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Powder River Basin Coalbed Methane Wells – Reserves and Rates

Gary S. Swindell, SPE

Abstract

Coalbed methane has become a significant source of U.S. natural gas production, contributing 9% of the country's supply and 10% of its proved reserves. The most active coalbed methane area is the Powder River basin of eastern Wyoming, with more than 20,000 wells completed in the last 10 years with annual additions of greater than 2,000 wells.

This study analyzed the projected ultimate recovery, flow rates and dewatering time of 6,600 wells producing from the Wyodak and Big George coal zones – the source of 58% of the basin's cumulative production, 61% of the current production and 45% of the CBM wells.

For the Big George and Wyodak wells, the estimated ultimate recovery (EUR) averages 223 million cubic feet (MMcf) per well (median 168 MMcf). An average peak gas rate of 319 thousand cubic feet per day (Mcf/D) (median 236 Mcf/D) occurred an average of 1.2 years after the well was placed on production. The average well declined at a rate of 45% per year after entering the decline phase with very little hyperbolic behavior (average b = .09). Distributions of EUR and peak rates were strongly log-normal.

The EUR and peak gas rates both show a slight overall deterioration over time, although the "spread" is larger with more high rate wells in later years. But the time to reach peak gas rate is shortening as more areas are dewatered.

There seems to be only a slight correlation between total depth and EUR and little correlation between gross perforated interval and estimated ultimate recovery or peak rate, although the perforated interval information is very incomplete.

Development of Powder River basin coalbed methane has an average finding cost of $.71/Mcf, and the mean well has a return-on-investment of 4.70:1 and a net present value index of 3.74, assuming a base gas price of $6.50/Mcf minus $1.50/Mcf for market differential and transportation.

Introduction

As conventional oil and gas resources become more difficult and expensive to pursue, the world will increasingly utilize coalbed methane (CBM) as an energy source. Proven oil reserves in 2005 for the world were 1,088 billion barrels 1 compared to resource estimates for coalbed methane that range up to 1,400 billion barrels equivalent. Although much of the coalbed methane will remain uneconomic to recover, it still represents a resource that will contribute to future energy production.

Coalbed methane has grown to become an important source of natural gas in the United States, and now contributes approximately 9% of the country's production and 10% of U.S. proved reserves. Production increased from only 196 billion cubic feet (Bcf) in 1990 to more than 1,720 Bcf annually in 2004 [2].

The State of Wyoming in the western U.S. was the source of 341 Bcf of production from coalbed methane reservoirs in 2005 (2% of total U.S. natural gas), and a single basin, the Powder River (PRB), contributed 99% of that. CBM production began in the State in 1989 and increased rapidly after 1999. By early 2006, there were nearly 20,500 completed CBM wells in the Powder River basin, producing a total average of 920,000 thousand cubic feet per day (Mcf/D). Cumulative CBM production in the basin is approaching 2 trillion cubic feet (Tcf) and the resource estimates range up to 39 trillion cubic feet [3].

Methodology

Many of the coal zones divide into thinner members in portions of the basin, and the naming conventions make separating the coal zones difficult. The State does, however, classify all wells into individual reservoir names, such as Anderson, Big George, Dietz, Canyon, Cook, Wall, and Wyodak. The majority of wells (88%) are assigned a single coal reservoir name, but there are some combinations of multiple coal names, for example, WALL-CANYON, or, COOK-WALL-PAWNEE, likely the result of completions in multiple coals.

The distribution of PRB coal zones by the State's primary, or first reservoir classification is shown in **Fig. 1** and **Fig. 2**, regarding well the current active well count and 2005 production, respectively.

The study covered the Wyodak and Big George reservoirs, together with multiple coal zones beginning with those two reservoir names. The Anderson, Cook and Canyon coal zones are "splits" of the thick Wyodak coal and the analysis of the Wyodak may provide a representation of the performance of those coals also. The beginning study group consisted of 5,525 Wyodak wells and 3,504 Big George wells, totaling 9,029 wells of the basin's 20,418 CBM wells, approximately 16,000 of which are active producers. The other wells are inactive or abandoned. The estimated ultimate recovery (EUR) from the inactive wells was included in the statistical study.

Some of the study group wells have not recorded any gas production to date and were not projectable through the use of rate vs. time plots. Others are in the increasing gas rate phase of production and/or have not established a decline rate as yet and are also not projectable. The well count "balance" was as follows:

Beginning study group	9,029
Never any gas production (dewatering) – active	(866)
Never any gas production – inactive or abandoned	(187)
Inclining or no decline established yet - unprojectable	(1,374)
Total wells forecast or P&A with known ultimate	6,602

Additional "failure" wells were also excluded from the analysis. There were 630 CBM wells in the reduced study group which are forecast to produce an ultimate recovery of less than 10,000 Mcf, some of which are already abandoned. These exceptionally poor wells, comprising 10% of the study group, skew the EUR and flow rate distributions toward the low side, making even the Loge (EUR) distribution non-normal. The bulk of these "failure" wells were drilled in 2001-2003 and their occurrence has significantly decreased since then. Although no analysis of the reasons for such poor performance was done, it is likely they were drilled as the play expanded west encountering thin coals, low gas content, and water rates that did not decrease. They should probably be considered as dry holes in evaluating the play, and because their occurrence has been decreasing they were left out of the statistical results.

Each of the 6,602 reduced study group wells was forecast to an estimated ultimate recovery (EUR) by the use of monthly rate vs. time plots. MS Access and Excel databases were assembled from these projections, recording well identification (well name, operator name, field, reservoir, location and API number); EUR; peak monthly gas and water rates and the month of occurrence; first production date; and the established gas decline rate and the hyperbolic exponent (b). For most wells, total depth (TD) was readily available, but only a small number, less than 4%, had easily tabulated perforation information that could be used to obtain a rough estimate of net feet of coal. The resulting Excel database was then used to develop statistical studies, correlations, and distributions.

Coal Characteristics

The basin contains unusually thick, highly permeable, Tertiary age, lignite and sub-bituminous coals at shallow depths from the surface to deeper than 2,000 ft.

The Wyodak coal is low rank sub bituminous with thickness typically 50-100 ft. and up to 200 ft., extending north-south for a distance of more than 40 miles along the Fort Union outcrop [4,5]. The more westerly and deeper Big George develops a thickness as much as 300 ft. To the north and northwest, the coals tend to become thinner and split into a number of different seams, making correlations difficult. Gas content is generally in the 50-70 cubic feet per ton range. The U.S. Bureau of Mines data on gas content lists only seven Anderson coal samples averaging 41 SCF/Ton, four Wall/Cook coal samples averaging 4 SCF/Ton and two Smith coal samples averaging 16 SCF/Ton (personal database). Two published Langmuir isotherms indicate gas content of 58 SCF/Ton [6] (based upon 40 Wyodak samples) and 65 SCF/Ton (Lance Oil & Gas data) [7]. Interestingly, the shape of the PRB isotherm differs significantly from those for other CBM basins, being much more linear in behavior. The isotherm shape suggests that far less hyperbolic behavior will occur in the rate vs. time curves – exactly what was observed in the actual production data. The coals are low ash, high moisture, and highly permeable ranging up to 1 darcy. The gas composition typically includes 2-8 mole % CO_2. Most sources agree that the gas is biogenic in origin, generated by anaerobic bacteria at temperatures less than 122 °F [8].

CBM Development

CBM production began in the State in April 1989 with two wells in Sec. 20 15N-72W, though there were earlier producers in 1986 from sandstones immediately underlying the coal zones, and three later wells in the deeper part of the basin that were production tested and then abandoned. Peck 9 gives a detailed history of the CBM development. At the beginning of 1999, drilling activity increased sharply as shown in **Fig. 3**, with a corresponding increase in production (**Fig. 4**).

For both the Wyodak and Big George coals, wells are typically drilled on 80 acre spacing with some test development on 40 acres. Hower, et al. [7] summarized simulation studies indicating that the recovery factor averaged 85% for both 40 acre and 80 acre spacing, with the denser drilling simply causing depletion of offset, undeveloped acreage. Some operators believe that wells could effectively drain 160 acres in the higher permeable areas, but competitive drainage situations force denser development, especially along lease lines.

Single zone wells are drilled with water to the top of the objective coal, 7 inch casing is set and cemented, and an open hole section is then drilled with air-foam through the coal zone, usually underreaming to 11-12 inch hole diameter after logging. Often, wells are then cleaned out, or "enhanced" by pumping water into the open hole section, typically 700-900 barrels. Some studies [10] have concluded that hydraulic fracturing takes place during these "water enhancement" treatments, but the analysis methods used to reach this conclusion do not appear to be rigorous. The water treatments clean the cleat system of fines and damage generated during the drilling process. For wells targeting multiple coal zones, casing is set through the entire section, the zones are individually perforated, isolated with packers, and treated with water injection of 20-30 bbl/minute. Modified agricultural submersible water pumps are used to lift the fresh water production and dewater the coals. The water production is handled though surface drainage and ponds, evaporation and some utility usage.

In areas of the basin it has been difficult or impossible to effectively dewater the coals because the seams are "overlain and underlain by large, thick aquifers that are essentially infinite acting in nature." [11]

Study Results - Introduction

Ultimate recovery determination by the application of rate vs. time plots has been established as a viable prediction method for coalbed methane wells. Mavor, et al. [12], in a study that included an examination of simulated rates vs. analytic decline curves, concluded that "…even when these conditions (i.e. pseudo-steady state flow) are violated, decline curve analysis is possible late in the coal well's life." Seidle [13] presented a very thorough review of decline curve analysis of coalbed methane wells, noting, "…actual coal well gas decline is almost always exponential when plotted against time" and calculating a simulated Powder River decline of 69% per year. In an early study of coalbed methane decline in the Black Warrior basin in Alabama, Hanby [14] listed decline rates between 17% to 31% per year in various fields.

Nearly 2,200 of the study group wells have more than five years of production history (**Fig. 5**). In analyzing the individual rate-time plots, nearly all the wells with five years of production history demonstrated well established decline rates that were able to reliably forecast future production. Furthermore, most of the wells which have been abandoned as depleted and therefore have a known EUR, had decline profiles that would have forecast recovery with reasonable accuracy.

For the purpose of determining the economic limit, assumptions included $5.00/Mcf net gas price, $1,100/month operating cost, 6% State severance tax, and 18.75% royalty burdens (81.25% net revenue interest).

A note about the forecasts: in analyzing the decline curves, the emphasis was on capturing data on the magnitude and timing of the peak monthly gas and water production, and on forecasting the estimated ultimate recovery. The decline profile was also recorded and summarized and for most of the wells, this profile (initial decline rate and hyperbolic "b") is representative. Many wells, however, do show periods of shut-in or reduced production, then come back to an established decline. In these cases, no attempt was made to fully describe the ups and downs of the production history, and instead, a curve fit was used that obtained a reliable EUR.

The water production data reported by operators to the state do not appear to be accurate for many of the wells, are often erratic and at times appears to be volumes from a group of wells rather than a single well. The peak water rate and peak month are presented here and are believed to reasonably reflect actual production, but the cumulative is suspect. Although a forecast of ultimate water production was made, and is in the database, the results are not believed to be sufficiently accurate to present here.

The initial statistical analysis kept the Wyodak and Big George coal zones separate. But no significant difference was found between the two coals and they are analyzed together here. The database retains data for zone name enabling further analysis. The average and median for several parameters are listed below for each coal zone.

Parameter	Wyodak	Big George
Average gas EUR (MMcf)	209	265
Median gas EUR (MMcf)	169	164
Average water EUR (MBBL)	274	272
Average gas peak rate (Mcf/mo)	9,767	9,544
Average gas decline rate (%/yr)	46	42
Median water peak rate (BBL/mo)	12,602	15,102

Study Results – Estimated Ultimate Recovery

A number of trade periodicals refer to an average ultimate recovery of 300-400 MMcf per well for Power River coalbed methane wells, citing numbers from companies active in the basin. Hower, et al. [7] developed a calibrated simulation model predicting recovery of 304 MMcf/well on 80 acre spacing and 154 MMcf/well on 40 acre spacing. In the first published study of EUR based upon actual production data from 8,904 wells through February 2003, Mavor, et al. [12] concluded that the average ultimate recovery would be 264 MMcf per well, and provided average EUR's by the first production year. This same paper gives an average EUR of 166 MMcf for a group of 765 Canyon Coal wells.

The mean estimated ultimate recovery from 5,972 projected or abandoned Wyodak and Big George coal wells was 223 MMcf/well with a median of 168 MMcf/well. The maximum single well EUR was 2,866 MMcf, and there are 67 wells with a forecast in excess of 1,000 MMcf, all but three of which produce from the Big George.

The EUR distribution (**Fig. 6**) is clearly log-normally distributed (**Fig. 7**) and skewed somewhat to the higher side. The empirical continuous distribution function (CDF), F*, is defined as [15]:

$$F^* = i/(n+1)$$

where i is the rank of an ordered list of samples, and n is the total number of samples. A plot of the MS Excel function, NORMSINV(F*) vs. EUR or LN (EUR) should be a straight line if the distribution is normal. These plots indicate that the EUR distribution is, of course, not normally distributed, but neither is the LN (EUR) in Fig. 7, another demonstration of the skewness of the distribution.

Changes in the EUR of the wells might be expected over time as dewatering takes place in infill drilling locations and as development moves into new areas. **Fig. 8** illustrates the per well EUR over time, plotting against the month of first production. Although the scatter increases after 2000 with more wells with unusually high EUR's, a trend line through the data actually shows slightly declining EUR over time. The high EUR wells may be the result of some infill drilling into dewatered areas, but because most of the high EUR wells are completed in the Big George, it is more likely that the wells found high permeability-high gas content deeper coal zones.

Study Results – Peak Gas and Water Rates

As coalbeds are dewatered, pressure reduction causes gas desorption from the coal matrix and the typical production profiles in CBM wells show increasing gas rates and decreasing water rates until a peak gas rate is reached, followed by a decline in gas production. **Fig. 9** summarizes the distribution of peak gas rates in Mcf/month for 5,442 Wyodak and Big George coal wells that were actively producing in March 2006.

The results are log-normally distributed with a mean of 9,709 Mcf/month (319 Mcf/D) and a median of 7,176 Mcf/month (236 Mcf/D). The distribution of Log_e (Peak gas rate) is skewed to the higher values and indicates a standard deviation of 10,712 Mcf/month (352 Mcf/D).

Over time, the average peak gas rate has declined slightly as infill locations were drilled and the deeper Big George coals were developed, although the occurrence of a relatively few high rate wells has increased. There is, of course, a good correlation between EUR and the peak gas rate: not surprising given that the ultimate recovery was determined from decline curves.

In CBM wells, the water production tends to also peak, then decline as the fracture and cleat system storage capacity is depleted. The distribution of peak water rate has a mean of 17,304 BBL/month/well (569 BWPD) and a median of 13,386 BBL/month/well (440 BWPD). There is no apparent correlation between EUR and the peak water rate.

Study Results – Decline Rate

Seidle [16] in a general study of decline behavior of coalbed methane wells noted that "actual coal well gas decline is almost always exponential when plotted against actual time", and, through a simulator, showed that Powder River basin wells were predicted to decline at 69% per year. He further noted that the actual decline rate was always less than the theoretical calculated result. In their 2003 study, Mavor, et al. [12], concluded that both simulation and analysis of actual wells indicated that an exponential type gas decline develops after the dewatering phase.

For the study group of Wyodak and Big George coal wells, the distribution of gas decline rates (after the decline phase became established) was normally distributed (**Fig. 10**) with a mean and median of 45 percent per year, and a standard deviation of 16%. There is no discernable trend in decline rate over time.

Once the gas decline is established, the curves do not flatten much. Nearly 60% of the projections exhibited an exponential decline with b=0 in the well known Arps equation, and the mean "hyperbolic" factor for all wells in the study group was only .09, log-normally distributed. Given the near linear shape of the Langmuir isotherms (which differ significantly from the very high gas content coals in the San Juan basin in New Mexico) this behavior is not surprising. Furthermore, the combination of relatively low peak flow rates, high decline, and nearly pure exponential decline type, leads to short well life, averaging just less than 8 years. Fig. 5, showing the total decline of wells vintaged by the year of first production, illustrates the effect of high decline rates and short well life on the overall CBM production. It is evident that sustaining the basin's coalbed methane production will require increasing drilling activity.

Study Results – Time to Peak Rates

Typical coalbed methane production profiles demonstrate inclining gas production as the water is produced from the fracture and cleat system, followed sometimes by a flat phase, and then settling into a generally exponential decline. From the study group, the number of months to reach peak gas and water rates was recorded and analyzed.

For the study group, it took an average of 0.4 years for the water production to peak, and 1.2 years from production startup for the gas production to peak. Peak gas followed 10 months behind peak water production. Furthermore, the time for peak gas to occur has been steadily decreasing, and for wells drilled in the last two years it averages only 0.6 years. There is no apparent correlation between EUR and the number of years to reach peak production.

Study Results – Normalized Rate vs. Time

An additional analysis was made to establish the composite rate vs. time curve for an average well in the study group.

Well production records were segmented or "vintaged" by the year of first production. For each year, individual well production data were brought back to the same time-zero, added together and then this total was divided by the well count. This "normalizing" provides an average well production decline profile for each year's vintage of wells, and further illustrates any changes in decline profile with time. **Fig. 11** summarizes the results of the normalized decline study for wells drilled between 2000 and 2004.

Study Results – Correlations with TD and Thickness

The data set of Wyodak and Big George coalbed methane wells contains a good deal of information on the total depth (TD) of the wells but very limited data on perforated intervals because most are open hole completions. Coal zone thickness data were not readily available, though this would make an excellent extension to the study. Assuming that the TD accurately reflects the base of the target coal zone, a correlation can be developed between EUR and total depth. The graph shows very little correlation between coal depth and EUR. (In their 2005 completion methods study, Colmenares and Zoback [10] also plotted average gas and water production vs. depth using a limited data set of 550 Powder River basin wells and found little correlation.).

For 232 of the wells in the study group, information existed regarding the producing formation top. Subtracting this top from the TD data may provide an estimate of the coal thickness. **Fig. 12** shows the correlation of this estimated thickness to EUR. Although there is a slight correlation between EUR and net coal thickness, gas content variation and permeability are thought to be more significant controlling factors than wellbore thickness.

Study Results – Drilling Economics

Current completed well cost for a 1,400 ft. Big George single coal completion is $165,000 including the gas gathering system and other infrastructure expenses necessary to produce the well. Actual direct drilling and completion cost is approximately $75,000. A multi-seam completion would add approximately $20,000 to the cost.

Because of the distance to markets and constrained pipeline takeaway capacity, the Rocky Mountain region suffers a significant gas price discount, or differential, at the wellhead, estimated at $1.50/Mcf for this study. At varying base gas prices, less the $1.50 differential, the measures of profitability are summarized below. Finding cost of the average 232 MMcf well at $165,000 completed expense is $.71 per Mcf.

Base Gas Price - ($/Mcf)	Rate of Return % (DCF)	Payout (years)	Profit-to-investment Ratio	NPV Index
$ 3.00	3%	4.00	1.05	0.85
$ 3.50	22%	2.33	1.55	1.25
$ 4.50	57%	1.67	2.58	2.07
$ 5.50	88%	1.42	3.64	2.90
$ 6.00	105%	1.33	4.17	3.32
$ 6.50	119%	1.29	4.7	3.74
$ 7.50	143%	1.25	5.78	4.58
$ 8.50	162%	1.17	6.86	5.42
$10.00	183%	1.08	8.49	6.69

Conclusions

1. An analysis of individual well rate vs. time projections of 6,600 Wyodak and Big George coalbed methane wells in the Powder River basin of Wyoming in the western U.S. indicated that the log-normal mean and median estimated ultimate recovery (EUR) from these wells is 232 MMcf/well and 168 MMcf/well, respectively.

2. The distribution of EUR is log-normal with a broad standard deviation of 259 MMcf, and somewhat skewed to the high side.

3. An average well reached a peak production rate of 319 Mcf/D after 1.2 years of production then declined at 45% per year. The decline curves showed little hyperbolic behavior. Peak average water rate of 569 BWPD was reached 0.4 years after the start of production. The length of time to reach peak gas rate is decreasing, likely an indication of successful dewatering in areas of the field.

4. Average well life is expected to be quite short, 8 years, primarily a result of the gas content isotherm shape, high coal permeability and high decline rates. Activity will have to remain high to sustain the basin's production.

5. Although over time the spread of EUR and peak gas rate is increasing, with more higher volume wells, the overall trend shows a slight decrease in EUR and peak gas rate. But the time to dewater and reach peak gas rate is decreasing.

6. Based upon a limited data set, there is no clear correlation between well total depth and EUR, and only a slight correlation between estimated net coal thickness and EUR.

7. The economics of a broad based drilling program indicate that the mean well will provide a rate-of-return (DCF) of greater than 100%, payout in less than 15 months and return 4.70:1 on the investment (3.74 net present value index), assuming a base gas price of $6.50/Mcf.

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Appendix

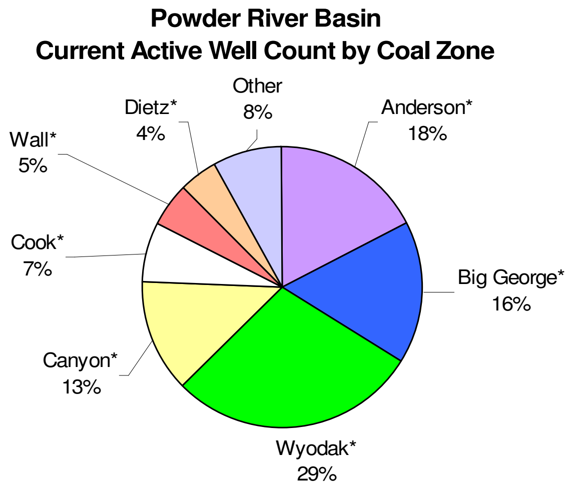

Fig. 1 – Active well count by coal zone - 2006

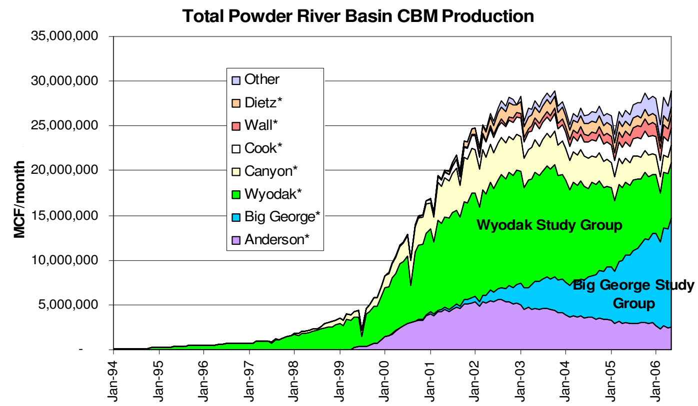

Fig. 4 – CBM production history by coal zone. Big George coal is now contributing 39% of the total basin CBM production and Wyodak 22% (the study group).

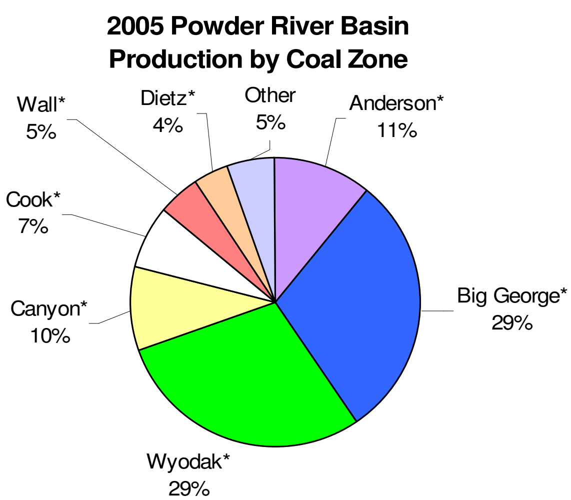

Fig. 2 – Powder River CBM production by coal zone in 2005.

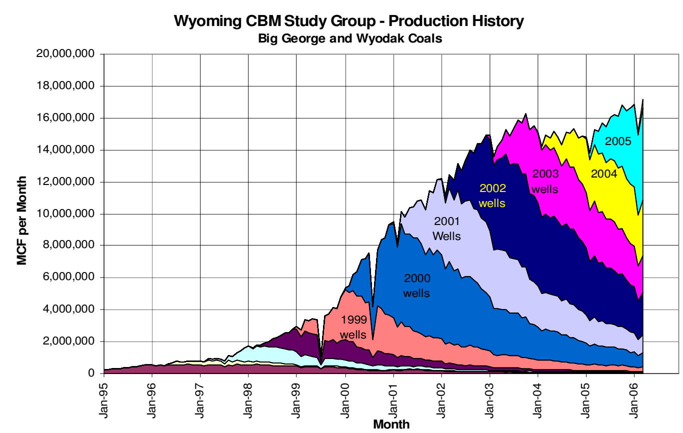

Fig 5 – CBM wells vintaged by year of first production. Average projected well life is 8 years.

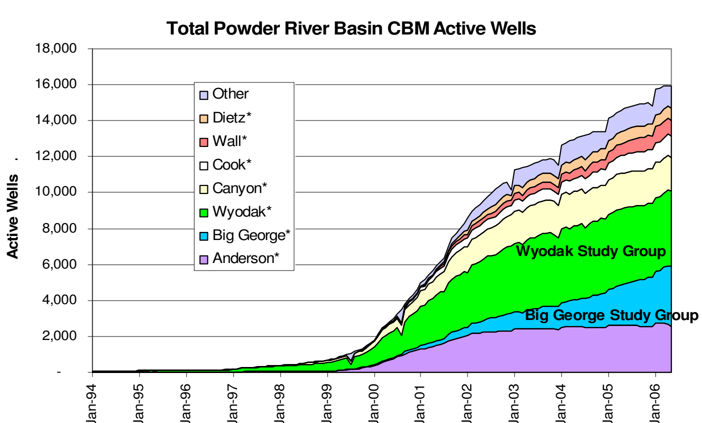

Fig. 3 – Active well count by coal zone. Active Wyodak wells are fairly constant; recent increases in Big George wells.

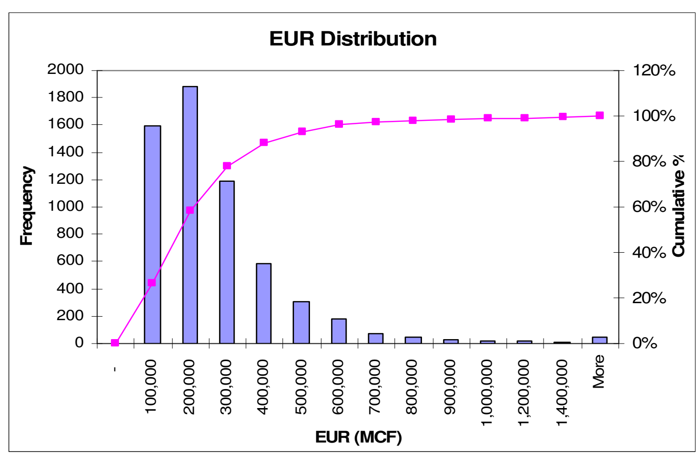

Fig. 6 – Distribution of estimated ultimate recovery – mean=223 MMcf/well, median=168 MMcf/well. Clearly log-normal.

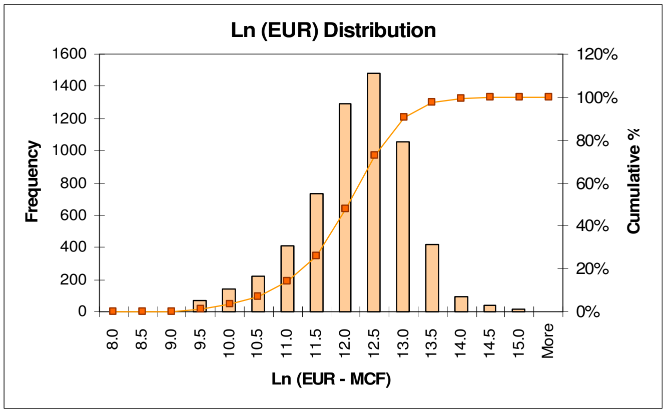

Fig. 7 – Distribution of Ln (EUR) – calculated log-normal mean of 232 MMcf/well, log-normal standard deviation 259 MMcf/well.

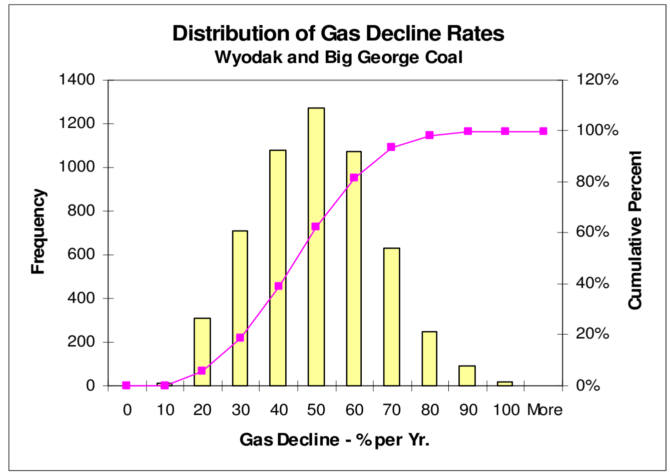

Fig. 10 – Distribution of gas production decline rates – mean and median = 45% per year. Average hyperbolic b=.09.

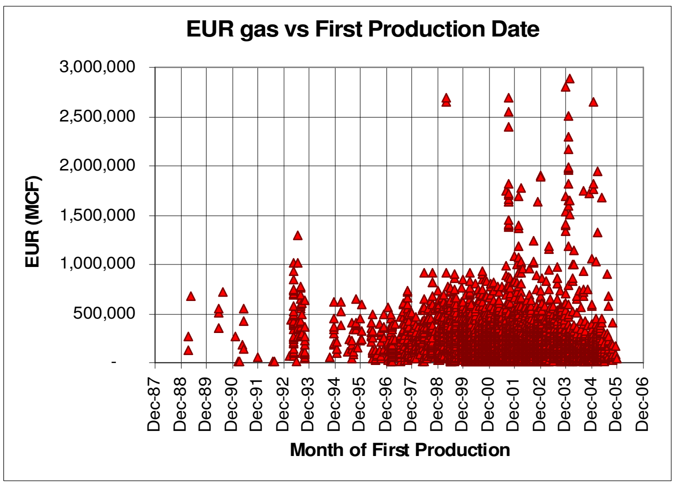

Fig. 8 – Changes in EUR over time – a trend line would show a decreasing average but increasing spread.

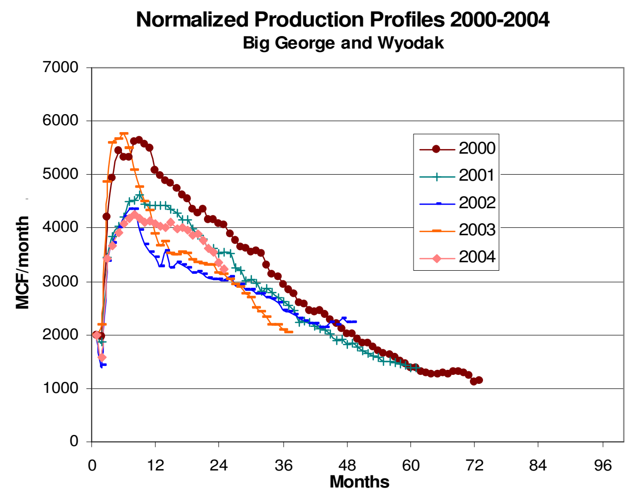

Fig. 11 – Normalized average production profiles for vintages of wells from 2000 to 2004. Average projected well life is 8 years.

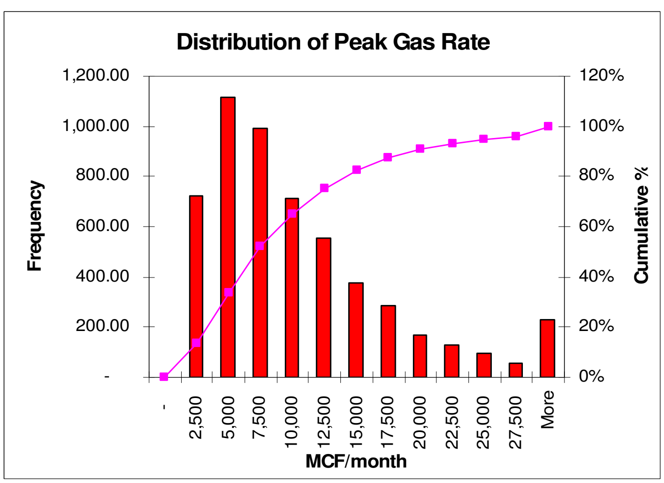

Fig. 9 – Distribution of peak gas rate – log-normal average 319 Mcf/D, median 236 Mcf/D. Trend over time shows a slight decrease. Peak water rate averages 17,300 BBL/month.

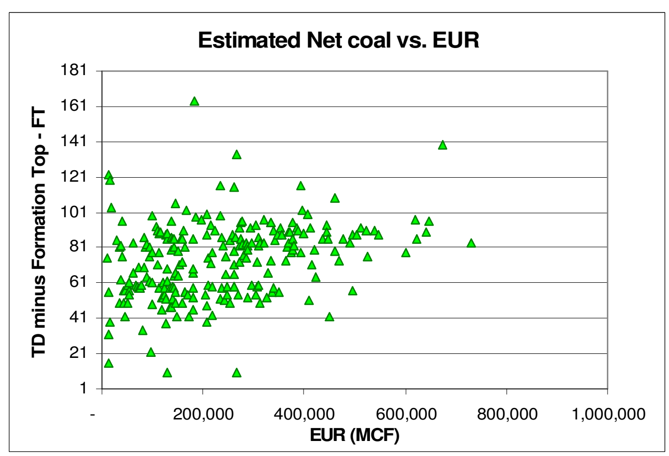

Fig. 12 – Projected ultimate recovery vs. estimated net thickness – showing little correlation (but with very limited data on only 232 wells.