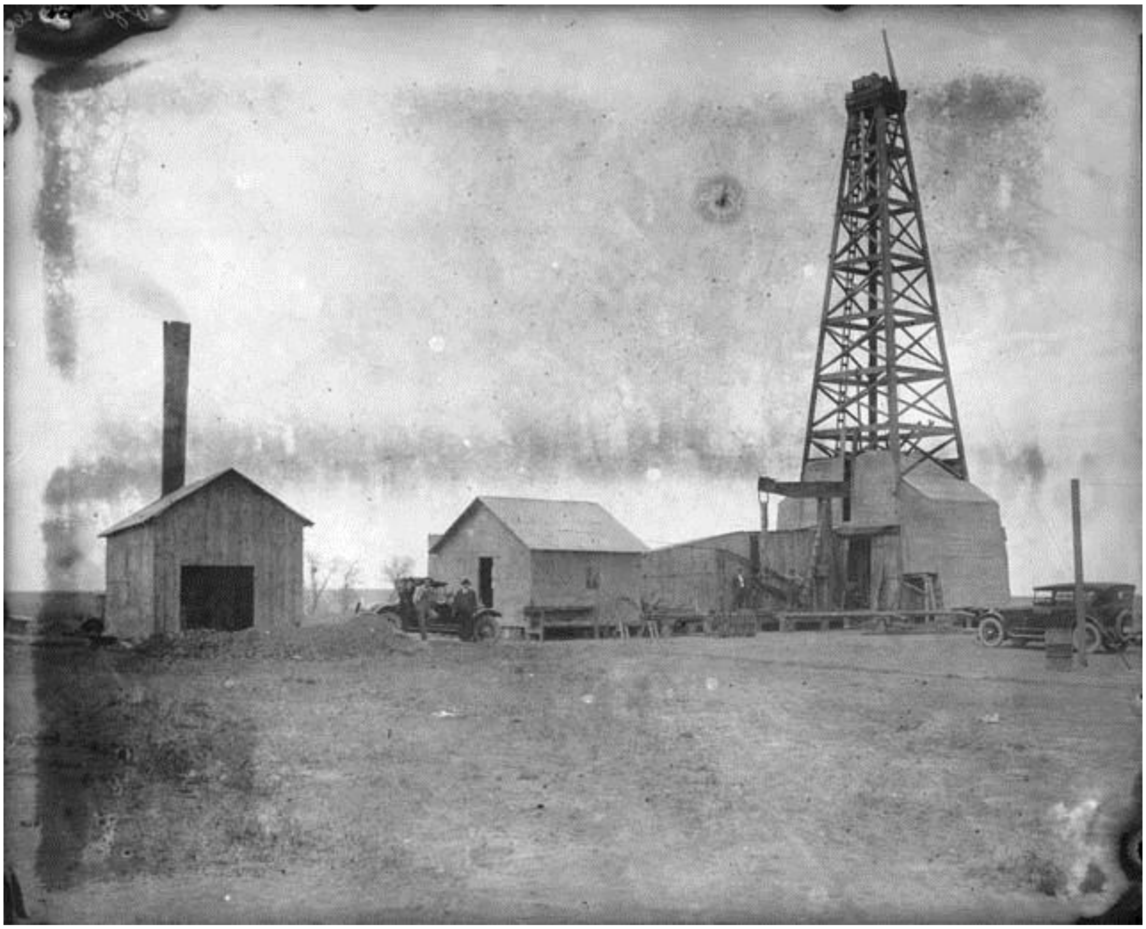
Reasonably Foreseeable Development Scenario for Oil and Gas
Grand Junction Field Office, Colorado



UNITED STATES DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

June 18, 2012

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I SUMMARY

The Bureau of Land Management (BLM) Grand Junction Field Office (GJFO) is updating its Resource Management Plan. To enable this update, a "Reasonably Foreseeable Development Scenario" (RFD) for oil and gas was developed. This baseline scenario provides the mechanism to analyze the effects that discretionary management decisions have on oil and gas activity. The RFD also provides basic information that is analyzed in the National Environmental Policy Act (NEPA) document under various alternatives.

This RFD, though speculative, is based primarily on geology (potential for oil and gas resource occurrence) along with past and present oil and gas activity. The scenario also considers other significant factors, including economics, technology, physical limitations on access, existing or anticipated infrastructure, and transportation. Surface uses necessary to implement the anticipated oil and gas exploration and/or development are also included in the description of the RFD.

As of December 2008, there were 692 active wells with an estimated 2,568 acres of disturbance on BLM-managed lands within the GJFO. There were 1,862 wells with 4,141 acres of surface disturbance for all mineral ownership, including federal, state, and private estate, as of December 2008. The baseline RFD scenario covers the period from 2009 to 2028 and predicts activity of oil and gas exploration, development, production, surface disturbance, and reclamation. The basis of the scenario assumes all potentially productive areas are available for development under standard lease terms and conditions, except those areas designated as closed to leasing by law, regulation, or executive order. The RFD is not a planning decision document, nor should the RFD be considered a No Action Alternative in any related environmental analysis.

The BLM examined available information for the GJFO area, including oil and gas operator input, environmental documents, unit agreement activity, publications, historical drilling data, and professional knowledge of the area. This study indicates that up to 3,938 conventional, shale and coal bed methane wells could be drilled on BLM lands in the next 20 years. Due to the directional drilling practices that are required in some areas and the resulting multi-well drilling pads, the projected development would require only 959 well pads. The anticipated short-term disturbance for the drilling, road construction, and pipeline installation is 9,387 acres. The long-term disturbance associated with operation of the new producing exploratory and development wells would be 3,138 acres. This long-term disturbance figure is based on the interim surface reclamation that occurs after wells are completed, pipeline rights-of-way are reclaimed, and dry hole wells and depleted well sites are restored. See Table 1, Table 2, Table 1 **Shale**, and Table 2 **Shale**.

The Study Area includes all lands within the Grand Junction Field Office boundary regardless of surface or mineral ownership. For all mineral ownership lands in the Study Area, it is estimated that the baseline scenario would result in drilling of 9116 wells and 2029 well sites (pads), with 20,386 acres disturbed. In the short term (see Table 1, Table 2, Table 1 **Shale**, and Table 2 **Shale**). The long-term disturbance after reclamation would be 6,415 acres.

II INTRODUCTION

The BLM GJFO is updating its Resource Management Plan. Compiled herein is resource information on the potential magnitude and trend of future oil, gas, and coalbed natural gas activity for the next twenty years (2009-2028).

III DESCRIPTION OF GEOLOGY

Piceance Basin

The Piceance Basin, formed during the Laramide Orogeny (late Cretaceous through Eocene), is located in the northeastern part of the GJFO and encompasses a significant portion of the field office surface area (Figure 11). Its present-day configuration was not defined until the White River Uplift began to rise, forming the present-day northeast margin of the basin (Johnson and Flores, 2003). Outside of the GJFO, the basin is bounded by the Grand Hogback and White River Uplift to the east, by the Gunnison Uplift to the south, by the Axial Basin Arch to the north, and by the Uncompahgre Uplift to the southwest. The Douglas Creek Arch separates the Piceance Basin from the Uinta Basin to the west. The kidney-shaped Uinta-Piceance Basin is about 100 miles long and 40 to 50 miles wide, with a northwest-southeast orientation.

Exposed bedrock in the Piceance Basin consists of sedimentary units ranging from Upper Cretaceous (late Mesozoic) to Middle Eocene (early Cenozoic) in age. Bedrock is exposed on dissected uplands, cliffs, and hogbacks. Outcrops include, in ascending order of age, the Mancos Shale, Mesaverde Group, Wasatch Formation, Green River Formation, and Uinta Formation. The Mesaverde Group is divided into the Iles Formation (including Rollins, Corcoran, and Cozzette sandstone members) and the overlying, massively stacked, lenticular non-marine Williams Fork Formation (including the Cameo Coal Zone). Most of the Mesaverde Group gas development has been from the Cozzette and Corcoran sandstones. The upper portion of the Piceance Basin sequence—the Uinta, Green River, and Wasatch Formations—is found in the De Beque area. The Wasatch and Mesaverde crop out along valley slopes, and the Mancos Shale is exposed in the valleys below the Mesaverde outcrop. The sequence of buried sedimentary rocks that overlie Precambrian igneous and metamorphic rocks include, in ascending order, the Chinle Formation, Wingate Sandstone, Kayenta Formation, Entrada Sandstone, Wanakah Formation, Morrison Formation, Burro Canyon Formation, Dakota Sandstone, Mancos Shale, Mesaverde Group, Wasatch Formation, and Green River Formation. A generalized stratigraphic column is shown on Figure 13.

The Piceance Basin is asymmetrical and deepest along its east side near the White River Uplift, where more than 20,000 feet of sedimentary rocks are present. Within the basin are numerous high-angle, small-displacement faults, and elongated anticlines and synclines. Structural dips are very steep to overturned along the eastern part of the basin (Grand Hogback); elsewhere in the basin, dips range between 1 and 20 degrees. Outcrops of Eocene- and Paleocene-age strata (Uinta, Green River, and Wasatch formations) dominate the surface exposures within the basin, with rocks of the Mesaverde Group and Mancos Shale occurring around the edges. In the structurally deepest parts of the basin, rocks of the Mesaverde Group are buried up to 4,000 feet below sea level (Johnson and Roberts, 2003).

Source rocks include coal beds and organic-rich carbonaceous shale rocks of the Upper Cretaceous Mesaverde Group, Mancos Formation, and Lower Cretaceous Mowry Formation. These rocks were deposited along the margins of the Western Interior Cretaceous Seaway in swamps and marshes associated with a deltaic and coastal plain environment. The thickest coals are found in the Cameo coal zone, which overlies the marine and marginal-marine sandstone successions in the lower part of the Mesaverde Group. Net coal thickness ranges from 20 to 80 feet. Gas expelled from coals and carbonaceous shales is interpreted as having migrated into nearby low-permeability sandstone beds of the Mesaverde Group, initiating basin-centered gas accumulations (Johnson and Roberts, 2002). The vertical migration of gas also expanded into the producing reservoir rocks of the overlying Tertiary Wasatch Formation. Peak gas generation from coals and carbonaceous rocks occurred about 47 million years ago (Johnson and Roberts, 2002). The Mancos Shale (Figure 20) is the source for gas that has migrated into the reservoirs in the lower part of the Mesaverde Group (Iles Formation). Gas migrated from the Mancos into the nearby fluvial, tidal, shoreface, and off-shore sandstone reservoirs of the Dakota Sandstone, Corcoran, Cozzette, and Rollins Sandstone Members. Other source rocks in the Piceance Basin include the Green River shales, mudstones, and marls that overlie the Wasatch Formation, and the Permian Phosphoria Formation, which is an oil source rock in the northern Piceance Basin (Figures 18 and 21).

The GJFO portion of the Piceance Basin (Figure 11) shows significant variation in thermal maturity of source rocks, as measured by vitrinite reflectance analyses. Thermally mature source rocks with higher vitrinite reflectance values indicate higher thermogenic gas generation based on depth of burial and higher temperatures, which occurs in the deeper part of the basin. The mature source rocks in the Piceance Basin, which delineate the areas of higher oil and gas resource potential, are shown on Figure 18 through Figure 21.

Productive and Potential Reservoirs

Productive and potential reservoir rocks within the GJFO include numerous sandstones and coals ranging in age from Upper Cretaceous to Lower Tertiary (Figure 13). These include the fluvial, tidal, and shoreface sandstone reservoirs of the Dakota Sandstone, tidal and shoreface deposits of the Corcoran, Cozzette, and Rollins Sandstone Members (Iles Formation), coal beds in the Cameo zone, fluvial channel sandstones in the middle and lower part of the Williams Fork Formation, and the Molina Member of the Wasatch Formation. Most of the data show that the Dakota, Cozzette, and Corcoran are low-permeability (tight) and unconventional gas reservoirs, which are defined as shales, tight gas, and coalbed methane reservoirs that may not produce economic volumes of gas without assistance from massive stimulation treatments or special recovery processes and technologies.

The fluvial sandstone reservoirs of the Williams Fork Formation are generally lenticular. They are and classified as tight, with low permeabilities, and are considered unconventional gas reservoirs. Enhanced permeability occurs with natural fracturing. The Wasatch fluvial reservoir is in the Molina Member, which is a relatively thin stratigraphic interval consisting of braided stream deposits. The vast majority of fluvial reservoir production is from the Williams Fork, with comparatively minor production from the Wasatch Molina Member.

In the north part of the GJFO, the Williams Fork fluvial sands and paludal (coal zone) intervals contain basin-centered gas accumulations and are considered unconventional or continuous based on the tight sands and regional extent of the reservoir. The gas accumulations in these fluvial lenticular sands are confined (sealed) by impermeable shales and the process of capillary seal or water block (Masters, 1979). The area of continuous gas accumulation overlies the area of mature source rocks (Figure 19). Additional gas may accumulate in structural and stratigraphic traps in conventional reservoirs, including fluvial sandstones in the Wasatch and a small potential for conventional-type accumulations in Mesaverde Group fluvial channel sandstones in basin-margin areas**.** The basin-margin gas is a low-permeability gas accumulation found in a shallow, permeable water-bearing zone around the margin of the basin containing scattered gas accumulations in reservoirs with conventional or near conventional permeabilities (Johnson et al., 1987).

The Iles Formation within the Mesaverde Group includes the Corcoran, Cozzette, and Rollins Sandstone Members. The two main types of traps within these sandstones are closed anticlinal structures and basin-centered accumulations (Brown et al., 1986). The anticlinal structures include Divide Creek, Coal Basin, and Wolf Creek. Basin-centered accumulations are represented by Shire Gulch, Plateau, and Rulison Fields (Brown et al., 1986). The Rollins Sandstone is water wet with minimal production, and the lack of a good seal (overlying coals) allows hydrocarbons to escape (Kirschbaum, 2002). The marine regressive limits (strandlines) of the Corcoran and Cozzette blanket reservoirs are oriented along a northeast-southwest trend in the southeastern portion of the basin, which defines the stratigraphic pinchout of these units. Because the Dakota Sandstone is classified as tight, it is generally considered a continuous gas accumulation, sealed by the overlying Mancos Shale.

The Mancos is a ubiquitous formation throughout many western basins that was deposited during the Late Cretaceous and is of approximately the same age as other known shale gas resource plays in the region including the Baxter, Hilliard, and Niobrara shales. This Mancos/Mowry system encompasses the formations from the top of the Mancos shale down through the Mowry shale. The Mancos is overlain by the Iles Formation of the Mesaverde Group and the Dakota Formation underlies the Mowry. The depth of the Mancos/Mowry section is over 4000' in areas of the Study Area.

Coalbed Natural Gas

The primary source of coalbed natural gas in the GJFO is the Cameo Coal Zone in the Williams Fork Formation. The northern portion of the GJFO is considered to have the highest potential for coal bed natural gas occurrence based on thicker net coal intervals and higher net gas content. However, coals that occur at depths in excess of about 5,500 feet are generally considered uneconomical because the coals tend to be more plastic and do not have the well-developed natural fracture permeability exhibited in coalbed productions regions. The United States Geological Survey (USGS) CBNG gas potential boundary shown on Figure 19 is based on a depth to significant coal beds of less than 7,000 feet, with the deeper coal beds excluded. Some of the previous attempts to produce coalbed gas in the southern part of the Piceance Basin were abandoned because of high water and low gas production. Other CBNG wells contained little water but were not very productive with respect to gas.

Coal Mine Gas

There is a potential coal mine gas resource associated with coal mines in the Book Cliffs. Currently there is only one small underground mine, the McClane Canyon coal mine operated by Central Appalachia Mining (Figure 24). No gas is being vented at this mine. Another much larger underground mine, the Red Cliff mine, is in the permitting process and may be located near the existing McClane Canyon mine.

Paradox Basin

The extreme southwestern portion of the GJFO lies within the Paradox Basin (Figure 23). The Paradox Basin was formed in Middle Pennsylvanian time as a result of faulting along the pre-existing, northwest-trending Uncompahgre lineament with uplift to the northeast and corresponding basin downwarping across the fault to the southwest. Salt anticlines developed in the deeper part of the basin as salt moved upward in response to sediment loading from the north (Scott, 2003). The basin contains the thickest sediments along the northeastern margin, where it is bounded by the Uncompahgre Uplift.

Rocks in the basin range in age from Precambrian through Cenozoic. The primary oil and gas-producing formation is the Middle Pennsylvanian Paradox Formation, which consists of cyclic carbonates, clastics, and evaporates deposited in a marine environment (Scott, 2003). The oldest formation with oil and gas production is the upper Mississippian Leadville Limestone. Overlying Pennsylvanian rocks include the Molas Formation and Hermosa Group, which includes the Paradox and Honaker Trail Formations. The Paradox Formation includes all of the evaporates, but production is from the interbedded carbonates. The overlying Honaker Trail consists of marine carbonates, shales, siltstones, and sandstones. The Permian Cutler Formation consists of fluvial sandstones and shales. The Cutler Formation is the youngest interval of potential gas production within the Study Area. A stratigraphic correlation chart for the Paradox Basin is shown on Figure 22.

The structures of Paradox Basin are controlled by northeast- and northwest-trending lineaments. The basin originated from faulting along the pre-existing northwest-trending Uncompahgre lineament, and the uplift resulted in basin downwarping to the southwest across the fault (Scott, 2003). Sinbad Valley is a northern extension of the Paradox Basin. Salt anticlines developed in portions of the basin, which appear as valleys because of the dissolution of the salt.

The Lower Paleozoic play within the Paradox Basin south of the GJFO consists of buried fault blocks, including the McCracken Sandstone and a dolomitized limestone reservoir in the Leadville Limestone. The source rocks are also the limestone. The gas is trapped and sealed by Paradox evaporates and by faults. The second play is salt anticline flanks, which includes the Permian Cutler Formation and the Pennsylvanian Honaker Trail Formation of the Hermosa Group. Reservoirs are developed in arkosic sandstones of the Cutler Formation and in limestones with minor sandstones in the Honaker Trail that accumulated as thick sediments in synclines along the margins of salt-cored anticlines. The trapping mechanism is a pinchout and updip termination against salt diapirs. The third play is fractured interbeds within the Paradox Formation, situated within the deep trough of the Paradox Basin and includes the Paradox fold and fault belt. The source rock and reservoir rock consists of fine-grained silty dolomite and dolomitic or calcareous black shale, trapped and sealed in fractures, with salt and shale interbeds (Witherbee, 1993). A fourth play includes the carbonate mounds buildup reservoirs within the Paradox Formation. Dolomitic shales are the source rocks for hydrocarbons within the carbonate mounds (Scott, 2003). Recently, a new play has been initiated in the western Paradox Basin of Colorado targeting the organic-rich Upper Paradox Gothic Shale interval, which is itself the source, reservoir, and seal of an unconventional, continuous-type gas accumulation. The play boundaries include a broad area of the Paradox Basin, and they are all located south of the GJFO.

IV. PAST AND PRESENT OIL AND GAS EXPLORATION ACTIVITY

Geophysical and Geochemical Surveys

There is one recorded geophysical project being permitted and run on public lands within the study area. The location of this seismic exploration project is in Township 8S, Range 102W and Range 103W on the Mesa and Garfield County line. The results of the project have not been made public.

Early Drilling History

The first recorded holes were drilled in the early nineteen hundreds around the Grand Junction town site. These tests were primarily for drinking water, but the Grand River Oil and Gas Company and the Eureka Oil Company were operators on some of these tests. Nearly every log records numerous oil or gas shows from the Dakota or Morrison Formations, but no production history is known.

The next major activity was in the early 1920s, when the prominent Garmesa anticline was drilled by the Carter Oil Company, Midwest Refining Company, J. Edgar Pew, Fulton Petroleum Corporation, and the Marland Oil Company. All of these tests were drilled to sufficient depth and encountered gas but were plugged for lack of a market.

The Gypsy Oil Company drilled their Marie #1 in 1926. This test in the Asbury Creek area (Section 9, Township 9S, and Range 101W) reported considerable gas before abandonment for the same reason. The Peerless Oil Company reported several shows in Section 23, Township 8S, Range 104W in 1927. None of these tests recovered commercial oil, and the area was more or less forgotten.

In 1948, Kerr-McGee drilled a Precambrian test on Garmesa anticline and completed this test as a gas well in the Morrison Formation. Amerada discovered Dakota gas in their Precambrian test on Asbury Creek in 1949. This well produced the first gas into Grand Junction in October 1952 and was the sole production until the line was extended to Garmesa in 1953. The Garmesa Field continues today, consisting of several temporarily abandoned wells. The current completions are from the Entrada Formation, which produces significant volumes of low British Thermal Unit (BTU) natural gas.

Exploratory Drilling and Success Rates

Areas of drilling activity are primarily delineated by the subsurface mapping of areas with favorable petroleum geology. Drilling will only occur where operators feel there is a likelihood of encountering hydrocarbons in the subsurface. Information from IHS Energy's PI/Dwight's well database was used to determine recent patterns in drilling activity in the Study Area. Electronic files of known oil, gas, and CBNG field boundaries were acquired from the Colorado Geological Survey and were also used in determining where future activity would likely be concentrated (Figure 9 through 10).

V. PAST AND PRESENT OIL AND GAS DEVELOPMENT ACTIVITY

Federal Mineral Leasing Activity

Existing federal oil and gas leases are shown in Figure 15. A review of the map finds that leases are concentrated in western Garfield County and northwestern Mesa County (north of the Colorado River), eastern Mesa County in the Plateau Creek Valley, and the Grand Mesa Slopes area east of Grand Junction. Drilling has occurred throughout this area starting in the early 1900s.

In southern Mesa County, i.e. south of the town of Gateway, leases have been issued in the past five years. The interest in this area for leasing is likely based on an increase in oil and gas prices. No drilling activity is known to have been proposed or performed for this area in the past 45 years.

United States Forest Service (USFS) lands have been leased in the Plateau Creek area with a recently approved proposed well development in the extreme eastern end of Mesa County (Township 9S, Range 92W). Very little development has occurred in the Study Area on USFS lands.

Historical leasing activity for federal minerals mirrors the swings in mineral commodity prices. The decrease in leased acreage in 2007 and 2008 resulted from a decision by the GJFO office to defer leases in areas with environmental concerns. Additionally, a large portion of the available lands with oil and gas potential or industry interest have already been leased.

Leasing Activity, 1989 - 2008

Year		Acres leased annually
1989		96,054
1990		21,042
1991		21,583
1992		17,596
1993		17,202
1994		44,169
1995		32,990
1996		14,893
1997		13,894
1998		7,927
1999		5,665
2000		38,395
2001		72,094
2002		20,441
2003		48,839
2004		61,085
2005		42,810
2006		122,937
2007		12,404
2008		10,517
Total		**722,537**

Federal Unit Agreements

A Federal unit agreement is a contract between the federal government and mineral interest owners 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 procedures, and permits controlled development of the unit area. This process stimulates exploration and development of federal lands and encourages the drilling of the optimum number of wells needed to maximize resource recovery.

Federal oil and gas leases are incorporated into 40 active conventional oil and gas unit agreement areas that lie wholly within the GJFO (Figure 2). Additionally, there are five active units with lands partially within the GJFO, but administered by other BLM Field Offices. Active units wholly within the GJFO encompass approximately 134,000 acres, or approximately 9.4 percent of the Study Area lands.

All but two of the above units are exploratory units in various stages of development. The earliest, the Bar X Unit managed by the Moab Field Office, was approved in 1952. While several exploratory units have been approved within the last ten years [Orchard, Ground Hog Gulch, Middleton Creek, Homer (Deep), and Whitewater], most active units were formed during the 1980s. Of the five units formed most recently, only the Homer (Deep) and Whitewater units are managed by the GJFO. The other three units have lands principally within and are managed by the Glenwood Springs Field Office.

The following ten companies operate the 38 active exploratory gas unit agreement areas:

- Fram Operating (1 unit) Formerly operated by Aspen
- Augustus Energy Partners, LLC (1 unit)
- Black Hills Exploration and Production (5 units)
- CDX Gas, LLC (1 unit)
- Chevron (1 unit)
- D&G Roustabout (1 unit)
- Delta Petroleum Corporation (2 units)
- Encana Oil and Gas (USA), Inc. (7 units)
- Maralex Resources, LLC (18 units)
- National Fuels (1 unit)

The largest of the 38 active exploratory units in the Study Area is the Whitewater Unit, which was originally proposed by Aspen Operating but is now operated by Fram America. The unit covers over 91,000 acres, with most of the acreage in the GJFO boundary (a portion extends into the Uncompahgre Field Office in Delta County). The size of this unit does not necessarily suggest high levels of drilling activity, as the unit drilling will target the Dakota Group gas using 80-acre spaced horizontal wells (generally, horizontal wells are more widely spaced than their vertical counterparts). Aspen had projected drilling up to 174 wells from 24 pad locations in the area (Aspen Operating, LLC, 2008), significantly reducing surface disturbance when compared to drilling each well from a unique location. This translates to an average of approximately 44 wells per township, considered herein to be a moderate level of activity.

The remaining two units, Asbury and Fruita, both located in Township 9S, Range 101W, are gas storage units operated by the Public Service Company of Colorado. Only the Asbury Unit has had any associated drilling of the unit (in this case, an injection well) since 1998. Both units are still active.

There are no secondary or enhanced recovery units within the Study Area. There are instances of coal bed methane participating areas located in exploratory units.

Operator Surveys

To aid the analysis of the RFD Scenario, we requested that operators who are active in the GJFO area (Study Area, see Figure 1) provide their projections for the location and intensity of future oil, gas, and CBNG exploration and development activity for the 2009-2028 planning period. The BLM provided each operator with two maps of the Study Area. Operators were asked to mark townships with their 2009-2028 projections of potential for conventional oil and gas drilling activity on one map, and potential for CBNG drilling activity on the other map. These maps included the entire Study Area, with a border of one full township surrounding the area for ease of use by the operators. These additional lands were not analyzed in this document; however, the information from operators was used to support estimations of future activity in adjacent townships within the Study Area. Operators were asked only for information concerning their own anticipated drilling plans, not for their estimations of future activity of the industry as a whole in the Study Area.

The BLM received written, e-mail, or verbal responses from 18 active companies in the Study Area (22 companies were sent letters with maps). Follow-up calls were made to some companies to further clarify their submittals. These companies account for the bulk of all oil, gas, and CBNG drilling in the Study Area in recent history.

Per the BLM's request, companies provided their insight by populating maps with areas and plays within the Study Area where they had a specific interest in developing an existing productive area or exploring for new hydrocarbon resources. Based on the numbers provided and recent drilling trends within the Study Area, most projections seemed to assume high commodity prices, ample rig availability, and the ability to obtain necessary drilling budgets. No operators submitted information suggesting any deep drilling efforts (wells greater than 15,000 feet in depth), but several showed their anticipation of future activity following a pad-drilling program, where a number of deviated wells are all drilled from the same surface location in areas where the spacing is tight. A limited amount of information relative to anticipated associated infrastructure (e.g., future pipeline needs) was also submitted.

The companies responding to our request for information included the following:

- Aspen Well Operating, LLC
- Augustus Energy Partners, LLC
- Berry Petroleum Company
- Black Hills Exploration and Production
- Chevron

- Delta Petroleum Corporation
- Encana Oil and Gas (USA), Inc.
- Marathon Oil Company
- National Fuel Corporation
- Oxy USA WTP LP
- Petroleum Development Corporation
- Plains Exploration & Production Company
- Walter Fees and Son
- Williams Production RMT Company

Well Spacing

The State of Colorado spacing requirement for wells greater than 2,500 feet deep is 40 acres (600-foot setbacks from lease line) but can be increased or decreased depending on geology and reservoir characteristics. The Colorado Oil and Gas Conservation Commission uses the term "default spacing," with modification occurring through cause orders. These adjustments are meant to maximize production of the resource while minimizing surface disturbance and expense. In some areas involving production from the Williams Fork Formation, 10-acre spacing has been justified and approved. The Wasatch Formation is being effectively drained of gas on 160-acre spacing. New spacing regulations will be necessary to accommodate new drilling and production techniques. Future production from previously undeveloped plays, such as the Niobrara, may also require spacing changes.

Communitization

Communitization (pool respective mineral interests) is used extensively within the Study Area. There are 112 communitization agreements involving more than 35,900 acres. They mainly communitize gas production from the Mesaverde/Williams Fork and the Cozzette Member of the Iles Formation.

Recent Historical Drilling Data

A total of 954 conventional oil and gas and 10 CBNG wells were spud (drilled) within the GJFO boundary since 1998 (IHS Energy, 2008). This represents approximately half of the total number of existing active wells in the Study Area as of December 2008. Wells spud since 1998 are shown with their status on Figures 3 and 4. Approximately 15 percent of the conventional wells and seven of the ten CBNG wells drilled since 1998 were drilled on federal mineral interests.

Conventional Drilling Activity

Of the 954 conventional wells spud within the Study Area boundary since 1998, most were drilled by operators or their predecessors who have provided input into this analysis. Of the wells drilled and completed, 96 percent were completed as producing gas wells. The remaining four percent were either dry holes or junked and abandoned wells. One gas storage injection well was completed during this time. There have been no recorded producing oil wells completed in the Study Area since 1998.

The high success rate (96 percent) of wells drilled in the Study Area is due to two factors:

- During the late 1970s and early 1980s, many exploratory wells were drilled that were determined to be capable of production in paying quantities but have never been produced to sales pipelines. Many of these wells are in locations where access to pipelines was restricted due to the well's low volume, pressure, or quality and have not been economically successful. Most producers do not view the wells as successful but are kept on the books to maintain leases. The BLM policy of not pursuing the further development of the leases is being discussed and may alter the status of these marginal or no production leases.

- Most of the recently completed wells were drilled as field development wells, and most of those were drilled as directional wells from multi-well pads (see Directional Drilling discussion below).

The majority of the abandoned wells were dry holes, with only three wells being junked and abandoned.

Operators

Since 1998, 35 operators have spud conventional gas wells, and five operators have spud CBNG wells in the Study Area (IHS Energy, 2008). The top five operators (Laramie Energy, Delta Petroleum Corporation, Oxy USA, Petroleum Development Corporation, and Plains Exploration and Production Company) were responsible for spudding 71 percent of the total conventional gas wells drilled. These five operators were among those providing information for this analysis.[1] Six of the thirty-five active operators have only drilled one conventional gas well within the Study Area in the past five years.

Although there are no active CBNG units in the Study Area, responses from industry indicated interest in developing CBNG plays of more than 250 wells in six townships. However, these are anticipated to be test pods (groupings generally of 9 or more wells) to determine the economics of any such play, and no CBNG wells have yet been spud in these areas.

Producing Intervals

Hydrocarbon production in the Piceance Basin comes from stratigraphic units ranging in age from the Tertiary Green River Formation to the Pennsylvanian Minturn Formation (U.S. Geological Survey, 2002).

The USGS groups reservoir and source rocks into logical "Total Petroleum Systems" based on the hydrocarbon genetic (chemical) relations within the formations (U.S. Geological Survey, 2002). Within the Piceance Basin, the USGS recognizes five such Total Petroleum Systems. They include:

- Green River System (Figure 18)
- Mesaverde System (Figure 19)
- Ferron/Wasatch Plateau System (located several miles outside of GJFO)

[1] Laramie Energy's interests were acquired by Plains Exploration and Production shortly before the operators were solicited for their comments. Plains' response included their anticipated development of the recently acquired leases. Shortly after all operator responses were received, Oxy USA purchased Plains' interests in the area.

- Mancos/Mowry System (Figure 20)
- Phosphoria System (Figure 21)

Each system is named for the hydrocarbon source rock and includes the formations in which the hydrocarbon has migrated to and become trapped, forming a reservoir. Some reservoirs contain hydrocarbons from more than one source and are thus included in more than one Total Petroleum System for analysis purposes (e.g., the Jurassic Morrison Formation contains hydrocarbon generated in both the Permian Phosphoria Formation and the Cretaceous Mancos and Mowry shales; thus, the Morrison is included in both the Phosphoria and Mancos/Mowry Total Petroleum Systems).

By far the most prolific production in the Study Area has come from the Cretaceous Dakota Sandstone, part of the Mancos/Mowry and Phosphoria Total Petroleum systems. Through November 2008, the Dakota has produced over 96 billion cubic feet of gas and 65 thousand barrels of oil (IHS Energy, 2008). This represents over 27 percent of the total cumulative gas production in the Study Area. The next largest producing horizons, each a part of the Mesaverde Total Petroleum System, include the following:

- Williams Fork Formation
- Corcoran Member of the Iles Formation
- Cozzette Member of the Iles Formation

It is difficult to attribute unique production values to the above formations, as each are routinely comingled with production from other formations in the same well. However, including comingled production, the above four formations account for approximately 28 percent of the total cumulative gas production in the Study Area. Together with the Dakota, these top five producing formations account for over half of the total cumulative gas production from the Study Area.

The Tertiary Wasatch Formation as well as the Jurassic Entrada Sandstone and Morrison Formation also produce gas and/or oil within the Study Area; however, their combined production represents less than 8 percent of the cumulative production from the area. The remaining 92 percent has come from Cretaceous-aged formations, including those from the Mesaverde Total Petroleum System discussed previously.

Carbonaceous shale is expected to be an important future source of natural gas in the United States. At present, there is little production information available to fully characterize the shale gas play that may be present within the Study Area. In the Piceance basin portion of the Study Area, the Mancos/Mowry Total Petroleum System assessment units are the most likely to be developed for shale gas resource plays.

These shales have proven attractive targets for gas drilling in recent years and a number of successful plays have been developed or are being developed in the Green River, Washakie, Sand Wash, Powder River, Denver, and Uintah basins (Energy Information Administration, 2010e).

Occasionally these plays are explored using vertical wellbores with multiple fracking and perforation zones but full development generally occurs using horizontal wellbores and large fracturing operations. Operators have targeted the Mancos shale in the northern portion of the Study Area starting in 2009. Figure 16a shows the location of the existing or proposed wells and the expected extent of the play.

Depths

Wells spud and completed in the past 10 years have been drilled over a wide depth range. Not including stratigraphic and CBNG tests and one deep, vertical, and unsuccessful recompletion to 15,531 feet, wells spud since 1998 in the Study Area have ranged from approximately 1,230 to 9,950 feet in vertical depth (IHS Energy, 2008). With the exception of the abovementioned recompletion, there have been no recently spud wells deeper than 10,000 feet in vertical depth.

Figure 5 shows the depth distribution of all wells spud since 1998. The majority of wells are between 5,500 and 9,500 feet in total vertical depth (88 percent of wells spud), and most of those (61 percent) are between 7,500 and 9,500 feet deep. Relatively few wells are shallower than 5,500 feet. In general, the deepest wells are found in the northeast and eastern portions of the Study Area, with depths progressively becoming shallower toward the southwest (Figure 6).

The three depth ranges most commonly drilled to on federal mineral interests are 3,500 to 4,500 feet (18 percent of spud wells), 5,500 to 7,000 feet (27 percent), and 8,500 to 9,000 feet (17 percent) total vertical depth.

Directional and Pad Drilling

Advances in drilling techniques have allowed for more widespread use of directional and horizontal drilling technology. Directional drilling has many benefits, but it also has limitations. For example, directional drilling may be employed to avoid sensitive or inaccessible surface features, increase the area that a well bore contacts a producing formation (allowing for increased production volumes), and, when multiple directionals are drilled from the same vertical well bore or from the same surface location, reducing associated waste volumes and emissions and providing greater protection of sensitive environments (Carr et al., 2003).

In addition to the benefits of directional and horizontal drilling outlined above, such wellbores will often be allowed to drift (updip) along the flanks of geologic structures (e.g., along the axis of a plunging anticline), thereby naturally contacting more of the producing formation. Directional wells also have the benefit of providing the operator with the option of drilling multiple wells from the same location, substantially reducing the surface disturbance and potentially avoiding environmentally sensitive areas.

Drilling and completion costs for directional and horizontal wells are typically significantly higher than for conventional vertical boreholes, even when the cost savings associated with reduced need for surface disturbance is taken into account. Eustes (2003) and Fritz et al. (1991) identified the following specialized requirements and risk factors unique to horizontal and directional drilling that can affect drilling and completion costs for these types of wells:

- Specialized equipment (e.g., mud motors, measurement while drilling tools) and specially trained personnel
- Larger drilling rig and associated equipment
- Casing and drilling string modifications to address problems associated with ovality and bending stresses
- Increased risk of borehole damage due to unique tectonic stresses

- Slower penetration rates lengthen overall drilling time on location, and/or increased torque and drag on borehole equipment

In addition to increased costs, the risk of losing the well due to geologic and/or mechanical failures is also greater in directional and especially horizontal boreholes than in conventional vertical boreholes. As a result of these increased costs and risk, operators tend to prefer vertical over directional or horizontal boreholes unless special circumstances exist that make such drilling a necessity or economically attractive. As an example, the geology of a reservoir may be such that a vertical borehole may only contact a few feet of the productive horizon, while a horizontal borehole may be able to contact tens to thousands of feet, depending on factors such as how the well is completed and the areal extent of the pool. In these cases, the operator must make the determination that the increased potential for productivity outweighs the inherent risks involved in directional and horizontal drilling.

It has become common in the Piceance Basin to drill multiple directional wells from a single surface location, a practice known as pad drilling. Pad drilling has many advantages to both the operator and the environment. While directional wells are generally more costly than their vertical counterparts, drilling multiple directional wells from a single location eliminates the costly process of moving the drilling rig and operations to a new location between spuds. Instead, many rigs today may simply be shifted on tracks several feet away from the recently drilled well to where the next well is spud.

Pad drilling may also maximize the efficiency of the production from a particular reservoir, depending on the geology. As these are directional (usually S-shaped) or horizontal wellbores, their close proximity on the surface has little bearing on their proximity in the producing formation. Depending on the anticipated area of drainage or spacing regulations, such well bores at the surface may only be separated by several feet, while in the subsurface they may be many hundreds of feet away from one another and spaced according to the most efficient means of production for that particular reservoir.

Drilling multiple wells from a single location may also minimize the impact of drilling activities on the local environment. In traditional drilling (i.e., one well per location), each well must have a drilling site cleared and a pad constructed to accommodate the drilling operations. Each location would have a road built for access, and each well may also need a right-of-way cleared for pipeline construction. Each location will usually have its own dedicated production equipment, which may cause an impact on the viewshed. Pad drilling centralizes the production equipment to one site, eliminates the need for multiple pipelines and roads, and requires only one surface location cleared for operations.

However, not all hydrocarbon reservoirs lend themselves to pad drilling. For example, many stratigraphic and structural traps are too small to be effectively developed using multiple, closely spaced wells. Reservoirs whose properties create wide drainage areas would likewise not benefit from the denser well spacing typical of pad drilling. As the geology of the area must be understood in great detail to design such programs, reservoirs whose lateral extent is unknown, or whose thicknesses are in question would also be poor candidates for these types of drilling programs.

Initial development of the Piceance Basin gas plays used traditional vertical wells. Ten years ago, only one in every six wells spud in the Study Area was a directional well (IHS Energy, 2008). Use of directional wells has steadily increased over time. This increase was a result of several factors, including overall cost reduction, federal and state requirements for reduced surface disturbance, and allowing more timely development of the resources.

By 2004, one of every three wells drilled was a directional or horizontal Dewell, and by 2005, operators in the area were drilling more directional and horizontal wells from multiple well pads than traditional vertical wells. By the end of 2007, the last full year of data for drilling trends in the area, operators drilled 20 directional wells for every single vertical well. These directional wells are generally of the S-shaped variety, and not diagonal nor horizontal. Horizontal drilling will be used to develop the Mancos- Niobrara shale plays.

The most active operators in the Study Area who responded to our request for information regarding their anticipated future drilling activity each showed plans to develop their acreage using pad drilling. Several productive gas reservoirs lend themselves to such drilling due to their depth and reservoir characteristics. These include the Williams Fork Formation (Mesaverde System), the Corcoran and Cozzette members of the Price River Formation (Mesaverde System), and the Dakota Sandstone and Mancos Shale of the Mancos/Mowry System.

Well Production Characteristics

Almost all wells that have been completed within the Study Area are gas wells. There are areas where the production of nitrogen and carbon dioxide (inerts) with the natural gas limit the economic viability of wells. There is one operational gas sweetening plant in the Badger Wash area, but it is currently shut in due to the current gas price. The operator reports that the plant may be shut in for an extended time due to economics and the capital expense needed to resize or redesign the plant.

Gas–oil ratios range from nearly dry gas to 30 mcf/bbl (thousand cubic feet per barrel) condensate. Gas BTU content will range from greater than 1,200 BTU per cubic foot ($ft^{3)}$ for Mesaverde completions in Plateau Valley to less than 500 BTU per ft^3 for Entrada completions in Township 9S, Range 104W in western Mesa County. The low BTU scenario contains significant levels of nitrogen and carbon dioxide, which lowers the quality and producing economics of the resource.

Helium has been reported in several wells in western Mesa County. Unsubstantiated reports indicate gas streams containing up to 4% helium. At this time, helium is not being separated from the gas stream in any facilities in the Study Area.

Produced Water

Many of the producing gas wells that are completed in the Mesaverde Group produce significant water. This water production is handled in one or a combination of methods. Some low-water producing wells are able to handle production using open produced water pits on the well location. Higher water producing wells require water to be either injected into disposal wells or placed in large produced water pits.

Disposing of produced water into subsurface reservoirs has had fair success due to the lack of surface reservoirs that are able to accept significant volumes of water. Currently, most water that cannot be handled by an individual well’s disposal pit is being transported by truck to commercial facilities near Cisco, Utah.

Well Life Determination

Abandonment rates for wells that were previously drilled in the Study Area cannot be estimated at this time. In some instances, wells with a status of dry and abandoned or junked and abandoned have no associated abandonment date; in others, abandonment dates are given, but the well status is still shown as active. For the purpose of calculating long-term surface disturbance, it is important to have an understanding of how many wells sites are likely to be reclaimed during the planning period. Toward this end, an average well life for gas wells within the Piceance Basin will be used. Published reports suggest that producing gas wells in the basin have well lives ranging between 17 and 30 years, with an average life of 20 years (West Hawk Development Corporation, 2006; Exxel Energy Corporation, 2007; Eden Energy Corporation, 2006). This report assumes that wells will be abandoned after a 20-year production cycle and that the associated well site and disturbed area will be reclaimed.

According to published academic research and industry briefs, the success rate for gas wells in the Piceance Basin ranges between 80 and 100 percent, with an average success rate of approximately 95 percent in most recent years (Bill Barrett Corporation, 2005; Boyce and Nostbakken, 2008; Delta Petroleum Corporation, 2006; Galaxy Energy Corporation, 2005; Kuuskraa, et al., 2007). However, most of the wells studied have been drilled in established resource plays (e.g., Williams Fork tight gas sand play) in the deeper part of the basin toward the northeastern and eastern portions of the Study Area. Lands in the western and southern portions of the basin, where significant exploration is still taking place, would be expected to have lower success rates. Recent technological advances have helped increase overall success rates in the industry, and since much of the drilling outside of the deeper part of the basin will still be infill and fringe drilling in or around existing fields, a success rate of 80 percent in these areas is not an unreasonable estimation.

Coalbed Natural Gas Activity

In 1986, Amoco Production Company formed the 150,000-acre Megas Unit to test the CBNG potential in the Bowie Coal Member of the Williams Fork Formation. The unit was terminated due to several factors, including economics, well performance, and seasonal access problems. Between 1989 and 1992, wells completed into coals and sandstones within the Grand Valley and Parachute Fields were found to have little contributing production from the coal beds, and additional attempts to complete wells into coals were abandoned.

Since 1998, only 10 CBNG wells have been spud within the Study Area (Figure 4). Seven of these wells are plug-backed well bores of deeper wells or sidetrack well bores from vertical wells that proved to be non-economic. None of the production data from any of these wells suggested that further CBNG development in the immediate area would prove to be economically feasible.

Operators contacted for information expressed limited interest in developing CBNG in the Study Area. This interest included the exploration of lands within six townships using pilot programs of 16 to 100 wells. It should be noted, however, that significant changes to these plans may occur, as no operator has yet begun development of these plays, there are no active coalbed plays in the area, and gas prices have fluctuated wildly in recent history. As of this writing, no applications to drill any of these proposed wells have been submitted for approval.

As there has been little production success or successful pilot programs of CBNG in the Study Area, it is difficult to say with authority which intervals, if any, will ultimately prove productive for CBNG during the planning period.

The USGS, in its 2002 oil and gas assessment of the Uinta-Piceance province, grouped several intervals of the Mesaverde and Ferron/Wasatch Plateau Total Petroleum Systems into CBNG assessment units. These units likely represent the most promising CBNG producers. The Ferron/Wasatch unit includes known coal deposits within the Cretaceous Ferron member of the Mancos Shale, and the Mesaverde unit includes coals from the Cretaceous Williams Fork Formation. Combined, these two units may ultimately contain up to 2.3 trillion cubic feet of gas; however, most of these potential resources lie north of the Field Office boundary in the northern portion of the Piceance Basin.

Oil Shale

The Study Area contains oil shale resources in the Green River Formation in several northern townships (Figure 17). The USGS performed an assessment of these in-place resources and presented its findings in an April 2, 2009 fact sheet. A review of the assessment indicates that the Study Area is on the far southern end of the USGS assessment unit and is estimated to contain 11% of the regional deposit. The township in the Study Area with the largest in-place oil shale volume is Township 5, Range 98W, with an estimated volume of 35,133 million barrels. See Table 3 for a listing of the townships that have oil shale resources in the Study Area and their respective estimated in-place oil volume.

The acreage that overlies the resource in the Study Area comprises approximately 110,000 acres of all mineral ownership, with approximately 51,600 acres of federal mineral ownership.

The ongoing research into the exploitation of oil shale is many years from resolution. Assigning economic or resource values to the resource is difficult at this time.

Commodity Price Estimates

Anticipated oil and gas prices are the single most important factor controlling the amount of future oil and gas drilling and production activity in the Study Area. Boswell (2006) reported that “in today’s market the average unconventional resource play breaks even at $4 per thousand cubic feet of gas and requires in excess of $7 per thousand cubic feet to achieve a 20 percent rate of return at the wellhead.” The National Petroleum Council (2003) has projected that through 2025 “supply and demand will balance at higher price ranges than historical levels” in the United States.

Gas Prices

Data for Figure 7 (historical and projected future natural gas prices) were obtained from the Energy Information Administration (2008a). The Energy Information Administration price projection data is an average for Lower 48 Wellhead Prices and is made in 2007 dollars. Historical prices are in nominal dollars. The trend in historical wellhead prices clearly shows the recent (2000 and later) volatility that has occurred in natural gas prices in Colorado. From 1986 to 1999, wellhead natural gas prices were relatively stable, with the exception of a drop and subsequent rebound in prices from 1994 to 1996. The drop of nearly 30 percent from 1985 to 1986 represents only a modest fluctuation when viewed in the context of the over 360 percent increase from 1986 to 2005 prices and the future price predictions outlined below.

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

The Energy Information Administration projects that natural gas prices will fall sharply in 2009 after the recent spike in prices that began in 2003 and likely culminated in 2008. Prices are then expected to begin a gradual and linear rise from $5.73 per thousand cubic feet (2007 dollars) in 2009 to $8.39 per thousand cubic feet in 2030 (Energy Information Administration, 2008a). It also predicts that this spike in natural gas prices will stimulate development of new gas supplies and constrain growth in natural gas consumption (Energy Information Administration, 2008b). The combination of a growing demand and limited supply has created market tightening and led to higher gas prices and price volatility (National Petroleum Council, 2003). However, the Energy Information Administration projects that in the long term, growth in domestic production will outpace growth in domestic demand, leading to a decline in net imports. Most of this growth is expected to come from nonconventional sources, in particular from gas shale production.

The National Petroleum Council anticipates that price ranges will be determined by response to "increased efficiency, conservation, and alternate fuel use, the ability to increase conventional and nonconventional supplies from North American… and increasing access to world resources through LNG imports" (National Petroleum Council, 2003). It is not known if liquefied natural gas imports will meet expectations or if new pipelines will connect gas supplies in northern Canada and Alaska with U.S. markets. While both scenarios would not happen for years, they could decrease future gas prices. Consequently, the projection of future natural gas prices should be considered speculative.

Drilling for natural gas in the Study Area has increased greatly over the last several years due in part to the increases in natural gas prices from 2002 to early 2008.[2] In 2002, when Colorado wellhead gas prices averaged $2.41 per million BTU (MBTU), the Study Area had 68 wells spud; conversely, by 2007 (the last year the Energy Information Administration has a published Colorado wellhead average gas price) the price had increased to over $4.50 and nearly 230 wells were spud.

An unprecedented rise and a precipitous drop in gas and oil prices occurred in 2008. Available drilling data suggest that the peak in prices seen in July of that year helped keep the Study Area drilling activity at near record levels, with at least 214 wells spud.[3] The Energy Information Administration predicts that average natural gas prices will level off near 2006 prices beginning in 2009 and slowly climb as demand increases through 2030.

[2] Drilling activity in the Study Area has also been greatly influenced by the increased use and efficiency of pad drilling, a practice that is expected to continue in the Study Area throughout the planning period. See *Directional Drilling* section above.

[3] IHS Energy wells data were incomplete for 2008 at the time of this writing. It is likely that the number of wells spud in the Study Area in 2008 was greater than the 214 wells in the database when these data were acquired in January 2009.

If the Energy Information Administration gas price scenario is accurate, the recent increase in drilling activity to current levels will likely ebb back to levels seen in 2005 and 2006 (100 to 200 wells drilled annually).

Oil Prices

Sieminski (2007) recently reported that West Texas Intermediate oil prices averaged $19.7 per barrel in the 1990s. In documentation submitted in support of his testimony before the U.S. House of Representatives Select Committee on Energy Independence and Global Warming, Sieminski (2008) stated that "our [Deutsche Bank] forecast for next year is that oil prices should average about $105 per barrel," and that "for the longer term... prices will settle toward the cost of marginal supply, or $85 per barrel..." While recent world events have seen oil prices fall from a high of over $146 per barrel (NYMEX light sweet crude futures price) in July 2008 to less than $65 per barrel in November 2008, it is likely that Sieminski's averages will approximate actual trends. Indeed, even with the large fluctuations in prices throughout 2008, the average price for light sweet crude was approximately $108 per barrel (Energy Information Administration, 2008c).

Data for Figure 8 (historical and projected crude oil prices) were obtained from the Energy Information Administration (2008a). The data are projected averages of imported Low Sulfur Light Crude Oil prices and are reported in 2007 dollars. Historical prices are in nominal dollars and show the historic volatility that has occurred in crude oil prices in Colorado. The significant climb seen in natural gas prices beginning in 1999 is also seen in crude oil wellhead acquisition prices in the Study Area.

The Energy Information Administration (2008a) projection of future prices predicts that world oil price projections will be higher for 2006-2030 than previous projections indicated. Domestic petroleum-based liquids consumption is expected to remain flat through 2030 (approximately 20 million barrels per day) due to increased use of and reliance on biofuels. However, worldwide demand will continue to increase during that time, driving world oil prices higher. The Energy Information Administration's reference case predicts that world oil prices will decline sharply from current levels to about $60 per barrel in 2009, start rising again as production in non-OPEC regions peaks, and continue to rise to $130 per barrel in 2030 (all prices in 2007 dollars). However, as stated in its 2008 projections, "recent volatility in crude oil prices demonstrates the uncertainty inherent in the projections" (Energy Information Administration 2008b). Such uncertainty is demonstrated in the Energy Information Administration's low-price and high-price case projections. These cases reflect a wide band of potential world oil price paths, ranging from $40-50 per barrel in the low case to over $180 per barrel in the high case in 2020 (Energy Information Administration, 2008a).

As the majority of production in the Study Area is from natural gas, and no significant oil fields have yet been discovered, it is unlikely that crude oil prices will have a significant effect on drilling activity beyond the influence crude oil prices have on the natural gas market unless new discoveries are made during the planning period.

Field Production Equipment and Field Operation Practices

A typical well location will contain a gas and fluid heater treater/separator for each well, at least one other tank to hold condensate, and water and gas metering equipment. Fluid is normally trucked or pipelined to central locations for processing or sale. Many low-volume producing wells will have one fluid tank where all liquid production is stored until there is sufficient volume to haul the water or condensate for disposal.

Gas compression operations are often performed on a field-wide basis with equipment sized to handle several dozen wells. The facilities will normally contain one or more compressors, gas dehydrators, water tanks, and gas metering equipment.

Production Facilities

Gas and Liquid Pipelines

The Study Area is served by several interstate transmission pipelines (Figure 14).

Williams Gas Pipeline – North West operates a 24-inch pipeline running through western Mesa and Garfield Counties. This pipeline is the transportation line for all production that leaves or enters the western end of the Study Area.

The TransColorado Gas Transmission Company operates a 300-mile natural gas pipeline that extends from the Greasewood area of Rio Blanco County, Colorado to a point of interconnection with the El Paso Natural Gas, Transwestern, and Southern Trails interstate pipelines at the Blanco Hub in San Juan County, New Mexico. The company reports a bidirectional flow capability of 650 MDth/d (million decatherms per day) northbound and an expanded capability of 425 MDth/d southbound.

Rocky Mountain National Gas operates a transportation system with lines heading south, west, and east of Plateau Valley. The line appears to be 6 inches in diameter, and the capacity is unknown.

In Colorado, the Rocky Mountain Natural Gas Company provides interconnections between natural gas producers in the western part of the state and the TransColorado Gas Transmission Company pipeline, discussed above. This pipeline travels south into New Mexico en route to the California market, through the Transwestern Gas Company and El Paso Natural Gas Pipeline Company systems.

The Public Service Company of Colorado (PSC) is the major distributor of gas in Colorado, with more end-use customers in a single state than any other company in the region. Colorado Interstate Gas Company provides nearly all of the gas to PSC of Colorado.

Compression Facilities

Oxy Petroleum maintains three gas compression facilities in or near the Plateau Valley. Two of the facilities, East Plateau and Brush Creek, are near Collbran and consist of four 1,400-horsepower (HP) gas engine-driven compressors. The discharge from the compressors is directed east through a 16-inch pipeline to a third compression facility in far-eastern Mesa County, Alkali Creek. This facility also contains four 1,400-HP compressors. This gas is then fed into an interstate pipeline owned by Questar; this pipeline heads to Rifle and then northwest. Alternatively, gas from the Plateau Valley area can be routed west to the DCP Anderson Gulch compression facility operated by Enterprise and then north into the Enterprise pipeline or into the TransColorado Gas Transmission Company system.

Delta Petroleum Corporation's Vega project is approximately 12 miles east of the town of Collbran in Mesa County, Colorado. At full field development, Delta's Vega area is projected to produce approximately 250 MMcfd (million cubic feet per day) from approximately 2,200 wells.

Delta recently completed construction on a natural gas compressor station in its North Vega field, the Mega Vega Station 1 (MVS1), approximately 12.5 miles east of Collbran along County Road 330. The station is designed to house eight compressors, but will start up with four compressors. The remaining four compressors will be installed in increments of two as additional development occurs. Once fully developed, MVS1 will have a capacity of 120 MMcfd.

Delta is planning a second compressor station, Mega Vega Station 2 (MVS2), which will be identical in compression capacity to MVS1 but will be located in the Buzzard Creek area. The combination of MVS1 and MVS2 will provide Delta with approximately 250 MMcfd of compression at full field development.

Delta currently relies on its Green Acres and Buzzard Creek compressor stations to support daily production in the Vega area. The Green Acres station consists of three compressors with a daily throughput capacity of 39 MMcfd. The Buzzard Creek station consists of two compressors with a throughput capacity of 13 MMcfd. Following MVS1 startup, both the Buzzard Creek and Green Acres compressor stations will be taken out of service.

Gas Plants

Natural gas liquids are produced at four gas plants and one fractionation plant in western Mesa County. These liquids are transported by truck and railway and by a pipeline operated by MAPCO, Inc.

The Bar X gas plant operated by ETC Canyon and the South Canyon Plant process gas from the western end of the Study Area.

The CFMI-operated fractionation plant processes high BTU natural gas, producing 1,000 bbls of Natural Gas Liquids that are trucked to the railhead in Fruita, Colorado for rail shipment. Historical throughput has been close to 2,000 bbls per day, but due to gas prices, many wells in the area have been shut in.

Badger Wash Nitrogen Rejection plant was shut in during early 2009 due to economics. The company does not expect to restart the plant for an extended period due to equipment limitations and product prices. This has caused many high-inert wells to also be shut in, as there is no other processing plant available for the production.

Conflicts with Other Mineral Development

The potential for conflicts with development of coal resources and natural gas production may occur in active coal mine areas within the Study Area. Central Appalachian Mining (CAM) is the operator of the one active coal mine in the Study Area. This subsurface mine is located in Township 8S, Range 102W in Mesa and Garfield Counties (Figure 24). In addition, the BLM is analyzing the permitting of an additional mine in the same township with the potential of a large increase in coal production. The mineable coal in the Book Cliffs area is often leased for oil and gas exploration or development, and the potential for both surface and subsurface conflicts may exist.

There is potential for oil and gas drilling in areas with potash deposits, but at this time there is no overlap of existing oil and gas operations and potash known areas of interest. It is likely than any future development of potash would be through solution mining operations. There should be adequate latitude in selection of well sites for either solution mining or oil and gas drilling to avoid direct impacts to either resource.

VI. OIL AND GAS OCCURRENCE POTENTIAL

Because hydrocarbons are nearly always found in sedimentary rock, the following definitions were used for classifying oil and gas occurrence potential:

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

The USGS has extensively mapped the surface and subsurface geology of the United States and publishes these data in the form of geologic maps and reports. The USGS also assesses oil and gas resources in major sedimentary basins in the United States, including the Uinta - Piceance Basin. The Piceance Basin covers the majority of the GJFO lands as well as lands to the north and the east; it continues to the west as the Uinta basin.

Conventional Oil and Gas Occurrence Potential

Recently, the USGS revised their method of preparing oil and gas resource assessments. They used this new method to update their previous quantitative estimate of the undiscovered oil and gas resource for the Uinta-Piceance province of Utah and Colorado (U.S. Geological Survey; 2002). This assessment was used to help better understand the likelihood for potentially undiscovered, technically recoverable oil and gas resources underlying the various lands within the Study Area and the potential for future development of these resources.

All areas within the Uinta-Piceance Basin in the Study Area are contained within specific plays or assessment units designated by the USGS; therefore, these areas are considered to have a high occurrence potential.

All areas within the Paradox Basin (within the GJFO) are designated as having an occurrence potential of "none" since one or more specific indicators of the presence of hydrocarbons (source rock, thermal maturation, reservoir strata possessing permeability and/or porosity, and traps) may not be present. The Uncompahgre Plateau forms the northeastern boundary of the Paradox Basin, and is not underlain by at least 1,000 feet of sedimentary rocks and therefore has no currently recognizable potential for oil and gas. The exposures are pre-Cretaceous, with intermittent Precambrian exposures, with a progressive thinning of the sedimentary section toward the north.

The 1,000-foot minimum sedimentary section is based on USGS geologic criteria for oil and gas potential. This includes sedimentary rocks that are covered with unconsolidated and volcanic deposits. Lands within the basin that are mapped as plutonic (intrusive) and metamorphic rocks have no oil and gas potential.

Coalbed Natural Gas Occurrence Potential

The northern portion of the GJFO is considered to have the highest potential for CBNG occurrence based on thicker net coal intervals and higher net gas content. However, coals that occur at depths in excess of about 5,500 feet are generally considered uneconomical because the coals tend to be more plastic and do not have the well-developed natural fracture permeability exhibited in coalbed production regions. The USGS CBNG potential boundary shown on Figure 19 is based on a depth to significant coal beds of less than 7,000 feet, with the deeper coal beds excluded. Some of the previous attempts to produce coalbed gas in the southern part of the Piceance Basin were abandoned because of high water and low gas production. Other CBNG wells contained little water, but were not very productive with respect to gas.

Using the above-cited criteria for classifying occurrence potential criteria, the Study Area has potential for the occurrence of CBNG ranging from high to none, as shown in Figure 19. All areas within the Mesaverde Coalbed Gas Geologic Boundary, as contained in the Mesaverde Total Petroleum assessment units designated by the USGS, are considered to have high occurrence potential. All areas outside of this boundary are designated as having no CBNG occurrence potential.

VII. DEVELOPMENT POTENTIAL

Conventional Oil and Gas Development Potential

Operator input on oil and gas development potential was considered and accepted unless it was in conflict with submittals from other operators, or other information was available to indicate a certain township should have a different potential designation than that submitted. Locations of established oil and gas fields, wells spud within the previous 10-year period, published data, geology and geologic trends, production statistics, and institutional knowledge of the region were all similarly used to determine where future activities would likely occur. These types of data were especially useful for making determinations of potential for future activities in townships for which operators did not indicate a potential.

The Piceance Basin southern boundary (U.S. Geological Survey; 2002) was used on the conventional oil and gas development potential map (Figure 9) and the Mancos shale gas development potential map (Figure 9a) to separate areas of no potential for development from areas with some potential for development, since immediately south of the basin metamorphic rocks (rocks which have undergone changes at temperatures and pressures to drive off any organics) crop out at or near the surface, and the USGS has not delineated potential assessments or plays within this area.

For a baseline RFD projection (Rocky Mountain Federal Leadership Forum, 2002, page 13), it was estimated that as many as 9,116 wells will be drilled in the Study Area during the planning period. This baseline activity scenario assumes all potentially productive areas can be open under standard lease terms and conditions, except those areas designated as closed to leasing by law, regulation, or executive order. Up to 250 of these wells could be CBNG wells (to be discussed below), with the remainder being conventional and shale gas wells.

Conventional Gas well development potential

A majority of the conventional gas wells, the majority (up to 4895 wells) are projected to be drilled in and around existing fields in the deeper portion of the Piceance Basin in the northeastern part of the Study Area. These areas are marked as very high, high, or moderate development potential on Figure 9. The remaining 357 conventional wells (those drilled in areas of low or very low potential) are projected to be drilled in areas generally not proven as productive by historical drilling, but which do contain existing active fields and lie within the USGS's Mesaverde Total Petroleum System mapped area. Also contributing to the low development potential areas are the townships south of the town of Palisade where one operator has already begun development of the Whitewater Unit with predicted development of low (3 to 39 wells per township) potential.

Drilling densities will vary by development area due to spacing limitations and pad drilling and are expected to follow recent trends in densities seen in the Study Area. As an approximation, the following shows the expected average density of fields in the five different development potential categories:

- Very high development potential
    - Developed predominately using multi-well pads
    - 4 pads per square mile (144 per township)

    - Downhole spacing between 10 and 40 acres per well

- High development potential

    - Developed with a mixture of single and multi-well pads
    - Up to 4 pads per square mile (144 per township)
    - Downhole spacing between 40 and 320 acres per well

- Moderate and Low development potentials

    - Developed principally with single well pads
    - Up to 4 pads per square mile
    - Variable downhole spacing depending on target

- Very low development potential

    - Developed with single well pads
    - Up to 2 pads per square mile
    - Variable downhole spacing depending on target

Several of the townships marked in Figure 9 as having very high and high development potential already are relatively densely drilled, though the majority is only partially developed. Most of the development in these townships is expected to be expansion of the existing Rulison and Grand Valley gas fields in the northeastern portion of the Study Area and the Vega and Brush Creek gas fields in the eastern portion of the Study Area.

Wells within townships marked in Figure 9 as having low and moderate development potential will likely be drilled as fringe and infill wells in existing fields, as wildcat wells looking to discover entirely new fields, or, in the townships south of Palisade, as expansion of the Whitewater Field. The variable well spacing in areas of low and moderate potential is likely to depend on the play(s) driving development.

In areas marked in Figure 9 as having very low development potential, very few new wells will be drilled and well densities will remain similar to what they are at present, with isolated townships having a small potential for an increase in drilling density, most likely around the fringes of townships marked with low or moderate development potential. In these areas, anticipated activity will be tied to exploration for new gas field discoveries, and most of these townships will not receive any drilling at all. If a new field discovery is made in any of these areas of very low development potential, subsequent drilling density could increase moderately. Based on previous exploration efforts in the Study Area, the probability of successful discovery of one or more new gas fields in these areas of very low development potential is unlikely (though possible) during the planning period.

Drilling depths (true vertical depth) are not anticipated to change significantly during the planning period (see Figures 5 and 6); however, there will likely be some minor localized increases in depth if deeper reservoirs are locally encountered. Few, if any, wells are expected to be drilled to depths exceeding 10,000 feet, as the productive formations within the Study Area's portion of the Piceance

Basin are generally found at significantly shallower depths. Most wells are expected to be drilled to depths between 5,500 and 9,500 feet. As such, pad drilling, and not drilling depth, is expected to be the limiting factor in well pad size.

Mancos Shale Gas Development Potential

The Mancos shale gas baseline shale gas wells are projected to be drilled from an area east of State Highway 139 to the field office boundary. The western and southern boundary of the play is based on known reservoir limits and the northern and eastern boundary is limited to the Study Area boundary. The majority of the shale gas wells (up to 3614 wells) will be drilled in the areas identified as very high, high or moderate (Figure 9a). All wells will be developed with multi well pads. Anticipated pad density will range from 36 to 72 per township and between 4 to 21 wells per pad.

- Very high development potential
  - Up to 250 wells per township

- High development potential
  - Up to 125 wells per township

- Moderate development potentials
  - Up to 72 wells per township

Coalbed Natural Gas Development Potential

Of the 502 anticipated CBNG wells, a large portion (up to 175 wells) are projected to be drilled in and around existing fields in the northeastern part of the Study Area (see below) and in areas shown to be of interest for development in operator responses. These areas are marked as high or moderate development potential on Figure 10. The remaining 327 wells (those drilled in areas of low or very low potential) are projected to be drilled in areas generally not proven as productive by historical drilling, but which do contain existing active wells and lie within the USGS Mesaverde Group coalbed methane assessment unit mapped area.

The USGS has identified the Mesaverde Group coalbed methane assessment unit as potentially productive within the Study Area. However, only limited exploratory drilling for CBNG has occurred in the Study Area. Since 1998, only 10 wells have been drilled that were identified as CBNG exploratory wells. None of these wells were part of a drilling program that included test pods designed to effectively dewater the coals prior to production.

Responses to our request for future drilling projections suggest moderate to high CBNG development potential in the northeast portion of the Study Area near and around the town of DeBeque. These townships are marked with moderate to high potential on Figure 10. It is anticipated that such development will likely occur as pods of 25 wells with spacing between 80 and 160 acres per well.

Two CBNG plays fall partially or wholly within the Study Area boundary, though each are predominately conventional gas plays containing several wells that have produced limited quantities of gas from coals. Grand Valley Field, a conventional gas play that includes several wells producing from Cretaceous coals within the Rollins Member of the Mesaverde Formation, lies mostly to the north of the Study Area but extends slightly into Townships 6S and 7S, Range 97W. South Shale Ridge Field, a CBNG field producing limited quantities from the Cretaceous Cameo Coal, lies wholly within Township 8S, Range 98W. Each of these townships lie adjacent to those mentioned above as areas of interest to industry and have also been assigned moderate potential, with development likely occurring as pods of 25 wells with spacing between 80 and 160 acres per well.

Three additional townships have CBNG wells spud since 1998 (Figure 4) but have not been further developed. These wells all targeted the Cretaceous Cameo Coal. Three of these wells are currently producing gas, and in anticipation of future interest in these areas, each of these townships was assigned low development potential. Development is expected to occur as pods of 9 to 16 wells with spacing between 80 and 160 acres per well.

Areas marked as very low development potential are lands that fall within the boundary of the USGS Mesaverde Group coalbed methane assessment unit but have not seen exploratory CBNG drilling since 1998, nor were identified as being of interest in operator responses. Areas marked with no potential are lands that fall outside of the Mesaverde Group coalbed methane assessment unit, the only coals thought to have potential for CBNG development within the Study Area.

VIII. RFD BASELINE SCENARIO ASSUMPTIONS AND DISCUSSION

It is difficult to accurately predict what will occur a few years from now and even more difficult to predict what will occur 20 years into the future. In an attempt to gain more insight as to what may occur in the Study Area, major oil and gas companies operating in the Study Area were contacted by letter and asked what development activity they anticipated during the next 20 years. The BLM also contacted many of these companies by telephone to clarify information after replies were received. These data were compiled and were used to help predict locations and amounts of future drilling activity within the Study Area. Available technical data were also reviewed to assist with these projections. Much of the data reviewed have been summarized above.

In the period from 2009 to 2012 operators have submitted approximately 80 well applications for Mancos development on Federal minerals within the Study Area. Many of these exploratory projects have not been drilled or are early in their production history so it is difficult to project their long term success.

Three maps were prepared to show the assessed potential for conventional, Mancos Shale gas and CBNG exploration and development activities for the planning period (see Figures 9, 9a and 10). Future activity was categorized into distinct categories based on the anticipated number of wells (individual wellbores, not well locations) to be drilled per township during the planning period.

For conventional drilling potential these categories were:

- Very High Potential: 500 or more wells per township
- High: 100 to 499 wells per township
- Moderate: 40 to 99 wells per township
- Low: 3 to 39 wells per township
- Very Low: less than 3 wells per township
- None: No anticipated drilling activity during the planning period

With respect to Mancos shale gas drilling potential these categories were:

- Very High Potential: 250 wells per township
- High Potential: 125 wells per township
- Low Potential: 72 wells per township

With respect to CBNG activity in the area during the planning period, the following categories were used:

- High: 100 or more wells per township
- Moderate: 20 to 99 wells per township
- Low: 2 to 19 wells per township
- Very Low: less than 2 wells per township
- None: No anticipated drilling activity during the planning period

Each map also outlines areas of no leasing (Wilderness Study areas, Colorado National Monument, and McInnis Canyons National Conservation Area). Areas of no leasing are by definition areas that will see no drilling activity and are thus labeled as "none" on these potential maps.

IX. SURFACE DISTURBANCE DUE TO OIL AND GAS ACTIVITY ON ALL LANDS

The following assumptions and guidelines for roads, drill pads, pipelines, and ancillary facilities were used to determine acres of surface disturbance expected to be associated with oil and gas exploration and development activities. Refer also to Table 1 and Table 1 - Shale.

The assumptions for conventional oil and gas development are based on existing oil and gas development across the Grand Junction Field Office.

Well and Pad Density –Conventional Oil and Gas

- Very High – 500 or more wells per township

  These areas would predominately be developed with multi-well pads at an average of 4 pads per square mile. Downhole spacing density will range from 10 to 40 acres per well (2,304 to 575 wells [wellbores] per township). These areas will be developed using an average of eight wells per pad.

- High – 100 to 499 wells per township

  These areas would predominately be developed with a mixture of single and multi-well pads. Well pad density would not exceed an average of 4 pads per square mile. Downhole spacing density will range from 40 to 320 acres per well (576 to 72 wells per township). These areas will be developed using an average of three wells per pad.

- Moderate – 40 to 99 wells per township

  These areas would be developed with single well pads with well density not exceeding an average of 4 pads per square mile. Downhole spacing density will range from 40 to 320 acres per well.

- Low – 3- 39 wells per township

  These areas would be developed with single well pads with well density not exceeding an average of 4 wells per square mile.

- Very Low – less than or equal to two wells per township.

  These areas would be developed with single well pads with well density not exceeding two wells per square mile.

Well and Pad Density –Mancos Niobrara Shale Gas

- Very High – 250 wells per township and an average of 1 pad per section.
- High – 125 wells per township and an average of 1 pad per section
- Moderate – 72 wells per township and an average of pad per section

Drill Pad Disturbance

Drill pad disturbance will vary based on the number of wells planned for a pad and the topography of the area. If a well is completed successfully mandatory partial reclamation of the pad disturbance area will occur. This interim reclamation reduces the amount of disturbed surface, and the resulting pad area is labeled below as long-term disturbance. If a well is unsuccessful, the entire well pad will be reclaimed, and no long-term disturbance will occur.

The table below was developed by reviewing past approvals of BLM or USFS projects in the area. The variability of differing surface topography is important, but the numbers presented below are representative average values.

Development Potential Conventional	Average Initial Disturbance (acres/pad)	Long-Term Disturbance (acres/pad)
Very high	5.4	1.5
High and Moderate	4.5	1.5
Low and Very low	2	1

Development Potential Mancos Shale Gas	Average Initial Disturbance (acres/pad)	Long-Term Disturbance (acres/pad)
Very high	12	8
High and Moderate	6	2
Low and Very low	6	2

Access Roads

A detailed study of recent development in the area labeled as Very High Conventional development potential indicates an access road disturbance of 6.5 acres per section would be required. The areas that were studied have been developed with four pads per section in moderate to severe terrain. The area had no prior existing roads, or the existing roads required major upgrades.

This office anticipates approving typical road widths of a total 24-foot disturbed area and an 18-foot running surface. These widths are based on the Gold Book standards and established Best Management Practices. The 6.5-acre surface disturbance per section assumes a road disturbance of 24 feet and is equivalent to 2.9 acres per linear mile.

Determining the access road disturbance for the High and Moderate development potential area would follow similar ideas to the Very High potential area; therefore, the use of 6.5 acres per section is used here also.

The anticipated access road disturbance for the Low to Very Low potential area is based on single well pads and would range widely based on the location of the well from other developed roads. Again assuming the area has no prior roads or has insufficient roads, the average road disturbance would be 2 acres per section, which is equivalent to 0.7-mile road length.

Pipelines

The table below assumes the well and well pad densities described above for Conventional Oil and Gas pipelines would be run parallel to the access roads, 50-foot average pipeline right-of-way widths, and full reclamation occurring at the time of installation. The assumption that the pipelines and access roads would be run parallel may result in higher estimates of surface disturbance than what is actually approved. In some installations the construction areas may overlap, which will reduce the initial disturbance figures. Calculations for Mancos Shale Gas pipeline disturbances are assumed to be similar to the table below.

Development Potential	Pipeline Average Initial Disturbance (acres per section)	Pipeline Long-Term Disturbance (acres per section)
Very high	17.5 (2.9 miles@ 50 feet)	0
High and Moderate	17.5 (2.9 mile @ 50 feet)	0
Low and Very low	4.2 (.7 miles@ 50 feet)	0

Miscellaneous Assumptions

The number of BLM-managed wells equals the number of total wells in each category times the percent of BLM-managed lands in each development category. This assumes wells are equally distributed aerially within each development category.

Ratio of new wells on BLM-managed lands to new wells on all lands within each development category will be proportional to the ratio of BLM-managed lands to total lands for each development category.

For new CBNG wells, approximately 63 percent will be located on BLM-managed lands and the wells will be developed with one well per pad due to the shallow depth of many current CBNG wells. Success rate for CBNG wells will approximate similar development in the Rocky Mountain basins of 90 percent. Existing CBNG wells will be treated as conventional wells for purposes of abandonment rates.

Average well life of Piceance Basin conventional gas wells is 20 years (West Hawk Development Corporation, 2006; Exxel Energy Corporation, 2007; Eden Energy Corporation, 2006).

Average well age range is 10 to 30 years.

Active wells completed in 1999 and earlier will be abandoned by 2027 (905 of the existing 1,816 wells).

Half of the active conventional gas wells completed from 2000 to 2008 will be abandoned by 2027 [0.5 * (1816-905) = 456 wells].

Wells assumed to be abandoned by potential area are as follows (wells on BLM-managed lands in parentheses):

Potential	Active Wells	Active Wells	Active Wells	Active Wells

	Completed 1999 and Earlier	Completed 1999 and Earlier to be Abandoned	Completed 2000 to 2008	Completed 2000 to 2008 to be Abandoned
Very High	85 (6)	85 (6)	764 (56)	382 (28)
High	56 (11)	56 (11)	61 (13)	31 (7)
Moderate	148 (89)	148 (89)	37 (21)	19 (11)
Low	583 (412)	583 (412)	61 (40)	31 (16)
Very Low	21 (13)	21 (13)	0	0
None[4]	12 (12)	12 (12)	0	0
CBNG Wells	35 (20)	35 (20)	11 (11)	6 (6)

[4] 12 wells completed prior to the designation of several no leasing areas in which they presently are located. Each is expected to be abandoned during the planning period.

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XI. APPENDIX

Table 1:	Study Area surface disturbance associated with new drilled wells and existing wells (through December 2008) for the baseline scenario (short-term disturbance) for the 2009-2028 period
Table 2:	Study Area surface disturbance associated with new producing wells, existing wells (through December 2008), and projected producing wells for the baseline scenario (long-term disturbance) for the 2009-2028 period
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XI. GLOSSARY

Basin-centered accumulation – For this report, the basin-centered gas is a continuous gas accumulation found in the structurally deeper part of the Piceance Basin.

Continuous gas accumulations – Also called unconventional, petroleum accumulations that are regional in extent, commonly having low matrix permeabilities; no obvious seals, traps, or hydrocarbon-water contacts; are abnormally pressured; are in close proximity to source rocks; and have low recovery factors.

Conventional gas accumulations – Discrete petroleum accumulation with a well-defined hydrocarbon-water contact, commonly having high matrix permeabilities, obvious seals and traps, and high recovery factors.

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.

Reservoir rock – A connected layer of porous rock, such as sandstone or carbonates, containing varying amounts of oil, gas, and/or water, based on variations in permeability, porosity, and water saturation.

Resource Play to describe accumulations of hydrocarbons known to exist over a large areal extent and a thick vertical section. They may be self-sourcing, may be developed with horizontal well completions, and are driven by development efficiencies rather than geologic risk.

Source rock – Rocks, such as coal, carbonaceous shale, or shale, which provide the source for gas generation and subsequent migration into reservoir rocks.

Table 1. Study Area surface disturbance associated with new Conventional drilled wells and existing wells (through December, 2008) for the baseline scenario (short-term disturbance) for the 2009-2028 period.

Wells			Disturbed Sites			Acres of Surface Disturbance (per site)			
Type	**Total**	**BLM Managed**	**Wells per pad (avg)**	**Total Disturbed Sites**	**BLM Managed Disturbed Sites**	**Access Roads and Pipelines**	**Well Pad**	**Total**	**BLM Managed**
New Exploratory and Development Coalbed Gas Wells	250	157	1	250	157	0.6	1.5	525	341
New Exploratory and Development Conventional Wells in:									
Very High Potential Areas	*3,695*	*1,020*	*8*	*462*	*127*	*6*	*5.4*	*5,265*	*1,453*
High Potential Areas	*950*	*262*	*3*	*317*	*87*	*6*	*4.5*	*3,325*	*915*
Moderate Potential Areas	*250*	*132*	*1*	*250*	*132*	*6*	*4.5*	*2,625*	*1,388*
Low Potential Areas	*325*	*246*	*1*	*325*	*246*	*7.85*	*2*	*3,201*	*2,427*
Very Low Potential Areas	*32*	*14*	*1*	*32*	*14*	*7.85*	*2*	*315*	*138*
Total New Exploratory and Development Conventional Wells	5,252	1,674	Total New Disturbed Sites (Conventional Wells)	1,386	607	Total New Surface Disturbance (Conventional Wells)		14,732	6,322
Total New Exploratory and Development Wells	5,502	1,831	Total New Disturbed Sites	1,636	765	Total New Surface Disturbance		15,257	6,663
Existing Active Coalbed Natural Gas Wells	46	31	1	46	31	0.6	0.5	51	36
Existing Active Conventional Wells in:									
Very High Potential Areas	*849*	*62*	*8*	*106*	*8*	*1.625*	*1.5*	*332*	*24*
High Potential Areas	*117*	*24*	*3*	*39*	*8*	*1.625*	*1.5*	*122*	*25*
Moderate Potential Areas	*185*	*110*	*1*	*185*	*110*	*1.625*	*1.5*	*578*	*344*
Low Potential Areas	*644*	*452*	*1*	*644*	*452*	*3.6*	*1*	*2,962*	*2,079*
Very Low Potential Areas	*21*	*13*	*1*	*21*	*13*	*3.6*	*1*	*97*	*60*
Total Existing Active Conventional Wells	1,816	661	Total Existing Disturbed Sites (Conventional Wells)	995	591	Total Existing Surface Disturbance (Conventional Wells)		4,091	2,532
Total Existing Wells	1,862	692	Total Existing Disturbed Sites	1,041	622	Total Existing Surface Disurbance		4,141	2,568
Total Wells	**7,364**	**2,523**	**Total Short-Term Disturbed Sites**	**2,677**	**1,386**	**Total Short-Term Disturbance**		**19,398**	**9,232**

Table 2. Study Area surface disturbance associated with new producing wells, existing wells (through December, 2008), and projected producing wells for the baseline scenario (long-term disturbance) for the 2009-2028 period.

Wells			Disturbed Sites			Acres of Surface Disturbance (per site)			
Type	**Total**	**BLM Managed**	**Wells per pad (avg)**	**Total Disturbed Sites**	**BLM Managed Disturbed Sites**	**Access Roads and Pipelines**	**Well Pad**	**Total**	**BLM Managed**
New Producing Coalbed Natural Gas Wells (90 percent success rate)	225	142	1	225	142	0.6	0.5	248	166
New Producing Conventional Wells in:									
Very High Potential Areas (95 percent success rate)	*3,510*	*969*	*8*	*439*	*121*	*1.625*	*1.5*	*1,371*	*379*
High Potential Areas (95 percent success rate)	*903*	*248*	*3*	*301*	*83*	*1.625*	*1.5*	*940*	*259*
Moderate Potential Areas (80 percent success rate)	*200*	*106*	*1*	*200*	*106*	*1.625*	*1.5*	*625*	*331*
Low Potential Areas (80 percent success rate)	*260*	*197*	*1*	*260*	*197*	*3.6*	*1*	*1,196*	*907*
Very Low Potential Areas (80 percent success rate)	*26*	*11*	*1*	*26*	*11*	*3.6*	*1*	*118*	*52*
Total New Producing Conventional Wells	4,898	1,532	Total New Disturbed Sites (Producing Conventional Wells)	1,225	518	Total New Surface Disturbance (Producing Conventional Wells)		4,250	1,926
Total New Producing Exploratory and Development Wells	5,123	1,673	Total New Disturbed Sites	1,450	660	Total New Surface Disturbance		4,498	2,092
Existing Active Coalbed Natural Gas Wells	5	5	1	5	5	0.6	0.5	6	6
Existing Active Conventional Wells in:									
Very High Potential Areas	*382*	*28*	*8*	*48*	*4*	*1.625*	*1.5*	*149*	*11*
High Potential Areas	*30*	*6*	*3*	*10*	*2*	*1.625*	*1.5*	*31*	*6*
Moderate Potential Areas	*18*	*10*	*1*	*18*	*10*	*1.625*	*1.5*	*56*	*31*
Low Potential Areas	*30*	*24*	*1*	*30*	*24*	*3.6*	*1*	*138*	*110*
Very Low Potential Areas	*0*	*0*	*1*	*0*	*0*	*3.6*	*1*	*0*	*0*
Total Existing Active Conventional Wells	460	68	Total Existing Active Disturbed Sites (Conventional Wells)	106	40	Total Existing Surface Disturbance from Active Conventional Wells		375	159
Total Existing Active Wells	465	73	Total Existing Active Disturbed Sites	111	45	Total Existing Active Surface Disturbance		380	165
Total Wells	**5,588**	**1,746**	**Total Long-Term Disturbed Sites**	**1,561**	**704**	**Total Long-Term Disturbance**		**4,878**	**2,257**

Table 1 Shale. **15 Rig Constraint** - Study Area surface disturbance associated with new drilled ***Mancos - Niobrara Horizontal Development*** for the baseline scenario **(short-term disturbance)**

Wells			Disturbed Sites			Acres of Surface Disturbance (per site)			
Type	**Total**	**BLM Managed**	**Wells per pad (avg)**	**Total Disturbed Sites**	**BLM Managed Disturbed Sites**	**Access Roads and Pipelines**	**Well Pad**	**Total**	**BLM Managed**
New Exploratory and Development Horizontal Wells in:									
Very High Potential Areas	*2,077*	*1,395*	*21*	*99*	*66*	*6*	*12*	*1,780*	*1,195*
High Potential Areas	*842*	*474*	*7*	*120*	*68*	*6*	*6*	*1,443*	*812*
Moderate Potential Areas	*695*	*239*	*4*	*174*	*60*	*6*	*6*	*2,085*	*716*
Total New Wells	3,614	2,107	Total New Disturbed Sites	393	194	Total New Surface Disturbance		5,309	2,724
Existing active or approved Horizontal wells in:									
Very High Potential Areas	*4*	*3*	*4*	*1*	*1*	*6*	*6*	*12*	*8*
High Potential Areas	*5*	*3*	*4*	*1*	*1*	*6*	*6*	*15*	*8*
Moderate Potential Areas	*20*	*7*	*6*	*3*	*1*	*6*	*6*	*40*	*14*
Total Existing Wells	29	12	Total Existing Disturbed Sites	6	3	Total Existing Surface Disturbance		67	30
Total Wells	**3,643**	**2,119**	**Total Short-Term Disturbed Sites**	**399**	**196**	**Total Short-Term Disturbance**		**5,376**	**2,754**

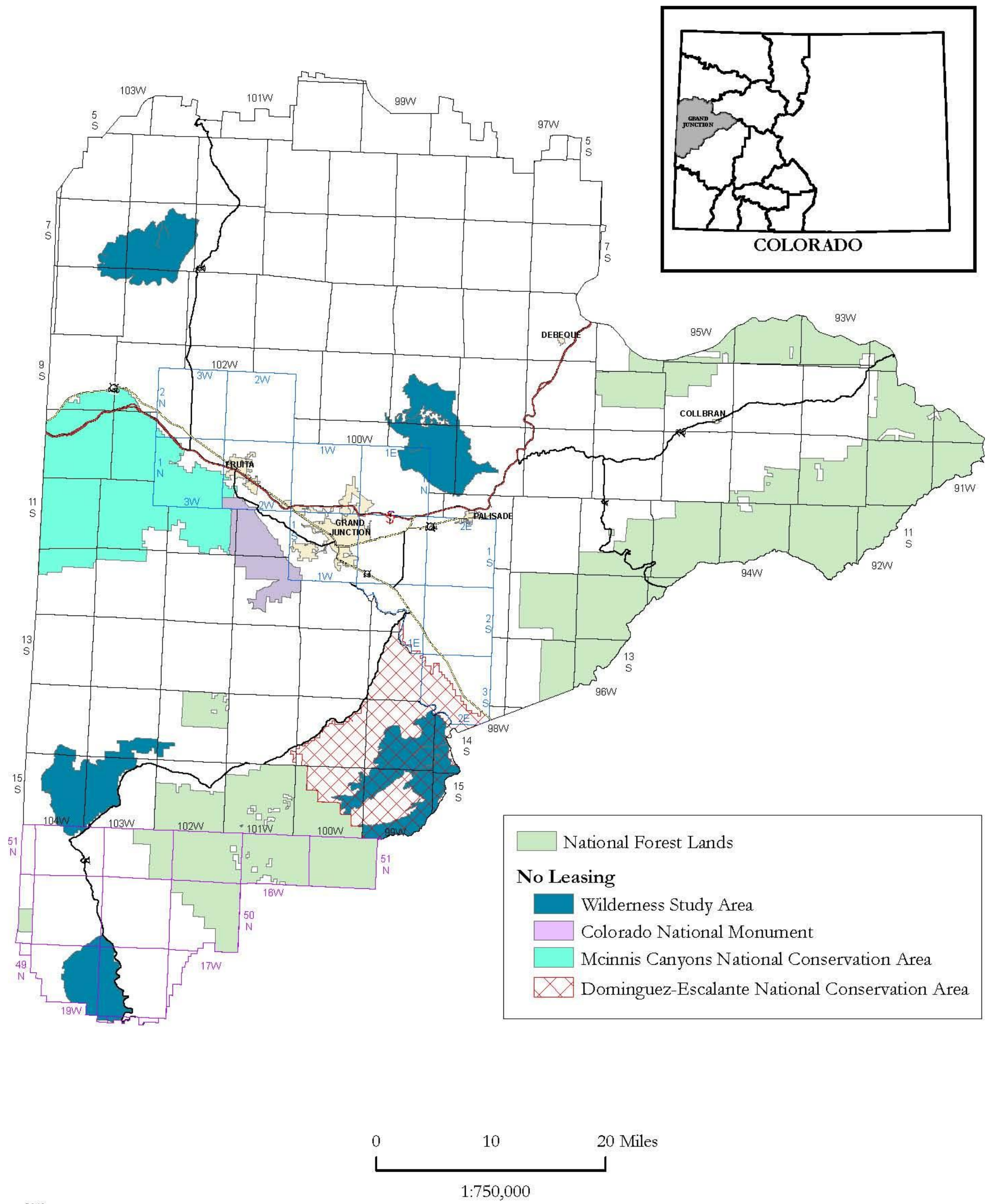
Table 2 Shale. Study Area surface disturbance associated with drilled Mancos - Niobrara development for the baseline scenario **(long-term disturbance)**

Wells			Disturbed Sites			Acres of Surface Disturbance (per site)			
Type	**Total**	**BLM Managed**	**Wells per pad (avg)**	**Total Disturbed Sites**	**BLM Managed Disturbed Sites**	**Access Roads and Pipelines**	**Well Pad**	**Total**	**BLM Managed**
New Producing Horizontal Wells in:									
Very High Potential Areas (95 percent success rate)	*1,973*	*1,325*	*21*	*94*	*63*	*1.625*	*8*	*904*	*607*
High Potential Areas (95 percent success rate)	*800*	*450*	*7*	*114*	*64*	*1.625*	*2*	*414*	*233*
Moderate Potential Areas (95 percent success rate)	*660*	*227*	*4*	*165*	*57*	*1.625*	*2*	*598*	*206*
Total New Producing Exploratory and Development Wells	3,433	2,002	Total New Disturbed Sites	373	184	Total New Surface Disturbance		1,917	1,046
Existing Horizontal Active Wells in:									
Very High Potential Areas	*4*	*3*	*4*	*1*	*1*	*1.625*	*2*	*4*	*3*
High Potential Areas	*5*	*3*	*4*	*1*	*1*	*1.625*	*2*	*5*	*3*
Moderate Potential Areas	*20*	*7*	*6*	*3*	*1*	*1.625*	*2*	*12*	*4*
Total Existing Active Horizontal Wells	29	13	Total Existing Active Disturbed Sites	6	3	Total Existing Active Surface Disturbance		20	10
Total Wells	**3,462**	**2,015**	**Total Long-Term Disturbed Sites**	**379**	**187**	**Total Long-Term Disturbance**		**1,937**	**1,055**

Table 3.In-place Oil from Shale Resources in the Grand Junction Field Office (USGS)	
Township and Range	**Oil in millions of barrels**
4S. 100W.	10,456
5S. 97W.	35,113
5S. 98W.	24,305
5S. 99W.	17,894
5S. 100W.	9,643
5S. 101W.	926
6S. 97W.	20,284
6S. 98W.	10,492
6S. 99W.	4,977
6S. 100W.	4,469
6S. 101W.	1,851
7S. 96W.	1,544
7S. 97W.	5,451
7S. 98W.	1,347
7S. 99W.	2,444
7S. 100W.	2,588
7S. 101W.	689
8S. 93W.	2,056
8S. 95W.	4,177
8S. 96W.	42
8S. 99W.	584
9S. 95W.	367
9S. 96W.	69
Grand Junction Field Office Total	**161,800** (11% of Regional Deposit)

Figure 1.

Bureau of Land Management, Grand Junction Colorado Field Office, Reasonably Foreseeable Development Study Area.



February, 2010
Dean Stilwell, Geologist
Al Elser, Geologist
Stan Lawrence, Petroleum Engineer

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Figure 2.

Federal unit agreement areas.

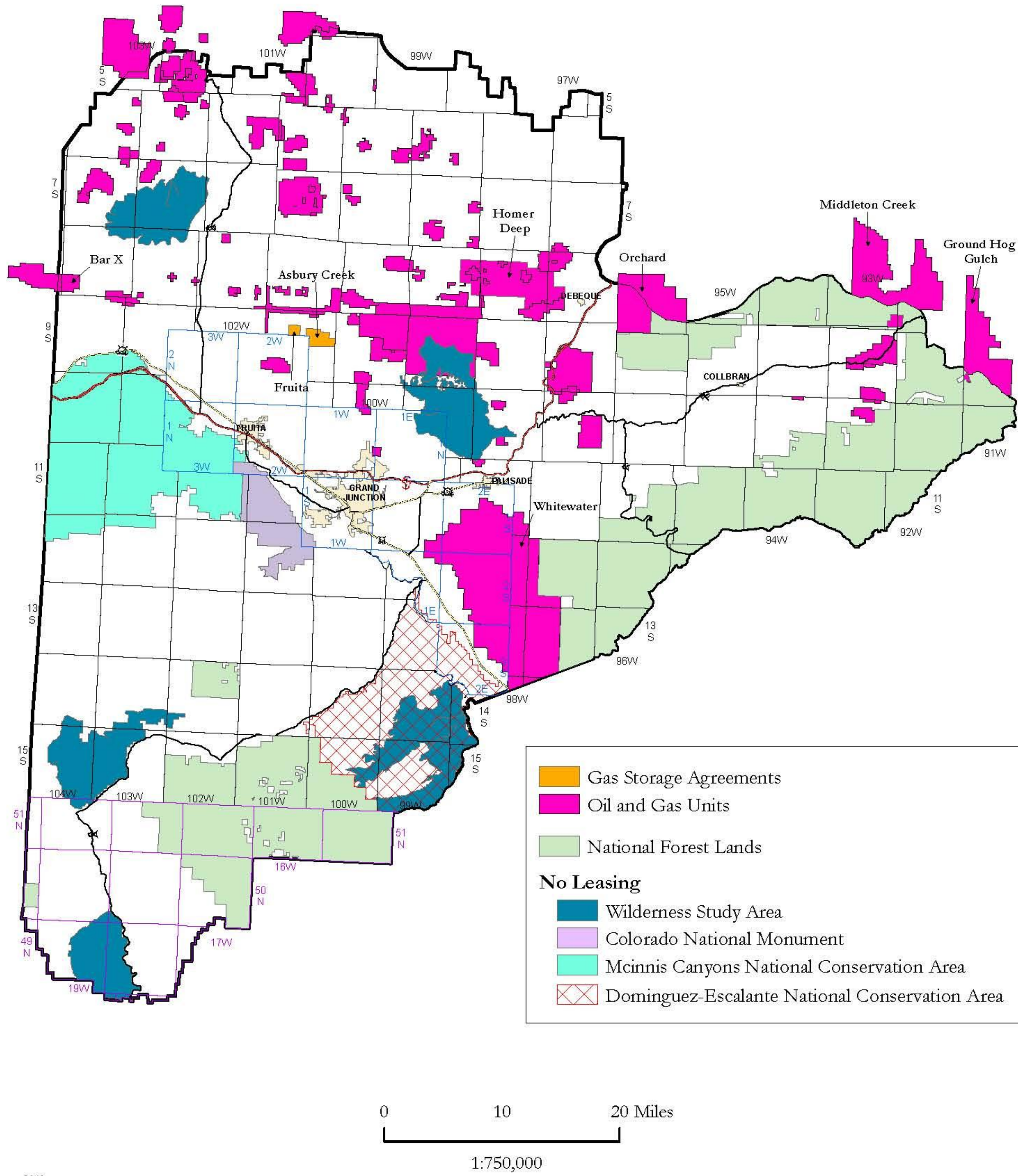

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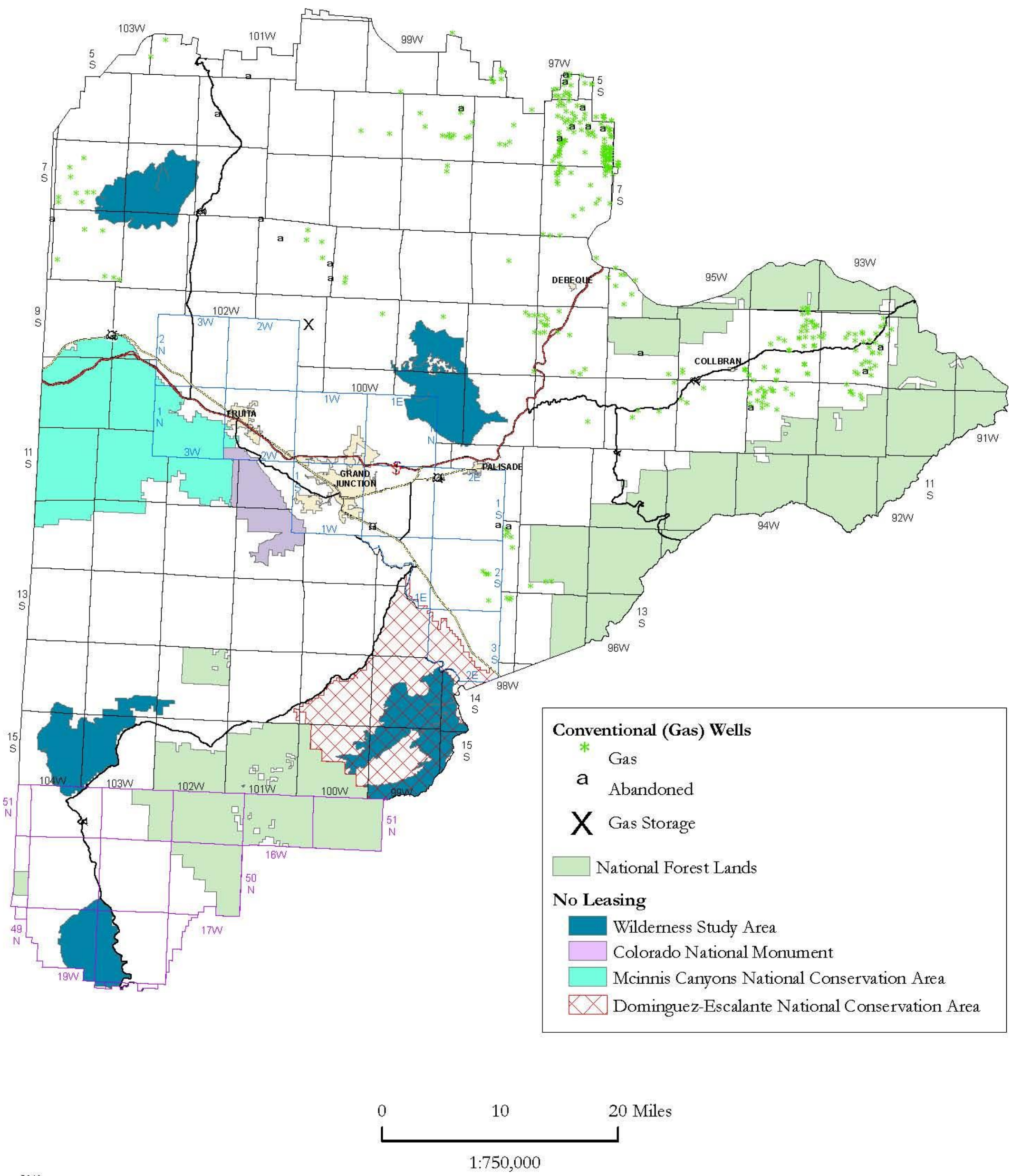
Figure 3.
Conventional oil and gas wells spud 1998 through 2008.



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Stan Lawrence, Petroleum Engineer

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Figure 4.
Coalbed natural gas wells.

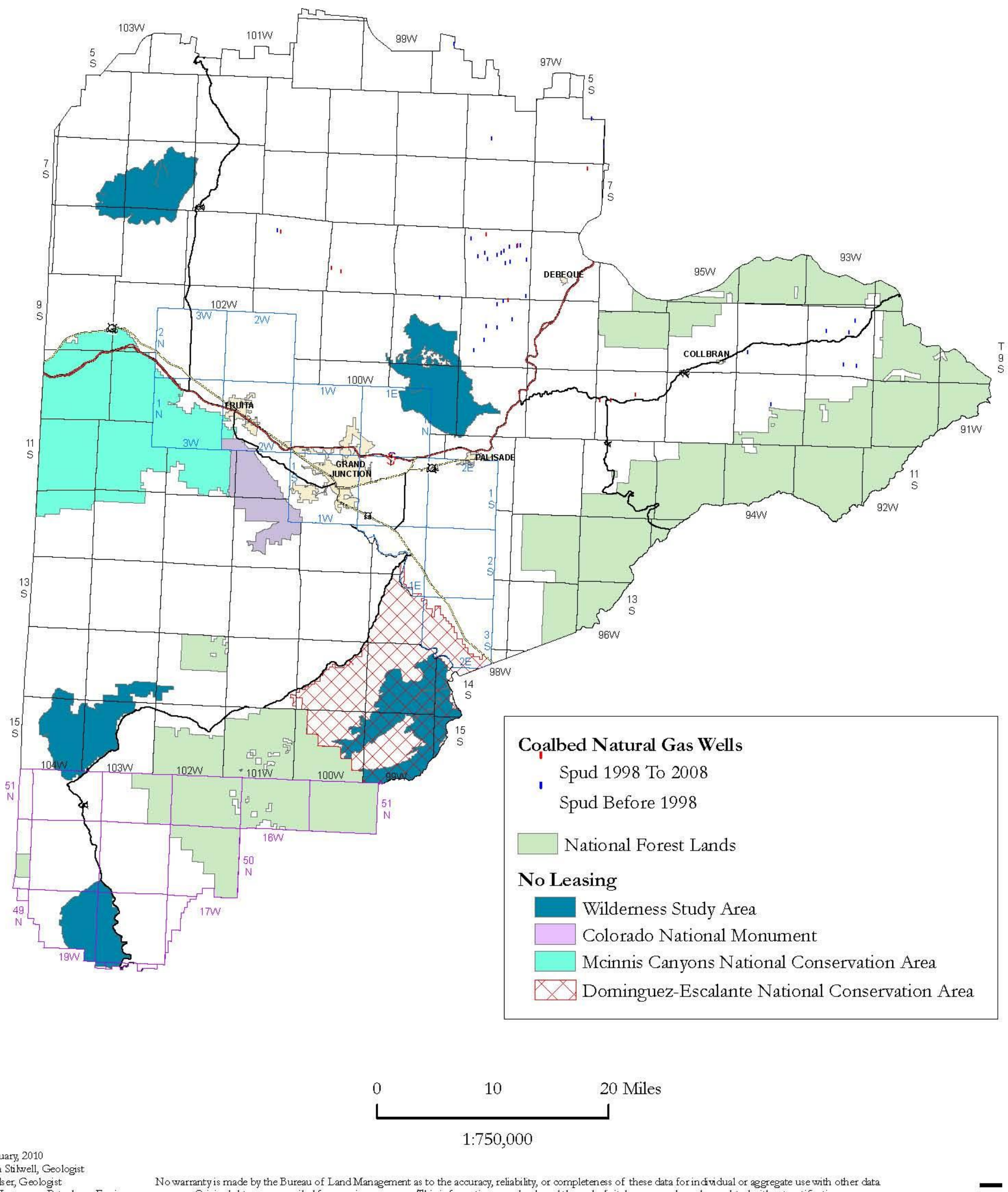

Figure 5. Histogram showing depth distribution of wells completed in the Study Area since 1998 (IHS Energy, 2008).

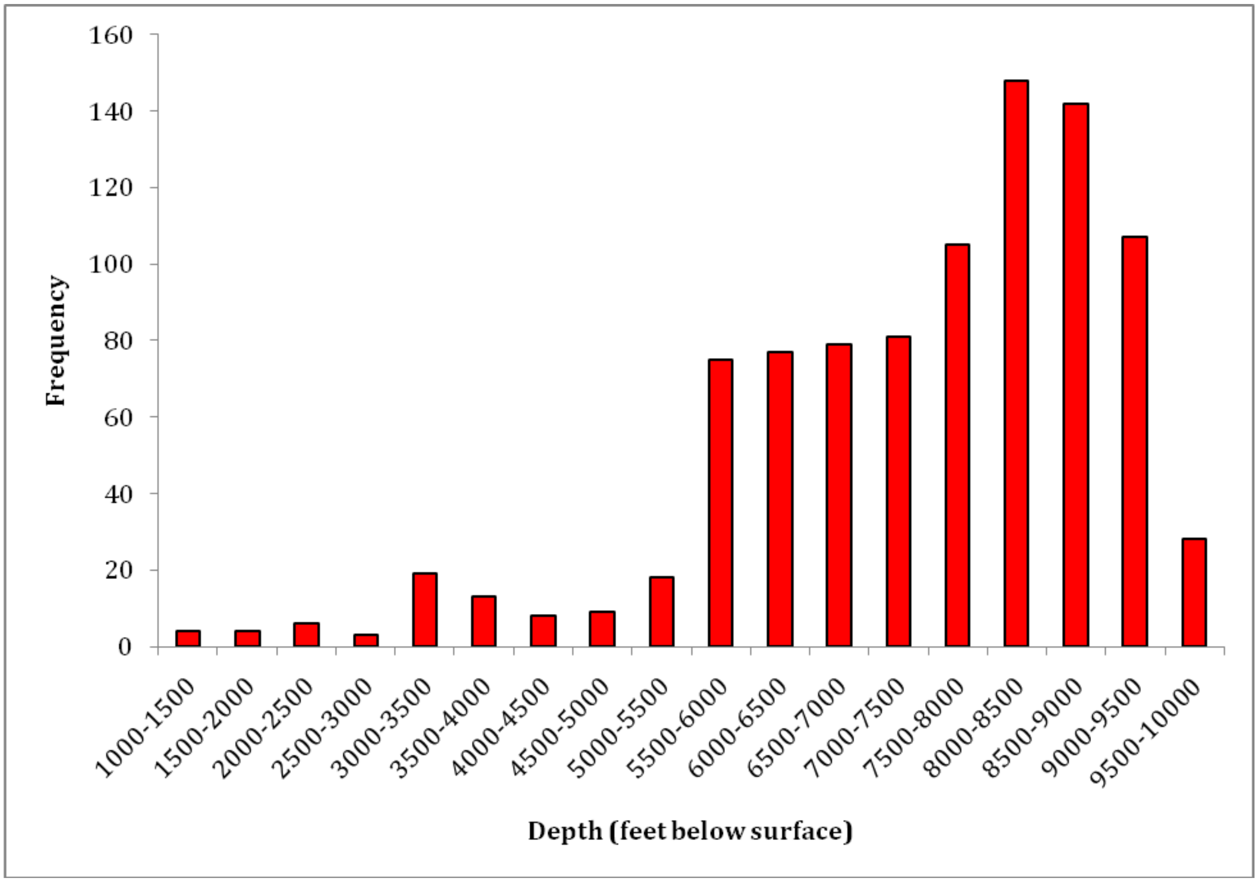

Figure 6.
True vertical depth of conventional wells spud 1998 to 2008.

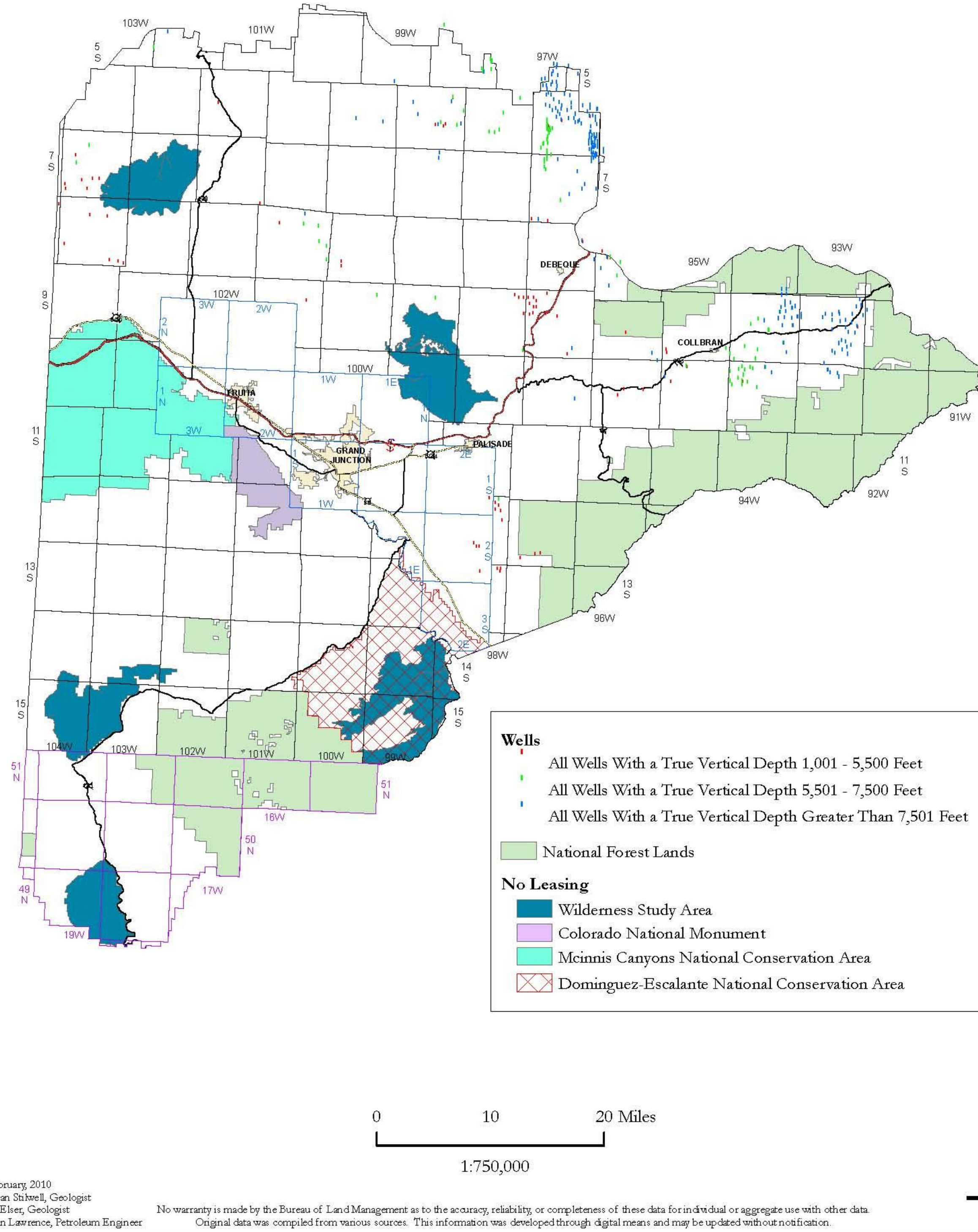

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Figure 7. Colorado historical natural gas prices with future natural gas price projections (Energy Information Administration, 2008a).

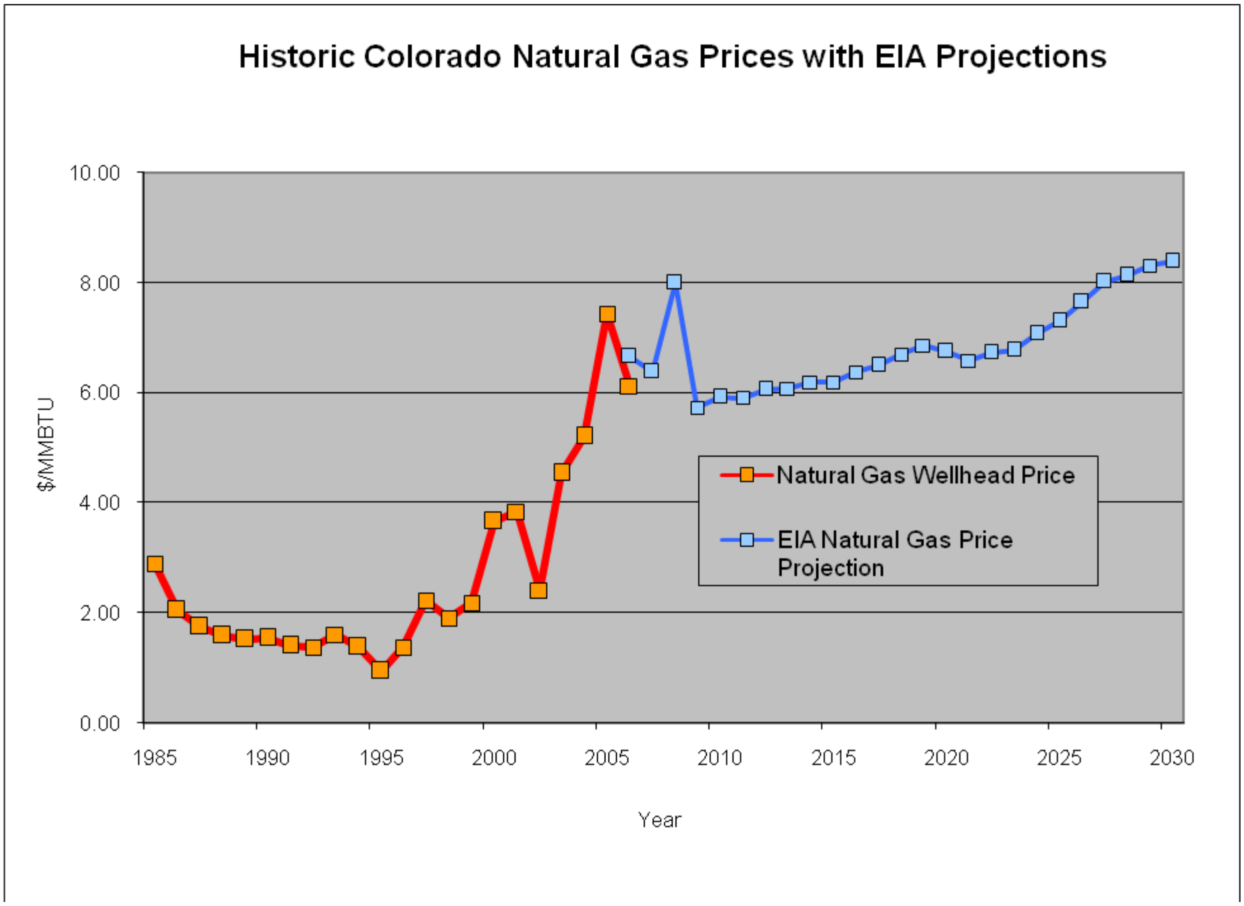

Figure 8. Colorado historical crude oil prices with future crude oil price projections (Energy Information Administration, 2008a).

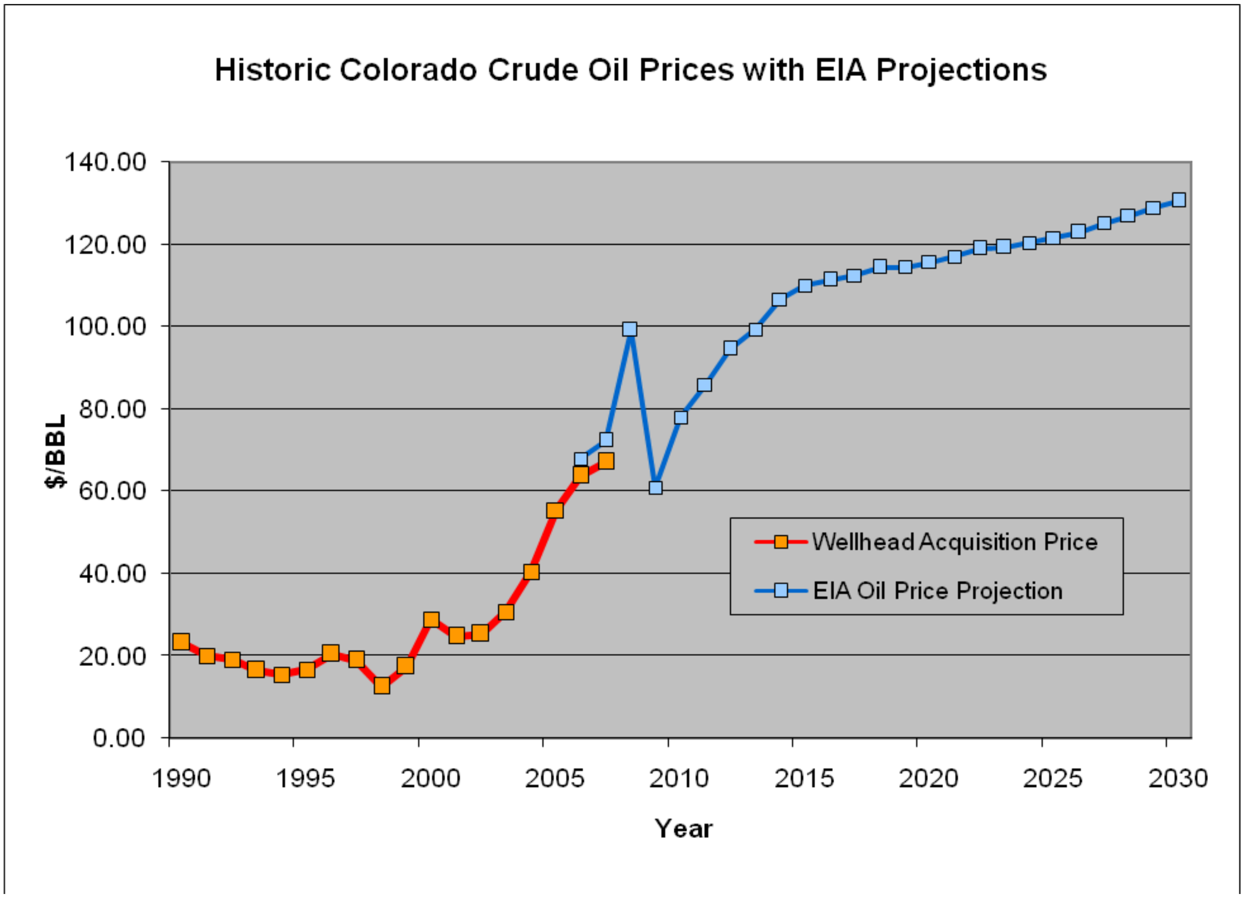

Figure 9.
Conventional oil and gas development potential, 2009-2028.

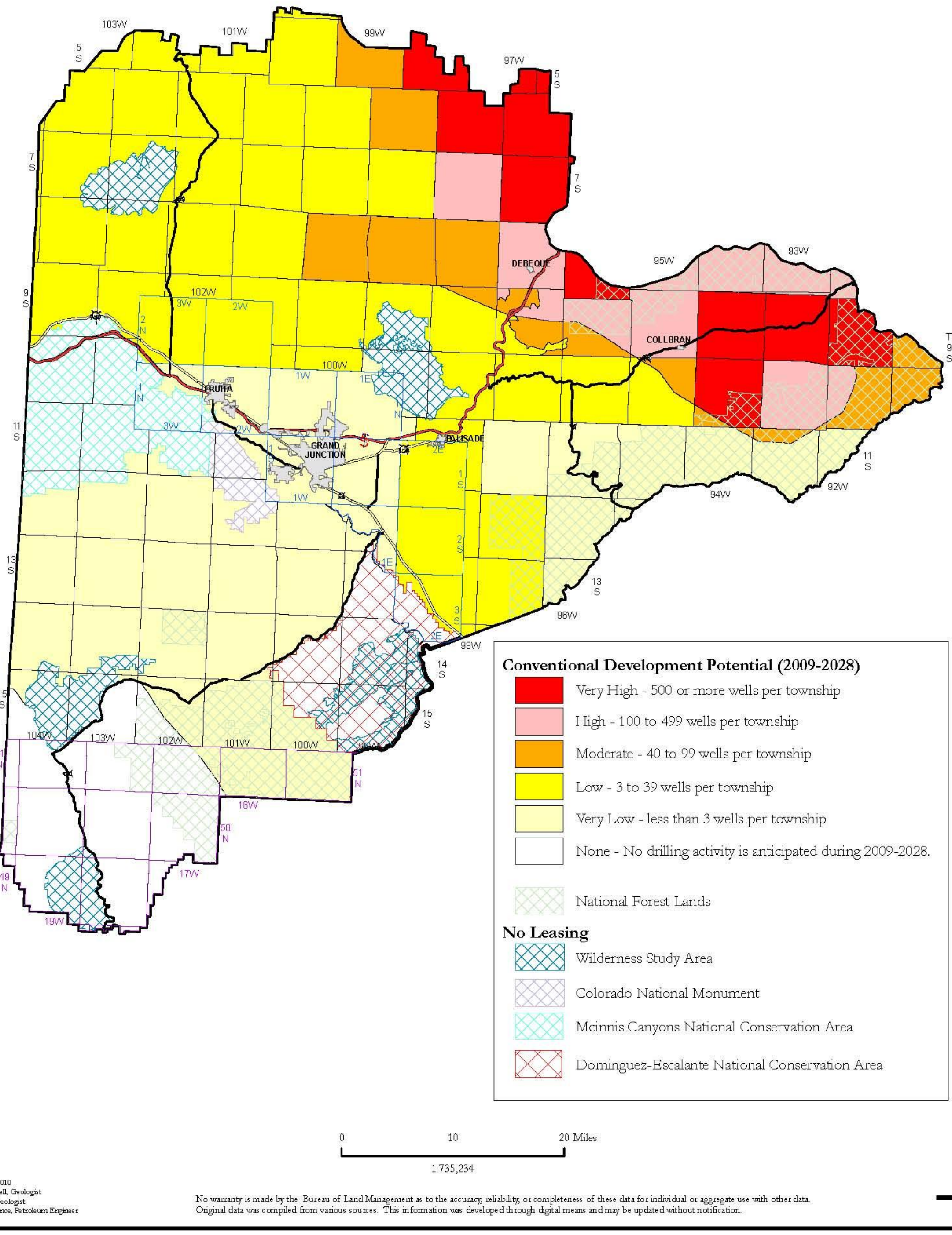

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Figure 9a

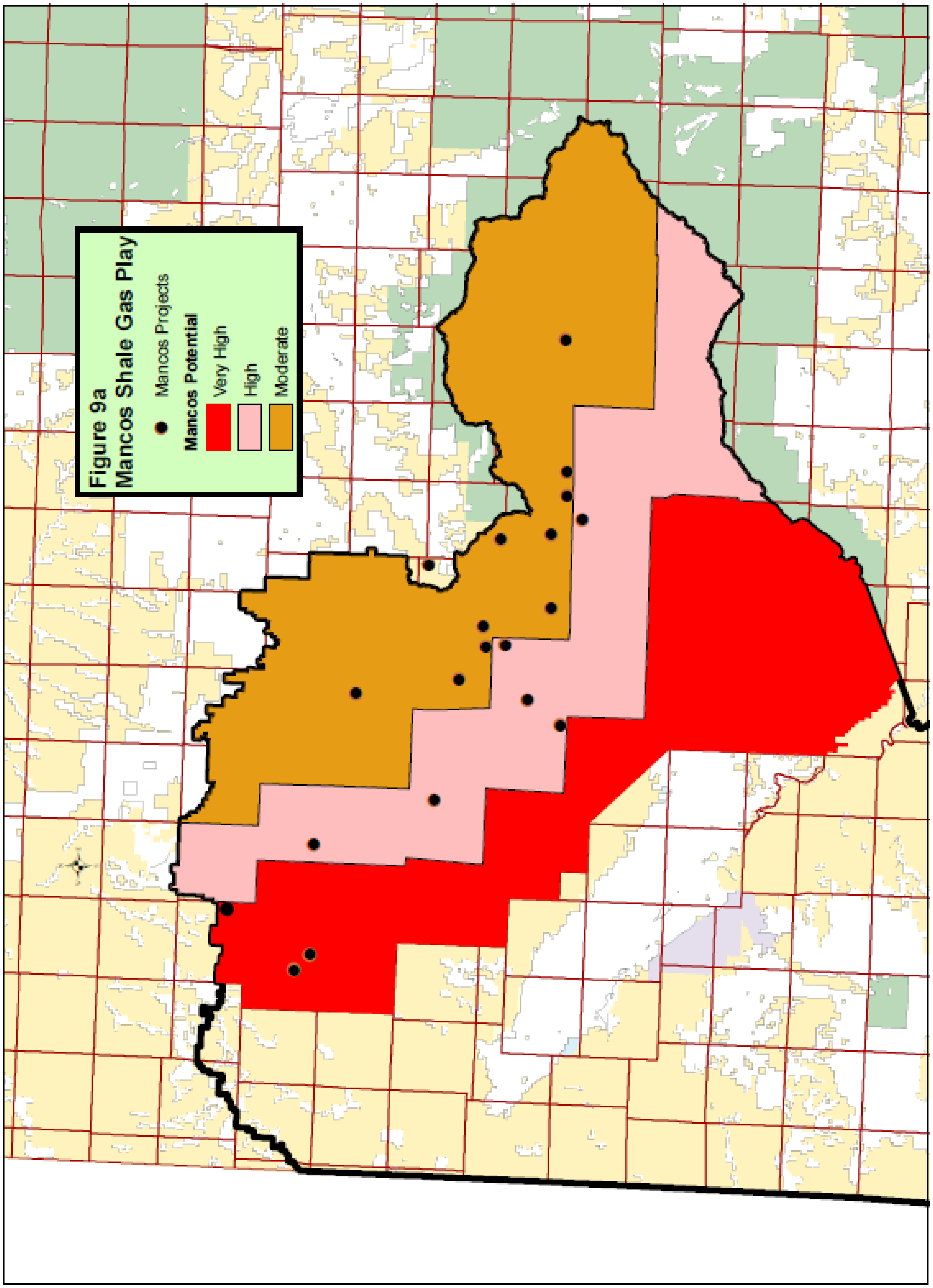
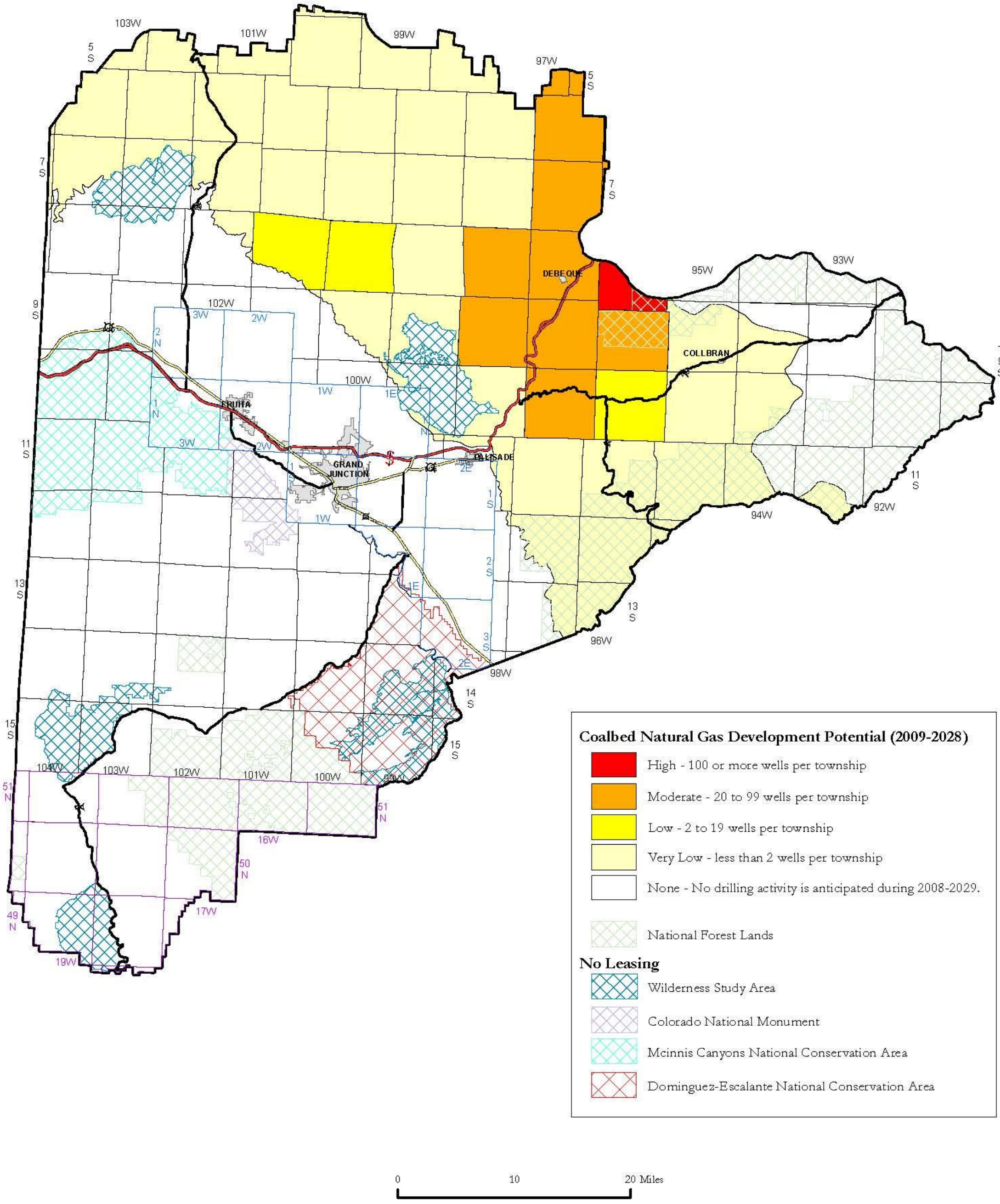


Figure 9a
Mancos Shale Gas Play
Mancos Projects
Mancos Potential
Very High
High
Moderate

Figure 10.
Coalbed natural gas development potential, 2009-2028.



December, 2010
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Al Elser, Geologist
Stan Lawrence, Petroleum Engineer

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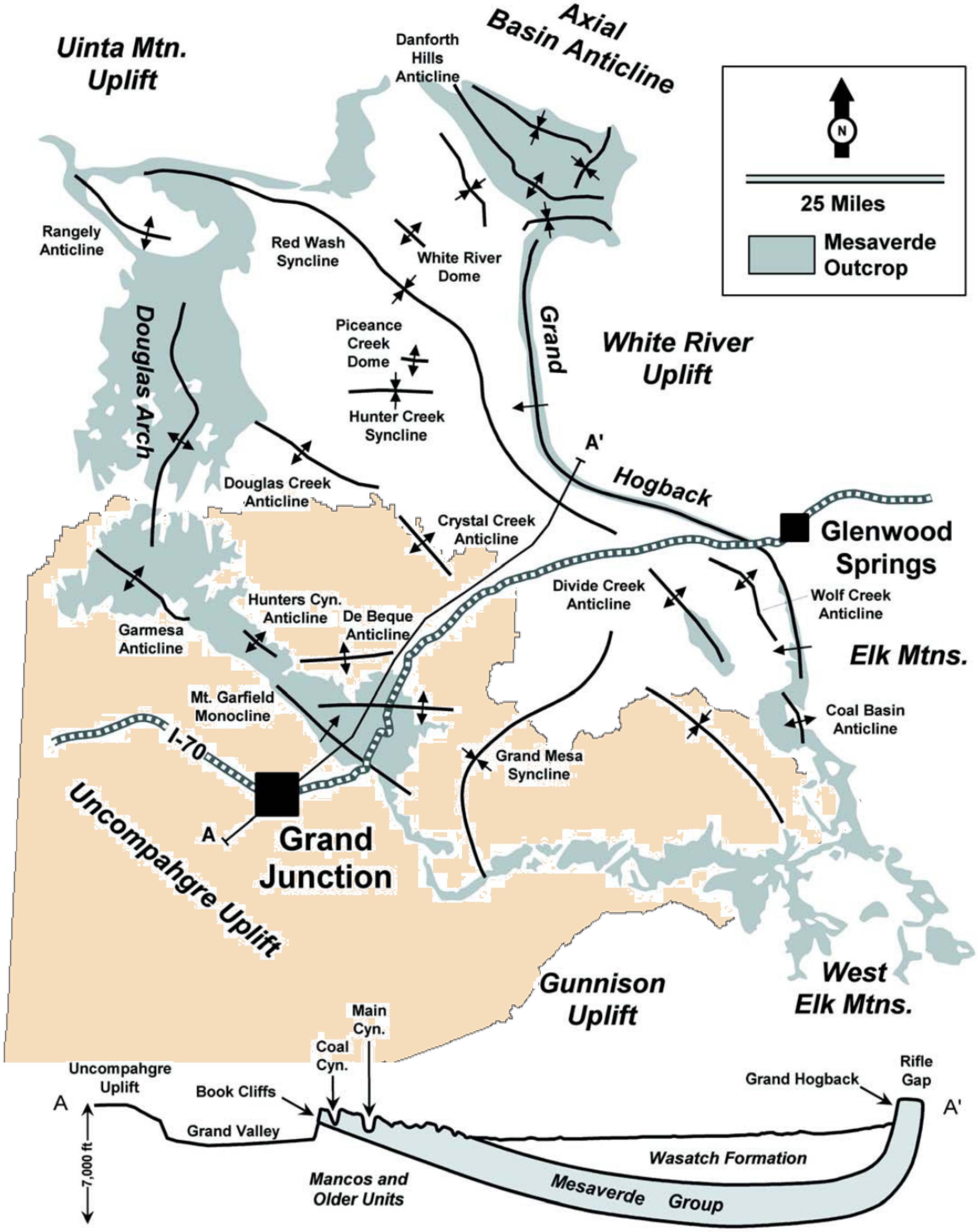
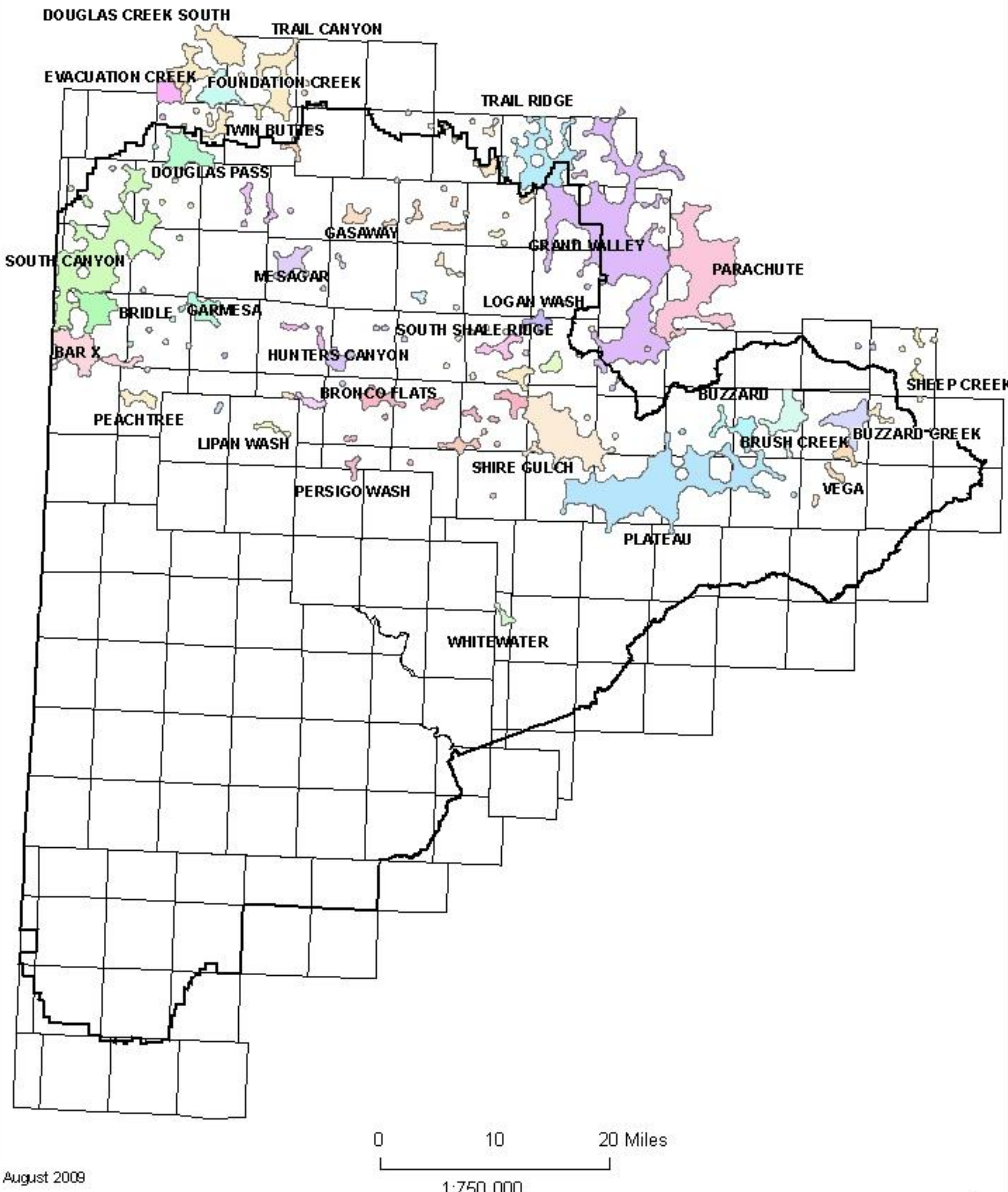
Structural Geology of the Piceance Basin   Figure 11



(Grand Junction Field Office Boundary in tan)

Figure 12 Oil and Gas Fields

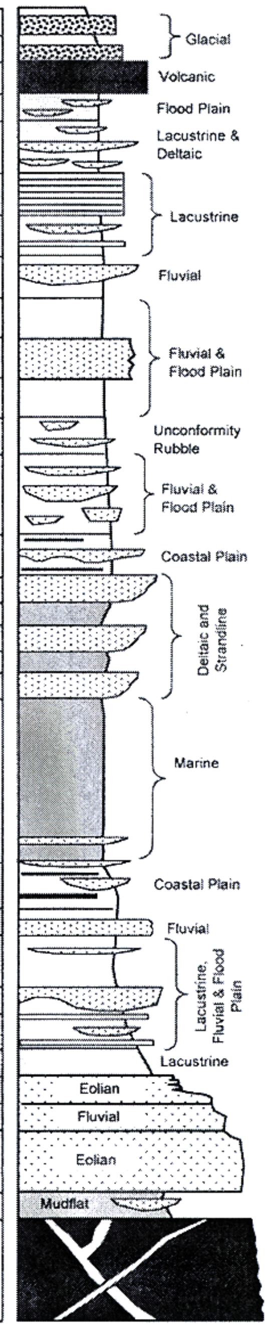


August 2009

Bob Hartman, Petroleum Engineer

Figure 13. General Stratigraphic Column for the Grand Junction Area. Data sources: Young and Young (1968), Hintze (1988), and Scott et al. (2001).

AGE	FORMATION	MEMBER	THICKNESS (ft)	DOMINANT ROCK TYPES
Quaternary	*Grand Mesa*		< 100	Gravel and Till
	Lands End		< 100	Gravel and Till
Miocene	*Basalt*		170-680	Basalt
Miocene	*Unnamed*		0-100	Sandst. & Mudrock
Eocene	*Uinta*		400+	Sandst. & Mudrock
	Green River	Parachute Creek	300-1,100	Oil Shale and Marlstone
		Garden Gulch	300-700	Mudrock, Limest. & Sandst.
		Douglas Creek	100-300	SS and Shale
	Wasatch	Shire	600-4,000	Mudrock
Paleocene		Molina	50-500	Sandstone
		Atwell Gulch	700-1,800	Mudrock
Upper Cretaceous	*Mesaverde Group* – *Williams Fork (Hunter Cyn.)*	Ohio Creek	0-100	Sandst. & Conglom.
		Undifferentiated	1,500-2,000	Sandst. & Mudrock
		Bowie Shale	300-450	Mudrock, Sandst. & Coal
	Mesaverde Group – *Iles (Mt. Garfield)*	Rollins	100-150	Sandstone
		Mancos tongue	80-120	Mudrock
		Cozzette	100-150	Sandstone
		Mancos tongue	40-80	Mudrock
		Corcoran	30-60	Sandstone
	Mancos	Juana Lopez Mbr	4,000-4,500	Mudrock and Silty Sandstone
	Dakota		80-120	Mudrock, Sandst. & Coal
L. Cretaceous	*Burro Canyon*		100-200	Sandst. & Mudrock
Jurassic	*Morrison*	Brushy Basin	200-300	Sandst. & Mudrock
		Saltwash	100-150	Sandst. & Mudrock
		Tidwell	50-120	Sandst., Mudrock & Limestone
	Wanakah		20-40	Mudrock
	Entrada		100-150	Sandstone
	Kayenta		50-80	Sandst. & Mudrock
	Wingate		250-320	Sandstone
Triassic	*Chinle*		80-120	Mudrock & Sandst.
Proterozoic (1.7-1.4 Ga)	*BLACK CANYON COMPLEX*	*GREAT UNCONFORMITY*	Feet	Schist, gneiss, pegmatite, granite, monzonite, and diorite.



Reprinted from Piceance Basin Guidebook (2003) by permission of Rocky Mountain Association of Geologists.

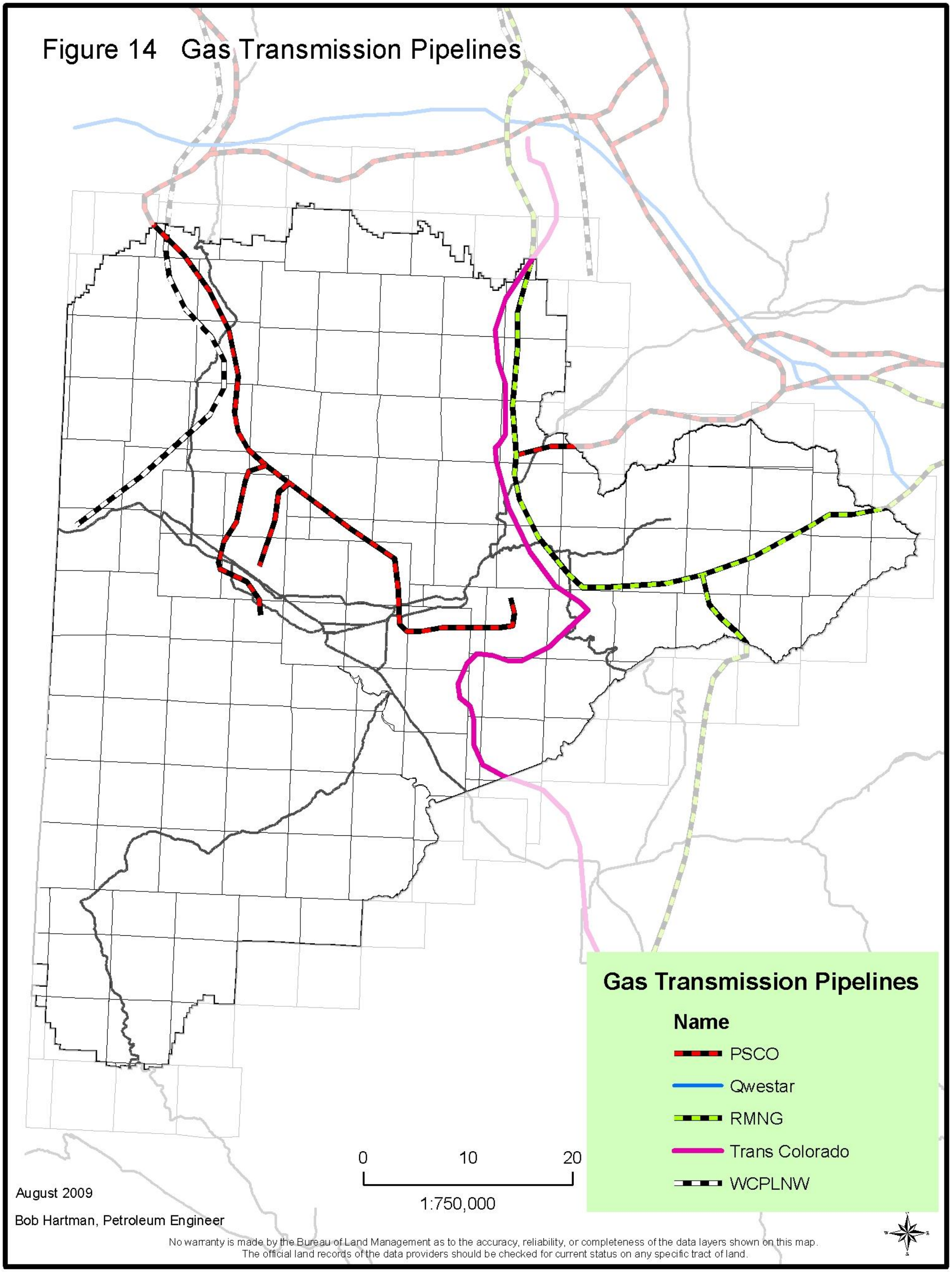


Figure 14   Gas Transmission Pipelines
Gas Transmission Pipelines
Name
PSCO
Qwestar
RMNG
Trans Colorado
WCPLNW
0
10
20
1:750,000
August 2009
Bob Hartman, Petroleum Engineer
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The official land records of the data providers should be checked for current status on any specific tract of land.

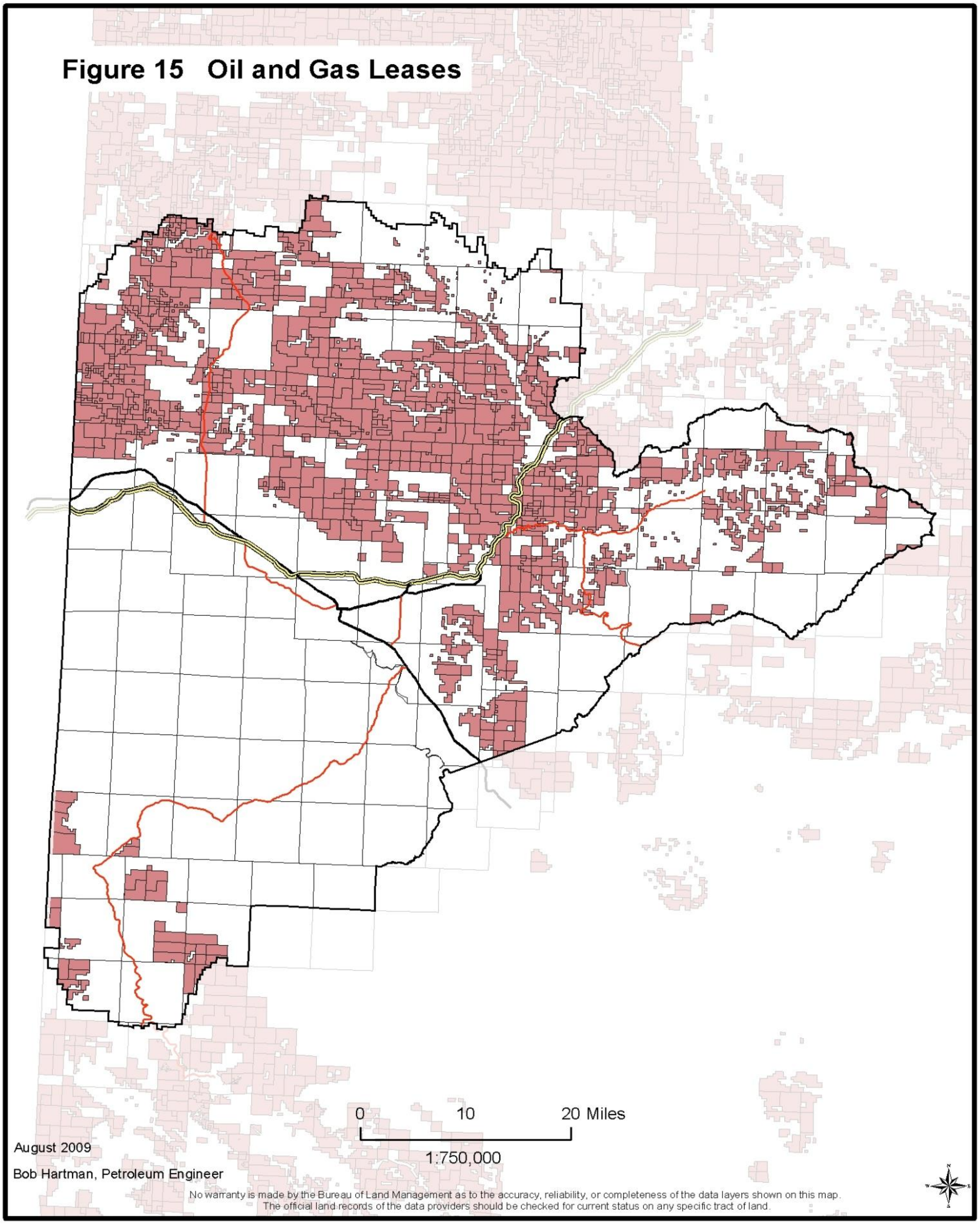

Figure 15 Oil and Gas Leases

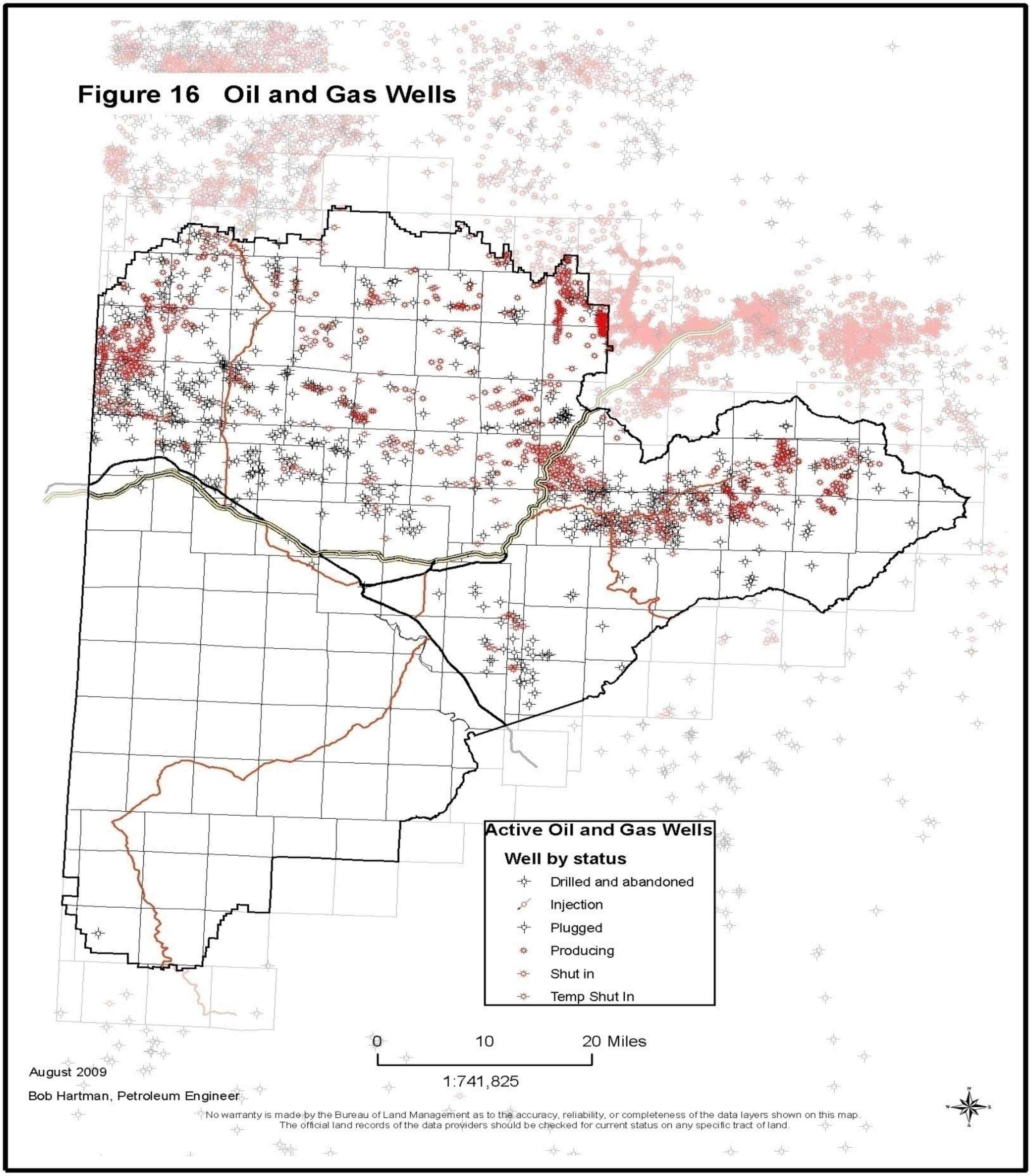
Figure 16 Oil and Gas Wells
Active Oil and Gas Wells
Well by status
Drilled and abandoned
Injection
Plugged
Producing
Shut in
Temp Shut In
0
10
20 Miles
1:741,825
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Figure 17 Oil Shale Resources

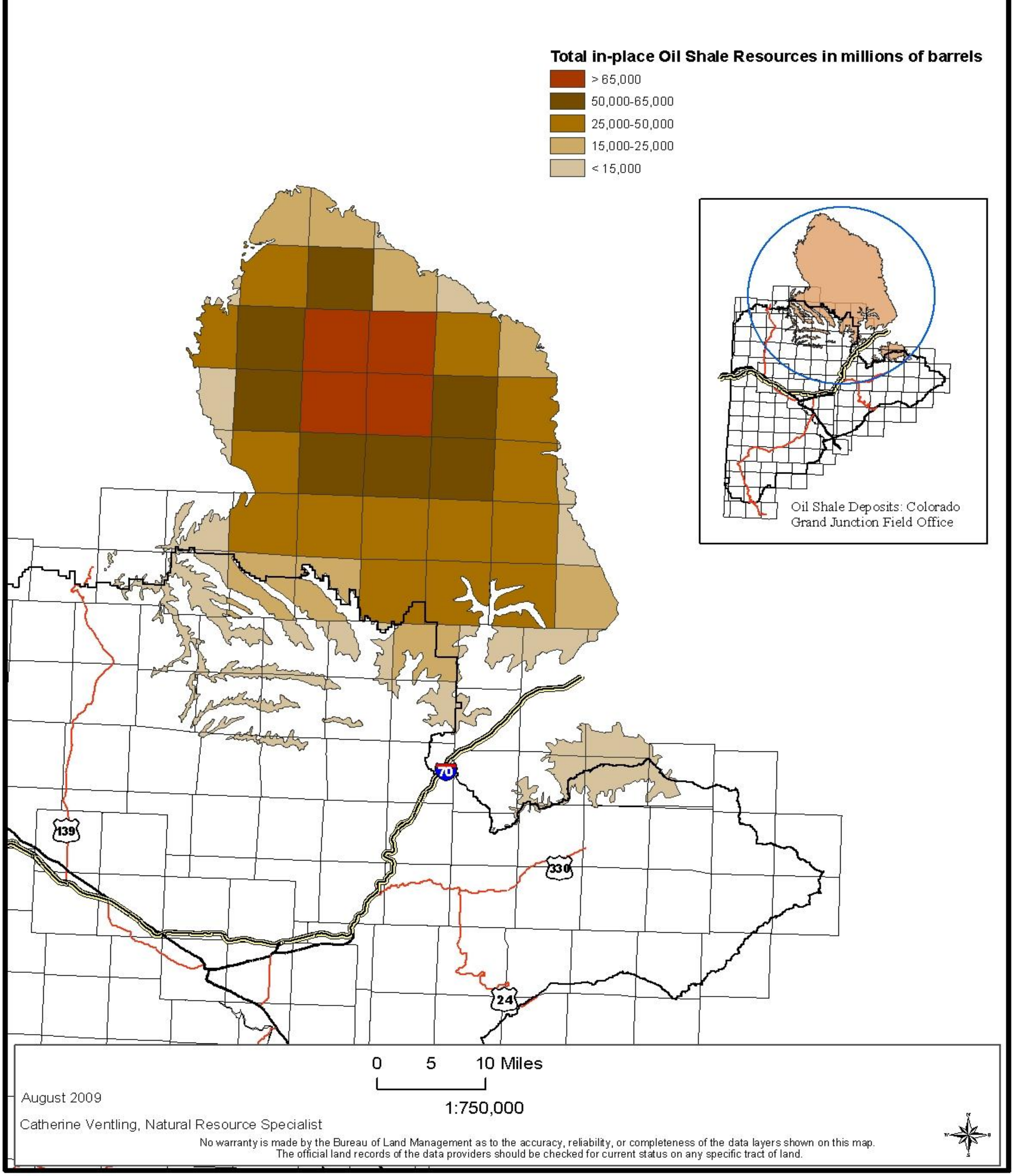


Figure 18. Green River Total Petroleum System

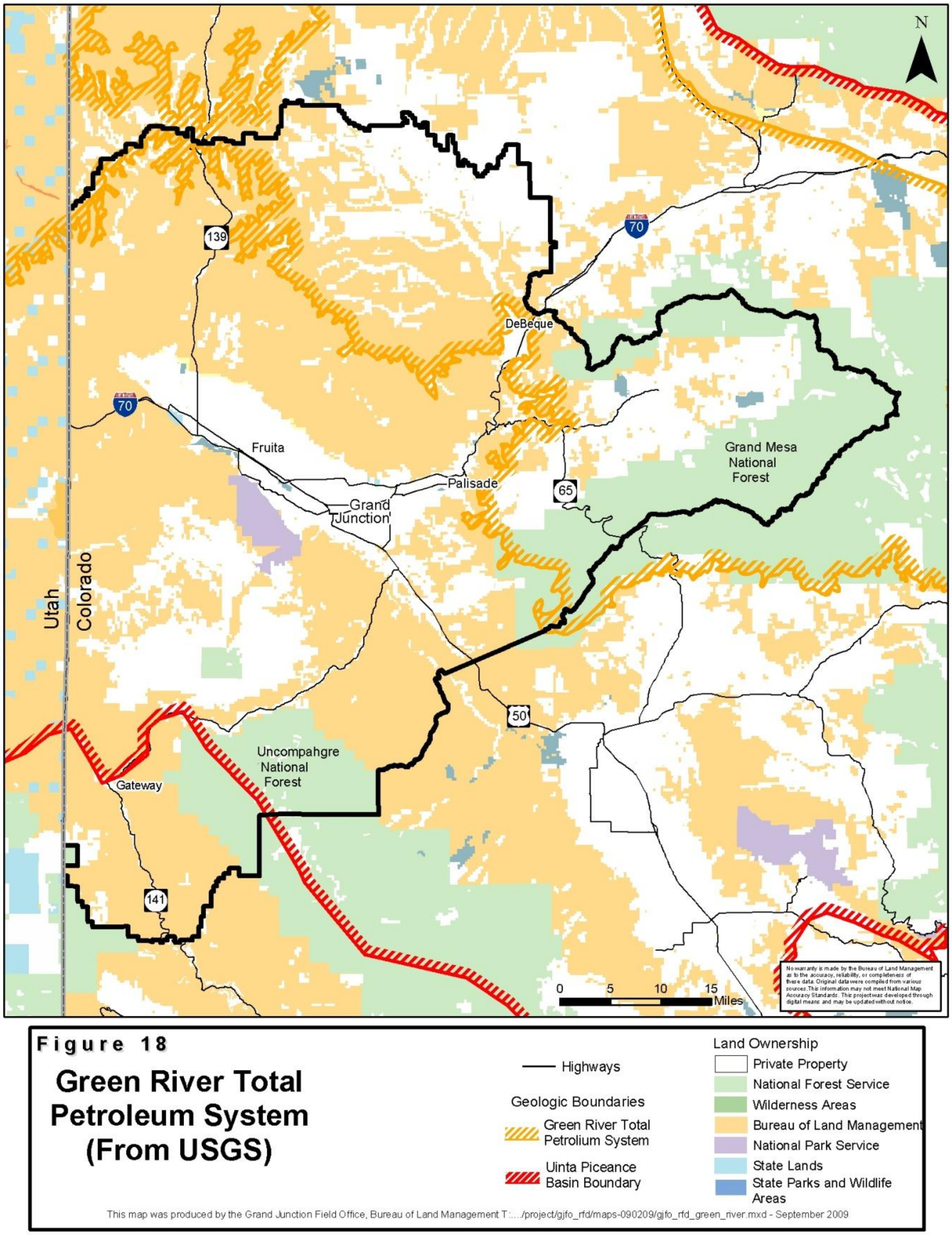


Figure 19. Mesaverde Total Petroleum System

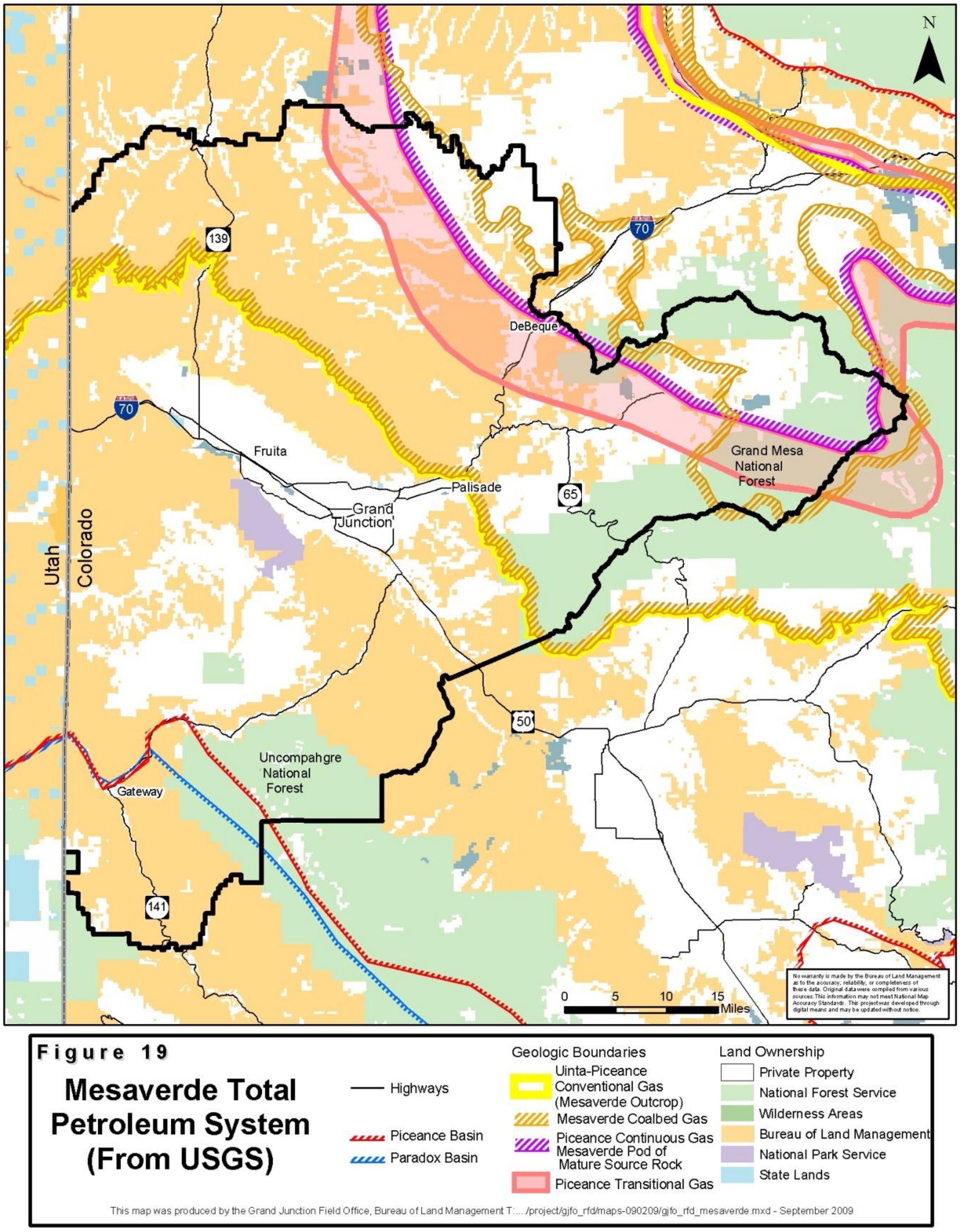


Figure 20. Mancos Mowry Total Petroleum System

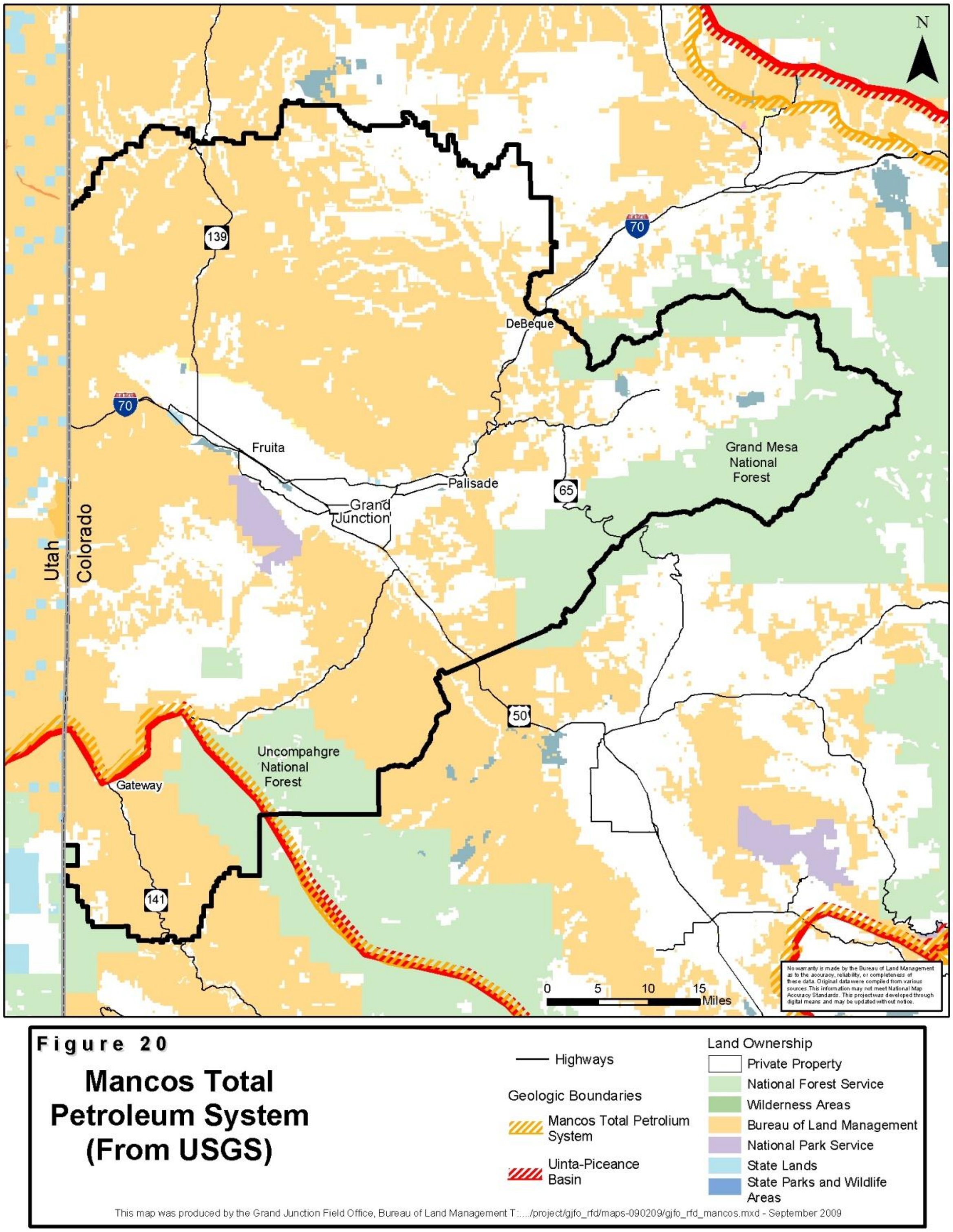
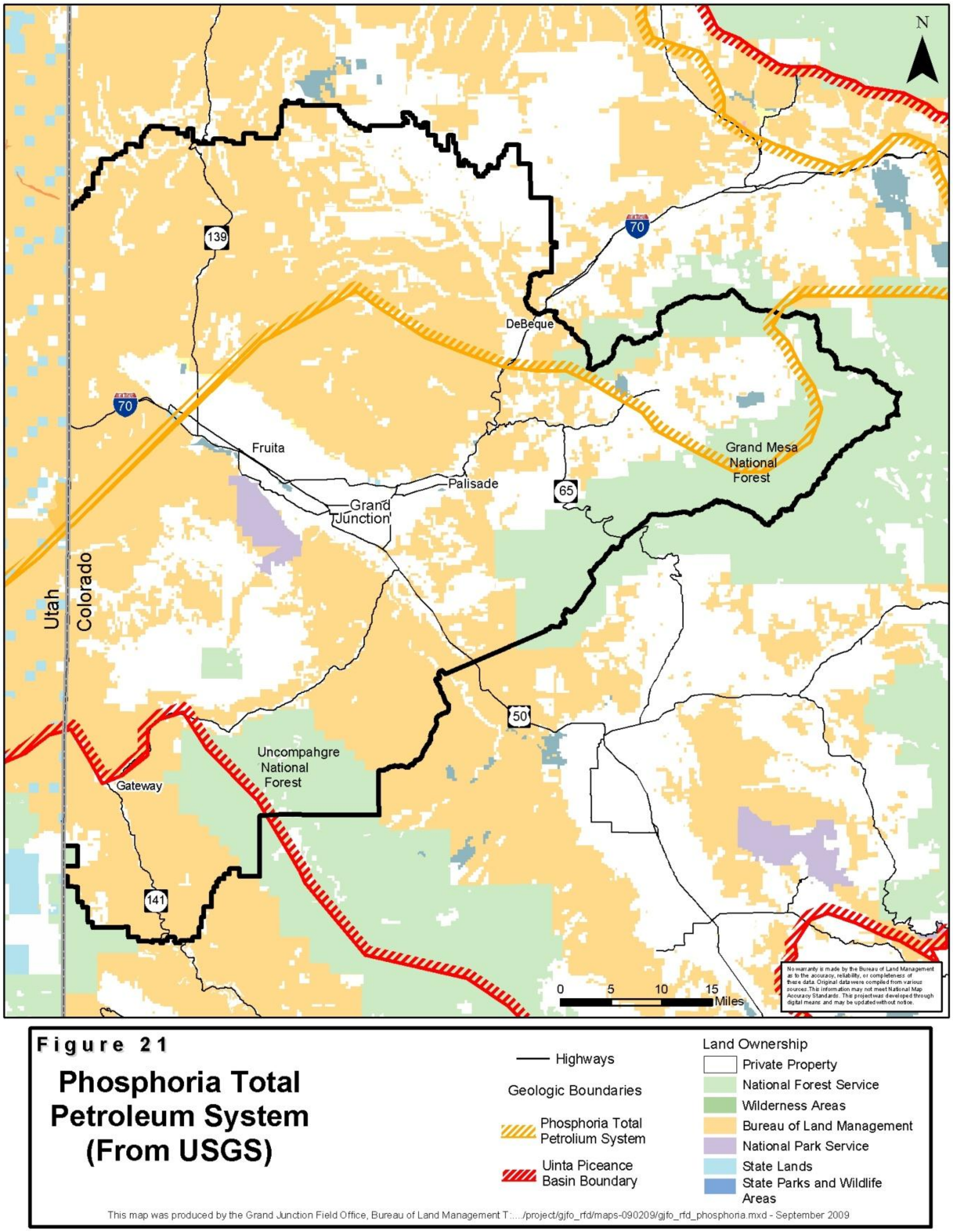
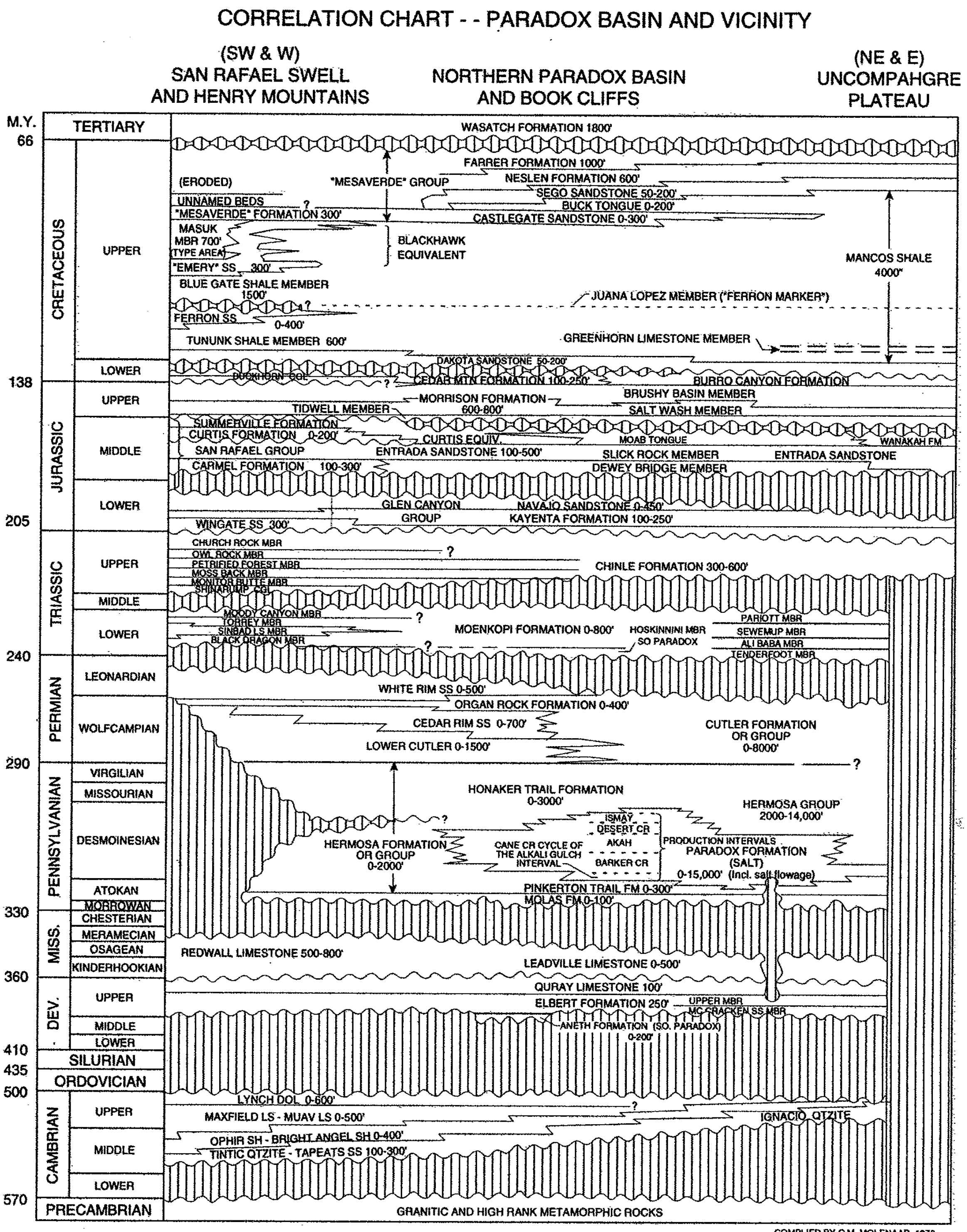


Figure 21. Phosphoria Total Petroleum System





Correlation chart for the rocks of the Paradox Basin and vicinity. Modified from Molenaar (1978).

(Nuccio and Condon, 1996)

Figure 22. Reprinted from Paradox Basin, Resource Series 43, 2003, CGS

Figure 23. Piceance and Paradox Play Boundaries (From USGS)

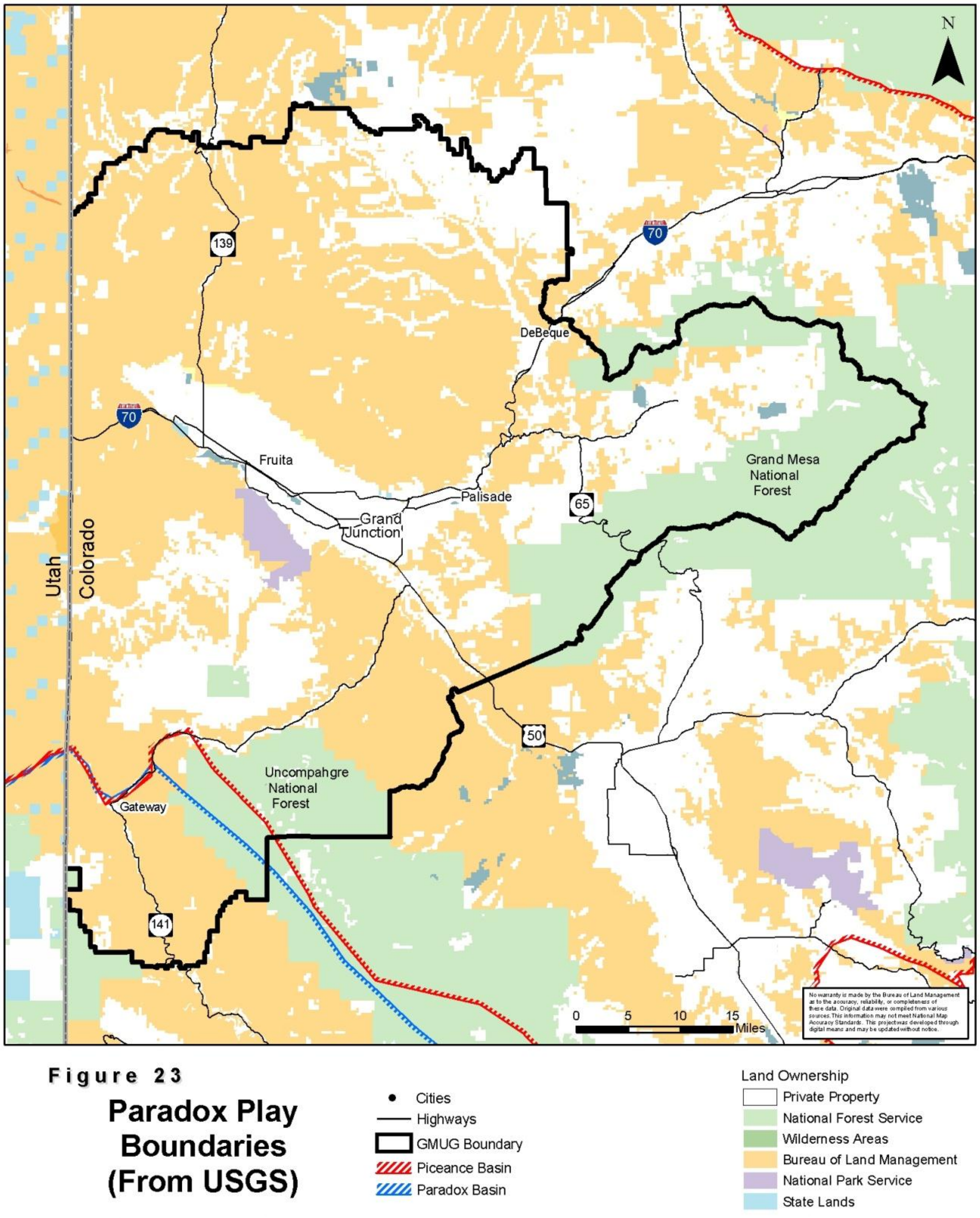


Figure 24. Coal Leases