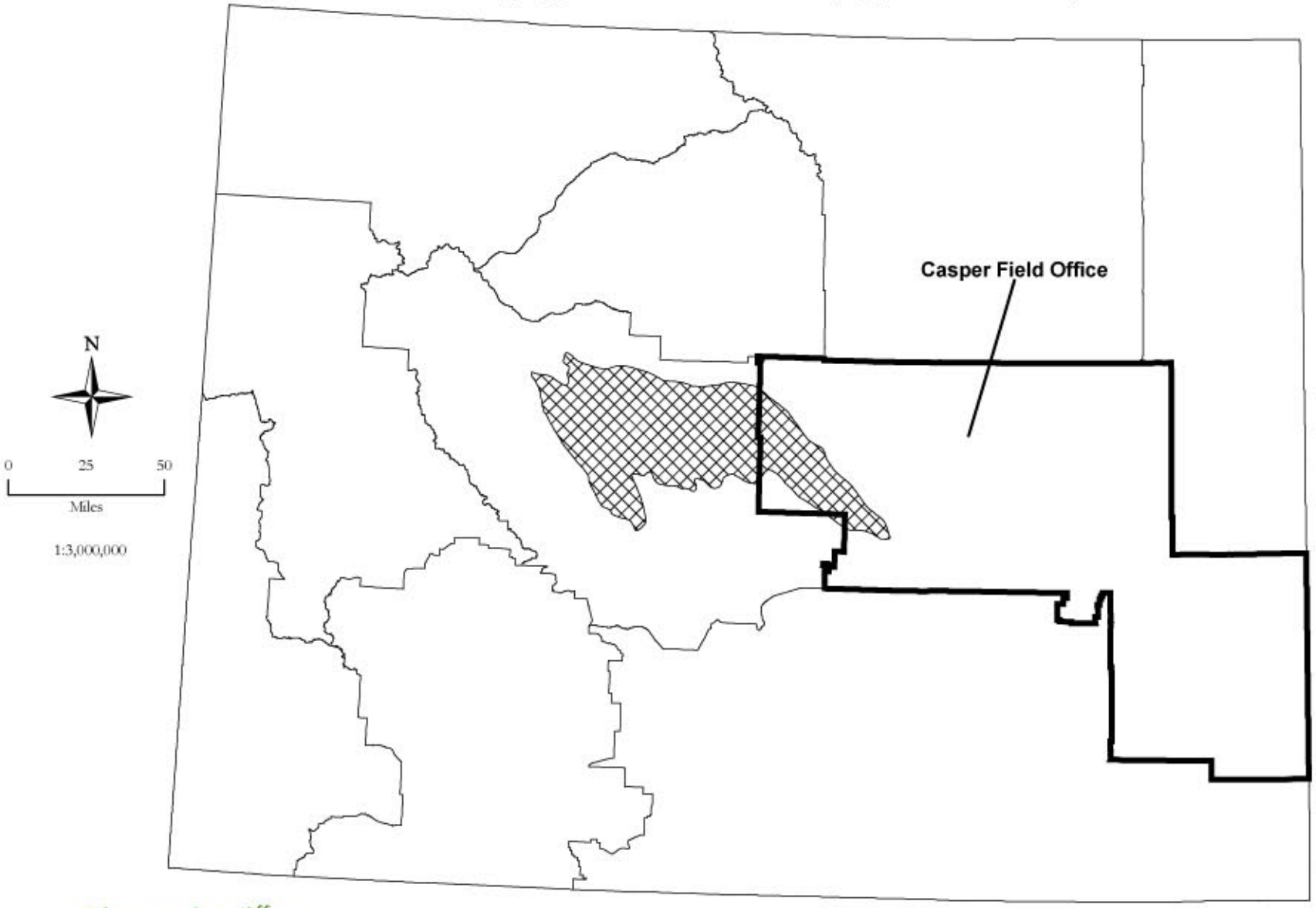

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Figure A1-34.

Location of Wind River Basin province, Cody and Frontier conventional play area (Beeman et al., 1996).

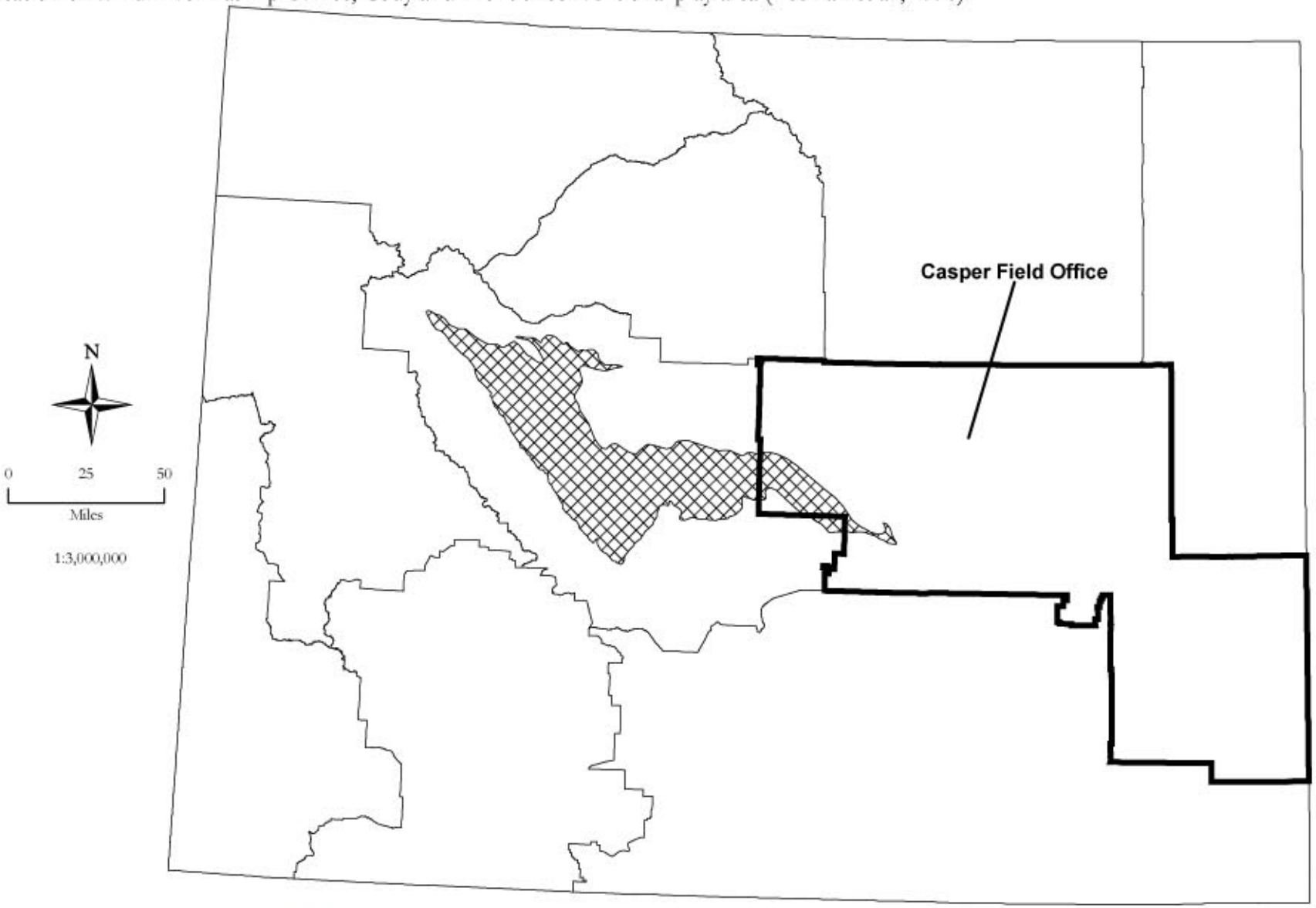

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Figure A1-35.

Location of Wind River Basin province, Basin-Center continuous gas play area (Beeman et al., 1996).

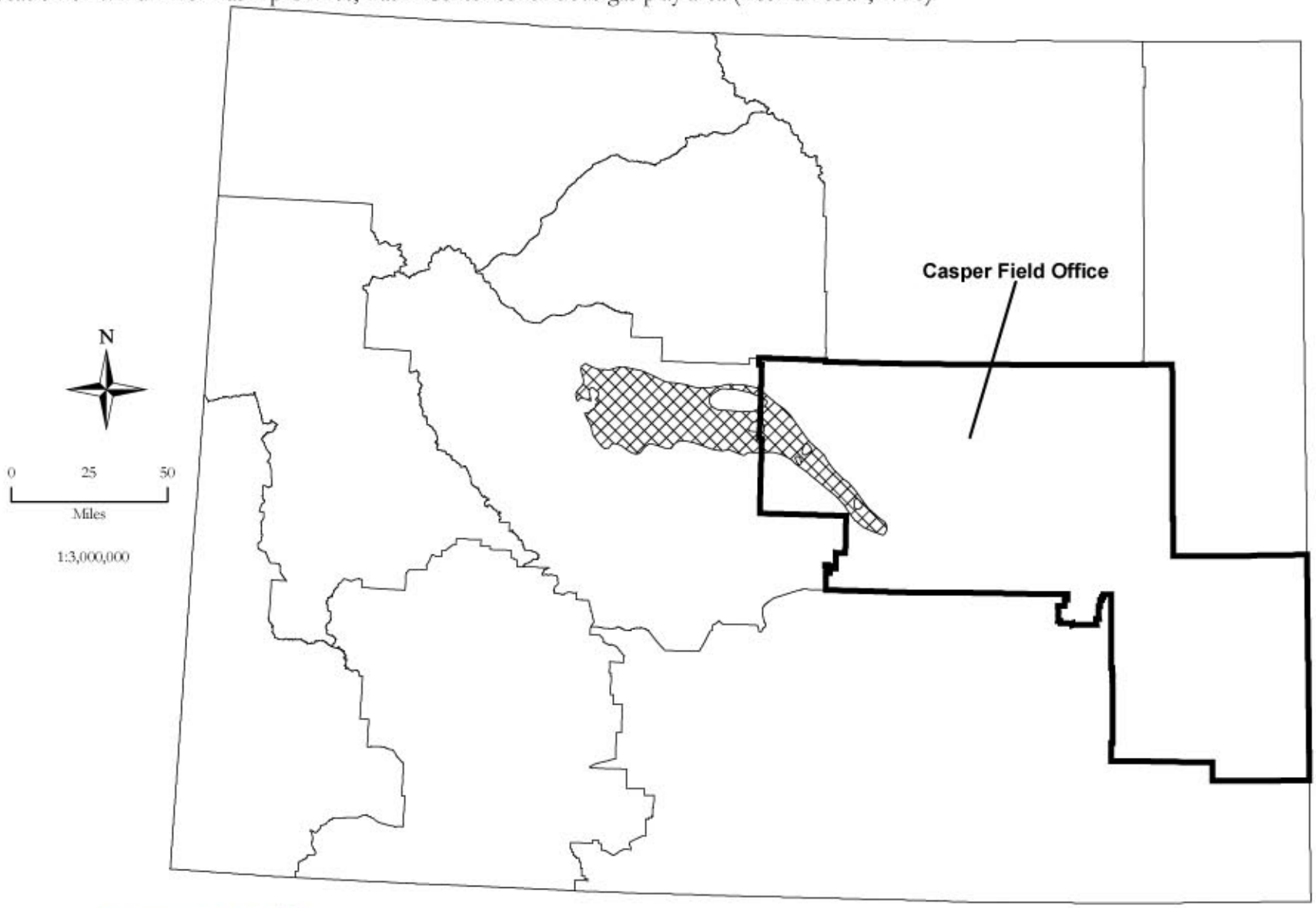

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Table A1-1.

Data for undiscovered conventional accumulations in plays or assessment units in the Powder River Basin province, Casper Field Office area.

		Undiscovered Oil Accumulations				Undiscovered Gas Accumulations		
Play or Assessment Unit Name	**Exploration Status**	**Number Range**	**Mean Size**	**Mean API Gravity (Degrees)**	**Drilling Depth Range (ft)**	**Number Range**	**Mean Size**	**Drilling Depth Range (ft)**
Basin Margin Subthrust Play	Hypothetical	1-15	9.8 MMBO	38	5,000-15,000	0-0	NA	NA
Basin Margin Anticline Play	Confirmed	1-5	2.8 MMBO	37	3,000-10,000	0-0	NA	NA
Leo Sandstone Play	Hypothetical	1-100	3.1 MMBO	30	6,000-17,000	0-0	NA	NA
Upper Minnelusa Sandstone Play	Confirmed	30-300	4.5 MMBO	28	5,000-15,000	0-0	NA	NA
Lakota Sandstone Play	Confirmed	5-50	3.1 MMBO	30	2,000-14,500	0-0	NA	NA
Fall River Sandstone Play	Confirmed	5-65	7.3 MMBO	32	4,000-14,500	0-0	NA	NA
Muddy Sandstone Play	Confirmed	5-35	4.2 MMBO	40	8,000-14,000	3-25	27.4 BCFG	8,000-14,000
Deep Frontier Sandstone Play	Confirmed	2-20	5.2 MMBO	42	8,000-13,000	0-0	NA	NA
Turner Sandstone Play	Confirmed	2-12	3.3 MMBO	40	500-8,000	0-0	NA	NA
Sussex-Shannon Sandstone Play	Confirmed	2-20	7.3 MMBO	37	7,000-11,000	0-0	NA	NA
Mesaverde-Lewis Play	Confirmed	2-20	6.3 MMBO	40	5,000-9,500	0-0	NA	NA
Eastern Basin Margin Upper Fort Union Sandstone Assessment Unit	Hypothetical	0-0	NA	NA	NA	1-15	5 BCFG*	300-2,500

MMBOE = Million Barrels of Oil Equivalent

BCFG = Billion Cubic Feet of Gas

* = Median Size

Data from U.S.Geological Survey (2003b)

Table A1-2.

Data for undiscovered continuous accumulations in assessment units in the Powder River Basin province, Casper Field Office area.

Assessment Unit Name	Exploration Status	Median Assessment Unit Size (acres)	Median Cell Size (acres)	Median Cell Total	Median Untested Cell Total (%)	Median Untested Cells With Potential to Add Reserves (%)	Median Carbon-dioxide Content (%)	Drilling Depth Range (ft)
Wasatch Formation coalbed gas	Hypothetical	4,669,000	80	58,362	100.00	13.0	3.0	200-1,480
Upper Fort Union Formation coalbed gas	Established	8,892,000	80	111,150	98.00	33.0	3.0	200-2,620
Lower Fort Union-Lance Formation coalbed gas	Hypothetical	4,514,000	80	56,425	100.00	3.0	3.0	1,510-8,200
Mowry Continuous	Established	6,325,00	270	23,425	99.70	25.0	NA	7,870-14,100
Niobrara Continuous	Established	4,602,000	130	35,400	99.87	16.4	NA	7,870-13,120
Shallow Continuous Biogenic Gas	Hypothetical	19,712,000	160	123,200	100.00	5.0	0.2	660-3,410

Data from U.S.Geological Survey (2003b)

Hypothetical = No discovered cells
Established = Greater than 24 discovered cells.
Cell = A volume having areal dimensions related to the drainage area of an individual well.

Table A1-3.

U.S. Geological Survey undiscovered conventional and continuous resources of assessment units within Powder River Basin province and Casper Field Office area.

		Estimated Undiscovered Powder River Basin Province Resource Quantities at Probabiities 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 Area or Assessment Unit (AU)	95%	5%	Mean	95%	5%	Mean	95%	5%	Mean	% of Assessment Unit Lying Within Field Office	95%	5%	Mean	95%	5%	Mean	95%	5%	Mean
Conventional Resource	Basin-Margin Subthrust Play	0.00	113.00	20.10	0.00	113.00	20.10	0.00	3.39	0.60	87.29	0.00	98.64	17.55	0.00	98.64	17.55	0.00	2.96	0.52
	Basin-Margin Anticline Play	1.30	16.50	6.80	0.78	9.90	4.08	0.02	0.10	0.12	31.82	0.41	5.25	2.16	0.25	3.15	1.30	0.01	0.03	0.04
	Leo Sandstone Play	0.00	261.40	81.40	0.00	15.68	4.88	0.00	0.00	0.00	42.24	0.00	110.42	34.38	0.00	6.62	2.06	0.00	0.00	0.00
	Upper Minnelusa Sandstone Play	38.20	1,055.20	522.30	2.29	63.31	31.34	0.00	0.00	0.00	5.44	2.08	57.40	28.41	0.12	3.44	1.70	0.00	0.00	0.00
	Lakota Sandstone Play	2.80	126.40	53.80	1.12	50.56	21.52	0.08	3.54	1.51	12.74	0.36	16.10	6.85	0.14	6.44	2.74	0.01	0.45	0.19
	Fall River Sandstone Play	16.20	408.10	192.40	9.72	244.86	115.44	0.68	17.14	8.08	23.15	3.75	94.48	44.54	2.25	56.69	26.72	0.16	3.97	1.87
	Muddy Sandstone Play	3.50	118.40	59.10	32.90	929.50	449.10	2.08	59.32	28.72	14.68	0.51	17.38	8.68	4.83	136.45	65.93	0.31	8.71	4.22
	Deep Frontier Sandstone Play	4.80	105.00	48.30	19.20	420.00	193.20	0.96	21.00	9.66	58.94	2.83	61.89	28.47	11.32	247.55	113.87	0.57	12.38	5.69
	Turner Sandstone Play	2.80	37.50	21.10	4.20	56.25	31.65	0.53	7.03	3.96	1.82	0.05	0.68	0.38	0.08	1.02	0.58	0.01	0.13	0.07
	Sussex-Shannon Sandstone Play	5.90	148.10	67.80	4.72	118.48	54.24	0.38	9.48	4.34	22.06	1.30	32.67	14.96	1.04	26.14	11.97	0.08	2.09	0.96
	Mesaverde-Lewis Play	5.20	124.20	58.10	5.20	124.20	58.10	0.36	8.69	4.07	28.49	1.48	35.38	16.55	1.48	35.38	16.55	0.10	2.48	1.16
	Eastern Basin Margin Upper Fort Union Sandstone AU				0.00	107.43	27.37	0.00	0.00	0.00	0.04				0.00	0.04	0.01	0.00	0.00	0.00
	Total Undiscovered Conventional Resource	**80.70**	**2,513.80**	**1,131.20**	**80.13**	**2,253.17**	**1,011.02**	**5.09**	**129.69**	**61.06**		**12.78**	**530.29**	**202.94**	**21.51**	**621.57**	**260.98**	**1.24**	**33.19**	**14.72**
Continuous Resource	Wasatch Formation AU (coalbed gas)				1,011.94	3,257.89	1,934.09	0.00	0.00	0.00	18.36				185.79	598.15	355.10	0.00	0.00	0.00
	Upper Fort Union Formation AU (coalbed gas)				7,232.13	18,721.10	12,132.50	0.00	0.00	0.00	14.97				1,082.65	2,802.55	1,816.24	0.00	0.00	0.00
	Lower Fort Union-Lance Formation AU (coalbed gas)				0.00	440.90	197.90	0.00	0.00	0.00	8.74				0.00	38.53	17.30	0.00	0.00	0.00
	Mowry Continuous Oil AU	116.99	306.38	197.61	103.35	332.95	197.61	5.56	21.37	11.86	30.11	35.23	92.25	59.50	31.12	100.25	59.50	1.67	6.43	3.57
	Niobrara Continuous Oil AU	135.53	349.03	226.67	119.54	379.87	226.67	6.43	24.40	13.60	36.53	49.51	127.50	82.80	43.67	138.77	82.80	2.35	8.91	4.97
	Shallow Continuous Biogenic Gas AU				341.92	1,483.26	786.64	0.00	0.00	0.00	11.29				38.60	167.46	88.81	0.00	0.00	0.00
	Total Undiscovered Continuous Resource	**252.52**	**655.41**	**424.28**	**8,808.88**	**24,615.97**	**15,475.41**	**11.99**	**45.77**	**25.46**		**84.73**	**219.75**	**142.30**	**1,381.83**	**3,845.71**	**2,419.75**	**4.02**	**15.35**	**8.54**
	Total Undiscovered Resource	**333.22**	**3,169.21**	**1,555.48**	**8,889.01**	**26,869.14**	**16,486.43**	**17.08**	**175.46**	**86.52**		**97.51**	**750.04**	**345.24**	**1,403.34**	**4,467.28**	**2,680.73**	**5.26**	**48.54**	**23.26**

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 or assessment unit.

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Table A1-4.
Data for undiscovered conventional accumulations in assessment units in the Denver Basin province, Casper Field Office area.

		Undiscovered Oil Accumulations					Undiscovered Gas Accumulations			
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 (%)**	**Drilling Depth Range (ft)**
Fractured Niobrara Limestone Transitional	Hypothetical	1-6	0.5-5 MMBO	30	0.4	3,000-8,000	0-0	NA	NA	NA
Dakota Group and D Sandstone	Established	5-60	0.5-20 MMBO	35	0.2	3,300-9,800	1-10	3-40 BCFG	0.9	3,300-7,900
Permian-Pennsylvanian Reservoirs	Frontier	1-20	0.5-15 MMBO	35	0.4	3,300-13,100	0-0	NA	NA	NA

MMBO = Million Barrels of Oil

BCFG = Billion Cubic Feet of Gas

Hypothetical = no discovered accumulations

Frontier = one to 13 discovered accumulations

Established = greater than 13 discovered accumulations

Data from U.S.Geological Survey (2003c)

Table A1-5.
U.S. Geological Survey undiscovered conventional and continuous resources of assessment units within Denver Basin province and Casper Field Office area.

		Estimated Undiscovered Denver Basin Province Resource Quantities at Probabiities 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)		
	Assessment Unit	95%	5%	Mean	95%	5%	Mean	95%	5%	Mean	% of Assessment Unit Lying Within Field Office	95%	5%	Mean	95%	5%	Mean	95%	5%	Mean
Conventional Resource	Fractured Niobrara Transitional	NA	NA	NA	0.00	2.08	0.58	0.00	0.21	0.06	15.90	NA	NA	NA	0.00	0.33	0.09	0.00	0.03	0.01
	Dakota Group and D Sandstone	12.37	68.79	36.27	14.18	90.80	45.43	0.91	6.75	16.52	7.85	0.97	5.40	2.85	1.11	7.13	3.57	0.07	0.53	1.30
	Permian-Pennsylvanian Reservoirs	2.11	23.70	10.74	1.03	12.55	5.45	0.06	0.79	0.33	10.40	0.22	2.46	1.12	0.11	1.31	0.57	0.01	0.08	0.03
	Total Undiscovered Conventional Resource	**14.48**	**92.49**	**47.01**	**15.21**	**105.43**	**51.46**	**0.97**	**7.75**	**16.91**		**1.19**	**7.86**	**3.96**	**1.22**	**8.76**	**4.23**	**0.08**	**0.65**	**1.34**
Continuous Resource	Denver Formation Coals (coalbed gas)	Not quantitatively assessed									6.27	Not quantitatively assessed								
	Laramie Formation Coals (coalbed gas)	Not quantitatively assessed									6.27	Not quantitatively assessed								
	Total Undiscovered Continuous Resource	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**		**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
	Total Undiscovered Resource	**14.48**	**92.49**	**47.01**	**15.21**	**105.43**	**51.46**	**0.97**	**7.75**	**16.91**		**1.19**	**7.86**	**3.96**	**1.22**	**8.76**	**4.23**	**0.08**	**0.65**	**1.34**

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 assessment unit.

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Table A1-6.
Data for undiscovered conventional plays in the Wind River Basin province, Casper Field Office area.

		Undiscovered Oil Accumulations				Undiscovered Gas Accumulations		
Play Name	**Exploration Status**	**Number Range**	**Mean Size**	**Mean API Gravity (Degrees)**	**Drilling Depth Range (ft)**	**Number Range**	**Mean Size**	**Drilling Depth Range (ft)**
Basin Margin Subthrust	Confirmed	1-9	9.4 MMBO	40	5,000-15,000	1-6	48.3 BCFG	5,000-20,000
Basin Margin Anticline	Confirmed	2-9	3.6	32	1,000-14,000	1-3	18.2 BCFG	1,000-14,000
Deep Basin Structure	Confirmed	1-6	3.1 MMBO	42	1,300-16000	3-12	57.1 BCFG	1,300-24,000
Muddy Sandstone	Confirmed	4-12	7.3 MMBO	38	5,000-15,000	2-6	37.7 BCFG	9,000-16,000
Phosphoria	Hypothetical	1-6	4.5 MMBO	30	2,000-20,000	0-0	NA	NA
Bighorn Wedge-Edge Pinchout	Hypothetical	Not quantitatively assessed						
Flathead-Lander and Equivalent	Hypothetical	Not quantitatively assessed						
Madison Limestone	Hypothetical	Not quantitatively assessed						
Darwin-Amsden Sandstone	Hypothetical	Not quantitatively assessed						
Triassic and Jurassic	Hypothetical	Not quantitatively assessed						
Shallow Tertiary-Upper Cretaceous	Hypothetical	0-0	NA	NA	NA	1-10	18.9 BCFG	1,000-10,000
Cody and Frontier	Hypothetical	Not quantitatively assessed						

MMBOE = Million Barrels of Oil Equivalent

BCFG = Billion Cubic Feet of Gas

Data from Beeman et al. (1996)

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Table A1-7.
U.S. Geological Survey undiscovered conventional resources of plays within Wind River Basin province and Casper Field Office area.

	Estimated Undiscovered Wind River Basin Province Resource Quantities at Probabiities 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)		
Conventional Play Name	**95%**	**5%**	**Mean**	**95%**	**5%**	**Mean**	**95%**	**5%**	**Mean**	**% of Play Area Lying Within Field Office**	**95%**	**5%**	**Mean**	**95%**	**5%**	**Mean**	**95%**	**5%**	**Mean**
Basin-Margin Subthrust	1.90	97.00	31.10	13.82	438.40	153.60	0.11	3.25	1.20	41.79	0.79	40.54	13.00	5.78	183.21	64.19	0.05	1.36	0.50
Basin-Margin Anticline	2.40	34.70	19.00	9.48	100.35	47.30	0.07	0.72	0.30	41.68	1.00	14.46	7.92	3.95	41.83	19.71	0.03	0.30	0.13
Deep Basin Structure	1.20	22.30	8.30	28.85	667.84	387.00	0.00	0.00	0.00	20.51	0.25	4.57	1.70	5.92	136.97	79.37	0.00	0.00	0.00
Muddy Sandstone	4.30	89.00	58.60	29.77	583.72	352.30	0.49	9.95	6.40	25.57	1.10	22.76	14.98	7.61	149.26	90.08	0.13	2.54	1.64
Phosphoria	0.00	33.00	11.70	0.00	33.00	11.70	0.00	1.65	0.60	16.83	0.00	5.55	1.97	0.00	5.55	1.97	0.00	0.28	0.10
Shallow Tertiary-Upper Cretaceous	0.00	0.00	0.00	0.00	212.20	55.20	0.00	1.80	0.50	22.57	0.00	0.00	0.00	0.00	47.89	12.46	0.00	0.41	0.11
Total Undiscovered Conventional Resource	**9.80**	**276.00**	**128.70**	**81.92**	**2,035.51**	**1,007.10**	**0.67**	**17.37**	**9.00**		**3.14**	**87.88**	**39.57**	**23.26**	**564.71**	**267.79**	**0.20**	**4.89**	**2.48**

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 or assessment unit.

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