Reasonable Foreseeable Development Scenario for Oil and Gas Activities on BLM-Managed Lands in the HiLine Planning Area, Montana

Bowdoin Dome well cementing, 1931

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Introduction

The HiLine planning area lies within north-central Montana (Figure 1). The main goal of our evaluation is to technically analyze the oil and gas resource known to occur and potentially occurring within the planning area and to project future development potential and activity levels for the period 2011 through 2030. Historic and present oil and gas related development is presented for all lands, including Indian Reservations (Figure 2).

Our analysis makes a base line projection that assumes future activity levels on all assessed lands within the HiLine planning area will not be constrained by management-imposed conditions (Rocky Mountain Federal Leadership Forum, 2002). Indian Reservation lands and Forest Service lands (Figure 3) are included in those lands assessed. Certain lands within the planning area are not assessed for the potential for future reasonable foreseeable development. Lands with legislatively imposed restrictions (no leasing) are not included in this assessment since oil and gas activities will not be allowed on those lands (Figure 3). Those lands are:

- Glacier National Park,
- Charles M. Russell National Wildlife Refuge, and
- Wilderness Study Areas.

Most areas within the main boundary of the above "no leasing" lands are also not assessed for future reasonable foreseeable development. Inliers of land in the Wildlife Refuge and one of the wilderness study area (Figure 3) are not managed by the federal government. These inliers are assessed for the potential for future development and are included within our base line projection. Finally, projections of future activity levels for each resource management plan alternative are presented.

The reasonable foreseeable development evaluation and projections presented below review and analyze past, present, and potential future exploratory, development, and production operations and activities. It also presents occurrence potential for oil and gas, coalbed gas, and deep 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 HiLine planning area. Additional factors used to project future activities include (but are not limited to) a review of published oil and gas resource information (including a number of on-line databases) for the area, a call for data from oil and gas operators, future oil and gas price estimates, a review of petroleum technology research and development, geophysical activity, and limitations on access and infrastructure. It must be emphasized that the reasonable foreseeable development projections presented are not worst-case projections, but reasonable and science based projections of the anticipated oil and gas activity and uses logical and technically based assumptions to make those projections.

The HiLine planning area contains about 15,873,473 surface acres of all mineral ownership types. Total federal oil and gas mineral ownership, in the HiLine planning area, amounts to about 4,307,538 acres, or about 27 percent of total acres. The Bureau of Land Management (Bureau) manages most of the federal oil and gas mineral lands in the planning area (81 percent). About 1,151,548 acres of state and private surface lands within planning 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 EIS. Bureau-managed oil and gas mineral lands are lowest in Glacier County (about 6,165 acres), Liberty County (about 53,964 acres), Hill County (about 72,419 acres), Chouteau County (about 112,272 acres) and Toole County (about 113,879 acres). The remaining three counties (Blaine, Phillips, and Valley) contain the remaining 3,121,468 acres of Bureau-managed oil and gas mineral lands.

Smaller amounts of federal oil and gas mineral lands within the HiLine planning area are managed by the National Park Service (8 percent), National Wildlife Refuges (8 percent), U.S. Forest Service (0.7 percent) and other minor ownership agencies. Decisions made as part of the Resource Management Plan EIS for the HiLine planning area will not be made for these lands.

We would like to thank Cathy Stilwell of the Bureau's Wyoming State Office Reservoir Management Group staff and Barney Whiteman of the Bureau's Great Falls Oil and Gas Field Office for the important contributions that they have made to this reasonable foreseeable development analysis.

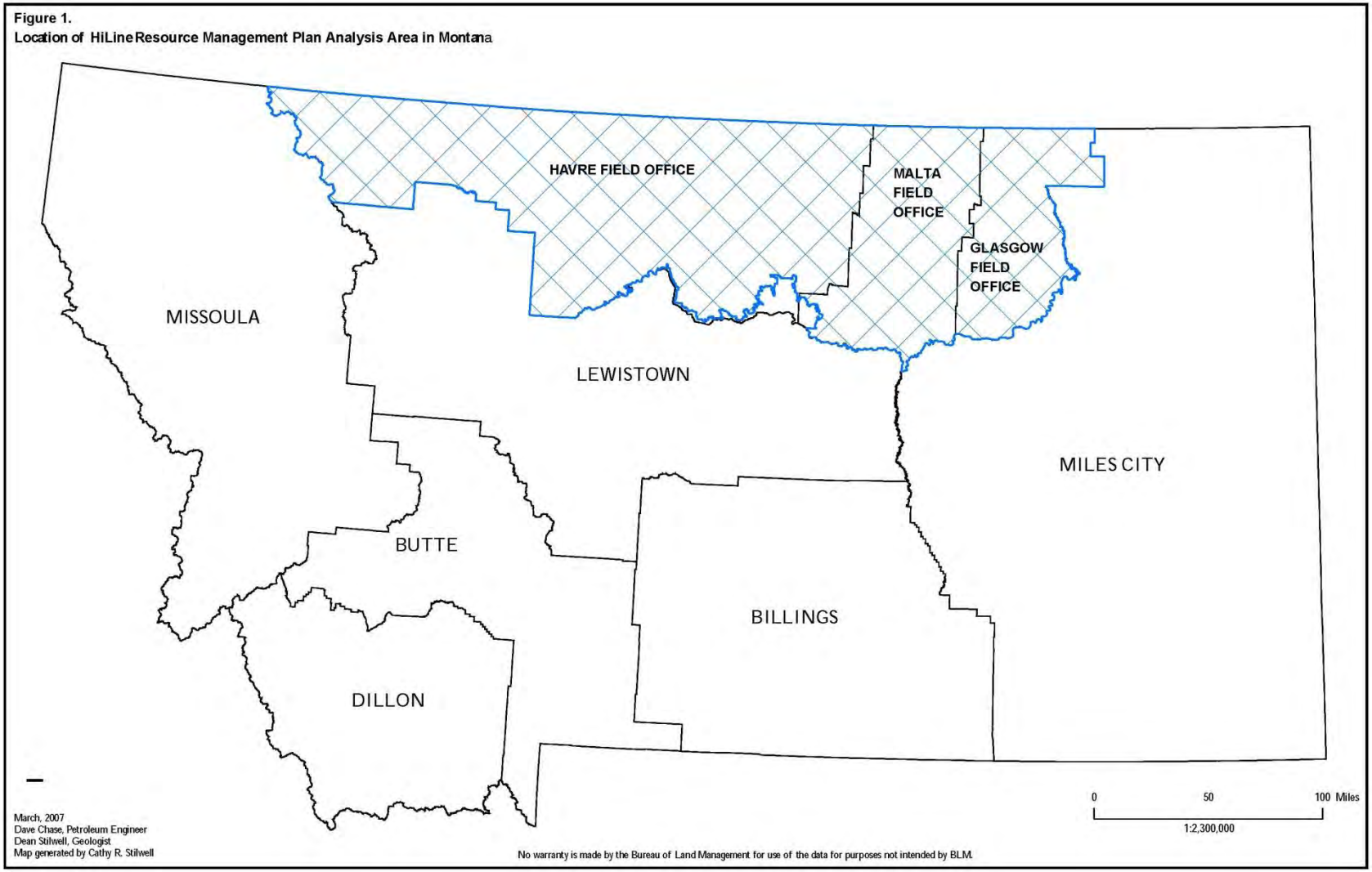
Figure 1.
Location of HiLine Resource Management Plan Analysis Area in Montana
HAVRE FIELD OFFICE
MALTA FIELD OFFICE
GLASGOW FIELD OFFICE
MISSOULA
LEWISTOWN
MILES CITY
BUTTE
BILLINGS
DILLON
0
50
100 Miles
1:2,300,000
March, 2007
Dave Chase, Petroleum Engineer
Dean Stilwell, Geologist
Map generated by Cathy R. Stilwell
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Figure 2.
Location and initial status of all wells drilled within the HiLine Planning Area. Well data from IHL Energy Group (2007) and Montana Oil and Gas Conservation Division (2007).

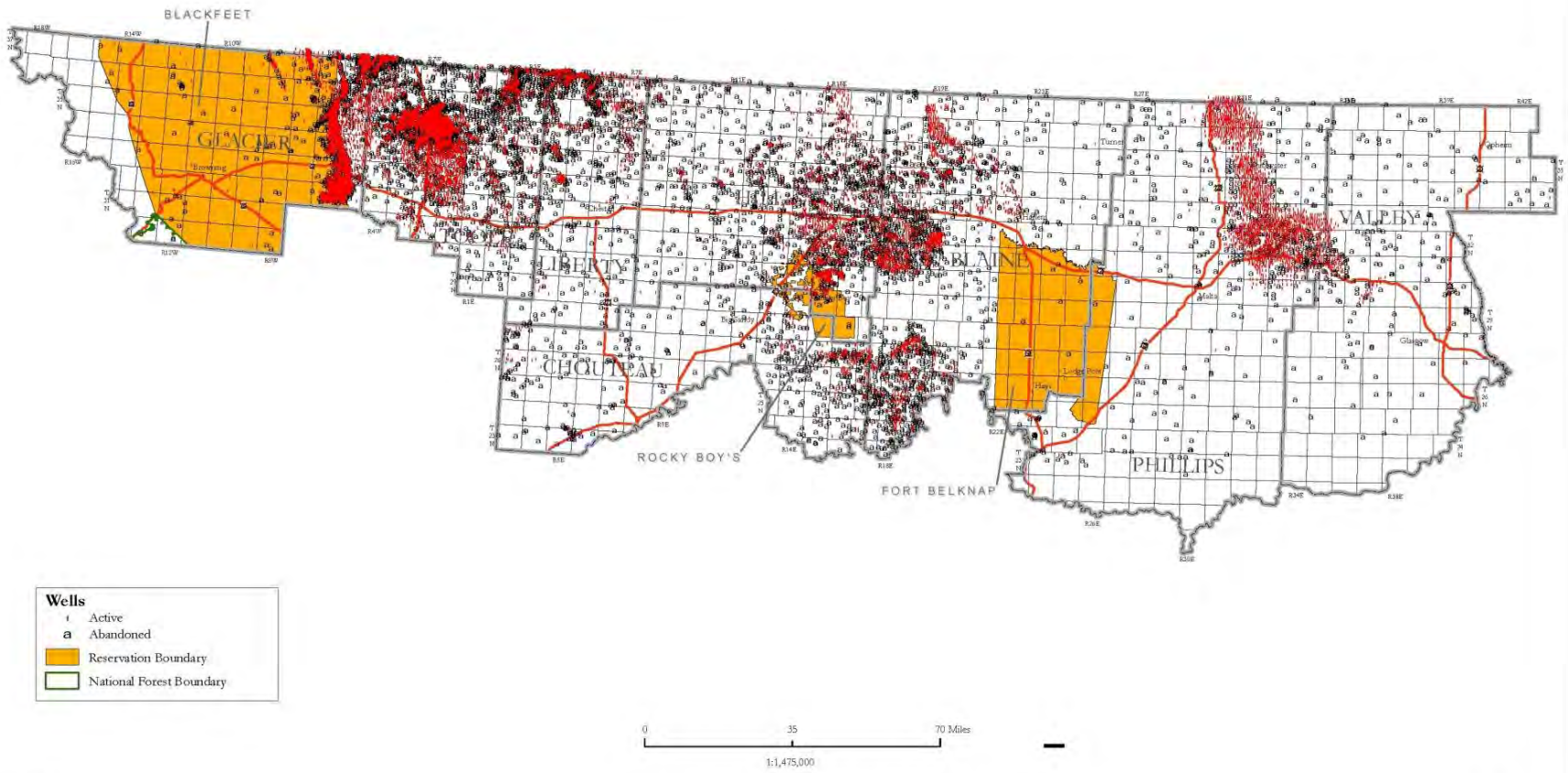
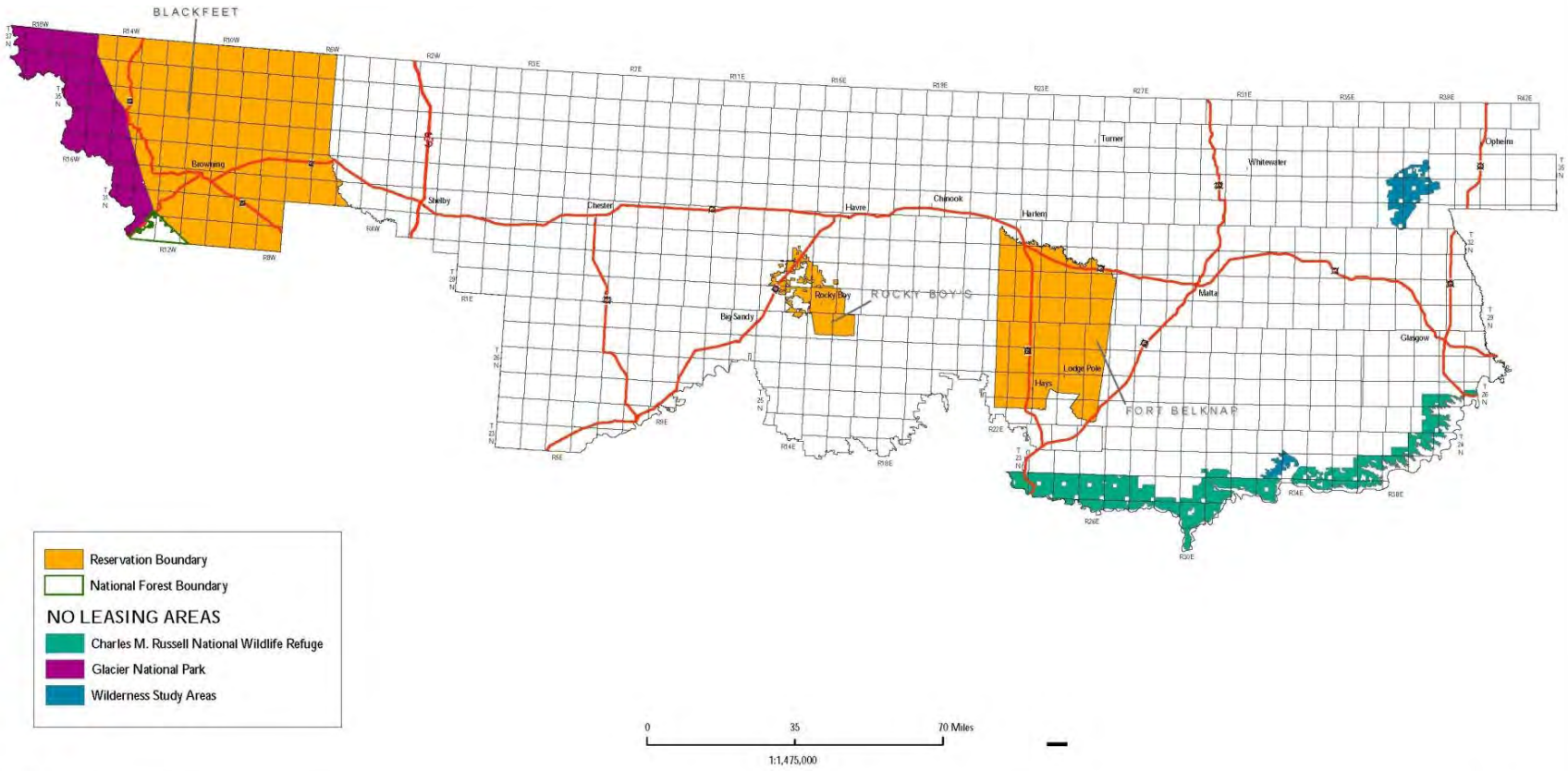


Figure 3.
HiLine Planning Area with Reservation, National Forest and National Park boundaries. Areas of legislatively imposed restriction on leasing are also indicated.



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Preliminary draft document. Does not represent final agency findings, opinions, or conclusions.

March, 2007

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 HiLine District area. Information is presented in the approximate sequence that occurs when project areas or fields are explored and then developed. The sequence begins when initial exploratory activity begins, and ends when projects are abandoned

Exploratory Activity and Operations

The petroleum industry in the U.S. 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;
- 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 gas, 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:

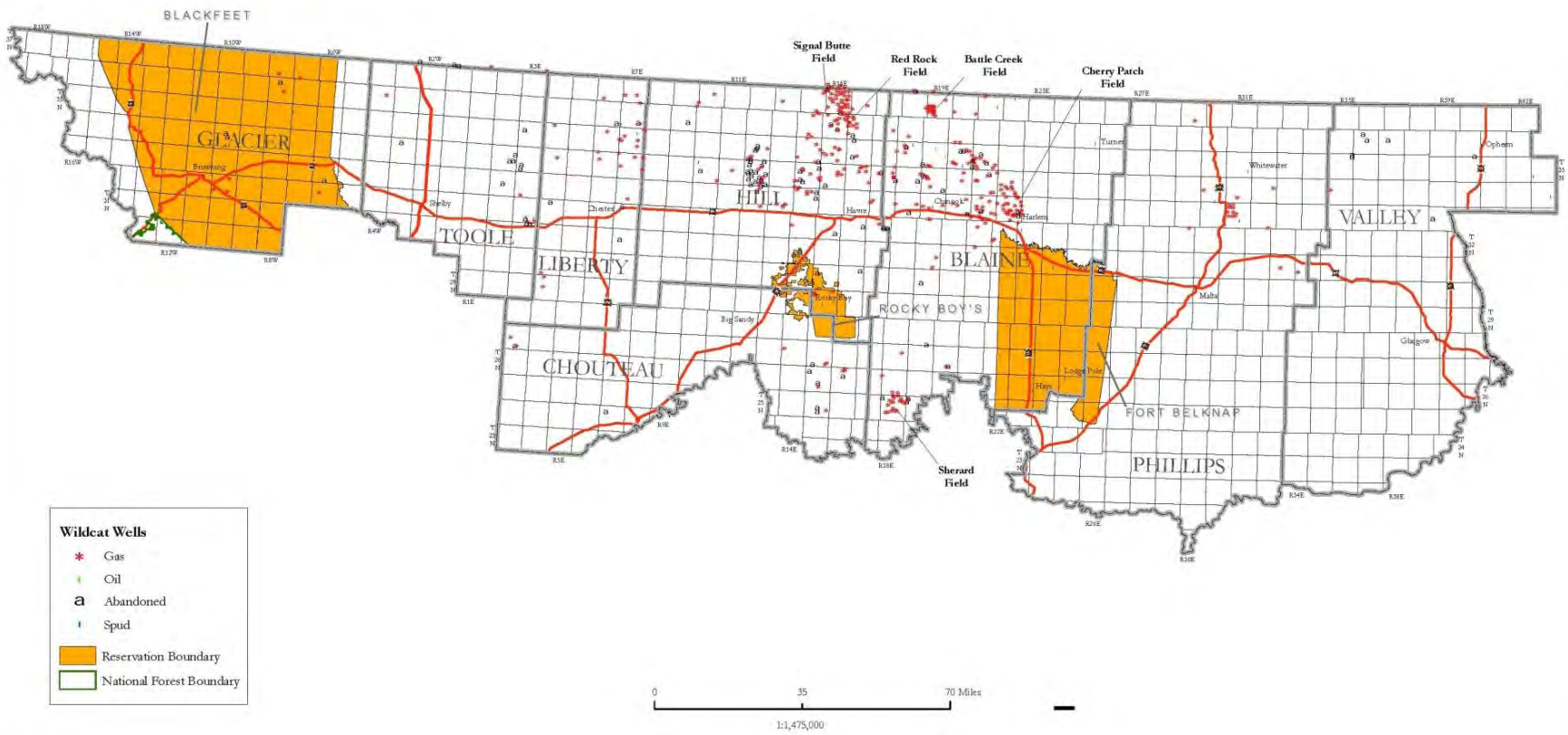
- the study and mapping of surface and subsurface geologic features to recognize potential oil and gas traps,
- determining a geologic formation's potential for containing economically producible oil and gas,
- pinpointing locations to drill exploratory wells to test all potential traps,
- drilling additional 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.

The components that can control and characterize potential oil and gas accumulations in the planning area are:

- burial and thermal histories that promoted oil and gas generation,
- existence of thick accumulations of sandstones, carbonates, shales, and locally coal (potential source and reservoir rocks),
- basin-wide and local stratigraphic variations that can create traps and reservoirs,
- structural variation and igneous intrusions with associated faulting as a means localizing oil and gas accumulations, especially when coupled with stratigraphy,
- seals that isolate the reservoir, and
- enough porosity and permeability to store oil and gas in the reservoir.

The 492 new wildcat wells, as defined by IHS Energy Group, (2007) spud in the past five years (January 2002 to March 2007) are scattered across the HiLine planning area (Figure 4). Only 402 of these wells have been completed as wildcat wells, while the rest have not received a final status or ended up being completed as development wells. Hill and Blaine counties have had the largest concentrations of wells, with 320 wildcats (80 percent) completed. Of the 402 wildcat wells, 288 wells (72 percent) were successful and the rest were abandoned.

Figure 4.
Location and initial status of all wildcat wells spud within the HiLine Planning Area in the five-year period from January 2002 to March 2007. Well data from IHS Energy Group (2007) and Montana Oil and Gas Conservation Division (2007).



Almost all abandoned wells were completed as new field wildcats in areas removed from existing fields. The rest of the wells completed were almost evenly split between new field wildcat deepening and wildcat outpost wells, with a handful from other wildcat categories.

Thirty-four operators were responsible for the 402 wildcat wells. The top six operators (Klabzuba Oil and Gas, Montana Land and Exploration, J. Burns Brown Operating, EnCana Oil and Gas, Encore Operating, and Devon Energy) drilled 307 (76 percent) of these wells. Wildcat wells (206 wells or about 51 percent) have been completed in the area of 29 fields, while the rest were drilled in scattered locations throughout the planning area. About 134 wells (33 percent) have been drilled in the vicinity of Red Rock, Cherrypatch, Signal Butte, Battle Creek, and Battle Creek fields (Figure 4).

All but two of the successful wells were completed as gas producers. The completion of only two oil wells indicates a low finding rate for these types of wildcats. Production has come from 14 producing intervals (all but two of Cretaceous age). The Eagle and Niobrara formations account for production from 237 (84 percent) of the 283 producing wells. Drilling depths for all 402 wildcats have ranged from 260 to 6,813 feet. Most wells (349 wells or 87 percent) have been drilled in the 1,000 to 2,999-foot range.

Innovative drilling and completion techniques have enabled the 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, 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). Industry is drilling fewer dry holes and reducing the number of wells needed to fully develop each reservoir. The Energy Information Administration (2007b) has projected the increase in percentage of wells drilled successfully will be 0.2 percent per year to 2030.

From the early 1990s to present, activity has focused almost entirely on very low risk development drilling in and around known field areas, which helped to improve the overall success rate. More future exploratory drilling will be required to discover new resources in the planning area and to determine whether its potential coalbed gas resource is economic to produce. Since the risk of failure is higher for these types of 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, 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 in these newly discovered traps (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 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 or leases that might contain reserves. U.S. Department of Energy (1999) estimated finding costs were approximately 2 to 16 dollars per barrel of oil equivalent in the 1970s. Finding costs

dropped to 4 to 8 dollars per barrel of oil equivalent in the 1993 to 1997 period. Since that time finding costs have fluctuated around the higher end of this range. During the 2002 to 2004 period, finding costs were 7.18 dollars per barrel of oil equivalent and they decreased by 7.1 percent to 6.67 dollars per barrel for the 2003 to 2005 period (Energy Information Administration, 2006a).

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 2005, lifting costs in the U.S. were 7.70 dollars per barrel of oil equivalent, which was an increase of 22.1 percent from a 2004 cost of 6.30 dollars per barrel (Energy Information Administration, 2006a). Lifting costs have increased in recent years because more producers are willing to spend more to produce oil and natural gas when their selling prices are higher.

Federal Development Contracts

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

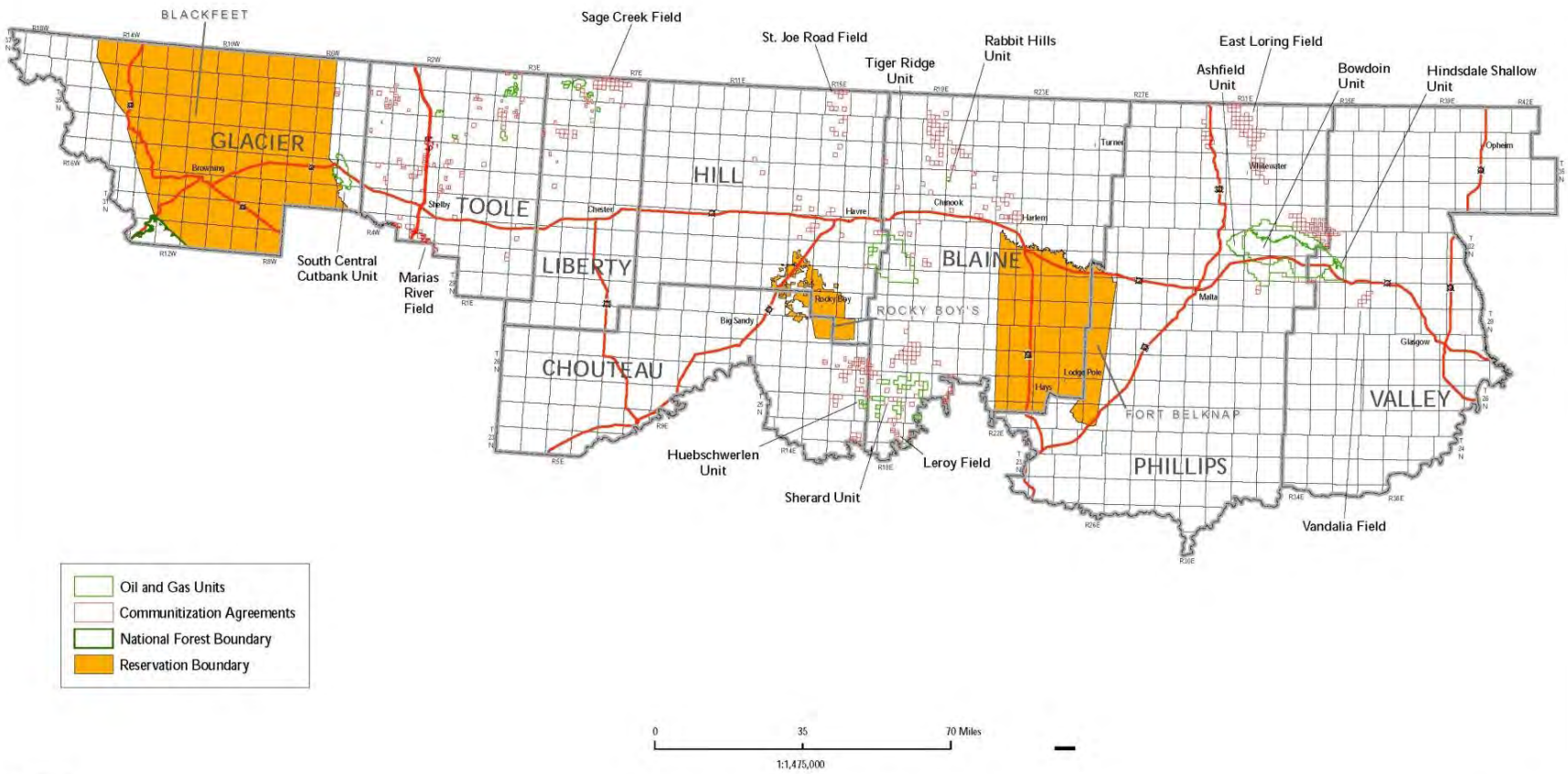
Federal oil and gas leases are incorporated into 21 active unit agreement areas that lie within the HiLine planning area boundary (Figure 5). Numerous other unit agreements have been approved but have since terminated. API/state units are established where federal lands make up less than 10 percent of the proposed unit. Four of the 21 units are API/state units.

Active units encompass lands totaling approximately 258,827 acres in area, or less than two percent of the total HiLine planning area. Only six of these unit agreements (Ashfield, Bowdoin, Hinsdale Shallow, Huebschwerlen, and Sherard units) were initially approved as exploration tools to investigate non-producing parts of the planning area. They have found and developed oil and gas and are now considered to be producing units. These six units account for 68 percent of the total unit area in the planning area. All other units were approved as secondary units to enhance the recovery of the oil resource.

Three exploratory units (Bowdoin, Ashfield, and Hindsdale Shallow) lie adjacent to each other in the east-central part of the HiLine planning area (Figure 5). Bowdoin Unit, established in 1942, is the oldest producing unit. Three exploratory units (Tiger Ridge, Huebschwerlen, and Sherard) and the Rabbit Hills secondary unit lie in the central part of the planning area. The exploratory units produce from multiple formations while the secondary unit produces from the Bowes Member of the Piper Formation.

The other 14 units (Bears Den, Dutch John Coulee, Ferdig, Flat Coulee, Fred and George Creek SASU, Fred and George Creek Sunburst B, Fred and George Creek SE, Fred and George Creek SW, Homestake, Laird Creek, Prichard Creek, South Central Cut Bank, Whitlash East, and Whitlash East Schafer) lie just east of the Blackfeet

Figure 5.
Location of all oil and gas units and communitization agreements within the HiLine Planning Area. Boundaries are from Bureau files.



Reservation to the north-central part of Liberty County (Figure 5). All are secondary or API/state type units and they produce from the Kootenai (Sunburst or Cut Bank sandstones) or Swift formations.

All units in the planning area are generally at a mature stage of development. No coalbed gas units have been established within the HiLine planning 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 Montana, the following circumstances can constitute good reason for communitization to occur.

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

As of August 30, 2006 there were 476 active communitization agreements lying within the HiLine planning area (Figure 5) that covered approximately 303,173 acres. Approximately 66 percent of these agreements covered an area of about one section (about one square mile). About 24 percent covered a half section and about seven percent cover one quarter of a section. Production in these agreements was reported from 12 different geologic units, which were:

- Judith River Formation – 11 agreements,
- Eagle Formation – 174 agreements,
- Niobrara Formation – 10 agreements,
- Carlile Formation – 51 agreements,
- Greenhorn Formation – 55 agreements,
- Blackleaf Formation – 89 agreements,
- Dakota Formation – 8 agreements,
- Kootenai Formation – 23 agreements,
- Swift Formation – 9 agreements, and
- Sawtooth, Birdbear, and Madison formations-1 agreement each.

The communitization agreements within the HiLine planning area were operated by 45 different companies. Companies operating more than 20 agreements were; Devon Energy (85 agreements), Omimex Canada (66 agreements), Noble Energy (59 agreements), Klabzuba Oil and Gas (54 agreements), Helis Oil and Gas (25 agreements) and Sands Oil (25 agreements). These six operators accounted for 66 percent of the total active agreements within the planning area. Many other agreements have been approved but have since terminated.

The oldest producing communitization agreement was approved in 1965. Agreements are concentrated in three areas of the HiLine planning area (Figure 5). In the eastern part of the planning area (northeast Phillips and west-central Valley counties) 116 agreements (24 percent) lie between East Loring Field on the north and Vandalia Field to the southeast. In the central part of the planning area (eastern Hill and western Blaine counties) 210 agreements (44 percent) lie between St. Joe Road Field on the northwest and Leroy Field on the southeast. In the part of the planning area east of the Blackfeet Reservation to the eastern part of Liberty County, 150 agreements (32 percent) lie between Sage Creek Field on the northeast and Marias River Field on the southwest.

Typical Drilling and Completion Sequence

Before an oil or gas well is drilled, an Application for Permit to Drill must be approved by the Montana Oil and Gas Conservation Division. If the well will be located on federal or Tribal 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 producing reservoir in the HiLine planning 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, which all result in easier penetration of the earth's surface;
- inserting casing to protect the subsurface and control the flow of fluids (oil, gas, and water) from the reservoir;
- perforating the well casing at the depth of the producing formation to allow flow of fluids from the formation into the borehole;
- hydraulically fracturing 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 after the well has ceased production and is plugged and abandoned.

Data was retrieved from IHS Energy Resources (2007) for wells completed between January 2002 and March 2007. Data for time from spud date to the final drill date was used to determine the average time required to drill a well within certain depth ranges. The data shows that most wells spud to depths up to 2,000 feet (average depth 1,548 feet) were completed in 4 days or less. Most wells spud to depths of 2,001 to 4, 000 feet (average depth 2,424 feet) were completed in 6 days or less. Data for only 21 wells was obtained for depths between 4,001 and 7,280 feet (average depth of 5,257 feet). Most of these wells were drilled in 6 to 13 days. One deep well (11,030 feet) took 44 days to drill.

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 HiLine planning area are could be:

- access to well sites is generally more difficult due to remoteness and sometimes steep terrain,
- harsh environments (particularly cold temperatures),
- 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 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 the loss of potential royalty

revenues for mineral estate owners. 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

Identification of the first oil in Montana in the same year that Montana Territory was established (1864). The first drilling to discover oil did not occur until the first year of Montana statehood (1889). Activity, although quite variable over time, has continued to the present with constant improvements being made in exploration and development techniques.

Early Exploration and Development Activity

Natural oil seeps have been discovered at several sites in Montana. The first recorded seep was noted in August of 1864 by immigrant train members crossing the northeast flank of the Pryor Mountains along the Bozeman Trail in Bighorn County (Erdmann, 1963). The first organized drilling to discover oil near a seep was made in 1889 in Carbon County and was unsuccessful. In 1901 drilling west of the planning area in Flathead County began. Traces of hydrocarbons were found in some of these tests. Erdmann (1963) reported that "sustained efforts to develop oil by drilling on or near obscure surface indications of petroleum and natural gas in Swiftcurrent Creek Valley throughout the 9-year period before the district became incorporated into Glacier National Park in 1910 resulted in seven tests that give it the nominal distinction of being the first oil and gas field in Montana and the only locality in the State where drilling on seepages proved successful." In 1919 these locations were flooded by water rising behind the Sherburne Lake Dam.

Exploration of surface geologic structures (anticlines and domes) has been more successful in the planning area. Surface structures display large variations in size, shape, and amount of structural relief. The major structures and locations of igneous rocks are shown on Figure 6. Bowdoin dome in Phillips and Valley counties and Kevin-Sunburst dome in northern Toole County occupy hundreds of square miles and are broad with low structural relief. On the other hand, Flat Coulee dome north of the Sweet Grass Hills is contained within only one square mile. Surface methods (surface geologic and structural mapping and aerial photograph interpretation) can be used to recognize surface structures.

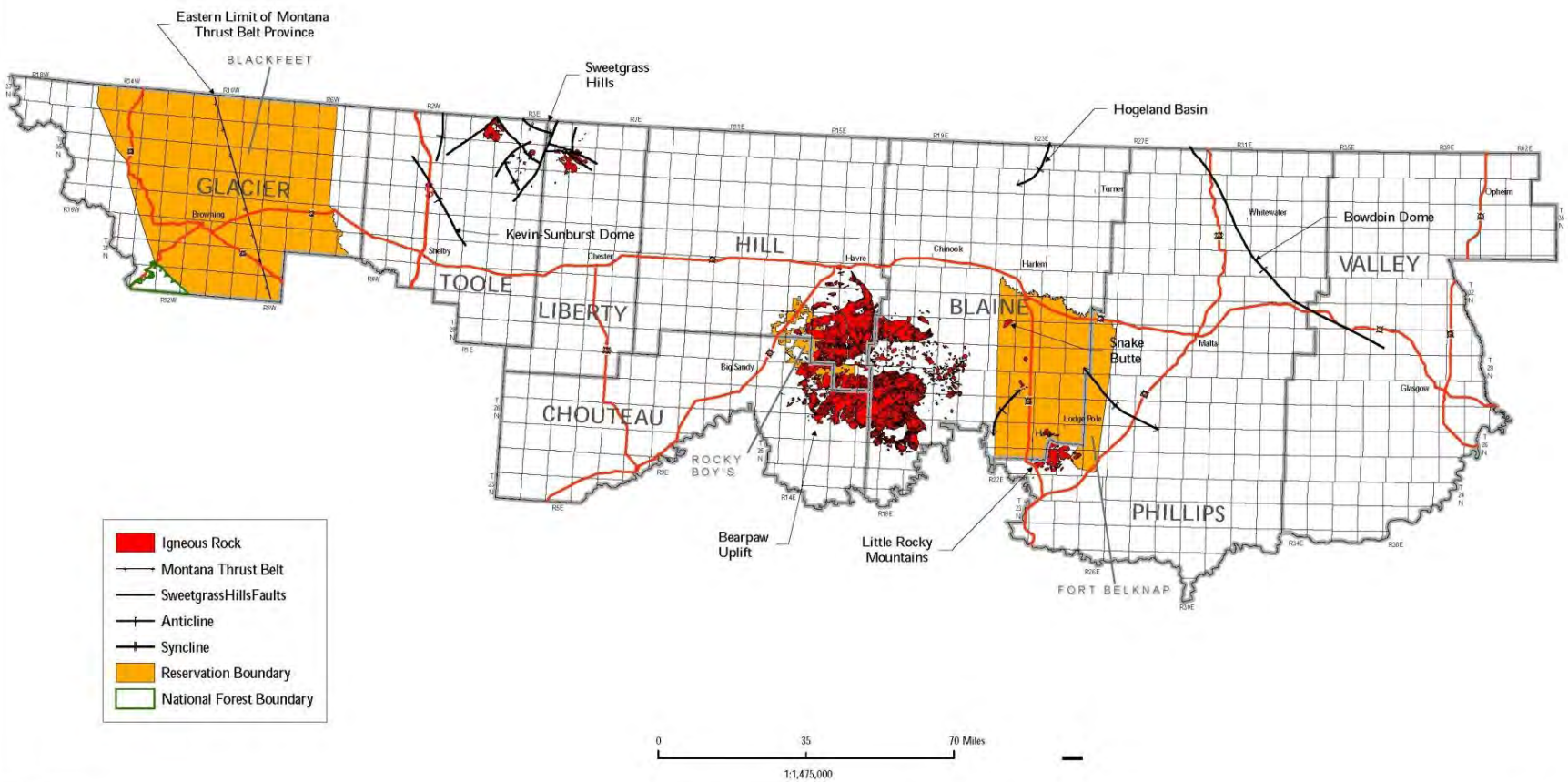
The first anticlinal test in Montana was begun in 1890 in Carbon County and the first field discovery was made at Gas City dome, outside the planning area, in 1913. Early structural fields found by surface methods in the planning area are:

- Havre (1914) abandoned,
- Box Elder gas field (1916),
- Bowdoin dome gas field (1917),
- Kevin-Sunburst dome (1922),
- Sherard (1923),
- Bears Den (1924),
- Bowes gas field (1926),
- Flat Coulee (1928), and
- Kicking Horse gas field (1943) abandoned.

National significance of Montana was achieved when oil was discovered on Kevin-Sunburst dome. Erdmann (1963) reported that this discovery, "together with the great size of the dome, first production from rocks of Paleozoic age in the Rocky Mountain region, shallow drilling, and demonstrated production from a low-dip structure, attracted immediate attention from major oil companies and numerous small operators."

A few early fields were found by a combination of mapping of surface geologic structures and the development of geophysical methods (seismic surveys) that led to deeper drilling (Erdmann, 1963). In the planning area three early fields were discovered by this combination of methods (west Utopia in 1943, North Reagan in 1947, and Bowes in 1949).

Figure 6.
Major structural elements and locations of igneous rocks within the HiLine Planning Area.



With increasing data obtained from drilled wells (12,840 wells drilled in Montana by the end of 1961) subsurface stratigraphic mapping began to contribute to exploration for new production. Erdmann (1963) reported four fields in the planning area whose discovery was primarily due to the use of subsurface stratigraphy (Reagan in 1941, Cut Bank north in 1945, Grandview in 1952, and Cut Bank southwest in 1959). A combination of subsurface stratigraphic mapping and seismic methods were responsible for four new fields in the Planning area before 1961 (Blackfoot in 1955, Red Creek in 1958, and Gold Butte and Middle Butte in 1959).

Random drilling is not based on geologic knowledge of an area, but has occasionally been used in the planning area where drilling depths are shallow and costs are relatively low. In early days this method of exploration was more common and it has become uncommon over time. Erdmann (1963) reported five early fields found by random drilling (Whitlash in 1918, Berthelote in 1926, Cut Bank gas and Devon in 1926, and Border-Red Coulee in 1929).

Producing Zones

Oil and gas occurs in the HiLine planning area in numerous geologic formations, and members of formations which range in age from the oldest producing formation (Birdbear (Nisku) Formation of Devonian age), upward in time to the Upper Cretaceous Judith River Formation. The range of producing oil and gas zones is shown in the stratigraphic chart presented in Figure 7. No Tertiary aged stratigraphic units produce within the planning area. Cretaceous aged stratigraphic units are the dominant producers throughout the planning area. These units produce mostly gas, with the Eagle Sandstone being the most widespread productive unit. Of the older stratigraphic units, the Madison Group and the Swift Formation (both producing oil and some gas) have been the most productive. Older stratigraphic units are concentrated in Toole County, with some production also in Liberty County and the easternmost part of Glacier County.

Lillis (2007) has defined two source rocks and associated reservoir gas systems for some of the gas bearing zones within the planning area. The older Colorado Group microbial (biogenic) gas system consists of Colorado Group rocks with shales of the Belle Fourche Formation, Greenhorn Formation, and the Carlile Shale being source rocks and interbedded Phillips and Bowdoin sandstones and the Greenhorn Formation being reservoirs for the generated gas. The younger (Late Cretaceous) Montana Group microbial system consists of Montana Group source rocks that include the Gammon Shale and possibly the Claggett Shale, and the Eagle Sandstone and Judith River Formation being the reservoirs for the generated gas.

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). The National Petroleum Council (2003) postulates that technology improvements will play a lesser role in gas resource enhancement in the 2003-2008 time periods. Technology improvements will play a greater role after 2008 when higher gas prices will motivate industry to invest more in development of technology. Future average improvement rates for certain types of technology are:

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

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 access restrictions delay drilling activity by an average of two years.

Figure 7. Stratigraphic chart of major producing oil and gas zones within the HiLine Planning Area. Formations and Members get progressively older from the top of the list to the bottom.

Periods	Groups	Formations and Members
Upper Cretaceous	Montana	Judith River Formation Clagget Formation Eagle (Virgelle) Sandstone Telegraph Creek Formation Niobrara Formation - (1st White Specks) Carlile Formation – Bowdoin Sandstone Greenhorn Formation – Phillips Sandstone and 2nd White Specks Belle Fourche Formation
	Colorado	
Lower Cretaceous		Blackleaf (Dakota, Mowry) Formation - Fish Scales and Bow Island Sandstone Kootenai Formation – Burwash, Sunburst, Moulton, Lander, and Cut Bank Sandstones
Jurassic	Ellis	Sawtooth (Piper) Formation Rierdon Formation Swift Formation Morrison Formation
Mississippian	Madison	Sun River Dolomite Mission Canyon Limestone Lodgepole Limestone
Devonian		Birdbear (Nisku) Formation

Drilling and Completion Activity

A total of 20,170 wells had been drilled or spud within the HiLine planning area through March 28, 2007 (IHS Energy Group, 2007). About 16 percent of these wells were drilled on Bureau-managed oil and gas lands.

The Montana Oil and Gas Conservation Division (2006b) provided information about active producing and producible oil and gas wells for all counties within the HiLine planning area. Table 1 shows total active or producible oil and gas wells (8,088 wells) within the planning area. About 62 percent of these wells are producing or shut-in gas wells and the rest are producing or shut-in oil wells. Three counties (Chouteau, Hill, and Phillips) have only gas completions. Hill County shows one shut-in oil well which may be the result of a wrong well classification.

Table 1. Total number of active federal, tribal, private, and state wells (excluding service, injection, water source, gas storage, unknown, completed, spud, and abandoned status wells) in the HiLine Planning Area. Toole County (2,738 wells) accounts for almost 34 percent of the total wells (8,088). Data are from the Montana Oil and Gas Conservation Division (2006b).

County	*Producible Gas Wells*	*Gas Shut-In Wells*	*Producible Oil Wells*	*Oil Shut-In Wells*	*Total Active Oil and Gas Wells*	*Total*
Blaine	707	250	52	59	4	**1,072**
Chouteau	112	37	0	0	0	**149**
Glacier	228	57	496	520	30	**1,331**
Hill	528	143	0	1	2	**674**
Liberty	180	84	83	63	2	**412**
Phillips	1,477	62	0	0	3	**1,542**
Toole	791	230	758	950	9	**2,738**
Valley	107	11	43	9	0	**170**
Total Wells	**4,130**	**874**	**1,432**	**1,602**	**50**	**8,088**

When all well types are considered, 44 percent of all drilled or spud wells are still in an active status (8,882 wells) while the rest have been abandoned or are in the process of being abandoned (IHS Energy Group, 2007 and Montana Oil and Gas Conservation Division, 2007). Wells are abandoned because:

- they were "dry"--no hydrocarbons were encountered, or hydrocarbons were not present in economic quantities;
- they initially were capable of producing hydrocarbons, but they became uneconomic to produce at a later date; or
- mechanical difficulties within a borehole prevented economic oil and gas production.

A map of the HiLine planning area shows locations of all 20,170 wells spud to March 28, 2007 (Figure 2). For this map we considered active wells to be those with an initial completion status of oil, gas, spud, temporarily

abandoned, injection, gas storage, or service. All other wells we considered to be abandoned. This map shows that drilling has been spread out across the planning area, with the largest drilling concentrations in northern Phillips County, western Blaine and eastern Hill counties, and Toole and easternmost Glacier counties. Even with many thousands of wells drilled, many townships have received little or no drilling activity. A few of the townships where there has been little or no activity have been closed to leasing (Figure 3).

As of April 2007 there were 8,882 wells of the original 20,170 wells spud that could still be considered to be active in the HiLine planning area (Table 2). The subject table shows that about one third of the active wells lie in Toole County and almost 83 percent lie in four of the eight counties. Chouteau and Valley counties each only contain between one and two percent of the total active wells in the planning area. Table 2 shows that wells related to oil development (oil and injection well types) account for almost 39 percent of all active wells. Figure 8 shows the locations of all active oil and injection well types. Almost 91 percent of the wells related to oil development are located in Glacier and Toole counties where there are few Bureau-managed oil and gas minerals (120,044 acres or less than 3 percent of Bureau-managed oil and gas minerals). Major oil producing fields in these counties are Kevin-Sunburst, Cut Bank, Fred & George Creek, Graben Coulee, and Regan. Liberty and Blaine counties contain the other nine percent of active oil and injection well types. The major oil producing fields in these two counties are Whitlash, Flat Coulee, Bowes, and Rabbit Hills. The other four counties only contain a small handful of oil wells.

Table 2 also shows that 60 percent of all active well types are gas wells. These wells cover a larger portion of the HiLine planning area (Figure 9) than those related to oil development. Four counties (Phillips, Toole, Blaine, and Hill) account for almost 84 percent of the total active gas wells. Remaining gas wells are split between the other four counties. Figure 9 shows the locations of the larger gas fields within the planning area.

Gas storage wells are used to temporarily store produced gas in a reservoir until it is sold and then shipped to the buyer. Gas storage wells (63 active wells) account for only a small percentage of total active wells in the HiLine planning area (Table 2, and Figure 9). Most of these wells are located in Cut Bank Field, with Box Elder, Old Shelby, and Kevin-Sunburst fields containing the rest.

Thirty active wells are used as water source wells by the petroleum industry. Nineteen wells are used to dispose of waste fluids associated with oil and gas developments.

Drilling Rates

Figure 10 graphically shows the number of wells completed (producers and dry holes) per year in the HiLine planning area from 1990 through 2005 (Montana Oil and Gas Conservation Division, 2006b). During the 16-year time period show, activity levels have fluctuated, but during the final six years (2000 through 2005) drilling activity has remained fairly high.

Table 3 shows wells completed (producers and dry holes) per year and presents the resultant failure rate for these wells from 1990 through 2006. The fewest wells (96 wells) were drilled in 1996 and the most wells (286 wells) were drilled in 2006. A total of 3,631 wells (excluding service, injection, and temporarily abandoned wells) were drilled during the 17-year time period. There were 2,767 gas completions, 204 oil completions, and 660 dry holes. About 93 percent of the successfully completed wells were natural gas completions. The failure rate for the 16-year time period averaged 18 percent. The failure rate has varied from a low of 11 percent in 2004 to a high of 32 percent in 1994. The failure rate has been lower from 2000 through 2006, due to the large number of development wells that have been drilled. During this period, the failure rate has been only 15.4 percent.

Production

Early exploration in Montana emphasized finding crude oil reserves. Erdman (1963) reported that "gas was an incidental, unwanted byproduct with little or no market that seldom brought a price of more than three cents per thousand cubic feet at the casing head, if it could be sold at all." He indicated that even into the 1960s interest in exploring for gas was less than that for oil due to the tradition of low field prices for this commodity. In more recent years rises in the value of natural gas have made it a highly sought after commodity. In 2005, Montana ranked 16th in the U.S. in natural gas production (Energy Information Administration, 2007c).

Table 2. Active oil and gas wells in the HiLine Planning Area as of April, 2007.

Well Type and Status	***Blaine***	***Chouteau***	***Glacier***	***Hill***	***Liberty***	***Phillips***	***Toole***	***Valley***	***Total Wells***
Gas- completed	1	4	3	7	4	3	36	3	**61**
Gas- producing	716	110	230	550	174	1,503	783	111	**4,177**
Gas- shut-in	251	38	57	159	100	101	245	11	**962**
Gas- spud	20	2	5	18	8	45	8		**106**
Gas- temporarily abandoned			2	2		3	3		**10**
Gas- unknown	2	1		6	5		8	1	**23**
Total Gas Wells	**990**	**155**	**297**	**742**	**291**	**1,655**	**1,083**	**126**	**5,339**
Oil- completed			33				29		**62**
Oil- producing	56		494	1	82		722		**1,355**
Oil- shut-in	55		521	1	63		995		**1,635**
Oil- unknown			17		2		10		**29**
Oil- spud	3		2		2	2	2	2	**13**
Oil- temporarily abandoned	4		28		2		6		**40**
Oil- permitted for injection					9				**9**
Total Oil Wells	**118**	**0**	**1,095**	**2**	**160**	**2**	**1,764**	**2**	**3,143**
Disposal- active			11				6		**17**
Disposal- temporarily abandoned			2						**2**
Total Disposal Wells	**0**	**0**	**13**	**0**	**0**	**0**	**6**	**0**	**19**
Injection, EOR[1]- active	7		37		16		40		**100**

Injection, EOR- producing			2						**2**
Injection, EOR- shut-in			1		9				**10**
Injection, EOR- temporarily abandoned			85		2		2		**89**
Injection, Indian- active			44						**44**
Injection, Indian- completed			21						**21**
Injection, Indian- producing			1						**1**
Injection, Indian- temporarily abandoned			21						**21**
Total Injection Wells	**7**	**0**	**212**	**0**	**27**	**0**	**42**	**0**	**288**
Total Gas Storage Wells	**4**		**17**	**2**			**40**		**63**
Water Source- completed	1		10		8		3	1	**23**
Water Source- shut-in			2				1		**3**
Water Source- producing							1		**1**
Water Source- unknown					1		1		**2**
Water Source- spud					1				**1**
Total Water Source Wells	**1**	**0**	**12**	**0**	**10**	**0**	**6**	**1**	**30**
Total Wells	**1,120**	**155**	**1,646**	**746**	**488**	**1,657**	**2,941**	**129**	**8,882**

[1] EOR = Enhanced Oil Recovery

Figure 8.
Active oil wells, injection wells, water source wells, and major oil fields within the HiLine Planning Area. Well data from Montana Oil and Gas Conservation Division (2007).

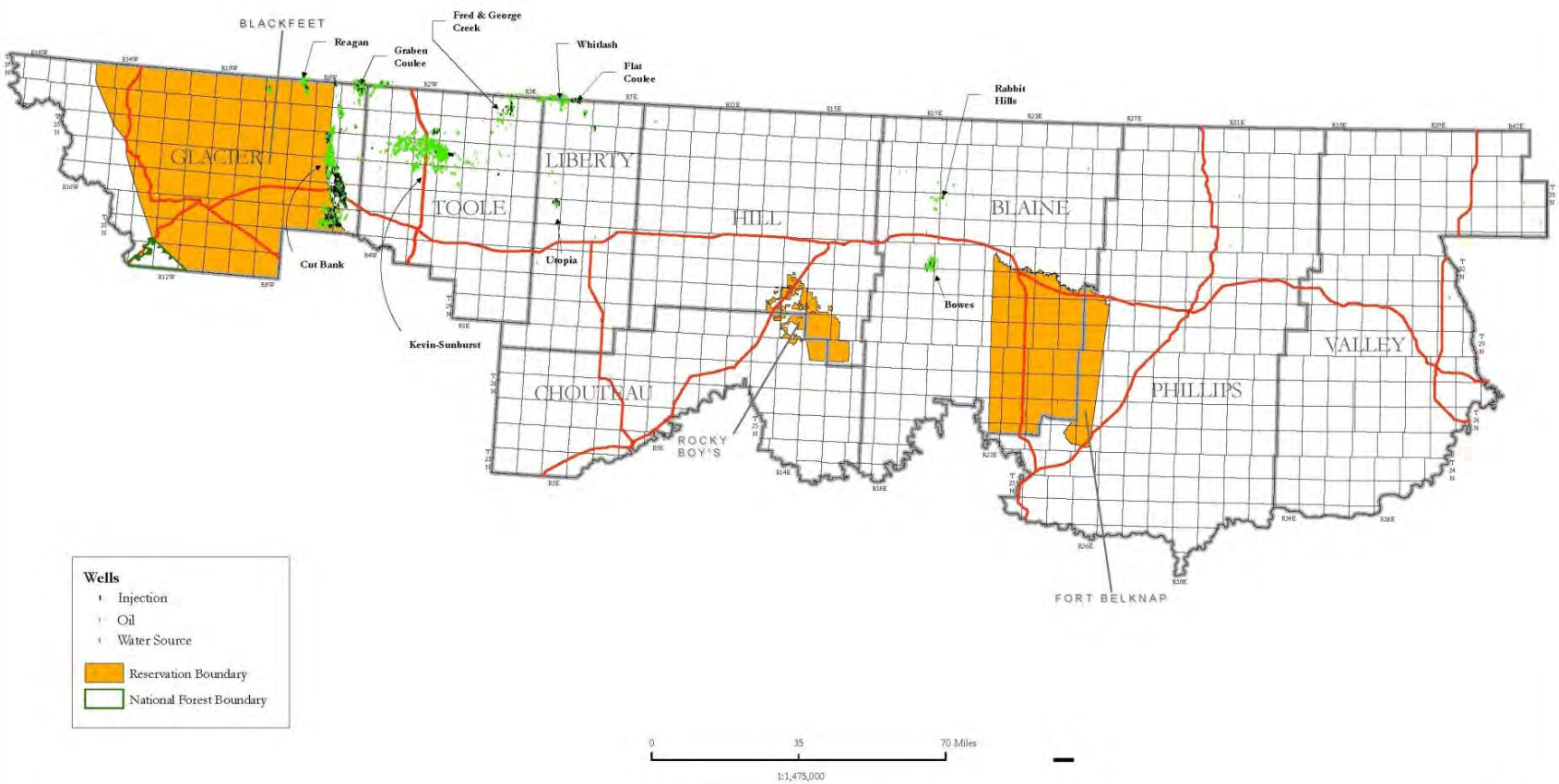


Figure 9.
Active gas wells, gas storage wells, and major gas fields within the HiLine Planning Area. Well data from Montana Oil and Gas Conservation Division (2007).

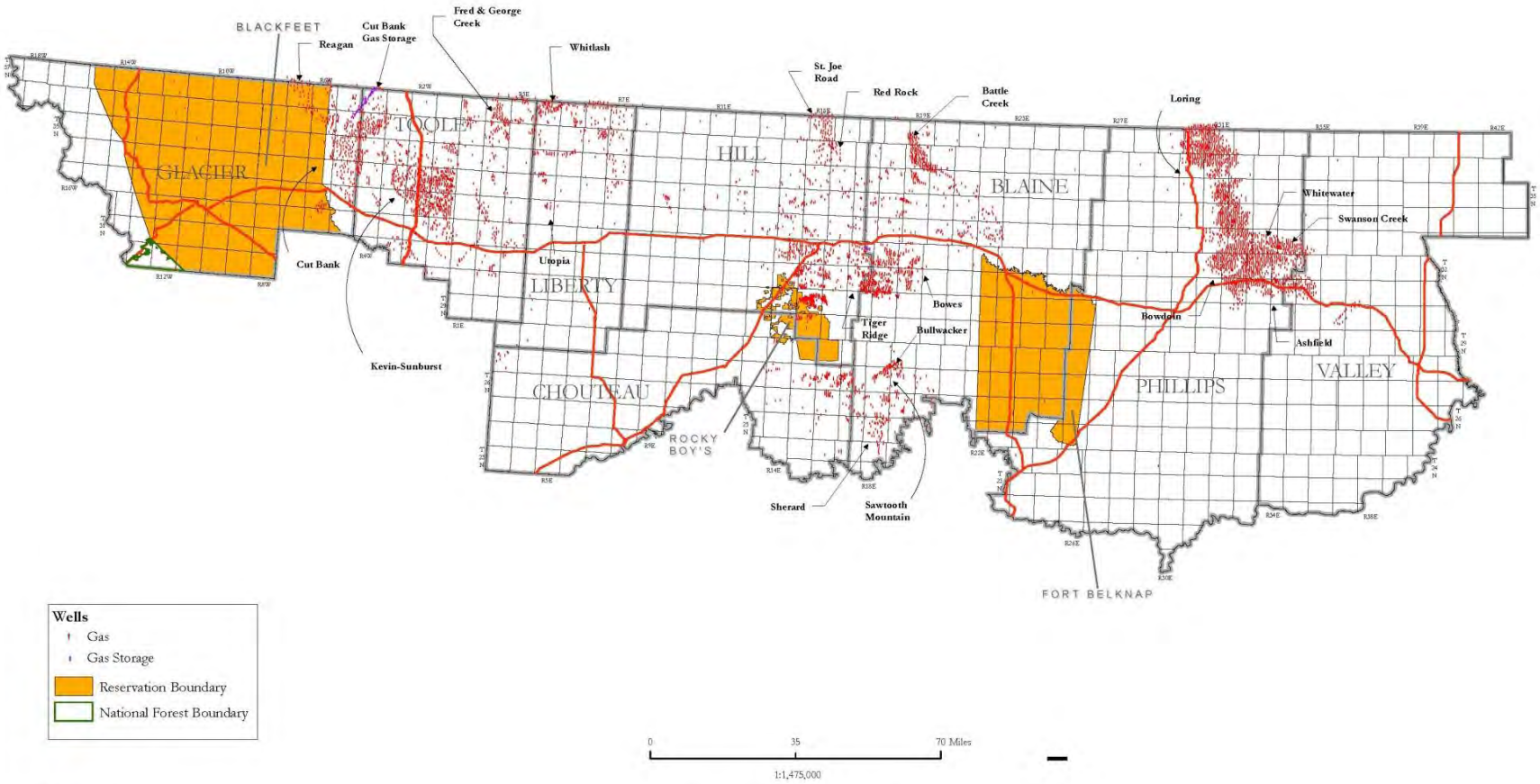


Figure 10. Annual well completions (excluding service, injection, and temporarily abandoned wells) from federal, tribal, private, and state wells in the HiLine Planning Area. Data are from the Montana Oil and Gas Conservation Division (2006b).

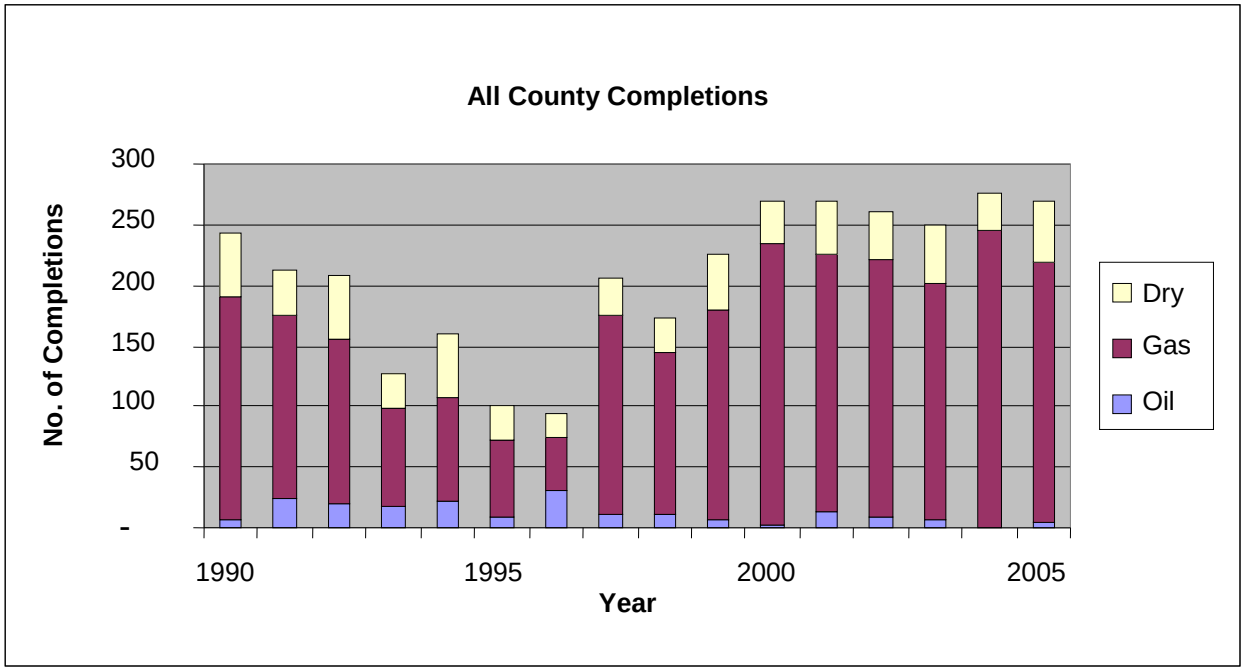


Table 3. Annual well completions (excluding service, injection, and temporarily abandoned wells) from federal, tribal, private, and state wells in the HiLine Planning Area. Data are from the Montana Oil and Gas Conservation Division (2006b and 2007).

Year	*Producible Oil Well/Oil Shut-In*	*Producible Gas Well/Gas Shut-In*	*Dry*	*Yearly Total*	*Percent Failure*
1990	7	184	53	244	22
1991	25	151	36	212	17
1992	19	136	52	207	25
1993	17	83	27	127	21
1994	22	86	51	159	32
1995	8	65	27	100	27
1996	31	43	21	96	22
1997	10	166	30	206	15
1998	11	134	29	168	17
1999	6	173	47	226	21
2000	2	232	35	269	13
2001	13	212	45	270	17
2002	9	213	39	261	15
2003	7	195	48	250	19
2004	1	244	30	275	11
2005	4	215	51	270	19
2006	12	235	39	286	14
Totals	**204**	**2,767**	**660**	**3,631**	

Gas from Upper Cretaceous sands is dominantly a "dry," sweet (no hydrogen sulfide) gas high in methane content with little or no ethane (Erdmann, 1963). It generally also contains a few percent nitrogen and sometimes carbon dioxide. BTU content averages about 979 (Erdmann, 1963). Gas found in Early Cretaceous – and Late Jurassic – age rocks often contain "wet," sweet solution gas (gas dissolved in oil reservoirs). Gas content is predominately methane, with up to 13 percent ethane, and smaller amounts of propane and butane. Percentages of nitrogen and carbon dioxide are larger than those found in Upper Cretaceous gas. BTU content averages 1,000 (Erdmann, 1963). Gas from older Paleozoic – aged formations usually contains some hydrogen sulfide. Most gas of this age is solution gas derived from crude oil. Gases rich in carbon dioxide and nitrogen have been found in some Devonian and Cambrian units on the Sweetgrass arch part of the planning area.

Figure 11 graphically shows oil and gas production from counties within the HiLine planning area since 1990 (Montana Oil and Gas Conservation Division, 2006b). During this period, annual overall gas production rates have increased while oil production rates have decreased. Increased drilling rates within the HiLine planning area have resulted in increased gas production, unlike the national trend reported by Foss (2007) above. In this region operators have been able to drill and test new play concepts while gas prices have been to their advantage and this has resulted in the increased production rate. A portion of this increase is due to improved success rates. Foss (2007) has reported a 25 percent nationwide improvement in success rates since the late 1990s.

Figure 11. Annual natural gas (excluding associated gas) and oil production from federal, tribal, private, and state wells in the HiLine Planning Area. Data are from the Montana Oil and Gas Conservation Division (2006b).

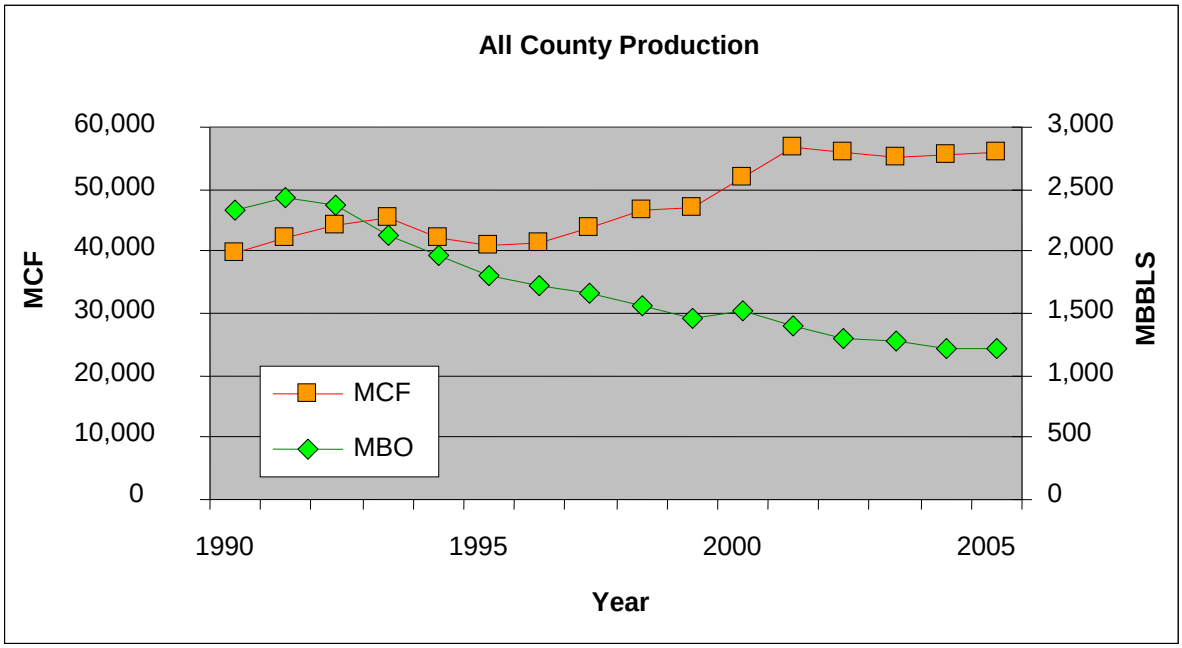


Table 4 shows the annual natural gas production (excluding associated gas) for each county since 1990 (Montana Oil and Gas Conservation Division, 2006b and 2007). In 2006, the HiLine planning area produced 56.3 billion cubic feet of natural gas. Natural gas production, within the planning area, was 61 percent of Montana's total natural gas production. Clearly the planning area is an important natural gas producing area for Montana. Production for 2006 was about 41 percent greater than the production recorded for 1990. For the 17-year time period, 2001 recorded the highest production at almost 56.8 million cubic feet of natural gas. Blaine, Hill, and Phillips counties accounted for 81 percent of the natural gas production in 2006, with Phillips County leading the way. Gas production in the planning area has remained fairly constant since 2001 after increasing in 1999 and 2000. Figure 12 presents the same information as Table 4, but in two types of graphical format.

Table 4. Annual natural gas production (excluding associated gas), per county, from federal, tribal, private, and state wells in the HiLine Planning Area. Associated gas accounts for less than one percent of the annual natural gas production in this area. Values are thousand cubic feet of gas. Data are from the Montana Oil and Gas Conservation Division (2006b and 2007).

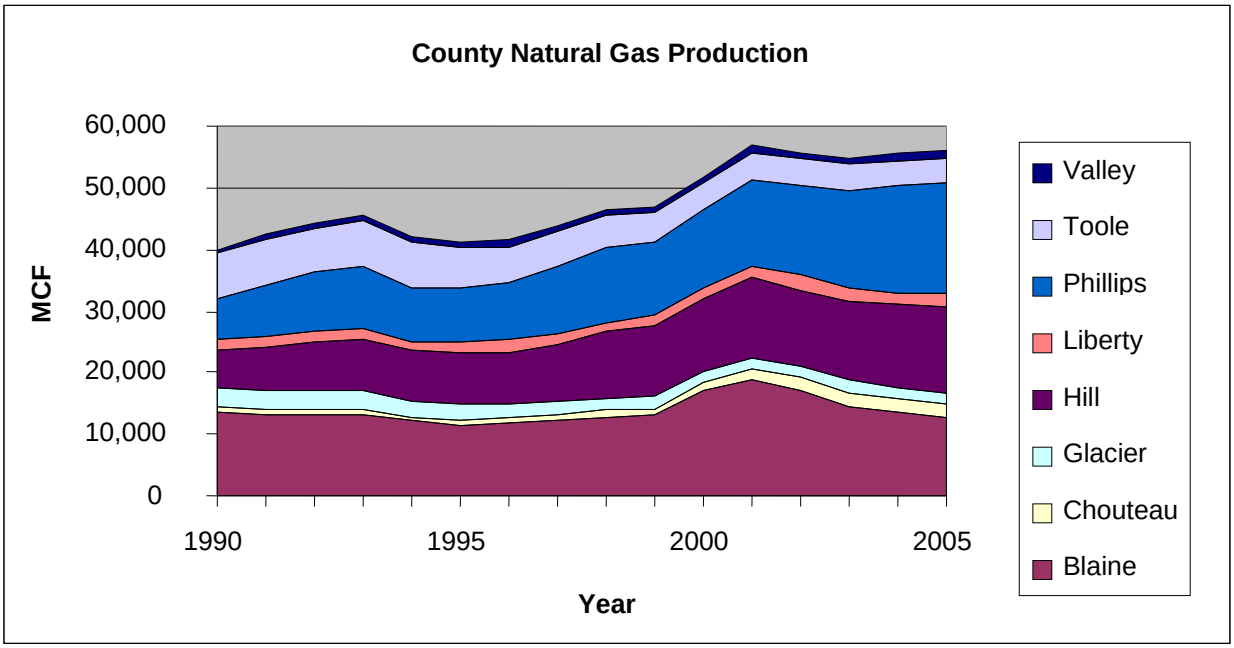
Year	*Blaine*	*Chouteau*	*Glacier*	*Hill*	*Liberty*	*Phillips*	*Toole*	*Valley*	*Total Annual Production*
1990	13,556	1,104	2,751	6,536	1,667	6,473	7,427	427	**39,851**
1991	13,087	1,088	2,927	7,024	1,847	7,983	7,456	900	**42,312**
1992	13,218	872	2,773	8,007	1,985	9,313	7,249	620	**44,036**
1993	13,194	838	2,852	8,343	1,986	9,991	7,639	498	**45,342**
1994	12,081	686	2,691	8,047	1,523	8,697	7,359	1,011	**42,095**
1995	11,558	884	2,341	8,556	1,597	8,758	6,541	827	**41,062**
1996	12,030	832	2,183	8,381	1,825	9,298	5,778	1,143	**41,470**
1997	12,445	892	2,093	9,081	1,743	11,158	5,342	1,226	**43,980**
1998	12,850	1,112	1,994	10,580	1,701	11,980	5,198	1,013	**46,428**
1999	13,129	1,057	1,836	11,682	1,481	11,904	4,906	992	**46,987**
2000	17,070	1,539	1,753	11,620	1,727	12,784	4,507	887	**51,887**
2001	18,723	1,841	1,779	13,062	1,895	13,899	4,458	1,106	**56,763**
2002	17,067	2,298	1,802	12,167	2,539	14,335	4,329	1,300	**55,836**
2003	14,374	2,447	1,849	12,680	2,317	15,818	4,377	1,095	**54,958**
2004	13,567	2,298	1,739	13,339	2,046	17,164	4,126	1,144	**55,422**
2005	12,820	2,043	1,620	14,099	2,171	18,025	4,101	1,141	**56,020**
2006	13,966	1,732	1,596	14,130	1,951	17,756	4,080	1,076	**56,317**

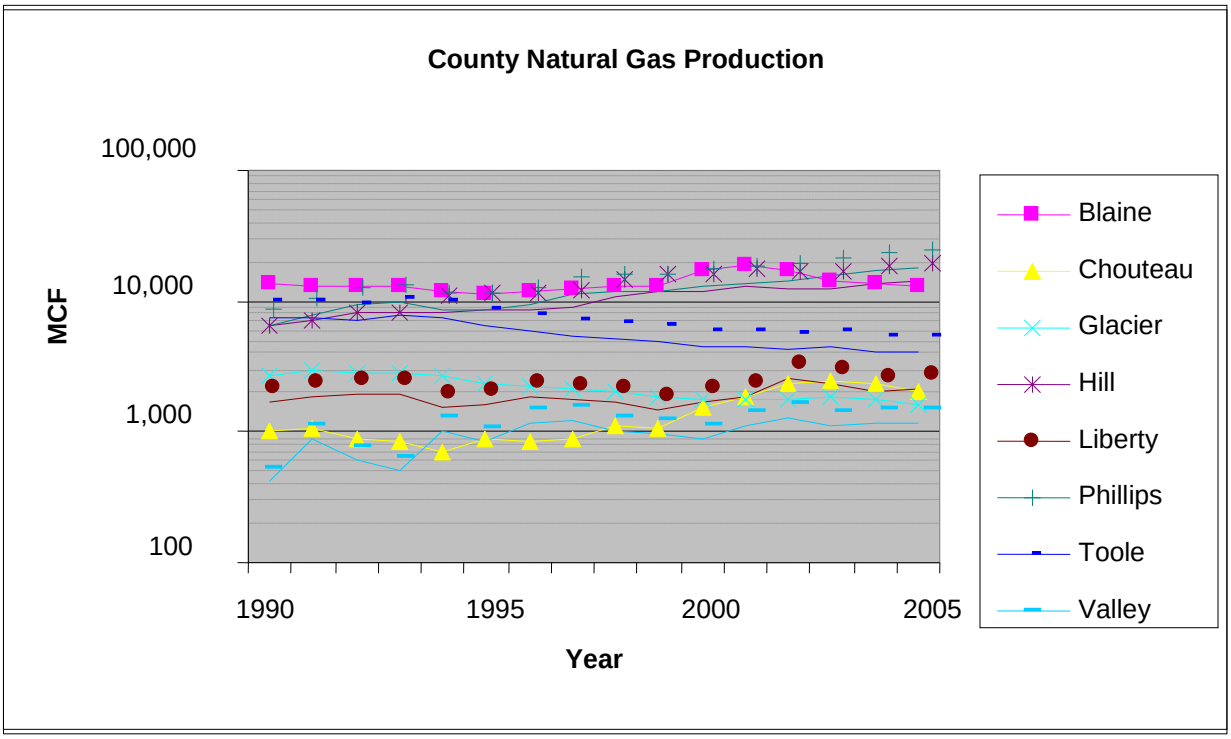
In 2005, HiLine planning area fields accounted for 21 of the top 25 gas producing fields and 40 of the top 50 gas producing fields for the State of Montana (Montana Oil and Gas Conservation Division, 2006a). Production for the top 10 producing gas fields (along with the number of producing wells in 2005) is presented in Table 5. The Bowdoin Field is the second largest producing gas field in Montana and produced 14 percent of the state's total natural gas production in 2005.

Table 5. The top ten producing gas fields in the HiLine Planning Area for 2005. Data are from the Montana Oil and Gas Conservation Division (2006a).

Field Name	*Producing Wells*	*Gas Produced (billion cubic feet)*
Bowdoin	627	12.577153
Tiger Ridge	544	11.689042
Whitewater	339	2.337836
Battle Creek	168	2.330854
Red Rock	87	2.158045
Sawtooth Mountain	64	2.112939
Bullwacker	73	2.000830
Cut Bank	678	1.918065
Sherard, Area	77	1.871248
Loring	242	1.580442

Figure 12. Annual natural gas production (excluding associated gas) per county from federal, tribal, private, and state wells in the HiLine Planning Area. The upper graph presents production cumulatively while the lower graph presents separate curves for each counties production. Associated gas accounts for less than one percent of the annual natural gas production. Data are from the Montana Oil and Gas Conservation Division (2006b).





Oil producing fields in the HiLine planning area presently make a smaller contribution to the state's oil production than gas production does. In 2006, planning area oil production was only about four percent of Montana's total oil production (Montana Oil and Gas Conservation Division, 2006a and 2007). Table 6 shows the annual oil production

for each county since 1990. Glacier, Toole, Blaine, Valley, and Liberty counties accounted for almost all of the oil production, with Glacier County leading the way at 37 per cent of production in 2006. Chouteau and Phillips counties recorded no oil production while Hill reported only 2,281 barrels. Figure 13 presents the same information as Table 6, but in two types of graphical format.

Table 6. Annual oil production (per county) from federal, tribal, private, and state wells in the HiLine Planning Area. Two counties (Chouteau and Phillips) do not report any oil production. Values are thousand barrels of oil. Data are from the Montana Oil and Gas Conservation Division (2006b and 2007).

Year	*Blaine*	*Chouteau*	*Glacier*	*Hill*	*Liberty*	*Phillips*	*Toole*	*Valley*	*Total*
1990	186	0	1,039	0	186	0	611	314	**2,337**
1991	312	0	1,041	1.052	182	0	615	286	**2,437**
1992	372	0	947	2.352	171	0	582	302	**2,377**
1993	306	0	850	0.740	174	0	506	288	**2,125**
1994	274	0	853	0.739	168	0	414	253	**1,963**
1995	255	0	755	0.819	160	0	379	250	**1,799**
1996	282	0	727	0.645	141	0	359	205	**1,716**
1997	261	0	714	0.497	134	0	370	188	**1,667**
1998	231	0	674	0.490	118	0	360	168	**1,551**
1999	233	0	621	0.397	104	0	349	149	**1,457**
2000	227	0	638	0.790	98	0	393	166	**1,522**
2001	211	0	582	0.770	106	0	320	172	**1,391**
2002	188	0	538	1.150	99	0	296	181	**1,303**
2003	180	0	520	0.852	106	0	285	190	**1,282**
2004	210	0	488	0.750	93	0	283	133	**1,207**
2005	207	0	465	0.786	90	0	297	157	**1,217**
2006	202	0	466	2.281	82	0	379	122	**1,252**

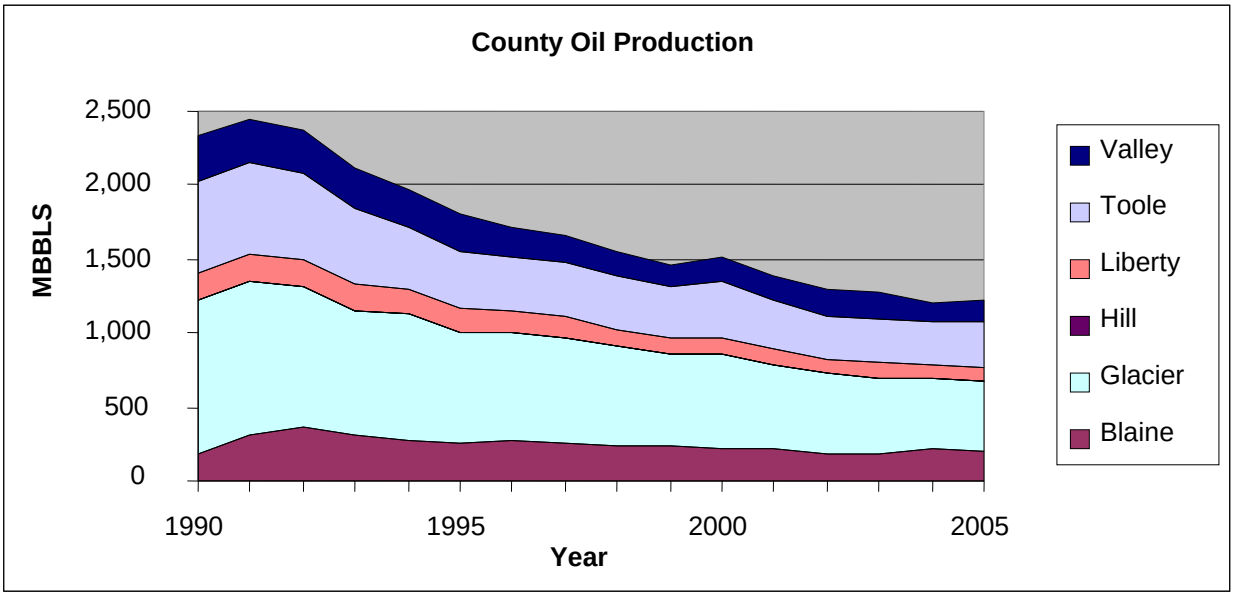
In 2005, the HiLine planning area produced 1.225 million barrels of oil (Montana Oil and Gas Conservation Division, 2006a). That year's production was about 50 percent less than the production recorded for 1991. The reported 1991 production was the highest of the 16-year time period and production has declined each year since then. It is unlikely that oil production in the planning area will increase in the future. Oil production will most likely continue to decline.

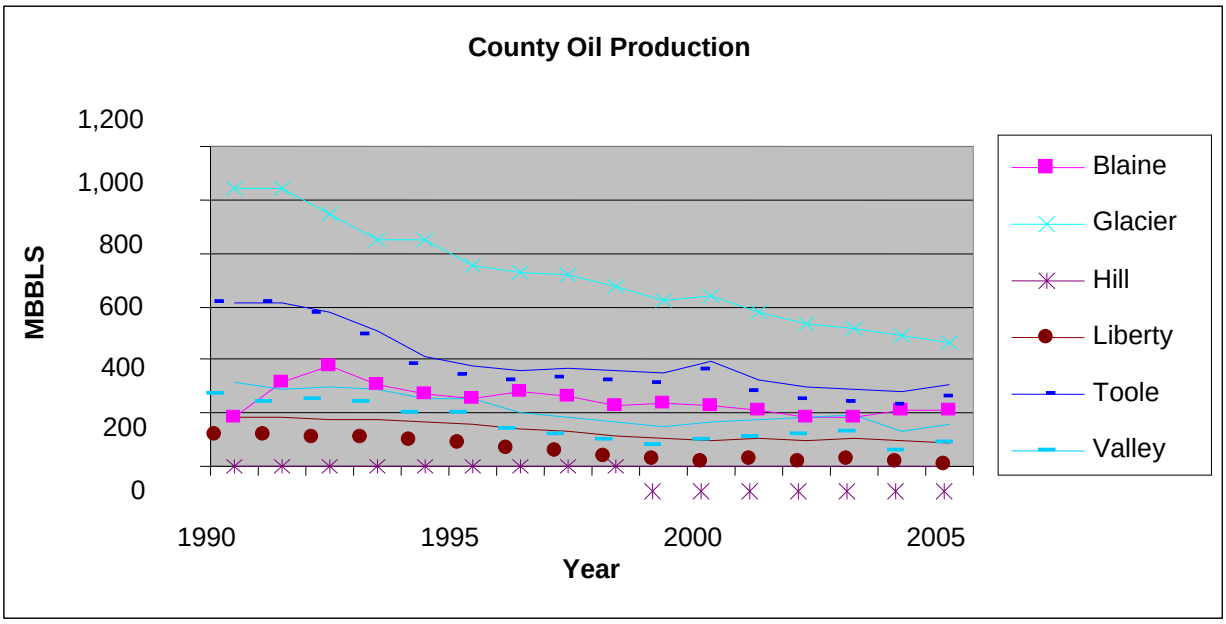
In 2005, only four fields (Cut Bank – ranked 9th, Kevin-Sunburst – ranked 13th, Rabbit Hills – ranked 35th, and Reagan – ranked 42nd) ranked in the top 50 oil producing fields in Montana (Montana Oil and Gas Conservation Division, 2006a). Production for those four oil fields (along with the number of producing wells in 2005) is presented in Table 7.

Table 7. The top four producing oil fields in the HiLine Planning Area for 2005. Data are from the Montana Oil and Gas Conservation Division (2006a).

Field Name	*Producing Wells*	*Oil Produced (barrels)*
Cut Bank	678	340,777
Kevin-Sunburst	862	208,617
Rabbit Hills	16	98,632
Reagan	54	77,269

Figure 13. Annual oil production per county from federal, tribal, private, and state wells in the HiLine Planning Area. The upper graph presents production cumulatively while the lower graph presents separate curves for each counties production. Two counties (Chouteau and Phillips) do not report any oil production. Data are from the Montana Oil and Gas Conservation Division (2006b).





Producing Fields

On April 30, 2007 we downloaded well information on all active wells (Figures 8 and 9) within the HiLine planning area. Wells were separated by well type and present status and are listed by field or field area name on Tables 8, 9, and 10. A few small fields contain no active wells and are not listed on these tables. Only eight fields or field areas exclusively contain oil wells (Table 8). Only 127 wells of the 8,882 currently active wells in the planning area are in these eight fields. The largest field is Graben Coulee (Figure 8) with 98 of these wells. This field and two others lie in Glacier County. Four fields lie in Toole County and one field (Horse Creek), with only one oil well, lies in Liberty County.

Table 8. Oil Fields in the HiLine Planning Area by well type and status.

Oil Field	*Well Type and Status*								
	Oil-Completed	*Oil-Producing*	*Oil-Shut-in*	*Total Oil Wells*		*Disposal*	*Injection*	*Water Source*	*Total Wells*
Berthelote			3	**3**					**3**
East Glacier			2	**2**					**2**
Graben Coulee		27	65	**92**		3	2	1	**98**
Horse Creek			1	**1**					**1**
Landslide Butte		9	9	**18**			1		**19**
Little Phantom			1	**1**					**1**
Ninemile			2	**2**					**2**
Pete Creek			1	**1**					**1**

Table 9. Gas Fields in the HiLine Planning Area by well type and status.

Gas Field	*Well Type and Status*										
	Gas-Completed	*Gas-Producing*	*Gas-Shut-in*	*Gas-Spud*	*Gas- Temp. Aban-doned*	*Gas-Unknown*	*Total Gas Wells*		*Gas Storage*	*Water Source*	*Total Wells*
Alma	1	1					**2**				**2**
Amanda		26	6				**32**				**32**
Antelope Coulee		1					**1**				**1**
Ashfield		179					**179**				**179**
Assiniboine Creek			1				**1**				**1**
Badlands		14	1				**15**				**15**
Black Butte		1	1				**2**				**2**
Black Coulee		12	9				**21**				**21**
Black Jack		12	2				**14**				**14**
Bowdoin	1	543	35	14			**593**				**593**

	Well Type and Status										
Gas Field	***Gas-Completed***	***Gas-Producing***	***Gas-Shut-in***	***Gas-Spud***	***Gas- Temp. Aban-doned***	***Gas-Unknown***	***Total Gas Wells***		***Gas Storage***	***Water Source***	***Total Wells***
Box Elder							**0**		6		**6**
Brown's Coulee		18	8				**26**				**26**
Bullwacker		78	7	1			**86**				**86**
Camp Creek		1					**1**				**1**
Chain Lakes		7	5				**12**				**12**
Cherry Patch		45	12				**57**				**57**
Chinook		6					**6**				**6**
Chip Creek		3					**3**				**3**
Coal Coulee			2				**2**				**2**
Coal Mine Coulee		5	1				**6**				**6**
Devon	2	38	18				**58**				**58**
Dunkirk		45	13	1			**59**				**59**
Eagle Springs		5	5				**10**				**10**
Ethridge		13	2				**15**				**15**
Fitzpatrick Lake		6	4				**10**				**10**
Fort Conrad		5	1				**6**				**6**
Fresno		16	2			1	**19**				**19**
Galata		3	6				**9**				**9**
Gildford			4				**4**				**4**
Gold Butte			1				**1**				**1**
Guinn Dome			1				**1**				**1**
Hardpan		8	1			1	**10**				**10**
Havre		1	1				**2**				**2**
Haystack Butte		16	4				**20**				**20**
Keith		33	8				**41**				**41**

	Well Type and Status										
Gas Field	***Gas-Completed***	***Gas-Producing***	***Gas-Shut-in***	***Gas-Spud***	***Gas- Temp. Aban-doned***	***Gas-Unknown***	***Total Gas Wells***		***Gas Storage***	***Water Source***	***Total Wells***
Kinyon Coulee South		1					**1**				**1**
Lakeside			1				**1**				**1**
Laredo			4			1	**5**				**5**
Ledger			4				**4**				**4**
Leroy		7	8				**15**				**15**
Little Creek	1	3	3				**7**				**7**
Little Rock		15	2				**17**				**17**
Lohman		2	1				**3**				**3**
Loring	2	417	35	22	2		**478**				**478**
Marias River	1	11	4				**16**				**16**
Martin Lake			5				**5**				**5**
Middle Butte		5	3				**8**				**8**
Milk River		12	4				**16**				**16**
Mt. Lilly	1	3	3				**7**				**7**
O'Briens Coulee		13	7			1	**21**				**21**
Old Shelby	1	101	8			1	**111**		2		**113**
Police Coulee		8	1				**9**				**9**
Rattlesnake Coulee			1				**1**				**1**
Red Rock		68	28	1			**97**				**97**
Rocky Boy		19	4				**23**				**23**
Rudyard		7	7				**14**				**14**
Sage Creek		11	17	2		3	**33**				**33**
Sandwich			1				**1**				**1**
Sawtooth Mountain	1	79	19	2			**101**				**101**
Sears Coulee		1	1				**2**				**2**

	Well Type and Status										
Gas Field	***Gas-Completed***	***Gas-Producing***	***Gas-Shut-in***	***Gas-Spud***	***Gas- Temp. Aban-doned***	***Gas-Unknown***	***Total Gas Wells***		***Gas Storage***	***Water Source***	***Total Wells***
Shelby	1	6	2				**9**				**9**
Sherard	2	98	52				**152**				**152**
Snoose Coulee		11	3				**14**				**14**
Snow Coulee			1				**1**				**1**
Spring Coulee		1	2				**3**				**3**
St. Joe Road		62	7	9			**78**				**78**
Strawberry Creek		1	1				**2**				**2**
Swanson Creek		73	6				**79**				**79**
Sweetgrass			2				**2**				**2**
Three Mile		3	1				**4**				**4**
Tiber		15	3				**18**				**18**
Tiger Ridge	6	550	119	12		3	**690**				**690**
Timber Creek		1	1		1		**3**				**3**
Trail Creek		8					**8**				**8**
Two Forks			2				**2**				**2**
Vandalia	3	9	5			1	**18**				**18**
West Butte Shallow		2	1				**3**				**3**
Whitewater		381	11	6	1		**399**				**399**
Wildcat Chouteau County	1	3	6	1			**11**				**11**
Wildcat Hill County	1	10	28	4	2	1	**46**				**46**
Wildcat Liberty County	2		28	5			**35**			2	**37**
Xeno		1					**1**				**1**

Table 10. Combined Oil and Gas Fields in the HiLine Planning Area by well type and status.

Well Type and Status	***Arch Apex***	***Battle Creek***	***Bear's Den***	***Big Rock***	***Blackfoot***	***Border***	***Bowes***	***Bradley***	***Canadian Coulee***	***Cut Bank***	***Dutch John Coulee***	***Flat Coulee***
Gas-completed	1									2		
Gas-producing	36	171	2	39	9	1	45	1		240	2	6
Gas-shut-in	10	18	1	5	1	2	13	1	4	45	2	2
Gas-spud	1	2					1			2		
Gas-temporarily abandoned				1								
Gas-unknown							1					
Total Gas Wells	**48**	**191**	**3**	**45**	**10**	**3**	**60**	**2**	**4**	**289**	**4**	**8**
Oil-completed										35		
Oil-producing		2	7	2	5	2	31	1	1	395	2	9
Oil- shut-in	2		2		4	13	46		1	476	2	11
Oil-unknown										17		1
Oil- spud												
Oil-temporarily abandoned					1		4			11		1
Total Oil Wells	**2**	**2**	**9**	**2**	**10**	**15**	**81**	**1**	**2**	**934**	**4**	**22**
Disposal					1					11		
Injection			4		5	1	6			197		13

Gas Storage										54		
Water Source							1			11		3
Total Wells	**50**	**193**	**16**	**47**	**26**	**19**	**148**	**3**	**6**	**1,496**	**8**	**46**
Well Type and Status	***Fred & George Creek***	***Grandview***	***Kevin-Sunburst***	***Kicking Horse***	***Kippen***	***Laird Creek***	***Miners Coulee***	***Phantom***	***Prairie Dell***	***Prichard Creek***	***Rabbit Hills***	***Regan***
Gas-completed			28									
Gas-producing	3	10	188	14		1	15	4	118			1
Gas-shut-in	4	5	80	4	1		9	2	27	1	1	1
Gas-spud			2						5			
Gas-temporarily abandoned							1					1
Gas-unknown			5									
Total Gas Wells	**7**	**15**	**303**	**18**	**1**	**1**	**25**	**6**	**150**	**1**	**1**	**3**
Oil-completed			27									
Oil-producing	30	3	654			6	2				19	49
Oil- shut-in	23		871	1	1	3	8	3	1	5	5	3
Oil-unknown			10									
Oil- spud							1					

Oil-temporarily abandoned			5									15
Total Oil Wells	**53**	**3**	**1,567**	**1**	**1**	**9**	**11**	**3**	**1**	**5**	**24**	**67**
Disposal	1		3									
Injection	12		24			1				1	1	4
Gas Storage			1									
Water Source	3		2			1						
Total Wells	**76**	**18**	**1,900**	**19**	**2**	**12**	**36**	**9**	**151**	**7**	**26**	**74**
Well Type and Status	***Red Creek***	***Thirty Mile***	***Utopia***	***West Butte***	***Weygand***	***Whitlash***	***Wildcat Blaine County***	***Wildcat Glacier County***	***Wildcat Phillips County***	**Wildcat Toole County**	**Wildcat Valley County**	**Willow Ridge**
Gas-completed	1					1		1				1
Gas-producing		5	6	4	2	45	25	2		2		12
Gas- shut-in		2	2		4	21	61	10	6	3	3	2
Gas- spud						1	7	3	3	3		
Gas-temporarily abandoned												1
Gas-unknown			1			1	1			1		
Total Gas Wells	**1**	**7**	**9**	**4**	**6**	**69**	**94**	**16**	**9**	**9**	**3**	**16**
Oil-completed			1									
Oil-producing	26		19	3	3	44	1			1		2

Oil- shut-in	5	2	4	5	1	50	1	2				
Oil- unknown						1						
Oil- spud						2	3	2	2	1	2	
Oil- temporarily abandoned	1					2						
Total Oil Wells	**32**	**2**	**24**	**8**	**4**	**99**	**5**	**4**	**2**	**2**	**2**	**2**
Disposal												
Injection	5		9			9						2
Gas Storage												
Water Source						2				1	1	
Total Wells	**38**	**9**	**42**	**12**	**10**	**179**	**99**	**20**	**11**	**12**	**6**	**20**

There are 79 gas fields or field areas, in the planning area, that exclusively contain active wells (Table 9). In addition; Chouteau County contains 11 active wells, Liberty County contains 37 active wells, and Hill County contains 46 active wells that have not been assigned a field name. There are 3,909 active wells of the 8,882 currently active wells in the planning area in these gas fields. Small gas fields, with less than 20 active wells, account for 71 per cent (56 fields) of the total. Toole and Hill counties each contain more than 10 small gas fields, while all other counties have fewer small gas fields. Gas fields containing 20 or more active wells make up 29 percent of the gas fields (23 gas fields) within the Planning area. All counties within the planning area, with the exception of Glacier County, contain at least one field with more than 20 active wells. Only eight fields contain more than 100 active gas wells. Tiger Ridge gas field (Figure 9) contains the greatest number of active wells (690 wells) and is followed by Bowdoin (593 wells), Loring (478 wells), Whitewater (390 wells), Ashfield (179 wells), Sherard (152 wells), Old Shelby (113 wells), and Sawtooth Mountain (101 wells).

There are 31 oil and gas fields or field areas, in the planning area, that exclusively contain active wells (Table 10). In addition; Blaine County contains 99 active wells, Glacier County contains 20 active wells, Phillips County contains 11 active wells, Toole County contains 12 active wells, and Valley County contains 6 active wells that have not been assigned a field name. Chouteau and Phillips counties do not contain any unnamed field areas with oil and gas production. There are 4,846 active wells of the 8,882 currently active wells in the planning area in these oil and gas fields. Small oil and gas fields, with less than 20 active wells, account for 42 per cent (13 fields) of the total. Toole County contains seven of these small oil and gas fields, while the other four counties split the other six oil and gas fields. Gas fields containing 20 or more active wells make up 58 percent of the oil and gas fields (18 oil and gas fields) within the Planning area. Four counties (Blaine, Glacier, Liberty, and Toole) contain at least one field with more than 20 active wells. Only six of the 18 largest oil and gas fields contain more than 100 active oil and gas wells. Kevin-Sunburst (1,900 active wells) and Cut Bank (1,496 active wells) are the two largest fields within the planning area (Figures 8 and 9). The other four large oil and gas fields are Battle Creek (193 wells), Whitlash (179 wells), Prairie Dell (151 wells), and Bowes (148 wells).

Coalbed Gas

Coalbed gas exploration has been negligible within the HiLine planning area and no gas content analyses were obtained. The planning area lies within the Northern Great Plains Coal Province. Figure 14 shows the planning area with mapped areas of known coal bearing strata (U.S. Geological Survey, 2001). The Blackfeet-Valier, North Central, and Fort Union coal regions lie within this province. The two western-most coal regions contain Cretaceous – aged bituminous and sub-bituminous coals and the eastern-most region contains Tertiary – aged lignite coals. Wood and Bour (1988) reported some information about these coal regions. They found:

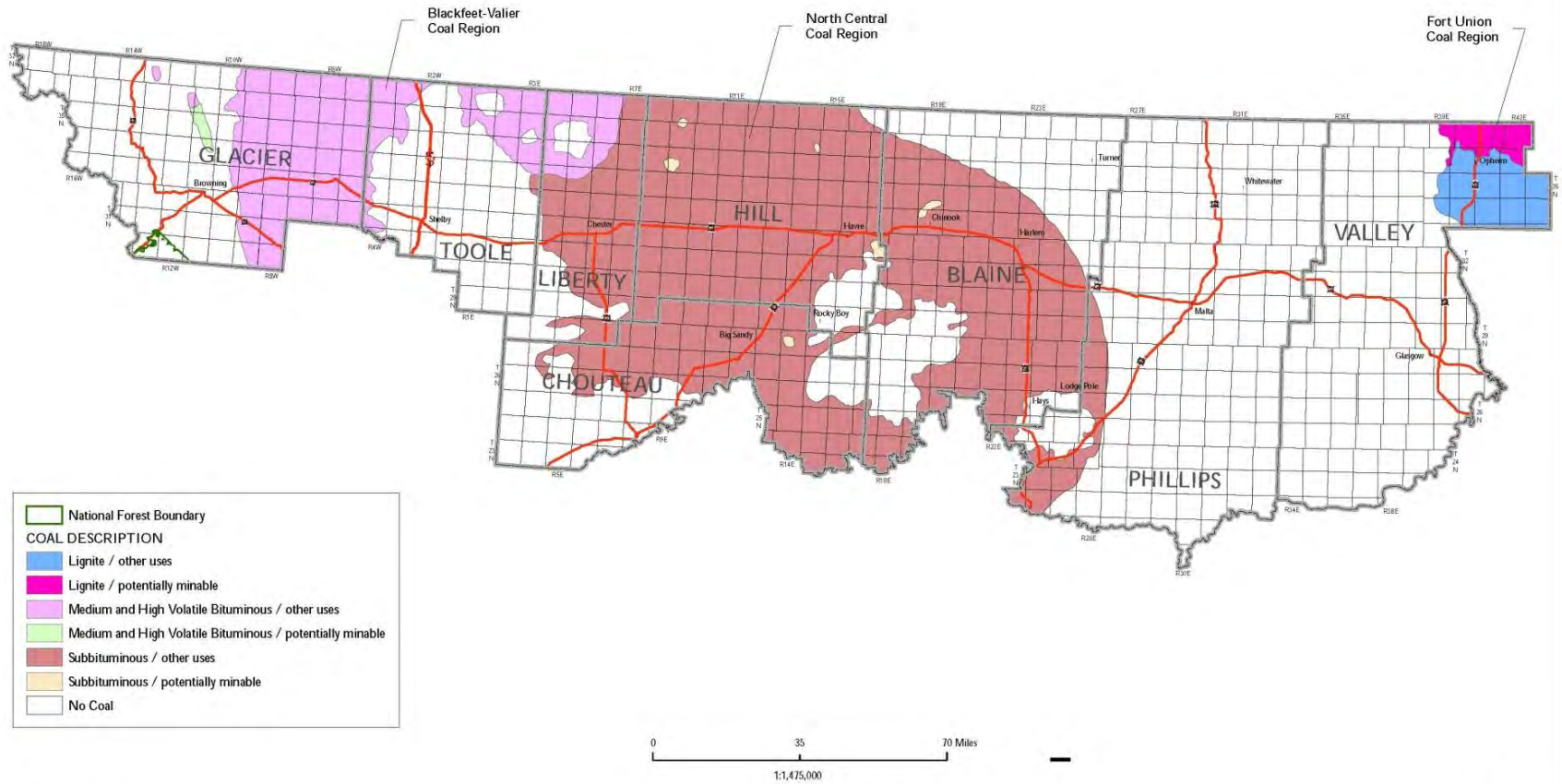
- Blackfeet-Valier coal region contains five known coal beds greater than 30 inches thick and at depths less than 2,000 feet in most of the area and less than 3,000 feet in some small areas,
- North Central Coal Region contains three known coal beds greater than 30 inches thick and at depths less than 2,000 feet, and
- Fort Union Coal Region contains up to 20 coal beds greater than 30 inches thick and at depths less than 2,000 feet. There are probably even fewer total coal beds within the planning area.

Parts of the planning area contain coals in the 2,000- to 6,000-foot range (U.S. Geological Survey, 2001), but there is very little available information on these coals. No pilot tests of any of these coals have been made in the planning area.

Montana Thrust Belt

To date, 60 wells have been drilled within the planning area portion of the Montana Thrust Belt (IHS Energy Group, 2007). In this area, Montana Thrust Belt lands include those in Glacier National Park, the Blackfeet Indian Reservation (includes some private land), and a small amount of National Forest lands. All 60 wells are located within Blackfeet Indian Reservation lands, with some wells drilled on private lands. Current status of these wells, as reported in IHS Energy Group (2007) is:

Figure 14.
Known areas of coal bearing sediments within the HiLine Planning Area, Northern Great Plains Province. Data from U.S. Geological Survey (2001).



- gas – 7 wells,
- oil – 3 wells,
- temporarily abandoned with gas shows – 3 wells,
- drilled and abandoned with gas shows – 5 wells,
- drilled and abandoned with oil shows – 8 wells,
- drilled and abandoned with oil and gas shows – 8 wells,
- drilled and abandoned with no shows – 26 wells.

To present, only 10 of the above wells (17 percent) have been completed as producing wells. An additional 24 wells (40 percent) have reported oil and gas shows.

The first well in this part of the planning area was completed in 1905 and the last was completed in 2004. Drilling has been spread out over this period, with drilling slightly more concentrated in the 1980s and in the first five years of the 21st century (13 wells completed during each of these periods). Total drilling depths have ranged from 180 to 14,519 feet, with about half drilled to depths of less than 5,000 feet and about a quarter drilled in the 5,000- to 10,000-foot interval and the rest to depths of greater than 10,000 feet.

Of the 10 producing wells, not all have actual reported production. Five of these wells are located in two fields. The other five wells were completed as gas wells at scattered locations, but none have reported production to date.

Two Medicine Creek field was discovered in 1955, when a well tested gas and condensate in the Mississippian Sun River Dolomite. The well was shut-in and never produced. The first producing well was completed in 1961 and a second was completed in 1980. Two additional wells have been drilled in the field area; one was abandoned with an oil and gas show and the other was dry and abandoned. Two Medicine Creek field was shut-in in 1982 after producing 274.681 million cubic feet of gas, 11,510 barrels of condensate, and 17,223 barrels of water. Production was from a fractured dolomite in an anticlinal trap bounded by a thrust fault to the east.

East Glacier field lies immediately northwest of the Two Medicine Creek Field. It was discovered in 1980 and two subsequent producing wells were completed. Only one of these three wells is presently producing. Through October of 2006, IHS Energy Group (2007) has reported 29,040 barrels of oil production with most of that coming from the active producing well. Two additional wells have been drilled in the vicinity and contained hydrocarbon shows but were abandoned. East Glacier field wells produce oil from the Cretaceous Greenhorn Formation; a fracture sandstone in an anticlinal trap bounded by a thrust fault to the east.

Marginal Wells

Low-volume oil and gas wells yield an important percentage of hydrocarbons produced in the U.S. During 2003, 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). 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 (IOGCC) defines stripper wells as wells that are producing 10 (or less) barrels of oil per day and no more than 60,000 cubic feet per day of natural gas. Most recent data of the IOGCC shows that marginal oil wells produced 17.2 percent of U.S. production and marginal gas wells produced 9.2 percent during 2005 (IOGCC, 2006a).

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). In addition, as long as these wells remain productive there are additional opportunities to use advanced technology to enhance recovery.

In 2005, Montana ranked 17th of the 28 major producing states in the number of marginal oil wells (IOGCC, 2006a). There were 2,424 marginal oil wells that produced 1,947,855 barrels of oil. Marginal well production amounted to almost six percent of total Montana oil production. Montana’s marginal oil well reserves are estimated to be 29,673,000 barrels from primary production and 34,834,000 barrels from secondary production (IOGCC, 2006a). The number of marginal oil wells in 2005 increased by 3.7 percent from those wells reported as producing in 2004.

In 2005, Montana ranked 14th of the 28 major producing states in the number of marginal gas wells (IOGCC, 2006a). There were 4,162 marginal gas wells that produced 27.427 billion cubic feet of gas. Marginal well production amounted to almost 30 percent of total Montana gas production. The number of marginal gas wells in 2005 increased by 5.7 percent from those wells reported as producing in 2004.

In 2005, the state received 9,539,386 dollars in marginal oil production tax revenue (IOGCC, 2006a). Montana also received 18,929,689 dollars in marginal gas production tax revenue.

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 gas wells are very costly due to the extremely high temperatures and pressures, and hard rock encountered. No wells drilled in the HiLine planning area have exceeded 15,000 feet (IHS Energy Group, 2007 and Montana Oil and Gas Conservation Division, 2007).

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

Only 14 wells in the HiLine planning area have drilled to the 10,000- to 15,000-foot depth range (IHS Energy Group (2007). All wells lie within the Blackfeet Reservation west of the eastern limit of the Montana Thrust Belt Province (Figure 6). Most wells have tested down to Mississippian-aged sediments, with two wells testing Devonian-aged sediments and one well bottoming in the Precambrian. Shows of hydrocarbons have been encountered in some tests of the Mississippian-aged sediments, but no wells have been determined to be productive and all wells have been abandoned.

Shallower Well Drilling: Less than 10,000 Feet

Figure 15 portrays the range of drilling depths within the HiLine planning area. Drilling depths are shallow in this region. More than 55 percent of all wells have been drilled in the 1,001- to 2,000-foot depth range. More than 27 percent of all wells have been drilled in the 2,001- to 3,000-foot depth range and 10.6 percent in the 3,001- to 4,000-foot depth range. The 1,001- to 4,000-foot depth range accounts for almost 93 percent of all wells drilled. The 5,001- to 10,000-foot depth range accounts for only about one percent of all wells drilled.

All counties but Glacier and Liberty have most drilled wells in the 1,001- to 2,000-foot depth range. In Glacier County, 57 percent are in the 2,001- to 3,000-foot depth range and 95 percent are in the 2,001- to 4,000-foot depth range. In Liberty County 58 percent are in the 2,001- to 3,000-foot depth range and 84 percent are in the 2,001- to 4,000-foot depth range.

Valley, Glacier, and Blaine counties contain 91 percent of all wells drilled in the 5,001- to 10,000-foot depth range. Phillips, Hill, and Toole counties contain eight percent of the wells in this depth range and Chouteau and Glacier counties contain the remaining one percent.

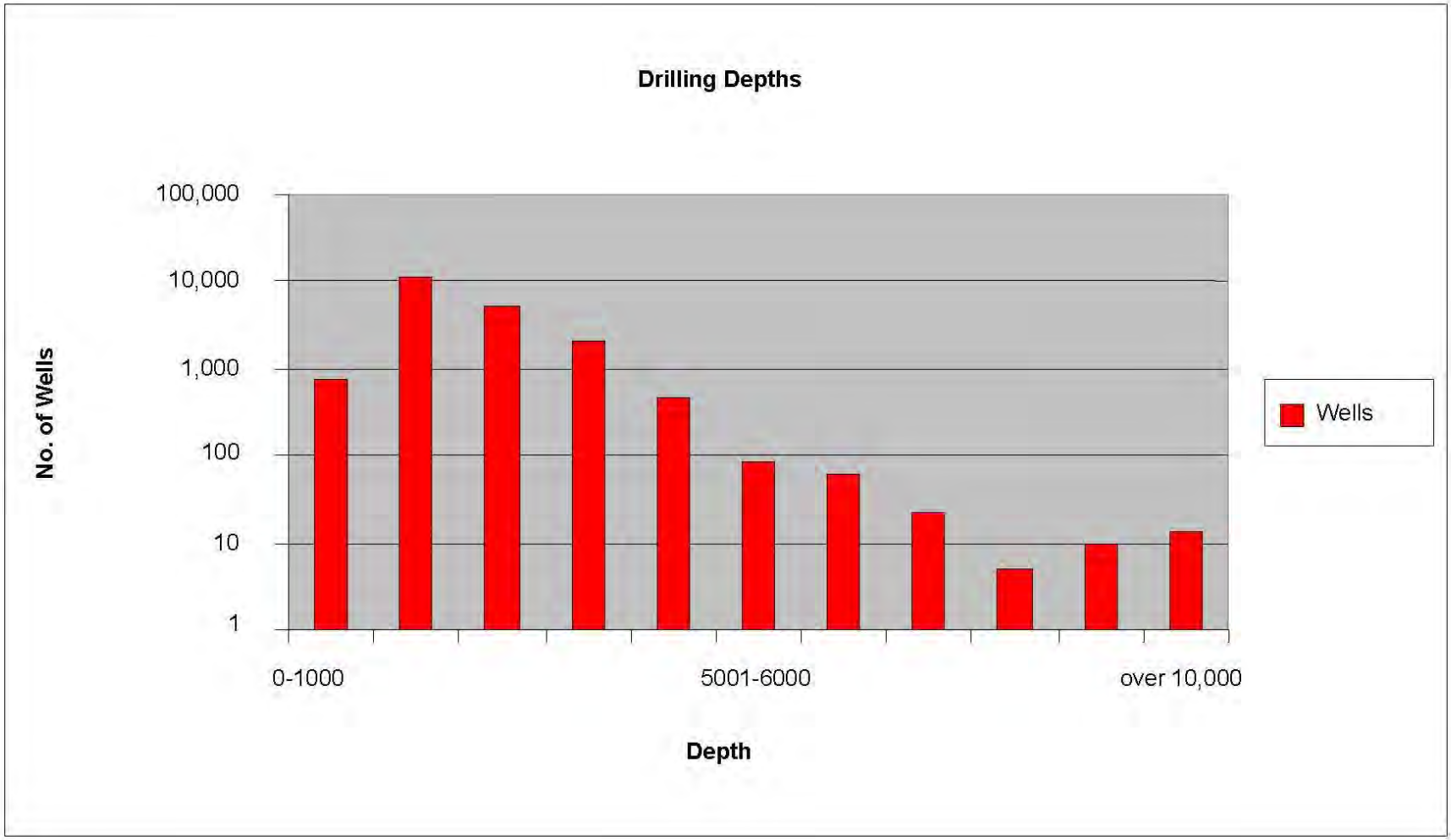
Summary of Current Drilling Techniques

Improvements in drilling technique have allowed avoidance of sensitive surface features, recovery of additional oil and gas reserves, reduced drilling time, reduced associated waste volumes, reduced emissions, and greater protection of sensitive environments. Most of this technology will be tested first in other regions where economic returns on investment are higher than this area of generally low volume production. Where technology is shown to provide significant cost benefits; local operators will begin to apply those methods when appropriate.

Directional and Horizontal Drilling and Completion Activity

Oil and gas wells traditionally have been drilled vertically throughout the HiLine planning area. Depending on subsurface geology, technology advances now allow operators to deviate boreholes by anywhere from a few degrees to completely horizontal. Directional and horizontal drilling uses boreholes that are deviated from the vertical. Deviation allows operators to reach reservoirs that are not located directly beneath the drilling rig, or to allow the

Figure 15. Range of drilling depths within the HiLine Planning Area. Data from IHS Energy Group (2007) and Montana Oil and Gas Conservation Division (2007).



borehole to contact more of the reservoir. Directional boreholes may be specifically deviated or allowed to "drift" updip naturally on the flanks of a geologic structure. In some cases directional drilling may be used specifically for avoidance of unfavorable surface locations.

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

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

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

Figure 16 shows the locations of known directional wells and current Applications for Permit to Drill new directional wells (as of April 2007), as reported by Montana Oil and Gas Conservation Division (2007). Very few wells in the planning area are classified as directional wells (91 directional wells). The locations of these wells are concentrated in Blaine and Hill counties, with 42 in each. Three wells were drilled in Glacier County and one well in Toole County. Three Applications for Permit to Drill have been filed for wells in Chouteau County. Status of all wells includes:

- Gas or Gas Shut-in – 50,
- Oil Shut-in – 1,
- Abandoned – 7,
- Spud – 5, and
- Application for Permit to Drill – 28.

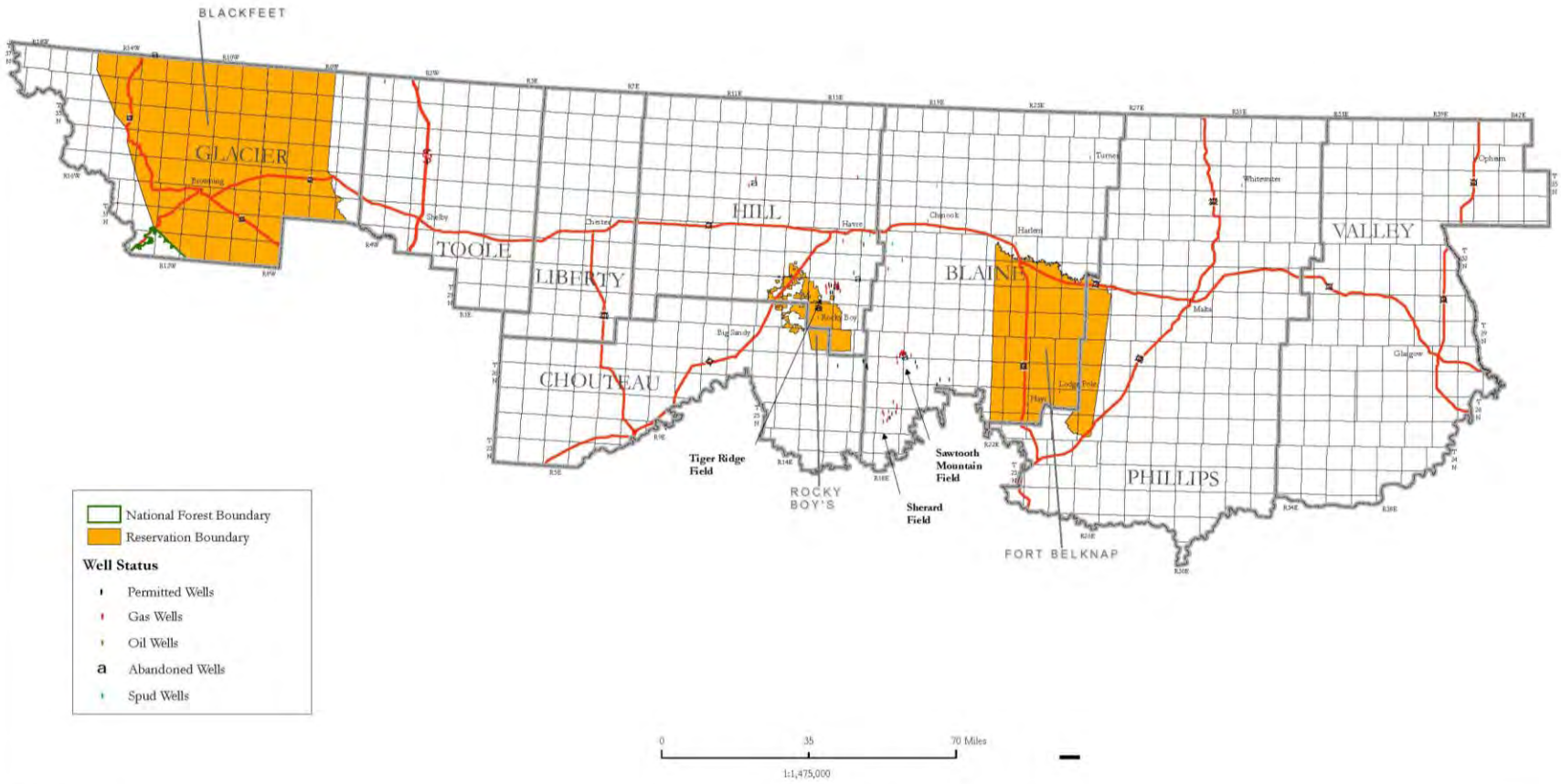
Directional wells have been almost entirely gas wells and the successful productive completion rate of these types of borehole has been 88 percent. The high success rate in the planning area is mainly due to the fact that almost 90 percent of completed wells have been field development wells. Industry prefers not to drill wildcat wells directionally, since details of geology and potential reservoir characteristics are not yet known and directional drilling adds an extra element of risk and increased costs.

Almost all directional wells drilled or spud (86 percent) and all wells with Applications for Permit to drill are operated by Devon Energy Production Company. The target formation for these wells has been almost entirely the Eagle Sandstone. Drilling depths for the Eagle Sandstone have been in the 1,200- to 2,800-foot depth range. Fields with the most drilled wells and current Applications for Permit to Drill (Figure 16) are:

- Tiger Ridge – 33,
- Sawtooth Mountain – 21, and
- Sherard - 9.

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

Figure 16.
Directional wells within the HiLine Planning Area. Data from Montana Oil and Gas Conservation Division (2007).



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

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

Horizontal boreholes have not been commonly used within the HiLine planning area. Horizontal boreholes appear to have only been used to contact more of the reservoir (increase drainage area) and to increase productivity. Figure 17 shows the locations of known horizontal wells and current Applications for Permit to Drill new horizontal wells, as reported by the Montana Oil and Gas Conservations Division (2007). Only 36 wells are classified as horizontal wells. The locations of these wells are concentrated in Toole (12 wells), Glacier (11 wells), and Blaine (10 wells) counties. One abandoned well and two spud wells are located in the northeast portion of Valley County. Status of all wells includes:

- Oil (including oil shut-in and temporarily abandoned oil) – 20,
- Gas – 1,
- Injection – 2,
- Abandoned – 7,
- Spud – 2, and
- Application for Permit to Drill – 4.

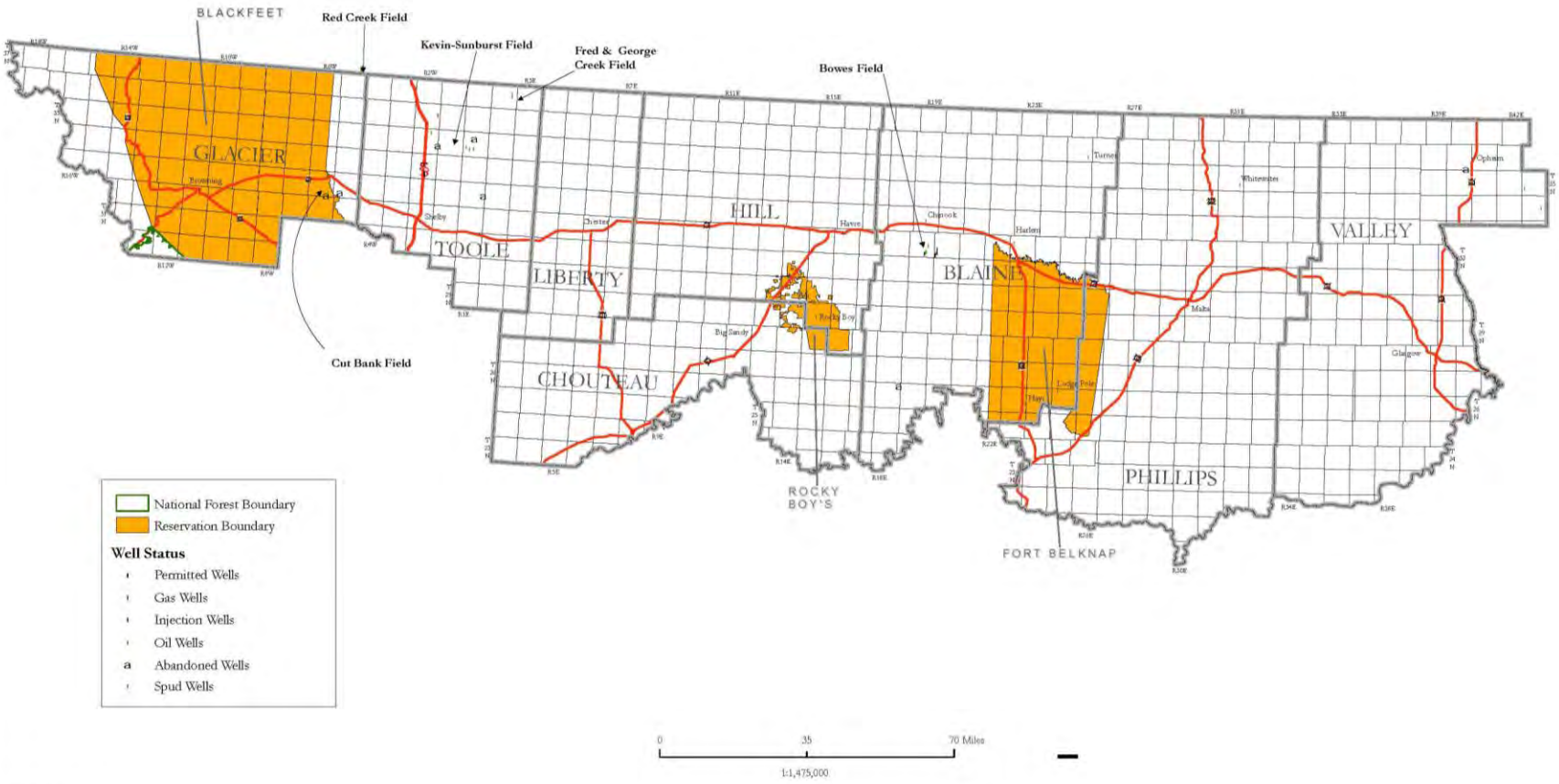
Horizontal wells have been almost entirely oil wells and the successful productive completion rate for these types of boreholes has been 75 percent. Almost all completed wells have been field development wells. Industry prefers not to drill horizontal wildcat wells, since details of geology and potential reservoir characteristics are not yet known and horizontal drilling adds an extra element of risk and increased costs.

Eleven different companies operate the 36 horizontal wells. Most operate in different fields. Fields are indicated in Figure 17. Those operators are:

- Citation Oil and Gas Corp. – Bowes Field (9 wells),
- Mountain View Energy, Inc. – Red Creek Field (6 wells),
- G.B. Coolidge, Inc. – Kevin-Sunburst Field (4 wells),
- K2 America Corp. – Cut Bank Field (3 wells: 2 are abandoned),
- Quicksilver Resources – Cut Bank Field (3 wells),
- Stone Energy Corp. – Wildcat (2 spud and 1 abandoned well),
- MCR, LLC – Fred & George Field (2 wells),
- Somont Oil Company, Inc. – Kevin-Sunburst Field (2 wells),
- EOG Resources, Inc. – Wildcat (2 abandoned wells),
- Devon Energy Production Co. – Wildcat (1 abandoned well), and
- Quest Petroleum Corp. – Kevin-Sunburst (1 abandoned well).

The target formations for these wells have been older and deeper than for directional wells discussed above. Most wells target the Jurassic Ellis Group (11 wells), Mississippian Madison Group (8 wells), and Devonian Birdbear (Nisku) Formation (6 wells). Target drilling depths have been 1,300 to 6,950 feet, with about 66 percent in the 2,500- to 3,500-foot range.

Figure 17.
Horizontal wells within the HiLine Planning Area. Data from Montana Oil and Gas Conservation Division (2007).



Reverse Circulation Drilling

Reverse circulation drilling uses a dual-wall drill string. Drilling fluid is carried to the bit between the outer and inner wall of the drill pipe and cuttings and fluid are returned to the surface in the inner part of the pipe. Reverse circulation drilling appears to be an ideal system for drilling and producing tight low- or under-pressured formations that could be easily damaged by conventional drilling. K2 Energy of Calgary has applied this technology to successfully drill and test gas wells in the low-pressure (formation pressure estimated at 150 pounds per square inch) Bow Island Formation on the Blackfeet Indian Reservation and in the Montana Thrust Belt (Mackay, 2003).

Slimhole Drilling and Coiled Tubing

Slimhole drilling—a technique sometimes used to drill small-diameter holes to recover reserves in mature fields—has not yet been used much in the HiLine planning area. It has the potential to improve efficiency and reduce costs of both exploration and production drilling. Coiled tubing—used effectively for drilling in reentry, underbalanced, and highly deviated wells—is often used in slimhole drilling. Most coiled tubing rigs are limited to relatively shallow drilling like those of the planning area. A review of coiled tubing intervention and drilling 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 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 (most wells in the area are considered to be shallow) 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 has reportedly been used in some workover situations in this part of northern Montana. Coiled tubing was used to replace existing producing tubing.

AltaCanada Energy Corp. (2006) recently signaled its intent to have its subsidiary (Montana Land & Exploration, Inc.) apply coiled tubing technology to its shallow Eagle Formation drilling program in Blaine county. Two coiled tubing units are presently stationed out of Chinook, Montana. 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 is not likely in the near future. Other Rocky Mountain plays (western Wyoming and western Colorado) have a higher priority for new rigs since more prolific reservoirs are being developed in those locations than reservoirs are capable of within the planning 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. Shallow drilling targets in the planning area are not conducive to the use of significant amounts of directional drilling so pad drilling would be unlikely in the area.

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. Many fields in the planning area 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 (by reducing formation damage and blowouts). At present, measurement-while-drilling is most often used when drilling horizontal boreholes. 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). Environmental benefits of faster drilling when using 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 also reduces potential impacts on soils, groundwater, wildlife, and air quality.

Summary of Current Completion Techniques

Standard completion techniques for the HiLine planning area will be described below. Once the operator determines that a well should be completed for production, the first step is to place casing in the borehole and cement it in-place. Since the potential producing zones are then sealed off by the casing and cement, perforations (holes made through the casing and cement and into the formation) are made in order for the oil and/or gas to flow into the borehole.

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

Carbonate reservoirs (e.g. the Madison Group and the Birdbear Formation) may be acidized. This process introduces acid into predominantly limestone reservoirs to enlarge pores by removing obstacles and constrictions and extending those pores into new drainage areas, thus lowering the resistance offered to hydrocarbon flow and stimulating increased production rates.

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.

The Bowdoin Dome (Figure 9) is one of the largest producing anticlines in the Rockies covering over 100 Township areas. In 2002, Fidelity Exploration & Production Company began a program to recomplete depleted gas wells (Thatcher et al., 2003) in the field. The program used coiled tubing conveyed fracturing across multiple thin zones. Coiled tubing fracturing was used to recover the multi-zone potential as economically as possible in order to make these marginal wells into commercially viable wells. Wells tested in this manner showed a 77 percent increase in production. Projects such as this are allowing field life to be extended and additional hydrocarbon recovery.

Drilling and Completion Costs

The National Petroleum Council (2003) reported drilling completion costs for the Williston/Northern Great Plains region. They reported that the average oil well drilling and completion cost for wells to depths of 5,000 feet was 280 thousand dollars. Wells in the 5,000 to 10,000 foot range cost an average of 955 thousand dollars to drill and complete. All cost components such as permitting, location construction, mobilization, rentals and services, tangible items, and stimulations were assumed to be included in these costs.

For gas wells, the National Petroleum Council (2003) reported an average cost for wells to depths of 5,000 feet was 83 thousand dollars. Wells in the 5,000 to 10,000 foot range cost an average of 571 thousand dollars to drill and complete.

The National Petroleum Council (2003) also reported dry hole well costs. They were 100 thousand dollars for average wells to depths of 5,000 feet and 506 thousand dollars for wells between 5,000 and 10,000 feet deep.

Operators in the Rocky Mountain region have recently been faced with increases in drilling and completion costs. Drilling rates have increased 20-50 percent (Rocky Mountain Oil Journal, 2005) and service costs have also increased. Rig shortages have affected most areas of the region.

In the planning area, AltaCanada Energy Corp. (2006) reported their cost to drill and case a gas well to 1,200 feet cost an average of 90,000 dollars in 2005. Freeman (2007) reported that the average dry hole cost of 500 to 1,400 feet deep Eagle Sandstone wells in the Bearpaw Mountain area (central part of planning area) is 50,000 dollars.

Summary of Production and Abandonment Techniques

Once production begins application of reservoir management procedures are needed to ensure maximum hydrocarbon production at the lowest possible cost, with minimal waste and environmental impact. In earlier days, recovery was only about 10 percent of the oil-in-place in a given field and sometimes the associated natural gas was vented or flared. Newer recovery techniques have allowed the production of up to 50 percent of the oil-in-place. Also, 75 percent or more of the natural gas-in-place in a typical reservoir is now recovered. Operators have also taken significant steps in reducing production costs. U.S. Department of Energy (1999) estimated that costs of production had decreased from a range of 9 to 15 dollars per barrel of oil equivalent in the 1980s to an average of about five to nine dollars per barrel of oil equivalent in 1999.

Since 1990, most reserve additions in the United States—89 percent of oil reserve additions and 92 percent of gas reserve additions—have come from finding new reserves in old fields (U.S. Department of Energy, 1999). Our review indicates that most recent reserve additions in the HiLine planning area have come from existing gas fields. As an example, this type of reserve addition has been important in the old Bowdoin Field and in the younger Loring Field: both in the eastern part of the planning area (Figure 9). The U.S. Department of Energy (1999) reports that about half of new reserve additions in the United States are from more intensive development within the limits of

known reservoirs. This type of activity is also presently occurring at Bowdoin Field and in the Sherard, Bullwacker, and Battle Creek areas where wells are being more closely spaced. They report that the other half of reserve additions has come from finding new reservoirs in old fields and extending field limits. Part of the increased drilling activity in the Bowdoin Field area has come from extending field limits.

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

The search for new fields in the planning area has been successful in finding new gas production (Figure 4). This new gas production has predominantly been on the edges of existing fields or near existing fields. Few successful new gas producing wells away from existing fields have been discovered. Very few oil wildcats have been drilled indicating the mature nature of oil plays within the planning area.

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

- Primary Recovery - Primary recovery produces oil, gas, and/or water using the natural pressure in the reservoir. Wells may be stimulated to improve the flow of oil and gas to the borehole. Other techniques, including artificial lift, pumping, and gas lift, help extend productive life when a reservoir's natural pressure dissipates.
- Secondary Recovery – Secondary recovery uses methods like gas reinjection to maintain reservoir pressure and boost primary production, water flooding to energize the reservoir and displace hydrocarbons not produced in the primary recovery phase, or the first enhanced recovery method of any type applied to the reservoir to produce oil not recoverable by primary recovery methods. Enhanced oil recovery involves the injection of liquids or gases (water, surfactants, polymers, or carbon dioxide) or sources of heat (steam or hot water) to stimulate hydrocarbon flow, "sweep" the reservoir, and move hydrocarbons that were bypassed in earlier recovery phases.

Due to the limited production efficiency of some primary recovery and water-flood projects, additional secondary oil recovery projects may be initiated (Williams and Pitts, 1997). Primary depletion in most Rocky Mountain reservoirs is only 10 to 20 percent. Williams and Pitts (1997) reported that locale can be important in enhancing oil recovery projects. For example, proximity to a carbon dioxide source is a factor in choosing a carbon dioxide project. A source of fresh or treatable water is needed for steam-flood or chemical projects. Accessibility of cheap natural gas is a consideration for gas injection projects. Oil and gas prices play a very important role in determining whether an enhanced oil recovery project will be viable, and deciding what type of recovery project would be appropriate. Water floods have been the predominate method of increasing oil recovery and few floods of different types have been used.

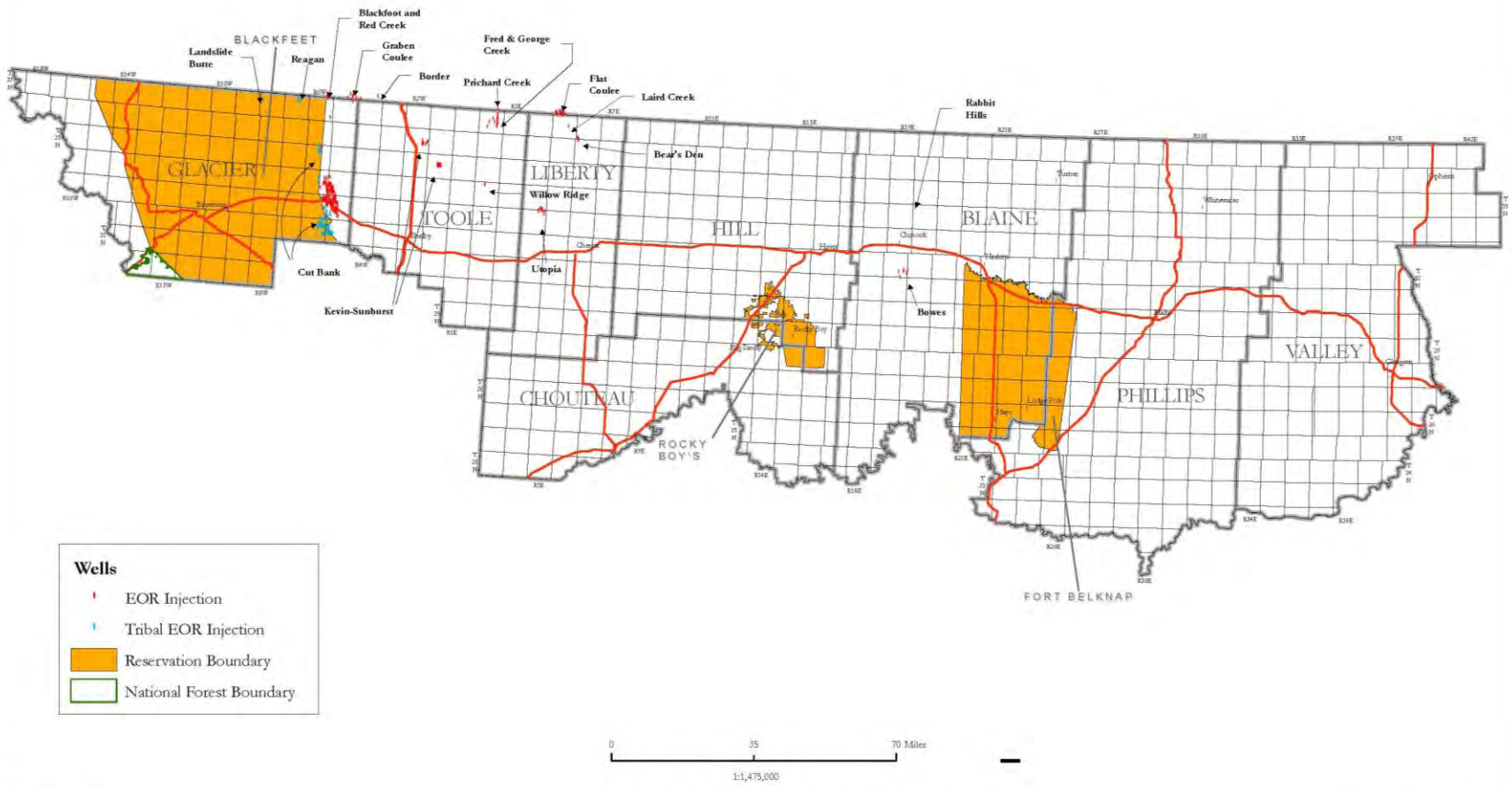
Approval of a gas repressuring project was approved for Dutch John Coulee Field, but it does not appear to be presently active. There no active gas injection projects within the planning area to maintain reservoir pressures or to aid in secondary recovery of oil or for enhanced oil recovery. There also are currently no air injection projects for pressure maintenance, in-situ combustion type projects, or hydrothermal injection projects for steam.

Secondary Recovery Fields

Secondary recovery is generally considered to be water flooding of a depleted reservoir. There are a number of water flooding projects, in older oil fields, in western parts of the HiLine planning area (Montana Oil and Gas Conservation Division, 2006b and 2007, and Bureau files). Locations of these injection wells are shown on Figure 18. Brief summaries of these projects are presented below.

Figure 18.

Locations of injection wells within the HiLine Planning Area. Well data from Montana Oil and Gas Conservation Division (2007).



1. Bear's Den Field has a secondary unit approved in 1989 and four active water injection wells. These wells are located in Liberty County and inject into the Jurassic Swift Formation. These wells are operated by FX Drilling Company, Inc.

2. Blackfoot and Blackfoot East waterflooding started in 1976 and four injectors are active with one injector temporarily abandoned. These wells are located in Glacier County and inject into the Cut Bank Sandstone of the Lower Cretaceous Kootenai Formation. These wells are operated by Croft Petroleum Company.

3. Border Field waterflooding was approved in 1973 and has one active injection well. This well is located in Toole County and injects into the Burwash Member of the Lower Cretaceous Kootenai Formation. The well is operated by Quicksilver Resources, Inc.

4. Bowes Field waterflooding began in 1965 with water from the Mississippian Madison. The field contains six active injection wells. These wells are located in Blaine County and inject into the Jurassic Sawtooth Formation. These wells are operated by Citation Oil & Gas Corporation.

5. Cut Bank Field contains the largest number of water injection wells (197 injectors) with some on Blackfeet Reservation lands and some on private lands. Reservation lands contain 39 active injection wells, 21 completed injection wells, 21 temporarily abandoned injection wells, and one producing injection well. The other lands contain 30 active injection wells, 84 temporarily abandoned wells, and one shut-in injection well. These wells are located in Glacier County. Injection formation information is not available for the Reservation lands. On the other lands, 113 presently inject into the Cut Bank Sandstone of the Lower Cretaceous Kootenai Formation and two inject into the Mississippian Madison. Quicksilver Resources, Inc. operates all but one of these injection wells.

6. Flat Coulee Field waterflooding was approved in 1971 and it has 12 active and one temporarily abandoned injection wells. These wells are located in Liberty County and inject into the Jurassic Swift Formation. These wells are operated by MCR, LLC.

7. Fred & George Creek Field has four secondary units approved for waterflooding, with the first approved in 1970. Twelve active injection wells are located in Toole County and inject into the Sunburst Member of the Lower Cretaceous Kootenai Formation. These wells are operated by MCR, LLC.

8. Graben Coulee Field waterflooding was approved in 1983. One active injection well to the Mississippian Madison and one temporarily abandoned injection well to the Cut Bank Sandstone of the Lower Cretaceous Kootenai Formation are located in this field. This field lies in Glacier County and is operated by Quicksilver Resources, Inc.

9. The Kevin-Sunburst field has three waterfloods presently operating, with 24 active injection wells. These wells are located in Toole County. At present 15 wells inject into the Jurassic Swift Formation, eight inject into the Sunburst Member of the Lower Cretaceous Kootenai Formation, and one injects into the Mississippian Madison. Somont Oil Company operates the Swift and Madison injection wells and Quicksilver Resources, Inc. operates the Sunburst injection wells.

10. Landslide Butte Field contains one active water injection well lying on Blackfeet Reservation lands and in Glacier County. Injection information is not available for this well.

11. Laird Creek Field waterflooding began in 1977. One temporarily abandoned injection well lies in Liberty County. This well injects into the Jurassic Swift Formation and is operated by G/S Producing, Inc.

12. Prichard Creek Field secondary unit was approved for waterflooding in 1973. One temporarily abandoned injection well lies in Toole County. This well injects into the Sunburst Member of the Lower Cretaceous Kootenai Formation and is operated by MCR, LLC.

13. Reagan Field was approved for waterflood in 1972. Four active injection wells lie on Blackfeet Reservation lands in Glacier County. Injection information is not available for these wells.

14. Red Creek Field contains three active water injection wells and two producing injection wells. These wells are in Glacier County and inject into the Mississippian Madison. Mountain View Energy, Inc. operates these injection wells.

15. Utopia Field was approved for waterflooding in 1989 and contains nine shut-in injection wells. These wells are located in Liberty County and inject into the Jurassic Swift Formation. True Oil LLC operates these injection wells.

16. Willow Ridge Field contains two active water injection wells. These wells are located in Toole County and inject into the Burwash Member of the Lower Cretaceous Kootenai Formation. Croft Petroleum Company operates these injection wells.

Tertiary Projects

Tertiary enhanced oil recovery projects use improved recovery methods that not only restore formation pressure but also improve oil displacement or fluid flow within the reservoir. The three major types of enhanced oil recovery operations are chemical flooding (alkaline flooding or micellar-polymer flooding), miscible displacement (carbon dioxide injection or hydrocarbon injection), and thermal recovery (steamflood or in-situ combustion. The optimal application of these projects depends on the properties of the reservoir (temperature, pressure, thickness, porosity, permeability, residual oil and water saturations, depth, etc.) and properties of the oil to be recovered, such as viscosity and gravity.

A pilot water-polymer flood was approved at Rabbit Hills Field (Figure 18) in 1995. A secondary unit for this area was approved in 2003. At present there is one active injection well that injects into the Jurassic Sawtooth Formation. Summit Resources, Inc. operates this injection well.

Acid Gas Removal and Recovery

Hydrogen sulfide or carbon dioxide gas must be removed from the gas stream before produced natural gas can be safely transported. Special plants are needed to separate and recover the unwanted gases and sweeten the gas for sale. Improvements in the process have made it possible to produce sour natural gas resources, almost eliminate noxious emissions, and recover almost all of the elemental sulfur and carbon dioxide for later sale or disposal. TDW Gas Processing LLC operates the TDW Sweetening Plant in Toole County. It removes unwanted constituents from the natural gas stream in this region of Montana.

Artificial Lift Optimization

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

Glycol Dehydration

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

Produced Water Management

The HiLine planning area lies mostly within the North Central Montana Basin. The USGS database of produced water contains 583 water quality samples (IOGCC, 2006b). Median salinity, expressed as Total Dissolved Solids, for those samples is 4,111 milligrams per liter (brackish water). The range in salinity is 1,081 milligrams per liter (slightly brackish) to 323,047 milligrams per liter (brine). Produced water from this area is generally very high quality with 86 percent of the samples having total dissolved solids of less than 10,000 milligrams per liter. Another 13 percent of these samples range from 10,000 to 49,999 milligrams per liter. This lower quality water appears to be mostly along the Montana-Canadian border (IOGCC, 2006b).

A number of produced water management practices are used within the HiLine planning area. Some waters, especially poorer quality oil field waters, are disposed of by reinjection into the subsurface. Locations of disposal wells are shown on Figure 19. Blackfoot East and Fred & George Creek fields each contain one active disposal well. Graben Coulee and Kevin-Sunburst fields each contain three disposal wells. One disposal well in Graben Coulee Field is temporarily abandoned and the others are active. Cut Bank Field contains 10 active disposal wells and one temporarily abandoned disposal well.

At Battle Creek gas field (Figure 9) a zero-discharge system of managing produced water has been developed. It uses enhanced evaporation ponds through aeration coupled with recycling the produced water for field uses (such as well completions and dust prevention). At Bowdoin Dome gas field only evaporation ponds are used and depending on the soil type, the pits are either lined with a geosynthetic liner or not lined at all. This technology is applicable to gas fields, producing low volumes of water, in an arid environment that encourages evaporation (IOCC, 2006).

Oil and solids are filtered out of the water produced at Rabbit Hills oil field (Figure 8). Due to the quality of the cleaned water it is discharged to a pond and consumed by cattle and wildlife (IOGCC, 2006b).

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). It could probably be successfully used in the cold climate of the planning area, in locations where production of poor quality water cannot be disposed of by other means.

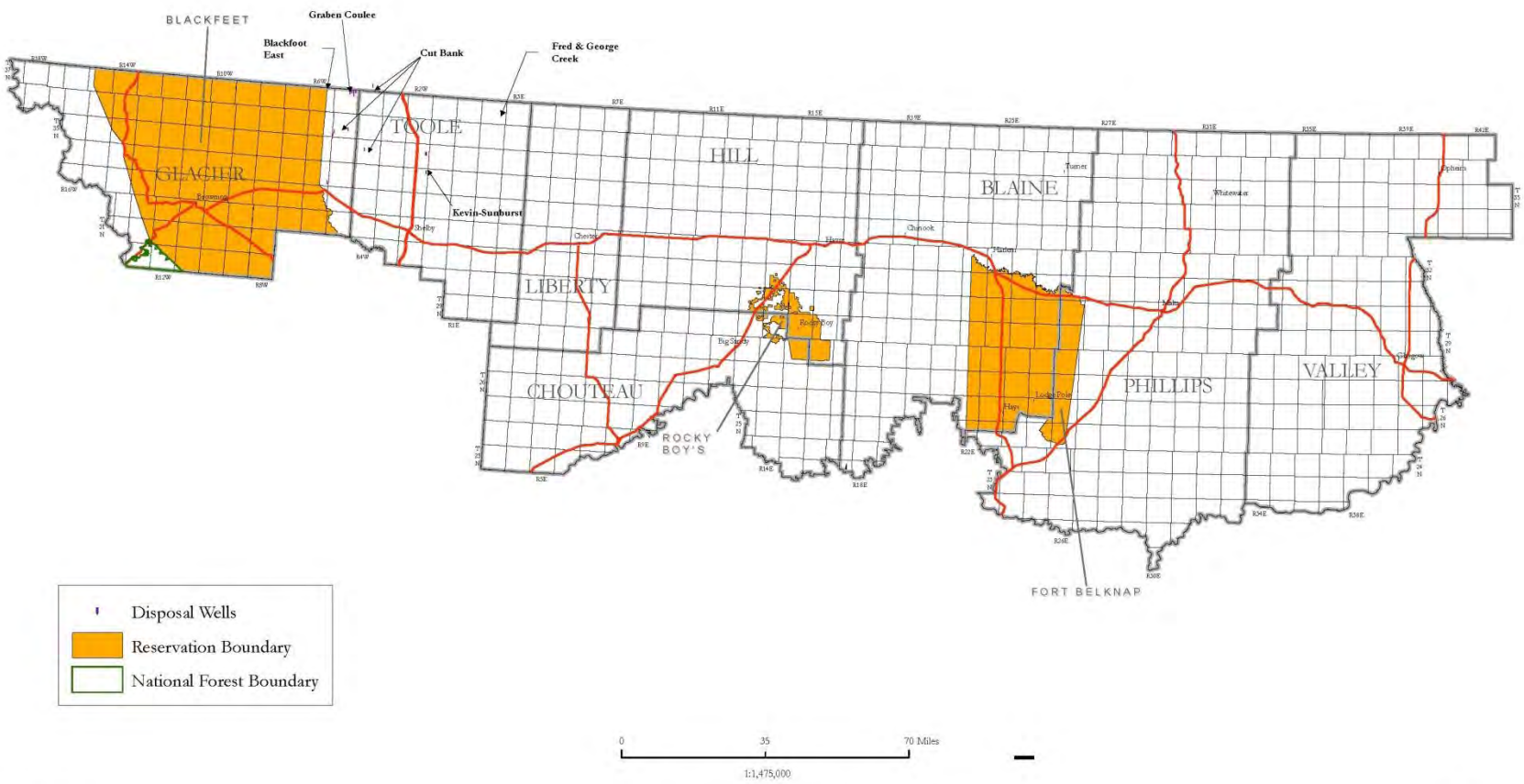
Leak Detection and Low-bleed Equipment

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

Downhole Water Separation

At least some water is produced along with the hydrocarbons in most wells within the HiLine planning area. It is most often stored, at least temporarily, in dug pits on the well site. Small amounts of water may be allowed to evaporate or percolate into the subsoil. Larger amounts may be trucked to bigger approved disposal pits, or it may be injected into approved subsurface zones. Emerging technology to separate oil and water could cut produced water volumes by as much as 97 percent in applicable wells (U.S. Department of Energy, 1999). By separating the oil and water in the borehole and injecting the water directly into a subsurface zone, only the oil needs to be brought to the surface. This new technology could help to minimize environmental risks associated with bringing water to the surface where it then has to be handled, treated, and then disposed of. It would also reduce the costs of lifting and disposing of produced water. In addition; surface disturbance could be reduced, oil production could be enhanced and marginal or otherwise uneconomic wells could become economic. Nearest use of this technology has been in southeastern Saskatchewan, Canada (Veil et al., 1999).

Figure 19.
Locations of disposal wells within the HiLine Planning Area. Well data from Montana Oil and Gas Conservation Division (2007).



Vapor Recovery Units

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

Site Restoration

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

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 63 gas storage wells located within the HiLine planning area (Figure 20). Brief summaries of these projects are presented below.

1. Box Elder Field was depleted and abandoned in 1959 and was later converted to gas storage. The reservoir is the Upper Cretaceous Eagle Sandstone. Depths of these wells range from 1,270 to 1,500 feet. The field contains six gas storage wells. The wells are located on the Hill/Blaine county line and the storage field is operated by NorthWestern Energy. The storage wells are used to augment deliveries to the Havre area during cold weather and for load balancing. Working load storage capability is 0.50 billion cubic feet of gas (NorthWestern Energy, 2006).

2. Cut Bank Field has the largest gas storage field in the planning area with 54 wells. It is called Cobb gas storage field by its operator (NorthWestern Energy). The wells are located on the northern end of Cut Bank Field in Glacier and Toole counties. The reservoir is the Moulton Sandstone of the Lower Cretaceous Kootenai Formation. The Cobb storage field is a depleted production reservoir with working load storage capability of 10.25 billion cubic feet of gas (NorthWestern Energy, 2006). This storage field serves peak-day load requirements on the NorthWestern Energy pipeline system.

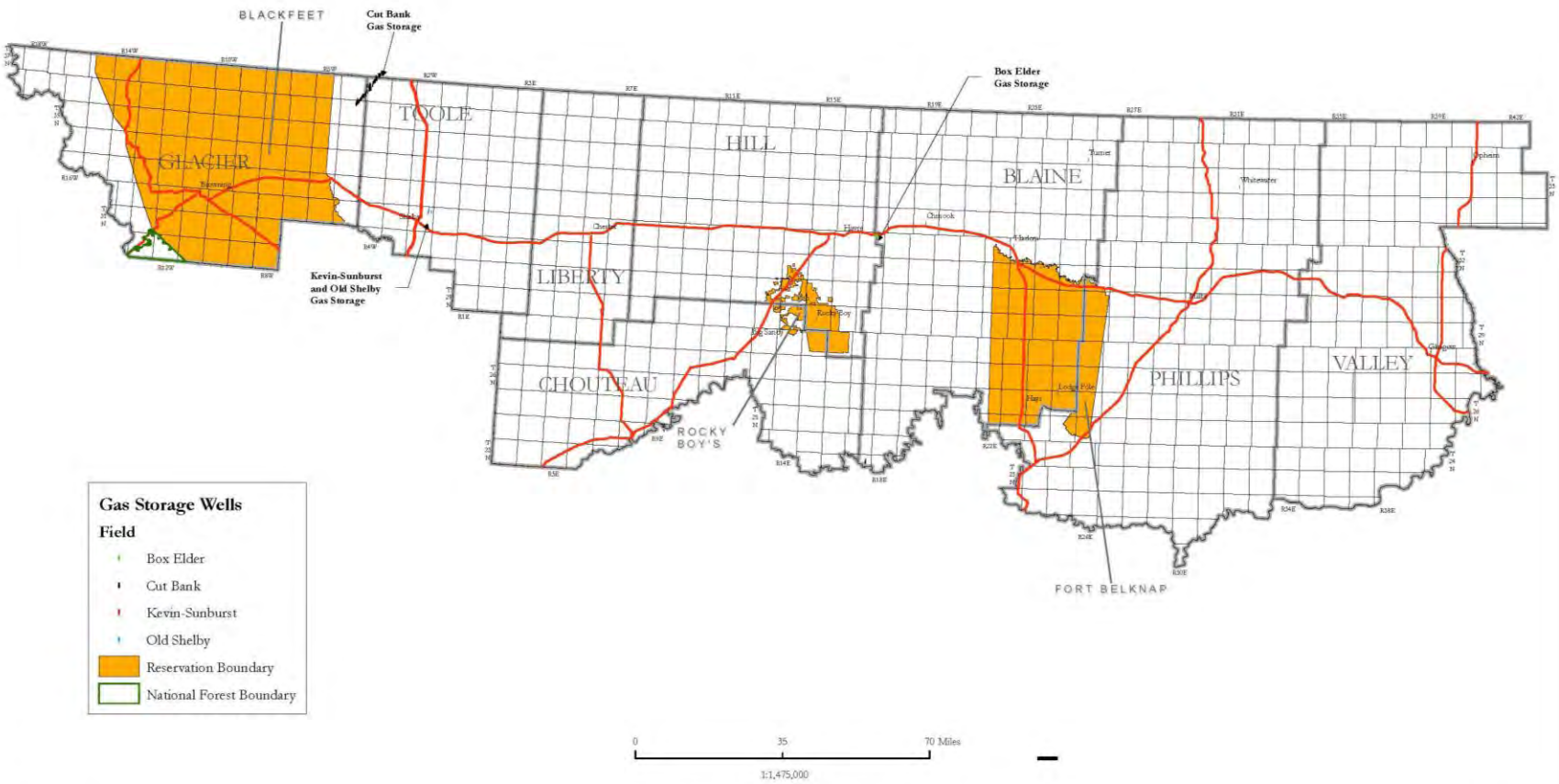
3. NorthWestern Energy also operates two gas storage wells at Old Shelby Field and one gas storage well at nearby Kevin-Sunburst Field. The Old Shelby Field wells are in the depleted Sunburst Sandstone of the Lower Cretaceous Kootenai Formation. No additional information is available on these storage wells.

Assessments of Oil and Gas Resources

The Energy Information Administration has recently provided forecasts of United States energy supply (Energy Information Administration, 2007a). Technically recoverable United States oil resources (as of January 1, 2005) were estimated to be 168.8 billion barrels. The technically recoverable natural gas resource was estimated to be 1,341 trillion cubic feet. The Rocky Mountains account for about 37 percent of the natural gas and 17 percent of the oil projections of the technically recoverable resource base on public lands in the lower 48 states (Humphries, 2004).

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

Figure 20.
Locations of completed gas storage wells within the HiLine Planning Area. Well data from Montana Oil and Gas Conservation Division (2007).



- The Energy Information Administration (2003) uses a natural gas resource base of 383 trillion cubic feet for the Rocky Mountain region.
- The Potential Gas Committee (2003) estimated 288 trillion cubic feet of natural gas, including 50 trillion cubic feet of proved reserves.
- As part of a study done in compliance with the Energy Policy and Conservation Act Amendments of 2000 (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 (including the Montana Thrust Belt) at 226 trillion cubic feet.
- The National Petroleum Council (2003) estimated 284 trillion cubic feet of natural gas for the Rocky Mountain region. The Council also presented a comparative analysis of their estimates with those of the Energy Information Administration, Potential Gas Committee and U.S. Geological Survey to better understand the factors that influenced the differences among each estimate.

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

As of January 1, 2002, the National Petroleum Council (2003) estimated the 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 coalbed gas reserves (14.8 trillion cubic feet) for the Rocky Mountain region. Growth to proved gas reserves in the Rockies was estimated at 26 trillion cubic feet (National Petroleum Council, 2003). Finally, undiscovered resources for conventional gas were estimated to be 173 trillion cubic feet, while nonconventional gas resources were estimated to be 209 trillion cubic feet (National Petroleum Council, 2003).

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

Significant amounts of oil and gas have been produced within the HiLine planning area to date, which helps supply a portion of this country's demand. The planning area also has significant potential for continuing to help meet rising national demand by supplying additional oil and gas that has not yet been discovered. A number of recent oil and gas resource assessments have been prepared that cover all or portions of the planning area. These assessments provide an indication of the range of undiscovered resource volumes that could be available for exploration, development, and production through the year 2026.

We will present below the results of a number of oil and gas resource assessments as they relate to the HiLine planning area. A discussion of oil-in-place and gas-in-place estimates will be followed by estimates available for proved oil and gas reserves.

Finally, we will review recoverable resource estimates that have recently been made by groups such as the U.S. Geological Survey, the Department of Energy via sponsored work, and the Potential Gas Committee. Each group uses slightly different methods and assumptions when making their predictions of potential resources. Although these estimates cannot be directly correlated, combined they provide an idea of the range of oil and gas resources that may be available for exploration and development in the HiLine planning area through 2026.

Oil-In-Place Estimates

No recent estimates of oil-in-place (see Glossary definition for *in-place*) were available. Curry (1971) and Glaze (1971) published estimates of oil-in-place. The estimate of Glaze (1971) indicated that the region of the HiLine planning area contained more than 1.185 billion barrels of original oil-in-place with about 217.2 million barrels produced through 1968. Approximately 968 million barrels of oil remained in-place at the time of Glaze's estimate. Curry (1971) indicated that an estimated 400 million barrels of in-place oil remained to be found. Very little of the potential undiscovered oil resources are managed by the Bureau (see section titled "Drilling and Completion Activity"). The Bureau does work with the Bureau of Indian Affairs to help manage tribal lands, and the Blackfeet Reservation does contain numerous active oil wells (Figure 8), while the Rocky Boys and Fort Belknap do not contain any active oil wells.

Gas-In-Place Estimates

Gas-in-place (see Glossary definition for *in-place*) estimates attempt to describe the gas resource in an area without considering its economic or technical viability (Boswell et al., 2002). Rakhit Petroleum Consulting LTD. (2007) has estimated 4.5 trillion cubic feet of shallow gas-in place in undiscovered gas reservoirs in the Western Plains area, which includes the HiLine planning area. No other gas-in-place estimates that cover the HiLine planning area are known.

Proved Oil and Gas Reserves

In 2005, estimated total United States proved reserves of crude oil were 21.757 billion barrels, natural gas liquid reserves were estimated at 8.165 billion barrels, and dry natural gas reserves were 204.385 trillion cubic feet (Energy Information Administration, 2006c).

Montana's estimated proved crude oil reserves rose from 364 million barrels at the end of 2004, to 427 million barrels at the end of 2005 (an increase of about 15 percent). Annual estimates of proved reserves have been rising from the 159 million barrels estimated for 1997, which was the lowest calculated for Montana since 1979. The Energy Information Administration (2006b) estimated almost 33 million barrels of Montana oil production in 2005, so an additional 30 million barrels of additional proved reserves were identified in 2004. Montana crude oil production in 2005 was at its highest level for the 1981-2005 reporting period. Additional proved reserves were identified by enlarging proved areas of fields or reservoirs, revisions due to new information, additional new reservoir discoveries in old fields, and other adjustments. No new field discoveries of oil were made in Montana in 2005.

The National Petroleum Council (2003) estimated that the Rockies had a remaining proved gas reserve of 49.7 trillion cubic feet, with 67.1 trillion cubic feet produced to that time. For the Williston/Northern Great Plains region they estimated 4.5 trillion cubic feet of cumulative gas production and 1.3 trillion cubic feet of remaining proven gas reserves, with an ultimate recovery for the region of 5.8 trillion cubic feet.

Montana's proved dry natural gas proved reserves declined from 995 billion cubic feet at the end of 2004, to 986 billion cubic feet at the end of 2005 (a decrease of 1 percent). Dry natural gas proved reserves have declined annual from a high of 1.059 trillion cubic feet in 2003. The highest estimated reserve value, for the 1977-2004 reporting period, was the 1.321 trillion cubic feet reported in 1981. The Energy Information Administration (2006b)

estimated that almost 107 billion cubic feet of Montana dry natural gas was produced in 2005 (a record for the 1982-2004 reporting period). Additional proved reserves were identified by enlarging proved areas of fields or reservoirs, revisions due to new information, additional new reservoir discoveries in old fields, and other adjustments. No new field discoveries of dry natural gas were made in Montana in 2005.

Montana's proved natural gas liquids proved reserves rose from 6 million barrels at the end of 2004, to 9 million barrels at the end of 2005 (Energy Information Administration, 2006c). This was an increase of 33 percent. The 2005 proved reserve was the highest reported for Montana since 1992, but lower than the reserve estimated for the 1979 through 1992 reporting period. The Energy Information Administration (2006b) estimated that about one million barrels of Montana natural gas liquids was produced in 2005. Additional proved reserves were identified by enlarging proved areas of fields or reservoirs, revisions due to new information, and other adjustments. No new field discoveries or new reservoir discoveries in old fields were made in Montana in 2005.

The only known recent attempts to estimate proved oil and gas reserves for an area covering the HiLine planning area are two reports prepared by the U.S. Departments of the Interior, Agriculture, and Energy (U.S. Departments of Interior, Agriculture, and Energy, 2003 and 2006). These reports were prepared in compliance with the Energy Policy and Conservation Act amendments of 2000. In the earlier report, the Energy Information Administration provided a detailed description of methods used to calculate proved oil and gas reserve estimates for the entire Montana Thrust Belt, and for other western regions. The Montana Thrust Belt occupies the westernmost part of planning area. In the 2003 and 2006 reports, Energy Information Administration detailed analysis of available data indicated that the Montana Thrust Belt contains 1,000 barrels of proved liquid reserves (both oil and natural gas liquids) and no gas reserves. These two reports did not calculate proved reserves of oil or gas for any other portion of the HiLine planning area.

The Montana Geological Society (2006) presents field summaries for most of the fields within the planning area. Most of these field summaries report an estimated ultimate recovery of oil and/or gas for their producing zones. Individual field production to date, obtained from Montana Oil and Gas Conservation Division (2007) or IHS Energy Group (2007) can be subtracted from these estimates of estimated ultimate recovery to calculate remaining proved reserves for each field. No other recent reports indicate a projection of proved reserves for the entire region of the HiLine planning area.

U.S. Geological Survey Resource Assessments

The U.S. Geological Survey is responsible for preparing the National Oil and Gas Resource Assessment for all provinces within the United States. Their "1995 National Assessment of United States Oil and Gas Resources" (Beeman et al., 1996; Charpentier et al., 1996; and Gautier et al., 1996) presents information about potential undiscovered accumulations of oil and gas in 71 geologic or structural provinces within the United States. Three of those assessed provinces are the Montana Thrust Belt, North-central Montana, and Williston Basin provinces. Each province lies partly within the HiLine planning area.

As part of a study prepared 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 prioritized oil and gas assessment studies for certain basins. An updated analysis covering the Montana Thrust Belt Province in the planning area was prepared in response to their new priorities. The two resulting reports for this province are titled "Assessment of undiscovered oil and gas resources of the Montana Thrust Belt Province, 2002" (U.S. Geological Survey, 2002) and "Montana Thrust Belt, Province 5027, General Assessment Results (2007b). In these two reports the U.S. Geological Survey updated their quantitative estimate of the undiscovered oil and gas resources for this province. A more complete discussion of the new assessment (Montana Thrust Belt Province) and the two 1995 assessments (North-central Montana and Williston Basin provinces), their locations, and estimates of the oil and gas resource volumes is presented in Appendix 1.

For the Montana Thrust Belt, North-central Montana, and Williston Basin province assessments, the U.S. Geological Survey estimated undiscovered technically recoverable resources (see Glossary definition) for each play or assessment unit (Tables A1-2, A1-4, and A1-6 in Appendix 1). When preparing estimates of resource quantities for each province, the U.S. Geological Survey used geology-based, well-documented estimates of quantities of oil and

gas having the potential to be added to reserves. For the Montana Thrust Belt assessment they used a future time frame—forecast span—of 30 years when estimating quantities of the potential oil and gas resource.

For each type of hydrocarbon, a mean estimated undiscovered resource volume was recorded for each assessment unit and a calculation of the portion lying within the HiLine planning area was made (Tables A1-2, A1-4, and A1-6 in Appendix 1). From that data, we estimate that all portions of assessment units lying within the planning area contain a mean undiscovered volume of **77.99 million barrels of oil, 9.16774 trillion cubic feet of gas, and 40.34 million barrels of natural gas liquids**.

In addition, we used the U.S. Geological Survey data to estimate that the planning area's oil resource could **range from 13.15 to 153.78 million barrels, the gas resource could range from 2.78646 to 20.1323 trillion cubic feet, and the natural gas liquids resource could range from 5.35 to 97.31 million barrels** (assuming fractile data used has a perfect positive correlation).

The U.S. Geological Survey in their 1995 assessment had estimated 42 trillion cubic feet of technically recoverable resources of continuous-type (unconventional) gas in Cretaceous shallow biogenic gas plays, with about 90 percent of this gas estimate in hypothetical plays. Over one-half of these estimates were based primarily on similarity of these plays to large shallow biogenic resources in southeastern Alberta and southwestern Saskatchewan. Additional preliminary work by the U.S. Geological Survey (Ridgley et al., 2001a) on these shallow biogenic resources indicated that a resource estimate would be less than 10 trillion cubic feet of gas, using a 30-year forecast.

Dyman et al. (1997) show that the Montana Thrust Belt Province (Figure 6) may contain sedimentary rocks at depths greater than 15,000 feet. Potential reservoirs could occur in these rocks below 15,000 feet. No assessment of potential resources deeper than 15,000 feet has been made in this area. The rest of the Planning area does not appear to contain potential deep reservoir rocks.

The U.S. Geological Survey recently completed a partial reassessment of the North-Central Montana Province (U.S. Geological Survey, 2008). Their assessment was prepared only for the Cretaceous Judith River through Belle Fourche Gas total petroleum system. The seven assessment units (Judith River Formation, Eagle Sandstone and Claggett Shale East, Eagle Sandstone and Claggett Shale West, Niobrara—Carlile, Greenhorn—Lower Belle Fourche, Greenhorn—Upper Belle Fourche, and Bowdoin Dome) were each assessed for their undiscovered shallow biogenic (also known as microbial) continuous gas resource potential. The U.S. Geological Survey estimated that there was a mean of 6.192 trillion cubic feet of shallow biogenic undiscovered gas resources. No additional information is presently available to determine how much of this gas resource could lie within the planning area. Oil, gas, and natural gas liquids in conventional accumulations were not assessed for the province during the reassessment.

Departments of the Interior, Agriculture, and Energy Resource Assessments

The U.S. Departments of the Interior, Agriculture, and Energy (2003 and 2006) have contributed to two publications that inventoried oil and gas resources in parts of the HiLine planning area. These publications only studied the Montana Thrust Belt in the western most part of the planning area. Their 2006 report estimated undiscovered resources, in the Montana Thrust Belt, of 170.5 million barrels of liquids (oil) and 6.3 trillion cubic feet of natural gas. We estimate that between 5 and 10 percent of this resource could be within the HiLine planning area. These resources would be about equally divided between Park Service lands and Blackfeet Reservation lands, with a very small portion located under Forest Service lands. No Bureau-managed lands appear to lie within the Montana Thrust Belt in the HiLine planning area.

The Energy Information Administration (2007b) projected a crude oil technically recoverable resource for the Rocky Mountains of 19.92 billion barrels. They also projected natural gas technically recoverable resources for the Rocky Mountains of 249.41 trillion cubic feet. The projected natural gas resource was further subdivided into several categories which are:

- Undiscovered nonassociated conventional gas – 14.68 trillion cubic feet
- Inferred reserves of nonassociated conventional gas – 15.74 trillion cubic feet

- Unconventional tight gas – 149.47 trillion cubic feet
- Unconventional shale gas - 14.11 trillion cubic feet
- Unconventional coalbed gas – 55.41 trillion cubic feet.

Potential Gas Committee Assessment

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

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

The Potential Gas Committee (2003) estimated the most likely quantity of resource for three regions that at least partly lie within the HiLine planning area. The Sweetgrass Arch, Central Montana Uplift (Blaine, Hill, Chouteau, Liberty, and Toole counties and the eastern part of Glacier County in the HiLine planning area and additional lands to the south) is estimated to contain 1.909 trillion cubic feet of gas from 0 to a depth of 15,000 feet and no gas resources are estimated for depths below 15,000 feet. We estimate that a large part of the shallower gas resource (greater than 75 percent) is present within the planning area.

For the Montana Thrust Belt (western Glacier County in the HiLine planning area and additional lands to the south and west), the Potential Gas Committee (2003) estimated that the most likely resources are 7.400 trillion cubic feet of gas from 0 to a depth of 15,000 and 5.220 trillion cubic feet of gas for depths below 15,000 feet. We estimate that as much as 50 percent of the shallower and deeper resource is present within the planning area.

The Potential Gas Committee (2003) defines the Williston Basin area as Phillips and Valley counties within the HiLine Planning and northeast Montana, western North Dakota, and northwestern South Dakota. For the Williston Basin area they estimated that the most likely resources are 1.722 trillion cubic feet of gas from 0 to a depth of 15,000 feet and 98 billion cubic feet of gas for depths below 15,000 feet. We estimate that less than five percent of the shallower resource is present within the planning area. None of the deeper resources are likely to be found in the planning area.

Most likely estimates of coalbed gas resources were made for the North Central Coal Region and Fort Union Coal Region (Potential Gas Committee, 2003). The Committee's North Central Coal Region includes the North Central and Blackfeet-Valier coal regions of Figure 14 and areas to the south of the HiLine planning area. Their estimate of most likely coalbed gas resources for the entire region is 1.200 trillion cubic feet. About 58 percent of the Committee's North Central Coal Region lies within the HiLine planning area and we estimate that about the same proportion of coalbed gas (0.7 trillion cubic feet) may occur within the planning area.

The Potential Gas Committee's (2003) Fort Union Coal Region includes the Fort Union Coal Region of Figure 14 and northeast Montana, western North Dakota, and northwestern South Dakota. Their estimate of most likely coalbed gas resources for the entire region is 500 billion cubic feet. The portion of this region within the planning area is only about one percent of the total Fort Union Coal Region, so only about five billion cubic feet of coalbed gas is estimated to come from this part of the planning area.

National Petroleum Council Assessment

The National Petroleum Council (2003) projected an undiscovered gas resource of 11.1 trillion cubic feet of gas for an area defined as the Williston/Northern Great Plains region. They compared the region to an equivalent area studied in the U.S. Geological Survey's 1995 assessment discussed above. The National Petroleum Council projection was about one quarter of the older U.S. Geological Survey's assessment of 45.8 trillion cubic feet of undiscovered gas resources. Their reduction from the U.S. Geological Survey's estimate was based on relatively unsuccessful exploratory drilling during the previous decade, which significantly reduced the hydrocarbon potential of the area. The U.S. Geological Survey (Ridgley et al., 2001a) lowered their estimates of potential shallow biogenic gas resources during a reassessment and was closer to the National Petroleum Council projection.

Rand Science and Technology Assessment

The William and Flora Hewlett Foundation funded an assessment of natural gas and oil resources of the Greater Green River Basin, in Wyoming by RAND Science and Technology, a research unit of RAND Corporation. 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.

The report by LaTourrette et al. (2003) indicated that the details of their spatial analysis and other data were available on request. We contacted the lead author and asked for this information in order to see the details of how the methodology was applied. Unfortunately, that information had been lost and was no longer available. This type of analysis has not been used to analyze any other regions within the Rocky Mountain region.

Biogenic gas

Twenty percent of the world's discovered natural gas reserves are of biogenic origin (Rice and Claypool, 1981). Biogenic gas is generated by anaerobic bacteria through the decomposition of organic matter in shale. Rice and Claypool (1981) reported that this can occur at temperatures between 0 and 75 degrees Celsius (32 and 167 degrees Fahrenheit). This gas is generated in thermally immature sediments and can accumulate in large quantities. Upper Cretaceous shales underlying the planning area represent effective source rocks for biogenic gas generation.

Large accumulations of biogenic gas are known to occur in shallow (less than 3,000 feet) Cretaceous reservoirs of the Northern Great Plains (mainly Montana) and southeastern Alberta and southwestern Saskatchewan (Ridgley et al., 2001). Production in Montana is from the Belle Fourche, Greenhorn, Carlile, Niobrara, Eagle, and Judith River formations. Fields and formations producing biogenic gas (Rice and Claypool, 1981; Ridgley et al., 2001a; Ridgley et al., 2001b; Shurr and Ridgley, 2002; and Lillis, 2007) within the planning area are:

- Ashfield – Phillips Sandstone,
- Battle Creek – Eagle Sandstone and Niobrara Formation (Martin sandy zone),
- Black Coulee – Eagle Sandstone,
- Bowdoin dome – upper Belle Fourche Formation, Greenhorn Limestone, Carlile Shale (Bowdoin Sandstone), and Niobrara Formation (Martin sandy zone),
- Brown's Coulee – Eagle Sandstone,
- Cassady (local field name for production in section 33 of T.34N., R.17E.) – Eagle Sandstone,
- Guinn – Eagle Sandstone,
- Havre – Eagle Sandstone,
- Kevin-Sunburst (east flank) – upper Belle Fourche Formation,

- Loring, East – Phillips Sandstone, Carlile Shale (Bowdoin Sandstone), Greenhorn Limestone, and Niobrara Formation (Martin sandy zone),
- Leroy – Eagle Sandstone,
- Lohman – Eagle Sandstone,
- Red Rock – Eagle Sandstone,
- Swanson Creek – Phillips Sandstone,
- Three Mile – Eagle Sandstone,
- Tiger Ridge – Eagle Sandstone and Judith River Formation, and
- Whitewater, East – Phillips Sandstone.

All biogenic gas fields except the Bowdoin dome and Kevin-Sunburst lie in the vicinity of the Bearpaw Mountains. Traps are formed by fault blocks related to this uplift and are considered to be conventional, structurally trapped reservoirs (Payenberg et al., 2003). At Bowdoin dome biogenic gas is stratigraphically entrapped over a large area (Rice and Claypool, 1981) and is considered to be an unconventional (continuous-type) reservoir. Kevin-Sunburst biogenic gas production also appears to by unconventional (Ridgley et al., 2001b).

Shurr and Ridgley (2002) reported cumulative production from some of these fields. In the area of Bowdoin dome, about 234 billion cubic feet of biogenic gas had been produced, mainly from the upper Belle Fourche Formation, the Greenhorn Limestone, and the Bowdoin Sandstone. At Battle Creek field about 50 billion cubic feet of biogenic gas has been produced from the Eagle Sandstone. The Tiger Ridge area has the majority of shallow biogenic gas production in Montana, with a cumulative total of 525 billion cubic feet.

U.S. Geological Survey estimates of biogenic gas-in-place are more than 100 trillion cubic feet (Rice and Shurr, 1980) and more recent calculations suggest about 40 trillion cubic feet of technically recoverable resources occur in Cretaceous shallow biogenic gas plays of northern and central Montana (Rice and Spencer, 1996). Between 1996 and 2000, the U.S. Geological Survey worked to determine controls on Upper Cretaceous shallow biogenic gas accumulations, in this region and into Canada (Ridgley et al., 1999). Preliminary results indicate that the resource estimate for biogenic gas will be less than 10 trillion cubic feet of technically recoverable resources that have the potential to be added to reserves in the next 30 years (Ridgley et al., 2001).

Shurr and Ridgley (2002) report in this part of Montana, "… reserves of shallow biogenic gas are ideally suited for exploration and development by small, independent operators. Drilling and completion costs are relatively low for these shallow accumulations, and lease costs also are low. Many accumulations are located in areas that are underdeveloped. Consequently, leases are relatively easy to acquire. Furthermore, formerly stranded sweet spots will come online as the domestic infrastructure expands to meet increased demands and attendant higher prices." Hester (2006) has reported that although the potential for production from these reservoirs exists, there are reasons for a lack of commercial development of these resources:

- the lack of pipeline infrastructure (gas pipeline and gathering systems) in the area,
- the lack of predictable and reliable rates of production due to the geologic nature of these continuous-type gas accumulations, and
- the difficulty in recognizing and selecting potentially productive gas-charged reservoirs.

The industry will need to overcome these obstacles in order to develop these resources.

Oil and Gas Occurrence Potential

We consider the HiLine planning area to have high potential for the occurrence of oil and gas. The entire planning area falls within at least one oil and gas play area as defined by the U.S. Geological Survey (see Appendix 1). These play areas were developed using a number of geologic characteristics that also qualify them as having high occurrence potential. Those characteristics include:

- presence of hydrocarbon source rocks,
- presence of reservoir rocks with adequate porosity/permeability,

- potential for structural/stratigraphic traps to exist,
- opportunity for migration from source to trap, and
- other conditions; such as temperature, depth of burial, and subsurface pressures.

Projections of Future Activity 2011-2030

The Energy Information Administration (2009) estimates that over the next two decades (through 2030):

- United States energy consumption will grow at an average annual rate of 0.5 percent, with liquid fuels growing at 0.1 percent and natural gas growing at 0.2 percent
- future natural gas supply will grow at an annual rate of 0.9 percent
- United States oil imports will decrease at an annual rate of 1.5 percent and natural gas imports will decrease at an annual rate of 2.6 percent
- price of natural gas will increase at an annual rate of 1.2 percent (in 2007 dollars)
- carbon dioxide emissions will remain the same from petroleum and will grow at an average annual rate of 0.3 percent for natural gas.

The above projected increases in demand and in oil and gas prices indicate continued industry emphasis on maintaining oil supplies and increasing gas supplies in the HiLine planning area. Much of the planning area gas supply growth is expected to come from production from reservoirs like those in the northern part of Phillips County and Bowdoin Dome area and in eastern parts of Hill County and western parts of Blaine County.

Oil and Gas Price Estimates

The National Petroleum Council (2003) has projected that through 2025 "… supply and demand will balance at higher price ranges than historical levels …" in the United States. The combination of a growing demand and limited supply has created market tightening and led to higher gas prices and price volatility (National Petroleum Council, 2003). They anticipate that price ranges will be determined by response to "… increased efficiency, conservation, and alternate fuel use, the ability to increase conventional and nonconventional supplies from North American… and increasing access to world resources through LNG imports."

Anticipated oil and gas prices are the single most important factor controlling the amount of future oil and gas drilling and production activity in the planning area. Boswell (2006) reported that "… in today's market the average unconventional resource play breaks even at four dollars per thousand cubic feet of gas and requires in excess of seven dollars per thousand cubic feet to achieve a 20 percent rate of return at the wellhead."

In recent years, oil and gas prices have been very volatile. Natural gas has shown the highest volatility of any commodity traded (Boswell, 2006). The three factors most affecting gas prices have been:

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

United States gas production for 2006 was about 1.1 trillion cubic feet lower than its peak in 2001. Simmons & Company International (2005) projected that "… limited rig availability, a shortage of attractive drilling prospects, and accelerating decline rates are likely to result in a falling domestic production." As a result, they project that this lack of supply will constrain demand growth for gas and keep prices relatively high.

Gas Prices

Sieminski (2007) projected that U.S. gas prices would average 7 dollars per thousand cubic feet for the next five years. Petak (2007) projected that Henry Hub gas prices will average between 6 and 8 dollars per thousand cubic feet in the long-term (to 2025).

Figure 21 presents historical natural gas prices (Montana Natural Gas Wellhead Price) obtained from the Energy Information Administration (2007d) and projected future natural gas prices were also obtained from the Energy Information Administration (2007a). Historical prices are in nominal dollars and show the historic volatility that has occurred in natural gas prices in Montana. The projection of future prices is an average for Lower 48 Wellhead Prices and is made in 2005 dollars.

The driving force behind the increase in drilling commencing in 1997 (Figure 10) can be directly attributed to an increase in natural gas prices. The graph of the history of natural gas prices shows that natural gas has enjoyed quite an increase in value since 1995 (Figure 21). An increase in product price in the oil and gas industry is almost always followed by an increase in exploration and development. In the HiLine planning area, most wells currently being drilled are replacement/infill/fringe wells in the Bowdoin Dome Field targeting the Eagle Formation.

The Energy Information Administration (2008) projection of future prices predicts that U.S. lower 48 natural gas prices will start decreasing from current levels (first half 2008 prices) "to an average of $5.32 per thousand cubic feet (2006 dollars) in 2016, then rise to $6.63 per thousand cubic feet in 2030. " They predict that the current high natural gas prices will stimulate development of new gas supplies and constrain growth in natural gas consumption, leading to the decline in prices projected through 2016. They predict the increased prices after 2016 will be due to "the increased cost of developing the remaining U.S. natural gas resource base.

It is not known if liquefied natural gas imports will meet expectations nor if new pipelines will connect gas supplies in northern Canada and Alaska with U.S. markets. While both scenarios would not happen for years, they could decrease future gas prices in the long term. Consequently, the projection of future natural gas prices should be considered speculative.

These natural gas price projections allow some generalizations concerning future gas drilling and production activity in the HiLine planning area. If the above gas price scenario is accurate, a continued high level of gas exploration and production in the HiLine planning area would be expected. Gas prices are predicted to decrease from 2009 through 2016, and then slowly increase until 2030. Starting in 2007, gas production will be mainly a function of the ability of industry to discover and economically develop gas accumulations and the ability to increase drilling, production, processing, and transportation efficiency.

U.S. demand for natural gas is expected to increase about 50 percent by 2020. Increases in future natural gas production, are projected to come partly from the Rocky Mountain area. Anticipated new production in the planning area is expected to mainly come from the discovery of new shallow biogenic gas reservoirs, the discovery of other unconventional types of reservoirs, and the addition of incremental gas production from existing gas fields.

Oil Prices

Sieminski (2007) recently reported that West Texas Intermediate oil prices averaged 19.7 dollars per barrel in the 1990s. He predicted that oil prices will average around 50 dollars per barrel during the current decade.

Figure 22 presents historical crude oil prices (Montana Crude Oil Wellhead Acquisition Price by First Purchase) obtained from the Energy Information Administration (2007e) and projected future crude oil prices were also obtained from the Energy Information Administration (2007a). Historical prices are in nominal dollars and show the historic volatility that has occurred in crude oil prices in Montana. The projection of future prices is an average imported Low Sulfur Light Crude Oil Price and is made in 2005 dollars.

The Energy Information Administration (2008a) projection of future prices predicts that world oil price projects are higher for 2006-2030 than those presented the previous year and "the higher price path reflects lower estimates of oil consumers' sensitivity to higher prices, and anticipation of lower additions to production capacity in key non-OPEC regions, and a reassessment of OPEC producers' willingness and ability to expand production and production capacity aggressively." Their reference case projects that "world oil prices moderate from current levels to about $57 per barrel in 2016, start rising again as production in non-OPEC regions peaks, and continue rising to $70 per barrel in 2030 (all prices in 2006 dollars). The low and high price cases reflect a wide band of potential world oil price paths, ranging from $42 to $119 per barrel in 2020." They also state that "recent volatility in crude oil prices demonstrates the uncertainty inherent in the projections."

Figure 21. Range of historic Montana natural gas prices (Energy Information Administration, 2007d) and Energy Information Administration (2007a) projections of future natural gas prices for the Lower 48.

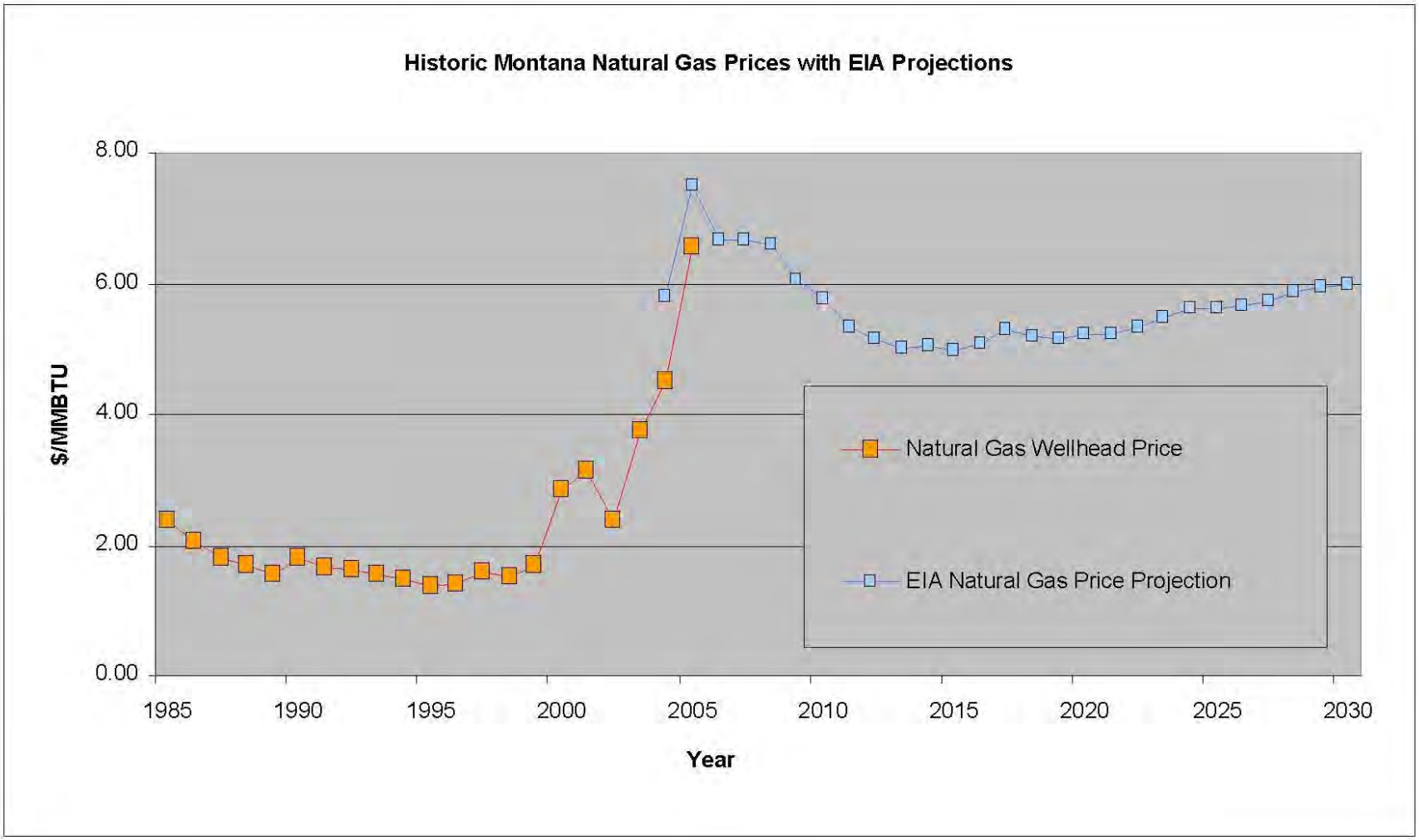
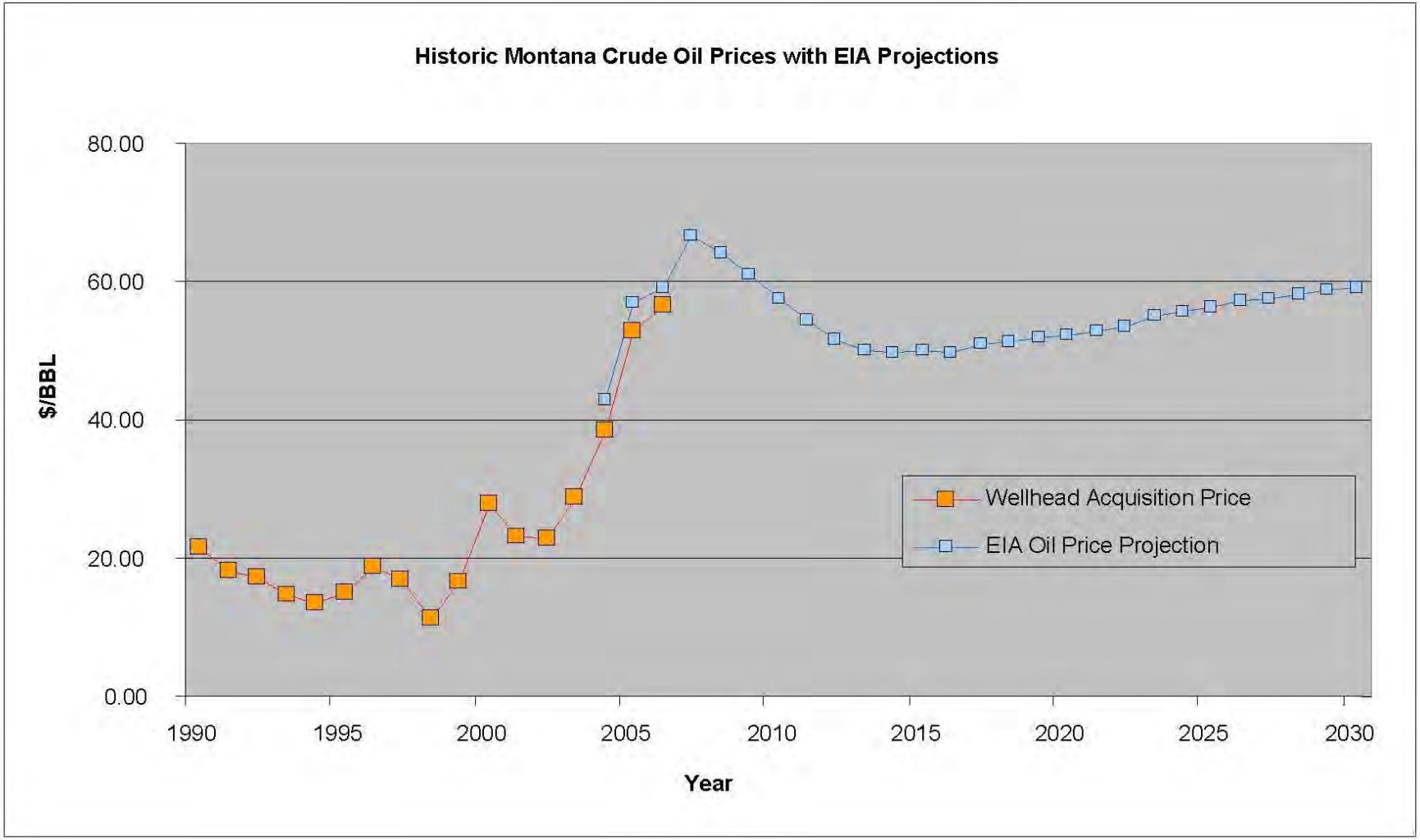


Figure 22. Range of historic Montana crude oil prices (Energy Information Administration, 2007e) and Energy Information Administration (2007a) projections of future crude oil prices.



There are a large number of shut-in oil wells, and to a lesser extent shut-in gas wells, in Glacier and Toole Counties (Table 1). Many of these shut-in wells are in the Cut Bank area. These high rates of shut-in status are related to the length of time that drilling has occurred in the Cut Bank area. Drilling first occurred in the Cut Bank area in 1922 with the discovery of the Kevin Field. Cut Bank Field was discovered in 1926. The area has been steadily drilled since that time. With the vintage of wells in the two counties (including reservation lands), many wells are not economic to produce even with the price of oil exceeding 70 dollars per barrel in 2006 and higher gas prices. It is unlikely that projected future crude oil prices will significantly increase oil related drilling and production activity in the planning area. Future drilling and production activity will be almost exclusively related to the future price for natural gas.

Little crude oil production is anticipated from newly discovered within the HiLine planning area. Industry will be mainly using existing and new technology to try to reduce declining rates in production in existing fields and will seek some limited new drilling through replacement/infill/fringe wells.

Leasing

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

Leases on lands where the U.S. owns the oil and gas rights are offered via oral auction at least quarterly. Maximum lease size is 2,560 acres and the minimum bid is two dollars per acre. A 75 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 and two dollar per acre thereafter. Leases are issued for a ten-year term and a 12.5 percent royalty on production is required. Leases that become productive, are held-by-production and do not terminate until all wells on the lease have ceased production. Many private oil and gas leases contain a “Pugh clause,” which allows only the developed portion of the lease to be held by production. However, federal leases have no such clause, allowing one well to hold an entire lease.

In Montana, federal oil and gas lease sales are held on odd numbered months; usually at the Bureau’s State Office in Billings, Montana. Since August 1996, only lands nominated by industry are offered for lease. Before that date, virtually all federal lands available for competitive leasing were offered at each sale. Each new lease contains restrictive stipulations which protect potentially affected, mainly surface, resource values.

Oil and gas prices, hydrocarbon prospectivity, and exploration success will, to a great extent, determine the amount of acreage leased and bonus bids received. Half of the money earned from oil and gas leases on public domain minerals goes to the State of Montana. The other half stays with the federal treasury, where it is split between the conservation fund and the general fund on a 4:1 ratio respectively.

Seismic Surveys

Seismic surveys are a critical part of exploration for oil and gas resources. They are authorized on Bureau-managed surface by approval of “Notices of Intent to Conduct Geophysical Operations.” Seismic surveys on surface not managed by the Bureau do not have to be permitted with the Bureau even though the surveys cover federal minerals. Two-dimensional seismic surveys have successfully been used for years in the HiLine planning area to explore for gas traps. Low-fold, three-dimensional seismic programs have more recently been used to help reduce costs in the pursuit of 500 to 1,400 foot deep gas traps in the Eagle Sandstone play surrounding the Bearpaw Uplift (Figure 6) in Blaine and Hill counties. Occasional seismic surveys will continue to be run in this part of the planning area and in western areas where potential structural traps are more common. Seismic surveys will be less frequent in eastern parts of the Planning area. We anticipate that the number of seismic surveys in the HiLine planning area will decrease with time.

Projections of Future Drilling Activity

It is difficult to predict what will occur a few years into the future, but it is even more difficult to predict 20 years ahead. In an attempt to gain more insight as to what may occur in the HiLine planning area, geologists and engineers in the oil and gas industry were contacted. Major oil and gas companies operating in the HiLine planning area were contacted by letter and asked what development activity they anticipated during the next 20 years. The Bureau also contacted most of these companies by telephone, either a few days after the letters were sent, or in order to clarify information after replies were received. These data were compiled and used to help project locations and amounts of future drilling activity within the planning area. A review of available technical data was also made to help make these projections. 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, 2002, page 13) we estimate that during the 20-year planning cycle of 2011 to 2030, as many as 6,102 wells will be drilled in the HiLine planning area. Up to 150 of these wells could be coalbed gas wells (to be discussed later). Of the 5,952 remaining wells, 1,091 wells are projected to lie within the Bowdoin Dome area.

The estimated development potential and related drilling density (per township) of the projected new 6,102 wells is shown on Figure 23. Development potential is defined as high, moderate, low, and very low and it is related to the relative hydrocarbon prospectivity (occurrence potential) of the area. Areas of high prospectivity (high potential for the occurrence of hydrocarbons) will tend to be areas of high development potential. The converse is also true, in the areas of low prospectivity (low potential for the occurrence of hydrocarbons) will also tend to be areas of low development potential.

High development potential indicates areas where we estimate **average** drilling density will exceed 100 well locations per township (one township is about 36 square miles) during 2011-2030. Moderate development potential indicates 20 to 100 wells per township; low development potential indicates 2 to 20 well locations per township; and very low development potential is defined as 2 wells or less per township. The Charles M. Russell National Wildlife Refuge, Glacier National Park, and wilderness study areas were not assessed for potential for future development.

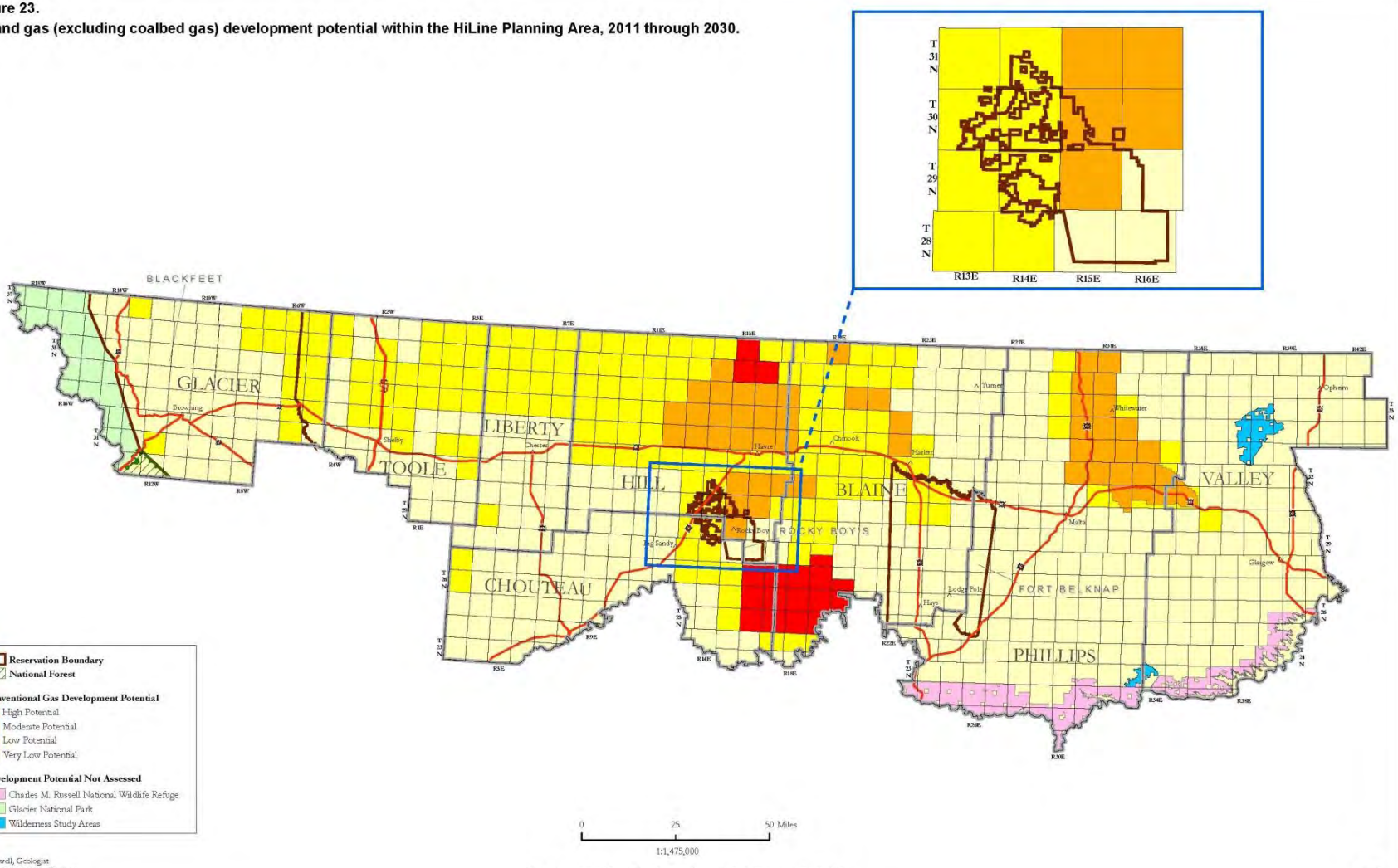
Estimated acres, number of townships, average drilling densities, and percentage of the planning area within each development potential classification type, shown in Figure 23, are summarized in Table 11. Much of the anticipated drilling activity will be concentrated in areas of high and moderate development potential, which only account for 10.3 percent of the area in which development potential was assessed.

Table 11. Estimated oil and gas (excluding coalbed gas) development potential classification acres, number of townships, average drilling densities, and percentage of the planning area within each development potential classification type for the HiLine Planning Area (2011-2030).

Development Potential	*Acres (thousands)*	*Area (townships)*	*% of HiLine Planning Area*
High	375	16.30	2.49
Moderate	1,175	51.00	7.81
Low	3,810	165.35	25.31
Very Low	9,692	420.65	64.39

Most of the townships marked high and moderate, already are relatively densely drilled (high contains an average of about 54 wells per township and moderate contains an average of 70 wells per township). Some townships have been less densely drilled and they contain only scattered wells with as few as one well per township. Many new wells in these areas will be drilled as infill or fringe wells. Additional wells will be drilled trying to discover and develop new pools or deeper pools within existing field areas, and to a lesser extent to search for entirely new fields.

Figure 23.
Oil and gas (excluding coalbed gas) development potential within the HiLine Planning Area, 2011 through 2030.



With additional wells projected, the density of wells within existing fields in these areas will generally range from one well per 40 acres to one well per 160 acres by 2030. Most of these townships will likely not be this closely spaced throughout their entire 23,040 acre area.

In areas marked as low development potential, fewer new wells will be drilled and well densities will remain similar to what they are at present, with isolated townships having a small potential for a significant increase in drilling density. In areas marked as very low development potential, most activity will be tied to exploration for new field discoveries. Many of these townships will not receive any drilling. If a new field discovery is made in any of these areas of low or very low development potential, subsequent drilling density could be at one well per 160 acres. It is very likely that a new field discovery in these areas would be in the small field size (less than one million barrels of oil equivalent or less than six billion cubic feet of gas) with six or fewer producing wells, since Root and Attanasi (1993) estimated that 89 percent of the ultimate number of discovered fields in the lower 48 U.S. would be in the small field category. Even if larger fields are discovered in these areas, they are not expected to be of such large size as to completely cover the area of an entire township. The probability of the successful discovery of one or more new fields in areas of very low development potential is likely to be low to very low.

In the Bowdoin Dome area, 57.44 percent of all historical wells have been drilled on federal-managed oil and gas minerals. We assume that future federal wells will continue to be 57.44 percent of all newly drilled wells in the Bowdoin Dome area. In the rest of the planning area, only 11.75 percent of all historical wells have been drilled on federal-managed oil and gas minerals. As previously discussed, a significant portion of historical drilling activity has been in the western portion of the planning area where there is a small percentage of federal-managed oil and gas minerals. This has led to the low 11.75 percent historical rate of drilling on federal managed oil and gas minerals. Since projections of future activity (Figure 23) show the highest potential areas of future activity (high and moderate potential) will be in the central portion of the planning area (excluding the Bowdoin Dome area in northern Phillips County and a small portion of Valley County) where federal-managed oil and gas minerals make up a larger percentage of total lands, we project that that future federal wells will be drilled at a higher rate of almost 27 percent.

We anticipate that average well depths will remain in the present range (see Figure 15) with some minor increases in average depths if deeper reservoirs are locally encountered. Deep wells, greater than 15,000 feet deep, will probably be very uncommon. A few deep wells could be drilled in the Montana Thrust Belt on the westernmost portion of the planning area.

Part of the anticipated activity will be finding and developing additional unconventional gas resources. In-order-to convert these potential gas resources to proven reserves and ultimate production, a number of technology requirements will be needed to be fulfilled. Foss (2007) listed the following requirements:

1. Exploration technology for establishing the higher permeability, naturally fractured areas of a tight gas basin or play.
2. Basin and regional studies to understand and avoid areas high water saturation.
3. Reservoir characterization to establish the total productive pay intersected by a wellbore.
4. Emphasis on steadily reducing well drilling and completion costs.
5. Applying intensive resource development.

Much of the rest of the anticipated activity will be additional drilling to grow identified reserves. Initial estimates of the size of new oil or gas fields are usually too low and over time, with the benefit of additional wells and increased knowledge of the reservoir, newer estimates of the size and ultimate recovery contribute to reserve growth (Central Region Energy Resources Team, 1996). Factors that contribute to reserve growth include:

- Physical expansion of fields by areal extensions and development of new producing intervals,
- Improved recovery resulting from application of new technology and engineering methods, and
- Upward revisions of reserve calculations based on production experience and changing relations between price and cost.

Projected Coalbed Gas Drilling

Coalbed gas production in Montana is presently only occurring in the Powder River Basin portion of the state (southeastern Montana). The potential for coalbed gas in the HiLine planning area does not appear to be as large as in other parts of the state. The U.S. Geological Survey (2002) identified an area of potential undiscovered resources of Jurassic/Cretaceous coalbed gas in the Montana Thrust Belt Province, but made no quantitative assessment of this potential resource.

In the rest of the planning area the only available information is a map of areas of known coal bearing strata (U.S. Geological Survey, 2001) shown in Figure 14. These strata occur in the Blackfeet-Valier, North Central, and Fort Union coal regions at depths less than 2,000 to 3,000 feet, depending on the region. Additional coals are known to occur in large parts of the region, outside the Montana Thrust Belt Province, at depths down to 6,000 feet, but no other detail is available. The Potential Gas Committee (2003) estimated 1.2 trillion cubic feet of potential recoverable coalbed gas resources in North Central Montana, which includes the Blackfeet-Valier and North Central coal regions and large areas to the south of the planning area. The Fort Union coal region lies in the easternmost part of the Planning area and extends east of the planning area, covering much of the Williston Basin Province. The Potential Gas Committee (2003) estimated 0.5 trillion cubic feet of potential recoverable coalbed gas resources in this large area. No drilling for coalbed gas has occurred in any part of these coal regions in the planning area.

As stated earlier, about 150 new coalbed gas wells are projected to be drilled in the planning area between 2011 and 2030. The estimated development potential of these new wells is shown on Figure 24. Only areas of very low potential and no potential were outlined. Areas of very low development potential are defined as averaging 2 wells or less per township.

Areas of known coal strata at shallow depths (less than 3,000 feet) were assigned a very low development potential. The rest of the assessed planning area was assigned no development potential for the 2011 to 2030 year period. Estimated acres, number of townships, average well densities, and percentage of the planning area within the very low and no development potential classification types, shown in Figure 24, are summarized in Table 12. Charles M. Russell National Wildlife Refuge, Glacier National Park, and wilderness study areas were not assessed for potential for future development.

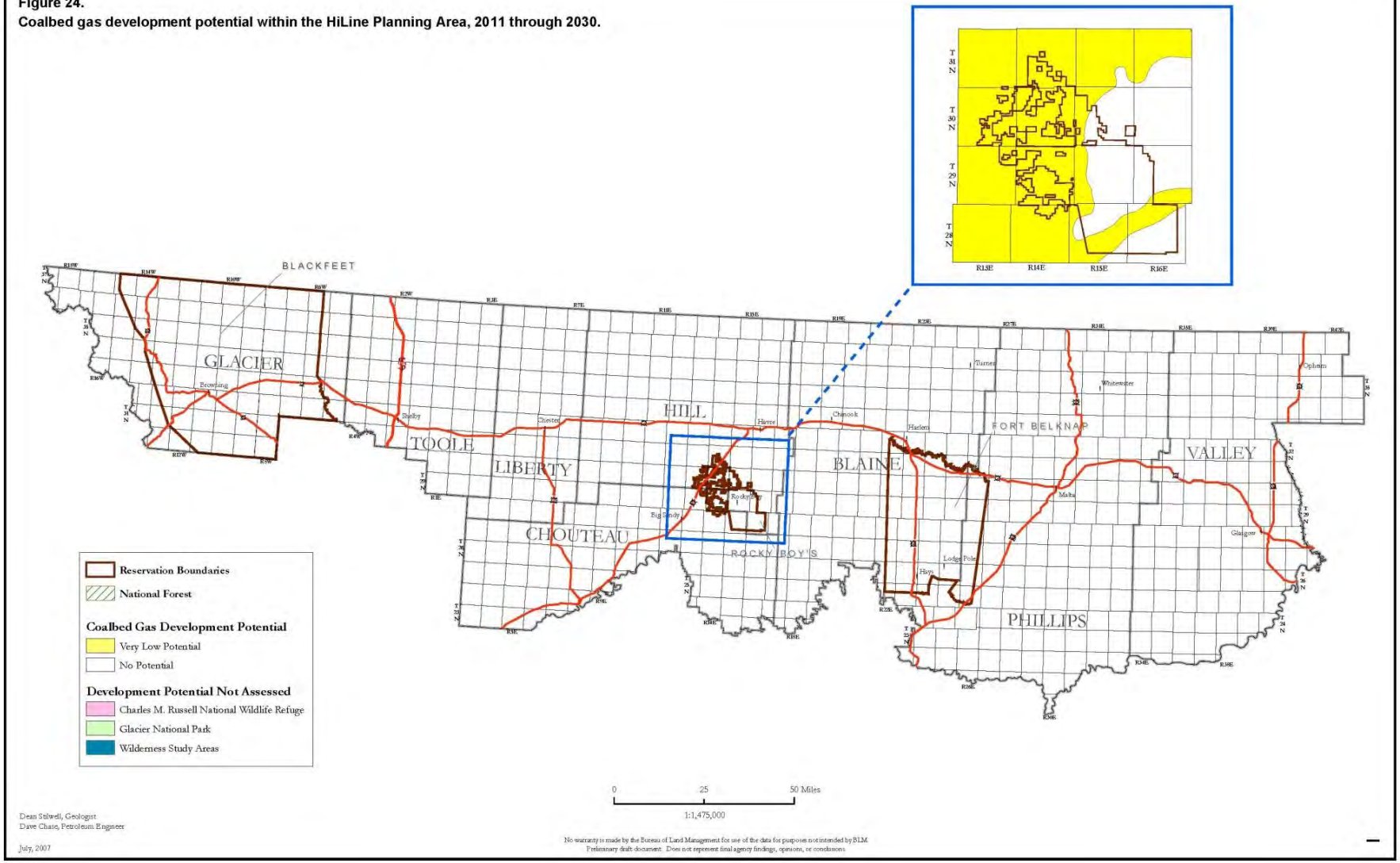
Table 12. Estimated coalbed gas development potential classification acres, number of townships, average drilling densities, and percentage of the planning area within each development potential classification type for the HiLine Planning Area (2011-2030).

Development Potential	*Acres (thousands)*	*Area (townships)*	*% of HiLine Planning Area*
Very Low	6,952	301.76	46.16
None	8,109	351.96	53.84

Since no drilling has yet occurred within the HiLine planning area to explore for coalbed gas, we consider this play as being only hypothetical at present. No proposed coalbed gas activities have been proposed by industry and operators did not submit projections of future activity or interest in future activity.

In order to assess potential impacts of some exploration and potential development of the coalbed gas resource in the HiLine planning area we are assuming that up to 150 new wells could be drilled. Results from coalbed gas pilot drilling projects in Wyoming suggest that often too few wells have been drilled to adequately evaluate the economic viability of a particular area. Past history indicates that pilots should contain 16 (four interior wells) to 25 (nine interior wells) wells to adequately evaluate an area (Lance Cook, 2002, Wyoming State Geologist, personal communication, and Don Likwartz, 2002, Wyoming Oil and Gas Supervisor, personal communication). History suggests that fewer than 16 to 25 wells may not adequately reduce pressure over a sufficient area and allow gas production. Also, heterogeneity in the coal may preclude the one interior well in a normal five or nine well pilot from providing the data necessary to adequately evaluate economic viability. We assume that most coalbed gas pilots will contain 16 to 25 wells. This should provide a better chance of obtaining adequate data and thus avoiding duplicate projects.

Figure 24.
Coalbed gas development potential within the HiLine Planning Area, 2011 through 2030.



A projection of 150 new coalbed gas wells will allow some exploration activity and preliminary development if this play is determined to be economic to produce. Any exploration will most likely occur in the final 10 years of the analysis period. Much of the potential coalbed gas drilling may occur in only a few of the townships outlined in Figure 24. It will probably not be spread evenly over the area of potential.

Production

When the Energy Information Administration (2004) looked at past U.S. 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 1990s 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 annual gas production in the U.S. has been lower than the recent high of 20.5 trillion cubic feet reported in 2001. This decline in total production for the U.S. has occurred even while drilling has reached an all-time high. Foss (2007) indicated that "with a maturing resource base and unconventional plays increasingly the target of drilling, the production of new wells does not match historical results, nor is it expected to." In general, we expect that new gas wells drilled within the planning area will follow this trend of reduced per well production from new wells completed. This reduced production will be mainly due to infill drilling (with reduced incremental additions to production) and industry's pursuit of reservoirs with lower productivity. This lower volume production will become available for economic development due to increases in projected oil and gas prices.

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

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

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

"Unconventional gas has become an increasingly important component of total lower 48 production over the past decade" (Energy Information Administration, 2004). It increased from 17 percent (3.0 trillion cubic feet) of total production in 1990 to 32 percent (5.9 trillion cubic feet) in 2002 (Energy Information Administration, 2004) and to 40 percent (7.5 trillion cubic feet) in 2004 (Energy Information Administration, 2006c). Unconventional gas production has offset recent declines in conventional gas production. It is expected to increase to 46 percent (9.5 trillion cubic feet) of total production by 2030 (Energy Information Administration, 2006c). Tight gas sand and coalbed gas production account for the largest portion of the undeveloped unconventional gas resource in the onshore lower 48 states. The Phillips Member, Greenhorn Formation, and Bowdoin Sandstone (Figure 7) are potential tight gas units lying within the planning area (Gas Technology Institute, 2001). These potential formations are located in the eastern part of the planning area, along the Bowdoin Dome anticlinal structure (Figure 6).

Natural gas production from the Rocky Mountains has increased 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 nonconventional resources, although conventional production has also been increasing. The Rocky

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

Other Potential Future Oil and Gas Activities

Shale Gas

Natural gas resources are potentially present in shales in the HiLine planning area. The Bakken Shale play, in parts of the Williston Basin east of the planning area, could extend into the easternmost part of the HiLine planning area (GRI, 2000; and Faraj, et al., 2004). This formation is considered to be a low potential shale gas target in the planning area because of its limited thickness (maximum of 65.5 feet), source rock properties, and low thermal maturity (Faraj, et al., 2004). Other carbonaceous shales are present within the planning area, but their potential for containing economic gas resources is unknown. At present, there is little information available to characterize any shale gas plays that may be present within the planning area.

Carbonaceous shale is expected to be an important future source of natural gas in the United States. At present, technology and completion methods are not available to economically produce any present natural gas that may be contained in shale in the planning area. However, this important future gas source could become viable before the end of the planning cycle.

When and if the shale gas play is characterized for the planning area and technology and well completion methods are developed, this potential energy source could become important. Initial development would probably use existing boreholes. However, if sufficient reserves per well are present, additional wells may be drilled specifically to recover natural gas from shale. Those additional wells would likely be drilled with a horizontal trajectory. Shale has very low permeability and large hydraulic fracture stimulations will probably be necessary to liberate the gas (Bereskin and Mavor, 2003). This production may be accompanied by significant volumes of water. Also, well spacing may be dense; one well per 40 acres should be expected for vertical wells and 80- to 160-acre spacing for horizontal wells. Opportunities for development of this resource in the planning area appear to be very low for the period extending through 2030.

Coal Gasification

Underground coal gasification may be a potential future process that is applied to coal deposits within the HiLine planning area. This process burns the coal in-situ producing a combustible gas with a low heating value that may 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 also evidence that combustion gases preferentially absorb to the coal cleat faces and displace coal bed methane gas from the coal, which would increase the heating value of the produced gas. The heat of reaction of the burned coal heats the unburned coal in front of the combustion front and drives off the hydrocarbon volatile matter contained in the coal. The removal of volatile matter is essentially the same process that coal goes through in the geologic process of changing 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. The limiting factor in depth would be potential reduced permeability of the coal and the ability to efficiently inject and produce the gas.

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, deep depths, and strong cap rocks should limit this. Currently, this technology, involving coal beds, does not appear to be economic and as a result there is little research activity in the state. Considering the relatively experimental status of coal gasification and the abundant energy supplies from mineable coal in the Powder River Basin, there is a low probability that this process will be utilized in the HiLine

planning area in the next 20 years. However, if it becomes economic to remove volatiles from coal beds, then there could be limited amounts of development activity in the planning area.

Carbon Dioxide Sequestration

Carbon dioxide sequestration is a method of storing captured carbon dioxide gas. This gas is a greenhouse gas that is generated by power plants, oil refineries, cement works, and iron and steel production. In the planning area, only petroleum and natural gas processing have been identified as the major industrial sources of carbon dioxide (U.S. Department of Energy, 2007). Capturing and storing this gas has been proposed to reduce the environmental effects caused by releases of this gas. Three types of types of geologic formations have been identified as potential carbon dioxide sequestrations sites (U.S. Department of Energy, 2007). Those formation types are:

- 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 is assumed to be non-potable. Larger oil and gas reservoirs in the planning area could be considered for sequestration. Carbon dioxide injected into a mature oil reservoir can enable incremental oil to be recovered. An additional 10 to 15 percent of original oil-in-place can be recovered when carbon dioxide is injected. Cut Bank Field has been identified as a potential candidate for carbon dioxide injection (Advanced Resources International, 2006). It contained 564 million barrels of oil in the Madison Limestone, with 139 million barrels produced and 5 million barrels of estimated remaining reserves. An additional 56 to 85 million barrels of incremental oil may be produced with carbon dioxide injection. This type of operation is being used in some oil fields in Wyoming and there are plans to bring carbon dioxide to parts of the Williston Basin, east of the planning area; but there is presently no plan to deliver carbon dioxide to the Cut Bank Field.

- Unmineable coal seams – Unmineable coal seams are considered to be those that are too deep or too thin to be economically mined. Most coals in the planning area meet these criteria. If methane contained in planning area coal beds becomes economically producible, 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 – These saline formations were defined in the U.S. Department of Energy (2007) atlas, as porous and permeable rocks containing water with total dissolved solids greater than 10,000 milligrams per liter, which has the capacity to store large volumes of carbon dioxide. They are much more extensive than coal seams or oil- and gas-bearing rocks, and thus 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. This process is being evaluated at the Lost Soldier oil and gas field in Wyoming.

Pipeline Infrastructure

Montana transports nearly one-half of its natural gas production to out-of-state markets (Energy Information Administration, 2007c). Shortfalls in pipeline capacity have been common in the Rocky Mountain region in recent years. These shortfalls appear to be the result of rapid growth in supply, which has outstripped construction of new pipelines. The National Petroleum Council (2003) projects that significant new infrastructure will be needed in the Rocky Mountain region through 2013 and then the need will decrease after that.

Major interstate natural gas pipelines in Montana include:

- KM Interstate Gas Co.,
- Northern Border Pipeline Co. (traverses planning area),
- Northern Natural Gas Co.,
- Northwest Energy Co.,

- Shoshone Pipeline Co., and
- Williston Basin Pipeline Co. (Energy Information Administration, 2007c).

HiLine planning area pipeline additions in the last few years have been primarily those needed to connect new production to the existing pipeline network. No major pipeline construction appears to be planned for the planning area in the near term.

Reasonably Foreseeable Development Scenarios for Resource Management Plan Alternatives A, B, C, D and E

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

Procedures Used to Determine Well Location Reductions

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

- Restriction Category A - These areas are open to leasing. Restrictions are relatively minor and result in standard lease terms and conditions that are applied to every federal oil and gas lease sold in Montana. These restrictions are considered to have little to no effect on the number of future well locations or production for any alternative.

- Restriction Category B – These areas are open to leasing subject to relatively minor constraints. These restrictions can have a moderate effect such as multiple, consecutive timing restrictions for protection of wildlife values such as; crucial winter range, raptor nesting habitat, or sage grouse strutting grounds. We also considered restrictions such as avoidance of areas within wetlands, riparian areas, or perennial waters could have a moderate effect on the potential locations of future wells and cumulative production.

- Restriction Category C – These areas are open to leasing, subject to major constraints. These restrictions can have a moderate to severe effect on the location of wells; such as no surface occupancy stipulations on an area more than 40 acres in size or requirements that view sheds be protected, thus requiring that well locations and production facilities not be visible from areas such as historic trails. Overlapping minor constraints may also severely limit the future development of oil and gas resources.

- Restriction Category D areas are closed to leasing. These are areas where a determination is made that other land uses or resource values cannot be adequately protected with even the most restrictive lease stipulations. Because areas are closed to leasing, this category has the most severe restrictions on future oil and gas activity and production.

Estimates of future reductions in well locations from the base line reasonably foreseeable development projection were determined as described below:

- An estimate of the number of well locations/township (average well density) that could be drilled in each development potential category over the 20-year life of the Resource Management Plan was made for conventional oil and gas development activity (within Bowdoin Dome area and within the rest of the HiLine planning area) and for coalbed gas development activity. The average well density per township for high development potential was projected to be 110 wells, for moderate development potential it was projected to be 60 wells per township, for low development potential it was projected to be 11 wells per township, and for very low development potential it was projected to be 0.5 wells per township.

- The acres of federal oil and gas ownership for each area of non-coalbed gas development potential (Figure 23) was determined using GIS software. Acres of non-federal oil and gas minerals were not included because proposed Resource Management Plan decisions will only apply to federal oil and gas minerals. We assumed development on non-federal minerals will occur as estimated in the base line foreseeable development projection.

- The acres of federal oil and gas ownership for each area of coalbed gas development potential (Figure 24) was determined using GIS software. Acres of non-federal oil and gas minerals were not included because proposed Resource Management Plan decisions will only apply to federal oil and gas minerals. We assumed development on non-federal minerals will occur as estimated in the base line foreseeable development projection.

- Next, the areas covered by each restriction categories (B, C, or D) within the high, moderate, low, or very low development potential areas for non-coalbed oil and gas (within Bowdoin Dome area and within the rest of the HiLine planning area) and coalbed gas potential were calculated using GIS software. The area within category A was not calculated, because we previously determined that this type of restriction would have no significant effect on the number of well locations for any alternative. As an example, the Alternative B acreage calculations for each potential area are presented in Table 13.

Table 13. Alternative B summary of the number of acres in each restriction category for each development potential type on Bureau-managed oil and gas minerals within the HiLine Planning Area (October 30, 2012).

Development Potential	***Category D Federal Acres***	***Category C Federal Acres***	***Category B Federal Acres***
Non-Coalbed Oil and Gas – Excluding Bowdoin Dome Area			
High	138,489	6,889	0
Moderate	50,383	14,119	0
Low	258,858	65,915	0
Very Low	2,427,013	133,968	0
Non-Coalbed Oil and Gas – Bowdoin Dome Area			
High	0	0	0
Moderate	232,964	31,128	0
Low	65,870	6,497	0
Very Low	0	0	0
Coalbed Gas			
Very Low	548,175	103,740	8,245

- After the acres of federal oil and gas were calculated for each alternative in each restriction category, the percent reduction in well locations for each alternative in each category of restriction was estimated. This estimate is a percent of the well locations which would not be drilled in each area due to the specific category of restriction. As an example, the results of our calculations for Alternative B, Category C restrictions are shown in Table 14. Category C restrictions for Alternative B indicate there would be a reduction of about 64 non-coalbed oil and gas well locations in the area excluding Bowdoin Dome area,

about 124 non-coalbed oil and gas well locations in the Bowdoin Dome area, and about 1.4 coalbed gas well locations on federal lands. The number of townships was calculated by dividing the federal acres by 23,040 acres per township.

Table 14. Analysis results showing the calculated reduction in federal wells of each type for Alternative B due to Category C restrictions. This calculation indicates there would be a reduction of about 40 non-coalbed oil and gas well locations in the area excluding Bowdoin Dome area, about 34 non-coalbed oil and gas well locations in the Bowdoin Dome area, and about 1.4 coalbed gas well locations on federal-managed oil and gas lands due to Category C restrictions. (October 30, 2012)

Development Potential	*Well Locations per Township*	*Federal Oil and Gas Mineral Acres*	*Federal Oil and Gas Mineral Townships*	*Percent Reduction in Federal Well Locations*	*Reduction in Federal Well Locations*
Non-Coalbed Oil and Gas – Excluding Bowdoin Dome Area					
High	110	6,889	0.299	30%	9.866
Moderate	60	14,119	0.613	40%	14.707
Low	10	65,915	2.861	50%	14.305
Very Low	0.5	133,968	5.815	55%	1.599
Non-Coalbed Oil and Gas – Bowdoin Dome Area					
High	110	0.0	0.000	30%	0.000
Moderate	60	31,128	1.351	40%	32.425
Low	10	6,497	0.282	50%	1.410
Very Low	0	0	0.000	0%	0.000
Coalbed Gas					
Very Low	0.5	103,740	4.50	60%	1.35

- The percent reduction in well location for each alternative, each category of restriction, and each development potential combination was determined. The estimates of reduction in well locations were then summed for non-coalbed oil and gas wells in all areas excluding Bowdoin Dome, the Bowdoin Dome area, and for coalbed gas for each alternative. The results of these calculations are shown in Table 15.

Table 15. Total wells projected to be drilled within the HiLine Planning Area for the base line and each alternative (projected from the base line) for the period 2011-2030. The projections of the percent of total future Federal wells drilled for this period is also presented in parentheses. (October 29, 2012)

Alternative	*Coalbed Gas Wells (% Fed. Wells)*	*Non-coalbed Oil and Gas Wells – Excluding Bowdoin Dome (% Fed. Wells)*	*Non-coalbed Oil and Gas Wells – Bowdoin Dome Area (% Fed. Wells)*	*Total Wells*
Baseline	150 (16.00%)	4,861 (26.98%)	1,091 (57.44%)	6,102
Alternative A	149 (15.44%)	4,802 (26.64%)	1,066 (56.12%)	6,017
Alternative B	137 (8.03%)	4,102 (22.80%)	546 (28.59%)	4,785
Alternative C	146 (13.70%)	4,686 (25.96%)	933 (47.12%)	5,765
Alternative D	149 (15.44%)	4,819 (26.74%)	1,068 (56.23%)	6,036
Alternative E	144 (12.50%)	4,720 (26.26%)	1,013 (53.75%)	5,877

- Because reductions in well locations were calculated only for federal wells, the percent of federal wells projected to be drilled for each alternative is different. The percentage of federal wells projected to be drilled for each alternative is modified from the base line analysis and is presented in Table 15.

Estimated Future Oil and Gas Production

Table 16 presents our yearly base line estimates of future number of newly completed producing conventional oil and gas wells within the HiLine planning area. These well counts were derived from our projection of total new gas and oil wells (Table 15). Calculations of spudded wells and associated production for the Analysis Period were generated via analysis through the program scripting language, Octave. The constraints used for the well spuds for conventional wells were cumulative values and historical trend. Also, new oil wells were projected to be drilled at a constant rate of 13 per year. A historical cumulative of spudded well data generates a smoother curve from which yearly differences can be extracted to produce annual projected well counts. Decline curves were then generated for gas and oil for the conventional oil and 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 oil and gas. The normalized decline curves were then convolved with the projected spudded well counts to produce annual mean projected oil and gas production (Table 16) for the conventional wells that are projected to be drilled during the Analysis Period. If future drilling activity does not meet our projections then production will not occur at the rate projected.

Table 16 also presents our estimates of the number of new oil and gas wells on federal lands, oil and gas production rates on federal lands, and abandonments of producing federal wells. The projections of numbers of new federal wells were derived from the projected total numbers of new wells by using calculated percentages of federal versus other types of producing wells, such as wells producing on private and state lands.

Since there is no history of coalbed gas production near the HiLine Planning area, no attempt was made to try to project rates of gas production for this type of development. Coalbed gas wells produce relatively low volumes of gas at other productive locations in the Rocky Mountains, so we do not project that there would be a significant increase in gas production from any coalbed gas wells found to be productive.

The above types of projections were also made for each alternative (Alternative A – Table 17, Alternative B – Table 18, Alternative C – Table 19, Alternative D – Table 20, and Alternative E – Table 21) and reflect the adjusted well count projections presented for each alternative in Table 15.

Potential Surface Disturbance

Table 22 presents our estimates of short-term and long-term disturbance associated with the base line projection of wells that could be drilled for the period of 2011 through 2030 that is presented in Table 15. The upper portion of Table 22 shows our projection of wells (6,102 wells with 1,962 of those wells managed by the Bureau) that could be drilled. An additional 9,214 existing unplugged wells (1,594 unplugged wells on Bureau-managed lands) lie within the HiLine planning area. This portion of Table 22 also calculates associated acres of total surface disturbance (short-term disturbance) directly associated with those wells. Approximately 28,814 acres of new short-term surface disturbance (8,674 acres of Bureau-managed surface disturbance) could occur if all projected wells are drilled. Including existing wells, short-term surface disturbance is projected to be about 36,970 acres (9,960 acres of Bureau-managed surface disturbance).

Table 16. Baseline projected new producing well totals and production for all producing wells and for all federal producing wells within the HiLine Planning Area for the period 2011 through 2030 (Feb. 16, 2011).

Year	*Gas Produced (thousand cubic feet)*	*Oil Produced (barrels)*	*New Oil Wells*	*New Gas Wells*	*Total New Producing Wells*	*New Federal Oil Wells*	*New Federal Gas Wells*	*Total New Producing Federal Wells*	*Federal Oil Produced (barrels)*	*Federal Gas Produced (thousand cubic feet)*	*Federal Wells Aban-doned*
2011	57,867	220,783	13	208	221	1.54	73.07	74.61	105,453	19,513	12.45
2012	40,174	184,796	13	161	175	1.54	57.34	58.87	101,225	13,547	12.45
2013	55,514	277,350	13	199	212	1.54	69.82	71.35	112,100	18,719	12.45
2014	47,587	128,719	13	158	171	1.54	56.25	57.79	94,635	16,046	12.45
2015	65,035	235,060	13	230	243	1.54	80.40	81.94	107,131	21,930	12.45
2016	71,481	705,834	13	293	307	1.54	101.83	103.37	162,446	24,103	12.45
2017	85,803	888,018	13	262	275	1.54	91.25	92.79	183,853	28,933	12.45
2018	52,815	750,251	13	212	225	1.54	74.43	75.97	167,665	17,809	12.45
2019	74,181	1,051,983	13	261	274	1.54	90.98	92.52	203,119	25,014	12.45
2020	90,401	1,210,240	13	334	348	1.54	115.67	117.21	221,714	30,483	12.45
2021	74,950	807,801	13	212	225	1.54	74.43	75.97	174,428	25,273	12.45
2022	58,561	704,847	13	208	221	1.54	73.07	74.61	162,331	19,747	12.45
2023	72,033	670,475	13	275	288	1.54	95.59	97.13	158,292	24,289	12.45
2024	79,680	652,209	13	240	253	1.54	83.92	85.46	156,146	26,868	12.45
2025	92,783	729,452	13	297	310	1.54	102.92	104.45	165,222	31,286	12.45
2026	51,637	369,962	13	182	196	1.54	64.39	65.93	122,982	17,412	12.45
2027	84,153	246,420	13	235	248	1.54	82.02	83.56	108,465	28,377	12.45
2028	71,814	499,269	13	227	240	1.54	79.31	80.85	138,175	24,216	12.45
2029	36,759	87,134	13	113	126	1.54	41.06	42.60	89,749	12,395	12.45
2030	65,199	38,143	13	218	231	1.54	76.33	77.87	83,993	21,985	12.45
Totals	**1,328,427**	**10,458,746**	**262**	**4,527**	**4,789**	**31**	**1,584**	**1,615**	**2,819,123**	**447,946**	**249**

Office of Natural Resources Revenue (ONRR Difference (Oil) = 79,511 bbls

Table 17. Alternative A projected new producing well totals and production for all producing wells and for all federal producing wells within the HiLine Planning Area for the period 2011 through 2030 (Feb. 16, 2011).

Year	*Gas Produced (thousand cubic feet)*	*Oil Produced (barrels)*	*New Oil Wells*	*New Gas Wells*	*Total New Producing Wells*	*New Federal Oil Wells*	*New Federal Gas Wells*	*Total New Producing Federal Wells*	*Federal Oil Produced (barrels)*	*Federal Gas Produced (thousand cubic feet)*	*Federal Wells Aban-doned*
2011	57,021	217,556	13	205	218	1.52	69.78	71.30	105,074	18,652	12.45
2012	39,587	182,095	13	159	172	1.52	54.78	56.30	100,907	12,949	12.45
2013	54,703	273,296	13	196	209	1.52	66.89	68.40	111,623	17,893	12.45
2014	46,891	126,837	13	156	169	1.52	53.73	55.25	94,414	15,338	12.45
2015	64,084	231,625	13	227	240	1.52	76.88	78.40	106,727	20,962	12.45
2016	70,436	695,517	13	290	302	1.52	97.40	98.92	161,234	23,040	12.45
2017	84,549	875,038	13	258	271	1.52	87.14	88.66	182,328	27,656	12.45
2018	52,043	739,285	13	209	222	1.52	71.10	72.61	166,377	17,023	12.45
2019	73,097	1,036,606	13	257	270	1.52	86.88	88.40	201,312	23,910	12.45
2020	89,080	1,192,550	13	327	340	1.52	109.77	111.29	219,636	29,138	12.45
2021	73,854	795,994	13	209	222	1.52	71.10	72.61	173,040	24,158	12.45
2022	57,705	694,545	13	205	218	1.52	69.78	71.30	161,120	18,875	12.45
2023	70,980	660,674	13	271	284	1.52	91.35	92.87	157,140	23,218	12.45
2024	78,515	642,676	13	236	249	1.52	80.04	81.56	155,025	25,682	12.45
2025	91,427	718,789	13	292	305	1.52	98.19	99.71	163,969	29,906	12.45
2026	50,882	364,555	13	180	193	1.52	61.62	63.14	122,346	16,643	12.45
2027	82,923	242,818	13	231	244	1.52	78.20	79.72	108,042	27,124	12.45
2028	70,764	491,971	13	224	236	1.52	75.83	77.35	137,318	23,147	12.45
2029	36,222	85,861	13	112	125	1.52	39.26	40.78	89,600	11,848	12.45
2030	64,246	37,585	13	215	228	1.52	72.94	74.45	83,927	21,015	12.45
Totals	**1,309,010**	**10,305,873**	**258**	**4,459**	**4,717**	**30**	**1,513**	**1,543**	**2,801,160**	**428,177**	**249**

Office of Natural Resources Revenue (ONRR Difference (Oil) = 79,511 bbls

Table 18. Alternative B projected new producing well totals and production for all producing wells and for all federal producing wells within the HiLine Planning Area for the period 2011 through 2030 (Feb. 16, 2011).

Year	*Gas Produced (thousand cubic feet)*	*Oil Produced (barrels)*	*New Oil Wells*	*New Gas Wells*	*Total New Producing Wells*	*New Federal Oil Wells*	*New Federal Gas Wells*	*Total New Producing Federal Wells*	*Federal Oil Produced (barrels)*	*Federal Gas Produced (thousand cubic feet)*	*Federal Wells Aban-doned*
2011	45,209	172,487	10	160	170	1.20	22.09	23.29	99,778	6,189	12.45
2012	31,386	144,372	10	124	135	1.20	17.22	18.42	96,475	4,297	12.45
2013	43,371	216,680	10	153	163	1.20	21.12	22.32	104,971	5,937	12.45
2014	37,177	100,561	10	121	131	1.20	16.78	17.98	91,327	5,090	12.45
2015	50,808	183,641	10	177	187	1.20	24.37	25.57	101,089	6,956	12.45
2016	55,844	551,433	10	226	236	1.20	31.08	32.29	144,304	7,645	12.45
2017	67,034	693,764	10	202	212	1.20	27.83	29.04	161,028	9,177	12.45
2018	41,262	586,134	10	163	173	1.20	22.52	23.73	148,382	5,649	12.45
2019	57,954	821,862	10	200	211	1.20	27.62	28.82	176,080	7,934	12.45
2020	70,626	945,500	10	255	265	1.20	35.09	36.29	190,607	9,669	12.45
2021	58,555	631,095	10	163	173	1.20	22.52	23.73	153,665	8,016	12.45
2022	45,751	550,662	10	160	170	1.20	22.09	23.29	144,214	6,263	12.45
2023	56,276	523,808	10	211	222	1.20	29.13	30.34	141,058	7,704	12.45
2024	62,250	509,538	10	184	195	1.20	25.45	26.65	139,382	8,522	12.45
2025	72,487	569,884	10	228	238	1.20	31.41	32.61	146,472	9,923	12.45
2026	40,341	289,033	10	140	150	1.20	19.38	20.59	113,472	5,523	12.45
2027	65,745	192,516	10	180	190	1.20	24.80	26.00	102,132	9,000	12.45
2028	56,105	390,054	10	174	184	1.20	24.04	25.24	125,342	7,681	12.45
2029	28,718	68,074	10	87	97	1.20	12.12	13.33	87,510	3,932	12.45
2030	50,937	29,799	10	167	177	1.20	23.07	24.27	83,012	6,973	12.45
Totals	**1,037,834**	**8,170,897**	**205**	**3,475**	**3,680**	**24**	**480**	**504**	**2,550,300**	**142,079**	**249**

Office of Natural Resources Revenue (ONRR Difference (Oil) = 79,511 bbls

Table 19. Alternative C projected new producing well totals and production for all producing wells and for all federal producing wells within the HiLine Planning Area for the period 2011 through 2030 (Feb. 16, 2011).

Year	*Gas Produced (thousand cubic feet)*	*Oil Produced (barrels)*	*New Oil Wells*	*New Gas Wells*	*Total New Producing Wells*	*New Federal Oil Wells*	*New Federal Gas Wells*	*Total New Producing Federal Wells*	*Federal Oil Produced (barrels)*	*Federal Gas Produced (thousand cubic feet)*	*Federal Wells Aban-doned*
2011	54,182	206,725	12	195	207	1.45	59.53	60.98	103,801	15,924	12.45
2012	37,616	173,029	12	153	166	1.45	47.29	48.74	99,842	11,055	12.45
2013	51,979	259,689	12	187	199	1.45	57.17	58.63	110,024	15,277	12.45
2014	44,556	120,522	12	150	163	1.45	46.34	47.79	93,672	13,095	12.45
2015	60,894	220,093	12	216	228	1.45	65.65	67.10	105,372	17,897	12.45
2016	66,929	660,889	12	274	286	1.45	82.60	84.05	157,165	19,670	12.45
2017	80,340	831,472	12	246	258	1.45	74.36	75.81	177,209	23,612	12.45
2018	49,452	702,478	12	199	211	1.45	60.71	62.16	162,052	14,534	12.45
2019	69,458	984,997	12	244	256	1.45	73.89	75.34	195,248	20,414	12.45
2020	84,645	1,133,176	12	311	324	1.45	93.67	95.12	212,659	24,877	12.45
2021	70,178	756,364	12	200	212	1.45	60.94	62.39	168,384	20,625	12.45
2022	54,832	659,966	12	195	207	1.45	59.53	60.98	157,057	16,115	12.45
2023	67,446	627,781	12	256	268	1.45	77.42	78.87	153,275	19,822	12.45
2024	74,606	610,679	12	226	238	1.45	68.48	69.93	151,266	21,927	12.45
2025	86,875	683,003	12	276	288	1.45	83.31	84.76	159,764	25,533	12.45
2026	48,349	346,405	12	174	186	1.45	53.17	54.62	120,214	14,210	12.45
2027	78,795	230,729	12	220	232	1.45	66.83	68.28	106,622	23,158	12.45
2028	67,241	467,478	12	213	225	1.45	64.71	66.16	134,440	19,762	12.45
2029	34,419	81,586	12	109	121	1.45	34.10	35.55	89,097	10,116	12.45
2030	61,047	35,714	12	205	217	1.45	62.35	63.81	83,707	17,942	12.45
Totals	**1,243,838**	**9,792,775**	**247**	**4,248**	**4,495**	**29**	**1,292**	**1,321**	**2,740,871**	**365,564**	**249**

Office of Natural Resources Revenue (ONRR Difference (Oil) = 79,511 bbls

Table 20. Alternative D projected new producing well totals and production for all producing wells and for all federal producing wells within the HiLine Planning Area for the period 2011 through 2030 (Feb. 16, 2011).

Year	*Gas Produced (thousand cubic feet)*	*Oil Produced (barrels)*	*New Oil Wells*	*New Gas Wells*	*Total New Producing Wells*	*New Federal Oil Wells*	*New Federal Gas Wells*	*Total New Producing Federal Wells*	*Federal Oil Produced (barrels)*	*Federal Gas Produced (thousand cubic feet)*	*Federal Wells Aban-doned*
2011	57,216	218,298	13	205	218	1.52	70.29	71.81	105,161	18,853	12.45
2012	39,722	182,716	13	160	173	1.52	55.45	56.97	100,980	13,088	12.45
2013	54,889	274,228	13	196	209	1.52	67.37	68.90	111,733	18,086	12.45
2014	47,051	127,270	13	156	169	1.52	54.12	55.65	94,465	15,503	12.45
2015	64,303	232,414	13	228	240	1.52	77.71	79.23	106,820	21,188	12.45
2016	70,676	697,888	13	290	303	1.52	98.38	99.90	161,513	23,288	12.45
2017	84,837	878,022	13	260	273	1.52	88.31	89.83	182,679	27,954	12.45
2018	52,220	741,806	13	210	223	1.52	71.88	73.40	166,673	17,207	12.45
2019	73,346	1,040,141	13	258	271	1.52	87.78	89.30	201,728	24,168	12.45
2020	89,387	1,196,616	13	330	343	1.52	111.63	113.15	220,113	29,452	12.45
2021	74,106	798,708	13	210	223	1.52	71.88	73.40	173,359	24,418	12.45
2022	57,902	696,913	13	206	219	1.52	70.55	72.08	161,398	19,079	12.45
2023	71,222	662,927	13	272	285	1.52	92.28	93.80	157,405	23,468	12.45
2024	78,783	644,867	13	237	250	1.52	80.89	82.41	155,283	25,959	12.45
2025	91,738	721,240	13	293	306	1.52	99.17	100.69	164,257	30,228	12.45
2026	51,055	365,798	13	180	193	1.52	62.07	63.60	122,492	16,823	12.45
2027	83,206	243,646	13	232	244	1.52	79.03	80.56	108,139	27,416	12.45
2028	71,006	493,649	13	224	237	1.52	76.65	78.17	137,515	23,396	12.45
2029	36,346	86,153	13	113	125	1.52	39.82	41.34	89,634	11,976	12.45
2030	64,465	37,713	13	215	228	1.52	73.73	75.26	83,942	21,241	12.45
Totals	**1,313,474**	**10,341,013**	**259**	**4,474**	**4,733**	**30**	**1,529**	**1,559**	**2,805,289**	**432,790**	**249**

Office of Natural Resources Revenue (ONRR Difference (Oil) = 79,511 bbls

Table 21. Alternative E projected new producing well totals and production for all producing wells and for all federal producing wells within the HiLine Planning Area for the period 2011 through 2030 (Feb. 16, 2011).

Year	*Gas Produced (thousand cubic feet)*	*Oil Produced (barrels)*	*New Oil Wells*	*New Gas Wells*	*Total New Producing Wells*	*New Federal Oil Wells*	*New Federal Gas Wells*	*Total New Producing Federal Wells*	*Federal Oil Produced (barrels)*	*Federal Gas Produced (thousand cubic feet)*	*Federal Wells Aban-doned*
2011	55,923	213,365	13	200	213	1.49	65.17	66.66	104,581	17,509	12.45
2012	38,824	178,586	13	156	169	1.49	51.34	52.82	100,495	12,156	12.45
2013	53,649	268,030	13	192	205	1.49	62.66	64.14	111,005	16,797	12.45
2014	45,988	124,393	13	152	165	1.49	50.08	51.57	94,127	14,399	12.45
2015	62,849	227,162	13	222	235	1.49	71.96	73.45	106,203	19,678	12.45
2016	69,079	682,116	13	283	296	1.49	91.08	92.57	159,660	21,629	12.45
2017	82,920	858,179	13	253	266	1.49	81.77	83.26	180,347	25,962	12.45
2018	51,040	725,041	13	205	218	1.49	66.68	68.17	164,703	15,981	12.45
2019	71,689	1,016,634	13	252	265	1.49	81.52	83.01	198,965	22,446	12.45
2020	87,364	1,169,573	13	322	335	1.49	103.41	104.89	216,936	27,354	12.45
2021	72,432	780,657	13	205	218	1.49	66.68	68.17	171,238	22,678	12.45
2022	56,593	681,163	13	201	214	1.49	65.42	66.91	159,548	17,719	12.45
2023	69,612	647,945	13	265	278	1.49	85.55	87.03	155,645	21,796	12.45
2024	77,003	630,293	13	232	244	1.49	74.98	76.47	153,570	24,110	12.45
2025	89,665	704,940	13	286	299	1.49	92.09	93.57	162,341	28,074	12.45
2026	49,901	357,531	13	176	189	1.49	57.63	59.11	121,521	15,624	12.45
2027	81,326	238,140	13	226	239	1.49	73.22	74.71	107,492	25,463	12.45
2028	69,401	482,493	13	219	231	1.49	70.96	72.44	136,204	21,729	12.45
2029	35,524	84,206	13	109	122	1.49	36.75	38.23	89,405	11,122	12.45
2030	63,008	36,861	13	210	223	1.49	68.19	69.68	83,842	19,728	12.45
Totals	**1,283,789**	**10,107,308**	**253**	**4,368**	**4,621**	**30**	**1,417**	**1,447**	**2,777,829**	**401,954**	**249**

Office of Natural Resources Revenue (ONRR Difference (Oil) = 79,511 bbls

Table 22. HiLine Planning Area surface disturbance associated with new wells projected for the base line development scenario for 2011 through 2030 and for existing active wells (February 15, 2011).

Disturbance Associated with All New Drilled Wells and Existing Active Wells (Short-Term Disturbance)						
Wells			***Acres of Surface Disturbance***			
Type	***Total***	***BLM-Managed***	***Access Roads/ Flow Lines***	***Well Pad***	***Total***	***BLM-Managed***
New Exploratory and Development Wells – Coalbed Gas	150	24	1.85	1	428	68
New Exploratory and Development Wells – Bowdoin Dome Area	1,091	627	1.85	1	3,109	1,786
New Exploratory and Development Wells – Rest of Planning Area	4,861	1,311	3.1	2.1	25,277	6,820
Existing Wells – Bowdoin Dome Area	1,887	1,060	0.25	0.5	1,415	795
Existing Wells – Rest of Planning Area	7,327	534	0.78	0.14	6,741	491
Total Wells/ Disturbance	**15,316**	**3,556**			**36,970**	**9,960**
Disturbance Associated with All New Producing Wells and Existing Active Wells Less Abandonments (Long-Term Disturbance)						
Wells			***Acres of Surface Disturbance***			
Type	***Total***	***BLM-Managed***	***Access Roads/ Flow Lines***	***Well Pad***	***Total***	***BLM-Managed***
New Exploratory and Development Wells – Coalbed Gas	135	22	0.25	0.5	101	16
New Exploratory and Development Wells – Bowdoin Dome Area	1,058	608	0.25	0.5	794	456
New Exploratory and Development Wells – Rest of Planning Area	3,731	1,007	0.78	0.14	3,432	926
Existing Wells – Bowdoin Dome Area	1,579	887	0.25	0.5	1,184	665
Existing Wells – Rest of Planning Area	6,279	458	0.78	0.14	5,777	421
Total Wells/ Disturbance	**12,782**	**2,981**			**11,288**	**2,484**

In addition, the lower portion of Table 22 calculates the estimated numbers of wells remaining after dry holes are abandoned and reclaimed and producing wells cease to be productive and are also abandoned and reclaimed (4,924 wells with 1,637 of those wells managed by the Bureau). An additional 7,858 existing unplugged and unreclaimed

wells (1,345 unplugged and unreclaimed wells on Bureau-managed lands) are projected to remain within the HiLine planning area in the long-term. This portion of Table 22 also calculates unreclaimed associated acres of total surface disturbance (long-term disturbance) directly associated with those wells. Approximately 4,327 acres of new unreclaimed surface disturbance (1,398 acres of Bureau-managed unreclaimed surface disturbance) could remain in the long-term. Including existing wells, long-term unreclaimed surface disturbance is projected to be about 11,288 acres (2,484 acres of Bureau-managed unreclaimed surface disturbance).

In the Bowdoin Dome area approximately 55 percent of all wells drilled are expected to be wells managed by the Bureau. In the rest of the planning area approximately 27 percent of all new wells are expected to be wells managed by the Bureau. We assumed that since Bureau-managed minerals occupy about 16 percent of the planning area, any future drilling on Bureau-managed minerals would likely mirror that percentage.

As additional wells are being drilled, some existing wells are being plugged and abandoned. The great majority of these are wells which are either unproductive (dry holes), or have become depleted and are not economic to produce. We have projected that total abandonments will be at a rate of:

- 10 percent for coalbed gas wells
- 3 percent for new exploratory and development wells in the Bowdoin Dome area
- 23.25 percent for new exploratory and development wells in the rest of the planning area
- 7.8 percent for existing wells in the Bowdoin Dome area
- 22.9 percent for existing wells in the rest of the planning area

Assumptions used in Table 22 to calculate short-term and long-term surface disturbance from access roads/flow lines and well pads associated with oil gas exploration and development drilling activities are based on existing oil and gas development across the HiLine planning area.

For each alternative, the same above described methods of calculating surface disturbance (short-term and long-term) were used. Projections of future wells for each alternative were brought forward from Table 15 and used in these calculations. The resulting short-term and long-term surface disturbance figures for each alternative are presented in Tables 23, 24, 25, 26 and 27.

Summary

For our base line projection we analyzed the oil and gas resource within the HiLine planning area, discussed types of future development that may occur, estimated the development potential for each type of resource (see Figures 23 and 24 and Tables 11 and 12 for oil and gas and coalbed gas development), and projected base line activity levels for the period 2011 through 2030. For our analysis of the base line projection, we assumed that the only land use restrictions on future oil and gas resource development would be those that have been legislatively imposed. Projections of future well numbers, oil and gas production, and surface disturbance were prepared (Tables 15 and 22). Projections of future well numbers (Table 15), oil and gas production (Tables 17, 18, 19, 20, and 21), and surface disturbance (Tables 23, 24, 25, 26, and 27) were also prepared for each alternative.

Table 23. HiLine Planning Area surface disturbance associated with new wells projected for Alternative A development scenario for 2011 through 2030 and for existing active wells (October 30, 2012).

Disturbance Associated with All New Drilled Wells and Existing Active Wells (Short-Term Disturbance) Alternative A Development Scenario – 2011-2030						
Wells			***Acres of Surface Disturbance***			
Type	***Total***	***BLM-Managed***	***Access Roads/ Flow Lines***	***Well Pad***	***Total***	***BLM-Managed***
New Exploratory and Development Wells – Coalbed Gas	149	23	1.85	1	425	66
New Exploratory and Development Wells – Bowdoin Dome Area	1,066	602	1.85	1	3,038	1,715
New Exploratory and Development Wells – Rest of Planning Area	4,802	1,249	3.1	2.1	24,970	6,497
Existing Wells – Bowdoin Dome Area	1,887	1,060	0.25	0.5	1,415	795
Existing Wells – Rest of Planning Area	7,327	534	0.78	0.14	6,741	491
Total Wells/ Disturbance	**15,231**	**3,468**			**36,589**	**9,564**
Disturbance Associated with All New Producing Wells and Existing Active Wells Less Abandonments (Long-Term Disturbance)						
Wells			***Acres of Surface Disturbance***			
Type	***Total***	***BLM-Managed***	***Access Roads/ Flow Lines***	***Well Pad***	***Total***	***BLM-Managed***
New Exploratory and Development Wells – Coalbed Gas	134	21	0.25	0.5	101	16
New Exploratory and Development Wells – Bowdoin Dome Area	1,034	584	0.25	0.5	776	438
New Exploratory and Development Wells – Rest of Planning Area	3,686	959	0.78	0.14	3,391	882
Existing Wells – Bowdoin Dome Area	1,579	887	0.25	0.5	1,184	665
Existing Wells – Rest of Planning Area	6,279	458	0.78	0.14	5,777	421
Total Wells/ Disturbance	**12,712**	**2,908**			**11,228**	**2,422**

Table 24. HiLine Planning Area surface disturbance associated with new wells projected for Alternative B development scenario for 2011 through 2030 and for existing active wells (October 30, 2012).

Disturbance Associated with All New Drilled Wells and Existing Active Wells (Short-Term Disturbance) Alternative B Development Scenario – 2011-2030						
Wells			***Acres of Surface Disturbance***			
Type	***Total***	***BLM-Managed***	***Access Roads/ Flow Lines***	***Well Pad***	***Total***	***BLM-Managed***
New Exploratory and Development Wells – Coalbed Gas	137	11	1.85	1	390	31
New Exploratory and Development Wells – Bowdoin Dome Area	546	79	1.85	1	1,556	224
New Exploratory and Development Wells – Rest of Planning Area	4,102	557	3.1	2.1	21,330	2,899
Existing Wells – Bowdoin Dome Area	1,887	1,060	0.25	0.5	1,415	795
Existing Wells – Rest of Planning Area	7,327	534	0.78	0.14	6,741	491
Total Wells/ Disturbance	**13,999**	**2,241**			**31,433**	**4,441**
Disturbance Associated with All New Producing Wells and Existing Active Wells Less Abandonments (Long-Term Disturbance)						
Wells			***Acres of Surface Disturbance***			
Type	***Total***	***BLM-Managed***	***Access Roads/ Flow Lines***	***Well Pad***	***Total***	***BLM-Managed***
New Exploratory and Development Wells – Coalbed Gas	123	10	0.25	0.5	92	7
New Exploratory and Development Wells – Bowdoin Dome Area	530	76	0.25	0.5	397	57
New Exploratory and Development Wells – Rest of Planning Area	3,148	428	0.78	0.14	2,896	394
Existing Wells – Bowdoin Dome Area	1,579	887	0.25	0.5	1,184	665
Existing Wells – Rest of Planning Area	6,279	458	0.78	0.14	5,777	421
Total Wells/ Disturbance	**11,659**	**1,859**			**10,347**	**1,545**

Table 25. HiLine Planning Area surface disturbance associated with new wells projected for Alternative C development scenario for 2011 through 2030 and for existing active wells (October 30, 2012).

Disturbance Associated with All New Drilled Wells and Existing Active Wells (Short-Term Disturbance) Alternative C Development Scenario – 2011-2030						
Wells			***Acres of Surface Disturbance***			
Type	***Total***	***BLM-Managed***	***Access Roads/ Flow Lines***	***Well Pad***	***Total***	***BLM-Managed***
New Exploratory and Development Wells – Coalbed Gas	146	20	1.85	1	416	57
New Exploratory and Development Wells – Bowdoin Dome Area	933	469	1.85	1	2,659	1,336
New Exploratory and Development Wells – Rest of Planning Area	4,686	1,128	3.1	2.1	24,367	5,868
Existing Wells – Bowdoin Dome Area	1,887	1,060	0.25	0.5	1,415	795
Existing Wells – Rest of Planning Area	7,327	534	0.78	0.14	6,741	491
Total Wells/ Disturbance	**14,979**	**3,211**			**35,598**	**8,547**
Disturbance Associated with All New Producing Wells and Existing Active Wells Less Abandonments (Long-Term Disturbance)						
Wells			***Acres of Surface Disturbance***			
Type	***Total***	***BLM-Managed***	***Access Roads/ Flow Lines***	***Well Pad***	***Total***	***BLM-Managed***
New Exploratory and Development Wells – Coalbed Gas	131	18	0.25	0.5	99	14
New Exploratory and Development Wells – Bowdoin Dome Area	905	455	0.25	0.5	679	341
New Exploratory and Development Wells – Rest of Planning Area	3,597	866	0.78	0.14	3,309	797
Existing Wells – Bowdoin Dome Area	1,579	887	0.25	0.5	1,184	665
Existing Wells – Rest of Planning Area	6,279	458	0.78	0.14	5,777	421
Total Wells/ Disturbance	**12,491**	**2,683**			**11,047**	**2,238**

Table 26. HiLine Planning Area surface disturbance associated with new wells projected for Alternative D development scenario for 2011 through 2030 and for existing active wells (October 30, 2012).

Disturbance Associated with All New Drilled Wells and Existing Active Wells (Short-Term Disturbance) Alternative D Development Scenario – 2011-2030						
Wells			***Acres of Surface Disturbance***			
Type	***Total***	***BLM-Managed***	***Access Roads/ Flow Lines***	***Well Pad***	***Total***	***BLM-Managed***
New Exploratory and Development Wells – Coalbed Gas	149	23	1.85	1	425	66
New Exploratory and Development Wells – Bowdoin Dome Area	1,068	604	1.85	1	3,044	1,720
New Exploratory and Development Wells – Rest of Planning Area	4,819	1,267	3.1	2.1	25,059	6,591
Existing Wells – Bowdoin Dome Area	1,887	1,060	0.25	0.5	1,415	795
Existing Wells – Rest of Planning Area	7,327	534	0.78	0.14	6,741	491
Total Wells/ Disturbance	**15,250**	**3,488**			**36,683**	**9,663**
Disturbance Associated with All New Producing Wells and Existing Active Wells Less Abandonments (Long-Term Disturbance)						
Wells			***Acres of Surface Disturbance***			
Type	***Total***	***BLM-Managed***	***Access Roads/ Flow Lines***	***Well Pad***	***Total***	***BLM-Managed***
New Exploratory and Development Wells – Coalbed Gas	134	21	0.25	0.5	101	16
New Exploratory and Development Wells – Bowdoin Dome Area	1,036	586	0.25	0.5	777	439
New Exploratory and Development Wells – Rest of Planning Area	3,699	973	0.78	0.14	3,403	895
Existing Wells – Bowdoin Dome Area	1,579	887	0.25	0.5	1,184	665
Existing Wells – Rest of Planning Area	6,279	458	0.78	0.14	5,777	421
Total Wells/ Disturbance	**12,727**	**2,924**			**11,241**	**2,436**

Table 27. HiLine Planning Area surface disturbance associated with new wells projected for Alternative E development scenario for 2011 through 2030 and for existing active wells (October 30, 2012).

Disturbance Associated with All New Drilled Wells and Existing Active Wells (Short-Term Disturbance) Alternative E Development Scenario – 2011-2030						
Wells			***Acres of Surface Disturbance***			
Type	***Total***	***BLM-Managed***	***Access Roads/ Flow Lines***	***Well Pad***	***Total***	***BLM-Managed***
New Exploratory and Development Wells – Coalbed Gas	144	18	1.85	1	410	51
New Exploratory and Development Wells – Bowdoin Dome Area	1,013	557	1.85	1	2,887	1,587
New Exploratory and Development Wells – Rest of Planning Area	4,720	1,181	3.1	2.1	24,544	6,144
Existing Wells – Bowdoin Dome Area	1,887	1,060	0.25	0.5	1,415	795
Existing Wells – Rest of Planning Area	7,327	534	0.78	0.14	6,741	491
Total Wells/ Disturbance	**15,091**	**3,350**			**35,998**	**9,068**
Disturbance Associated with All New Producing Wells and Existing Active Wells Less Abandonments (Long-Term Disturbance)						
Wells			***Acres of Surface Disturbance***			
Type	***Total***	***BLM-Managed***	***Access Roads/ Flow Lines***	***Well Pad***	***Total***	***BLM-Managed***
New Exploratory and Development Wells – Coalbed Gas	130	16	0.25	0.5	97	12
New Exploratory and Development Wells – Bowdoin Dome Area	983	540	0.25	0.5	737	405
New Exploratory and Development Wells – Rest of Planning Area	3,623	907	0.78	0.14	3,333	834
Existing Wells – Bowdoin Dome Area	1,579	887	0.25	0.5	1,184	665
Existing Wells – Rest of Planning Area	6,279	458	0.78	0.14	5,777	421
Total Wells/ Disturbance	**12,593**	**2,808**			**11,128**	**2,338**

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Glossary

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

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

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

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

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

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

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

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

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

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

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

Proved 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.

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

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

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

APPENDIX 1

U.S. Geological Survey Assessments of Undiscovered Oil and Gas Resources within the HiLine Planning Area

Introduction

The U.S. Geological Survey has published a number of resource assessments of undiscovered oil and gas resources that cover parts of the HiLine planning area. Their "1995 National Assessment of United States Oil and Gas Resources" (Beeman et al., 1996: Charpentier et al., 1996: Gautier et al., 1996: and U.S. Geological Survey, 2007a) scientifically estimated the amount of crude oil, natural gas, and natural gas liquids that could be added to proved reserves in the United States, assuming existing technology. It presented information about potential undiscovered accumulations of oil and gas in 71 geologic or structural provinces within the United States. Three of those provinces, the North-Central Montana, Williston Basin and Montana Thrust Belt provinces, lie partly within the Planning area.

Recently the U.S. Geological Survey revised their methods of preparing oil and gas resource assessments. They used their new method to update their quantitative estimate of the undiscovered oil and gas resource for the Southwestern Montana Thrust Belt Province (U.S. Geological Survey; 2002, and 2007b). In the following analysis, we will use the newest assessment to describe the potential undiscovered technically recoverable oil and gas resources lying within the Montana Trust Belt Province and the older two assessments to describe those resources for the North-Central Montana and Williston Basin Provinces. Figure A1-1 shows the location of each of these three provinces and their relation to the planning area.

Montana Thrust Belt Province Assessment

The Montana Thrust Belt Province lies in the generally mountainous terrain of western Montana and the western-most part of the HiLine planning area (Figure A1-1). The Province consists of numerous thrust sheets and intrusive bodies. Sediments have been strongly folded and thrust eastward into their present location. Thrusting took place during Late Cretaceous and Paleocene time. The Montana Thrust Belt has failed to yield significant hydrocarbons in spite of more than 90 years of exploration and wildcat drilling, favorable source rocks in the eastern part of the province, and hydrocarbon seeps in the northern part. A summary of past oil and gas related activities in the planning area portion of the province is presented in the main body of this report.

Assessment Unit Summaries

In their newest assessment, the U.S. Geological Survey (2002 and 2007b) divided the Montana Thrust Belt Province into "total petroleum systems" and "assessment units" (see Glossary definitions) rather than "plays" as they had done in previous assessments. "The total petroleum system approach is designed to focus the geologic studies on the hydrocarbon source rocks, processes that create hydrocarbons, migration pathways, reservoirs, and trapping mechanisms" (U.S. Departments of Interior, Agriculture, and Energy, 2003). Seven total petroleum systems have been identified in the Montana Thrust Belt Province, four of which lie at least partly within the planning area (Paleozoic/Mesozoic Composite, Bakken Formation, Marias River Shale, and Jurassic/Cretaceous total petroleum systems). The Paleozoic/Mesozoic Composite Total Petroleum System contains three conventional accumulations (see Glossary definition) that lie at least partly within the planning area (Figures A1-2, A1-3, and A1-4). Those accumulations are:

- Thrust Belt conventional gas and oil assessment unit,
- Sawtooth Range Structure conventional oil and gas assessment unit,
- Frontal Structures conventional oil and gas assessment unit.

The U.S. Geological Survey has made available some statistical information for the three Paleozoic/Mesozoic Composite Total Petroleum System conventional assessment units (Table A1-1). Some small quantities of carbon dioxide and hydrogen-sulfide can be expected to be produced with any gas discovered.

The other three total petroleum systems each contain one continuous accumulation (see Glossary definitions) that lies at least partly within the planning area (Figures A1-5, A1-6, and A1-7). Continuous accumulations can include tight reservoirs, shale reservoirs, unconventional reservoirs, basin-centered reservoirs, fractured reservoirs, coalbeds, oil shales, and shallow biogenic gas. The continuous accumulations are:

- Bakken continuous oil assessment unit,
- Marias River Shale continuous oil assessment unit, and
- Jurassic-Cretaceous coalbed gas assessment unit.

The Bakken and the Jurassic-Cretaceous coalbed gas assessment units are hypothetical and only limited data is available. Supporting geologic studies for this assessment await formal publication. The Marias River Shale continuous oil assessment unit is considered to have a frontier exploration status for oil resources. Drilling depths for this assessment unit are expected to be between 1,640 and 9,840 feet.

Assessment Unit Resource Results

The U.S. Geological Survey (2002 and 2007b) estimated undiscovered technically recoverable resource quantities of oil and gas that could be added to the proved reserves within each assessment unit, using a forecast span of 30 years. A 30-year forecast span affects the minimum undiscovered accumulation size, the number of years in the future that reserve growth is estimated, economic assessments, the accumulations chosen for consideration, and the assessment of risk. Below, we summarize the estimated volumes of hydrocarbons in the three conventional and three continuous assessment units, which both lie at least partly within the planning 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 and continuous assessment units in the Montana Thrust Belt Province, together with our projection of the amount of those hydrocarbons that could be present within the HiLine planning area. To determine the potential resource within the planning 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 planning area, and
- multiplied that percentage by the U.S. Geological Survey resource value estimates for each entire assessment unit to calculate planning area resource values.

Our estimates of recoverable resources for each assessment unit within the province and within the Field Office area, are presented as a range of possibilities: a low case having a 95 percent probability of that amount or more occurring, a high case having a 5 percent probability of that amount or more occurring, and a mean case representing an arithmetic average of all possible outcomes. We estimate that the planning area contains a **mean undiscovered volume of 14.72 million barrels of oil, 988.91 billion cubic feet of gas, and 36.59 million barrels of natural gas liquids, in the Montana Thrust Belt province assessment units.**

In addition, we estimate that the planning area's oil resource in the Montana Thrust Belt province could **range from 6.30 to 27.70 million barrels, the gas resource could range from 0.14003 to 2.38555 trillion cubic feet, and the natural gas liquids resource could range from 4.92 to 91.29 million barrels** (assuming fractile data used has a perfect positive correlation).

North-Central Montana Province Assessment

The North-Central Montana Province occupies the central and largest part of the HiLine planning area (Figure A1-1). It is bounded by the Montana Thrust Belt Province on the west and Williston Basin Province to the east. Geologic features included in the province are the Kevin-Sunburst and Bowdoin Domes, Sweetgrass Hills, Bearpaw Uplift, and Little Rocky Mountains (Figure 6). The planning area fields; Kevin-Sunburst and Cut Bank are the largest in the western part of the province and Bowdoin Field is the largest on the eastern side. Tiger Ridge is the largest planning area field in the central portion of the province.

Play Summaries

The "1995 National Assessment of United States Oil and Gas Resources" (Beeman et al., 1996: Charpentier et al., 1996: Gautier et al., 1996) was not updated with the latest U.S. Geologic Survey assessment of oil and gas resources. The assessment divided the North-Central Montana Province into "play" areas. Each play area is a set of discovered or undiscovered oil and gas accumulations or prospects that are geologically related. The U.S. Geological Survey defined a play "by the geological properties (such as trapping style, type of reservoir, nature of the seal) that are responsible for the accumulations or prospects. A conventional play will contain oil and gas accumulations having hydrocarbon-water contacts (due to the buoyancy of hydrocarbons in water) and seals that hold or trap the hydrocarbons. The hydrocarbons in these plays can be recovered using traditional development and production practices. Five of their eight conventional oil and gas plays lie at least partly within planning area boundaries (Figures A1-8, A1-9, A1-10, A1-11, and A1-12). The U.S. Geological Survey has made available some statistical information for these plays (Table A1-3). Supporting geologic studies for these play areas are available at Gautier et al. (1996).

Two unconventional plays were described in the North-Central Montana Province, with one play (the Northern Great Plains Biogenic Gas play) being subdivided into high, moderate, and low potential plays. The Bakken Shale Fracture Systems play (Figure A1-13) is a hypothetical play and is defined as an analog to the known Bakken production in the Williston Basin. Depths to this potential play would by 5,000 to 10,000 feet. No production was identified in the Bakken Shale in the North-Central Montana Province. This undiscovered resource is considered to be an unconventional continuous-type accumulation.

The Northern Great Plains Biogenic Gas; high, moderate, and low plays (Figures A1-14, A1-15, and A1-16) occur in continuous-type (tight) Upper Cretaceous sediments that extend into the Williston Basin Province. Reservoirs occur at depths of less than 4,000 feet and the gas is underpressured. Almost no wildcat drilling for the biogenic gas play had occurred at the time the U.S. Geologic report was completed in 1995. These low reservoir pressure, thin interbedded shale, siltstone, and sandstone, and high silt and clay content sandstones cause difficulty in recognizing potential pays on borehole geophysical logs. The high potential play is recognized by its better quality reservoirs; especially the Bowdoin Field. These thicker sandstone reservoirs have higher estimated recoveries for individual wells. The hypothetical moderate potential play is modeled after a Canadian production analog, but is relatively unexplored in the United States by wells seeking a biogenic gas reservoir. The hypothetical low potential play is also relatively unexplored in the United States. Reservoir sediments will be thinner than those of the moderate potential play.

Play Resource Results

The U.S. Geological Survey ((Beeman et al., 1996: Charpentier et al., 1996: Gautier et al., 1996) estimated undiscovered technically recoverable resource quantities of oil and gas that could be added to the proved reserves within the conventional and unconventional play areas at least partially within the HiLine planning area. In Table A1-4, the U.S. Geological Survey resource estimates for three types of hydrocarbons (oil, gas, and natural gas liquids) are shown for the conventional and unconventional plays in the North-Central Montana Province, together with our projection of the amount of those hydrocarbons that could be present within the HiLine planning area. To determine the potential resource within the planning 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 planning area, and
- multiplied that percentage by the U.S. Geological Survey resource value estimates for each entire assessment unit to calculate planning area resource values.

Our estimates of recoverable resources for each of the play areas within the province and within the HiLine planning area, are presented as a range of possibilities: a low case having a 95 percent probability of that amount or more occurring, a high case having a 5 percent probability of that amount or more occurring, and a mean case representing an arithmetic average of all possible outcomes. We estimate that the planning area contains a **mean undiscovered volume of 52.84 million barrels of oil, 8.15188 trillion cubic feet of gas, and 0.57 million barrels of natural gas liquids, in the North-Central Montana Province play areas.**

In addition, we estimate that the planning area's oil resource could **range from 5.79 to 109.33 million barrels, the gas resource could range from 2.64335 to 17.70318 trillion cubic feet, and the natural gas liquids resource could range from 0.07 to 0.90 million barrels**(assuming fractile data used has a perfect positive correlation).

Williston Basin Province Assessment

The Williston Basin Province occupies the easternmost and smallest part of the HiLine planning area (Figure A1-1). The Williston Basin is a structural-sedimentary basin located on the western shelf of the Paleozoic North American craton. It occupies a large part of the northern Great Plains and extends into Canada. Its western border is defined by Bowdoin Dome. There are presently no producing wells in the planning area portion of this province.

Play Summaries

The "1995 National Assessment of United States Oil and Gas Resources" (Beeman et al., 1996: Charpentier et al., 1996: Gautier et al., 1996) was not updated with the latest U.S. Geologic Survey assessment of oil and gas resources. The assessment divided the Williston Basin Province into "play" areas. Five of their six conventional oil and gas plays lie at least partly within planning area boundaries (Figures A1-17, A1-18, and A1-19). The U.S. Geological Survey has made available some statistical information for these plays (Table A1-5). Supporting geologic studies for these play areas are available at Gautier et al. (1996). No production was identified in any of these plays within the portion of the Williston Basin Province lying within the planning area.

One of four unconventional continuous-type plays lies at least partly within the planning area (Figure A1-20). The Bakken Outlying play is a hypothetical play with the lowest prospective success potential of the three unconventional Bakken plays identified. The other two unconventional Bakken plays do not lie within the planning area. Depths to the Bakken Outlying potential play would by 7,000 to 10,800 feet. No production was identified in the Bakken Shale play within the portion of the Williston Basin Province lying within the planning area.

Play Resource Results

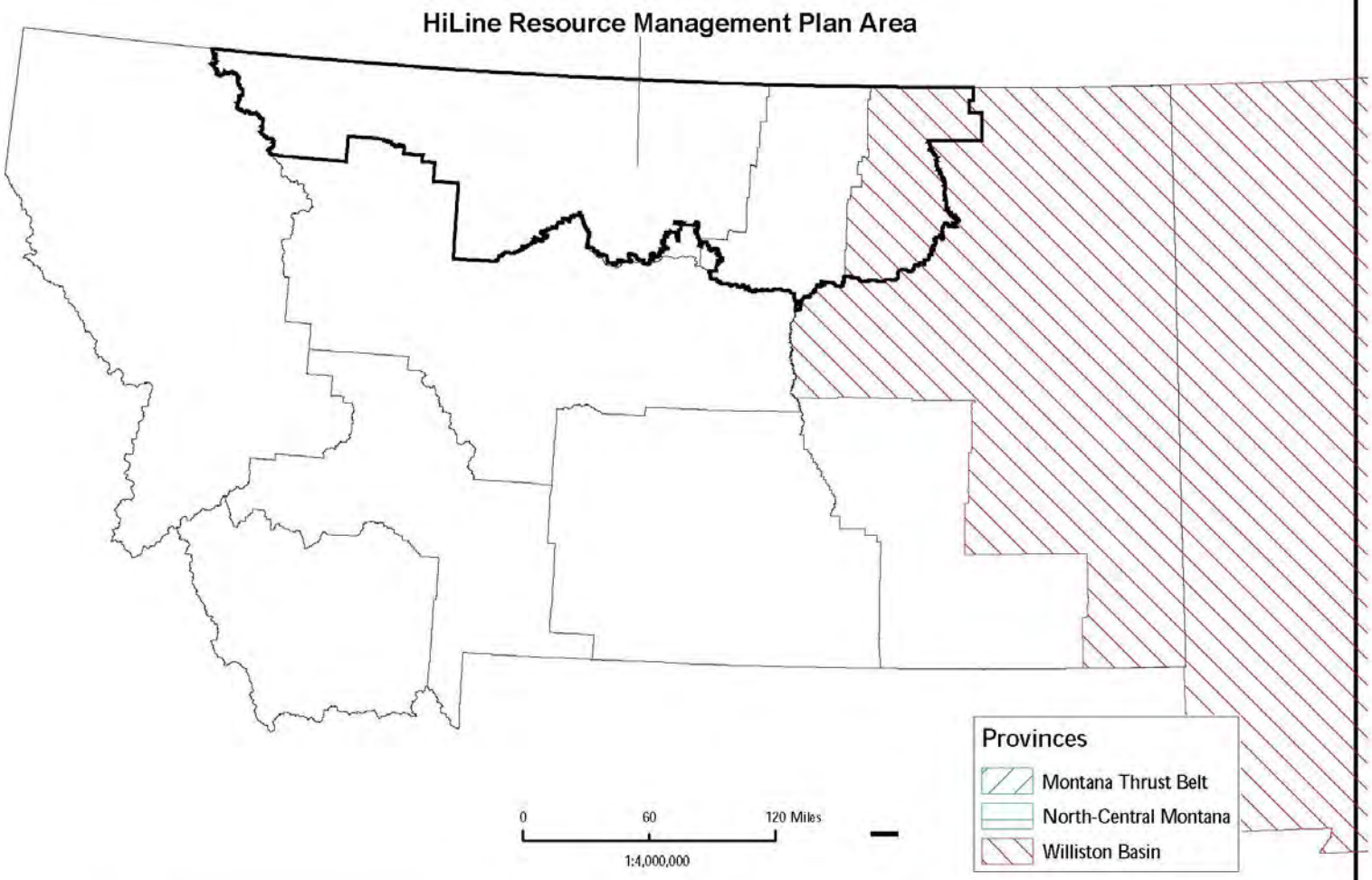
The U.S. Geological Survey (Beeman et al., 1996: Charpentier et al., 1996: Gautier et al., 1996) estimated undiscovered technically recoverable resource quantities of oil and gas that could be added to the proved reserves within the conventional and unconventional play areas at least partially within the HiLine planning area. In Table A1-6, the U.S. Geological Survey resource estimates for three types of hydrocarbons (oil, gas, and natural gas liquids) are shown for the conventional and unconventional plays in the Williston Basin Province, together with our projection of the amount of those hydrocarbons that could be present within the HiLine planning area. To determine the potential resource within the planning 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 planning area, and
- multiplied that percentage by the U.S. Geological Survey resource value estimates for each entire assessment unit to calculate planning area resource values.

Our estimates of recoverable resources for each of the play areas within the province and within the HiLine planning area, are presented as a range of possibilities: a low case having a 95 percent probability of that amount or more occurring, a high case having a 5 percent probability of that amount or more occurring, and a mean case representing an arithmetic average of all possible outcomes. We estimate that the planning area contains a **mean undiscovered volume of 10.43 million barrels of oil, 26.95 billion cubic feet of gas, and 3.18 million barrels of natural gas liquids, in the Williston Basin Province play areas.**

In addition, we estimate that the planning area's oil resource could **range from 1.06 to 16.75 million barrels, the gas resource could range from 3.08 to 43.57 billion cubic feet, and the natural gas liquids resource could range from 0.36 to 5.12 million barrels** (assuming fractile data used has a perfect positive correlation).

Figure A1-1.
Location of the provinces lying partially within the HiLine Planning Area (U.S. Geological Survey, 2007a and 2007b).



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Dave Chase, Petroleum Engineer

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Figure A1-2.
Location of Montana Thrust Belt Province, Thrust Belt conventional gas and oil assessment unit with respect to HiLine Planning Area boundary. Assessment unit boundary from U.S. Geological Survey (2007b).

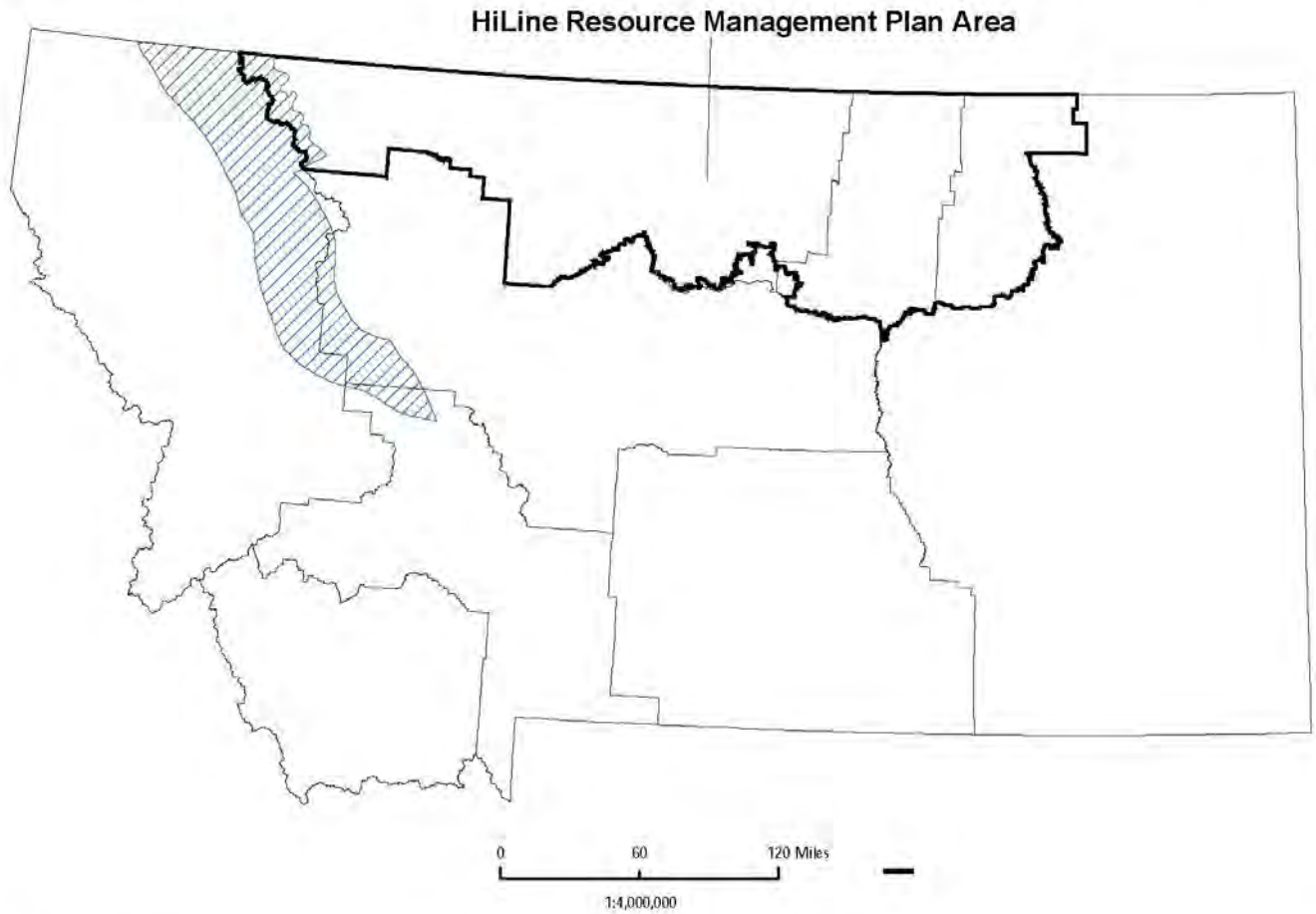

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Figure A1-3.
Location of Montana Thrust Belt Province, Sawtooth Range Structure conventional oil and gas assessment unit with respect to HiLine Planning Area boundary. Assessment unit boundary from U.S. Geological Survey (2007b).

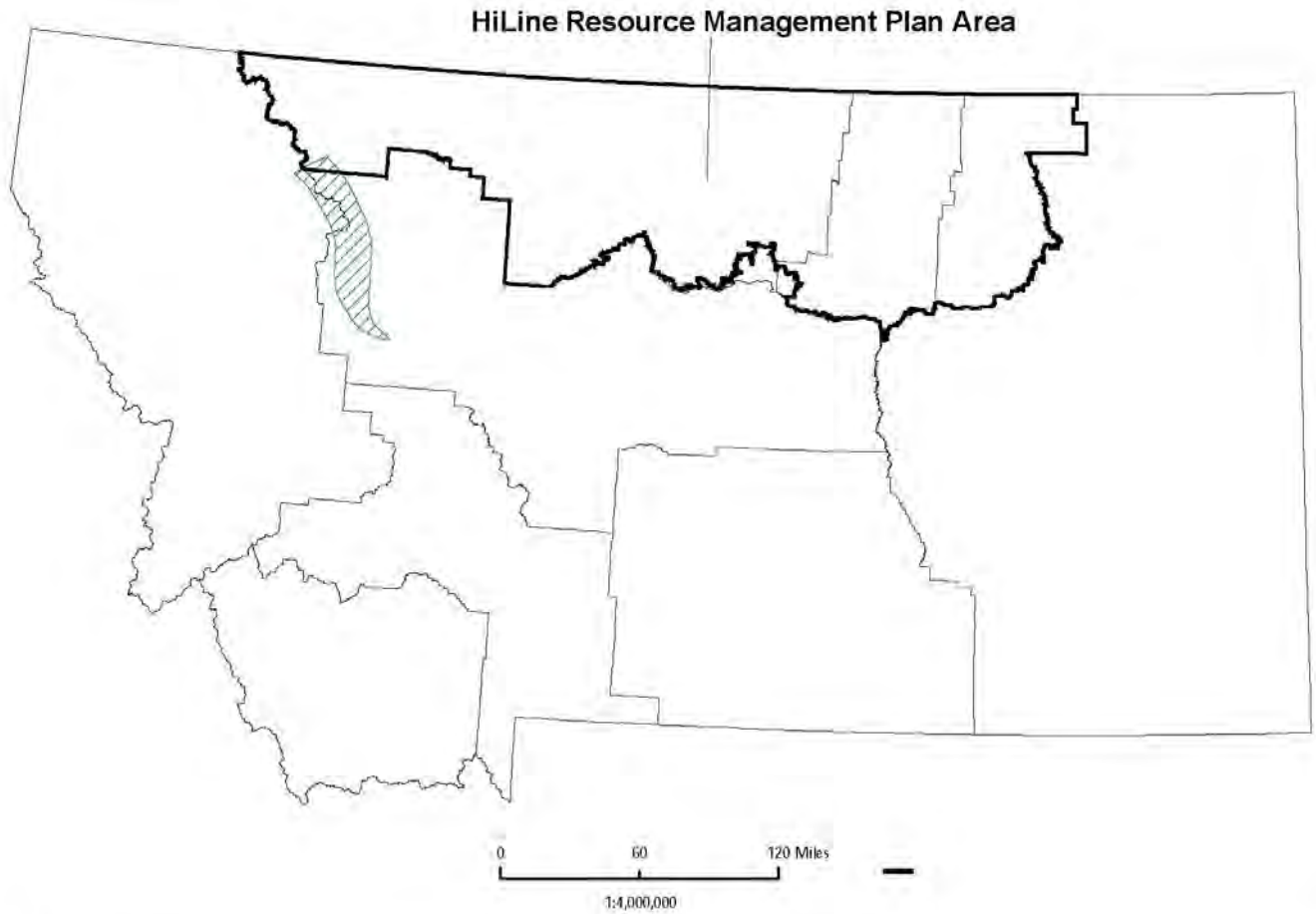

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Figure A1-4.
Location of Montana Thrust Belt Province, Frontal Structures conventional oil and gas assessment unit with respect to HiLine Planning Area boundary. Assessment unit boundary from U.S. Geological Survey (2007b).

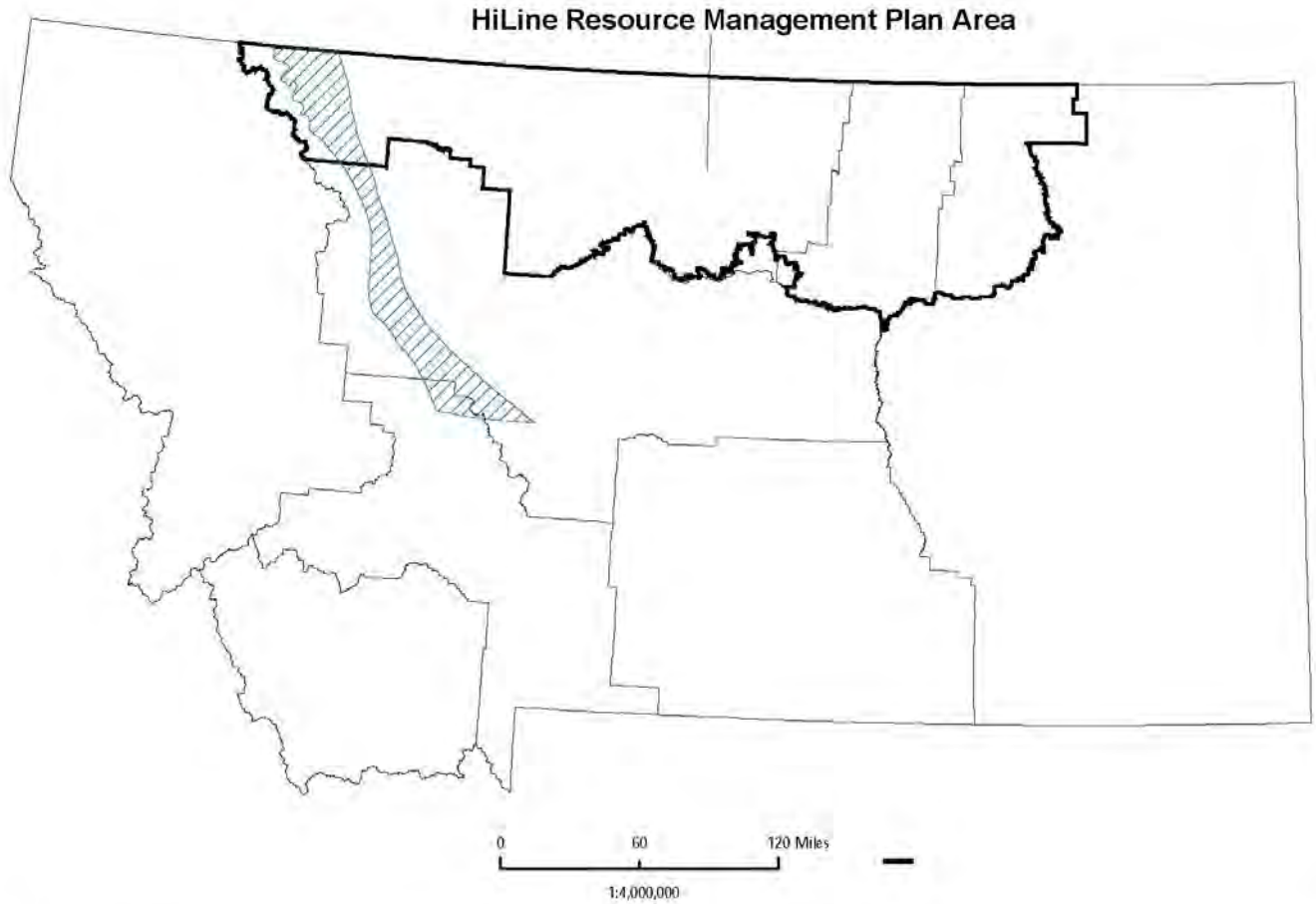

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Figure A1-5.

Location of Montana Thrust Belt Province, Bakken continuous oil assessment unit with respect to HiLine Planning Area boundary. Assessment unit boundary from U.S. Geological Survey (2007b).

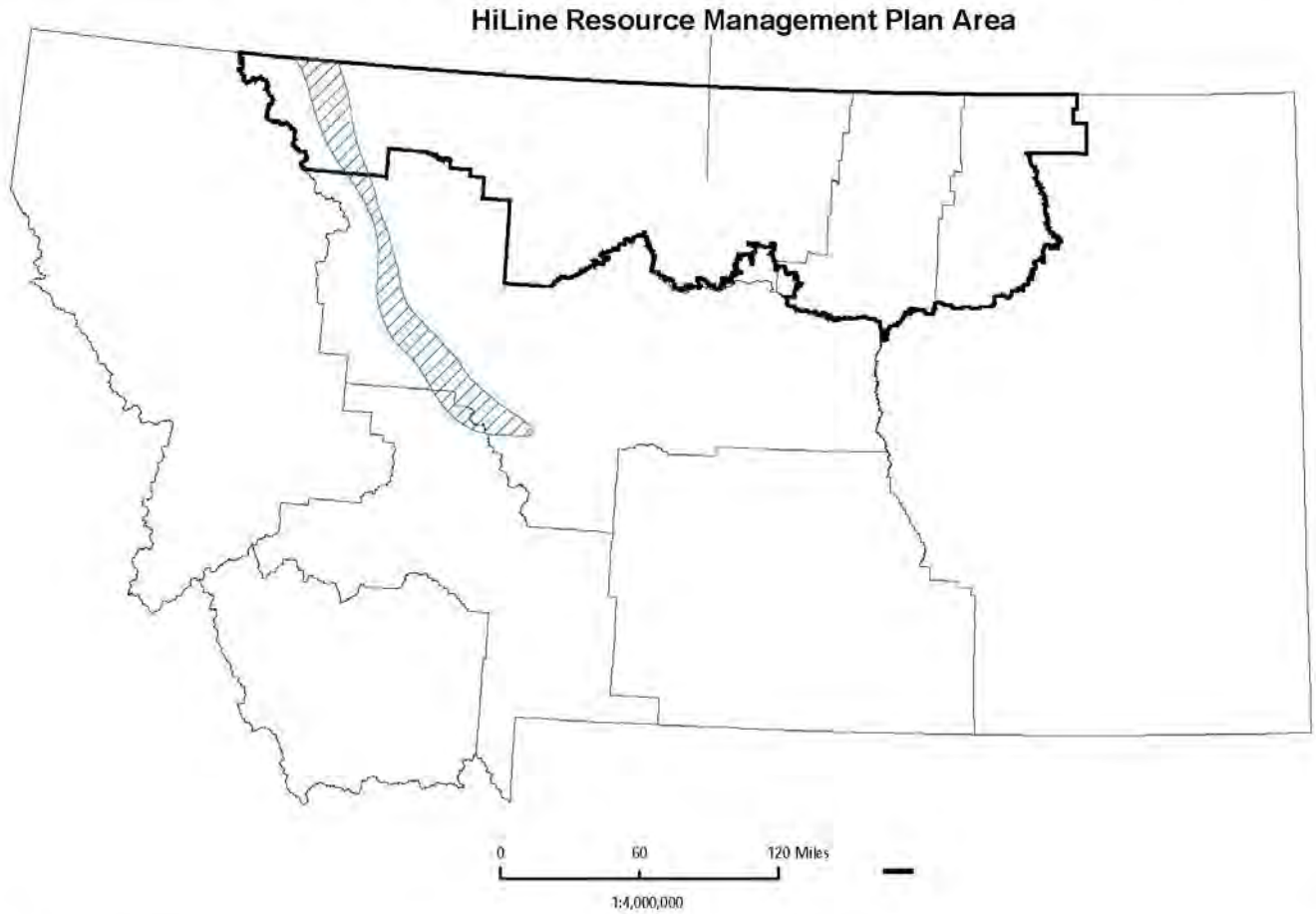

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Figure A1-6.
Location of Montana Thrust Belt Province, Marias River Shale continuous oil assessment unit with repsect to HiLine Planning Area boundary. Assessment unit boundary from U.S. Geological Survey (2007b).

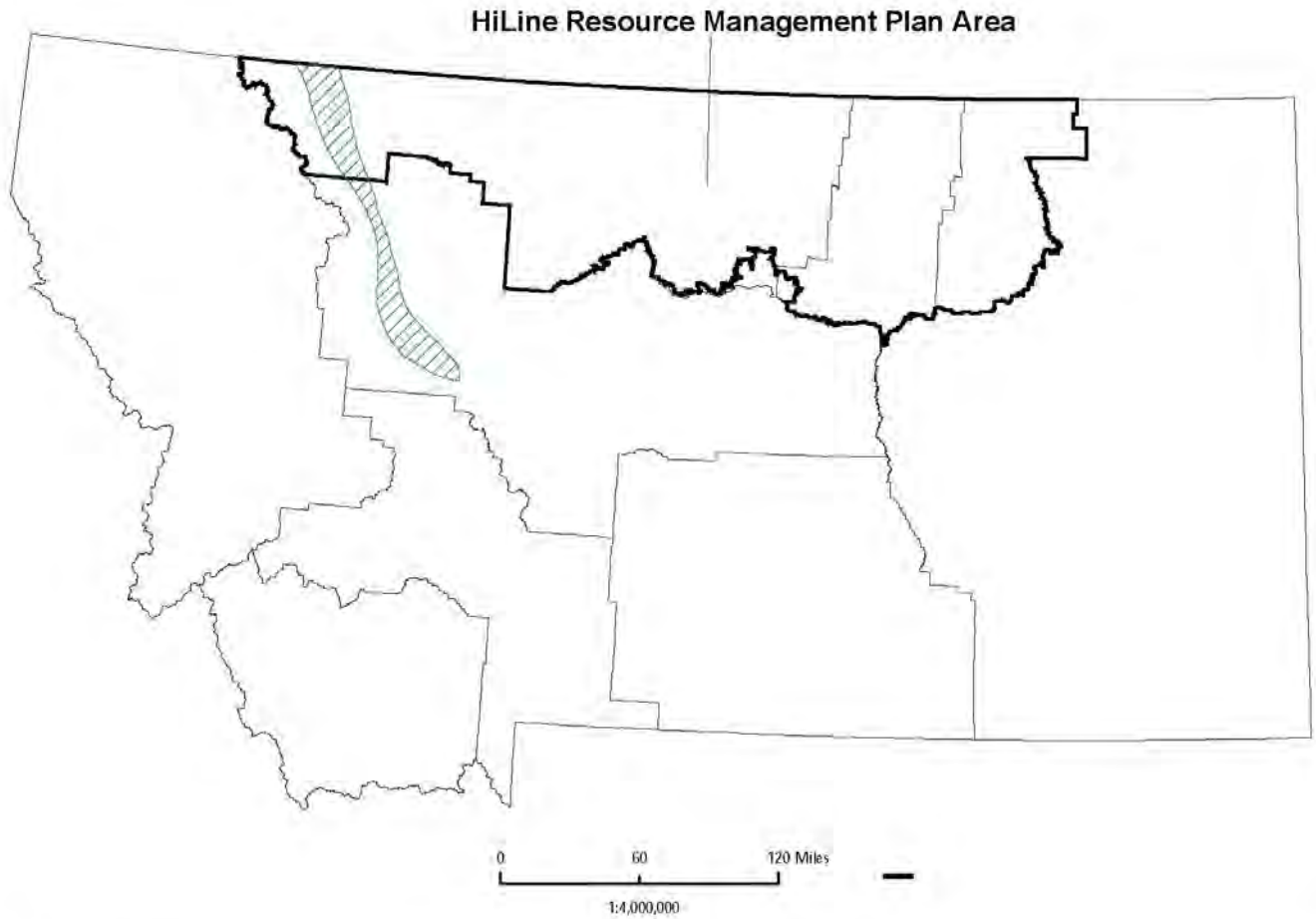

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Figure A1-7.
Location of Montana Thrust Belt Province, Jurassic-Cretaceous coalbed gas assessment unit with respect to HiLine Planning Area boundary. Assessment unit boundary from U.S. Goelogical Survey (2007b).

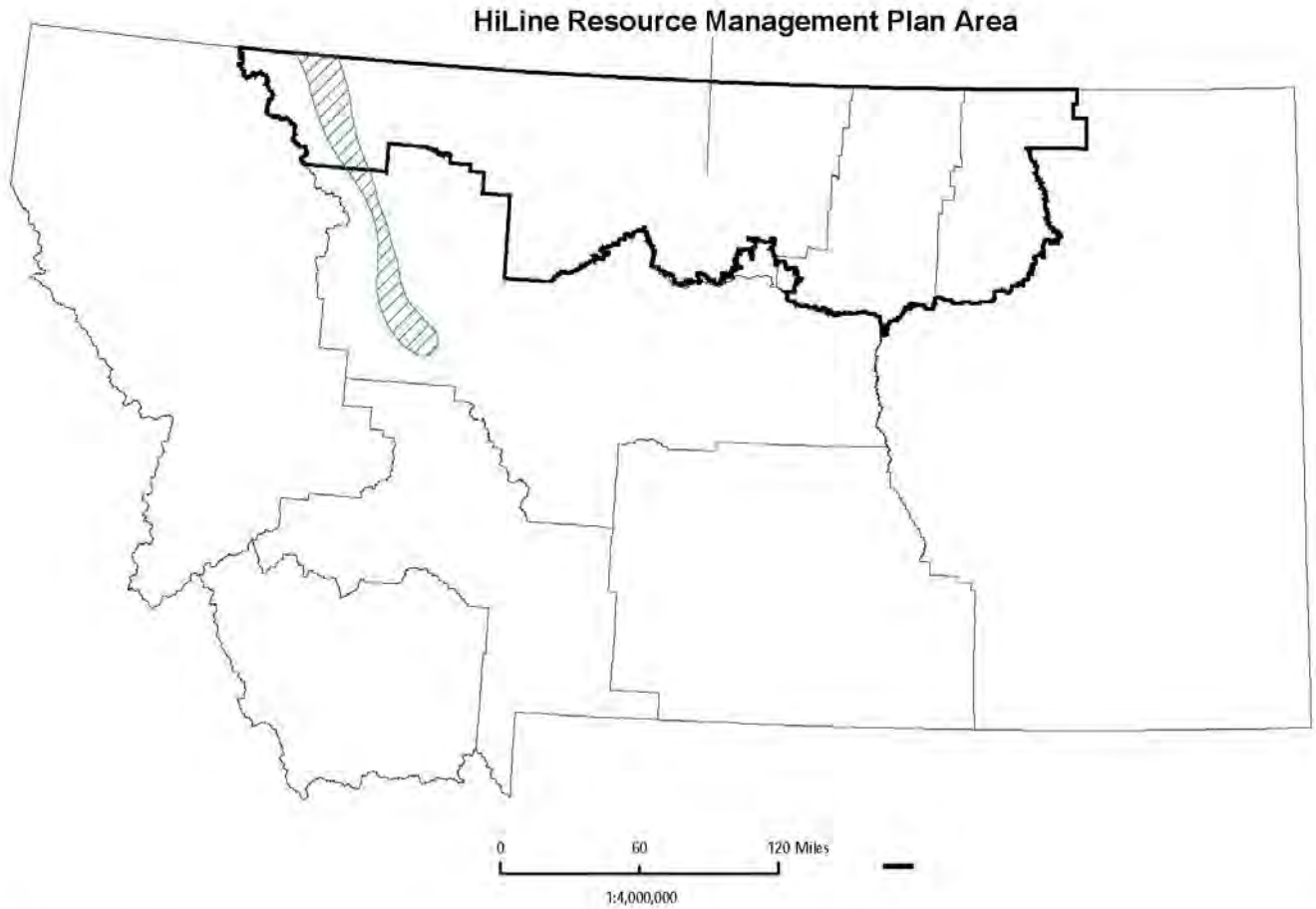

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Figure A1-8.
Location of North-Central Montana Province, Red River Carbonates conventional play with respect to HiLine Planning Area boundary. Boundary from U.S. Geological Survey (2007b).

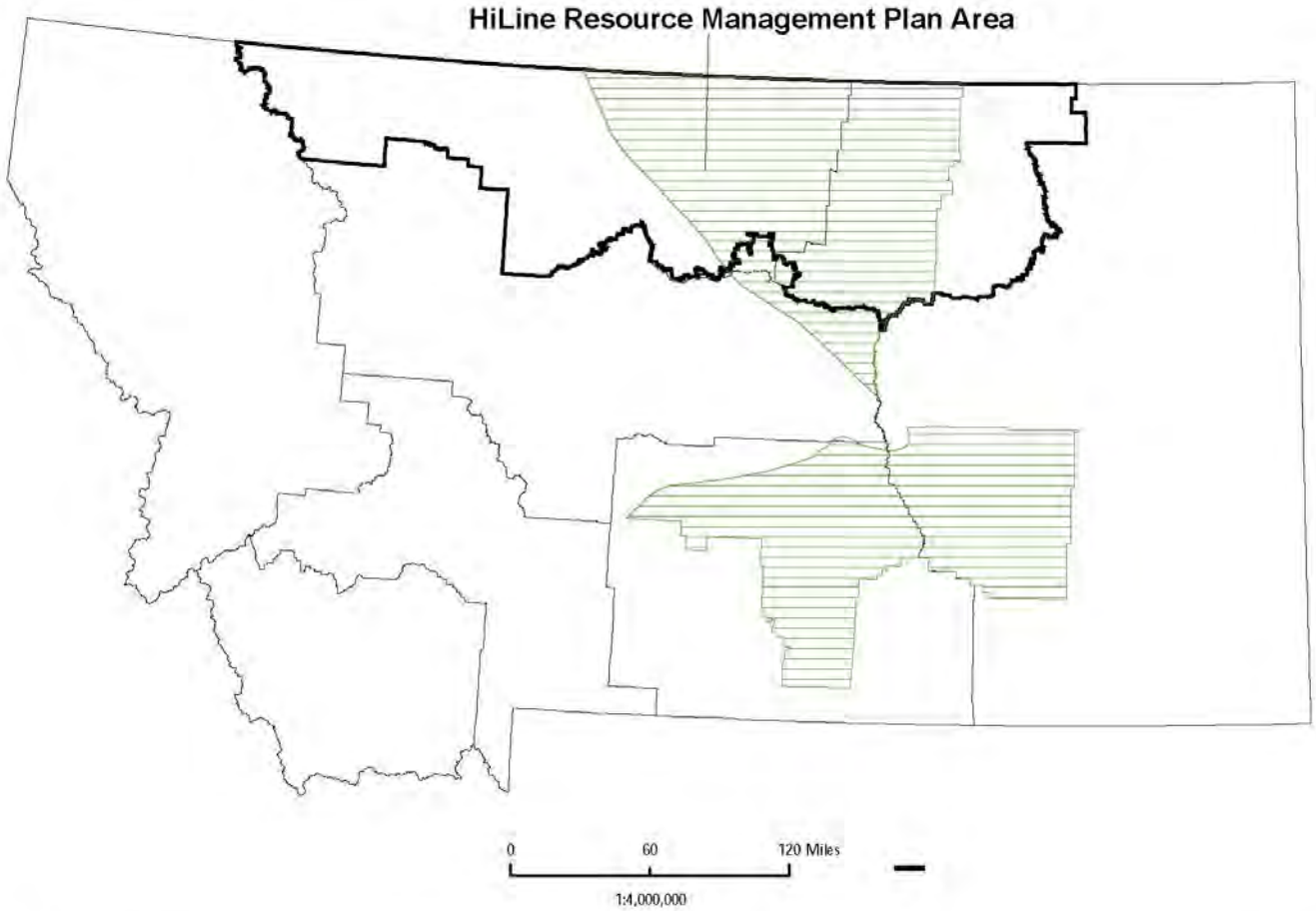

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Figure A1-9.
Location of North-Central Montana Province, Devonian-Mississippian Carbonates conventional play with respect to HiLine Planning Area boundary. Boundary from U.S. Geological Survey (20007b).

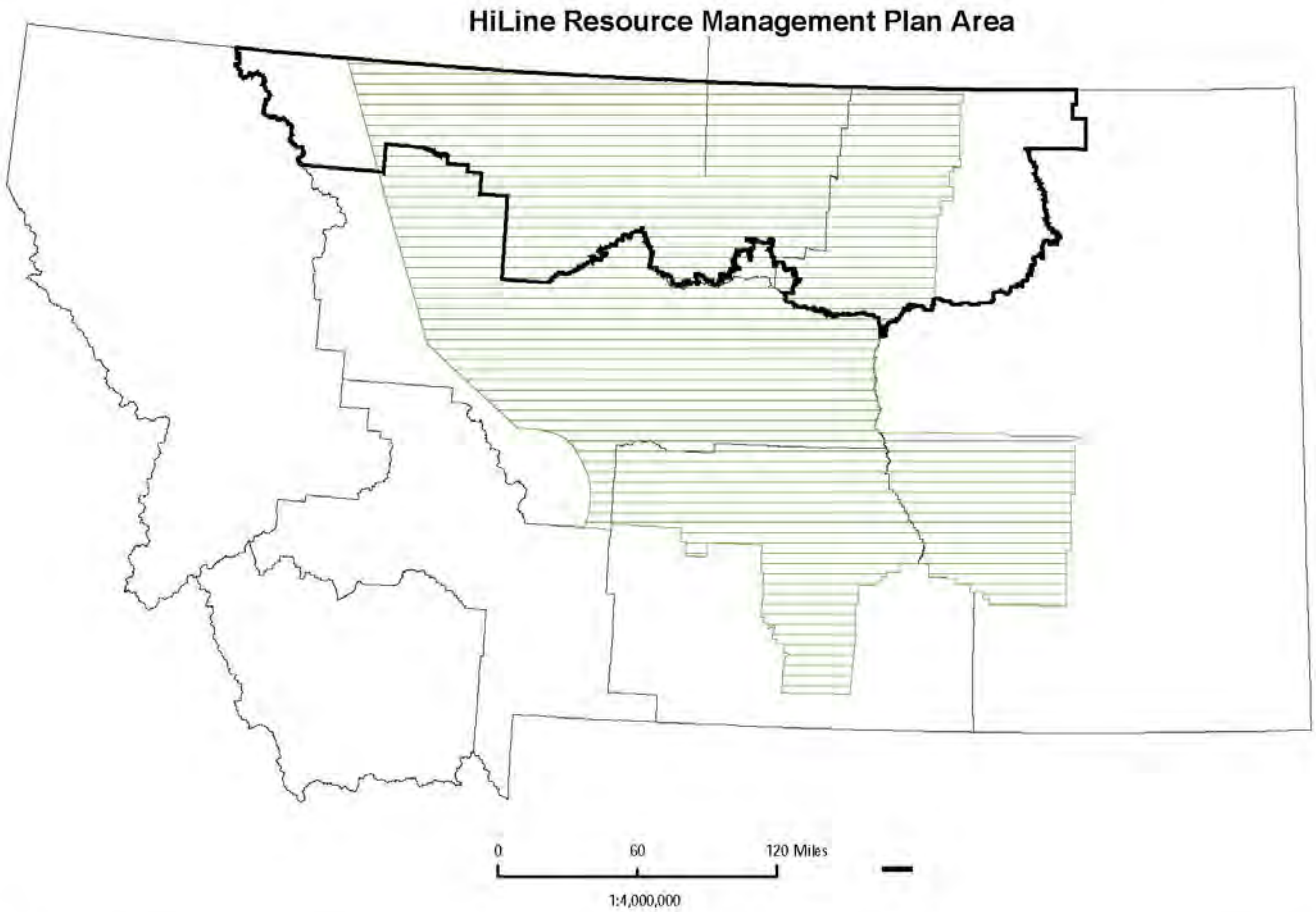

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Figure A1-10.
Location of North-Central Montana Province, Fractured-Faulted Carbonates in Anticlines conventional play with respect to HiLine Planning Area Boundary. Boundary from U.S. Geological Survey (2007b).

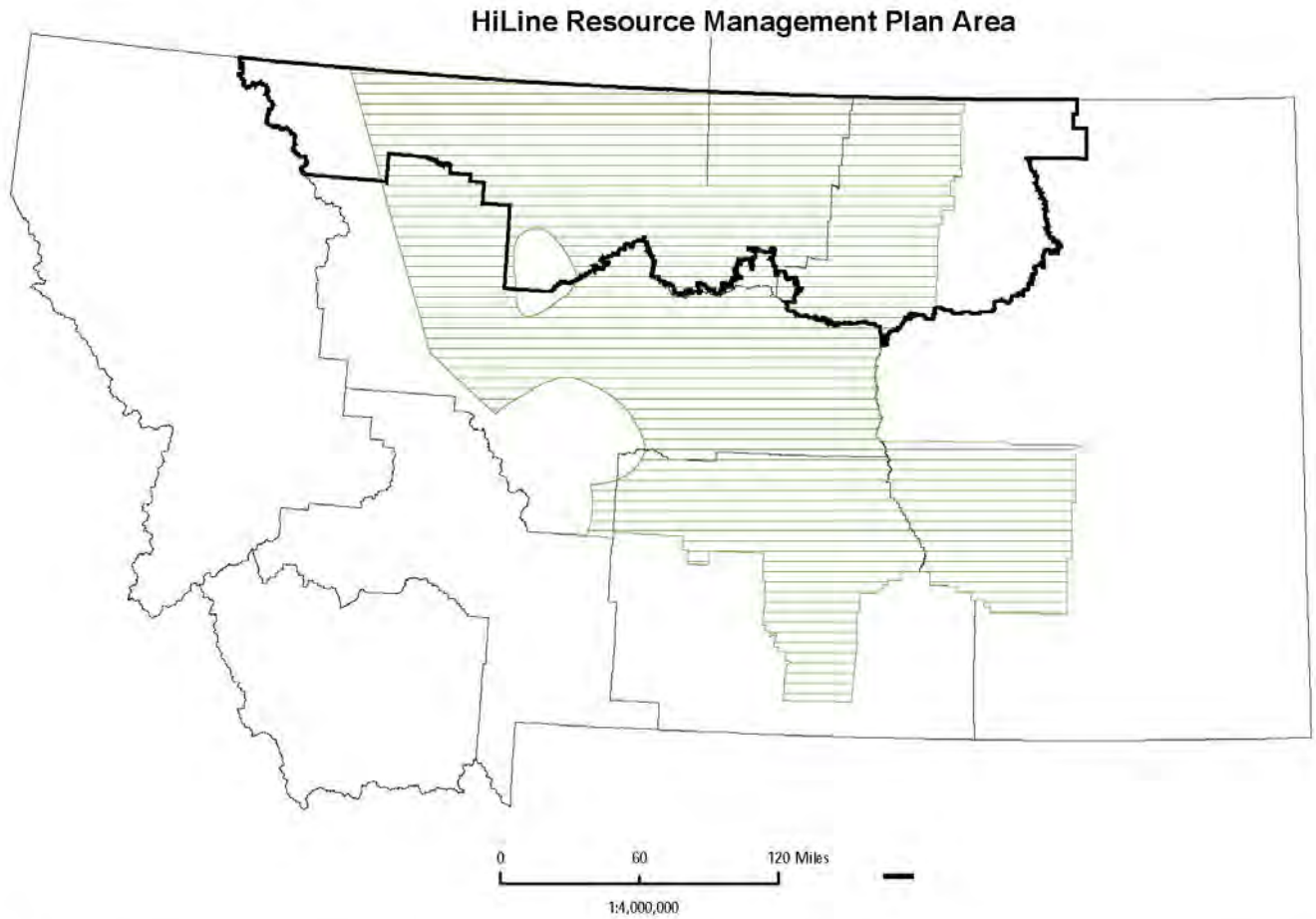

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Figure A1-11.
Location of North-Central Montana Province, Jurassic-Cretaceous Sandstones conventional play with respect to HiLine Planning Area boundary. Boundary from U.S. Geological Survey (2007b).

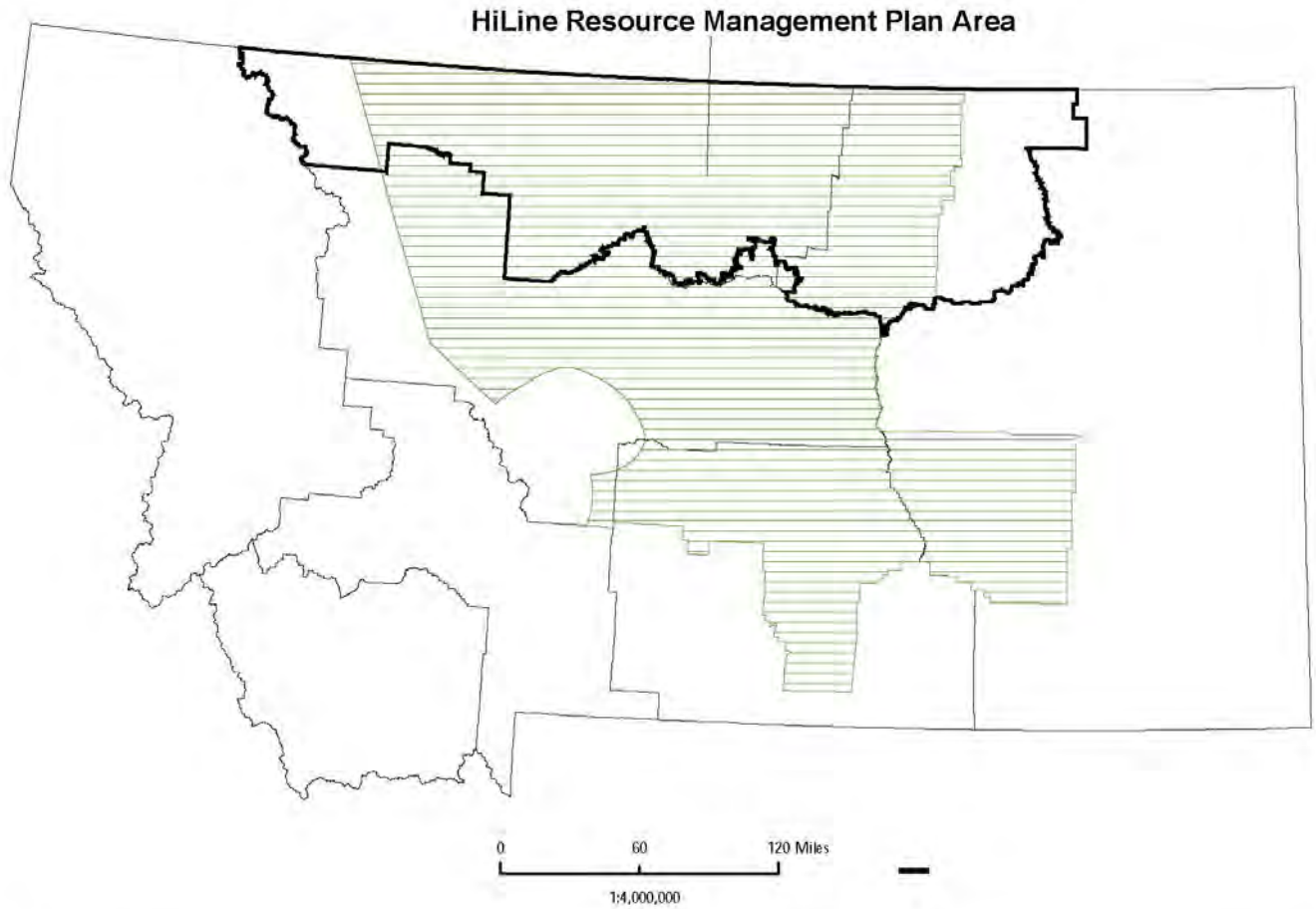

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Figure A1-12.

Location of North-Central Montana Province, Shallow Cretaceous Biogenic Gas conventional play with respect to HiLine Planning area boundary. Boundary from U.S. Geological Survey (2007b).

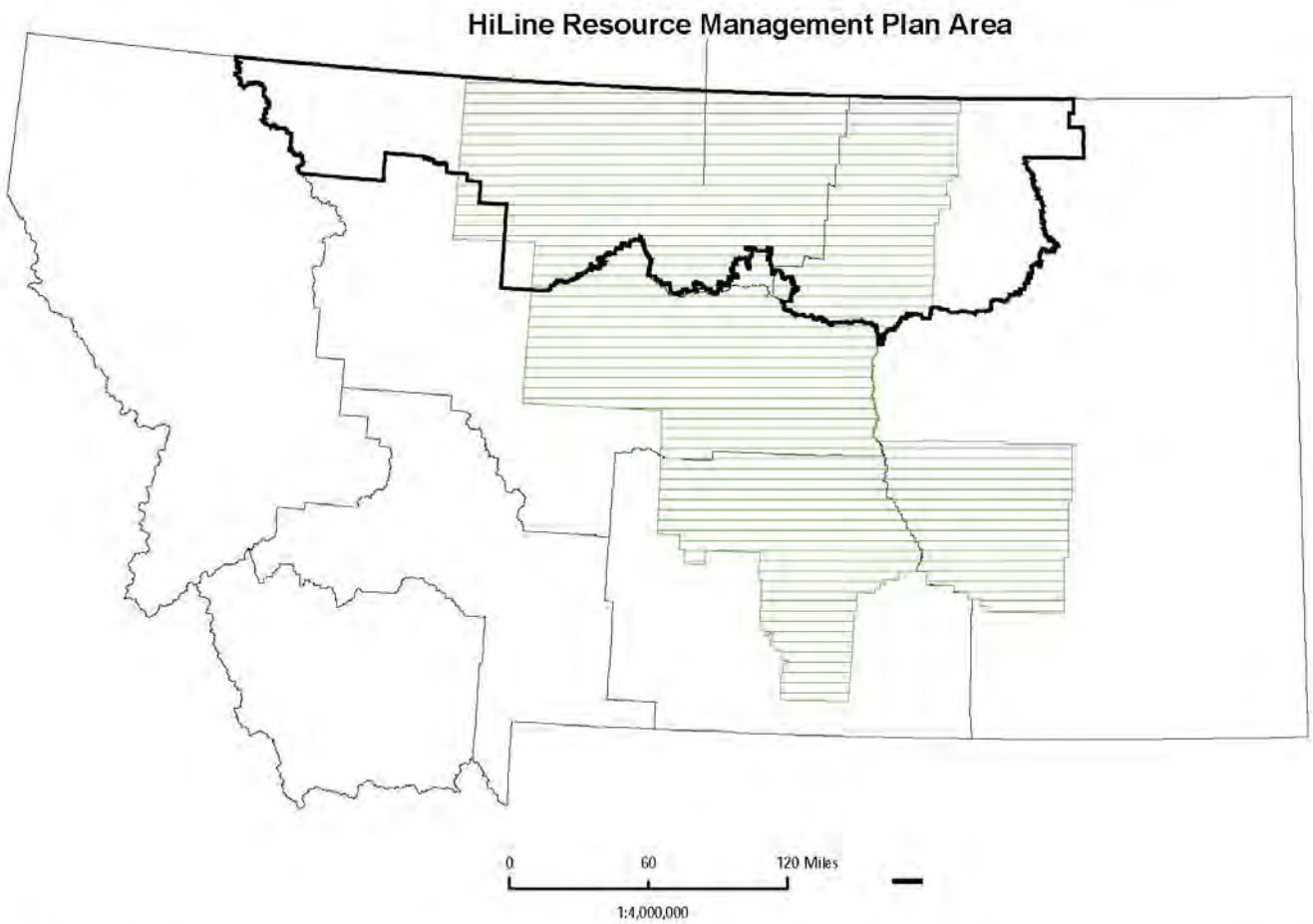

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Figure A1-13.
Location of North-Central Montana Province, Bakken Shale Fracture Systems unconventional play with respect to HiLine Planning Area boundary. Boundary from U.S. Geological Survey (2007b).

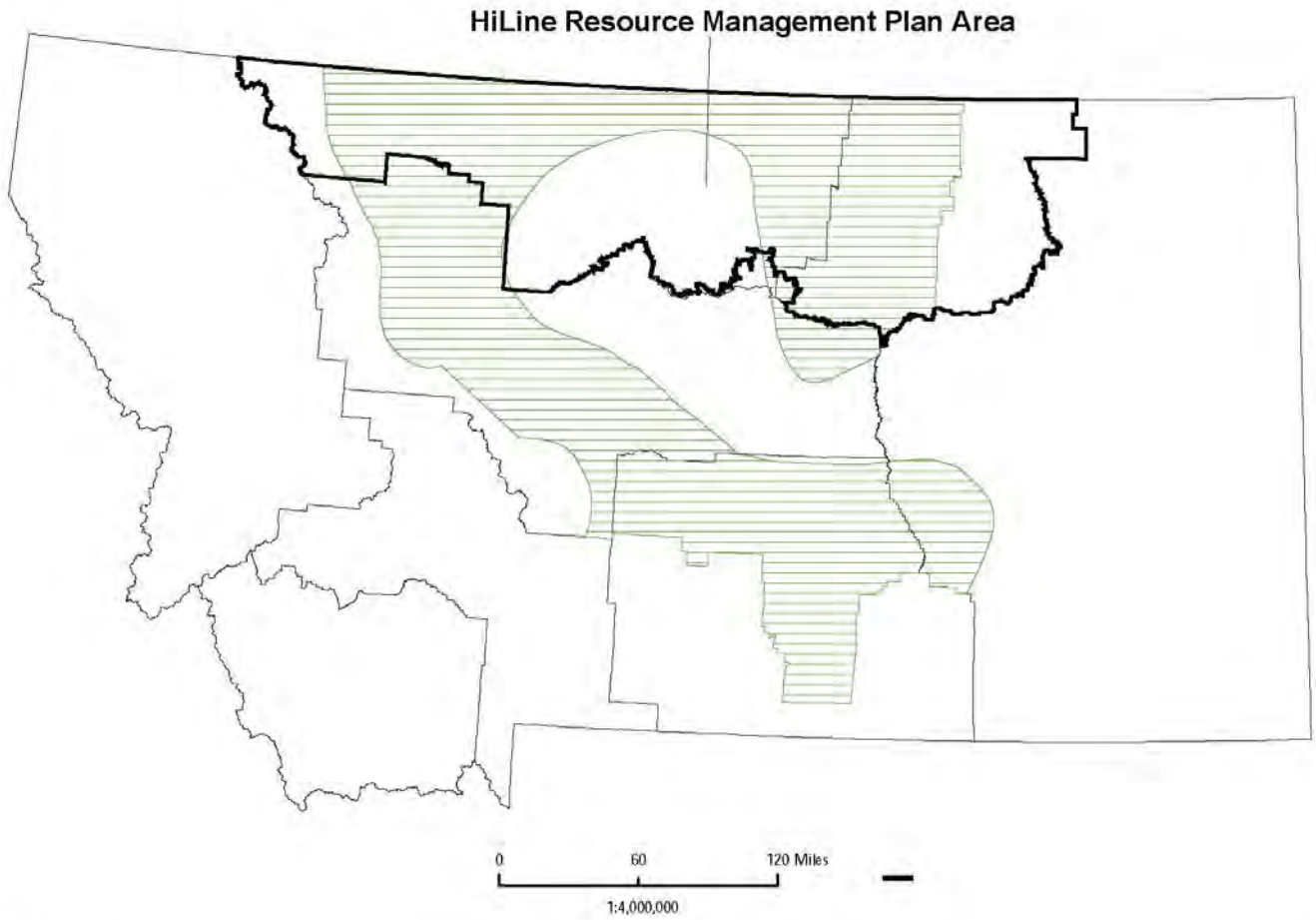

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Figure A1-14.
Location of North-Central Montana Province, Northern Great Plains Biogenic Gas, unconventional high potential play with respect to HiLine Planning Area boundary. Boundary from U.S. Geological Survey (2007b).

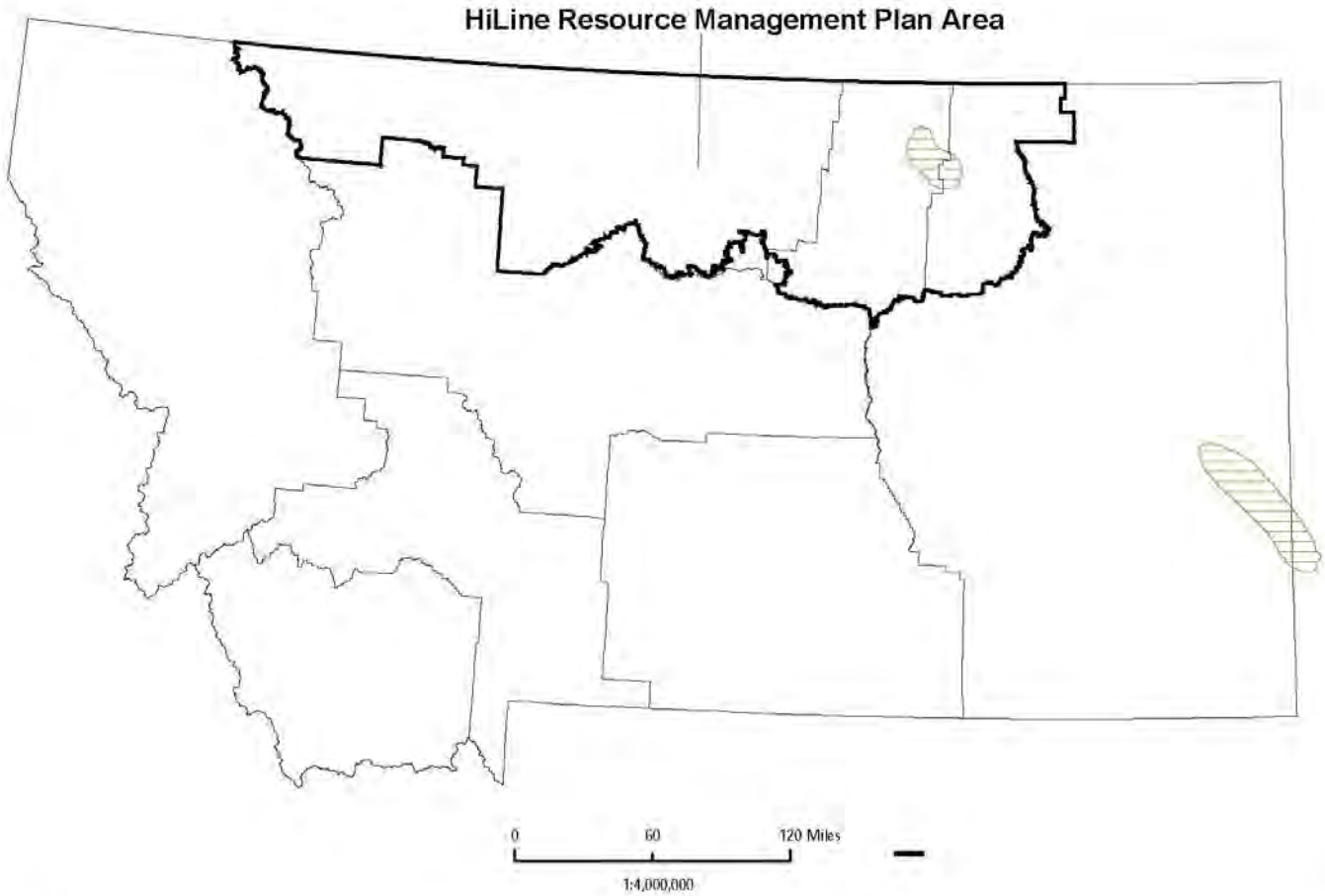

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Figure A1-15.
Location of North-Central Montana Province, Northern Great Plains Biogenic Gas, unconventional moderate potential play with respect to HiLine Planning Area boundary. Boundary from U.S. Geological Survey (2007b).

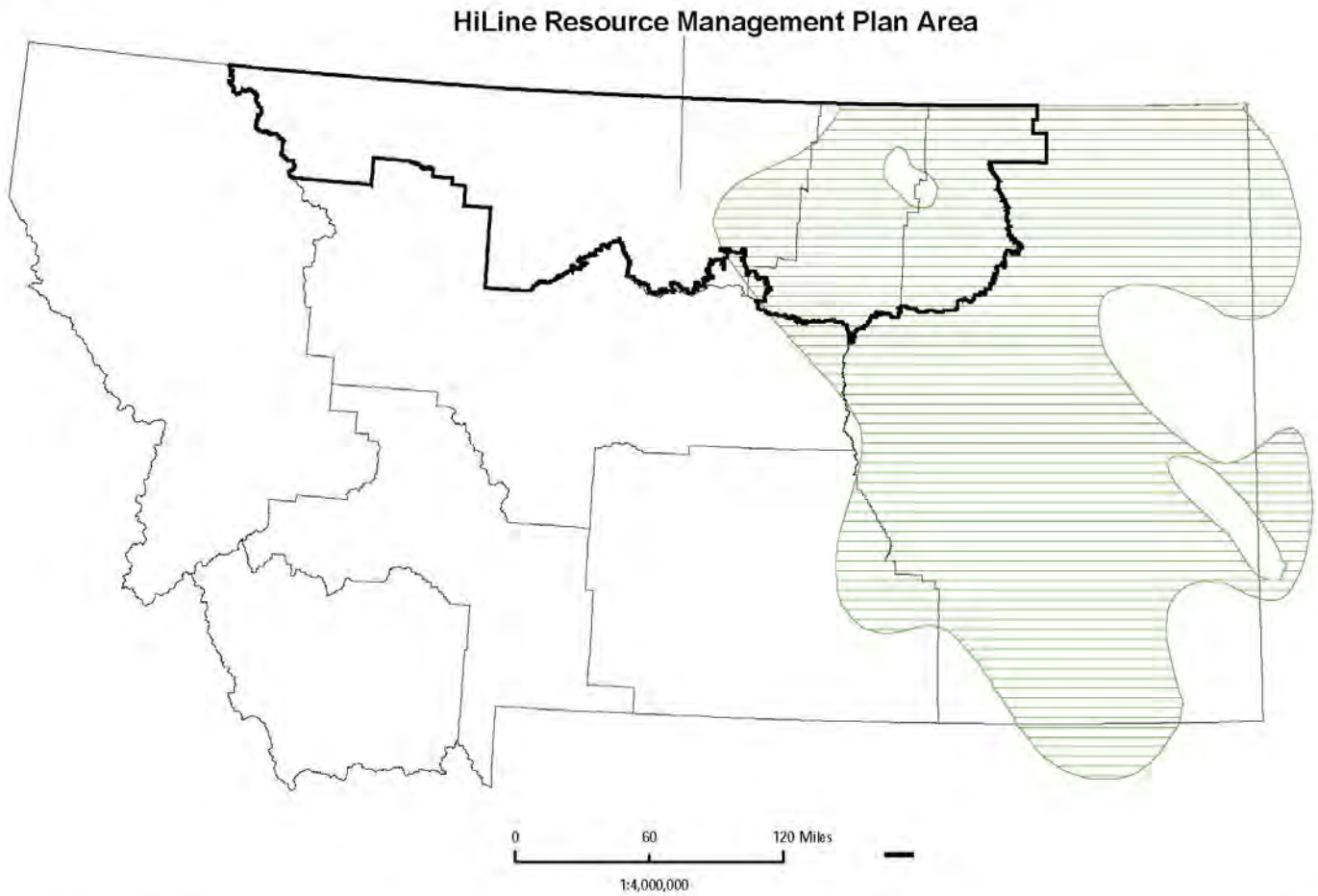

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Figure A1-16.
Location of North-Central Montana Province, Northern Great Plains Biogenic Gas, unconventional low potential play with respect to HiLine Planning Area boundary. Boundary from U.S. Geological Survey (2007b).

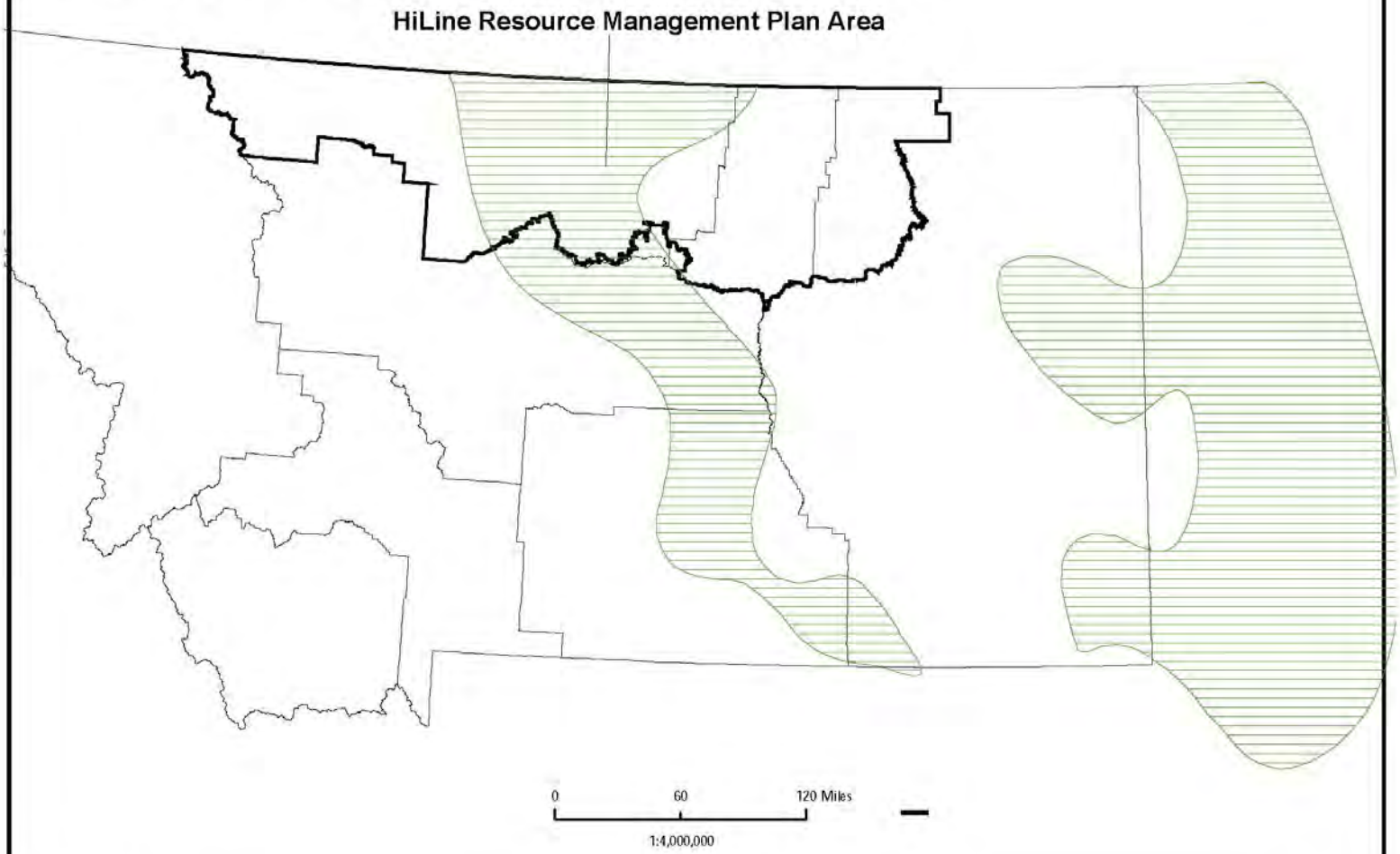

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Figure A1-17.
Location of Williston Basin Province, Madison (Mississippian), Red River (Ordovician), and Middle and Upper Devonian (Pre-Bakken-Post-Prairie Salt) conventional plays with respect to HiLine Planning Area boundary. Boundary from U.S. Geological Survey (2007b).

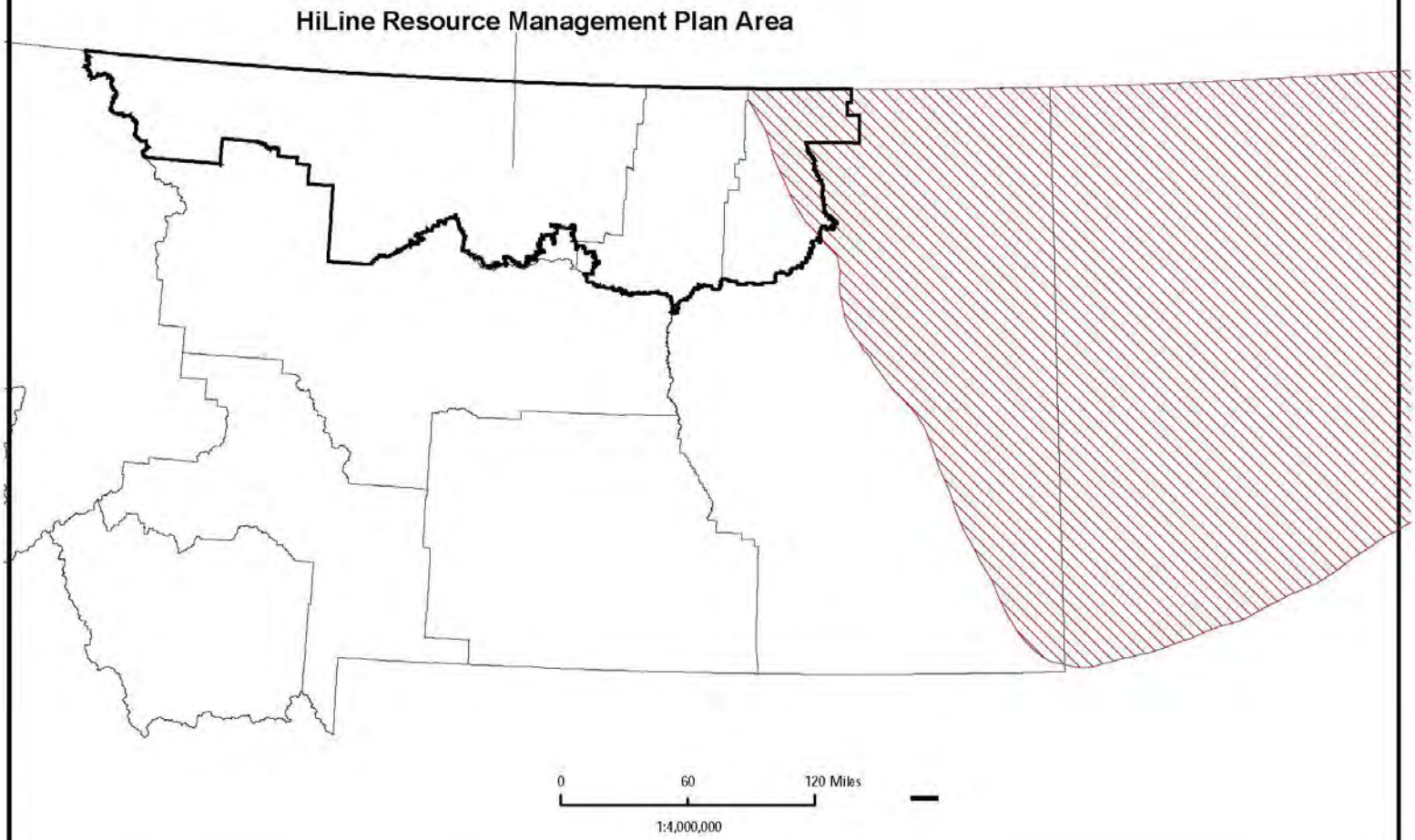

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Figure A1-18.
Location of Williston Basin Province, Pre-Prairie Middle Devonian and Silurian conventional play with respect to HiLine Planning Area boundary. Boundary from U.S. Geological Survey (2007b).

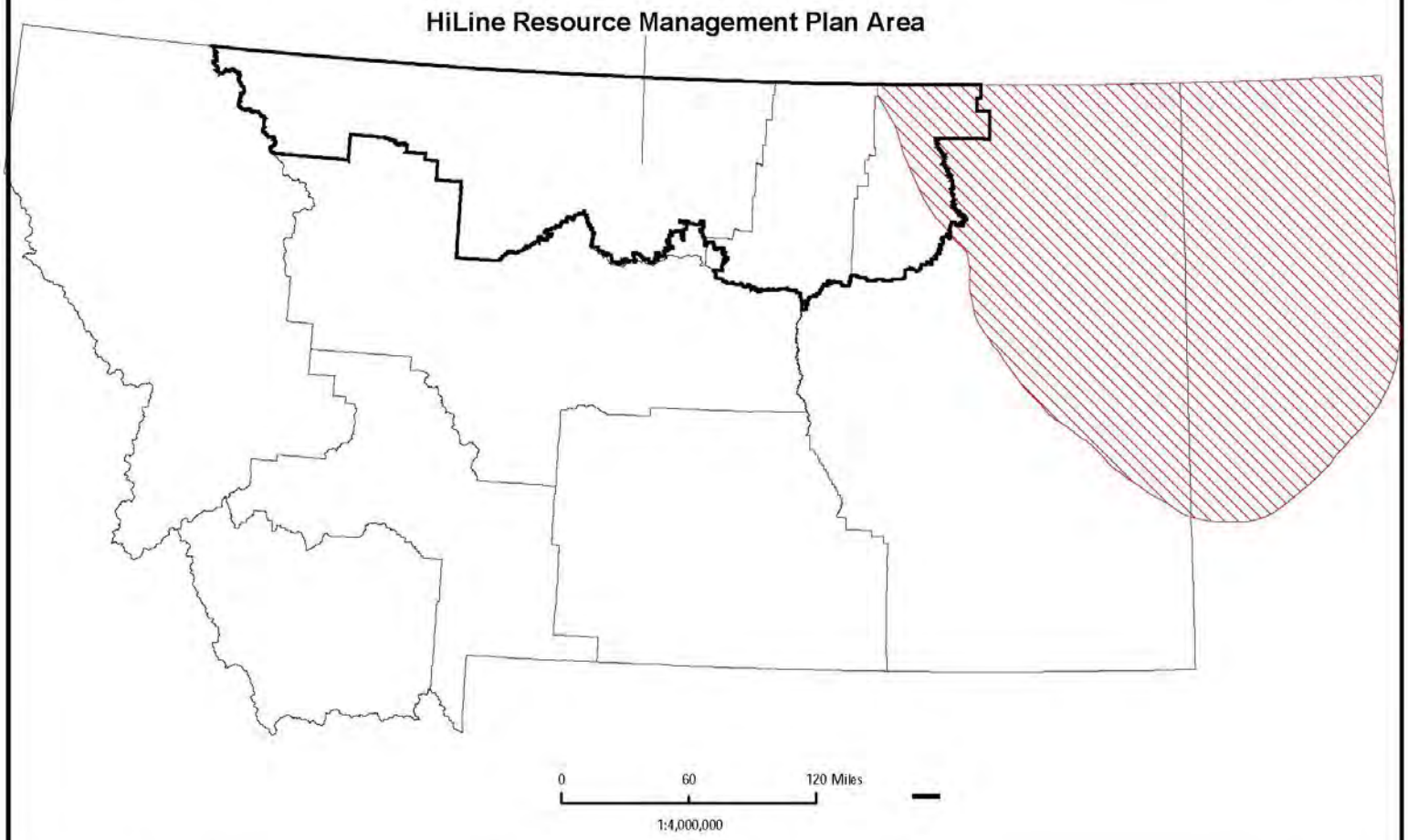

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Figure A1-19.
Location of Williston Basin Province, Post-Madison to Triassic Clastics conventional play with respect to HiLine Planning Area boundary. Boundary from U.S. Geological Survey (2007b).

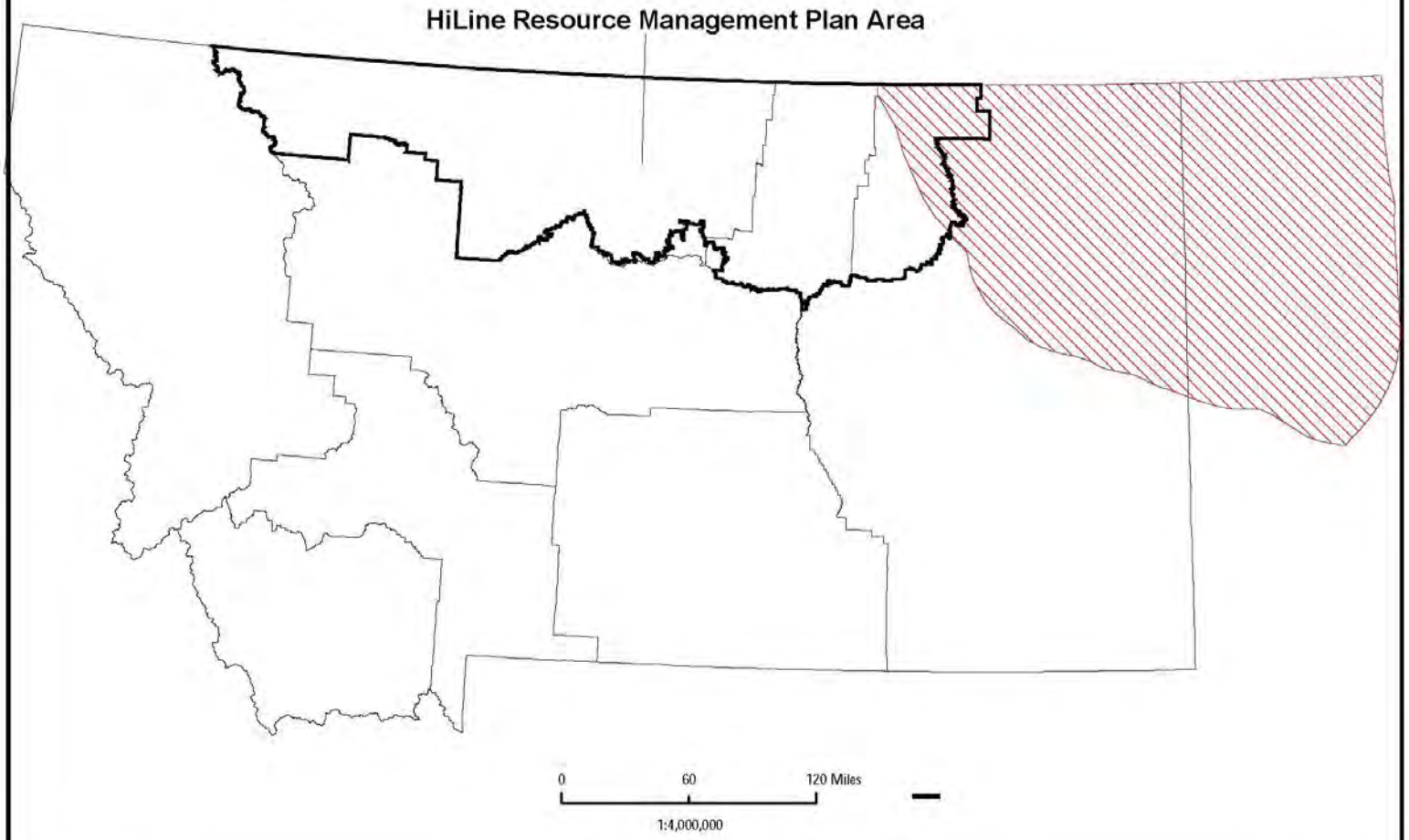

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Figure A1-20.
Location of Williston Basin Province, Bakken Outlying unconventional continuous-type play with respect to HiLine Planning Area boundary. Boundary from U.S. Geological Survey (2007b).

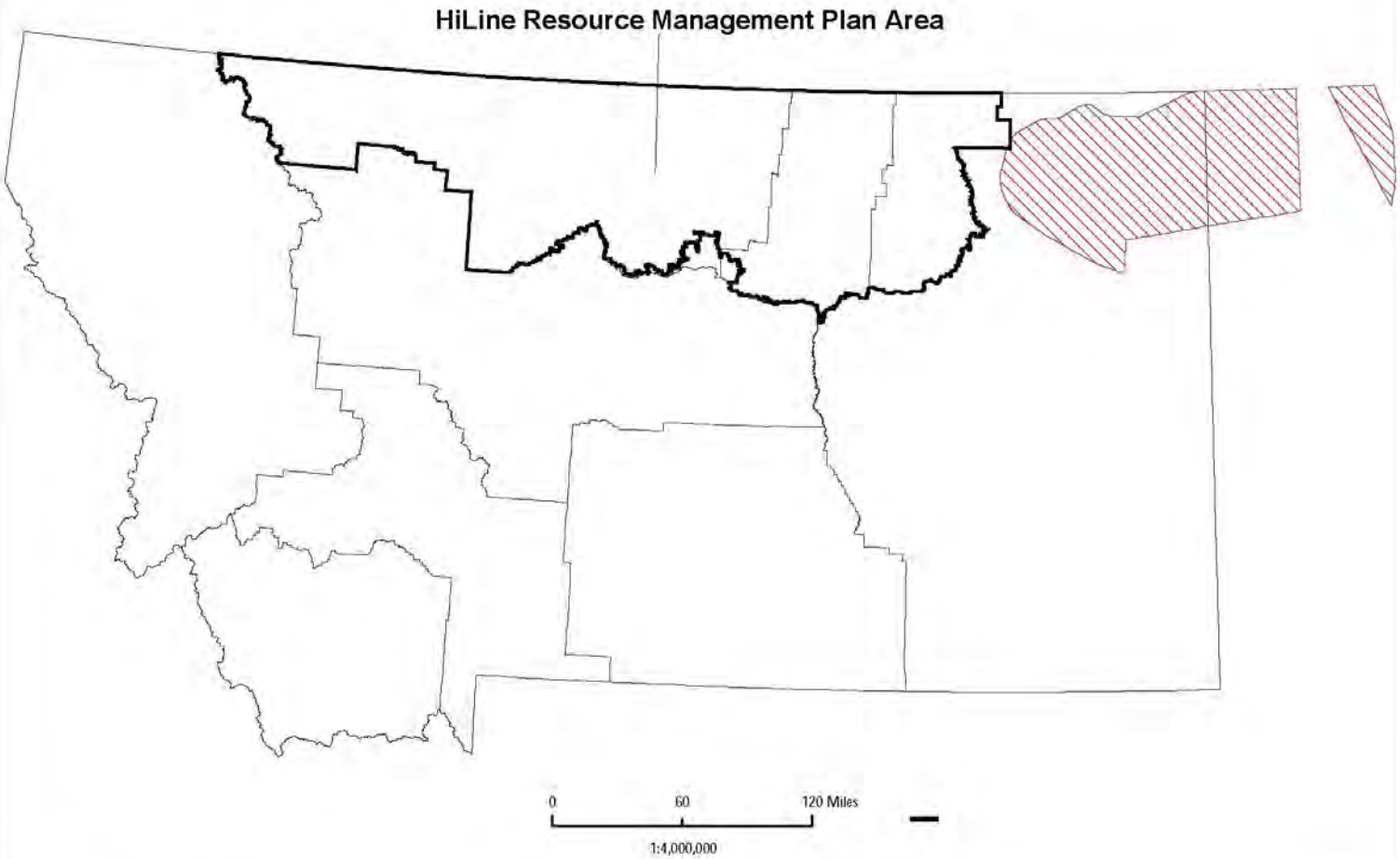

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Table A1-1.
Statistical Information for Montana Thrust Belt Province, Paleozoic/Mesozoic Composite Total Petroleum System conventional assessment units

Assessment Unit Name	*Exploration Status*	*Undiscovered Oil Accumulations*				*Undiscovered Gas Accumulations*		
		Number Range	*Median Size*	*Median API Gravity (Degrees)*	*Drilling Depth Range (ft)*	*Number Range*	*Median Size*	*Drilling Depth Range (ft)*
Thrust Belt	Hypothetical	0				1-100	36 BCFG	3,280-26,900
Sawtooth Range Structure	Hypothetical	0				1-30	36 BCFG	1,710-9,120
Frontal Structures	Frontier	1-7	1.5 MMBO	32	1,640-9,840	2-60	18 BCFG	2,130-10,170

Source: U.S. Geological Survey (2007b)
MMBO = Million Barrels of Oil
BCFG = Billion Cubic Feet of Gas

Table A1-2.
U.S. Geological Survey Estimated Undiscovered Technically Recoverable Resource Quantities within Montana Thrust Belt Province and HiLine Planning Area

	Estimated Undiscovered Denver Basin Province Resource Quantities at Probabilities of Occurrence of 95 and 5 Percent and for the Mean Case										*Estimated Undiscovered Study Area Resource Quantities at Probabilities of Occurrence of 95 and 5 Percent and for the Mean Case[1]*								
	Oil (MMBO)			*Gas (BCFG)*			*NGL (MMBNGL)*				*Oil (MMBO)*			*Gas (BCFG)*			*NGL (MMBNGL)*		
Assessment Unit Name	*95%*	*5%*	*Mean*	*95%*	*5%*	*Mean*	*95%*	*5%*	*Mean*	*% of Unit Lying within Field Office*	*95%*	*5%*	*Mean*	*95%*	*5%*	*Mean*	*95%*	*5%*	*Mean*
Conventional Thrust Belt Gas				783.40	13,772.70	5,761.40	17.10	331.80	133.60	8.10				63.43	1,115.18	466.50	1.38	26.87	10.82
Conventional Sawtooth Range Structure Gas				88.80	1,963.70	794.50	2.00	47.20	18.40	5.10				4.53	100.18	40.53	0.10	2.41	0.94
Conventional Frontal Structures Oil	1.70	14.90	6.70	6.20	61.80	26.70	0.30	3.20	1.30	36.31	0.62	5.41	2.43	2.25	22.44	9.69	0.11	1.16	
Conventional Frontal Structures Gas				135.50	2,901.10	1,165.30	6.60	153.90	60.30	36.31				49.20	1,053.33	423.10	2.40	55.88	21.89
Bakken Continuous Oil	Not Quantitatively Assessed																		

Marias River Shale Continuous Oil	12.90	50.60	27.90	46.80	214.30	111.40	2.10	11.30	5.60	44.06	5.68	22.29	12.29	20.62	94.41	49.08	0.93	4.98	2.47
Jurassic/Cretaceous Coalbed Gas	Not Quantitatively Assessed																		
Total Undiscovered Resources	14.60	65.50	34.60	1,060.70	18,913.60	7,859.30	28.10	547.40	219.20		6.30	27.70	14.72	140.03	2,385.54	988.90	4.92	91.29	36.59

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

Table A1-3.
Statistical Information for North-Central Montana Province Play Areas

		Undiscovered Oil Accumulations				*Undiscovered Gas Accumulations*		
Assessment Unit Name	***Exploration Status***	***Number Range***	***Median Size***	***Median API Gravity (Degrees)***	***Drilling Depth Range (ft)***	***Number Range***	***Median Size***	***Drilling Depth Range (ft)***
Red River Carbonates	Hypothetical	1-7	1 MMBO	43	3,000-6,500	0-0	NA	NA
Devonian-Mississippian Carbonates	Confirmed	3-21	4 MMBO	32	1,300-7,000	0-0	NA	NA
Fractured-Faulted Carbonates in Anticlines	Confirmed	3-17	1 MMBO	32	1,000-6,700	0-0	NA	NA
Jurassic-Cretaceous Sandstones	Confirmed	6-28	2 MMBO	38.5	900-3,500	4-19	7 BCFG	1,000-3,500
Shallow Cretaceous Biogenic Gas	Confirmed	0-0	NA	NA	NA	5-26	20 BCFG	700-3,000

Source: Beeman et al. (1996)
MMBO = Million Barrels of Oil
BCFG = Billion Cubic Feet of Gas

Table A1-4.
U.S. Geological Survey Estimated Undiscovered North-Central Montana Province and HiLine Planning Area Resource Quantities

	Estimated Undiscovered North-Central Montana Province Resource Quantities at Probabilities of Occurrence of 95 and 5 Percent and for the Mean Case										*Estimated Undiscovered Planning Area Resource Quantities at Probabilities of Occurrence of 95 and 5 Percent and for the Mean Case[1]*								
	Oil (MMBO)			*Gas (BCFG)*			*NGL (MMBNGL)*				*Oil (MMBO)*			*Gas (BCFG)*			*NGL (MMBNGL)*		
Assessment Unit Name	*95%*	*5%*	*Mean*	*95%*	*5%*	*Mean*	*95%*	*5%*	*Mean*	*% of Unit Lying within Field Office*	*95%*	*5%*	*Mean*	*95%*	*5%*	*Mean*	*95%*	*5%*	*Mean*
Red River Carbonates	0.00	9.70	3.70	0.00	9.70	3.70	0.00	0.19	0.10	48.22	0.00	4.68	1.78	0.00	4.68	1.78	0.00	0.09	0.05
Devonian-Mississippian Carbonates	7.80	93.80	57.80	3.90	46.90	28.90	0.11	1.27	0.80	39.94	3.12	37.47	23.09	1.56	18.73	11.54	0.04	0.51	0.32
Fractured-Faulted Carbonates in Anticlines	2.00	17.10	11.40	1.00	8.55	5.70	0.02	0.17	0.10	40.85	0.82	6.99	4.66	0.41	3.49	2.33	0.01	0.07	0.04
Jurassic-Cretaceous Sandstones	4.50	55.30	40.00	14.79	143.65	104.10	0.05	0.55	0.40	41.39	1.86	22.89	16.55	6.12	59.45	43.08	0.02	0.23	0.17
Shallow Cretaceous Biogenic Gas				44.90	594.50	400.20				43.33				19.46	257.61	173.42			
Bakken Shale Fracture Systems	0.00	89.21	16.16	0.00	71.37	12.93				41.83	0.00	37.32	6.76	0.00	29.86	5.41			
Northern Great Plains Biogenic Gas, High Potential				2,259.70	10,514.30	5,436.74				26.66				602.50	2,803.39	1,449.58			
Northern Great Plains Biogenic Gas, Moderate Potential				6,752.10	44,666.50	20,479.70				20.60				1,391.08	9,202.27	4,219.26			
Northern Great Plains Biogenic Gas, Low Potential				4,242.65	36,299.30	15,353.60				14.67				622.23	5,323.70	2,251.78			
Total Undiscovered Resources	**14.30**	**265.11**	**129.06**	**13,319.04**	**92,354.77**	**41,825.57**	**0.18**	**2.18**	**1.40**		**5.79**	**109.33**	**52.84**	**2,643.35**	**17,703.18**	**8,158.18**	**0.07**	**0.90**	**0.57**

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

Table A1-5.
Statistical Information for Williston Basin Province Play Areas

Assessment Unit Name	*Exploration Status*	*Undiscovered Oil Accumulations*				*Undiscovered Gas Accumulations*		
		Number Range	*Median Size*	*Median API Gravity (Degrees)*	*Drilling Depth Range (ft)*	*Number Range*	*Median Size*	*Drilling Depth Range (ft)*
Madison (Mississippian)	Confirmed	9-60	2 MMBO	37	3,000-12,000	0-0	NA	NA
Red River (Ordovician)	Confirmed	5-50	2 MMBO	38	7,000-14,000	5-55	10 BCFG	12,000-15,000
Middle and Upper Devonian (Pre-Bakken – Post-Prairie Salt)	Confirmed	9-50	2 MMBO	Unknown	7,000-12,000	2-10	10 BCFG	7,000-12,000
Pre-Prairie Middle Devonian and Silurian	Confirmed	5-25	3 MMBO	45	8,000-12,500	3-10	15 BCFG	8,000-12,500
Post-Madison to Triassic Clastics	Confirmed	4-15	2 MMBO	33	5,500-9,000	0-0	NA	NA

Source: Beeman et al. (1996)
MMBO = Million Barrels of Oil
BCFG = Billion Cubic Feet of Gas

Table A1-6.
U.S. Geological Survey Estimated Undiscovered Williston Basin Province and HiLine Planning Area Resource Quantities

	Estimated Undiscovered North-Central Montana Province Resource Quantities at Probabilities of Occurrence of 95 and 5 Percent and for the Mean Case										*Estimated Undiscovered Planning Area Resource Quantities at Probabilities of Occurrence of 95 and 5 Percent and for the Mean Case*[1]								
	Oil (MMBO)			*Gas (BCFG)*			*NGL (MMBNGL)*				*Oil (MMBO)*			*Gas (BCFG)*			*NGL (MMBNGL)*		
Assessment Unit Name	*95%*	*5%*	*Mean*	*95%*	*5%*	*Mean*	*95%*	*5%*	*Mean*	*% of Unit Lying within Field Office*	*95%*	*5%*	*Mean*	*95%*	*5%*	*Mean*	*95%*	*5%*	*Mean*
Madison (Mississippian)	12.60	305.60	168.50	12.60	305.60	168.50	1.07	25.98	14.30	2.53	0.32	7.72	4.26	0.32	7.72	4.26	0.03	0.66	0.36
Red River (Ordovician)	7.20	88.20	53.50	50.00	634.80	371.50	7.03	89.57	52.20	2.53	0.18	2.23	1.35	1.26	16.04	9.39	0.18	2.26	1.32
Middle and Upper Devonian (Pre-Bakken – Post-Prairie Salt)	6.20	79.40	55.30	16.00	203.20	126.10	0.50	6.35	4.40	2.53	0.16	2.01	1.40	0.40	5.13	3.19	0.01	0.16	0.11
Pre-Prairie Middle Devonian and Silurian	6.00	68.70	49.30	22.00	294.10	202.70	2.96	42.30	28.70	4.83	0.29	3.32	2.38	1.06	14.20	9.78	0.14	2.04	1.39
Post-Madison to Triassic Clastics	1.90	25.10	17.70	0.61	8.03	5.70				5.88	0.11	1.47	1.04	0.04	0.47	0.33			
Bakken Outlying	0.00	17.45	8.16	0.00	13.96	6.53				0.03	0.00	0.01	0.00	0.00	0.00	0.00			
Total Undiscovered Resources	**33.90**	**584.45**	**352.46**	**101.21**	**1,459.69**	**881.03**	**11.56**	**164.20**	**99.60**		**1.06**	**16.75**	**10.43**	**3.08**	**43.57**	**26.95**	**0.36**	**5.12**	**3.18**

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