APPENDIX C

Reasonably Foreseeable Development Scenario for Oil and Gas Development in the Buffalo Field Office Area, Wyoming (as put on the Wyoming BLM web page (www.wy.blm.gov/nepa/nfdocs.html) in June 2000)

(As of December 2000 these projections are being revised and will be evaluated as part of the Powder River Oil and Gas EIS which is scheduled for completion in spring 2002.)

SUMMARY

Estimating how much oil and gas activity will occur on federal acreage in the Buffalo Field Office area (BFOA) during the next ten years is difficult. It is expected that, with a few exceptions, all public domain and acquired minerals will be available for leasing as indicated by the current land use plan. Separate estimates are given for leasing, seismic, drilling, and production activities during the next five to ten years. Coalbed methane (CBM) is considered separately from conventional oil and gas.

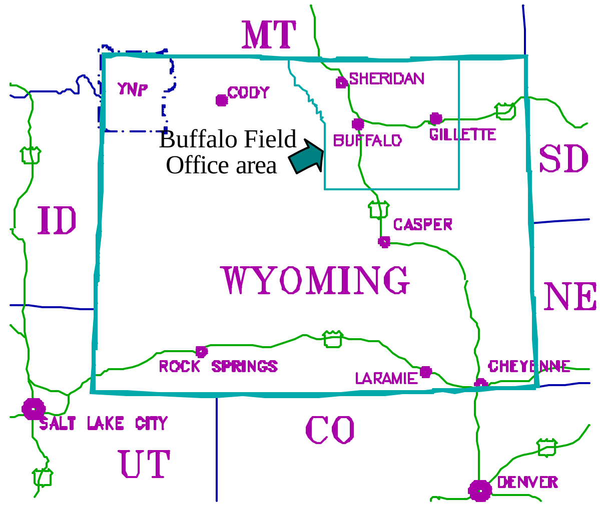
The BFOA is in northeast Wyoming (map 1). Most of the BFOA is in the Powder River Basin (PRB). Fifteen oil and gas plays have been identified in the BFOA and summarized by the U.S. Geological Survey (Dolton 1990). The coalbed methane (CBM) play covers the central part of the BFOA and is currently one of the most active gas plays in the country. An oil and/or gas play is an area, geologic formation, or geologic trend which has good potential for oil and/or gas development or is generating a large amount of interest in leasing and drilling.

Federal oil and gas leasing from 2000 to 2010 is estimated to average between 100,000 and 500,000 acres per year. Average bids are estimated between $10 to $50 per acre. In the BFOA, from February 1990 to August 1999, $83 million have been received by the BLM for federal oil and gas lease bonuses. The estimated amount that can be directly attributed to CBM is $51 million.

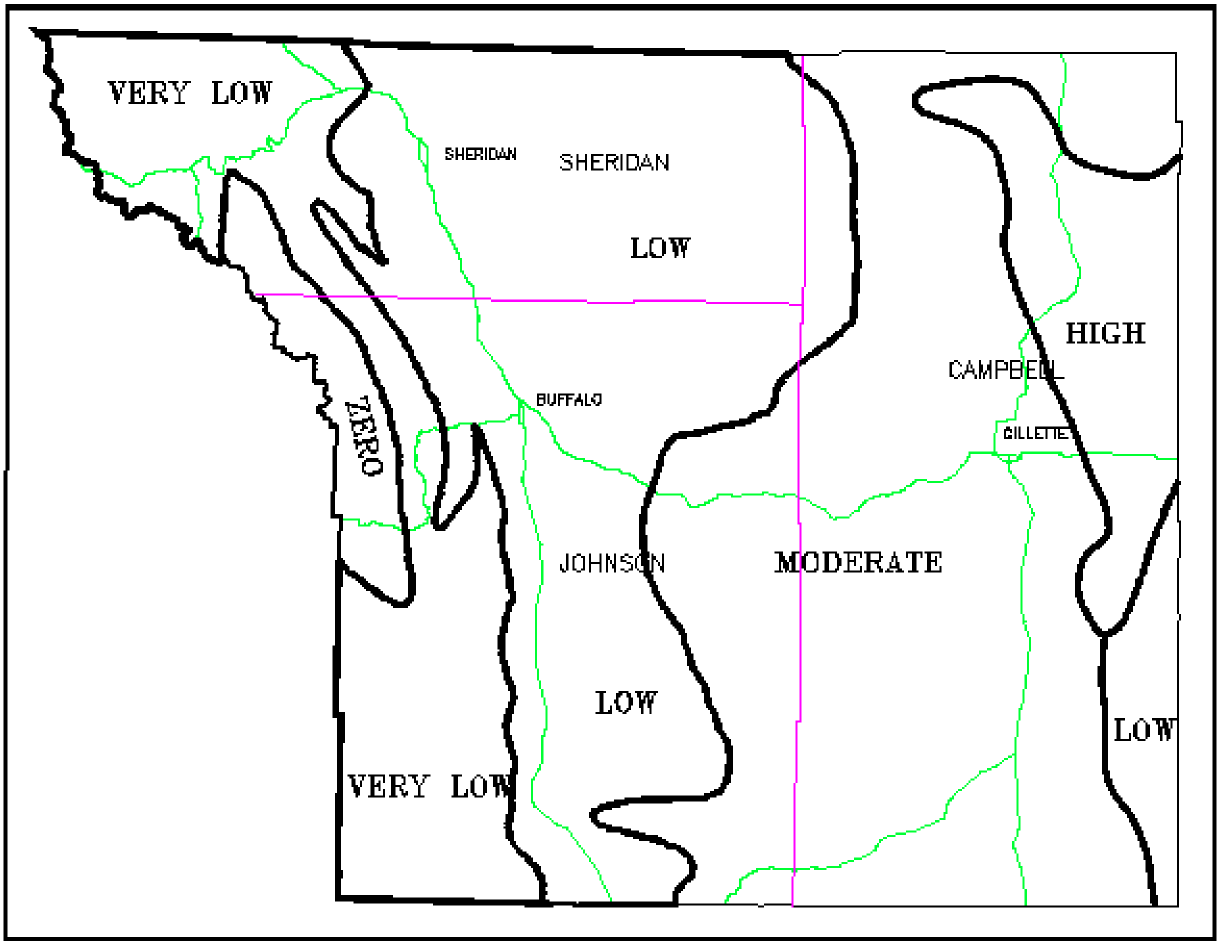
Seismic activity on BLM-administered public surface will probably average fewer than 10 surveys per year from 2000 to 2010. Most will be three-dimensional (3D) surveys rather than 2D, and most will continue to occur in Campbell County.

From 2000 to 2010 federal nonCBM wells are expected to average between 25 and 110 per year but could be as high as 150 per year. The location of anticipated drilling activity is shown on map 2. During the next ten years new nonCBM field discoveries will probably average between five and ten per year with average field size being two to five wells.

Oil production in 1998 was 17 million barrels per year in the BFOA. Although oil production may show minor year-to-year increases, overall it is anticipated to decline an estimated 5% per year during the next ten years, unless a major oil play develops, or prices increase substantially. Oil production from federal leases will continue to be about 50% of total oil production.



Map 1: Buffalo Field Office Area Location



Map 2: Oil and gas development potential map for nonCBM wells in the BFOA.

Development potentials are based on estimated average drilling density and are defined as:

***HIGH*--**over 1 wells/township/year;

***MODERATE*--**0.1 to 1.0 wells/township/year;

***LOW*--**less than 0.1 well/township/year;

***VERY LOW*--**less than 0.02 well/township/year;

***ZERO*--**no drilling.

Gas production in the BFOA, including CBM, has increased from 1.7 billion cubic feet of gas (bcfg) per month in January 1995 to 5.1 bcfg/month in April 1999. This increase is from expanding CBM production and is expected to continue during the next two to five years. Gas production will probably be more or less steady for a few years before starting to decline. Excluding CBM, gas production has declined from 3.4 bcfg/month in January 1986 to 1.3 bcfg/month in January 1999. Although there may be a few year-to-year increases, this decline in nonCBM gas is expected to continue from 2000 to 2010.

Currently there are about 1,282 productive federal nonCBM oil and gas wells in the BFOA. Although the number of producing oil wells may increase slightly year-to-year it will almost certainly decline over the next 10 years. During the next 10 years the number of federal nonCBM wells abandoned will exceed the number of federal nonCBM wells drilled.

Coalbed Methane Summary

CBM gas production increased from 0.28 bcfg/month in January 1995 to 4.57 bcfg/month in June 1999, an average annual increase of 62%. During June 1999, 14 million barrels of water (1,800 acre-feet) were produced. Since February 1996 approximately $51 million have been received in federal lease bonuses because of CBM development.

Based on data from published CBM resource estimates (which will probably be revised upward), as many as 70,000 productive CBM wells may ultimately be drilled with as many as 35,000 being drilled by 2010.

CBM drilling and production estimates require accurate estimates of the resource. CBM resource estimates are based on coal gas content measurements, in standard cubic feet per ton of coal and coal thicknesses and tonnages per given area. In the past, there were no accurate figures available for any of these quantities. Only limited coal gas content measurements were available, which were all obtained using procedures that have been shown to be inadequate. The only coal thicknesses and tonnages available were outdated and based on limited data. As a result, CBM resource estimates made by both BLM and the mineral industry have been markedly inaccurate. Planning and National Environmental Policy Act (NEPA) analyses prepared on the basis of these estimates have failed, by a wide margin, to anticipate the pace and extent of CBM development. The deficiencies in data and resource estimates are discussed in greater detail later in this appendix.

Federal and private efforts to obtain more accurate, publicly available data are underway. The 1999 Coal Resource Assessment prepared by the U. S. Geological Survey (USGS 1999) provides comprehensive and updated mapping and stratigraphy of the Fort Union Formation and individual coal seams, and contains detailed coal resource estimates based on updated current data. In early 1999, BLM and USGS began a cooperative project to collect gas content measurements and other CBM data, using current industry standard procedures, from coal cores donated by participating CBM operators. These data will support more accurate gas-in-place estimates, allowing future planning and environmental analyses to more accurately predict CBM drilling and production.

INTRODUCTION

Impacts caused by oil and gas development, and impacts to oil and gas development cannot be assessed without estimating future oil and gas activity. Oil and gas development activity is subdivided into leasing, seismic, drilling, and production, with a separate estimate for each.

This scenario presents an estimate of future activity within the BFOA, under the existing BLM resource management plan (the current land use plan), unless otherwise noted. It is assumed that all public domain and acquired minerals in the BFOA will be available for leasing and development without excessive restrictions except for the following areas:

1. Wilderness and wilderness study areas (WSAs) (only the Fortification Creek WSA, 12,419 acres mostly in T. 52 N., R. 72 W., has high oil and gas occurrence potential);

2. Selected areas within federally approved coal mine plans; and,

3. Wyoming Game and Fish Department's (WGFD) big game winter ranges adjacent to the Bighorn National Forest.

Present and future oil and gas development in the BFOA is primarily based on three factors:

1. Crude oil and natural gas prices (figures 1 and 2) and anticipated price changes;

2. Development of new plays, such as horizontal drilling in the Niobrara Formation or CBM development, or renewed interest in old plays; and,

3. Advances in and application of technology such as secondary and enhanced oil recovery, and 3-D seismic surveys.

These factors are cannot be predicted with certainty, but some generalizations are possible. The estimates presented here are based on past trends and anticipated future price increases.

Oil and Gas Prices

The average annual change in oil prices for the lower 48 states was estimated to range between -1.3% and +1.5% from 1996 to 2020 by the Energy Information Administration (1998); their best guess is 0.4% per year increase from 1996 levels (figure 2). Average US petroleum consumption is estimated to increase 18% to 46% from 1996 to 2020. Petroleum consumption as a percent of US energy consumption is expected to increase from 38% today, to 40% by 2020 (Energy Information Agency, 1998).

The average annual change in gas prices is projected to be between -0.7% and 1.2% from

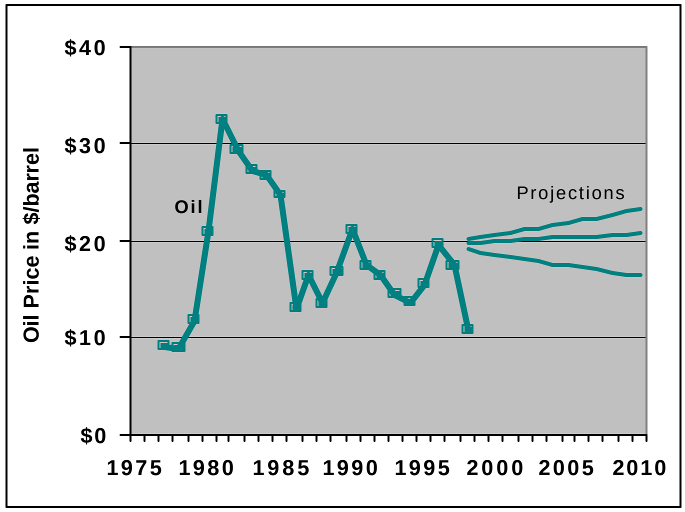


Figure 1: Historic Oil Prices and Projections. Oil prices are from *Wyoming GeoNotes.* Projections are from Energy Information Administration.

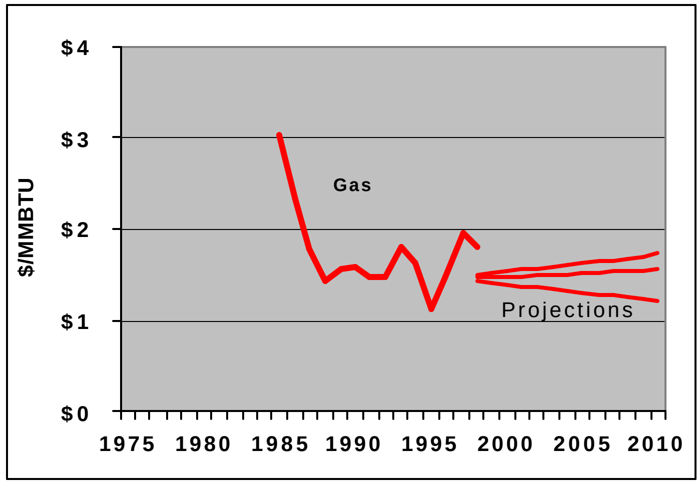


Figure 2: Historic Gas Prices and Projections. Gas prices are from *Wyoming GeoNotes.* Projections are from Energy Information Administration.

1996 to 2020, with the best guess case being 0.5%. Figure 2 shows this projection.

Oil and Gas Plays

There were 15 oil and gas plays identified in the BFOA and described by Dolton, et al. (1990). An oil and gas play is an area where a geologic formation contains oil and/or gas deposits. These plays are summarized in table 1. Nearly all the oil produced from fields within the BFOA is from these plays. The percentages in table 1 were measured from the maps in Dolton et al (1990). The amount of undiscovered oil and gas remaining in the BFOA cannot be estimated from the information in table 1. For example, because of geologic hererogenity, uneven distribution of resources, and reservoir size variations, it cannot be assumed that if 20% of a play area is within the BFOA or that approximately 20% of the estimated undiscovered reserves are also within the BFOA. Two plays not mentioned by Dolton et al (1990) are the coalbed methane gas play and the Niobrara Formation fractured shale play.

Coalbed Methane

During deposition and compaction of the organic material which ultimately becomes coal, large quantities of methane gas are generated. Methane gas produced from coal has a lower energy (Btu) content than other natural gas produced in the BFOA. Methane molecules are trapped by adsorption in the coal micro pores and porosity.

The BFOA contains some of the largest coal deposits in the country. The most extensive coal beds are in the Paleocene age Tongue River member of the Fort Union Formation in Wyoming.

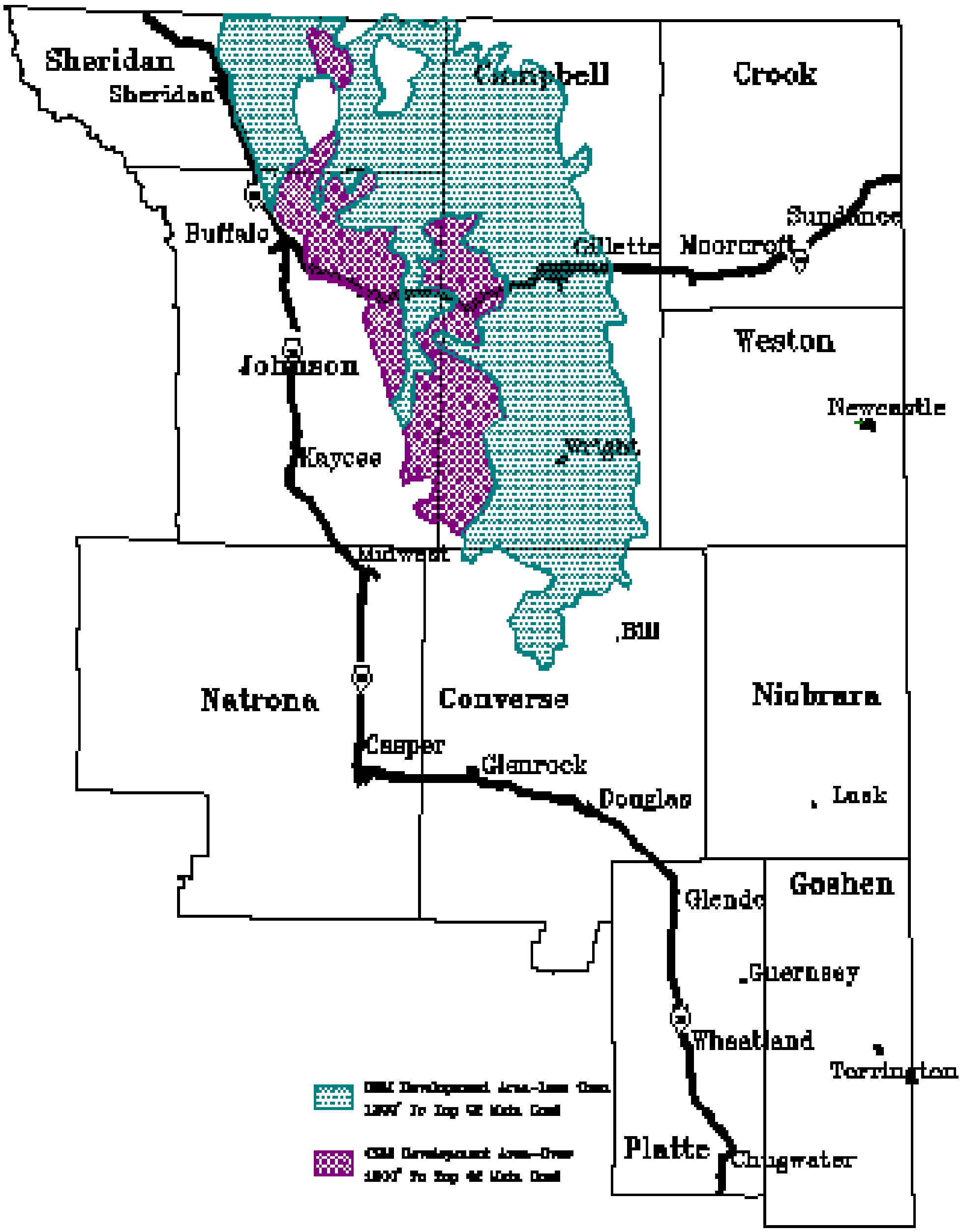
The approximate area of potential CBM development can be defined based on depth to coal and coal thickness (map 3). The CBM play in the BFOA was one of the most active gas plays in the country in 1998 and 1999. Initially wells were less than 500 feet deep and concentrated just west of coal mines on the east side of the play area. Over time well depths have increased; many wells currently being drilled are more than 1,000 feet deep. To develop the deepest coals in the Tongue River member, wells may need to be drilled as deep as 3,000 feet.

In October 1999 there were over 1,230 producing and 900 shut-in CBM wells. CBM production for October 1999 was 5.8 bcfg. CBM production in the BFOA has increased an average 62% per year during the past five years (figure 3). Production was limited by pipeline capacity until late 1999 when two trunk lines into the PRB were completed. These new pipelines increased capacity several-fold. Based on Wyoming Oil and Gas Conservation Commission (WOGCC) data cumulative coalbed methane production through October 1999 was 110 bcfg.

Coalbed methane resource estimates by the Potential Gas Committee (PGC; 1998) ranged from 4,664 to 15,859 bcfg (best guess is 9,329 bcfg) for CBM resources in the

Table 1 Summary of all the oil and gas plays evaluated by Dolton et. al (1990). The reader is cautioned from estimating undiscovered reserves in the BFOA based on this table.

Oil and Gas Play	Total Play Area	Play Area in BFOA	Play Area in BFOA (%)	BFOA in Play Area (%)	No. of Fields	Estimated Reserves MMBO	Estimated Reserves BCFG	Remarks
Basin Margin Anticline	8.12	1.37	16.9	18.6	5	24	21	Exploration nearing conclusion; future discoveries probably in small subtle traps.
Basin Margin Subthrust	2.12	0.54	25.5	7.3	NA	NA	NA	Geologic data limited; accurate prediction of future reserves or field sizes not possible.
Dakota	18.63	0.77	4.1	10.5	21	158	158	
Deep Frontier	5.47	0.85	15.6	11.6	6	37	100	
Lakota	21.21	4.06	19.2	55.2	NA	NA	NA	Undiscovered fields are probably small.
Leo	8.05	0.30	3.7	4.0	60	110	30	
Mesaverde & Lewis (stratigraphic)	7.99	3.41	42.7	46.3	10	66	91	
Minnelusa (total)	17.01	3.22	18.9	43.7	165	822	203	In explored area, most discoveries will be fields with 3MMBO or less. In unexplored area, field size will be similar to explored area.
Minnelusa (explored area)	NA	NA	NA	NA	26	48	10	
Minnelusa (unexplored area)	NA	NA	NA	NA	139	775	194	
Minnelusa (less prospective)	4.93	0.00	0.0	0.0	NA	NA	NA	
Mowry Shale	11.63	3.96	34.1	53.9	NA	NA	NA	Lightly explored; possible large nonconventional resource.
Muddy (total)	21.25	4.04	19.0	55.0	39	441	1298	
Muddy (explored area, shallow)	NA	NA	NA	NA	10	60	82	
Muddy (unexplored area, deep)	NA	NA	NA	NA	30	381	1216	
Shannon marine shelf	8.40	4.07	48.4%	55.3	20	128	103	Sx & Sh combined
Sussex marine shelf	10.77	3.46	32.1%	47.0	(combined w/Shannon)			



Map 3: Approximate CBM Development Area. The boundary is based on depth to top of coal, thickness of thickest coal, CBM well locations, and federal oil and gas lease sale results.

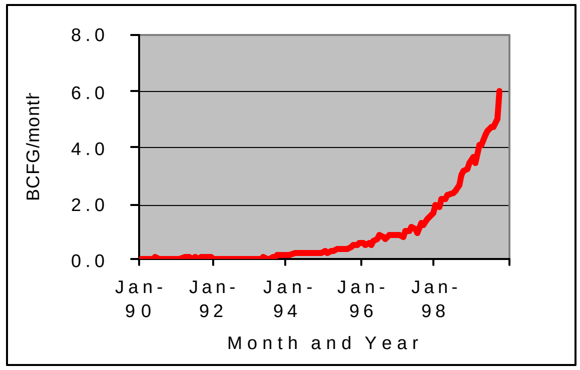


Figure 3: Coalbed Methane Production in the BFOA.

Powder River Basin. These estimates are based on reasonable gas price scenarios. The USGS also estimated the coalbed methane resources in the PRB. The estimate is several years old and was made before the play began rapid and extensive expansion. The USGS estimates appear to be too low and were not used in this analysis.
Figure 4 displays the drilling history in the BFOA from 1990 to1998. There was a general decline in the number of wells drilled through 1994 then an abrupt increase due to CBM drilling. As shown in figure 4, most drilling activity was in the Minnelusa play until 1994.

Niobrara Formation

Economic development of the Niobrara Formation fractured shale play will almost certainly depend on successful application of horizontal well technology. This play is currently in its infancy and is somewhat hypothetical. Undiscovered reserves cannot be predicted with reasonable certainty, except that the potential recovery may be as large as several million barrels of oil and associated natural gas. Although horizontal wells were used to develop oil and gas reserves in fractured shale reservoirs in southeast Wyoming, overall results have been disappointing in the PRB. Unless there are a few economic wells drilled, it is unlikely that this play will have significant development in the foreseeable future.

Oil and Gas Occurrence Potential

Projection of future oil and gas activity must first consider where oil and gas resources might occur. To do this an oil and gas occurrence potential map was constructed (map 4). The oil and gas occurrence potential was classified as high, moderate, low, or none. These classifications are based on geology, data from oil and gas test wells, and the play areas described by Dolton, et al. (1990). The *Geologic Map of Wyoming* (Love and Christiansen 1984) and the *Structure Contour Map of the Powder River Basin and* Casper Arch, Wyoming and Montana (Petroleum Information 1987) were also used extensively. Map 4 was drawn to show the occurrence potential of oil and gas and does not indicate whether these resources can be developed economically. Definitions of the occurrence potential classifications are given on map 4. Note that most of the BFOA has high occurrence potential.

LEASING

After initial field work, research, and subsurface mapping (which sometimes 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.

By statute, leases on lands where the US owns the oil and gas rights are offered via oral auction at least quarterly. Lands offered for lease are listed by legal subdivision (usually quarter-quarter section) and combined into parcels. The maximum lease size is 2,560 federal acres. The minimum bid for a federal oil and gas lease is $2.00 per acre. An administrative fee of $75.00 per parcel is also required. Each successful bidder must meet citizenship and legal requirements. Leases have ten-year terms and a 12.5% royalty

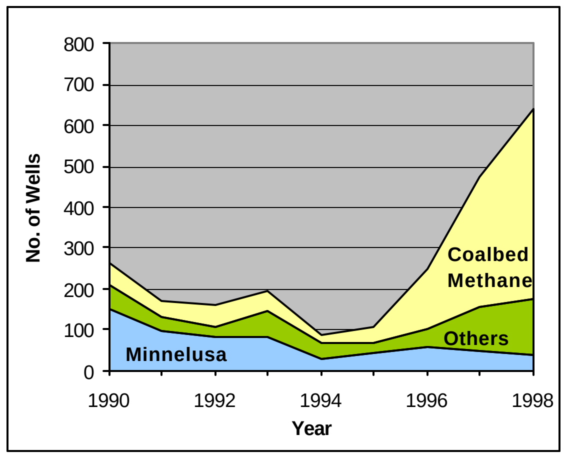
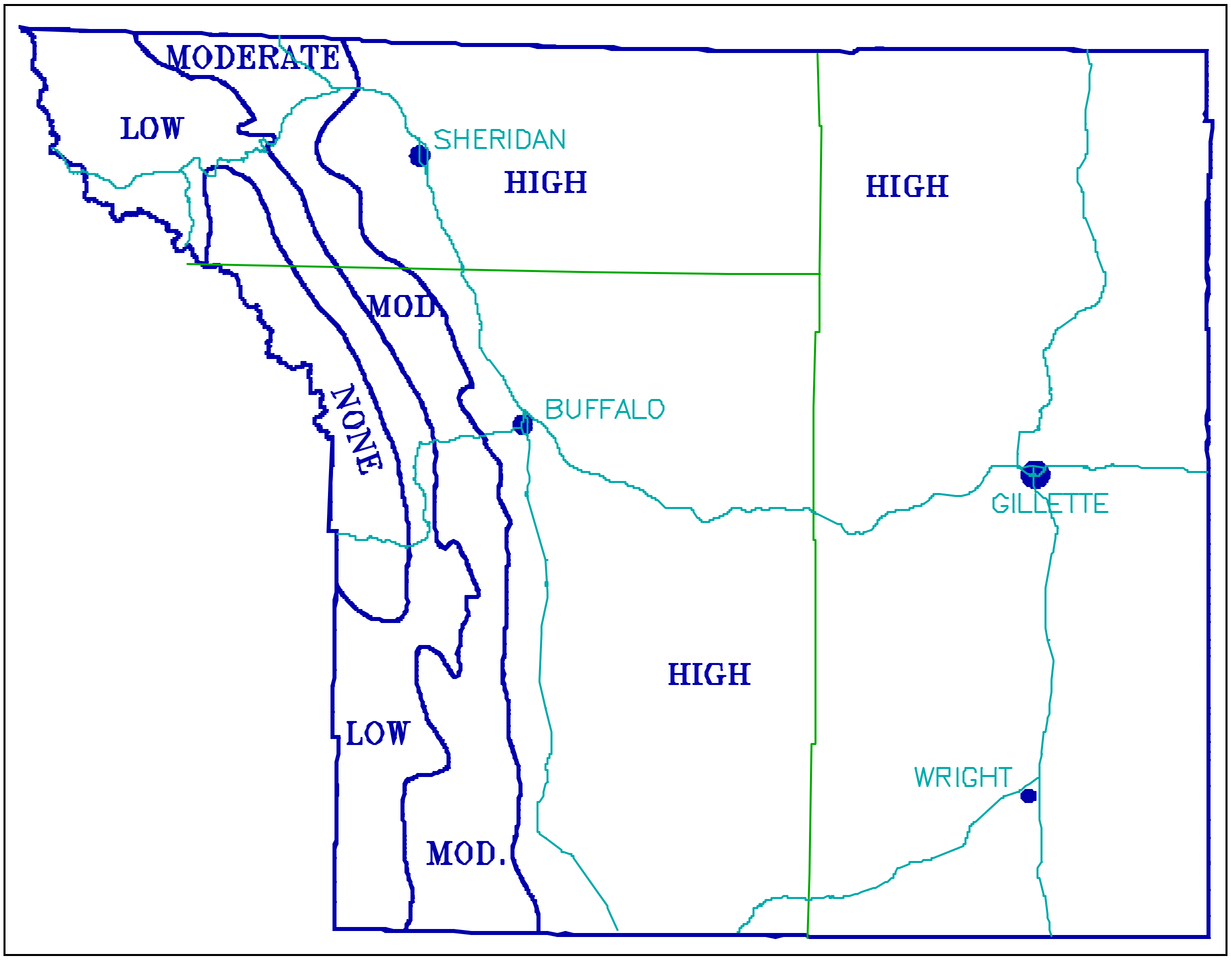


Figure 4: Wells Drilled in the BFOA From 1990 to 1998. Most wells listed as “others” were drilled to the Shannon or Sussex sandstones. Data are from PI/Dwights.



Map 4: Oil and Gas Occurrence Potential Map. Definitions of occurrence potentials follow.

HIGH**--**There is a demonstrated existence of petroleum source, reservoir quality strata, and traps. Areas of high potential have discovered oil occurrences or free oil recovery from well tests.

MODERATE--There is direct or indirect geological evidence that petroleum source, reservoir quality strata, and trapping mechanisms are present. Discovered occurrences are not present but there may be shows of oil in core or drill stem tests.

LOW--There is geological evidence that a petroleum source, reservoir quality strata, or trapping mechanisms are not present.

NONE--There is a demonstrated absence of a petroleum source, reservoir quality strata, or trapping mechanisms. Demonstrated absence means physical evidence documented in geological literature.

rate. Leases sold competitively before December 1992 had five-year terms. Leases which become productive are held by production and do not terminate until all wells on the lease have ceased production. Many private oil and gas leases contain a Pugh clause, which allows only the developed portion of the lease to be held by production. However, federal leases have no such clause, allowing one well to hold an entire lease.

In Wyoming, federal oil and gas lease sales are held on even numbered months (except for April 1996), usually in Cheyenne. Parcels usually contain 40 to 2,000 acres. Parcel lists are available about six weeks before the sale date. Since August 1996, only lands requested for lease are offered. Before August 1996 virtually all federal lands available for lease were offered. Federal oil and gas leases contain restrictive stipulations which protect other resource values.

The number of federal acres in the BFOA offered for lease, and leased, on a sale-by-sale basis is shown in figure 5. Note the abrupt increase in acreage leased during the June-December 1998 lease sales; a result of interest in CBM. The additional acreage was mostly in Johnson and Sheridan counties. Total bonus bids for each sale and the average per-acre bid for federal oil and gas leases in the BFOA on a sale-by-sale basis are shown in figure 6. Note the steady decline in average per-acre bid prices until December 1995. The increase in bids starting in December 1995 and the substantial increase starting in August 1997, are due almost entirely to increased interest in CBM. Since December 1998 the amount of acreage and bonus money received has dropped substantially. This is probably because nearly all available federal acreage is under lease. During 1997 and 1998, 675 leases were sold competitively; the average lease size was 1,004 acres; and, 81 of the leases were more than 2,000 acres in size.

From February 1990 through August 1999 approximately $83 million in federal oil and gas lease bonuses was received by the BLM for land in the BFOA. An estimated $51 million was a direct result of leasing for CBM. Maps 5 and 6 are contour maps of average dollar-per-acre bids compiled on a township-by-township basis. These maps compare federal oil and gas leasing in 1995 and 1998. Note that most of the leasing activity was in the BFOA. Sale-by-sale results of federal oil and gas leasing is shown in figure 6.

The amount of federal oil and gas acreage under lease in the BFOA each year from 1985 through 1993 ranged from 2.3 to 3.4 million acres. From 1988 through 1995, the amount of acreage leased annually in the BFOA decreased from 301,000 acres to 143,000 acres. In June 1999, 2.63 million acres of federal oil and gas were under lease in the BFOA. During 1998, 660,608 acres were leased competitively in the BFOA. As shown in figures 5 and 6 this amount of acreage is unusually high. The lease results on maps 5 and 6 were compiled on a township-by-township basis. These maps show the dramatic change in leasing in the CBM play area.

Although federal leasing increased sharply in 1998, and federal leases do not contain a Pugh clause, the amount or federal oil and gas acreage under lease will probably not

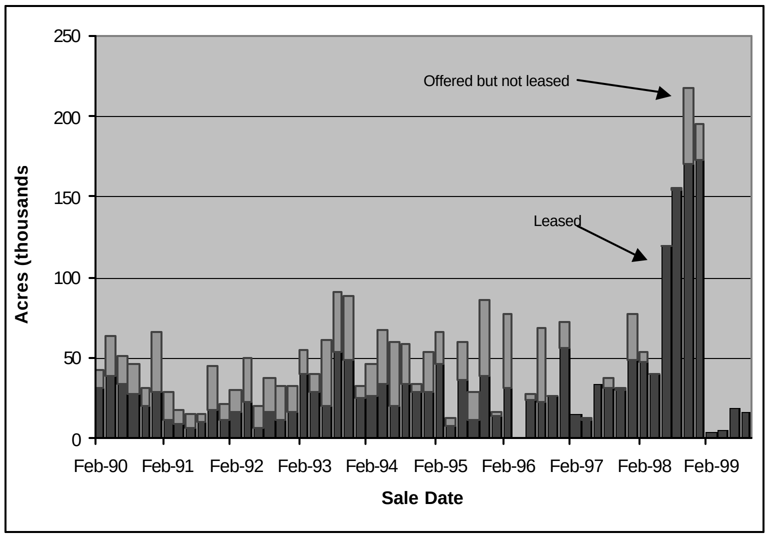


Figure 5: Federal Oil and Gas Lease Sale Results for BFOA.

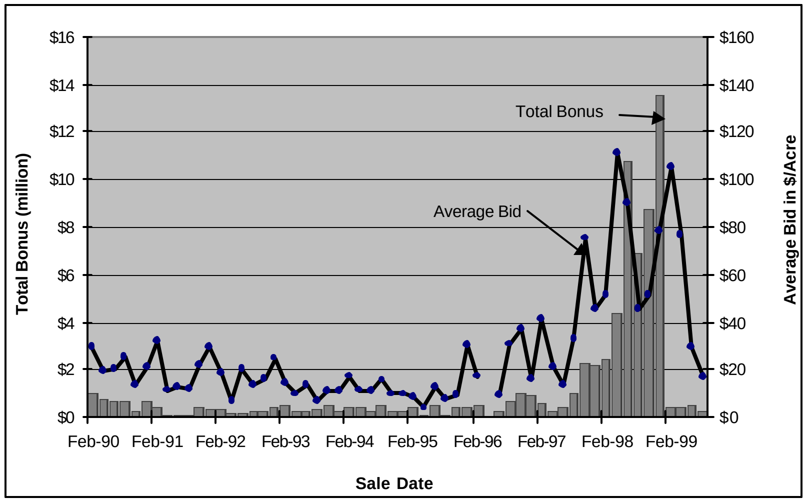
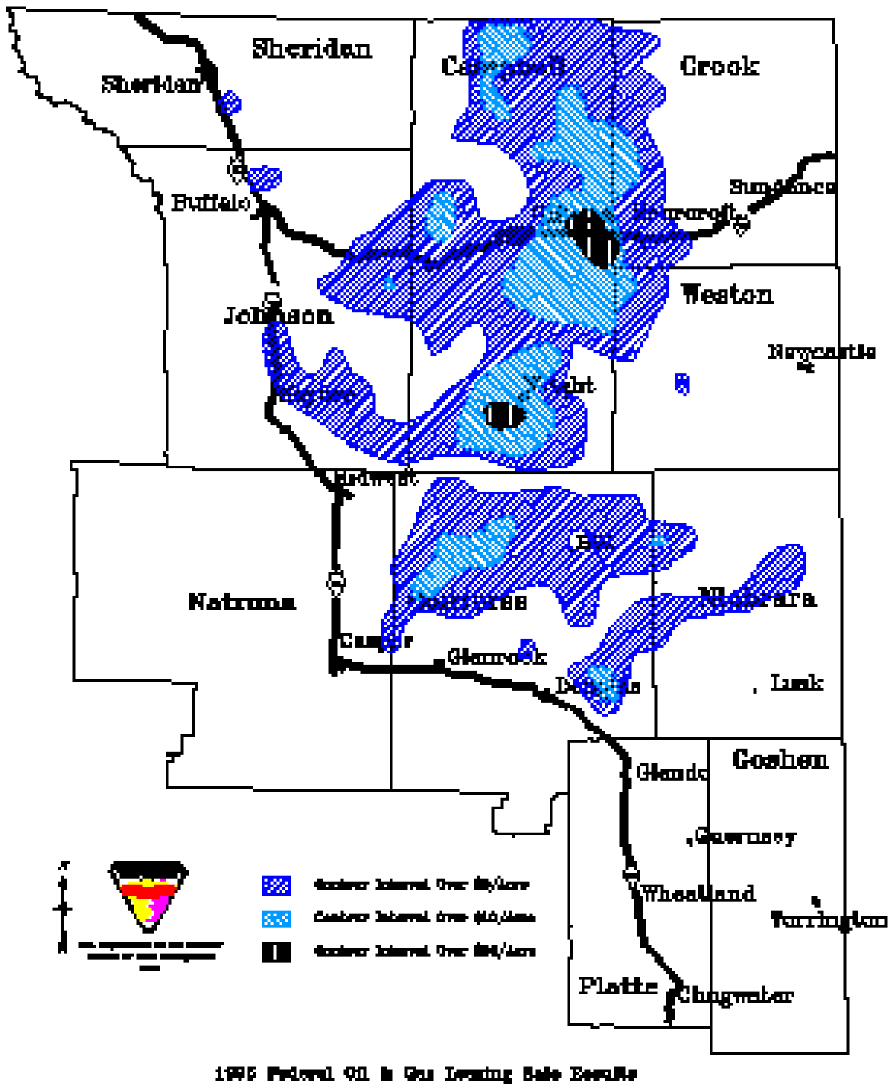
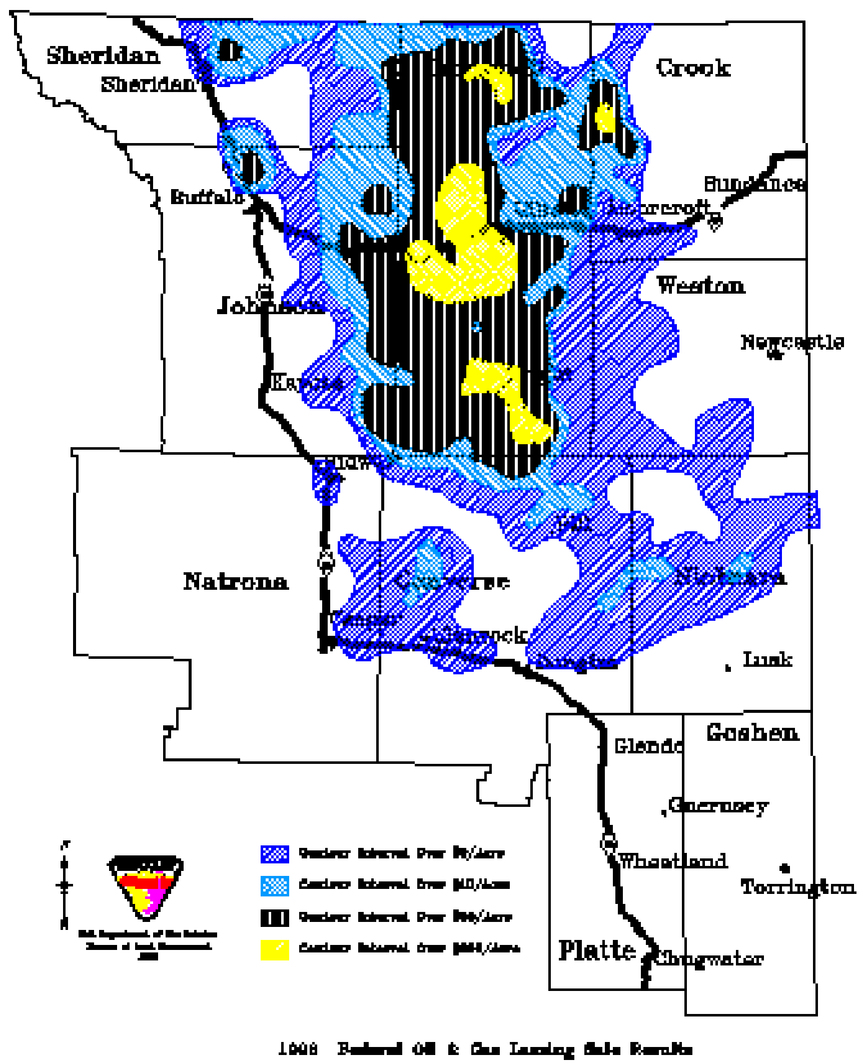


Figure 6: Federal Oil and Gas Lease Sale Results for Acreage in the BFOA.



Map 5: Average Dollar-per-acre Bids from 1995 Federal Oil and Gas Lease Sales. Data were compiled on a township-by-township basis from federal lease sale results. Contour intervals are $2.00, $10.00, $50.00 per acre.



Map 6: Average Dollar-per-acre Bids from 1998 Federal Oil and Gas Lease Sales. Data were compiled on a township-by-township basis. Contour intervals are $2.00, $10.00, $50.00, $200.00 per acre.

decrease substantially after the primary lease term (10 years) is reached. Many of the federal leases in the CBM play area are very large (more than 1,000 acres), and the entire lease will be held by production until the last well ceases production. For most leases this will be many years beyond the primary term. Because many leases will be held by production it will be more difficult for individuals to acquire adequate acreage for drilling deals to drill the deeper horizons. This will probably suppress development of the deeper oil and gas horizons in the CBM play area. The amount of federal oil and gas acreage under lease during the next five to ten years is projected to be between 1.5 and 3.0 million acres. The amount of federal oil and gas acreage leased annually during the next five to ten years is projected to average between 100,00 and 500,000 acres. Average bids on a sale-by-sale basis are estimated to be between $10 and $50 per acre. Because a large amount of federal acreage has been leased in the past two years the amount leased during the next several years will probably be less than the 1990 through 1998 average.

A long-term price increase for oil or a new play could change the picture substantially. If prices increase or if a new play develops, the amount of acreage leased, average per acre bids, and total acreage under lease would increase. Likewise if anticipated price and play developments are more negative than anticipated these acreage and dollar numbers will be less.

SEISMIC SURVEYS

Seismic surveys on BLM-administered public surface are authorized by approval of Notices of Intent to Conduct Geophysical Operations (NOIs). From 1984 through 1998 the number of NOIs approved by the BFOA manager has decreased substantially (figure 7). These NOIs are for BLM-administered surface only. Until a sustained oil price in excess of $30.00 per barrel occurs the number of NOIs will probably remain low. However, it is questionable whether a significant increase NOIs would occur even with an increase in oil price because of the extensive seismic coverage over most of the BFOA. Much of this data could probably be reprocessed instead of collecting new seismic data.

During the past several years there has been increasing interest in 3-D seismic surveys. Although these surveys are more expensive than conventional 2-D seismic surveys, they provide a three-dimensional picture of the subsurface. Most 3-D surveys have been over or near oil fields in eastern Campbell County where there is little BLM-managed surface. However, the success of 3-D seismic surveys probably will increase the number of NOIs in the BFOA to more than about 15 per year. Seismic data is not generally used in the CBM play; therefore, activity in this play is not expected to increase the number of NOIs in the BFOA.

In summary, during the next ten years NOIs will probably average 15 or fewer per year. Most of the seismic activity will probably be in Campbell County. It is unlikely that the number of NOIs will increase significantly unless nonCBM oil and gas activity in western Campbell, or eastern or southern Johnson counties increases substantially; however, this is not considered likely.

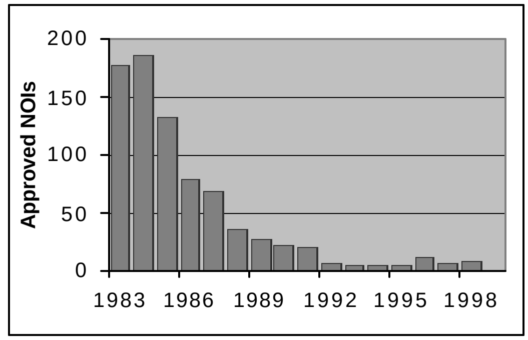


Figure 7: Approved NOIs to Conduct Geophysical Operations on BLM-administered Public Surface.

DRILLING OPERATIONS

Before a federal oil or gas well is drilled, an application to drill (APD) must be approved by the BLM. Figure 8 shows the total and federal APDs from 1985 to 1999. During this time period, there were 1,397 federal and 2,851 total APDs approved. Approximately 50% of total APDs were federal; approximately 80% of the approved APDs were drilled.

Historical data indicate there is a direct, but imprecise, correlation between the number of approved nonCBM APDs in the BFOA and oil price. Although not shown here, this correlation seems to indicate that a sharp increase in APDs and wells should not be expected until oil prices are $25 to $30 per barrel for a sustained time period.

Based on historical precedents, it is estimated that during the next five to ten years the annual average number of nonCBM APDs will range between 100 and 300, and possibly be as high as 400 although this is not likely unless oil prices increase to $25 to $30 per barrel for at least a few years. The number of federal APDs will probably average about 50% of total APDs. Federal APDs will probably average between 30 and 150 annually.

The number of wells drilled to develop CBM has greatly exceeded the number of all other wells since 1996. This trend will almost certainly continue during the next five to ten years. As many as 70,000 productive CBM wells may eventually be drilled with as many as 35,000 drilled by 2010.

General areas of anticipated development activity in the BFOA are shown on map 2. This map was drawn based on past drilling locations, the oil and gas plays outlined by Dolton, et al. (1990), Glaser (1992), federal oil and gas lease sale results, and a general knowledge of Powder River Basin geology. This map shows the general areas of anticipated drilling activity, exclusive of CBM, during the next five to ten years.
Discovery of new oil and gas fields is a virtual certainty. The number and size of new fields that will be discovered is difficult to predict with a high degree of confidence; however, some estimates are possible. As figure 9 shows the number of new oil and gas fields discovered has been somewhat erratic but trends upward until the 1981 through1985 interval then trends downward. The number of new field discoveries may have peaked in the mid-1980s and is now trending downward. Most of the new fields discovered during the next several years will be CBM fields.

The size of new field discoveries as measured by the number of wells producing in 1997 shows a distinct downward trend over time (figure 9). This trend suggests that newly discovered nonCBM fields will average less than ten productive wells per field. About 20% of the nonCBM fields discovered since 1980 are one well fields that will produce less than 30,000 barrels of oil and are probably uneconomic. Many of the fields discovered since the mid-1980s are productive from the Minnelusa Formation. These fields typically have fewer than ten productive wells but usually have relatively high oil recoveries on a per-well basis.

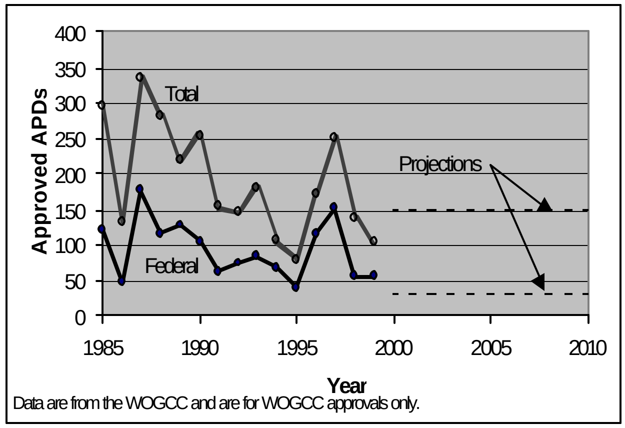


Figure 8: Approved nonCBM APDs and Projections Through 2010.

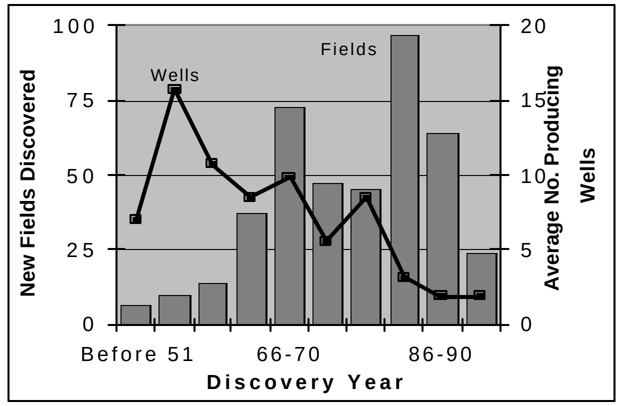


Figure 9: New Oil and Gas Fields Discovered and Average Number of Producing Wells (in 1997) per Field. SOURCE: WOGCC.

Historical president indicates the number of new, nonCBM field discoveries should average between two and ten annually over the next ten years. Average field size of new discoveries will probably be fewer than ten productive wells per field. Between 1981 and 1990 an average of 16 nonCBM, oil and gas fields were discovered annually in the BFOA. It is unlikely this pace of new field discoveries will occur again.

These well, discovery, and field size estimates are based on past activity and may be less than what actually happens if price and play developments are more positive than anticipated. If exploration in existing plays is disappointing, new plays are not developed, and commodity prices are less than anticipated, these estimates may be optimistic.

Coalbed Methane Wells

CBM development is currently undergoing a “boom” in the BFOA. Figure 10 shows the number of approved CBM APDs. Note the ten-fold increase since 1995. This “boom” will almost certainly continue for a few more years, with the eastern side of the CBM development area (map 3) being established first. Because the western part of the CBM area contains a larger amount of federal mineral acreage than the eastern part of the

CBM play area, delays in approving federal APDs may slow development in the western part of the area.

Based on maximum CBM resources (15,859 bcfg) estimated by the PGC (1998), and an average recovery of 0.20 bcfg per well a total of as many as 70,000 CBM wells could be drilled during the life of the play. Based on reasonable estimates for well completion rates as many as 35,000 productive wells may be drilled by 2010. These estimates may be revised upward if estimates of recoverable resources are revised upward as new and better data become available. Figure 11 shows one possible scenario for wells drilled annually and productive wells in the BFOA. It must be remembered these are estimates based on very incomplete data.

Most CBM drilling will be confined to the main CBM development area (map 2). However, some CBM development outside this area should be expected.

Figure 12 shows the estimated number of active drill rigs that would be required to drill the wells shown in figure 11. The assumptions used to calculate figure 12 are listed below.

Figures 11 and 12 were calculated from PGC report (1998) estimates and a series of technical assumptions. That report estimated the amount of CBM present “. . . not subject to the assumptions of the time of development of the resource, life span of the natural gas industry, or specific price to be paid for the produced gas” (Potential Gas Committee 1998; p. 161). In other words, the amount of recoverable CBM in the ground was estimated, not the amount that will be recovered during a specific time interval. The estimates in figure 12 are reasonable based on the currently available data, but will almost certainly change as better data become available. It is reasonable to expect between

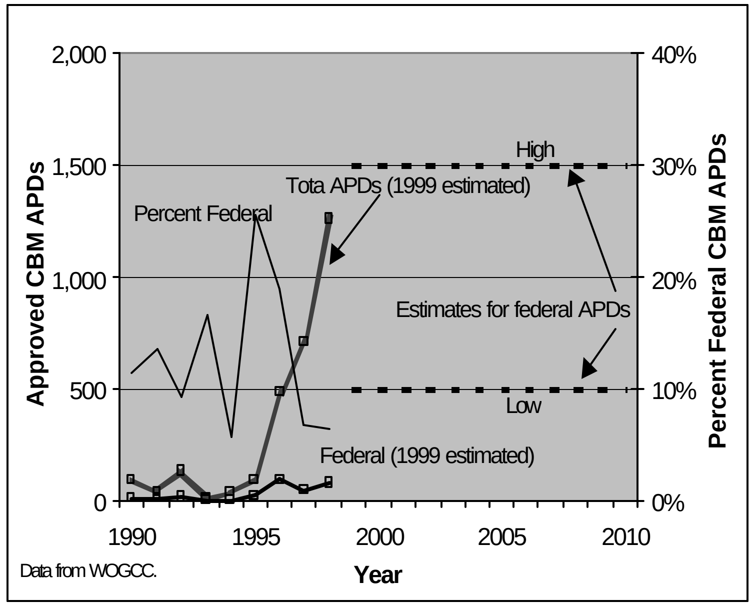


Figure 10: Total and Federal Approved APDs for CBM Wells in the BFOA.

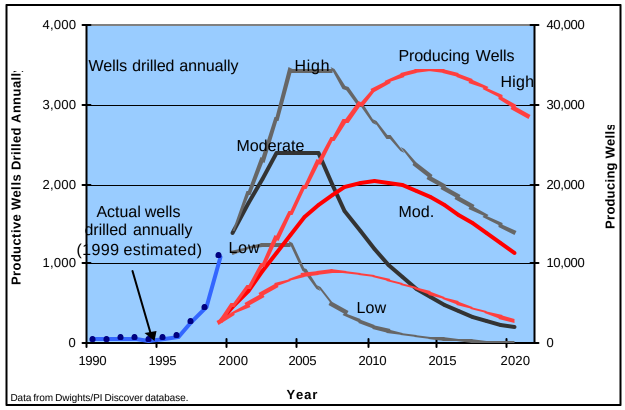


Figure 11: Possible Scenario for CBM Wells Drilled Annually and the Number of Producing CBM Wells. Projections are keyed to resource estimates by the Potential Gas Committee, 1998.

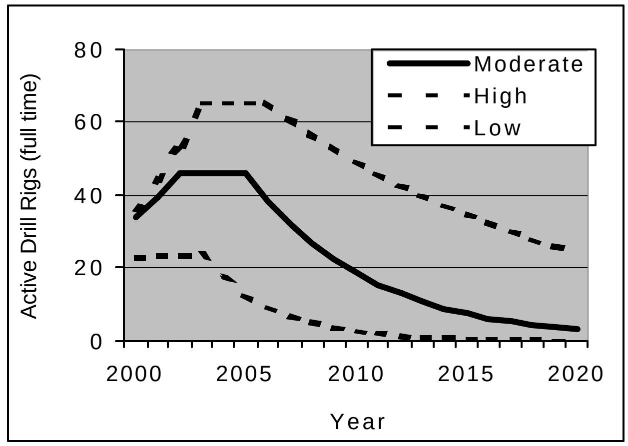


Figure 12: Estimates for Active Drill Rigs Required to Drill Wells.

9,000 and 33,000 additional productive wells will be drilled in the BFOA during the next ten years. These well estimates may be revised upward if resource estimates are revised upward. About 90% of the projected activity is expected to be in the BFOA.

Assumptions and methodology used are listed below.

1. Maximum wells were calculated by dividing assumed average per well recovery of 0.20 bcfg per well (minimum) into 15,859 bcfg (maximum PGC estimate).

2. Minimum wells were calculated by dividing assumed average per-well recovery of 0.40 bcfg/well (maximum) into 4,664 bcfg (minimum PGC estimate).

3. Completion rate for wells 0-1,100 feet deep is 61 wells/year/drill rig.

4. Completion rate for wells over 1,100 feet is 40 wells/year/drill rig.

5. Of the wells drilled, 30% will be deeper than 1,100 feet.

6. Estimated ultimate recoverable reserves are 15,859 bcfg maximum, 9,329 bcfg most likely, and 4.664 bcfg minimum.

7. Of the CBM reserves estimated by the PGC, 90% are in the BFOA.

8. Incline and decline rates for annual well completions were selected to generate ultimate well numbers which match the calculated well numbers for high, moderate, and low well estimates based on estimated ultimate reserves and assumed per-well recoveries.

9. Curves for annual wells drilled were calculated to approximately match the shape of the drilling history curve for the “D” and “J” sandstone play in western Nebraska.

10. Wells were assumed to be abandoned at the following rate: eight years-13%;, 13 years-50%; 18 years-80%; and, 23 years-100%.

CBM development forecasts for previous planning and environmental analyses in the Powder River Basin/BFOA have been impaired by a lack of adequate data, in particular by inaccurate estimates of gas-in-place. The primary method of measuring gas content in coals is by measuring gas desorption from core samples. It is now known that measurements obtained by early CBM development activities used procedures that allowed substantial errors to occur.

Recent research by the Gas Research Institute (Mavor and Nelson, 1997) documents a variety of errors that can affect estimates of in-situ gas content. The following primary errors were identified: use of drill cuttings rather than cores to estimate gas content resulting in errors of approximately -25%; conducting gas desorption measurements at ambient rather than reservoir temperatures resulting in errors of approximately -60 to 70%

in lost gas calculations and -30% in total gas calculations; and, use of incorrect average coal densities, resulting in errors of approximately -10 to 13%. The publicly available data from the early projects indicates that some of the desorptions were made from cuttings rather than cores, and that the core desorptions were conducted at ambient rather than reservoir temperatures. Density logs were generally collected; however, their uses cannot be determined from the records available.

Our current knowledge indicates that the early coal gas measurements, on which development forecasts and planning/environmental reviews were based, used procedures that were technically incorrect. The measurement errors that were made systematically underestimated the *in-situ* coal gas content. As a result, gas-in-place estimates inevitably underestimated CBM resource volumes, making accurate projections of drilling and production impossible. Until better data are obtained, we can only state with certainty that CBM resource estimates will increase and drilling and production will exceed expected levels. The magnitude of these increases cannot be determined with the data presently available. Given these uncertainties and previous experience with CBM development, it is probably prudent to plan for the higher levels of development, as shown in figure 13.

The BLM Reservoir Management Group/USGS cooperative coalbed methane project is currently collecting more accurate gas content data. Continuous cores of entire coal seam thicknesses are being desorbed using current industry standard practices, including desorption at reservoir temperatures and direct density measurements of coal core samples. When these data are available and analyzed, beginning in mid-to-late 2000, more accurate estimates of gas-in-place can be made and more reasonable development forecasts can be derived.

Horizontal Wells

Horizontal drilling results in the BFOA have been disappointing. If future attempts are successful in exploiting oil and gas reserves in the Niobrara or other formations, horizontal drilling in the BFOA could rise abruptly. Because of this uncertainty, estimates of horizontal wells drilled per-year range from two to ten or higher.

OIL AND GAS PRODUCTION

Oil and gas production from wells on federal, fee, and state minerals is shown in figures 14 and 15. Oil production from 1984 to1991 was relatively stable but has declined sharply since 1991. The decline averaged 8% per year from 1991 to1998. From 1990 to 1995 oil production from wells on federal minerals averaged 51% of the total oil production.

Oil production will probably continue to decline about five to eight percent per year unless large new discoveries are made, or there is a long term increase in oil prices. An oil price increase would stimulate the search for new deposits, allow old fields to be produced longer, and allow increased use of enhanced oil recovery (EOR) methods. If inexpensive carbon dioxide becomes available then EOR would also be more likely. It is however,

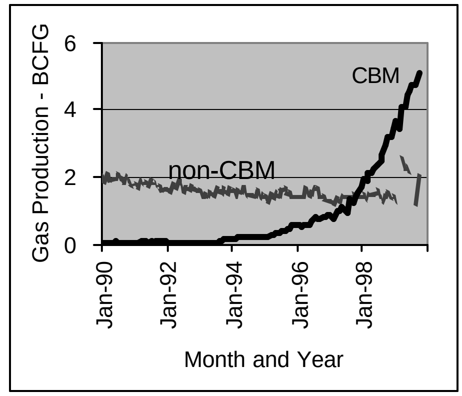


Figure 13: CBM and nonCBM gas production from BFOA. SOURCE: WOGCC and Dwights/PI.

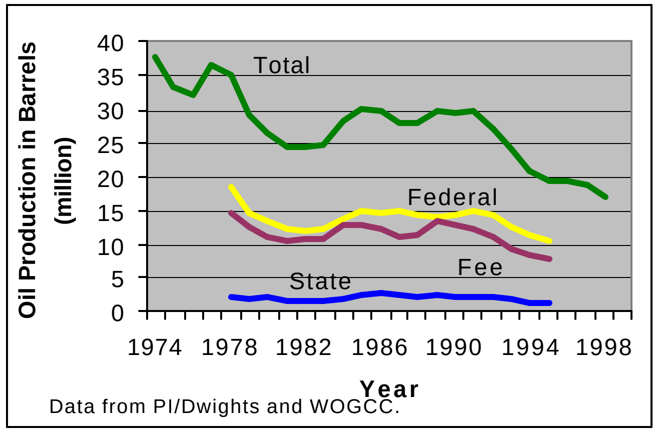


Figure 14: ***Oil Production*** **from Federal, Fee, and State Wells in the BFOA.**

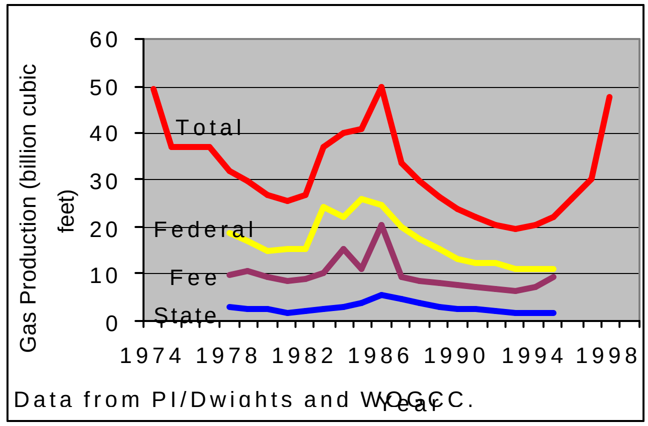


Figure 15: ***Gas Production*** **from Federal, Fee, and State Wells in the BFOA.** The abrupt increase since 1996 is caused by CBM production.

unlikely that annual oil production will again reach 30 mmb.

Gas production has been much more erratic (figure 15). Total gas production declined 53% from 1987 to1994. In 1994 CBM was only 12% of total gas production in the BFOA. The gas production decline was reversed in 1995 due to increasing CBM production. Total gas production increased 21% per year since 1994. This trend is expected to continue.

Total gas production will increase substantially over the next three years due to CBM development. CBM production from federal leases will increase at a faster rate than total CBM production.

Federal CBM production is only about 15% of the total CBM production in the BFOA (figure 15). Eventually federal CBM production should increase to about 50% of total CBM production. During October 1999, CBM wells in the BFOA produced 5.96 bcfg.

Large quantities of water are produced with CBM. During June 1999, 3.4 barrels of water were produced for every thousand cubic foot of CBM. This ratio should decrease over time because water production generally declines during the life of a CBM well. Figure 16 shows water production associated with CBM production in the BFOA. During June 1999, 14 million barrels of water (1,800 acre-feet) were produced in the BFOA.

The total number of nonCBM producing wells in the BFOA increased from 1978 to 1984 but has decreased since 1990. The number of producing nonCBM wells will probably continue to decline during the next five to ten years. From 1990 to 1995, about 50% of the total producing wells in the BFOA were federal wells. Between 1990 and 1994, 58 more nonCBM federal wells were abandoned per year than were drilled per year. This trend is expected to continue, but the number of wells plugged in excess of the number of new wells drilled will probably decrease.

It is anticipated that during the next five to ten years the total number of producing nonCBM wells will continue to decline, although there may be a few year-to-year increases. The number of productive federal wells will probably average about 50% of total productive wells.

CONCLUSIONS

A “boom” in CBM development is currently underway in the BFOA. Gas production has increased sharply and will probably continue increasing sharply for the next few years. Oil and gas development, exclusive of CBM, will continue to slowly decline. Oil production will continue to decline. Seismic activity as measured by the number of approved NOIs, has increased from the low activity levels of the early 1990s but will probably not go much higher. The amount of federal acreage under lease has increased substantially since 1997. Because federal leases do not contain a pugh clause much of the federal acreage under lease in the CBM area will be held by production for many years after the primary

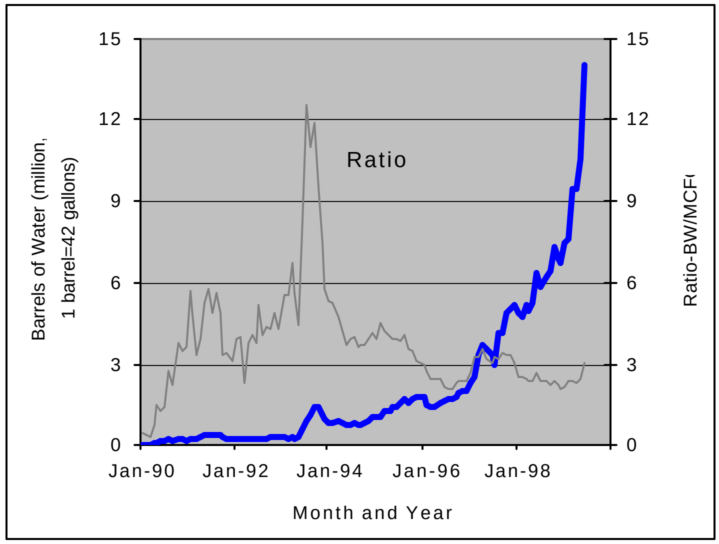


Figure 16: Water Production Associated with CBM Production in the BFOA. One million barrels of water is equivalent to 129 acre-feet. SOURCE: WOGCC.

lease term.

REFERENCES

Dolton, Gordon L.
1990 Personal communication with Fred Crockett, BLM Geologist. Dolton is with tthe US Geological Survey.

Dolton, Gordon L., James E. Fox, and Jerry L. Clayton.
1990 "Petroleum Geology of the Powder River Basin, Wyoming and Montana." US Geological Survey Open-File Report 88-450-P.

Glaser, Terry.
1992 Personal communication with Fred Crockett, BLM Geologist. Glaser is with the Conoco Oil Company.

Love, J. D. and Ann Coe Christansen.
1985 *Geologic Map of Wyoming.* U.S. Geological Survey, Denver, CO.

Mavor, M.J., and Nelson, C.R.
1997 "Coalbed Reservoir Gas-In-Place Analysis." Gas Research Institute Report No. GRI 97/0263, Chicago, IL.

Oil and Gas Journal
1992 "Conoco Details World Energy Outlook," v. 90, no. 25.

Petroleum Information Corp.
n.d. Historical Well Data Base.

1987 *Structure Contour Map of the Powder River Basin and Casper Arch, Wyoming and Montana.*

1992 Oil and Gas Production Reports for Wyoming.

Potential Gas Committee Report
1998 "Potential Supply of Natural Gas in the United States." Report of the Potential Gas Committee. Michael K. Decker President and General Chairman, p. 169.

Wyoming State Geological Survey
1996 Wyoming Geo-notes, Number 49, Wyoming State Geol. Survey, Laramie, Wyoming.

Wyoming Oil and Gas Conservation Commission.
1977-1994 Statistical summaries. Available from the Wyoming Oil and Gas Conservation Commission, Casper, Wyoming.

U.S. Geological Survey.

1999 “Resource Assessment of Selected Tertiary Coal Beds and Zones in the Northern Rocky Mountains and Great Plains Region” by Fort Union Coal Assessment Team. Geological Survey Professional Paper 1625-A.

GLOSSARY

Abandon To cease producing oil and/or gas from a well. This may involve several steps: one or more cement plugs are placed in the borehole to prevent migration of fluids between the different formations, equipment is removed, and the wellsite is reclaimed.

Acquired Minerals Mineral rights that were patented into nonfederal ownership and were later reacquired by the United States. In the Thunder Basin National Grassland this was through Title III of the Bankhead-Jones Farm Tenant Act of 1937.

APD Application to drill an oil and gas well. For a proposed well on federal surface an APD must be filed with and approved by the Wyoming Oil and Gas Conservation Commission and the Bureau of Land Management.

BCFG Billion cubic feet of gas.

BLM Bureau of Land Management, U. S. Department of Interior.

BOPD Barrels of oil per day, this is usually the unit of measure for oil production at the wellhead. One barrel is 42 U.S. gallons.

BOE Barrels of oil equivalent. Gas volume is converted to barrels of oil according to some ratio often 6:1.

BFOA Buffalo Field Office area, comprised of Campbell, Johnson, and Sheridan counties, Wyoming.

CBM Coalbed methane, natural gas originating from and residing in coal beds.

Development Potential Oil and gas development potentials are based on estimated average drilling density and are defined as follows: HIGH--over one well/township/year, MODERATE–-0.2 to 1.0 wells/township/year, LOW--less than 0.2 wells/township/year, VERY LOW-- less than 0.02 wells/town ship/year, ZERO--no drilling.

Dry Hole An oil and gas well that did not encounter economic quantities of oil or gas when it was drilled. Dry holes are usually plugged within a day or two after the target depth is reached.

Enhanced Oil Recovery (EOR) A process where chemicals such as surfactants or carbon dioxide are injected into the reservoir to mix with the oil so that additional oil can be recovered.

MBO Thousand of barrels of oil.

MCFGPD Thousand cubic feet of gas at one atmosphere pressure, this is usually the unit of measure for gas flow at the wellhead.

MMBO Million barrels of oil.

MMCFG Million cubic feet of gas at one atmosphere pressure.

NEPA National Environmental Policy Act

NEPA Process A procedure involving environmental analyses and public comment whereby management of natural resources may be changed.

New Field Discovery A well, usually a wildcat well, that discovers a previously unknown oil and gas field.

Occurrence Potential HIGH--There is a demonstrated existence of petroleum source, reservoir quality strata, and traps. Areas of high potential have discovered oil occurrences or free oil recovery from well tests. MODERATE--There is direct or indirect geological evidence that petroleum source, reservoir quality strata, and trapping mechanisms are present. Discovered occurrences are not present but there may be shows of oil in core or drill stem tests. LOW--There is geological evidence that a petroleum source, reservoir quality strata, or trapping mechanisms are not present. NONE--There is a demonstrated absence of a petroleum source, reservoir quality strata, or trapping mechanisms. Demonstrated absence means physical evidence documented in geological literature.

Oil and Gas Field A natural accumulation of oil and gas in the subsurface. Oil and gas may be present in two or more reservoirs at different depths.

Oil and Gas Lease A federal oil and gas lease is a legal document that gives the lease holder the right to explore for and develop any oil and gas that may be present under the area designated in the lease while complying with any surface use conditions which may have been stipulated when the lease was issued.

Oil and Gas Reservoir A geologic layer containing hydrocarbons and enough porosity and permeability so that the hydrocarbons can be produced.

Play The geographic extent of an oil and/or gas bearing formation or interval.

Public Domain Minerals Mineral rights that have always been the property of the United States.

Pugh Clause A term in an oil and gas lease that prevents a productive well from holding acreage not allocated to that well. In other words if well spacing is 40 acres/well, one well cannot keep more than 40 acres of the oil and gas lease from expiring after the primary term of the lease.

Secondary Recovery A process whereby pressure in an oil and gas reservoir is artificially maintained or increased so that more oil can be recovered. This is usually done by injecting water or natural gas into the reservoir.

Spud Begin drilling a well.

TBNG Thunder Basin National Grassland.

USFS United States Forest Service, U.S. Dept. of Agriculture.

Wildcat Well An test well drilled for the purpose of locating an undiscovered oil and/or gas field.

WYOGCC Wyoming Oil and Gas Conservation Commission