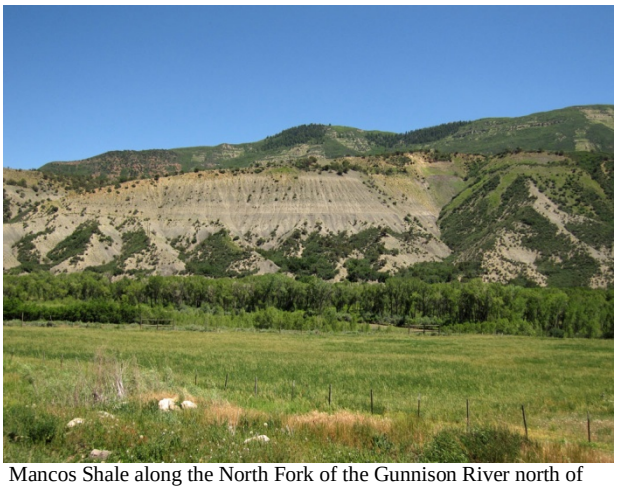
REASONABLE FORESEEABLE DEVELOPMENT SCENARIO FOR OIL AND GAS FOR THE UNCOMPAHGRE FIELD OFFICE, COLORADO



Mancos Shale along the North Fork of the Gunnison River north of Paonia on State Highway 133.

Dakota Sandstone along U.S. 550 near Ridgeway showing coal seam near base of section.

Mesaverde Group showing paleo-river channel along State Highway 133 near McClure Pass.

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UNITED STATES DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

FINAL REPORT

February 16, 2012

UNITED STATES DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

WYOMING STATE OFFICE
RESERVOIR MANAGEMENT GROUP

FINAL

Reasonable Foreseeable Development Scenario for Oil and Gas, Uncompahgre Field Office, Colorado
February 16, 2012

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INTRODUCTION

The Uncompahgre Planning Area (hereafter the Planning Area) represents the lands managed by the Uncompahgre Field Office of the Colorado Bureau of Land Management (hereafter the Bureau). The Uncompahgre Field Office (Figure 1) is responsible for managing more than 900,000 acres of public land in southwestern Colorado, including the Gunnison Gorge National Conservation Area and Wilderness, as well as portions of the newly designated Dominguez-Escalante National Conservation Area and Dominguez Canyon Wilderness Area and four river systems (the Gunnison, San Miguel, Dolores, and Uncompahgre).

A Resource Management Plan and associated Environmental Impact Statement are currently being prepared for the Planning Area. The Resource Management Plan will replace the existing 1985 San Juan/ San Miguel Resource Management Plan and the 1989 Uncompahgre Basin Resource Management Plan. The lands studied for this analysis will henceforth be called the Study Area. The Study Area (Figure 2a) is located in Delta, Gunnison, Mesa, Montrose, Ouray and San Miguel counties, Colorado. The area encompasses approximately 675,677 acres of public land, and excludes the Gunnison Gorge National Conservation Area and the Dominguez-Escalante National Conservation Area, which are managed under separate Resource Management Plans.

In support of the Resource Management Plan revision, this reasonable foreseeable development projection technically analyzes the oil and gas resource known to occur and potentially occurring within the Study Area and projects future development potential (See Glossary for development potential) and activity levels for the period 2010 through 2030.

Hydrocarbon activities and projections of future development will be discussed separately for coalbed natural gas (see Glossary for coalbed natural gas and natural gas) and for all other types of oil and gas (hereafter referred to as conventional oil and gas). When both types of hydrocarbon are being referenced, we will hereafter refer to them as oil and gas. Figure 3a presents historic and present conventional oil and gas related development areas for all lands within the Study Area. Figure 3b presents historic and present coalbed natural gas related development areas for all lands within the Study Area.

Our analysis makes a base line projection that assumes future conventional oil and gas and coalbed natural gas related activity levels on all assessed lands within the Study Area will not be constrained by management-imposed conditions (Rocky Mountain Federal Leadership Forum, 2004). National Forest lands, other Federal agency lands, and State and Private managed lands are included in the base line projection for those lands assessed for future development. Certain other federally managed lands within the Study Area are not assessed for the potential for future reasonable foreseeable conventional oil and gas and coalbed natural gas related development. Those lands with legislatively imposed restrictions (no leasing) are not included in this base line projection since activities will not be allowed in the foreseeable future. Those restricted lands are National Forest managed wilderness, Bureau managed wilderness and wilderness study

areas, and Black Canyon of the Gunnison National Park (Figure 2a). In addition, a separate baseline projection is made for just those lands managed by the Bureau.

The reasonable foreseeable development evaluation and projections presented below review and analyze past, present, and potential future exploratory, development, and production operations and activities. It also presents occurrence potential (See Glossary for occurrence potential) for conventional oil and gas, coalbed natural gas, and deep conventional oil and gas (at depths greater than 15,000 feet) as well as available estimates of the hydrocarbon resources that may be present within the Study Area. Additional factors used to project future activities include (but are not limited to) a review of published resource information (including a number of on-line databases) for the area, a call for data from conventional oil and gas and coalbed natural gas operators, a review of petroleum (see Glossary) technology research and development, geophysical activity, and limitations on access and infrastructure. It must be emphasized that the reasonable foreseeable development projections presented are possible and/or likely to happen and should not be considered to be worst-case scenarios, but reasonable and science based projections of the anticipated activity that use logical and technically based assumptions to make those projections (Rocky Mountain Federal Leadership Forum, 2004). Finally, projections of future activity levels for each resource management plan alternative are presented.

The Study Area contains about 3,099,400 surface acres of all mineral ownership types (Figure 2b). Mineral ownership types were obtained from the Bureau's Colorado State Office. This data base may not be a complete and accurate representation of all Federal oil and gas minerals within the Study Area. Oil and gas mineral ownership is not included for lands within the Gunnison Gorge National Conservation Area Planning Area or the Dominguez-Escalante National Conservation Area.

The Study Area contains about 2,162,580 acres of Federal oil and gas mineral ownership (Figure 2b), or about 71 percent of total acres. The remaining 936,820 acres (29 percent) is managed by state and private interests. The Bureau manages a portion of the Federal oil and gas mineral lands in the Study Area (904,096) acres, or about 41.8 percent of the 2,162,580 acres. The Bureau manages all oil and gas minerals beneath BLM Wilderness on Figure 2b. We assume that about 236,614 acres of state and private surface lands within Study Area boundaries overlie Bureau managed oil and gas mineral lands. All Bureau managed oil and gas mineral lands will be covered by decisions made in the associated Resource Management Plan Environmental Impact Statement.

The U.S. Forest Service manages about 1,229,892 acres (Figure 2b), or 56.9 percent of Federal oil and gas mineral lands within the Study Area. The Forest Service manages all oil and gas minerals beneath Forest Service Wilderness on Figure 2b. About 27,123 acres (1.3 percent) are managed by the National Park Service. Decisions made as part of the Resource Management Plan Environmental Impact Statement for the Study Area will not be made for these lands.

We would like to thank Ms. Cathy Stilwell of the Bureau of Land Management Wyoming State Office Reservoir Management Group staff for the important Geographic Information System contributions that she has made to this reasonable foreseeable development analysis. In addition we would like to thank Thane Stranathan of the Bureau of Land Management Uncompahgre Field Office staff for his assistance in preparing the analysis for the surface disturbance section of this document. We would also like to thank Ryan Taylor (USFS Paonia Ranger District Geologist), Pam Leschak (Bureau of Land Management Tres Rios Field Office Fluid Minerals Geologist), and Pat Gallagher (Bureau of Land Management Colorado State Office Petroleum Engineer) for their comments on the draft of this report.

GEOLOGIC OVERVIEW

Most of the Study Area is within the Colorado Plateau physiographic province, a region of distinct topography and geology. The Colorado Plateau is actually a large basin ringed by highlands and containing many plateaus within western Colorado, northwestern New Mexico, southern and eastern Utah, and northern Arizona. The portion of the Study area lying in and around the Black Canyon of the Gunnison and the area to the east lies within the Southern Rocky Mountains physiographic province.

The major structural elements (uplifts, basins, anticlines, synclines, and faults) and Precambrian, Tertiary igneous, and Mesaverde rock outcrops of the Study Area are shown on Figure 4. The Paradox basin lies mostly in eastern Utah and southwestern Colorado. It has been further divided into smaller tectonic divisions, with the Paradox Fault and Fold Belt area located in the northern part of the larger Paradox basin. The Fault and Fold Belt includes the Nucla-Naturita and Norwood parts of the Study Area and lands to the north as far as the Uncompaghre Uplift. This area is also often termed the Salt Anticline region because it contains a number of salt cored anticlines such as the Paradise Valley Salt Cored Anticline on the southwest side of the Study Area.

Local topography in the Paradox basin portion of the Study Area is dominated by fairly flat or gently dipping mesas that are dissected by steep canyons. Cretaceous aged rock dominates the mesa areas, with older rocks outcropping in the canyons. The Paradox basin developed during Pennsylvanian-Permian time and has been modified by later uplifts. It is a strongly asymmetrical basin with its thickest sequence of sedimentary deposits on its northeast flank and near the adjacent Uncompahgre uplift (Figure 4). Structural relief has been estimated to be greater than 25,000 feet (Molenaar, 1972). Numerous surface igneous dikes and faults are located in the southeast part of the basin in the Sawpit region of the Study Area. Very little historic oil and gas production is reported from the portion of the Paradox basin lying within the Study Area.

The Uncompaghre uplift trends in a northwesterly direction along the northeastern border of the Paradox basin and it lies partly in Colorado and Utah. It occupies the central part of the Study Area. The uplift's southwestern boundary is defined by the thrust fault shown in Figure 4. Major uplift occurred during the Pennsylvanian and Permian (Stone, 1977). "During the Laramide orogeny, the uplift was regionally tilted to the northeast," (Stone, 1977). The Uncompaghre uplift contains a Precambrian core, with Precambrian outcrops shown on Figure 4. No historic oil and gas production has been reported from that portion of the Uncompahgre uplift lying within the Study Area.

The western parts of the San Juan Volcanic Field lie along the eastern border of the Study Area. The area was blanketed by thick volcanic sequences erupted from multiple centers to the southeast and east. The volcanic activity that deposited these sequences occurred from about 30 to 22 million years before present. No historic oil and gas production has been reported from that portion of the San Juan Volcanic Field lying within the Study Area.

The Gunnison uplift runs in a northwest-southeast direction, sub parallel to the Grand Mesa syncline (Figure 4). Precambrian rocks outcrop in the core of the uplift. About 60 million years ago, during the Laramide Orogeny, these rocks were uplifted to near the surface. The area was later covered by volcanic rocks that produced the San Juan Volcanic Field. Over time most of the volcanic deposits have been eroded from the area and the Gunnison River has cut down through the Precambrian rocks, creating today's Black Canyon of the Gunnison. No historic oil and gas production has been reported from that portion of the Gunnison uplift lying within the Study Area.

The Piceance basin lies in the northernmost part of the Study Area. The outcrop of the Mesaverde Formation marks the approximate southern boundary of the Piceance basin in the Study Area (Figure 4). The Piceance basin is northwest-trending, is asymmetric in shape (gently dipping strata on its southwest limb), and is Laramide in age. Maximum thickness of sediments in the basin is 27,000 feet (Dunn, 1972) although maximum thickness in the Study Area is much less (probably less than 20,000 feet). Present oil and gas production and coalbed natural gas production in the Study Area comes from Piceance basin sediments.

EXPLORATORY AND PRODUCTION ACTIVITY AND OPERATIONS

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

EXPLORATORY ACTIVITY AND OPERATIONS

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

- the anticlinal theory (1885) that oil and gas tend to accumulate in anticlinal structures, which allowed drillers to locate better drilling spots with improved opportunities to find oil and gas;
- rotary drilling rigs (1900s), which became the chief method of drilling deeper wells (see Glossary for rotary drilling rig);
- seismograph (1914), which allowed one dimensional subsurface imaging;
- well logging (1924), which allowed measurement of subsurface rock and fluid properties;
- offshore drilling (1930s), which allowed drillers to access new areas and basins;
- digital computing (1960s), which allowed two dimensional imaging of data;
- directional drilling (1970s), which allowed more cost efficient management of reservoirs;

- three dimensional seismic (1980s), which allowed more accurate subsurface imaging;
- three dimensional modeling and four dimensional seismic (1990s), which allowed the prediction of fluid movement in the subsurface;
- identification of new types of reservoirs and improved exploitation methods (1990s to present) allowed development of heavy oil, tight gas, shale gas, coalbed natural gas, shale oil, and the use of carbon dioxide in the flooding process to increase recoveries; and
- multi-discipline collaboration (2000s), which allows for better drilling decisions, higher success rates, improved risk assessment, and enhanced reservoir development.

Exploratory activity includes:

- the study and mapping of surface and subsurface geologic features to recognize potential oil and gas traps,
- determining a geologic formations potential for containing economically producible oil and gas,
- pinpointing locations to drill exploratory wells to test all potential traps,
- drilling additional wells to establish the limits of each discovered trap,
- testing wells to determine geologic and engineering properties of geologic formation(s) encountered, and
- completing wells that appear capable of producing economic quantities of oil and gas.

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

1. Locations of major tectonic features (Figure 4) that have developed over many millions of years. Some features (anticlines and faults) may improve opportunities for the development of oil and gas reservoirs while others (igneous intrusive and Precambrian rocks) may indicate reduced opportunities for the development of reservoirs.
2. The Paradox and Piceance basins contain thick sections of sediments (Molenaar, 1972 and Dunn, 1972). In the Paradox basin, thick accumulations of Paleozoic and Mesozoic aged carbonates, sandstones, and shales (potential source and reservoir rocks) exist, with thin near surface coals present in the Dakota Sandstone. Figure 5 presents a stratigraphic chart for the Paradox Basin portion of the Study Area showing nomenclature used for these accumulations in our report. Hydrocarbon producing zones (including carbon dioxide production) in the Paradox basin are also shown. Although few of these zones have been productive in the Study Area, there is potential that additional production from some of these zones could be obtained in the future.
3. The Piceance basin contains thick accumulations of Paleozoic and Mesozoic aged carbonates, sandstones, and shales (potential source and reservoir rocks) exist, with coals present in the Mesaverde Group. Figure 6a presents a stratigraphic chart for the Piceance basin part of the Study Area showing nomenclature used

for these accumulations in our report. Although no Paleozoic or Cenozoic zones have been productive in the Study Area, there is potential that production from some of these zones could be obtained in the future. Mesozoic zones (Mesaverde Group, Mancos Shale, Dakota Sandstone, and Morrison Formation) have had the only historic production within the Study Area. The predominate hydrocarbon producers in the Study Area have been units within the Mesaverde Group. Since this group has a complicated depositional history authors have been able to further subdivide this group into formations and members (Figure 6b), all of which have been productive, from coal beds and/or sandstones.

4. Figure 7 shows all oil and gas fields lying within or partly within the Study Area. These fields help define areas were there has been the greatest historical interest in exploring for and developing the oil and gas resource within the Study Area. Most fields lie within the Piceance basin on the north end of the Study Area.
5. Burial and thermal histories that could promote the development and preservation of diagenetic pore-throat traps (see Glossary) and oil and gas generation in the center of the Piceance and Paradox basins.
6. Structure traps (see Glossary), that have played a role in localizing some oil and gas accumulations within the Study Area.
7. Stratigraphic traps (see Glossary), have played a role in exploration and development activities within the Study Area.
8. Pressure regimes, ranging from slightly under-pressured to highly over-pressured, could be important near the center of the Paradox basin and in deeper zones in that part of the Piceance basin within the Study Area. In areas of abnormally high pressures, productive capacity can be greatly increased. Over-pressuring also creates problems in drilling and completion, increasing the cost of both.
9. Secondary porosity, produced by the dissolution of unstable grains (see Glossary) and rock fragments, is important in local accumulations.

We believe that these components are also important in exploring for and developing new oil and gas resources in the Study Area. In the last 10 years 57 new exploratory and development wells (Figure 8) have been spudded (see glossary). Thirteen wells have been spudded in the Paradox basin part of the Study Area, with 11wells initially classed as new field wildcats, one well classed as a wildcat outpost well, and one as a development well. Three of these wells (one new field wildcat, one wildcat outpost, and one development well) were drilled in the vicinity of Hamilton Creek Field and the remaining nine wildcat wells were scattered across the basin.

Forty-four of the 57 new wells spudded in the past ten years are located in the Piceance basin part of the study area (Figure 8). Twenty-seven of the 44 wells were initially spudded as coalbed gas tests with two being stratigraphic tests (see Glossary), eight new field wildcats, 16 development wells, and the remaining well a deepening of a development well. Seventeen new wells in the area were spudded as conventional well tests, with 12 new field wildcats, one wildcat outpost well, one unclassified well, and three development wells. Most of the new wells in this part of the Piceance basin have been spudded in or around the oil and gas fields shown on Figure 7.

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

1. Tight Sands Gas – formed in sandstone or carbonate (called tight gas sands) with low permeability, which prevents the gas from naturally flowing to a borehole.
2. Coalbed Natural Gas – formed in coal deposits and adsorbed (see Glossary) by coal particles.
3. Shale Gas – formed in fine-grained shale rock (called gas shales) with low permeability in which gas has been adsorbed by clay particles or is held within minute pores and microfractures.

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

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

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

Of the 57 wells spudded in the last 10 years (January 1, 2000 to December 31, 2009), their type, present status, and percentage of the total were:

• Coalbed Gas – Producing	13 wells	22.81 percent,
• Coalbed Gas – Shut-In or Waiting on Orders	8 wells	14.04 percent,
• Coalbed Gas – Abandoned	6 wells	10.53 percent,
• Conventional Gas – Producing	5 wells	8.77 percent,
• Conventional – Shut-In, Temporarily Abandoned, or Waiting on Orders	14 wells	24.56 percent,
• Conventional – Spudded	1 well	1.75 percent,
• Conventional – Abandoned	8 wells	14.04 percent, and
• Injection – Waiting on Orders	2 wells	3.51 percent.

Locations of these wells are shown in Figure 9. To date only 14 wells (24.56 percent) have been abandoned, while the remaining 43 wells (75.46 percent) are still active. There were a total of 36 new field wildcats, wildcat outpost wells, stratigraphic tests, or

unclassified wells drilled for 63.2 percent of the total. Of the 57 boreholes spudded, only one was redrilled as a coalbed natural gas test after an earlier completion as a conventional well. All but three wells were drilled as vertical well tests. The three wells drilled with a directional trajectory are located in the Paradox basin part of the Study Area.

Of the 57 wells spudded in the last 10 years (January 1, 2000 through December 31, 2009), 38.6 percent were drilled in seven fields (Figure 7):

- Spaulding Peak 7 wells,
- Hamilton Creek 3 wells,
- Oil Well Mountain 3 wells,
- Ragged Mountain 3 wells,
- Bull Mountain 2 wells,
- Coal Basin 2 wells, and
- West Muddy Creek 2 wells.

No recent drilling occurred in the three other fields located within the Study Area.

Of the 17 coalbed natural development wells completed during the past 10 years, only two wells (11.76 percent) have been abandoned. An additional 10 wells were drilled as new field wildcats or stratigraphic tests. Four of these wells (40 percent) have been abandoned.

Of the four conventional oil and gas development wells spudded during the past 10 years, all are presently still active (including one spudded well that has not been completed). An additional 24 wells were drilled as wildcats (including one unclassified well). Eight of these wells (33.33 percent) have been abandoned.

Two injection wells have been drilled in the past 10 years and they are classified by the Colorado Oil and Gas Conservation Commission (2010) as waiting on orders.

There were five operators active in the Paradox basin part of the Study Area during the 10-year period from January 1, 2000 to December 31, 2009. They accounted for 13 boreholes drilled there. Encana O & G (USA) Incorporated was the operator for seven wells. Cabot Oil & Gas Corporation and Redwine Resources Incorporated each operated two wells and Cleary Petroleum Corporation and Devon Energy Corporation each drilled one well.

There were only three operators active in the Piceance basin part of the Study Area during the 10-year period from January 1, 2000 to December 31, 2009. They accounted for 44 boreholes drilled there. Gunnison Energy Corporation operated 24 wells, SG Interests I, LTD operated 16 wells, and Aspen Operating Company, LLC operated the remaining four wells.

During the last 10 year period, completions have been made in the Permian Cutler Formation and Pennsylvanian Honaker Trail Formation in the Paradox basin part of the Study Area (Figure 5). In the Piceance basin part of the Study Area, coalbed natural gas

completions have been made in coals of the Upper Cretaceous Mesaverde Group (Figure 6b). Conventional completions have also been made in sandstone members of the Upper Cretaceous Mesaverde Group, the Upper Cretaceous Mancos Shale, and the Lower Cretaceous Dakota Sandstone.

Drilling depths for Paradox basin wells drilled in the last 10-year period from January 1, 2000 to December 31, 2009 have ranged from 6,585 to 14,421 feet. Seven wells were drilled to 10,000 feet or deeper. The deepest well was a new field wildcat drilled near the center of the basin in section 4 of township 47 north, range 19 west as a dry hole (Figure 9) on the south flank of the Paradise Valley Salt Cored Anticline (Figure 4). The deepest completed interval was in the Permian Cutler Formation (10,205 to 10,165 feet) in section 7 of township 44 north, range 14 west (Figure 9) at Hamilton Creek Field (Figure 7).

Drilling depths for Piceance basin coalbed natural gas wells drilled in the last 10-year period from January 1, 2000 to December 31, 2009 have ranged from 2,400 to 7,865 feet. Two coalbed natural gas stratigraphic tests only drilled to 460 and 1,240 feet. Cameo Coal (Figure 6b) completions have been as shallow as the 1,738 to 1,800 foot interval and as deep as the 6,845 to 6,928 foot interval. Drilling depths for other types of wells have been in the 3,000 to 9,800 foot range.

Innovative drilling and completion techniques have enabled the United States oil and gas industry to drill fewer dry holes and to recover more oil and gas reserves per well. Smaller accumulations once thought to be uneconomic can now also be produced. In some cases these improvements have also allowed down spacing to occur. Increased drilling success rates have cut the number of both wells drilled and dry holes (U.S. Department of Energy, 1999). The Energy Information Administration (2007a) has projected the increase in percentage of United States wells drilled successfully will be 0.2 percent per year to 2030.

During the last 10 years, exploratory and development activity has concentrated on that part of the Piceance basin within the Study Area to explore for and develop coalbed natural gas resources and other Cretaceous aged sediments. Additional future exploratory drilling will be required to discover new resources in this area and other parts of the Study Area. Since the risk of failure is higher for these types of exploratory activities, the success rates could decline slightly in the future.

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

- computer processing capability and speed;
- remote sensing and image-processing technology;
- developments in global positioning systems;
- advances in geographical information systems;

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

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

Technology improvements have also cut the average cost of finding oil and gas reserves in the United States. Finding costs are the costs of adding proven reserves of oil and natural gas via exploration and development activities and the purchase of properties that might contain reserves. The U.S. Department of Energy (1999) estimated finding costs were approximately 2 to 16 dollars per barrel of oil equivalent in the 1970's. Finding costs then dropped to 4 to 8 dollars per barrel of oil equivalent in the 1993 to 1997 period. Finding costs then fluctuated around the higher end of this range for a number of years. During the 2003 to 2005 period, finding costs were 7.05 dollars per barrel of oil equivalent and they then increased by 60.9 percent to 11.34 dollars per barrel for the 2004 to 2006 period (Energy Information Administration, 2007b). Since the 2004 to 2006 period finding costs have increased considerably. During the 2005 to 2007 period they went to 13.72 dollars per barrel and then they jumped by 77 percent to 24.31 dollars per barrel for the 2006 to 2008 period (Energy Information Administration, 2009a). Most of this increase was reported to have come from a rise in exploration and development spending, which was amplified by a drop in reserves found. Producers have been willing to spend more to find oil and gas since prices received during this period had been higher.

Once hydrocarbons have been found, acquired, and developed for production the expense of operating and maintaining wells and related equipment and facilities is tracked. This cost is referred to as a lifting or production cost. During 2006, lifting costs in the United States were 9.09 dollars per barrel of oil equivalent, which was an increase of 20.0 percent from a 2005 cost of 7.57 dollars per barrel (Energy Information Administration, 2007b). Lifting costs increased to 12.16 dollars in 2007 and then increased over 24 percent in 2008 to 15.10 dollars (Energy Information Administration, 2009a). Lifting costs have increased in recent years because more producers have been willing to spend more to produce oil and natural gas since their selling prices for oil and gas have been higher.

FEDERAL DEVELOPMENT CONTRACTS

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

FEDERAL OIL AND GAS UNIT AGREEMENTS

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

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

Federal oil and gas leases are incorporated into 11 active conventional oil and gas unit agreement areas that lie wholly within the Field Office boundary (Figure 10). Active units wholly within the Study Area encompass lands totaling 113,438 acres, or approximately 3.7 percent of the total Study Area lands. Additionally, there are two active units with lands partially within the Field Office boundary, but administered by other Field Offices: Hamilton Unit managed by the Dolores Field Office, and Whitewater Unit, managed by the Grand Junction Field Office. Study Area lands within these two units' total 22,589 acres, or approximately 0.7 percent of the total Study Area lands.

All of the above units were initiated as exploratory units and they are in various stages of development. The earliest, the Leon Lake Unit, was approved in 1980. It has since contracted to its producing area. Three other units were also approved in the early 1980s:

Ragged Mountain (1980), Coal Basin (1981), and Hamilton (1983). All three have also contracted to their producing areas. Of the remaining nine active units, all have been formed since 2000 and include the Huntsman (2000), Bull Mountain (2003), Somerset (2008), Whitewater (2008), Horn (2008), Deadman Gulch (2010), Spaulding Peak (2011), Iron Point (2011), and Dugout Creek (2011) units.

Six companies operate the 13 active exploratory gas unit agreement areas. These are: Encana O & G (USA) Incorporated (Hamilton and Horn units), Fram Operating LLC (Whitewater Unit), Gunnison Energy Corporation (Leon Lake, Spaulding Peak, Deadman Gulch, and Iron Point units), Petrox Resources Incorporated (Somerset Unit), Riviera Drilling & Exploration Company (Ragged Mountain Unit), and SG Interests I, LTD (Bull Mountain, Coal Basin, Huntsman, and Dugout Creek units).

The largest of the 13 active exploratory units with lands wholly or partially within the Study Area is the Whitewater Unit. The unit covers over 90,400 acres; approximately 22,419 acres are located in the Study Area. This unit's most recent plan of development indicates few wells will be constructed on lands within the Study Area (Fram Operating, 2011).

The exploratory units in the northern part of the Study Area will target coalbed natural gas, shale gas, and/or Upper Cretaceous aged sandstones of the Mesaverde Group (see Figure 6b). At Spaulding Peak unit Gunnison Energy Corporation has proposed drilling 18 gas wells on 15 locations (15 vertical and three directional wells). The project is still in its early exploratory stage, with one Mancos Shale well that is still in a testing and evaluation stage. If results are encouraging, additional exploration will occur.

At Bull Mountain unit, SG Interests has 11 existing wells capable of producing natural gas. They propose as many as 150 wells on as many as 55 multiple-well pads. This unit lies mostly on private surface.

Gunnison Energy Corporation has drilled one shale gas well in the Iron Point unit. It is still in a testing and evaluation stage.

Ragged Mountain and Coal Basin units produce primarily from sandstones of the Cozzette Member and also from the Corcoran Member (Figure 6b). Coalbed natural gas wells have been drilled in Spaulding, Iron Point, Bull Mountain, and Deadman Gulch units.

No units have been approved for secondary recovery, as gas storage, or just for coalbed natural gas production within the Study Area.

COMMUNITIZATION AGREEMENTS

Communitization Agreements may be authorized when a Federal lease cannot be independently developed and operated in conformity with an established well-spacing or

well-development program. In Colorado, the following circumstances can constitute good reason for communitization to occur.

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

At present, only one active communitization agreement lies within the Study Area (Figure 10). This agreement covers an area of about 160 acres and was established for the Corcoran and Cozzette members of the Upper Cretaceous Iles Formation. The operator is Riviera Drilling & Exploration Company.

TYPICAL DRILLING AND COMPLETION SEQUENCE

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

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

- reclaiming the entire pad and access road if the well is not successful and is immediately plugged and abandoned after drilling, or after the well has ceased production and is plugged and abandoned.

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

- access to some well sites can be more difficult when they are remote from the main activity areas and when they are located in steep terrain,
- harsh environments (particularly cold temperatures),
- changes in rig availability,
- changes in development priority as industry focus on certain plays evolves with new discoveries and changes in oil and gas price,
- labor market conditions, and
- restrictions (many of them environmental restrictions of some type) on land use.

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

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

DRAINAGE PROTECTION

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

HISTORICAL DRILLING AND COMPLETION ACTIVITY AND TECHNIQUES EMPLOYED FOR CONVENTIONAL OIL AND GAS

The existence of oil and gas in western Colorado has been known for more than 100 years. Earliest geologic work was done by the King and Hayden surveys of the 1870s and 1880s. Oil and gas seeps were reported during these early years of exploration in other parts of the Piceance basin. Earliest drilling in the region was in 1890 north of the Study Area near the White River gas seeps west of the town of Meeker (Dunn, 1972). In 1902 oil in shallow fractured Mancos Shale was discovered at Rangely field on the northwest edge of the Piceance basin.

Early Exploration and Development Activity

Information on early periods of exploration and development of oil and gas within the Paradox basin is available from Molenaar (1972) and within the Piceance basin from Dunn (1972).

The earliest known well test in the Study Area appears to have been on the northeast flank of the Uncompahgre uplift in 1907 (IHS Energy Group, 2010). This test was drilled to 1,706 feet and it was dry and abandoned in section 35 of township 49 north, range 10 west (Figure 3a). No additional drilling occurred until the 1920s when a period of surface mapping of anticlinal structures began (Dunn, 1972). The next test in the Study Area was also the earliest known test in the Paradox basin. It was drilled in 1924 to 4,160 feet and was located in section 4 of township 46 north, range 17 west. Shows of oil and gas were encountered before abandonment.

Figure 11 shows the rate that conventional and coalbed natural gas wells were spudded in the Study Area by decade. Little drilling occurred in the Study Area until the late 1940s, apparently due to the regions remoteness from markets and the lack of success in the few wells drilled before then. In addition, the first oil pipeline out of the Piceance basin was not installed until 1945 and the first gas pipeline was not installed until 1955. Outside markets were not easily accessible until these pipelines were installed.

An additional 19 wells were drilled and abandoned at scattered locations across the Study Area before the first producing well was completed in 1947 in the Paradox basin area. A small volume, shallow Mancos Shale gas well (410 feet) was discovered near the town of Ridgeway in township 45 north, range 8 west (Figure 3a). An additional 13 wells have been drilled in the vicinity of this test with only three wells completed as Mancos Shale producers. The state (Colorado Oil and Gas Conservation Commission, 2010) reports that three of the four wells are still productive, but they have no records of production for these wells. The remaining well has apparently been converted to a domestic use of the gas.

Between 1947 and 1957 an additional 42 wells (not including those drilled near the Ridgeway wells) were drilled and abandoned before the next producing well was drilled in the Study Area. This well was the discovery for the Montrose Dome field (Figure 7).

This well was completed as a Hermosa Group discovery between 5,138 and 5,196 feet and has since been abandoned.

Between the discovery in 1957 and the next discovery in 1963, an additional 18 wells were drilled and abandoned in the Study Area. This discovery was the first in the Piceance basin area. It was completed as a Mesaverde Group producer between 4,150 and 4,154 feet and has since been abandoned.

Through the year 1999, there were 190 conventional wells spudded that were initially completed as productive gas, oil, or carbon dioxide wells or they were abandoned (wells in an injection, service, temporary abandonment, or shut-in status were not included in this count). Only 26 wells were completed as productive (IHS Energy Group, 2010). During this period the success rate was only 13.68 percent. Figure 12 shows an annual breakdown of conventional wells drilled from 2000 through 2009. During this period 18 conventional wells were spudded that were initially completed as gas productive or they were abandoned (wells in a service, temporary abandonment, or shut-in status were not included in this count). In addition, six wells are in a spudded but not completed status. Ten wells were completed as productive (IHS Energy Group, 2010). During this period the success rate improved to 55.56 percent for completed wells.

The first coalbed natural gas well was spudded in the Piceance basin part of the Study Area in 1982, but was not completed until 1985. Through the year 1999 a total of 5 wells were completed as coalbed natural gas tests and two conventional wells were reentered and completed as coalbed natural gas tests (Figure 11). Only one of the seven wells was originally completed as an abandoned well. Since then an additional five of these wells have been plugged and abandoned and the remaining well is in a shut-in status (Colorado Oil and Gas Conservation Commission, 2010). Figure 12 shows an annual breakdown of coalbed natural gas wells drilled for 2000 through 2009. During this period 24 coalbed natural gas wells were spudded that were initially completed as productive or they were abandoned. In addition, three wells are in a spudded but not completed status. Twenty-two wells were completed as productive (IHS Energy Group, 2010). During this period the success rate was 91.67 percent for completed wells.

All fields in the Study Area are considered to be gas fields. Only two wells were completed as predominantly oil producers and they are now abandoned.

Producing Zones

Oil and gas can occur in numerous geologic formations within the Study Area (Figures 5, 6a, and 6b), but the formations with actual reported historic production are much more limited. Reported conventional oil and gas occurring in the Paradox basin part of the Study Area (Figure 4) is reported only from the Permian Cutler Formation, the Pennsylvanian Hermosa Group, and the Honaker Trail Formation (Table 1). One well in each zone has been reported to be productive in the period from 1974 to present (IHS Energy Group, 2010). Only 520 barrels of oil and 227,651,000 cubic feet of gas have

been produced from these wells. Cumulative water production is reported as 4,395 barrels.

All other wells listed in Table 1 produce in the Piceance basin part of the Study Area (Figure 4). The Dakota Sandstone is Lower Cretaceous in age (Figure 6a), while the remaining zones are from the Upper Cretaceous (Figure 6b). The Corcoran and Cozzette members of the Iles Formation are productive in most wells in this area. Cumulative oil production for the 31 Piceance basin wells from 1974 to present (IHS Energy Group, 2010) is reported as 6,010 barrels of oil, 3,023,875,000 cubic feet of gas, and 10,812 barrels of water.

Production from coalbeds comes only from the Piceance basin part of the Study Area (Figure 3b). Operators in the area were asked to indicate which wells they now classify as coalbed gas wells. Table 2 shows these wells with their reported production and zones that have produced gas, oil, and water (IHS Energy Group). It is possible that some of the reported production in the Corcoran and Cozzette members comes from earlier production associated with the sandstones in these two zones before those wells were reentered and completed as coalbed gas zones. Coalbed production in the Study Area presently only comes from sediments of Upper Cretaceous age (Figure 6b). Most of the water produced in these wells has been re-injected into a deeper formation in the Hotchkiss Federal 12-89 #18-22D, which lies in section 18 of township 12 south, range 89 west (Figure 3a). This well began taking water in April of 2007, with 1,701,657 barrels re-injected.

Technology Development

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

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

Unconventional gas plays, sometimes called resource plays, will be a significant potential component of future exploration and production within the Study Area if reserves can be established. We use the term Resource Play to describe accumulations of hydrocarbons known to exist over a large areal extent and/or thick vertical section, may be self-sourcing, may be developed with horizontal well completions, and are driven by development efficiencies rather than geologic risk. Initial exploration and development for these types of plays will most likely be centered in the northeast part of the Study Area (southeast Piceance basin) and possibly in the Paradox basin area, if the shale gas plays being explored to the south of the Study Area can be extended into the Study Area. The Energy Policy Act of 2005 established funding for unconventional gas research and development and selected the Research Partnership to Secure Energy for America to oversee and manage new projects (Reeves et al., 2007). The goals of this organization are to:

- Increase the volume of the technically recoverable unconventional gas resource base by 30 trillion cubic feet,
- Convert 10 trillion cubic feet of technically recoverable unconventional gas to economically recoverable gas,
- Develop technologies for developing unconventional resources with minimum environmental impact, and
- Emphasize science-building capacity and effective technology dissemination.

Technologies that will be required to tap currently undeveloped unconventional gas resources (Reeves et al., 2007) may be:

- Detection methods to find where the highly productive, naturally fractured "fairways" of a play exist,
- Improving reservoir characterization in order to identify the entire productive pay interval,
- Advanced well stimulation methods to establish the low-end of reservoir quality for using well stimulation to yield economic results, and
- Enhanced recovery technology using injection of nitrogen and/or carbon dioxide to accelerate and increase gas recovery from coals, shales, and possibly tight sands.

With the rise in well drilling and well stimulation costs in recent years there had been concerns that much of the unconventional resource may become uneconomic to pursue. Gobec et al. (2007) have projected that the pursuit of efficiencies and technology improvements will at least partially offset the recent increases in costs. Most recently, costs have begun to level out and in some cases they have decreased in recent months, due to decreases in oil and gas demand and in price. We do not expect costs to increase significantly in the near future. Once oil and gas demand and prices begin to increase again in the long-term, then costs will also likely begin to rise.

The National Petroleum Council (1999) suggested that access restrictions can add 25 thousand dollars to the average cost of drilling a well in the Rocky Mountains. They also suggested that access restrictions can delay drilling activity by an average of two years.

Drilling and Completion Activity

There have been 254 surface well locations spudded or completed in the Study Area through April 20, 2010 (IHS Energy Group, 2010 and Colorado Oil and Gas Conservation Commission, 2010). Of the 254 wells spud or completed in the Study Area, 70 wells (27.6 percent) appear to have been located on Bureau managed oil and gas lands. In addition, 50 wells (19.69 percent) appear to have been located on U.S. Forest Service managed oil and gas lands.

Figure 13 presents the locations of all wells that are in an active status or are locations with a proposal to perform new drilling or additional testing (IHS Energy Group, 2010 and Colorado Oil and Gas Conservation Commission, 2010) as of April 20, 2010. Of these 82 wells, their well type and present status is:

- Coalbed Gas – Location Filed 3 wells
- Coalbed Gas – Producing 13 wells
- Coalbed Gas – Shut-In or Waiting on Orders 9 wells
- Gas – Location Filed 17 wells
- Gas – Spudded 1 well
- Gas – Producing 8 wells
- Gas – Domestic Production 1 well
- Gas – Shut-In, Waiting on Orders, or Temporarily Abandoned 27 wells
- Injection – Water 1 well
- Injection – Waiting on Orders 2 wells.

One well location is listed twice in the above compilation. A location notice has been filed for one of the above shut-in gas wells to reenter and test for coalbed gas production. Some of the above gas wells produce some associated oil, but no well in the Study Area presently produces enough oil to qualify it as an oil well. All three injection wells are, or will be used solely for disposal purposes.

At present only 62 wells shown in Figure 13 have been spudded or drilled to total depth, with the rest having only a drilling location notice filed. These 62 wells, account for about 24.4 percent of all the 254 oil and gas wells spudded or drilled to total depth within the Study Area.

About 75.6 percent (192 wells) of the 254 total wells have been plugged and abandoned and their surface locations have been reclaimed or are in the process of final reclamation. Wells have been abandoned because:

- they were “dry” – no hydrocarbons were encountered, hydrocarbons were not present in economic quantities, or mechanical difficulties within a borehole prevented economic oil and gas production;
- they were considered to be stratigraphic tests just drilled to obtain information about subsurface geologic horizons and their depths; or

- they initially were capable of producing hydrocarbons but they became uneconomic to produce at a later date or they were used as disposal or service wells and were no longer needed for those purposes.

Marginal Wells

Low-volume oil and gas wells, known as "marginal" or "stripper" wells, contribute an important percentage of the hydrocarbons produced in the United States. In 2006, about 29 percent of crude oil production and more than 10 percent of natural gas production was credited to marginal wells (Duda and Covatch, 2005). In 2007, their contribution remained relatively constant: approximately 28 and 11 percent, respectively (Interstate Oil and Gas Compact Commission, 2008).

Producing oil or natural gas wells are considered to be “marginal” when their producing rate is at the limit of profitability. The Interstate Oil and Gas Compact Commission (2008) defines marginal or stripper wells as wells that are producing 10 or fewer barrels of oil per day and no more than 60,000 cubic feet per day of natural gas. The majority of marginal wells are owned, maintained, and produced by independent operators rather than integrated exploration and production firms which operate globally. They account for a large proportion of the jobs and corresponding economic growth associated with the petroleum industry in this country (Duda and Covatch, 2005). The Interstate Oil and Gas Compact Commission (2008) estimates that the abandonment of marginal wells in 2007 cost an estimated 719 million dollars of lost Federal royalty revenue and nearly 2,000 jobs nationwide. In addition to the economic and employment impacts, keeping marginal wells in production allows for additional opportunities to use advanced technology to enhance recovery.

In 2008, Colorado ranked 12th of the 30 major producing states in the number of marginal oil wells, and 10th of the 28 major gas producing states (Interstate Oil and Gas Compact Commission, 2008). In the previous year there were 6,866 marginal oil wells that produced 7,170,856 barrels of oil in the state of Colorado, and 10,740 marginal gas wells which produced 102,321,123 thousand cubic feet of gas (data for 2008 was not available at the time of this writing). These totals represent 29.8 and 5.1 percent of the total production of oil and gas for the state, respectively (Interstate Oil and Gas Compact Commission, 2008, and Energy Information Administration, 2010a).

As of June 2009, no marginal oil wells and 18 marginal gas wells (both shut-in and producing) were located within the Study Area (IHS Energy, 2010). None of these wells are located on Bureau managed oil and gas minerals. According to the Interstate Oil and Gas Compact Commission (2008), the average daily production for marginal gas wells in Colorado in 2007 was 26.1 thousand cubic feet of gas. Assuming these averages have not changed significantly since the 2007 data was analyzed, production from marginal wells within the Study Area may account for approximately 172 million cubic feet of gas annually.

Deep Well Drilling: Greater than 15,000 feet

Dyman et al. (1990, 1993a, 1993b, and 1997) characterized deep wells as those drilled to depths greater than 15,000 feet. Drilling and completing deep wells is very costly due to the extremely high temperatures and variable pressures and hard rock that can be encountered at great depth. Only five of the 252 wells with an available depth measurement (1.98 percent) have been drilled to 15,000 feet or greater (IHS Energy Group, 2010) in the Study Area (Figure 14). All wells are located in the Paradox basin area, with the three westernmost wells located on or near the Paradise Valley Salt Cored Anticline and the other two wells located near the axis of the San Miguel Syncline (Figure 4).

The first deep well in the Study Area was completed in 1958 and the last one in 1992. The deepest well was an 18,354 foot drilled and abandoned wildcat located in section 26 of township 48 north, range 17 west that was spudded in April of 1962 and completed earlier in April almost a year later. It bottomed in the Permian Cutler Formation.

None of the five deep wells were completed as oil or gas producers. In 1988 the U.S. Bureau of Reclamation completed a 16,000 foot injection well in section 30 of township 47 north, range 18 west that penetrated Precambrian rocks. This well is used to dispose of salt-water and appears to be the only deep well still active in the Study Area.

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

Only 20 of 252 wells (7.94 percent), with an available depth measurement in the Study Area have drilled to the 10,000- to 14,999-foot depth range (IHS Energy Group, 2010). As Figure 14 shows, all wells in this depth range are located in the Paradox basin part of the Study Area. Most wells are concentrated along the Paradise Valley Salt Cored Anticline and the anticlinal trend to the southeast, with three additional wells located between the San Miguel Syncline and the thrust fault that marks the southern boundary of the Uncompaghre Uplift (Figure 4). Most wells have been completed as drilled and abandoned, with one well junked and abandoned (IHS Energy Group, 2010). Presently one well is in a temporarily abandoned status and two are classed as gas wells (Colorado Oil and Gas Conservation Commission, 2010). Both gas wells are considered as Hamilton Creek field producers with one producing from the Cutler Formation and the other from the Hermosa Group. Both wells produce from perforations that extend just beyond the 10,000-foot depth.

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

There are 68 of 252 wells (26.98 percent), with an available depth measurement, in the Study Area, that were drilled to the 5,000- to 9,999-foot depth range (IHS Energy Group, 2010). As Figure 14 shows, 32 wells in this depth range are scattered across the Paradox basin part of the Study Area, and the other 36 wells lie in the Piceance basin part; from the Mesaverde Formation outcrop (Figure 4) and northward. Completion status of most of the Paradox basin wells has been drilled and abandoned. Four wells were initially

completed as gas wells (two at Hamilton Creek field, one at Montrose Dome field and one at an unnamed field) and two were temporarily abandoned (unnamed fields). All the gas wells have been plugged and abandoned and one well has been converted to a shut-in status while the other remains temporarily abandoned. Completions were made in the Cutler and Honaker Trail formations and in the Hermosa Group.

Ten of the 36 wells in the Piceance basin part of the Study Area were drilled as coalbed natural gas wells. Nine wells were completed as coalbed natural gas producers and the remaining well is still recorded as being in a spudded status. Some coalbed natural gas well completions were as deep as the 6,800 to 6,900 foot range. Three of these wells have since been plugged and abandoned while the remaining six are productive, shut-in, or waiting on orders.

Twelve of the remaining 26 wells in the Piceance basin part of the Study Area were initially drilled and abandoned. The status of the others was:

- Spudded 2 wells,
- Gas 9 wells,
- Temporarily Abandoned 2 wells, and
- Injection 1 well.

The gas wells were completed as Cozzette and/or Corcoran member producers. All of the gas wells and temporarily abandoned wells are presently in a shut-in status (Colorado Oil and Gas Conservation Commission, 2010).

Shallowest Well Drilling: Less than 5,000 feet

The most wells (159 wells, or 63.1 percent of the 252 total wells with an available depth measurement) in the Study Area have drilled to less than 5,000 feet (IHS Energy Group, 2010). Locations of these wells (Figure 14) are:

- on the Paradise Valley Salt Cored Anticline (a small number of this type of well),
- just south of the thrust fault bounding the south flank of the Uncompahgre Uplift and southeast to the vicinity of the town of Ridgeway,
- in flank areas of the Grand Mesa Syncline and the southern flank of the Piceance basin (south of the Mesaverde Formation outcrop, and
- the Piceance basin part of the Study Area.

Twenty-three of the 159 wells in this depth range were drilled as coalbed natural gas wells. Three wells were completed as drilled and abandoned or junked and abandoned, 19 were completed as coalbed natural gas wells, and one was spudded. Nine of these 19 wells still produce, while nine have been plugged and abandoned and one is presently shut-in. Of the remaining 136 wells, 106 wells were drilled and abandoned. Completion status of the remaining 30 wells was:

- Spudded 4 wells,
- Service 2 wells,
- Oil 2 wells,
- Gas 13 wells,
- Carbon Dioxide 1 well,

- Shut-In 1 well, and
- Temporarily Abandoned 7 wells.

The oil and carbon dioxide wells have been abandoned as have three of the gas wells, two temporarily abandoned wells, and one service well. The remaining the remaining 21 wells are still in an active status (Colorado Oil and Gas Conservation Commission, 2010).

Summary of Current Drilling Techniques

Most Study Area oil and gas wells are recorded as having been drilled vertically (IHS Energy Group, 2010), with only four directional wells and one horizontal well drilled to date (April 20, 2010). Developments in drilling techniques have allowed for more widespread use of directional and horizontal drilling technology. Directional drilling has many benefits, but also some limitations. For instance, directional drilling may be employed to avoid sensitive or inaccessible surface features, increase the area that a borehole contacts a producing formation, and when multiple directional wells are drilled from the same vertical borehole or from the same surface location, reduce drilling time, associated waste volumes and emissions, and provide greater protection of sensitive environments. Most of this technology will be tested first in other regions where economic returns on investment are higher than in the Study Area. Where technology is shown to provide significant cost benefits, local operators will apply those methods when appropriate.

Directional and Horizontal Drilling and Completion Activity

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

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 and others (1991) identified the following specialized requirements and risk factors unique to horizontal and directional drilling that can affect drilling and completion costs for these types of wells:

- specialized equipment (e.g., mud motors, measurement while drilling tools) and specially trained personnel,

- a larger drilling rig and associated equipment,
- casing and drilling string modifications to address problems associated with ovality and bending stresses,
- increased risk of borehole damage due to unique tectonic stresses,
- slower penetration rates that 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 a case such as this, the operator must make the determination that the increased potential for productivity outweighs the additional costs and inherent risks involved in directional and horizontal drilling.

Almost all of the oil and gas wells and all of the coalbed natural gas wells in the Study Area have been drilled vertically. Only four wells have been drilled directionally and one well has been drilled horizontally (Figure 15). All four directionally drilled wells have been drilled in the Paradox basin part of the Study Area. One well was completed in 2007 as a Cutler Formation gas well and it still produces at a measured depth of just over 10,100 feet. Two other wells were drilled and abandoned (in 1988 and 2002) and the fourth well was temporarily abandoned in 2008 and remains in that status. Since most directional well bores are S-shaped, the true vertical depth and measured depths (borehole lengths) are usually within a few percent of each other.

The only horizontal well was completed in 1994 in the Piceance basin part of the Study Area (Figure 15) and is presently shut-In. It was completed as a Cozzette member gas well at just over 6,000 feet in true vertical depth.

On April 20, 2010 there were active proposals for three directional wells and one horizontal well (Figure 15) in the Study Area. In the Paradox basin part of the Study Area a 10,757 foot directional test to the Cutler Formation was proposed. In the Piceance basin part of the Study Area a 6,336 foot Corcoran member directional test and a 4,368 foot Cozzette/Corcoran member test were proposed. Also, in this area a horizontal coalbed natural gas well was proposed to test the Cameo Coal.

Increased use of directional and horizontal boreholes is anticipated in the future. At the Whitewater unit (Figure 10) the operator has proposed pad drilling with up to 10 directional wellbores per pad. In additional, we anticipate that any future development of gas shale prospects would likely be via horizontal boreholes. Gas shale prospects are reviewed in more detail latter in this report under the “Resource Plays” discussion.

Slimhole Drilling and Coiled Tubing

Slimhole drilling—a technique used to tap into reserves in mature fields—has not yet been used much in the Rocky Mountain Area. In eastern Colorado the technology has been used in the Niobrara unconventional gas play.

Coiled tubing—used effectively for drilling in reentry, underbalanced, and highly deviated wells—is often used in slimhole drilling. Most coiled tubing rigs are limited to relatively shallow drilling. These types of rigs have been used in the Niobrara play in eastern Colorado and to the north in other parts of the Piceance basin

A review of coiled tubing drilling and intervention (well work during the life of a well) and its advantages, disadvantages, and limitations was presented for the U.S. Department of Energy (2005). Most likely, future applications may be for drilling shallow development wells (including coalbed natural gas wells), reservoir data monitoring holes, shallow re-entry wells, and deeper exploration holes (Spears & Associates, Inc., 2003). Brown (2006) has reported that slimhole drilling with coiled tubing may soon begin to replace conventional rotary drilling in the shallow depths across the United States. He reported that cost savings can range from 25 to 35 percent per hole, and other advantages include:

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

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

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

Light Modular Drilling Rigs and Pad Drilling

Now in production, new light modular drilling rigs can be more easily used in remote areas and are quickly disassembled and moved. Rig components are made with lighter and stronger materials and their modular nature reduces surface disturbance impacts. Also, these rigs reduce fuel use and emissions. Use of this type of rig in the Study Area is not likely in the near future. Other Rocky Mountain plays (western Wyoming, the Piceance basin north of the Study Area, and North Dakota) have a higher priority for new rigs since more prolific reservoirs are being developed in those locations than reservoirs are known to be capable of within the Study Area.

Light modular rigs also have potential for use in situations where pad drilling is being used. Pad drilling refers to the drilling of multiple directional boreholes from one surface location. Pads are the flat graded land surfaces that serve as the foundation for the drilling rig. Since modular rigs allow quicker breakdown and movement to new locations, they reduce time to drill and rig costs. Several formations could conceivably contain resource plays which generally lend themselves to horizontal completions and thus pad drilling. The Mancos Shale in the Piceance basin and the Hovenweep and Gothic shales in the Paradox basin are three such potential plays, though others may exist as well. Gas shale prospects are reviewed in more detail latter in this report under the "Resource Plays" discussion.

Pneumatic Drilling

Pneumatic drilling is a technique in which boreholes are drilled using air or other gases rather than water or other drilling liquids. This type of drilling can be used in mature fields and formations with low downhole pressures and where formations are sensitive to the fluids commonly used in drilling. Few fields in the Study Area are expected to meet these criteria. It is an important tool that can be used when drilling horizontal wells, so it could be used in those types of situations in the future. This type of drilling significantly reduces waste, shortens drilling time, cuts surface disturbance, and decreases power consumption and emissions.

Measurement-While-Drilling

Measurement-while-drilling systems measure borehole and formation parameters during the actual drilling process. These systems allow more efficient and accurate drilling. They can reduce costs, improve safety of operations, reduce time on site, and fewer wells may need to be drilled. At present, measurement-while-drilling would be critical for use in drilling future horizontal boreholes within the Study Area. In the future, use of this type of drilling system may become more widespread and may be used when drilling other types of directional boreholes.

Improved Drill Bits

Advances in materials technology and bit hydraulics have yielded tremendous improvement in drilling performance. Latest-generation polycrystalline diamond compact bits drill 150 to 200 percent faster than similar bits just a few years ago (U.S. Department of Energy, 1999). Additional improvements have continued to be made to enable faster drilling. Environmental benefits of improved bits include:

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

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

Summary of Current Completion Techniques

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

Some form of hydraulic fracturing is then usually used to improve hydrocarbon flow into the borehole. Hydraulic fracturing of reservoirs can enhance well performance, minimize drilling, and allow the recovery of otherwise inaccessible oil and gas resources. The flow of hydrocarbons is restricted in some low-permeability, tight formations and in nonconventional reservoirs (such as coalbed natural gas), but can be stimulated by hydraulic fracturing to produce economic quantities of hydrocarbons. Fluids are initially pumped into the formation at pressures high enough to cause fractures to open in the reservoir rock. Sand slurry is pumped into the opened fractures, which keeps the fractures propped open, allowing hydrocarbons in the reservoir to more easily enter the borehole. Improvements such as carbon dioxide-sand fracturing, new types of additives, and fracture mapping, promise more effective fractures and greater ultimate hydrocarbon recovery.

Only one horizontal well has been drilled to date in the Study Area. New types of horizontal fracturing technology will likely be used to stimulate these types of wells in the future. Development could be similar to that used to stimulate the Bakken Formation Middle Member in North Dakota. For horizontal boreholes, multi-stage fracture stimulations could be used. The Energy Information Administration (2006a) has reported that once the Bakken Formation has been fractured an un-cemented pre-perforated liner is installed in the borehole.

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

Drilling and Completion Costs

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

The National Petroleum Council (2003) reported drilling and completion costs for vertical wells in the Uinta-Piceance basin region and the Great Basin & Paradox basin. All cost components such as permitting, location construction, mobilization, rentals and services, tangible items, and stimulations were assumed to be included in these costs. They reported the average gas well cost for wells in four depth ranges. Those costs for the Uinta-Piceance basin were:

- 0 to 5,000 feet 216 thousand dollars,
- 5,000 to 10,000 feet 570 thousand dollars,
- 10,000 to 15,000 feet 1.574 million dollars, and
- 15,000 to 20,000 feet 4.407 million dollars.

Gas well costs for the Great Basin & Paradox basin were:

- 0 to 5,000 feet 222 thousand dollars,
- 5,000 to 10,000 feet 712 thousand dollars,
- 10,000 to 15,000 feet 1.697 million dollars, and
- 15,000 to 20,000 feet 5.412 million dollars.

Since oil wells have been so rarely drilled within the Study Area, those costs are not included in this report.

Reported dry hole well costs for the Uinta-Piceance basin were estimated to be:

- 0 to 5,000 feet 113 thousand dollars,
- 5,000 to 10,000 feet 295 thousand dollars,
- 10,000 to 15,000 feet 739 million dollars, and
- 15,000 to 20,000 feet 2.506 million dollars.

Reported dry hole well costs for the Great Basin & Paradox basin were estimated to be:

- 0 to 5,000 feet 138 thousand dollars,
- 5,000 to 10,000 feet 288 thousand dollars,
- 10,000 to 15,000 feet 821 million dollars, and
- 15,000 to 20,000 feet 2.468 million dollars.

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

SUMMARY OF CONVENTIONAL OIL AND GAS PRODUCTION AND ABANDONMENT TECHNIQUES

Once production begins application of reservoir management procedures are needed to ensure the maximum hydrocarbon production at the lowest possible cost, with minimal waste and environmental impact. In earlier days, recovery was only about 10 percent of

the oil-in-place (see Glossary for in-place) in a given field, and sometimes, the associated natural gas was vented or flared. Newer recovery techniques have allowed the production of up to 50 percent of the oil-in-place. Also, 75 percent or more of the natural gas-in-place in a typical reservoir is now recovered. Operators have also taken significant steps in reducing production costs. U.S. Department of Energy estimated that costs of production had decreased from a range of nine to 15 dollars per barrel of oil equivalent in the 1980's to an average of about five to nine dollars per barrel of oil equivalent in 1999.

Operating costs in the United States have been rising in recent years. Annual Rocky Mountain operating costs rose to about 55,000 dollars per 12,000 foot well in 2005, as reported by Kim (2007).

Since 1990, most reserve additions in the United States (89 percent of oil reserve additions and 92 percent of gas reserve additions) have come from finding new reserves in old fields (U.S. Department of Energy, 1999). The U.S. Department of Energy (1999) reports that about half of new reserve additions in the United States are from more intensive development within the limits of known reservoirs. They report that the other half of reserve additions have come from finding new reservoirs in old fields and extending field limits. Our review indicates that most recent reserve additions in the Study Area have come from development of the coalbed natural gas resource in the Piceance basin area.

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

- remoteness and cold temperatures which often requires dehydrators and line heaters, more expensive types of steel casing, and insulation of surface equipment;
- workovers and preventive maintenance is more frequent which minimizes shut-in days in the winter when well site access is difficult; and
- lack of rig availability due to its lower drilling priority in the Rockies.

Recovering oil and gas from a geologic reservoir often occurs in a staged process using different recovery techniques (or a combination of techniques) as the reservoir is drained. Traditionally, processes were referred to as primary, secondary, or tertiary depending on when the process was applied. However, as technology has improved and the price of oil and gas has increased, reservoirs that had previously been bypassed are now being tapped using secondary or tertiary processes from the outset. Therefore, the terms "secondary" and "tertiary" are seeing less usage, or are more narrowly defined. "Secondary recovery" has become synonymous with water flooding and gas (not carbon dioxide) injection and "enhanced recovery" broadly encompasses any recovery techniques that are not part of primary recovery or waterflooding. The following definitions will be used in this report:

- Primary Recovery - Primary recovery produces oil, gas, and/or water using the natural pressure in the reservoir. Wells may be stimulated to improve the flow of oil and gas to the borehole. Other techniques, including artificial lift, pumping, and gas lift, help extend productive life when a reservoir's natural pressure dissipates.
- Secondary Recovery – Stimulation of reservoir production via injection of water into the producing formation thereby driving oil to production wells, or via injection of gas to expand the gas cap and/or regulate the reservoir pressure. Since there presently are no unplugged oil wells within the Study Area, this process will not be used in the future unless new oil reserves are discovered and first go through the primary recovery process.
- Enhanced Oil Recovery - Injection of fluids (e.g., water, surfactants, polymers, or carbon dioxide) or sources of heat (steam or hot water) to stimulate hydrocarbon flow and move hydrocarbons that were bypassed in earlier recovery phases. This phase also will not occur within the Study Area unless new oil reserves are discovered and first go through the primary recovery and secondary recovery processes.

Hydrogen Sulfide Occurrence

Hydrogen sulfide is a colorless, flammable gas that occurs naturally in most crude oil and many natural gas reservoirs (Levorsen, 1967). Hydrogen sulfide is toxic to humans and animals, and a single breath may provide enough exposure to be fatal (International Programme on Chemical Safety, 1994). It has a characteristic foul, or "rotten egg" odor, and is heavier than air, so it tends to accumulate in low-lying areas. Hydrogen sulfide is an impurity that must be removed from oil or natural gas through desulfurization in oil refineries and natural gas "sweetening" plants (natural gas containing hydrogen sulfide is commonly referred to as "sour gas") (Skrtic, 2006). The presence of hydrogen sulfide in hydrocarbons is problematic not only because it is an impurity that must be removed in processing, but also because it is corrosive to metals both as a free gas and in solution, and because of its toxicity to personnel, wildlife, and the public. On Federal lands, operators are required by law to follow specific safety practices and have public protection plans in place where hydrogen sulfide can "reasonably be expected to be present in concentrations of 100 parts per million or more in the gas stream" (43 CFR 3160). To date, no fields in the Study Area have been identified as containing hydrogen sulfide gas. Nearest known hydrogen sulfide produced with hydrocarbons is at Lisbon Valley field in Utah and at southeast Lisbon field to the south of the Study Area in San Miguel County, Colorado (Wilson et al., 2003). If future test wells are drilled within the Paradox basin part of the Study Area they could encounter hydrogen sulfide in older sediments such as the Mississippian Leadville Limestone and Devonian McCracken Member of the Elbert Formation.

Carbon Dioxide

Carbon dioxide has been discovered during oil and gas exploration at numerous places within the Colorado Plateau and Southern Rocky Mountain physiographic provinces. In

the region it has been found in concentrations that exceed 98 percent (Allis et al., 2001). Uses have included dry ice sales, industrial uses, and for injection into oil reservoirs to enhance oil recovery. Enhanced oil recovery has been the dominate use for the carbon dioxide resource.

In the Colorado part of the Paradox basin carbon dioxide in large quantities is found in the Mississippian Leadville Limestone at McElmo Dome field in Montezuma County) and at Doe Canyon, Impel Redd, and Gulf Gillespie fields in Dolores County (Wilson et al., 2003). Smaller quantities are found at Lisbon Valley field in Utah and at southeast Lisbon field to the south of the Study Area in San Miguel County, Colorado (Wilson et al., 2003). If future test wells are drilled within the Paradox basin part of the Study Area they could encounter carbon dioxide in older sediments such as the Mississippian Leadville Limestone.

There is also some potential for carbon dioxide to occur in the Leadville Limestone in the Piceance basin (Wilson et al., 2003). If the Leadville Limestone is encountered in deep tests in that part of the Piceance basin within the Study Area, then carbon dioxide needs to be considered as a potential resource.

One well in the Study Area (section 12, of township 14 north, range 97 west) was completed as a carbon dioxide producer in the Morrison Formation (Figure 3a). That well was completed in 1982 with a test of 408,760 cubic feet of gas. No production was reported from this well and it was plugged and abandoned in 1992 (Colorado Oil and Gas Conservation Commission, 2010).

Acid Gas Removal and Recovery

Before natural gas or oil can be transported safely, any hydrogen sulfide or carbon dioxide gas must be removed. Special plants are needed to recover these unwanted gases and sweeten the hydrocarbon product for sale. Improvements in the removal process have made it possible to produce sour natural hydrocarbon resources, almost eliminate noxious emissions, and recover almost all of the elemental sulfur and carbon dioxide for later sale or disposal. Presently producing oil and gas formations within the Study Area do not produce hydrogen sulfide or carbon dioxide, or they produce in such minor amounts that removal is not required.

Artificial Lift Optimization

Artificial lift is used to produce oil once reservoir pressure declines and natural processes can no longer push the oil to the surface. Improvements in artificial lift have enhanced production, lowered costs, and lowered power consumption, which reduce air emissions. Artificial lift could be used in the future if oil production is discovered in the future.

Glycol Dehydration

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

Produced Water Management

Coproduction of a variable amount of water with oil and gas and with coalbed natural gas is unavoidable at most locations. Table 1 shows the cumulative volume of produced water from conventional oil and gas wells in the Study Area and Table 2 shows the cumulative volume of water produced with coalbed natural gas. Colorado allows produced water to be disposed of as follows:

1. Injection into a Class II well, permitted in accordance with Rule 325;
2. Evaporation/percolation in a properly permitted pit;
3. Disposal at permitted commercial facilities;
4. Disposal by road spreading on lease roads outside sensitive areas for produced waters with less than 3,500 milligrams per liter total dissolved solids when authorized by the surface owner;
5. Discharge into state waters, in accordance with the Water Quality Control Act and the rules and regulations promulgated thereunder; and
6. Evaporation in a properly lined pit at a centralized Exploration & Production waste management facility permitted in accordance with Rule 908.

Figure 16 documents the geographic distribution of water quality samples across the Study Area and shows the distribution of sampled salinity, expressed as total dissolved solids, in those water samples. This information is from a U.S. Geological Survey (2008a) database of water quality samples. Water quality information is available for only eight samples and total dissolved solids range from 3,659 to 299,590 milligrams per liter. Water quality sample distribution and sampled zones are:

- less than 5,000 milligrams per liter – 1 sample (Cutler Formation),
- 5,000 to 9,999 milligrams per liter – 1 sample (Cutler Formation),
- 10,000 to 49,999 milligrams per liter – 3 samples (Rollins/Cozzette members, Burro Canyon Formation, and Mississippian)
- Greater than 50,000 milligrams per liter – 3 samples (one Devonian and two Mississippian samples).

The Bureau considers total dissolved solids concentrations of less than 10,000 milligrams per liter to be fresh water. Only two of the eight water quality samples fall within this range. The samples from these two wells were also from the shallowest zones tested (less than 4,100 feet). Water quality samples that have a total dissolved solids concentration of greater than 10,000 milligrams per liter are from deeper zones and from older formations.

A new freeze-thaw/evaporation process has been shown to be useful in separating out dissolved solids, metals, and chemicals that are contained in water produced along with the oil and gas production of wells. In 1998, this type of produced water facility was determined to be successful in southwestern Wyoming (PTTC, 2002) and the San Juan basin in New Mexico (Boysen and Boysen, 2008). It could probably be successfully used in higher elevation/colder climate parts of the Study Area, in locations where production of poor quality water cannot be disposed of by other means.

The Gas Technology Institute tested the performance and costs associated with the application of electrodialysis to produced water management (Hayes, 2004). Pilots have been run in the Rocky Mountain region and could be used in the Study Area in the future.

Leak Detection and Low-bleed Equipment

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

Vapor Recovery Units

Vapor recovery can reduce a lot of the fugitive hydrocarbon emissions that vaporize from crude oil storage tanks, mainly from tanks associated with high-pressure reservoirs, high vapor releases, and large operations. The emissions usually consist of 40 to 60 percent methane, along with other volatile organic compounds, and hazardous air pollutants (U.S. Department of Energy, 1999). Where useable, this technology can capture over 95 percent of these emissions. No record of use of this equipment is available for the Study Area.

UNDERGROUND GAS STORAGE

Produced gas can be stored in some existing good quality reservoirs that have already been depleted of their native gas content. The objective of gas storage is to allow lands to be used to store natural gas during periods of excess production so that those supplies can be made available to meet peak gas demands and to maximize the efficiency of the gas delivery system. At present there are no gas storage projects within the Study Area.

PREVIOUS ASSESSMENTS OF OIL AND GAS RESOURCES

RECOVERABLE NATURAL GAS RESOURCES – ENERGY INFORMATION ADMINISTRATION, POTENTIAL GAS COMMITTEE, AND NATIONAL PETROLEUM COUNCIL

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

- The Energy Information Administration (2003) uses a natural gas resource base of 345 trillion cubic feet for the Rocky Mountain region.
- The Potential Gas Committee (2003) estimated 288 trillion cubic feet of natural gas; including 50 trillion cubic feet of proved reserves (see Glossary).
- As part of a study done in compliance with the Energy Policy and Conservation Act Amendments of 2000 (U.S. Departments of Interior, Agriculture, and Energy, 2003) the U.S. Geological Survey estimated the technically recoverable gas resource for five basins in the Rocky Mountain region at 226 trillion cubic feet. Of that total, they estimated a conventional gas resource of 13 trillion cubic feet, tight gas sand and shale gas resources of 127 trillion cubic feet, and 43 trillion cubic feet each of coal-bed natural gas and proved reserves.
- The National Petroleum Council (2003) estimated 284 trillion cubic feet of natural gas for the Rocky Mountain region. The Council also presented a comparative analysis of their estimates with those of the Energy Information Administration, Potential Gas Committee and U.S. Geological Survey to better understand the factors that influenced the differences among each estimate.

Assumptions to the Annual Energy Outlook 2010 with Projections to 2035 Energy Information Administration (2010)

In April 2010, the Energy Information Administration released their update for total technically recoverable resources (see Glossary). As of January 1, 2008, estimated total technically recoverable crude oil resources for the Rocky Mountain region are 20.9 billion barrels of oil (Energy Information Administration, 2010b). For the total United States, the estimated total technically recoverable resources for crude oil are 208.4 billion barrels of oil. Total technically recoverable natural gas resources as of January 1, 2008 for the Rocky Mountain region vary based on sources of natural gas. Natural gas from conventional reservoirs is estimated to have 345.0 trillion cubic feet of total technically recoverable resources in the Rocky Mountain region (2010). Natural gas technically recoverable as shale gas and coal-bed natural gas is estimated at 21.9 and 94.3 trillion cubic feet of gas respectively in the Rocky Mountain region. Total recoverable natural gas resources in the United States are estimated to be 2,118.7 trillion cubic feet (2010). Marc Humphries, Analyst in Energy Policy from the Congressional Research Service,

stated that 37 percent of natural gas and 17 percent of oil in the United States comes from the Rocky Mountain Region (Humphries, 2004).

The National Petroleum Council (2003)

The National Petroleum Council (2003) has divided remaining natural gas resources into proved natural gas reserves, proved growth reserves, and undiscovered technically recoverable resources (see Glossary for descriptions of each). They further divided undiscovered technically recoverable resources into conventional and unconventional (also known as nonconventional) types (see Glossary for descriptions of each).

As of January 1, 2002, the National Petroleum Council (2003) estimated Rocky Mountain region proved natural gas reserves to be 50 trillion cubic feet. Energy Information Administration (2004) was able to split out proved tight sand gas reserves (26.8 trillion cubic feet) and proved coal-bed natural gas reserves (14.8 trillion cubic feet) for the Rocky Mountain region. Growth of proved gas reserves in the Rockies was estimated at 26 trillion cubic feet (National Petroleum Council, 2003). Finally, undiscovered technically recoverable resources for conventional gas were estimated to be 173 trillion cubic feet, while unconventional gas resources were estimated to be 209 trillion cubic feet (National Petroleum Council, 2003).

The U.S. Department of Energy (2003) has reported that "as geologic knowledge and technology for finding and producing natural gas have improved, the estimated volume of natural gas resources in the Rocky Mountain States has grown." They assumed that as long as investment continued towards expanding the geologic knowledge base and technology progress, then there would be a continued upward trend in future resource assessment volumes and recovery would be expected to continue to increase. These reserve additions will be needed in the future to replace those that are being depleted due to production and consumption.

"The importance of natural gas as a primary energy source in the United States has grown considerably during the past decade" (Curtis and Montgomery, 2002). Rising demand in this country will result in a 1.1 percent average annual increase in our consumption of energy to 2030 (Energy Information Administration, 2007a). During that period natural gas consumption is expected to rise from 21.08 trillion cubic feet in 2005 to 26.9 trillion cubic feet in 2030 (Energy Information Administration, 2007b). Domestic production rose from 17.7 to 19.7 trillion cubic feet (11.3 percent increase) from 1990 to 2000 (Curtis and Montgomery, 2002) and then dropped to 18.3 trillion cubic feet by 2005. It is expected to rise to 20.6 trillion cubic feet by 2030 (Energy Information Administration, 2007b). North American producing areas are expected to provide 75 percent of long-term domestic gas needs, but they will be unable to meet the entire projected demand (National Petroleum Council, 2003). The gap between consumption and production has necessitated a rise in imports and concern about future domestic energy supply.

ATLAS OF MAJOR ROCKY MOUNTAIN GAS RESERVOIRS (1993)

The Atlas of Major Rocky Mountain Gas Reservoirs assessed both the Paradox basin and the Uinta-Piceance basin in 1993 (Morgan and Hemborg, 1993). The Paradox basin has a fold and fault belt in the northern part of the basin. There are salt-cored anticlines in this area. The three main gas producers of the Paradox basin include the Cutler-Honaker Trail, Paradox Formation, and Leadville Limestone plays. Source rocks are primarily from shale in the Paradox Formation. Hydrocarbons are stored in algal mounds of the Paradox Formation.

The Paradox Formation play has eight plays that produced more than 330 billion cubic feet of gas (Morgan and Hemborg, 1993). Reservoirs occur in algal mounds and oolitic bank deposits in the Ismay and Desert Creek zones of the Pennsylvanian Paradox Formation. Gas and oil are produced from these reservoirs. Due to decreased circulation in a past sea, thick deposits of salts and anhydrite were deposited in the area resulting in alternating beds of shale and salt in the Paradox Formation.

An important play in the Paradox basin in the Study Area is the Cutler-Honaker Trail play. Andy's Mesa field had cumulative production of 18.5 billion cubic feet of non-associated gas as of 1993 (Morgan and Hemborg, 1993). The original field pressure was 2,345 psi at 6,915 ft. The last discovery in the Cutler-Honaker Trail play was the Hamilton Creek field in 1976. The Hamilton Creek Field is in Township 44 North, Range 14 West of the Study Area. Monthly field production peaked at 377 million cubic feet of gas in 1970. Production declined to 34.7 million cubic feet of gas per month by 1990. There were 16 total wells drilled in this play with 9 of those wells producing gas (Morgan and Hemborg, 1993).

In the Paradox basin, five reservoirs have produced more than 608 billion cubic feet of gas from the Leadville Limestone. A major field in the Leadville Limestone is the Lisbon field. Just west of the Study Area and in San Miguel County, the Lisbon field produced 538 billion cubic feet of the total 608 billion cubic feet produced in the Leadville Limestone (Morgan and Hemborg, 1993). Also, the Lisbon field has produced 48 million barrels of condensate oil and contains an estimated recoverable reserve of 250 billion cubic feet of gas. The driving mechanism of the migration of hydrocarbons is likely gas expansion and gravity. Although the field is productive, numerous downfalls preclude the field from being highly economic.

The Greater Piceance Plays include those in the Piceance, Uinta, and North Park basins. Six gas plays with 46 major reservoirs are in these basins (Tremain et al., 1993). Cumulative production was 1.867 trillion cubic feet of gas as of 1993. Production is mainly from the Wasatch, Green River, and Mesaverde Formations. The Greater Piceance Plays have produced more gas than any other area in Colorado. The authors of the Atlas suggested that advancements in technology would need to occur to develop more gas in the area.

The Mesaverde Group was also analyzed in the Atlas of Major Rocky Mountain Gas Reservoirs. In the Piceance basin, the Mesaverde Group produces gas from lenticular, fluvial sands (Tremain et al., 1993). There are seven major reservoirs that had produced approximately 118 billion cubic feet of gas as of 1993. In addition, 30 smaller reservoirs had produced 30 billion cubic feet of gas. The assessment determined the best technique for producing gas was from "unstimulated wells containing reservoirs with natural fractures" (Tremain et al., 1993).

Cumulative production of natural gas as of December of 1990 in the Upper Mancos Shale of Colorado and Utah was 359.5 billion cubic feet (Tremain, 1993). Production was from 37 fields along the Douglas Creek arch and the margins of the Uinta and Piceance basins. Approximately 87 percent of production was from the Emery Sandstone in the middle Mancos Shale. There were 400 producing wells added since 1976, with an average production of one to two billion cubic feet of gas per well. The decline rate for this area averaged 6 percent as of 1993 (Tremain, 1993).

In the Dakota Sandstone, Cedar Mountain Formation, and Morrison Formation there were 18 major fields that produced more than 362 billion cubic feet of natural gas as of December 31, 1990 (Tremain, 1993). Average drilling depths ranged from 3,000 to 8,800 feet. Many of the reservoirs in this area have high nitrogen and carbon dioxide concentrations. The depositional framework for these formations ranges from fluvial to nearshore marine (Tremain, 1993).

The Entrada and Weber Sandstones were also analyzed in The Atlas of Major Rocky Mountain Gas Reservoirs. The play areas (see Glossary) identified in the atlas, do not extend into the Study Area.

MAJOR OIL PLAYS IN UTAH AND VICINITY: QUARTERLY TECHNICAL PROGRESS REPORTS (2003-2008)

Another assessment completed in the Paradox basin was "Major Oil Plays in Utah and Vicinity: Quarterly Technical Progress Reports ", by Thomas C. Chidsey, Jr. Reports from July 2003, to February 2008, were analyzed for pertinent data to the Study Area and reviewed below.

The July 2003 report discussed optimal drilling techniques in the Paradox basin. These techniques include increasing mud weight during drilling to 12.5 pounds, centralize treatment facilities, and mix produced water down dip to reduce salt precipitation. The optimal drilling horizon at that time was noted to be the Desert Creek zone of the Paradox Formation in the Blanding sub-basin. Other techniques discussed included disposal of produced water and maintenance of reservoir pressure to create a low-cost waterflood (Chidsey et al., July 2003)

The September 2003 report stated the Paradox basin reservoirs are heterogeneous, which is the principle reason for low recovery rates. Heterogeneity is due to gaps in algal mounds in the Paradox Formation. As of Sept. 2003, horizontal drilling has had no

commercial success in the Paradox, except the Greater Aneth field (Chidsey et al., September 2003).

The March 2004 report discusses the Leadville Limestone in the Paradox basin. The Leadville Limestone is a major oil and gas reservoir. Most of the Leadville Limestone is found in the Paradox basin fold and fault belt, which occurs in the southwestern portion of the Study Area (Chidsey et al., March 2004).

The April 2005 report details the Leadville Limestone extensively. It had produced over 53 million barrels of oil and 845 billion cubic feet of gas as of this report. The seals were noted as the clastic beds of the Molas Formation and evaporite beds of the Paradox Formation. Traps include structural traps with closure on anticlines, faults, and fault planes. Source rocks are from the Paradox Formation. The Leadville Limestone has varying porosity and permeability. Dolomitization has partly occurred along with leaching. Fracturing is present in the limestone. To the east of the Study Area, the Leadville Limestone in San Miguel County had an initial reservoir pressure of 2,340 pounds per square inch in the Lisbon Southeast field. Average monthly production was 313 barrels of oil and 50,295 thousand cubic feet of gas. Cumulative production was 164,922 barrels of oil and 16.2 billion cubic feet of gas as of the 2005 report (Chidsey, April 2005).

In the July 2006 report the Paradox Formation was discussed in detail. It was reported that over 500 million barrels of oil and 650 billion cubic feet of gas had been produced in Utah. Most of the gas produced was cycled for pressure maintenance. The characteristics of Paradox Formation oil are sweet, paraffinic, and the average API gravity is 43 degrees. Viscosity ranges from 33 to 49 seconds at 100 degrees Fahrenheit (Chidsey, July 2006).

The November 2006 report also discussed the Paradox Formation. The Cane Creek shale member total organic content is 15 to 28 percent. The Chimney Rock shale member total organic content is 1 to 3 percent with an average vitrinite reflectance of 1.3 to 2.5 percent. The Gothic Shale member has a total organic content of 1.5 to 4 percent and a vitrinite reflectance of 1.3 to 2.5 percent. The Gothic Shale member occurs in the southern part of the Study Area, south of the Uncompahgre Uplift. This report also notes that the Paradox Formation only produced gas in the southeast part of the basin in Colorado (Chidsey, November 2006).

The May 2007 report discusses seals and source rocks for the Paradox Formation. The vertical reservoir seals include shale, halite, and anhydrite. The lateral seals include un-fractured beds, off mound mudstone, wackestone, and anhydrite) and anhydrite. Source rocks are the Cane Creek, Chimney Rock, and Gothic Shales (Chidsey, May 2007).

The February 2008 report detailed sources of carbon dioxide in the Paradox basin. The McElmo Dome field in southwest Colorado is a carbon dioxide source. The Ouray Formation and Leadville Limestone supply carbon dioxide to the Greater Aneth Field southwest of the Study Area (Chidsey et al., February 2008).

INVENTORY OF ONSHORE FEDERAL OIL AND NATURAL GAS RESOURCES AND RESTRICTIONS TO THEIR DEVELOPMENT: PHASE III INVENTORY—ONSHORE UNITED STATES (2008)

For oversight and regulatory purposes, the Department of Interior is required by the Energy Act of 2000 to report oil and gas resources underlying Federal lands. Restrictions and causes for delays are also required in the report. The Inventory of Onshore Federal Oil and Natural Gas Resources and Restrictions to Their Development; Phase III Inventory—Onshore United States fulfilled this requirement in 2003, 2006, and 2008. The Phase III report (2008) contains the most current Onshore United States inventory.

The 2008 report gave estimates for undiscovered technically recoverable resources, remaining proved ultimate recovery growth, and proved reserves on Federal Lands including the Study Area. The proved liquid reserves in the Uinta-Piceance basin were 254 million barrels of oil. Federal government reserves were 143 million barrels of oil (U.S. Departments of the Interior, 2008). Proved gas reserves in the Uinta-Piceance basin were 7,182 billion cubic feet of gas. Federal government reserves were 3,794 billion cubic feet of gas. These reserve estimates were made in 2008. The Paradox basin proved liquid reserves were 119 million barrels of oil with 36 million barrels of oil on Federal Land. The total proved gas reserves in the Paradox basin were 14,156 billion cubic feet of gas with 7,497 billion cubic feet of gas on Federal Land (2008). .

Of these reserves, different accessibility levels exist that constrain oil and gas development in the Uinta-Piceance basin and Paradox basin. Federal Land in the Uinta-Piceance basin is broken up as follows: 40.4% (5,301,000 acres) is not accessible and there is no leasing or no surface occupancy, 32.4% (4,257,000 acres) is accessible and can be leased but there are timing limitations or controlled surface use, and 27.1% (3,549,000 acres) is accessible and can be leased with standard leasing terms (U.S. Departments of the Interior, 2008). The same accessibility issues relate to the Paradox basin. Federal Land in the Paradox basin is broken up as follows: 59.4% (8,698,000 acres) is not accessible and there is no leasing or no surface occupancy, 14% (2,039,000 acres) is accessible and can be leased but there are timing limitations or controlled surface use, and 26.5% (3,878,000 acres) is accessible and can be leased with standard leasing terms (2008).

Standard leasing terms include conditions of approval and stipulation exception factors. In the Study Area, conditions of approval for the Uncompahgre Field Office include studies of archeology, big game, construction, noise, pipeline, roads, and soil (U.S. Departments of the Interior, 2008). Stipulation exception factors in the Uinta-Piceance basin are big game winter range and raptors with an extended drilling buffer zone of 0.25 miles. In the Paradox basin, big game winter range, raptors, and bald eagle winter roost are the stipulation exception factors. The extended drilling buffer zone is 0.50 miles (2008).

The “Inventory of Onshore Federal Oil and Natural Gas Resources and Restrictions to Their Development; Phase III Inventory—Onshore United States” was completed in 2008. Any updates to the proved reserves are in this Reasonable Foreseeable Development Scenario

OIL AND GAS POTENTIAL AND REASONABLE FORESEEABLE DEVELOPMENT SCENARIOS IN THE SAN JUAN NATIONAL FOREST AND BLM PUBLIC LANDS, COLORADO (2006)

The “Oil and Gas Potential and Reasonable Foreseeable Development Scenarios in the San Juan National Forest and BLM Public Lands, Colorado” (Gault Group Inc., 2006) encompasses lands immediately south of the Study Area. The Reasonable Foreseeable Development Scenarios projected 25 wells per year would be drilled in conventional fields over a 15 year period in the Paradox Basin Province (2006). The San Juan National Forest is southeast of the Paradox Basin Province. Since it is in close proximity to the Study Area it is prudent to discuss the projections made for the San Juan National Forest. Coal-bed natural gas is produced from the Fruitland Formation in the San Juan Basin Province. In the Study Area, the Tongue Mesa coal field also produces from the Fruitland Formation. It was projected that 60 coal-bed natural gas wells per year would be drilled at the current 160 acre spacing (2006). Spacing decreases were anticipated with potential for more wells to be drilled than projected. Also, it was projected that 2 wells per year would be drilled on conventional-type fields. Overall, 1,185 new wells were projected to be drilled over the 15 year period. These wells would produce 19 million barrels of oil and 3.25 trillion cubic feet of gas. The total surface disturbance from wells would be 212 acres per year for a total of 3,181.2 acres over the 15 year period. The total disturbance from pipelines would be 424 to 937 acres (Gault Group Inc., 2006).

OIL AND GAS POTENTIAL AND REASONABLE FORESEEABLE DEVELOPMENT SCENARIOS IN THE GRAND MESA, UNCOMPAHGRE, AND GUNNISON (GMUG) NATIONAL FORESTS, COLORADO (2004)

The “Oil and Gas Potential and Reasonable Foreseeable Development (RFD) Scenarios in the Grand Mesa, Uncompahgre, and Gunnison (GMUG) National Forests, Colorado” was prepared by Bruce Fowler and Pat Gallagher from the Bureau of Land Management. The report was published August 27, 2004. The report encompasses the entire Study Area and it states that the Piceance basin contains reservoirs mainly in the Mesaverde Group. The Paradox basin contains plays mainly in Paleozoic rocks. From drilling history and industry input, the subject predicted there would be a total of 45 wells drilled over the next 15 years (from 2004 to 2019). Total disturbance was predicted to be 153 acres. After temporary reclamation, the total disturbance was predicted to be 82 acres (Fowler and Gallagher, 2004). Spencer (2006) updated the well projections to 48 sandstone wells and 88 coalbed natural gas wells. Beecham (2010) further updated the projections for the remaining nine years of the analysis (2011-2019). He projected that 103 wells would be drilled from 58 locations. He also modified previous assumptions about acres disturbed.

The Grand Mesa National Forest had a high occurrence potential based on major plays including the Williams Fork fluvial sands, Cameo coal zone, and Cozzette/Corcoran reservoirs. The Gunnison National Forest has a high gas potential in the north and decreases to low potential in the southwest as predicted in the Reasonable Foreseeable Development Scenarios for the Grand Mesa, Uncompahgre, and Gunnison National Forests in 2004. The Uncompahgre National Forest shows medium to low oil and gas occurrence potential in the 2004 assessment. Refer to Figures 18 and19, to see our occurrence potential maps (see "Oil and Gas Occurrence Potential") and Figures 23, and 24 to see our development potential maps (see "Projections of Future Oil and Gas Drilling Activity") for the Study Area.

RESOURCE POTENTIAL AND GEOLOGY OF THE GRAND MESA, UNCOMPAHGRE, AND GUNNISON (GMUG) NATIONAL FORESTS AND VICINITY, COLORADO (2004)

The U.S. Geological Survey assessed the Grand Mesa, Uncompahgre, and Gunnison National Forests and the vicinity in 2004. The report mainly discussed potential mineral deposits, excluding oil and gas. The main content pertinent to the Study Area and this report was the assessment of coal underlying the national forests. Information relating to coal and coal resource potential can be found under "Summary of Coal Fields in the Study Area" in this Reasonable Foreseeable Development scenario. In general, the main coal-bearing formations are of Upper Cretaceous age (U.S. Geological Survey, 2004). The estimated combined coal resource under the Grand Mesa, Uncompahgre, and Gunnison National Forests is 38 billion short tons (Hettinger et al., 2004). Along with the coal resource assessment, this report also discusses the geochemistry of mineral deposits, gravity, aeromagnetics, and radiometrics of the area, and mines and mineralized areas. The report was revised in 2006 by the U.S. Forest Service. The report is titled "Grand Mesa, Uncompahgre, and Gunnison National Forests: Coal Resource and Development Potential Report". Most of the information remains the same but some updates exist.

PETROLEUM SYSTEMS AND GEOLOGIC ASSESSMENT OF OIL AND GAS IN THE UINTA-PICEANCE PROVINCE, UTAH AND COLORADO (2002)—ALONG WITH THE PARADOX BASIN (1995) UNITED STATES GEOLOGICAL SURVEY

The U.S. Geological Survey is responsible for preparing the National Oil and Gas Resource Assessment for all provinces within the United States. Their overview of the "1995 National Assessment of United States Oil and Gas Resources" (U.S. Geological Survey, 1995) presents information about potential undiscovered accumulations of oil and gas in 71 geologic or structural provinces within the United States. The Uinta-Piceance Basin Province and Paradox Basin Province assessed at that time were partly within the Study Area. The National Oil and Gas Resource Assessment, was updated in 2002. The Uinta-Piceance Basin Province was updated in the 2002 Assessment. The

Paradox Basin Province was not updated in the 2002 Assessment. Summaries of the Uinta-Piceance Basin Province (both 1995 and 2002 assessments) and the Paradox Basin Province (1995 assessment) can be found in Appendix I.

The Uinta-Piceance Basin Province boundary for the 1995 U.S. Geological Survey assessment is defined by the Uinta Mountain Uplift to the north and the southern Park Range and Sawatch Uplift on the east. North of the Uncompahgre Uplift axis defines the southern boundary. The Utah thrust belt defines the western boundary (Spencer, 1995). The Douglas Creek arch separates the Uinta-Piceance basin in two halves. In the south-central portion of the Uinta-Piceance Basin Province there is a fold belt and igneous intrusions in the southeast. Numerous folds are in the northeastern Piceance basin along with many normal faults in the western Uinta basin. Normal faulting occurs in the middle of the Uinta-Piceance basin (U.S. Geological Survey Uinta-Piceance Assessment Team, chapter 2, 2003). The southern boundary of the 1995 assessment for the Uinta-Piceance Basin Province matches the northern boundary of the 1995 Paradox Basin Province Boundary. Conversely, the southern boundary of the 2002 Uinta-Piceance Basin Province assessment is defined by Uncompahgre Uplift and the San Rafael Swell. A gap on the east side of the Study Area, between the Uinta-Piceance 1995 and 2002 southern boundaries, was not assessed because there are no play areas or assessment units (see Glossary) covering this gap.

The Paradox Basin Province covers an area of approximately 33,000 square miles in Colorado and Utah and occupies approximately 2,447.94 square miles (1,566,681.48 acres) of the Study Area. The province is 280 miles long and 200 miles wide (Huffman, 1995). Located in southwestern Colorado, the Paradox Basin Province is bounded by the Uncompahgre Plateau to the northeast, the San Juan Dome to the east, and the Monument uplifts, Circle Cliffs, and the Henry Mountains to the west. The San Rafael Swell is the northwest boundary. The Paradox basin, Kaiparowits, Henry Mountains basin, and the Wasatch and Pausaugunt Plateaus are other geologic features in the Paradox Basin Province. The province has thick sequences of Phanerozoic sediments with 5,000 to 8,000 feet of sediment in the central part of the basin. There is greater than 15,000 feet of total sediment in the Paradox basin, Kaiparowits basin, and the Wasatch Plateau (Huffman, 1995). A small gap exists where the San Juan Basin Province boundary comes into the Study Area. The gap had no play areas or assessment units that covered this area, so it was not assessed. Refer to Appendix I for a detailed summary of the 1995 Paradox Basin Province and the 2002 and 1995 Uinta-Piceance Province U.S. Geological Survey Assessments.

A NEW APPROACH TO ASSESSING GAS AND OIL RESOURCES IN THE INTERMOUNTAIN WEST (2001): RAND SCIENCE AND TECHNOLOGY ASSESSMENT

The William and Flora Hewlett Foundation funded research assessments of natural gas and oil resources of the Rocky Mountain region. The assessment was performed by RAND Corporation, a non-profit research organization aspiring to improve policy and decision making. A number of reports were published as a result of the RAND Science

and Technology study (LaTourrette et al, 2002a; LaTourrette et al., 2002b; LaTourrette et al, 2003; and Vidas et al, 2003). The LaTourrette et al., (2002a and 2002b) reports were prepared to:

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

Issues were raised that the term "technically recoverable" was not inclusive of oil and natural gas that is actually producible. The report continues to state that "technically recoverable" resources do not include exploration and production costs, infrastructure and transportation costs, and environmental impacts (2003). The American Association of Petroleum Geologists' Secretary, Charles J. Mankin, dismissed this contention based on the fact that "viability" of future oil and gas production is more dependent on technology advances and public demand of resources than on cost (Nation, 2002). Therefore, the term and assessment of "technically recoverable" resources is still used today.

In "Assessing Gas and Oil Resources in the Intermountain West" (LaTourrette, p. 16, 2002b), a graph shows Rocky Mountain Region technically recoverable gas resources to be approximately 310 trillion cubic feet of gas. In contrast, the economically recoverable gas at the well head was approximately 60 trillion cubic feet of gas. This difference was emphasized in the RAND reports as to why "viable" resources should be reported instead of "technically recoverable" resources. Debra Knopman, a Senior Engineer at RAND, testified to the Subcommittee on Energy and Mineral Resources that their report is not meant to replace previous assessments, but their suggestions are meant to enhance, build upon, and more clearly define future reports (2002). The RAND Corporation incorporated their approach in the Greater Green River basin (LaTourrette, 2003). The lead author was contacted in August of 2006, and we asked for the information regarding the Greater Green River basin in order to see the details of how the methodology was applied. Unfortunately, that information had been lost and was no longer available. Therefore, their analysis methodology has not been used to analyze the Study Area.

ASSESSMENT OF THE COALBED NATURAL GAS RESOURCE

COALBED NATURAL GAS ACTIVITY

The Colorado Plateau contains coal deposits in Colorado, Utah, Arizona, and New Mexico. The major coal deposits are of Cretaceous age with older coals in the western

plateau grading to younger coals in the eastern plateau. These coal deposits are found in the Mount Garfield Formation, Mesaverde Formation, Fruitland Formation, and Dakota Sandstone (Kirschbaum, chapter A, 2000). The Study Area contains the Nucla-Naturita, Tongue Mesa, Somerset, and Grand Mesa coal fields. Figure 17 shows coal fields within the Study Area. Coal fields are determined by the U.S. Geological Survey based on four criteria:

- Areas containing significant mineral ownership that is administered by the federal government,
- Areas that have active coal mining,
- Areas where coal-bed methane is currently being produced or coal is the source rock for gas production, and
- Areas that have a high resource or development potential .

In the entire Colorado Plateau, it is estimated that 40 to 68 percent of the coal is recoverable (Kirschbaum, chapter A, 2000). Intrusives are associated with the Piceance Deep, Somerset, and Carbondale coal fields (Figure 17) and could have influenced gas generation in the nearby coals (Spencer, 1995).

In the Colorado Plateau, the U.S. Geological Survey (2000) estimated 173 trillion cubic feet of in-place coal-bed natural gas resource within the Piceance basin in Colorado, San Juan basin in Colorado and New Mexico, and the Uinta basin in Utah. Most of the estimated in-place coal-bed gas is outside of the Study Area. However, exploration for coal bed methane is taking place in the northern part of the Study Area in the Piceance basin.

Only 36 coal-bed natural gas wells have been drilled in the Study Area (Figure 3b). All 36 wells are in the Piceance basin. Four wells have been plugged, five wells are locations, and the remaining wells are producing gas (IHS Energy Group, 2010). A location means the well will likely be drilled or the data has not been updated. The six companies that drilled the 36 coal-bed natural gas wells were:

- Amoco Production Company,
- BDS International LLC,
- DIA and Associates Inc.,
- Gunnison Energy Corporation,
- Riviera Drilling and Exploration Company, and
- SG Interests, Ltd.

Amoco Production Company drilled four coal-bed natural gas wells from 1982 to 1987 at depths averaging 2,350 feet (IHS Energy Group, 2010). Two of the wells have no reported production. Cumulative production for the other two wells is 3,400 thousand cubic feet of natural gas (IHS Energy Group, 2010). All four wells are plugged and abandoned according to the Colorado Oil and Gas Conservation Commission.

BDS International LLC drilled two coal-bed natural gas wells in 2003. Average drilling depth was 7,152 feet (IHS Energy Group, 2010). Cumulative gas production for both wells is 199,642 thousand cubic feet of gas. Cumulative water production is 7,006

barrels of water. Oil was produced from these two wells along with water and gas. Cumulative oil production is 815 barrels of oil. Both wells are plugged and abandoned according to the Colorado Oil and Gas Conservation Commission.

DIA & Associates Inc. drilled one coal-bed natural gas well in the Study Area in 1991. The well was completed in 1993 with a total drilled depth of 3,050 feet. The IHS database reports the well was drilled and abandoned while the Colorado Oil and Gas Conservation Commission reports the well as shut-in. Production tests show 30 thousand cubic feet of gas and 78 barrels of water were produced.

Gunnison Energy Corporation drilled 16 coal-bed natural gas wells in the Study Area from 2003 to 2007. Average depth drilled was 2,292 feet. Cumulative gas production is 1,510,513 thousand cubic feet for all 16 wells (IHS Energy Group, 2010). Cumulative water production is 1,734,404 barrels of water. Cumulative oil production is 683 barrels of oil. Nine out of the 16 wells had reported production. Two wells are plugged and abandoned. Three wells are labeled as locations. The other wells are active gas wells (IHS Energy Group and Colorado Oil and Gas Conservation Commission, 2010).

Riviera Drilling & Exploration Company drilled one well in the Study Area in 1977 with an updated status in 1981. Its current status is shut-in (Colorado Oil and Gas Conservation Commission, 2010). The well was drilled to 4,125 feet. There is no production data for this well.

SG Interest I LTD drilled 12 coal-bed methane wells in the Study Area from 2002 to 2008. Average drilled depth of the 12 wells is 4,790 feet (IHS Energy Group and Colorado Oil and Gas Conservation Commission, 2010). Two wells are locations and the remaining 10 wells are active gas wells. Seven of the 12 wells report production in the IHS Energy Group database. Cumulative production for the seven wells is 3,099,690 thousand cubic feet of gas, 21,751 barrels of water, and 6,980 barrels of oil (IHS Energy Group, 2010).

SUMMARY OF COAL FIELDS IN THE STUDY AREA

Grand Mesa Coal Field

The Grand Mesa coal field is in the northwestern part of the Study Area. The Mesaverde Formation is the major coal bearing formation in the Grand Mesa coal field. Coal present in the Mount Garfield Formation has an ash content of 2.1 to 23.3 percent, a sulfur content of 0.4 to 2.2 percent, and a heating value of 8,300 to 13,490 British thermal units (see Glossary) per pound (Kirschbaum et al., chapter B, 2000). In coal beds greater than five feet thick it is estimated that 8.6 billion short tons of coal are recoverable with an overburden of 6,000 feet (2000). The Roadside mine is the only active mine in the Grand Mesa coal field. A small portion of the Grand Mesa coal field is within the Grand Mesa National Forest. There is a high occurrence potential for coal-bed natural gas in the Grand Mesa Coal Field (Figure 19). Development potential is moderate in the Grand Mesa Coal Field for coal bed natural gas development (Figure 24).

Somerset Coal Field

The Somerset coal field is in the north and northeast part of the Study Area. Numerous mines are located in this area. These mines include the West Elk Mine, Sanborn Creek Mine, Bear Creek #3 Mine, and the Bowie Mine #1 (Kirschbaum et al., chapter B, 2000). All of these mines are underground mines. Coal bed thickness ranges from 8.5 to 30 feet with coal zones residing in the Mesaverde Formation. Quality of coal is bituminous, of coking capability, and has an ash content of 2.4 to 29.9 percent. Sulfur content is 0.3 to 3.2 percent and the heating value is 8,160 to 14,380 British thermal units per pound (2000). Eight billion short tons of coal is the resource estimate down to 6,000 feet. Occurrence potential for coal-bed natural gas in the Somerset Coal Field is high. Development potential for coal-bed natural gas in the Somerset Coal Field is moderate.

Carbondale Coal Field

The Carbondale Coal Field is in the northeast part of the Study Area in the Piceance basin. Coal is sourced from three zones in the Williams Fork Formation (U.S. Forest Service, 2006). The Illes Formation also sources coal in the Carbondale Coal Field (Kirschbaum et al., chapter B, 2000). The three zones in the Williams Fork Formation are the Cameo-Wheeler, South Canyon, and Coal Ridge zones. Individual coal beds in these zones average 25 feet thick (U.S. Forest Service, 2006). Coal in this area is metamorphosed by igneous intrusions to bituminous and anthracite ranked coal with strong coking abilities. Methane levels range from 1,000 to 4,000 cubic feet of gas per ton and a heating value of 10,160 to 15,190 British thermal units per pound (2006). Ash content is between 1.9 and 16.2 percent. Sulfur content ranges from 0.3 to 2.1 percent (2006). Original in-place estimates of coal were 5.2 billion short tons (Kirschbaum et al, chapter B, 2000). Thirteen mines operated in this field between 1888 and 1990 (2000).

Nucla-Naturita Coal Field

The Nucla-Naturita coal field is located in the southwestern part of the Study Area in the Paradox basin. The Dakota Sandstone is the coal bearing formation. The Dakota Sandstone averages 330 feet thick with three to five foot thick mineable coal beds. The quality of coal is as follows: ash content is 6.1 to 12.8 percent, sulfur content is 0.5 to 1.1 percent and the heating value is 10,010 to 13,380 British thermal units per pound (Kirschbaum et al., chapter B, 2000). The estimated resource value is 114 million short tons of coal in a portion of the coal field having an area of 15 square miles. The New Horizon Mine is an active surface mine in the Nucla-Naturita coal field. This mine supplies coal to the Nucla power plant. The Uncompahgre National Forest covers the north and southeast Nucla-Naturita Coal Field. The occurrence potential for coal-bed natural gas ranges from moderate to low potential (Figure 19). Coal-bed natural gas development potential is very low to none in the Nucla-Naturita Coal Field (Figure 24).

Tongue Mesa Coal Field

Tongue Mesa Coal Field is located in the eastern part of the Study Area (Figure 17). It is within the 1995 Piceance basin boundary and the 1995 Paradox basin boundary. The coal is sourced from the Fruitland Formation in an isolated section of the northern San Juan Mountains. The Uncompahgre National Forest covers the southern half of the Tongue Mesa Coal Field. Multiple coal beds are within the Fruitland Formation. About 200 feet of coal bearing strata is within the Tongue Mesa Coal Field within the Uncompahgre National Forest (Hettinger et al., chapter M, 2004). Maximum coal bed thickness is 40 feet. Minimum coal bed thickness is five feet. The rank of coal is subbituminous with 6.7 to 8.4 percent ash content, 0.5 to 0.9 percent sulfur content, and 9,350 to 10,200 British thermal units per pound (Kirschbaum et al., chapter B, 2000). Estimated resource quantity is as high as 4,000 million short tons (2000). Historically, underground coal mines have operated in this area but currently none are active. The occurrence potential for coal-bed natural gas in the Tongue Mesa Coal Field is moderate. The development potential for coal-bed natural gas is low.

The U.S. Geological Survey analyzed the southern Piceance basin coal. They defined coal beds with greater than 1 feet thick beds and less than 6,000 feet deep as a "coal resource". Coals outside this criterion are non-resources. In the Study Area, the Cameo-Fairfield coal group contains large quantities of the coal and natural gas in the southern part of the Piceance basin. The Cameo-Fairfield coal group is in the Williams Fork, Mount Garfield, and Mesaverde Formations. The coal zones in the Cameo-Fairfield coal group are the Cameo-Wheeler, South Canyon, and Coal Ridge. As much as 140 feet of net coal exists in the Cameo-Fairfield coal group. There are 26 coal beds that make up the 140 feet net coal thickness with each bed ranging from one to 44 feet thick each (Hettinger et al., chapter O, 2000) Coal rank ranges from subbituminous A to anthracite with coking properties. Mineral resources for this area include 34 billion short tons of mineable coal. Thirteen billion short tons of coal are non-minable but may be a good resource for coal-bed methane. Coal with overburden of 3,000 to 14,000 feet deep is non-mineable but contains 170 billion short tons of coal (2000). These deep coal beds currently have small potential for coal-bed methane production because most coal-beds are produced from wells at depths less than 3,000 feet. Potential for mining and natural gas in the Cameo-Fairfield coal is high. Gas content for coals in the Piceance basin is as much as 604 cubic feet per short ton. The U.S. Geological Survey estimated in 2000 that there was 60 billion cubic feet of coal resource per square mile in the deepest part of the Piceance basin.

R.D. Hettinger, L.N.R. Roberts, and M.A. Kirschbaum discuss coal under Forest Service lands that have less than 6,000 feet of overburden in the 2004 report "Coal Resources and Coal Resource Potential". The national forests assessed were the Uncompahgre National Forest, the Grand Mesa National Forest, and the Gunnison National Forest. In areas underlain by the Dakota Sandstone, there is low to moderate potential for development of coal. The Dakota Sandstone has discontinuous, thin coal-beds and is not developed. There is moderate to high development potential in areas underlain by the Fruitland Formation and the Mesaverde Group and Mesaverde Formation. The Mesaverde Group

and Formation is a source for natural gas. There are many constraints on development of coal in these areas. For example, in underground mining, coal needs to be less than 3,000 feet deep, 3.5 feet thick coal beds or greater, dipping strata less than 12 degrees, and no more than 14 feet of coal can be mined (Hettinger et al., chapter M, 2004).

The Tongue Mesa Cretaceous coal field is in the east part of the Study Area and within the Uncompahgre National Forest. It has approximately 1,000 feet of section in the Mesaverde Formation, with 200 feet of the section assigned to the Fruitland Formation. The Fruitland Formation coal has one 20 to 40 feet thick coal-bed and multiple coal-beds that are 5 to 13 feet thick. The original coal resource of the Fruitland Formation coal is approximately 2,355 million short tons to 4,000 million short tons within and outside the forest service.

OIL AND GAS OCCURRENCE POTENTIAL

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

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

- HIGH: Inclusion in an oil and gas play as defined by the USGS [U.S. Geological Survey] national assessment, or, in the absence of play designation by the USGS, 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."

Using the above criteria, we consider that Study Area lands have either high or low potential for the occurrence of oil and gas (excluding coalbed natural gas) as shown in Figure 18. All areas within the Paradox basin, the Piceance basin, and the Uinta-Piceance basin provinces are contained within specific plays or assessment units designated by the U.S. Geological Survey (1995 and 2003) so are considered to have high occurrence potential. All areas outside the provinces are designated as low occurrence

potential since one or more specific indicators of the presence of hydrocarbons (source rock, thermal maturation, reservoir strata possessing permeability and/or porosity, and traps) may not be present.

A separate map of occurrence potential for coalbed natural gas was prepared (Figure 19). The lands within the Uinta-Piceance Basin, Mesaverde Total Petroleum System (see Glossary), Coalbed Gas Assessment Unit as mapped by the U.S. Geological Survey (2010), were designated as having high occurrence potential. Portions of the Study Area which are known to contain Cretaceous aged sediments that can contain coalbeds, but were not assessed by the U.S. Geological Survey in their most recent assessment, were designated as having medium occurrence potential. The presence of coalbeds indicates that the criterion for a designation of medium occurrence potential is met. All areas outside the high and medium occurrence potential areas are designated as having an occurrence potential of "none" since geologic mapping (Stoeser et al., 2005) shows that in these areas Cretaceous aged rocks have been removed by erosion. Only Cretaceous aged sediments in the Study Area are known to contain coalbeds which act as the source rock and the reservoir strata for coalbed natural gas resources.

PROJECTIONS OF FUTURE OIL AND GAS ACTIVITY 2012-2031

The Annual Energy Outlook 2011, written by the Energy Information Administration (EIA), focuses on the factors that shape the U. S. energy system over the long term. Key results highlighted in the Annual Energy Outlook 2011 include:

• Strong growth in shale gas production. Shale gas production continues to increase strongly in the Annual Energy Outlook 2011 reference case, growing almost fourfold from 2009 to 2035. Shale gas production grows to 12.2 trillion cubic feet in 2035, when it makes up 47 percent of total U.S. production—up considerably from the 16 percent share in 2009. Shale gas production could become important in the part of the Piceance Basin that lays in the northeast part of the Study Area (Figure 4), if Mancos Shale exploration occurring there is determined to be economically successful. It could also become important in the Paradox basin part of the Study Area (Figure 4) it the Gothic and Hovenweep shale plays extended from their current location to the south of the Study Area.

• Growing use of natural gas and renewables in electric power generation. The role of natural gas in power generation grows due to low natural gas prices and the relatively low capital costs for new natural gas plants that make it more attractive than coal. The share of generation of power from natural gas increases from 23 percent in 2009 to 25 percent in 2035.

• Declining reliance on imported liquid fuels. Although U. S. consumption of liquid fuels continues to grow through 2035, reliance on petroleum imports as a share of total liquids consumption decreases. Total U.S. consumption of liquid fuels rises from about 18.8 million barrels per day in 2009 to 21.9 million barrels per day in 2035. The import share

which reached 60 percent in 2005 falls to 42 percent in 2035. Rising fuel prices spur domestic energy production across all fuels.

The above projected increases in demand and in oil and gas prices indicate continued industry emphasis on searching for additional oil and natural gas supplies in the Study Area. The combination of horizontal drilling and hydraulic fracturing technologies has made it possible to produce shale gas and tight gas economically. Much of the Study Area oil and gas supply growth is expected to come from production from existing known reservoirs, with most new reservoir discoveries potentially coming from exploration for nonconventional plays in the continuous assessment units (including shale gas and coalbed natural gas) identified by the U.S. Geological Survey in Appendix 1.

OIL AND GAS PRICE ESTIMATES

Anticipated oil and gas prices are an important factor controlling the amount of future drilling and production activity in the Planning Area. Kaiser (2012) reported that "unconventional gas resources are abundant, but their development is particularly sensitive to technologic risk, geologic uncertainty, and gas price". Conventional plays in 2010 reportedly had an operational costs break-even price of $3-4 per thousand cubic feet (Schaefer, 2010). The National Petroleum Council (2011) stated "Significant technology advances have unlocked abundant natural gas and oil resources, but the potential benefits can only be realized if developed prudently."

Gas Prices

In 1996, natural gas prices in Colorado started on a general increase (Figure 20). Several peaks and valleys in the price trend have occurred since that time, but by 2005, prices had increased to an average of $7.43 per thousand cubic feet. Colorado wellhead prices declined sharply from 2005 to 2007 ($4.57 per thousand cubic feet), peaking again in 2008. As world economies struggled in 2009, Colorado wellhead gas prices fell to $3.21 per thousand cubic feet. In recent months gas prices have fallen below $3 per thousand cubic feet. "Natural gas in the New York market slipped further below $2.50/MMBTU, and given the more mild weather forecasts, we don't expect this to improve much anytime soon" (Raymond James, 2012).

Data for Figure 20 (historical and projected future natural gas prices) were obtained from the Energy Information Administration (2011). In the Annual Energy Outlook 2012 (Lower 48), average annual wellhead prices for natural gas remain below $5 per thousand cubic feet (nominal dollars) through 2017. The projected prices reflect continued industry success in tapping the Nation's extensive shale gas resource. Natural gas prices rise as production gradually shifts to resources that are less productive and more expensive. Natural gas wellhead prices (nominal dollars) reach $10.24 per thousand cubic feet in 2035. The forecasted natural gas price using 2009 dollars is $6.42 per thousand cubic feet in 2035.

The natural gas price projections allow for some generalizations concerning future gas drilling and production activity in the Uncompahgre Planning Area. For the short term, the interest in natural gas exploration in the Uncompahgre Planning Area will likely continue or decrease since prices dropped sharply in 2011 and 2012. Similarly, recent interest in new exploration of potential gas plays may be curtailed by low gas prices. The resilience of drilling levels, despite low natural gas prices, is in part a result of high crude oil prices, which significantly improve the economics of natural gas plays that have high concentrations of crude oil, condensates, or natural gas liquids. The level of future drilling activity will likely be driven more by the success of drilling efforts currently underway in the southern Piceance basin, than by wellhead prices.

Increases in future natural gas production to accommodate projected increased demand is anticipated to come partly from the Rocky Mountain area, in particular shale gas resources. It is difficult to predict how much new gas production is expected to come from reservoirs in the Study Area. According to the United States Geological Survey, 0.06 percent of the total United States undiscovered conventional gas resource is attributed to the Piceance basin, and 0.91 percent attributed to the Paradox basin (U.S. Geological Survey, 2008c). Much of the current gas production from these basins lies outside of the Study Area. Any additional gas produced from the Study Area plays is expected to come mainly from new Cretaceous shale gas and coalbed gas discoveries in the southern Piceance basin, and possibly the extension of Pennsylvanian (Gothic and Hovenweep) shale gas plays into the Paradox basin part of the Study Area. If these plays prove successful in the Study Area, gas drilling will likely be at levels not historically experienced in the Study Area.

Oil Prices

U.S. energy demand and economic activity in 2012 will gain some momentum from last year's doldrums but growth for each will remain anemic (Radler, 2012). Total energy demand will increase by 1.2% in the U. S., according to Oil & Gas Journal's annual Forecast & Review. Early estimates indicate that in 2011 demand climbed by a mere 0.3%. But uncertainties abound this year—from the state of the European Union and its economies weakened by debt defaults to the effect of the West's reactions to Iran's development of nuclear capabilities—and it's those uncertainties that will drive the 2012 oil market.

Data for Figure 21 (historical and projected crude oil prices) were obtained from the Energy Information Administration (2011). The data are projected averages of low sulfur light crude oil prices and are made in nominal dollars. Historical prices represent the actual average price at the wellhead and show the historic volatility that has occurred in crude oil prices in Colorado. Prices began declining in the early 1980's from a high of $35.69 in 1981 to a low of $12.56 in 1998. A significant climb is seen in oil prices starting in 1999 up to 2008. The rise from a low of $12.56 per barrel to the most recent average high of nearly $100 per barrel represents nearly an order of magnitude increase in prices in just eleven years.

Prices for crude oil in 2011 remained generally in a range between $74 and $100 per barrel. Low sulfur light crude oil prices (nominal dollars) in the Annual Energy Outlook rise to $125 per barrel in 2019 as pipeline capacity from Cushing, Oklahoma, to the Gulf Coast increases, the world economy recovers, and global demand grows more rapidly than the available supplies of liquids from producers outside the Organization of the Petroleum Exporting Countries (OPEC). In 2035, the average real price of crude oil is about $125 per barrel in 2009 dollars, or about $200 per barrel in nominal dollars.

The Annual Energy Outlook assumes that limitations on access to energy resources restrain the growth of non-OPEC conventional liquids production between 2012 and 2035, and that OPEC targets a relatively constant market share of total world liquids production. There is a wide range of price scenarios and a great deal of uncertainty surrounding future world oil prices. In several resource rich regions, high oil prices, oil sands, expanded infrastructure, further investment in exploration and drilling contribute to additional non-OPEC oil production.

Historically, exploration for oil in the Study Area has been minimal and only two wells have been classified as oil producers. Data from the U.S. Geological Survey's 1995 and 2002 oil and gas assessments for the Paradox and Piceance basins suggests that in the Study Area, only 30 million and 0.74 million barrels of oil exists as an undiscovered resource (U.S. Geological Survey, 1995 and 2002). Two-thirds of the undiscovered resource in the Paradox basin is attributed to the hypothetical Fractured Interbed continuous oil play. If any exploration specifically for oil is to occur in the Study Area it will likely occur in the Paradox basin. However, none of the wells drilled to date have made oil discoveries in the Study Area's portion of the Paradox basin, and any future drilling is thus expected to be minimal. Any new discoveries would most likely come from plays associated with U.S. Geological Survey's Fractured Interbed continuous oil play.

The future gas drilling target areas discussed in the above “Gas Prices” discussion will generally also produce condensate in association with the gas production.

LEASING

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

Leases on lands where the United States owns the oil and gas rights are offered via oral auction at least quarterly. Starting in 2010 these auctions will be held on the first Tuesday of the second month in each quarter. A list of parcels that will be offered for lease, plus their associated environmental stipulations, is published in a “Notice of Competitive Oil and Gas Lease Sale” which is posted at least 45 days prior to the date of each sale. Leasing is a discretionary act of the Secretary of Interior. Parcels offered for lease may be withdrawn at any time prior to lease issuance.

Maximum lease size is 2,560 acres and the minimum bid is two dollars per acre. A 365 dollar per parcel administrative fee is charged and the successful bidder must meet citizenship and legal requirements. In addition to the lease bonus, a 1.50 dollar per acre rental is charged for the first five years of the lease and two dollar per acre is charged thereafter. Leases are issued for a ten-year term and a 12.5 percent royalty on any production is required. Leases that become productive are held-by-production and normally do not terminate until all wells on the lease have ceased production. Many private oil and gas leases contain a "Pugh clause," which allows only the developed portion of the lease to be held by production (see Glossary). However, Federal leases have no such clause, allowing one well to hold an entire lease.

Since August 1996, only lands nominated by industry have been offered for lease. Before that date, virtually all Federal lands available for competitive leasing were offered at each sale. Each new lease is reviewed for resource conflicts and contains restrictive stipulations which protect potentially affected, mainly surface, resource values.

Oil and gas prices and exploration success will, to a great extent, determine the amount of acreage leased and bonus bids received. Forty-nine percent of the money earned from oil and gas leases on public domain (see Glossary) minerals goes to the State of Colorado. The rest stays with the Federal treasury, where it is split between the conservation fund and the general fund on a 4:1 ratio, respectively.

Figure 22 presents the locations of leased and unleased Federal oil and gas minerals within the Study Area.

PROJECTIONS OF FUTURE OIL AND GAS DRILLING ACTIVITY

It is difficult to predict what will occur a few years into the future, but it is even more difficult to predict 20 years ahead. In an attempt to gain more insight as to what may occur in the Study Area, geologists and engineers in the oil and gas industry were approached for their input. 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 Bureau also contacted many of these companies by telephone, either a few days after the letters were sent, or in order to clarify information after replies were received. In addition, minerals staff of the Bureau's Uncompahgre and Grand Junction field offices were consulted to get their ideas and input for our projections. Information obtained was compiled and used to help predict locations and amounts of future drilling activity within the Study Area. A review of available technical data was also used to help make these predictions. Much of the data reviewed has been summarized above.

Projected Oil and Gas Drilling Activity

For a base line, unconstrained reasonable foreseeable development projection (Rocky Mountain Federal Leadership Forum, 2004, page 13) we estimate that during the planning cycle of 2010 through 2030, as many as 1,271 wells will be drilled in the Study Area. Up to 782 of these wells could be coalbed natural gas wells (to be discussed latter)

and the remaining wells (up to 489 wells) would be considered to be conventional type wells.

As many as 10 of the conventional wells could be deep wells (greater than 15,000 feet in depth) that would be located in the deeper parts of the Paradox basin. At present, identified plays and known interest in the Paradox basin is for oil and gas targets at depths shallower than 15,000 feet. Any future deep wells would be part of a potential high-risk exploratory play that has not yet been identified. Our projection assumes that operators not currently exploring deep targets could show an interest in this type of exploration during the Analysis Period. As such development is at this point hypothetical, no provisions were made in our calculations to include additional disturbance from deep wells (all conventional wells were treated the same for surface disturbance calculations to be discussed later).

The estimated conventional oil and gas development potential and drilling densities within the entire Study Area during the Analysis Period (see Glossary) are shown in Figure 23a. Figure 23b shows potential just on Bureau managed oil and gas minerals and Figure 23c shows potential just on Forest Service managed minerals. No leasing areas (wilderness lands), shown on map 23a, are not shown on maps 23b and 23c to reduce confusion. Estimated acres, number of townships, and percentage of the entire Study Area within each development potential classification type shown in Figure 23a are summarized in Table 3. The percentage of Bureau managed oil and gas minerals of each conventional oil and gas development potential type is:

- Very high 15 percent,
- High 98 percent,
- Moderate 48 percent,
- Low 6 percent,
- Very low 29 percent, and
- Negligible 12 percent.

Overall, the Bureau manages about 30 percent of all Study Area lands assigned a development potential.

The percentage of Forest Service managed oil and gas minerals of each conventional oil and gas development potential type is:

- Very high 74 percent,
- High 0 percent,
- Moderate 25 percent,
- Low 42 percent,
- Very low 34 percent, and
- Negligible 40 percent.

Overall, the Forest Service manages about 36 percent of all Study Area lands assigned a development potential.

We estimate that the **average** ranges of drilling densities per township (one township is about 36 square miles) during the Analysis Period will be:

- Very High >12 wells,
- High > 6 to 12 wells,
- Moderate > 2 to 6 wells,
- Low > 1 to 2 wells,
- Very Low > 0.25 to 1 wells, and
- Negligible less than 0.25 wells.

Forest Service wilderness lands and Bureau wilderness and wilderness study areas were not assessed for future oil and gas development potential activities since those areas cover Federal lands that are removed from oil and gas leasing and thus, oil and gas development cannot occur.

The boundary of the very high potential was drawn to include two U.S. Geological Survey (2003) assessment units within their Mancos/Mowry Total Petroleum (Piceance Basin Continuous Gas and Uinta-Piceance Transitional and Migrated Gas assessment units). Hydrocarbons generated from the marine Mancos/Mowry shales, where maturation has reached a vitrinite reflectance (see Glossary) of at least 0.75 percent, has potentially charged all porous sandstones and fractured beds of Cretaceous age. Three groups of reservoirs rocks can be present within this area of very high potential. They are:

1. Lower Cretaceous – Morrison Formation, Cedar Mountain Formation, and Dakota Sandstone (Figure 6a);
2. Lower part of Upper Cretaceous – Frontier Formation, Mancos Shale, and the Mancos B (Figure 6a); and
3. Upper part of Upper Cretaceous – Rollins, Cozzette, and Corcoran sandstone members of the Iles Formation (Figure 6b).

Production in this part of the Study Area has historically come from the third group of reservoirs and recent horizontal well completions have been made in the Mancos Shale (see following "Resource Plays" discussion for more information about the Mancos Shale play) of the second group of reservoirs. The dominate future targets in the very high potential area are expected to be for reservoir groups two and three.

Although we assume an average township in the area of very high potential will contain 25 conventional wells (Table 3), it is likely that actual drilling locations will be preferentially located on private/state surface ownership where it is traditionally easier for operators to negotiate for use of drilling locations than it is on National Forest lands. Most of the oil and gas minerals beneath these private/state lands are managed by the Bureau, with minor amounts controlled by private/state ownership.

The part of the Whitewater Unit lying within the Study Area is assigned a high potential for development. The operator (Fram Operating LLC) presently proposes to develop the Dakota Formation in a part of the unit just north of the Study Area with well pads that may accommodate up to nine wells. Over the analysis period it is possible that one or two additional pads could be located within the Study Area.

As much as 29 percent of the conventional wells projected in the Study Area, could be drilled in areas of moderate potential. The Paradox basin portion of the Study Area was assigned a moderate development potential based on past moderate rates of exploration and development activity and potential for additional exploration related to three existing plays defined by the U.S. Geological Survey (1995). The three plays include the Salt Anticline Flank and Buried Fault Blocks, Fractured Interbed, and Porous Carbonate Buildup plays (see Appendix 1 for additional discussion of these plays). Also included is the potential for future shale gas related exploration in shales such as the Gothic and Hovenweep in this part of the Paradox basin. The area of moderate potential on the north contains Cretaceous aged sediments that may be deep enough to contain hydrocarbons that may be associated with the Phosphoria Total Petroleum System of the U.S. Geological Survey (2003). Some limited activity has occurred here in recent years.

A limited number of wells (less than seven percent of the 489 wells projected) are projected in areas of low, very low, and negligible potential. None of the oil and gas industry operators surveyed for this report indicated an interest in future drilling in any of these three potential areas. Only a limited number of wells in these areas have been completed as productive by historical drilling and only a few very low production gas wells are still reported to be active near the town of Ridgeway. Most of the townships in these three areas will not receive any drilling activity during the Analysis Period. If new field discoveries are made in any of these three areas, subsequent drilling density could increase in those areas immediately around a discovery. However, predicting a well density for such areas is not possible at this time.

Historically, about 90 percent of conventional wells have drilled to a depth of less than 10,000 feet, with drilling spread from very shallow to deep. We anticipate that future drilling depths will be predominantly within the range of 5,000 to 10,000 feet.

Projected Coalbed Natural Gas Drilling Activity

As previously stated, up to 782 coalbed natural gas wells are projected in the Study Area for the Analysis Period. The estimated coalbed natural gas development potential and drilling densities within the Study Area during the Analysis Period are shown in Figure 24a. Figure 24b shows potential just on Bureau managed oil and gas minerals and Figure 24c shows potential just on Forest Service managed minerals. No leasing areas (wilderness lands), shown on map 24a, are not shown on maps 24b and 24c to reduce confusion. Estimated acres, number of townships, and percentage of the entire Study Area within each development potential classification type shown in Figure 24a are summarized in Table 4. The percentage of Bureau managed oil and gas minerals of each coalbed natural gas development potential type is:

- High 19 percent,
- Moderate 22 percent,
- Low 26 percent,
- Very low 27 percent, and
- None 38 percent.

Overall, the Bureau manages about 30 percent of all Study Area lands assigned a development potential.

The percentage of Forest Service managed oil and gas minerals of each coalbed natural gas development potential type is:

- High 68 percent,
- Moderate 64 percent,
- Low 39 percent,
- Very low 23 percent, and
- None 40 percent.

Overall, the Forest Service manages about 36 percent of all Study Area lands assigned a development potential.

We estimate that the **average** ranges of drilling densities per township (one township is about 36 square miles) during the Analysis period will be:

- High ≥ 40 wells,
- Moderate: 20 to 39 wells,
- Low: 2 to 19 wells,
- Very Low: > 2 wells, and
- None no drilling activity expected.

Forest Service wilderness lands and Bureau wilderness and wilderness study areas were not assessed for future oil and gas development potential activities since those areas cover Federal lands that are removed from oil and gas leasing and thus, oil and gas development cannot occur.

The areas we projected as having high and moderate coalbed natural gas development potential during the Analysis Period lie within the boundary of the Mesaverde Total Petroleum System, Coalbed Gas Assessment Unit (Figure A1-7). In addition, historical drilling data and operator supplied information was used to define which parts of the assessment unit would have high potential and which would have moderate potential. As many as 95 percent of the 782 projected coalbed natural gas wells could be drilled in these two areas.

Although we assume an average township in the area of high and moderate potential will contain 60 (high potential) or 30 (moderate potential) coalbed natural gas wells (Table 4), it is likely that actual drilling locations will be preferentially located on private/state surface ownership where it is traditionally easier for operators to negotiate for use of drilling locations than it is on National Forest Lands. Most of the oil and gas minerals beneath these private/state lands are managed by the Bureau, with minor amounts controlled by private/state ownership.

The area of low potential outlines the Tongue Mesa Coal Field (figure 17) where individual coal beds are up to 40 feet thick. To outline the area of very low potential, remaining areas containing Cretaceous aged sediments that could contain coal (in beds generally less than six feet thick) were buffered back one half mile from their outcrop.

No present interest in coalbed natural gas exploration has been identified in the short-term for either the low or very low potential areas, but some limited activity could occur at a later date in the Analysis Period. Areas of no potential for coalbed natural gas activity during the Analysis Period are those determined to have no occurrence potential (see Figure 19) and those areas with Cretaceous sediments near the outcrop (a one half mile buffer back from the outcrop).

Historically, most coalbed gas wells have produced at depths between 2,000 and 5,000 feet, although one well has completed in an interval between 6,845 and 6,928 feet. We anticipate that future drilling producing intervals will remain predominantly within the range of 2,000 to 5,000 feet.

PROJECTIONS OF FUTURE OIL AND GAS PRODUCTION

Natural gas production from the Rocky Mountains has grown steadily since 1992 (National Petroleum Council, 2003). The Rockies are currently the largest producing region in the onshore lower 48 states. Much of this growth has been from unconventional resources, although conventional production has also been increasing.

When the Energy Information Administration (2004) looked at past United States gas production they found that "Just a few years ago, it was believed that natural gas supplies would increase relatively easily in response to an increase in wellhead prices because of the large domestic natural gas resource base. This perception has changed over the past few years. While average natural gas wellhead prices since 2002 have generally been higher than during the 1990's and have led to significant increases in drilling, the higher prices have not resulted in a significant increase in production. With increasing rates of production decline, producers are drilling more and more wells just to maintain current levels of production. A significant increase in conventional natural gas production is no longer expected. Drilling deeper wells in conventional reservoirs is expected to slow the overall decline." More recent analysis has confirmed this trend. Foss (2007) found that gas production in the United States has been lower than the recent high of 20.5 trillion cubic feet reported in 2001. This decline in total production for the United States has occurred even while drilling has reached an all-time high. Foss (2007) indicated that the United States resource base (conventional oil and gas reservoirs) is maturing and unconventional plays are increasingly the target of drilling. Since unconventional plays tend to have a lower ultimate oil and gas recovery, overall production from new wells does not match historical results, nor is it expected to in the future. In general, we expect that new gas wells drilled within the Study Area will follow this trend of reduced production per well from new wells completed, unless a new gas play develops.

Onshore oil production in the lower 48 states has been declining since the late 1980s and is expected to continue into the future (Energy Information Administration (2006c). Oil production in the Study Area presently is as a byproduct that is associated with the primary gas production.

ESTIMATED FUTURE CONVENTIONAL OIL AND GAS PRODUCTION

As indicated above, we projected 489 conventional oil and gas wells and 782 coalbed natural gas wells could be drilled within the Analysis Period of 2010 through 2030. The first step in projecting future production activity was to project a spudded well count for conventional wells and coalbed natural gas wells. The following data tables for spudded well counts and production were generated via analysis through the program scripting language, Octave. The constraints used for the well spuds for both conventional wells and coalbed natural gas wells were cumulative values and historical trend. A historical cumulative of spudded well data generates a smoother curve from which yearly differences can be extracted to produce annual projected well counts. The resulting calculation of mean spudded conventional and coalbed natural gas wells is presented in Table 5.

Decline curves were then generated for gas and oil for both the conventional and coalbed natural gas analysis. The decline curves were then normalized and convolved with the historical spudded well counts to generate a best fit with the **historical** production of gas and oil. The normalized decline curves were then convolved with the projected spudded well counts to produce annual mean projected conventional oil and gas production (Table 6a) for the Analysis Period. About 31.27 percent of projected conventional wells are expected to be located on Bureau managed oil and gas minerals, so we project that production associated with these wells will also be about 31.27 percent of that projected in Table 6a. Table 6b projects conventional oil and gas production associated with Bureau managed oil and gas minerals.

The same methods described above were used to projection production of coalbed natural gas hydrocarbons (Table 7a) for the Analysis Period. Some small amounts of oil have been produced in conjunction with the gas production so we projected associated oil production for the Analysis Period. About 33.91 percent of projected coalbed natural gas wells are expected to be located on Bureau managed oil and gas minerals, so we project that production associated with these wells will also be about 33.91 percent of that projected in Table 7a. Table 7b projects coalbed natural gas hydrocarbons associated with Bureau managed oil and gas minerals.

Since projected well activity is expected to increase over the Analysis Period, conventional and coalbed natural gas related hydrocarbon production is also expected to increase. If future drilling activity does not meet our projections then production will not increase at the rates projected.

OTHER POTENTIAL FUTURE OIL AND GAS ACTIVITIES

Resource Plays

We use the term Resource Play to describe accumulations of hydrocarbons known to exist over a large areal extent and/or thick vertical section, may be self-sourcing, may be

developed with horizontal well completions, and are driven by development efficiencies rather than geologic risk. Within the Study Area, resource plays could include continuous resource plays and assessment units identified by the U.S. Geological Survey (1995 and 2002). In the Piceance basin, those assessment units could include the:

- Mancos/Mowry Total Petroleum System, Uinta-Piceance Basin, Continuous Gas (Figure A1-8),
- Mancos/Mowry Total Petroleum System, Uinta-Piceance Basin, Transitional and Migrated Gas (Figure A1-8),
- Mesaverde Total Petroleum System, Uinta-Piceance Basin, Continuous Gas (Figure A1-6), and
- Mesaverde Total Petroleum System, Uinta-Piceance Basin, Transitional Gas (Figure A1-6).

In the Paradox basin the Fractured Interbed (hypothetical) Play (Figure A1-2) could be included as a resource play. In addition to the hypothetical Fractured Interbed Play, operators in the Paradox basin immediately south of the Study Area have successfully targeted the shale gas resource plays of the Pennsylvanian Gothic and Hovenweep shales (Ismay member of the Paradox Formation).

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

The Fractured Interbed Play is the only identified oil resource play in the Study Area. As it is still hypothetical and no operators have shown recent interest in exploration within the play, the likelihood for its development in the Study Area during the Analysis Period is very low.

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 any 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 (Continuous Gas and Transitional and Migrated Gas assessment units) are the most likely to be developed for shale gas resource plays in the Study Area. Though still in the early exploration phase, operators have targeted the Mancos shale in the area covered by these two assessment units, in the northern portion of the Study Area. Figure A1-8 shows the location of these two plays. The Mancos is a ubiquitous formation throughout many western basins 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. 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 frac/perforation zones, as appears to be the case with the wells spud in the Study Area, but full development generally occurs using horizontal wellbores and large fracs.

Three wells are presently reporting gas production from the Mancos in the very high conventional development potential area of Figure 23a. Two are operated by Gunnison Energy Corporation (section 17 of T. 12 S., 89 W. and section 23 of T. 12 S., Range 94 W.) and one is operated by SG Interests (section 15 of T. 11 S., R. 90 W). The SG Interests well has produced for 18 months (through November of 2011). One Gunnison Energy Corporation well has produced gas for 21months while the other produced seven months, but did not report production for November of 2011. One additional test of the Mancos was made by Gunnison Energy Corporation at a location outside the very high development potential area defined in Figure 23a (section 12, of T 13 S., R. 93 W.). A test of the Mancos Shale in this well only recovered water. A better understanding of this potential play should be available once additional testing of the play is undertaken and its economics becomes clearer.

Exploration and development activities in the Gothic and Hovenweep shale gas resource plays of the Paradox basin have been recently initiated immediately south of the Study Area, with initial Gothic Shale wells located in Dolores and Montezuma counties and Hovenweep Shale wells located in San Miguel County. The development potential for these areas south of the Study Area were recently been assessed by Leschak (2009). Developed by predominately using horizontal wellbores and large hydraulic fracs, these plays are in their infancy (fewer than ten wells are presently drilled), but are proving to be productive. In the area being explored south of the Study Area, these shales tend to lie at around 9,000-10,000 feet below the surface (Colorado Oil and Gas Conservation Commission, 2010). While the recently completed wells have provided encouraging results, the likelihood the plays will extend into the Study Area is low. The Paradox basin is distinctly asymmetrical, with the deepest portion of the basin (thickest sedimentary rock column) located adjacent to the Uncompahgre Uplift in the southern portion of the Study Area (Schamel, 2009). Several thousand feet of additional vertical drilling would be required to encounter the Gothic or Hovenweep shales in the Study Area, pushing the limits of the economics. Additionally, the Gothic Shale is likely to become less productive as it nears the clastic input from the Silverton Delta (a river delta developed contemporaneously to the deposition of these shales). The delta is mapped as occurring in western San Miguel County, with input of clastic material to the deltaic system having occurred from paleo-rivers to the east. Thus, only extreme western Montrose County would be likely to have shallow enough sediment packages located distally enough from the Silverton Delta to present a reasonable target for exploration.

When and if the Mancos, Gothic, or Hovenweep shale gas plays are fully characterized for the Study Area and technology and well completion methods are optimized, this energy source could become important. If adjacent to or overlapping existing plays, development would likely commence at a faster rate than if found to be geographically separated from such areas. Such an overlap appears to be the case with the initial Mancos wells located within the areal boundary of the coalbed play presently being developed.

When a shale gas play overlaps an existing play in the Study Area, as is the case with the Mancos, existing wellbores may be utilized in addition to new wells drilled specifically for the shale gas. However, the nature of shale gas plays would likely require drilling of

horizontal wells, so the existing wellbores would likely still have to be re-entered and a horizontal lateral drilled into the zone of interest using the existing wellbore as a pilot. Shale has very low permeability and as is the case with shale gas plays being developed in the region, large hydraulic fracture stimulations will probably be necessary to liberate the gas (Bereskin and Mavor, 2003). Existing coalbed gas well pads could similarly be utilized for the drilling of new shale gas wells, or new pads could be configured to allow simultaneously.

The Mesaverde Total Petroleum System Uinta-Piceance Basin Continuous and Transitional Gas assessment units are also present, but are quite small in areal extent, covering only 2,088 acres (0.06%) and 45,360 acres (1.41%), of the Study Area, respectively. These plays are characterized as upper Mesaverde fluvial sandstone reservoirs sourced from the underlying thermally mature coals and carbonaceous shales of the lower part of the Mesaverde (i.e., the Iles Formation coal and shale members) (U.S. Geological Survey, 2002). Only limited exploration of these plays has occurred in the Study Area. Of the 13 wells drilled to the Mesaverde Formation and its members (not including coalbed natural gas wells), four were dry and abandoned, one is temporarily abandoned, one has been converted to a water injection well, and only seven have been completed as Mesaverde gas wells, all of which were either shut-in or choked back due to pipeline constraints at the time of this writing (IHS Energy Group, 2010; Colorado Oil and Gas Conservation Commission, 2010). If this play becomes fully characterized in the Study Area, development would be expected to proceed similarly to the aforementioned shale gas plays. However, being characterized as fluvial sandstone reservoirs, large hydraulic fracs would not be as necessary, and development would be more likely to occur using vertical wells, or multiple directional wells drilled from a single pad.

Although there has not been a lot of past interest in exploration of the Study Area's potential resource plays, some operators have indicated an interest in exploration during the Analysis Period. Their projections were used to assist in preparing the development potential map (Figure 23) and projection of 489 conventional wells for the Analysis Period. The development potential in parts of the Study Area underlain by the four assessment units in the Piceance basin (Figures A1-6 and A1-8) and for the Gothic and Hovenweep shales in the Paradox basin is predominantly tied to operator identified plays associated with these assessment units or our projections of potential for development of these assessment units.

A large portion of the wells projected in the very high conventional development potential area (Figure 23a) could be Mancos wells if this play is determined to be economic in the Study Area. Our projections of moderate conventional development potential in the Paradox basin part of the Study assumes at least some potential for exploration of the Gothic and Hovenweep shales in the future. If one or both shales become economic to produce in this area, a large portion of the wells projected for this area would be related to Gothic and/or Hovenweep shale drilling.

Coal Gasification

Underground coal gasification may be a potential future process that is applied to coal deposits within the Study Area. This process burns the coal in-situ producing a combustible gas with a low heating value that can be used in industrial processes and gas turbines. Air or oxygen commingled with steam is injected into the coal seam resulting in the coal being burned outward from the injection well. The combustion products react with the non-burned coal to form hydrogen, carbon monoxide, and pyrolysis products that are produced at a production well. There is evidence that combustion gases preferentially absorb to the coal cleat faces and displace coalbed natural gas from the coal, which increases the heating value of the produced gas. The heat of reaction of the burned coal heats up the unburned coal in front of the combustion front and drives off the hydrocarbon volatile matter contained in the coal. The removal of volatile matter is essentially the same process that coal goes through in the geologic process of changing from lignite to anthracite by adding geothermal heat (increasing burial depth) and geologic time.

Underground coal gasification is usually at depths too deep to be economically mined. Depth is a positive factor in the gasification process as the higher pressures at depth appear to give better reaction results and a gas with a higher heating value. The limiting factor in depth would be potential reduced permeability of the coal and the ability to efficiently inject and produce the gas.

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

There are coal beds in the Study Area at depths too deep for mining but good candidates for underground gasification. Presently, the underground gasification technology involving deep coal beds does not appear to be economic and there is no known research activity into future development in the Study Area. Considering the relatively experimental status of underground coal gasification and the abundant coal found elsewhere in the region, there is a very low probability that this process will be utilized in the Study Area during the Analysis Period.

Carbon Dioxide Sequestration

Carbon dioxide sequestration is a method of storing captured carbon dioxide gas, a greenhouse gas. The primary industrial sources of carbon dioxide include electrical power plants, oil refineries, chemical refineries, agricultural processing plants, cement works, and iron and steel production. Power and industrial plants, agricultural processing, chemical processing, and petroleum and natural gas processing (including refineries and sources associated with pipeline infrastructure) have been identified as the

major industrial sources of carbon dioxide (U.S, Department of Energy, 2007). Of these sources, electrical power plants produce the most carbon dioxide by a substantial margin.

Within the Study Area and the region, the largest carbon dioxide emission sources are power plants. Small amounts or carbon dioxide may be produced in association with oil and gas production within the Study Area, but no information was available to quantify amounts.

Capturing and storing carbon dioxide has been proposed to reduce the environmental effects caused by releasing the gas to the atmosphere. Three types of geologic formations have been identified as potential carbon dioxide sequestrations sites, with only two of these occurring in the Study Area (U.S. Department of Energy, 2008). Those formation types are:

- Mature Oil and gas reservoirs – These reservoirs have hosted natural accumulations of oil and/or gas and could, in the future, be used to store carbon dioxide. The entrapment of hydrocarbons indicates that a containment seal is present and any associated water (see Glossary) is assumed to be nonpotable. The Study Area is not known to contain any large oil and gas reservoirs that could be considered for sequestration, nor could the known reservoirs be considered as mature.
- Unminable coal seams – Unminable coal seams are considered to be those that are too deep or too thin to be economically mined. Many of the Cretaceous coals in the Study Area meet these criteria. If methane contained in the Study Area coal beds grows to a more mature stage of development then there could be a future opportunity to inject carbon dioxide, which could sweep additional methane from the coalbeds and allow adsorption by the coals of the carbon dioxide. Since coal beds preferentially adsorb carbon dioxide, they provide excellent storage sites.
- Saline formations – Saline formations suitable for carbon sequestration were defined in the U.S. Department of Energy (2008) atlas as porous and permeable rocks containing water with total dissolved solids greater than 10,000 milligrams per liter, which have the capacity to store large volumes of carbon dioxide. Saline rocks can have a large potential for carbon dioxide storage. Many of these potential formations are made up of reactive carbonate rocks that could potentially react with and convert the carbon dioxide into compounds for storage in the host rock. Currently, there are no projects to evaluate this process in saline formations within the Study Area.

POTENTIAL OIL AND GAS SURFACE DISTURBANCE

As a first step, assumptions were made about the numbers of wells drilled in each well type category, the number of new wells drilled per pad (disturbed site), completion success, and percentages of Bureau managed oil and gas minerals. These were then combined with assumptions about disturbance associated with well pads and associated

roads and pipelines. Data obtained from operators, the Uncompahgre Field Office, and our historical analysis was used to make the following assumptions.

Well Assumptions – Wells Drilled, Wells Drilled per Disturbed Site (Pad), Completion Success, and Bureau and Forest Service Managed Oil and Gas Minerals

As stated previously, the conventional oil and gas well category includes all wells that may be drilled other than coalbed natural gas wells. Thus, any shale gas wells that may be drilled are included in the conventional category. The method used to determine the number of new wells drilled during this period has been previously discussed. In addition, we assumed that:

1. In the high conventional potential area (Whitewater Unit) there will be one pad with up to nine wells per pad. Bureau managed oil and gas minerals will cover more than 98 percent of wells and all surface pads will be on Bureau managed oil and gas minerals. No Forest Service managed oil and gas minerals lie within high conventional development potential. The success rate will be 75 percent for wells, with the one pad remaining active in the short-term and long-term.
2. In the very high conventional development potential area of the Piceance basin, wells spudded between January 1, 2000 and December 31, 2009 were: 27.78 percent on Bureau managed oil and gas minerals; 19.44 percent on Forest Service managed oil and gas minerals; and 52.78 percent on private/state managed oil and gas minerals.
3. In the very high and moderate conventional development potential and high and moderate coalbed natural gas parts of the Piceance basin, coalbed natural gas wells would use vertical wellbores. The conventional wells could be for shale gas targets or for sandstones of the Mesaverde Group and could be drilled either conventionally or with multiple horizontal wellbores to minimize the number of well pads required to drain the resource.
4. In the very high and moderate conventional development potential and high and moderate coalbed natural gas parts of the Piceance basin, 32 of the 52 existing one well locations will receive an average of 3 additional wells (one additional coalbed natural gas well and two additional conventional wells on each existing location). Up to 96 new wells are projected. Bureau managed oil and gas mineral lands cover over 27.78 percent of the locations in the area and 19.44 percent on Forest Service managed oil and gas mineral lands, with the remaining locations on private/state oil and gas minerals. The success rate for coalbed natural gas wells will be 90 percent and for conventional wells it will be 75 percent, with all 32 pads remaining active in the short-term and long-term.
5. In the very high and moderate conventional development potential and high and moderate coalbed natural gas parts of the Piceance basin, 125 new pads will be constructed with an average of two coalbed natural gas wells and two

conventional wells on each pad for a total of 500 wells. About one third of the new pads will be on Bureau managed oil and gas mineral lands, one third on Forest Service managed oil and gas minerals and one third on private/state lands. The success rate for coalbed natural gas wells will be 90 percent and for conventional wells it will be 75 percent, with 98 percent of all 125 pads remaining active in the short-term and the remaining two percent abandoned. In the long-term, remaining pads will continue to be active.

6. In the Piceance basin part of the Study Area, 229 new pads will be constructed with an average of two coalbed natural gas wells on each pad for a total of 458 wells. About one third of the new pads will be on Bureau managed oil and gas mineral lands, one third on Forest Service managed oil and gas minerals and one third on private/state lands. The success rate for coalbed natural gas wells will be 90 percent, with 95 percent of all 229 pads remaining active in the short term and the remaining five percent abandoned. In the long-term, all remaining pads will continue to be active.
7. In the rest of the Study Area (areas of low and very low coalbed natural gas potential), 42 single coalbed natural gas well pads will be constructed. The Bureau will manage oil and gas mineral lands on about 26 percent of the wells in areas of low potential and about 27 percent of the wells in the areas of very low potential. The Forest Service will manage oil and gas mineral lands on about 39 percent of the wells in areas of low potential and about 23 percent of the wells in the areas of very low potential. The success rate for coalbed natural gas wells will be 90 percent, with 10 percent abandoned after drilling. In the long-term, remaining wells will continue to be active.
8. In the rest of the Study Area (areas of moderate and low conventional oil and gas development potential in the Paradox basin and the very low and negligible development potential areas), the remaining 166 conventional wells will be drilled, with an average of 1.5 wells per pad. The Bureau will manage oil and gas mineral lands on about 49 percent of the wells in areas of moderate potential, six percent of the wells in areas of low potential, about 29 percent of the wells in the areas of very low potential, and about 12 percent of the wells in the areas of negligible potential. The Forest Service will manage oil and gas mineral lands on about 23 percent of the wells in areas of moderate potential, 42 percent of the wells in areas of low potential, about 34 percent of the wells in the areas of very low potential, and about 40 percent in areas of negligible potential. The success rate for conventional wells will be 75 percent, with 25 percent abandoned after drilling. In the long-term, remaining wells will continue to be active.
9. The projected numbers of new wells per pad were derived from industry sources, consultation with the Uncompaghre Field Office, and our analysis.

10. The average well life for the new projected conventional and coalbed natural gas wells will be at least 20 years.
11. All presently active wells completed prior to 1990 (not including one water injection well) will be abandoned during the analysis period. This totals 15 wells that would be abandoned in the long-term.

Surface Disturbance Assumptions

Assumptions about the different types of surface disturbance associated with drilling new wells were also made. The assumptions include those made for the potential types of drill pads, roads associated with the drill pads, and pipelines associated with drill pads.

Drill Pads

Drill Pad disturbance is projected to vary with the number of wells planned for each pad and the local topography. If a well is successfully completed, then the operator will be required to begin mandatory interim reclamation of a large part of the area initially disturbed during preparation for drilling of all wells on the pad. This interim reclamation reduces the amount of disturbed surface and the resulting unreclaimed 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.] Average surface disturbance will remain whether wells are drilled conventionally or horizontally.

Conventional Wells

Development potential	*Average initial disturbance (acres/pad)*	*Long term disturbance (acres/pad)*
Multi-Well Pads	*6*	*2.0*
Single & 2 Well Pads	*4*	*1.5*

Coalbed Natural Gas Wells

Development potential	*Average initial disturbance (acres/pad)*	*Long term disturbance (acres/pad)*
Multi-Well Pads	*4*	*1.5*
Single Well Pads	*3*	*1.5*

Access roads (all well categories)

A detailed study of recent development in the entire Uncompaghre Field Office was completed. 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. The study indicates an access road disturbance of **8.0** acres per section has occurred. The 8.0 acre surface disturbance per section assumes a road disturbance width of 40 feet, which equates to an equivalent of 4.85 acres per linear mile of road (1.65 mile of road per section).

Pipelines

The table below assumes that with the well and well pad densities described above that

- pipelines would be run parallel to the access roads,
- pipeline Right-Of-Way widths would average 50, and
- full reclamation would occur at the time of installation.

The assumption that the pipelines and access roads 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.

Development potential	*Pipeline average initial disturbance (acres per section)*	*Pipeline long term disturbance (acres per section)*
CBM, Conventional, Shale (all categories)	*10.0 acres (1.65 miles@ 50')*	*0*

Analysis Results

Table 8a shows our projection of new exploratory and development wells (1,271 wells with 418 of those wells drilled on Bureau managed oil and gas minerals) that could be drilled in the Study Area from 2010 through 2030. There are an additional 62 existing active well locations (IHS Energy Group, (2010) and Colorado Oil and Gas Conservation Commission, 2010), as of April 2010, for a total of 1,333 existing and projected coalbed natural gas and conventional oil and gas wells in the short-term. Of those 1,333 existing and projected wells; 432 will lie on Bureau managed oil and gas minerals. Bureau managed wells were calculated using a percentage for well type. Those percentages are presented above in "Well Assumptions." The 1,271 new wells drilled will be located on 540 disturbed sites, with 174 sites projected on Bureau managed oil and gas minerals.

Table 8a also calculates associated acres of total surface disturbance (short-term disturbance) directly associated with all new wells and existing active wells (as of April 2010). Number of disturbed sites are multiplied by acres of disturbance (per site) to calculate total acres of surface disturbance and Bureau managed well disturbance for each well type (e.g., total disturbed sites * (access roads and pipelines + well pad). For well sites that are abandoned (two percent for Coalbed Gas/Conventional Well Multipads, five percent for Coalbed Gas Multipads, 10 percent for Coalbed Gas Single Well Pads, and 25 percent for Conventional One and Two Well Pads) pipelines will not be installed so pipeline disturbance is not included in the calculation. Approximately 10,984 acres of new short-term surface disturbance (3,578 acres of disturbance on Bureau managed oil and gas minerals) could occur if all 1,271 projected wells are drilled. Total short-term surface disturbance (for all well types) would be 11,201 acres, with 3,627 of those acres on Bureau managed oil and gas minerals.

Table 8b includes our long-term projections of wells and associated disturbance. This projection factors in the dry-hole abandonment and reclamation of some new wells

drilled (see above assumptions) and abandonment of some presently active wells. In the long-term 1,070 (352 Bureau managed) of the projected 1,271 (418 Bureau managed) new wells drilled will remain active at the end of the Analysis Period. We also project that 494 (159 Bureau managed) of the 540 (174 Bureau managed) new disturbed sites will also remain active. Total wells in active status will be 1,117 (366 Bureau managed) in the long term, with 541 active disturbed wells sites (173 Bureau managed disturbed well sites).

Finally, Table 8b shows the calculated unreclaimed acres of total surface disturbance (long-term disturbance) directly associated with all remaining active wells. Approximately 4,465 acres of new unreclaimed surface disturbance (1,456 acres of unreclaimed Bureau managed oil and gas minerals) from new wells drilled during the Analysis Period could remain in the long-term. Total unreclaimed long-term surface disturbance (for all well types) would be 4,630 acres, with 1,505 of those acres on Bureau managed oil and gas minerals.

Both Table 8a and 8b use calculations that contain decimals, but all results shown are rounded to whole numbers. As a result of this rounding, the whole numbers shown may not exactly add up to the totals shown.

SUMMARY

For our base line projection we analyzed the oil and gas resource within the Study Area, discussed types of future development that may occur, estimated the development potential for each type of resource, and projected base line activity levels for the Analysis Period 2010 through 2030. We projected that as many as 489 conventional oil and gas wells and 782 coalbed natural gas wells could be drilled during this period. Our forecast of annual oil and gas production for 2010 through 2029 is presented in Table 7. Short-term and long-term surface disturbance associated with existing wells and future projected wells is presented in Tables 8a and 8b for all lands and for Bureau managed oil and gas mineral lands. For our analysis of the base line projection, we assumed that the only land use restrictions on future oil and gas resource development would be those that have been legislatively imposed.

APPENDIX 1 – U.S. GEOLOGICAL SURVEY ASSESSMENTS OF UNDISCOVERED TECHNICALLY RECOVERABLE OIL AND GAS RESOURCES WITHIN THE UNCOMPAHGRE STUDY AREA

INTRODUCTION

The U.S. Geological Survey has published a number of resource assessments of undiscovered technically recoverable oil and gas resources that cover parts of the Uncompahgre Study Area. Their "1995 National Assessment of United States Oil and Gas Resources" (Huffman, 1995) scientifically estimated the amount of crude oil, natural gas, and natural gas liquids (see Glossary) that could be added to proved reserves in the United States, assuming existing technology. It presented information about potential undiscovered accumulations of oil and gas in 71 geologic or structural provinces within the United States. Two of those provinces, the Uinta-Piceance basin and the Paradox basin, lie within the Study Area. Figure A1-1 shows the location of the two provinces within the field office. The Uinta-Piceance basin was assessed in both the U.S. Geological Survey 1995 Assessment and the U.S. Geological Survey 2002 Assessment. Because of the change in methodology from the 1995 assessment to the updated 2002 assessment (see below), the two assessments have different southern boundaries defined for the Piceance basin.

Recently the U.S. Geological Survey revised their methods for preparing oil and gas resource assessments. Thirty two basins have been reassessed or will be re-assessed since the 1995 report. The U.S. Geological Survey used the new method to update their quantitative estimate of undiscovered technically recoverable oil and gas resource for the Uinta-Piceance Basin Province (U.S. Geological Survey Uinta-Piceance Assessment Team, chapter 1, 2003). The Paradox Basin Province was not updated in the 2002 report. The 1995 Paradox Basin Province assessment, the 1995 Uinta-Piceance Basin assessment, and the updated 2002 Uinta-Piceance Basin assessment are summarized below to describe the potential undiscovered technically recoverable oil and gas resources lying within the Uncompahgre Study Area. Also included is a summary of each Total Petroleum System and the Assessment Units within the Study Area. The area southeast of the 2002 Piceance Basin boundary and the area southeast of Ouray County, labeled as San Juan, are two gaps with no Assessment Units or play areas. The two gaps were not analyzed for undiscovered accumulations. Figure A1-1 shows the basin boundaries. The information was taken from the U.S. Geological Survey Assessments. For more detailed information, please refer to the complete reports published by the U.S. Geological Survey.

PARADOX BASIN PROVINCE ASSESSMENT

The Paradox Basin Province occupies approximately 2,447.94 square miles (1,566,681.48 acres) of the Study Area. It covers an area of approximately 33,000 square miles, is 280 miles long, and 200 miles wide throughout Colorado and Utah (Huffman, 1995). Located in southwestern Colorado, the Paradox Basin Province is bounded by the Uncompahgre Plateau to the northeast, the San Juan Dome to the east, and the Monument uplifts, Circle Cliffs, and the Henry Mountains to the west. The San Rafael Swell is the northwest boundary. The Paradox basin, Kaiparowits Plateau, Henry Mountains basin, and the Wasatch and Pausaugunt Plateaus are other geologic features in the Paradox Basin Province. The province has thick sequences of Phanerozoic sediments with 5,000 to 8,000 feet of sediment in the central part of the basin. There is greater than 15,000 feet of total sediment in the Paradox basin, Kaiparowits basin, and the Wasatch Plateau (Huffman, 1995).

Production in the province is mainly from porous carbonate buildups (algal mounds). The Paradox Basin Province is one of four principal oil and gas producing regions in Colorado. The Giant Aneth field, containing more than one billion barrels of oil in place, is located in the Paradox basin. The Aneth field is southwest of the Study Area. There have been at least 84 wells drilled in the Paradox basin within the Study Area as of June 30, 2009 (IHS Energy Group, 2009). No coal bed gas wells have been drilled in the Study Area as of June, 2009 (IHS Energy Group, 2009). In the Paradox Basin Province, the Paradox basin is defined by "the maximum extent of salt in the Middle Pennsylvanian Paradox Formation" (Nuccio et al., 1996). There are eight wells that reached total depth in the Pennsylvanian salt of the Paradox basin in the Study Area (IHS Energy Group, 2009). The northern part of the basin includes a structural fold and fault belt.

Play Summary

The "1995 National Assessment of United States Oil and Gas Resources" (Beeman et al., 1996; Charpentier et al., 1996; Gautier et al., 1996) did not update the Paradox Basin Province assessment with the latest U.S. Geologic Survey assessment of oil and gas resources completed in 2002. The 1995 resource assessment includes six conventional oil and gas plays. Five of these plays are within the Study Area (Figures A1-2 and A1-3). The five play areas in the Study Area include the Salt Anticline Flank, Porous Carbonate Buildup, Permian-Pennsylvanian Marginal Clastics, Fractured Interbed, and Buried Fault Blocks. Each play area is a set of discovered or undiscovered oil and gas accumulations or prospects that are geologically related. The U.S. Geological Survey defined a play "by the geological properties (such as trapping style, type of reservoir, nature of the seal) that are responsible for the accumulations or prospects" (Huffman, 1995). The U.S. Geological Survey has made available some statistical information for these plays. Listed in Table A1-1 is the information for the Salt Anticline Flank, Porous Carbonate Buildup, Permian-Pennsylvanian Marginal Clastics, and Buried Fault Blocks plays. Since there is only one unconventional play, the Fractured Interbed play is only discussed in paragraph form, below.

Play Descriptions

Salt Anticline Flank

The Salt Anticline Flank play is located in the southwest part of the Study Area. It encompasses approximately 784,741.75 acres. Gas is the predominant hydrocarbon produced from this play. Six wells in the Salt Anticline Flank play, within the Study Area, have produced in the past. Reservoirs include the Hermosa Group limestone and the Cutler Formation arkosic sandstone (Huffman, 1995). Amongst these reservoirs is a well-developed fracture system with good vertical communication. Source rocks are from the Hermosa Group black dolomitic shale and the contact between the Cutler-Hermosa which is coaly carbonaceous shale. Gas migration coincided with salt movement and anticlinal growth. Traps include thinning and permeability pinchouts. Seals are from steeply dipping flanks of salt anticlines and updip termination against salt diapirs. Exploration in this play is mainly outside the Study Area in Andy's Mesa. Projections from the 1995 assessment state a low resource potential for oil and fair to good resource potential for gas (Huffman, 1995). See Figure A1-2 for the location of the Salt Anticline Flank play within the Study Area.

Buried Fault Blocks

The Buried Fault Blocks play is in the southwest part of the Study Area (Figure A1-2). It shares a common boundary with the Salt Anticline Flank play and the Fractured Interbed play. There are 784,750.244 acres of the Buried Fault Blocks play within the Study Area. The reservoirs in this play store oil in the Leadville dolomite or dolomitic limestone and the McCracken Sandstone Member of the Elbert Formation (Huffman, 1995). The source rock for this area is the Paradox Formation black dolomitic shale. Traps are on uplifted fault blocks with the Paradox Formation evaporite beds as a seal. Future resource potential is low to moderate. Unexplored fields are predicted to be small to medium sized with a minimal oil column (Huffman, 1995).

Fractured Interbed

The Fractured Interbed play is the only unconventional play in the Paradox basin within the Study Area (Figure A1-2). An unconventional accumulation includes "oil and gas resources that exist as geographically extensive accumulations that generally lack well-defined oil/water or gas/water contacts…" (Beeman et al., 1996; Charpentier et al., 1996; and Gautier et al., 1996). Coal-bed gas, tight gas, and oil and gas shales are examples of unconventional oil and gas plays. The Fractured Interbed play has approximately 784,741.75 acres within the Study Area. The median cell size is 960 acres. A cell is a volume having dimensions related to the drainage area of an individual well (Beeman et al., 1995: Charpentier et al., 1996: Gautier et al., 1996). The median cell total is 1,812 with a median untested cell total of 99.34 percent. The median untested cells with potential to add reserves were 20 percent. Information was not available regarding median carbon-dioxide content. The drilling depth range to the Fractured Interbed play is 8,000 to 10,000 feet (Huffman, 1995).

Porous Carbonate Buildup

The Porous Carbonate Buildup play is in the far south portion of the Study Area (Figure A1-3). It contains only 11,306.79 Acres. This play is primarily an oil play. The Great Aneth field is developed in this play. Reservoirs include the Hermosa Group limestone and dolomite (Huffman, 1995). Zones in the Hermosa Group are the Alkali Gulch, Barker Creek, Akah, Desert Creek, and Ismay. The Desert Creek and Ismay are the largest producers in the play. The Paradox Formation dolomite and mudstone are the primary source of hydrocarbons. There is one to five percent total organic carbon content in these source rocks. Stratigraphic traps predominate. Seals include porosity differences in overlying evaporate beds and interbedded shale. Most fields in the play produce between one and three million barrels of oil. The one exception is the Great Aneth (Huffman, 1995).

Permian-Pennsylvanian Marginal Clastics

Within the Study Area, the Permian-Pennsylvanian Marginal Clastics play is 255,863.61 acres. It is located in the southern part of the Study Area (Figure A1-3). The play is gas prone. The hydrocarbon-bearing reservoir, with shows present, is the Cutler Formation sandstone (Huffman, 1995). Hydrocarbons are sourced from Desmoinesian dolomitic shale and mudstone. Traps include a combination of sandstone lenses pinched out on folds and faults. The seal is formed from shale beds or low permeable clays. There is little to no exploration in the area and not production existed as of 1995 (Huffman, 1995).

Play Resource Results

Unlike the "2002 National Assessment of United States Oil and Gas Resources", the U.S. Geological Survey (Beeman et al., 1996; Charpentier et al., 1996; Gautier et al., 1996) did not use a forecast span to estimate undiscovered technically recoverable resource quantities for the five play areas from their "1995 National Assessment of United States Oil and Gas Resources." Below is a summary of the estimated volumes of hydrocarbons in the four conventional plays and the one unconventional (continuous-type) play, which lie at least partly within the Study Area.

In Table A1-2, the U.S. Geological Survey resource estimates for three types of hydrocarbons (oil, gas, and natural gas liquids) are shown for the conventional plays and the continuous play in the Paradox Basin Province, together with our projection of the amount of those hydrocarbons that could be present within the Study Area. To determine the potential resource within the Study Area we:

- assumed a homogenous distribution of each hydrocarbon type within each Assessment Unit or play area,
- calculated the percent of each Assessment Unit or play area that lies within the Study Area, and

- multiplied that percentage by the U.S. Geological Survey resource value estimates for each entire Assessment Unit or play area to calculate Study Area resource values.

The U.S. Geological Survey estimates of recoverable resources for each play area within the province are presented as a range of possibilities. There is a high estimate of recoverable petroleum resources, a mean estimate, and a low estimate of petroleum resources. The high estimate of recoverable petroleum products is the least probable to be recoverable. Therefore, it is shown as a five percent probability of occurrence. The low estimate of recoverable resources is the most likely amount of petroleum product to be recovered. Ninety-five percent probability of occurrence of recovery is likely to occur for the low estimate. The mean is an average of all the probabilities of occurrence. Similarly, the Bureau of Land Management followed the U.S. Geological Survey example to estimate potential abundance of petroleum resources for the Uncompahgre Field Office. We estimate that the Study Area contains a **mean undiscovered cumulative volume of 29.44 million barrels of oil, 144.78 billion cubic feet of gas, and 4.14 million barrels of natural gas liquids, in the Paradox Basin Province play areas for the 1995 assessment** (Table A1-2).

In addition, we estimate that the Study Area's oil resource in the Paradox Basin Province could **range from 5.60 to 75.04 million barrels, the gas resource could range from 13.74 to 339.88 billion cubic feet, and the natural gas liquids resource could range from 0.35 to 11.05 million barrels** (Table A1-2). These estimates are based on the 1995 assessment.

UINTA-PICEANCE BASIN PROVINCE ASSESSMENT

The Uinta-Piceance Basin Province is located in southwestern Colorado and southeastern Utah. It has approximately 21 trillion cubic feet of undiscovered natural gas (U.S. Geological Survey Uinta-Piceance Assessment Team, chapter 1, 2002). Most of the natural gas is in unconventional (continuous) accumulations. Thirteen trillion cubic feet of gas lies within the Mesaverde Total Petroleum System and seven trillion cubic feet of gas reside in the Mancos/Mowry Total Petroleum System. An average of sixty million barrels of oil is undiscovered. The main source rocks for the Uinta-Piceance basin include the Phosphoria Formation, Mancos Shale, Mancos/Mowry Shales, Mesaverde group, and Green River formations (U.S. Geological Survey Uinta-Piceance Assessment Team, chapter 2, 2002). Within the Study Area there have been at least 255 conventional wells and 36 coal-bed methane wells drilled as of April 29, 2010 (IHS Energy Group, 2010).

The Uinta-Piceance Basin Province boundary for the 1995 U.S. Geological Survey assessment is defined by the Uinta Mountain Uplift to the north and the southern Park Range and Sawatch Uplift on the east. North of the Uncompahgre Uplift axis defines the southern boundary. The Utah thrust belt defines the western boundary (Spencer, 1995). The Douglas Creek arch separates the Uinta-Piceance basin in two halves. In the south-central portion of the Uinta-Piceance Basin Province there is a fold belt and igneous

intrusions in the southeast. Numerous folds are in the northeastern Piceance basin along with many normal faults in the western Uinta basin. Normal faulting occurs in the middle of the Uinta-Piceance basin (U.S. Geological Survey Uinta-Piceance Assessment Team, chapter 2, 2003).

Play Summaries

The "1995 National Assessment of United States Oil and Gas Resources" (Spencer, 1995) had three conventional accumulation (see Glossary) plays within the Study Area: the Basin Margin Subthrust, Upper Cretaceous Conventional Play, and the Cretaceous Dakota to Jurassic Gas Oil plays (Figure A1-4). Continuous accumulation (see Glossary) play areas inside the Study Area include the Tight Gas Piceance Mesaverde Williams Fork Continuous Gas, Piceance Basin-Divide Creek Anticline Coal-bed Gas, Piceance Basin-Igneous Intrusion Coal-bed Gas, and Piceance Basin-Western Basin Margin Coal-bed Gas plays (Figure A1-5). Each play area is a set of discovered or undiscovered oil and gas accumulations or prospects that are geologically related. The U.S. Geological Survey defined a play "by the geological properties (such as trapping style, type of reservoir, nature of the seal) that are responsible for the accumulations or prospects." A conventional play contains oil and gas accumulations having hydrocarbon-water contacts and seals that hold or trap hydrocarbons. The hydrocarbons in these plays can be recovered using traditional development and production practices. Supporting geologic studies for these play areas are available at http://certmapper.cr.usgs.gov/data/noga95/prov20/text/prov20.pdf (Spencer, 1995). Since the Uinta-Piceance Basin Province was re-assessed in 2002, estimates of resources in the area were only calculated for the Uinta-Piceance Basin Province 2002 assessment.

Total Petroleum Systems and Assessment Unit Summaries

In their newest assessment (written in 2002 and published in 2003), the U.S. Geological Survey divided the Uinta-Piceance Basin Province into "Total Petroleum Systems" and "Assessment Units" (see Glossary definitions) rather than "plays." Summaries of the Total Petroleum Systems and Assessment Units are provided below.

Mesaverde Total Petroleum System

The Mesaverde Total Petroleum System encompasses approximately 20,000 square miles (12,800,000 acres) in the Uinta-Piceance Province. Within the Study Area, the Mesaverde Total Petroleum System covers approximately 1,722.36 square miles (1,102,312.93 acres). Sediment thickness ranges from less than 1,500 feet on the northwest boundary of the Study Area to greater than 10,000 feet in the deepest part of the Piceance basin (Johnson et al., chapter 7, 2003). There are seven gas Assessment Units within the Mesaverde Total Petroleum System, with four of these units lying within the Study Area (Figure A1-6, Figure A1-7). The four Assessment Units in the Study Area include the Piceance Basin Continuous Gas Assessment Unit, the Piceance Basin Transitional Gas Assessment Unit, the Mesaverde Sandstone Gas Assessment Unit, and the Mesaverde Group Coal-bed Methane Assessment Unit.

The U.S. Geological Survey defines a Total Petroleum System as being mappable, contains genetically related petroleum from source rocks, and contains a reservoir and seal, with migration and timing as critical components (2003). The Mesaverde Total Petroleum System's source rocks are from coals and carbonaceous shales in the Cretaceous Mesaverde Group. The main gas producing coal deposit in the Piceance basin is the Cameo-Fairfield coal group of the Williams Fork Formation. Reservoirs in the Piceance basin (the northern focus of the Study Area) are fluvial channel sandstone beds of the Wasatch Formation and Fort Union Formation. The seal of the Mesaverde Total Petroleum System is likely lacustrine shales of the Tertiary Green River Formation. The trapping mechanism is likely from capillary seal or water block (Johnson et al., chapter 7, 2003).

The upper limit of the Mesaverde Total Petroleum System in the study area is defined by the Tertiary Green River Formation (Johnson et al., chapter 7, 2003). The lower limit of the Mesaverde Total Petroleum System has an indistinct seal throughout the Uinta-Piceance basin because the Mancos/Mowry Total Petroleum System intertongues with the Mesaverde Total Petroleum System. In the Piceance basin, the lower limit is defined as the lowest coal zone of the Williams Fork Formation. Gas generation began 55 million years ago and peaked between 47 and 39 million years ago in the Piceance basin (2003). There are no major gas fields that lie within the Mesaverde Total Petroleum System of the Study Area. Of the 96 wells that tested the Mesaverde Total Petroleum System, approximately 22 wells have production (gas only) sourced from the Mesaverde Total Petroleum System (IHS Energy Group, 2009). Thirty-one Coal-bed natural gas wells tested the Mesaverde Total Petroleum System. Approximately 26 of those Coal-bed natural gas wells have production sourced from the Mesaverde Total Petroleum System. No wells produce oil in this Total Petroleum System.

Piceance Basin Continuous Gas Assessment Unit

The Piceance Basin Continuous Gas Assessment Unit covers less than one-tenth a township (2,088.28 acres) in the Study Area (Figure A1-6). Located in the northeastern portion of the Study Area, the Assessment Unit boundary is defined by a vitrinite reflectance line of 1.10 percent R0 (Johnson et al., chapter 7, 2003). Since the vitrinite reflectance represents thermally mature source rocks, the potential for gas is high. Fluvial channels in the Williams Fork and Wasatch Formations are the primary gas producing stratigraphy. Permeability in the sandstone from these formations is low. A well defined fracture system is has not been identified, so enhancement of permeability is likely to produce gas in this Assessment Unit (2003). Ninety percent of the Assessment Unit remains unexplored so values in Table A1-5 are estimates. There are no wells in the Piceance Basin Continuous Gas Assessment Unit that lie within the Study Area.

Piceance Basin Transitional Gas Assessment Unit

Approximately 45,358.31 acres of the Piceance Basin Transitional Gas Assessment Unit lie within the Study Area (Figure A1-6). The boundary of the Assessment Unit is defined

by the vitrinite reflectance values between 0.75 percent and 1.10 percent R_0 (Johnson et al., chapter 7, 2003). The main petroleum product produced is natural gas from the White River Dome, Divide Creek, and Parachute fields located outside the Study Area. Reservoir rocks from these fields are fluvial channel sandstone mainly in the Mesaverde Group and partly in the Wasatch Formation. The reservoir rocks are likely more water-saturated due to less mature source rocks of the Cameo-Fairfield (Mesaverde Group) coal group, resulting in fewer successful future tests (2003). From the base of the Cameo-Fairfield coal group to the base of the first significant lacustrine shale in the Green River Formation are the Assessment Unit's stratigraphic extents. Pressure in the Assessment Unit formations is variable and the maximum estimated ultimate recovery is four billion cubic feet of gas (Table A1-5). Ninety percent of the field remains unexplored (2003).

Mesaverde Sandstone Gas Assessment Unit

The Mesaverde Sandstone Gas Assessment Unit is a conventional oil and gas resource (Figure A1-6 and Table A1-3). The trapping mechanisms include both structural and stratigraphic with distinct gas-water contacts (Johnson et al., chapter 7, 2003). Source rocks from the lower Mesaverde Group include coal beds and carbonaceous units. The reservoirs are primarily fluvial channel sandstones from the Wasatch Formation. While there is small potential for conventional-type hydrocarbons in the Mesaverde Group in the basin margins, production was only allocated from the Wasatch Formation. The conventional-type accumulations from the Wasatch Formation are located primarily in the Piceance Creek Dome and Sulphur Creek fields in the north-central Piceance basin. The average well depth in these fields is 4,800 feet with a minimum field size of 0.5 million barrels of oil equivalent (2003).

Mesaverde Group Coal-bed Methane Assessment Unit

The approximate area of the Mesaverde Group Coal-bed Methane Assessment Unit is 4,815,000 acres in the Uinta-Piceance Basin Province (Figure A1-7). While the Assessment Unit is largely untested, the maximum estimated ultimate recovery is five billion cubic feet of gas, assuming future Coal-bed methane technology advances (Johnson et al., chapter 7, 2003). The Grand Valley and Parachute fields were not used by the Survey in calculating the estimated ultimate recovery because these fields commingle Coal-bed methane and sandstone reservoirs. Overall, Coal-bed methane production has not been commercially successful, likely due to thin coal beds, under saturation of gas, steeply dipping beds, and gas leakage (2003). Exceptions are in the White River Dome and Pinyon Ridge fields. These fields have more production likely due to folding and fracturing. The coal beds in the Mesaverde Group Coal-bed Methane Assessment Unit are less than 7,000 feet deep in the Williams Fork Formation in the Piceance basin. Thermal maturity of the coals ranges from less than 0.65 percent to 1.35 percent R_0. Thirty-one Coal-bed methane wells have been drilled in this Assessment Unit. Twenty-six of these wells have been productive.

Mancos/Mowry Total Petroleum System

The Mancos/Mowry Total Petroleum System is in the northern part of the Study Area and encompasses 287,576.47 acres (449.34 square miles) of the Study Area. The Piceance Basin Continuous gas Assessment Unit and the Uinta-Piceance Transitional and Migrated Gas Assessment Unit are the two Assessment Units within the Mancos/Mowry Total Petroleum System that reside in the Study Area (Figure A1-8). The Mancos/Mowry Total Petroleum System is rich in organic shales and interbedded sandstones (Kirschbaum, chapter 6, 2003). Permeability was enhanced by a Laramide orogeny fracture system and gas generation. There is more than 5,000 feet of Mancos Shale and Mowry Formation sediment (2003).

Reservoirs in the Mancos/Mowry Total Petroleum System can be in fluvial, tidal, and shoreface deposits. Fluvial deposits include the Morrison Formation, Cedar Mountain Formation, and the Dakota Sandstone. These fluvial reservoirs are predominantly tight and underpressured (Kirschbaum, chapter 6, 2003). Well spacing is typically 60 to 640 acres. Tidal and shoreface deposits include the Dakota, Castlegate, Sego Sandstone, Morapos Sandstone member of the Mancos Shale, Corcoran-Cozzette-Rollins Sandstone members of the Iles Formation or Mount Garfield Formation, and the Mancos B. Gas production is mainly from tight sandstones but these formations vary in hydrocarbon production, pressure, porosity, and permeability. The Douglas Creek Arch has a gas cap in the Mancos B/Emery sandstone. Oil may be under the gas cap where trapping allows. Traps include stratigraphic and structural traps. Seals are from the Mancos and Mowry shales and mudstone. The system is sourced by hydrocarbons generated from 9 to 76 million years ago. Maximum hydrocarbon generation was 19 to 35 years ago (2003).

There were 68 wells tested in the Mancos/Mowry Total Petroleum System as of June 30th, 2009 (IHS Energy Group, 2009). Of these 68 wells, four wells were completed in the Dakota Sandstone. Two of the wells were completed as gas wells and are therefore sourced from the Mancos/Mowry Total Petroleum System. The remaining two wells were completed as oil wells and appear to be sourced from the Phosphoria Total Petroleum System.

Piceance Basin Continuous Gas Assessment Unit

The Piceance Basin Continuous Gas Assessment Unit's boundary is defined by the vitrinite reflectance of greater than 1.1 percent R_0 at the base of the Mancos Shale (Kirschbaum, chapter 6, 2003). The Assessment Unit has approximately 92,747.77 acres (144.92 square miles) in the Study Area (Figure A1-8). Potential to recover hydrocarbons is dependent on the depth of the reservoir. The lower reservoir group is the Morrison, Cedar Mountain, and Dakota Formations. The upper reservoir group is the Iles sandstones. Historical production for the lower reservoir is at depths less than 10,000 feet. The upper reservoir has historical production at depths less than about 6,000 feet. Outside these depths there is no potential for producing hydrocarbons. The economic depths to drill may vary with technological advances. Table A1-5 shows the estimated undiscovered technically recoverable resource quantities for the Piceance Basin

Continuous Gas Assessment Unit. Please note that this Assessment Unit is labeled as "Mancos/Mowry Total Petroleum System Piceance Basin Continuous Gas Assessment Unit" in Table A1-5 to distinguish it from the Piceance Basin Continuous Gas Assessment Unit residing in the Mesaverde Total Petroleum System.

Uinta-Piceance Transitional and Migrated Gas Assessment Unit

The Uinta-Piceance Transitional and Migrated Gas Assessment Unit's boundary is where vitrinite reflectance values from 0.75 percent to 1.1 percent R_0 occur at the base of the Mancos shale (Kirschbaum, chapter 6, 2003). Within the Study Area, the Assessment Unit covers approximately 194,828.70 acres (304.42 square miles). The reservoirs in this Assessment Unit include the Morrison Formation, Cedar Mountain Formation, Dakota Sandstone, Frontier Formation, Mancos B, Castlegate Sandstone, Sego Sandstone, Morapos Sandstone, Niobrara Formation, and Blackhawk Formation (hypothetical). These reservoirs are tight with pressures from normal to underpressured. Continuous accumulations are predominant, but conventional gas/water contacts or water-saturated reservoirs exist (2003). Table A1-4 shows details of the Assessment Unit and Table A1-5 shows estimated undiscovered technically recoverable resource quantities. Figure A1-8 shows the Uinta-Piceance Transitional and Migrated Gas Assessment Unit within the Study Area.

Phosphoria Total Petroleum System

The Phosphoria Total Petroleum System encompasses approximately 1,822,437.72 acres (2,847.56 square miles) within the Study Area. Oil in the Phosphoria Total Petroleum System has accumulated in the Weber Sandstone, Phosphoria and Park City Formations, Shinarump Member of the Chinle Formation, Entrada Sandstone, Curtis Formation, Morrison Formation, and the Dakota Sandstone (Figure 6a). The boundary of the Phosphoria Total Petroleum System is based on the extent of the Phosphoria-type oil. The trapping mechanisms include both stratigraphic and structural traps. Stratigraphic traps are dominated by eolian and alluvium deposits intertonguing. The structural traps include thrusted and cluster anticlines. The seal includes carbonate rocks and mudstone with low porosity and permeability (Johnson, chapter 9, 2003). The Assessment Units within the Phosphoria Total Petroleum System that also lie within the Study Area include the Hanging Wall Assessment Unit and the Paleozoic/Mesozoic Assessment Unit (Figure A1-9, Table A1-3).

There are 41 wells that penetrated the Phosphoria Total Petroleum System in the Study Area (IHS Energy Group, 2009). Of these 41 wells, two conventional oil wells have production that appears to be sourced from the Phosphoria Total Petroleum System. The other 39 wells are plugged and abandoned. No gas or coal-bed gas wells produce from the Phosphoria Total Petroleum System in the Study Area.

Hanging Wall Assessment Unit

The Hanging Wall Assessment Unit has only 120.77 acres (0.19 square miles) that are within the Study Area (Figure A1-9). It contains conventional type hydrocarbon accumulations in structural and stratigraphic-structural traps (Johnson, chapter 9, 2003). The structural traps are thrusted anticlines. The sealing mechanism is from low-permeability rocks. Source rocks include the Middle Pennsylvanian Minturn Formation, Phosphoria Formation, and the Mancos Shale. The Hanging Wall Assessment Unit contains non-associated gas likely sourced from Mesaverde coals. Oil is mainly from the Phosphoria Formation (2003). There are no wells from this Assessment Unit that are within the Study Area.

Paleozoic/Mesozoic Assessment Unit

The Paleozoic/Mesozoic Assessment Unit covers the north half of the Study Area (Figure A1-9). The Assessment Unit includes rocks from the Paleozoic time period or a combination of Paleozoic and Mesozoic rocks. The source rock is mainly from the Phosphoria Formation. Paleozoic source rocks are known to have high concentrations of carbon dioxide and inert gases when produced. Reservoir rocks are from sandstones and carbonate rocks (Johnson, chapter 9, 2003). These include the Lower Permian Kaibab Limestone, Lower Triassic Moenkopi Formation, Entrada Sandstone, Morrison Formation, Cedar Mountain Formation, and the Dakota Sandstone. Trapping is from anticlinal features associated with the Douglas Creek arch and Uncompahgre Uplift. The seal includes rocks with low permeability. This Assessment Unit mainly produces oil from the Dakota Formation. The two producing oil wells discussed above appear to be from the Paleozoic/Mesozoic Assessment Unit.

Each Assessment Unit falls within one of two types of potential undiscovered accumulation: conventional and continuous accumulations (see Glossary definitions). Of the five Assessment Units evaluated in the "2002 National Assessment of United States Oil and Gas Resources" in the Uinta-Piceance Basin Province, three Assessment Units lie within Field Office boundaries: the Paleozoic/Mesozoic, Mesaverde Sandstone, and the Hanging Wall Assessment Units (Tables A1-3, A1-5).

Continuous accumulations include tight reservoirs, shale reservoirs, unconventional reservoirs, basin-centered reservoirs, fractured reservoirs, Coal-beds, oil shales, and shallow biogenic gas. Assessment Units categorized as continuous accumulations that lie within the Study Area include the Mesaverde Total Petroleum System Piceance Basin Continuous Gas, Uinta-Piceance Transitional and Migrated Gas, Piceance Basin Transitional Gas, Mancos/Mowry Total Petroleum System Piceance Basin Continuous Gas, and the Mesaverde Group Coal-bed Gas (Tables A1-4 and A1-5).

Conventional accumulations have "discrete geographic entities with well-delineated hydrocarbon-water contacts" (U.S. Geological Survey Uinta-Piceance Assessment Team, chapter 1, 2003). Also, conventional accumulations have rocks with high permeability, discrete seals and traps, and high recovery factors (2003). In the Study Area, the

Assessment Units categorized as conventional resources are the Paleozoic/Mesozoic Conventional Oil, Mesaverde Sandstone Gas, and Hanging Wall Assessment Units (Tables A1-3 and A1-5).

Assessment Unit Resource Results

The U.S. Geological Survey estimated undiscovered technically recoverable resource quantities of oil and gas that could be added to the proved reserves within each Assessment Unit, using a forecast span of 30 years. A 30-year forecast span affects the minimum undiscovered accumulation size, the number of years in the future that reserve growth is estimated, economic assessments, the accumulations chosen for consideration, and the assessment of risk. Below is a summary of estimated hydrocarbon volumes in the three conventional Assessment Units and five continuous Assessment Units that reside in the Field Office boundaries.

In Table A1-5, the U.S. Geological Survey resource estimates for three types of hydrocarbons (oil, gas, and natural gas liquids) are shown for the both conventional and continuous Assessment Units in the Uinta-Piceance Basin Province, together with our projection of the amount of those hydrocarbons that could be present within the Study Area. To determine the potential resource within the Study Area we:

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

The U.S. Geological Survey estimates of recoverable resources for each Assessment Unit or play area within the province are presented as a range of possibilities. There is a high estimate of recoverable petroleum resources, a mean estimate, and a low estimate of petroleum resources. The high estimate of recoverable petroleum products is the least probable to be recoverable. Therefore, it is shown as a five percent probability of occurrence. The low estimate of recoverable resources is the most likely amount of petroleum product to be recovered. Ninety-five percent probability of occurrence of recovery is likely to occur for the low estimate. The mean is an average of all the probabilities of occurrence. Similarly, the Bureau of Land Management followed the U.S. Geological Survey example to estimate potential abundance of petroleum resources for the Uncompahgre Field Office. For the 2002 report, we estimated the total undiscovered technically recoverable resource that the Study Area contains is a **mean undiscovered cumulative volume of 0.74 million barrels of oil, 308.85 billion cubic feet of gas, and 0.56 million barrels of natural gas liquids, in the Uinta-Piceance Basin Province Assessment Units** (Table A1-5).

In addition, we estimate that the Study Area's oil resource in the Paradox Basin Province could **range from 0.31 to 1.36 million barrels, the gas resource could range from**

187.78 to 489.93 billion cubic feet, and the natural gas liquids resource could range from 0.19 to 1.18 million barrels (Table A1-5).

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GLOSSARY

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

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

Analysis period. January 1, 2010 through December 31, 2030.

Associated water. Water that is produced from a well that also produces coalbed natural gas.

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

Brittish Thermal Unit. A measure of heat energy. One million BTU's is the heating value of one thousand cubic feet of methane.

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

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

Coalbed natural gas. The gas that is produced from coalbeds. It is mostly biogenic and may include nitrogen and carbon dioxide. Coalbed natural gas is used inerchangeably with coalbed gas.

Continuous accumulation. Common geologic characteristics of a continuous accumulation include occurrence down dip from water-saturated rocks, lack of obvious trap and seal, pervasive oil or gas charge, large aerial extent, low matrix permeability, abnormal pressure (either high or low), and close association with source rocks. Common production characteristics include a large in-place petroleum volume, low recovery factor, absence of truly dry holes, dependence on fracture permeability, and

sweet spots within the accumulation that have generally better production characteristics but where individual wells still have serendipitous hit or miss production characteristics (Schmoker, 2003).

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

Development potential. A projection of expected oil and gas and coalbed natural gas activity that is reasonably assumed to occur during the Planning Period (2010 through 2030). This activity projection projects the types and levels of anticipated exploratory and development activity and is primarily based on operator input, geology, and past and present activity in the Study Area. Economics, drilling and completion technology, accessibility to drilling locations and infrastructure, and risk some of the factors used to project development potential.

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

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

Held by production. This usually refers specifically to oil and gas leased that are productive and are held beyond their primary term because they are producing oil or gas in economic quantities.

In-place. The total volume of oil and/or gas thought to exist (both discovered and yet-to-be discovered) without regard to the ability to either access or produce it. Although the in-place resource is primarily a fixed, unchanging volume, the current understanding of that volume is continually changing as technology improves.

Natural gas. Any gas of natural origin that consists primarily of hydrocarbon molecules producible from a borehole.

Natural gas liquids. Hydrocarbons found in natural gas that are liquefied at the surface in field facilities or in gas processing plants. Natural gas liquids are commonly reported separately from crude oil.

Nonconventional gas (Unconventional gas). Nonconventional gas is generally thought of as gas that is created in formations without the permeability necessary to allow significant migration. It is generally described as those gas accumulations that are hard

to discover, characterize, and commercially produce by common exploration and production technologies. It may include coalbed natural gas, tight sand, tight carbonates, shale, or deep gas.

Occurrence Potential. A rating of the potential for the presence of hydrocarbon resources to occur within the Study Area. The rating is based on geological and geophysical indications that hydrocarbons are present. Other factors, such as, accessibility, exploration cost, risk, oil and gas prices, and analysis period are not include in an analysis of Occurrence Potential.

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

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

Play area. An area where productive oil or gas wells may be drilled based on a specific geologic concept.

Proved growth reserves or reserve growth. The increases in known petroleum volume that commonly occur as oil and gas accumulations are developed and produced, synonymous with field growth.

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

Public domain. Minerals that have been owned continuously by the United States.

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

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

Spacing pattern. The pattern of well locations, which could be one well location per 40, 80, 160, 320, or 640 acres for in the Study Area.

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

Stratigraphic test. A well drilled to obtain geologic and/or engineering data about the coal.

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

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

Technically recoverable resources. The volume of hydrocarbons which are recoverable using current exploration and production technology without regard to cost, which is a proportion of the estimated in-place resource.

Total petroleum system. A total petroleum system consists of all genetically related petroleum generated by a pod or closely related pods of mature source rocks. Particular emphasis is placed on similarities of the fluids of petroleum accumulations and is therefore closely associated with the generation and migration of petroleum. The geologic elements of a total petroleum system, include (1) source-rock distribution, thickness, organic richness, maturation, petroleum generation, and migration; (2) reservoir-rock type (conventional or continuous), distribution, and quality; and (3) character of traps and time of formation with respect to petroleum generation and migration.

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

Unstable grains. Said of mineral grains within a sedimentary rock, that don't resist chemical change after deposition.

Vitrinite reflectance. The most common thermal maturity indicator. Vitrinite is a maceral derived from the woody tissues of vascular plants. Vitrinite reflectance is a measure of the amount of light reflected by vitrinite present in the rock's organic component. Generation of gas is considered to begin at 0.75 percent.

Figure 1.
The Uncompahgre Field Office and it's location within Colorado.

0 20 40 Miles

1:2,000,000

April, 2010

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

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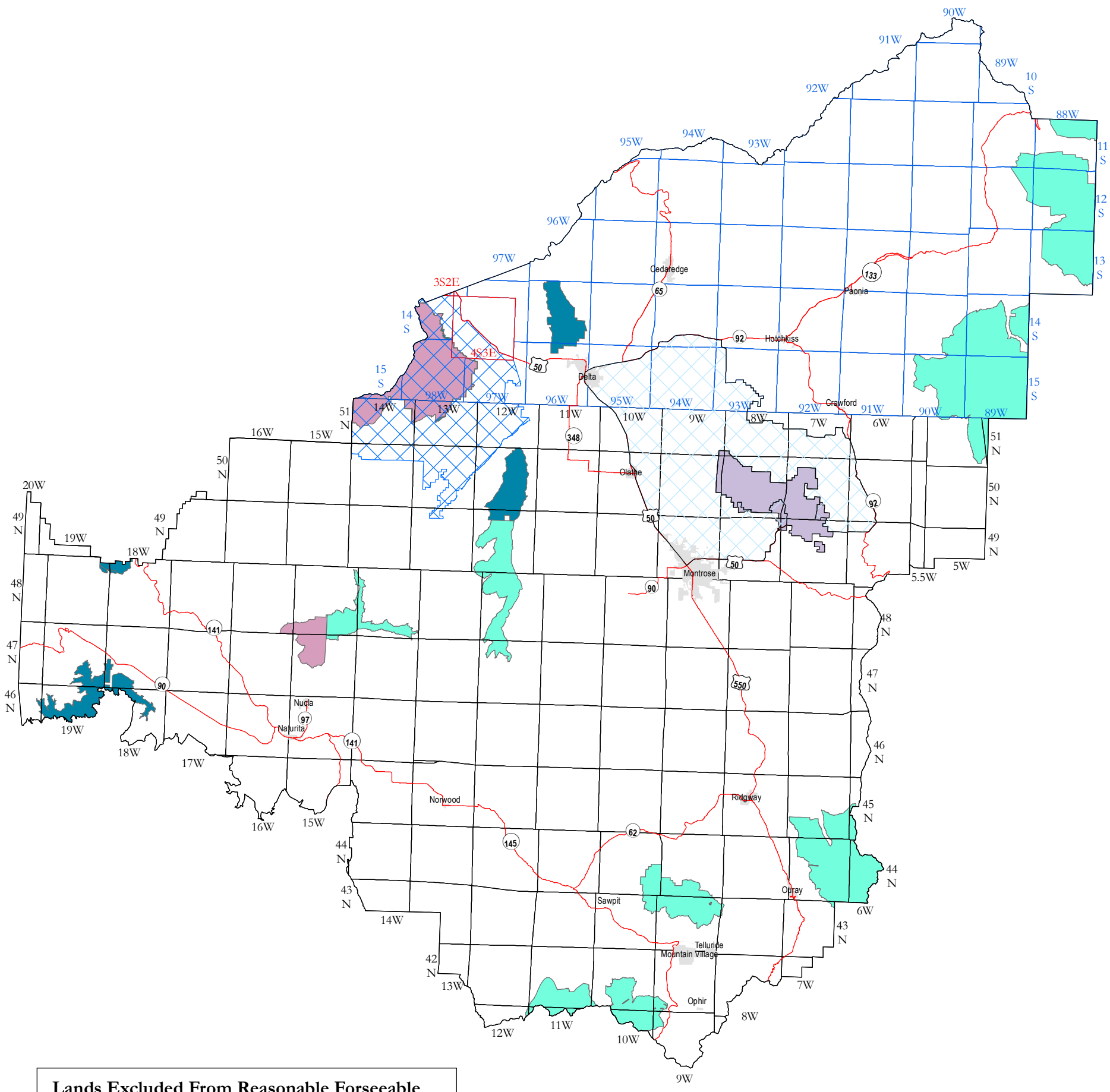
Figure 2a.
Location of Uncompahgre Study Area within Uncompahgre Field Office.



Lands Excluded From Reasonable Forseeable Development Analysis

- Gunnison Gorge National Conservation Area Planning Area
- Dominguez-Escalante National Conservation Area

No Leasing

- BLM Wilderness
- Forest Service Wilderness
- Black Canyon of the Gunnison National Park
- BLM Wilderness Study Areas
- Dominguez Canyon Wilderness

0 15 30 Miles

1:700,000

January, 2012

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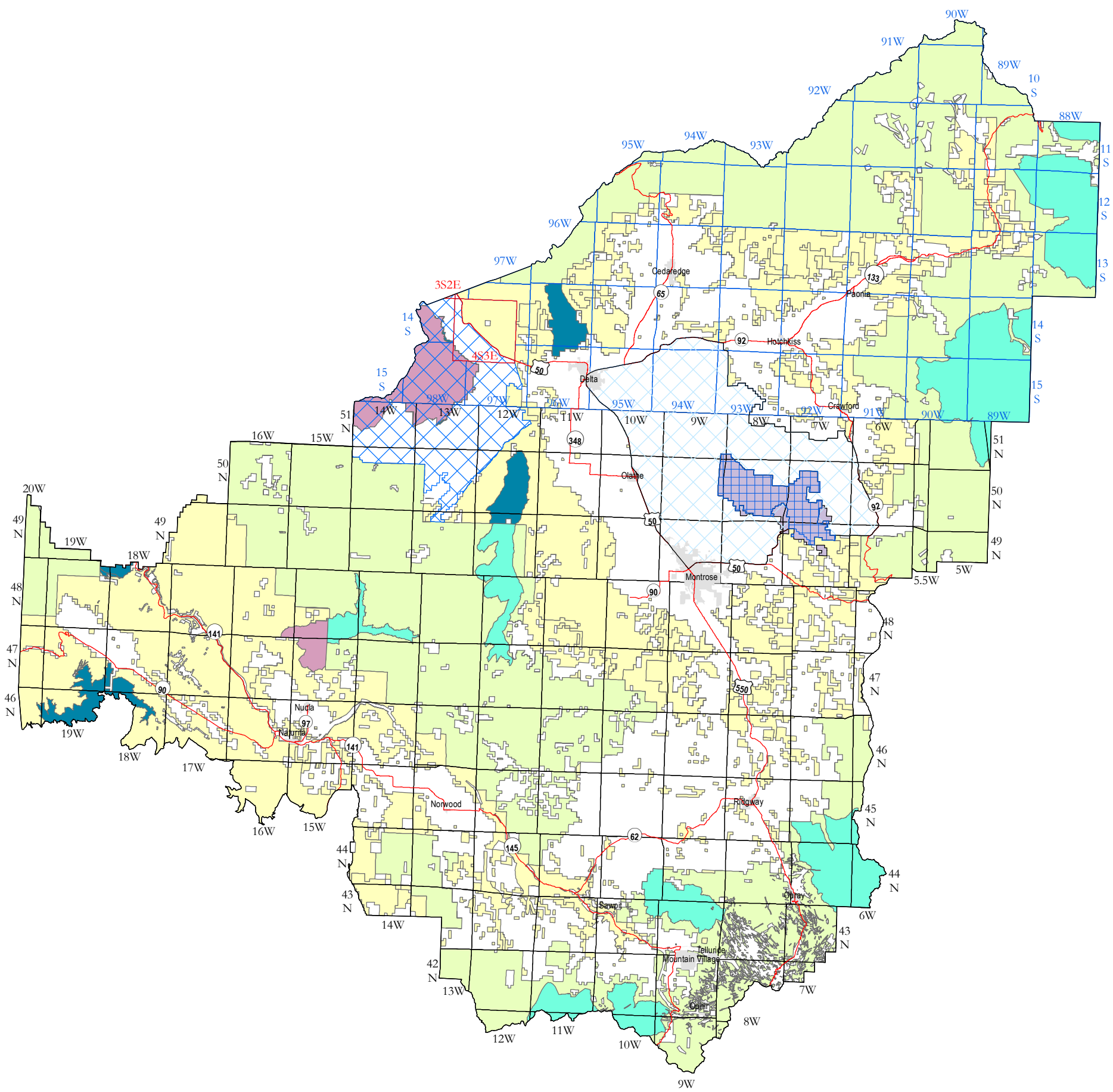
Figure 2b.
Location of oil and gas mineral ownership within the Uncompahgre Study Area.



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- Dominguez-Escalante National Conservation Area

No Leasing

- BLM Wilderness
- Forest Service Wilderness
- Black Canyon of the Gunnison National Park
- BLM Wilderness Study Areas
- Dominguez Canyon Wilderness

Oil and Gas Mineral Ownership

- Bureau Managed
- Forest Service
- Park Service
- Private/State

0 15 30 Miles

1:700,000

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Figure 3a.
Location and initial status of all conventional oil and gas wells drilled within the Uncompahgre Study Area. Data from IHS Energy Group (2010) and Colorado Oil and Gas Conservation Commission (2010).

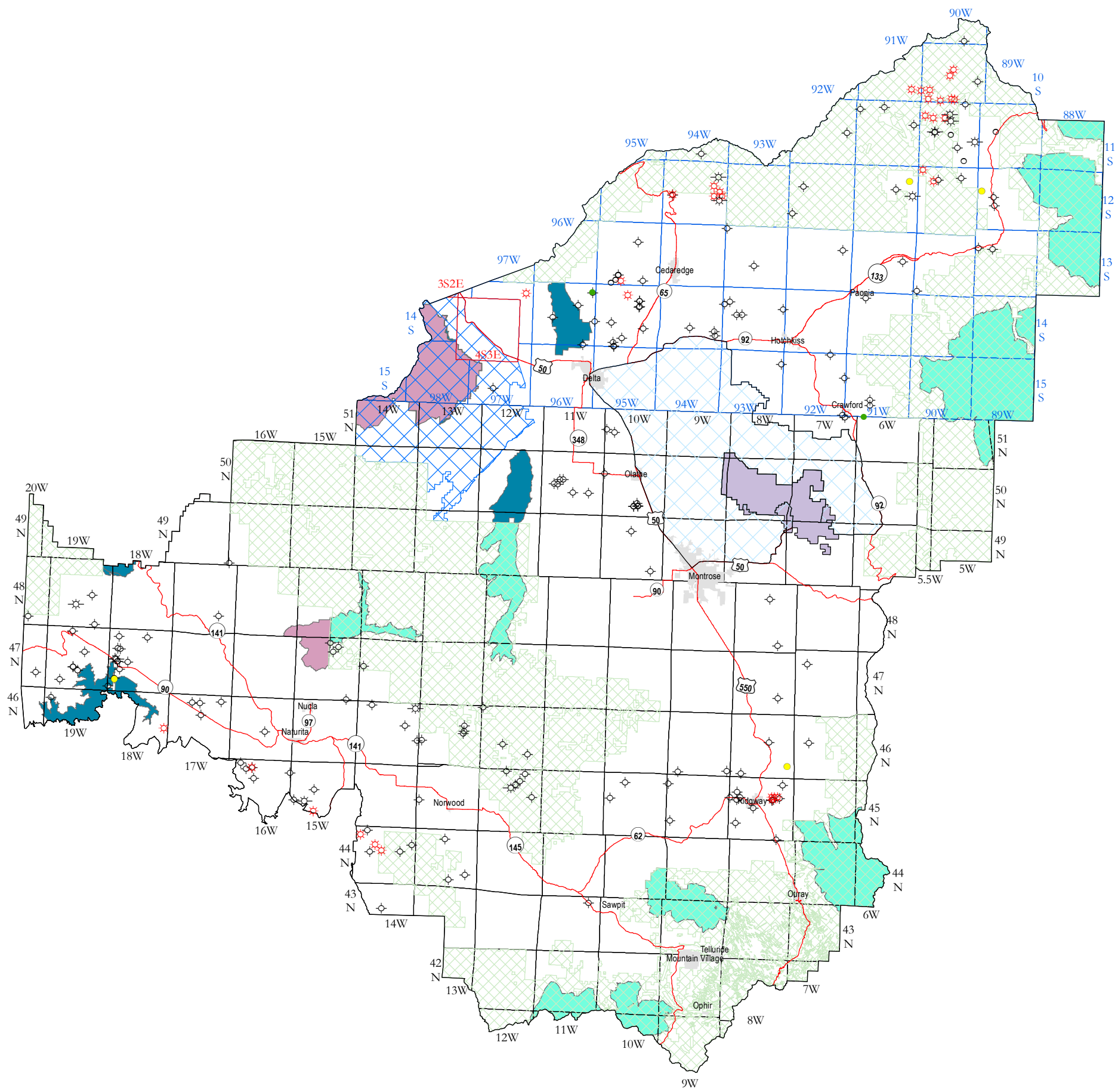

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Figure 3b.

Location and initial status of all coalbed natural gas wells drilled within the Uncompahgre Study Area. Data from IHS Energy Group (2010) and Colorado Oil and Gas Conservation Commission (2010).

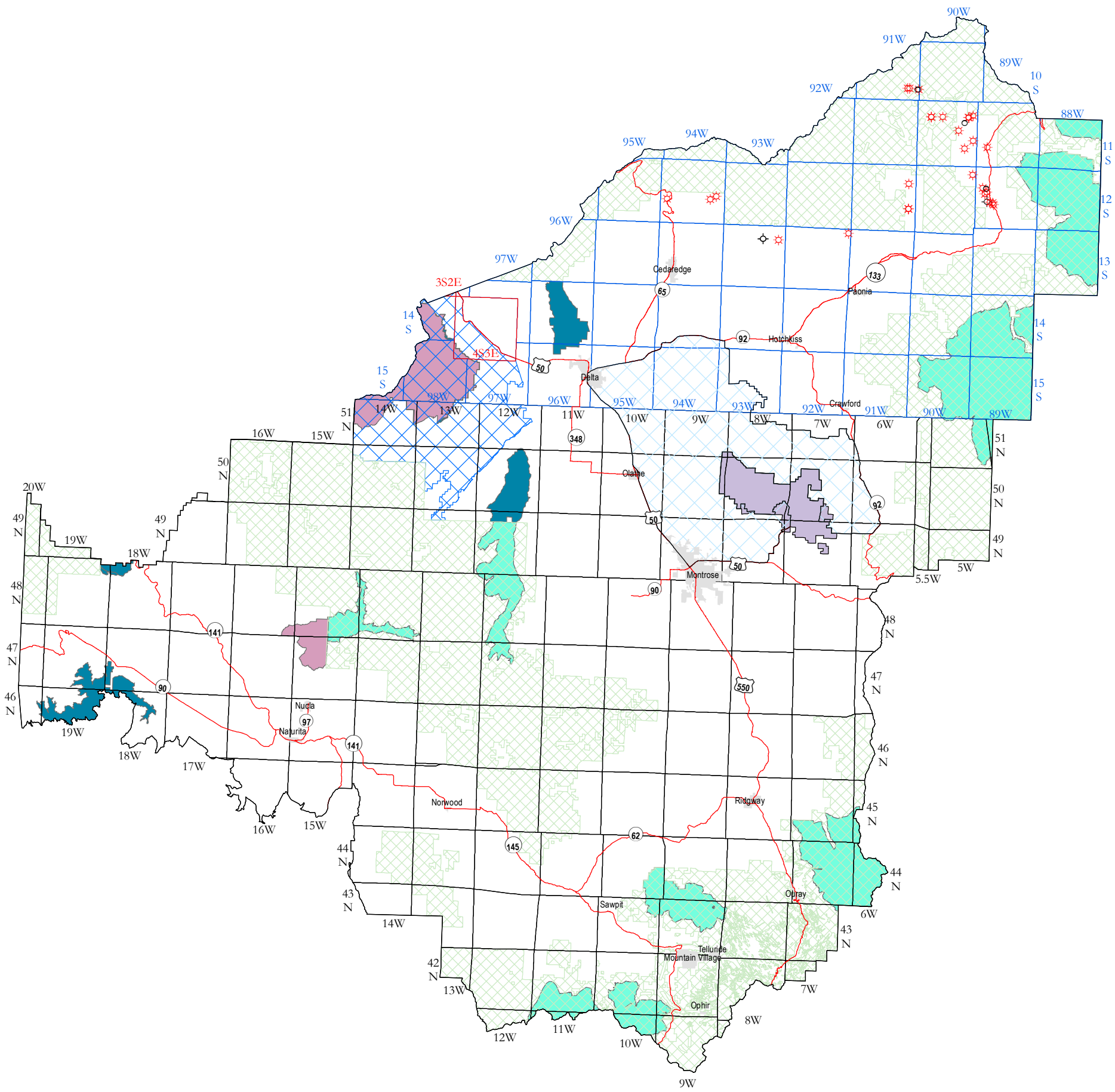

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Figure 4.
Major structural elements and selected geologic units of the Uncompahgre Study Area.

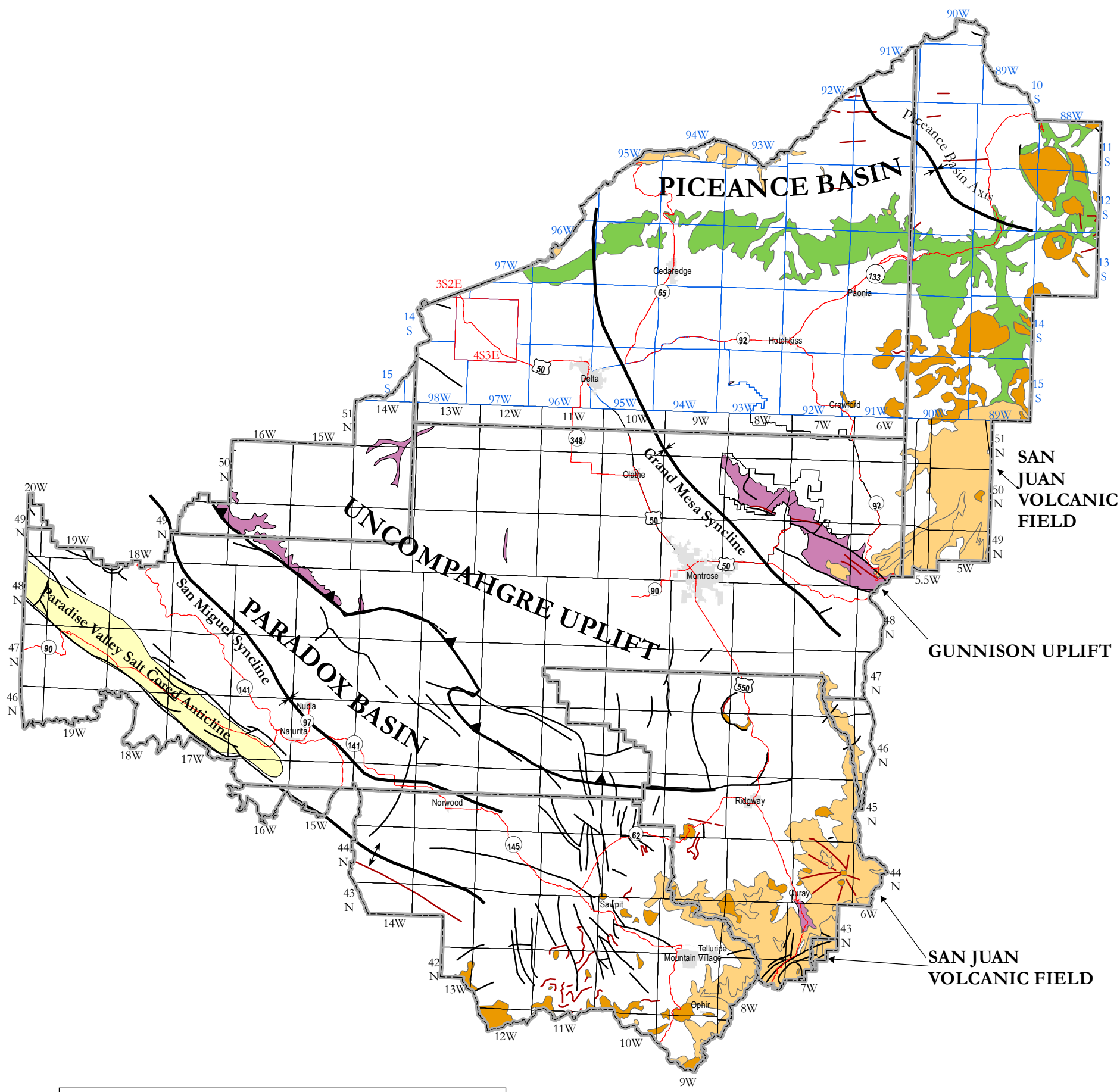

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Figure 5. Generalized stratigraphic chart of the Paradox basin within the Study Area (after Huffman, 1995; Stevenson and Wray, 2009), with hydrocarbon and carbon dioxide producing zones.

Era	Age	Stratigraphic Unit			Hydrocarbon Production[1]
Cenozoic	Tertiary	Wasatch Formation			Gas Oil
Mesozoic	Cretaceous	Mesaverde Group			Gas
		Mancos Shale (includes Ferron Sandstone member)			Gas Oil
		Dakota Sandstone			Gas Oil
		Burro Canyon Formation			Gas Oil
	Jurassic	Morrison Formation	Recapture member		Gas Oil
			Bluff Sandstone		Gas Oil
		Carmel Formation			
		Glen Canyon Group	Navajo Sandstone		Oil
			Kayenta Formation		
			Wingate Sandstone		
	Triassic	Chinle Formation (includes Shinarump member)			
		Moenkopi Formation	Timoweap member		
			Hoskinnini member		Oil
Paleozoic	Permian	Cutler Formation	Kaibab Limestone, White Rim and De Chelley Sandstones		Oil (White Rim S.S.)
			Organ Rock Tongue member		Gas (Cutler Formation undifferentiated)
			Cedar Mesa Sandstone		
			Halgaito Tongue member		
	Pennsylvanian	Hermosa Group	Honaker Trail Formation		Gas
			Paradox Formation	Ismay member (includes Hovenweep and Gothic Shales)	Gas Oil
				Desert Creek member (includes Chimney Rock Shale)	Gas Oil
				Akah member	Gas Oil
				Barker Creek member	Gas Oil
				Cane Creek Shale	Gas Oil
			Pinkerton Trail Formation		
		Molas Formation			
	Mississippian	Leadville Limestone			Gas Oil CO_2
	Devonian	Ouray Limestone			CO_2
		Elbert Formation (includes McCracken member)			Gas Oil
		Aneth Formation			
	Silurian	*hiatus*			
	Ordovician				
	Cambrian	Lynch Dolomite			
		Muav Limestone			
		Bright Angel Shale			
		Tapeats Sandstone/Ignacio Quartzite			

[1]Only limited production has occurred in the Study Area portion of the Paradox basin. Thus, basin-wide hydrocarbon producing zones (including CO2) are shown here.

Figure 6a: Generalized stratigraphic chart of the Piceance basin within the Study Area (after Johnson and Roberts, 2003), with hydrocarbon producing zones.

Era	Age	Stratigraphic Unit NW	Stratigraphic Unit SE	Hydrocarbon Production
Cenozoic	Tertiary	Green River Formation		Gas
		Wasatch Formation		Gas
		Fort Union Formation		Gas
Mesozoic	Cretaceous	Mesaverde Formation or Group[1]		Gas Oil
		Mancos Shale or Group		Gas
		"Mancos B"		Gas Oil
		Ferron Sandstone	Frontier Formation	Gas
		Mowry Shale		Oil
		Dakota Sandstone		Gas Oil
		Cedar Mountain Formation	*hiatus*	Gas
	Jurassic	Morrison Formation		Gas Oil
		Stump Formation	Curtis Formation	Oil (Curtis)
		Entrada Sandstone		Gas Oil (Entrada)
	Triassic	Glen Canyon Sandstone and equivalents		
		Chinle Formation (includes Shinarump member)		Oil (Shinarump)
		Moenkopi Formation		
Paleozoic	Permian	Park City Formation	Phosphoria Formation	Oil
		Upper Weber Sandstone		Oil
	Pennsylvanian	Lower Weber Sandstone		Oil
		Morgan Formation	Minturn Formation	
		hiatus	Belden Shale	
	Mississippian	Leadville Limestone		
	Devonian	Chaffee Group		
	Silurian	*hiatus*		
	Ordovician	*hiatus*	Manitou Formation	
	Cambrian	Dotsero Formation		
		Sawatch Sandstone		

[1]See Figure 6b for detailed stratigraphic relationships within the Mesaverde Group.

Figure 6b: Generalized stratigraphic chart of the Mesaverde Group of the Piceance basin within the Study Area (after Hettinger and Kirschbaum, 2002; Cole and Cumella, 2003), with hydrocarbon producing zones.

Era	**Age**	**Stratigraphic Unit**			**Hydrocarbon Production**
		Group	**Formation**	**Member**	
Mesozoic	Upper Cretaceous	Mesaverde	Williams Fork	Ohio Creek	Gas Oil (Williams Fork -- undifferentiated)
				Bowie Shale[1]	Gas (including coal bed gas)
			Iles	Rollins	Gas
				Cozzette[2]	Gas
				Corcoran[2]	Gas

[1]Includes the Cameo coal zone.
[2]The Cozzette Sandstone and Corcoran Sandstone members of the Iles Formation have an intertonguing relationship with the underlying Mancos Shale. As a result, occasionally these members are found in stratigraphically lower positions that the Mancos.

Figure 7.
Oil and gas fields within the Uncompahgre Study Area. Data from Colorado Oil and Gas Conservation Commission (2010).

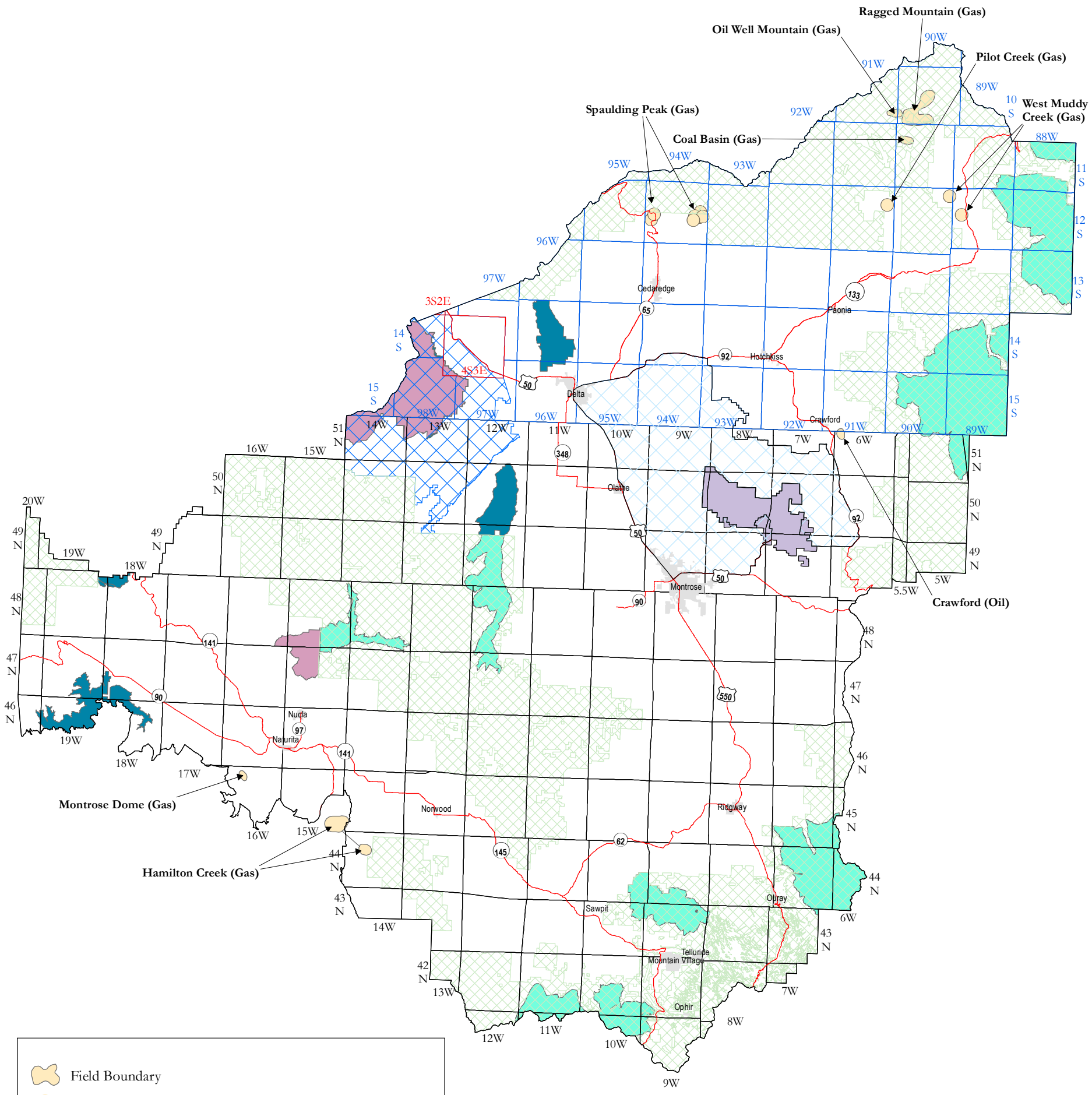

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Figure 8.
Location and initial classification of Uncompahgre Study Area oil, gas, and coalbed natural gas wells spudded between January 1, 2000 and December 31, 2009. Data from IHS Energy Group (2010).

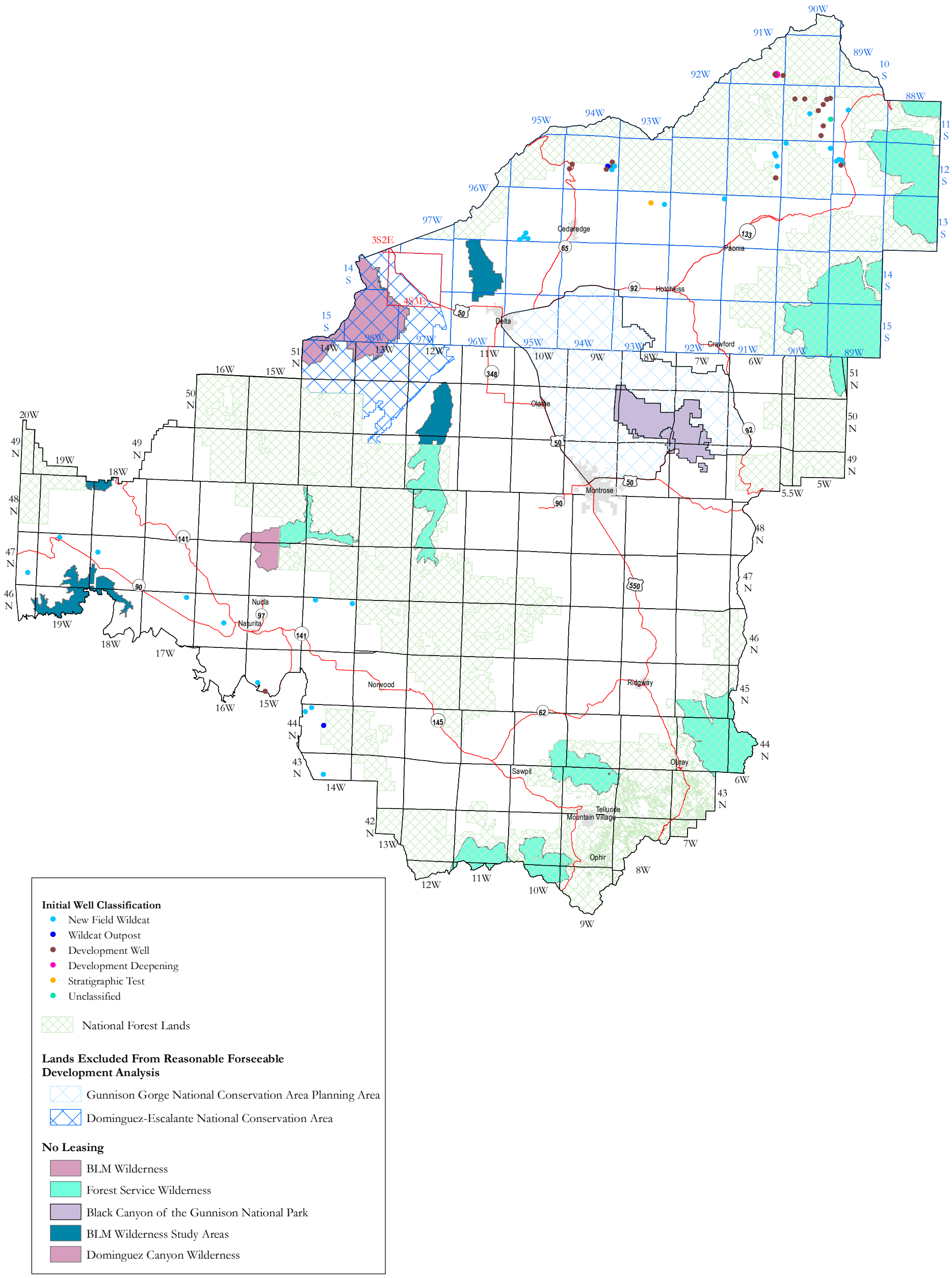

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Figure 9.

Location and present status of Uncompahgre Study Area oil, gas, and coalbed natural gas wells spudded between January 1, 2000 and December 31, 2009. Data from IHS Energy Group (2010) and Colorado Oil and Gas Conservation Commission (2010).

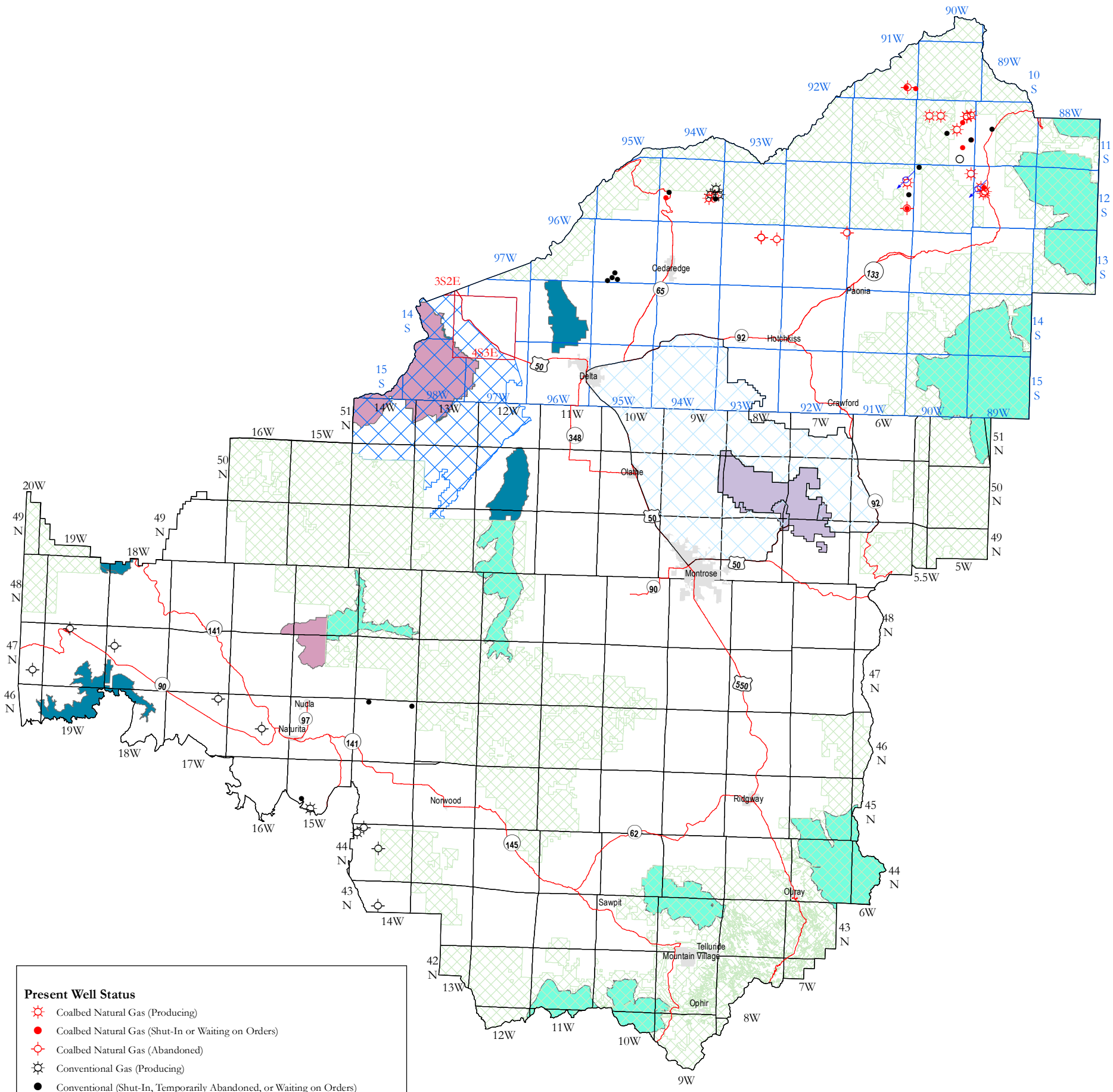

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Figure 10.

Location of oil and gas units and a communitization agreement within the Uncompahgre Study Area. Data from Bureau files.

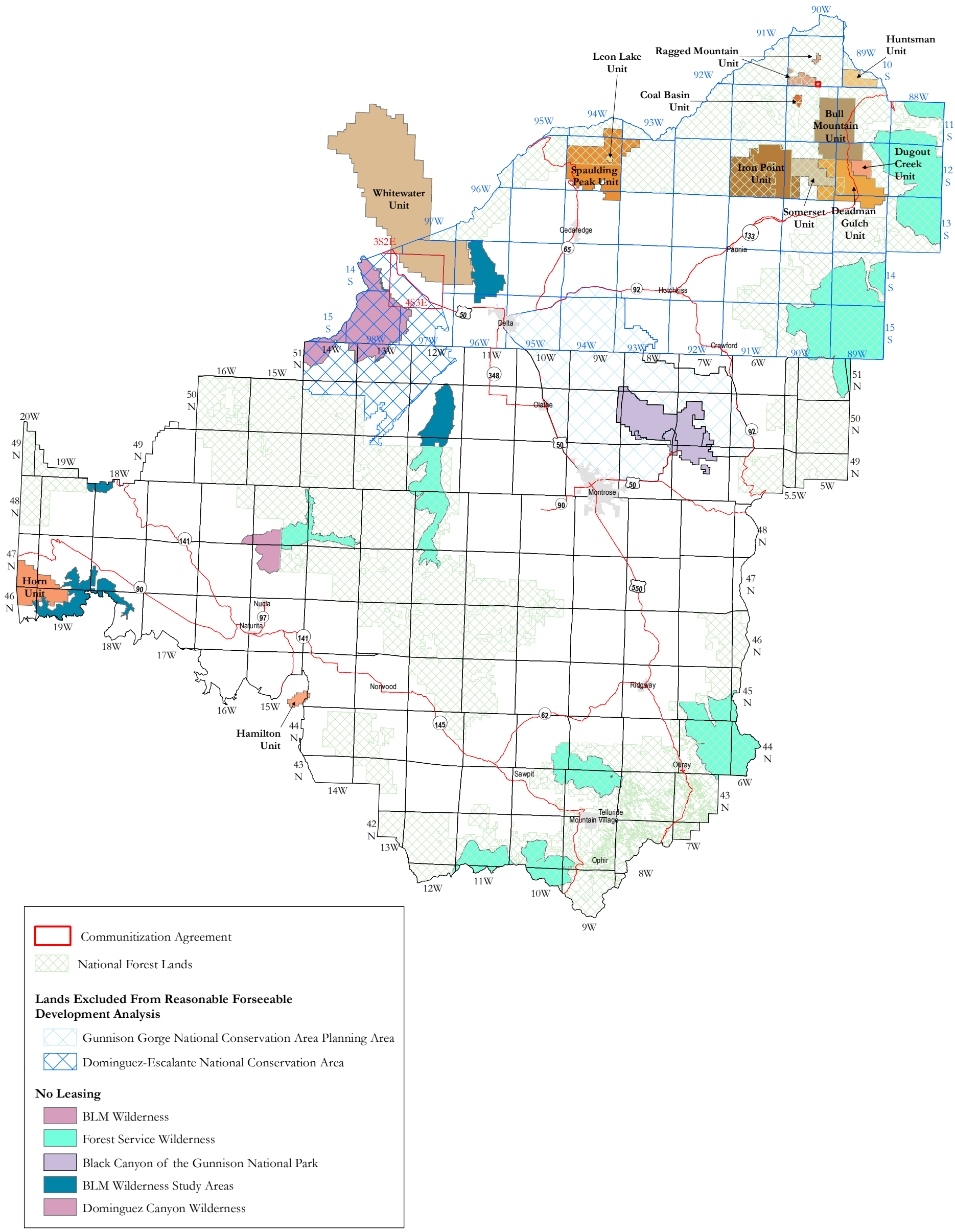

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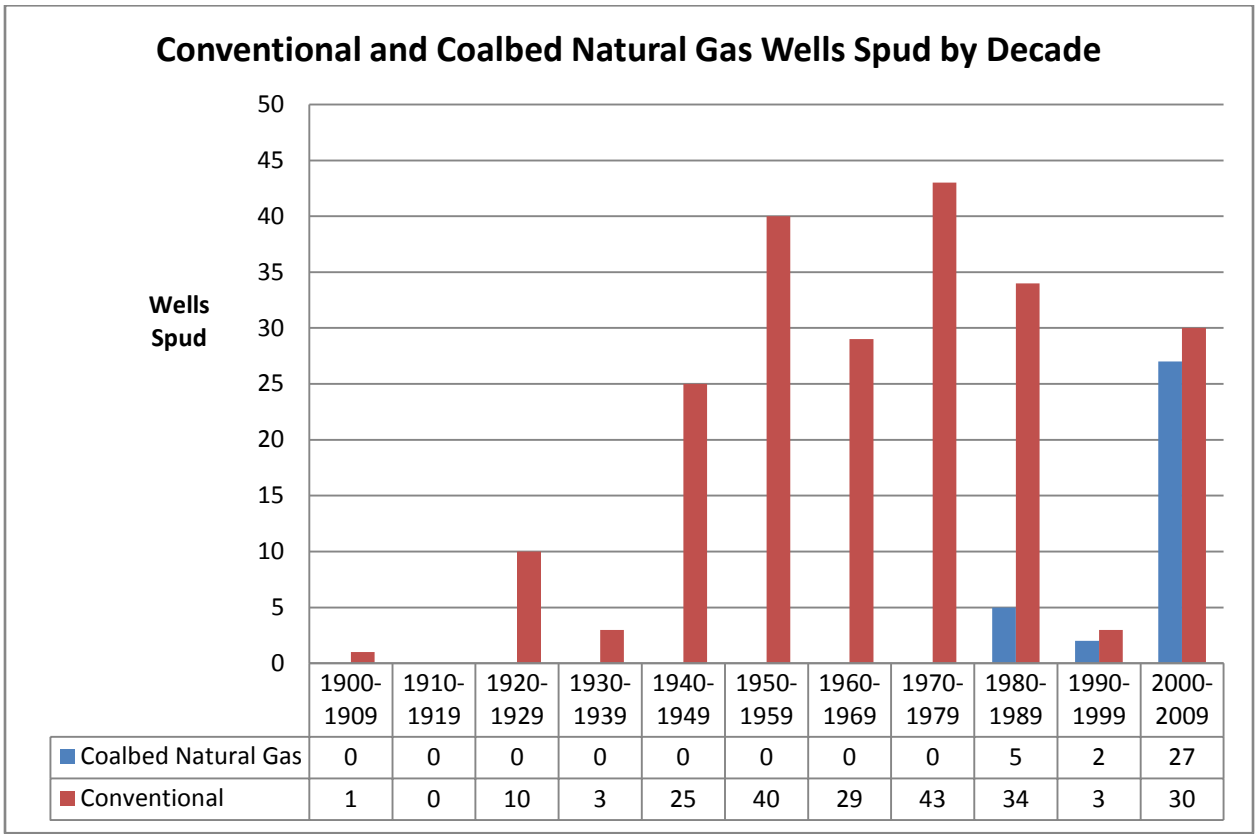
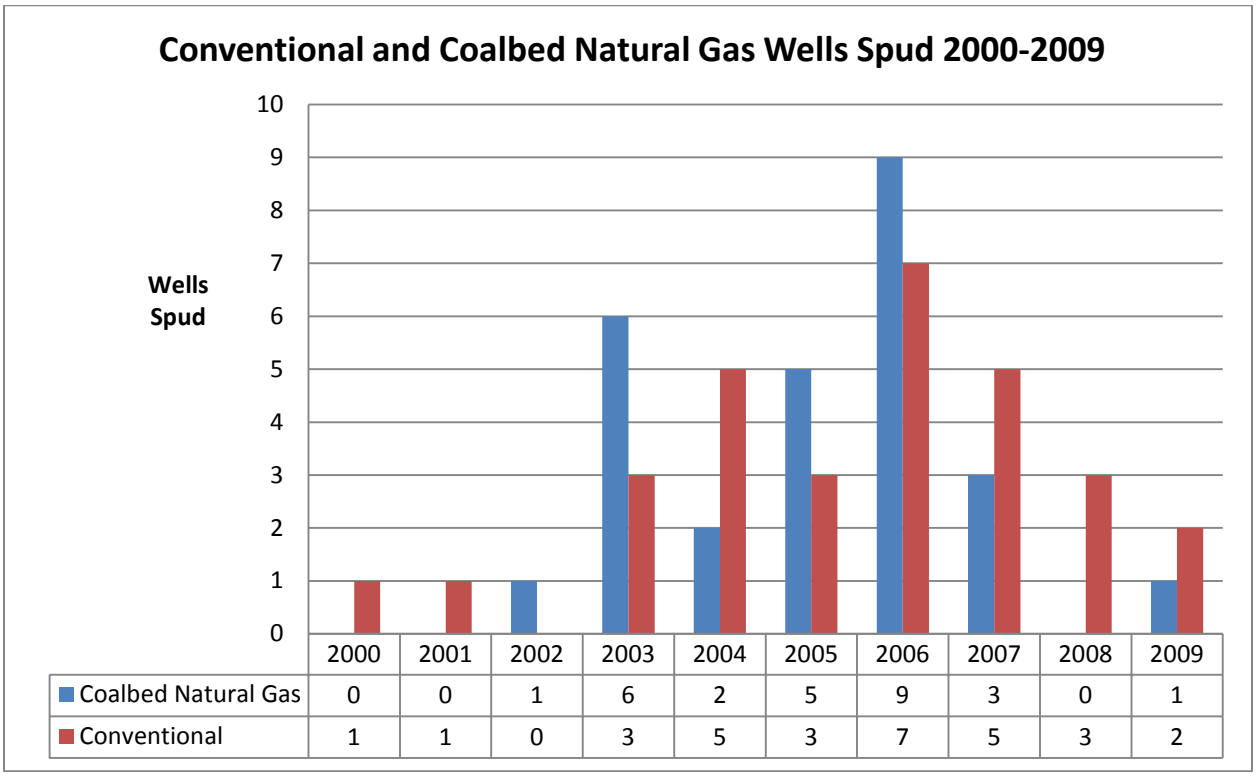
Figure 11. Conventional and coalbed natural gas wells spud by decade within the Uncompahgre Study Area. Data from IHS Energy Group (2010).



	1900-1909	1910-1919	1920-1929	1930-1939	1940-1949	1950-1959	1960-1969	1970-1979	1980-1989	1990-1999	2000-2009
Coalbed Natural Gas	0	0	0	0	0	0	0	0	5	2	27
Conventional	1	0	10	3	25	40	29	43	34	3	30

Note: Coalbed natural gas wells include three wells which co-produce coalbed and conventional gas; conventional wells excluded two wells for which no spud date was available.

Figure 12. Conventional and coalbed natural gas wells spud within the Uncompahgre Study Area for 2000-2009. Data from IHS Energy Group (2010).



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Coalbed Natural Gas	0	0	1	6	2	5	9	3	0	1
Conventional	1	1	0	3	5	3	7	5	3	2

Note: Coalbed natural gas wells include three wells which co-produce coalbed and conventional gas; conventional wells exclude two wells for which no spud date was available.

Figure 13.
Uncompahgre Study Area locations of all conventional gas and coalbed natural gas wells that have been spudded and not completed and those still in an active status. Data from Colorado Oil and Gas Conservation Commission (2010) and IHS Energy Group (2010).

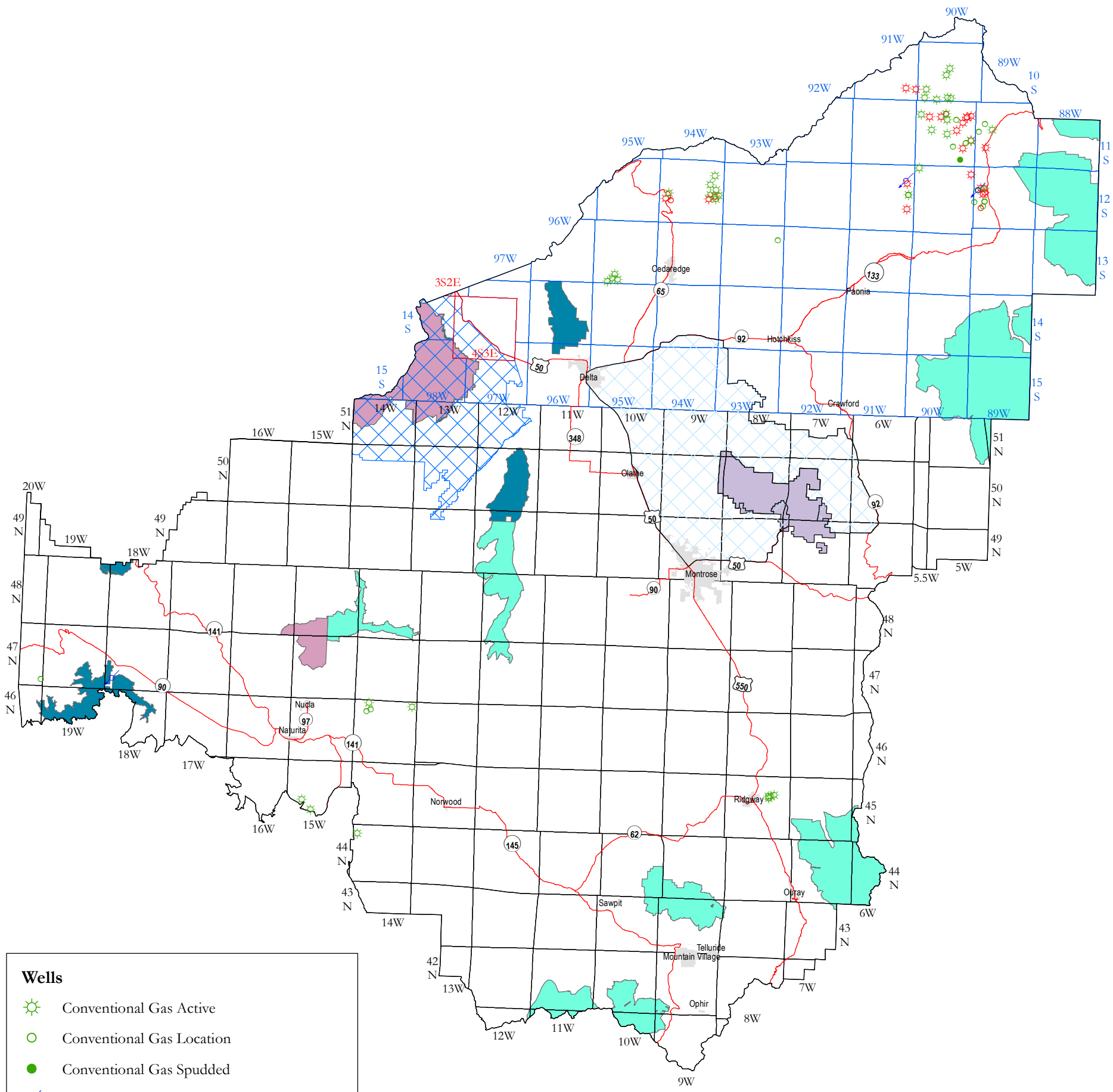


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Figure 14.
True vertical depths of vertical, directional, and horizontal wells drilled within the Uncompahgre Study Area. Data from IHS Energy Group (2010).

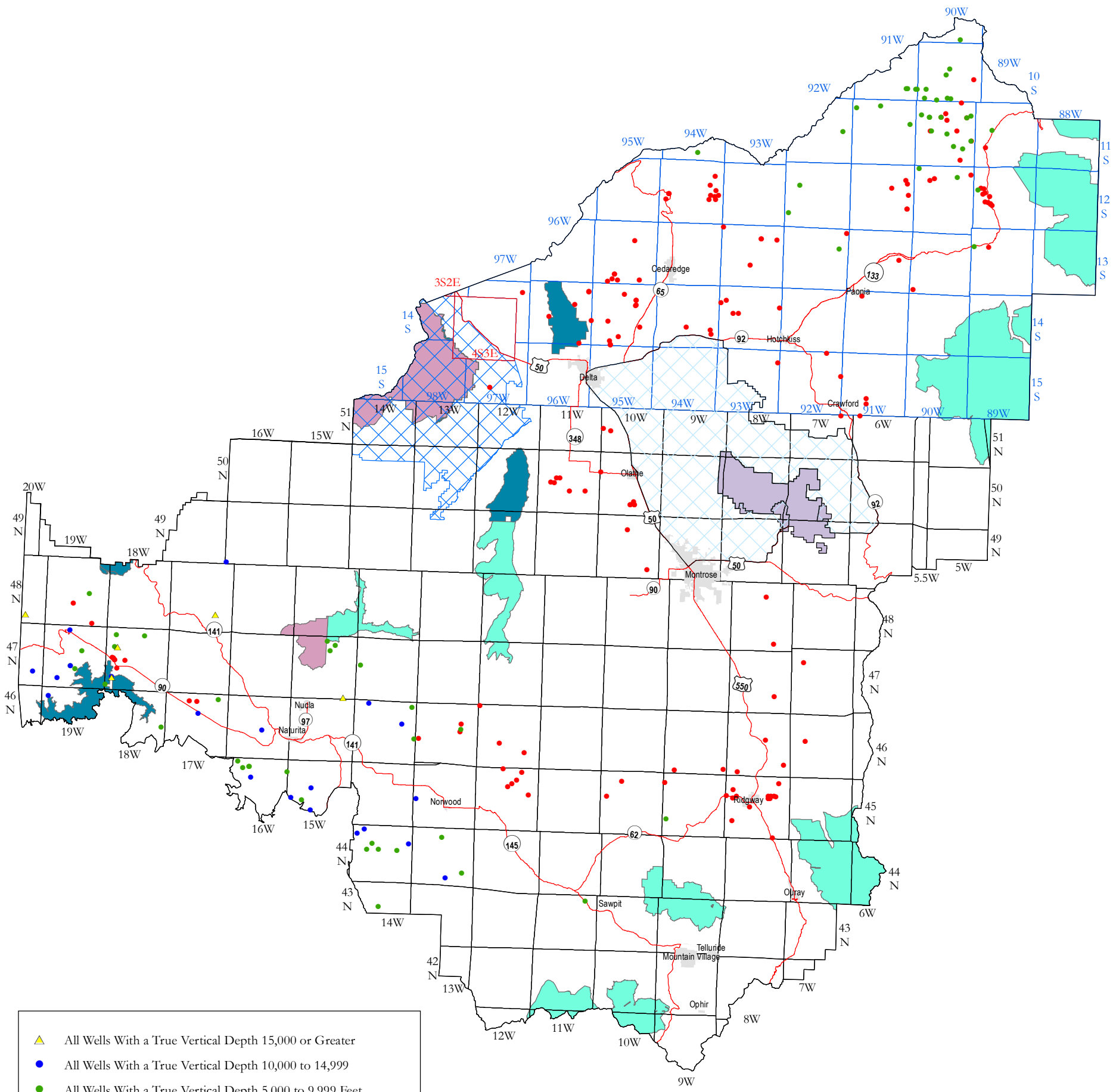

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Figure 15.
Existing and proposed directional and horizontal borehole locations within the Uncompahgre Study Area. Data from IHS Energy Group (2010).

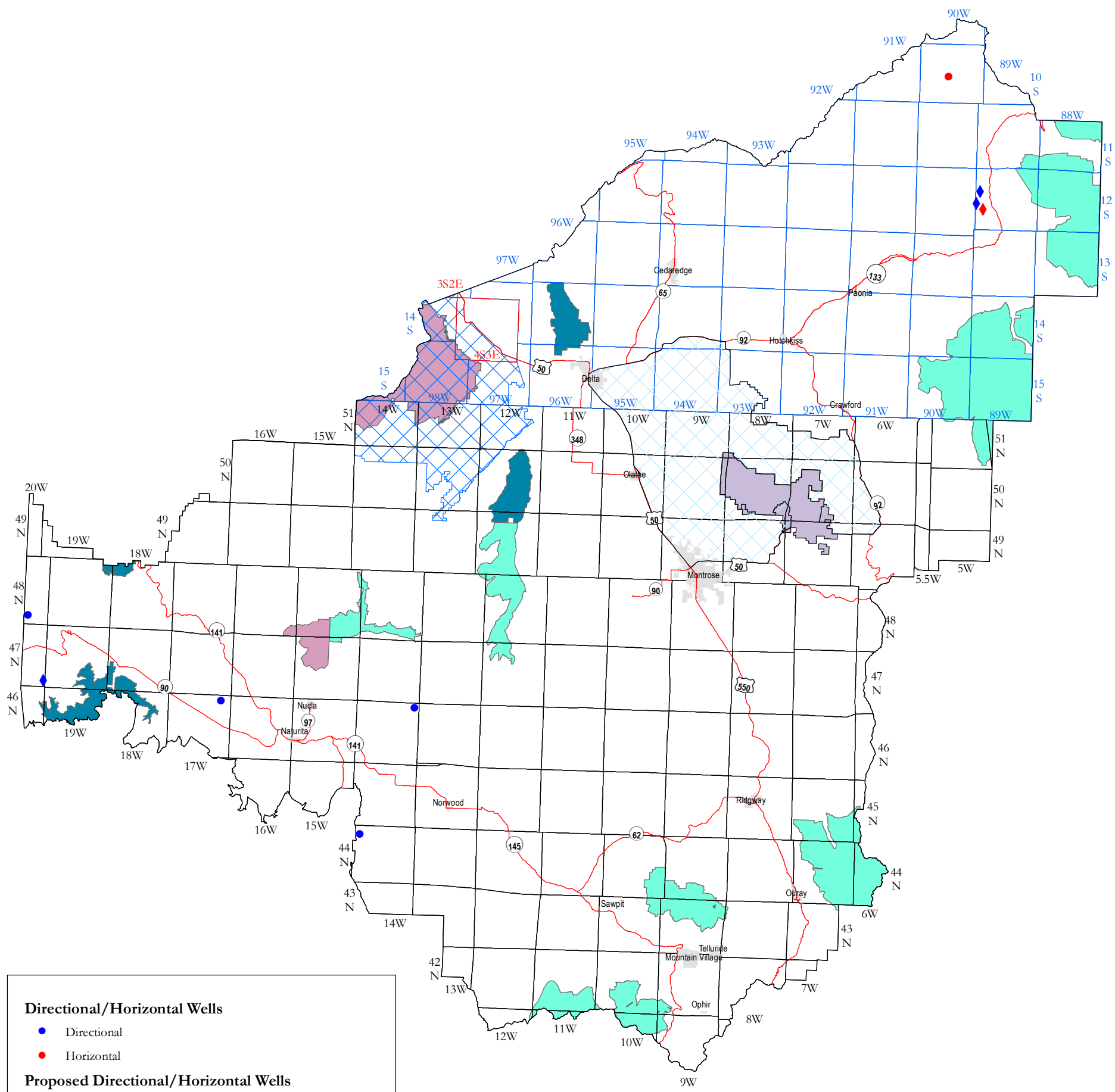

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Figure 16.
Geographic distribution of water quality samples across the Uncompahgre Study Area and distribution of sample salinity. Data from U.S. Geological Survey (2008a).

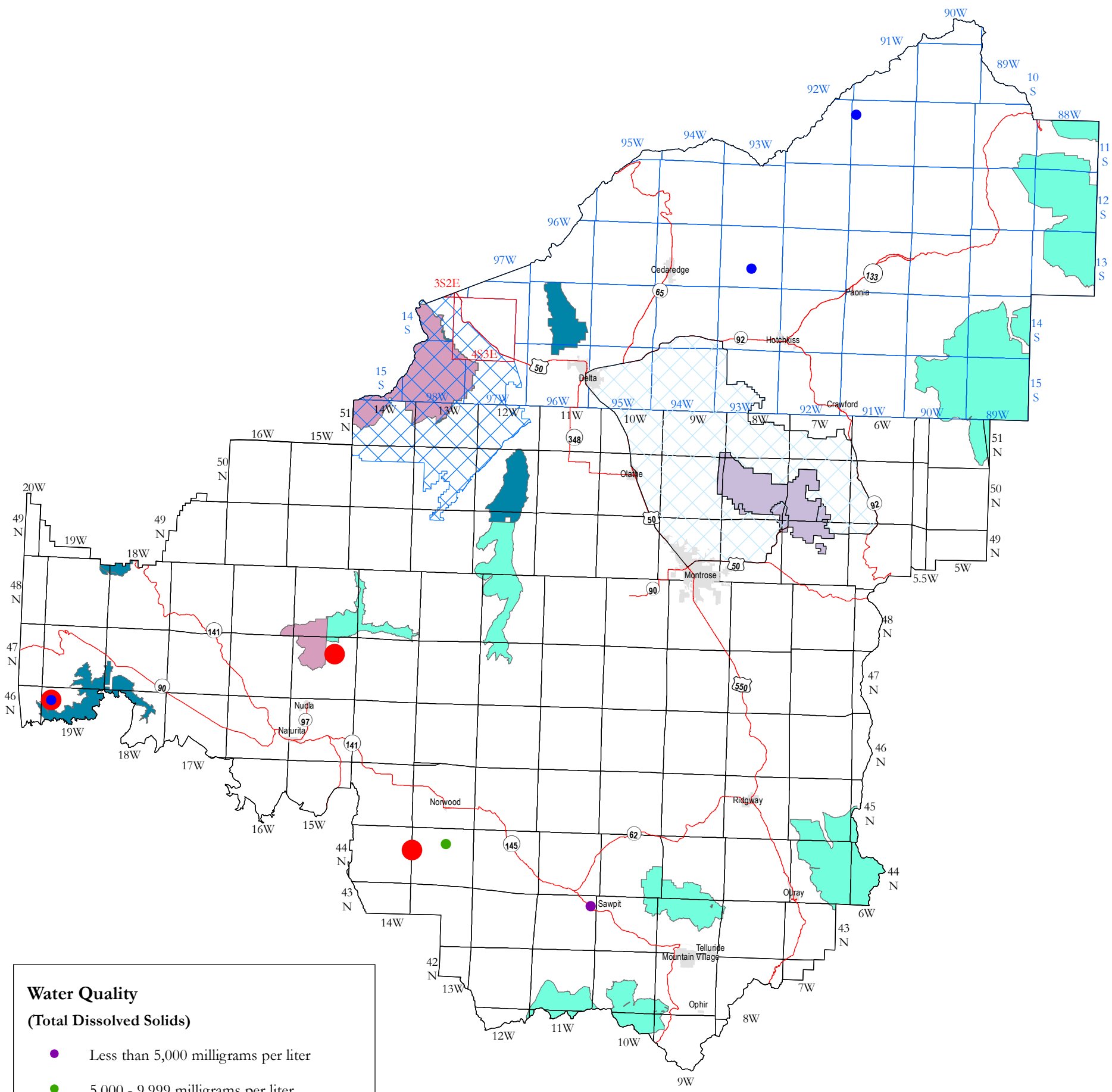

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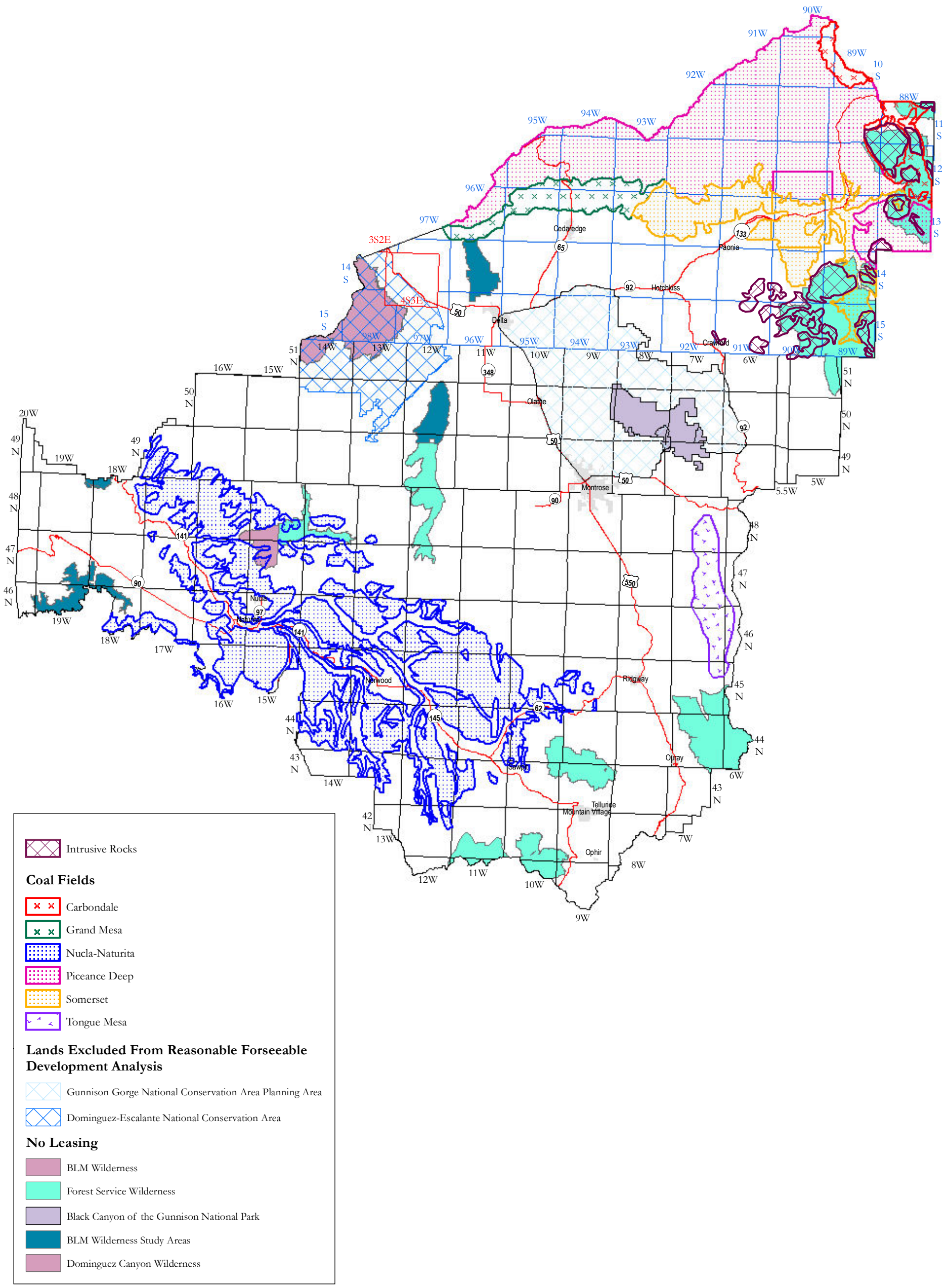
Figure 17.
Location of coal fields within the Uncompahgre Study Area.



0 15 30 Miles

1:700,000

April, 2010

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

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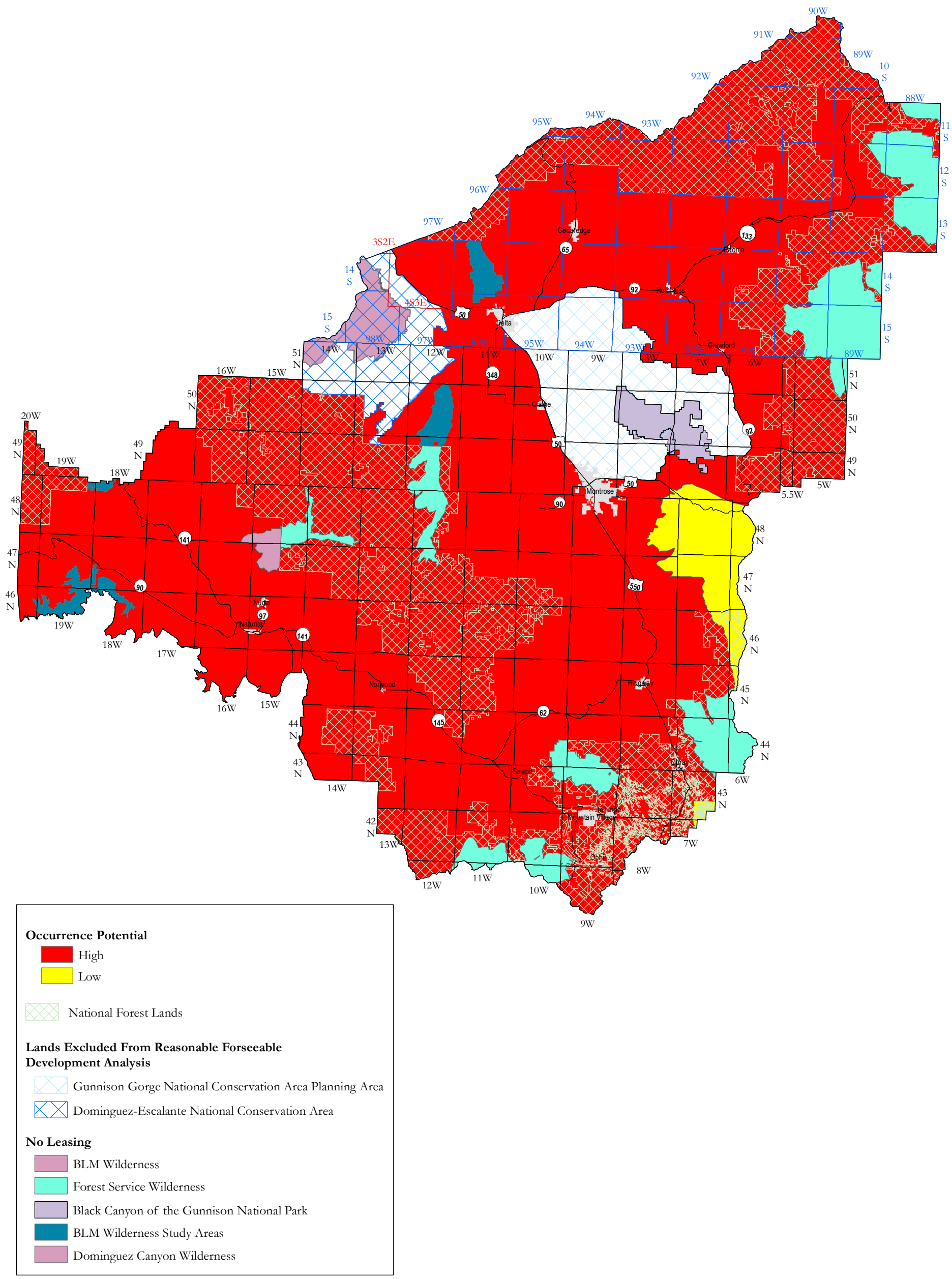
Figure 18.

Potential for occurrence of oil and gas (excluding coalbed natural gas) within the Uncompahgre Study Area.



June, 2010

Dean Stilwell, Geologist
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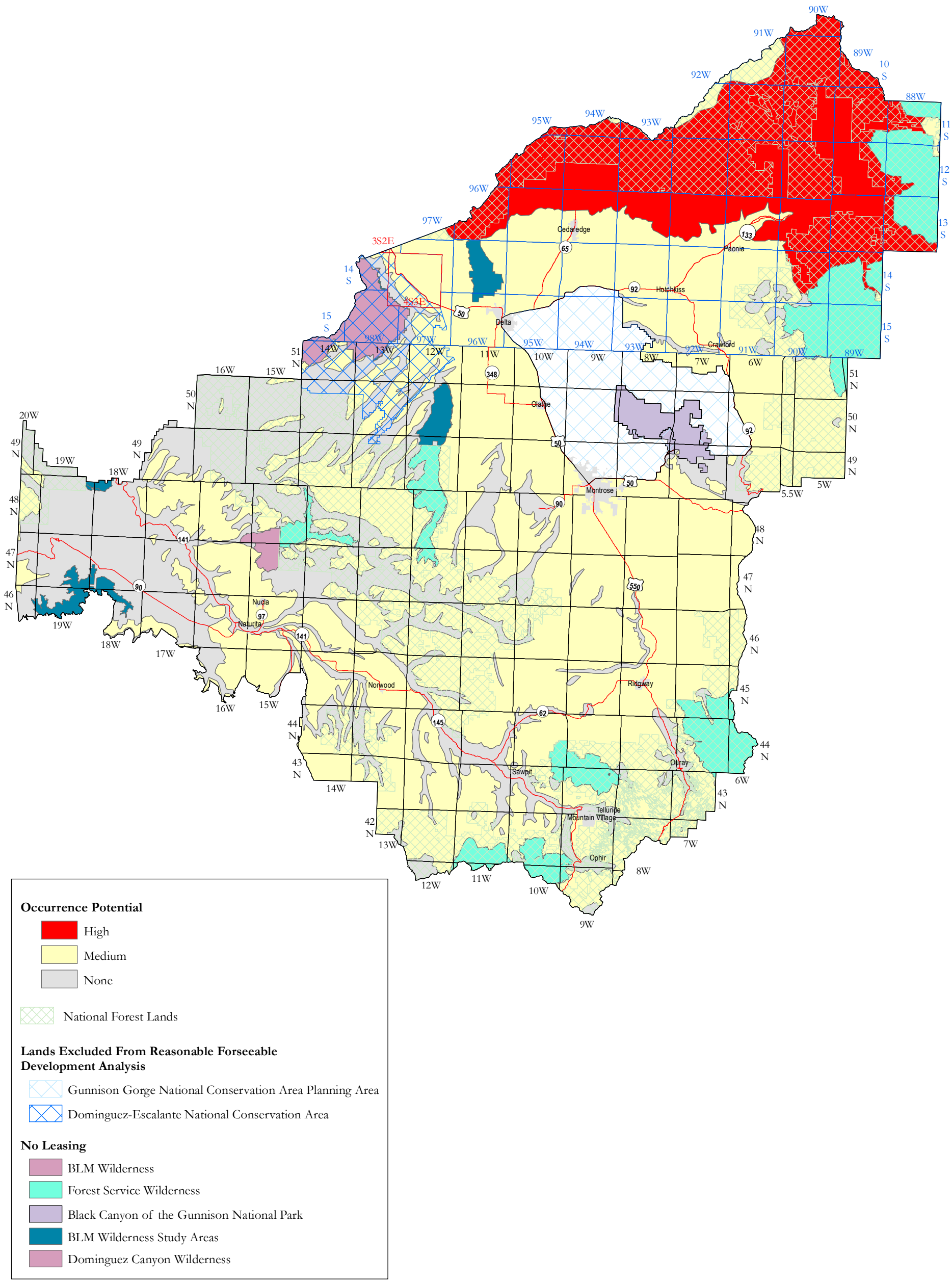
Figure 19.

Potential for occurrence of coalbed natural gas within the Uncompahgre Study Area.



June, 2010

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Figure 20. Colorado historical natural gas prices with future natural gas price projections (Energy Information Administration, 2011).

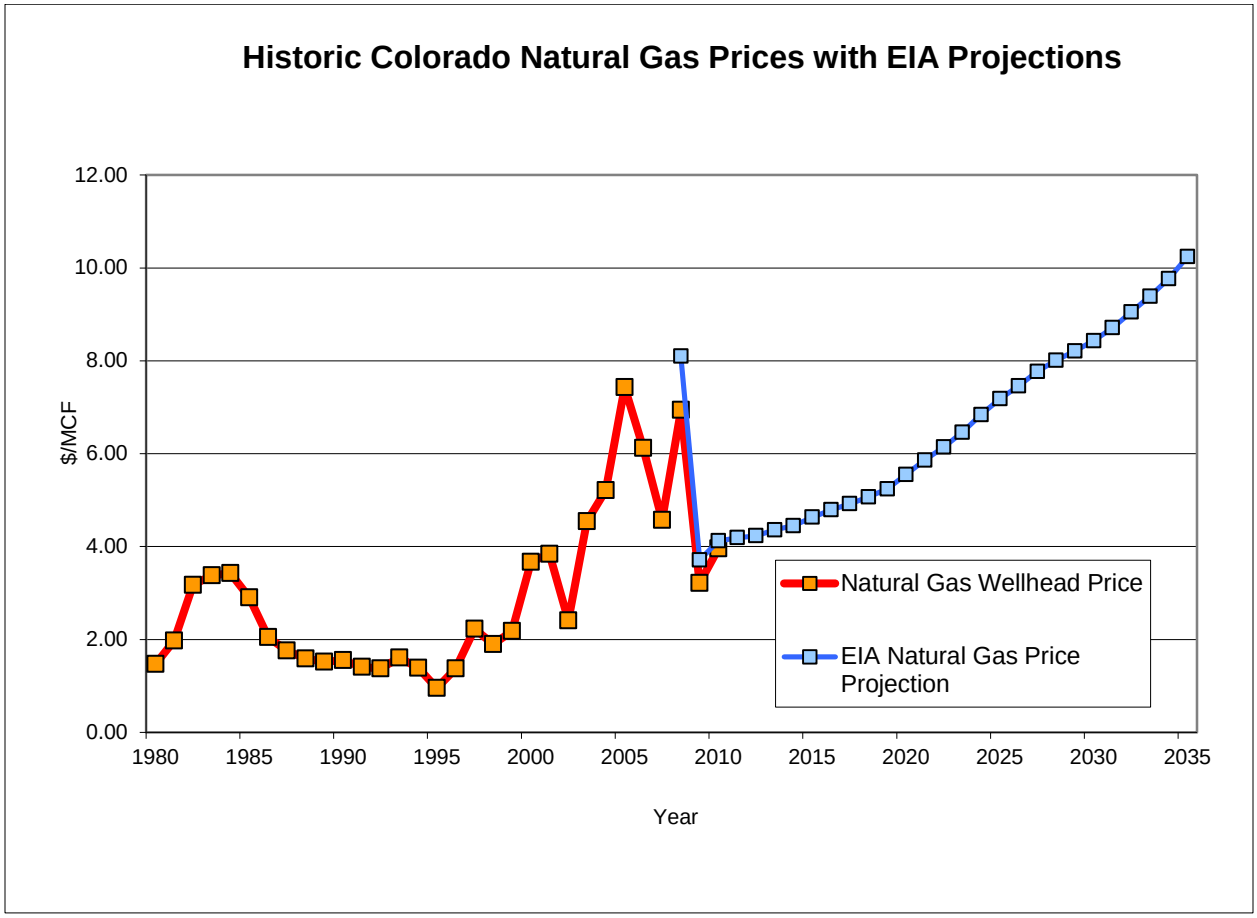


Figure 21. Colorado historical crude oil prices with future oil price projections (Energy Information Administration, 2011).

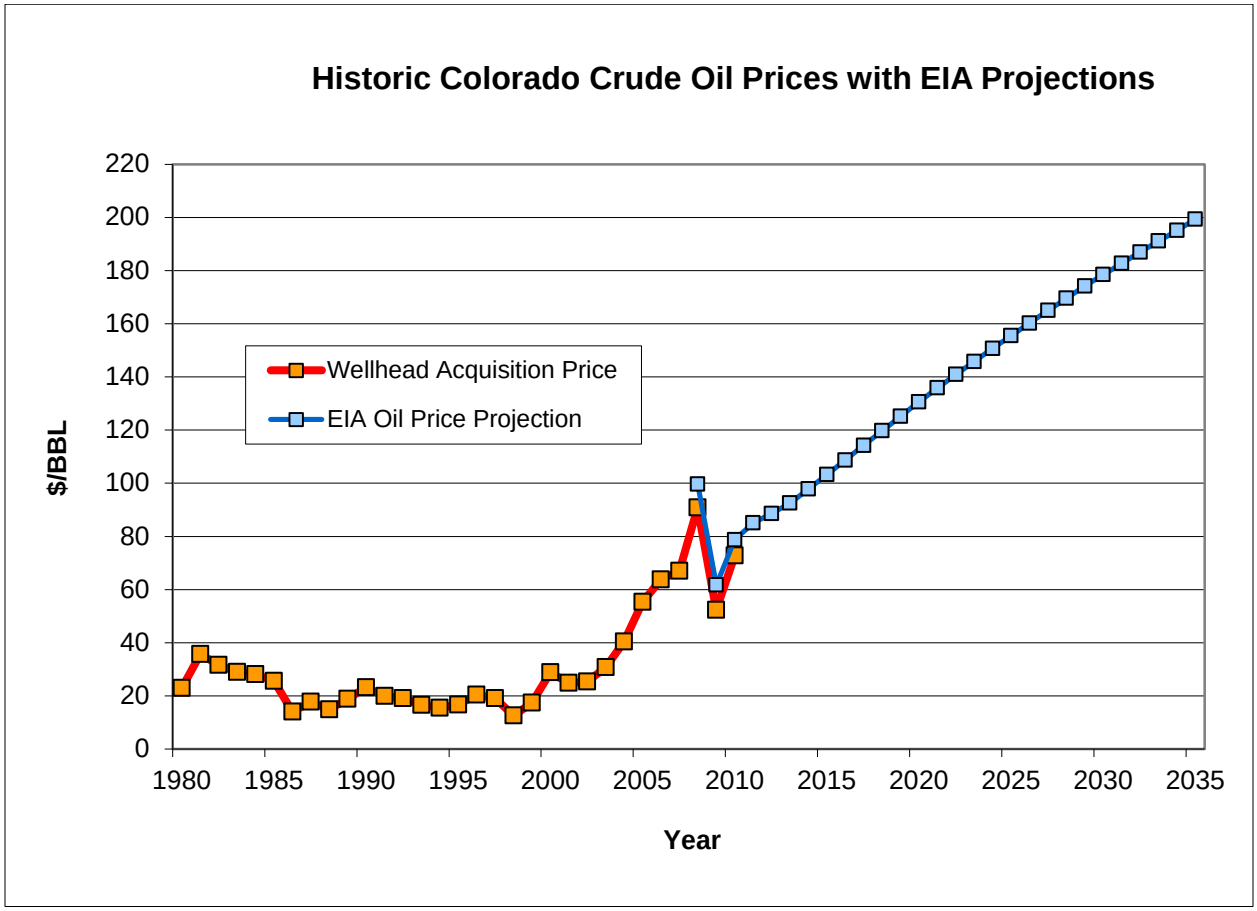
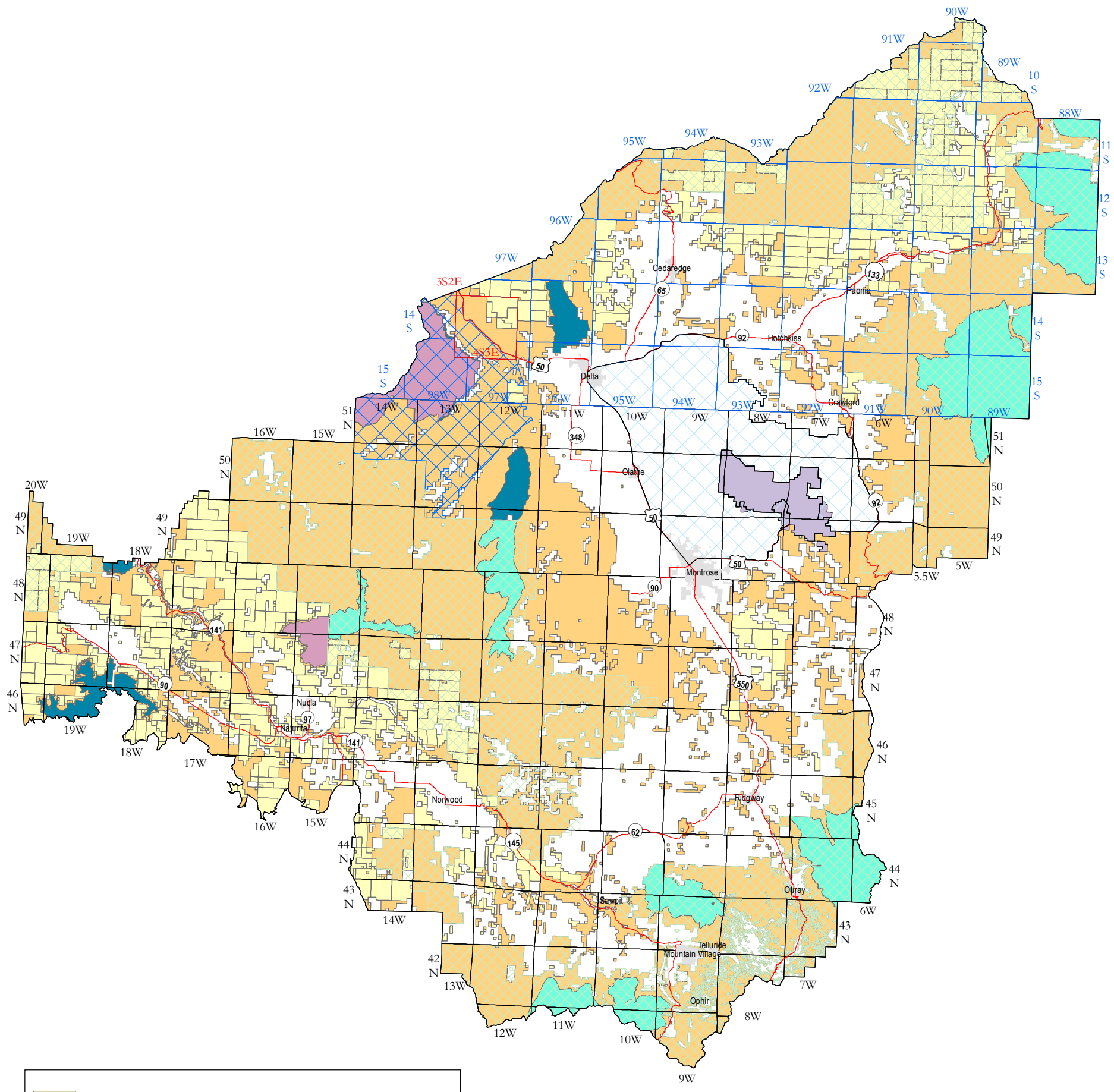


Figure 22.

Leased and unleased Federal oil and gas minerals within the Uncompahgre Study Area. Data from Bureau files.



June, 2010

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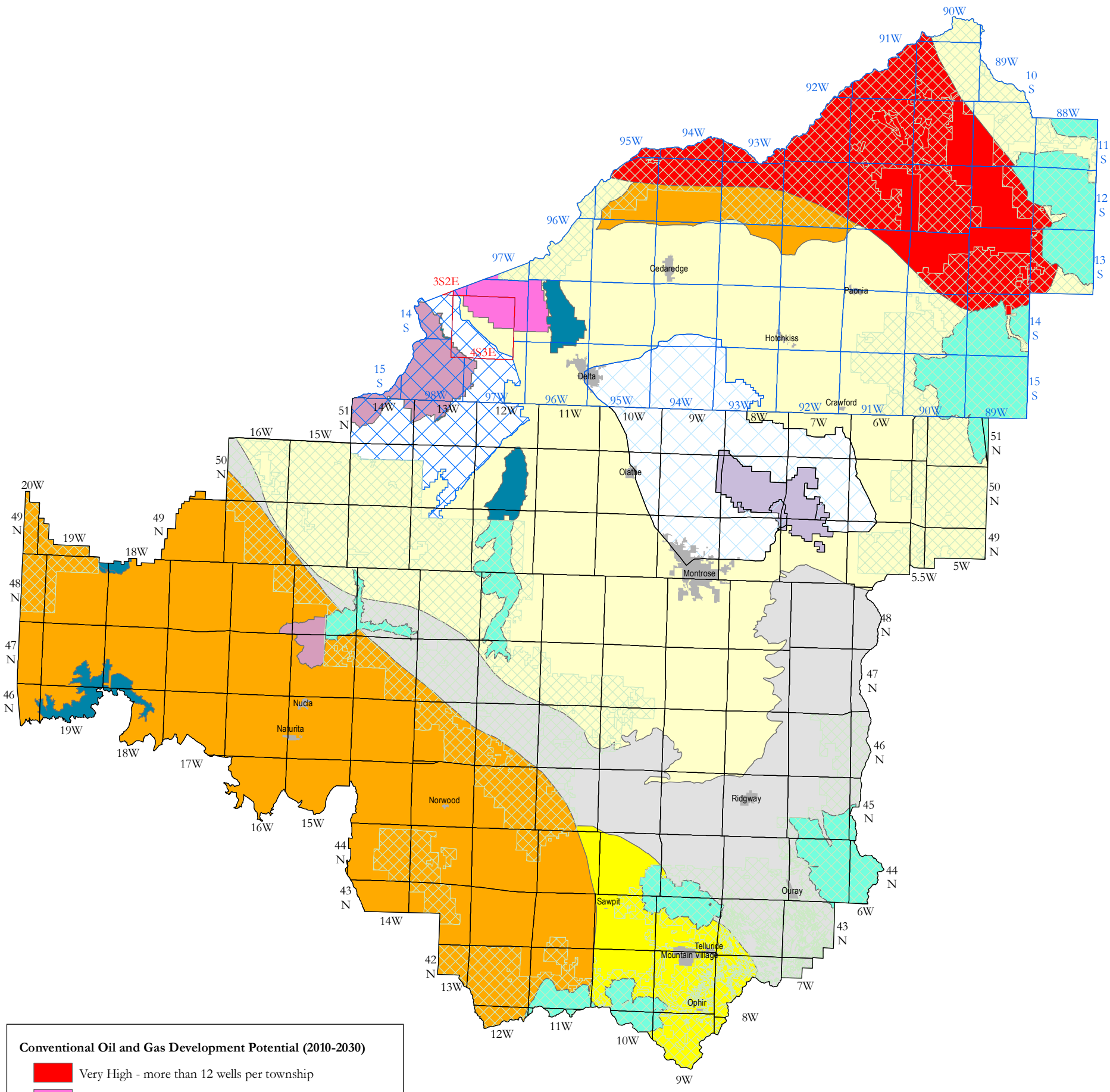
Figure 23a.
Conventional oil and gas development potential and projected drilling densities within the Uncompahgre Study Area for 2010 through 2030.



Conventional Oil and Gas Development Potential (2010-2030)

- Very High - more than 12 wells per township
- High - more than 6 to 12 wells per township
- Moderate - more than 2 to 6 wells per township
- Low - more than 1 to 2 wells per township
- Very Low - 0.25 to 1 well per township
- Negligible - less than 0.25 wells per township

National Forest Lands

Lands Excluded From Reasonable Forseeable Development Analysis

- Gunnison Gorge National Conservation Area Planning Area
- Dominguez-Escalante National Conservation Area

No Leasing

- BLM Wilderness
- Forest Service Wilderness
- Black Canyon of the Gunnison National Park
- BLM Wilderness Study Areas
- Dominguez Canyon Wilderness

0 15 30 Miles

1:700,000

January, 2012

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

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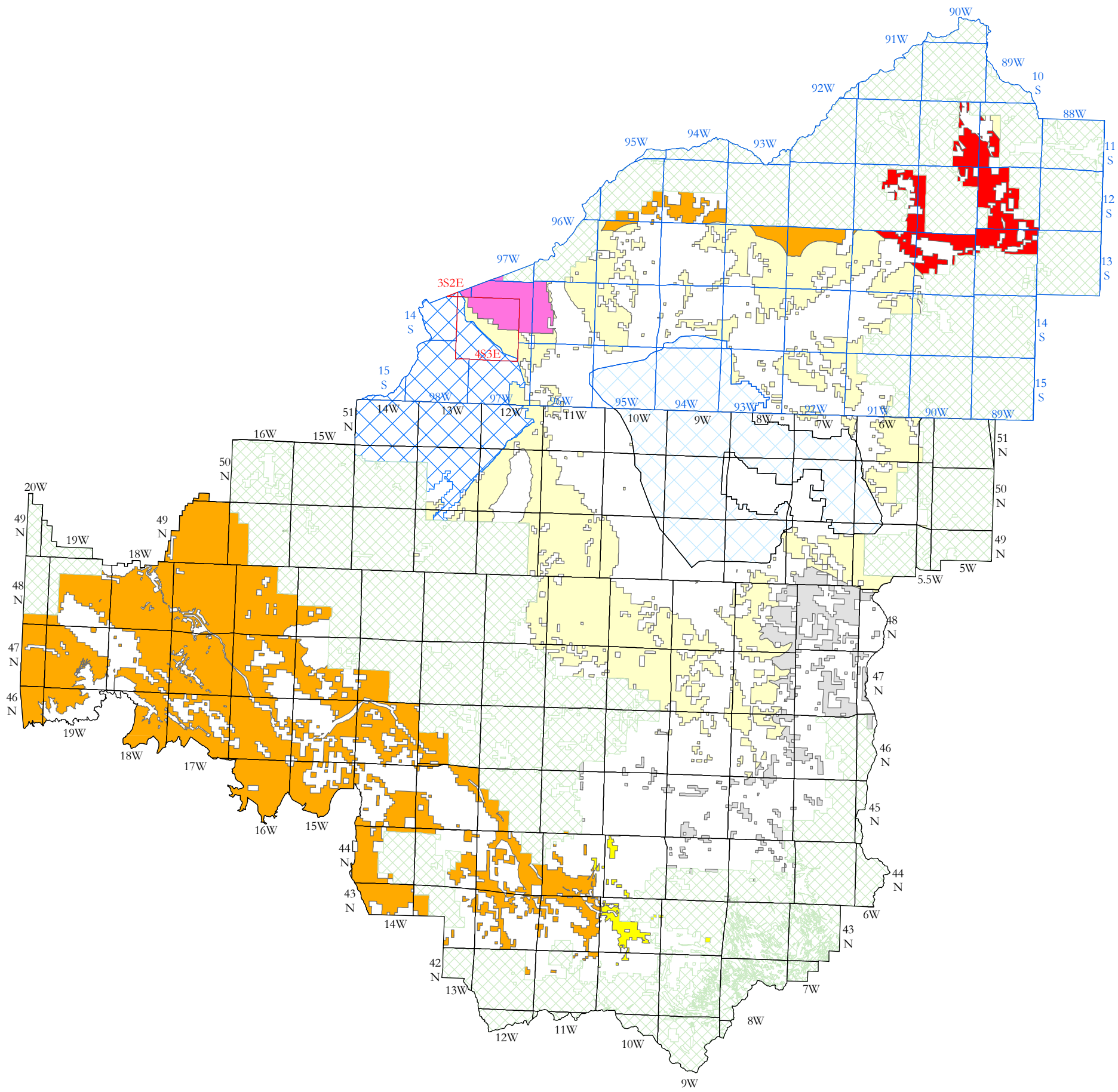
N

Figure 23b.
Conventional oil and gas development potential and projected drilling densities on Bureau managed oil and gas minerals within the Uncompahgre Study Area for 2010 through 2030.



Conventional Oil and Gas Development Potential (2010-2030)

- Very High - more than 12 wells per township
- High - more than 6 to 12 wells per township
- Moderate - more than 2 to 6 wells per township
- Low - more than 1 to 2 wells per township
- Very Low - 0.25 to 1 well per township
- Negligible - less than 0.25 wells per township

National Forest Lands

Lands Excluded From Reasonable Forseeable Development Analysis

- Gunnison Gorge National Conservation Area Planning Area
- Dominguez-Escalante National Conservation Area

0 15 30 Miles

1:700,000

January, 2012

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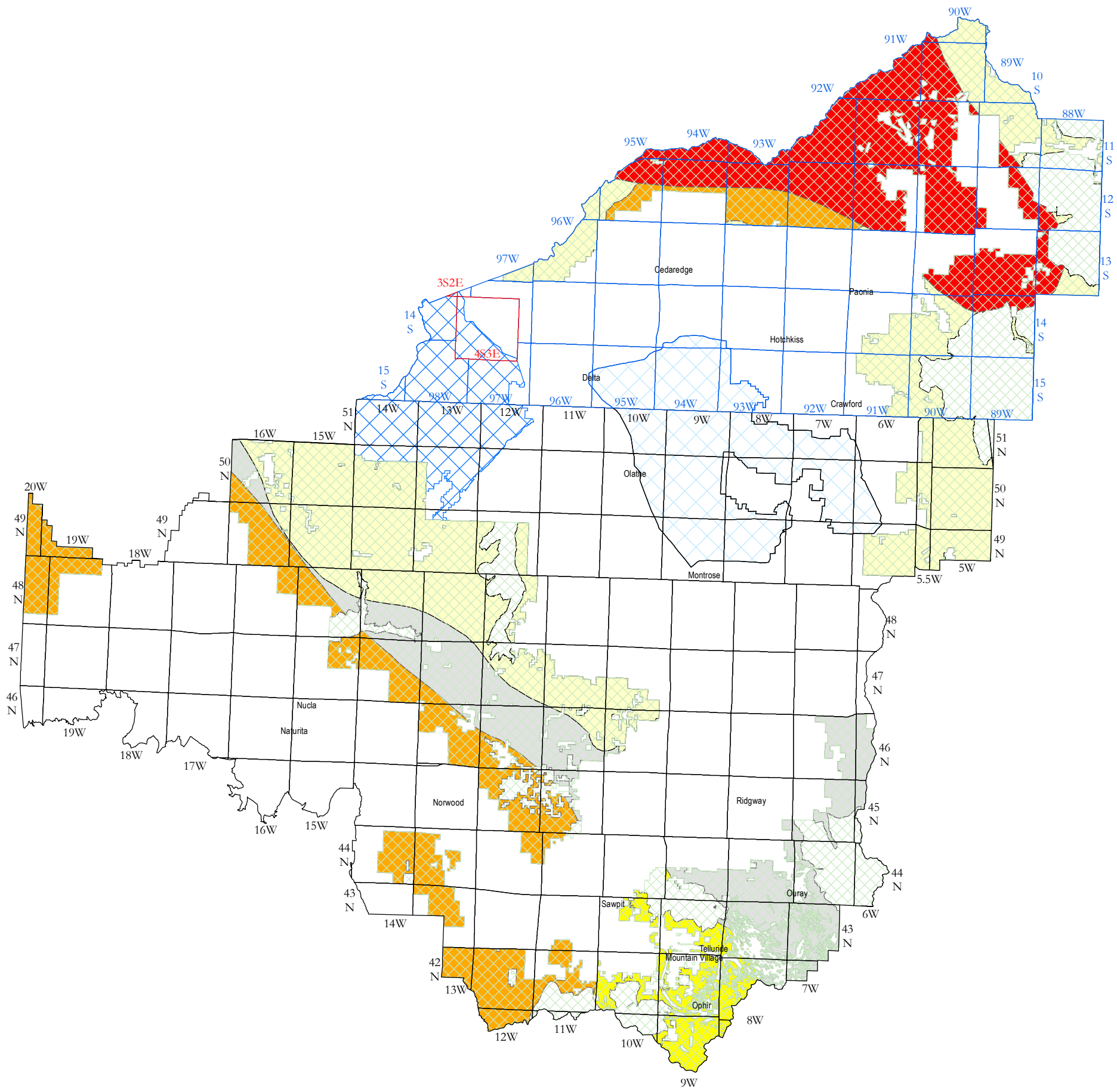
N

Figure 23c.

Conventional oil and gas development potential and projected drilling densities on Forest Service managed oil and gas minerals within the Uncompahgre Study Area for 2010 through 2030.



Conventional Oil and Gas Development Potential (2010-2030)

- Very High - more than 12 wells per township
- High - more than 6 to 12 wells per township
- Moderate - more than 2 to 6 wells per township
- Low - more than 1 to 2 wells per township
- Very Low - 0.25 to 1 well per township
- Negligible - less than 0.25 wells per township

National Forest Lands

Lands Excluded From Reasonable Forseeable Development Analysis

- Gunnison Gorge National Conservation Area Planning Area
- Dominguez-Escalante National Conservation Area

0 15 30 Miles

1:700,000

January, 2012

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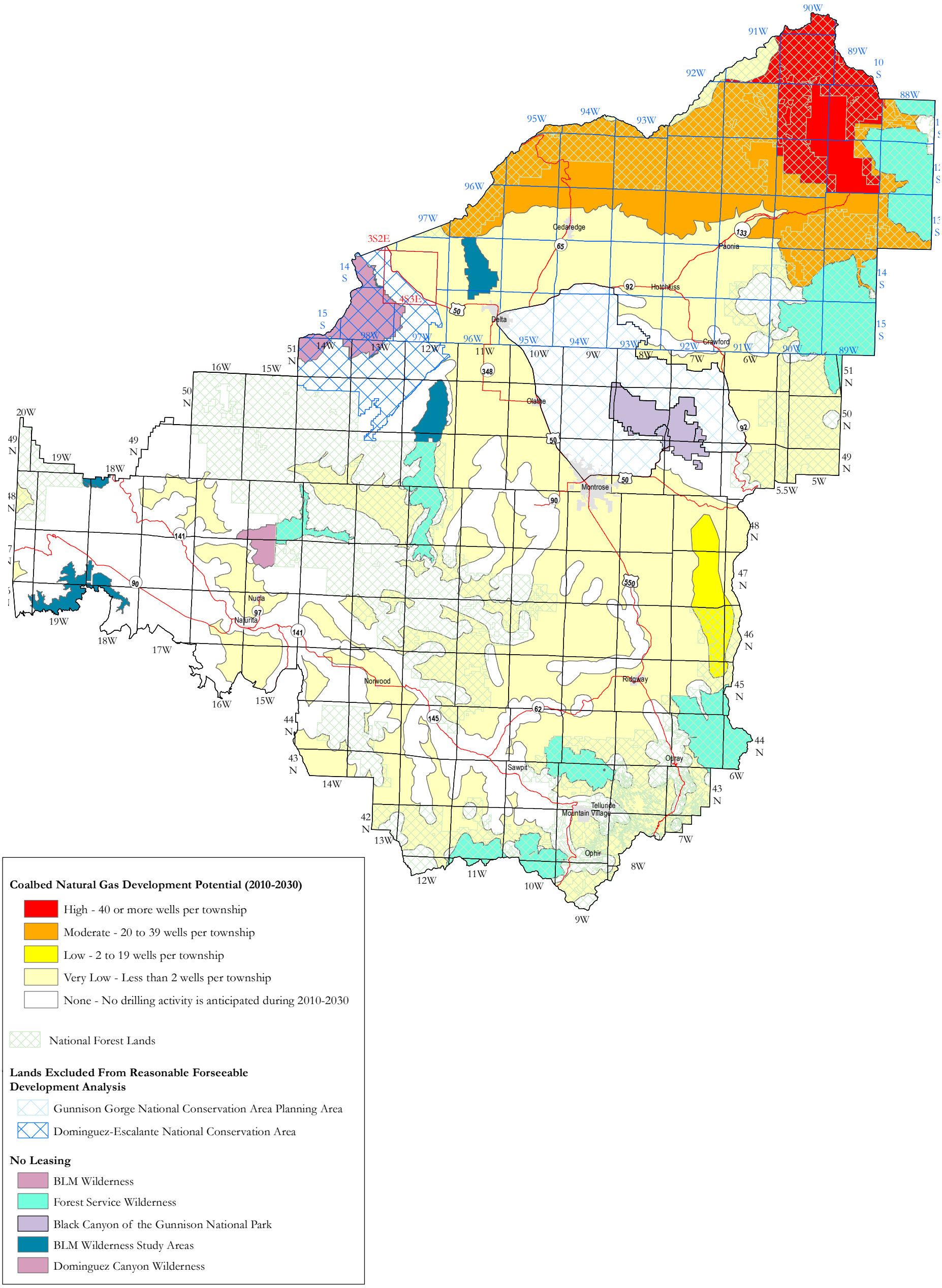
Figure 24a.

Coalbed natural gas development potential and projected drilling densities within the Uncompahgre Study Area for 2010 through 2030.



February, 2012

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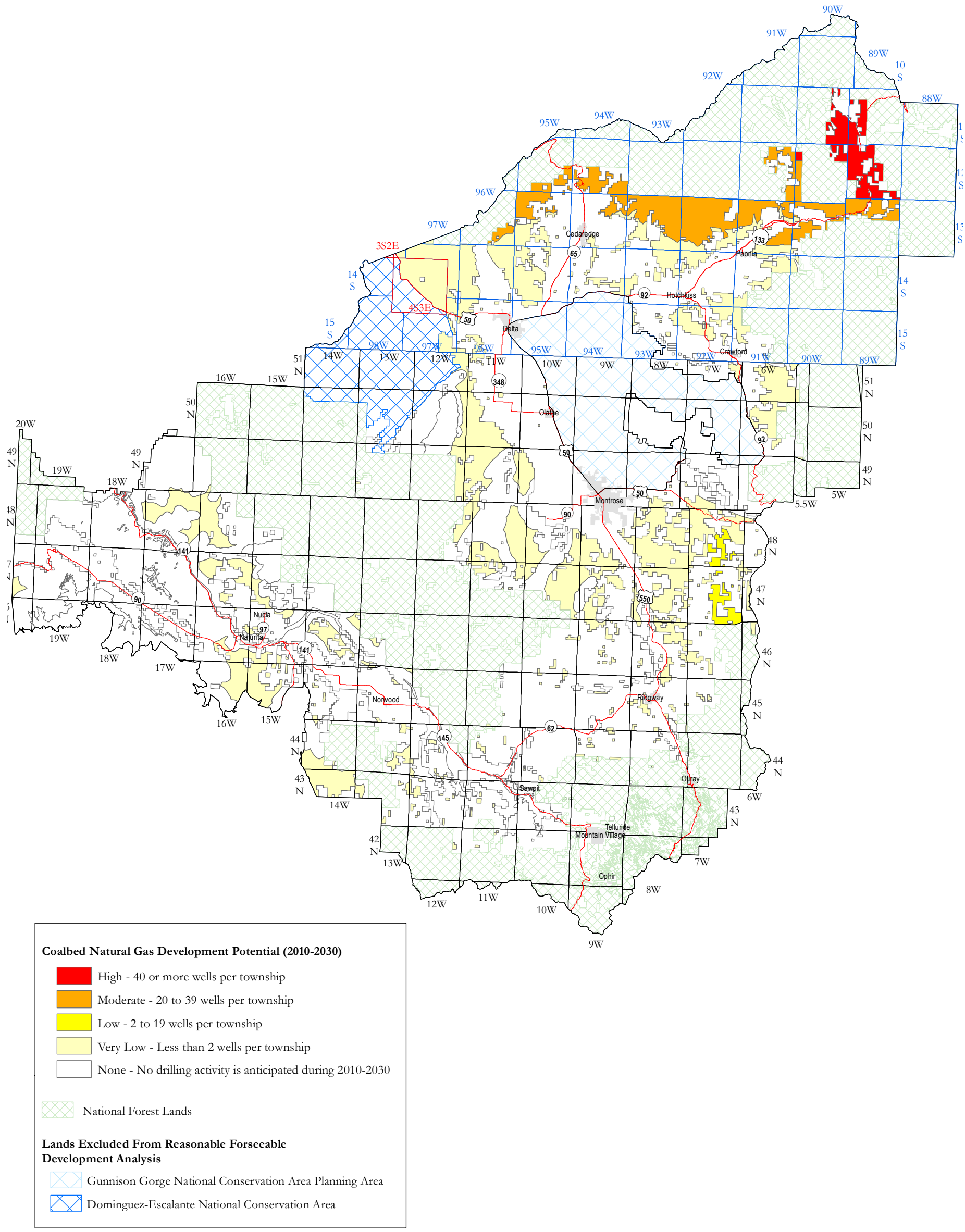
Figure 24b.
Coalbed natural gas development potential and projected drilling densities on Bureau managed oil and gas minerals within the Uncompahgre Study Area for 2010 through 2030.



February, 2012

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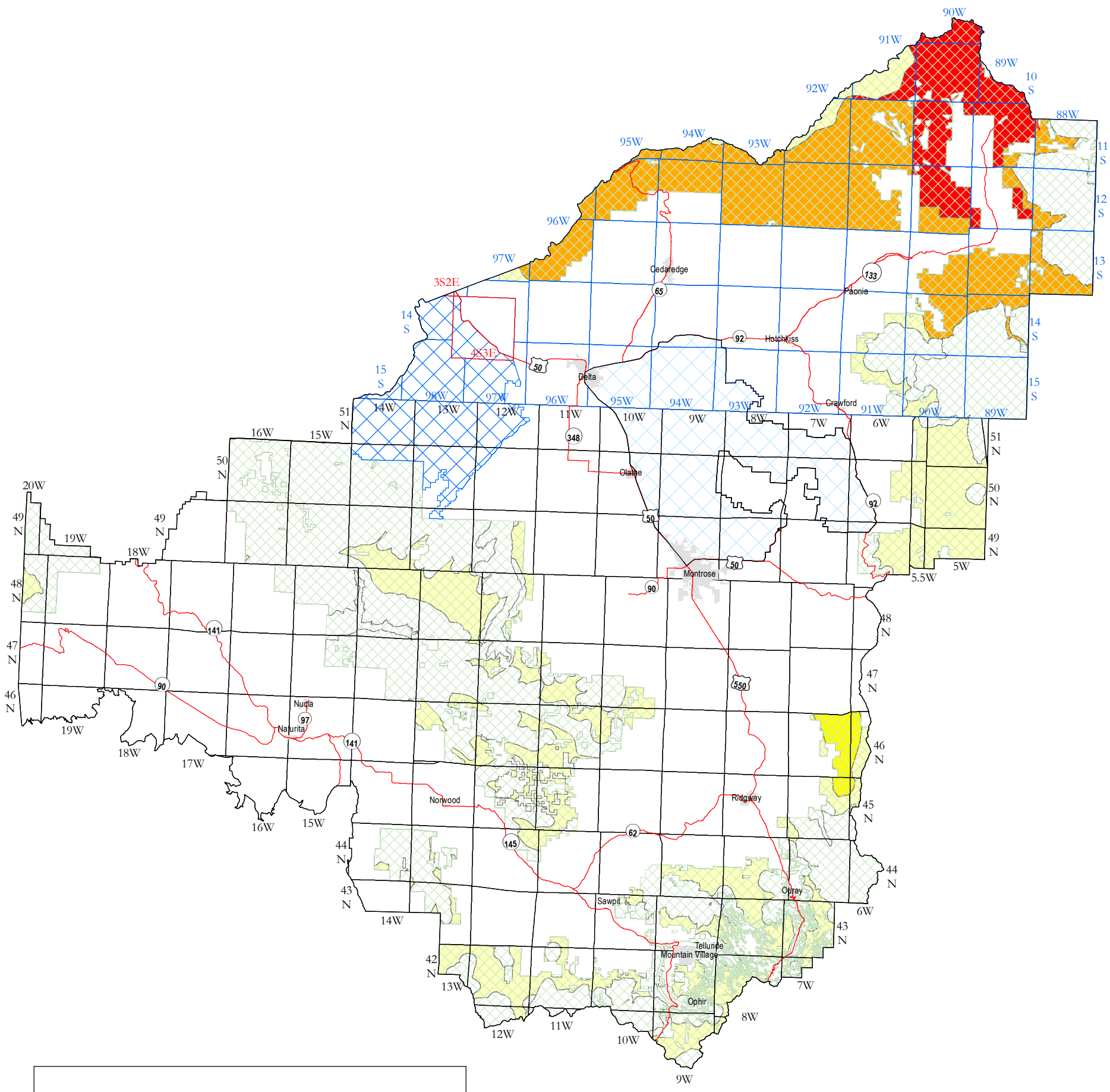
Figure 24c.
Coalbed natural gas development potential and projected drilling densities on Forest Service managed oil and gas minerals within the Uncompahgre Study Area for 2010 through 2030.



Coalbed Natural Gas Development Potential (2010-2030)

- High - 40 or more wells per township
- Moderate - 20 to 39 wells per township
- Low - 2 to 19 wells per township
- Very Low - Less than 2 wells per township
- None - No drilling activity is anticipated during 2010-2030

National Forest Lands

Lands Excluded From Reasonable Forseeable Development Analysis

- Gunnison Gorge National Conservation Area Planning Area
- Dominguez-Escalante National Conservation Area

0 15 30 Miles

1:700,000

February, 2012

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N

Table 1. Historical conventional oil, gas, and water production from formations within the Uncompahgre Study Area. Data from IHS Energy Group (2010).

CONVENTIONAL WELLS WITH PRODUCTION				
RESERVOIR NAME	**NUMBER OF WELLS**	**CUMULATIVE OIL (barrels)**	**CUMULATIVE GAS (cubic feet)**	**CUMULATIVE WATER (barrels)**
Corcoran	8	2,126	663,568,000	3,180
Corcoran/Cozzette	7	2,048	1,712,799,000	5,850
Cozzette	8	260	359,170,000	834
Cutler	1	405	57,442,000	2,987
Dakota	1	1,004	1,629,000	0
Hermosa	1	120	41,087,000	1,308
Honaker Trail	1	0	129,122,000	0
Mesaverde	1	26	3,884,000	968
Rollins	2	0	9,954,000	0
Williams Fork	3	322	142,547,000	69
Williams Fork Cameo	1	219	130,324,000	11
TOTALS	**34**	**6,530**	**3,251,526,000**	**15,207**

Table 2. Historical coalbed natural gas, oil, and water production from formations within the Uncompahgre Study Area. Data from IHS Energy Group (2010).

COALBED NATURAL GAS WELLS WITH PRODUCTION				
RESERVOIR NAME	**NUMBER OF WELLS**	**CUMULATIVE OIL (barrels)**	**CUMMULATIVE GAS (cubic feet)**	**CUMULATIVE WATER (barrels)**
Cameo	1	16	51,929,000	7,686
Cameo Coal	3	236	103,281,000	6,695
Cameo Coal Williams Fork	1	0	64,000	7
Corcoran	2	1,083	1,100,237,000	1,484
Corcoran/ Cozzette/ Mesaverde	1	532	80,125,000	899
Cozzette	1	4	15,329,000	768
Mesaverde	3	4	18,704,000	768
Williams Fork	10	6,519	3,385,018,000	1,746,012
Williams Fork Coal	1	96	48,688,000	1,519
Williams Fork Cameo	1	0	3,000	0
TOTALS	**24**	**8,490**	**4,803,378,000**	**1,765,838**

Table 3. Estimated conventional oil and gas development potential classification acres, number of townships, projected average drilling densities, and percentage of the entire Uncompahgre Study Area for each development potential classification type for the period 2010 through 2030.

Development Potential	Acres	Area (townships)	Average new wells per township	% of Study Area
Very High	280,901	12.19	25	8.73
High	22,419	0.97	9	0.70
Moderate	807,514	35.05	4	25.10
Low	119,013	5.17	1.5	3.70
Very Low	1,167,738	50.68	0.50	36.30
Negligible	425,608	18.47	0.10	13.23
Not Assessed	393,739	17.09	0	12.24
Totals	**3,216,933**	**139.62**		**100**

Table 4. Estimated coalbed natural gas development potential classification acres, number of townships, projected average drilling densities, and percentage of the Uncompahgre Study Area within each development potential classification type for the period 2010 through 2030.

Development Potential	Acres	Area (townships)	Average new wells per township	% of Study Area
High	114,462	4.97	60	3.56
Moderate	339,344	14.73	30	10.55
Low	33,652	1.46	10	1.05
Very Low	1,262,581	54.80	0.50	39.25
None	1,072,891	46.57	0	33.35
Not Assessed	393,739	17.09	0	12.24
Totals	**3,216,668**	**139.62**		**100**

Table 5. Annual conventional and coalbed natural gas well spuds projected for the Uncompahgre Study Area.

YEAR	CONVENTIONAL SPUDS	COALBED NATURAL GAS SPUDS
2010	2	7
2011	3	6
2012	5	11
2013	7	7
2014	11	12
2015	17	17
2016	22	22
2017	25	20
2018	26	17
2019	28	32
2020	31	30
2021	32	54
2022	32	60
2023	31	47
2024	30	71
2025	29	71
2026	28	94
2027	28	58
2028	34	83
2029	42	62

Table 6a. Annual conventional natural gas and oil production projected for the Uncompahgre Study Area.

YEAR	CONVENTIONAL GAS (thousand cubic feet)	CONVENTIONAL OIL (Barrels)
2010	10,262	0
2011	15,804	0
2012	12,982	0
2013	46,215	0
2014	88,775	0
2015	157,500	961
2016	260,700	2,749
2017	391,200	5,159
2018	531,020	7,845
2019	666,310	10,400
2020	809,060	12,454
2021	965,490	13,776
2022	1,125,400	14,367
2023	1,271,800	14,490
2024	1,397,200	14,553
2025	1,509100	14,948
2026	1,601,600	15,856
2027	1,672,400	17,090
2028	1,744,500	18,042
2029	1,857,200	17,755

Table 6b. Annual conventional natural gas and oil production projected for wells on Bureau managed oil and gas minerals in the Uncompahgre Study Area.

YEAR	CONVENTIONAL GAS (thousand cubic feet)	CONVENTIONAL OIL (Barrels)
2010	3,209	0
2011	4,942	0
2012	4,059	0
2013	14,451	0
2014	27,760	0
2015	49,250	301
2016	81,521	860
2017	122,328	1,613
2018	166,050	2,453
2019	208,355	3,252
2020	252,993	3,894
2021	301,909	4,308
2022	351,913	4,493
2023	397,692	4,531
2024	436,904	4,551
2025	471,896	4,674
2026	500,820	4,958
2027	522,959	5,344
2028	545,505	5,642
2029	580,746	5,552

Table 7a. Annual coalbed natural gas production and associated oil production projected for the Uncompahgre Study Area.

YEAR	GAS (thousand cubic feet)	OIL (Barrels)
2010	697,341	1,139
2011	1,014,091	1,335
2012	1,672,897	2,171
2013	1,714,779	1,977
2014	2,094,916	2,567
2015	2,726,814	3,597
2016	3,657,532	4,690
2017	4,143,067	4,920
2018	4,080,733	4,570
2019	5,114,376	6,617
2020	5,765,390	7,142
2021	8,320,738	10,848
2022	10,548,777	13,425
2023	10,998,736	12,455
2024	12,804,283	15,735
2025	13,856,355	17,003
2026	16,744,206	20,732
2027	15,635,355	17,314
2028	16,454,692	19,315
2029	14,962,892	17,304

Table 7b. Annual coalbed natural gas production and associated oil production projected for wells on Bureau managed oil and gas minerals in the Uncompahgre Study Area.

YEAR	GAS (thousand cubic feet)	OIL (Barrels)
2010	236,468	386
2011	343,878	453
2012	567,279	736
2013	581,482	670
2014	710,386	870
2015	924,663	1,220
2016	1,240,269	1,590
2017	1,404,914	1,668
2018	1,383,777	1,550
2019	1,734,285	2,244
2020	1,955,044	2,422
2021	2,821,562	3,679
2022	3,577,090	4,552
2023	3,729,671	4,223
2024	4,341,932	5,336
2025	4,698,690	5,766
2026	5,677,960	7,030
2027	5,301,949	5,871
2028	5,579,786	6,550
2029	5,073,917	5,868

Table 8a. Uncompahgre Study Area surface disturbance associated with new drilled wells and existing wells for the baseline scenario (short-term disturbance) for the 2010-2030 period.

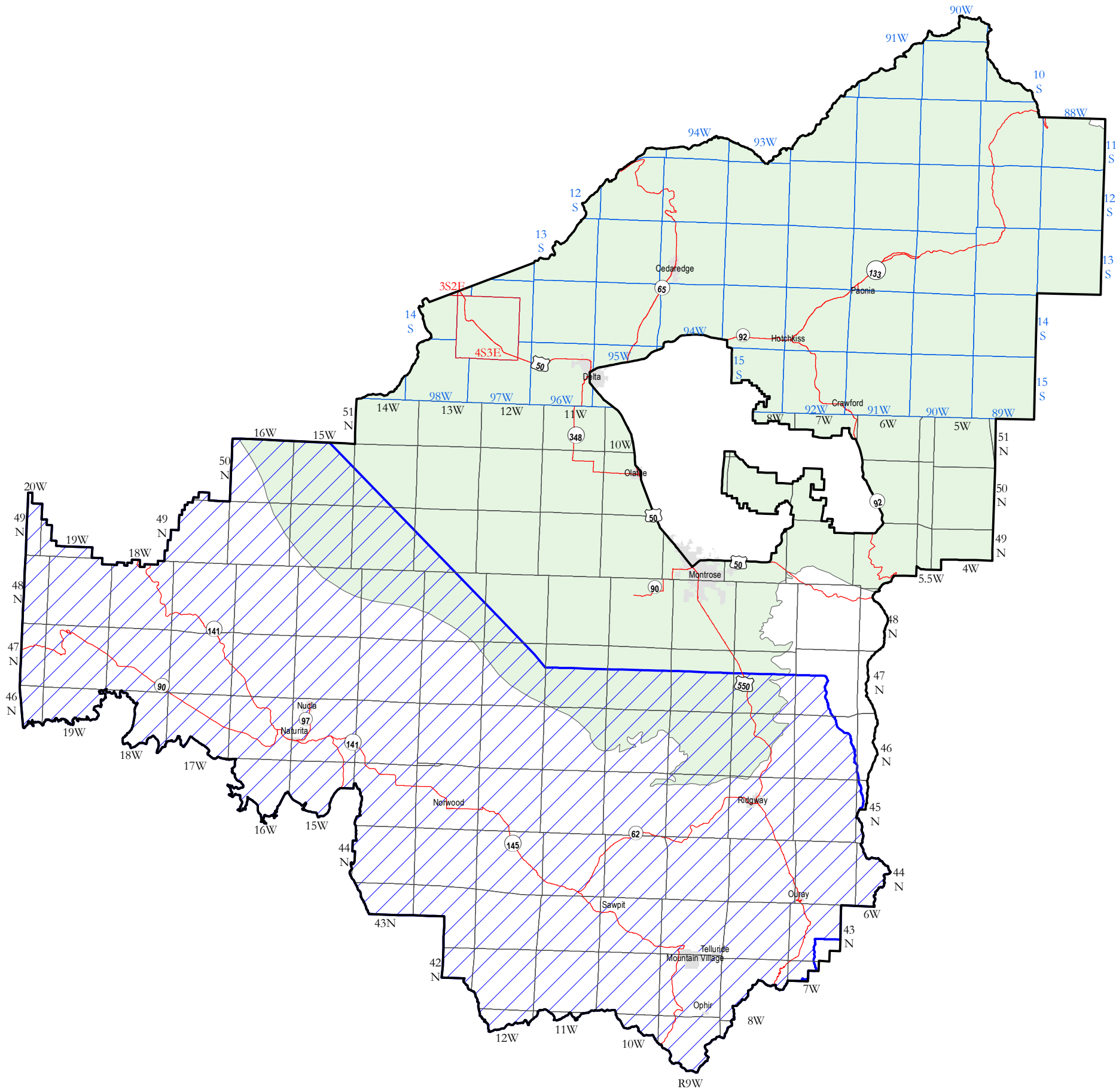
Wells			Disturbed Sites			Acres of Surface Disturbance (per site)		Acres of Disturbance by Well Type	
Type	**Total**	**BLM Managed**	**New Wells per pad (average)**	**Total Disturbed Sites**	**BLM Managed Disturbed Sites**	**Access Roads and Pipelines**	**Well Pad**	**Total**	**BLM Managed**
Wells in Whitewater Unit	9	9	9	1	1	18	6	23	23
Additional Coalbed Gas/Conventional Wells at 32 Existing Locations	96	27	3	32	9	0	2	64	18
Coalbed Gas/Conventional Well Multipads	500	167	4	125	42	18	6	2,975	992
Coalbed Gas Multipads	458	153	2	229	76	18	4	4,924	1,641
Coalbed Gas Single Well Pads	42	11	1	42	11	18	3	840	228
Conventional One and Two Well Pads	166	52	1.5	111	35	18	4	2,158	677
Total New Exploratory and Development Wells	1,271	418	Total New Exploratory and Development Well Disturbed Sites	540	174	Total New Exploratory and Development Well Surface Disturbance		10,984	3,578
Existing Active Coalbed Natural Gas Wells	22	6	1	22	6	2	1.5	77	21
Existing Active Conventional Wells	40	8	1	40	8	2	1.5	140	28
Total Existing Active Wells	62	14	Total Existing Disturbed Well Sites	62	14	Total Existing Well Surface Disturbance		217	49
Total Wells	**1,333**	**432**	**Total Short-Term Disturbed Well Sites**	**602**	**188**	**Total Short-Term Disturbance**		**11,201**	**3,627**

Table 8b. Uncompahgre Study Area surface disturbance associated with new active wells and existing wells determined to remain in an active status for the baseline scenario (long-term disturbance) for the 2010-2030 period.

Wells			Disturbed Sites			Acres of Surface Disturbance (per site)		Acres of Disturbance by Well Type	
Type	**Total**	**BLM Managed**	**Wells per pad (average)**	**Total Disturbed Sites**	**BLM Managed Disturbed Sites**	**Access Roads and Pipelines**	**Well Pad**	**Total**	**BLM Managed**
Wells in Whitewater Unit	7	6	9	1	1	8	2	10	10
Additional Coalbed Gas/Conventional Wells at 32 Existing Locations	77	21	3	32	9	0	0.5	16	4
Coalbed Gas/Conventional Well Multipads	413	137	3	123	41	8	2	1,225	408
Coalbed Gas Multipads	412	137	2	218	73	8	1.5	2,067	689
Coalbed Gas Single Well Pads	38	10	1	38	10	8	1.5	359	97
Conventional One and Two Well Pads	125	39	1.5	83	26	8	1.5	789	247
Total New Active Wells	1,070	352	Total New Active Disturbed Well Sites	494	159	Total New Active Well Surface Disturbance		4,465	1,456
Remaining Active Coalbed Natural Gas Wells	22	6	1	22	6	2	1.5	77	21
Remaining Active Conventional Wells	25	8	1	25	8	2	1.5	88	28
Total Remaining Active Wells	47	14	Total Remaining Well Sites	47	14	Total Remaining Wells Surface Disturbance		165	49
Total Wells	**1,117**	**366**	**Total Long-Term Disturbed Well Sites**	**541**	**173**	**Total Long-Term Well Disturbance**		**4,630**	**1,505**

Figure A1-1.

Location of the Uinta-Piceance 2002 and Paradox Basin 1995 province boundaries within the Uncompahgre Study Area. Data from United States Geological Survey (2010).



Province Boundaries

Paradox Basin

Uinta-Piceance Basin

0 15 30 Miles

1:700,000

May, 2010

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

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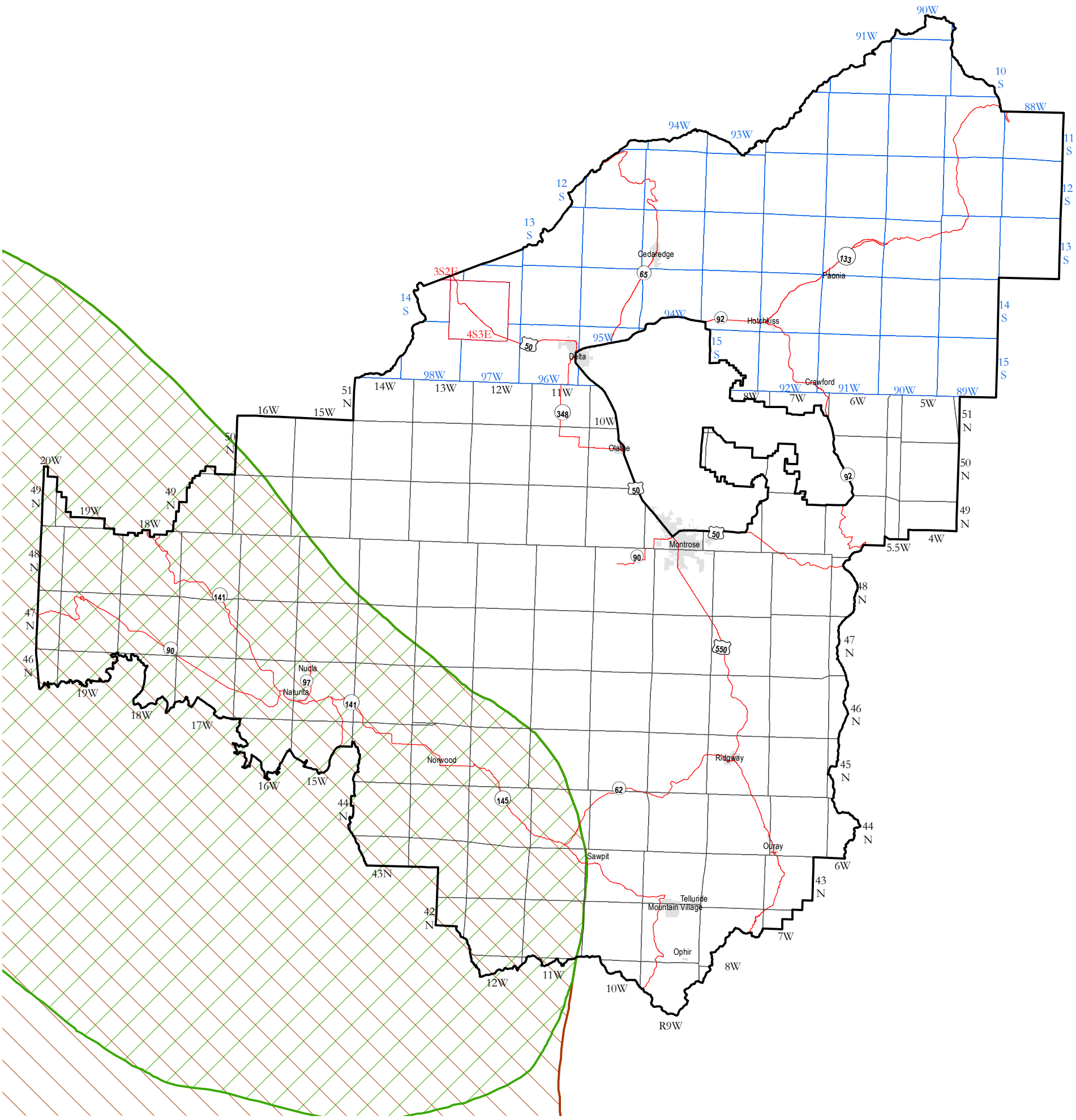
N

Figure A1-2.
Location of the 1995 Paradox Basin Province Salt Anticline Flank, Buried Fault Blocks, and Fractured Interbed Plays within the Uncompahgre Study Area. Data from United States Geological Survey (2010).



Paradox Basin Plays

- Salt Anticline Flank and Buried Fault Blocks
- Fractured Interbed

0 15 30 Miles

1:700,000

May, 2010

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Amber Robbins, Geologist
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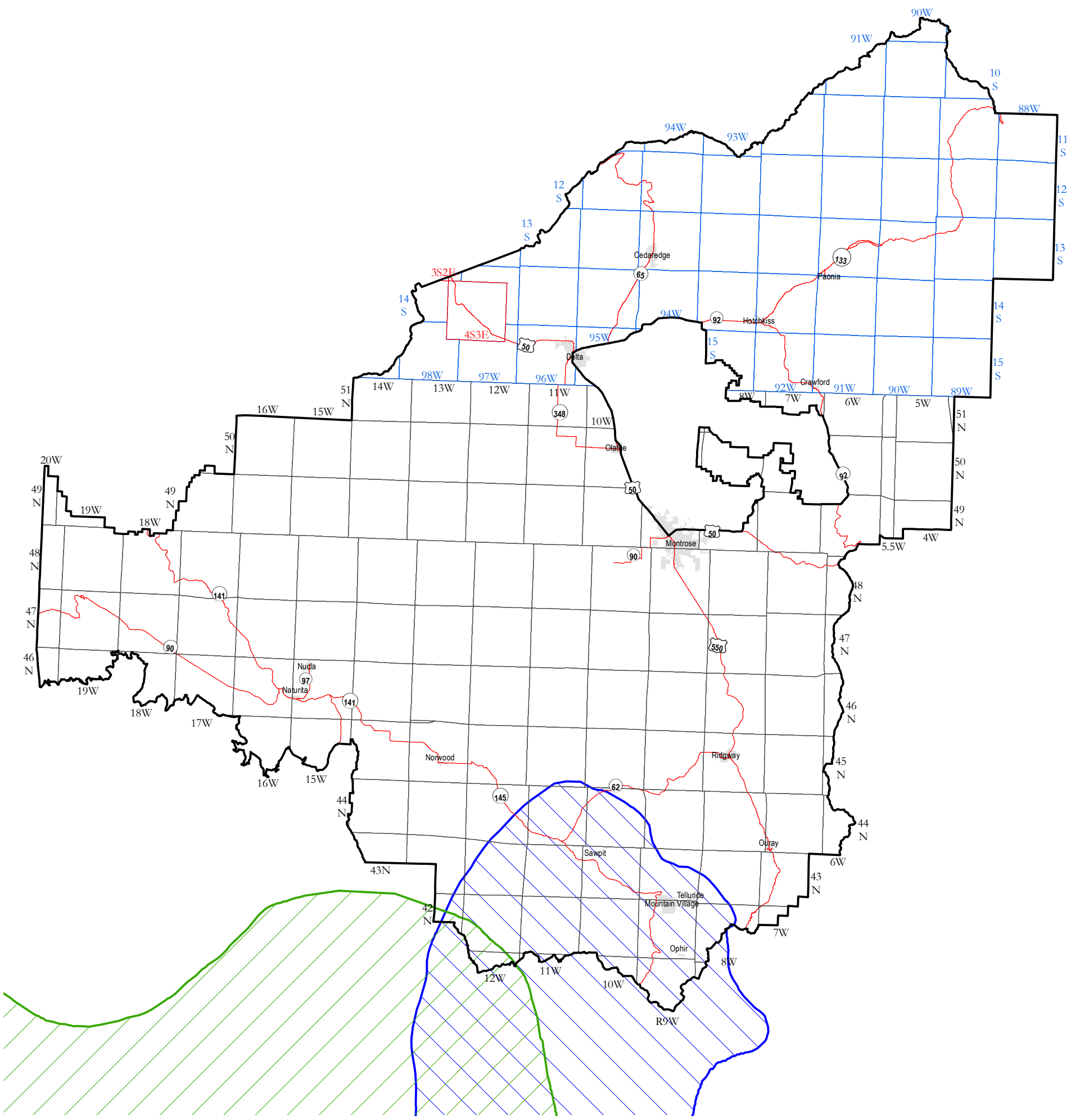
N

Figure A1-3.
Location of the 1995 Paradox Basin Province Porous Carbonate Buildup and Permian-Pennsylvanian Margin Clastics Plays within the Uncompahgre Study Area. Data from United States Geological Survey (2010).



Paradox Basin Plays

- Porous Carbonate Buildup
- Permian Pennsylvanian Margin Clastics

0 15 30 Miles

1:700,000

May, 2010

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Amber Robbins, Geologist
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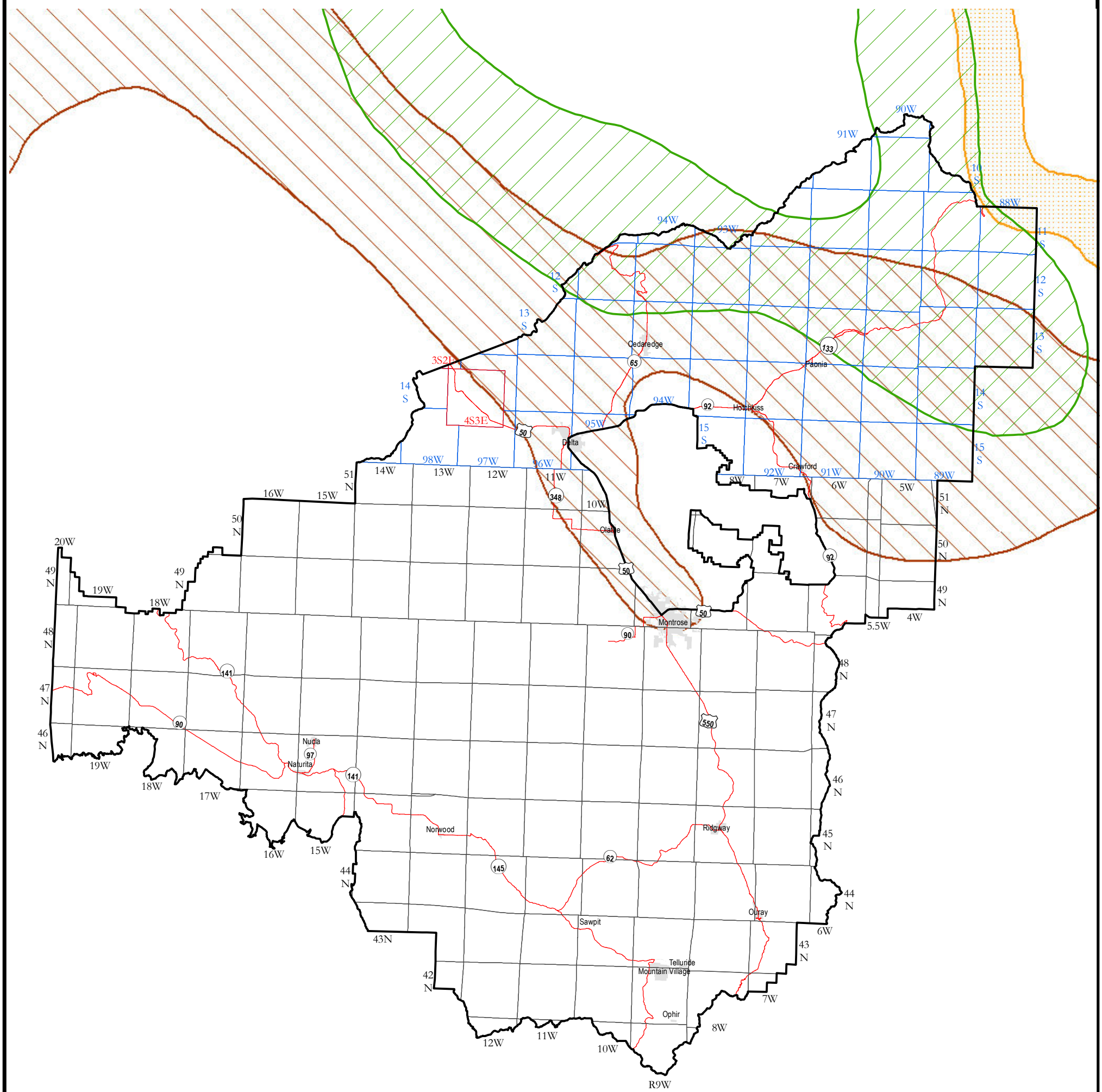
N

Figure A1-4.
Location of the 1995 Piceance Basin Province conventional accumulation plays within the Uncompahgre Study Area. Data from United States Geological Survey (2010).



Piceance Basin Plays

- Upper Cretaceous
- Basin Margin Subthrusts
- Cretaceous Dakota To Jurassic

0 15 30 Miles

1:700,000

May, 2010

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

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

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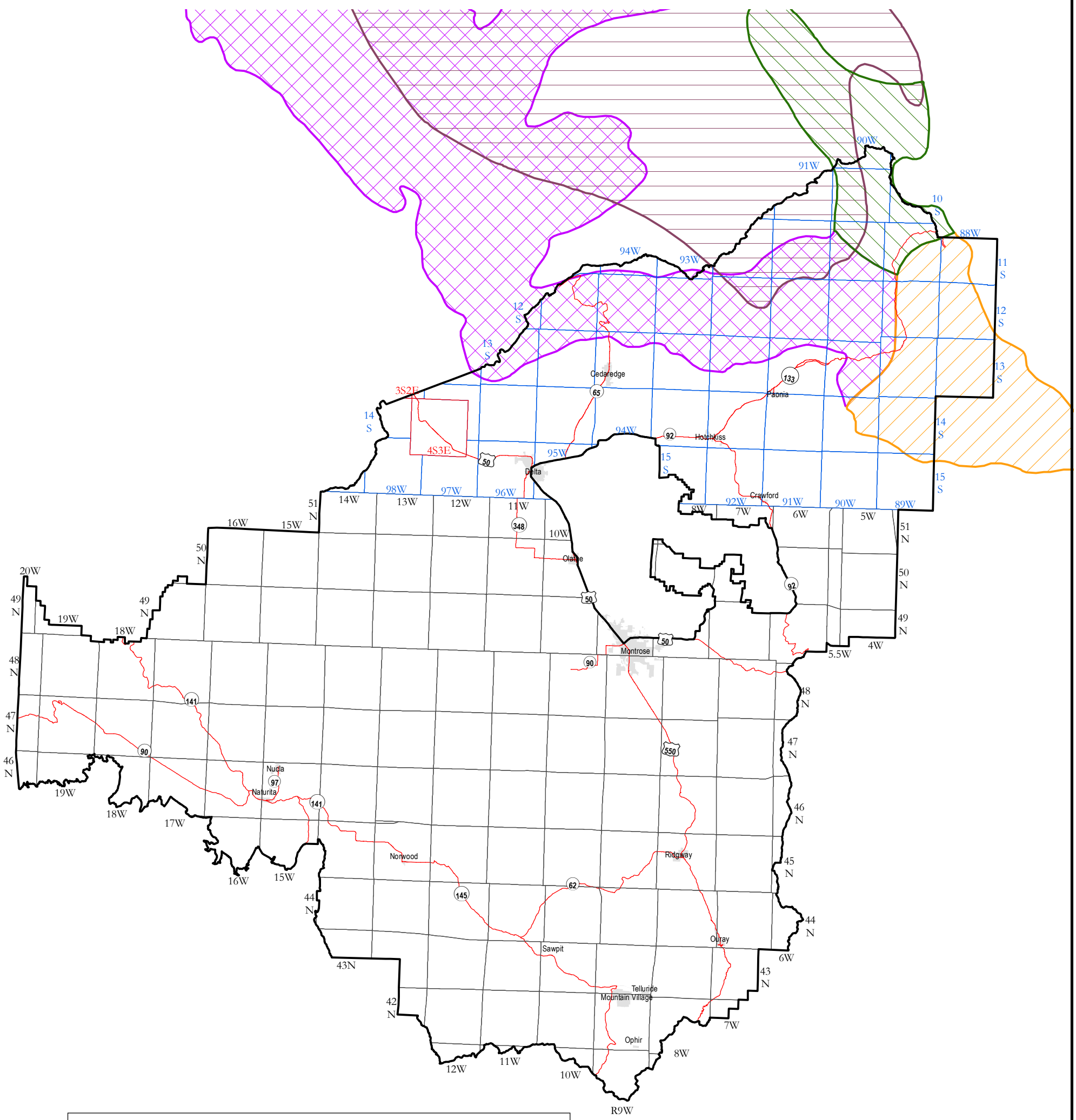
Figure A1-5.
Location of the 1995 Piceance Basin Province continuous accumulation plays within the Uncompahgre Study Area. Data from United States Geological Survey (2010).



1995 Piceance Basin Plays

- Divide Creek Anticline
- Igneous Intrusion
- Tight Gas Piceance Mesaverde Williams Fork
- Western Basin Margin

0 15 30 Miles

1:700,000

May, 2010

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

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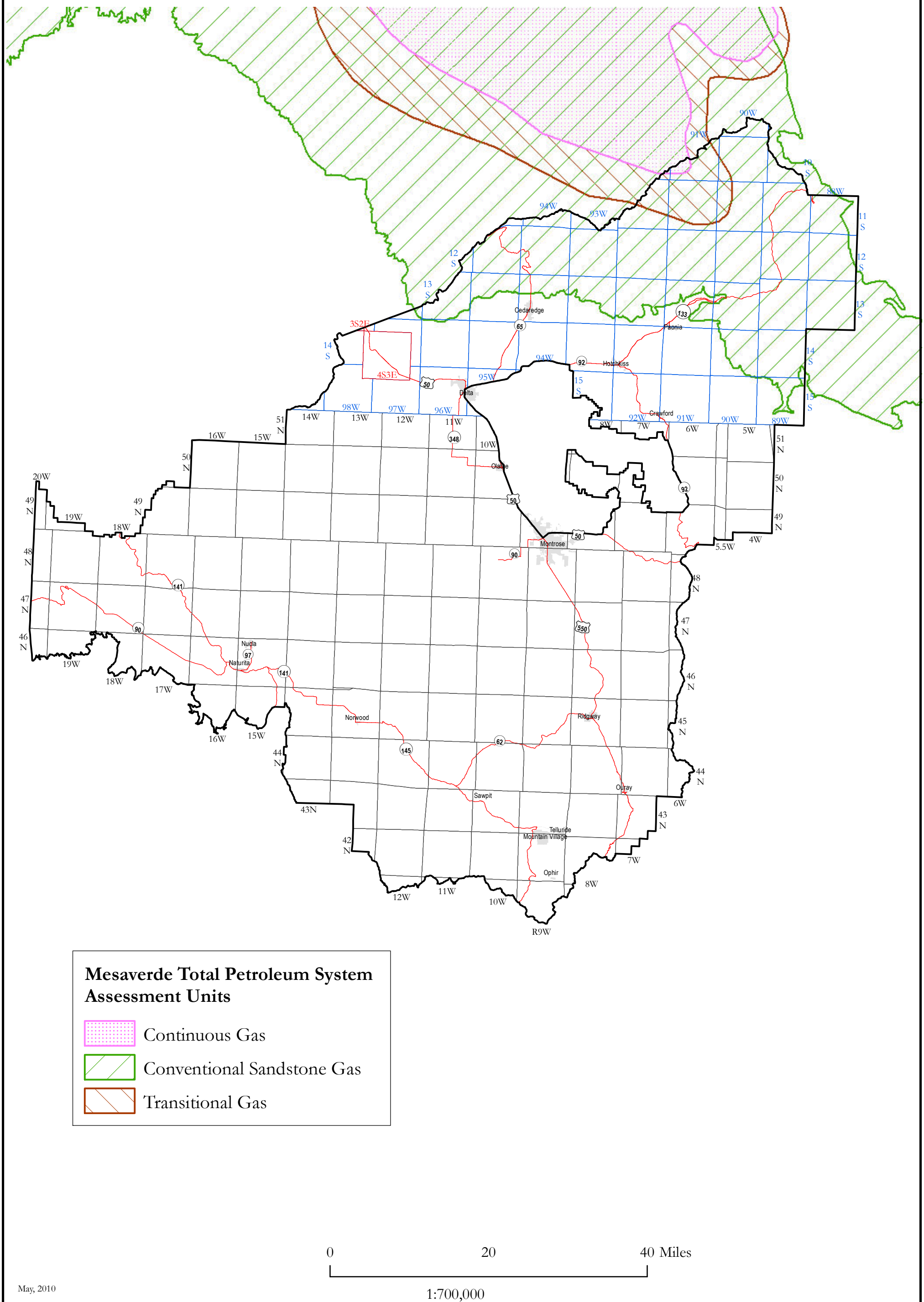
Figure A1-6.

Location of the 2002 Uinta-Piceance Basin Mesaverde Total Petroleum System within the Uncompahgre Study Area. Data from United States Geological Survey (2010).



May, 2010

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

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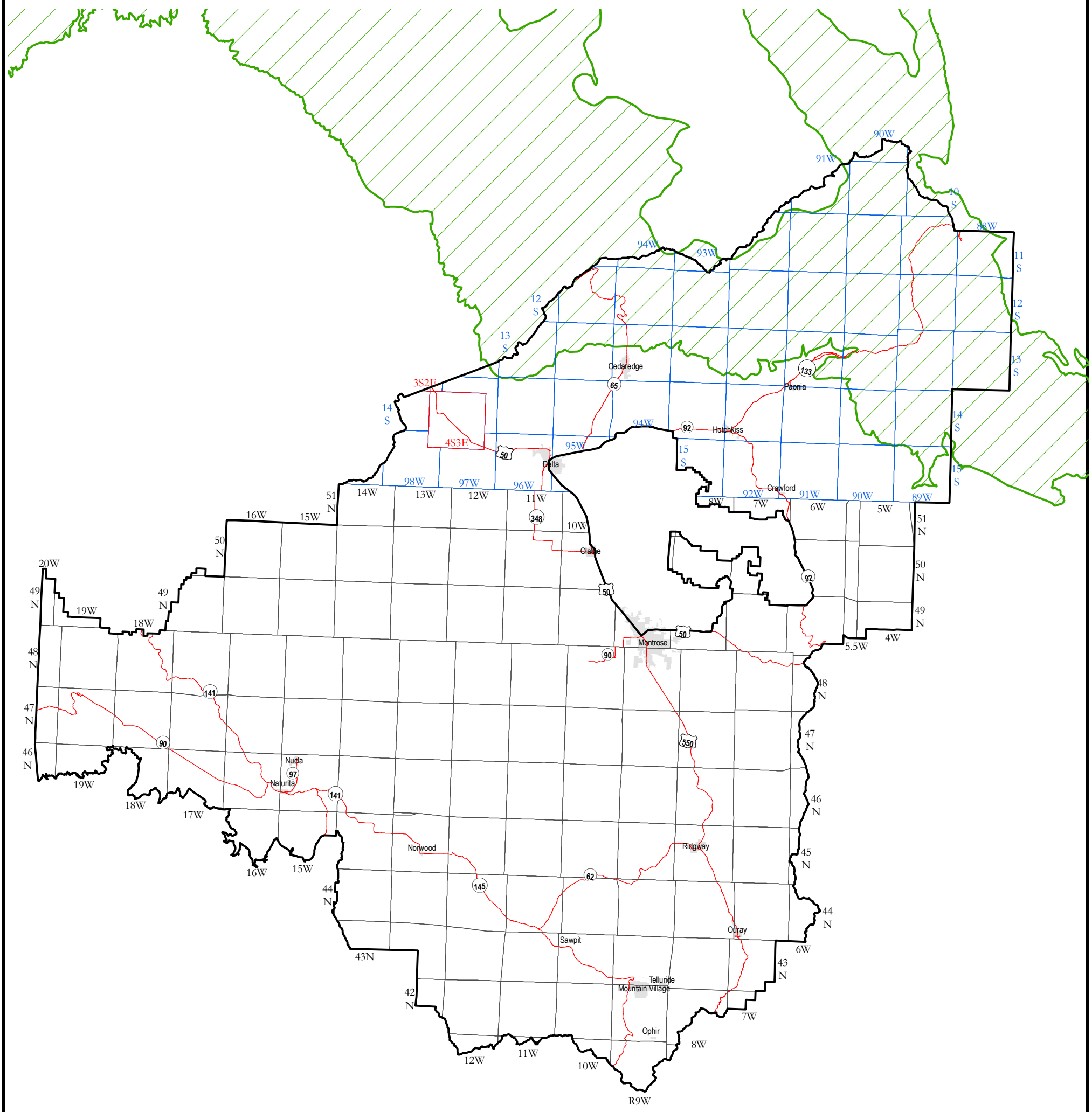
Figure A1-7.
Location of the 2002 Uinta-Piceance Basin Mesaverde Total Petroleum System Coalbed Gas Assessment Unit within the Uncompahgre Study Area.
Data from United States Geological Survey (2010).



Mesaverde Total Petroleum System Assessment Unit

Mesaverde Group Coalbed Gas

0 15 30 Miles

1:700,000

May, 2010

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

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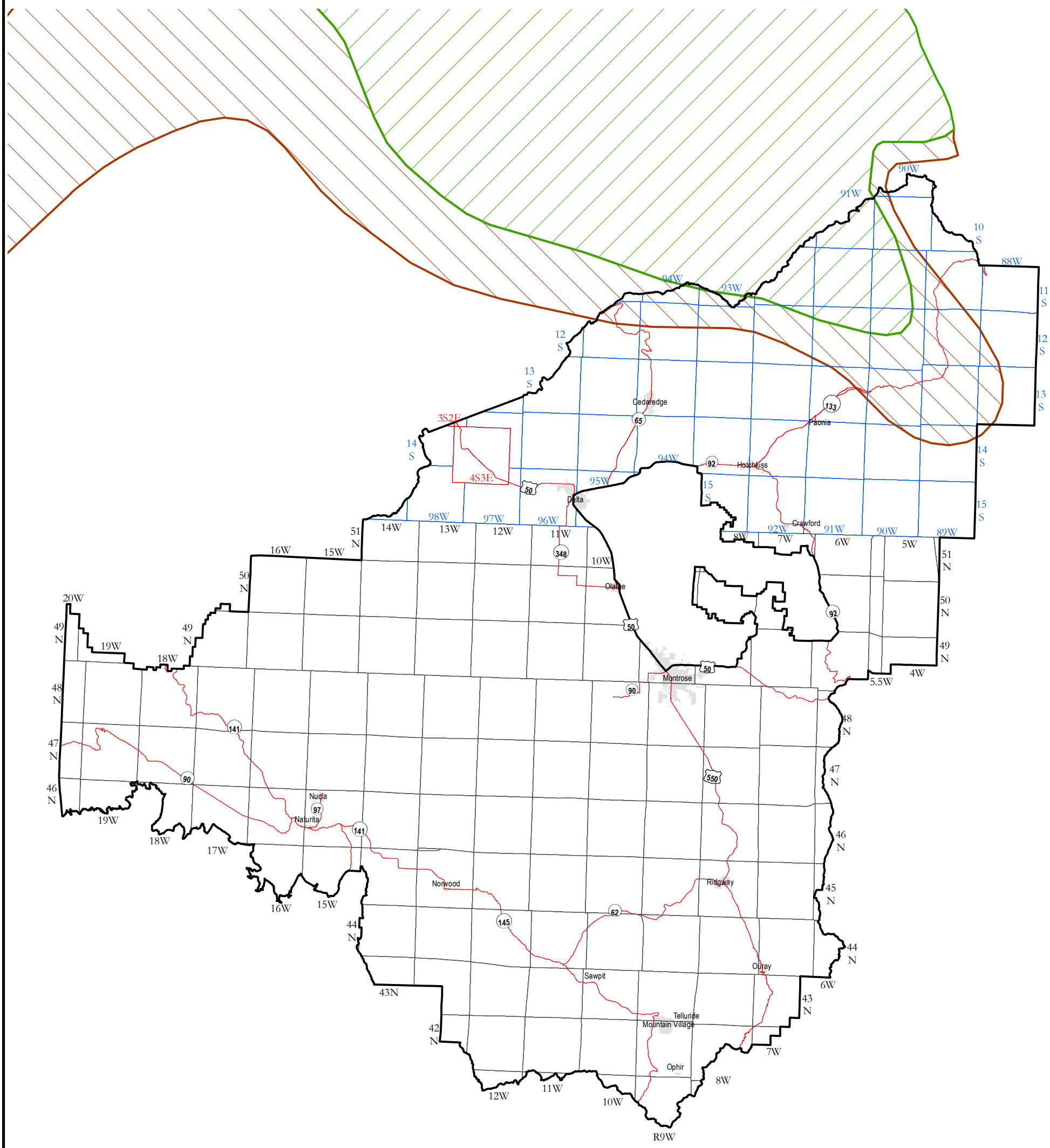
Figure A1-8.
Location of the 2002 Uinta-Piceance Basin Mancos/Mowry Total Petroleum System within the Uncompahgre Study Area. Data from United States Geological Survey (2010).



Mancos/Mowry Total Petroleum System Assessment Units

Continuous Gas

Transitional And Migrated Gas

0 15 30 Miles

1:700,000

May, 2010

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

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Table A1-1.

U.S. Geological Survey 1995 assessment of undiscovered conventional accumulation plays in the Paradox Basin Province, Uncompahgre Study Area.

		Undiscovered Oil Accumulations				Undiscovered Gas Accumulations		
Play Name	**Exploration Status**	**Number Range**	**Mean Size (MMBO)**	**Mean API Gravity (Degrees)**	**Drilling Depth Range (feet)**	**Number Range**	**Mean Size (BCFG)**	**Drilling Depth Range (feet)**
Buried Fault Blocks, Older Paleozoic	Confirmed	1-14	7.3	48	6,000-15,000	1-12	30.7	6,000-15,000
Porous Carbonate Buildup	Confirmed	10-50	6.3	43	2,500-14,000	3-15	13.1	4,000-14,000
Permian-Pennsylvanian Marginal Clastics	Hypothetical	1-4	1.3	N/A	3,000-7,000	1-15	9.0	3,000-20,000
Salt Anticline Flank	Confirmed	1-7	6.3	47.5	3,000-15,000	3-20	39.5	3,000-15,000

MMBO= Million Barrels of Oil

BCFG = Billion Cubic Feet of Gas

N/A = Not Available

Data from Huffman (1995)

Table A1-2.

U.S. Geological Survey 1995 assessment of undiscovered conventional and continuous resource plays within the Paradox Basin Province and Uncompahgre Study Area.

		Estimated Undiscovered Resources Quantities for 95 Percent, 5 Percent, and the Mean Case Probabilities of Occurrence for the Paradox Basin Province										Estimated Undiscovered Resource Quantities for 95 Percent, 5 Percent, and the Mean Case Probabilities of Occurrence for the Uncompahgre Field Office Area[1]								
		Oil (MMBO)			Gas (BCFG)			NGL (MMBNGL)				Oil (MMBO)			GAS (BCFG)			NGL (MMBNGL)		
	Play Area	95%	5%	Mean	95%	5%	Mean	95%	5%	Mean	% of Play Lying Within Field Office	95%	5%	Mean	95%	5%	Mean	95%	5%	Mean
Conventional Resource	Buried Fault Blocks, Older Paleozoic	3.30	109.50	40.10	29.22	761.30	291.70	1.96	59.29	22.00	16.30	0.54	17.85	6.54	4.76	124.09	47.55	0.32	9.66	3.59
	Porous Carbonate Buildup	10.00	235.70	152.00	37.50	756.55	482.40	2.65	62.21	40.10	0.13	0.01	0.31	0.20	0.05	0.98	0.63	0.003	0.08	0.05
	Permian-Pennsylvanian Marginal Clastics	0.00	5.50	2.30	0.00	143.00	56.20	0.00	1.76	0.70	29.80	0.00	1.64	0.69	0.00	42.61	16.75	0.00	0.52	0.21
	Salt Anticline Flank	1.70	50.70	18.10	31.35	825.75	396.30	0.16	4.79	1.80	16.30	0.28	8.26	2.95	5.11	134.60	64.60	0.03	0.78	0.29
	Total Undiscovered Conventional Resource	**15.00**	**401.40**	**212.50**	**98.07**	**2,486.60**	**1,226.60**	**4.77**	**128.05**	**64.60**	**-**	**0.83**	**28.06**	**10.37**	**9.92**	**302.29**	**129.52**	**0.35**	**11.05**	**4.14**
Continuous Resource	Fractured Interbed	60.68	597.03	242.32	48.55	477.62	193.86	N/A			7.87	4.78	46.99	19.07	3.82	37.59	15.26	N/A		
	Total Undiscovered Continuous Resource	**60.68**	**597.03**	**242.32**	**48.55**	**477.62**	**6.00**	**0.00**	**0.00**	**0.00**	**-**	**4.78**	**46.99**	**19.07**	**3.82**	**37.59**	**15.26**	**0.00**	**0.00**	**0.00**
	Total Undiscovered Resource	**75.68**	**998.43**	**454.82**	**146.62**	**2,964.22**	**1,232.60**	**4.77**	**128.05**	**64.60**	**-**	**5.60**	**75.04**	**29.44**	**13.74**	**339.88**	**144.78**	**0.35**	**11.05**	**4.14**

MMBO = Million Barrels of Oil

BCFG = Billion Cubic Feet of Gas

NGL = Natural Gas Liquids

MMBNGL = Million Barrels of Natural Gas Liquids

N/A = Not Available

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

Data from Huffman (1995)

Table A1-3.

U.S. Geological Survey 2002 assessment of undiscovered conventional accumulation assessment units in the Uinta-Piceance Basin Province, Uncompahgre Study Area.

		Undiscovered Oil Accumulations				Undiscovered Gas Accumulations		
Assessment Unit Name	**Exploration Status**	**Number Range**	**Mean Size (MMBO)**	**Mean API Gravity (Degrees)**	**Drilling Depth Range (feet)**	**Number Range**	**Mean Size (BCFG)**	**Drilling Depth Range (feet)**
Mesaverde Sandstone Gas	Confirmed	0-0	N/A	N/A	N/A	1-18	5.0	500-5,500
Paleozoic/Mesozoic	Confirmed	2-8	1.2	37	300-4,000	2-12	7.2	300-4,000
Hanging Wall	Confirmed	1-5	1.2	37	150-3000	1-5	7.2	150-3,000

MMBO= Million Barrels of Oil

BCFG = Billion Cubic Feet of Gas

N/A = Not Available

Data from U.S. Geological Survey Uinta-Piceance Assessment Team (2003)

Table A1-4.

U.S. Geological Survey 2002 assessment of undiscovered continuous accumulation assessment units in the Uinta-Piceance Basin Province, Uncompahgre Study Area.

Assessment Unit Name	Exploration Status	Median Assessment Unit Size (acres)	Median Cell Size (acres)	Median Cell Total	Median Untested Cell Total (%)	Median Untested Cells With Potential to Add Reserves (%)	Median Carbon-dioxide Content (%)	Drilling Depth Range (feet)
Mesaverde TPS PiceanceBasin Continuous Gas	Confirmed	1,273,000	67	822	97.00	20.0	3.0	1,200-4,300
Uinta-Piceance Transitional and Migrated Gas	Confirmed	2,540,000	130	2270	88.00	28.0	1.0	400-4,500
Piceance Basin Transitional Gas	Confirmed	622,000	80	188	97.00	12.0	3.0	750-2,700
Mancos/Mowry TPS Piceance Basin Continuous Gas	Confirmed	2,058,000	110	731	96.00	18.0	2.0	700-5,000
Mesaverde Group Coalbed Gas	Confirmed	4,815,000	120	90	99.80	5.0	4.0	100-1,830

Cell = A volume having areal dimensions related to the drainage area of an individual well.

Data from U.S.Geological Survey Uinta-Piceance Assessment Team (2003)

Table A1-5.

U.S. Geological Survey 2002 assessment of undiscovered conventional and continuous resource assessment units within the Uinta-Piceance Basin Province and Uncompahgre Study Area.

		Estimated Undiscovered Resources for 95 Percent, 5 Percent, and the Mean Case Probabilities of Occurrence for the Uinta-Piceance Basin Province										Estimated Undiscovered Resources for 95 Percent, 5 Percent, and the Mean Case Probabilities of Occurrence for the Uncompahgre Field Office area [1]								
		Oil (MMBO)			Gas (BCFG)			NGL (MMBNGL)				Oil (MMBO)			GAS (BCFG)			NGL (MMBNGL)		
	Assessment Unit Name	95%	5%	Mean	95%	5%	Mean	95%	5%	Mean	% of Assessment Unit Lying Within Field Office	95%	5%	Mean	95%	5%	Mean	95%	5%	Mean
Conventional Resources	Paleozoic/Mesozoic Conventional Oil and Gas Assessment Unit	2.66	11.55	6.29	16.53	97.99	49.93	0.51	3.44	1.65	11.77	0.31	1.36	0.74	1.95	11.53	5.88	0.06	0.40	0.19
	Mesaverde Sandstone Gas	N/A			17.91	140.12	66.41	0.13	1.18	0.53	5.31	0.00	0.00	0.00	0.95	7.44	3.53	0.01	0.06	0.03
	Hanging Wall	1.75	8.37	4.47	10.95	52.94	28.15	0.33	1.87	0.94	0.00004	0.000001	0.000003	0.000002	0.000004	0.000020	0.000011	0.000000	0.000001	0.000000
	Total Undiscovered Conventional Resource	**4.41**	**19.92**	**10.76**	**28.86**	**193.06**	**94.56**	**0.46**	**3.05**	**1.47**	N/A	**0.31**	**1.36**	**0.74**	**2.90**	**18.97**	**9.40**	**0.07**	**0.47**	**0.22**
Continuous Resources	Mesaverde TPS Piceance Basin Continuous Gas	N/A			1,902.23	4,594.01	3,064.27	5.00	15.09	9.19	0.16	N/A			3.04	7.35	4.90	0.01	0.02	0.01
	Uinta-Piceance Transitional and Migrated Gas	N/A			1,429.61	2,124.11	1,755.26	0.74	5.31	2.37	8.61	N/A			123.09	182.89	151.13	0.06	0.46	0.20
	Piceance Basin Transitional Gas	N/A			161.74	500.33	301.73	0.29	1.07	0.60	7.28	N/A			11.77	36.42	21.97	0.02	0.08	0.04
	Mancos/Mowry TPS Piceance Basin Continuous Gas	N/A			649.30	3,296.86	1,652.90	0.60	3.45	1.65	4.50	N/A			29.22	148.36	74.38	0.03	0.16	0.07
	Mesaverde Group Coal-bed Gas	N/A			138.72	749.54	367.77	N/A	N/A	N/A	12.80	N/A			17.76	95.94	47.07	N/A	N/A	N/A
	Total Undiscovered Continuous Resource	**0.00**	**0.00**	**0.00**	**4,281.60**	**11,264.85**	**7,141.93**	**6.63**	**24.92**	**13.81**	N/A	**0.00**	**0.00**	**0.00**	**184.88**	**470.96**	**299.45**	**0.12**	**0.71**	**0.34**
	Total Undiscovered Resource	**4.41**	**19.92**	**10.76**	**4,310.46**	**11,457.91**	**7,236.49**	**7.09**	**27.97**	**15.28**	N/A	**0.31**	**1.36**	**0.74**	**187.78**	**489.93**	**308.85**	**0.19**	**1.18**	**0.56**

MMBO = Million Barrels of Oil

BCFG = Billion Cubic Feet of Gas

NGL = Natural Gas Liquids

MMBNGL = Million Barrels of Natural Gas Liquids

N/A = Not Applicable

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

Data from U.S. Geological Survey Uinta-Piceance Assessment Team (