United States Department of the Interior
Bureau of Land Management
Kemmerer Field Office, Wyoming

FINAL
Reasonable Foreseeable Development Scenario for Oil and Gas
Kemmerer Field Office, Wyoming
October 2006

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FINAL
REASONABLE FORESEEABLE DEVELOPMENT SCENARIO FOR OIL AND GAS

Kemmerer Field Office Planning Area

U.S. Department of the Interior
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Kemmerer Field Office, Wyoming

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Science Applications International Corporation (SAIC) prepared this ***Final Reasonable Foreseeable Development Scenario for Oil and Gas, Kemmerer Planning Area, Wyoming*** (RFD) for the Bureau of Land Management (BLM). The outline and topics included in the Kemmerer RFD reflect the Final Reasonable Foreseeable Development Scenario for Oil and Gas, Pinedale Field Office (October 2003) and Casper Field Office (June 2006), Wyoming prepared by the BLM Reservoir Management Group (RMG). Using the Pinedale and Casper Final RFD documents as examples, SAIC prepared the Kemmerer RFD in accordance with direction from the BLM's RMG, Kemmerer Field Office, and State Office. The RFD utilized materials and information prepared for or provided by the BLM, Colorado database – IHS Energy Group 2002 Rocky Mountain U.S. Well Data, U.S. Geological Survey, Wyoming State Geologic Survey, Wyoming Oil and Gas Conservation Commission, and private industry.

Due to the constraints for revising the Kemmerer Resource Management Plan, historical well production, leasing, and seismic project activity data provided in Sections 4 and 7 of the RFD were not updated through 2005. Historical well production information is current through 2003 and leasing and seismic project activity is current through 2002.

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ACRONYMS AND ABBREVIATIONS

AEO	Annual Energy Outlook
ARI	Advanced Resources International, Inc.
Bcf	billion cubic feet
BLM	Bureau of Land Management
CBNG	coalbed natural gas
CFR	Code of Federal Regulations
DOE	United States Department of Energy
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EPCA	Energy Policy and Conservation Act
GIS	Geographic Information System
H_2S	hydrogen sulfide
Mcf	thousand cubic feet
mD	millidarcy
MMBbl	million barrels
MMcf	million cubic feet
NGL	natural gas liquid
RFD	Reasonably Foreseeable Development
RMG	Reservoir Management Group
RMP	Resource Management Plan
SAIC	Science Applications International Corporation
Tcf	trillion cubic feet
UOA	units of assessment
USFS	United States Department of Agriculture Forest Service
USGS	United States Geological Survey
WSGS	Wyoming State Geological Survey

EXECUTIVE SUMMARY

This Kemmerer planning area Reasonable Foreseeable Development (RFD) Scenario is part of the Bureau of Land Management's (BLM) Resource Management Plan (RMP) revision process. The purpose of the document is to provide land management planners with estimates of potential oil and gas occurrences and projections of oil and gas exploration and production activity within the planning area for the period 2001 through 2020. The information will be incorporated into the RMP and its associated Environmental Impact Statement (EIS).

Located in the southwestern corner of Wyoming, the Kemmerer planning area includes most of Uinta and Lincoln counties, the western portion of Sweetwater County, and a small area of Sublette County. Within the planning area are 1.4 million acres of public land and 1.6 million acres of federal mineral estate managed by the BLM.

Geologically, the planning area is part of both the Wyoming Overthrust Belt Province and the Southwestern Wyoming Province, which includes the Greater Green River Basin. The United States Geological Survey (USGS) has performed extensive studies of the oil and gas resources of the area. In 1995, they issued an assessment of the undiscovered oil and gas potential for the two provinces. This information, along with other studies sponsored by the United States Department of Energy (DOE), and information provided by the BLM's Wyoming State Office Reservoir Management Group (RMG), was used to estimate the remaining undiscovered potential within the planning area. These studies indicate that between 137 and 179 trillion cubic feet (Tcf) of gas may be in place within the Green River Basin portion of the planning area. Estimates for undiscovered potential within the Green River Basin portion of the area range from 1.6 Tcf of gas and 27 million barrels (MMBbl) of oil to 14.3 Tcf of gas and 252 MMBbl of oil and natural gas liquids. The Overthrust Belt Province has not been studied as extensively, but the most recent estimates place the undiscovered potential within the planning area between 1.1 and 19.5 Tcf of gas and between 170 and 3,143 MMBbl of oil and natural gas liquids.

Using historical activity information from the Wyoming Oil and Gas Conservation Commission, private industry, the DWIGHTS production database, and the RMG, along with interviews with oil and gas companies on projections of future activity, an estimate of future oil and gas exploration activity was developed. During the period from 2001 through 2020, baseline drilling activity is anticipated to average around 100 wells per year for non-coalbed natural gas resources (2,040 wells total) with an additional 32 wells per year to be drilled to develop coalbed natural gas resources (640 wells total) during the next 20 years. Using guidelines developed by the BLM, this activity may result in approximately 9,800 net disturbed acres during the study period.

Alternatives A, B, C, and D are described in detail. The alternatives are created through a combination of baseline data and agency created constraints from resource management decisions. Alternative A is the no action alternative, and alternative D is the agency preferred alternative. Alternatives A and D are similar in total wells drilled during the planning period and long-term surface disturbance. Alternative C is the resource development scenario having a slighter greater number of wells drilled and long-term surface disturbance. Alternatives A, C, and D are similar in forecasted oil and gas production during the planning period. Alternative B represents the resource conservation scenario and has less total wells drilled, long-term surface disturbance, and forecasted production of oil and gas as compared to Alternatives A, C, and D.

No recommendations for oil and gas resource management have been developed at this time. Appropriate recommendations relating to management of future oil and gas activity within the Kemmerer planning area will be developed during the RMP revision.

1.0 INTRODUCTION

The Bureau of Land Management (BLM) Kemmerer planning area is revising the Resource Management Plan (RMP). As part of the RMP revision process, the BLM is required to prepare a Reasonable Foreseeable Development (RFD) Scenario for Oil and Gas that provides specific information regarding oil and gas occurrences and development potential within the Kemmerer planning area. The information in the RFD will be incorporated into the RMP and the Environmental Impact Statement (EIS) for the RMP revision.

The main goals of this Kemmerer RFD were to technically analyze the oil and gas resources occurring within the planning area and to project future alternatives of development potential and activity levels for the period 2001 through 2020. The baseline scenario is discussed in sections 2.0 through 7.0 and assumes that future activity levels will not be constrained by management-imposed conditions (Rocky Mountain Federal Leadership Forum 2002). The BLM recognizes current legislatively imposed restrictions that could affect future activity levels and constrain this baseline scenario where those types of restrictions have been applied to lands within the planning area.

The RFD scenario presented in this report reviews past and potential future exploration and production operations and activities. It also presents occurrence potential for oil and gas, coalbed natural gas (CBNG), 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 planning 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 online databases) for the area, a request for data from oil and gas operators, future oil and gas price estimates, petroleum technology research and development, geophysical activity, bid performance at lease sales, limitations on access, and infrastructure. The RFD alternatives presented are reasonable and science-based projections of the anticipated oil and gas activity based on information obtained and analyzed and use logically and technically based assumptions to make projections.

Four management alternatives (A, B, C, and D) are founded on the baseline and selected for analysis of impacts during the preparation of the preliminary RMP for the planning area. Each alternative reflects management-imposed constraints that will impact oil and gas development activity. These constraints will decrease the baseline estimate for wells in varying amounts to be drilled in areas of federal oil and gas ownership. The alternative descriptions and their effects on the baseline are discussed in Section 8.0.

Analyses reflected in this document utilize data and information obtained from the BLM, the Wyoming State Geological Survey (WSGS), the Wyoming Oil and Gas Conservation Commission, the United States Geological Survey (USGS), and private industry. The data and information obtained from these sources were used to make future projections for all mineral land ownership within the planning area.

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2.0 PHYSICAL SETTING

This section describes the geography and land management aspects of the planning area. Section 2.1 discusses the geography of the area, and Section 2.2 describes land management responsibilities.

2.1 Location

The planning area is in the southwestern corner of Wyoming. As shown on Figure 2-1, the Rock Springs Planning Area lies east and the Pinedale Planning Area lies north and east of the planning area. The Wyoming – Utah state line defines the south and west boundaries. The planning area includes most of Uinta and Lincoln counties, the western part of Sweetwater County, and a small portion of Sublette County (refer to Figure 2-2). Within the planning area are the towns of Alpine on the northern border, with Afton and Cokeville to the west, and Kemmerer centrally located at the junction of highways 189 and 30 (refer to Figure 2-2). The towns of Evanston and Lyman are found in the southern part of the area on Interstate 80, which runs east to Granger on the eastern side of the planning area.

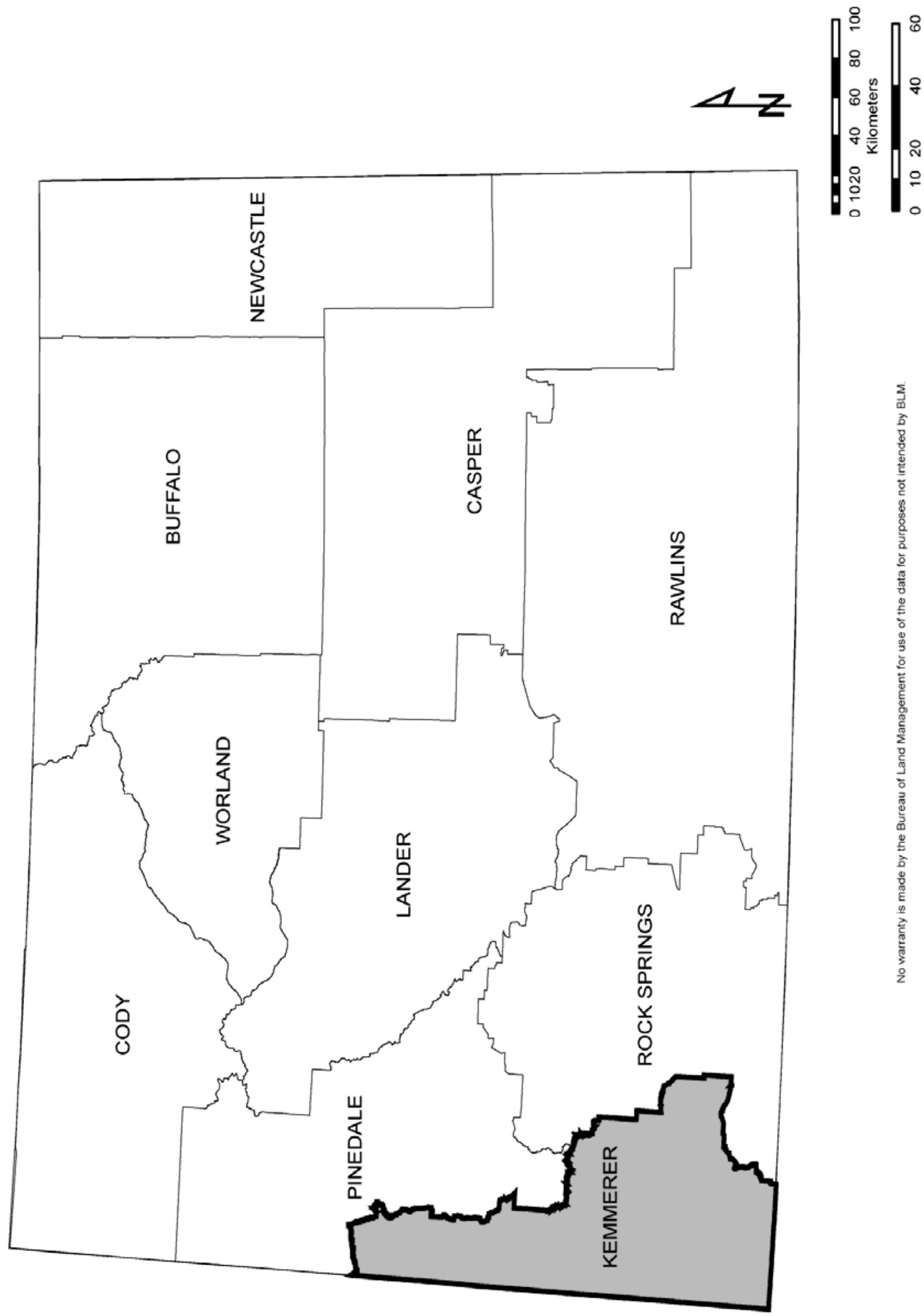
On a large regional scale, the planning area lies within the Wyoming Basin and Middle Rocky Mountain physiographic provinces (refer to Figure 2-3). On a smaller scale, it is further divided, with portions of the Wyoming Overthrust Belt covering the western half and the Green River Basin found in the central and eastern areas. The topography of the Overthrust Belt comprises north-south trending rugged ridges of moderate relief. To the east is the Green River Basin low relief, well-eroded terrain cut by intermittent streams, leaving rounded rolling hills and small mesas. The area is vegetated primarily by a mixed grass prairie with large elements of sagebrush and other shrub species, and is similar to the many basins that make up the high plains interior of the western United States.

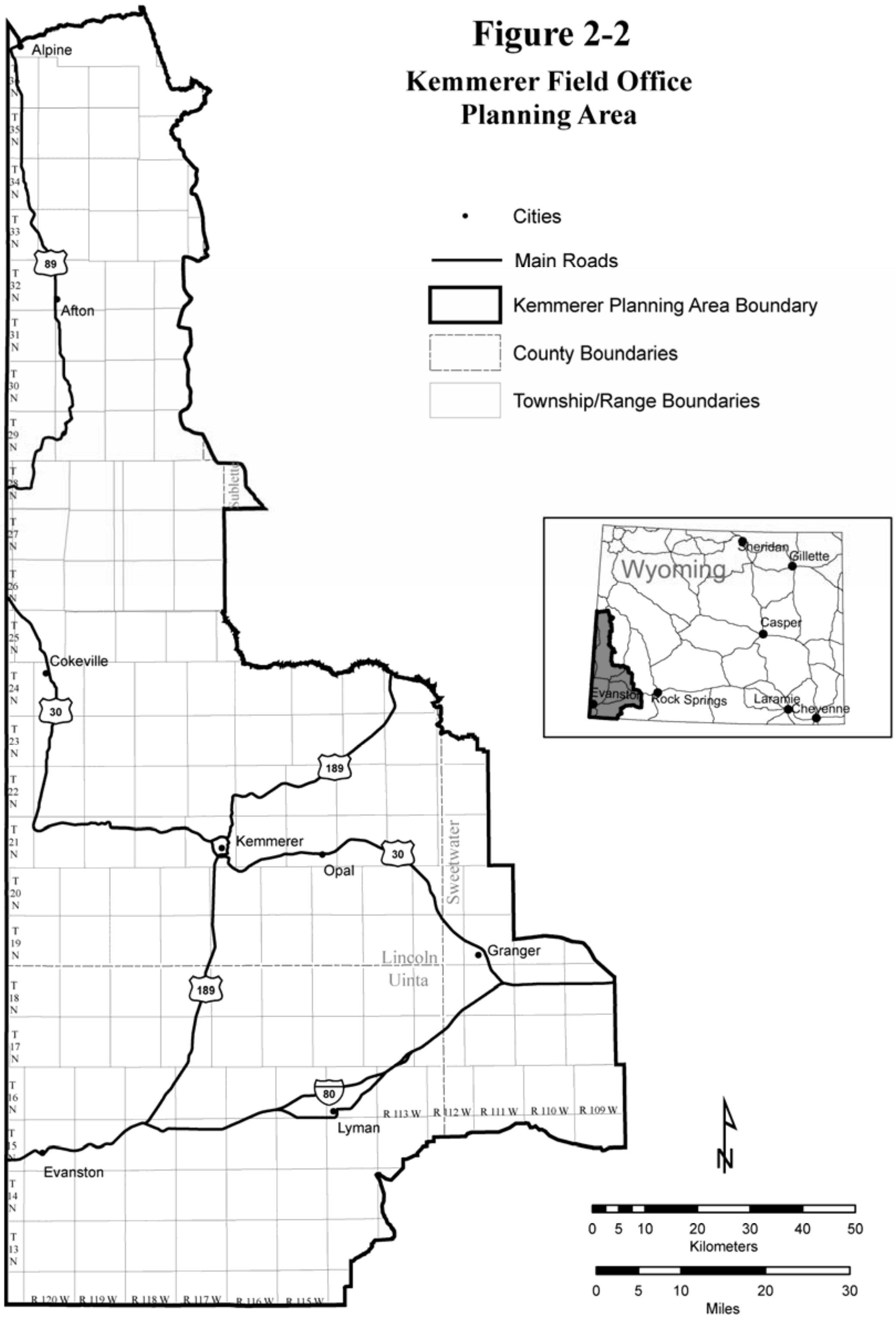
2.2 Management Responsibility

The planning area administers approximately 1.4 million surface acres of public land (refer to Figure 2-4) and 1.6 million acres of federal mineral estate (refer to Figure 2-5). By county, there are approximately 922,000 BLM acres in Lincoln County; 167,000 acres in the western portion of Sweetwater County; and 489,000 acres in Uinta County in federal mineral estate (BLM 2006b). Within the planning area border, land also is managed by the U.S. Department of Agriculture Forest Service (USFS), the U.S. Department of the Interior Bureau of Reclamation and National Park Service, the State of Wyoming, and by private landowners (BLM 2003). Table 2-1 shows the surface acreage managed by each entity and the federal mineral acreage by mineral type.

Figure 2-1

BLM - Wyoming Field Office Planning Areas





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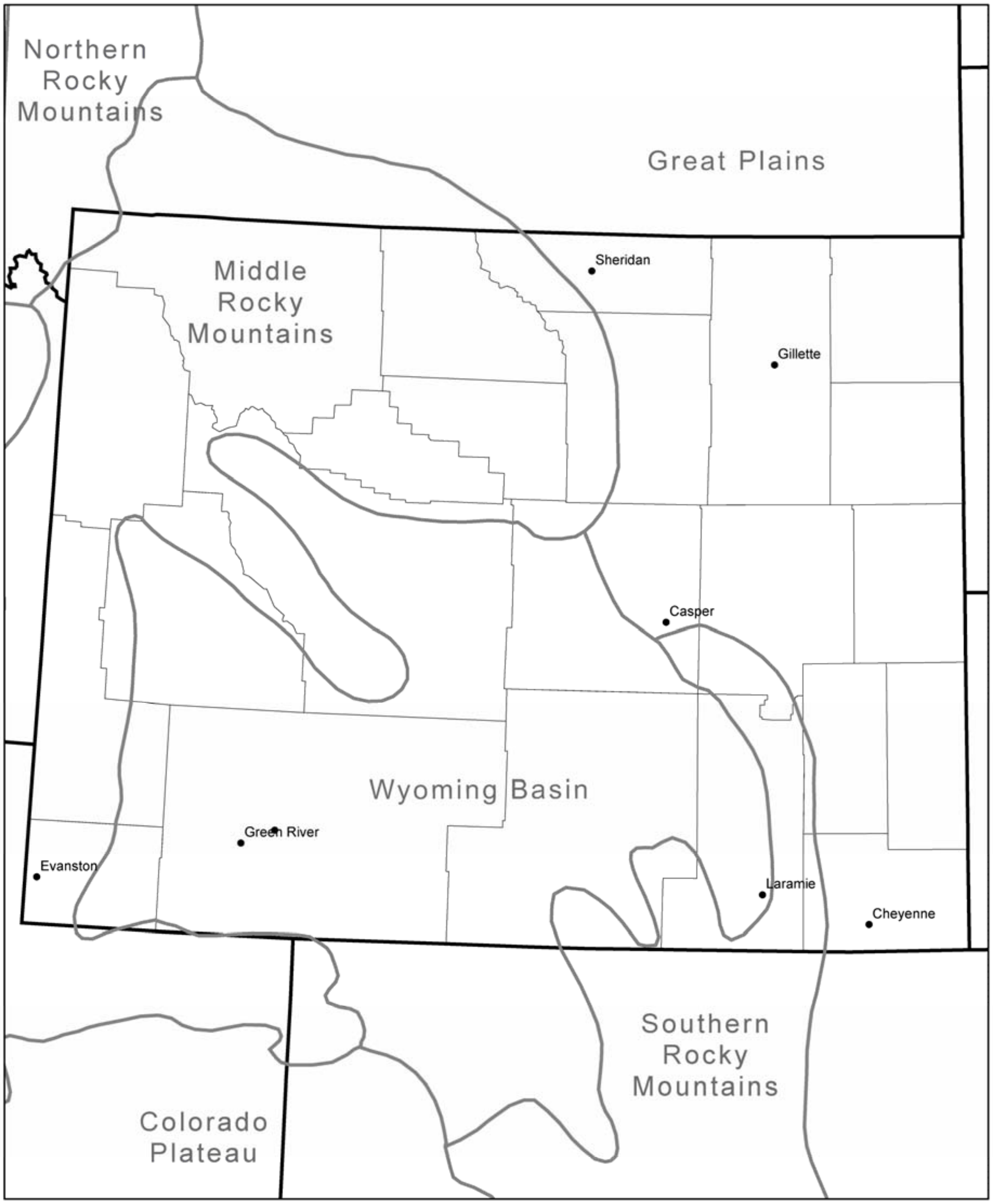
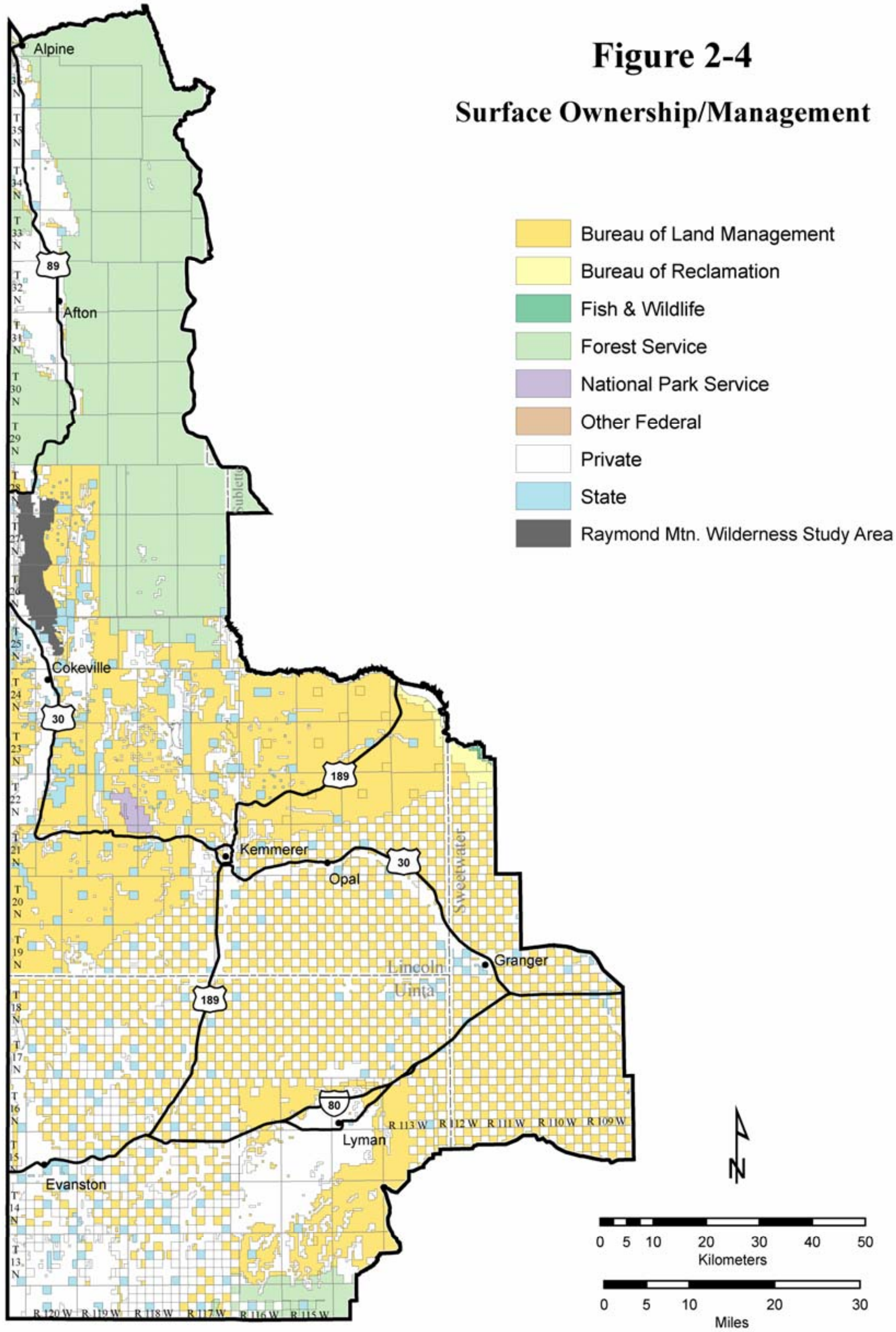


Figure 2-3
Physiographic Provinces in the Central Rocky Mountains

Sources: Howard et al. 1972; Fenneman 1993

Figure 2-4

Surface Ownership/Management



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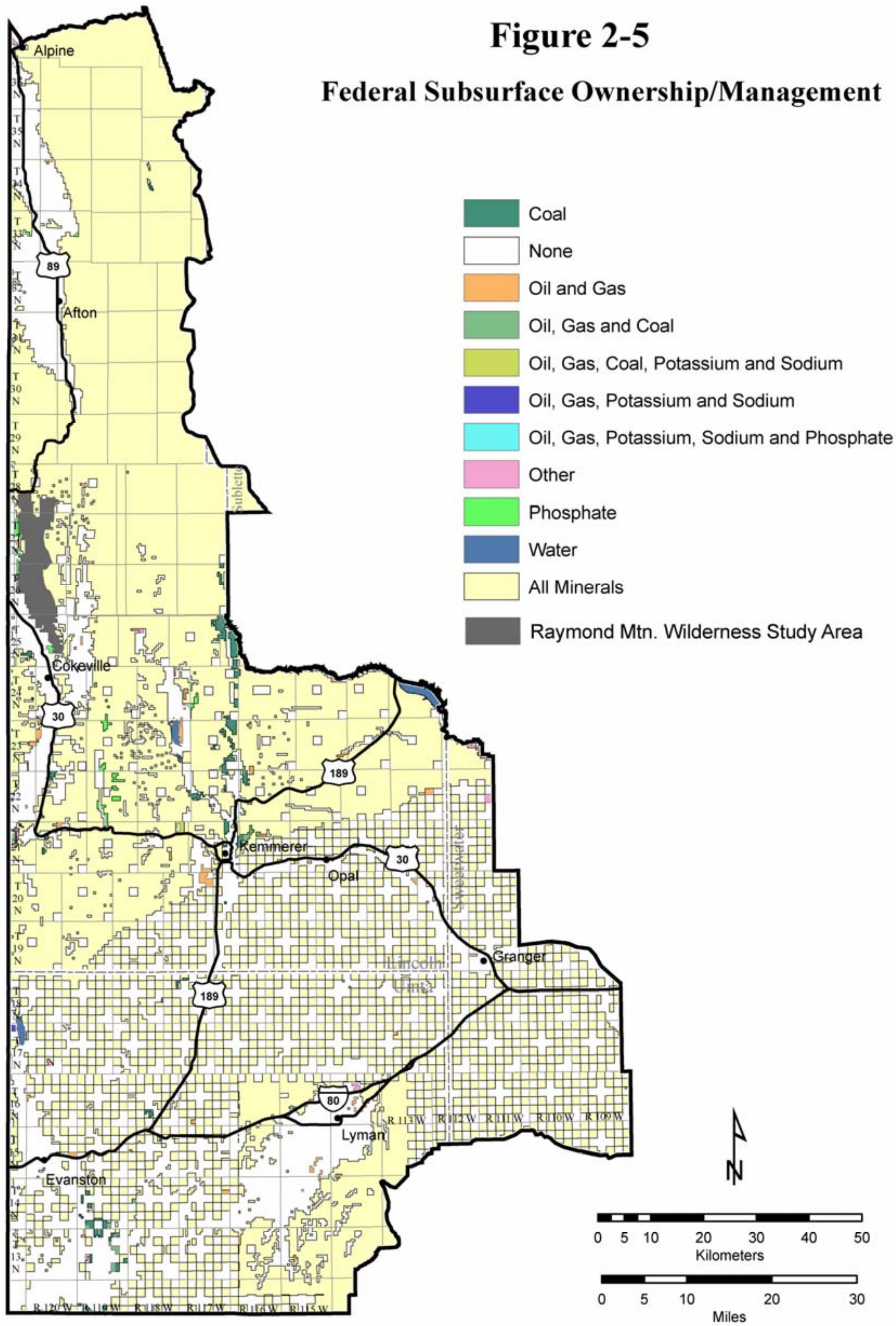

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**Table 2-1. Kemmerer Planning Area
Acres by Surface Ownership/Management and by
Mineral Type**

Kemmerer Surface Acres	
Surface	Acres
Bureau of Land Management	1,428,806
Forest Service	814,229
Bureau of Reclamation	20,382
Fish & Wildlife	1,792
National Park Service	8,387
Private	1,513,561
State	156,030
Water	8,175
Total Acres	3,951,361
Kemmerer Mineral Acres	
Minerals	Acres
All U.S Minerals	2,383,319
Coal	16,937
None (Private & State Minerals)	1,519,246
Oil, Gas	10,191
Oil, Gas, Coal	3,100
Oil, Gas, Coal, Potassium, Sodium	797
Oil, Gas, Potassium, Sodium	292
Oil, Gas, Potassium, Sodium, Phosphate	43
Other	3,631
Phosphate	5,598
Restricted	31
Water	8,175
Total Acres	3,951,361

Source: RMG 2003

Note: Some numbers (e.g., total acres, surface ownership) may be different in document due to revised Geographic Information System (GIS) calculations (BLM 2006b).

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3.0 GEOLOGIC SETTING

The planning area lies within a geologically complex setting. The eastern portion of the area is within the Greater Green River Basin, which is part of the Southwestern Wyoming Province as defined by the USGS. The western portion of the area is part of the Wyoming Overthrust Belt. Sections 3.1 and 3.2 describe each of the two provinces, respectively. Figure 3-1 shows the relationship of the two provinces.

3.1 Southwestern Wyoming Province

The Green River, Great Divide, and Washakie basins of Wyoming, and the Sand Wash Basin in northwestern Colorado comprise the Greater Green River Basin. Each basin is not separated completely by mountain ranges, and the depositional units are continuous across all the basin areas. The Green River Basin is controlled on the east by the Rock Springs uplift, bound on the north by the Wind River Mountains, on the south by the Uinta Mountains, and on the west by the Overthrust Belt. The basin center is just west of the Rock Springs uplift, with beds gently dipping from the western edge of the Green River Basin to this low structural position. The major structure on the western side of the basin is the subsurface Moxa Arch. It trends mostly north-south and is just east of the Overthrust Belt and helps form the structural high on the western side of the basin.

3.1.1 Stratigraphy

Sedimentary rocks in the Greater Green River Basin vary widely throughout the greater basin with one of the deepest basins in the Rocky Mountain region being the Hanna Basin, with a Phanerozoic thickness of greater than 42,000 feet (Law 1995). In the northern portion of the Green River Basin and Washakie Basin, the Precambrian basement is at 32,000 feet. The Shirley Basin has a thickness of 7,000 feet for units of Cambrian to Tertiary rocks. In Figure B 2-1 of Appendix B, a stratigraphic column for the Overthrust Belt Area is presented showing Formations from the Cambrian to Tertiary periods.

Sedimentation in the province occurred in three stages within shelf, foreland, and intrabasinal environments. The first period of deposition was from the middle Cambrian through the middle Jurassic time; deposition was from periodic inundation from west to east by shallow-water seas. This area formed the Rocky Mountain shelf environment and persisted until the late Jurassic time when foreland sedimentation began. The original source area was originally east of today's basin area and changed over time to include sediments derived from the west. Mountain building in eastern Idaho and central Utah were source areas for these deposits. The final stage of development was intrabasinal sedimentation, beginning in the Upper Cretaceous time, and is seen as foreland uplifts and adjacent basin development. Sediments derived from local uplifts were redeposited in adjacent basins in the area of the Greater Green River Basin (Law 1995).

3.1.2 Structure

By the late Cretaceous time, the Green River Basin was forming via a general crustal downwarping. As the basin formed, it filled with sediments from the surrounding mountain ranges, including the Uinta, Wind River, and Overthrust Belt. During the continued downwarping of the Green River Basin in the Eocene time, a large lake, Lake Gosiute, formed.

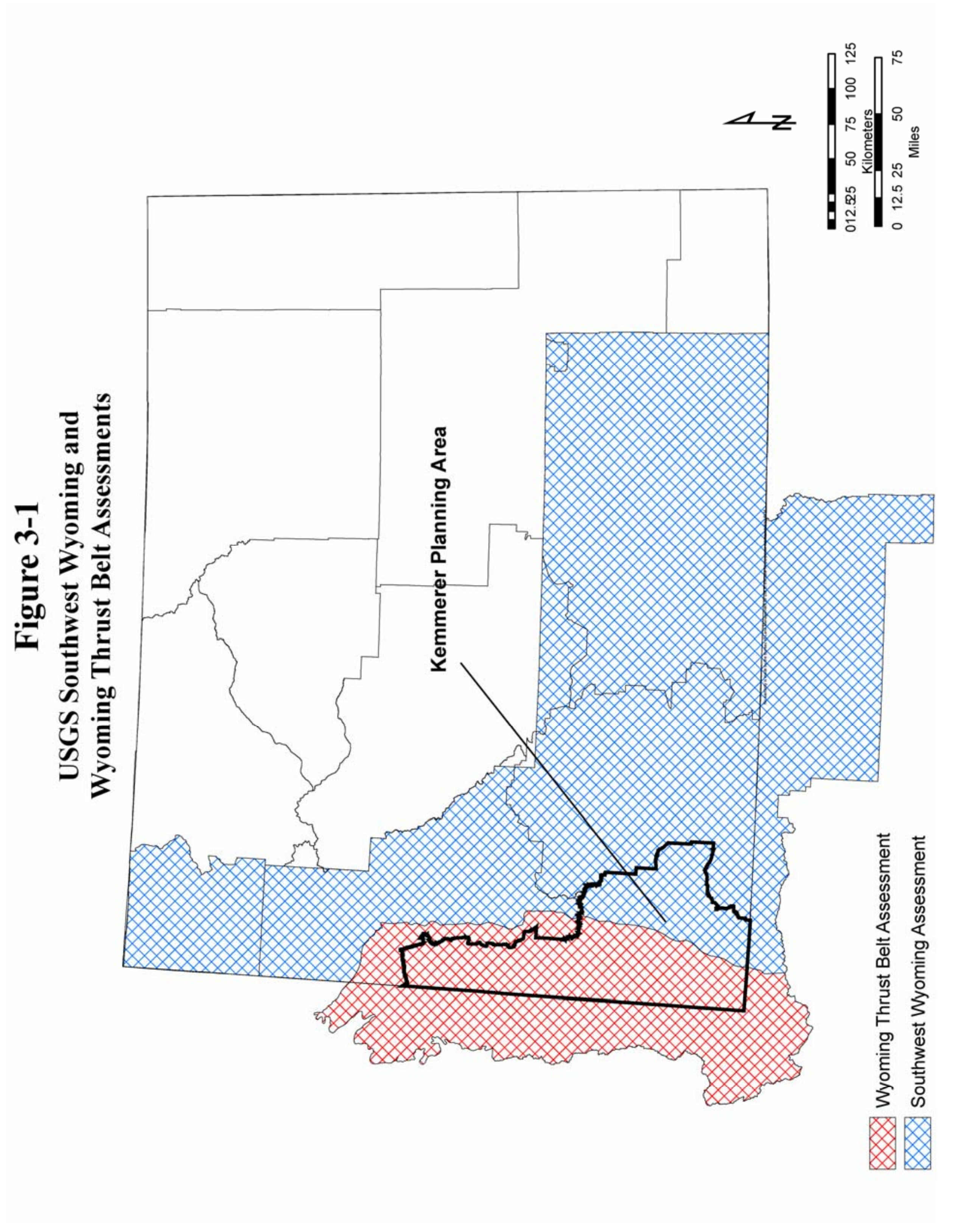
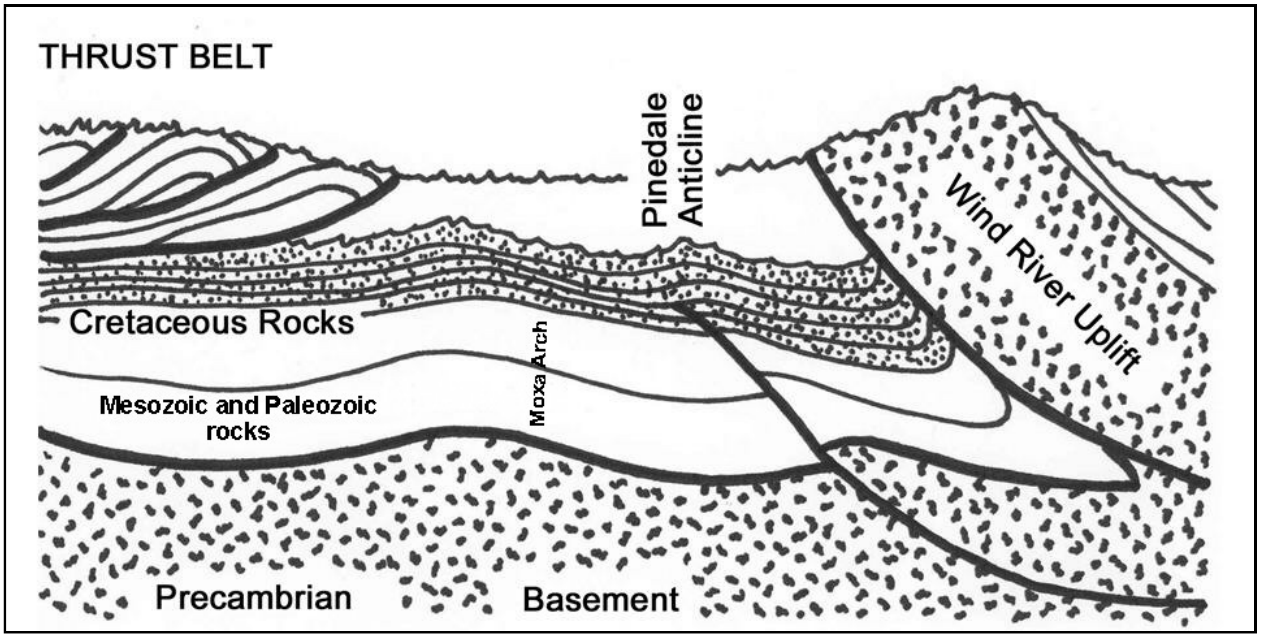


Figure 3-1
USGS Southwest Wyoming and Wyoming Thrust Belt Assessments

It lasted 4 to 8 million years, fluctuating in size over time. The deposition was intense and thick sequences of rocks were deposited. This has led to placement of the oil and gas in the formations existing in the area today (Law 1995). Figure 3-2 is a cross-section of the planning area which shows the northern portion of the Green River Basin from the western Overthrust Belt to the Wind River uplift. In the planning area, portion of the basin, concentrations of hydrocarbons are associated with the La Barge Platform/Moxa Arch structural trend, a broad high point and linear arch in the subsurface running from the Big Piney-La Barge gas fields southward to the Uinta Mountains. Figure 3-3 shows the location of the Moxa Arch.

Figure 3-2. Structural Cross-Section of the Kemmerer Planning Area

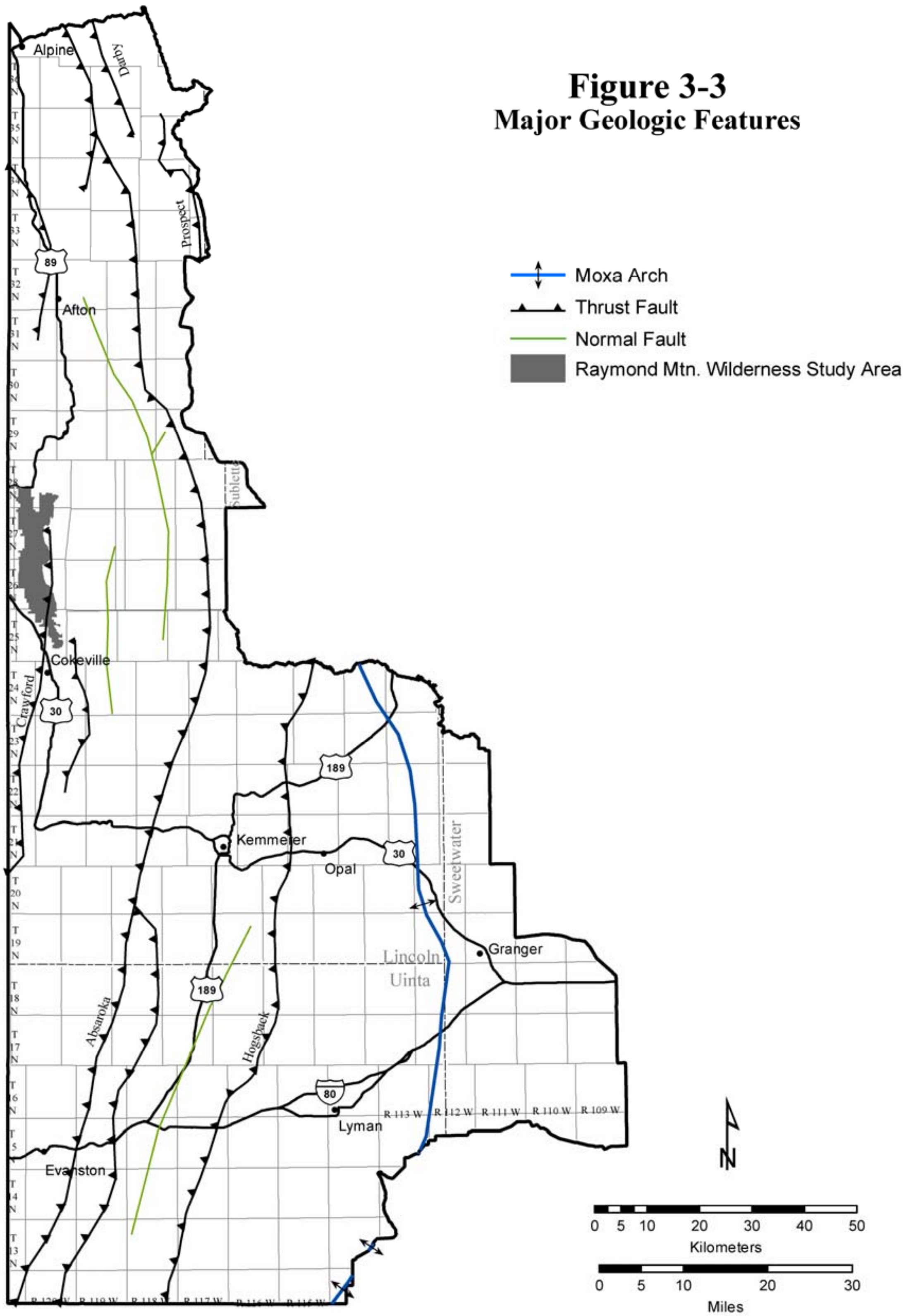


Source: RMG 2003

3.1.3 Petroleum Occurrence

Reservoirs

As shown in Figure 3-4, most conventional petroleum occurrence occurs in the eastern portion of the planning area in the Green River/Moxa Arch Basin. The oldest stratigraphic units of the Green River Basin are of the lower Paleozoic era and contain productive gas zones in limestone and dolomite. These deeper horizons are sour gas (high in sulfur content) producers and are found at depths greater than 15,000 feet. The prolific producer is the Madison Limestone of Mississippian age. The lower Mesozoic units are interfingered sandstone and limestone formations with no established production in the Triassic units. The lower Jurassic Nugget Sandstone is a prolific producer when found in the correct structural position and has developed the necessary porosity and permeability. The Dakota Sandstone of the lower Cretaceous age is a strong producer when the necessary reservoir-quality rock develops. The upper Cretaceous section is a series of thick marine shales and sandstones that develop good production where there is a structural advantage or where reservoir rock develops. The thickest of these formations are the Mesaverde Group and Hilliard Shale, comprising beds of shale with interbedded



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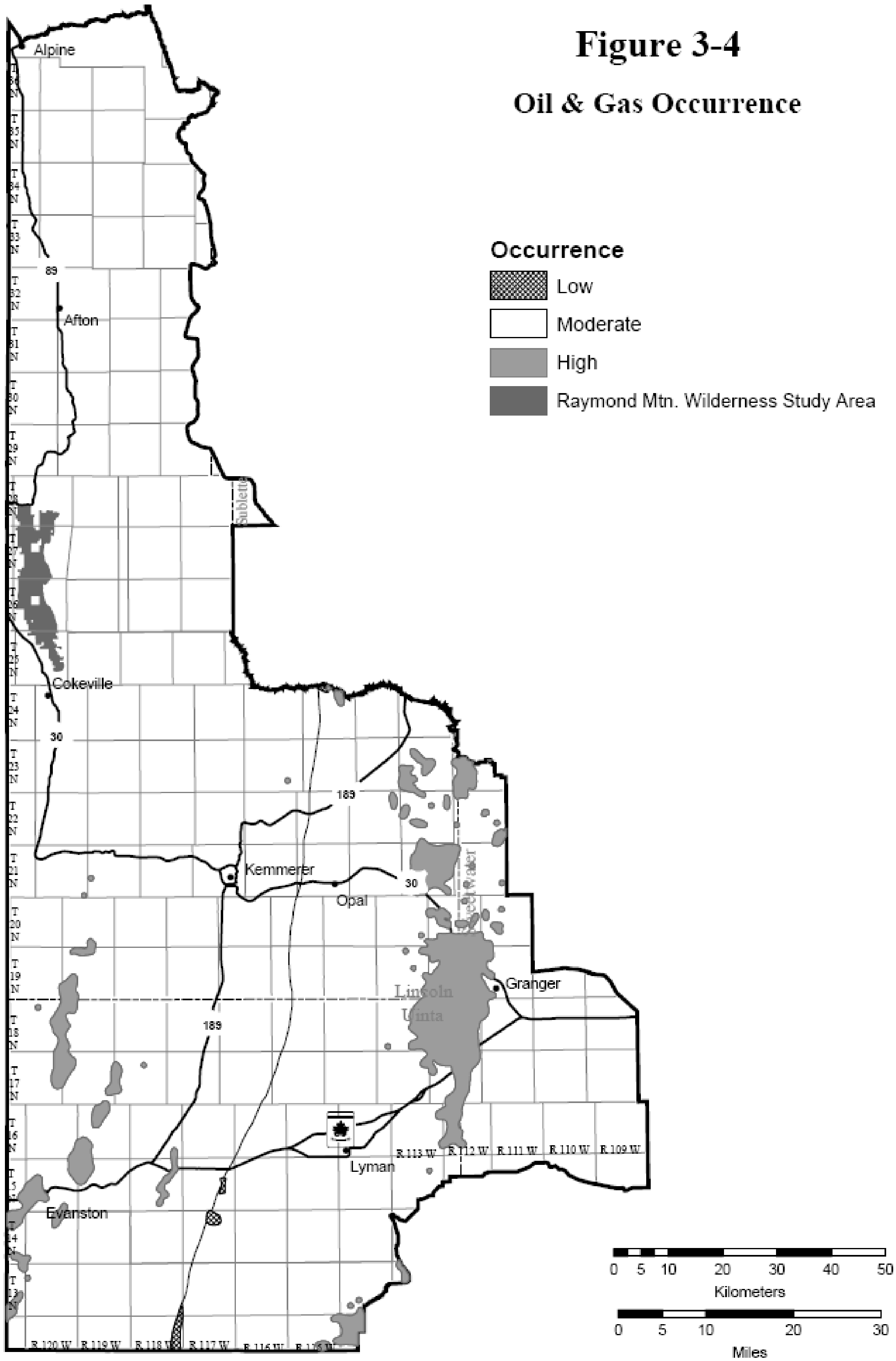

Figure 3-4

Oil & Gas Occurrence

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sandstones and coals. The Frontier Formation is one of the main producers in the Moxa Arch area. Other productive intervals include the Paleocene Hoback and Almy Formations. Some of the formations and plays have fields included in this section outside of the planning area, such as the La Barge Field, and are only included due to data limitations. Figure B 3-1 in Appendix B depicts the stratigraphic nomenclature of the Greater Green River Basin and the intervals known to produce oil and gas.

Future production of undiscovered petroleum reserves could be possible from continuous gas and conventional gas from the Mowry Shale, Mesaverde Group/Lance/Fort Union formations. In addition, the Fort Union Formation has the potential for CBNG development. The Green River and Wasatch formations could have undiscovered continuous gas potential.

Traps

The Moxa Arch field area produces from the Madison Limestone, Morgan Formation, Nugget Sandstone, Bear River Formation, Dakota Sandstone, Frontier Formation, Mesaverde Group, and Almy Formation. The trap for hydrocarbon accumulation in the northern part of the field is based on subtle structural traps. To the south, the traps tend to change from structural to stratigraphic traps (Law 1995). All zones mentioned earlier are productive across the entire field area, but not all have shown to be commercial producers. The entire field area is considered to be a mature play, and most future drilling will be based on field extension between established production trends. New exploration in the area would involve exploring the deep horizons in hope of finding new reservoirs with oil and gas potential.

Source Rocks

Source rocks for oil and gas accumulation are thought to be the Phosphoria Formation and Mowry Shale. Additional nonassociated gas in the Cretaceous reservoirs could be from any part of the Cretaceous sequence where conditions allow for generation. Some of the Cretaceous rocks identified as source rocks are the Baxter and Lewis Shales and possibly coal beds within the Almond Formation. In the southern area of the Moxa Arch, oil and condensate in the Dakota Sandstone is from the Mowry Shale. Gases from the Pennsylvanian and Mississippian reservoirs commonly include nonflammable and (or) sour gases, such as carbon dioxide, nitrogen, and hydrogen sulfide.

Timing and Migration

The structural elements in the area are the result of compressional Laramide deformation, and forced the generation and migration during this time or perhaps later. There has been some pre-Laramide deformation possibly beginning in the late Paleozoic age. Source rocks generated over this long period of time subsequent to the Laramide deformation could have migrated to the favorable structural and stratigraphic positions along high structural positions on the crest of the structure. Positions that are structurally low today in the southern area were structurally high through the early late Cretaceous time and affected the generation and migration of hydrocarbons. In addition, the structural traps were filled at this time. Pre-Cretaceous rocks and most Cretaceous rocks in this area are within the oil generation window. Cretaceous rocks obtained their present levels of thermal maturity by the late Eocene or Oligocene times (Law 1995). Reservoir depths range from 2,500 to 18,000 feet.

3.2 Wyoming Overthrust Belt Province

The large intermontane basins and uplifts that characterize the western interior of the United States were developed during the Laramide orogeny and are termed geologically as Laramide structures. During the late Jurassic, Cretaceous, and Tertiary geologic periods, deposition and deformation occurred in the area of the Overthrust Belt and Green River Basin. Beginning in the late Cretaceous period and continuing through Paleocene and Eocene epochs, a series of north-south trending thrust-to-the-east faults developed that resulted in the displacement and folding of thick wedge sequences of accumulated Paleozoic and Mesozoic sediments.

3.2.1 Stratigraphy

Stratigraphy and producing reservoirs seen in the Overthrust area include those discussed earlier for the Green River Basin and are detailed in the following sections.

3.2.2 Structure

The last episode of structural development occurred in Paleocene and Eocene times when numerous thrusts formed the western boundary of the Green River Basin. The thrusting occurred west to east on low-angle faults with a north-south trend through the western side of the planning area (Figure 3-3). The western-most thrust is the Crawford-Meade thrust followed by the Absaroka and Prospect-Darby-Hogsback thrusts. The thrust faults run in beds of Cambrian to Cretaceous in geologic age; in some areas, the thrusts are well recognized and in other areas only suggested. The Absaroka thrust runs almost the full length of the thrust belt portion of the planning area. The thrusts are located immediately east and west of the town of Kemmerer and east of Evanston, Wyoming. The rugged topography is well expressed in the thrust belt portion of the planning area and has complicated the extraction of oil and gas. Figure 3-3 depicts the thrust faults in the planning area; Figure B 2-1 in Appendix B is a stratigraphic column for the Overthrust Belt area.

3.2.3 Petroleum Occurrence

Reservoirs

Only some of the fields in the Overthrust play reside in the western part of the planning area and are highly speculative in nature. More details regarding which fields reside in the Overthrust play can be found in Section 4.4.3. Petroleum occurrence from the Overthrust play can also involve any of the reservoirs producing in the western portion of the Green River Basin.

Source Rocks

The Tertiary and Cretaceous shales, the Phosphoria Formation, and Amsden equivalent rocks are thought to be the source rocks for the hydrocarbon accumulations in this western area.

Timing and Migration

The thrusting is thought to be from mostly the Laramide age with structural traps formed at this time. This would mean that accumulation could be no older than the late Cretaceous age in some reservoirs; however, some reservoir trapping was pre-thrusting and accumulated much earlier than that time. Some Lower Cretaceous Dakota Sandstone reservoirs were charged with oil prior to thrusting, when they were structurally in a higher position, relative to present-day structures (Law 1995).

Traps and Seals

Traps seen in the overthrust area are conventional anticline, stratigraphic, fault, and fracturing. Anticlinal traps occurred prior to or as the thrusting occurred within the area. Pre-thrusting anticlinal traps were the result of basin movements based on pre-Larimide and early Larimide events. In the Moxa Arch vicinity, pre-thrusted conventional anticlines were overridden by later forming thrusted anticlines. Seals include low-permeability Cretaceous and older shales, plus faults that developed within the more brittle-acting sections of rock.

4.0 EXPLORATION AND PRODUCTION ACTIVITY

Oil and gas exploration and development began in the area in the late 1800s with the discovery of oil seeps in the Overthrust Belt area. The area has experienced several surges of activity over the past century. The two most recent increases within the planning area centered on new discoveries in the Overthrust Belt in the late 1970s and early 1980s and on development of reserves on the Moxa Arch in the Green River Basin in the mid 1970s, with a resurgence in drilling in the early 1990s.

4.1 Summary of Activity

Oil and gas reserves in the planning area have been the focus of industry attention since commercial discoveries began around the year 1900 (BLM 2003). Oil and gas production in the Green River Basin, as a whole, began with the 1916 discovery of the Lost Soldier field (Law 1995). Figure B 3-1 in Appendix B is a stratigraphic column of the Green River Basin and shows the known and potentially productive horizons in the basin.

Oil and gas exploration of the Overthrust Belt dates to the 1890s. Following the discovery of Utah's Pineview field in 1975 and Ryckman Creek field in 1976, intense exploration, including seismic and drilling programs, resulted in major discoveries of oil and gas in what is known as the fairway of the Overthrust Belt (BLM 2003). Figure B 2-1 in Appendix B is a stratigraphic column of the Overthrust Belt showing the known and potentially productive horizons of this area.

At the end of 2002, there were more than 40 active oil and gas fields in the planning area. Of these, 5 of the 25 largest gas fields and 3 of the 25 largest oil fields in Wyoming for 2002 were in the planning area (Wyoming Oil and Gas Conservation Commission 2003). Some of the oil and gas fields in the planning area overlap with the Pinedale Planning Area, and (or) with the Rock Springs Planning Area. Figure 4-1 shows oil and gas fields in the Kemmerer planning area. Figure 4-2 shows oil and gas wells. Of the 1.6 million acres of oil and gas mineral estate managed by the Kemmerer planning area, approximately 1,134,000 acres currently are leased for oil and gas development. Figure 4-3 depicts federal oil and gas leases in the planning area.

4.2 Federal Oil and Gas Unit Agreements

In areas of federally owned minerals, an exploratory unit can be formed before a wildcat exploratory well is drilled. Federal units were authorized by the *Mineral Leasing Act of 1920*. Title 43 Code of Federal Regulations (CFR) Subpart 3186 (2002) sets forth a model onshore unit agreement for unproven areas. The boundary of the unit is based on geologic data. A unit operator is determined by agreement of the leaseholders; the leaseholder with the largest leasehold position often is designated operator of the unit.

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 that 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

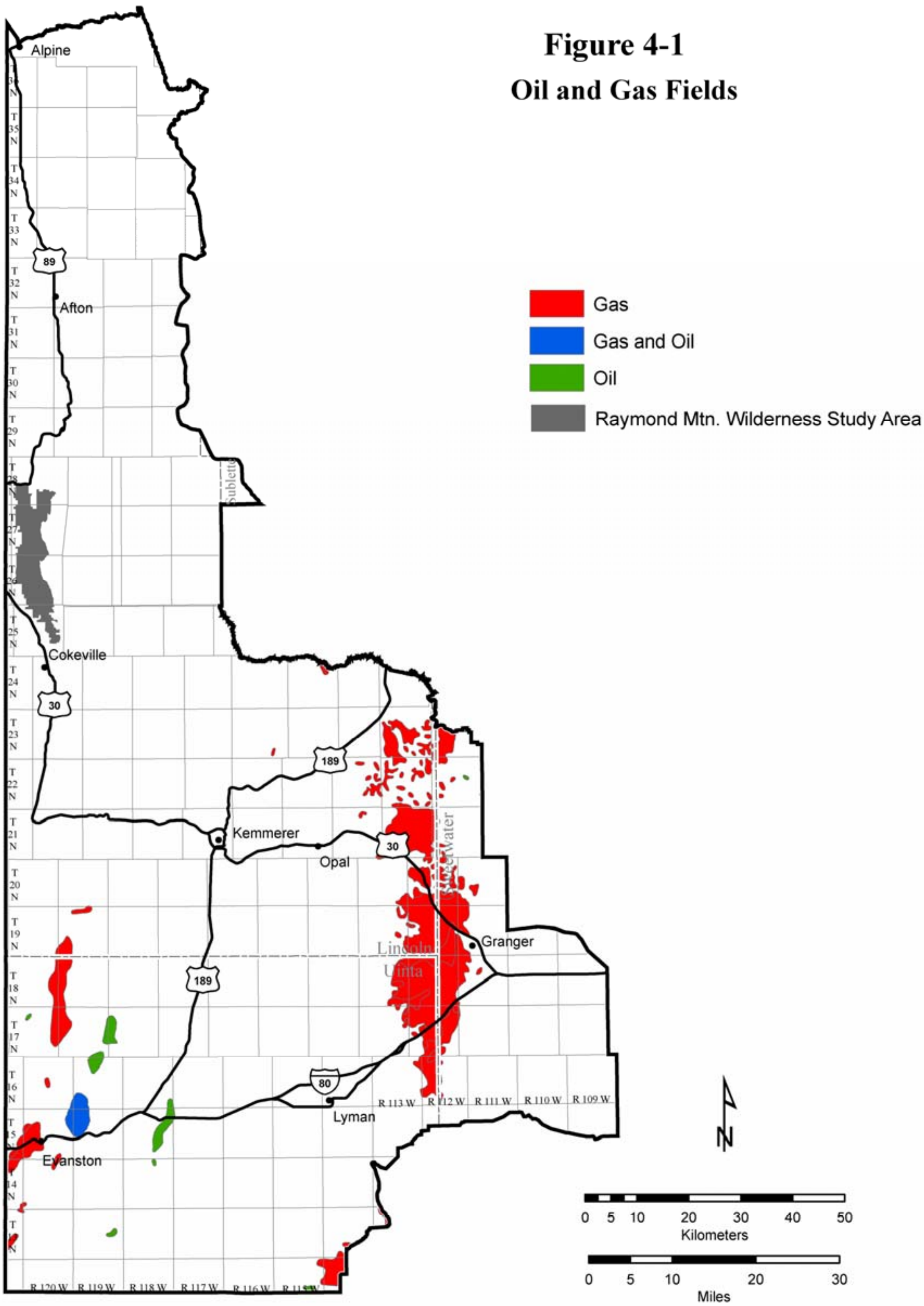

Figure 4-1
Oil and Gas Fields
Gas
Gas and Oil
Oil
Raymond Mtn. Wilderness Study Area
Alpine
Afton
Cokeville
Kemmerer
Opal
Granger
Lyman
Evanston
89
30
189
80
Sublette
Sweetwater
Lincoln
Uinta
R 113 W
R 112 W
R 111 W
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Kilometers
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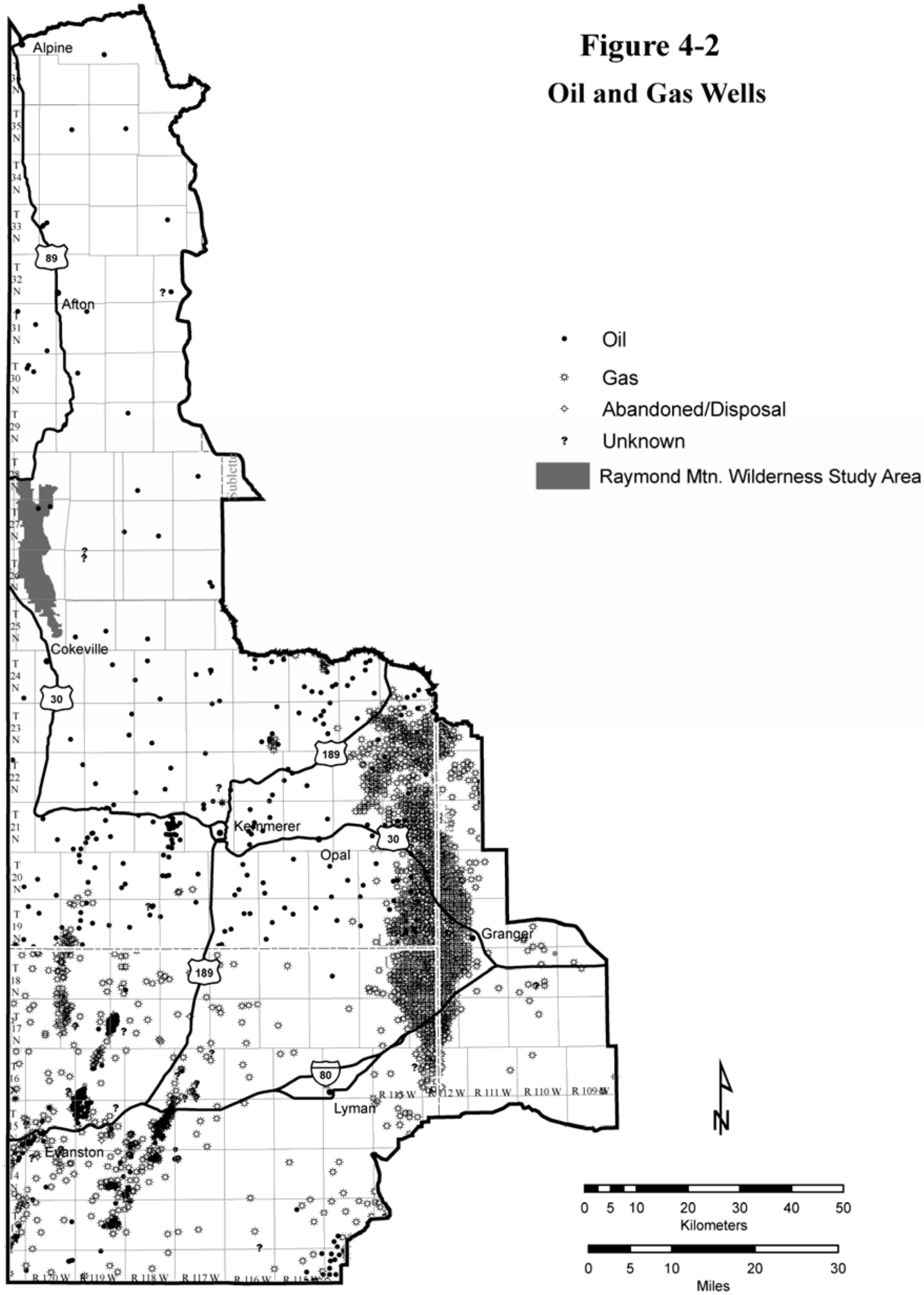
Miles



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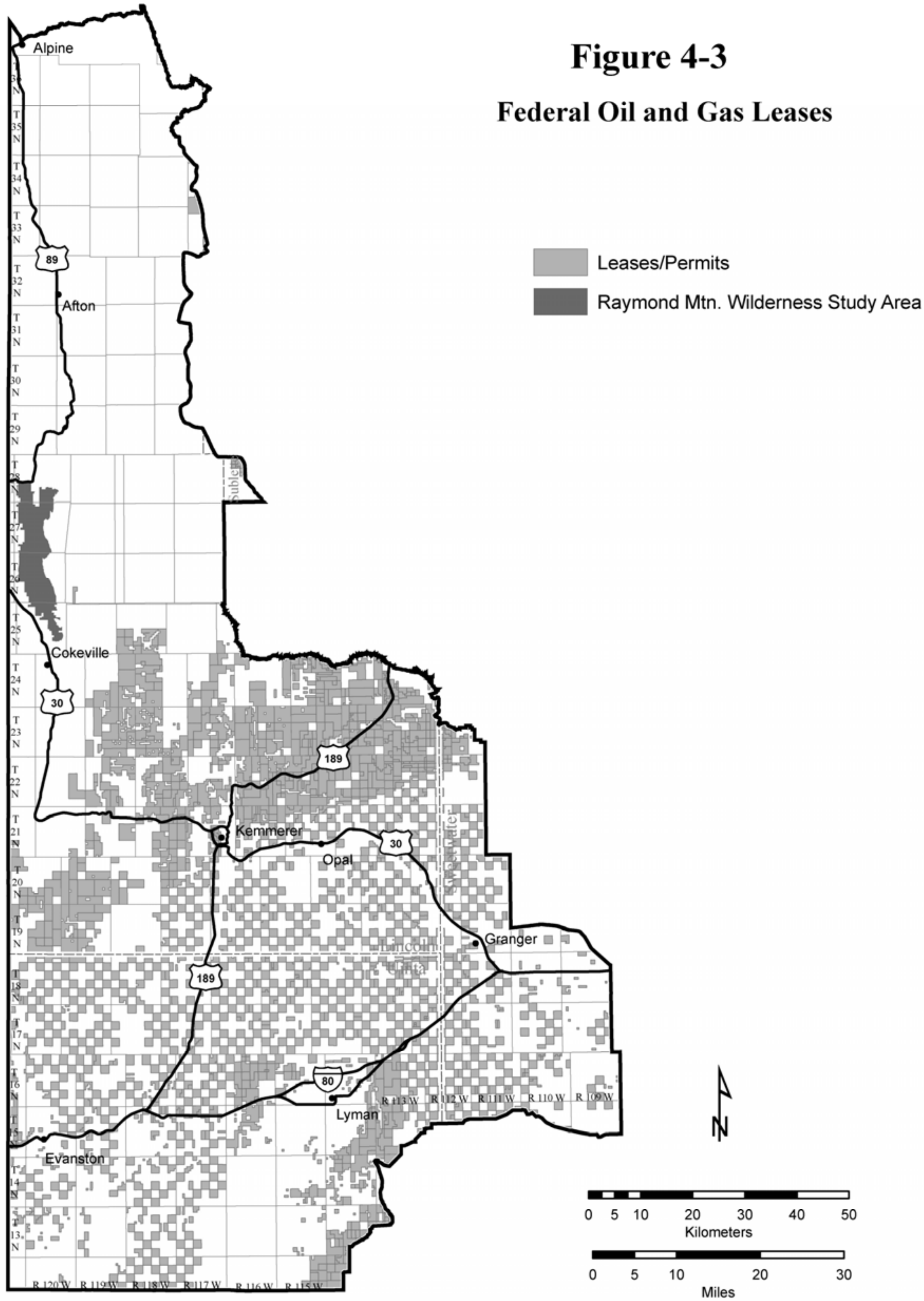

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procedures, and permits controlled development of the unit. This process stimulates exploration and (or) development of federal lands and encourages the drilling of the optimum number of wells needed to maximize resource recovery.

As oil and gas are discovered, unit development can proceed in a deliberate and efficient manner to minimize waste of hydrocarbon resources. Each proposal to unitize federally supervised leases is evaluated on its specific merits. The unit agreement provides for the exploration, development, and production by a single operator. In effect, the unit functions as one large lease. For instance, pressure maintenance wells can be installed prior to full-scale production, which, in some types of reservoirs, may significantly increase recovery factors. Spacing in a unit is not regulated except for offset distances to the unit boundary. This allows location of wells to take advantage of reservoir heterogeneity, thereby increasing recovery. Another advantage of unitization is that surface use is minimized because all wells are operated as though on a single lease. Duplication of field processing facilities is reduced because development and operations are planned and conducted by a single operator. Often, powerlines can be distributed throughout the unit, and well pumps can be powered by electric motors. Unitization may enable the field to be developed with fewer wells, minimizing surface disturbance through fewer locations and roads.

Federal oil and gas leases are incorporated into 28 unit agreement areas that lie wholly or partly within the Kemmerer Field Office boundary (Figure 4-4). The units encompass lands totaling approximately 182,000 acres in area, or approximately 6 percent of the total field office area. These unitized areas are located mostly in the eastern part of the Kemmerer field office, generally within the Moxa Arch/Green River Basin area.

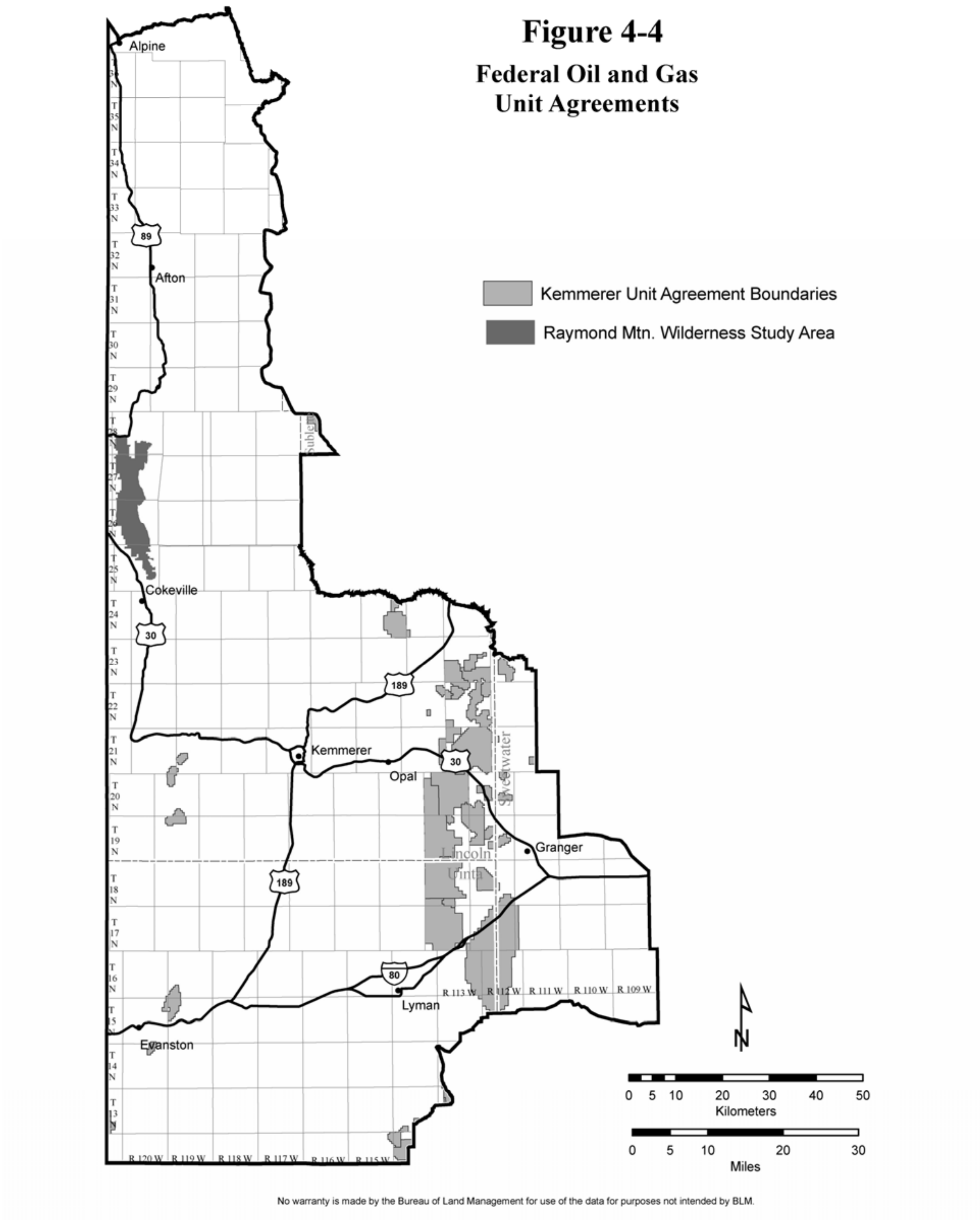
Most of the units in the field office area have been primarily gas productive. As of December 17, 2003, the Wyoming Oil and Gas Conservation Commission (2003) classified five units as primary oil producers. The remaining units either primarily produce oil or substantial quantities of both commodities.

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. One unit is undergoing secondary recovery operations. Five units are considered to have exploratory status.

Currently, CBNG units have not been established within the Kemmerer Field Office area.

4.2.1 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. The communitization agreement is the same as a private industry pooling agreement. The intent of the agreement is to set the rules so that the different parties work together to keep their respective shares proportional and to make sure that they produce resources in the best manner. In Wyoming, the following circumstances can constitute good reason for communitization to occur.



Note: 28 Unit Agreements Total: 18 gas, 5 exploratory, 5 oil. Oil Unit Agreements include Bridger Fork, Collett Creek, Glasscock, Luckey Ditch, and Painter Reservoir.

- Communitization is required to form a drilling unit that conforms to acceptable spacing patterns established by state order.
- Adequate engineering and (or) geological data are 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, approximately 159 active communitization agreements lie within the Kemmerer Field Office area.

4.3 Historical Drilling and Completion Activity

Oil and gas well records indicate that before 1970, only 401 wells had been drilled in the planning area (IHS Energy Group 2002). From 1970 through 2002, that number increased to 2,182 wells, with 61 wells currently permitted and waiting to be drilled (Figure A-1) at the end of 2002. A higher number of exploration wells were drilled in 1975 and 1976 in both the Overthrust Belt and Green River Basin portions of the planning area. In 1977, drilling returned to normal levels of one to four wells per year. Since 1989, the planning area has seen a sharp increase in the number of development wells drilled, with nearly 200 wells drilled in 1992, declining to present levels. Much of the increased drilling activity is due to the development of the Moxa Arch and the Overthrust Belt in the southwestern part of the planning area.

4.3.1 Green River Basin

Table 4-1 summarizes graphical information for exploration and development drilling in the Green River Basin. A total of 1,425 wells were drilled from 1970 through 2002. Well activity shown in Table 4-1 includes some drilling within the Green River Basin that is outside the planning area.

Table 4-1. Well Activity for Green River Basin, 1970 through 2002

Well Class	Dry	Successful	Total	Success Rate
Exploration	102	124	226	55%
Deep	-	-	17	-
Directional/Horizontal	-	-	2	-
Conventional	-	-	207	-
Development	72	1127	1199	94%
Deep	-	-	13	-
Directional/Horizontal	-	-	18	-
Conventional	-	-	1168	-

Sources: RMG 2003; WOGCC 2003

Figure 4-5 shows the western boundary of the Green River Basin and the oil and gas fields that are located within the planning area portion of the basin. Most of the fields are located on the Moxa Arch.

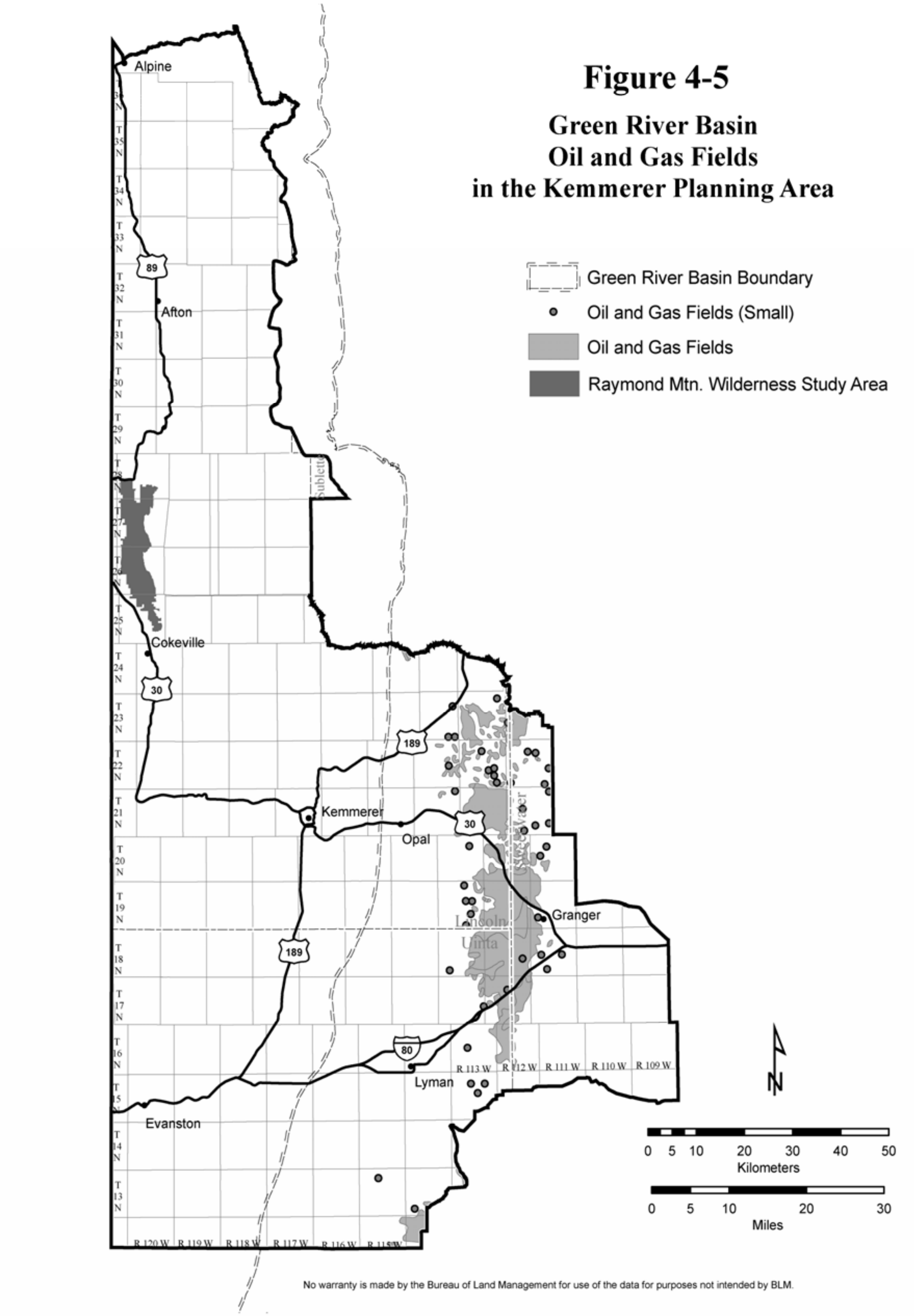


Figure 4-5
Green River Basin
Oil and Gas Fields
in the Kemmerer Planning Area
Green River Basin Boundary
Oil and Gas Fields (Small)
Oil and Gas Fields
Raymond Mtn. Wilderness Study Area
Alpine
Afton
Cokeville
Kemmerer
Opal
Granger
Lyman
Evanston
Lincoln
Uinta
Sublette
89
30
189
80
R 113 W
R 112 W
R 111 W
R 110 W
R 109 W
R 120 W
R 119 W
R 118 W
R 117 W
R 116 W
N
0 5 10 20 30 40 50
Kilometers
0 5 10 20 30
Miles
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Figure 4-6 illustrates exploration drilling in the Green River Basin from 1970 through 2002. The upper graph illustrates numbers of deep wells, directional/horizontal wells, and conventional wells drilled. The lower graph shows the dry holes and successful well completions for the area. The overall success rate of exploration wells was 55 percent. Figure 4-6 includes some drilling in the Green River Basin that is outside the planning area.

Figure 4-7 illustrates development drilling in the Green River Basin from 1970 through 2002. The upper graph illustrates the number of deep wells, directional/horizontal wells, and conventional wells drilled. The lower graphs show the dry hole and successful well completions for the area. The success rate for development wells during the period was 94 percent. Figure 4-7 includes some drilling in the Green River Basin that is outside the planning area.

4.3.2 Prospect-Darby-Hogsback Thrust

Table 4-2 summarizes graphical information for exploration and development drilling on the Prospect-Darby-Hogsback Thrust. A total of 181 wells were drilled from 1970 through 2002.

Table 4-2. Well Activity for Prospect-Darby-Hogsback Thrust Area, 1970 through 2002

Well Class	Dry	Successful	Total	Success Rate
Exploration	100	15	115	13%
Deep	-	-	3	-
Directional/Horizontal	-	-	1	-
Conventional	-	-	111	-
Development	20	46	66	70%
Deep	-	-	0	-
Directional/Horizontal	-	-	0	-
Conventional	-	-	66	-

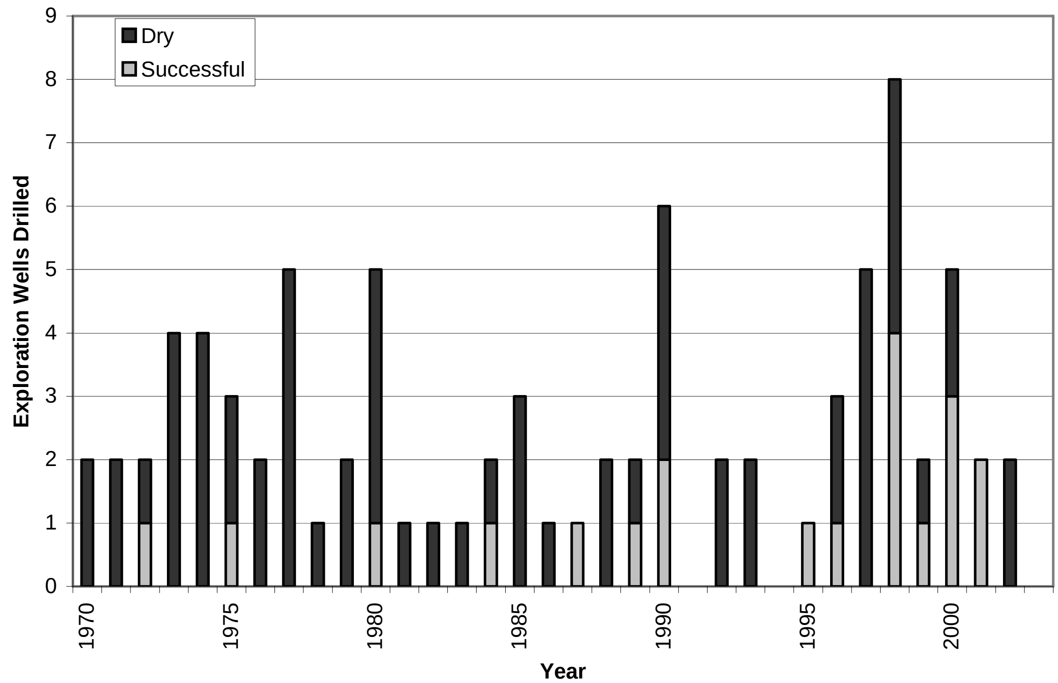
Sources: RMG 2003; WOGCC 2003

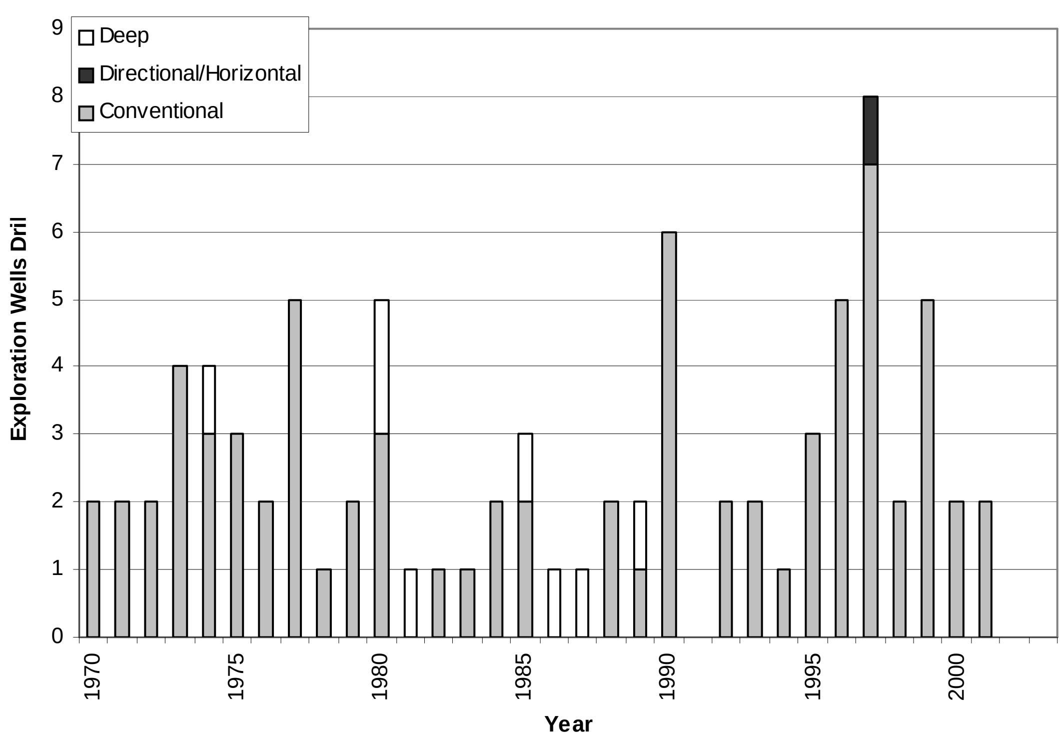
Figure 4-8 shows the oil and gas fields in the Prospect-Darby-Hogsback Thrust area located within the planning area.

Figure 4-9 illustrates exploration drilling on the Prospect-Darby-Hogsback Thrust area for the years 1970 through 2002. The upper graph shows the number of deep wells, directional/horizontal wells, and conventional wells drilled in the area. The lower graph illustrates the number of dry hole and successful well completions for the area.

Figure 4-10 illustrates the history of development drilling on the Prospect-Darby-Hogback Thrust area from 1970 through 2002. The upper graph shows the number of deep wells, directional/horizontal wells, and conventional wells drilled on the structure during the period. The lower graph shows the number of dry hole and successful well completions for the area.

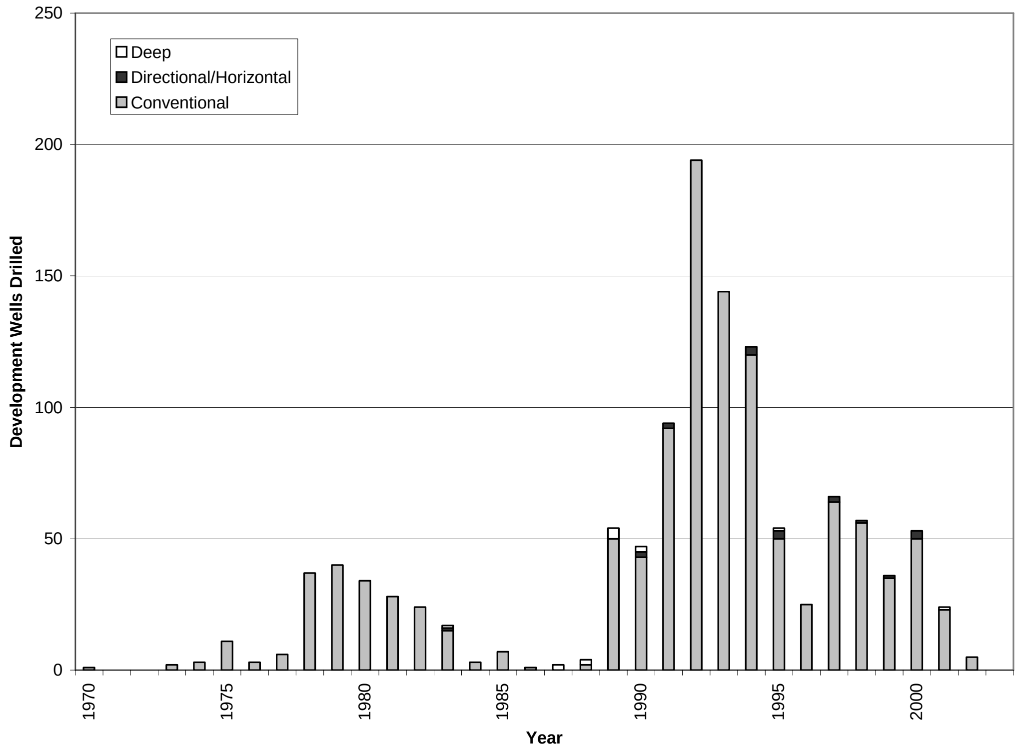
Figure 4-6. Exploration Well Activity for Green River Basin

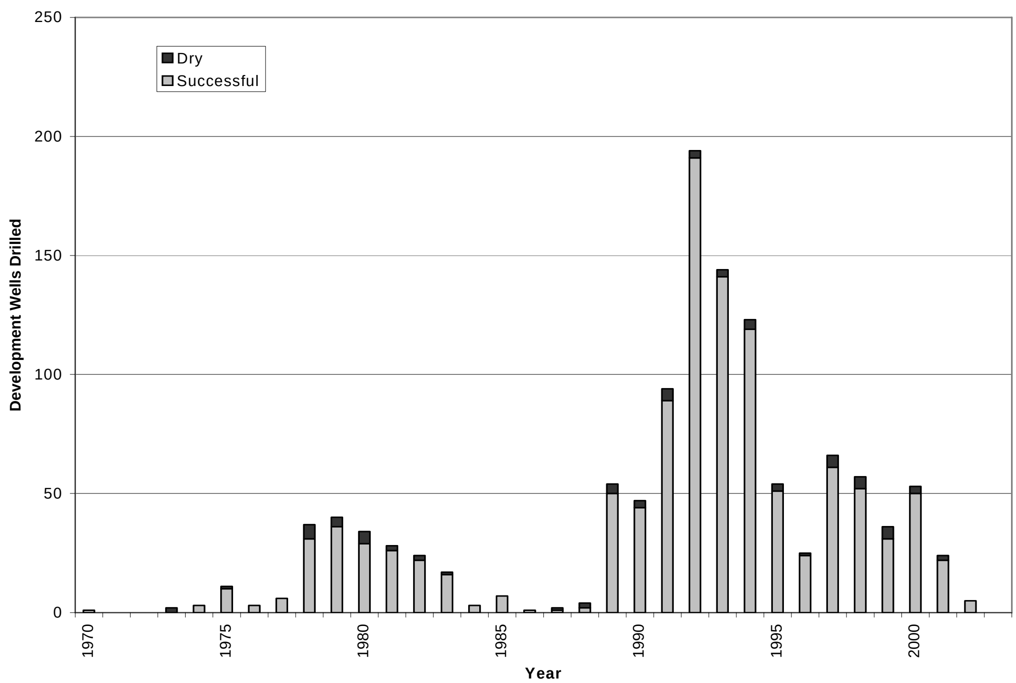




Sources: RMG 2003; WOGCC 2003

Figure 4-7. Development Well Activity for Green River Basin





Sources: RMG 2003; WOGCC 2003

Figure 4-8

Prospect-Darby-Hogsback Thrust Oil and Gas Fields in the Kemmerer Field Office Planning Area

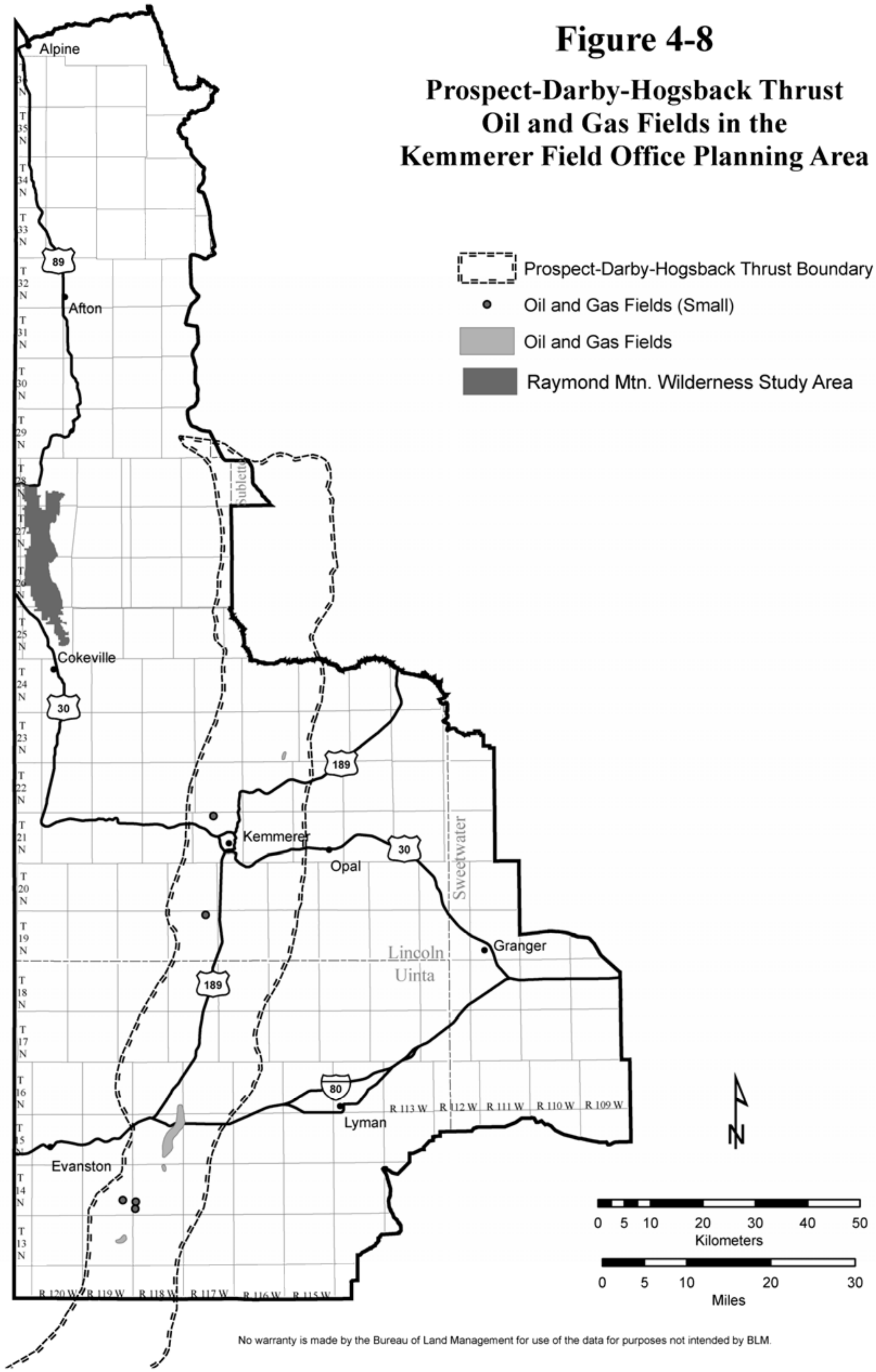


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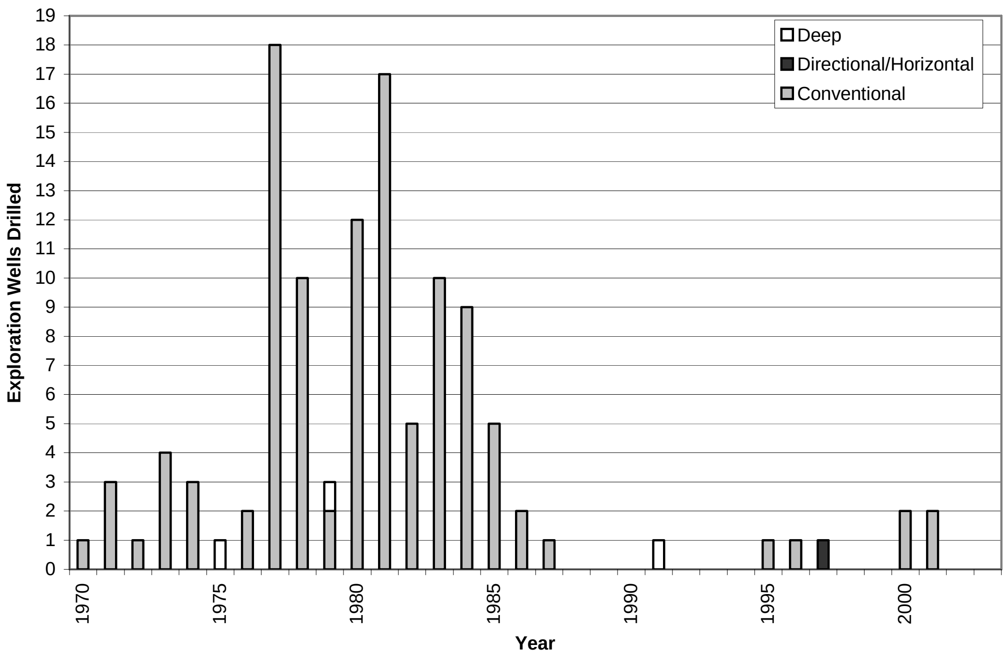
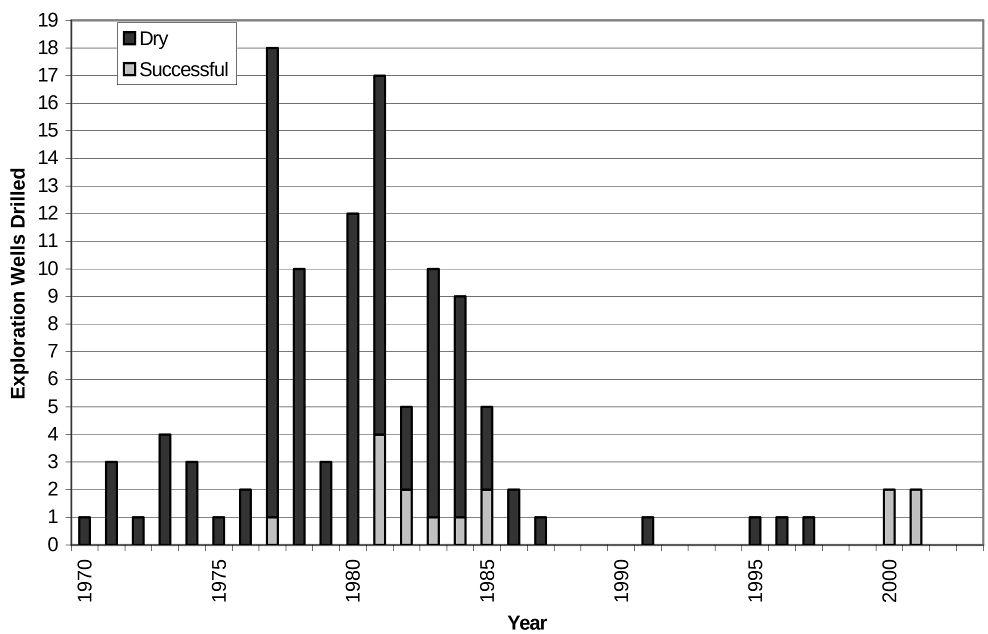
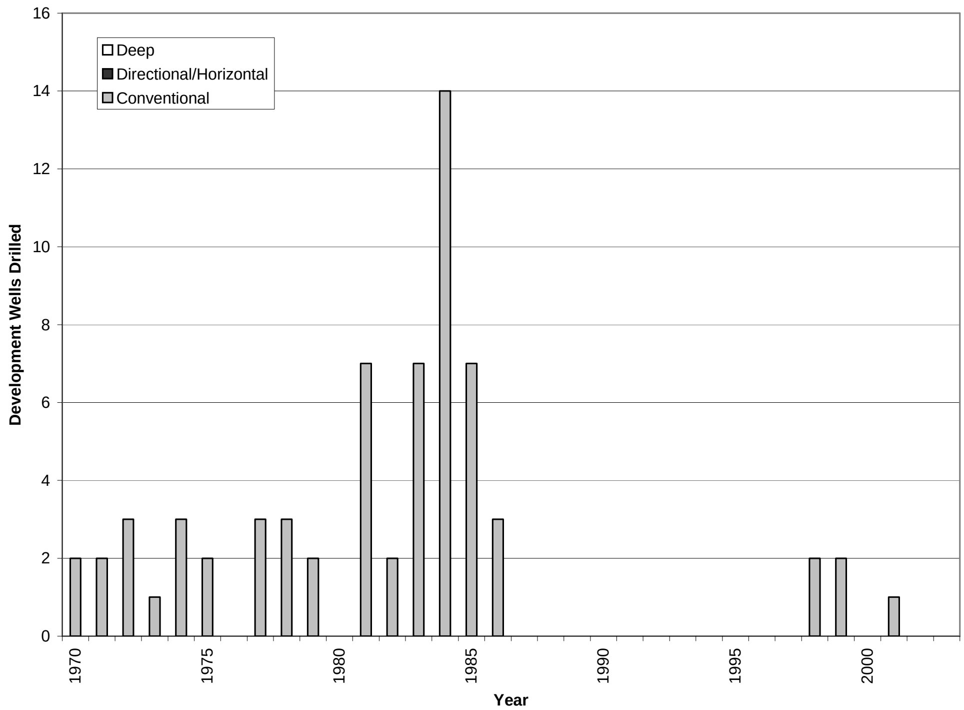
Figure 4-9. Exploration Well Activity for Prospect-Darby-Hogsback Thrust Area

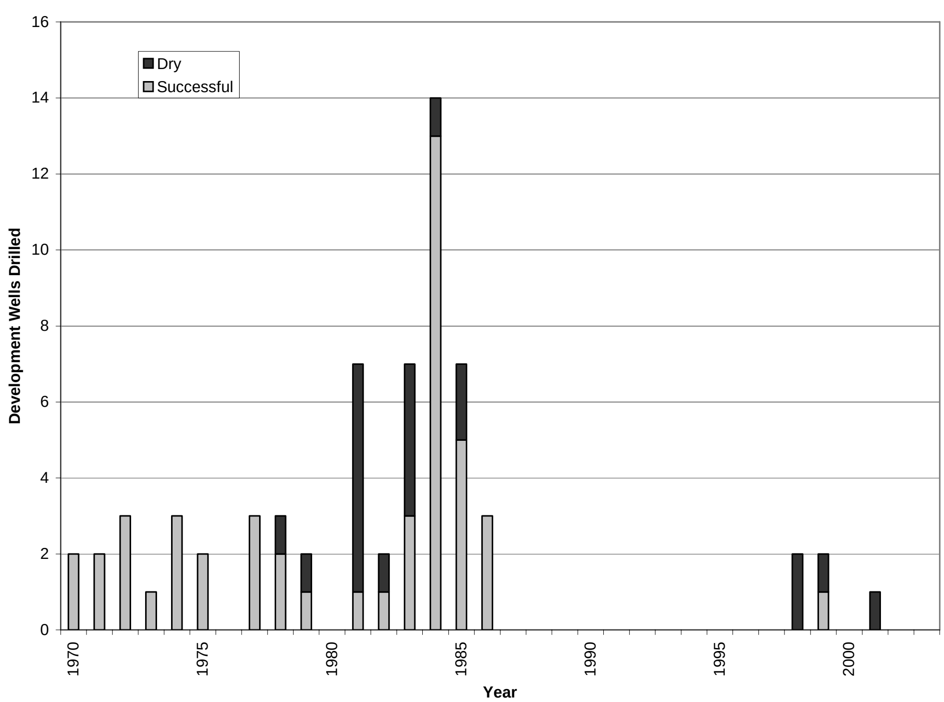




Sources: RMG 2003; WOGCC 2003

Figure 4-10. Development Well Activity for Prospect-Darby-Hogsback Thrust Area





Source: RMG 2003; WOGCC 2003

4.3.3 Absaroka Thrust

Table 4-3 summarizes the graphical information for exploration and development drilling on the Absaroka Thrust. A total of 532 wells were drilled from 1970 through 2002.

Table 4-3. Well Activity for Absaroka Thrust Area, 1970 through 2002

Well Class	Dry	Successful	Total	Success Rate
Exploration	145	90	235	39%
Deep	-	-	68	-
Directional/Horizontal	-	-	5	-
Conventional	-	-	162	-
Development	39	258	297	87%
Deep	-	-	81	-
Directional/Horizontal	-	-	48	-
Conventional	-	-	168	-

Sources: RMG 2003; WOGCC 2003

Figure 4-11 shows the oil and gas fields in the Absaroka Thrust area located within the planning area.

Figure 4-12 illustrates exploration drilling on the Absaroka Thrust from 1970 through 2002. The upper graph illustrates the number of deep wells, directional/horizontal wells, and conventional wells drilled during the period. The lower graph shows the number of dry hole and successful well completions for thrust area.

Figure 4-13 shows development drilling on the Absaroka Thrust area from 1970 through 2002. The upper graph shows the number of deep wells, directional/horizontal wells, and conventional wells drilled during the period, while the lower graph illustrates how many of those wells were dry holes or successful well completions for the thrust area.

4.3.4 Coalbed Natural Gas

The presence of CBNG, consisting primarily of methane, in coal seams was historically recognized as a potential hazard in coal mining. CBNG originally was extracted from coal prior to mining to provide a margin of safety for underground coal mining. Concentrations of methane gas between 5 percent and 15 percent are an explosion hazard. Methane released by surface mining methods generally is not considered hazardous because, in the absence of an enclosed space, it can seldom build to an explosive concentration. Methane is a greenhouse gas and a valuable resource otherwise lost in the mining process. In the early 1980s, Congress considered CBNG to be an unconventional gas resource and enacted tax incentives for the production of the gas from coal seams. Only two productive CBNG were completed within the planning area, both in the mid-1990s. Gas production from the two wells has been minimal. In addition, three CBNG wells have been plugged and abandoned; two are proposed for abandonment (one is dormant). Drilling and testing have begun on three others.

Figure 4-11

Absaroka Thrust Oil and Gas Fields in the Kemmerer Planning Area

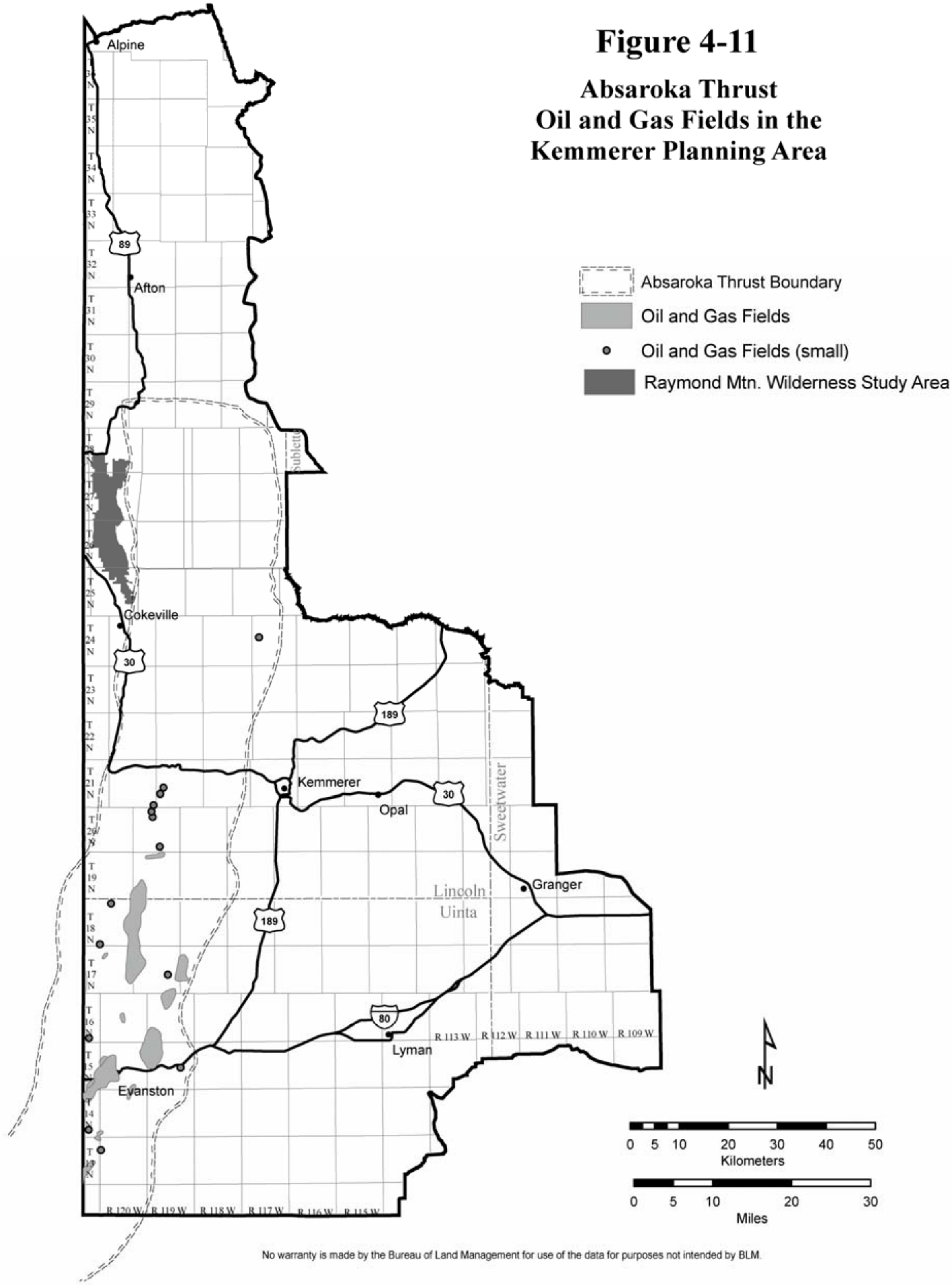


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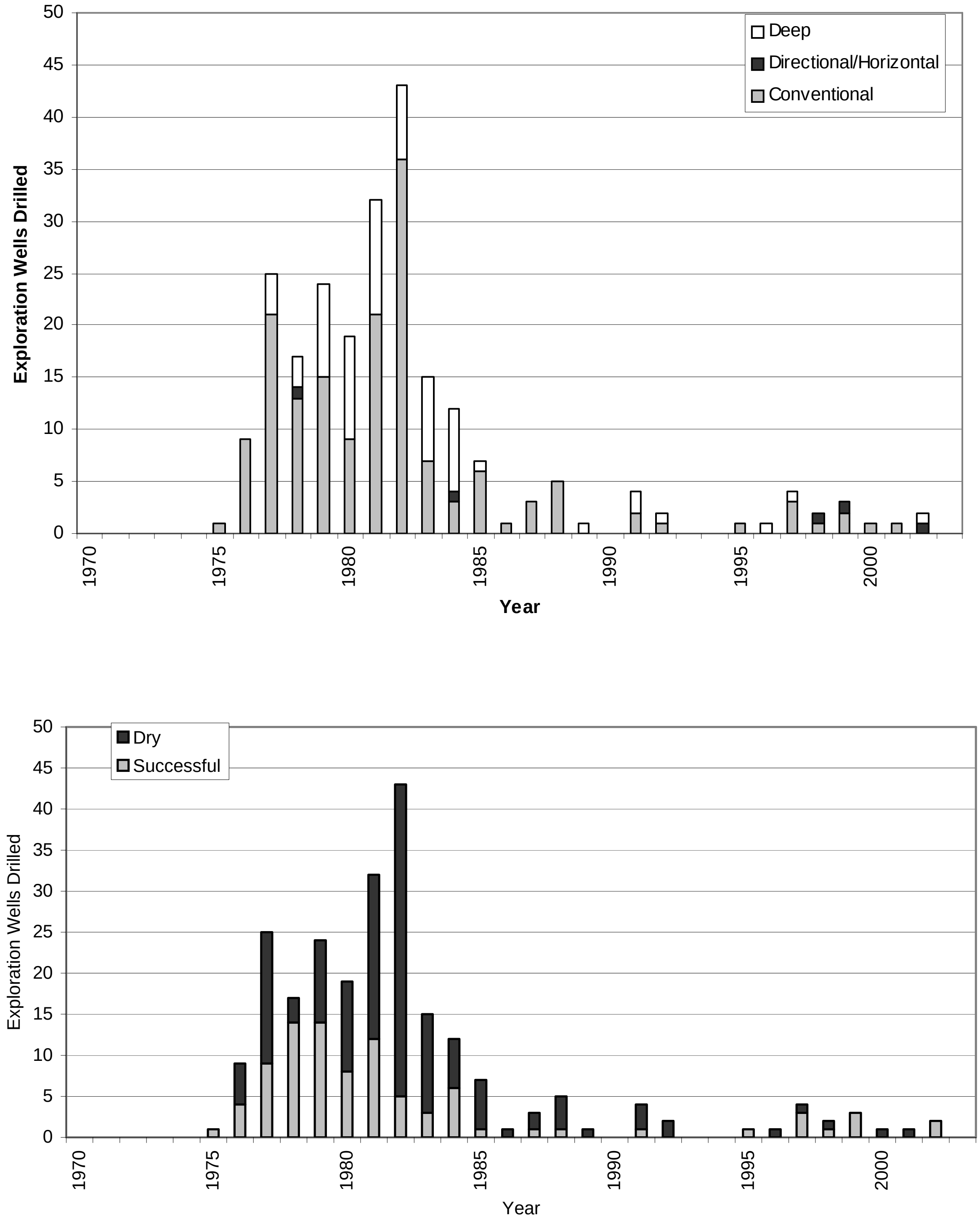
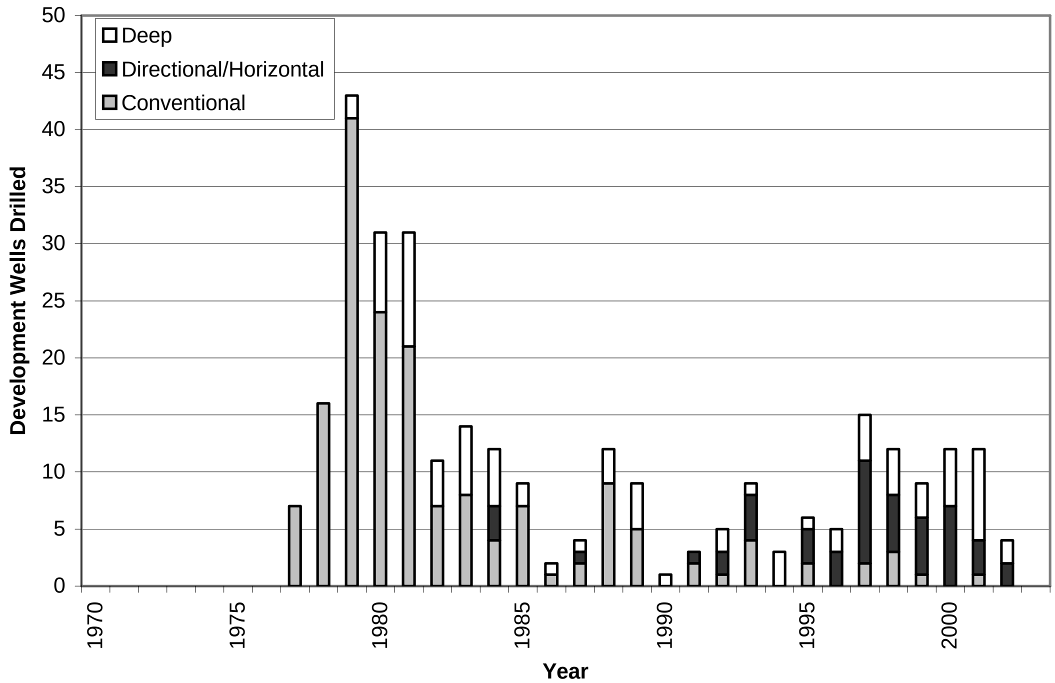
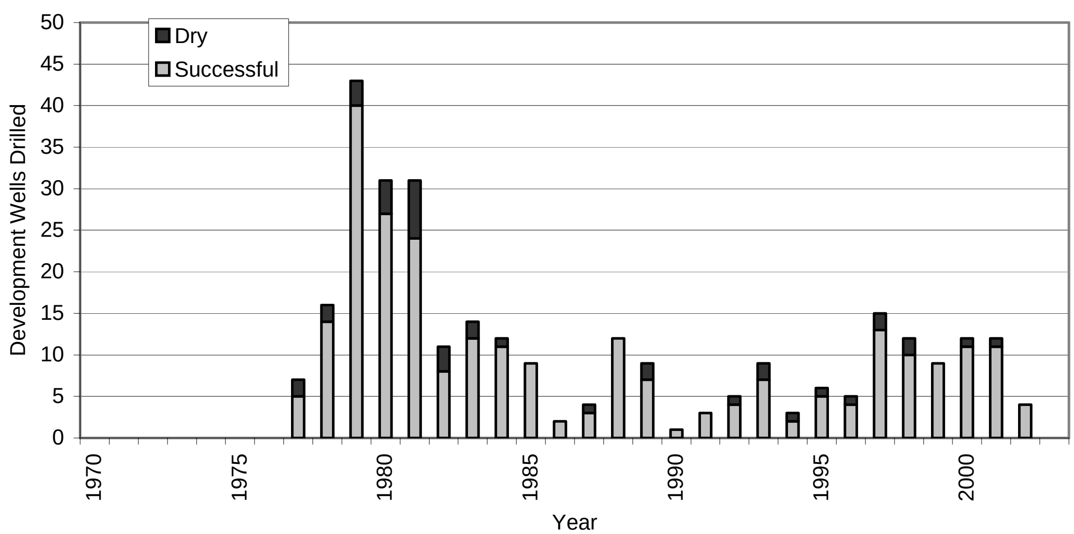
Figure 4-12. Exploration Well Activity for Absaroka Thrust Area



Sources: RMG 2003; WOGCC 2003)

Figure 4-13. Development Well Activity for Absaroka Thrust Area





Source: RMG 2003; WOGCC 2003

4.4 Oil and Gas Production

Following the discovery of Utah's Pineview field in 1975 and Ryckman Creek field in 1976, intense exploration, that included seismic and drilling programs resulted in major discoveries of oil and gas in what is known as the fairway of the Overthrust Belt (BLM 2003). Figure B 3-1 in Appendix B is a stratigraphic column of the Green River Basin and shows the possible producing horizons in the basin. Oil production rose from 1.8 million barrels (MMBbl) in 1978 to a high of 12.4 MMBbl in 1985; however, since 1985, oil production has declined steadily each year, falling to 3.5 MMBbl in 2002. Gas production in the planning area rose from 15 billion cubic feet (Bcf) in 1978, to a high of 343.5 Bcf in 1995. Since 1995, gas production has declined steadily each year, falling to 251.4 Bcf in 2002 (RMG 2003). An important factor in the success of oil and gas exploration in the Overthrust Belt has been the improvement in geophysical techniques and in the processing of data, enabling companies to decipher more clearly some of the very complex, deep structures in the subsurface that trap oil and gas (BLM 2003). Table 4-4 lists oil and gas production levels in the planning area for selected years from 1978 through 2002.

Table 4-4. Oil and Gas Production, 1978 through 2002

Year	Oil (MMBbl)	Gas (Bcf)
1978	1.8	15.2
1985	12.4	242.8
1995	6.5	343.5
1999	5.7	288.4
2001	4.4	269.4
2002	3.5	251.4

Source: RMG 2003
MMBbl million barrels
Bcf billion cubic feet

The average depth of wells was around 9,500 feet in the planning area until the year 2001. After 2001, the depth of wells increased, reflecting the greater drilling depths on the south part of the Moxa Arch trend for deeper Frontier and Dakota horizons and the deep Madison gas seen in the southwestern part of the planning area (BLM 2006b).

At the end of 2002, there were more than 40 active oil and gas fields in the planning area. Of these, 5 of the 25 largest gas fields and 3 of the 25 largest oil fields in Wyoming for 2002 were in the planning area (WOGCC 2003). Some of the oil and gas fields in the planning area overlap with the Pinedale Planning Area and (or) with the Rock Springs Planning Area. Figure 4-1 shows oil and gas fields in the Kemmerer planning area. Figure 4-2 shows oil and gas wells. Figure 4-14 shows oil and gas pipelines that traverse or carry production from the planning area.

Figure 4-15 shows a production decline curve for wells that existed as of the year 2000. This curve was created for oil and gas production by averaging all wells in the planning area. For this analysis, 6 years of annual production data (2000-2005) were obtained from DWIGHTS database accessed through the BLM Colorado State Office (DWIGHTS 2005). DWIGHTS is a comprehensive database used by the oil and gas industry and regulators to monitor and plan a wide range of oil and gas exploration, production, and development. DWIGHTS data were obtained for all well records in the planning area specified by township and range. The data were then filtered for wells drilled and completed prior to 2001 to prevent annual spikes from

Figure 4-14
Oil and Gas Pipelines

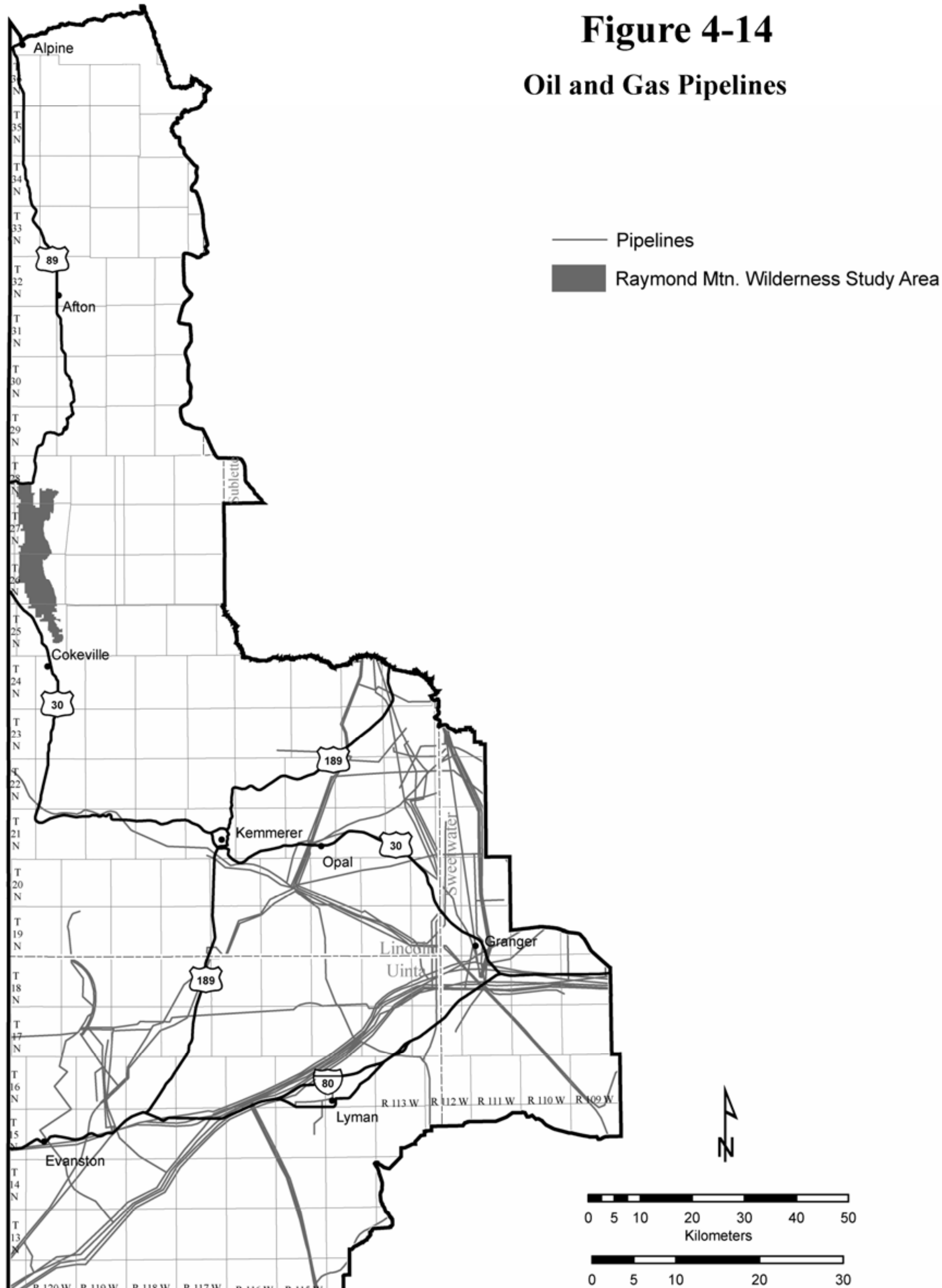


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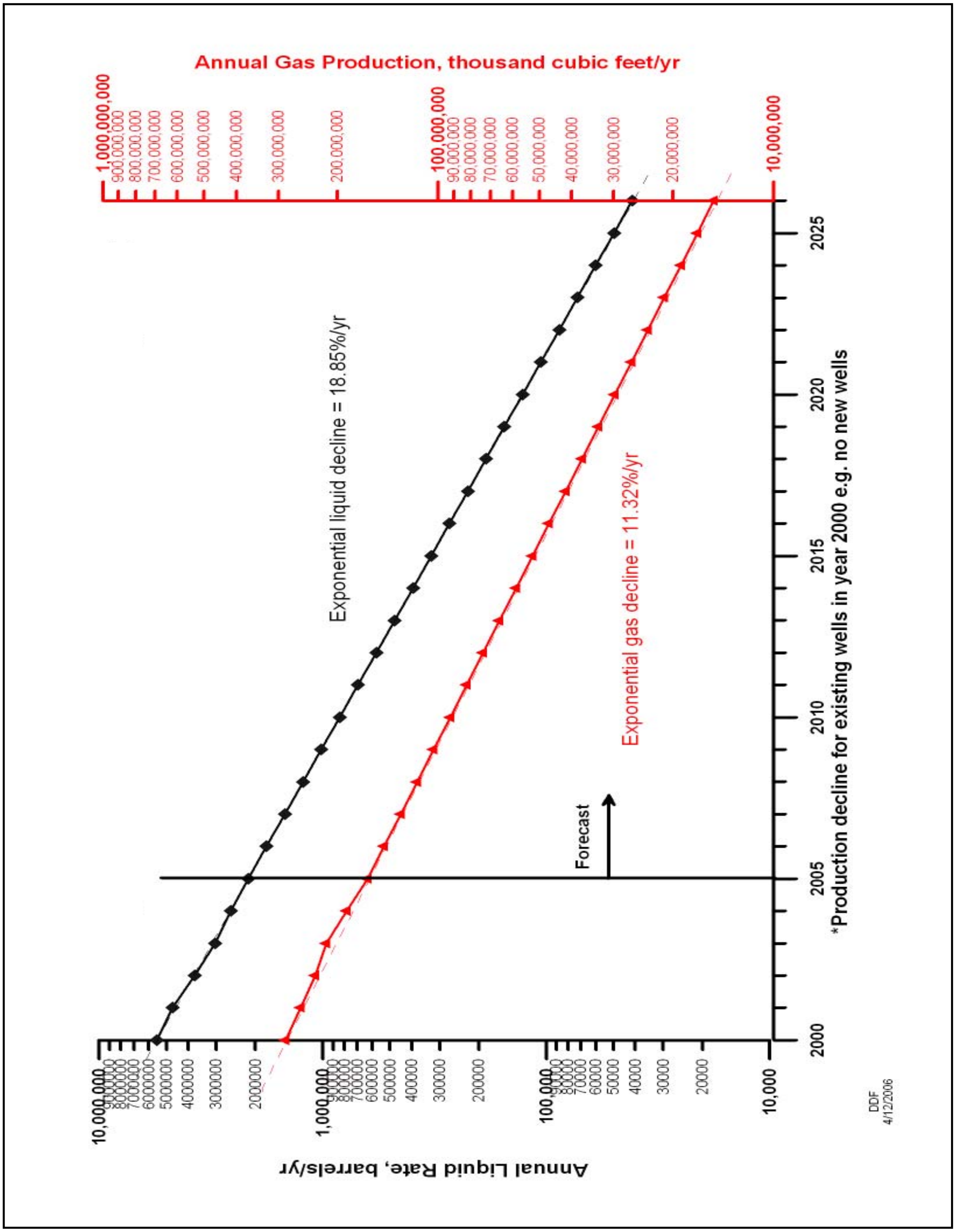
Figure 4-15. Existing Wells Production Forecast



Source: DWIGHTS 2005

increased drilling and production activities in later years (2001-2005). This process reduced the number of producing oil and gas wells of interest to approximately 1,400 wells in the year 2000. The annual oil and gas production for these wells was manually sorted to obtain annual production volumes and well counts. The nominal decline rate was then calculated as 18.8 percent per year for oil, and 11.32 percent per year for gas. This decline of production represents a hypothetical situation if no new wells were drilled after the year 2000. New wells drilled for the planning area will initially cause spikes (period of increased production) in the decline curve. After the production spike, the decline curve will have a greater negative nominal decline (slope) than the decline shown in Figure 4-15. The higher drilling activity forecasted by this planning document for each alternative will cause the finite oil and gas resources in the planning area to deplete at a faster rate.

This decline curve also will be used to predict future production from individual wells newly drilled in the planning area after 2000 for each alternative in the two tables at the end of Section 8.0. This curve is not meant to predict individual well production for a field in the planning area.

The following sections provide a brief overview of the fields within each of the plays that lie within the planning area.

4.4.1 Green River Basin

There are 35 named fields within the planning area portion of the Green River Basin. The first of these, Church Buttes, was discovered in 1956. The most recent, Haven, was discovered in 1994. The general location of the fields that lie within the Moxa Arch/Green River Basin portion of the planning area is shown in Figure 4-5. Most of the fields produce from the Frontier Formation, the Dakota Sandstone, or both. Seven horizons have produced or currently are producing in the Moxa Arch/Green River Basin portion of the planning area. The following sections contain a brief summary of each field and are listed in chronological order based on data at discovery.

Church Buttes

The Church Buttes field was discovered in 1956. Church Buttes is on the southern end of the Moxa Arch and generally covers portions of Township 17 North (T17N), Range 112 West (R112W); T16N, R112W; T16N, R113W; and T15N, R112W. It ranks second in total gas production and 19th in oil and gas liquids production. Table 4-5 shows the statistics for the field.

Table 4-5. Church Buttes Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Frontier	113	101	115,569,169	556,859	66,0487
Frontier - 2	14	10	15,962,339	77,158	77,844
Dakota	48	28	154,879,127	535,070	803,714
Morgan	1	0	1,540,971	106,054	142
Frontier-Dakota	1	0	35,4673	5,328	7,770
Field Total	177	139	288,306,279	128,0469	1,549,957

Source: WOGCC 2003
*As of 12/31/03

Willow Creek

Willow Creek Field was found in 1957. It is located just west of the north end of the Moxa Arch in T24N, R114W. It ranks 29th in gas production and 34th in oil and gas liquids production. Table 4-6 summarizes the field.

Table 4-6. Willow Creek Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Almy	2	0	176,971	12	1,192
Frontier	1	0	233,664	54	84
Field Total	3	0	410,635	66	1,276

Source: WOGCC 2003
* As of 12/31/03

Emigrant Springs

Emigrant Springs was discovered in 1958. It is located on the north end of the Moxa Arch in T23N, R112W. This field ranks 10th in gas production and 10th in oil and natural gas liquids production. Table 4-7 shows the field statistics.

Table 4-7. Emigrant Springs Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Morapos (Mancos)	1	0	279,356	6,895	3,820
Frontier	43	32	37,496,869	620,556	222,700
Frontier - 2	11	8	312,8499	80,721	64,269
Muddy	1	1	168,0265	49,426	2,644
Dakota	1	0	30,575	704	45
Field Total	57	41	42,615,564	758,302	293,478

Source: WOGCC 2003
* As of 12/31/03

Opal

Opal Field was discovered in 1959. It is located south of Emigrant Springs in T22N, R112W. Opal ranks 23rd in gas production and 26th in oil and natural gas liquids. Table 4-8 shows a summary of the field's production.

Table 4-8. Opal Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Dakota	6	4	1,963,669	35,150	2,624
Field Total	6	4	1,963,669	35,150	2,624

Source: WOGCC 2003
* As of 12/31/03

Moxa

The Moxa Field was discovered in 1961. Lying near the midpoint of the Moxa Arch, Moxa Field is located generally in T18N, R112W and T19N, R112W. Moxa Field is 15th in gas production, but 29th in production of oil and natural gas liquids. Table 4-9 shows the field summary.

Table 4-9. Moxa Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Frontier	3	3	5,767,361	10,487	20,719
Dakota	1	0	517,447	478	714
Field Total	4	3	6,284,808	10,965	21,433

Source: WOGCC 2003
* As of 12/31/03

Wilson Ranch

Wilson Ranch was discovered in 1973. The field is located on the west flank of the Moxa Arch in T20N, R113W. Wilson Ranch ranks 5th in gas production and 7th in oil and natural gas liquids production. Table 4-10 shows a summary of the field.

Table 4-10. Wilson Ranch Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Frontier	28	11	19,205,677	214,583	4,5503
Frontier - 2	54	50	52,958,087	409,133	154,381
Dakota	23	18	50,373,591	483,308	67,522
Field Total	105	79	122,537,355	1,107,024	267,406

Source: WOGCC 2003
* As of 12/31/03

Bruff

Bruff Field was found in 1974. It ranks 1st in gas production and 3rd in oil and natural gas liquids production. Bruff is located at the heart of the Moxa Arch, generally in T19N, R112W. Table 4-11 shows a summary of the field production.

Table 4-11. Bruff Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Frontier	241	176	257,288,250	1,202,830	1,212,854
Frontier - 2	93	86	101,103,986	618,594	313,179
Muddy	2	2	5,599,252	74,975	15,713
Dakota	161	102	292,505,858	1,757,545	1,041,794
Morgan	1	0	21,409	7,815	863
Commingled Frontier-Dakota	63	45	86,998,886	611,261	551,852
Field Total	561	411	743,517,641	4,273,020	3,136,255

Source: WOGCC 2003
* As of 12/31/03

Shute Creek

Shute Creek was discovered in 1975. The field generally is located at the north end of the Moxa Arch in T23N, R112W. Shute Creek ranks 9th in gas production and 9th in oil and natural gas liquids production for the 35 fields discussed in this section. Table 4-12 is a summary of the production.

Table 4-12. Shute Creek Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Frontier	36	17	28,392,678	350,672	221,177
Frontier - 2	33	29	20,628,623	292,054	210,818
Dakota	5	5	6,584,935	178,822	27,939
Field Total	74	51	55,606,236	821,548	459,934

Source: WOGCC 2003
* As of 12/31/03

Storm Shelter

Storm Shelter was discovered in 1975. The field is located on the northeast corner of the planning area portion of the Moxa Arch, generally in T23N, R111W. It ranks 13th in gas production and 15th in oil and gas liquids production. Table 4-13 is a summary of the production.

Table 4-13. Storm Shelter Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Frontier	22	13	11,689,315	286,207	114,601
Frontier - 2	2	1	951,691	13,908	6,682
Field Total	24	14	12,641,006	300,115	121,283

Source: WOGCC 2003
* As of 12/31/03

Verne

Verne was discovered in 1975. It is located in T18N, R113W on the west flank of the Moxa Arch. In gas production, Verne ranks 14th among the 35 fields and 18th in oil and natural gas liquids production. Table 4-14 shows the completions and productions for the field.

Table 4-14. Verne Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Frontier	8	6	4,429,765	75,469	28,509
Frontier - 2	4	3	1,595,872	27,032	10,976
Muddy	1	0	30,097	897	161
Dakota	3	2	3,597,590	48,472	4,774
Commingled Frontier-Dakota	1	1	457,500	6,452	20,739
Field Total	17	12	10,110,824	158,322	65,159

Source: WOGCC 2003
*As of 12/31/03

Whiskey Butte

Whiskey Butte was discovered in 1975 and generally is located in T22N, R111W, which is in the northeast part of the Moxa Arch within the planning area. Whiskey Butte is the 3rd largest gas producer and 6th largest oil and natural gas liquids producer. Table 4-15 is a summary of the completions and production.

Table 4-15. Whiskey Butte Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Mesaverde	1	0	193,299	1,029	42
Frontier	63	25	37,981,815	369,243	382,476
Frontier - 2	96	94	120,525,654	933,978	263,366
Dakota	13	7	10,310,823	127,042	18,886
Field Total	173	126	169,011,591	1,431,292	644,770

Source: WOGCC 2003
* As of 12/31/03

Black Jack

Black Jack Field was discovered in 1976. It is located in T22N, R113W, on the northwest flank of the Moxa Arch. Black Jack Field ranks 22nd in gas and 21st in oil and natural gas liquid production among the 35 fields discussed in this section. Table 4-16 is a summary of the field's completions and production.

Table 4-16. Black Jack Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Frontier	1	1	729,887	12,776	5,988
Frontier - 2	1	0	150,354	1,266	545
Dakota	2	2	1,364,303	69,053	6,439
Commingled Frontier-Dakota	1	1	533,843	8,174	84
Field Total	5	4	2,778,387	91,269	13,056

Source: WOGCC 2003
*As of 12/31/03

Fabian Ditch

Also discovered in 1976, Fabian Ditch is also in the heart of the Moxa Arch area, located generally in T20N, R112W, immediately and north of Bruff Field. Fabian Ditch is 4th among the 35 fields in gas production and 11th in oil and natural gas liquids production. Table 4-17 is a summary of completions and production for the field.

Table 4-17. Fabian Ditch Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Frontier	29	20	24,077,015	66,469	86,796
Frontier - 2	23	23	36,620,145	128,290	82,230
Dakota	26	7	69,925,930	492,973	127,878
Commingled Fort Union – Mesa Verde	1	1	0	9,643	2,419
Commingled Frontier - Dakota	7	3	11,497,330	42,548	68,986
Field Total	86	54	142,120,420	739,923	368,309

Source: WOGCC 2003

* As of 12/31/03

Sevenmile Gulch

Sevenmile Gulch was discovered in 1976. It covers portions of T21N, R112W; T21N, R11W; T20N, R112W; and T20N, R111W, just north and east of Fabian Ditch. Overall, it ranks 12th in gas production and 17th in oil and gas production. Table 4-18 is a summary of the field's completions and production.

Table 4-18. Sevenmile Gulch Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Frontier	2	1	210,489	622	1,063
Frontier - 2	2	0	113,097	1,255	3,331
Dakota	1	0	56,268	167	0
Commingled Frontier - Dakota	10	9	21,079,916	163,566	50,610
Field Total	15	10	21,459,770	165,610	55,004

Source: WOGCC 2003

* As of 12/31/03

Craven Creek

Craven Creek was discovered in 1977. It is located in T24N, R114W, northwest of the main Moxa Arch area. Craven Creek ranks 24th in gas production and 32nd in oil and natural gas liquids production. Table 4-19 is a summary of the completions and production for the field.

Table 4-19. Craven Creek Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Wasatch	3	2	209,649	7	6,543
Fort Union	4	0	1,885,210	711	4,544
Mesaverde	3	0	2,540,757	1,,515	32
Hilliard	1	1	57,601	0	0
Field Total	11	3	4,693,217	2,233	11,119

Source: WOGCC 2003

* As of 12/31/03

Opal Bench

Opal Bench was discovered in 1977. The field is off the west flank of the Moxa Arch, located generally in T21N, R113W. Opal Bench ranks 34th in gas and production and 35th in oil and natural gas liquids production. Table 4-20 is a summary of the completions and production for the field.

Table 4-20. Opal Bench Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Frontier - 2	1	0	1,888	0	0
Field Total	1	0	1,888	0	0

Source: WOGCC 2003

* As of 12/31/03

Pipeline Crossing

Pipeline Crossing was added in 1977. Pipeline Crossing generally is located in T18N, R111W, on the east edge of the Moxa Arch coming in 29th in gas production and 33rd in oil and gas production. Table 4-21 is a summary of the completions and production.

Table 4-21. Pipeline Crossing Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Frontier	2	1	210,489	622	1,063
Frontier - 2	2	0	113,097	1,255	331
Dakota	1	0	56,268	167	0
Field Total	5	1	379,854	2,044	4,394

Source: WOGCC 2003
* As of 12/31/03

Wild Hare Gulch

Wild Hare Gulch was discovered in 1977. It is located in T20N, R111W, on the east flank of the Moxa Arch. In gas production, Wild Hare Gulch ranks 19th and 24th in oil and natural gas liquids production, respectively, among the 35 fields in the planning area portion of the Green River Basin/Moxa Arch complex. Table 4-22 is a summary of the field's completions and production.

Table 4-22. Wild Hare Gulch Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Frontier	7	3	1,988,143	23,262	19,013
Frontier - 2	6	3	1,444,851	22,003	6,754
Dakota	1	0	160,052	1,057	413
Field Total	14	6	3,593,046	46,322	26,108

Source: WOGCC 2003
* As of 12/31/03

Henry

Henry Field was discovered in 1980. Henry lies at the south end of the Moxa Arch in T13N, R113W. Most of the field falls within the Rock Springs Field Office area; however, the field is included here for completeness. Henry ranks 7th in gas production and 2nd in oil and gas liquids production. Table 4-23 reflects completion and production information for all of the Henry Field.

Table 4-23. Henry Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Frontier	1	1	24,098	12,239	106
Mowry	1	1	27,924	11,255	341
Dakota	17	7	71,6542,27	5,118,831	370,387
Field Total	19	9	71,706,249	5,142,325	370,834

Source: WOGCC 2003
* As of 12/31/03

Big Dry Creek

Big Dry Creek was discovered in 1981. Generally located in T15N, R113W, Big Dry Creek lies at the south end of the Moxa Arch. Of the 35 fields discussed in this section, Big Dry Creek ranks 26th in gas production and 22nd in oil and natural gas liquids production. Table 4-24 is a summary of the completions and production for the field.

Table 4-24. Big Dry Creek Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Frontier	1	0	496,085	40,892	2,586
Muddy	1	1	316,507	21,924	11,712
Field Total	2	1	812,592	62,816	14,298

Source: WOGCC 2003
* As of 12/31/03

Hickey Mountain

Hickey Mountain was discovered in 1981. It lies in the same area as Henry and Big Dry Creek, off the south end of the Moxa Arch in T13N, R114W. Hickey Mountain is different than most of the fields in the planning area because it is primarily an oil field. Among the 35 fields, Hickey Mountain ranks 33rd in gas production but 23rd in oil and natural gas liquids production. Table 4-25 is a summary of the completions and production for Hickey Mountain.

Table 4-25. Hickey Mountain Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Frontier	1	0	4,270	24,350	1,329
Dakota	1	0	55,463	5,724	337
Phosphoria	1	0	4,488	26,465	440
Field Total	3	0	64,221	56,539	2,106

Source: WOGCC 2003
* As of 12/31/03

Graham Reservoir

Like Hickey Mountain, the Graham Reservoir Field, discovered in 1983, is primarily an oil field. Graham Reservoir lies southwest of the Moxa Arch structure and generally is located in T12N, R115W. Ranking only 30th in gas production, Graham Reservoir ranks 12th in oil and natural gas liquids production. Table 4-26 is a summary of the field's completions and production.

Table 4-26. Graham Reservoir Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Frontier	1	1	108,450	13,7099	4,086
Dakota	1	0	13,499	13,454	0
Commingled Muddy - Dakota	1	1	216,071	492,139	431,333
Field Total	3	2	338,020	642,692	435,419

Source: WOGCC 2003
* Production as of 12/31/03

Henry South

Henry South was discovered in 1985. It is located in T13N, R113W, south of the Moxa Arch and northeast of Graham Reservoir. Henry South ranks 17th in gas production and 13th in oil and natural gas liquids production. Table 4-27 is a summary of the field's completions and production.

Table 4-27. Henry South Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Frontier	1	0	3,535	1,097	136
Dakota	3	1	4,147,502	640,933	58,410
Field Total	4	1	4,151,037	642,030	58,546

Source: WOGCC 2003
* As of 12/31/03

Luckey Ditch

Luckey Ditch was discovered in 1985. It generally is located in T12N, R114W, near the southwest corner of the planning area. Luckey Ditch ranks 1st in oil and natural gas liquids production and 8th for gas production. Table 4-28 is a summary of the field's completions and production.

Table 4-28. Luckey Ditch Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Dakota	11	8	69,351,345	9,447,331	2,125,838
Field Total	11	8	69,351,345	9,447,331	2,125,838

Source: WOGCC 2003
* As of 12/31/03

Milich Ditch

Milich Ditch, located northwest of Luckey Ditch in T13N, R115W, also is an oil field. It ranks 35th in gas production. In oil and natural gas liquids production Milich Ditch ranks 30th among the 35 fields discussed in this section. Table 4-29 is a summary of the field's completions and production.

Table 4-29. Milich Ditch Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Dakota	1	0	1,585	7,900	1,752
Field Total	1	0	1,585	7,900	1,752

Source: WOGCC 2003
* As of 12/31/03

Cow Hollow

Cow Hollow was discovered in 1986. It generally is located in T22N, R112W, on the north end of the planning area portion of the Moxa Arch structure. Cow Hollow ranks 6th in gas and 5th in oil and natural gas production among the 35 fields in this portion of the planning area. Table 4-30 is a summary of the field's completions and production.

Table 4-30. Cow Hollow Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Frontier	64	31	3,368,6878	429,958	153,414
Frontier - 2	53	43	41,654,470	453,974	179,424
Dakota	30	20	19,978,044	358,033	139,802
Commingled Frontier - Dakota	13	10	11,620,707	230,900	124,160
Field Total	160	104	106,940,099	1,472,865	596,800

Source: WOGCC 2003
* As of 12/31/03

Dog Spring

Dog Spring Field, also discovered in 1986, is a relatively small field at the south end of the main Moxa Arch fields. It generally is located in T15N, R113W. The field ranks 28th in gas production and 31st in oil and natural gas liquids production. Table 4-31 is a summary of the field's completions and production.

Table 4-31. Dog Spring Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Dakota	1	0	382,894	2,930	1,112
Field Total	1	0	382,894	2,930	1,112

Source: WOGCC 2003
* As of 12/31/03

Taylor Ranch

Also added in 1986, Taylor Ranch is located in T13N, R114W. It is one in the group of fields located southwest of the main Moxa Arch area. Taylor Ranch places 16th in gas production and 14th in oil and natural gas liquids production. Table 4-32 is a summary of the field's completions and production.

Table 4-32. Taylor Ranch Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Frontier	1	0	3,526	3,774	7,764
Dakota	6	2	6,101,892	509,373	159,943
Field Total	7	2	6,105,418	513,147	167,707

Source: WOGCC 2003
* As of 12/31/03

Whiskey Springs

Whiskey Springs Field was discovered in 1988. It lies at the south edge of the planning area and southwest of the main Moxa Arch area in T12N, R114W. It ranks 11th in gas production and 4th in oil and natural gas liquids production. Table 4-33 is a summary of the field's completions and production.

Table 4-33. Whiskey Springs Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Dakota	8	6	25,844,440	3,247,680	664,041
Field Total	8	6	25,844,440	3,247,680	664,041

Source: WOGCC 2003
* As of 12/31/03

Legacy

Legacy was added in 1989. It generally is located in T22N, R111W, is on the northeast flank of the Moxa Arch and the east edge of the planning area. Ranking 25th in gas production, Legacy places 16th in oil and natural gas liquids production. Table 4-34 is a summary of the field's completions and production.

Table 4-34. Legacy Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Frontier	3	1	878,152	21,737	15,633
Dakota	1	1	141,092	257,117	474,876
Field Total	4	2	1,019,244	278,854	490,509

Source: WOGCC 2003
* As of 12/31/03

Ziegler's Wash

Ziegler's Wash was discovered in 1989. Generally located in T19N, R113W, Ziegler's Wash lies on the west flank of the Moxa Arch structure. It ranks 21st in gas production and 25th in oil and natural gas liquids production as of the end of 2003. Table 4-35 is a summary of the field's completions and production.

Table 4-35. Ziegler's Wash Field

Producing Formation	Total Completions	Active Completions	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Frontier	5	5	2,374,526	27,052	17,845
Frontier - 2	1	0	280,834	7,112	1,001
Dakota	3	0	477,526	4,577	1,017
Field Total	9	5	3,132,886	38,741	19,863

Source: WOGCC 2003
* As of 12/31/03

Sugarloaf Butte

Discovered in 1990, a portion of Sugarloaf Butte Field lies within the planning area and is included in this discussion. Generally located in T22N, R110W, the field is on the northeast flank of the Moxa Arch. Gas production ranks 20th and oil and natural gas liquids production ranks 8th among the 35 fields described in this section. Table 4-36 is a summary of the field's completions and production.

Table 4-36. Sugarloaf Butte Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Frontier	1	1	22,951	1,131	1,227
Frontier - 2	8	1	1,652,966	483,685	1,780
Dakota	1	1	3,210	610	971
Commingled Dakota - Mowry	10	3	1,679,127	485,426	3,978
Field Total	1	1	3,358,254	970,852	7,956

Source: WOGCC 2003
* As of 12/31/03

Dodge Rim

Dodge Rim was discovered in 1991 in the Green River Basin/Moxa Arch portion of the planning area. Generally located in T22N, R111W, Dodge Rim is immediately west of Sugarloaf Butte on the northeast side of the Moxa Arch. Dodge Rim places 31st in gas production and 27th in oil and natural gas liquids production among the 35 fields. Table 4-37 is a summary of the completions and production.

Table 4-37. Dodge Rim Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Frontier	2	0	137,503	15,350	5,321
Frontier - 2	2	0	137,503	15,350	5,321
Field Total	2	0	275,006	30,700	10,641

Source: WOGCC 2003
* As of 12/31/03

Trumpeter

Trumpeter was added in 1991. It also lies immediately south of Dodge Rim in T21N, R111W. It ranks 32nd in gas production and 28th in oil and natural gas liquids production among the 35 fields. Table 4-38 is a summary of the field's completions and production.

Table 4-38. Trumpeter Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Frontier	1	0	114,391	11,303	1,210
Dakota	1	1	14,090	1,033	1,463
Field Total	2	1	128,481	12,336	2,673

Source: WOGCC 2003
* As of 12/31/03

Haven

Haven was discovered in 1994. It is located in T23N, R111W. Haven ranks 18th in gas production and 20th in oil and natural gas liquids production. Table 4-39 is a summary of the field's completions and production.

Table 4-39. Haven Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Frontier	6	4	1,809,482	47,384	32,162
Frontier - 2	5	5	2,222,453	49,719	29,171
Field Total	11	9	4,031,935	97,103	61,333

Source: WOGCC 2003
* As of 12/31/03

4.4.2 Prospect-Darby-Hogsback Thrust

Eight named fields have been found in the planning area portion of the Prospect-Darby-Hogsback Overthrust trend. The oldest, Spring Valley, is also the oldest field in the planning area. Other than Horse Trap, all the fields have been oil fields. None of the fields is particularly large, especially when compared to the fields on the Moxa Arch or in the Absaroka Thrust trend. Most of the fields produce from either the Frontier Formation or the Aspen Shale. Figure 4-8 shows the general location of the fields. The following sections, presented by year of discovery, contain a brief summary of each field.

Spring Valley

Spring Valley was discovered in 1900. The field generally is located in T15N, R118W, in the southern portion of the planning area. The recorded production is mainly oil. Any gas produced would have been flared or vented due to a lack of pipelines and market. Oil production is probably understated due to inconsistent reporting over the years. Table 4-40 shows the documented production for the field.

Table 4-40. Spring Valley Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Frontier	31	18	613	60,950	83,847
Aspen	9	2	98	8,133	364
Field Total	31	18	613	60,950	83,847

Source: WOGCC 2003
* As of 12/31/03

Aspen

Aspen was discovered in 1903. It is located south of Spring Valley in T14N, R118W. Aspen is the second oldest field in the planning area. Like Spring Valley, reported gas and oil production volumes are misleading due to a lack of pipelines, market, and reporting mechanisms. Table 4-41 shows the documented production for the field.

Table 4-41. Aspen Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Frontier	1	1	3	1,093	273
Aspen	3	0	0	1,495	685
Field Total	4	1	3	2,588	958

Source: WOGCC 2003
* As of 12/31/03

Stove Creek

Stove Creek was discovered in 1941. It generally is located west of Aspen in T14N, R119W. Only a small volume of oil production and no gas production are reported on the Wyoming Oil and Gas Conservation Commission web site. Table 4-42 shows the documented production for the field.

Table 4-42. Stove Creek Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Frontier	3	0	0	593	0
Field Total	3	0	0	593	0

Source: WOGCC 2003
* As of 12/31/03

Sulphur Creek

Sulphur Creek was added in 1942. It generally is located in T13N, R119W. Again, because of a lack of pipelines, market, and reporting mechanisms, oil and gas production are probably underreported. Table 4-43 shows the documented production for the field.

Table 4-43. Sulphur Creek Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Aspen	2	1	0	1,316	1,269
Field Total	2	1	0	1,316	1,269

Source: WOGCC 2003
* As of 12/31/03

Sulphur Creek West

Sulphur Creek West was discovered in 1979. Another oil field, Sulphur Creek West, generally is located in T13N, R119W. Table 4-44 shows the documented production for the field.

Table 4-44. Sulphur Creek West Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Aspen	2	2	20	8,894	4,256
Gannett	1	0	30,525	0	0
Field Total	3	2	30,545	8,894	4,256

Source: WOGCC 2003
* As of 12/31/03

Horse Trap

In 1982, Horse Trap, the most prolific field in the planning area portion of the Prospect-Darby-Hogsback thrust, was discovered. Located generally in T23N, R115W, Horse Trap is the northernmost of the Prospect-Darby-Hogsback fields and lies west of the Moxa Arch gas fields. Table 4-45 shows the documented production for the field.

Table 4-45. Horse Trap Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Amsden	1	0	1,585,753	6,194	670
Field Total	1	0	1,585,753	6,194	670

Source: WOGCC 2003
* As of 12/31/03

Elkol

Discovered in 1985, Elkol is a small oil field located in T19N, R117W. Elkol produced a small volume of oil and associated gas. Table 4-46 shows the documented production for the field.

Table 4-46. Elkol Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Dakota	1	0	239	248	100
Field Total	1	0	239	248	100

Source: WOGCC 2003
* As of 12/31/03

Lazeart

Also discovered in 1985, Lazeart also is a small oil field. The field generally is located in T21N, R116W, near the town of Kemmerer. Table 4-47 shows the documented production for the field.

Table 4-47. Lazeart Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Frontier - 2	1	0	0	1,358	114
Field Total	1	0	0	1,358	114

Source: WOGCC 2003
* As of 12/31/03

4.4.3 Absaroka Thrust

The planning area portion of the Absaroka Thrust Play contains 16 named fields, including the two largest gas-producing fields in the planning area. Compared to the Green River Basin/Moxa Arch and the Prospect-Darby-Hogsback areas, the Absaroka Thrust Play is relatively recent. The first field, Ryckman Creek, was not discovered until 1976, three-quarters of a century after the first production of oil at Spring Valley and 20 years after the discovery of the Church Buttes Field on the Moxa Arch. Only a few of the fields produce from the Nugget Sandstone, Bighorn Dolomite, and Mission Canyon-Madison. Thirteen different formations produce in this portion of the planning area. Whitney Canyon – Carter Creek produces from nine of these formations. Figure 4-11 shows the general location of the fields. The following sections contain a brief summary of each field.

Ryckman Creek

Discovered in 1976, Ryckman Creek Field, generally is located in T17N, R118W, in the south central portion of the planning area. Ryckman Creek ranks 4th in both gas and oil and natural gas liquids production among the 16 fields in this group. Table 4-48 shows the documented production of the field.

Table 4-48. Ryckman Creek Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Nugget	35	0	462,646,499	33,438,553	31,107,942
Field Total	35	0	462,646,499	33,438,553	31,107,942

Source: WOGCC 2003
* As of 12/31/03

Yellow Creek

Yellow Creek Field was also discovered in 1976. Generally located in T14N, R121W, Yellow Creek is at the southwest edge of the planning area. It places 6th in gas production and 8th in oil and natural gas liquids production among the 16 fields in the planning area portion of the Absaroka Thrust play. Table 4-49 shows the documented production of the field.

Table 4-49. Yellow Creek Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Twin Creek	25	1	24,627,635	2,038,332	964,970
Nugget	2	0	145,159	24,452	11,238
Phosphoria	6	0	37,723,908	707,385	979,409
Weber	1	0	154,836	0	6,317
Field Total	34	1	62,651,528	2,770,169	1,961,934

Source: WOGCC 2003
* As of 12/31/03

Painter Reservoir

Painter Reservoir was discovered in 1977. Generally located in T15N, R119W, Painter Reservoir Field is located between Ryckman Creek and Yellow Creek Fields. Painter Reservoir ranks 3rd in gas production and 2nd in oil and natural gas production among the fields in this group. Table 4-50 shows the documented production of the field.

Table 4-50. Painter Reservoir Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Nugget	44	19	1,177,286,105	65,922,030	47,580,651
Field Total	44	19	1,177,286,105	65,922,030	47,580,651

Source: WOGCC 2003
* As of 12/31/03

Whitney Canyon – Carter Creek

Whitney Canyon – Carter Creek was discovered in 1977. Generally located in T17N, R119W; T18N, R119W; and T19N, R119W, Whitney Canyon – Carter Creek lies along the southwest edge of the planning area between Evanston and Kemmerer. It ranks 1st in gas production and

3rd in oil and natural gas production among the 16 Absaroka Thrust fields. Table 4-51 shows a summary of the field.

Table 4-51. Yellow Creek Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Nugget	1	0	1,038,221	10,450	1,467
Thaynes	2	0	4,962,511	59,451	25,540
Dinwoody	1	0	527,942	36,330	269
Phosphoria	2	2	8,706,005	67,083	10,307
Weber	10	6	8,710,171	110,664	30,302
Amsden	1	0	5,522,656	37,428	0
Mission Canyon	30	23	547,956,549	7,309,458	838,497
Bighorn	10	2	141,666,921	1,874,994	215,530
Commingled Madison-Weber	1	0	334,811	7,362	0
Commingled Pennsylvanian-Triassic	1	1	1,864,960	14,817	0
Field Total	59	34	721,290,747	9,528,037	1,121,912

Source: WOGCC 2003
* As of 12/31/03

Clear Creek

Clear Creek was found in 1979. It generally is located in T16N, R119W, just south of the Whitney Canyon – Carter Creek Field. Clear Creek Field ranks 5th in both gas production and oil and natural gas liquids production. Table 4-52 shows the documented production of the field.

Table 4-52. Clear Creek Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Twin Creek	1	0	55,313	268	0
Nugget	13	1	163,226,474	6,291,322	12,088,213
Field Total	14	1	163,281,787	6,291,590	12,088,213

Source: WOGCC 2003
* As of 12/31/03

Glasscock Hollow

Glasscock Hollow Field was discovered in 1980. It is located generally in T14N, R120W, in the southwest corner of the planning area. Overall, Glasscock Hollow ranks 9th in gas production and 6th in oil and natural gas liquids production among the 16 fields discussed in this section. Table 4-53 shows the documented production of the field.

Table 4-53. Glasscock Hollow Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Nugget	6	3	16,018,170	2,805,166	5,709,907
Field Total	6	3	16,018,170	2,805,166	5,709,907

Source: WOGCC 2003
* As of 12/31/03

Road Hollow

Road Hollow was added in 1981 to the list of Absaroka Thrust fields in the planning area. Road Hollow generally is located in T19N, R119W, near the north end of Whitney Canyon – Carter Creek Field. Road Hollow is the largest of the three, ranking 7th in gas production and 9th in oil and natural gas liquids production among the 16 planning area portion of the Absaroka Thrust fields. Table 4-54 shows the documented production of Road Hollow Field.

Table 4-54. Road Hollow Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Bighorn	7	4	45,960,001	1,784,297	266,487
Field Total	7	4	45,960,001	1,784,297	266,487

Source: WOGCC 2003
* As of 12/31/03

Thomas Canyon

Thomas Canyon was discovered in 1981. It generally is located in T16N, R121W, on the west edge of the planning area. Thomas Canyon ranks last in gas production and last in oil and gas liquids production. Table 4-55 shows the documented production of the field.

Table 4-55. Thomas Canyon Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Bear River	1	0	0	2,382	15,291
Field Total	1	0	0	2,382	15,291

Source: WOGCC 2003
* As of 12/31/03

Woodruff Narrows

Woodruff Narrows was discovered in 1981. It is located in T15N, R120W, southeast of Thomas Canyon Field. Woodruff Narrows ranks 12th in gas production and 14th in oil and natural gas production among the planning area portion of the Absaroka Thrust fields. Table 4-56 shows the documented production of the field.

Table 4-56. Woodruff Narrows Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Bighorn	3	2	3,832,920	21,290	67,634
Field Total	3	2	3,832,920	21,290	67,634

Source: WOGCC 2003
* As of 12/31/03

Anschutz Ranch East

Anschutz Ranch East was discovered in 1982. Generally located in T13N, R121W, Anschutz Ranch East lies in the southwest corner of the planning area. Anschutz Ranch East ranks 8th in both gas production and in oil and natural gas liquids production. Table 4-57 shows the documented production of the field.

Table 4-57. Anschutz Ranch East Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Nugget	9	5	48,940,450	2,416,574	22,265,905
Field Total	9	5	48,940,450	2,416,574	22,265,905

Source: WOGCC 2003
* As of 12/31/03

Shurtleff Creek

Shurtleff Creek was discovered in1982. It generally is located in T17N, R119W. Shurtleff Creek ranks 15th in both gas production and in production of oil and natural gas liquids. Table 4-58 shows the documented production of the field.

Table 4-58. Shurtleff Creek Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Ankareh	1	0	66,142	14,287	808
Field Total	1	0	66,142	14,287	808

Source: WOGCC 2003
* As of 12/31/03

Bessie Bottom

Bessie Bottom Field was found in 1983 in the planning area portion of the Absaroka Thrust play. Generally located in T13N, R120W, Bessie Bottom is in the southwest corner of the planning area. Among the 16 fields in this portion of the play, Bessie Bottom ranks 14th in gas production and 13th in oil and natural gas liquids production. Table 4-59 shows the documented production of the field.

Table 4-59. Bessie Bottom Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Nugget	1	1	1,484,682	152,516	430,917
Field Total	1	1	1,484,682	152,516	430,917

Source: WOGCC 2003
* As of 12/31/03

Chicken Creek

Another field discovered in 1983, Chicken Creek generally is located in T13N, R121W, just west of Bessie Bottom Field. Chicken Creek ranks 11th in gas production and 10th in oil and natural gas liquids production among the 16 fields discussed in this section. Table 4-60 shows the documented production of the field.

Table 4-60. Chicken Creek Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Nugget	5	2	5,652,530	927,529	4,700,355
Field Total	5	2	5,652,530	927,529	4,700,355

Source: WOGCC 2003
* As of 12/31/03

Session Mountain

Session Mountain Field was discovered in 1983. Generally located in T18N, R120W, Session Mountain is on the western edge of the planning area. It ranks 10th in gas production and 12th in oil and natural gas liquids production, Table 4-61 shows the documented production of the field.

Table 4-61. Session Mountain Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Madison	2	1	1,411,168	22,053	12,948
Bighorn	2	1	9,992,146	121,582	0
Commingled Bighorn - Madison	1	1	1,518,884	14,470	979
Field Total	5	3	12,922,198	158,105	13,927

Source: WOGCC 2003
* As of 12/31/03

Painter Reservoir East

Painter Reservoir East was discovered in 1987. The field generally lies in T15N, R119W, adjacent to Painter Reservoir Field. Among the 16 fields in this section, Painter Reservoir East ranks second in gas production and first in oil and natural gas liquids production. Table 4-62 shows the documented production of the field.

Table 4-62. Painter Reservoir East Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Nugget	29	21	1,093,030,917	87,658,448	14,417,091
Field Total	29	21	1,093,030,917	87,658,448	14,417,091

Source: WOGCC 2003
* As of 12/31/03

Collett Creek

The last field discovered in the Absaroka Thrust portion of the planning area is Collett Creek, found in 1989. Collett Creek generally is located in T21N, R118W, and is the northernmost field in the planning area portion of the Absaroka Thrust play. Of the 16 fields discussed in this section, Collett Creek ranks 13th in gas production and 11th in oil and natural gas liquids production. Table 4-63 shows the documented production of the field.

Table 4-63. Collett Creek Field

Producing Formation	Total Completions*	Active Completions*	Gas Produced* Mcf	Oil Produced* Bbls	Water Produced* Bbls
Bighorn	2	2	3,532,447	793,299	42,717
Field Total	2	2	3,532,447	793,299	42,717

Source: WOGCC 2003
* As of 12/31/03

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5.0 ASSESSMENTS OF OIL AND GAS RESOURCES

Oil and natural gas are a significant natural resource. According to the Energy Information Administration's (EIA) most recent annual energy outlook, Annual Energy Outlook (AEO) 2004 (EIA 2004), world demand for oil is projected to increase from 78 MMBbl per day in 2002 to 118 MMBbl per day by 2025. Within the United States, total petroleum demand is expected to increase from 19.6 MMBbl per day in 2002 to 28.3 MMBbl per day in 2025. Similarly, the demand for natural gas is expected to increase from 22.8 Tcf to 31.4 Tcf during the same period. In 2002, oil and gas were used to generate 18.8 percent of the electricity generated in the United States. Besides the obvious uses of oil and gas to generate electricity and provide fuel for transportation, these resources form the basis of the petrochemical industry, which provides countless products ranging from paints to plastics to synthetic fibers to medicines. Most of this demand for oil and natural gas is supplied from outside sources. In 2002, 54 percent of the total U.S. petroleum demand was fulfilled with imported oil. The contribution from foreign sources is expected to increase to 70 percent by 2025.

As a result of this reliance on imported oil, there have been numerous assessments of the nation's oil and gas resources to determine areas of potential growth for the domestic supply. The following sections summarize the results of recent assessments to evaluate oil and gas resources in the Greater Green River Basin and the Overthrust Belt, portions of which lie within the planning area. Section 5.1 includes estimates of total in-place natural gas resources. Since oil is a minor resource in the area compared to natural gas, a recent estimate of total oil resources has not been developed. Section 5.2 summarizes recent estimates for proven oil and gas reserves in the region. Sections 5.3 and 5.4 describe assessments of potential undiscovered petroleum resources prepared by or for the USGS and the DOE, respectively. Since each assessment uses different assumptions and methodologies, the result is a range of estimates for resources within the region and planning area. These estimates are used in Section 7.0 of this report as the basis for projecting future oil and gas activity for the planning area.

5.1 Gas-In-Place Estimates

Gas-in-place estimates indicate the total volume of natural gas thought to exist (both discovered and yet-to-be discovered) within the matrix for a given volume of rock, regardless of whether the recovery of the natural gas is technically or economically feasible. As such, in-place estimates represent an upper limit of the volume of natural gas present in the rocks for which the estimate was prepared.

5.1.1 Scotia Group Assessment

In 1997, the Scotia Group presented a summary of the results of a series of DOE-funded studies in Cretaceous and Tertiary tight gas formations in the Greater Green River Basin, the Piceance Basin, and the Uinta Basin (Scotia Group 1997). The Greater Green River Basin Formations included in the study were the Cloverly-Frontier, Almond, Ericson, Rock Springs, Blair, undifferentiated Mesaverde Group, Lewis, Lance-Fox Hills, and Fort Union. The combined estimated gas-in-place volume for these formations was placed at 1,968 Tcf. Assuming that the gas resources are evenly distributed across the basin, approximately 9 percent or 179 Tcf of gas may be present in these formations within the planning area. Gas-in-place estimates have not been identified for older productive formations present in the planning area or for the portion of the Overthrust Belt that lies within the planning area.

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

In February 2003, DOE's National Energy Technology Laboratory issued the final version of a study titled *Natural Gas Resources of the Greater Green River and Wind River Basins of Wyoming*, an assessment of marginal, subeconomic, and unappraised resources to support DOE's natural gas program planning (DOE 2003). Included in the study is a report by Boswell et al. titled "Assessing the Technology Needs of Unconventional and Marginal Resources, Phase I: The Greater Green and Wind River Basins." This report attempts to provide a better understanding of the size and nature of gas resources in the Greater Green River and Wind River basins of Wyoming and northwestern Colorado. The report is discussed in more detail in Appendix C.

According to the report, portions of five of the seven units of assessment (UOA)—the Almond UOA, Ericson UOA, Lower Mesaverde UOA, Frontier UOA, and the Dakota UOA—fall within the planning area. The Frontier UOA includes all five benches of the Lower Cretaceous Frontier Sandstones and any sandstones that appear within the underlying Mowry Shale. The Dakota UOA includes the Muddy Sandstone, Dakota Sandstone, and sandstones within the Morrison Formation. Nothing older than the Morrison Sandstones was evaluated. The report does not address proven reserves. Total in-place gas resources for the five UOAs is estimated at 3,638 Tcf with 588 Tcf below 15,000 feet. Assuming an even distribution of the resource, the total combined in-place resource within the planning area is estimated to be 137 Tcf of gas, including 46 Tcf of gas below 15,000 feet.

5.2 Proven Oil and Gas Reserves

Each year, the EIA collects information from oil and gas companies on their activities for the previous year, including their estimates of proven oil and gas reserves. The EIA (2003) defines proven reserves as "the estimated quantities which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions." The EIA presents the results of this data collection in an annual report. The report summarizes results by state or region. The most recent report available is for 2004.

For the year ending December 31, 2002, estimated total proven oil reserves in the United States were 22,677 MMBbl; natural gas reserves were estimated at 186,946 Bcf; and natural gas liquids reserves were estimated to be 7,994 MMBbl. Wyoming's contribution to the totals included 524 MMBbl of oil; 20,527 Bcf of dry gas (including 2,371 Bcf of CBNG); and 938 MMBbl of natural gas liquids (Wyoming and Utah combined). Wyoming accounts for approximately 11 percent of the U.S. natural gas reserves. Fifteen of the top 100 gas fields are found in Wyoming. Of the 15 fields, 11 are in the Greater Green River Basin and 1 is in the Overthrust Belt. One Green River Basin field (Bruff) and one Overthrust field (Whitney Canyon – Carter Creek) are in the planning area.

In January 2003, the Departments of the Interior, Energy, and Agriculture jointly issued a report titled *Scientific Inventory of Onshore Federal Lands' Oil and Gas Resources and Reserves and the Extent and Nature of Restrictions or Impediments to their Development* (DOI et al. 2003) to comply with Section 604 of the EPCA Amendments of 2000. This report covers proven reserves of crude oil, natural gas, and natural gas liquids (NGLs) in the Paradox/San Juan, Uinta/Piceance, Greater Green River, and Powder River basins, as well as the Montana Thrust Belt. In *Table 2b, Proven Reserves Summary Statistics, 2001*, estimated total liquid reserves (oil and NGLs) for the Greater Green River Basin are listed as 177,362,000 barrels and estimated total gas reserves are listed as 12,703,038 million cubic feet (MMcf). Of these volumes, 122,234,000 barrels of liquid reserves and 10,081,667 MMcf of gas are estimated to be on federal land. Approximately 9 percent of the Greater Green River Basin lies within the planning area. Assuming an even distribution of reserves across the basin (a necessary simplifying assumption for this document), the planning area contains an estimated 16,087,000 barrels of proven liquid reserves and 1,152,166 MMcf of proven natural gas reserves.

5.3 U.S. Geological Survey Resource Assessments

The USGS has performed numerous assessments of various types of mineral resources over the years. In 1995, the results of a nationwide assessment of undiscovered oil and gas resources was published in the report, *1995 National Assessment of the United States Oil and Gas Resources*—results, methodology, and supporting data (Law 1995). This report divided the United States into 71 provinces and developed estimates of potential oil and gas resources for each province. Parts of two of these provinces, the Wyoming Thrust Belt Province and the Southwestern Wyoming Province, fall within the boundaries of the planning area. In response to the EPCA, the Southwestern Wyoming Province was reevaluated and a summary of the results was published in 2002. In February 2004, the USGS released a summary of its reevaluation of the Wyoming Thrust Belt Province. Sections 5.3.1 through 5.3.4 provide a brief summary of these assessments. Appendix B discusses the assessments in more detail.

5.3.1 1995 Assessment – Wyoming Thrust Belt Province

In the 1995 assessment, each province was subdivided into groups of accumulations or "plays" based on common characteristics of geology, occurrence, and geography. Six plays were identified and assessed in the Wyoming Thrust Belt Province. Portions of all six of these plays fall within the planning area. Total undiscovered liquid (oil and NGL) resource quantities for the province were estimated to range from 170 MMBbl (95% confidence level) to as high as 3,143 MMBbl (5% confidence level) with a mean of 1,692 MMBbl. The USGS estimated total undiscovered natural gas resources to be within a range of 1,128 Bcf (95% confidence level) to 19,480 Bcf (5% confidence level), with a median of 10,063 Bcf. If the accumulations within each play are spread equally throughout the play, then the total estimated undiscovered liquid resource quantities range from 70 MMBbl to 1,379 MMBbl, with a mean of 766 MMBbl within the planning area. Similarly, total undiscovered gas accumulations within the planning area are estimated to range from 386 Bcf to 7,008 Bcf, with a mean of 3,721 Bcf. The breakdown by play is shown in Tables B 2-1 and B 2-2 in Appendix B.

5.3.2 1995 Assessment – Southwestern Wyoming Province

Of the plays evaluated in the Southwestern Wyoming Province, which includes the Greater Green River Basin, four extended into the planning area. Two of the plays were conventional plays; the other two were classified as unconventional, one being a basin-centered gas play and the other a CBNG play. Additional discussion of these plays can be found in Appendix B. The total estimated undiscovered resources attributable to these plays ranged from 174 MMBbl of liquids (95% confidence level) to 1,386 MMBbl (5% confidence level) with a mean of 602 MMBbl. Total estimated natural gas resources for these four plays ranged from 11,354 Bcf at the 95 percent confidence level to 87,091 Bcf at the 5 percent confidence level, with a mean estimate of 38,143 Bcf. Within the planning area, the total estimated liquid resources attributable to these plays ranged from 27 MMBbl (95% confidence level) to 230 MMBbl at the 5 percent confidence level, with a mean of 99 MMBbl. Total estimated natural gas resources within the planning area ranged from 1,656 Bcf at the 95 percent confidence level to 12,803 Bcf (5% confidence level) with a mean of 5,629 Bcf. The breakdown by play is shown in Tables B 3-1 and B 3-2 in Appendix B.

5.3.3 2002 Assessment – Southwestern Wyoming Province

A different approach was taken regarding the grouping of productive horizons in the 2002 update to the Southwestern Wyoming Province. Instead of grouping resources by "play," the concept of total petroleum systems, subdivided into assessment units, including both source and reservoir rocks, was used. Basin-centered gas accumulations, known as continuous accumulations, also played a larger part in the estimate. As of April 2004, the supporting geologic studies had not been released, but a summary of the results is now available in USGS Fact Sheet FS-145-02, dated November 2002, and available on the Internet at http://energy.cr.usgs.gov/oilgas/noga/.

Nine assessment units, one of which was not quantitatively assessed, are partially located within the planning area. Total estimated undiscovered petroleum liquids (oil and natural gas liquids) for the nine assessment units range from 749 MMBbl (95% confidence level) to 3,046 MMBbl (5% confidence level) with a mean of 1,610 MMBbl. Total estimated undiscovered natural gas quantities range from 20,951 Bcf (95% confidence level) to 60,212 Bcf (5% confidence level) with a mean of 36,880 Bcf. Within the planning area, petroleum liquid resources are estimated at 62 MMBbl (95% confidence level) to 258 MMBbl (5% confidence level), with a mean of 133 MMBbl. Estimated undiscovered natural gas resources range from 2,011 Bcf (95% confidence level) to 5,527 Bcf, with a mean of 3,444 Bcf. Additional details on estimated resources by assessment unit are included in Table B 4-1 in Appendix B.

5.3.4 2003 Assessment – Wyoming Thrust Belt Province

In February 2004, the USGS released a fact sheet summarizing its reevaluation of the Wyoming Thrust Belt Province. Like the 2002 reevaluation of the Southwestern Wyoming Province, the concept of total petroleum systems was used. As of September 2004, the supporting geologic studies had not been released, but a summary of the results now is now available in USGS Fact Sheet FS-2004-3025, dated February 2004, on the Internet at http://pubs.usgs.gov/fs/2004/3025/.

The reevaluation simplified the assessment area to two total petroleum systems, each containing one assessment unit. Total estimated undiscovered petroleum liquids (oil and natural gas liquids) for the two assessment units range from 22 MMBbl (95% confidence level) to 211 MMBbl (5% confidence level) with a mean of 96 MMBbl. Total estimated undiscovered natural gas quantities range from 283 Bcf (95% confidence level) to 1,875 Bcf (5% confidence level) with a mean of 918 Bcf. This reevaluation represents a significant reduction in estimated undiscovered reserves. Since the acreages associated with each system were not available, an estimate of undiscovered reserves within the planning area could not be made, but it can be assumed that there is a similar reduction in estimated reserves.

5.4 Department of Energy-Sponsored Resource Assessments

In recent years, the DOE has sponsored three natural gas resource assessments of the Greater Green River Basin area. Sections 5.4.1 through 5.4.3 provide a brief discussion of the results of each of these assessments.

5.4.1 Scotia Group Assessment

In addition to determining estimated gas-in-place, the Scotia Group study in 1997 developed estimates of potentially recoverable gas reserves. For the Greater Green River Basin, that assessment placed potentially recoverable reserves at 33, 600 Bcf of gas. If 9 percent of the total reserves is present within the planning area, assuming an even distribution of reserves throughout the basin, then the estimated potentially recoverable gas is 3,024 Bcf of gas in the Cretaceous and Tertiary reservoirs within the study area.

5.4.2 Advanced Resources International Assessment

In May 2001, Advanced Resources International, Inc. (ARI), issued a report on the DOE-sponsored study of the natural gas resources on federal lands in southern Wyoming and northwestern Colorado. In addition to determining the potential technically recoverable gas resources of the area, the study also evaluated the impact of various lease restrictions or stipulations on those resources.

Within the whole study area, ARI estimated total technically recoverable natural gas resources to be approximately 160 Tcf. For the 10 plays that at least partially fall within the planning area—3601, 3602, 3603, 3604, 3606, 3607, 3704, 3705, 3740, and 3755—ARI estimated the total technically recoverable gas resources to be approximately 35 Tcf. Assuming an even distribution of resources within each play, the total technically recoverable gas resources within the planning area are estimated to be 7,442 Bcf. Compared to the USGS 1995 estimate of 9,350 Bcf of gas, the ARI estimate is lower by 1,908 Bcf. The difference can be attributed to a difference in the estimates for Play 3740, the Cloverly-Frontier Continuous Gas Play, which the USGS estimated at 37,251 Bcf for the play (5,398 Bcf within the planning area), versus ARI's estimate of 24, 074 Bcf (3,489 Bcf within the planning area) for the same area.

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

In addition to estimating gas resource in-place, Boswell et al. (DOE 2003) estimated technically recoverable and economically recoverable resources for the Greater Green River and Wind River basins. In Table 8 of that report, technically recoverable gas reserves for the Frontier UOA in the Greater Green River Basin is estimated at 59 Tcf of gas, while the Dakota UOA contains an estimated 37 Tcf of gas. The portion of these reserves that lies within the planning area is estimated to be 7.1 Tcf and 4.2 Tcf for the Frontier and Dakota UOAs, respectively. The economically recoverable gas reserves, assuming a gas price of $3.50 per thousand cubic feet (Mcf), are estimated to be less than 1 Tcf in the Frontier UOA and only 1 Tcf in the Dakota UOA.

5.5 Summary

Resource estimates from several sources are presented in the preceding sections. Table 5-1 presents a comparison of resource estimates. Each agency or group used different approaches to arrive at their conclusions, using different assumptions and methodologies. The result is a range of estimates for in-place, proven, or potentially productive resources.

Table 5-1. Comparison of Resource Estimates

Study	Greater Green River Basin				Overthrust Belt				Comments
	Total	Units	Planning Area	Units	Total	Units	Planning Area	Units	
Estimate of Gas in Place									
Scotia Group - 1997	1,968,000	Bcf	179,000	Bcf	N/A		N/A		Upper Cretaceous and Younger Rocks only
EG&G/ARI - 2003	3,638,000	Bcf	136,801	Bcf	N/A		N/A		
Proven Reserves									
EPCA - 2003	12,703	Bcf	1,152	Bcf	N/A		N/A		
Undiscovered Potential									
USGS - 1995	11,354	Bcf	1,656	Bcf	1,128	Bcf	386	Bcf	95% Confidence Limit
USGS - 1995	87,091	Bcf	12,803	Bcf	19,480	Bcf	7,008	Bcf	5% Confidence Limit
USGS - 1995	38,143	Bcf	5,629	Bcf	10,063	Bcf	3,721	Bcf	Mean
USGS - 1995	174	MMBbl	27	MMBbl	170	MMBbl	70	MMBbl	95% Confidence Limit
USGS - 1995	1,386	MMBbl	230	MMBbl	3,143	MMBbl	1,379	MMBbl	5% Confidence Limit
USGS - 1995	602	MMBbl	99	MMBbl	1,692	MMBbl	766	MMBbl	Mean
USGS - 2002	20,408	Bcf	1,931	Bcf	N/A		N/A		95% Confidence Limit
USGS - 2002	58,667	Bcf	5,285	Bcf	N/A		N/A		5% Confidence Limit
USGS - 2002	35,937	Bcf	3,296	Bcf	N/A		N/A		Mean
USGS - 2002	745	MMBbl	63	MMBbl	N/A		N/A		95% Confidence Limit
USGS - 2002	3,003	MMBbl	252	MMBbl	N/A		N/A		5% Confidence Limit
USGS - 2002	1,625	MMBbl	137	MMBbl	N/A		N/A		Mean
USGS - 2003	N/A		N/A		283	Bcf	**	Bcf	95% Confidence Limit
USGS - 2003	N/A		N/A		1,875	Bcf	**	Bcf	5% Confidence Limit
USGS - 2003	N/A		N/A		918	Bcf	**	Bcf	Mean
USGS - 2003	N/A		N/A		22	MMBbl	**	MMBbl	95% Confidence Limit
USGS - 2003	N/A		N/A		211	MMBbl	**	MMBbl	5% Confidence Limit
USGS - 2003	N/A		N/A		96	MMBbl	**	MMBbl	Mean
Scotia Group - 1997	33,600	Bcf	3,024	Bcf	N/A		N/A		
ARI - 2001	35,000	Bcf	7,442	Bcf	N/A		N/A		
EG&G/ARI - 2003	363,000	Bcf	14,292	Bcf	N/A		N/A		Technically recoverable

ARI Advanced Resources International, Inc.
Bcf billion cubic feet
EPCA Energy Policy and Conservation Act
N/A Not applicable
MMBbl million barrels
USGS United States Geological Survey

6.0 OIL AND GAS OCCURRENCE POTENTIAL ACCORDING TO USGS ESTIMATES

The information collected concludes that portions of the planning area have a high potential for the occurrence of economic concentrations of oil and gas. This assumption is based on the USGS's determination that oil and gas play areas and assessment units are considered to have high occurrence potential. Portions of the planning area with no identified oil and gas play areas or assessment units are considered to have a low development potential. Some portions of the planning area may contain resources from multiple plays or assessment units, making them more attractive for exploration and development. Figure 6-1 shows the estimated undiscovered, technically recoverable natural gas resource by township within the planning area. The resource estimate does not include proven resources.

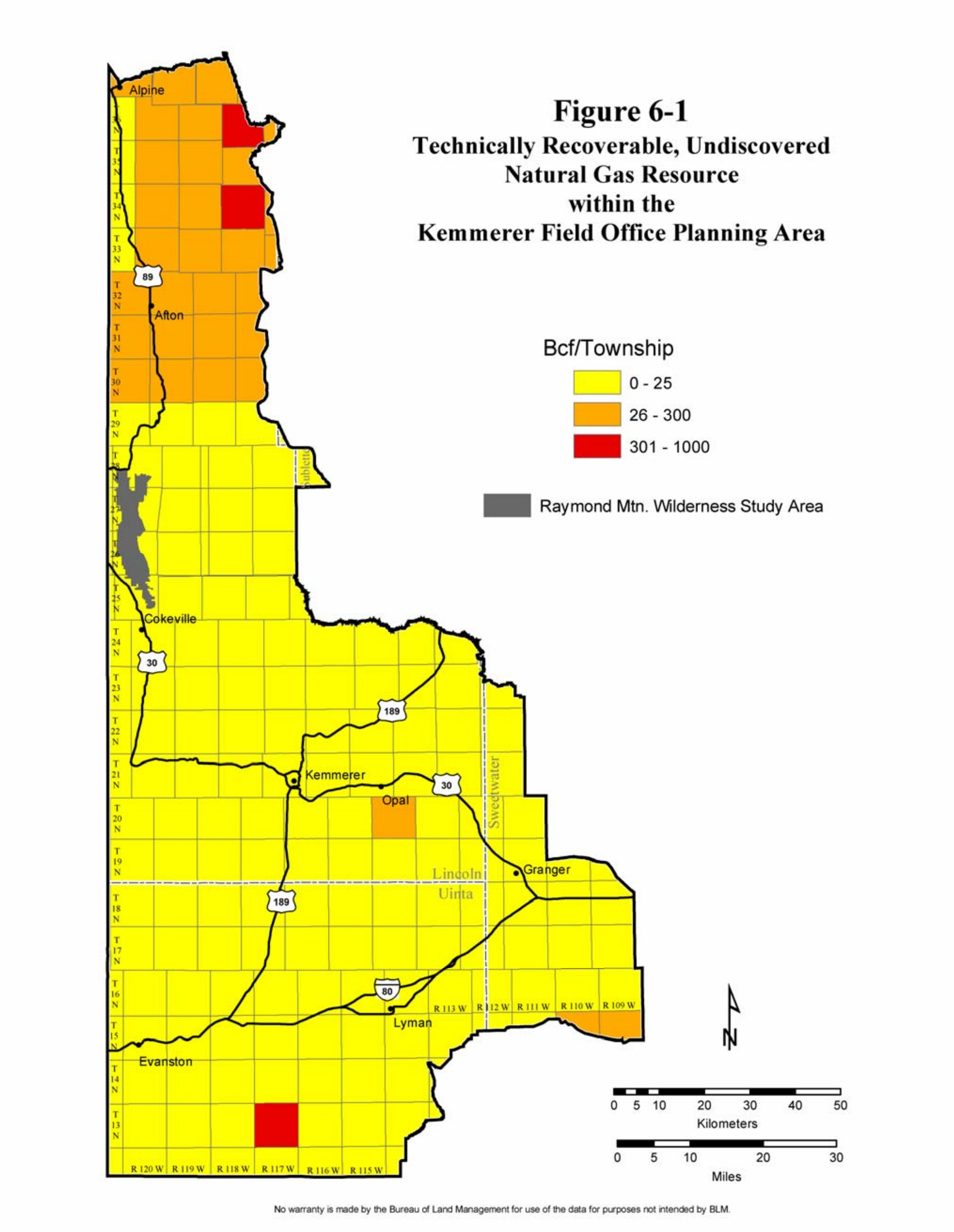


Figure 6-1
Technically Recoverable, Undiscovered
Natural Gas Resource
within the
Kemmerer Field Office Planning Area
Bcf/Township
0 - 25
26 - 300
301 - 1000
Raymond Mtn. Wilderness Study Area
Alpine
Afton
Cokeville
Kemmerer
Opal
Granger
Lyman
Evanston
Sublette
Sweetwater
Lincoln
Uinta
89
30
189
80
R 120 W
R 119 W
R 118 W
R 117 W
R 116 W
R 115 W
R 113 W
R 112 W
R 111 W
R 110 W
R 109 W
0 5 10 20 30 40 50
Kilometers
0 5 10 20 30
Miles
No warranty is made by the Bureau of Land Management for use of the data for purposes not intended by BLM.

7.0 PROJECTIONS OF FUTURE ACTIVITY, 2001 – 2020

7.1 Oil and Gas Price Estimates

The EIA's AEO projected average oil prices to decrease from $23.75 per barrel (2002 dollars) in October 2003 to $23.61 in 2010, and then increase to $26.72 per barrel in 2025 (EIA 2003).

After 2002, natural gas prices were projected to move higher as technology improvements became inadequate to offset the impacts of resource depletion and increased demand (EIA 2003). Natural gas prices were projected to increase in an uneven fashion, as higher prices allowed the introduction of major new, larger-volume natural gas projects that temporarily depress prices when initially brought on-line. In 2003, EIA projected prices to reach about $3.70 per Mcf by 2020 and $3.90 per Mcf by 2025 (EIA 2003). At $3.70 per Mcf, the 2020 wellhead natural gas price in the AEO 2003 projection was more than 35 cents higher than the AEO 2002 projection. This was due to a reduction in estimates of the potential for inferred natural gas reserve appreciation, and a reduced expectation for technology improvement over time. As demand for gas increases, technology improvements were not expected to completely offset the effects of resource depletion (EIA 2003).

Geopolitical factors and natural catastophes in oil rich and refinery process areas of the world have been shown to cause unpredictable spikes in the cost of a barrel of oil due to disruptions in supply. No attempt is made here to predict the effects of these factors, which will undoubtedly influence the price of crude oil and natural gas. The sources utilized to predict the cost of oil in the future are conservative in this respect. For example, the price of a barrel of oil could be three to four times or more higher than predicted by EIA's estimate during the 20-year planning period, but no reliable estimates have been made in the literature to predict these trends influenced by geopolitical forces.

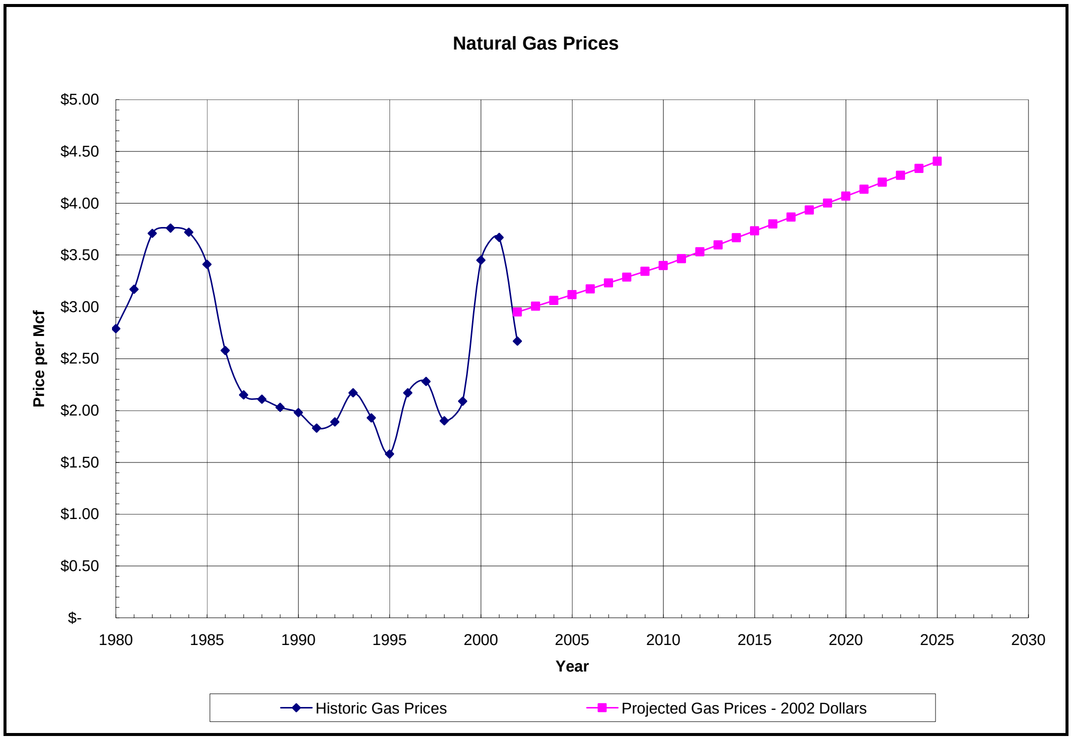
Further, it should be assumed that the price of commodity will influence the drilling activity in the planning area. As the price of oil and gas rises in the market, the drilling activity in the planning area will increase proportionally. Increases in drilling activity cannot be predicted within this analysis from factors related to economics or disruptions of imported supplies.

Oil and natural gas prices are volatile. Figures 7-1 and 7-2 show price fluctuation since the 1980s, as well as provide estimates of potential future highs and lows. These projections were prepared for the BLM's Pinedale Planning Area (BLM 2003).

7.2 Leasing

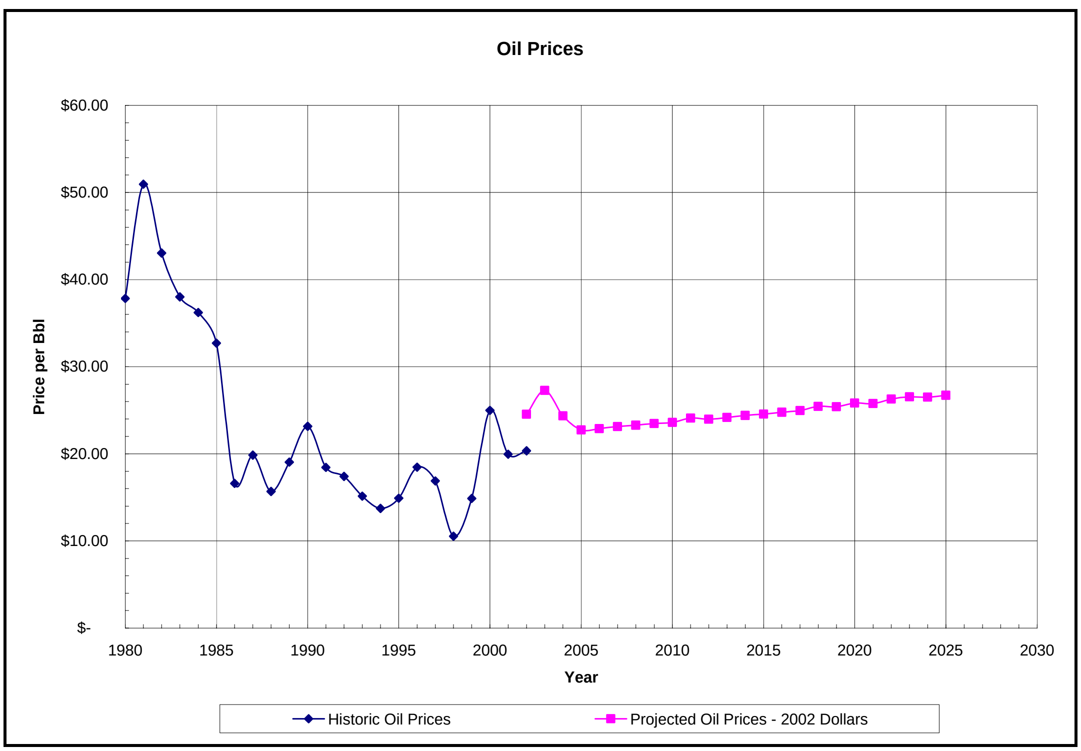
Once a company has identified an area that it wants to explore for oil and gas, it must acquire leases allowing the company access to the land.Where the federal government owns the oil and gas rights, the leases are offered for bid on at least a quarterly basis via oral auction. The maximum lease size is 2,560 acres and the minimum allowable bid is $2.00 per acre. An administrative fee also must be paid, and the successful bidder must meet certain citizenship and legal requirements. In addition to the lease bid, or bonus payment, an annual rental of $1.50 per acre must be paid for each of the first 5 years, with an annual rental of $2.00 per acre due for the next five years. Leases are issued for a 10-year period. If oil or gas production is established on the lease, the lease is considered to be "held by production," and the lease does not expire until the last well ceases production. A 12.5-percent royalty fee must be paid on all production from federal leases. Each new lease contains restrictions, or stipulations, designed to protect potentially sensitive resource values, primarily surface resources such as wildlife or water.

Figure 7-1. Natural Gas Prices



Source: BLM 2003

Figure 7-2. Oil Prices



Source: BLM 2003

In Wyoming, lease auctions are held bimonthly on the even numbered months. Since August 1996, only lands nominated by industry are offered for lease. Prior to that date, all federal lands available for competitive leasing were offered to industry at each sale. Table 7-1 depicts leasing activity for federal acreage from 1996 through 2002.

Table 7-1. Leasing Activity

Year	Leased (thousand acres)	Not Leased (thousand acres)	Offered (thousand acres)	Bonus ($)	Average Bid ($)
1996	38	46	84	780,824	20.59
1997	42	39	80	2,173,340	52.31
1998	120	39	160	2,167,104	13.57
1999	25	7	31	150,101	4.79
2000	87	12	100	1,286,947	12.93
2001	116	9	126	1,666,274	13.27
2002	74	28	101	328,185	3.23

Source: RMG 2003

Through the end of 2002, there were 3,817 federal oil and gas leases covering 991,705 acres in the planning area. This represents approximately 69 percent of the total federal acreage and approximately 25 percent of the 3,951,599 acres in the planning area. Of the approximately 1.6 million mineral acres managed by the BLM, 949,660 acres (or 5%) are leased for oil and gas exploration or held by production.

Figure 7-3 shows a summary of leasing activity for federal acreage from 1996 through 2002. As seen in the graph, since 1999, the majority of the acreage offered each year has been leased. This is due, in part, to the industry's being more selective about the acreage nominated for bid. Because leases may be nominated again after the previous lease expires, the amount of acreage to be leased during the period 2004 to 2024 is expected to remain between 75,000 and 125,000 acres per year, with total acreage leased or held by production ranging between 750,000 and 125,000 during the period.

Figure 7-4 shows the total bonus received each year from lease sales and the average bid per acre from 1996 through 2002. The average bonus per year for the period was $1.2 million dollars, and the average price per acre was $17.24. Assuming bid prices will remain at approximately $17 per acre, income from lease sales should range from $1.3 million to $2.1 million per year for the period 2004 to 2024. Major factors that might impact this projection are natural gas prices, exploration successes, technology improvements, lease stipulations, and the amount of acreage available for leasing.

7.3 Geophysical Activity

Reflection seismic prospecting is the most common indirect method for locating subsurface structures that may contain hydrocarbons. Using one of several types of energy sources at regularly spaced stations (known as source or shot points) along a line of interest or seismic line, shock waves are generated. As the waves travel downward and outward from the energy source, a portion of the energy is reflected back to the surface from the interface between individual rock layers when there is a significant difference in the velocities at which the energy is transmitted through the layers.

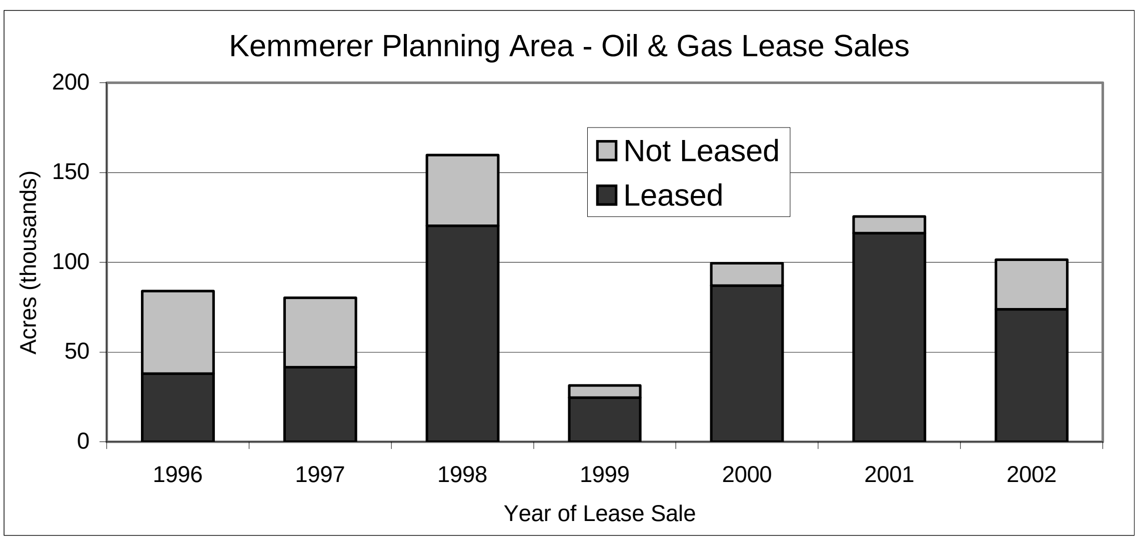
These differences typically occur at significant lithology changes, such as going from sandstone to shale. The reflected energy is measured at the surface and the data are processed to generate a seismic section that can be interpreted to determine the rock sequence and subsurface structures. Early seismic work generated a series of two-dimensional "slices" through the area of interest. With the advent of faster and more powerful computers capable of handling more data, exploration companies are collecting more data more closely spaced to develop three-dimensional models of the subsurface. Figure 7-5 and Table 7-2 show the exploration seismic activity from 1998 through 2003 in the planning area. Future activity is expected to remain at these levels with an increasing emphasis on three-dimensional work.

7.4 Drilling and Completion Cost

The drilling and completion sequence for the targeted reservoir in the planning area generally involves the following:

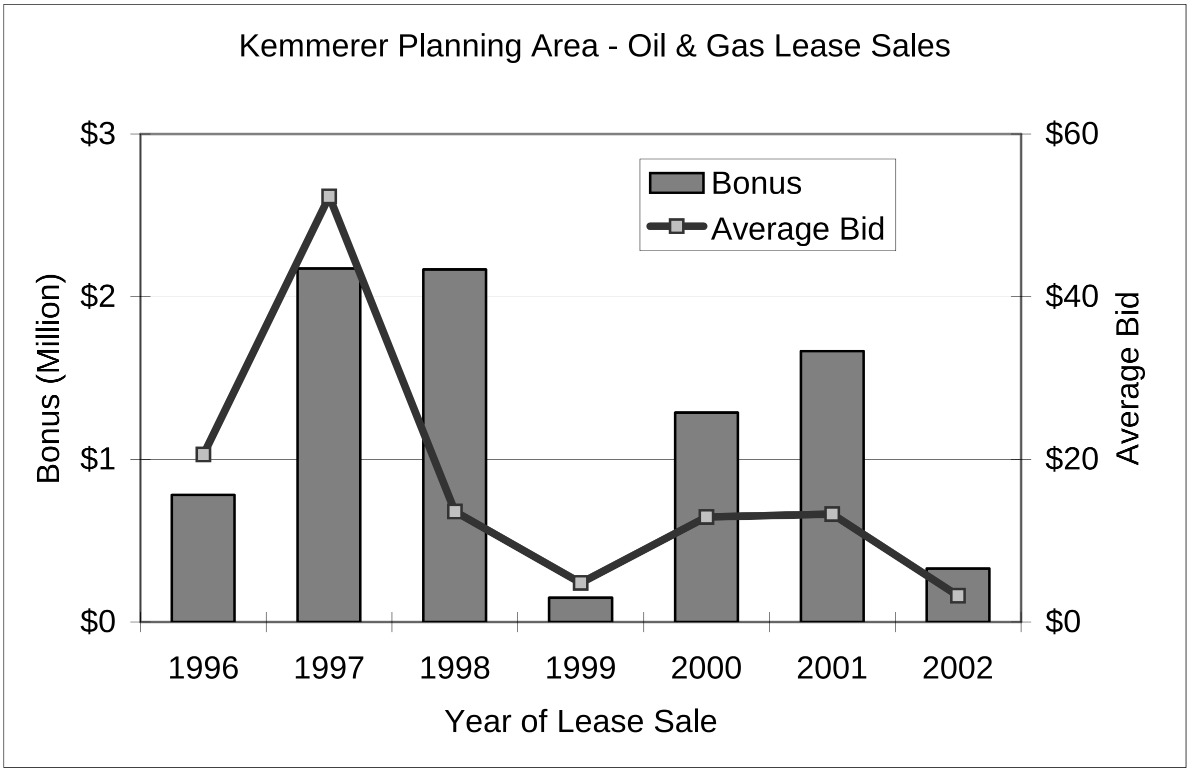
- Using rotary equipment, hardened drill bits, drill pipe/collars, and drilling fluids to cool and lubricate, which all result in easier penetration of the earth's surface
- Inserting casing and tubing into each well to protect the subsurface and control the flow of fluids (oil, gas, and water) from the reservoir
- Perforating the well casing at the depth of the producing formation to allow flow of fluids from the formation into the borehole
- Installing a wellhead at the surface to regulate and monitor fluid flow and prevent potentially dangerous blowouts.

Figure 7-3. Comparison of Total Offered Federal Acreage vs. Acreage Leased for Kemmerer Planning Area



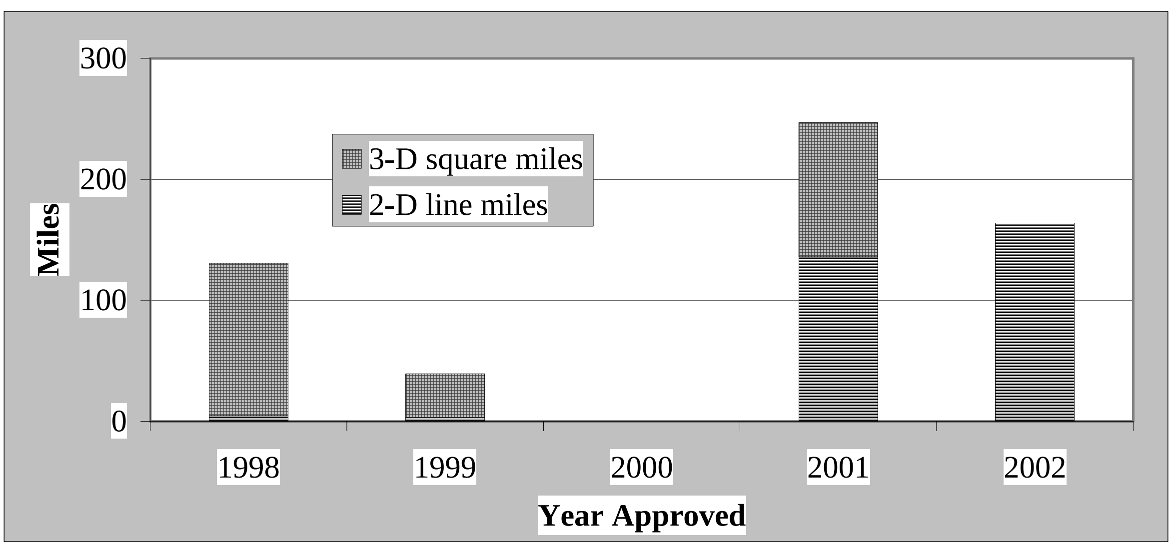
Source: RMG 2003

Figure 7-4. Total Bonuses Received and Average Bid Per Acre for Kemmerer Planning Area



Source: RMG 2003

Figure 7-5. Seismic Projects in the Kemmerer Planning Area



Source: RMG 2003

Table 7-2. Kemmerer Planning Area Notices of Intent for Seismic Lines

Year	2-D line miles	3-D square miles	Surveys
1998	4.8	126	3
1999	3.25	36	2
2000	0	0	0
2001	136	111	4
2002	163.93	-	1

Source: RMG 2003

Drilling improvements have occurred in new rotary rig types, coiled tubing, drilling fluids, and borehole condition monitoring during the drilling operations. Technology now allows the use of directional and horizontal drilling in many applications. New bit types have boosted drilling productivity and efficiency. New casing designs have reduced the number of casing strings required. Table 7-3 is a break down of drilling and completion costs with the number of days required to drill and to complete each type of well. Tangible drilling costs are a smaller portion of the normal completion cost because across-the-basin production casing is cemented in the well and unrecoverable during plugging operations. This limits tangible costs to tubing and removable downhole equipment and surface production equipment that can be salvaged for a new location or sold to other operators. Intangible costs would involve most drilling costs and equipment and services that have no continued salvaged value at the completion of the project. This information was assembled from operator interviews in the planning area.

Table 7-3. Drilling and Completion Costs

Assumption	Conventional Wells		Coalbed Natural Gas Wells
	Moxa Arch	Overthrust Belt	
Drilling Costs			
($/well)	$549,000	$2,429,000	$50,000
Completion Costs			
($/well)	$256,000	$1,059,000	$40,000

Source: Drilling and completion costs are from BLM 2004a, adjusted from 2003 to 2004 dollars using IMPLAN adjustment factors. Moxa Arch well costs correspond to 9,000- to 10,000-foot Frontier wells, and Overthrust Belt well costs correspond to a weighted average of 12,000-foot Frontier wells (70%) and 15,000- 16,000-foot Dakota/Frontier wells (30%). Local drilling and completion costs are calculated using data provided by Taylor (2004).

The cost to drill and complete wells varies with the size of the company doing the work. Major oil companies tend to spend more than medium-sized, independent or small private oil companies. In addition, the cost to drill and complete will limit a company's participation in a particular play because of a smaller drilling budget. The more expensive wells tend to be drilled by companies with larger drilling budgets; because of this, some deeper plays are not viable for all development or exploration plans. The many producing zones, from shallow to deep, make the Green River Basin attractive to a variety of operators. The controlling factor for future oil and gas drilling and production activity in the planning area will be long-term oil and gas prices.

7.5 Drilling Activity

The following subsections describe projected drilling activity within the planning area. Section 7.5.1 explains the methods used to project future drilling activity. Sections 7.5.2 and 7.5.3 describe projected drilling activity for conventional oil and gas resources and CBNG, respectively, while Section 7.5.4 deals with other unconventional gas resources.

7.5.1 Methods Used to Project Future Drilling Activity

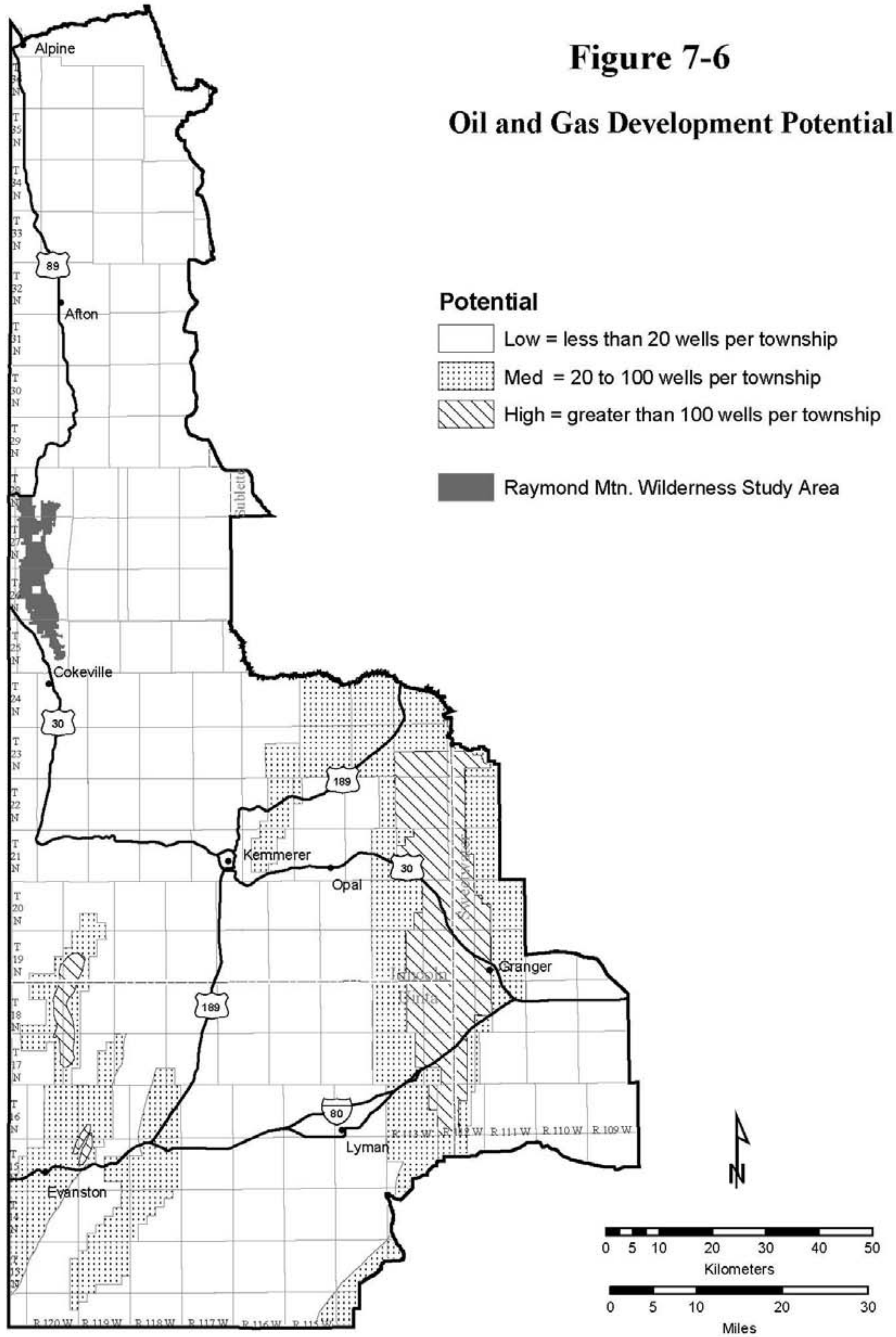
It is very difficult to predict what may occur in the next few years and much more difficult to predict as much as 20 years ahead. The oil and gas RFD scenario for the planning area is based on information received from oil and gas operators and the evaluation of exploration and development trends by the Kemmerer Field Office oil and gas engineer and geologists.

This unconstrained estimate of oil and gas activity covers the 20-year planning cycle of the Kemmerer Resource Management Plan currently under revision. Between 2001 and 2020, an estimated 2,680 new wells may be drilled within the planning area. Approximately 75 percent of these wells will be conventional oil and gas wells and 25 percent will be CBNG wells. Figure 7-6 shows the estimated non-coalbed oil and gas development potential in wells per township for the planning area. Figure 7-7 shows the estimated CBNG development potential.

Areas with high development potential are those areas where the average drilling density is expected to be greater than 100 wells per township (36-square miles) during the planning cycle. Moderate development potential is a density of 20 to 100 new wells per township, low is defined as fewer than 20 wells per township, and very low is defined as fewer than 2 wells per township. In areas estimated as not having development potential, wells are not anticipated. Well depths for conventional wells probably will continue to increase slightly as deeper reservoirs are developed. As many as 10 percent of the new wells may be deep wells, drilled to depths of 15,000 feet or greater.

7.5.2 Projected Oil and Gas Drilling

The majority of the anticipated conventional oil and gas drilling activity will be infill wells in the fields on the Moxa Arch in the Green River Basin. Over the past few years, oil and gas operators have been successful in drilling infill wells on 80-acre spacing in some portions of the Moxa Arch. Additional exploration and infill wells also are anticipated in the Overthrust Belt region. Table 7-4 shows a range of estimated well numbers for each geologic play.



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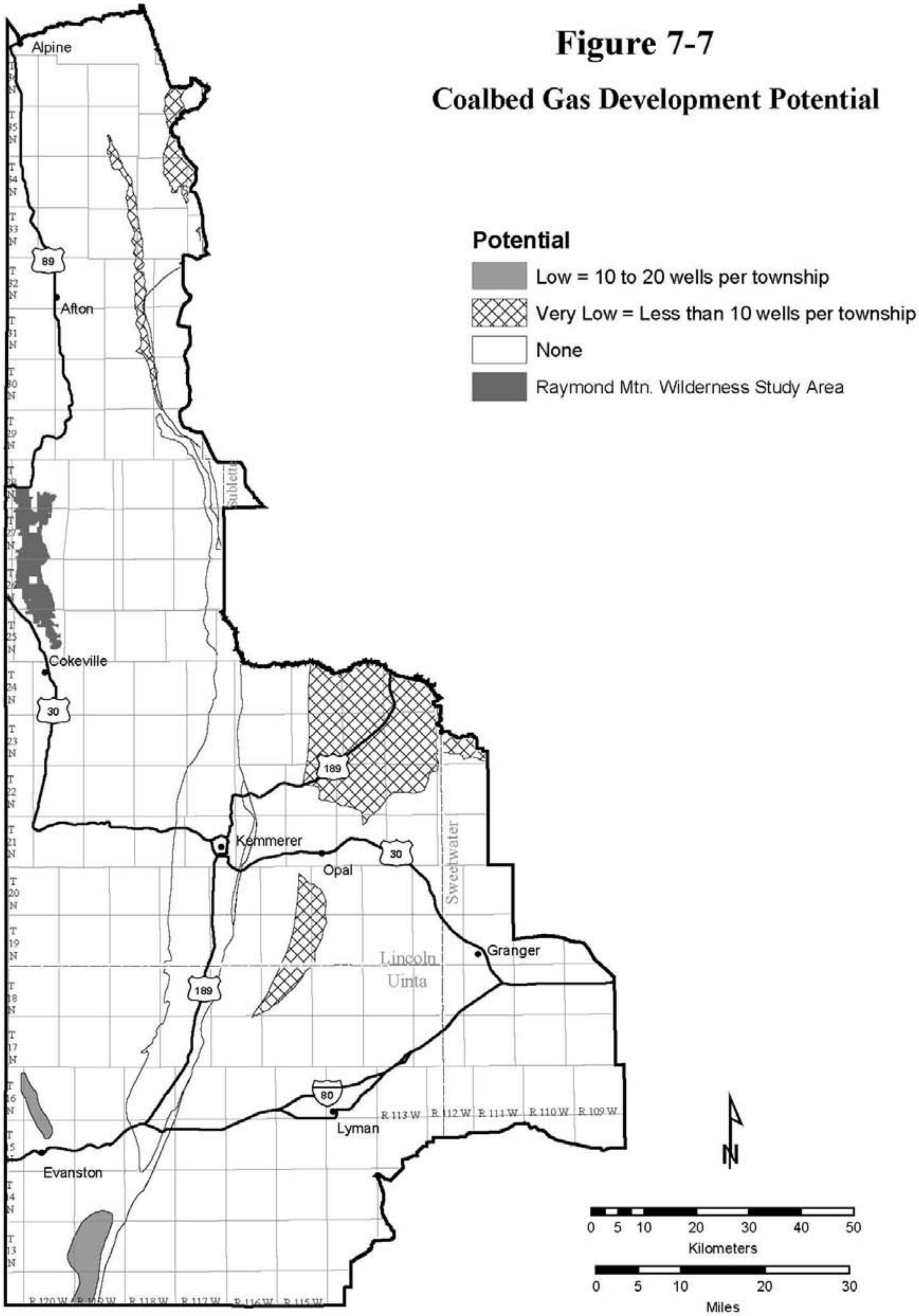

No warranty is made by the Bureau of Land Management for use of the data for purposes not intended by BLM.

Table 7-4. Kemmerer Planning Area Conventional Oil and Gas Wells Well Number Estimates by Geologic Play

Geologic Play	Wells
Green River Basin (Moxa Arch)	1,740
Absaroka Thrust	160
Prospect-Darby-Hogsback Thrust	100
Crawford-Meade Thrust	20
Cretaceous Stratigraphic	20
Total Wells	2,040

Sources: BLM 2006b; RMG 2003

The Moxa Arch/Green River Basin geologic play estimate is based on the “proven production” and “flank” areas shown in Figure 2-1 in the Moxa Arch Draft EIS. The Moxa Arch EIS analyzed an average of 2 wells per section in the “flank” area; that well spacing also was used in the current estimate. However, recent drilling down to 80-acre spacing or 8 wells per section has occurred over the past few years in some portions of the “proven production” area. In the future, the well spacing is expected to range from 4 to 12 wells per section, with an average of 6 wells per section, resulting in an additional 760 new wells drilled in the “proven production” area that were not analyzed in the Moxa Arch EIS. It is estimated that 1,740 new wells could be drilled in the Moxa Arch/Green River Basin during the 20-year planning period.

The Absaroka Thrust geologic play estimate is based on 20 exploratory and 140 development wells, for a total of 160 new wells.

The Prospect-Darby-Hogsback Thrust geologic play estimate is based on 20 exploratory wells and 60 development wells outside of the current exploration and development area. The 60 development well estimate is based on 6 new fields with an average of 10 wells per field. In addition, another 20 development wells could be drilled in the current exploration and development area; therefore, 100 new wells could be drilled in the Prospect-Darby-Hogsback Thrust geologic play.

The Crawford-Meade Thrust geologic play and the Cretaceous Stratigraphic geologic play estimates are based on 20 new exploratory wells being drilled in each geologic play.

7.5.3 Projected Coalbed Natural Gas Drilling

CBNG has become a significant portion of natural gas exploration and development in Wyoming. In 2002 (EIA 2003), the estimated total proven reserves of CBNG were 2,371 Bcf, or 11.6 percent of the estimated total proven reserves of dry gas for the state. CBNG makes up an even larger share of the production. Of the 1,388 Bcf of gas produced in 2002, 302 Bcf, or 21.8 percent, was CBNG.

In the Assessment of Undiscovered Oil and Gas Resources of the Southwestern Wyoming Province (USGS 2002), the USGS identified one CBNG assessment unit that extended into the planning area—the Fort Union coalbed natural gas unit (AU682), as shown in Figure B 4-8 (in Appendix B). A second and perhaps more significant CBNG unit has been identified in the Wyoming Thrust Belt Province—the Frontier-Adaville-Evanston coalbed natural gas unit (AU360281), as shown in Figure B 2-8. As shown in Table B 4-1, estimated resource quantities for the Fort Union Coalbed assessment unit within the planning area range from 86 Bcf (95% confidence level) to as much as 266 Bcf (5% confidence), with a mean of 160 Bcf of gas. Resource estimates for the Frontier-Adaville-Evanston Coalbed natural gas unit have not been released to date.

CBNG development is in its infancy in the planning area, with only 11 wells drilled and 2 wells no longer producing, with a cumulative production of 5,591 Mcf of gas and 202,990 barrels of water as of October 31, 2003. Industry interest is increasing, as evidenced by the announcement of a possible project in the adjacent Pinedale Planning Area and queries to the Kemmerer planning area. The BLM Kemmerer Field Office estimates that up to 640 CBNG wells could be drilled in the Kemmerer planning area over the next 20 years (Table 7-5).

Table 7-5. Kemmerer Planning Area Coalbed Natural Gas Wells Well Number Estimates by Geologic Play

Geologic Play	Wells
Frontier-Adaville-Evanston	600
Fort Union	40
Total Wells	640

Sources: BLM 2006b; RMG 2003

The Frontier-Adaville-Evanston geologic play estimate is based on 20 percent of the play acreage being productive and a range of 4 to 8 wells per section for an average of 6 wells per section; therefore, 600 new wells could be drilled in the Frontier-Adaville-Evanston geologic play.

The Fort Union geologic play estimate is based on 20 exploratory wells and one 20-well pilot test; therefore, 40 new wells could be drilled in the Fort Union geologic play.

7.5.4 Unconventional Gas Resources

Extensive natural gas resources are almost certainly present in shales in the planning area. A report by PACE Global Energy Services indicates there are numerous carbonaceous shales in the Green River Basin that are known to contain substantial gas resources that, as of today, have not been tested. Carbonaceous shales are the most unexplored, and potentially largest, gas resources in the Rocky Mountain region. Carbonaceous shales could be an important source of future natural gas production. At present, technology and well completion methods are not available economically to produce shale gas; however, this important future gas source could become viable before 2020.

When and if technology and well completion methods are developed, this energy source will become significant. Initial development probably will use existing boreholes previously being used to produce from conventional reservoirs. If sufficient reserves per well are determined to be present, however, additional wells may be drilled specifically to recover this shale gas. Shale has very low permeability and large hydraulic fracture stimulations will probably be necessary to liberate the gas. Significant volumes of water may accompany gas production. Well spacing could be dense; one well per 40 acres should be expected if shale gas is developed.

Small concentrations of helium, carbon dioxide, and hydrogen sulfide are present in natural gas. Since their presence is undesirable, they are partially or totally removed as part of the treatment process. Carbon dioxide, at some locales, is recovered as part of the treatment process. When collected, it is primarily used for re-injection in support of enhanced oil recovery efforts in the local production area. When found in smaller uneconomic concentrations, it is removed during the natural gas processing and treatment and vented to the atmosphere. When substantive concentrations of helium occur, it is produced as a byproduct, but at lower concentrations is not removed. Its uses include lighter-than-air aircraft, magnetic resonance imaging, semiconductor processing, and purging of rocket engines. It is sold on the open market when profitable. Hydrogen sulfide is an undesirable component of natural gas and is removed as part of the treatment process. Today, much of the elemental sulfur is produced as a waste product of the petroleum industry. At higher concentrations of hydrogen sulfide, the hydrogen can be extracted for fuel where economically viable in the future. Since helium, carbon dioxide, and hydrogen sulfide are produced whether they can be profitably sold or not, they are considered to be byproducts and not included in this analysis.

7.6 Projected Oil and Gas Production

United States crude oil production in the contiguous 48 states is projected to increase from 4.8 MMBbl per day in 2001 to 5.3 MMBbl per day in 2007, and then to decline to 4.2 MMBbl per day in 2025 (EIA 2003). United States natural gas production is expected to increase by 7.3 Tcf through 2005 (EIA 2003). The largest increase in domestic natural gas production, from 2001 through 2025, is projected to come from the Rocky Mountain region, predominantly from unconventional sources.

In response to recommendations by the National Petroleum Council in their 1999 report, *Meeting the Challenges of the Nation's Growing Natural Gas Demand*, the National Energy Technology Laboratory began a program combining resource assessment, industry tracking, and technology modeling focused primarily on resources that were considered sub-economic and unrecoverable. The program used a log-based, gas-in-place approach with a high level of geographic and stratigraphic detail. The first phase of the program focused on the Greater Green River and Wind River basins, which contain the majority of the total low-permeability sandstone resource for the Rocky Mountain region (DOE 2003). This estimate was based on past gas-in-place resource assessments conducted for DOE by the USGS.

Results of the National Energy Technology Laboratory program confirmed past accounts of large quantities of natural gas existing in the two basins. In the Green River Basin, more than 3,600 Tcf of gas were determined to be remaining in place (DOE 2003). Accessing these resources would require the development and application of advanced exploration, drilling, completion, stimulation, and production technologies.

8.0 ALTERNATIVES TO THE BASELINE REASONABLE FORSEEABLE DEVELOPMENT SCENARIO

Four management alternatives were selected for analysis of impacts during the preparation of the preliminary resource management plan for the planning area. Each alternative reflects management-imposed constraints that may impact oil and gas development activity. These constraints may decrease the baseline estimate for wells to be drilled in areas of federal oil and gas ownership. The following sections provide a brief overview of the process used and the impacts of the constraints applied in each of the four management alternatives.

8.1 Descriptions of Alternatives

As part of the development of the resource management plan, two workshops were conducted to construct a range of alternatives that might be used to manage the various resources administered by the Kemmerer Field Office. Four sets of alternatives were developed in the preliminary resource management plan, representing different priorities in resource management.

This section summarizes the four alternatives (A through D) considered in the Preliminary Draft Resource Management Plan and Environmental Impact Statement for the Kemmerer Planning Area in detail (BLM unpublished). A narrative description of each alternative is provided under the following headings:

- Overview of the Alternative
- Physical, Biological, and Heritage Resources
- Resource Uses and Support
- Special Designations.

Other than *Overview of the Alternative*, the above headings reflect categories through which program-specific guidance for land use planning decisions must be applied (BLM 2005).

The Details of Alternatives section describes the goals and objectives for each of eight resource topics (e.g., physical, mineral, biological, etc.). Each alternative under the eight resource topics describes the different allowable uses and management actions as potential decisions under those topics. Goals and objectives (desired outcomes) are not described in the alternative narrative because they do not differ among alternatives.

8.1.1 Alternative A (No Action Alternative)

Overview of the Alternative

Alternative A represents the continuation of current management of BLM-administered lands in the planning area and is referred to as the “No Action Alternative”. Resources and resource uses on lands administered by the BLM within the planning area are currently managed under the existing plan (BLM 1986), as amended (including currently authorized activity plans [e.g., allotment management plans, habitat management plans]). Existing designations, allowable uses, and management actions for the planning area will continue under Alternative A. In general, Alternative A focuses more on analyzing proposed activities on a case-by-case basis rather than relying on pre-determined decisions to manage resources and resource uses in the planning area.

Physical, Biological, and Heritage Resources

Physical resources are managed under Alternative A to conserve air, water, and soil resources and to support resources and resource uses. For example, BLM currently maintains ambient air quality in the planning area through monitoring and cooperation with regulatory agencies such as the Wyoming Department of Environmental Quality and the Environmental Protection Agency. While sometimes necessary for resource use activities, surface disturbance can adversely impact physical resource values through fugitive dust emissions, soil erosion, and (or) sedimentation. To conserve water and soil resources within the planning area, BLM complies with standard practices and Wyoming BLM mitigation guidelines for land and resource use on BLM administered public lands; restricts oil and gas-related activities on slopes greater than 25 percent; allows no surface occupancy (NSO) on slopes greater than 40 percent; restricts surface-disturbing activities within 500 feet of 100-year floodplains, wetlands, riparian areas, or perennial streams; considers lining of reserve pits on a case-by-case basis; and reviews all proposed water disposal to ensure compliance with local, state, and federal laws and regulations. To protect water quality, disposal of water produced from coalbed natural gas (CBNG) wells under Alternative A is considered on a case-by-case basis and requires a soils analysis of the downstream area and additional information necessary to determine compliance with current laws.

Fire Management and Ecology under Alternative A focus on wildland fire suppression and prescribed fire. As described in the 2004 Fire Management Plan Southwestern Wyoming BLM, wildland fire suppression under Alternative A follows the Appropriate Management Response (AMR) (BLM 2004b). To protect resource values, Alternative A prohibits use of fire suppression chemicals and fire suppression vehicles in special status plant species' populations and prohibits use of these chemicals within 200 feet of surface water. Prescribed fire, as well as chemical, biological, and mechanical treatments can be used to reduce hazardous fuels under Alternative A and prescribed fire can be used to reintroduce fire to its natural role in the ecosystem to meet fire and fuels resource management objectives.

Biological resources are managed under Alternative A to provide habitat for fish and wildlife, meet public demand for forestland, protect natural functions in riparian areas, control the spread of INNS, and to comply with the Endangered Species Act and BLM policy for special status plant and animal species. Alternative A does not include specific decisions to conserve large contiguous blocks of habitat, avoid or minimize habitat fragmentation, protect ecological connections between habitat types, identify and manage migration or travel corridors, or retain old growth forests. Alternative A does establish a 500 feet avoidance buffer around wetlands, riparian areas, aquatic habitats, and 100-year floodplains to protect resource values from surface-disturbing activities. Similarly, Alternative A prohibits mixing chemicals within 500 feet of riparian areas, water sources, floodplains, and known special status plant species populations; however, no similar buffers are established for aerial, vehicle, or hand application of chemicals. The application of chemicals around special status plant species is managed on a case-by-case basis under Alternative A.

Fish and wildlife and special status species resource conservation under Alternative A is generally supported by BLM's management of habitat and only includes decisions to address key planning issues and requirements existing when the current plan was established. For example, Alternative A does not identify seasonal limitations of surface disturbing activities to protect fish resources. Alternative A does not require mitigation to prevent birds from perching on overhead powerlines, restrict high-profile structures within sagebrush obligate habitats, or siting equipment placement to limit noise levels that may impact wildlife or special status species. On the other hand, Alternative A does require new fence construction to meet fencing standards to accommodate wildlife movement.

Special status plant species are protected in a few cases under Alternative A by specific constraints on resource uses; otherwise, potential impacts to these species are managed on a case-by-case basis. For example, the existing NSO designation for four populations of *Physaria dornii* in the planning area continues under Alternative A to protect known locations of this species from surface disturbance and disruptive activities. In addition, special status plant species locations are considered ROW avoidance areas under Alternative A, although the Authorized Officer can grant exceptions. Alternative A also does not allow range improvement projects on special status plant species populations. Prior to project approval, Alternative A requires potential habitat areas for special status plant species be searched for the presence of protected plant species. In addition, potential habitat areas are managed as controlled surface use relative to surface-disturbing activities and vegetation treatments under Alternative A.

Special status wildlife species are generally managed to avoid or minimize impacts from surface disturbance and disruptive activities under Alternative A. For example, surface disturbance is prohibited within ¼ mile of occupied greater sage-grouse leks and human activity between 8 p.m. and 8 a.m. is avoided between March 1 and May 15 within this buffer. In addition, Alternative A requires avoidance of surface-disturbing and disruptive activities in greater sage-grouse nesting and early brood rearing habitat that is within 2 miles of occupied greater sage-grouse leks. To protect nesting raptors, Alternative A restricts activity or surface disturbance for up to ¾ mile radius from any active raptor nest in the planning area from February 1 – July 31. The restrictive buffer is extended to 1 mile radius for ferruginous hawk nests within the Moxa Arch area of oil and gas development. Alternative A does not include specific decisions for conserving pygmy rabbit habitats or white-tailed prairie dog complexes.

Heritage resources are generally protected by evaluation of potential impacts on a project-by-project basis under Alternative A. Inventories of heritage resources are conducted prior to all surface disturbing activities and all significant historical, archeological, and cultural sites are protected or mitigated under Alternative A. In addition, approximately 480 acres of federal mineral estate in the Bridger Antelope Trap are designated NSO to protect heritage resources under Alternative A.

Visual Resource Management (VRM) will continue in accordance with the 1986 VRM maps under Alternative A. The area within the viewshed of the Bridger Antelope Trap lacks specific prescriptions and is managed according to the VRM class for the area under Alternative A. Trails are protected from visual intrusion and surface disturbance under Alternative A by a protective corridor extending 1,320 feet from either side of National Historic Trails and Other Historic Trails or within the visual horizon of the trail whichever is closer.

Resource Uses and Support

Mineral resource uses are managed by identifying BLM-administered lands within the planning area suitable for leasing, exploration, or sales consideration. Constraints on mineral resource use in the planning area are identified to protect resource values. Under Alternative A, federal mineral estate in the planning area is open to leasing consideration for oil and gas and other solid leasable minerals with the following constraints: approximately 261,564 acres subject to standard stipulations, 855,554 acres subject to minor constraints, 368,427 acres subject to major constraints, and 104, 817 acres are unavailable for leasing. In addition, fluid mineral leasing is allowed under Alternative A within areas containing highly significant trail segments and within potential habitat for plant and animal species protected by the Endangered Species Act. New oil and gas leases will not be issued and existing leases are suspended in the Mechanically Minable Trona Area under Alternative A.

Coal mining in the planning area (outside of the Raymond Mountain WSA) is currently subjected to the coal screening process under Alternative A. The planning area outside of the Raymond Mountain WSA is currently available for leasing for sodium, phosphate, and other solid leasables. The entire planning area is available for consideration of mineral materials sales and (or) free use permits; however, the Interim Management Plan requires any activity within the Raymond Mountain WSA comply with the non-impairment criteria (BLM 1995). The area within the viewshed of the Fossil Butte National Monument, developed campground areas, and areas with special status plant and wildlife species are currently available for consideration of mineral materials sales and (or) free use permits under Alternative A. No withdrawals from phosphate minerals or other leasable minerals currently exist on BLM-administered land within the planning area; however, some lands within the planning area are currently withdrawn from locatable mineral entry to protect oil shale, coal, and phosphate resources.

Forest use under Alternative A specifies neither the acreage of forestlands or woodlands to be treated annually or the annual allowable probable sale quantity. However, Alternative A does restrict the annual volume of timber removal to the annual sustained yield capacity of the land. Old growth forests are managed in accordance with Healthy Forest Restoration Act under Alternative A.

Disposal of BLM-administered lands may occur under Alternative A for those lands identified for disposal in the existing plan. Lands may be identified for disposal because they are relatively small in area and isolated from large tracts of other BLM-administered lands and therefore difficult for BLM to manage. Most of the areas currently identified for disposal do not occur near communities within the planning area. Although Desert Land Entries are unlikely to occur in the planning area due to salinity issues, applications are considered on their merits providing the applicant provides evidence of a water right and an acceptable conservation plan.

ROW exclusion areas are not identified under Alternative A for the following archeological sites: Emigrant Spring/Slate Creek, Emigrant Spring/Dempsey, Johnston Scout Rock, Alfred Corum and Nancy Hill emigrant gravesites, Pine Grove emigrant camp, Rocky Gap trail landmark, and Bear River Divide trail landmark. Decisions regarding ROW corridors, communication sites, and renewable energy projects are not specifically identified in the existing plan. Acquisition of access for the Raymond Mountain WSA, Dempsey Basin, Commissary Ridge, and the Bear River Divide area is identified as high priority Under Alternative A.

Livestock grazing under Alternative A is managed in accordance with the Standards for Healthy Rangelands (BLM 1998). Other than a few small parcels which are not currently permitted or leased, the entire planning area is open to livestock grazing and the 224 existing grazing allotments will continue under Alternative A. For "I" allotments Alternative A focuses on improvement whereas for M and C allotments, the focus is on maintenance. Consideration of temporary nonrenewable permits issued for unallocated parcels will continue. The private allocation of 827 Animal Unit Months (AUMs) associated with the Lost Creek/Ryan Creek land acquisition will continue to be designated for wildlife use only and not available for livestock use under Alternative A. Forage reserves under Alternative A are not considered, developed campgrounds remain unavailable for livestock grazing, and grazing in the Mike Mathias Wetlands at Wheat Creek Meadows is only available as a management tool. Alternative A does not restrict the distance of livestock salt or mineral supplements from water sources, riparian areas, aspen stands, or special status plant species.

Recreation facilities in the planning area are retained under Alternative A. To protect the recreation experience, the existing NSO within 400 feet of developed campgrounds is also retained. No Special Recreation Management Areas (SRMAs) or Extensive Recreation Management Areas (ERMAs) exist and none are proposed within the planning area under Alternative A. Dispersed camping continues to be allowed throughout the planning area under Alternative A in accordance with recreational use rules.

Motor vehicle travel in the planning area is currently limited to existing roads and trails except for the Raymond Mountain WSA where it is prohibited. In addition, motor vehicle travel is seasonally limited (closed January 1 to April 30) in Slate Creek, Rock Creek, and Bridger Creek crucial big game winter range areas. Approximately 23 miles of groomed snowmachine trails exist in the planning area and new trails are considered on a case-by-case basis under Alternative A. Snowmachine use in Pine Creek Canyon is currently limited to the groomed trail and is limited to available dates prior to January 1 in Slate Creek, Rock Creek, and Bridger Creek crucial big game winter ranges and in the Raymond Mountain WSA. Existing roads and trails in the planning area are classified as open for OHV use.

Special Designations

Currently, the only ACEC in the planning area is the Raymond Mountain ACEC. This area was designated for the protection of watershed resources for Bonneville Cutthroat Trout. Surrounding the Raymond Mountain ACEC is the Raymond Mountain WSA. The Raymond Mountain ACEC is retained and no additional ACECs are proposed under Alternative A. Other than Raymond Mountain, no other special designations occur in the planning area and none are proposed under Alternative A. In addition, no RNAs, WSRs, National Back Country Byways, or Special Management Areas are either identified or proposed for the planning area under Alternative A.

8.1.2 Alternative B

Overview of the Alternative

Alternative B addresses the key planning issues by placing more emphasis on conservation of physical, biological, and heritage resources and more constraints on resource uses compared to Alternative A. Relative to all alternatives, Alternative B identifies the most land area are for the protection of physical, biological, and heritage resource values; designates the highest number of ACECs (10); identifies the most land area for special management; places the most restrictions on OHV use; and places the most constraints and allows the smallest leasing area for coal, oil and gas, and other solid leasable minerals.

Physical, Biological, and Heritage Resources

Physical resources under Alternative B are managed with more of an emphasis towards conserving air, water, and soil resources and less of an emphasis on supporting resource uses compared to Alternative A. For example, under Alternative B BLM will enhance existing criteria pollutant and AQRV monitoring compared to Alternative A. In addition, Alternative B places more emphasis on conservation of soils within the planning area by requiring consolidation of road networks and equipment placement to reduce the number of access roads and prohibiting surface disturbing activities in areas identified as having slopes greater than 10 percent, poor topsoil, sensitive or fragile soils, highly erosive soils, and low reclamation potential. The current NSO for slopes greater than 40 percent and restrictions on oil- and gas-related activities on slopes greater than 25 percent will continue under Alternative B. Alternative B places more emphasis on conservation of water resources compared to Alternative A by prohibiting surface-disturbing activities within ¼ mile of 100-year floodplains, wetlands, riparian areas, or perennial streams; requiring all reserve pits to be lined (when the preferred closed mud systems for handling drill cuttings are unavailable); and prohibiting discharge of produced waters to streams, other flow-connected surface features, and uplands administered by BLM.

Fire Management and Ecology under Alternative B places more of an emphasis on protection of soil, water, and special status species compared to Alternative A. Wildland fire suppression under Alternative B follows the 2004 Fire Management Plan Southwestern Wyoming BLM, AMR as described for Alternative A (BLM 2004b); however, Alternative B prohibits soil disturbance from heavy equipment during suppression activities unless structures are at risk. Alternative B also expands the prohibition area for fire suppression chemicals and fire suppression vehicles in special status plant species populations to ¼ mile from the boundary of species status plant species populations. Unlike Alternative A, Alternative B prohibits fire suppression vehicle use in special status plant species populations. Alternative B also expands the prohibition area for use of fire suppression chemicals to 500 feet of surface water compared to Alternative A. Use of prescribed fire to reduce hazardous fuels is the same as described for Alternative A; however, Alternative B sets acreage thresholds for meeting management objectives to reintroduce fire to its natural role in the ecosystem to meet fire and fuels resource management objectives.

Biological resources management under Alternative B places more emphasis on conservation of habitat for fish and wildlife, ecosystem management, protection of natural functions in riparian areas, control of INNS, and more constraints on resource uses that may impact biological resources compared to Alternative A. To increase protection of biological resources relative to Alternative A, Alternative B restricts habitat fragmentation to no more than 3 percent of available habitats; maintains ecological connections between habitat types; identifies and preserves migration and travel corridors for big game, migratory birds, and special status species; and retains old growth forests. To protect water quality, aquatic species, and natural habitat functions, Alternative B excludes surface-disturbing activities, vehicle and hand application of chemicals, and mixing of chemicals within ¼ mile of wetlands, riparian areas, aquatic habitats, and 100-year floodplains. In addition, aerial application of chemicals is not allowed within ½ mile of these same areas and special status plant species.

Fish and wildlife and special status species resource values under Alternative B are protected more compared to Alternative A by increasing constraints on resource uses. For example, Alternative B applies seasonal limitations for surface disturbing activities within the floodplain or within 1,000 feet of fish-bearing streams to protect fish resources. Alternative B also removes or modifies all BLM fences to comply with fencing standards that accommodate wildlife movement. To prevent birds from perching on overhead powerlines, Alternative B requires all new low voltage utility lines be buried and BLM-approved anti-perching devices be installed on all new high voltage utility lines. To protect special status wildlife species, Alternative B prohibits new high-profile structures within 1 mile of occupied sagebrush obligate habitats and prohibits these structures from relying on guy wires for support in these habitats. To minimize the impacts of continuous noise on special status species, Alternative B requires facilities not exceed 49 decibel (dBA) as measured 150 feet from the noise source.

Special status plant species receive increased protection under Alternative B compared to Alternatie A. For example, all locations of of *Physaria* dornii are designated NSO under Alternative B. In addition, special status plant species locations are considered ROW exclusion areas under Alternative B compared to avoidance areas under Alternative A. Range improvement projects are not allowed within ½ miles of special status plant species populations unless they would benefit the species under Alternative B. Like Alternative A, Alternative B requires Searches of potential habitat areas for special status plant species continue to be required under Alternative B prior to project approval. Surface-disturbing activities in these areas are prohibited and vegetation treatments are only allowed when they benefit special status plant species under Alternative B.

Special status wildlife species receive increased protection under Alternative B compared to Alternative A. For example, protection of the greater sage-grouse described for Alternative A is increased by extending the temporal human activity avoidance buffer an additional month to February 1 within ¼ mile of the perimeter of occupied greater sage-grouse leks between 8 p.m. and 8 a.m. In addition, Alternative B prohibits surface-disturbing and disruptive activities in greater sage-grouse nesting and early brood rearing habitat that is within 2 miles of occupied greater sage-grouse leks or in identified nesting or brood rearing habitats outside the 2-mile buffer from March 15 through July 15. Unlike Alternative A, Alternative B also protects greater sage-grouse during the winter by prohibiting surface-disturbing and disruptive activities in suitable winter concentration areas from November 15 through April 30. To protect nesting raptors, Alternative B prohibits surface-disturbing and disruptive activities within 1 ½ miles of an active raptor nest during:

- February 1 through July 15 (all raptors:
- March 1 through July 31 (short-eared, long-eared, and screech owl, ferruginous hawk, peregrine falcon)
- April 1 through July 31 (osprey, merlin, sharp-shinned hawk, kestrel, prairie falcon, northern harrier, Swainson’s hawk, Cooper’s hawk)
- April 15 through September 15 (burrowing owl)
- April 1 through August 31 (northern goshawk)

Alternative B includes specific decisions to protect the pygmy rabbit and white-tailed prairie dog. Alternative B prohibits development in identified pygmy rabbit habitats and prohibits surface-disturbing and disruptive activities in all white-tailed prairie dog colonies or complexes that are 100 acres or greater size.

Heritage resources benefit from more protection under Alternative B compared to Alternative A. For example, heritage resources are researched and tribes are consulted to proactively identify all sensitive sites within the planning area under Alternative B. Class III inventories are conducted in all priority areas and prohibit right-of-way corridors, wind energy projects, surface disturbing activities, OHV use, prescribed burns, and vegetation treatments in the following sites: Emigrant Spring/Slate Creek, Emigrant Spring/Dempsey, Johnston Scout Rock, Alfred Corum and Nancy Hill emigrant gravesites, Pine Grove emigrant camp, Rocky Gap trail landmark, and Bear River Divide trail landmark. Approximately 640 acres of federal mineral estate containing the Bridger Antelope Trap are excluded from surface disturbing activities, OHV use, prescribed burns, and vegetation treatments. The physical evidence of National Historic Trails and Other Historic Trails receive additional protection under Alternative B by extending the surface disturbing activities buffer to within 1 mile of high significance segments, within ½ mile of medium significance segments, and within ¼ mile of low significance segments.

Visual Resource Management (VRM) under Alternative B updates the planning area classification to: Class I – Raymond Mountain WSA; Class II – 3-mile buffer around all sensitive roads, NHTs and Other Historic Trails, campgrounds, towns, and sites registered on the National Register of Historic Places; Class IV – areas of high human disturbance and low visual stimulation; and Class III – the remaining planning area. Alternative B provides more protection of the viewshed compared to Alternative A. For example, Alternative B preserves the viewshed within 10 miles of the Bridger Antelope Trap juniper fence, Emigrant Spring/Slate Creek, Emigrant Spring/Dempsey, Johnston Scout Rock, Alfred Corum and Nancy Hill emigrant gravesites, Pine Grove emigrant camp, Rocky Gap trail landmark, Bear River Divide trail landmark, and Gateway petroglyphs by prohibiting rights-of-way corridors and other developments with structures greater than 12 feet high. The viewsheds of NHTs and Other Historic Trails segments are also preserved for 10 miles (highly significant segments), 5 miles (medium significant segments), and ½ mile (low significant segments) under Alternative B.
Resource Uses and Support

Mineral resource uses are constrained more under Alternative B compared to Alternative A. For example, under Alternative B, less acreage of federal mineral estate is open to leasing for oil and gas and other solid leasable minerals with standard stipulations (13,796) and minor constraints (103,704); more acreage of federal mineral estate is open to leasing with major constraints (751,804); and more acreage of federal mineral estate is unavailable for leasing (710,058). In addition, Alternative B does not allow new fluid mineral leasing on currently unleased areas within potential habitats for plant and wildlife species protected by the Endangered Species Act or within 5 miles of highly significant trail segments. Moreover, when current leases expire they would not be reoffered in these areas under Alternative B. The Mechanically Mineable Trona Area is permanently closed to new fluid mineral leasing and suspension of existing oil and gas leases continues under Alternative B.

Coal mining is more constrained under Alternative B compared to Alternative A. No new coal leasing is considered in the planning area and federal mineral estate within the Haystack project are determined to not be acceptable for further consideration for coal leasing and development under Alternative B. No new exploration or leasing for sodium, phosphate, or other solid leasables is allowed within the viewshed of the Fossil Butte National Monument or incorporated towns and cities under Alternative B. In addition, mineral withdrawals from sodium, phosphate, and other solid leasables are pursued for areas with special status plant and wildlife species. Alternative B does not allow mineral materials sales and (or) free use permits within the Raymond Mountain WSA, the viewshed of the Fossil Butte National Monument, ½ mile of developed campground areas, or areas with special status plant and wildlife species. In addition to existing withdrawals, Alternative B withdraws developed campgrounds, BLM-administered surface of the Bridger Antelope Trap, and areas with special status species (plants and wildlife) from operation of the mining laws.

Forest use under Alternative B specifies an annual allowable probable sale quantity of 200 MBF and restricts the annual treatment (i.e., mechanical methods or prescribed fire) of forestland and woodland to 50 acres each to reduce stocking levels to more historical conditions. In addition, Alternative B restricts the allowable probable sale quantity in the planning area to 367 CCF (200 MBF). Approximately 50 acres each of forestland and woodland are treated annually under Alternative B to reduce stocking levels and structure and (or) composition toward historical conditions. Approximately 3, 000 acres of forestland within the Raymond Mountain WSA are managed by fire to simulate natural alteration of vegetation to meet wilderness and healthy forest landscape objectives; however, no mechanical or surface disturbing activities and no removal of forest products are allowed in this area. Under Alternative B, old growth forest areas are retained and other forested areas are restored to pre-suppression composition, structure and processes.

Disposal of BLM-administered lands is not considered and no BLM-administered lands are available for agricultural entry under Desert Land Entry under Alternative B.

ROW exclusion areas are established for the archeological sites identified in Alternative A to protect heritage resource values. Alternative B also does not designate corridors through NRHP identified sites or where they are in conflict with NHT management objectives. To minimize surface disturbance, Alternative B requires new intrastate pipelines link the Jona Gas/Pinedale Anticline Fields to existing plant sites in the planning area and new interstate pipelines to follow the existing California and Pacific Coast States pipelines. Alternative B consolidates communication sites in four areas (Quealy Peak, Medicine Butte, Hickey Mountain, and BLM Wareyard) compared to no decision under Alternative A. To minimize surface disturbance and habitat fragmentation, wind energy projects are prohibited in areas containing important resource values including crucial winter range, active raptor nests, raptor migration corridors, potential nesting habitat and leks of greater sage-grouse, within five miles of significant cultural sites (Bridger Antelope Trap, Emigrant Spring/Slate Creek, Emigrant Spring/Dempsey, Johnston Scout Rock, Alfred Corum and Nancy Hill emigrant gravesites, Pine Grove emigrant camp, Rock Gap trail landmark, Bear River Divide trail landmark, and Gateway petroglyphs), the Raymond Mountain WSA, Class A or B scenery areas, or areas of sensitive and highly erosive soils. High priority areas for access identified under Alternative B are the same as described under Alternative A.

Livestock grazing continues to be managed on 224 grazing allotments in accordance with the Standards for Healthy Rangelands under Alternative B (BLM 1998). The planning area is open to livestock grazing on a case-by-case basis under Alternative B where it does not conflict with other resources. No temporary nonrenewable permits for unallocated parcels are issued under Alternative B. Instead of focusing on livestock and improving or maintaining the grazing allotment categories described in Alternative A, grazing systems and range improvements are managed to enhance watershed, riparian, and wildlife values under Alternative A. Suspended AUMs are not activated for livestock use under Alternative B and unalloted public lands, excluding livestock driveways, exclude livestock use. The private allocation of 827 AUMs associated with the Lost Creek/Ryan Creek land acquisition will continue to be designated for wildlife use only and not available for livestock use. In addition, under Alternative B, the Christy Canyon Allotment is designated as a forage reserve, developed campgrounds remain unavailable for livestock grazing, and grazing within the Mike Mathias Wetlands at Wheat Creek Meadows is closed. Alternative B prohibits livestock salt or mineral supplements within ½ mile of water sources, riparian areas, aspen stands, or special status plant species.

Recreation facilities in the planning area are retained under Alternative B; however, no new facilities will be developed. To protect the recreation experience, the existing NSO within 400 feet of developed campgrounds is expanded to ¼ mile under Alternative B. Under Alternative B, the Pine Creek Canyon, Raymond Mountain, selected BLM-administered lands in the Dempsey Ridge area, and NHTs and Other Historic Trails are designated as SRMAs. Remaining acreage in the planning area is designated as an ERMA. Under Alternative B, dispersed camping (in accordance with recreational use rules) continues to be allowed in the planning area; however, riparian areas are closed to camping to protect resource values.

Motor vehicle travel in the planning area under Alternative B is more restricted compared to Alternative A. For example, motor vehicle travel is limited to crowned and ditches roads under Alternative B and is seasonally limited (closed November 15 to April 30) in Slate Creek, Rock Creek, and Bridger Creek crucial big game winter range areas. The existing 23 miles of groomed snowmachine trails in the planning area remain open under Alternative B; however, the prohibition of new trails is intended to protect resource values. The current seasonal restriction on snowmachine use in Slate Creek, Rock Creek, and Bridger Creek crucial big game winter ranges and in the Raymond Mountain WSA is extended to include November 15 to April 15 under Alternative B. Crowned and ditched roads in the planning area are classified as open for OHV use under Alternative B and is more restrictive compared to Alternative A.

Special Designations

Special designations, Raymond Mountain WSA and ACEC, are retained under Alternative B and nine additional ACECs including the Raymond Mountain Expansion for Bonneville cutthroat trout habitat are designated. Under Alternative B, two of the proposed nine ACECs (Special Status Plant Species and Cushion Plan Communities) are also proposed for designation as RNAs and the proposed Fossil Basin ACEC is also identified as a SMA. Alternative B also proposes the Huff Creek and Raymond Creek WSRs and the Emigrant Spring National Back Country Byway. In general, Alternative B designates the most acreage in the planning area as ACECs and identifies the most RNAs and SMAs compared to all other alternatives. The designations of ACECs and RNAs and the identification of SMAs under Alternative B conserve physical, biological, and heritage resources more and constrain resource uses more compared to Alternative A.

8.1.3 Alternative C

Overview of the Alternatives

Alternative C addresses the key planning issues by placing more emphasis on resource uses (e.g., energy and mineral development, recreation, and forest products) and by maintaining or reducing constraints placed on resource uses to protect physical, biological, and heritage resource values. Compared to all alternatives, Alternative C conserves the least land area for protecting physical, biological, and heritage resource values; designates no ACECs; identifies the smallest area for special management; is the least restrictive to OHV use; and places the fewest constraints and allows the most land area for leasing oil and gas and other solid leasable minerals.

Physical, Biological, and Heritage Resources

Physical resources under Alternative C are managed with a similar emphasis as Alternative A with respect to conserving air, water, and soil resources and constraining resource uses. For example, under Alternative C BLM will retain current management actions for maintaining and monitoring ambient air quality. Alternative C also places a similar emphasis on conservation of soils within the planning area compared to Alternative A by managing surface-disturbing activities to reduce the amount of soil disturbance on a site-specific basis. However, rather than complying with standard practices for surface-disturbing activities and the *Wyoming BLM Mitigation Guidelines for Surface-Disturbing and Disruptive Activities,* Alternative C requires the use of Best Management Practices to limit soil erosion. Alternative C places similar emphasis on conservation of water resources compared to Alternative A, including prohibiting surface-disturbing activities within 500 feet of 100-year floodplains, wetlands, riparian areas, or perennial streams; reviewing all proposed water disposal to ensure compliance with local, state, and federal laws and regulations. Produced water disposal from CBNG wells under Alternative C is the same as Alternative A.

Fire Management and Ecology under Alternative C places more emphasis on suppression and less emphasis on conservation of soil, water, and special status species compared to Alternative A. For example, all wildland fires in the planning area are suppressed under Alternative C following the 2004 Fire Management Plan Southwestern Wyoming BLM, and use of heavy equipment for suppression can disturb soils (BLM 2004b). In addition, use of fire suppression chemicals is prohibited within the extent of special status plant species populations under Alternative C, the same as Alternative A; however, under Alternative C the 200 feet buffer distance to protect surface water from fire suppression chemicals is removed. Unlike Alternative A, use of prescribed fire, wildland fire, chemical, mechanical, and biological treatments to reduce hazardous fuels are not considered for reducing hazardous fuels under Alternative C. In addition, prescribed fire and wildland fire are not used to reintroduce fire to its natural role in the ecosystem under Alternative C.

Biological resources are managed under Alternative C to provide the same or fewer constraints on resource uses that may impact vegetation and habitat for fish, wildlife, and special status species compared to Alternative A. Alternative C lacks specific protection for large contiguous blocks of habitat like Alternative C; however, the latter provides more protection for special status species' habitat compared to Alternative A by avoiding habitat fragmentation in identified habitats through attenuation, siting, and consolidation of roads and other development infrastructure. Alternative C also identifies and develops management for migration and travel corridors for big game, migratory birds, and special status species unlike Alternative A which does not specifically address these issues. Alternative C also provides more protection for old growth forests compared to Alternative A by retaining appropriate locations and distribution levels. To protect water quality, aquatic species, and natural habitat functions, Alternative C avoids surface-disturbing activities, within 500 feet of wetlands, riparian areas, aquatic habitats, and 100-year floodplains. Alternative B does not identify specific buffer distances from these habitats for the application of chemicals; however, Alternative C prohibits mixing of chemicals near riparian areas, water sources, and floodplains, but, within a smaller buffer (100 feet).

Fish and wildlife and special status species resource values under Alternative C are protected the same or less compared to Alternative A. For example, Alternative C does not apply seasonal limitations for surface disturbing activities within the floodplain or near fish-bearing streams to protect fish resources. Alternative C applies the same fencing standards as Alternative A. Like Alternative A, burial of low voltage utility lines and installation of BLM-approved anti-perching devices on new high voltage utility lines; restrictions on high-profile structures within 1 mile of occupied sagebrush obligate habitats; and limits on equipment noise levels are not required under Alternative C.

Special status plant species generally receive the same or less protection under Alternative C compared to Alternative A. For example, an NSO is not designated for four populations of *Physaria* dornii as described under Alternative A. In addition, special status plant species locations are only considered ROW avoidance areas under Alternative C. Alternative C also only requires searches for federally listed, proposed, and candidate species prior to project approval as opposed to alls special status plant species under Alternative A. Alternative C does not place limitations on surface-disturbing activities in potential habitat areas for special status plant species and allows vegetation treatments in these areas, thereby providing less protection for these species compared to Alternative A.

Special status wildlife species under Alternative C generally receive the same or less protection compared to Alternative A. For example, protections for the greater sage-grouse are the same as Alternative A except Alternative C also avoids disruptive activities in the ¼ mile buffer around occupied leks. Alternative C provides greater temporal protection (see Alternative B) for nesting raptors compared to Alternative A; however, disruptive activities are only prohibited to ½ mile under Alternative C.

Alternative C avoids development in occupied pygmy rabbit habitats but like Alternative A, does not include management decisions protecting white-tailed prairie dog colonies or complexes from surface-disturbing and disruptive activities.

Heritage resources under Alternative B are similarly protected compared to Alternative A. Heritage resources are managed on a project-by-project basis where known site types are encountered under Alternative C. Class II or III inventories are conducted in areas where impacts from activities are likely; however, inventories are not required in low site density areas for future projects. Current management of federal mineral estate in the Bridger Antelope Trap continues and all significant historical, archeological, and cultural sites are protected or mitigated. The physical evidence of National Historic Trails and Other Historic Trails are protected under Alternative C by restricting surface disturbing activities within 1/4 mile segments with high significance, within 500 feet of segments with medium significance, and within 100 feet of segments with low significance.

Visual Resource Management (VRM) uses the same classification system as other action alternatives except Raymond Mountain WSA is managed as Class I and high potential wind energy areas are managed as VRM IV. Alternative C continues current VRM management of the Bridger Antelope Trap compared to Alternative A; however, viewshed protection for NHTs and Other Historic Trails segments changes under Alternative C to 1 mile (highly significant segments), 1/4 mile (medium significant segments), and in accordance with the VRM class (low significant segments).

Resource Uses and Support

Mineral resource uses under Alternative C are similar compared to Alternative A. Federal mineral estate under Alternative C is open to leasing for oil and gas and other solid leasable minerals with approximately 264,414 acres subject to standard stipulations, 860,249 acres subject to minor constraints, 348,882 acres subject to major constraints, and 104,817 acres are unavailable for leasing. Like Alternative A, fluid mineral leasing is allowed under Alternative C within areas containing highly significant trail segments and within potential habitat for plant and animal species protected by the Endangered Species Act. New oil and gas leases are not issued and existing leases are suspended in the Mechanically Minable Trona Area.

Coal mining under Alternative C is subject to similar constraints compared to Alternative A. Applications for coal leasing outside of the Raymond Mountain WSA are subjected to the coal screening process and federal land within the proposed Haystack project are determined to be acceptable for further consideration for coal leasing and development under Alternative C. Like Alternative A, the planning area outside of the Raymond Mountain WSA is available for leasing for sodium, phosphate, and other solid leasables; however, unlike Alternative B, no withdrawals for these minerals would be pursued in special status plant and wildlife species areas under Alternative C. Management actions for salable minerals under Alternative C are the same as under Alternative A. Under Alternative C, existing locatable mineral withdrawals in the planning area intended to protect oil shale, coal, and phosphate resources are lifted.

Forest use under Alternative C identifies an allowable probable sale quantity of 1,100 CCF (600 MBF). Approximately 150 acres each of forestland and 100 acres of woodland are treated annually by mechanical methods or prescribed fire to reduce stocking levels and structure and (or) composition toward historical conditions. Under Alternative C, management of 3, 000 acres of forestland within the Raymond Mountain WSA is the same as described for Alternative B. Likewise, management of 15,000 acres of woodland (aspen, aspen conifer, and juniper) is the same as described for Alternative B. Under Alternative C, old growth forest areas are retained at appropriate locations and distribution levels and connectivity of existing or potential old growth areas is adopted whenever feasible.

Disposal of BLM-administered lands under Alternative C are considered for disposal on a case-by-case basis. Applications for a Desert Land Entry are considered as described for Alternative A.

ROWs and corridors under Alternative C are managed similarly to Alternative A, on a case-by-case basis. Corridor widths are not restricted under Alternative C and placement of corridors is not prohibited in archeological sites. In addition, Alternative C allows for wind and other renewable energy development throughout the planning area except for the Raymond Mountain WSA and the Bridger Antelope Trap. Access across public lands is pursued as needed with emphasis on specific areas under Alternative C.

Livestock grazing continues to be managed on 224 grazing allotments in accordance with the Standards for Healthy Rangelands under Alternative C (BLM 1998). Temporary nonrenewable permits for unallocated parcels are issued, and grazing is allowed on all public lands in the planning area. Grazing system and range improvements are designed to maximize livestock grazing while maintaining other resource values under Alternative C. Suspended AUMs are activated for livestock use under Alternative C if monitoring data determine forage is available. The private allocation of 827 AUMs, associated with the Lost Creek/Ryan Creek land acquisition, are available for wildlife and livestock use under Alternative C. In addition, the Christy Canyon Allotment is not designated as a forage reserve, developed campgrounds can be opened to livestock grazing on a case-by-case basis, and the Mike Mathias Wetlands at Wheat Creek Meadows is open to livestock grazing. Under Alternative C management of livestock salt, mineral supplements, and range improvement projects relative to the distance from water sources, riparian areas, aspen stands, or special status plant species is the same as Alternative A.

Recreation facilities in the planning area are retained and enhanced and additional recreational facilities are developed where appropriate under Alternative C. The current NSO designation within 400 feet of developed campgrounds remains under Alternative C. Like Alternative A, no SRMAs or ERMA are identified within the planning area under Alternative C. Under Alternative B, dispersed camping (in accordance with recreational use rules) continues to be allowed throughout the planning area.

Motor vehicle travel in the planning area under Alternative C is limited to existing roads and trails outside of the Raymond Mountain WSA; however, unlike Alternative A, no seasonally closures exist under Alternative C. The existing 23 miles of groomed snowmachine trails in the planning area remain open under Alternative C and new trails are considered on a case-by-case basis. The current seasonal limitations on snowmachine use in Slate Creek, Rock Creek, and Bridger Creek crucial big game winter ranges and in the Raymond Mountain WSA are removed under Alternative C. In addition, the entire Pine Creek Canyon is available for snowmachine use under Alternative C. OHV use under Alternative C is the same as Alternative A.

Special Designations

The existing Raymond Mountain WSA is retained, the Raymond Mountain ACEC is not retained, and no new areas are designated as ACECs, RNAs, WSAs, WSRs, or National Back Country Byways under Alternative C. In addition, no areas are identified as SMAs under Alternative C. Compared to all Alternatives, Alternative C designates the least acreage of special designations and identifies the least (none) area for special management.

8.1.4 Alternative D (Preferred Alternative)

Overview of the Alternative

Alternative D addresses the key planning issues by emphasizing a moderate level of protection for physical, biological, and heritage resource values and moderate constraints on resource uses. Alternative D is a balanced approach to land management that BLM believes best addresses the issues, management concerns, and purpose and need for revising the existing RMP. For these reasons, Alternative D represents BLM's preferred alternative.

Physical, Biological, and Heritage Resources

Physical resources under Alternative D are managed with more of an emphasis towards conserving air, water, and soil resources and a similar emphasis towards supporting resource uses compared to Alternative A. For example, BLM will enhance existing criteria pollutant and AQRV monitoring on a project-specific or as needed basis under Alternative D. In addition, Alternative D places more emphasis on conservation of soils within the planning area compared to Alternative A by utilizing existing road networks to reduce surface disturbances, impacts, and habitat fragmentation; and by avoiding surface disturbance on soil types identified as having poor topsoil, sensitive or fragile soils, highly erosive soils, soils with low reclamation potential, and sensitive soils on slopes greater than 20 percent. The current NSO for slopes greater than 40 percent will continue under Alternative D. Alternative D places similar emphasis on conservation of water resources compared to Alternative A, including prohibiting surface-disturbing activities within 500 feet of 100-year floodplains, wetlands, riparian areas, or perennial streams; and lining all reserve pits unless other more effective methods are necessary to prevent impacts. Management of water disposal is similar to Alternative A except Alternative D requires a BLM approved discharge plan for discharge of produced water to streams or other flow-connected surface features.

Fire Management and Ecology under Alternative D places more emphasis on protection of soil, water, and special status species compared to Alternative A. Wildland fire suppression under Alternative D follows the 2004 Fire Management Plan Southwestern Wyoming BLM - AMR, in areas of high-density urban or industrial interface with BLM-administered lands and generally suppresses wildland fires in these areas for human health and safety (BLM 2004b). In low-density urban and industrial interface areas, Alternative D allows use of wildland fire to achieve resource objectives. To minimize soil erosion and protect other resource values in the planning area, the BLM authorized officer must approve soil disturbance during suppression activities under Alternative D. In addition, Alternative D expands the size of the prohibition area for fire suppression chemicals and fire suppression to 200 feet from the boundary of species status plant species' populations, compared to Alternative A. Alternative D also restricts fire suppression vehicle use in special status plant species populations to existing roads and trails compared to no restrictions under Alternative A. The current prohibition of fire suppression chemicals within 200 feet of surface water for the protection of water resources and aquatic habitats will continue under Alternative D. Use of prescribed fire to reduce hazardous fuels is the same as under Alternative A; however, Alternative D sets acreage thresholds for meeting management objectives to reintroduce fire to its natural role in the ecosystem to meet fire and fuels resource management objectives.

Biological resources management under Alternative D places more emphasis on conservation of habitat for fish and wildlife, ecosystem management, protection of natural functions in riparian areas, control of INNS, and more constraints on resource uses that may impact biological resources compared to Alternative A. Alternative D benefits biological resources more compared to Alternative A by identifying ecological connections between habitat types; minimizing habitat fragmentation; identifying migration and travel corridors for big game, migratory birds, and special status species; and retaining old growth forests. Protection of water quality, aquatic species, and natural habitat functions from surface-disturbing activities is achieved by the same 500 feet avoidance area for wetlands, riparian areas, aquatic habitats, and 100-year floodplains identified for Alternative A. Under Alternative D, application of chemicals to control INNS is not allowed within 100 feet of wetlands, riparian areas, and aquatic habitat for aerial application, 25 feet for ground vehicle application, and 10 feet for application by hand. Mixing of chemicals under Alternative D is allowed closer (100 feet) to water sources, and floodplains compared to Alternative A (500 feet).

Fish and wildlife and special status species resources values under Alternative D are protected by more constraints on resource uses compared to Alternative A. For example, Alternative D decides on a case-by-case basis whether to apply seasonal limitations for surface disturbing activities in fish-bearing streams to protect fish resources. Alternative D also eliminates or modifies existing fence on a case-by-case basis to reduce conflicts with wildlife movement. To prevent birds from perching on overhead powerlines, Alternative D requires new low voltage utility lines be buried and BLM-approved anti-perching devices be installed on all new high voltage utility lines. Alternative D relies on impact analysis to determine whether installation of anti-perch devises and (or) burial of powerlines are necessary in habitats that already exhibit structures used for perching. To protect special status wildlife species, Alternative D benefits special status wildlife species more compared to Alternative A by avoiding new high-profile structures within 1 mile of occupied sagebrush obligate habitats unless anti-perch devices are installed on the structures. Alternative D also prohibits these structures from relying on guy wires for support in these habitats; however, exceptions can be granted. To minimize the impacts of continuous noise on species that rely on aural cues for successful breeding, Alternative D requires facilities do not exceed 49 dBA as measured 900 feet from the noise source.

Special status plant species under Alternative D do not include the NSO designation for four populations of *Physaria dorni* under Alternative A. Special status plant species' locations are considered ROW avoidance areas and searches of potential habitat areas for special status plant species prior to project approval are still required under Alternative D. In addition, Alternative D retains the controlled surface use restriction for surface-disturbing activities in potential habitat areas of special status plant species. Vegetation treatments in special status plant species' habitats can be conducted on a case-by-case basis under Alternative D.

Special status wildlife species under Alternative D receive more protection from surface disturbance compared to Alternative A. For example, protection of the greater sage-grouse described for Alternative A is increased under Alternative D by the prohibition of surface occupancy within ¼ mile of occupied leks. In addition, Alternative D adds the requirement to avoid surface-disturbing and disruptive activities in greater sage-grouse nesting and early brood rearing habitat that is within 2 miles of occupied greater sage-grouse leks or in identified nesting or brood rearing habitats outside the 2-mile buffer from March 15 through July 15. Finally, Alternative D requires avoiding disturbance and disruptive activities in occupied greater sage-grouse habitat from November 15 through March 14. Prohibiting surface-disturbing and disruptive activities to protect active raptor nests is similar to Alternative A but with the following spatial and temporal buffers under Alternative D:

- 1-mile buffer for ferruginous hawk nests within the entire planning area; ¾ mile for all other raptors
- February 1 through July 15 (all raptors)
- March 1 through July 31 (short-eared, long-eared, and screech owl, ferruginous hawk, peregrine falcon)
- April 1 through July 31 (osprey, merlin, sharp-shinned hawk, kestrel, prairie falcon, northern harrier, Swainson's hawk, Cooper's hawk)
- April 15 through September 15 (burrowing owl)
- April 1 through August 31 (northern goshawk)

Compared to Alternative A, Alternative D includes specific decisions to protect the pygmy rabbit and white-tailed prairie dog. Alternative D avoids development in occupied pygmy rabbit habitats and avoids disruptive activities that could collapse burrows in occupied white-tailed prairie dog colonies or complexes greater than 200 acres in size.

Heritage resources benefit from more protection under Alternative D compared to Alternative A. Under Alternative D, the timing and degree of Native American consultation is determined by the presence of known site types and tribal concerns for specific types of projects until such time that zones of high, medium, and low probability are established. The current Class I overview will be used to identify zones of high, medium, and low probability and Class III inventories will be conducted in zones with the greatest threats to cultural resources. To protect cultural resources from surface disturbing activities, Alternative D designates an NSO for minerals on newly issued leases, restricts OHV use to established roads, and by designating the following sites as ROW exclusion areas: Emigrant Spring/Slate Creek, Emigrant Spring/Dempsey, Johnston Scout Rock, Alfred Corum and Nancy Hill emigrant gravesites, Pine Grove emigrant camp, Rocky Gap trail landmark, and Bear River Divide trail landmark. Approximately 640 acres of federal mineral estate containing the Bridger Antelope Trap are subject to an NSO for minerals, restricting OHV use to established roads. The physical evidence of National Historic Trails are protected under Alternative D by prohibiting surface disturbing activities within 1/4 mile of high significance segments, within 500 feet of medium significance segments, and within 100 feet of low significance segments.

Visual Resource Management (VRM) uses the same classification system as other action alternatives but with different parts of the planning area identified for management under Classes II, III, and IV. Alternative D increases the Bridger Antelope Trap viewshed to 3 miles compared to Alternative A. In addition, Alternative D also prohibits ROWs and corridors or high profile structures (higher than 12 feet) such as wind power from this viewshed. Alternative D also protects the viewshed from high profile structures within 3 miles of select archeological sites. Viewshed protection for NHTs and Other Historic Trails segments changes under Alternative D to 1 mile (highly significant segments), 1/2 mile (medium significant segments), and in accordance with the VRM class (low significant segments).

Resource Uses and Support

Mineral resource use under Alternative D is more constrained compared to Alternative A. Federal mineral estate open to leasing for oil and gas and other solid leasable minerals is 64,171 acres with standard stipulations, 1,042,502 acres with minor constraints, and 290,973 acres with major constraints. In addition, 181,716 acres of federal mineral estate are unavailable for leasing. Fluid mineral leasing is allowed on currently unleased areas within potential habitats for plant and wildlife species protected by the Endangered Species Act or within 5 miles of highly significant trail segments. The Mechanically Mineable Trona Area is withheld from new fluid mineral leasing and the suspension of existing oil and gas leases in this are continues under Alternative D.

Coal mining under Alternative D is subject to similar constraints compared to Alternative A. Federal mineral estate within the Haystack project is determined to be acceptable for further consideration for coal leasing and development. Except for the Raymond Mountain WSA, exploration or leasing for phosphate or other solid leasables is allowed. Exploration for sodium in the rest of the planning area is considered on a case-by-case basis. Under Alternative D, no mineral withdrawals from sodium leasable minerals, from phosphate leasable minerals, or from other solid leasable minerals will be pursued in areas with special status plant or wildlife species. Mineral material sales and (or) free use permits are prohibited within the Raymond Mountain WSA, the viewshed of the Fossil Butte National Monument, or within developed campgrounds (unless impacts to campground users are minimal). Mineral material sales and (or) free use permits are authorized in areas with special status plant and wildlife species on a case-by-case basis under Alternative D. In addition to existing withdrawals, Alternative D withdraws developed campgrounds, BLM-administered surface of the Bridger Antelope Trap, and areas with special status plant species from operation of the mining laws.

Forest use under Alternative D includes an annual allowable probable sale quantity of 300 MBF and restricts the annual treatment (i.e., mechanical methods or prescribed fire) of forestland and woodland to 75 acres each to reduce stocking levels to more historical conditions. Approximately 3, 000 acres of forestland within the Raymond Mountain WSA are managed by fire to simulate natural alteration of vegetation to meet wilderness and healthy forest landscape objectives; however, no mechanical or surface disturbing activities and no removal of forest products are allowed in this area. Approximately 15,000 acres of woodland (aspen, aspen conifer, and juniper) are actively managed, referred to as *woodland ecosystem management areas,* and forest products are removed as a byproduct consistent with forest health, landscape restoration, and fuel reduction objectives. Under Alternative B, old growth forest areas are retained and other forested areas are restored to pre-suppression composition, structure and processes.

Disposal of BLM-administered lands under Alternative D are identified if they meet the disposal critieria. Applications for a Desert Land Entry are considered as described for Alternative A.

ROWs and corridors under Alternative D can be up to 2 miles wide. Consolidated communication sites are considered by type in designated areas and other communication sites are developed on a case-by-case basis. Alternative D also prohibits placement of rights-of-way in the archeological sites identified as Emigrant Spring/Slate Creek, Emigrant Spring/Dempsey, Johnston Scout Rock, Alfred Corum and Nancy Hill emigrant gravesites, Pine Grove emigrant camp, Rocky Gap trail landmark, and Bear River Divide trail landmark. Alternative D identifies preferred areas for wind energy development considers renewable energy projects other than wind on a case-by-case basis. Legal access across private land is sought if a need is identified in support of resource programs.

Livestock grazing continues to be managed on 224 grazing allotments in accordance with the Standards for Healthy Rangelands under Alternative D (BLM 1998). The same area currently open to livestock grazing remains open under Alternative D. Issuance of temporary nonrenewable permits for unallocated parcels is a discretionary decision for BLM under Alternative D. Alternative D retains the focus on improving I allotments and maintaining M and C allotments described for Alternative D. Suspended AUMs can be activated for livestock use on a case-by-case basis. The private allocation of 827 AUMs associated with the Lost Creek/Ryan Creek land acquisition will continue to be designated for wildlife use only and not available for livestock use. In addition, under Alternative D, the Christy Canyon Allotment is designated as a forage reserve, developed campgrounds remain available for livestock grazing, and grazing within the Mike Mathias Wetlands at Wheat Creek Meadows is allowed as a management tool. Alternative D prohibits livestock salt or mineral supplements within 1/4 mile of water sources, riparian areas, aspen stands, or special status plant species. Range improvement projects are not allowed on special status plant species populations.

Recreation facilities are maintained and enhanced and additional recreational facilities are developed where appropriate under Alternative D. The current NSO designation within 400 feet of developed campgrounds remains under Alternative D Like Alternative A, no SRMAs or ERMA are identified within the planning area under Alternative D. Dispersed camping (in accordance with recreational use rules) continues to be allowed under Alternative D.

Motor vehicle travel in the planning area under Alternative D is generally the same compared to Alternative A. The existing 23 miles of groomed snowmachine trails in the planning area remain open under Alternative D and new trails are considered on a case-by-case basis. Snowmachine use under Alternative D is also the same compared to Alternative D for the Pine Creek Canyon and the Slate Creek, Rock Creek, and Bridger Creek crucial big game winter ranges; however, no snowmachine use is allowed in the Raymond Mountain WSA. Existing roads and trails in the planning area are classified as open for OHV use under Alternative D, the same as Alternative A.

Special Designations

Under Alternative D, the existing Raymond Mountain WSA and ACEC are retained, ACECs for special status plant species habitat and cushion plan communities are considered on a case-by-case basis, the Bridger Butte ACEC is designated, the Rock Creek/Tunp and Bear River Divide Special Management Areas are identified, the Huff Creek and Raymond Creek WSRs are identified for further consideration, and the Emigrant Springs National Back Country Byway is designated. Compared to Alternative A, Alternative D retains existing designations and adds two WSRs, two SMAs, one National Back Country Byway, one ACEC, and two ACECs are considered on a case-by-case basis.

From these alternatives and their associated constraints, a set of maps was developed illustrating the areas impacted and the general level of impact to oil and gas leasing – open with standard restrictions, open with minor restrictions, open with major restrictions, and closed to leasing.

Figures 8-1 through 8-4 illustrate constraints applied from the resource restrictions to alternatives A-D.

Using Geological Information System (GIS) software, the amount of federal oil and gas acreage in each category was calculated for each of the four alternatives. Table 8-1 shows the results of those calculations.

Table 8-1. Classifications of Leasable Acreage by Alternative

Classification	Alternative A	Alternative B	Alternative C	Alternative D
Acreage Open with standard restrictions	261,564	13,796	265,414	64,171
Acreage Open with minor restrictions	844,554	103,704	860,249	1,042,502
Acreage Open with major restrictions	368,427	751,804	348,882	290,973
Acreage Closed	104,817	710,058	104,817	181,716
Total Acreage	1,579,362	1,579,362	1,579,362	1,579,362

Source: BLM 2006b

8.2 Procedures Used To Determine Well Location Reductions

Well location reductions from the baseline RFD 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 RFD 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:

- 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 effect 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 greater sage-grouse strutting grounds. Restrictions, such as avoidance of areas within 500 feet of wetlands, riparian areas, or perennial waters, were also considered, and 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 viewsheds be protected, thus requiring that well locations and production facilities not be visible from areas such as historic trails. Overlapping minor constraints also may 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 baseline RFD projection were determined as described below:

- An estimate of the number of well locations/townships that could be drilled in each development potential category over the 20-year life of the RMP was made for conventional oil and gas development activity (Table 7-4) and for CBNG development activity (Table 7-5).
- The acres of federal oil and gas ownership for each area of non-coalbed gas development potential was determined using GIS software. Acres of nonfederal oil and gas minerals were not included because proposed RMP decisions would apply only to federal oil and gas minerals. It was assumed that development on nonfederal mineral estate would occur as estimated in the baseline RFD.
- The acres of federal oil and gas ownership for each area of CBNG development potential was determined using GIS software. Acres of nonfederal oil and gas minerals were not included because proposed RMP decisions would apply only to federal oil and gas minerals. It was assumed that development on nonfederal mineral estate would occur as estimated in the baseline RFD.
- 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 it was previously determined that this type of restriction would have no affect on the number of well locations for any alternative.
- 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 that would not be drilled in each area due to the specific category of restriction.
- 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 later 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 CBNG for each alternative. The results of these calculations are shown in Table 8-2.
- Because reductions in well locations were calculated for federal wells only, 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 8-2.

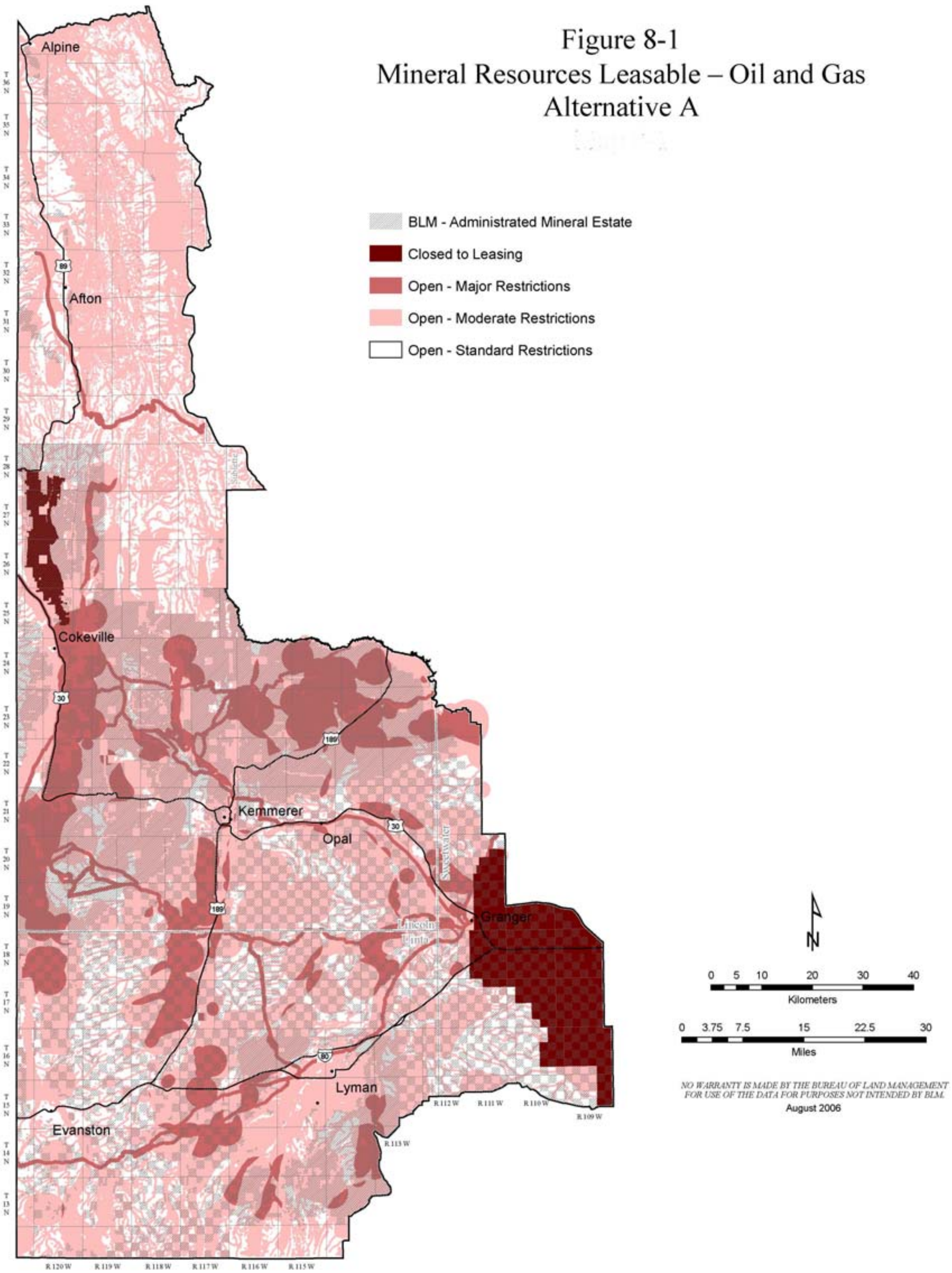

Figure 8-1
Mineral Resources Leasable – Oil and Gas
Alternative A

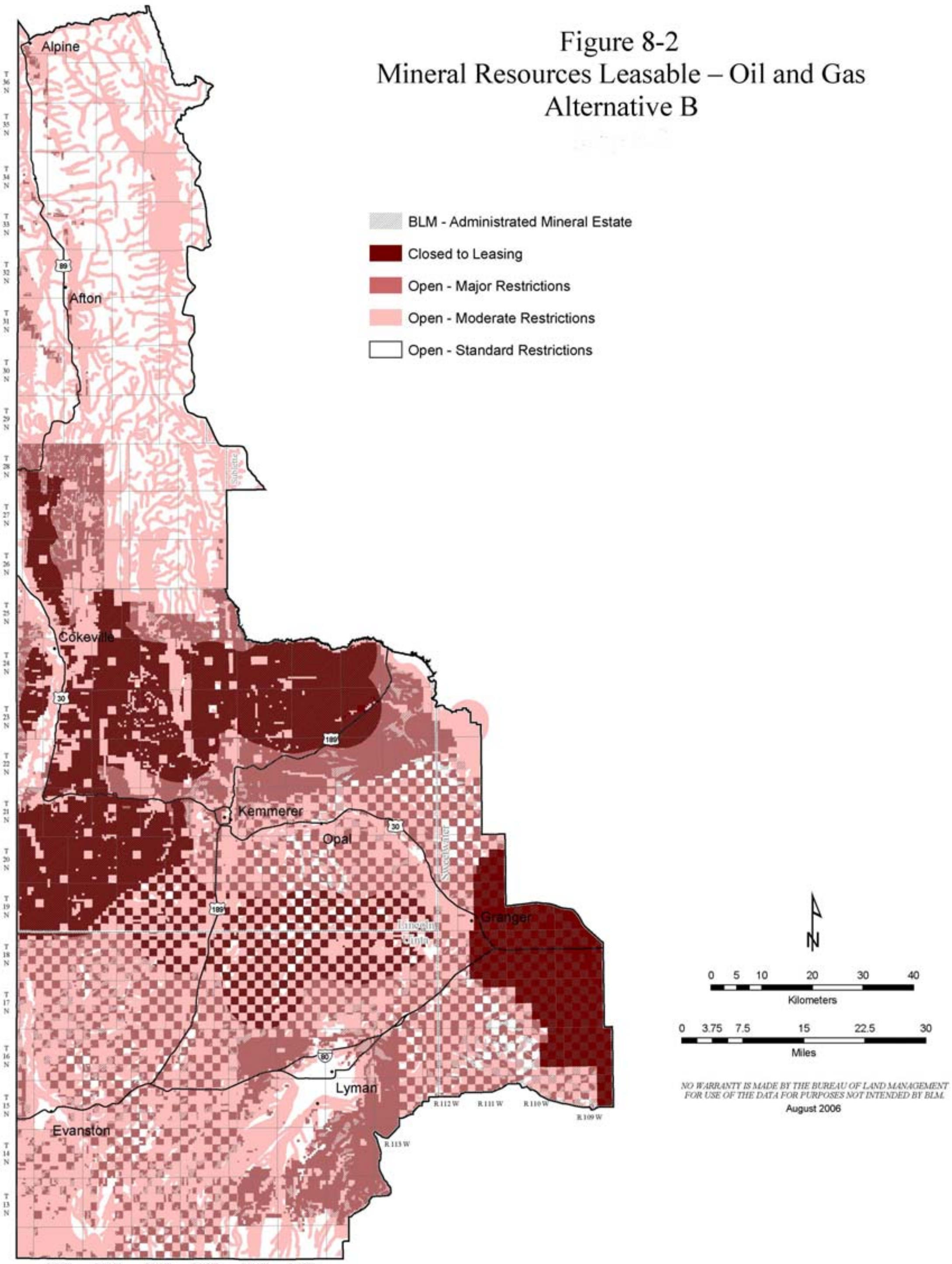
Figure 8-2
Mineral Resources Leasable – Oil and Gas
Alternative B
BLM - Administrated Mineral Estate
Closed to Leasing
Open - Major Restrictions
Open - Moderate Restrictions
Open - Standard Restrictions
Alpine
Afton
Cokeville
Kemmerer
Opal
Granger
Lyman
Evanston
0 5 10 20 30 40
Kilometers
0 3.75 7.5 15 22.5 30
Miles
NO WARRANTY IS MADE BY THE BUREAU OF LAND MANAGEMENT FOR USE OF THE DATA FOR PURPOSES NOT INTENDED BY BLM.
August 2006

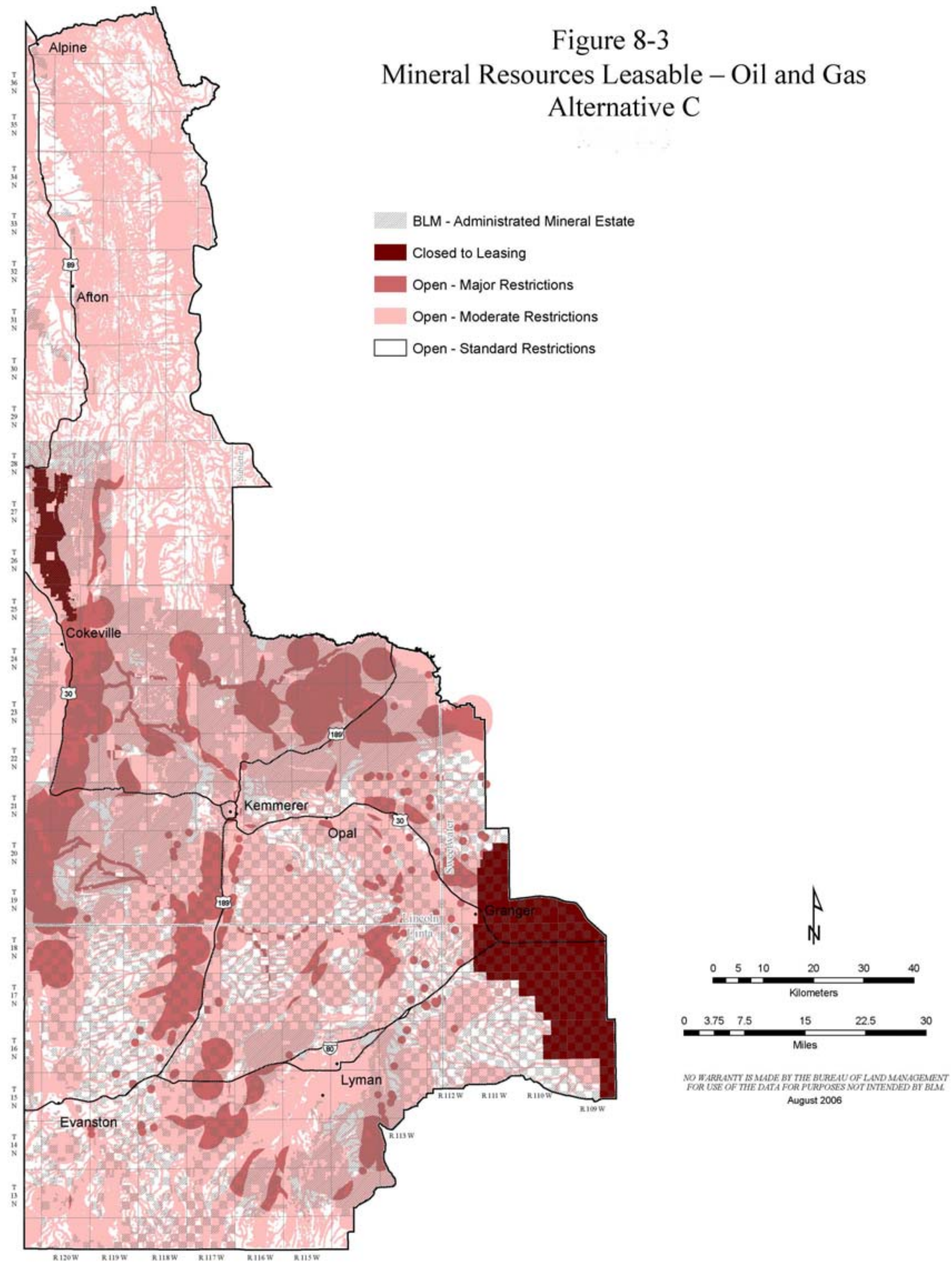
Figure 8-3
Mineral Resources Leasable – Oil and Gas
Alternative C
BLM - Administrated Mineral Estate
Closed to Leasing
Open - Major Restrictions
Open - Moderate Restrictions
Open - Standard Restrictions
Alpine
Afton
Cokeville
Kemmerer
Opal
Granger
Lyman
Evanston
0 5 10 20 30 40
Kilometers
0 3.75 7.5 15 22.5 30
Miles
NO WARRANTY IS MADE BY THE BUREAU OF LAND MANAGEMENT FOR USE OF THE DATA FOR PURPOSES NOT INTENDED BY BLM.
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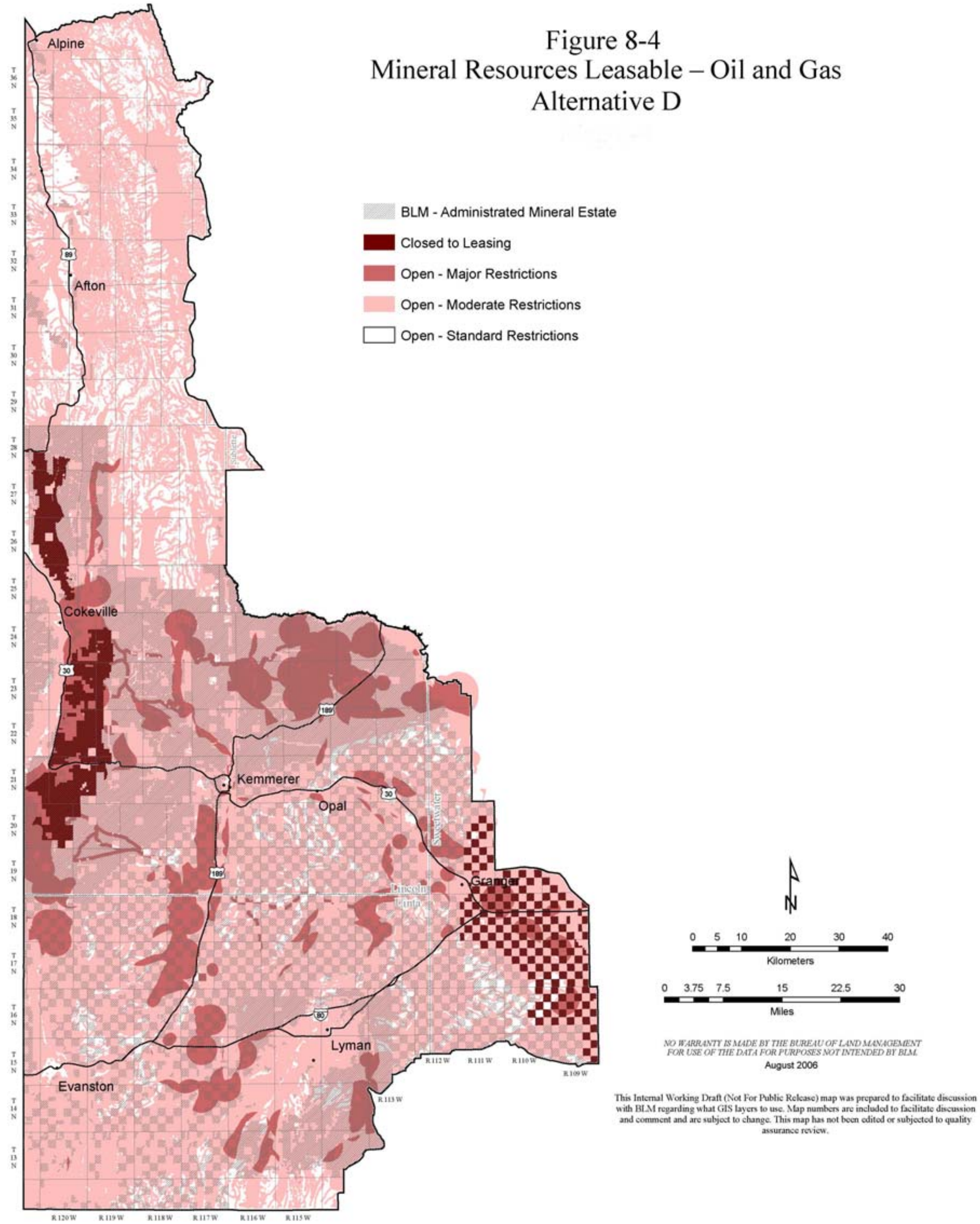

Figure 8-4
Mineral Resources Leasable – Oil and Gas
Alternative D

8.2.1 Well Count Summary

Table 8-2. Total Wells Drilled by Alternative, 2001 through 2020

	Coalbed Natural Gas Wells	Oil and Gas Wells	Total Wells	Number/Percent [1] Federal of Total [2]
Base Case[3]	640	2,040	2,680	1,221/46%
Alternative A (No Action)	589	1,882	2,471	1,012/41%
Alternative B	479	1,588	2,067	608/29%
Alternative C	593	1,886	2,479	1,020/41%
Alternative D	592	1,877	2,469	1,010/41%

Source: BLM 2006b
[1] Percents are rounded and do not give exact well counts when multiplied by the total wells.
[2] Federal wells are calculated for each alternative after applying constraints in GIS.
[3] Base Case is from Table 7-4.

Table 8-3. Well Count By Area and Alternative, 2001 through 2020

	Coalbed Natural Gas	Moxa Arch	Overthrust Belts	Total Wells
Base Case[1]	640	1,740	300	2,680
Alternative A(No Action)	589	1,605	277	2,471
Alternative B	479	1,373	215	2,067
Alternative C	593	1,609	277	2,479
Alternative D	592	1,606	271	2,469

Source: BLM 2006b
[1] Base Case is from Table 7-4.

Table 8-4. Total Producing Wells Drilled By Area, 2001 through 2020

	Coalbed Natural Gas	Moxa Arch	Overthrust Belts	Total Producing Wells[1]
Base Case[2]	528	1,543	203	2,274
Alternative A (No Action)	496	1,424	189	2,109
Alternative B	398	1,218	147	1,763
Alternative C	491	1,427	189	2,107
Alternative D	491	1,425	185	2,101

Source: BLM 2006b
[1] Abandonment Rates: Coalbed Natural Gas: Exploration 93%, Development 15%
Moxa Arch: No Exploration, Development 12%
Overthrust Belts: Exploration 68%, Development 21%
[2] Base Case is from Table 7-4.

8.2.2 Well Count Assumptions

The following assumptions will be used to project the number and types of wells to be drilled and abandoned for Moxa Arch, Overthrust Belt, and CBNG in each alternative. Tables 8-2 through 8-4 were calculated based on the following assumptions.

8.2.2.1 Moxa Arch Well Count Assumptions

Existing Producing Wells

13 wells per year ~ average abandonment rate

Future Activity: (Prediction estimates based on Section 7.5.2 and Table 4-1. Some reasonable adjustments were made for historical success rates.)

Approximately 100% of wells to be drilled will be development wells
Approximately 0% of wells to be drilled will be exploration wells
Approximately 88% of development wells will be successful
No exploration wells

Baseline Development Wells (total wells without constraint)			
Productive		1543 wells	76.2 wells per year average
Dry		197 wells	9.85 wells per year average
	Total	**1740 wells**	**87 wells per year average**
Baseline Exploration Wells (total wells without constraint)			
Productive		0 wells	0 wells per year average
Dry		0 wells	0 wells per year average
	Total	**0 wells**	**0 wells per year average**
Baseline Total Wells (total wells without constraint)			
Productive		1543 wells	76.2 wells per year average
Dry		197 wells	9.85 wells per year average
	Total	**1740 wells**	**87 wells per year average**

8.2.2.2 Overthrust Belt Well Count Assumptions

Existing Producing Wells

2 wells per year ~ average abandonment rate

Future Activity (Prediction estimates based on Section 7.5.2 and Table 4-3. Some reasonable adjustments were made for historical success rates.)

Approximately 79% of development wells will be successful
Approximately 32% of exploration wells will be successful

Baseline Development Wells (total wells without constraint)			
Productive		175 wells	8.7 wells per year average
Dry		45 wells	2.2 wells per year average
	Total	**220 wells**	**11 wells per year average**
Baseline Exploration Wells (total wells without constraint)			
Productive	28 wells		1.4 wells per year average
Dry	52 wells		2.6 wells per year average
Total	80 wells		4 wells per year average
Baseline Total Wells (total wells without constraint)			
Productive		203 wells	10.1 wells per year average
Dry		97 wells	4.85 wells per year average
	Total	**300 wells**	**15 wells per year average**

8.2.2.3 Coalbed Natural Gas Well Count Assumptions

Future Activity. (Prediction estimates based on Section 7.5.2 and Table 4-1. Some reasonable adjustments were made for historical success rates.)

Approximately 85% of wells to be drilled will be development wells
Approximately 15% of wells to be drilled will be exploration wells
Approximately 85% of development wells will be successful
Approximately 7% of exploration wells will be successful
20-well pilot project to be installed in year 10 (placeholder)

Baseline Development Wells (total wells without constraint)			
Productive		527 wells	26 wells per year avg plus 20 wells in Year 10
Dry		93 wells	5 wells per year average
	Total	**620 wells**	**25.5 wells per year avg plus 20 wells in Year 10**
Baseline Exploration Wells (total wells without constraint)			
Productive		1 wells	0 wells per year average
Dry		19 wells	1 well per year average
	Total	20 wells	**1 well per year average**
Baseline Total Wells (total wells without constraint)			
Productive		528 wells	26 wells per year average
Dry		112wells	6 wells per year average
	Total	**640 wells**	**31 wells per year avg plus 20 wells in Year 10**

8.3 Surface Disturbance

Because of the wide range of surface and geologic settings in the planning area, three models have been developed to calculate the surface area disturbed as the result of oil and gas activities in the planning area. The surface disturbance models comprise four main elements: a summary of unit area disturbance assumptions that show the areas disturbed and reclaimed on a per well basis, a well count element that specifies the number and types of wells being drilled, a timeline element that places each activity relative to others in the process, and a spreadsheet that integrates the first three elements to calculate the disturbed and reclaimed areas during the 20-year study period. In Section 8.3.1, a model for wells drilled in the Green River Basin area is presented. This model covers the majority of wells projected to be drilled within the planning area over the next 20 years. Section 8.3.2 presents a model applicable to most wells drilled in the Overthrust Belt portion of the planning area. These wells typically are deeper and have the potential for encountering hydrogen sulfide (H_2S) gas, which is poisonous. The larger rigs required to drill the deep holes need wider roads and bigger drill pads. Safety requires an additional emergency route if H_2S is a possibility. Section 8.3.3 contains the model for potential CBNG disturbance and reclamation within the planning area. Section 8.3.4 summarizes the surface disturbance and reclamation calculations.

8.3.1 Green River Basin/Moxa Arch Model

Unit Area Assumptions

The following guidelines and assumptions will be used to calculate disturbance and reclamation areas on a per-well basis.

Access Road Disturbance
Assumes construction 1 year before drilling begins.
Initial Access Road Disturbance Width

40 feet (typically 30- to 40-feet wide)
211,200 square feet/mile
4.85 acres/mile
0.5 miles/well (typically 0.25- to 0.5-miles long)
2.42 acres initial disturbance per well

Long-term Access Road Disturbance Width

20 feet (typically 14- to 16-feet wide)
105,600 square feet/mile
2.42 acres/mile
0.5 miles/well (typically 0.25- to 0.5-miles long)
1.21 acres long-term disturbance per producing well
1.21 acres reclaimed per producing well within 4 years

Assumes approximately 20 feet of initial disturbed width reclaimed within 4 years

2.42 acres reclaimed per abandoned dry well within four years.
1.21 acres reclaimed per abandoned producing well within 3 years after abandonment

Drill Pad Disturbance

Assumes construction 1 year before drilling begins.

5 acres per well drilled
3.7 acres reclaimed per producing well within 4 years
1.3 acre long-term disturbance per producing well
5 acres reclaimed per abandoned dry well within 4 years
1.3 acre reclaimed per abandoned producing well within 3 years after abandonment

Pipeline Disturbance

50 feet initial disturbance width (typically 30 feet, but requests are usually for 50 feet)
264,000 square feet/mile
6.06 acres/mile
0.5 miles/well
3.03 acres initial disturbance per producing well
3.03 acres reclaimed per producing well within 3 years of installation

Powerline Disturbance

All Moxa Arch wells are powered by solar, wind generators, or natural gas.

Compressor Station Disturbance

10 acres per installation, remaining as long-term disturbance

Timeline Assumptions

The following assumptions will be used to determine the timeline of disturbance and reclamation activities.

Existing Production

Area reclaimed per year

Sum of
(Long-term access road disturbance) * (13 wells abandoned per year, starting in year 1) and
(Long-term drill pad disturbance) * (13 wells abandoned per year, starting in year 1).

New Activity

Area disturbed per year

Assumes road and pad construction are completed 1 year prior to drilling; year 1 drilling construction already completed.

Sum of

(Initial access road disturbance area) * (87 wells per year for 20 years, starting in year 1),

(Initial drill pad disturbance area) * (87 wells per year for 20 years, starting in year 1),

(Pipeline disturbance area) * (77 wells per year for 10 years, starting in year 1, then 76 wells per year for remaining 10 years), and

(Compressor station disturbance area) * (8 stations per year for 20 years, starting in year 1).

Area reclaimed per year

Assumes road and pad construction are completed 1 year prior to drilling; year 1 drilling construction already completed; credit for reclamation taken 4th year after construction, 3rd year after drilling.

Sum of

(Initial access road disturbance area) * (11 dry holes per year for 10 years, starting in year 4, then 10 dry holes per year for remaining 7 years),

(Initial drill pad disturbance area) * (11 dry holes per year for 10 years, starting in year 4, then 10 dry holes per year for remaining 7 years),

(Initial access road disturbance area – long-term access road disturbance) * (77 wells per year for 10 years, starting in year 4, then 76 wells per year for remaining 7 years),

(Initial drill pad disturbance area – long-term drill pad disturbance area) * (77 wells per year for 10 years, starting in year 4, then 76 wells per year for remaining 7 years), and

(Pipeline disturbance area) * (77 wells per year for 10 years, starting in year 4, then 76 wells per year for remaining 7 years).

8.3.2 Overthrust Belt Model

Unit Area Assumptions

The following guidelines and assumptions will be used to calculate disturbance and reclamation areas on a per-well basis.

Access Road Disturbance

Assumes construction 1 year before drilling begins.

Initial Access Road Disturbance Width

50 feet (typically 30- to 50-feet wide)

264,000 square feet/mile

6.06 acres/mile

1.25 miles/well (typically 1-mile long plus H_2S egress route)

7.58 acres initial disturbance per well

Long-term Access Road Disturbance Width

28 feet (typically 20- to 24-feet wide)
147,840 square feet/mile
3.39 acres/mile
1.0 mile/well (typically 1-mile long)
3.39 acres long-term disturbance per producing well
4.19 acres reclaimed per producing well within 4 years

Assumes approximately 30 feet of initial disturbed width reclaimed within 4 years

7.58 acres reclaimed per abandoned dry well within 4 years.
4.19 acres reclaimed per abandoned producing well within 3 years after abandonment

Drill Pad Disturbance

Assumes construction 1 year before drilling begins.

10 acres per well drilled
7 acres reclaimed per producing well within 4 years
3 acres long-term disturbance per producing well
10 acres reclaimed per abandoned dry well within 4 years
3 acres reclaimed per abandoned producing well within 3 years after abandonment

Pipeline Disturbance

50 feet initial disturbance width (typically 30 feet, but requests are usually for 50 feet)
264,000 square feet/mile
6.06 acres/mile
1.0 mile/well
6.06 acres initial disturbance per producing well
6.06 acres reclaimed per producing well within 3 years of installation

Powerline Disturbance

10 feet (typically 30- to 40-feet wide)
52,800 square feet/mile
1.21 acres/mile
1.0 mile/well (typically 0.25 to 0.5 miles long)
1.21 acres initial disturbance per well
1.21 acres per year per well, reclaimed within 3 years of installation

Compressor Station Disturbance

None required

Timeline Assumptions

The following assumptions will be used to determine the timeline of disturbance and reclamation activities.

Existing Production

Area reclaimed per year

Sum of
(Long-term access road disturbance) * (2 wells abandoned per year, starting in year 1) and

(Long-term drill pad disturbance) * (2 wells abandoned per year, starting in year 1).

New Activity

Area disturbed per year

Assumes road and pad construction completed 1 year prior to drilling; year 1 drilling construction already completed.

Sum of

(Initial access road disturbance area) * (15 wells per year for 20 years, starting in year 1),

(Initial drill pad disturbance area) * (15 wells per year for 20 years, starting in year 1),

(Pipeline disturbance area) * (12 wells per year for 2 years, starting in year 1, then 11 wells per year for remaining 18 years),

(Powerline disturbance area) * (12 wells per year for 2 years, starting in year 1, then 11 wells per year for remaining 18 years),

Area reclaimed per year

Assumes road and pad construction completed 1 year prior to drilling; year one drilling construction already completed; credit for reclamation taken 4th year after construction, 3rd year after drilling.

Sum of

(Initial access road disturbance area) * (4 dry holes per year for 17 years, starting in year 4),

(Initial drill pad disturbance area) * (4 dry holes per year for 17 years, starting in year 4),

(Initial access road disturbance area – long-term access road disturbance) * (12 wells per year for 2 years, starting in year 4, then 11 wells per year for remaining 15 years),

(Initial drill pad disturbance area – long-term drill pad disturbance area) * (12 wells per year for 2 years, starting in year 4, then 11 wells per year for remaining 15 years),

(Pipeline disturbance area) * (12 wells per year for 2 years, starting in year 4, then 11 wells per year for remaining 15 years), and

(Powerline disturbance area) * (12 wells per year for 2 years, starting in year 4, then 11 wells per year for remaining 15 years).

8.3.3 Coalbed Natural Gas Model

Unit Area Assumptions

The following guidelines and assumptions will be used to calculate disturbance and reclamation areas on a per well basis.

Access Road Disturbance

Assumes construction 1 year before drilling begins.

Initial Access Road Disturbance Width

50 feet (typically 30- to 40-feet wide)

264,000 square feet/mile

6.06 acres/mile

0.5 miles/well (typically 0.25- to 0.5-miles long)
3.03 acres initial disturbance per well

Long-term Disturbance Width
20 feet (typically 14- to 20-feet wide)
105,600 square feet/mile
2.42 acres/mile
0.5 miles/well (typically 0.25- to 0.5-miles long)
1.21 acres long-term disturbance per producing well
1.21 acres reclaimed per producing well within 4 years

Assumes approximately 24 feet of initial disturbed width reclaimed within 4 years
3.03 acres reclaimed per abandoned dry well within 4 years.
1.21 acres reclaimed per abandoned producing well within 3 years after abandonment

Drill Pad Disturbance
Assumes construction 1 year before drilling begins.
2 acres per well drilled
1.5 acres reclaimed per producing well within 4 years
0.5 acres long-term disturbance per producing well
2 acres reclaimed per abandoned dry well within 4 years
0.5 acres reclaimed per abandoned producing well within 3 years after abandonment

Pipeline Disturbance
50 feet initial disturbance width (typically 30 feet, but requests are usually for 50 feet)
264,000 square feet/mile
6.06 acres/mile
0.5 miles/well
3.03 acres initial disturbance per producing well
3.03 acres reclaimed per producing well within 3 years of installation

Powerline Disturbance
Powerlines will be installed in same trench as pipeline. No additional disturbance.

Compressor Station Disturbance
7 acres per installation, remaining as long-term disturbance

Timeline Assumptions

The following assumptions will be used to determine the timeline of disturbance and reclamation activities.

New Activity

Area disturbed per year
Assumes road and pad construction completed 1 year prior to drilling; year 1 drilling construction already completed.

Sum of
(Initial access road disturbance area) * (31 wells per year for 20 years, starting in year 1, plus 20 wells in year 10 for pilot project),
(Initial drill pad disturbance area) * (31 wells per year for 20 years, starting in year 1, plus 20 wells in year 10 for pilot project),

(Pipeline disturbance area) * (27 wells per year for 20 years, starting in year 1, plus 20 wells in year 10 for pilot project), and
(Compressor station disturbance area) * (3 stations per year for 20 years, starting in year 1).

Area reclaimed per year

Assumes road and pad construction completed 1 year prior to drilling; year 1 drilling construction already completed; credit for reclamation taken 4th year after construction, 3rd year after drilling.

Sum of
(Initial access road disturbance area) * (4 dry holes per year for 17 years, starting in year 4),
(Initial drill pad disturbance area) * (4 dry holes per year for 17 years, starting in year 4),
(Initial access road disturbance area – long-term access road disturbance) * (31 wells per year for 17 years, starting in year 4, plus 20 wells in year 14),
(Initial drill pad disturbance area – long-term drill pad disturbance area) * (31 wells per year for 17 years, starting in year 4, plus 20 wells in year 14), and
(Powerline disturbance area) * (31 wells per year for 17 years, starting in year 4, plus 20 wells in year 14).

8.3.4 Surface Disturbance Summary

Table 8-5 shows the total new disturbed area, total reclaimed area, and net disturbed area for projected new oil and gas activity in the planning area for each alternative. This activity includes new drilling for conventional oil and gas, new drilling for CBNG, and abandonment of currently producing wells as their recoverable reserves are depleted. The total acreages shown are greater than the sum of state and fee and federal acreages because for 2001 and 2002, acreage was calculated for only the total wells drilled. Projected surface disturbance does not include existing surface disturbance from wells drilled prior to 2001.

Table 8-5. Summary of Surface Disturbance Calculations by Alternative

	Baseline	Alternative A	Alternative B	Alternative C	Alternative D
State and Fee Initial Disturbed Area	15,495	15,495	15,495	15,495	15,495
Federal Initial Disturbed Area	13,643	11,371	6,700	11,418	11,243
Total Initial Disturbed Area	29,138	26,866	22,195	26,913	26,738
State and Fee Reclaimed Area	9,410	9,410	9,410	9,410	9,410
Federal Reclaimed Area	9,846	8,352	5,212	8,355	8,221
Total Reclaimed Area	19,256	17,762	14,622	17,765	17,631
State and Fee Long-Term Disturbed Area	6,085	6,085	6,085	6,085	6,085
Federal Long-Term Disturbed Area	3,798	3,019	1,488	3,063	3,022
Total Long-Term Disturbed Area	9,883	9,104	7,573	9,148	9,107

Source: BLM 2006b
[1] Projected surface disturbance does not include existing surface disturbance from wells drilled prior to 2001.

8.4 Well Production

Future oil and gas production was estimated for the baseline scenario and each alternative by using the well counts in combination with the production decline curve produced from data from DWIGHTS database as described in Section 4.4. Kemmerer's production historical decline curve for oil and gas was created with historical production data from the DWIGHTS database with estimated nominal decline for oil and gas resources and is as shown in Figure 4-15. Future estimates utilized the decline curve of all wells averaged together for the planning area. The resulting estimates of future yearly oil production and total oil production for the period 2001-2020 are presented in Table 8-6 for the baseline and for each alternative.

Gas production was determined using a procedure similar to that for the estimate of oil production. Information from gas well calculations and the CBNG 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 8-7 for the baseline and for each alternative.

Well production tables do not include production from existing wells drilled prior to 2001.

8.4.1 Well Production Summary

The estimates of future yearly oil production and total oil production for the period 2001-2020 are presented in Tables 8-6 for the baseline and for each alternative.

The estimates of future yearly gas production and total gas production for the period 2001-2020 are presented in Table 8-7 for the baseline and for each alternative.

Well production summary tables do not include production from existing wells drilled prior to 2001.

Table 8-6. Future Oil Production (in thousand [MBO]) for the Kemmerer Field Office area, estimated for the baseline and each alternative

Year	Baseline	Alternative A (No Action)	Alternative B	Alternative C	Alternative D
2001	134	134	134	134	134
2002	148	148	148	148	148
2003	465	443	403	443	443
2004	725	679	601	681	678
2005	944	882	767	885	880
2006	1,135	1,052	904	1,053	1,049
2007	1,295	1,202	1,027	1,204	1,197
2008	1,431	1,324	1,128	1,328	1,319
2009	1,550	1,433	1,215	1,438	1,428
2010	1,648	1,521	1,289	1,524	1,518
2011	1,732	1,601	1,354	1,605	1,597
2012	1,806	1,664	1,404	1,669	1,660
2013	1,866	1,723	1,453	1,728	1,717
2014	1,918	1,768	1,490	1,771	1,762
2015	1,964	1,812	1,523	1,816	1,805
2016	2,001	1,843	1,551	1,846	1,837
2017	2,033	1,876	1,574	1,879	1,868
2018	2,059	1,898	1,592	1,899	1,893
2019	2,082	1,916	1,613	1,922	1,916
2020	2,101	1,933	1,625	1,937	1,932
Total	29,039	26,854	22,796	26,910	26,780

Source: BLM 2006b

Table 8-7. Future gas production (in billions of cubic feet) for the Kemmerer Field Office area, estimated for the baseline and each alternative

Year	Baseline	Alternative A (No Action)	Alternative B	Alternative C	Alternative D
2001	7.32	7.32	7.32	7.32	7.32
2002	8.96	8.96	8.96	8.96	8.96
2003	27.27	26.07	23.86	26.06	26.06
2004	43.89	41.21	36.66	41.31	41.14
2005	59.75	55.94	48.82	56.10	55.78
2006	74.22	68.95	59.54	69.04	68.74
2007	87.10	80.94	69.44	81.06	80.63
2008	99.83	92.54	78.97	92.73	92.16
2009	111.76	103.59	87.95	103.80	103.12
2010	122.72	113.59	96.29	113.70	113.23
2011	133.00	123.15	104.13	123.27	122.69
2012	142.91	131.79	111.16	131.98	131.28
2013	151.87	140.04	118.04	140.28	139.48
2014	159.94	147.39	124.12	147.51	146.77
2015	167.51	154.42	129.81	154.59	153.75
2016	174.31	160.67	135.02	160.75	159.98
2017	180.59	166.69	139.81	166.82	165.96
2018	186.38	171.98	144.13	172.02	171.39
2019	191.72	176.81	148.43	177.05	176.47
2020	196.65	181.35	152.05	181.53	180.94
Total	2,327.70	2,153.38	1,824.50	2,155.86	2,145.85

BLM 2006b

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10.0 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 mapable 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 so that each unit is sufficiently homogenous 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.

Conventional accumulation. The United States 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.

Field. A production unit comprising 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 United States 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 United States 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 United States 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 comprised 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.

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.

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

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 have been proven by drilling and are available for profitable production.

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

Undiscovered technically recoverable resource. A subset of the in-place resource hypothesized to exist on the basis of geologic knowledge, data on past discoveries, or theory, 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, therefore, are 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 Bcf of gas were included in the earlier 1995 assessment.