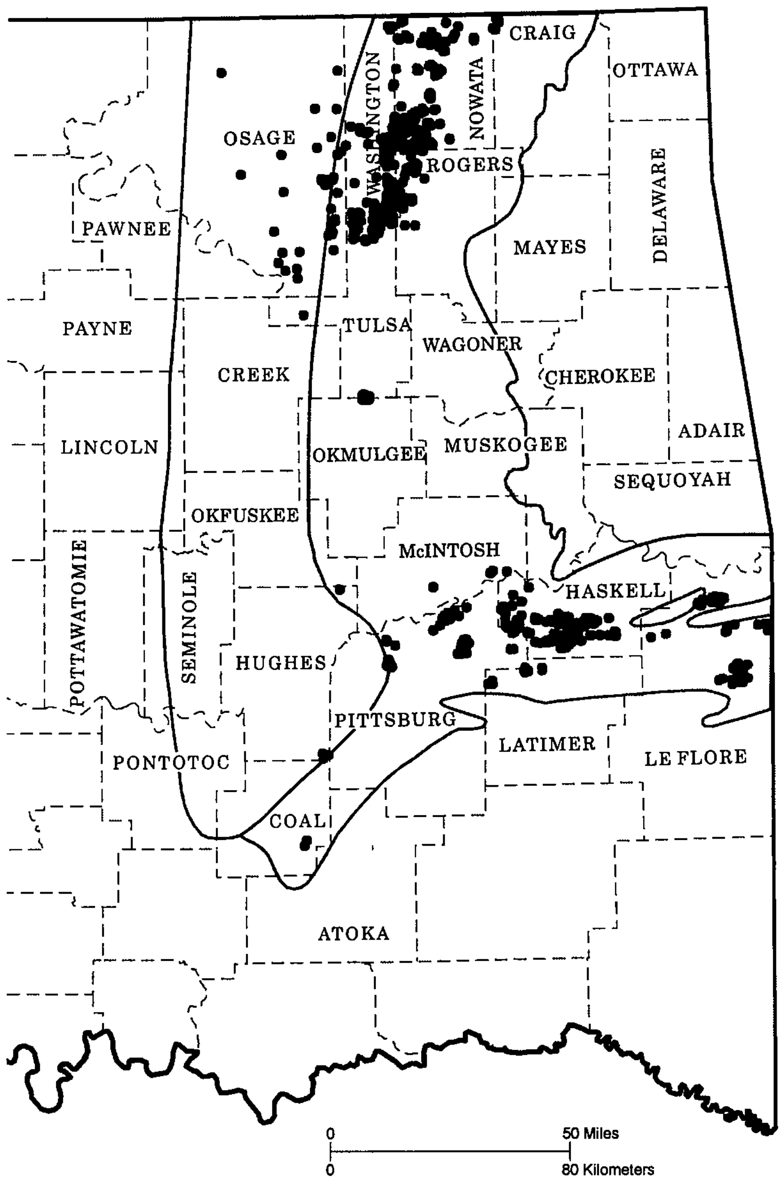
OKLAHOMA GEOLOGICAL SURVEY
OPEN-FILE REPORT OF 6-99

OKLAHOMA COALBED-METHANE WORKSHOP



OKLAHOMA GEOLOGICAL SURVEY
OPEN-FILE REPORT OF 6-99

OKLAHOMA COALBED-METHANE WORKSHOP

Compiled by
Brian J. Cardott

Co-sponsored by
Oklahoma Geological Survey,
Petroleum Technology Transfer Council
(South-Midcontinent Region),
and Oklahoma Independent Petroleum
Association/Gas Research Institute

Moore-Norman Technology Center
Norman, OK
December 1, 1999

CONTENTS

1

Changing perceptions regarding the size and production potential of coalbed methane resources

David G. Hill, Charles R. Nelson,
and Chuck F. Brandenburg
Gas Research Institute
Chicago, IL

Hill, D.G., C.R. Nelson, and C.F. Brandenburg, 1999, Changing perceptions regarding the size and production potential of coalbed methane resources, in Oklahoma coalbed-methane workshop: Oklahoma Geological Survey, Open-File Report OF 6-99, p. 1-11.

Changing Perceptions Regarding the Size and Production Potential of Coalbed Methane Resources

David G. Hill, Charles R. Nelson, Chuck F. Brandenburg

Gas Research Institute, Chicago, IL

Coalbed methane is enjoying a second resurgence in the U.S. with respect to drilling and production. It has "officially" survived the expiration of the Section 29 non-conventional fuels tax credit and new basins are emerging with economically viable coalbed methane (CBM) plays that are catching the attention of a wide range of companies who have not been involved in coalbed methane before. Several factors have contributed to the rapid growth and renewed interest in CBM and are the topic of this paper.

Over the past decade, the gas industry's pessimistic perception of the total in-place and recoverable coalbed resource base in the U.S. lower-48 have been shown to be wrong. In addition, the gas industry has found that finding costs of new coalbed methane reserves can be comparable or even lower than those of conventional natural gas resources. New reservoir property evaluation methods, improved drilling and completion practices, and new geologic information are enabling the gas industry to expand the size of the economically recoverable coalbed methane resource base. New technologies and environmental issues on the horizon will also grow the economically recoverable resource base within the next decade. Two of the more promising examples, which are complimentary, are enhanced recovery technology and carbon sequestration.

Coalbed Methane Resource Estimates

Coalbed methane has grown from almost complete obscurity twenty years ago to become a commercially important, mainstream natural gas source that in 1997 supplied 5.9 percent (1.13 Tcf) of total domestic natural gas production and represented 7 percent (11.5 Tcf) of total domestic natural gas proved reserves. Currently, there are over 8,000 coalbed methane wells in the U.S. and over the past twenty years the total cumulative coalbed methane production in the U.S. has exceeded 7.0 Tcf. From a resource perspective, there is a large, abundant coalbed methane resource base in the lower-48 U.S., (see **Figure 1**). **Table 1** is a breakdown of GRI's estimates of economically recoverable and total undiscovered coalbed methane for new fields in the United States. The Potential Gas Committee place economically recoverable estimates for coalbed methane reservoirs in the lower-48 U.S. at 84.4 Tcf. This number consists of 14.37 Tcf of probable, 43.47 Tcf of possible, and 26.59 Tcf of speculative resources, for more information see Pierce *et al.*, 1999.

Figure 1. Coalbed Methane Resource Pyramid Showing Produced Volume, Proved Reserves, Economically Recoverable, and Undiscovered Reserves in the U.S. Lower-48.

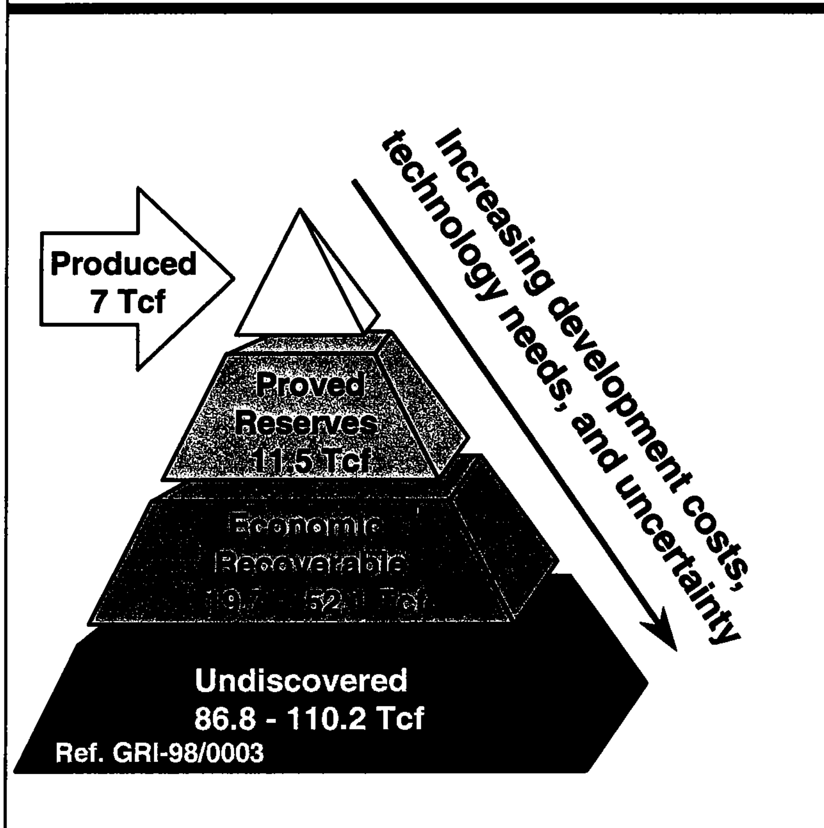


Table 1. Lower-48 U.S. Coalbed Methane Resource Base (Cochener)				
	Economically Recoverable Resource*		Total Undiscovered Resource	
	Current Technology	Advanced Technology	Current Technology	Advanced Technology
Tcf	19.7	52.1	86.8	110.2

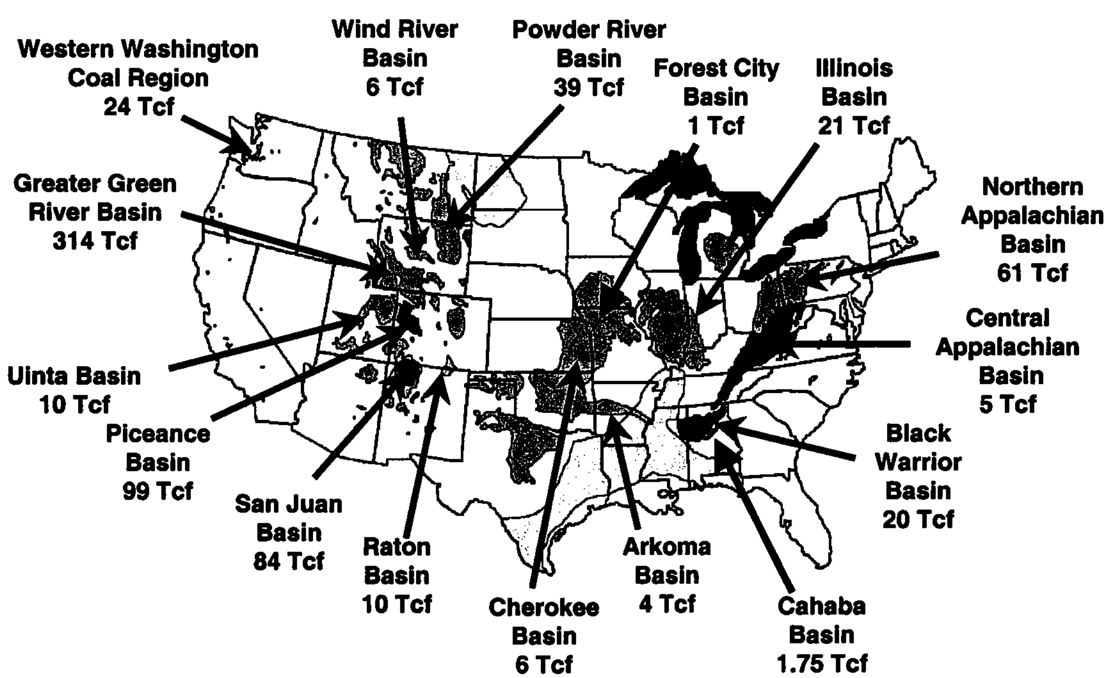
* Economically recoverable resource is the amount of undiscovered resource that can be developed with an acceptable rate of return at a gas price of $2.00/MMBtu.

Coalbed Methane Resource Base Perceptions

Sixteen major coal-bearing basins have been identified in the U.S. lower-48 states, **Figure 2**. In 1989, it was estimated that the coal deposits in these basins contained 398 Tcf of coalbed methane resources (Kuuskraa and Brandenburg, 1989), but the current in-place resource estimates for these basins have increased by 77% to a total of 703 Tcf (Nelson, 1999c). There are also huge coal resources in Alaska which contain an estimated 1,000 Tcf of coalbed methane resources (Smith, 1995). A decade ago, the Potential Gas Committee estimated the recoverable U.S. coalbed methane resources at 90.1 Tcf (Mantek *et al.*, 1989). The committee's 1998 report estimates that the recoverable U.S. coalbed methane resources have increased by 57% to a total of 141.4 Tcf, which includes 57 Tcf of speculative resource in Alaska (Pierce *et al.*, 1999).

These significantly higher in-place and recoverable resource estimates are a result of several factors. First, the information derived from exploration activities and commercial successes in many new play areas (Pierce *et al.*, 1999). Second, the use of more accurate gas content analysis methods (Mavor *et al.*, 1995a, 1995b, McLennan *et al.*, 1995). Third, a greater abundance and spatial coverage of gas content data for the enormous Cretaceous and Tertiary age coal deposits in Rocky Mountain Region basins.

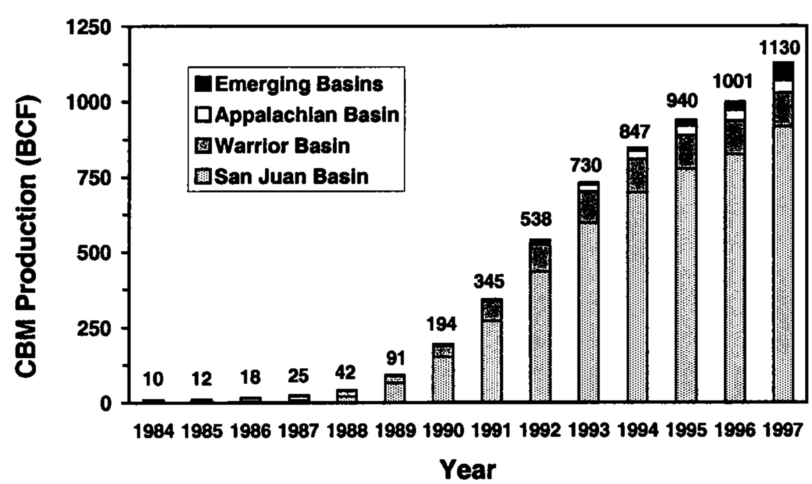
Figure 2. U.S. Lower-48 States Coalbed Methane Resources (data are from Nelson, 1999c).



Gas Production Economics Perception

Annual coalbed methane production data from 1984 to 1997 are highlighted in **Figure 3** (Nelson, 1999c). Coalbed methane production totaled only 10 Bcf from 284 wells in 1984, but by 1996, annual coalbed methane production had increased one hundred-fold, to 1,001 Bcf from over 7,300 wells. This dramatic production increase was primarily the result of the large-scale commercial exploitation of coalbed methane resources in the San Juan and Black Warrior basins during the late 1980s and early 1990s. The explosive growth in coalbed methane production during this period was largely driven by two factors. The first of these was exploration, completion and production technology advances that helped producers turn the significant coalbed methane resources in the San Juan and Black Warrior basins (see **Figure 2**) into profitable gas plays (Schraufnagel *et al.*, 1994).

Figure 3. Annual U.S. Coalbed Methane Production and Well Data (data are from Nelson, 1999c).



The second factor was the availability of the Section 29 non-conventional fuels production tax credits, which helped the gas industry attract the large R&D and capital investments needed to rapidly exploit this unconventional gas play. To qualify for Section 29 tax credits, worth about $0.95 per Mscf in 1993, coalbed methane wells had to be drilled prior to year-end 1992. A decade ago, it was believed that most new coalbed methane development projects in other play areas and basins might not be economically viable in the absence of the Section 29 tax credits (Kuuskraa and Brandenburg, 1989). However, the continued growth in coalbed methane annual production after 1992 (see **Figure 3**) clearly demonstrates that this unconventional gas play can be economically developed without tax credits.

Initial Reservoir Gas-In-Place Perception

Initial gas-in-place is one of the key reservoir parameters that influences the gas production and producible reserve potential of coalbed gas reservoirs. This reservoir parameter is intrinsically difficult to accurately determine (Mavor and Nelson, 1997, Nelson, 1998, 1999b). In many established coalbed methane plays the cumulative gas production volumes have exceeded the initial gas-in-place estimates. As an example, the 10-year cumulative gas production of the 23 coalbed gas wells at the Oak Grove Field in the Black Warrior Basin, Alabama was 3.2 Bcf, more than double the initial gas-in-place estimate of 1.55 Bcf (Diamond *et al.*, 1989). The cumulative gas production volumes of many coalbed methane wells in the San Juan and Powder River basins also greatly exceed the initial gas-in-place estimates (Mavor and Nelson, 1997, Pratt *et al.*, 1999). This type of underestimation error indicates that the reservoir parameters used to calculate the initial gas-in-place values were inaccurate and that significant potential may exist for large reserve volume gains in many existing fields. Over the past decade, results from GRI-funded studies have improved our understanding of the common causes of gas-in-place underestimation errors and identified practical methods for avoiding or minimizing these errors (Mavor *et al.*, 1995a, 1995b, 1996, Mavor and Nelson, 1997, Nelson, 1998, 1999b, Pratt *et al.*, 1999).

Maximum Gas Recovery Factor Perception

It is commonly accepted that the maximum initial gas-in-place recovery from coalbed methane reservoirs is only about 50 to 70% (see **Table 2**). This type of recovery factor, somewhat lower than that of conventional reservoirs, is an inherent feature of the pressure depletion recovery method that is universally utilized for production of coalbed methane. This gas recovery method involves continuously removing water from natural fractures thereby progressively reducing the reservoir pressure which, in turn, results in the desorption of the sorbed phase gas.

There are both practical and economic limits on the extent to which average reservoir pressure can be reduced using this methodology, and the maximum initial gas-in-place resource recovery is typically only about 50 to 70%. Over the past decade, the gas industry has devised and experimented with enhanced coalbed methane recovery technologies to both accelerate gas production rates and overcome the recovery factor limitation of the pressure depletion recovery method. These enhanced recovery technologies, involving injection of nitrogen or carbon dioxide into coalbed reservoirs to promote the desorption of sorbed phase gas, are currently undergoing field evaluation by industry in the San Juan Basin (Stevens *et al.*, 1996, 1999). These enhanced recovery technologies can increase gas production rates as much as six-fold and increase producible gas reserves as much as two-fold. In the future, these enhanced recovery technologies may also enable commercial exploitation of coalbed methane resources that cannot be economically exploited using the pressure depletion recovery method.

Over the next decade, the issue of reducing greenhouse gas emissions will continue to grow in prominence as a major social issue. Government and industry are currently focusing on ways to reduce these emissions. CO_2 capture and geologic sequestration holds promise as a key greenhouse emission reduction technology. Options for geologic storage of CO_2 include sequestration in depleted or depleting oil or gas wells, coal seams, or deep underground saline formations. Coal seams provide a unique opportunity to sequester large volumes of CO_2 while increasing the efficiency and profitability of commercial coalbed methane operations. Sequestration may prove to be a research catalyst that provides new technology and knowledge to unlock the coalbed methane potential in frontier areas or basins.

Play Area Perceptions

A decade ago there was no significant commercial coalbed methane production from any formations other than the Fruitland Formation coal in the San Juan Basin and the Pottsville Formation coal in the Black Warrior Basin (Kuuskraa and Brandenburg, 1989). It was commonly believed that the other basins (see **Figure 2**) had relatively little exploitation potential since their coal deposits typically did not possess the unique geologic and reservoir property characteristics of the highly productive coalbed reservoirs in the San Juan and Black Warrior basins (Tyler *et al.*, 1991). Based on the extensive study of the San Juan, the Piceance and the Greater Green River basins, a producibility model for coalbed methane was developed. The exceptionally high productivity in the San Juan Basin is governed by interplay of the following five factors.

- Thick, laterally continuous coals of high thermal maturity
- Adequate permeability
- Basinward flow of ground water through coals of high rank and gas content orthogonally toward no-flow boundaries (regional hingelines, fault systems, facies changes, and/or, discharge areas)
- Generation of secondary biogenic gases
- Conventional trapping along those boundaries to provide additional gas beyond that generated during coalification.

However, over the past decade, the gas industry has discovered good quality coalbed methane reservoirs in many other play areas or basins where one or more of these five critical factors is absent. Today, commercial production of coalbed methane also occurs in the Northern and Central Appalachian, Cahaba, Piceance, Uinta, Powder River, Raton, Greater Green River, Arkoma, Cherokee, Forest City, and Illinois basins (Pierce *et al.*, 1999).

Table 2 summarizes typical reservoir properties for coalbed methane plays in historically productive areas (Nelson, 1999c). The most prolific coalbed methane production is from the Fruitland Formation coals in the San Juan Basin where there are over 3,000 coalbed methane wells. To date, the total cumulative coalbed methane production from this basin exceeds 6.0 Tcf. At year-end 1998, there were 35 coalbed methane wells in this basin with cumulative gas production totals of over 12 Bcf. The most productive coalbed methane well is the Burlington Resources San Juan

30-6 Unit #412 well located in S14 T30N R7W, Rio Arriba County, N.M., which had a total cumulative gas production of 35.3 Bcf.

Table 2. Coalbed Gas Reservoir Properties in Historically Productive Areas.

Coal Basin or Deposit	State(s)	No. of Producing Wells in 1996	Cumulative CBM Production 1981 - 1996 (Bcf)	Coal Rank	Typical Net Coal (feet)	Typical Gas Content (scf/ton)	Typical Well Spacing (Acres)	In-situ Density (g/cm^3)	Initial GIP Recovery Factor	Avg. Well Production (Mcfd)	Reserve Finding Cost ($/Mcf) *
San Juan	CO, NM	3,036	3,856.64	Hvb	70	430	320	1.54	0.80	2,000	0.11
Black Warrior	AL, MS	2,739	728.21	Mvb	25	350	80	1.40	0.65	100	0.25
Central Appalachian	WV, VA, KY, TN	814	120.86	Mvb	16		80		0.50	120	
Piceance	CO	123	35.78	Hvb	80	768	40	1.35	0.15	140	1.23
Powder River	WY, MT	193	17.29	Sb	75	30	80	1.34	0.60	250	0.25
Uinta	UT	72	14.04	Hvb	24	400	160	1.54	0.50	690	0.25
Arkoma	OK, AR	107	11.17	Hvb	6	250				50	
Raton	CO, NM	59	7.96	Hvb	35	300	160	1.50	0.55	300	0.18
Northern Appalachian	PA, WV, OH, KY, MD	85	4.94	Hvb	12	150				50	
Cahaba	AL	32	3.2	Hvb	50	260					
Cherokee	KS, OK, MO	28	1.73	Hvb	4	200	80	1.50	0.50	100	0.46
Forest City	KS, IA, MO, NE	65	0.74	Hvb	30	100	40				
Greater Green River	WY, CO	1	0.22	Hvb	30	349	160	1.54	0.60	240	0.36

* Note: Reserve Finding Cost ($/Mcf) = Well Cost/(Initial GIP X Recovery Factor) Data are from Nelson, 1999a, 1999c.

Hvb - high volatile bituminous

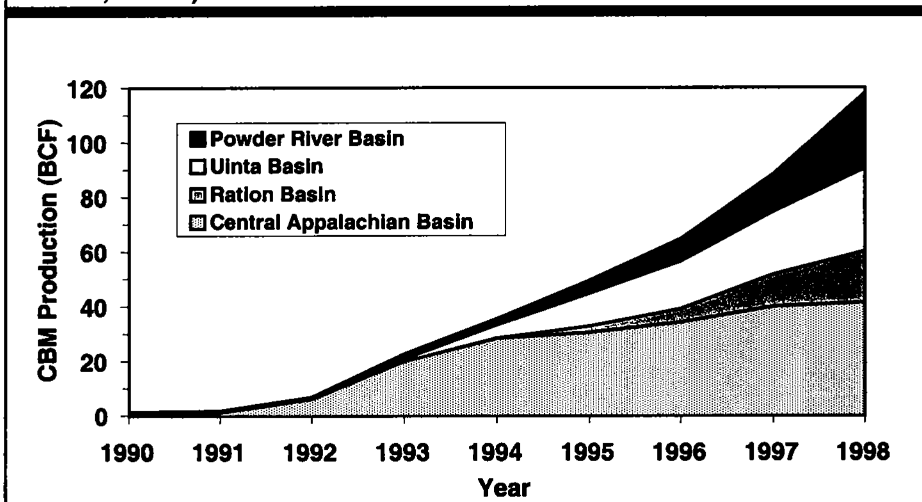
Mvb - medium volatile bituminous

Sb - subbituminous

The second most prolific coalbed methane play is located in Black Warrior Basin which has about 2,700 coalbed methane wells currently producing about 112 Bcf annually. The average stabilized production rate of the coalbed methane wells in this basin is about 100 Mcfd, and total per well recoveries are generally below 0.5 Bcf. To date, the total cumulative coalbed methane production from the Black Warrior Basin is about 1.0 Tcf.

The four most active coalbed methane play areas today are located in the Uinta, Powder River, Raton, and Central Appalachian basins (see **Figure 2**). Annual coalbed methane production data from these four basins for the period 1990 through 1998 are highlighted in **Figure 4**. In 1998, the total coalbed methane production from these four basins totaled 118 Bcf from more than 2,200 wells. The current interest in commercial exploitation of coalbed methane resources in these four basins is primarily motivated by opportunities for developing significant low-cost natural gas reserves. Small

Figure 4. Annual Coalbed Methane Production Data for the Powder River, Uinta Raton, and Central Appalachian Basins (data are from Nelson, 1999c).



independents have played a pivotal role in the bringing commercial viability to these plays. Representative reserve finding (well drilling and completion) costs for several coalbed methane play areas are given in **Table 2**. The coalbed methane plays in the Powder River, Uinta and Raton basins have finding costs of between $0.18 to $0.25 per Mcf of reserves which are comparable to the current average finding costs of from $0.20 to $0.35 per Mcf of reserves in conventional on-shore natural gas plays (Cochener, 1998).

Currently, the Powder River Basin Fort Union Formation subbituminous coal is the fastest growing coalbed methane play (see **Figure 4**). Over forty operators and developers are currently active in this play. This basin has a surface area of 22,500 mi^2 and contains a coal in-place resource of 1.3 trillion short tons which is the largest coal deposit in the United States. The three largest coalbed methane plays are the Rough Draw, Marquiss, and Lighthouse projects located along the eastern margin of this basin downdip from large surface coal mines in Campbell County, WY (Pratt *et al.*, 1999). At year-end 1998, the Wyoming Oil & Gas Conservation Commission had approved 3,300 permits for coalbed methane wells. The Wyoming Bureau of Land Management anticipates that over the next decade this coalbed methane play may eventually grow to 5,000 wells (Pierce *et al.*, 1999).

Five critical factors are driving this new coalbed methane play. These are:

- A large coalbed methane resource (see **Figure 2**)
- Good quality reservoirs
- Favorable economics (see **Table 2**)
- Availability of large amounts of unleased acreage
- Rapidly expanding pipeline, gas processing and compression capacity.

This play is an example of a dramatic turnaround in gas industry perceptions regarding coalbed methane resource production potential. In the early 1990s, a multi-basin assessment study concluded that the Powder River Basin Fort Union Formation subbituminous coals had very limited coalbed methane production potential (Tyler *et al.*, 1991). The reservoir characteristics of the subbituminous rank coals in this basin were dramatically different from those of the bituminous rank coals in the productive play areas in the San Juan Basin. In particular, the sorbed gas content was an order of magnitude lower while the absolute water permeability was typically an order of magnitude greater (see **Table 2**). These reservoir characteristics suggested that the subbituminous coals in the Powder River Basin would be difficult and expensive to sufficiently "dewater" to enable desorption and commercial production of the sorbed phase natural gas (Tyler *et al.*, 1991, Pratt *et al.*, 1999).

As the 1990s progressed, however, the gas industry's initial pessimistic perception regarding the production potential of the coalbed methane resources in this basin progressively evolved to a point where today it is the hottest and most active play area for coalbed methane development. The operators currently working this play are attracted by the potential for obtaining average gas production rates of 100 Mcfd and greater from relatively shallow wells, typically only 250 to 1,000 feet deep, that cost only about $50,000 to drill and complete. Although the water production rates from these shallow wells can be high, averaging about 330 STB/day, the produced water quality is relatively good permitting beneficial uses such as discharge into stock watering ponds or surface drainages, thereby greatly improving the overall gas production economics (Pratt *et al.*, 1999).

To date, only limited commercial exploitation of coalbed methane resources occurs in other basins. Small coalbed methane plays have been established in the Piceance, Greater Green River, Arkoma, Cherokee, and Illinois basins (see **Figure 2**). Annual coalbed methane production is currently about 7.8 Bcf in the Piceance Basin, about 2.0 to 3.0 Bcf in the Arkoma and Cherokee basins, and about 0.1 to 0.2 Bcf in the Greater Green River and Illinois basins.

Although the activity in the Arkoma basin is not as robust as the Powder River Basin, it is another example of how coalbed methane perceptions are changing. The Arkoma Basin encompasses an area of approximately 13,488 square miles in the states of Arkansas and Oklahoma. The basin contains extensive bituminous coal reserves in Pennsylvanian age rocks and total coal resource is estimated at approximately 7.89 billion short tons. Coalbed methane resource estimates range from 1.59 – 3.55 Tcf (Rieke and Kirr, 1984) to 4 Tcf (Pierce *et al.*, 1999). Coalbed methane production is primarily from the Hartshorne coals in the basin. Commercial production was established in the Oklahoma portion of the basin in 1988, and there are over 280 coalbed methane completions through April of 1999, **Figure 5** (Cardott, 1999). The average completion depth is approximately 1,335 feet and average production is 72 Mcfd of gas and 10 STB/day of water per well (Cardott, 1999). **Figure 6** is a plot of selected basins showing average coalbed methane gas production through 1996. The production from these basins range from 120 Mcfd to 20 Mcfd. As mentioned above, more recent data shows the Arkoma average gas production to be approaching the production from the Central Appalachian Basin. Although water production is not plotted, both basins report low produced water volumes. Coalbed methane development in these basins is critically dependent upon obtaining favorable project economics through economies of scale, controlling drilling and completion costs, and low produced water volumes.

Figure 5. Coalbed Methane Completions in the Oklahoma Portion of the Arkoma Basin (Cardott, 1999).

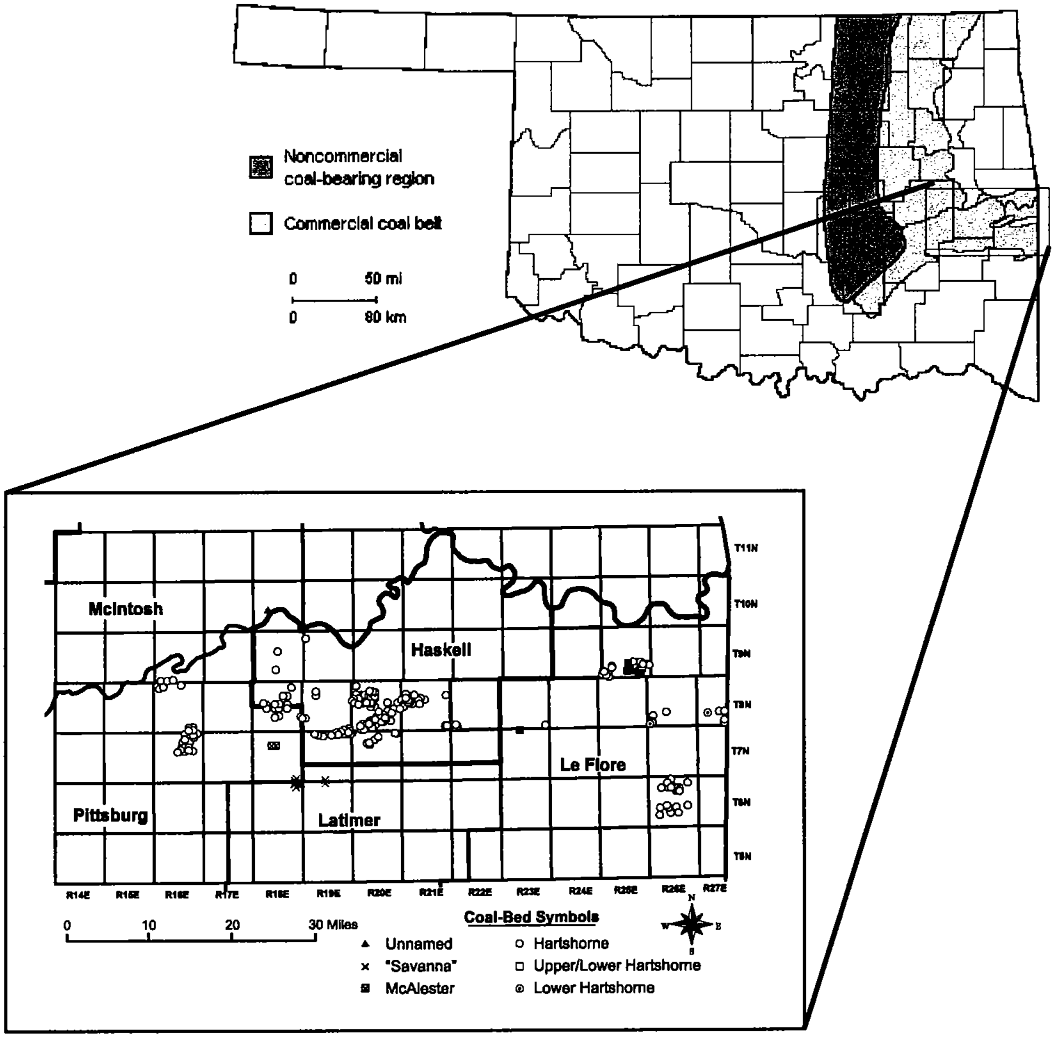


Figure 7 is a plot of five reservoir attributes on a generalized scale of 0-10 for four different basins. The five attributes are permeability, thickness, gas content, coal rank, and daily water production. For a given basin, the attributes are normalized to a range where 10 represents a maximum known value for the attribute and 0 represents the minimum value, usually 0. This plotting technique is a useful tool to compare different basins. The figure shows the striking differences in these attributes for the prolific San Juan basin, the exploding Powder River Basin, the emerging Central Appalachian basin, and the Arkoma Basin. The Arkoma Basin and the Central Appalachian Basin show similar characteristics with respect to the five attributes. This should be a helpful tool for screening and for identifying analogues. Other attributes can also be plotted in a similar manner.

Three basins with large in-place coalbed methane resources can still be considered frontier areas; Piceance, Greater Green River, and Alaska. While there are huge coalbed methane resources in both the Piceance and Greater Green River basins, the low permeabilities common to the reservoirs in these two basins makes large-scale commercial exploitation economically unattractive with current technology (Tyler *et al.*, 1991). Alaska's coalbed methane resources are estimated to total 1,000 Tcf (Smith, 1995), but no commercial exploitation of these resources has occurred to date. The Potential Gas Committee estimates that Alaska's recoverable coalbed methane resources total 57 Tcf (Pierce *et al.*, 1999). During 1999, Unocal Corporation plans to initiate exploration drilling to evaluate the production potential of an estimated 3.6 Tcf of coalbed methane resources on a 72,000-acre prospect located in the Matanuska Valley at the northern end of the Cook Inlet Basin (Pierce *et al.*, 1999).

Figure 6. Average Coalbed Methane Gas Well Production for Selected U.S. Basins.

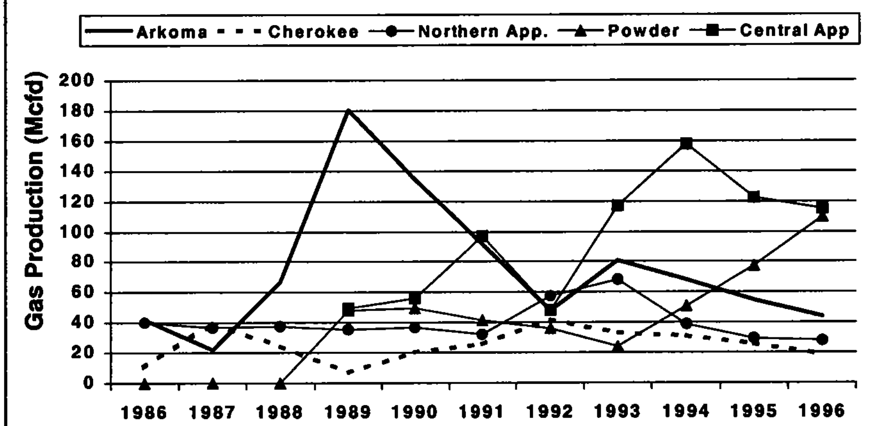
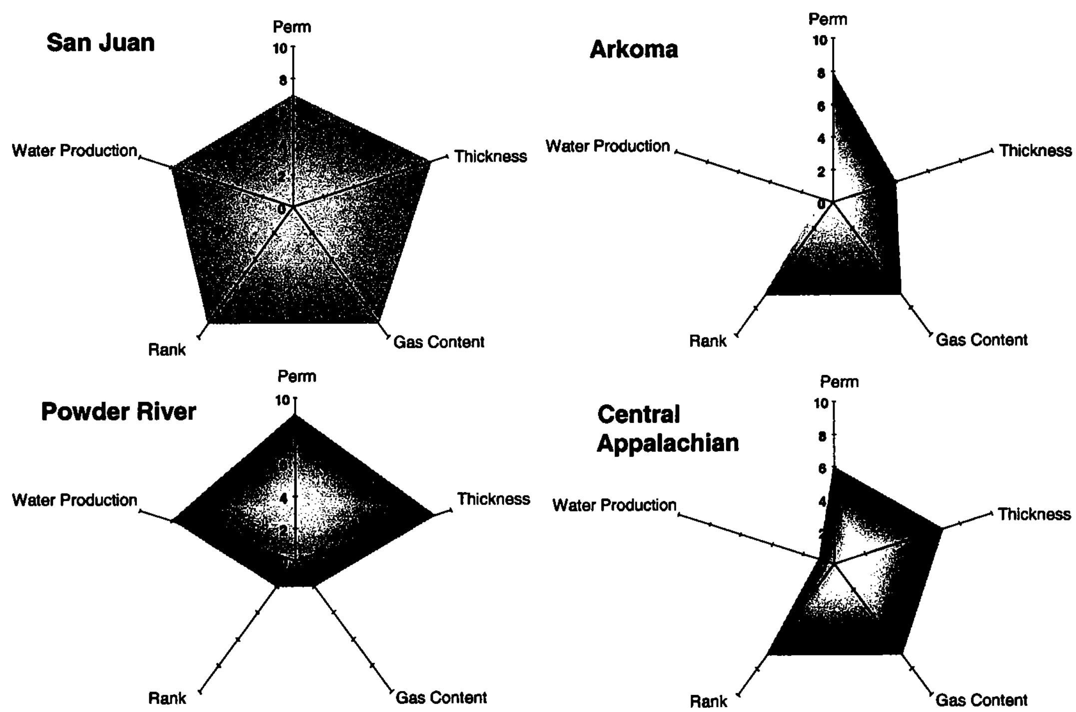


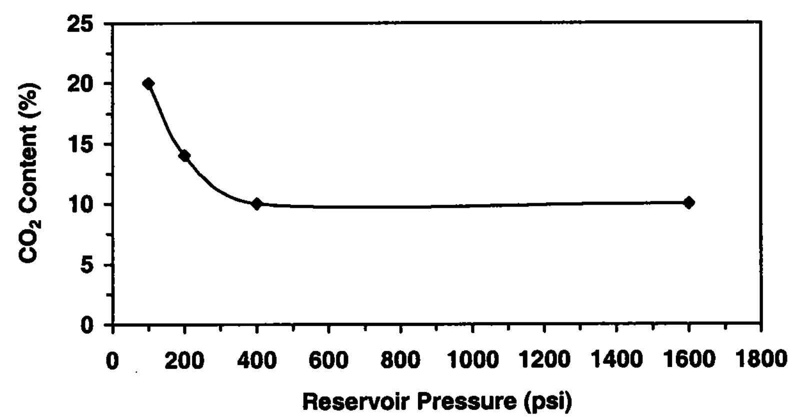
Figure 7. Multi-basin Comparison Using Five Reservoir Attributes.



Produced Gas Composition Perception

A decade ago it was commonly believed that coalbed reservoirs only produced methane-rich gas. However, over the past decade, the gas industry has found that the composition of produced gas streams from coalbed methane plays varies widely, depending on numerous site-specific geologic and reservoir property variables. Coalbed methane reservoirs in the Black Warrior and Appalachian basins typically produce a methane-rich gas having low CO_2 (<1 percent) and non-methane hydrocarbon (~0.1 percent) contents. By contrast, the produced gas streams from coalbed methane reservoirs in the U.S. Rocky Mountain Region exhibit widely varying CO_2 (<1 to >40 percent) and non-methane hydrocarbon (~0.1 to 23 percent) contents (Nelson *et al.*, 1997). In the San Juan Basin more than 0.16 Bcf per day of CO_2 is currently separated from produced coalbed methane and vented to the atmosphere.

Figure 8. Variation of CO_2 Content in Raw Produced Coalbed Gas as a Function of Reservoir Pressure Draw Down (from Nelson, 1999a).



The CO_2 content of the gas produced from San Juan Basin coalbed methane reservoirs varies as a complex function of both site-specific geologic and reservoir property variables. **Figure 8** is an illustration of how the CO_2 content of the gas produced from a coalbed methane reservoir in the northern part of this basin varies as a function of reservoir pressure draw down (Nelson, 1999a). This CO_2 content variability can significantly impact gas production operations since the raw produced gas is commonly used as fuel for field compressors. The gas-fired engines on these compressors will not operate when the CO_2 content of the fuel gas exceeds 15 to 16 percent.

Lessons for the Future

Over the past decade, many of the gas industry's pessimistic perceptions regarding the production potential of U.S. lower-48 coalbed methane resources have been invalidated. Focusing research on this natural gas resource is clearly important because the total in-place and potentially recoverable natural gas resource volumes available for exploitation are very significant. In addition, the finding costs of new coalbed methane reserves are often very low compared to those of conventional natural gas. Finally, over the past decade, new reservoir property evaluation methods, improved drilling and completion practices, and enhanced recovery technologies have been developed which are enabling the gas industry to greatly expand the size of the economically recoverable coalbed methane resource base.

The rapid growth in coalbed methane well completions and production that occurred during 1988 to 1992 in the San Juan and Black Warrior basins is being repeated today in large, new coalbed methane plays in the Powder River, Uinta, Raton, and Central Appalachian basins. These new coalbed methane plays are chiefly being driven by the powerful economic incentive of low reserve finding costs (see **Table 2**). Each of these coalbed methane plays has presented new challenges and opportunities to the industry and operators have overcome them by identifying and solving problems unique to their situation. The success of these new, low-cost coalbed methane plays has sparked a resurgence of industry interest in evaluating the production potential of the huge, as yet untapped coalbed methane resources present in basins throughout the United States.

References

Cardott, B., 1999. "Oklahoma Coalbed Methane – From Mine Explosion to Gas Resource," presented at the American Association of Petroleum Geologist, 1999 Midcontinent Section Meeting, Wichita, KS, (August 29-31).

Cochener, J., and Brandenburg, C., 1998. "Expanding the Role of Onshore Deep Gas," GasTIPS, Vol. 4, No. 3 (Fall 1998), p. 4-8.

Cochener, J., "The Long-Term Trends in U.S. Gas Supply and Prices: The 1998 Edition of the GRI Baseline Projection of U.S. Energy Supply and Demand to 2015," GRI Report No. GRI-98/0003.

Diamond, W.P., Bodden, W.R., III, Zuber, M.D., and Schraufnagel, R.A., 1989. "Measuring the Extent of Coalbed Gas Drainage After 10 Years of Production at the Oak Grove Pattern, Alabama," Paper 8961, Proceedings of the 1989 Coalbed Methane Symposium, The University of Alabama, Tuscaloosa, AL (April 17-20), pp. 185-193.

Kuuskraa, V.A. and Brandenburg, C.F., 1989. "Coalbed Methane Sparks a New Energy Industry," Oil & Gas Journal, Vol. 87, No. 41 (October 9), pp. 49-56.

Mantek, W.E., Derrick, A.M., Jenkins, J.S., Knobloch, M., Rochester, D.A., Burgess, R.J., and Kent, H.C., eds., 1989. "Potential Supply of Natural Gas in the United States,". Potential Gas Agency, Colorado School of Mines, 160 p.

Mavor, M.J., Pratt, T.J., and Nelson, C.R., 1995a. "Quantitative Evaluation of Coal Seam Gas Content Estimate Accuracy," Paper SPE 29577, presented at the 1995 Joint Rocky Mountain Regional/Low-Permeability Reservoirs Symposium, Denver, CO (March 20-22).

Mavor, M.J., Pratt, T.J., and Nelson, C.R., 1995b. "Quantify the Accuracy of Coal Seam Gas Content," Petroleum Engineer International, Vol. 68, No. 10 (October), pp. 37-42.

Mavor, M.J., Pratt, T.J., Nelson, C.R., and Casey, T.A., 1996. "Improved Gas-In-Place Determination for Coal Gas Reservoirs," Paper SPE 35623, presented at the 1996 Gas Technology Symposium, Calgary, Alberta, Canada (April 28 - May 1).

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

McLennan, J.D., Schafer, P.S., and Pratt, T.J., 1995. "A Guide to Determining Coalbed Gas Content," GRI Report No. GRI-94/0396.

Nelson, C.R., Li, W., Lazar, I.M., Malik, A., and Lee. M.L., 1997. "Influence of Geologic Variables on the Content of Light Oils in U.S. Coals," Paper 9731, Proceedings 1997 International Coalbed Methane Symposium, University of Alabama, Tuscaloosa, AL (May 12-16), pp. 313-322.

Nelson, C.R., 1998. "Advances in Coalbed Reservoir Gas-In-Place Analysis," GasTIPS, Vol. 4, No. 1 (Winter 1997/1998), pp. 14-19.

Nelson, C.R., 1999a. "Gem In The Rough, Technology, Economics Putting New Shine On Coalbed Methane," The American Oil and Gas Reporter, Vol. 42, No. 3 (March), pp. 85-92.

Nelson, C.R., 1999b. "Critical Assessment of Coalbed Reservoir Gas-In-Place Analysis Methods," Paper 9916, Proceedings 1999 International Coalbed Methane Symposium, University of Alabama, Tuscaloosa, AL (May 3-7), pp. 77-90.

Nelson, C.R., 1999c. "Gas Research Institute North American Coalbed Methane Resource Map," GRI Report No. GRI-99/0131.

Pratt, T.J., Mavor, M.J., and DeBruyn, R.P., 1999 "Coal Gas Resource and Production Potential of Subbituminous Coal in the Powder River Basin," Paper SPE 55599, Proceedings SPE Rocky Mountain Regional Meeting, Gillette, WY (May 15-18), p. 195-204.

Pierce, D.L, Byrd, L.D. Dwight, K.H., Haun, J.D., Heinz, D.R., Kelley, A.L., Schwochow, S.D., Curtis, J.B., Decker, M.K., and Jenkins, J.S., eds., 1999. "Potential Supply of Natural Gas in the United States," Potential Gas Agency, Colorado School of Mines, 195 p.

Rieke, H.H., Kirr, J.N., 1984. "Geologic Overview, Coal, and Coalbed Methane Resources of the Arkoma Basin – Arkansas and Oklahoma," in Coalbed Methane Resources of the United States, AAPG Studies in Geology Series #17, Rightmire, C.T., Eddy, G.E., and Kirr, J.N., eds., American Association of Petroleum Geologists, Tulsa, OK, pp. 135-161.

Schraufnagel, R.A., Hill, D.G., and McBane, R.A., 1994. "Coalbed Methane - A Decade of Success," Paper SPE 28581, 69th Annual Technical Conference and Exhibition of the Society of Petroleum Engineers, New Orleans, LA (September 25-28).

Smith, T.N., 1995. "Coalbed Methane Potential for Alaska and Drilling Results for the Upper Cook Inlet Basin," Paper 9501, Proceedings INTERGAS '95, Tuscaloosa, AL, pp. 1-21.

Stevens, S.H., Kuuskraa, J.A., and Schraufnagel, R.A., 1996. "Technology Spurs Growth of U.S. Coalbed Methane," Oil and Gas Journal, Vol. 94, No. 1 (January 1), pp. 56-63.

Stevens, S.H., Schoeling, L, and Pekot, L., 1999. "CO2 Injection for Enhanced Coalbed Methane Recovery: Project Screening and Design," Paper 9934, Proceedings 1999 International Coalbed Methane Symposium, University of Alabama, Tuscaloosa, AL (May 3-7), pp. 309-317.

Tyler, R., Ambrose, W.A., Scott, A.R., and Kaiser, W.R., 1991. "Coalbed Methane Potential of the Greater Green River, Piceance, Powder River, and Ration Basins," Gas Research Institute Topical Report GRI-91/0315.

OKLAHOMA GEOLOGICAL SURVEY
OPEN-FILE REPORT OF 6-99

2

Review of key hydrogeologic factors affecting coalbed methane producibility and resource assessment

Andrew R. Scott
Bureau of Economic Geology
Austin, TX

Scott, A.R., 1999, Review of key hydrogeologic factors affecting coalbed methane producibility and resource assessment, <u>in</u> Oklahoma coalbed-methane workshop: Oklahoma Geological Survey, Open-File Report OF 6-99, p. 12-36.

Review of Key Hydrogeologic Factors Affecting Coalbed Methane Producibility and Resource Assessment

Andrew R. Scott
Bureau of Economic Geology
The University of Texas at Austin
Austin, Texas 78713-8924

ABSTRACT

Geologic and hydrologic comparisons of several coal basins indicate that depositional systems and coal distribution, coal rank, gas content, permeability, hydrodynamics, and tectonic/structural setting are critical controls on coalbed methane producibility. A dynamic interplay among these controls determines high coalbed methane productivity. This paper reviews a basin-scale exploration model for the prolific and marginal gas production in two basins that can be applied to evaluation of coalbed methane potential in coal basins worldwide. High productivity is governed by (1) thick, laterally continuous coals of high thermal maturity; (2) moderate to high permeability; (3) basinward flow of ground water through coals of high rank orthogonally toward no-flow boundaries (regional hingelines, fault systems, facies changes, and/or discharge areas); (4) generation of secondary biogenic gases; and (5) conventional trapping of migrated thermogenic and secondary biogenic gases at permeability barriers to provide additional gas beyond that generated during coalification. Understanding the dynamic interaction among geologic and hydrologic factors is important for delineating areas within basins that potentially have higher coalbed methane productivity.

INTRODUCTION

Coalbed methane is an important part of the natural gas supply for the United States and now represents more than 6 percent of total gas production and 7 percent of dry gas proved reserves (Energy Information Administration, 1998). Although coal gas exploration and development was initially performed by major oil companies and larger independents, smaller operators have played a progressively more important role in developing this natural resource. Coal gas resources are estimated to be more than 690 Tcf (19.5 Tm^3), more than 80 percent of which is located in the western United States (Figure 1).

Annual coal gas production has increased from less than 10 Bcf in 1986 to more than 1,003 Bcf (28.9 Bm^3) in 1996 (Figure 2). Although more than 80 percent of current coal gas production is derived from the San Juan Basin, coal gas production from other western basins continues to increase. Coal gas proved reserves remained relatively constant, increasing slightly over the past 4 years, and are currently estimated to be approximately 11.5 Tcf (325 Bm^3). The increase in proved coal gas reserves despite the significant increase in production is attributed to the efforts of smaller operators and independents in finding new reserves. Coal gas production and reserves are expected to increase as exploration continues in unexplored areas and as secondary recovery techniques using nitrogen or carbon dioxide are employed.

The traditional view of production from coalbed methane reservoirs is inadequate to explain the contrasts in methane producibility of coal basins. This paper presents our explanation of the geological and hydrological controls that are critical to coalbed methane producibility. In the traditional view, coal gases are generated in situ during coalification and are stored primarily in micropores on the coal matrix's large internal surface area by sorption (Thimons and Kissell, 1973). The sorption process is pressure dependent, and the gas is held in coal micropores by the pressure of water in the coal's natural fracture network, or cleat system (Kolesar and others, 1990). Gas production is achieved by reducing the reservoir pressure through dewatering and thus liberating the gases from the coal matrix into the cleat system for flow to the well bore. The traditional view is oversimplified because it fails to recognize the need for additional sources of gas beyond that generated initially during coalification to achieve high gas content following basinal uplift and cooling. Migrated conventionally and hydrodynamically trapped gases, in-situ-generated secondary biogenic gases, and solution gases are required to achieve high gas contents or fully gas saturated coals for consequent high productivity. To delineate the presence and origin of these additional sources of gas requires an understanding of the interplay among coal distribution, coal rank, gas content, hydrodynamics, depositional fabric, and structural setting (Kaiser and others, 1995).

Controls Critical to Coal Gas Producibility

Coalbed methane exploration strategies are often based only on the location of the greatest net coal thickness and ignore other hydrologic and geologic factors affecting coalbed methane producibility. Coalbed methane producibility is determined by the complex interplay among six critical controls: depositional systems and coal distribution, coal rank, gas content, permeability, hydrodynamics, and tectonic/structural setting (Figures 3 and 4). If one or more of these key hydrogeologic factors is missing, then the potential for higher coalbed methane producibility is reduced. However, the coalbed methane play may remain economically viable. For example, the Piceance Basin is characterized by exceptionally high gas content values (more than 700 scf/ton; 21.8 cm^3/g), but coalbed methane production has been limited because of low permeability. The Powder River Basin remains economically successful with gas contents generally less than 30 scf/ton (0.9 cm^3/g), however, because thick (more than 100 ft; 30 m) coal beds are present at shallow depths. A review of each hydrogeologic factor will be followed by examples from the San Juan and Greater Green River Basins.

Depositional Setting and Coal Distribution

Coal beds are the source and reservoir for methane, indicating that their widespread distribution within a basin is critical to establishing a significant coalbed methane resource. Coal distribution is closely tied to the tectonic, structural, and depositional settings (Figure 4a) because peat accumulation and preservation as coal require a delicately balanced subsidence rate that maintains optimal water-table levels but excludes disruptive clastic sediment influx. The depositional systems define the substrate upon which peat growth is initiated and within which the peat swamps proliferate. Net coal thickness trends and depositional fabric strongly influence migration pathways and the distribution of gas content. The depositional setting also controls the types of organic matter (macerals) that affect sorption characteristics and the quantity of hydrocarbons produced from the coal. Knowledge of depositional framework enables prediction of coal bed thickness, geometry, and continuity and, therefore, the location of potential coalbed methane resources.

Tectonic and Structural Setting

The tectonic and structural setting of a basin control the distribution and geometry of coal beds in the basin during deposition and, therefore, exert a strong control on the lateral variability of maceral (Figure 4b). Both the burial history and stress direction control the timing of cleat development in various parts of the basin and the final orientation of face cleats. The basin burial history and variability of regional heat flow control coalification and the types and quantities of thermogenic gases generated from the coals. Additionally, present-day in situ stress directions may significantly affect coalbed methane producibility. Stress directions orthogonal to face cleats will lower permeability, whereas stress directions parallel to face cleat orientation may enhance permeability. Uplift and basinal cooling often result in undersaturation with respect to methane in the coals and possible degassing of coal beds. Finally, the location and geometry of faults may strongly influence the recharge of meteoric water and, therefore, the generation of biogenic gases.

Coal Rank and Gas Generation

Coals must reach a certain threshold of thermal maturity (vitrinite reflectance values between 0.8 and 1.0 percent; high-volatile A bituminous) before large volumes of thermogenic gases are generated. The amount and types of coal gases generated during coalification are a function of burial history, geothermal gradient, maceral composition, and coal distribution within the thermally mature parts of a basin (Figure 4c). Gases in coal beds may also be formed through the process of secondary biogenic gas generation. Secondary biogenic gases are generated through the metabolic activity of bacteria, introduced by meteoric waters moving through permeable coal beds or other organic-rich rocks. Thus, secondary biogenic gases differ from primary biogenic gases because the bacteria are introduced into the coal beds after burial, coalification, and subsequent uplift and erosion of basin margins. The bacteria metabolize wet gas components, n-alkanes, and other organic compounds at relatively low temperatures (generally less than 150°F; 56°C) to generate methane and carbon dioxide. Secondary biogenic gases are known to occur in subbituminous through low-volatile bituminous and higher rank coals (Scott, 1993, 1994).

Gas Content

Gas content is one of the more important controls of coalbed methane producibility, yet it is often one of the more difficult parameters to accurately assess. Gas content is not fixed but changes when equilibrium conditions within the reservoir are disrupted, and it is strongly dependent upon other hydrogeologic factors and reservoir conditions (Scott and Kaiser, 1996) (Figures 4d and 5). The distribution of gas content varies laterally within individual coal beds, vertically among coals within a single well, and laterally and vertically within thicker coal beds. In general, gas content increases with depth and coal rank but is often highly variable owing to geological heterogeneities, the type of samples taken, and/or the analytical laboratory. The gas content of coals can be enhanced, either locally or regionally, by generation of secondary biogenic gases or by diffusion and long-distance migration of thermogenic and secondary biogenic gases to no-flow boundaries such as structural hingelines or faults for eventual resorption and conventional trapping.

Permeability

Permeability in coal beds is determined by its fracture (cleat) system, which is in turn largely controlled by the tectonic/structural regime, as mentioned previously (Figure 4e). Cleats are the permeability pathways for migration of gas and water to the producing well head, and cleats may either enhance or retard the success of the coalbed methane completion. Permeability will decrease with increasing depth, suggesting that in the absence of structurally enhanced permeability at depth, coalbed methane production may be limited to depths less than 5,000 to 6,000 ft (1,524 to 1,829 m). Permeability is highly variable in coal beds ranging from darcies to microdarcies, but the most highly productive wells have permeability ranging between 0.5 to 100 md (Figure 6). Permeability that is too high results in high water production and may be as detrimental to the economic production of coalbed gas as extremely low permeability. Permeability strongly influences the recovery of coal gases from the reservoir (Figure 7).

Hydrodynamics

Hydrodynamics strongly affects coalbed methane producibility and includes the movement of meteoric water basinward as well as the migration of fluids from deeper in the basin. Basinward migration of ground water is intimately related to coal distribution and depositional and tectonic/structural setting because ground-water movement through coal beds requires recharge of laterally continuous permeable coals at the structurally defined basin margins (Figure 4f). Coal beds not only act as conduits for gas migration but also are commonly ground-water aquifers having permeabilities that are orders of magnitude larger than associated sandstones. The presence of appreciable secondary biogenic gas indicates an active dynamic flow system with overall permeability sufficient for high productivity. Migration of thermogenic gases may result in abnormally high gas contents in lower rank coals or coals that are saturated or oversaturated with respect to methane. Basin hydrogeology, reservoir heterogeneity, location of permeability barriers (no-flow boundaries), and the timing of biogenic gas generation and trap development are critical for exploration and development of unconventional gas resources in organic-rich rocks.

Simply knowing the characteristics of the geological and hydrological controls will not lead to a conclusion about coalbed methane producibility because it is the complex interplay among these controls and their spatial relationships that governs producibility; high coalbed methane productivity requires a synergistic interplay among these controls. This synergy is evident in a comparison of the San Juan and Greater Green River/Sand Wash Basins. The Sand Wash Basin is a subbasin of the Greater Green River Basin, where net coal beds are thickest and coalbed methane industry activity is highest (Kaiser and others, 1994a; Tyler and others, 1995)

Interplay of Controls in the San Juan and Sand Wash Basins

In terms of controls critical to coalbed methane production, the San Juan and Sand Wash Basins share comparable characteristics (Figure 8). The San Juan Basin has moderate permeability and low to high water production, whereas the Sand Wash Basin has high permeability and water production. Low to high coal rank and gas contents of the San Juan Basin are comparable to the low to moderate coal rank and gas contents of the Sand Wash Basin. Comparison of these basins, however, indicates a number of fundamental differences in the interplay of the geological and hydrological attributes, which help explain the contrasts in coalbed methane productivity.

San Juan Basin

The Upper Cretaceous Fruitland Formation is the major coalbed methane exploration target in the San Juan Basin. Fruitland coals are best developed in the north-central part of the basin (Figure 9a) and occur in several major northwest-trending belts that parallel depositional strike and are intersected by secondary northeast-trending belts parallel to depositional dip. Net coal thickness in the main northwest-trending belt is typically 50 ft (15 m) and locally exceeds 100 ft (30 m), whereas the dip-elongate belts typically contain from 30 to 50 ft (9 to 15 m) of net coal. The strike-parallel coals formed just landward of the progradational shorelines of the underlying Pictured Cliffs Sandstone, and the dip-oriented coals were deposited in the interchannel areas between northeast-trending Fruitland rivers, which supplied sediment to the prograding Pictured Cliffs shorelines (Ambrose and Ayers, 1991; Ayers and Kaiser, 1994). The structural setting of the basin is characterized by steep dips around the northwestern, northern, and eastern margins, horizontal strata on the central basin floor, and a monocline dipping approximately 1° to the northeast in the southern half of the basin. The intersection of the monocline in the southern half of the basin with the nearly horizontal strata in the central part of the basin defines a 6- to 10-mi-wide (9.6- to 16-km) structural hingeline (Figure 9a), which is inferred from the coincidence of several geological anomalies such as a change in structural attitude, a fault zone, facies transitions, marked changes in reservoir pressure, coal gas composition, and formation water (Ayers and Kaiser, 1994).

Coal-rank trends do not correspond to the present structural configuration of the basin. Although lower rank high-volatile C bituminous coals occur in the shallow southern part of the basin and along the basin margins and coal rank generally increases in the deeper parts of the basin, the highest rank coal (low-volatile bituminous) occurs at intermediate depths in the northernmost part of the basin. The coal-rank trends suggest that significant local, postcoalification basin uplift and/or higher heat flux occurred in this area (Scott and others, 1991). The gas content of Fruitland coals generally increases with burial depth and pressure but does not necessarily correspond to increasing rank; high-volatile A bituminous coals along the structural hingeline have gas contents (400 to 600 scf/ton = 12.48 to 18.72 cm^3/g) that would normally be expected of medium- and low-volatile bituminous coals. These unusually high gas contents in lower rank coals are related to conventional hydrodynamic trapping of migrated gases along a structural hingeline (Kaiser and Ayers, 1991; Ayers and Kaiser, 1992, 1994) and generation of secondary biogenic gases from the coals (Scott and others, 1991, 1994a).

Ground-water recharge occurs mainly at the elevated, wet, northern basin margin in the foothills of the San Juan Mountains. The strongly cleated Fruitland coals are the primary aquifers and are orders of magnitude more permeable than associated low-permeability sandstones. These coal beds accept and transmit recharge from the outcrop belt along the northern basin margin basinward (southward), where flow turns sharply up at the basinward pinch-out of the coals and/or at their offset near faults along the structural hingeline (no-flow boundary). Ground water flows orthogonally toward the no-flow boundary through the area of highest rank coals, resulting in relatively large volumes of gas to be dissolved or entrained and swept basinward in meteoric water for resorption and conventional trapping along the structural hingeline (Kaiser and Ayers, 1991).

Greater Green River/Sand Wash Basin

The Upper Cretaceous Williams Fork Formation and lower Tertiary Fort Union Formation are the major coal-bearing units in the greater Green River Basin. Upper Cretaceous coals are widespread and thickest in the southeastern half of the Greater

Green River Basin, predominantly in the Sand Wash Basin (Figure 9b) where average net coal thickness exceeds 200 ft (>61 m). The thickest, most laterally extensive coals accumulated in a coastal-plain setting behind northeast-southwest-oriented linear-shoreline systems. Bypass of coarse clastic sediment, maintenance of high water tables, and optimal rate of subsidence in this setting provided ideal conditions for peat accumulation and preservation (Hamilton, 1993).

The major lower Tertiary coalbed methane target of the Sand Wash Basin is the lower coal-bearing unit of the Paleocene Fort Union Formation (Tyler and others, 1994, 1995). Deposition of the Fort Union Formation was controlled by syntectonic sedimentation, and depositional systems consist of intermontane-fluvial, floodplain, lacustrine, and paludal deposits. The lower coal-bearing unit of the Fort Union Formation contains north-trending fluvial sandstones and floodplain coal beds, which are laterally continuous above the thickest intermontane fluvial-trunk stream development in the center of the basin. An increase in the suspended load carried by the fluvial system resulted in the building of levees that stabilized the channel axes and allowed the formation of extensive floodplains. Coal beds are thicker and more numerous in floodplain areas above and on the flanks of the thickest fluvial sandstones, where some of the thickest individual coal beds are as much as 50 ft (15 m) thick. Net coal thickness ranges from 0 to 80 ft (0 to 24 m) in as many as 12 seams at depths as much as 8,000 ft (2,440 m) below surface (Tyler and others, 1994, 1995).

Despite good reservoir quality, low gas content and hydrodynamics account for the low gas production and high water production to date from coals in the Sand Wash Basin. The low to moderate gas contents in the basin reflect lower coal rank. Most coal beds are high-volatile C to B bituminous rank or lower, having gas contents generally less than 200 scf/ton (<6.24 cm^3/g). Lower Williams Fork coals were not deposited in the western part of the basin where the highest levels of thermal maturity occur and thus could not serve as conduits for long-distance migration of gas (Figure 9b). Moreover, the regional ground-water flow is east to west, from areas of low thermal maturity to high thermal maturity, indicating that relatively small volumes of coal gas may be available for solution and entrainment for basinward resorption and conventional trapping (Kaiser and others, 1994b). High permeabilities of the Upper Cretaceous coal beds (tens to thousands of millidarcys) and their communication with recharge areas at the eastern and southern outcrop belts contribute to excessive water production, which may prove to be uneconomical for coalbed methane production. The Williams Fork is hydraulically interconnected regionally with good vertical connectivity, reflecting a lack of seals and few permeability contrasts, which is also indicated by the absence of regionally extensive abnormal pressure regimes (Kaiser, 1993). The absence of permeability contrasts decreases the chances for conventional trapping and increases the chances for gas loss through flushing.

Basin Comparison

Simply understanding the geologic and hydrologic characteristics of a basin will not lead to a conclusion about coalbed methane producibility because it is the interplay among geologic and hydrologic controls on production and their spatial relation that governs producibility. High producibility requires that controls be synergistically combined. The importance of this synergism to coalbed methane producibility is evident in a comparison of the prolific San Juan Basin and marginally producing Sand Wash Basin, which are thought to represent end members of a producibility continuum (Figure 9a and 9b). Areas of thick coal and high thermal maturity coincide in the San Juan Basin to maximize thermogenic methane generation, whereas coals are absent in the most thermally mature part of the Sand Wash Basin, thus minimizing thermogenic methane generation. In the San Juan Basin, ground water flows through higher rank coals toward a structural hingeline and associated permeability barrier, or no-flow boundary. However, in the Sand Wash Basin, ground water flows across an area of low thermal maturity toward a major fault zone that is leaky to flow.

Because of the dynamic interaction among geologic and hydrologic factors in the San Juan Basin, a relatively large volume of gas is available to be swept basinward for conventional trapping at the hingeline and, coupled with high coal permeability, accounts for exceptionally high gas production and relatively low water production along this zone. Additionally, secondary biogenic gases were generated by bacteria transported basinward by meteoric water moving through permeable coal beds. Therefore, trapping of thermogenic and secondary biogenic gases along the hingeline combines conventional and hydrodynamic elements and provides an additional source of gas (Figure 10). The presence of permeability contrasts in the San Juan Basin is implicit in regional overpressure and underpressure (Kaiser, 1993), whereas their apparent absence in the Sand Wash Basin suggests good aquifer interconnectedness and less potential for conventional traps and trapping.

Resource Assessment

Accurately assessing coal and coalbed methane resources and delineating areas within basins that contain the largest resources are important aspects of resource development. The coalbed methane producibility model can be used to predict areas within basins that may have higher than expected gas contents. Gas content variability is one of the more difficult parameters to constrain during resource calculations (Scott and others, 1995). However, ash-free gas content data in addition to net coal thickness, coal rank, ash content, and ash-free and bulk coal density values can be contoured, digitized, and converted into a grid and note system for coal and coalbed methane resource calculations if sufficient data are available. Modified approaches to coal and coalbed methane resource calculations are required in the absence of sufficient data or well control (Scott and others, 1995). Accurate assessment of resources and application of the producibility model may provide a basis for economic evaluation of coal and coalbed methane resources on the basis of incremental increases in drilling depth. Additionally, specific areas in the basin having large gas resources can be delineated, providing a basis for future exploration efforts. Therefore, accurate determination of coalbed methane resources is important in assessing the potential of future coalbed methane production.

CONCLUSIONS

The complex interplay and spatial relationship among coal distribution, coal rank, gas content, permeability, hydrodynamics, and depositional and tectonic/structural setting govern the occurrence and production of coalbed methane. High productivity requires that these controls be synergistically combined. In the San Juan Basin, they are combined synergistically, resulting in prolific production because ground water flows through thick coals of high thermal maturity toward a structural hingeline (no-flow boundary). The relatively large volume of gas available in thermally mature coals and secondary biogenic gases generated by bacteria after uplift and basinal cooling are swept basinward for conventional trapping along the hingeline, providing additional sources of gas beyond that sorbed initially on the coal surface. Conventional trapping plays a much more important role in coalbed methane production than is generally recognized. In the Sand Wash Basin, flow is basinward through thick coals of low thermal maturity, suggesting that only relatively small volumes of thermogenic gases are available to be swept basinward for conventional trapping along potential flow barriers. Moreover, Upper Cretaceous coals did not accumulate in the most thermally mature parts of the basin, indicating that relatively large volumes of thermogenic gases were never generated. Coalbed methane potential in the Sand Wash Basin was further inhibited by high coal permeability and interconnectedness, which promoted dynamic ground-water flow and, consequently, extremely high water production. The conceptual model provides a rationale for exploration and development strategies and has application in both the United States and frontier basins of China for evaluating coalbed methane resource potential or for finding "sweet spots" in basins having established production.

ACKNOWLEDGMENTS

This paper summarizes more than a decade of coalbed methane research performed by a creative research team consisting of W. R. Kaiser, Walter B. Ayers, Jr., Roger Tyler, Douglas S. Hamilton, and Andrew R. Scott. The encouragement and support of the Energy Minerals Division of the American Association of Petroleum Geologists is also acknowledged. Word processing was by Susan Lloyd, and editing was performed under the direction of Susie Doenges. Drafting was provided by the Graphics staff of the Bureau of Economic Geology under the supervision of Joel Lardon. The concepts discussed in this paper evolved from coalbed methane research funded by the Gas Research Institute under contracts 5087-214-1544 and 5091-214-2261. Publication was authorized by the Director, Bureau of Economic Geology, The University of Texas at Austin.

REFERENCES

Ambrose, W. A., and Ayers, W. B., Jr., 1991, Geologic controls on coalbed occurrence, thickness, and continuity, Cedar Hill field and the COAL site, *in* Ayers, W. B., Jr., and others, Geologic and hydrologic controls on the occurrence and producibility of coalbed methane, Fruitland Formation, San Juan Basin: Chicago, Gas Research Institute, Topical Report, GRI-91/0072, p. 47–68.

Ayers, W. B., Jr., and Kaiser, W. R., 1992, Coalbed methane occurrence and producibility, Fruitland Formation, Navajo Lake Area, San Juan Basin, New Mexico, *in* Ryan, B., and Cunningham, J., eds., Proceedings, The Canadian Coal and Methane Geoscience Forum: Alberta Geological Survey, Alberta Research Council, p. 4–20.

Ayers, W. B., Jr., and Kaiser, W. R., eds., 1994, Coalbed methane in the Upper Cretaceous Fruitland Formation, San Juan Basin, New Mexico and Colorado: The University of Texas at Austin, Bureau of Economic Geology Report of Investigations No. 218; Colorado Geologic Survey, Department of Natural Resources, Resource Series 31; and New Mexico Bureau of Mines and Mineral Resources Bulletin 146, 216 p.

Bryer, C. W., and Guthrie, H. D., 1999, Appalachian coals: potential reservoirs for sequestering carbon dioxide emissions from power plants while enhancing CBM production: Proceedings of the 1999 International Coalbed Methane Symposium, The University of Alabama, College of Continuing Education, Tuscaloosa, Alabama, p. 319–328.

Energy Information Administration, 1998, Crude oil, natural gas, and natural gas liquids reserves, 1997 Annual Report, DOE/EIA – 0216(97), Coalbed Methane, p. 34-35.

Hamilton, D. S., 1993, Stratigraphy and coal occurrence of the Upper Cretaceous Mesaverde Group, San Wash Basin, *in* Kaiser, W. R., and others, Geologic and hydrologic controls on coalbed methane: San Wash Basin, Colorado and Wyoming: Chicago, Gas Research Institute, Topical Report, GRI-92/0420, p. 23–49.

Kaiser, W. R., 1993, Abnormal pressure in coal basins of the western United States: The University of Alabama, Proceedings, 1993 International Coalbed Methane Symposium, paper 9333, v. 1, p. 173–186.

Kaiser, W. R., and Ayers, W. B., Jr., 1991, Geologic and hydrologic characterization of coalbed methane reservoirs, Fruitland Formation, San Juan Basin, Colorado and New Mexico: Richardson, Texas, Society of Petroleum Engineers, SPE paper 23458, v. 1, p. 173–186.

Kaiser, W. R., Scott, A. R., Hamilton, D. S., Tyler, Roger, McMurry, R. G., Naijiang, Zhou, and Tremain, C. M., 1994a, Geologic and hydrologic controls on coalbed methane: Sand Wash Basin, Colorado and Wyoming: The University of Texas at Austin, Bureau of Economic Geology Report of Investigations No. 220, and Colorado Geologic Survey, Department of Natural Resources, Resource Series 30, 151 p.

Kaiser, W. R., Hamilton, D. S., Scott, A. R., and Tyler, Roger, 1994b, Geological and hydrological controls on the producibility of coalbed methane: Journal of the Geological Society, v. 151, p. 417–420.

Kaiser, W. R., Scott, A. R., and Tyler, Roger, 1995, Geology and hydrology of coalbed methane producibility in the United States: analogs for the world: Tuscaloosa, The University of Alabama, Intergas '95 Short Course, 516 p.

Kolesar, J. E., Ertekin, T., and Obut, S. T., 1990, The unsteady-state nature of sorption and diffusion phenomena in the micropore structure of coal: part 1—theory and mathematical formulation: SPE Formation Evaluation, v. 5, p. 81–88.

Scott, A. R., 1993, Composition and origin of coalbed methane from selected basins in the United States: The University of Alabama, Proceedings, 1993 International Coalbed Methane Symposium, paper 9370, v. 1, p. 207–222.

Scott, A. R., 1994, Composition of coalbed gases: In Situ, v. 18, no. 2, p. 185-208.

Scott, A. R., 1999, Improving coal gas recovery with microbially enhanced coalbed methane, *in* Mastalerz, M., Glickson, M., and Golding, S. D., eds., Coalbed methane: scientific, environmental, and economic evaluation: Kluwer Academic Publishing, p. 89–110.

Scott, A. R., and Kaiser, W. R. , 1996, Factors affecting gas content distribution in coal beds: a review (exp. abs.), *in* Expanded abstracts volume, Rocky Mountain Section Meeting: American Association of Petroleum Geologists, p. 101–106.

Scott, A. R., Kaiser, W. R., and Ayers, W. B., Jr., 1991, Composition, distribution, and origin of Fruitland and Pictured Cliffs sandstone gases, San Juan Basin, Colorado and New Mexico, *in* Schwochow, S. D., ed., Coalbed methane of western North America: Rocky Mountain Association of Geologists Guidebook, p. 93–108.

Scott, A. R., Kaiser, W. R., and Ayers, W. B., Jr., 1994a, Thermogenic and secondary biogenic gases, San Juan Basin, Colorado and New Mexico—implications for coalbed gas producibility: American Association of Petroleum Geologists Bulletin, v. 78, no. 8, p. 1186–1209.

Scott, A. R., Tyler, Roger, Hamilton, D. S., Zhou, Naijiang, 1994b, Coal and coal gas resources of the Greater Green River Basin: application of an improved approach to resource estimation, *in* Sonneburg, S. A., compiler, Rocky Mountain Association of Geologists and Colorado Oil and Gas Association, First Biennial Conference: Lakewood, Colorado, Natural Gas in the Western United States, unpaginated (4 pages).

Scott, A. R., Zhou, Naijiang, and Levine, J. R., 1995, A modified approach to estimating coal and coal gas resources: example from the Sand Wash Basin, Colorado: American Association of Petroleum Geologists, v. 79, p. 1320–1336.

Thimons, E. P., and Kissell, F. N., 1973, Diffusion of methane through coal: Fuel, p. 274–280.

Tyler, Roger, Kaiser, W. R., Scott, A. R., Hamilton, D. S., McMurry, R. G., and Zhou, Naijiang, 1994, Geologic and hydrologic assessment of natural gas from coal seams in the Mesaverde Group and Fort Union Formation, Greater Green River Basin, Wyoming and Colorado: The University of Texas at Austin, Bureau of Economic Geology, topical report prepared for the Gas Research Institute under contract no. 5091-214-2261 (GRI-93/0320), 120 p.

Tyler, Roger, Kaiser, W. R., Scott, A. R., Hamilton, D. S., and Ambrose, W. A., 1995, Geologic and hydrologic assessment of natural gas from coal: Greater Green River, Piceance, Powder River, and Raton Basins, Western United States: The University of Texas at Austin, Bureau of Economic Geology, Report of Investigations No. 228, 219 p.

Zuber, M. H., 1999, Coalbed methane production and well completion methods: Workshop Notes on Developing a Model for Coalbed Methane Exploration and Production Technology in Louisiana, presented by the Central Gulf Region of the Petroleum Technology Transfer Council, September 1, 1999, Baton Rouge, Louisiana, variously paginated.

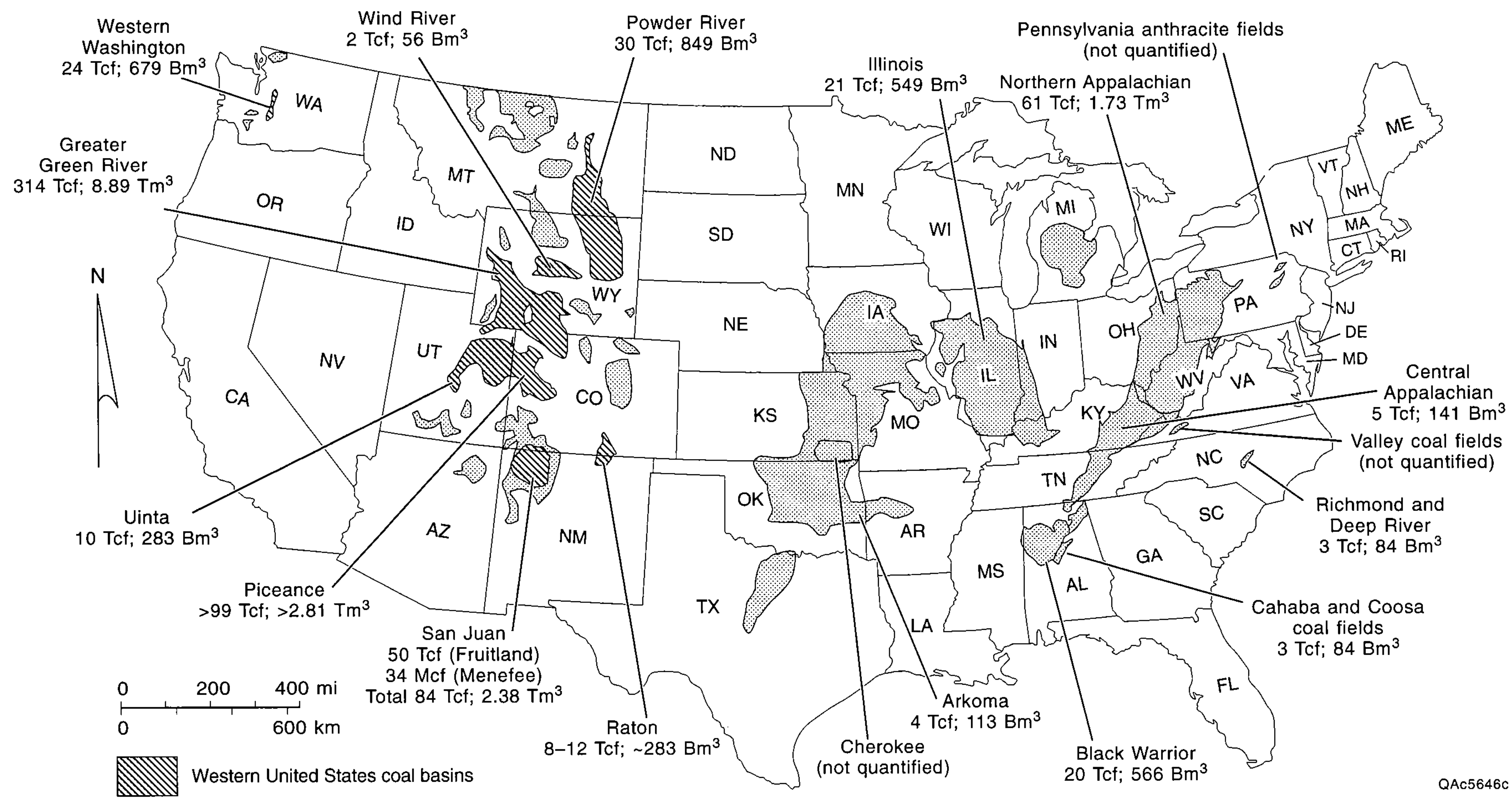


Figure 1. Coal basins and coalbed gas resources of the United States. Total coalbed gas resources are estimated at 690 Tcf (19.5 Tm^3). From Scott and others (1994b).

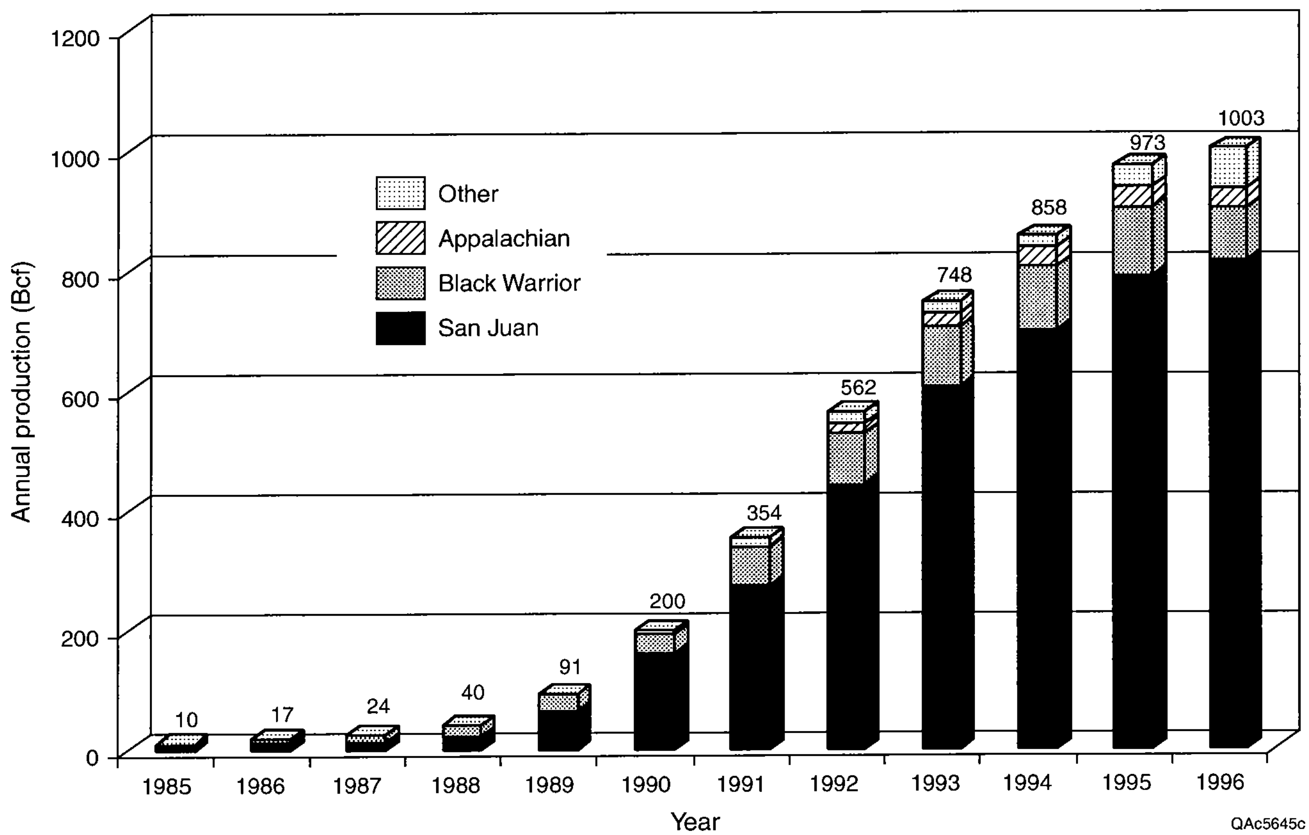


Figure 2. Coal gas production trends in the United States (Bryer and Guthrie, 1999). Coal gas production has increased significantly since 1985 and has consistently represented approximately 6 percent of the total dry gas production in the United States for the past several years.

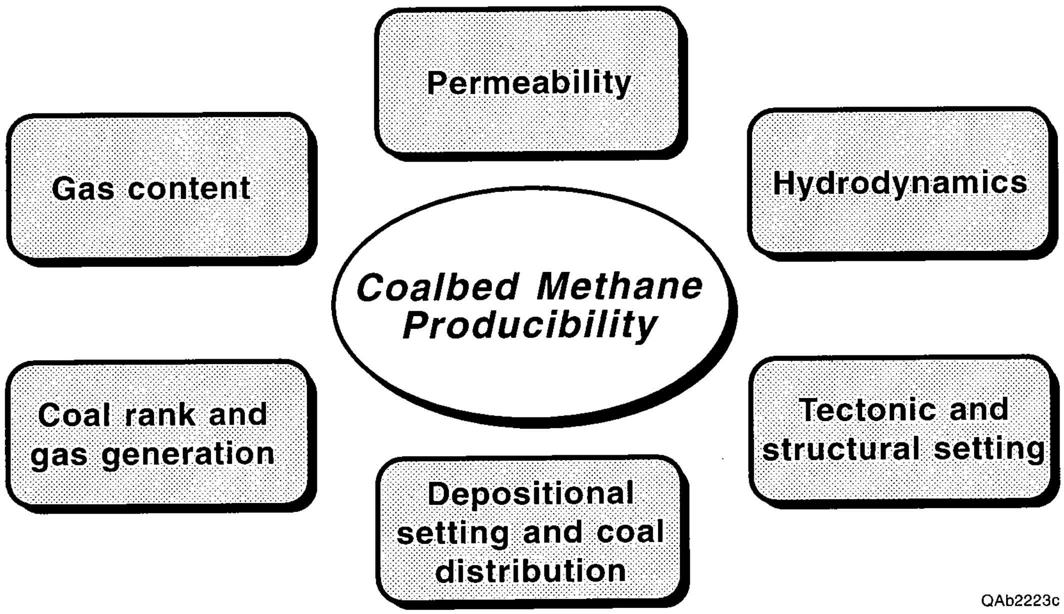


Figure 3. Geologic and hydrologic controls critical to coalbed gas producibility. A dynamic interaction among these controls and their spatial relations governs producibility.

(a)

DEPOSITIONAL SETTING AND COAL DISTRIBUTION	
Tectonic setting	Regionally affects geometry, occurrence, and thickness of coal beds
Hydrodynamics	Recharge and ground-water flow influenced by coal continuity and geometry
Permeability	Local permeability enhancement associated with compaction over sandstones
Gas content	Maceral composition affects gas sorption and desorption rates
Coal rank and gas generation	Maceral type affects hydrocarbon generation rates and types of hydrocarbons

(b)

TECTONIC AND STRUCTURAL SETTING	
Depositional setting	Regionally controls orientation, geometry, and occurrence of facies and coal beds
Coal rank and gas generation	Burial history, coalification, gas generation, and timing of cleat development
Gas content	Uplift and cooling produces undersaturation and possible degassing of coals
Permeability	Decreases with depth; cleat orientation; present-day in-situ stress; anticlines
Hydrodynamics	Hydrologic control on peat accumulation; uplift of basin margins for recharge; isolation of coals from outcrop

(c)

COAL RANK AND GAS GENERATION	
Gas content	Thermogenic gas generation may result in higher gas contents
Depositional setting	The presence of thick, thermally mature coals enhances coalbed methane producibility
Tectonic setting	Burial history controls coalification and thermogenic gas generation
Hydrodynamics	Wet gases and condensate converted into secondary biogenic methane by bacteria
Permeability	Cleat frequency and, therefore, permeability increase with increasing rank

QAc6447(a)c

Figure 4. Synergistic interplay among the key geologic and hydrologic factors affecting producibility. (a) depositional setting and coal distribution, (b) tectonic and structural setting, (c) coal rank and gas generation.

(d)

GAS CONTENT	
Coal rank and gas generation	Generally increases with coal rank and depth; updip migration; diffusion coefficients
Depositional setting	Macerals affect gas sorption and desorption; shale seals; coal thickness and continuity
Tectonic setting	Conventional trapping of gases at faults and anticlines; burial history; diagenesis
Hydrodynamics	Secondary biogenic methane; high or low gas content at convergent flow; low gas content possible near recharge zone
Permeability	High permeability near recharge zone may allow flushing and low gas content

(e)

PERMEABILITY	
Hydrodynamics	Meteoric recharge and enhanced permeability near outcrop; diagenesis in sands; low/high permeability detrimental
Tectonic setting	Permeability decreases with depth; present-day in-situ stresses; enhancement associated with structures; fault barriers
Depositional setting	Enhancement through compaction; sands as barriers; coal pinch-out; macerals and cleats
Coal rank and gas generation	Cleat frequency and, therefore, permeability increase with rank
Gas content	High permeability and flushing; high gas content and moderate permeability

(f)

HYDRODYNAMICS	
Tectonic setting	Uplifted margins; faults as flow barriers; flow enhancement along structures; isolation of outcrop coals; in-situ stresses; cross flow
Depositional setting	Permeability contrasts associated with facies; coal aquifer continuity; macerals and cleats
Coal rank and gas generation	Ground-water flow through higher rank coals; updip migration thermogenic gases
Gas content	High with convergent flow and permeability barriers; low near recharge, absence seals
Permeability	Water production implies permeability; high and low permeability detrimental; bacteria

QAc6447(b)c

Figure 4 (cont.). Synergistic interplay among the key geologic and hydrologic factors affecting producibility. (d) gas content, (e) permeability, and (f) hydrodynamics.

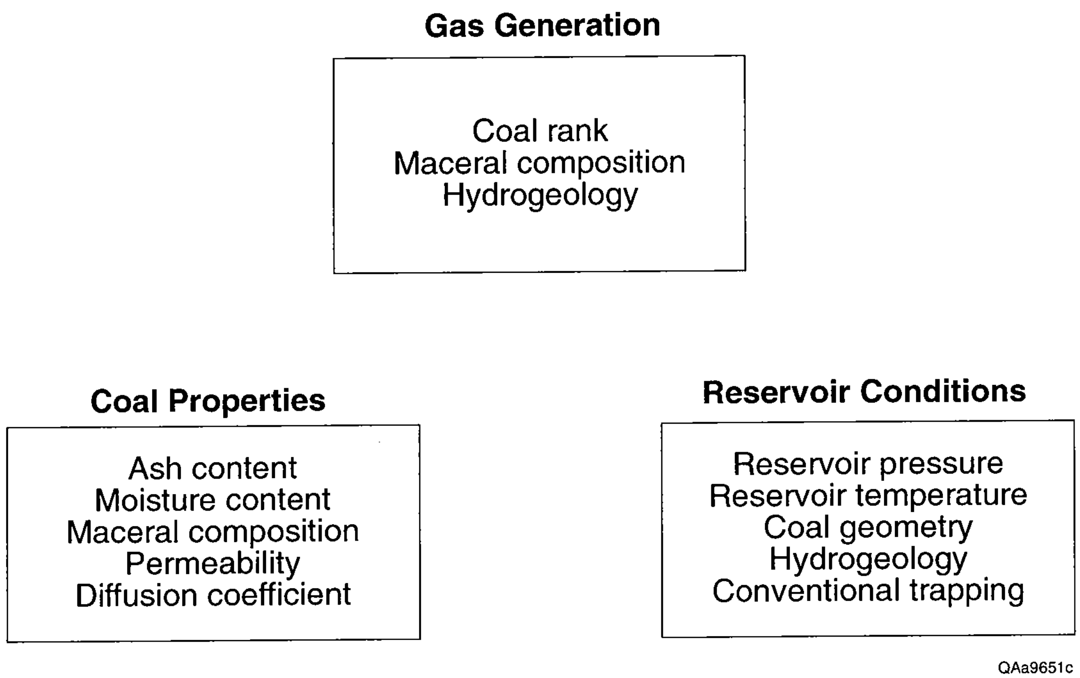


Figure 5. Primary factors affecting gas content distribution in coal beds. Gas content is not fixed but changes when equilibrium conditions in the reservoir change. From Scott and Kaiser (1996).

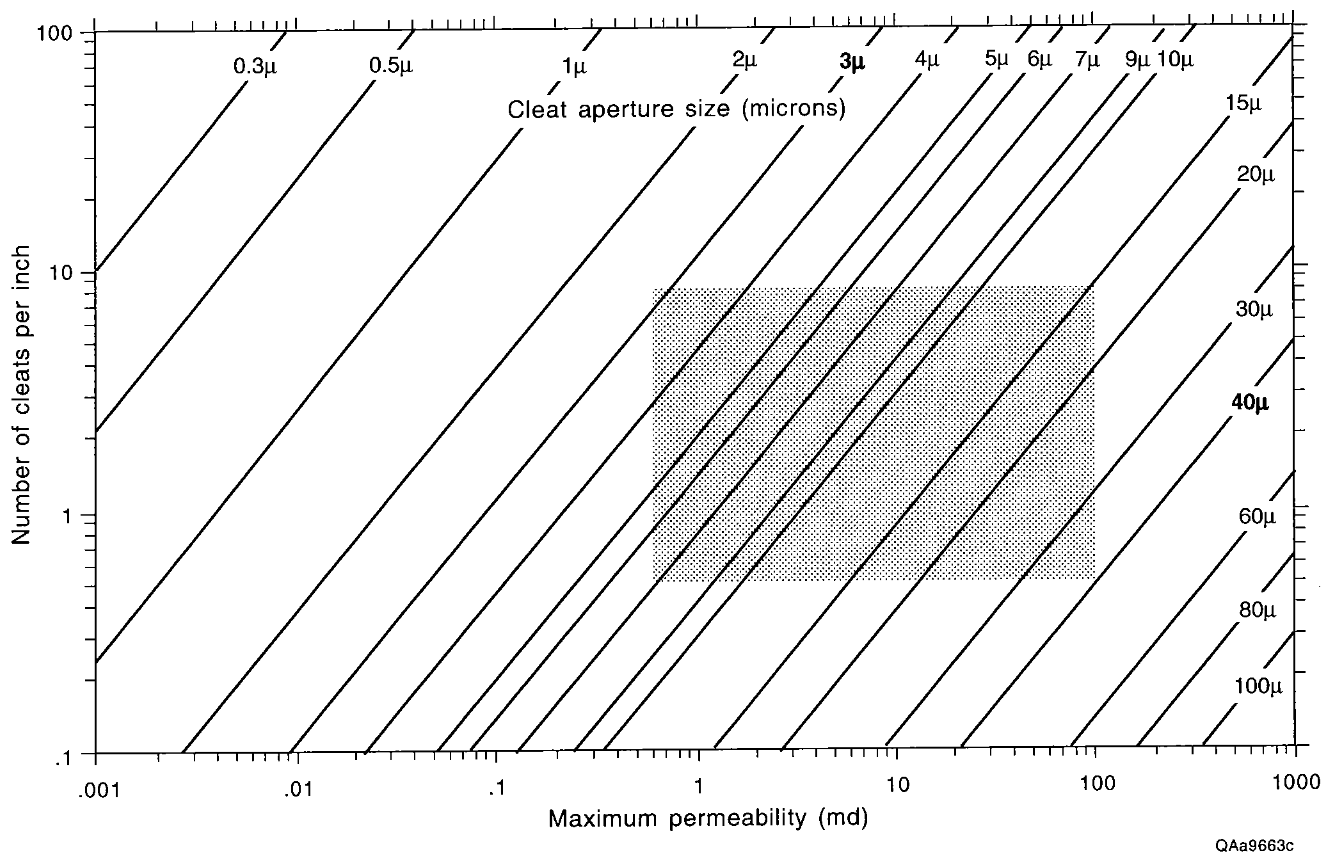


Figure 6. Relationship among face-cleat spacing, permeability, and cleat aperture. Cleat tortuosity will decrease fluid permeability, suggesting that cleat-aperture size in the subsurface may be larger than the apertures indicated on this figure. The range of permeability in highly productive coalbed methane wells in the San Juan and Black Warrior Basins is shown in the stippled pattern. From Scott (1999).

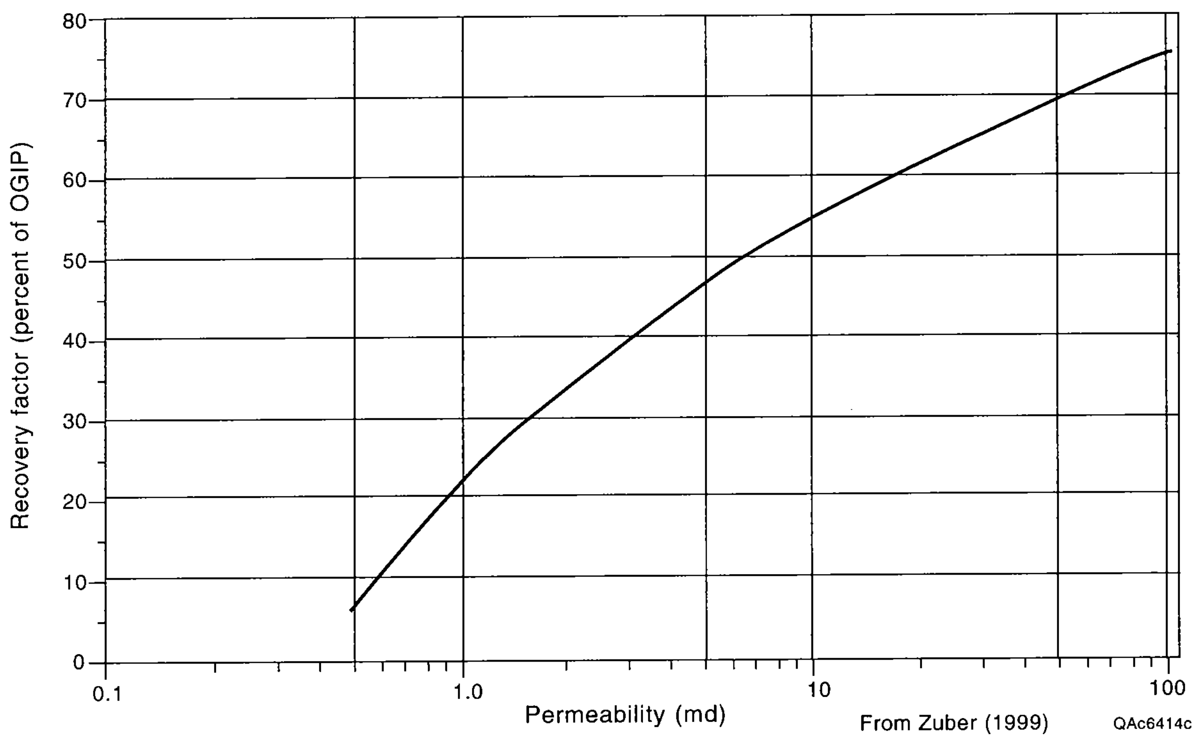


Figure 7. The effect of permeability on recovery efficiency in coalbed methane wells (Zuber, 1999).

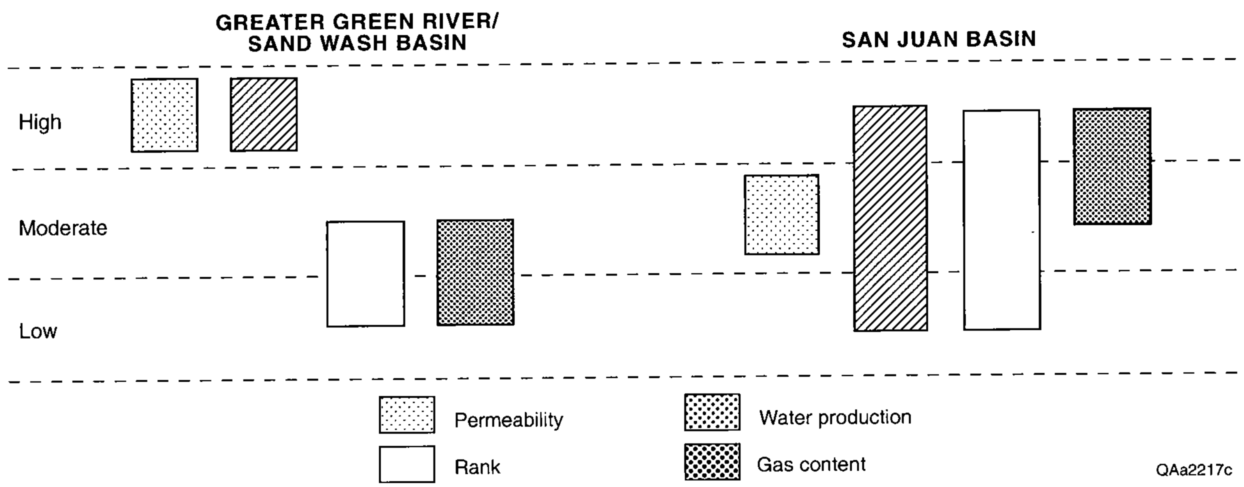


Figure 8. Characteristics of key geological and hydrological controls overlap in the San Juan and Sand Wash Basins. From Kaiser and others (1994b).

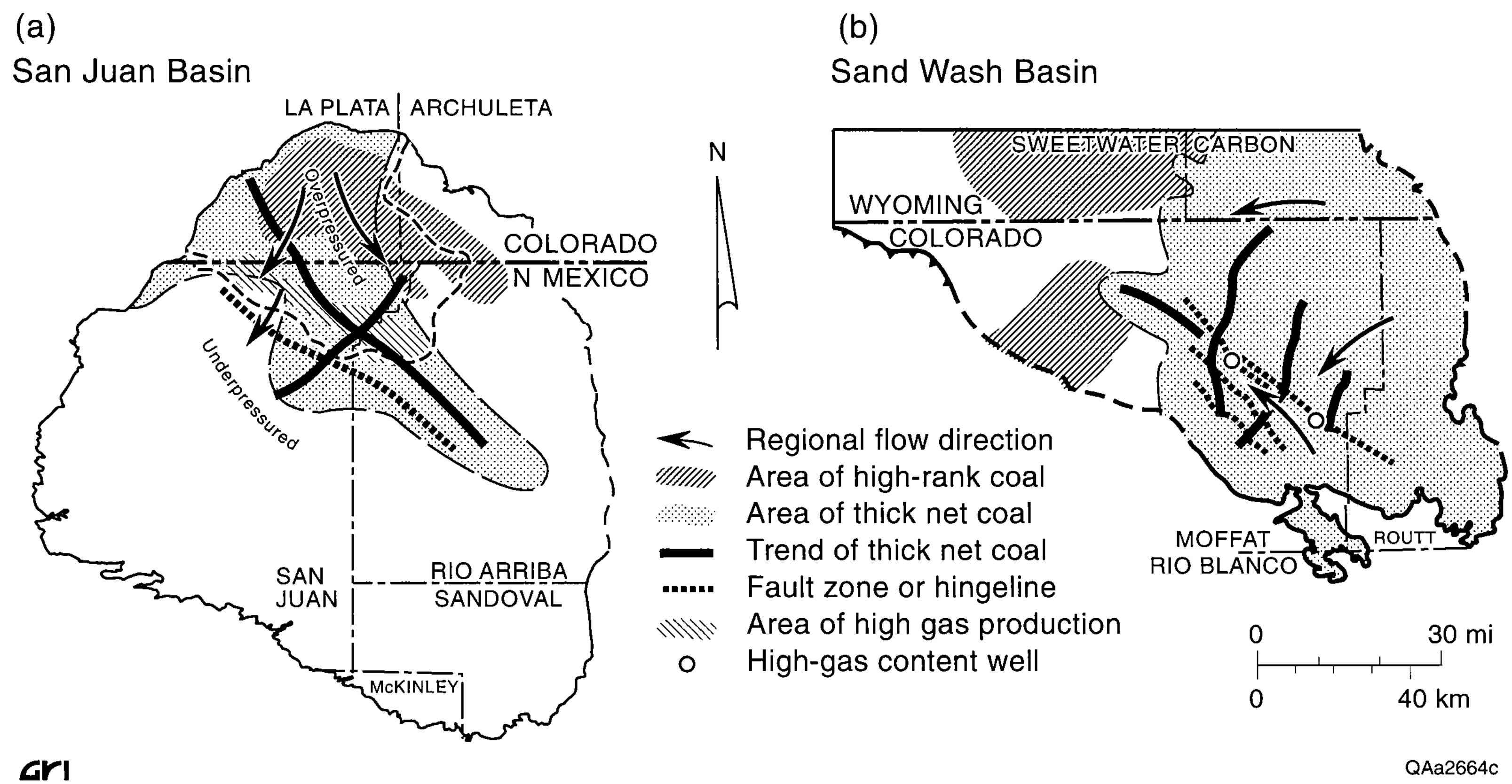


Figure 9. Geologic and hydrologic comparison of the San Juan and Sand Wash Basins. In the San Juan Basin, a hydrodynamic trap exists along a structural hingeline. Conventionally trapped gas and high coalbed permeability explain high gas production and relatively low water production at this point in the basin. In the Sand Wash Basin, flow is toward and along a leaky, regional thrust-fault system. Lack of seals and permeability contrasts limit the potential for conventional trapping of gas. From Kaiser and others (1994a).

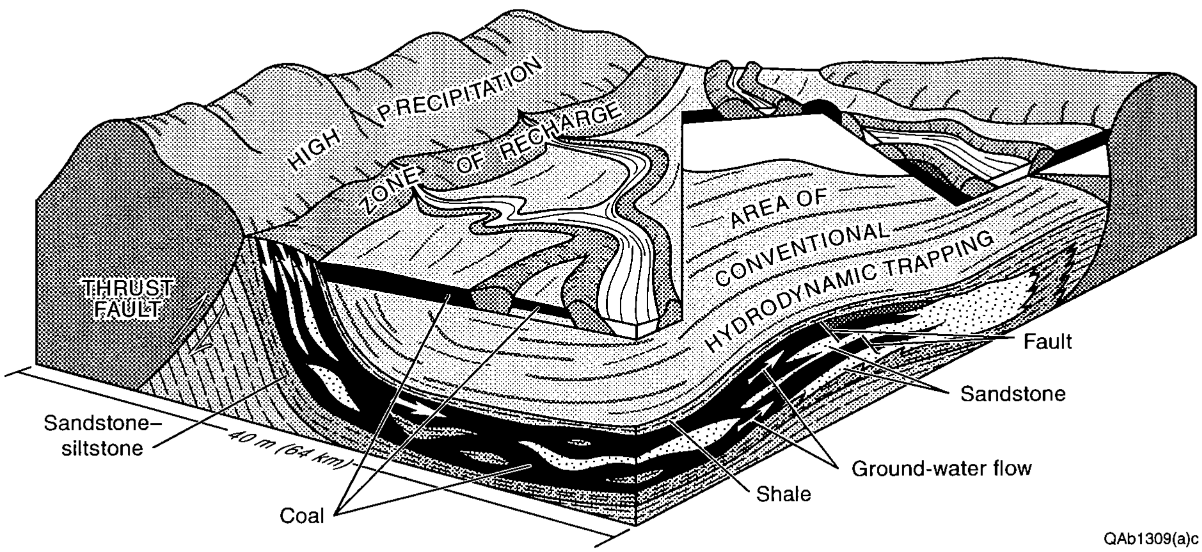


Figure 10. Conceptual model for high coalbed gas producibility based on the San Juan Basin, the most prolific coalbed-gas-producing basin in the world. The model's essential elements are (1) ground-water flow through coals of high rank and gas content orthogonally toward no-flow boundaries, (2) generation of secondary biogenic gases, and (3) conventional trapping of migrated and solution gases along those barriers.

OKLAHOMA GEOLOGICAL SURVEY
OPEN-FILE REPORT OF 6-99

3

Effects of coalbed reservoir property analysis methods on gas-in-place estimates

Charles R. Nelson
Gas Research Institute
Chicago, IL

Nelson, C.R., 1999, Effects of coalbed reservoir property analysis methods on gas-in-place estimates, in Oklahoma coalbed-methane workshop: Oklahoma Geological Survey, Open-File Report OF 6-99, p. 37-46.

Effects of Coalbed Reservoir Property Analysis Methods on Gas-In-Place Estimates

Charles R. Nelson

Gas Research Institute, Chicago, IL

INTRODUCTION

Coalbed reservoirs in the United States contain an estimated 703 trillion cubic feet (Tcf) of natural gas resources, hold 11.7% (141.4 Tcf) of the estimated total recoverable U.S. natural gas resource base, and currently account for 6% (1.13 Tcf) of total annual U.S. natural gas production.[1-5] Accurately determining the initial gas-in-place volume is one of the first crucial steps in coalbed gas resource and reservoir evaluation.[6,7] This key parameter influences the gas production rate and producible reserve potential of the reservoir.

The current perception of gas-in-place analysis results is that they may not be very reliable since the cumulative gas production volumes of numerous coalbed reservoirs have exceeded the initial gas-in-place values. For example, the 10-year cumulative gas production volume of the 23 coalbed gas wells at the Oak Grove Field in the Black Warrior Basin, Alabama totaled 3.2 billion cubic feet (Bcf), more than double the initial gas-in-place value of 1.55 Bcf.[8] This large variance indicates that the reservoir property values used to calculate the initial gas-in-place value were inaccurate.

Several case study evaluations have shown that many commonly used coalbed reservoir property analysis methods have inherent shortcomings that can result in large (50% or greater) underestimation error of the gas-in-place value.[1,9,10] This paper describes the inherent shortcomings of the most commonly used coalbed reservoir property analysis methods and identifies practical methods for avoiding or minimizing reservoir property analysis errors.[11-22]

GAS-IN-PLACE ANALYSIS

Gas-in-place volume is the total amount of gas stored within a specific, bulk reservoir rock volume. Four physical reservoir properties are needed to calculate the gas-in-place volume. These four properties are: (1) reservoir or well drainage area, (2) gross reservoir rock thickness, (3) average reservoir rock density, and (4) average in-situ gas content. **Equation 1** is the mathematical relationship linking these four reservoir properties with the total volume of gas stored within a specific, bulk reservoir rock volume.

$$G = 1359.7 A h \bar{\rho}_c \bar{G}_c \qquad (1)$$

Where:

G	gas-in-place, standard cubic feet (scf)
A	drainage area, acres
h	thickness, feet
$\bar{\rho}_c$	average in-situ density, g/cm^3
$\bar{G}_c$	average in-situ gas content, scf/ton

Errors in the four reservoir property values used in **Equation 1** limit the accuracy of gas-in-place analysis results. Accurately determining these four reservoir properties presents several unique data acquisition and analysis challenges.[20-22] These challenges arise from two major sources. The first is natural geologic heterogeneities that can dramatically vary the lateral coalbed reservoir thickness and continuity, drainage area geometry, and compositional properties of the bulk reservoir rock. The second is the propensity of coal to undergo irreversible compositional changes during storage and testing.

Different reservoir property analysis methods can give very different gas-in-place values.[20-22] **Table 1** compares the results from two published coal in-place and gas-in-place resource assessments for San Juan Basin Fruitland Formation coal.[23,24] The coal in-place resource values, which are the product of the first four terms in **Equation 1**, differ by only 10% whereas the gas-in-place resource values differ by 61%. This large gas-in-place resource value difference is primarily due to the use of different methods for determining the gas content of the coal. The lower gas-in-place resource value (31 Tcf) is primarily based on gas content data obtained from drill cutting samples while the higher gas-in-place resource value (50 Tcf) is solely based on gas content data obtained from conventional, whole core samples.[23,24]

TABLE 1. San Juan Basin Fruitland Formation Coal In-Place and Gas-In-Place Resources

Coal Resource (Billion Short Tons)	Gas Content Analysis Method	Gas Content Range (scf/ton)	Gas-In-Place (Tcf)	Ref.
200	Drill Cuttings	50 - 200	31	23
220	Conventional Core	50 - 500	50	24

RESERVOIR DRAINAGE AREA

Two common rule-of-thumb analysis practices when calculating drainage area are to assume that the lateral continuity of coalbed reservoirs is invariant and that the reservoir has a simple geometric shape that can be defined using physical surface parameters such as property limits, section boundaries, or well spacing intervals. **Figure 1** is a schematic cross section of a coalbed gas reservoir illustrating several common types of geologic structural and stratigraphic heterogeneities such as permeability facies changes, coal seam pinch outs, channel sandstone deposits, and fault offsets.[17,20-22] These geologic heterogeneities disrupt the lateral coalbed continuity. The magnitude of reservoir area error due to these types of geologic heterogeneities will be highly site dependent.

An accurate reservoir area analysis requires constructing detailed structural and stratigraphic maps as well as analysis of the fluid production characteristics of the reservoir. A geologic evaluation alone often will not detect lateral coalbed discontinuities but their presence will be indicated by unexpected patterns in gas or water production behavior.[17,20]

Another source of reservoir drainage area error is permeability anisotropy that can affect the shape and effective drainage area around the wellbores within a reservoir. Natural fractures, called cleats, are the primary conduits for bulk fluid flow in coalbed reservoirs.[25-27] Typically, the cleat system of coal comprises two orthogonal sets of subparallel fractures, called face and butt cleats, oriented essentially perpendicular to the bedding plane. The spacing, aperture, and effective porosity (i.e., total interconnected void volume) of these cleats strongly affect the reservoir permeability. These cleat properties are not uniform throughout the coal in a given reservoir but vary both vertically and laterally as a function of such geologic variables as coal rank, effective stress, and mineralization.

As a result of spatial cleat property variability there is commonly a significant horizontal permeability anisotropy in coalbed reservoirs.[26-30] This permeability anisotropy can cause the effective drainage area around a wellbore to have a pronounced elliptical shape, and, as a result, the effective drainage area may be substantially different than rule-of-thumb well spacing-based estimates of reservoir area. Well testing or laboratory core analysis is required to evaluate the magnitude of permeability anisotropy.[26-30] The magnitude of reservoir area error due to permeability anisotropy is highly site dependent.

RESERVOIR THICKNESS

Coal is an organic matter rich, sedimentary rock whose physical properties are, in general, quite different than those of other rock types commonly encountered in coal-bearing sedimentary sequences. Due to its organic richness, coal has a much lower bulk density than, for example, shale or sandstone, and as a result, the thickness of coal-bearing intervals can be determined using geophysical log data.

Coal density varies as a function of its bulk composition.[20,31,32] Gross coalbed thickness is commonly computed using high-resolution open-hole density log data by summing the thicknesses of the intervals having densities less than 1.75 g/cm^3.[17-22] **Figure 2** is an example of this type of analysis. This upper density limit value corresponds to the maximum, mineral matter content limit in the geologic definition of coal. According to this geologic definition, to be classified as coals, sedimentary rocks must contain less than 50% mineral matter by weight and more than 70% carbonaceous matter by volume.[33]

The commonly used coalbed reservoir thickness analysis practice is to use 1.75 g/cm^3 as the maximum log density value for the gas-bearing organic matter rich rocks comprising coalbed reservoirs.[17-22] It is commonly assumed that interbedded rocks having densities greater than 1.75 g/cm^3 have negligible gas storage capacity. The density of ash in San Juan Basin Fruitland Formation coal is typically 2.4 to 2.5 g/cm^3.[19-22] The amount of gas stored in coalbed reservoir rocks between density values of 1.75 and 2.5 g/cm^3 can be significant.

Figure 1. Coalbed Reservoir Geometry

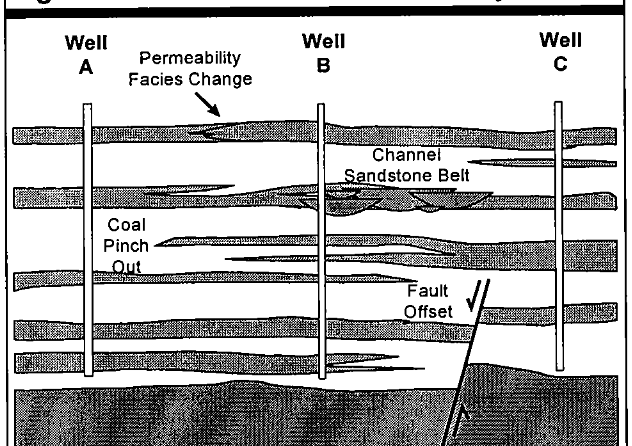
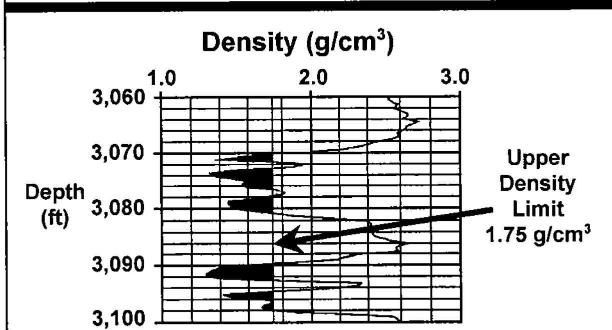


Figure 2. Coal Thickness Analysis

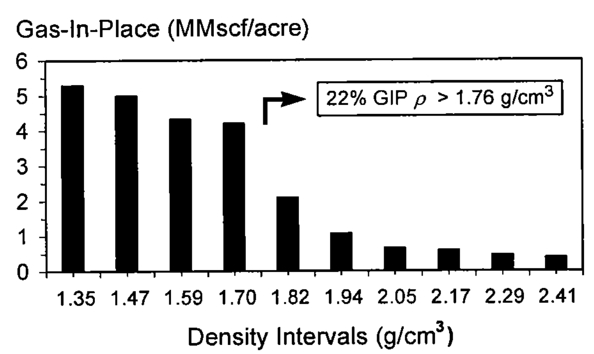


San Juan Basin Fruitland Fm. Open-Hole Density Log

Figure 3 shows a histogram of the gas-in-place distribution for a San Juan Basin Fruitland Formation coalbed reservoir as a function of the bulk reservoir rock density.[19-22] Most of the gas-in-place volume (78%) is contained within rocks having density values below 1.76 g/cm^3. However, if the reservoir thickness analysis were based upon a maximum log density value of 1.76 g/cm^3 the calculated reservoir gas-in-place volume (see Equation 1) would be 22% low.[19-22] In general, using the rule-of-thumb value of 1.75 g/cm^3 results in a calculated gross coalbed reservoir thickness value that is 15 to 50% low.[19-22]

Because the rule-of-thumb density log analysis practice can greatly underestimate the gross coalbed reservoir thickness and hence the gas-in-place volume there is significant potential for reserve estimate growth in many existing coalbed gas fields. As an example, Burlington Resources Oil & Gas Company recently reported[34] that reservoir simulation history matches of gas production data from its San Juan Basin Fruitland Formation coalbed gas wells could not be achieved if the analysis excluded the gas present in interbedded carbonaceous shales having densities greater than 1.75 g/cm^3.

Figure 3. Reservoir Gas-In-Place Distribution



IN-SITU DENSITY

The density of coal is a function of its composition.[20,31,32] Since the mineral matter component of coal has a significantly higher density than the bulk organic matter, in general, all other compositional factors being equal, coal density will be directly correlated with the mineral matter content. A major source of in-situ density analysis error is the assumption that the compositional properties of coalbed reservoirs are homogeneous. Coal compositional and density properties are not uniform throughout the bulk rock comprising a coalbed reservoir but vary both vertically and laterally as a function of such geologic variables as depositional environment, overlying and underlying rock lithologies, coal rank, equilibrium moisture content, mineral matter content, and maceral composition.[20,31,32]

Table 2 gives examples of the average vertical and lateral variations in ash content and in-situ density that occur in the intermediate and basal Fruitland Formation coalbed reservoirs at three well locations in the San Juan Basin.[20,22] These data illustrate the significant vertical and lateral compositional and in-situ density heterogeneity that can occur in coalbed reservoirs. The greater the heterogeneity, the greater the number of samples and sampling sites needed for accurate characterization of average in-situ reservoir properties. In general, compositional analysis data from reservoir samples having a broad range of mineral matter content are needed to accurately determine the average in-situ properties.[12,16,19,20]

A common practice in coalbed reservoir gas-in-place analysis is to use a rule-of-thumb value of 1.32 to 1.36 g/cm^3 for the in-situ reservoir rock density.[1,6,7] For vitrinite-rich bituminous rank coal, the organic matter density is about 1.295 g/cm^3 and the mineral matter density is about 2.497 g/cm^3.[20] The rule-of-thumb density value range of 1.32 to 1.36 g/cm^3 would only be appropriate for use with bituminous rank coal having an in-situ moisture content of about 1.5% and a mineral matter content range of about 5 to 10%.[20] The average mineral matter content of bituminous rank coalbed reservoirs in the San Juan, Uinta and Black Warrior Basins rarely corresponds to this narrow range of values.[6,8,9,20,35]

TABLE 2. San Juan Basin Fruitland Formation Coalbed Reservoir Properties

Well Name (Location)	Interval	Avg. Ash Content (%)	Avg. In-Situ Density (g/cm^3)	Avg. In-Situ Gas Content (scf/ton)
Southern Ute 5-7 (Section 7 T32N R11W)	Intermediate	27.2	1.49	370
	Basal	20.4	1.44	402
Valencia Canyon 32-1 (Section 32 T33N R11W)	Intermediate	36.4	1.56	425
	Basal	31.7	1.52	460
GRI # 2 (COAL Site) (Section 17 T32N R10W)	Intermediate	61.3	1.83	343
	Basal	43.3	1.63	512

Commonly, this rule-of-thumb density value range is significantly lower than the lowest in-situ density values recorded by high-resolution density logs for bituminous rank coalbed reservoirs (see **Figure 2**) or calculated using coal compositional data.[7,11,20,31,35] As shown in **Table 2**, the average in-situ density values for San Juan Basin Fruitland Formation coalbed reservoirs range from 1.44 to 1.83 g/cm^3.[19-22] Using these higher in-situ density values increases the gas-in-place value by 10 to 36%.[19-22]

The density log response of coal is a function of its bulk properties that, in turn, are a function of the rank, mineral matter, moisture, hydrocarbon gas, and carbonaceous matter composition and content of the coal. In general, the presence of adsorbed hydrocarbon gas has little effect on the density of coal. For example, an in-situ adsorbed methane content of 500 scf/ton increases the density of bulk coal organic matter by only 0.009 g/cm^3 or 0.7%.[20]

Moisture content affects the coal density. The moisture content varies inversely as a function of coal rank.[31,32,36] Bituminous rank coals have low in-situ moisture content values (< 10%) whereas subbituminous coals have very high in-situ moisture content values (>25%).[31,32,36,37] Powder River Basin subbituminous coalbed reservoirs are prolific sources of natural gas.[2-4,37,38] At a 5% ash content, Powder River Basin subbituminous coal has a dry-basis density of about 1.40 g/cm^3 but at an in-situ moisture content of 27% and an ash content of 5% the bulk density is only about 1.33 g/cm^3.[20,31,37]

Compositional changes during storage or testing are additional sources of errors in coal property analysis results. Coal is a chemically unstable material, and coal samples must be carefully handled to avoid exposure to air during collection at the well site, transport, storage, and testing in order to preserve the original in-situ compositional properties.[16,20,36] Air exposure results in a progressive alteration of coal's organic and mineral matter components due to a degradation phenomenon known as weathering.[36]

A commonly used coal analysis procedure is the high-temperature, destructive ASTM proximate analysis, which yields a weight fraction value for an ash component of coal. The mass and composition of this ash component are not identical to those of the original mineral matter in the coal since ash is an artifact generated by the proximate analysis procedure, which alters some mineral components.[39] For example, carbon dioxide is lost from carbonates during proximate analysis. The common practices of drying coal in air and determining ash content rather than true mineral matter content can result in significant errors in coal property analysis results.[16,20,36]

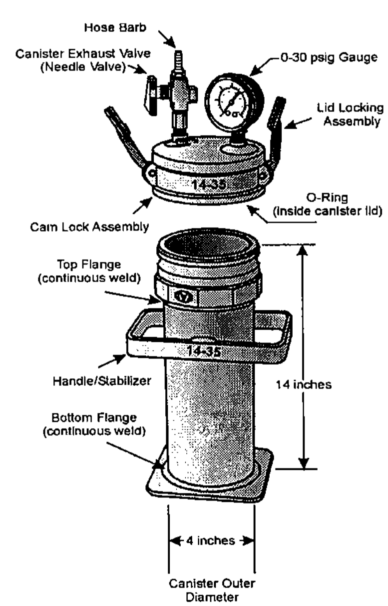
IN-SITU GAS CONTENT

In coalbed reservoirs the natural gas is predominantly (~95%) stored as a molecularly adsorbed phase within micropores.[1,20] The in-situ adsorbed phase gas content of coalbed reservoirs can only be accurately determined by measuring the volume of gas that desorbs from freshly cut reservoir coal samples. The inaccurate determination of this reservoir property is commonly the single largest source of gas-in-place analysis error.[11-14,16-21] The two methods commonly used to determine the total in-situ gas content are pressure coring and the direct method.[15,20] Both methods have some inherent shortcomings.

Pressure Coring Gas Content Determination. The pressure coring method involves trapping a cored rock sample downhole within a sealed barrel thereby preventing any loss of gas by desorption during retrieval of the core to the surface.[15,20] The total in-situ gas content can be directly determined by measuring the total volume of gas that desorbs from the core. The primary advantage of pressure coring is that it is the only method capable of directly measuring the total in-situ gas content of a cored rock sample. However, this method requires specialized equipment that is difficult to successfully operate on a routine basis in the field. Pressure coring is also about five times as expensive as conventional coring, and its use has generally been restricted to research studies.[19-21]

Direct Method Gas Content Determination. The direct method analysis procedure was originally developed by the coal mining industry to evaluate the severity of natural gas emissions during underground coal mining operations.[40-43] This analysis procedure involves sealing freshly cut core or drill cuttings coal samples in airtight desorption canisters (see **Figure 4**) and then measuring the volume of gas that desorbs from the sample as a function of time at ambient temperature and pressure conditions.[15,20] A disadvantage of this analysis procedure is that the measured desorbed gas volume is not equal to the total in-situ gas content since a large amount of gas is commonly lost by desorption during sample recovery and some gas may not desorb from the coal

Figure 4. Gas Desorption Canister



during the time interval of the desorption measurements. The lost gas volume is estimated by numerical analysis of the measured gas desorption rate data.[15,20]

The rate of gas desorption from many coals is so slow that impracticably long time intervals would be required for complete gas desorption to occur. This slowly desorbing, residual gas volume can be quantified by measuring the gas volume released by crushing and heating the coal sample at the conclusion of the desorption measurements.[15,20]

The total in-situ gas volume of the coal is equal to the sum of the estimated lost gas volume, the measured desorbed gas volume, and the measured residual gas volume. The accuracy of the desorbed gas volume data is affected by temperature and atmospheric pressure variations during the desorption measurements.[11,15,16,20] The chief limitation of this direct method analysis procedure is that it yields widely different in-situ gas content values depending upon the coal sample type, gas desorption testing conditions, and lost gas estimation method.[9-21]

Effect of Residual Gas Content. One common source of error in coalbed reservoir gas content analysis is the failure to quantify and account for any residual gas volume that may remain in the coal sample at the end of the canister gas desorption measurements. This gas content analysis practice is due, at least in part, to an assumption that this residual gas volume is negligible or that it does not make a significant contribution to the total producible gas reserve.[9,44] However, this gas content analysis practice can resulted in significant underestimation errors in coalbed gas resource and reservoir gas-in-place evaluations. **Table 3** gives examples of residual gas volume values for coalbed reservoirs in several U.S. basins.[1,35,45-47,49-52]

The data in **Table 3** show that the residual gas volume can be a significant fraction (e.g., 5 to 50%) of the total in-situ adsorbed gas content of coalbed reservoirs.[1,11,16,35,44-52] The magnitude of this underestimation error will be sample specific since the residual gas volume is largely dependent on the coal sample temperature and total desorption time during the gas desorption measurements.[16,48]

TABLE 3. Residual Gas Volume Values

Basin	Coal Rank	Residual Gas Volume (% Total Gas Vol.)
Powder River	Subbit.	5 %
Uinta	Hvb	7 %
Illinois	Hvb	8 – 20 %
Northern Appalachian	Hvb	20 – 50 %
Black Warrior	Mvb	5 – 15 %
Central Appalachian	Lvb	6 – 10 %
Arkoma	Lvb	4 – 12 %

Effect of Sample Type. Another major source of error in coalbed reservoir gas content analysis is the use of gas desorption data collected from drill cuttings as the basis for the in-situ gas content value. This gas content analysis practice can result in significant underestimation error in coalbed gas resource and reservoir gas-in-place evaluations.[20] **Figure 5** shows a comparison of the gas content values for a San Juan Basin Fruitland Formation coalbed reservoir obtained by analysis of gas desorption data from three different types of coal samples.[11,20-22] The gas content value obtained from the conventional core is similar to the benchmark gas content value obtained from the pressure core but these values are 34 and 42% greater than the gas content value obtained from the drill cuttings. Gas content errors of this magnitude cause large underestimation errors in the gas production rates and cumulative recovery estimated using reservoir simulation models.[13,19-22,53]

Figure 5 demonstrates that, in general, gas desorption data obtained from drill cuttings cannot be used to accurately quantify the total in-situ gas content of coalbed reservoirs.[12,13] This finding is comparable to results reported by others.[37,48] **Figure 6** illustrates the effect of a 30% gas content underestimation error on the cumulative gas production predicted using a reservoir simulation model for a high productivity San Juan Basin coalbed reservoir.[13,19-22] This error results in a 63% underestimation of the long-term

Figure 5. Comparison of Gas Content Values Obtained Using Different Analysis Methods

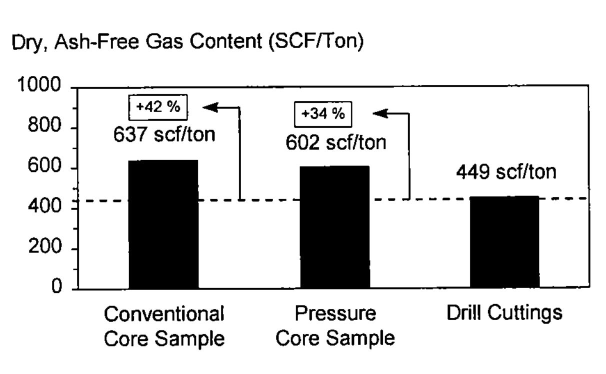
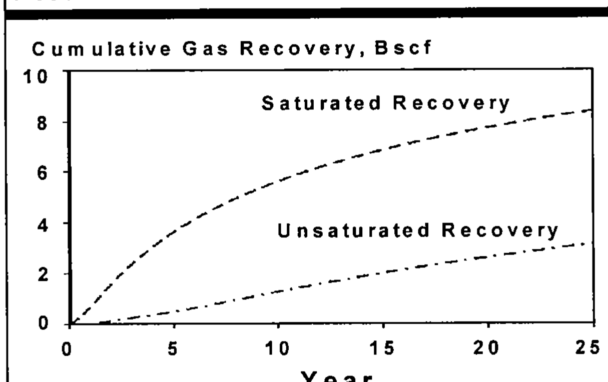


Figure 6. Comparison of Gas Production Behavior for Saturated and Undersaturated Reservoirs



cumulative gas production and a comparable reduction in the economic value of the gas reserves.

Effect of Lost Gas Analysis Method. The technical literature describes three different procedures for estimating the lost gas volume. These procedures are commonly known as the Bureau of Mines[40-43], Smith & Williams[54-56], and Amoco[57] methods. These three analysis methods commonly yield widely different lost gas volume and total gas content values.[9-14,16-22] **Figure 7** shows that the highest lost gas volume estimate accuracy (closest agreement with the benchmark gas content values) was always obtained when the gas desorption data were analyzed using the Bureau of Mines method.[11-14,16-22] The benchmark gas content values were obtained from pressure core samples and sorption isotherm data measured at in-situ reservoir conditions.[11]

In the Bureau of Mines lost gas analysis method, a graph is plotted of the cumulative measured desorbed gas content versus the square root of elapsed time since the start of gas desorption (defined as time zero) during the core recovery process. The lost gas content is the absolute value of the result obtained by extrapolating the plotted data to time zero. **Figure 8** illustrates an example of this type of graph.[13,20,22] Gas desorption testing conditions, specifically the coal sample temperature and the presence of air in the canister head space during gas desorption, can significantly affect the accuracy of the lost gas volume estimate. These two sources of error can be significant and are discussed separately in the following sections.

Effect of Gas Desorption Temperature. The Bureau of Mines recognized that the temperature of the coal sample during the gas desorption measurements affects the accuracy of the direct method gas content estimate and recommended that the coal samples be maintained at a fairly constant temperature during the gas desorption measurements.[41] Nonetheless, it is quite common for direct method gas desorption measurements to be performed without control of the coal sample temperature. Two temperature related factors affect the accuracy of the direct method analysis procedure. First, the rate of gas desorption from the coal is exponentially dependent upon temperature, and second, the gas sorption capacity of the coal is inversely proportional to temperature.[12-14,16-22] Hence, the coal sample temperature during gas desorption measurements affects the incremental volume of gas that desorbs as a function of time, the total measured desorbed gas volume, and the residual gas volume. The higher the coal sample temperature during the canister gas desorption measurements, the greater the rate of gas desorption and, consequently, the greater the lost gas volume calculated using the Bureau of Mines method.

Coal cores can experience a significant temperature decrease during coring, retrieval, and desorption. This temperature decrease significantly affects the accuracy of the lost gas volume estimate. The insert in **Figure 8** illustrates the temperature behavior of a San Juan Basin Fruitland Formation coal core during the wellbore retrieval (cooling) time interval.[13,20,22] **Figure 8** illustrates the results obtained when the Bureau of Mines lost gas analysis procedure was used to analyze gas desorption data collected from San Juan Basin Fruitland Formation coal cores maintained at reservoir and ambient surface temperature conditions.[13,20,22]

For the data plotted in **Figure 8**, the ambient temperature gas desorption data underestimated the actual lost gas volume by 58%. This lost gas content error results in a total gas content estimate that is 30% low. The magnitude of the lost gas content error seen with coal samples from other reservoirs will depend upon the difference between the reservoir and ambient temperatures as well as the coal's gas storage and diffusion properties.[13,14,16-22] This source of error can be minimized or eliminated by using water baths to maintain the desorption canisters at reservoir temperature while performing the gas desorption measurements.[13,15,18-22]

Effect of Coal Oxidation. The reaction of coal with the oxygen in air can be a significant source of error in the direct method gas content analysis procedure.[11,12,15,20,37,58]

Figure 7. Comparison of Conventional Core Gas Content Estimates with Benchmark Values

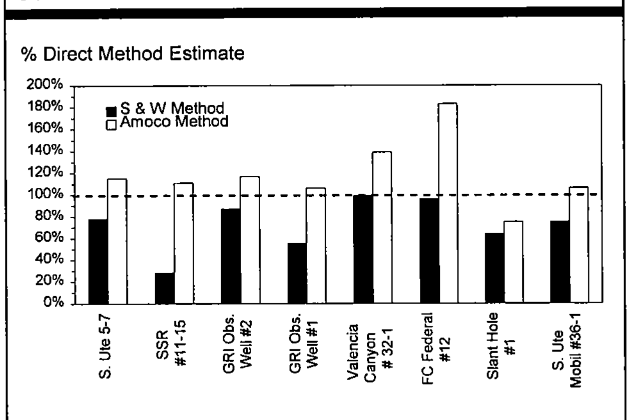
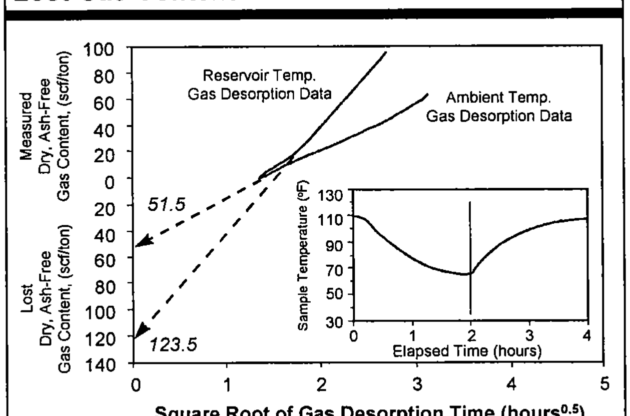


Figure 8. Effect of Temperature On Estimated Lost Gas Content



Coal is a very air sensitive material and progressively reacts with the oxygen in air.[36] At ambient temperature conditions, the rate of reaction of oxygen with a freshly cut reservoir coal sample can be comparable to the methane emission rate from the sample.[58] If freshly cut reservoir coal samples are sealed in desorption canisters with a large headspace air volume the subsequent chemical reaction between the oxygen and the coal can cause a significant underestimation error in both the measured gas desorption rate and the total measured desorbed gas volume.[37,58] **Figure 9** illustrates the effect of air oxidation on direct method gas content analysis results for Powder River Basin, Fort Union Formation subbituminous coal cores.[37]

In general, the magnitudes of this type of error will be inversely proportional to the rank of the coal sample[36] and will be greatest when the ratio between the total measured desorbed gas volume and the free-space void volume in the desorption canister is greater than 2:1.[58] This source of error can be avoided or minimized by using either an inert gas or formation water to displace air from the remaining free-space void volume prior to sealing the canister and initiating the gas desorption measurements.[11,15,16,36,37,58]

Best Practice Gas Content Analysis Procedure. The coal sample type (**Figure 5**), lost gas analysis method (**Figure 7**), gas desorption temperature (**Figure 8**), and gas desorption atmosphere (**Figure 9**) significantly affect the accuracy of the direct method gas content analysis results. **Table 4** lists the major causes and magnitudes of these direct method gas content analysis errors.[12-14,16-22] The highest direct method gas content accuracy (closest agreement with the benchmark gas content values) was obtained using gas desorption data collected at reservoir temperature conditions from conventional core samples and analyzed with the Bureau of Mines lost gas procedure. The benefit of using this "best practice" analysis procedure is that it provides results of comparable accuracy to the pressure coring method at only a fraction of the cost.[13,19-22]

RESERVE ESTIMATE IMPLICATIONS

Coalbed reservoir gas-in-place analysis involves several unique reservoir property data acquisition and analysis challenges. Many commonly used reservoir property analysis practices have inherent shortcomings that affect the accuracy of gas-in-place analysis results. Seven common reservoir property analysis practices are: (1) basing the reservoir volume on the assumption that the coalbed reservoir thickness and lateral continuity are invariant, (2) using 1.75 g/cm^3 as the maximum log density value when determining gross reservoir thickness, (3) using 1.32 to 1.36 g/cm^3 for the in-situ density of the bulk coalbed reservoir rock, (4) basing the in-situ gas content on gas desorption data obtained at ambient temperature conditions, (5) basing the in-situ gas content on gas desorption data obtained with air present in the canister void volume, (6) basing the in-situ gas content on gas desorption data obtained from drill cuttings, and (7) basing the in-situ gas content on the assumption that the residual gas volume is negligible. These seven analysis practices can result in large underestimation errors in reservoir properties and gas-in-place values.[20-22] Because these error prone analysis practices have been so widely used in the past there may be significant potential for large gas-in-place and reserve estimate gains in many existing coalbed gas fields.

Table 5 illustrates an analysis protocol that can be used to avoid or minimize common sources of errors during the evaluation of coalbed reservoir properties.[17-22] The reservoir property data obtained with this analysis protocol provide more accurate gas-in-place estimates, which generally result in significant gains in the estimated reserves and economic value of producing properties. As an example, Emerald Gas Operating Company realized a 74% gain over their original gas-in-place estimate after using this analysis protocol to reevaluate their reservoir property data for a 17-well coalbed gas field in the San Juan Basin.[17-22]

Figure 9. Effect of Air Oxidation on Direct Method Gas Content Values

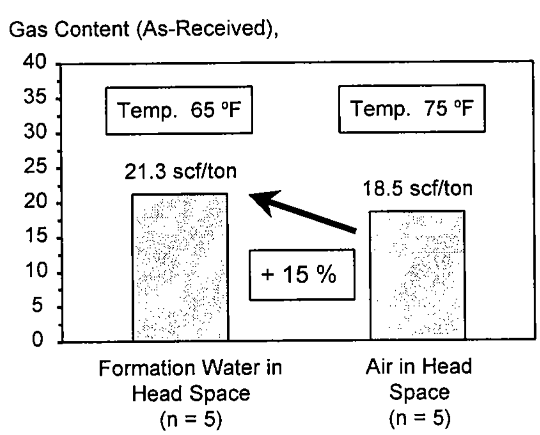


TABLE 4. Direct Method Gas Content Errors

1.	Using drill cuttings for the gas desorption measurements (25% underestimation error).
2.	Using either the Smith & Williams method (40% underestimation to 14% overestimation error) or Amoco method (31% underestimation to 119% overestimation error) to calculate the lost gas volume.
3.	Performing gas desorption measurements at ambient surface temperature conditions (30% underestimation error).
4.	Performing gas desorption measurements with air present in the desorption canister (5 to 15% underestimation error).

TABLE 5. Coalbed Reservoir Gas-In-Place Analysis Protocol	
1.	Perform gas desorption measurements at reservoir temperature on conventional core samples.
2.	Estimate the total gas content of each sample using the Direct Method lost gas content procedure.
3.	Relate the total gas content of multiple samples to sample composition.
4.	Relate the sample composition to density.
5.	Determine the in-situ moisture content from laboratory moisture content measurements.
6.	Estimate the gross thickness and average in-situ density from open-hole density log data.
7.	Compute the in-situ gas content at the average reservoir density and moisture content.
8.	Compute the gas-in-place volume.

REFERENCES

1. Rightmire, C.T., Eddy, G.E., and Kirr, J.N., eds.: *Coalbed Methane Resources of the United States*, AAPG Studies in Geology Series #17, American Association of Petroleum Geologists, Tulsa, Oklahoma (1984) 375 p.
2. Schwochow, S., ed.: *The International Coal Seam Gas Report*, Carin Point Publishing, Inc., Denver, Colorado (1997) 218 p.
3. Nelson, C.R.: *Gas Research Institute North American Coalbed Methane Resource Map*, Gas Research Institute Report GRI-99/0131, Chicago, Illinois (1999).
4. Nelson, C.R.: "Changing Perceptions Regarding the Size and Production Potential of Coalbed Methane Resources," *GasTIPS*, **Vol. 5, No. 2** (Spring 1999) Gas Research Institute, Chicago, Illinois, pp. 4-11.
5. Pierce, D.L., *et al.*, eds.: *Potential Supply of Natural Gas in the United States*, Potential Gas Agency, Colorado School of Mines, Golden, Colorado (1999) 195 p.
6. Malone, P.G., Briscoe, F.H., Camp, B.S., and Boyer, C.M., II: "Methods of Calculating Coalbed Methane Reserves with Insight into the Advantages and Disadvantages of Each Method," paper 8716, *Proc., 1987 Coalbed Methane Symposium*, The University of Alabama, Tuscaloosa, Alabama, pp. 73-79.
7. Richardson, J.S., Sparks, D.P., and Burkett, W.C.: "The TEAM Project Reserve Analysis: A Comprehensive Evaluation to Predict Ultimate Recovery of Coalbed Methane," paper 9105, *Proc., 1991 Coalbed Methane Symposium*, The University of Alabama, Tuscaloosa, Alabama, pp. 293-306.
8. Diamond, W.P., Bodden, W.R., III, Zuber, M.D. and Schraufnagel, R.A.: "Measuring the Extent of Coalbed Gas Drainage After 10 Years of Production at the Oak Grove Pattern, Alabama," paper 8961, *Proc., 1989 Coalbed Methane Symposium*, The University of Alabama, Tuscaloosa, Alabama, pp. 185-193.
9. Close, J.C. and Erwin, T.M.: "Significance and Determination of Gas Content Data as Related to Coalbed Methane Reservoir Evaluation and Production Implications," paper 8922, *Proc., 1989 Coalbed Methane Symposium*, The University of Alabama, Tuscaloosa, Alabama, pp. 37-55.
10. Mavor, M.J., Close, J.C., and McBane, R.A.: "Formation Evaluation of Exploration Coalbed Methane Wells," in *Coalbed Methane*, SPE Reprint Series No. 35, Society of Petroleum Engineers, Richardson, Texas (1992) p. 27-45.
11. Mavor, M.J., Pratt, T.J., and Britton, R.N.: "Improved Methodology for Determining Total Gas Content, Volume I. Canister Gas Desorption Data Summary," Gas Research Institute Topical Report GRI-93/0410, Chicago, Illinois (1994) 230 p.
12. Mavor, M.J., Pratt, T.J. and Nelson, C.R.: "Quantitative Evaluation of Coal Seam Gas Content Estimate Accuracy," paper SPE 29577 presented at the 1995 SPE Joint Rocky Mountain Reğional/Low-Permeability Reservoirs Symposium, Denver, Colorado March 20-22.
13. Mavor, M.J., Pratt, T.J., and Nelson, C.R.: "Quantify the Accuracy of Coal Seam Gas Content," *Petroleum Engineer International*, **V. 68, No. 10** (October 1995) pp. 37-42.
14. Mavor, M.J., Pratt, T.J., and Nelson, C.R.: "Quantitative Evaluation of Coal Seam Gas Content Estimate Accuracy," paper 9525, *Proc., INTERGAS '95*, The University of Alabama, Tuscaloosa, Alabama (May 15-19, 1995) pp. 379-388.
15. McLennan, J.D., Schafer, P.S., and Pratt, T.J.: *A Guide to Determining Coalbed Gas Content*, Gas Research Institute Report GRI-94/0396, Chicago, Illinois (1995) 182 p.
16. Mavor, M.J. and Pratt, T.J.: "Improved Methodology for Determining Total Gas Content, Volume II. Comparative Evaluation of the Accuracy of Gas-In-Place Estimates and Review of Lost Gas Models," Gas

Research Institute Topical Report GRI-94/0429, Chicago, Illinois (1996) 167 p.

17. Mavor, M.J., Pratt, T.J., Nelson, C.R., and Casey, T.A.: "Improved Gas-In-Place Determination for Coal Gas Reservoirs," paper SPE 35623, presented at the SPE Gas Technology Symposium, Calgary, Alberta, Canada, April 28 - May 1, 1996.
18. Nelson, C.R. and Mavor, M.J.: "Improved Coal Seam Reservoir Gas-In-Place Analysis Protocol," Gas Research Institute Report GRI-96/0481, Chicago, Illinois (1996) 4 p.
19. Nelson, C.R., Mavor, M.J., Pratt, T.J. and T.A. Casey, T.A.: "Protocol Ups Coal Seam Gas Analysis," *The American Oil and Gas Reporter*, **V. 40, No. 10** (October 1997) pp. 86-89.
20. Mavor, M.J. and Nelson, C.R.: *Coalbed Reservoir Gas-In-Place Analysis*, Gas Research Institute Report GRI-97/0263, Chicago, Illinois (1997) 144 p.
21. Nelson, C.R.: "Advances in Coalbed Reservoir Gas-In-Place Analysis," *GasTIPS*, **Vol. 4, No. 1** (Winter 1997/1998) Gas Research Institute, Chicago, Illinois pp. 14-19.
22. Nelson, C.R.: "Effects of Coalbed Reservoir Property Analysis Methods on Gas-In-Place Estimates," paper SPE 57443, presented at the SPE Eastern Regional Meeting, Charleston, WV, October 20-22, 1999.
23. Choate, R., Lent, J., and Rightmire, C.T.: "Upper Cretaceous Geology, Coal, and the Potential for Methane Recovery from Coalbeds in San Juan Basin - Colorado and New Mexico," in *Coalbed Methane Resources of the United States*, AAPG Studies in Geology Series #17, Rightmire, C.T., Eddy, G.E. and Kirr, J.N., eds., American Association of Petroleum Geologists, Tulsa, Oklahoma (1984) pp. 185-222.
24. Kelso, B.S., Wicks, D.E., and Kuuskraa, V.A.: "A Geologic Assessment of Natural Gas From Coal Seams in the Fruitland Formation, San Juan Basin," Gas Research Institute Topical Report GRI-87/0341, Chicago, Illinois (1988) 56 p.
25. Close, J.C.: "Natural Fractures in Coal," in *Hydrocarbons From Coal*, AAPG Studies in Geology #38, Law, B.E. and Rice, D.D., eds., American Association of Petroleum Geologists, Tulsa, Oklahoma (1993) pp. 119-132.
26. Jones, A.H., Bell, G.J., and Schraufnagel, R.A.: "A Review of the Physical and Mechanical Properties of Coal with Implications for Coal-Bed Methane Well Completion and Production," in *Geology and Coal-Bed Methane Resources of the Northern San Juan Basin, Colorado and New Mexico*, Fassett, J.E., ed., Rocky Mountain Association of Geologists, Denver, Colorado (1988) pp. 169-181.
27. Mavor, M.J.: "Coalbed Reservoir Properties," in *A Guide to Coalbed Methane Reservoir Engineering*, Saulsberry, J.L., Schafer, P.S. and Schraufnagel, R.A., eds., Gas Research Institute Report GRI-94/0397, Chicago, Illinois (1996) pp. 4.1-4.58.
28. Enever, J.R.E. and Hennig, A.: "The Relationship Between Permeability and Effective Stress for Australian Coals and Its Implications with Respect to Coalbed Methane Exploration and Reservoir Modelling," paper 9722, *Proc., 1997 International Coalbed Methane Symposium*, The University of Alabama, Tuscaloosa, Alabama, pp. 13-22.
29. Saulsberry, J.L., Lambert, S.W., Wallace, J.A., Spafford, S.D., and Steidl, P.F.: "Rock Creek Multiple Coal Seams Project," Gas Research Institute Final Report GRI-95/0036, Chicago, Illinois (1995) 110 p.
30. Mavor, M.J. and Logan, T.L.: "Western Cretaceous Coal Seam Project," Gas Research Institute Final Report GRI-94/0089, Chicago, Illinois (1995) 155 p.
31. Neavel, R.C., Smith, S.E., Hippo, E.J., and Miller, R.N.: "Interrelationships Between Coal Compositional Parameters," *Fuel*, **V. 65** (1986) pp. 312-320.
32. Unsworth, J.F., Fowler, C.S., and Jones, L.F.: "Moisture in Coal: 2. Maceral Effects on Pore Structure," *Fuel*, **V. 68** (1989) pp. 18-26.
33. Schopf, J.M.: "A Definition of Coal," *Economic Geology*, **V. 51** (1956) pp. 521-527.
34. Close, J., Woolverton, S., and Swainson, K.: "Non-Fairway, Underpressured Fruitland Coal Resource Characterization Study, Southern San Juan Basin, New Mexico," paper 9727, *Proc., 1997 International Coalbed Methane Symposium*, The University of Alabama, Tuscaloosa, Alabama, pp. 23-32.
35. Burns, T.D. and Lamarre, R.A.: "Drunkards Wash Project: Coalbed Methane Production from Ferron Coals in East-Central Utah," paper 9709, *Proc., 1997 International Coalbed Methane Symposium*, The University of Alabama, Tuscaloosa, pp. 507-520.
36. Nelson, C.R., ed.: *Chemistry of Coal Weathering*, Elsevier Science Publishers, New York (1989) 230 p.
37. Pratt, T.J., Mavor, M.J., and DeBruyn, R.P.: "Coal Gas Resource and Production Potential of Subbituminous Coal in the Powder River Basin," paper SPE 55599 presented at the 1999 Rocky Mountain Regional Meeting, Gillette, WY, May 15-18.
38. Holland, J.R. and Kimmons, J.W.: "Characteristics and Economics of Coalbed Methane Production from the Fort Union Formation, Powder River Basin," paper 9549, *Proc., INTERGAS '95*, The University of Alabama, Tuscaloosa, Alabama (May 15-19, 1995) pp. 115-123.
39. Standard Test Method for Ash in the Analysis Sample of Coal and Coke From Coal, D 3174 - 82: *Annual Book of ASTM Standards*, Philadelphia, Pennsylvania (1988) pp. 297-299.
40. Bertard, C., Bruyet, B., and Gunther, J.: "Determination of Desorbable Gas Concentration of Coal (Direct Method)," *International Journal of Rock Mechanics and Mining Science*, **V. 7** (1970) pp. 43-65.

41. Kissell, F.N., McCulloch, C.M., and Elder, C.H.: "The Direct Method of Determining Methane Content of Coalbeds for Ventilation Design," Report of Investigations 7767, U.S. Department of the Interior, Bureau of Mines, Washington, D.C. (1973) 17 p.
42. McCulloch, C.M., Levine, J.R., Kissell, F.N., and Deul, M.: *Measuring the Methane Content of Bituminous Coalbeds*, Report of Investigations 8043, United States Department of the Interior, Bureau of Mines, Washington, D.C. (1975) 22 p.
43. Diamond, W.P. and Levine, J.R.: *Direct Method Determination of the Gas Content of Coal: Procedures and Results*, Report of Investigations 8515, United States Department of the Interior, Bureau of Mines, Washington, D.C. (1981) 36 p.
44. Eddy, G.E., Rightmire, C.T., and Byrer, C.W.: "Relationship of Methane Content of Coal Rank and Depth: Theoretical vs. Observed," paper SPE/DOE 10800, presented at the 1982 SPE/DOE Unconventional Gas Recovery Symposium, Pittsburgh, Pennsylvania, May 16-18.
45. Hewitt, J.L.: "Geologic Overview, Coal and Coalbed Methane Resources of the Warrior Basin - Alabama and Mississippi," in *Coalbed Methane Resources of the United States*, AAPG Studies in Geology Series #17, Rightmire, C.T., Eddy, G.E., and Kirr, J.N., eds., American Association of Petroleum Geologists, Tulsa, Oklahoma (1984) pp. 73-104.
46. Telle, W.R. and Thompson, D.A.: "Coalbed Methane Development Prospects in Southern Tuscaloosa County, Alabama," paper 8966, *Proc., 1989 Coalbed Methane Symposium*, The University of Alabama, Tuscaloosa, Alabama, pp. 225-239.
47. Hunt, A.M. and Steele, D.J.: "Coalbed Methane Development in the Northern and Central Appalachian Basins - Past, Present and Future," paper 9161, *Proc., 1991 International Coalbed Methane Symposium*, The University of Alabama, Tuscaloosa, Alabama, pp. 127-141.
48. Knox, L.M.: "Coalbed Methane in Upper Silesia, Poland - A Comprehensive, Integrated Study," paper 9728, *Proc., 1997 International Coalbed Methane Symposium*, The University of Alabama, Tuscaloosa, Alabama, pp. 127-135.
49. Archer, P.L. and Kirr, J.N.: "Pennsylvanian Geology, Coal, and Coalbed Methane Resources of the Illinois Basin – Illinois, Indiana, and Kentucky," in *Coalbed Methane Resources of the United States*, AAPG Studies in Geology Series #17, Rightmire, C.T., Eddy, G.E., and Kirr, J.N., eds., American Association of Petroleum Geologists, Tulsa, Oklahoma (1984) pp. 105-134.
50. Harper, D.: "Coalbed Methane in Indiana," Indiana Geological Survey Occasional Paper 56, Bloomington, IN (1991) 18 p.
51. Diamond, W.P, LaScola, J.C., and Hyman, D.M.: *Results of Direct-Method Determination of the Gas Content of U.S. Coalbeds*, Bureau of Mines Information Circular 9067, United States Department of the Interior, Washington, D.C. (1986) 95p.
52. Cardott, B.J.: "Coal as Gas-Source Rock and Reservoir, Hartshorne Formation, Oklahoma," in *The Hartshorne Play in Southeastern Oklahoma: Regional and Detailed Sandstone Reservoir Analysis and Coalbed-Methane Resources*, Oklahoma Geological Survey Special Publication 98-7, The University of Oklahoma, Norman, Oklahoma (1998) pp. 41-62.
53. Zuber, M.D. and Olszewski, A.J.: "The Impact of Errors in Measurements of Coalbed Methane Reservoir Properties on Well Production Forecasts," paper SPE 24908, presented at the 1992 SPE Annual Technical Conference and Exhibition, Washington, D.C., October 4-7.
54. Smith, D.M. and Williams, F.L.: "A New Technique for Determining the Methane Content of Coal," *Proc., 16th Intersociety Energy Conservation Engineering Conference*, Atlanta, Georgia (1981) pp. 1,267-1,272.
55. Smith, D.M. and Williams, F.L.: "Diffusion Models for Gas Production From Coals, Application to Methane Content Determination," *Fuel*, **V. 63** (1984) pp. 251-255.
56. Smith, D.M. and Williams, F.L.: "Direct Method of Determining the Methane Content of Coal - A Modification," *Fuel*, **V. 63** (1984) pp. 425-427.
57. Yee, D., Seidle, J.P., and Hanson, W.B.: "Gas Sorption on Coal and Measurement of Gas Content," in *Hydrocarbons From Coal*, AAPG Studies in Geology #38, Law, B.E. and Rice, D.D., eds., American Association of Petroleum Geologists, Tulsa, Oklahoma (1993) pp. 203-218.
58. Ulery, J.P. and Hyman, D.M.: "The Modified Direct Method of Gas Content Determination: Applications and Results," paper 9163, *Proc., 1991 Coalbed Methane Symposium*, The University of Alabama, Tuscaloosa, Alabama, pp. 489-500.

4

Coalbed methane activity in Oklahoma

Brian J. Cardott
Oklahoma Geological Survey
Norman, OK

Cardott, B.J., 1999, Coalbed methane activity in Oklahoma, in Oklahoma coalbed-methane workshop: Oklahoma Geological Survey, Open-File Report OF 6-99, p. 47-66.

COALBED METHANE ACTIVITY IN OKLAHOMA

Brian J. Cardott, Oklahoma Geological Survey

ABSTRACT

Coalbed-methane (CBM) drilling activity in Oklahoma began in 1988 with 7 wells drilled to the Hartshorne coal bed (Desmoinesian; Middle Pennsylvanian) in the Kinta gas field of the Arkoma basin. CBM completions are separated into two regions in the State, the northeast Oklahoma shelf and the Arkoma basin. Completions in the Mulky and Rowe coal beds (Desmoinesian; Middle Pennsylvanian) began activity on the northeast Oklahoma shelf in 1994. By the end of September 1999, there were 808 CBM completions reported in Oklahoma, 334 in the basin and 474 on the shelf. The CBM completions are evaluated by coal bed, depth, initial potential gas rate, and initial produced water rate.

INTRODUCTION

The Oklahoma coalfield in eastern Oklahoma is in the southern part of the western region of the Interior Coal Province of the United States (Campbell, 1929). The coalfield is divided into the northeast Oklahoma shelf and the Arkoma basin (Friedman, 1974; Fig. 1). The commercial coal belt (Fig. 1) contains coal beds of mineable thickness ($\geq$ 10 in. [25 cm] thick and < 100 ft [30 m] deep for surface mining); coal beds in the noncommercial coal-bearing region (Fig. 1) are too thin, of low quality, or too deep for mining. CBM exploration has occurred in both areas.

Figures 2 and 3 are generalized stratigraphic columns of the northeast Oklahoma shelf and Arkoma basin, showing the range in coal thickness measured from surface exposures and shallow cores.

Figure 4 shows the rank of coal beds in the Oklahoma coalfield, generalized for all coal beds at or near the surface. Coal rank ranges from high-volatile bituminous on the shelf and western part of the Arkoma basin to medium- and low-volatile bituminous in the eastern part of the Arkoma basin in Oklahoma. Rank increases from west to east and with increasing depth in the Arkoma basin. As an example of increasing rank with depth, the Hartshorne coal is medium-volatile bituminous rank at 2,574 ft (785 m) deep in the Continental Resources 1-3 Myers well in Pittsburg County (sec.3, T.7N., R.16E.) in the high-volatile bituminous area in Figure 4 (see Fig. 11 for location of well).

Commercial production of CBM in Oklahoma began in 1988 with methane production from the Hartshorne coal (depth range of 611–716 ft [186–218 m]; initial-potential gas rate per well of 41–45 MCFGPD [thousand cubic feet of gas per day]) from seven wells in the Kinta gas field (sec. 27, T.8N., R.20E.) in Haskell County by Bear Production. Bear Production was the only CBM operator in Oklahoma from 1988–1990.

The following discussion of Oklahoma CBM completions is based on information reported to the Oklahoma Corporation Commission and Osage Indian Agency. The names of coal beds are as reported by the operator and may not conform to usage accepted by the Oklahoma Geological Survey. Since not all of the wells are reported as CBM gas wells, some interpretation was necessary. Dual completions, including perforations of coal beds, were made in some wells. Therefore, not all of the wells are exclusively CBM completions. This summary is incomplete since some wells may not have been known to be CBM wells or were not reported by the time of this compilation.

This evaluation is based on reported CBM completions, which may or may not have been connected to a gas pipeline. Likewise, some completions may have produced gas but have since been plugged.

The data for this report were compiled in the coalbed-methane completions table of the Oklahoma Coal Database. Each record (well completion) in the table includes operator, well name, API number, completion date, location (county, field name, TRS, latitude/longitude), coal bed, production depth interval, initial gas potential and produced water, pressure information, and comments. The database is available at the Oklahoma Geological Survey. A searchable version of the coalbed-methane completions table is available on the internet as a link from the OGS web site: http://www.ou.edu/special/ogs-pttc/.

Through September 1999, there were 808 CBM completions reported in Oklahoma, 334 in the basin and 474 on the shelf (Fig. 5). The CBM play began in the basin in 1988, with a peak of 68 completions in 1992. There were 4 CBM completions on the shelf in 1994. In 1995 there were 23 completions in the basin and 41 completions on the shelf, signaling increased activity on the shelf. As of September 1999, there were 47 completions in the basin and 175 completions on the shelf reported in 1998.

NORTHEAST OKLAHOMA SHELF

Figure 6 shows the locations of 474 CBM completions on the shelf reported by 34 operators through September 1999. CBM completions on the shelf have been reported in Craig, Nowata, Osage, Rogers, Tulsa, and Washington counties. In ascending order, the coal beds producing methane on the shelf are the Riverton

(McAlester Formation), Rowe and Drywood (Savanna Formation), and Bluejacket (Boggy Formation) in the Krebs Group; Weir-Pittsburg, Croweburg, Bevier, Iron Post, and Mulky (Senora Formation) in the Cabaniss Group; and Dawson (Holdenville Formation) in the Marmaton Group of Desmoinesian (Middle Pennsylvanian) age (Fig. 2). The commercial coal beds on the shelf are 0.8–5.0 ft (0.2–1.5 m) thick, average 2.0 ft (0.6 m) thick, and dip westward ½° to 2° (Friedman, 1999).

Figure 7 shows the depth range of CBM completions on the shelf. Coal beds were perforated at depths-to-top of coal of 216–2,428 ft ([66–740 m]; average of 918 ft [280 m] from 408 wells). Most of the wells on the shelf are in the Mulky coal (238 wells, depth range of 216–1,568 ft [66–478 m]). The Mulky coal is the uppermost coal bed in the Senora Formation and occurs at the base of the Excello Shale Member (Hemish, 1987). The Mulky coal ranges from bituminous coal to carbonaceous shale with increasing amounts of mineral matter. The next most important CBM reservoir on the shelf is the Rowe coal (165 wells, depth range of 801–1,810 ft [244–552 m]). The deepest CBM completion on the shelf is in the Weir-Pittsburg coal in Osage County (Calumet Oil Co., 7 Catlett well, sec. 32, T.28N., R.8E.). There were 40 completions on the shelf that perforated more than one coal bed.

Initial-potential CBM rates for individual wells on the shelf range from a trace to 260 MCFGPD (average of 29 MCFGPD from 359 wells; Fig. 8). The Mulky coal ranges from a trace to 125 MCFGPD, and the Rowe coal ranges from 2–260 MCFGPD. Four of the 5 wells having the highest initial potential gas rates on the shelf were from the Rowe coal in T.25 N., R.14 E. These 4 wells initially produced 130–260 MCFGPD and 30–90 BWPD (barrels of water per day) from depths of 1,136–1,190 ft (346–363 m).

Gas production in Oklahoma is reported by lease. Therefore, it is difficult to obtain gas production data by well. However, many of the CBM wells on the shelf are on single-well leases. Typical production-decline curves of 3 wells (believed to be single-well leases) in Nowata and Rogers counties illustrate production histories for wells with initial potential rates of 7–36 MCFGPD and 12–120 BWPD (Fig. 9; gas production data came from the Natural Resources Information System of the Oklahoma Geological Survey). Following a period of 3 to 12 months of erratic production in some wells, production can stabilize at more than 1 million cubic feet of gas per month. The maximum monthly production for the 3 wells selected is 4,664 MCFG, an average of 155 MCFGPD, attained 12 months after completion in the 1 Mitchell well (Fig. 9B).

Initial produced water on the shelf ranged from 0–1,201 BWPD (average of 66 BWPD from 337 wells; Fig. 10). Most of the water is believed to be formation water and not water from fracture stimulation. These wells require nearby disposal wells for the produced water. Water volume is not metered. Therefore, the volume of disposed water and the effect of water production on gas rate is not known. Data on water quality is not available.

ARKOMA BASIN

Figure 11 shows the locations of 334 CBM completions in the basin reported by 35 operators through September 1999. CBM completions in the basin have been reported in Coal, Haskell, Hughes, Latimer, Le Flore, McIntosh, and Pittsburg counties. In ascending order, the coal beds producing methane in the basin are the Hartshorne (undivided), Lower Hartshorne, and Upper Hartshorne (Hartshorne Formation), McAlester (McAlester Formation; a CBM completion in Coal County reported to be in the "Lehigh" coal is equivalent to the McAlester coal), "Savanna" (Cavanal? coal; Savanna Formation), Secor (Boggy Formation), and unnamed coal in the Krebs Group of Desmoinesian (Middle Pennsylvanian) age (Fig. 3). Most (94%) of the CBM completions in the Arkoma basin are from the Hartshorne coal beds. The commercial coal beds in the basin are 1–10 ft (0.3–3 m) thick and dip 3° to nearly vertical in eroded, narrow anticlines and broad synclines that trend northeastward (Friedman, 1999).

Figure 12 shows the depth range of CBM completions in the basin. Coal beds were perforated at depths-to-top of coal of 598–3,726 ft ([182–1,136 m]; average of 1,335 ft [407 m] from 277 wells). The 3 deepest CBM completions (3,632–3,726 ft [1,107–1,136 m]) in the basin are in the Hartshorne coal in Hughes County (T.4N., R.11E.).

Initial-potential CBM rates for individual wells in the basin range from a trace to 595 MCFGPD (average of 72 MCFGPD from 234 wells; Fig. 13). Most (84%) of the wells produced 10–120 MCFGPD. The highest initial-potential gas rates are from the Hartshorne coal. The first horizontal CBM completion in Oklahoma was by Bear Production in August 1998. By the end of September 1999, there were 12 horizontal CBM completions in Haskell, Le Flore, and Pittsburg counties reported by 4 operators (Fig. 14). Initial-potential CBM rates of the horizontal wells were 80–595 MCFGPD. Higher CBM rates are possible in horizontal CBM wells by drilling perpendicular to the face cleat to drain a larger area than for a vertical well.

Initial produced water in the basin ranged from 0–147 BWPD (average of 10 BWPD from 186 wells; Fig. 15). Most (85%) of the wells produced less than 20 BWPD. Most Arkoma basin CBM completions are on the flanks of anticlines (Fig. 16) and have relatively little produced water. An undisclosed amount of initial water production is frac water (introduced during fracture stimulation).

A Hartshorne CBM field study in the Spiro Southeast Gas Field (T.9N., R.25E.) indicated "The average daily gas production per well ranged from 6 to 127 MCFGPD, with an average of 50 MCFGPD. Gas production from all 28 wells was about 1,400 MCFGPD...Cumulative gas production from September 1994 through March 1998 was 1,178,372 MCF." (Andrews, Cardott, and Storm, 1998, p. 62). Production decline curves showed an increase in production through restimulation (using freshwater and sand) and servicing the water pump (Fig. 17). The best well (26-1 Rice-Carden) had a peak of 6,631 MCFG in the fifth month of production (Fig. 17A).

CONCLUSIONS

The Oklahoma CBM play began in the Arkoma basin in 1988. The play spread to the northeast Oklahoma shelf in 1994. Through September 1999, there were 808 CBM completions reported in Oklahoma, 334 in the basin and 474 on the shelf. There were 42% more completions on the shelf than in the basin. The primary CBM objectives were the Hartshorne coals in the basin and the Mulky and Rowe coals on the shelf. There were 44% more completions in the Mulky coal than in the Rowe coal.

The range in depth of the CBM completions was 216–2,428 ft ([66–740 m]; average of 918 ft [280 m] from 408 wells) on the shelf, and 598–3,726 ft ([182–1,136 m] average of 1,335 ft [407 m] from 277 wells) in the basin.

Initial-potential gas rates ranged from a trace to 260 MCFGPD (average of 29 MCFGPD from 359 wells) on the shelf, and a trace to 595 MCFGPD (average of 72 MCFGPD from 234 wells) in the basin. The maximum initial gas rate was from a horizontal well in the Hartshorne coal in Haskell County at a true vertical depth of 824 ft (251 m).

Produced water ranged from 0–1,201 BWPD (average of 66 BWPD from 337 wells) on the shelf, and from 0–147 BWPD (average of 10 BWPD from 186 wells) in the basin.

Low initial gas rates and minimal initial increase in gas production during dewatering are often attributed to formation damage caused by well stimulation, including the generation of coal fines that plug permeability. Present industry emphasis is on matching the completion technique to the specific coal bed.

REFERENCES CITED

Andrews, R.D., Cardott, B.J., and Storm, T., 1998, The Hartshorne play in southeastern Oklahoma: regional and detailed sandstone reservoir analysis and coalbed-methane resources: Oklahoma Geological Survey Special Publication 98-7, 90 p.

Arbenz, J.K., 1956, Tectonic map of Oklahoma showing surface structural features: Oklahoma Geological Survey Map GM-3, scale 1:750,000.

______ 1989, Ouachita thrust belt and Arkoma basin, in R.D. Hatcher, Jr., W.A. Thomas, and G.W. Viele, eds., The Appalachian-Ouachita orogen in the United States: Geological Society of America, Geology of North America, v. F-2, p. 621-634.

Berry, R.M., and W.D. Trumbly, 1968, Wilburton gas field, Arkoma basin, Oklahoma, in L.M. Cline, ed., A guidebook of the western Arkoma basin and Ouachita Mountains: Oklahoma City Geological Society Guidebook, p. 86-103.

Campbell, M.R., 1929, The coal fields of the United States; general introduction: U.S. Geological Survey, Professional Paper 100-A, 33 p.

Friedman, S.A., 1974, An investigation of the coal reserves in the Ozarks section of Oklahoma and their potential uses: Oklahoma Geological Survey Special Publication 74-2, 117 p.

_______ 1999, Coal geology of Oklahoma, in Keystone coal industry manual: Intertec Publishing Company, Chicago, Illinois, p. 654-659.

Hemish, L.A., 1987, Names of coal beds in the northeastern Oklahoma shelf area: Oklahoma Geological Survey, Oklahoma Geology Notes, v. 47, no. 3, p. 96-113.

_______ 1988, Report of core-drilling by the Oklahoma Geological Survey in Pennsylvanian rocks of the northeastern Oklahoma coal belt, 1983–86: Oklahoma Geological Survey, Special Publication 88-2, 174 p.

Suneson, N.H., 1998, Geology of the Hartshorne Formation, Arkoma basin, Oklahoma: Oklahoma Geological Survey Guidebook 31, 74 p.

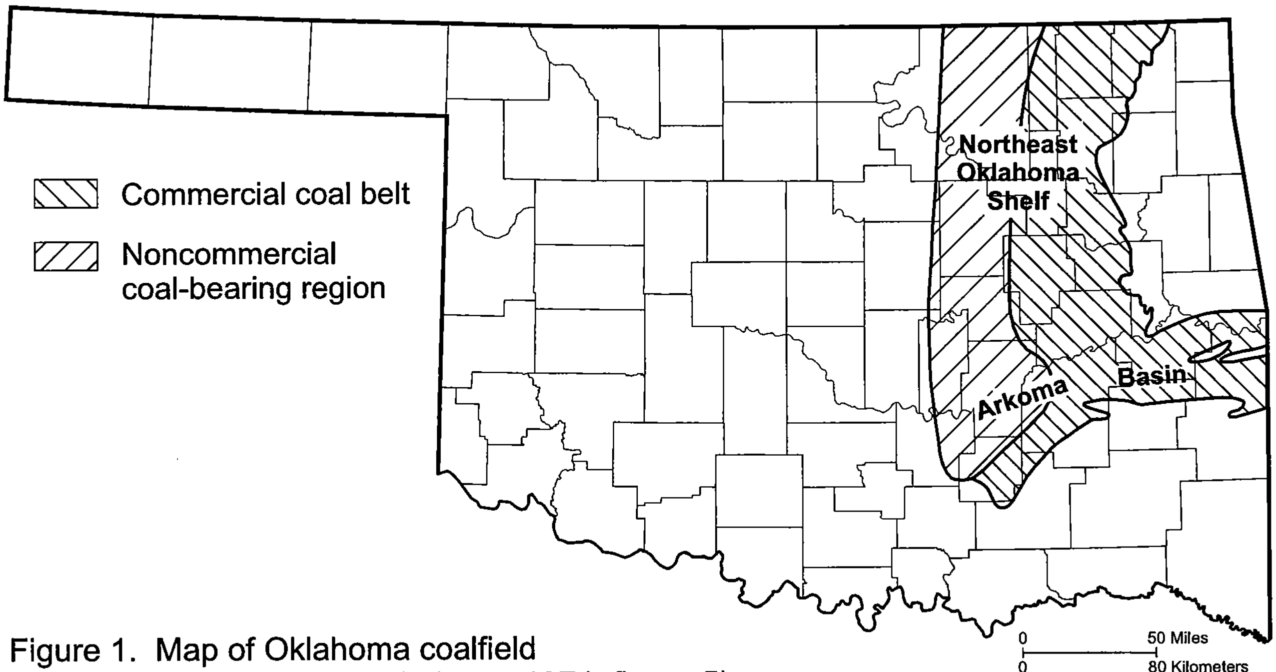


Figure 1. Map of Oklahoma coalfield
(modified from Friedman, 1974, figure 5)

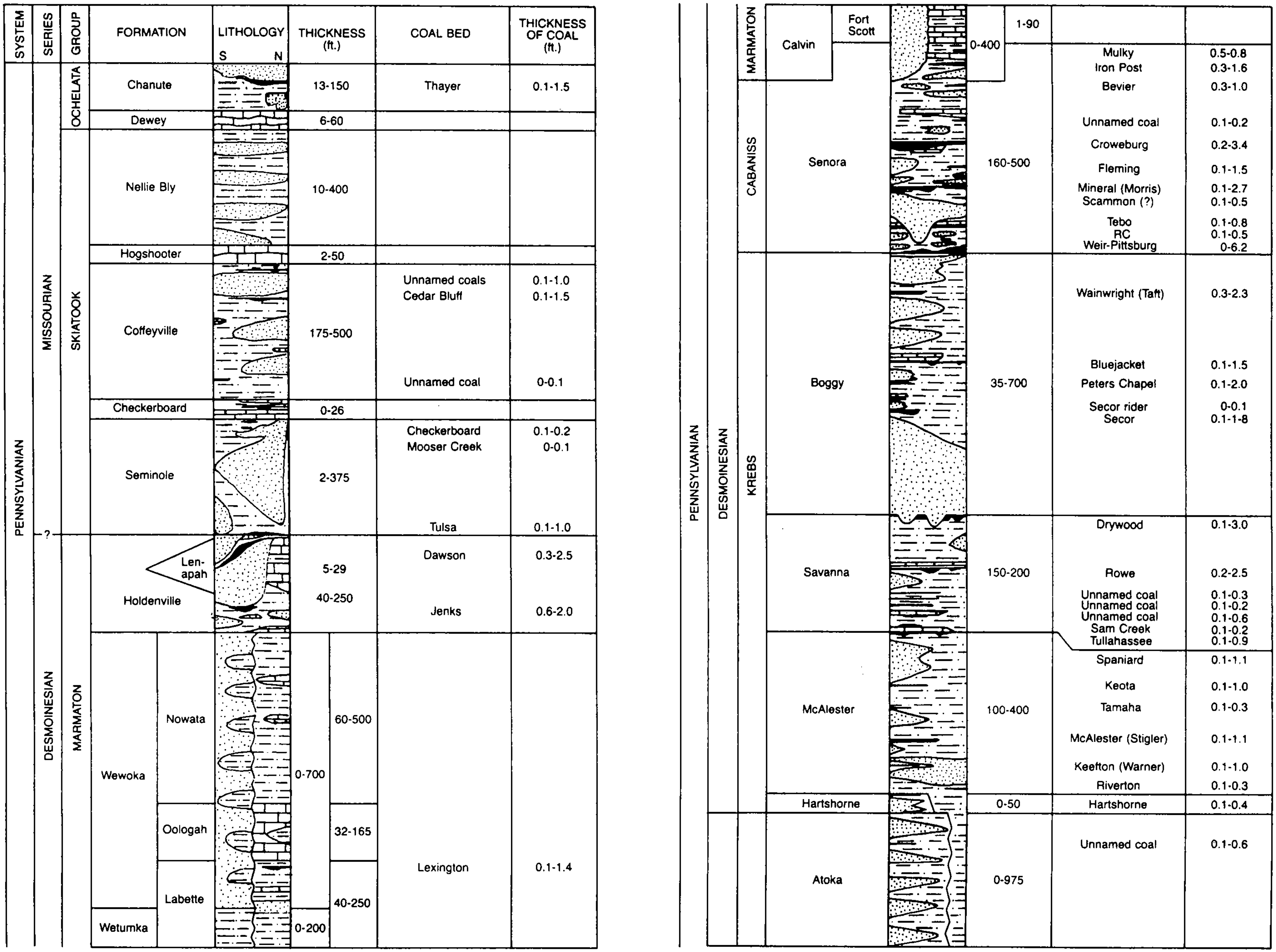


Figure 2. Generalized stratigraphic column of coal-bearing strata of the northeast Oklahoma shelf (from Hemish, 1988, figure 6).

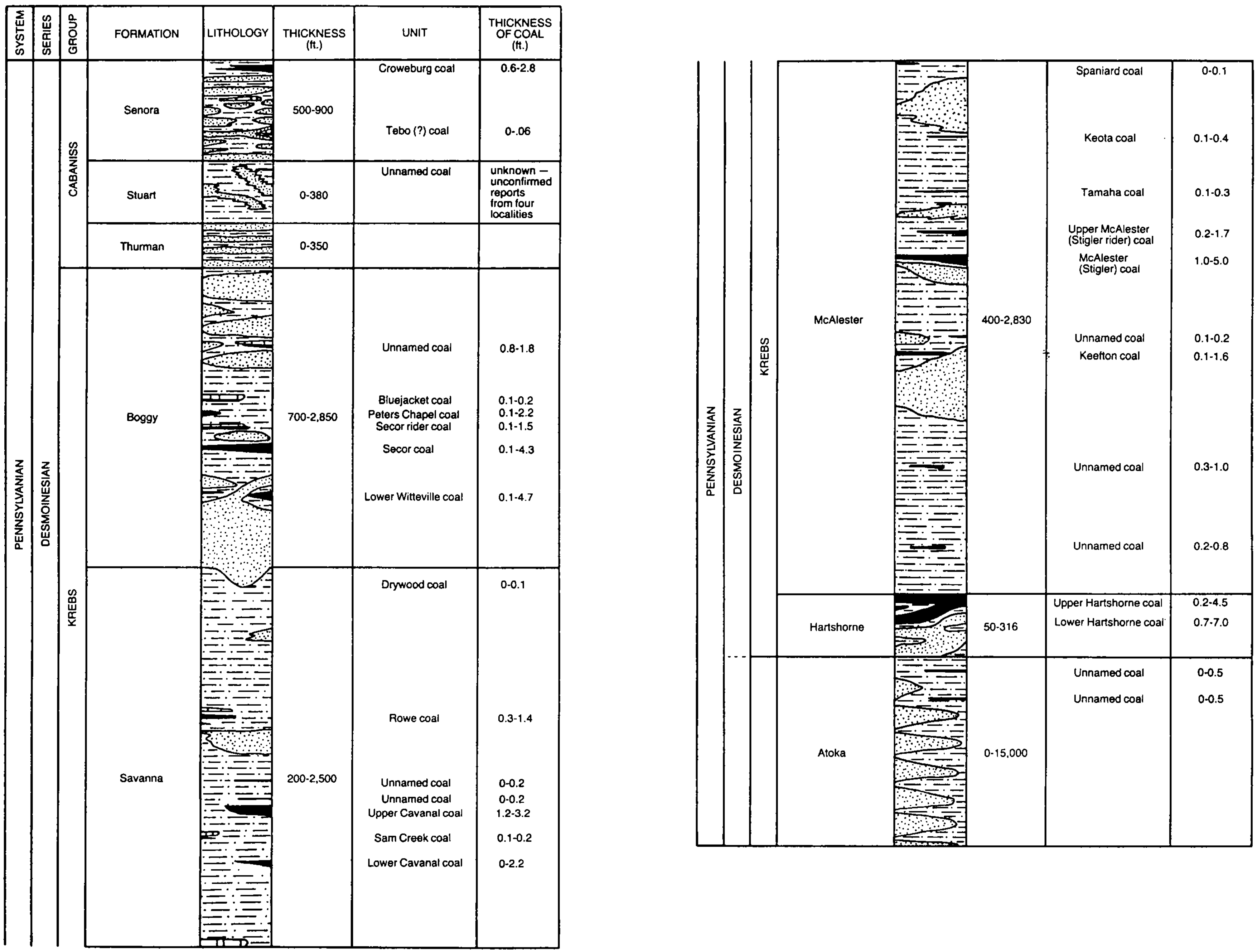


Figure 3. Generalized stratigraphic column of coal-bearing strata of the Arkoma basin (from Hemish, 1988, figure 5).

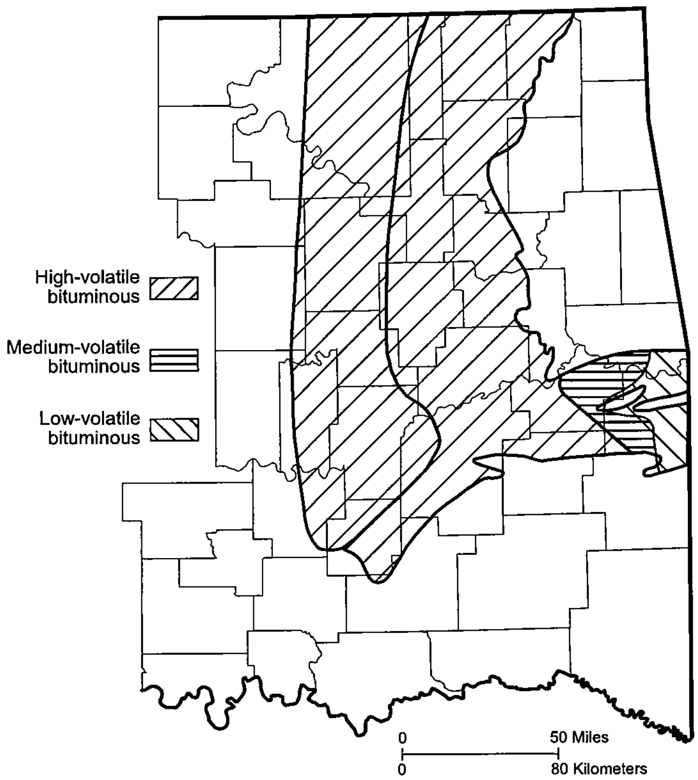


Figure 4. Map of the Oklahoma coalfield showing generalized rank of coal beds near surface (modified from Friedman, 1974, figure 20, and Andrews and others, 1998, figure 34).

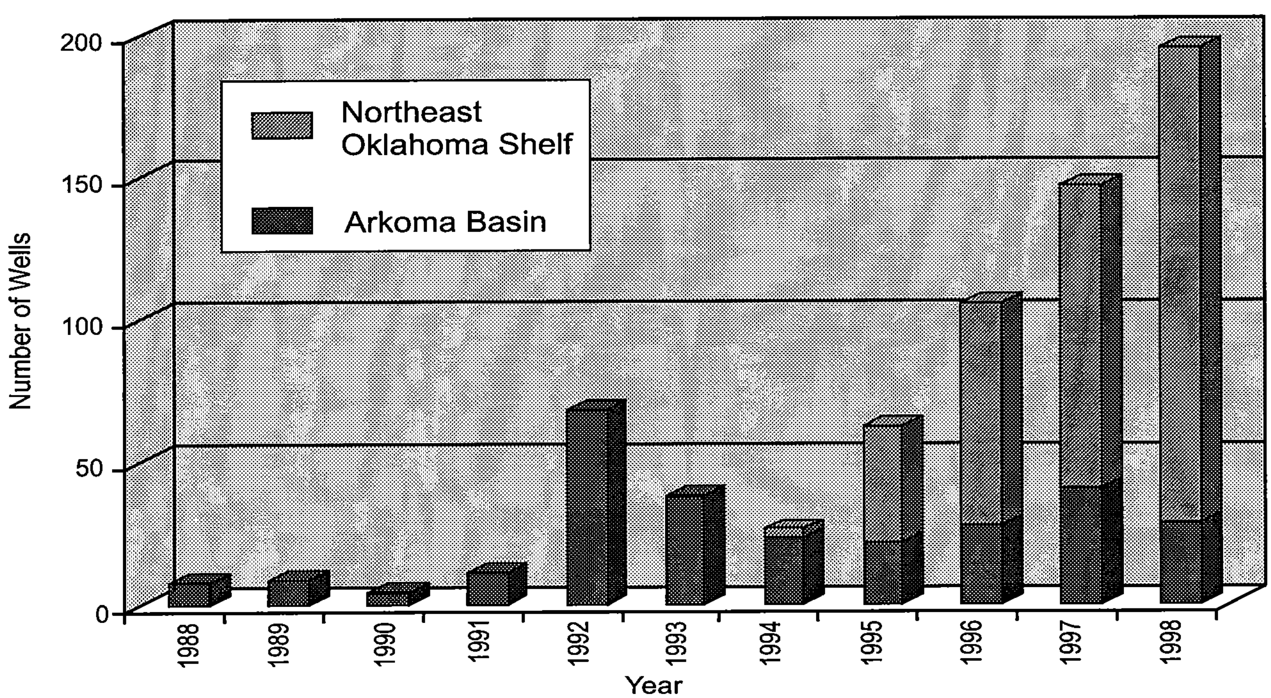


Figure 5. History of Oklahoma coalbed-methane completions.

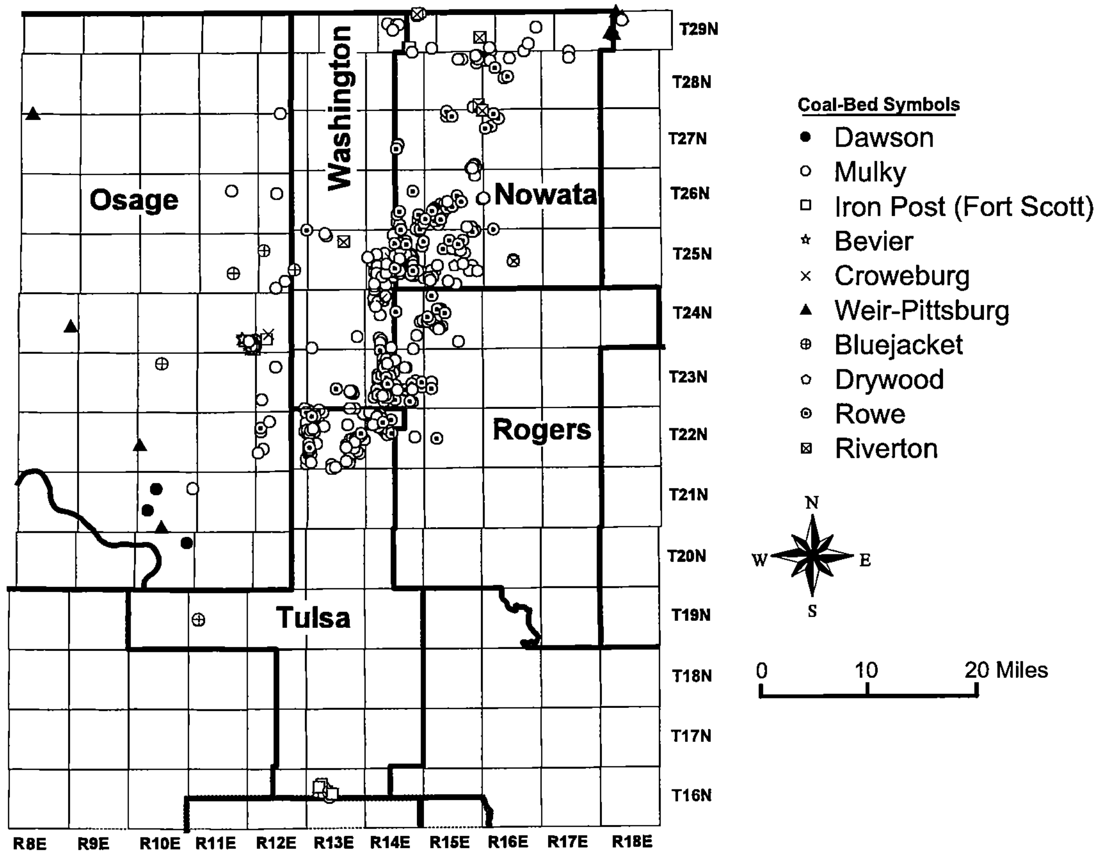


Figure 6. Map showing coalbed-methane completions on the northeast Oklahoma shelf.

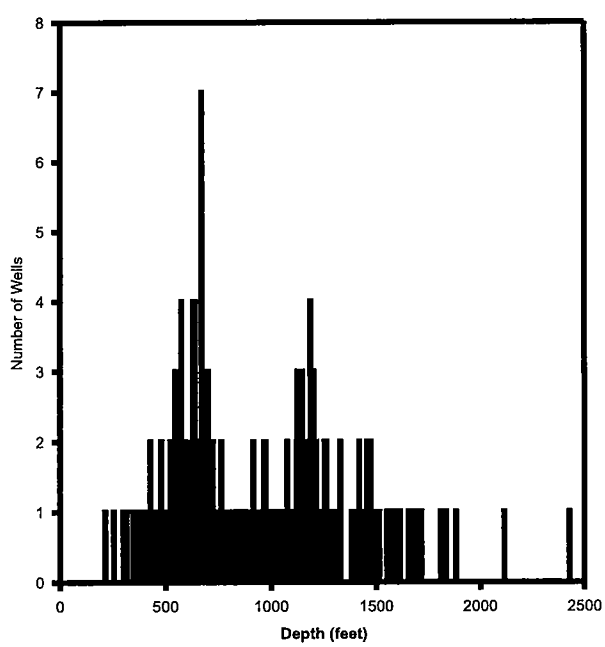


Figure 7. Histogram of coalbed-methane completions by depth on the northeast Oklahoma shelf.

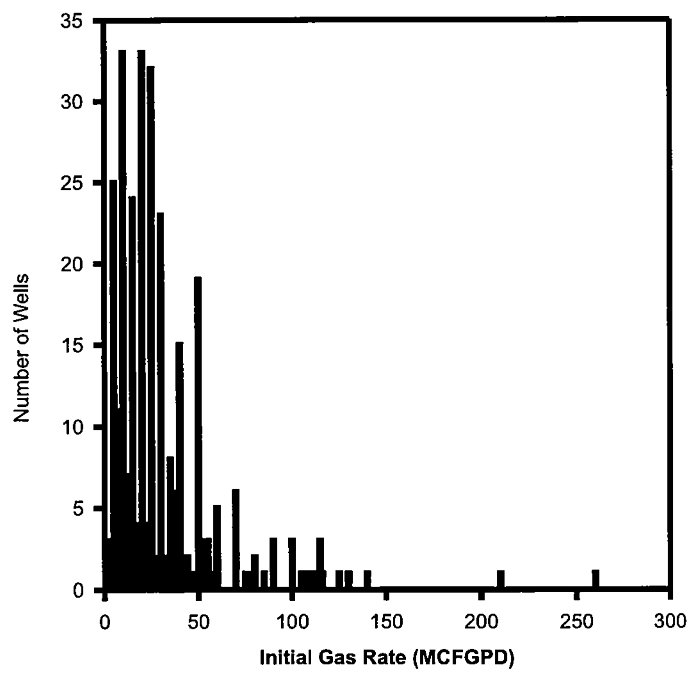
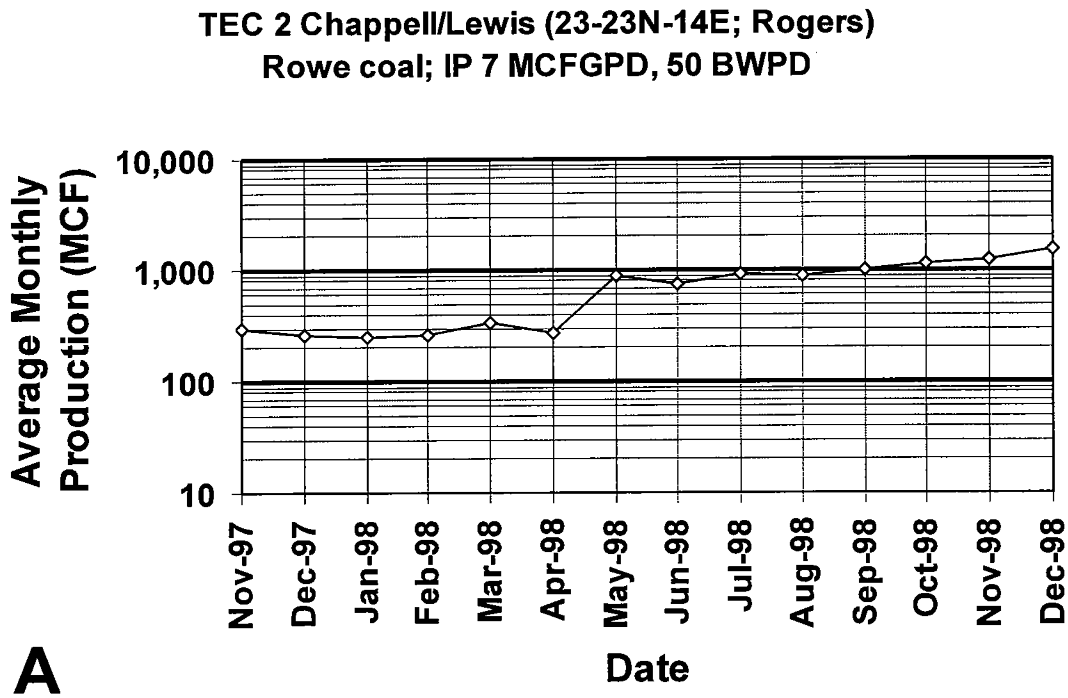


Figure 8. Histogram of coalbed-methane completions by initial potential gas rate on the northeast Oklahoma shelf.



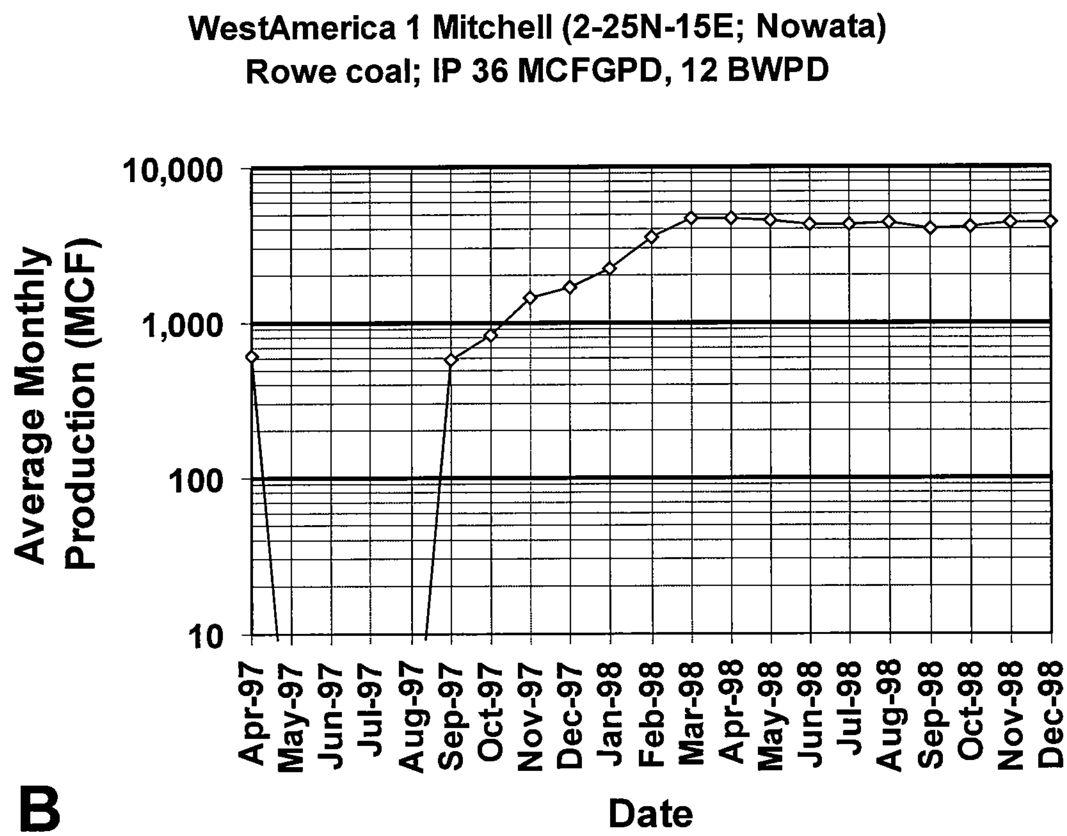


Figure 9. (above and next page). Gas-production decline curves. (A) TEC Resources 2 Chappell/Lewis well. (B) WestAmerica 1 Mitchell well. (C) Dome Engineering T-1 Webster well.

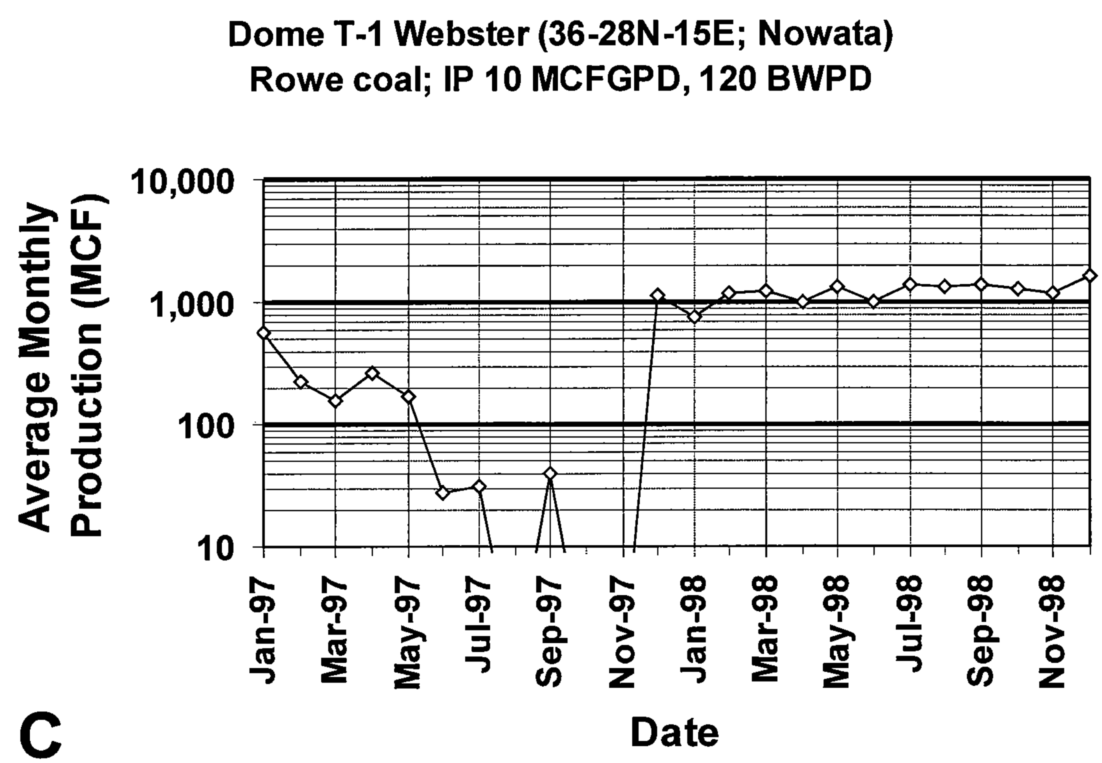


Figure 9. (continued).

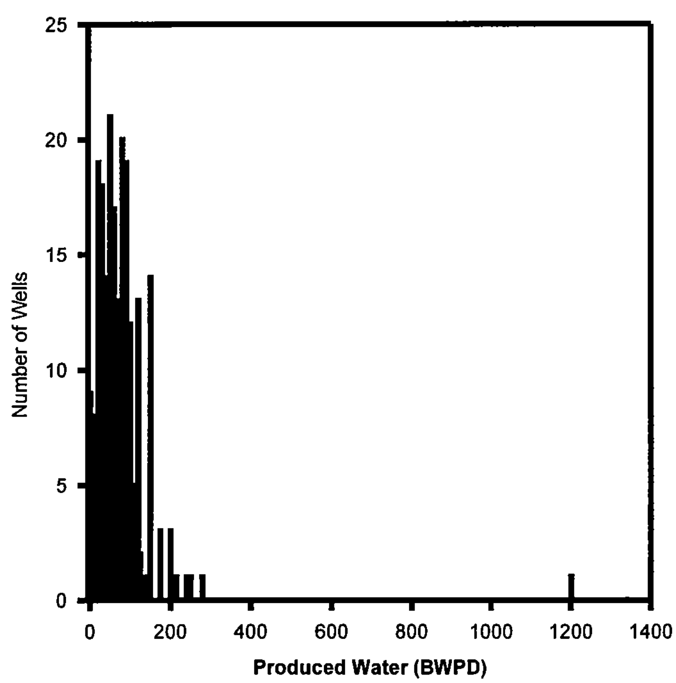


Figure 10. Histogram of coalbed-methane completions by produced water on the northeast Oklahoma shelf.

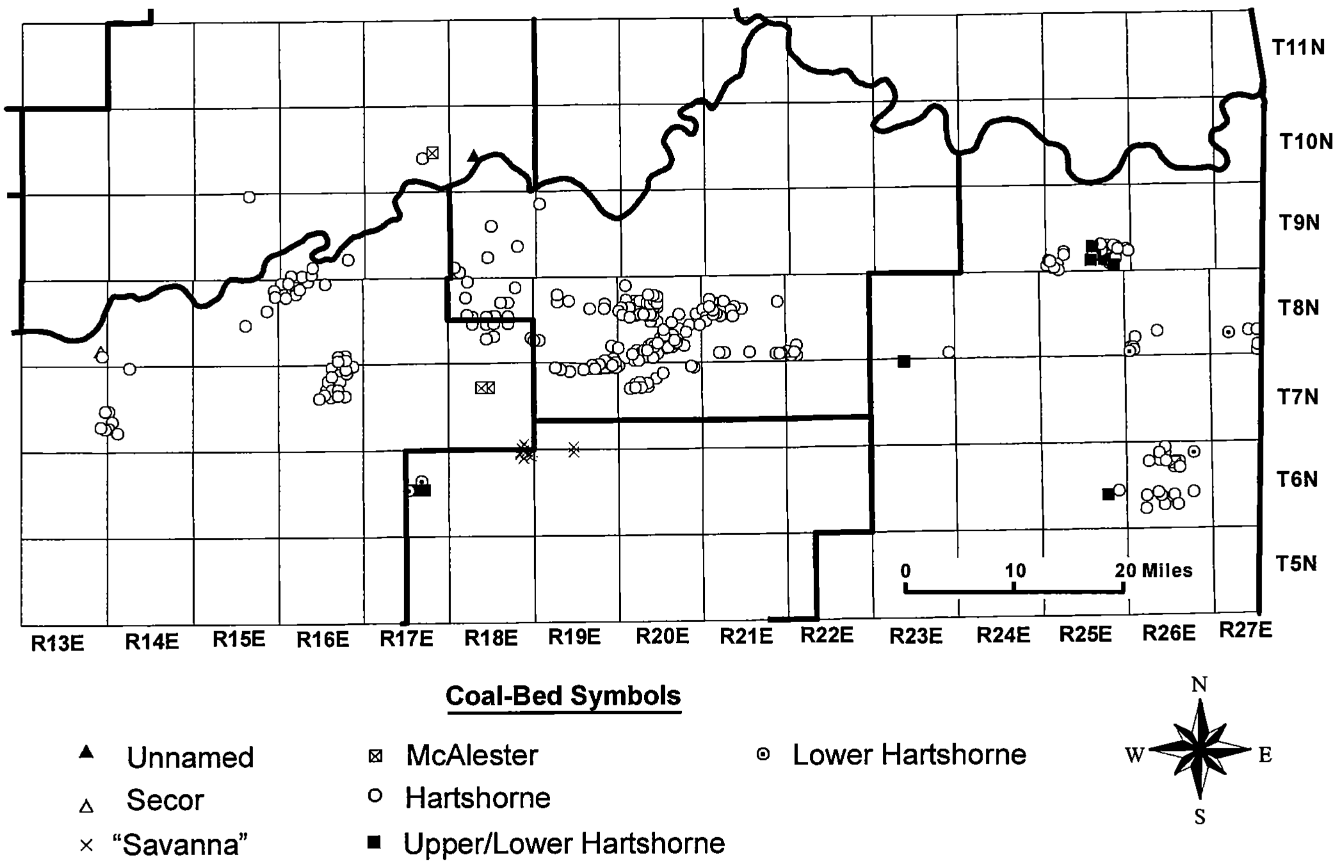


Figure 11. Map showing coalbed-methane completions in the Arkoma basin.

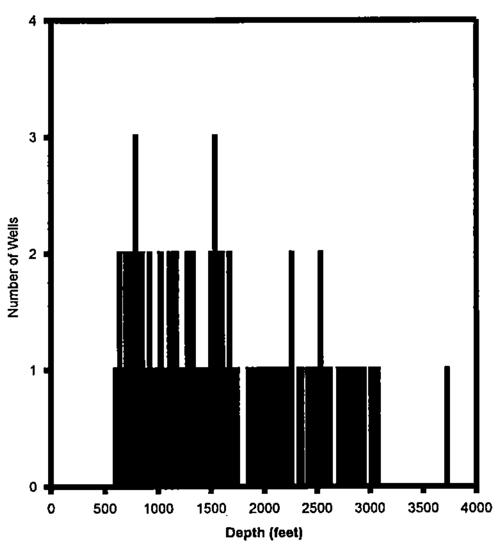


Figure 12. Histogram of coalbed-methane completions by depth in the Arkoma basin.

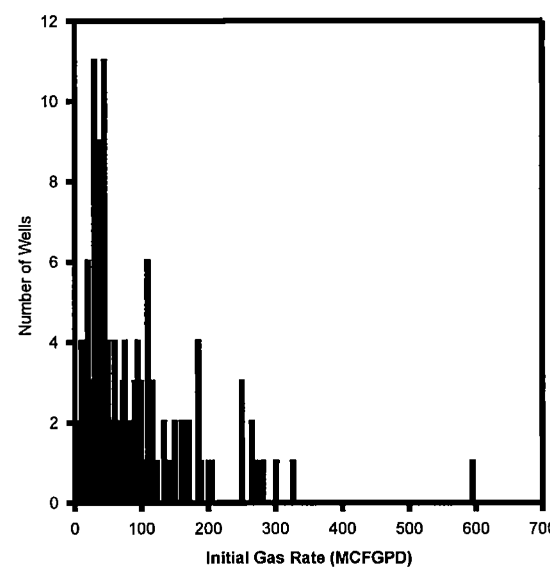


Figure 13. Histogram of coalbed-methane completions by initial potential gas rate in the Arkoma basin.

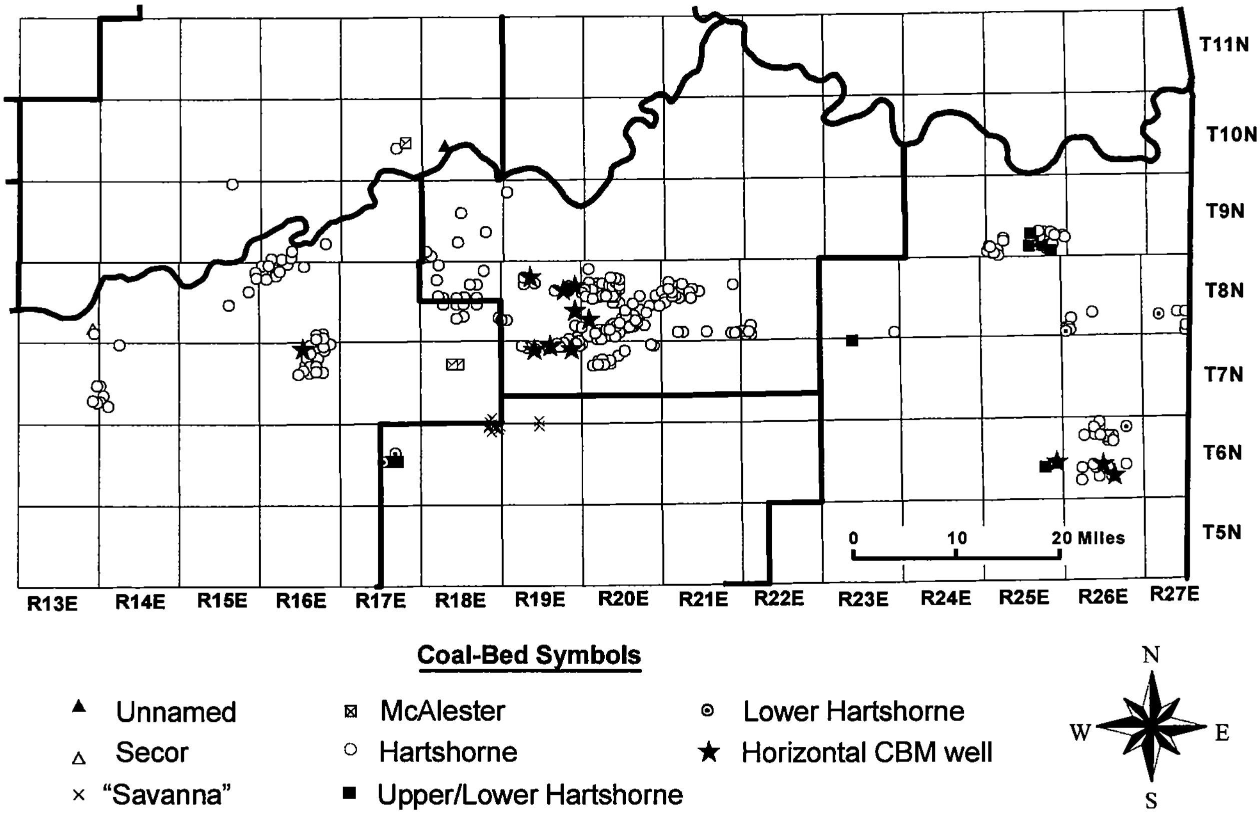


Figure 14. Map showing horizontal coalbed-methane completions in the Arkoma basin.

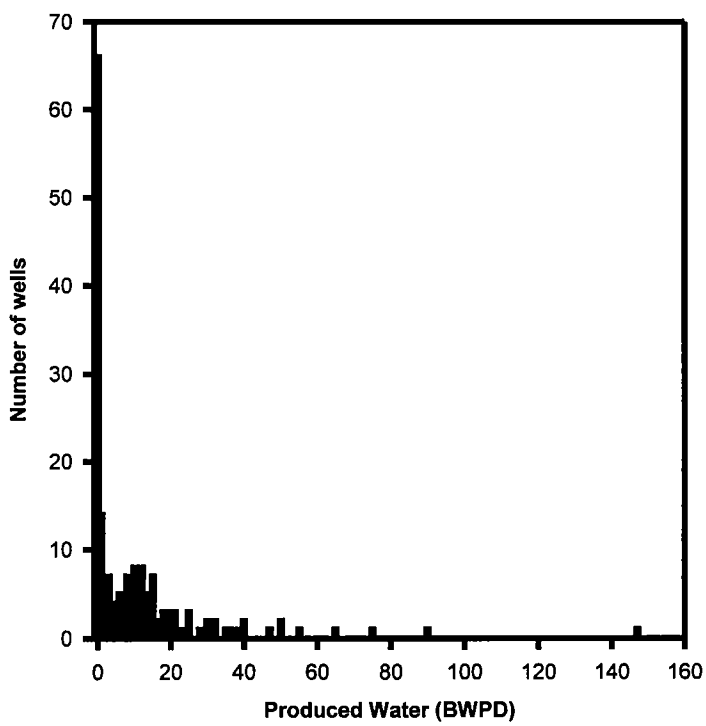


Figure 15. Histogram of coalbed-methane completions by produced water in the Arkoma basin.

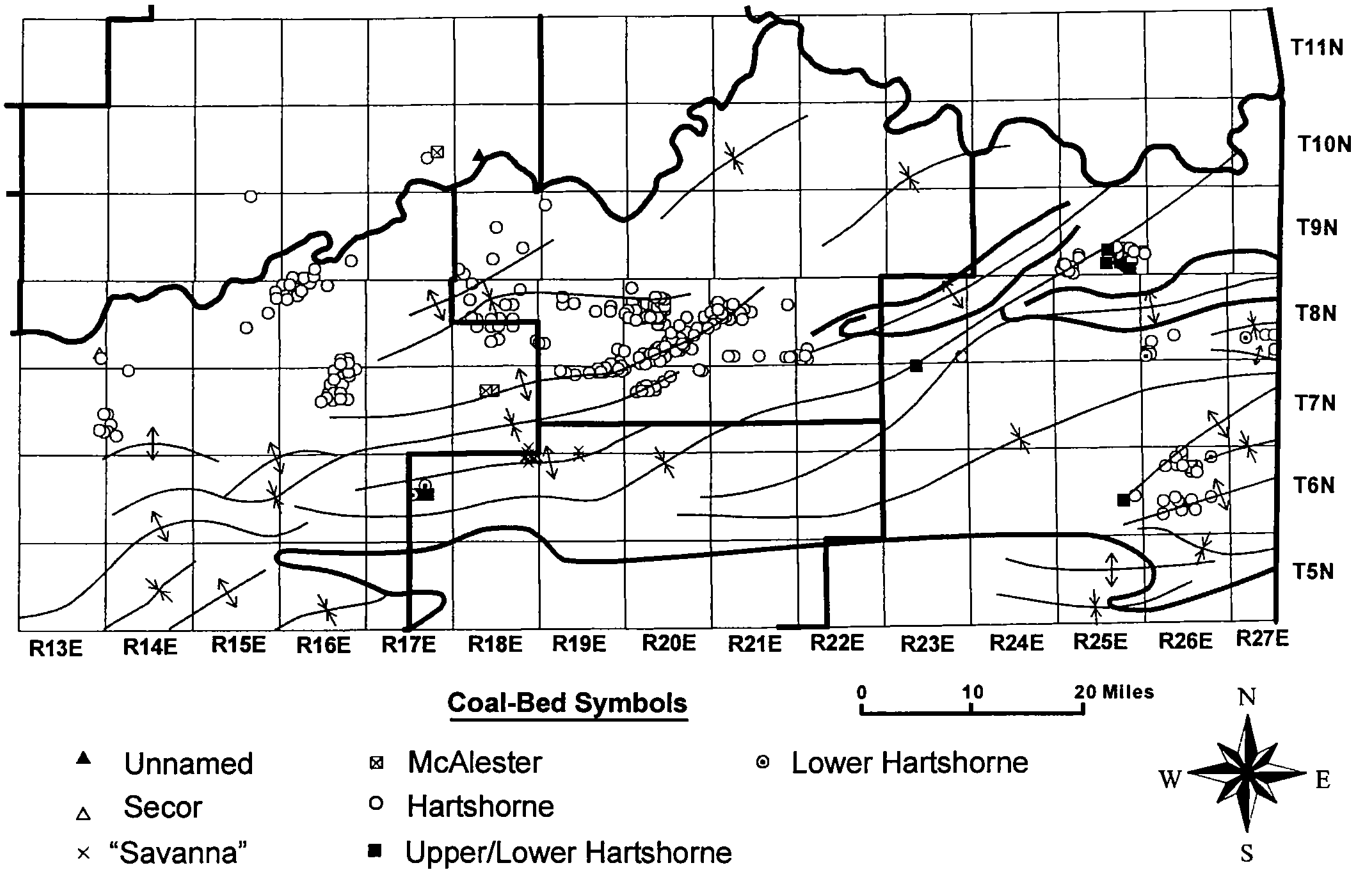


Figure 16. Map showing major surface folds, Hartshorne coal outcrop, and coalbed-methane completions in the Arkoma basin, Oklahoma. (Structure was modified from Arbenz, 1956, 1989, plate 8; Berry and Trumbly, 1968, figure 1; and Suneson, 1998, figure 10)

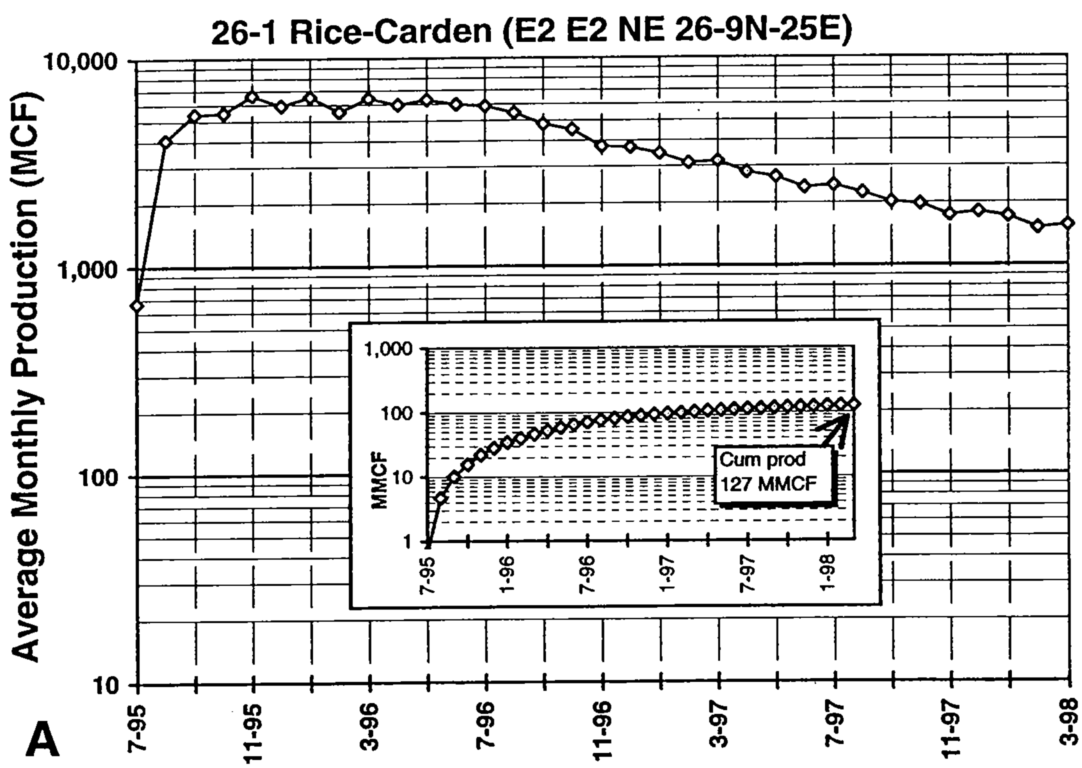
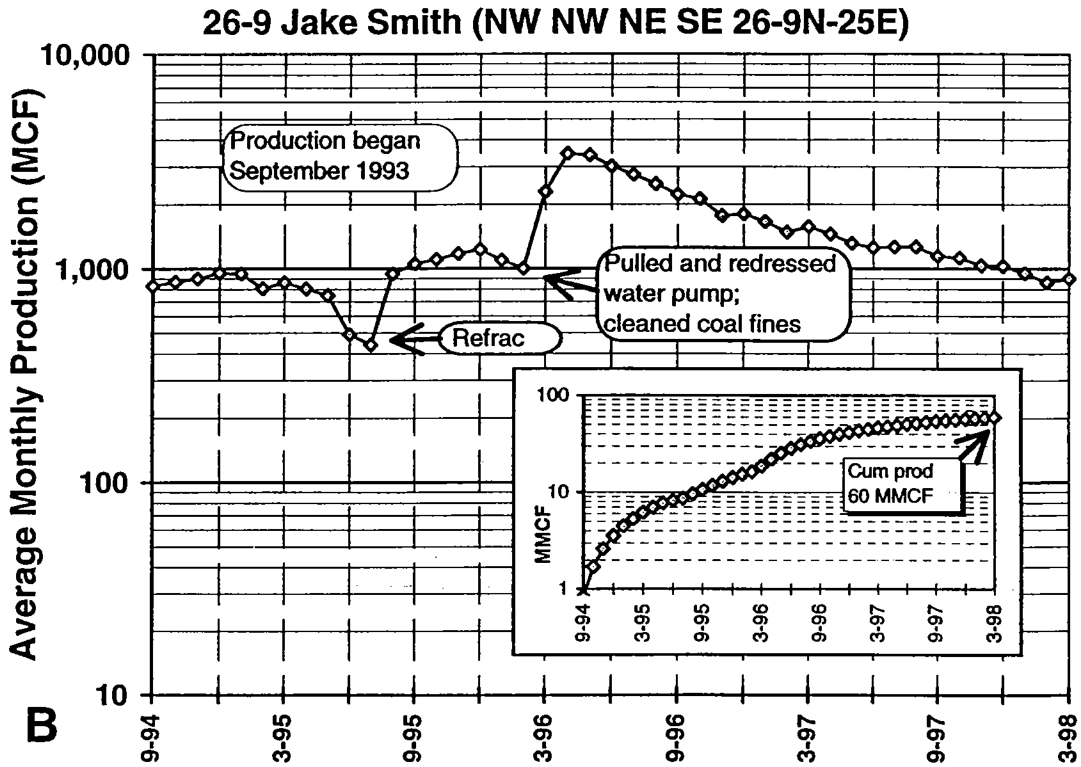


Figure 17. (Above and next page). Gas-production decline curves (from Andrews and others, 1998). (A) OGP Operating 26-1 Rice-Carden well. (B) CWF Energy 26-9 Jake Smith well. (C) CWF Energy 26-13 Rhodes well.



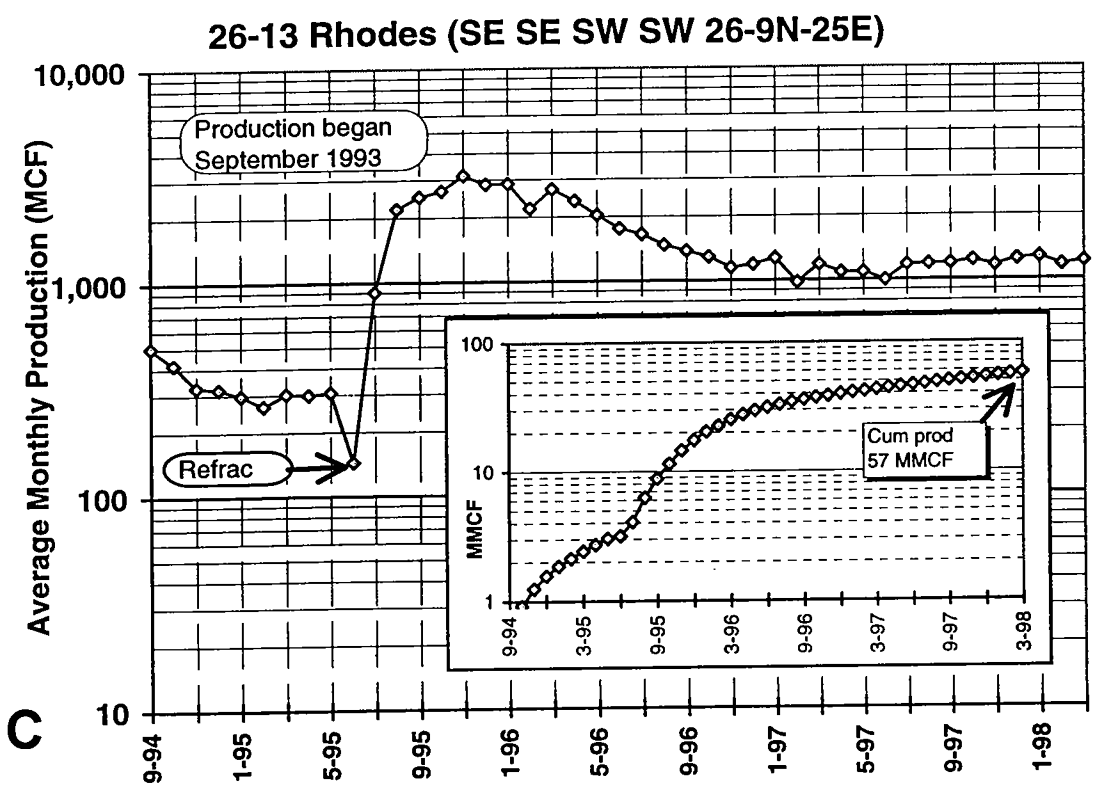


Figure 17. (Continued).

OKLAHOMA GEOLOGICAL SURVEY
OPEN-FILE REPORT OF 6-99

5

Cleat in Oklahoma coals

Samuel A. Friedman
Oklahoma Geological Survey (retired)
Norman, OK

Friedman, S.A., 1999, Cleat in Oklahoma coals, in Oklahoma coalbed-methane workshop: Oklahoma Geological Survey, Open-File Report OF 6-99, p. 67-70.

Cleat in Oklahoma Coals

Samuel A. Friedman
Oklahoma Geological Survey Geologist/Retired
and Independent Coal Geologist

Friedman and Hemish have routinely documented and mapped coal-bed cleat orientation and mineralization, while mapping Pennsylvanian coal beds, stratigraphy, and structure in the eastern Oklahoma coal field during the past 28 years, because efficiency in coal mining is greatly impacted by cleat orientation. Long ago, surface miners discovered that they could extract large blocks of coal and produce fewer fines by digging at right angles to the face cleat. During the last 30 years knowledge of face cleat orientation has been applied for safety purposes to coal-bed methane drainage from underground mines.

Cleats are the dominant set of vertical fractures in a coal bed. Cleats are perpendicular or almost perpendicular to bedding planes. A cleat system or set consists of a primary cleat called the face cleat and a secondary cleat called the butt cleat. Face cleats are continuous and straight both laterally and vertically through a coal bed. Face cleats occur with greatest frequency in the vitrain lithotype. In a cleat system each face cleat is parallel to the other face cleats (Figures 1 and 2). Face cleat frequency is lowest in low-rank coal, such as lignite, and in high-rank coal, such as anthracite. Face cleat frequency is highest in high-rank coal such as high-volatile A bituminous and medium-volatile bituminous coal, which are present in Oklahoma. In the Oklahoma coal field, the greatest face cleat frequency is 10 per inch, which occur in a core of low-volatile bituminous, Lower Hartshorne coal from eastern Le Flore County.

Butt cleats occur almost at right angles to face cleats, are discontinuous and not straight, and commonly terminate against face cleats in an upper-case T pattern. Thus the face cleats rather than the butt cleats are the primary source of coal-bed permeability. Face cleat orientation or strike is the primary factor determining natural-fluid flow direction in a coal bed.

Little or nothing had been documented on cleat in Oklahoma coals until 1971, when I began measuring and noting cleat orientation while collecting channel samples of coal at this state's active mines. Hemish began similar activity in 1978. We mapped and measured coal cleat orientations at some 500 locations. Iannacchione and Puglio (1979) measured cleat orientations in Haskell and Le Flore counties. Thus cleat strike has been determined by state and federal coal geologists in 27 bituminous coals in 17 counties in eastern Oklahoma. The coals, in ascending stratigraphic sequence, are Atoka 1 and Atoka 2 in the upper part of the Atoka Formation, the Hartshorne coal, including the Lower and the Upper Hartshorne coals in the Hartshorne Formation, the Keefton, McAlester, Upper McAlester, and Stigler coals in the McAlester Formation, the Lower Cavanal, Cavanal, Calhoun, Rowe, Drywood, and Lower Witteville* coals in the Savanna Formation, the Secor, Secor rider, Peters Chapel, and Bluejacket coals in the Boggy Formation, the Weir-Pittsburg, Tebo, Mineral, Fleming, Croweburg, and Iron Post coals in the Senora Formation, the Dawson coal in the Seminole Formation, and the Cedar Bluff coal in the Coffeyville Formation.

The cleat measurements in these coals indicate that the average face cleat strikes or trends north-northwestward in most of the Arkoma Basin and also in the northeast Oklahoma shelf. This trend is at right angles to the strike or axes of major anticlines, synclines, and faults (or the regional structural trend) in eastern Oklahoma. In Coal, Atoka, and Pittsburg counties the structural trends are northeastward, north-northeastward, and eastward. Thus in these three counties the face cleat is somewhat different for each structural location or area.

Face cleat strikes northeastward, however, and is parallel to the regional geologic structure in the Stigler coal in a strip mine in eastern Haskell County.
This anomalous cleat orientation is near a major fault that strikes northeastward. Ting (personal communication, 1975) and others also observed face cleat "bending" or with a changed orientation parallel to nearby faults in other coal fields.

Most of the channel samples of Oklahoma coals collected by Friedman and by Hemish for chemical analysis at the Oklahoma Geological Survey contained pyrite, calcite, kaolinite, and gypsum in the cleats. Of these minerals, mostly the calcite and gypsum may be altered by acids introduced during fracture stimulation in wells drilled or recompleted for coal-bed methane production. This alteration may produce other solid compounds in cleats that block fluid flow, thus decreasing rather than increasing permeability. Field experiments in other states have demonstrated (1) that small quantities instead of large quantities of stimulation fluids result in increased gas flow in coal beds, (2) that horizontal or lateral open-hole completion in coal beds, without fracture stimulation, increased gas flow, and (3) that horizontal or lateral open-hole completions drilled normal to the face cleats resulted in the greatest quantity of gas flow to a well.

Therefore, knowledge of face cleat orientation and frequency and of minerals that fill cleats, especially face cleats, is necessary and must be applied to maximize efficiency in coal-bed methane exploration, drilling, recompletion, and production in Oklahoma and in other areas.

*The Lower Witteville coal may occur in the Boggy Formation (Hemish, 1994a).

Selected References

Close, J. C., 1993, Natural fractures in coal, *in* Law, B. E., and D. D. Rice, Editors, Hydrocarbons from coal: AAPG Studies in geology no. 38, p. 119-132, figs. 2-5.

Cross, A. T., 1952, The geology of the Pittsburgh Coal: Stratigraphy, petrology, origin and composition, and geologic interpretation of mining problems, *in* Second conference on the origin and constitution of coal: Nova Scotia Department of Mines and Nova Scotia Research Foundation, p. 77, figs. 31 and 32.

Diamond, W. P., 1993, Methane control for underground coal mines, *in* Law, B. E., and D. D. Rice, Editors, Hydrocarbons from coal: AAPG Studies in geology no. 38, p. 237-267, figs. 6, 15, 16, and 29.

Ertekin, T., W. Sung, and H. I. Bilgesu, 1991, Structural properties of coal that control coalbed methane production, *in* Peters, D. C., Editor, Geology in coal resource utilization: TechBooks, Fairfax, Virginia, p. 121-122, fig. 10.

Hemish, L. A., 1986, Coal geology of Craig County and eastern Nowata County, Oklahoma: Oklahoma Geological Survey Bulletin 140, 131 p., 17 figs., 8 plates, 2 tables.

_____1989, Coal geology of Rogers County and western Mayes County, Oklahoma: Oklahoma Geological Survey Bulletin 140, 118 p., 12 figs., 8 plates, 2 tables.

_____1990, Coal geology of Tulsa, Wagoner, Creek, and Washington counties, Oklahoma: Oklahoma Geological Survey Geologic Map GM 33, text and 5 plates on 3 sheets (scale 1:63,360).

_____1994a, Correlation of the Lower Witteville coal bed in the Arkoma Basin, eastern Oklahoma: Oklahoma Geological Survey Oklahoma Geology Notes, v. 54, no. 1, p. 4-28.

_____1994b, Coal geology of Okmulgee County and eastern Okfuskee County, Oklahoma: Oklahoma Geological Survey Special Publication 94-3, 86 p., 9 figs., 8 plates, 2 tables, 4 appendices.

_____1998a, Coal geology of Muskogee County, Oklahoma: Special Publication 98-2, 111 p., 7 figs., 2 tables, 3 plates.

_____1998b, Coal geology of McIntosh County, Oklahoma: Oklahoma Geological Survey Special Publication 98-6, 74 p., 8 figs., 2 tables, 2 plates.

Iannacchione, A. T., and Puglio, D. G., 1979, Methane content and geology of the Hartshorne coal bed in Haskell and Le Flore counties, Oklahoma: U.S. Bureau of Mines Report of Investigations 8407, 14 p., 11 figs., 3 tables.

McCulloch, C. M., M. Deul, and P. W. Jeran, 1974, Cleat in bituminous coalbeds: U. S. Bureau of Mines Report of Investigations no. 7910, 23 p.

Ting, F. T. C., 1977, Origin and spacing of cleats in coal beds: Transactions of the American Society of Mechanical Engineers, p. 624-626.

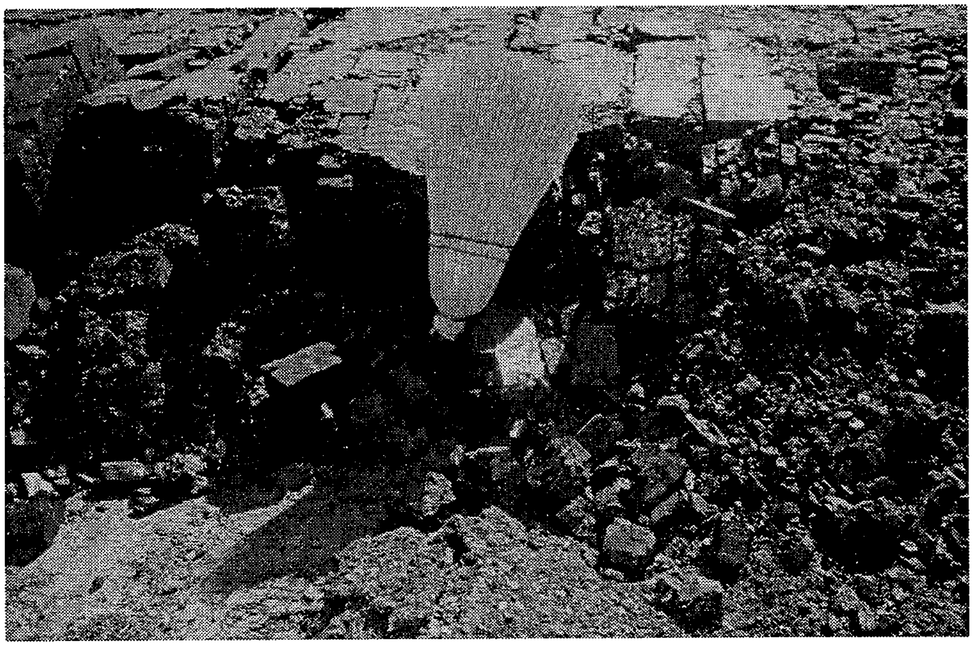


Figure 1. Looking eastward at Keefton coal, nine inches thick, in Interchem Coal Co. strip mine, near Warner, Oklahoma, 1990. Parallel face cleat fractures are clearly visible and give the coal a blocky appearance (whisk broom for scale).

Figure 2. Looking down at top of Keefton coal (McAlester Formation), same location as figure 1. Parallel face cleat are straight and average two per inch (dime for scale).

OKLAHOMA GEOLOGICAL SURVEY
OPEN-FILE REPORT OF 6-99

6

Coalbed methane completion practices in Oklahoma

Brad Wilkins
Wilkins Engineering & Supervision
McAlester, OK

Wilkins, B., 1999, Coalbed methane completion practices in Oklahoma, in Oklahoma coalbed-methane workshop: Oklahoma Geological Survey, Open-File Report OF 6-99, p. 71-87.

DRILLING CONSIDERATIONS

CASED HOLE vs. OPEN HOLE

ADVANTAGES

1) REDUCES DAMAGE FROM DRILLING FLUIDS AND CEMENT

DISADVANTAGES

1) TENDENCY TO PRODUCE COAL FINES AND FRAC SAND
2) DIFFICULT TO CONTROL FRAC DUE TO EXCESS EXPOSURE OF OTHER FORMATIONS
3) LIMITED AMOUNT OF RATHOLE FOR PUMP PLACEMENT

AFTER DRILLING

1) TD WELL AND TRIP OUT OF HOLE
2) ONLY LOAD HOLE IF SAND OR OTHER FORMATION WARRANTS NEED FOR INDUCTION LOG. ONLY INTERESTED IN BULK DENSITY LOG. RUN HIGH RESOLUTION IF AVAILABLE.
3) IF NEEDED LOAD WITH KCL WATER
4) DO NOT USE GEL OR MUD

CEMENTING & PERFORATING

1) EXTREMELY CRITICAL TO SUCCESS OF WELL
2) 2 sks CEMENT CAN FILL CLEATS IN 4 ft COAL TO RADIUS OF 5'
3) USE ARKOMA BLEND. 50:50:0/SODIUM-META-SILICATE/LATEX BLEND @ 14.5 ppg WITH 1.25 cu. ft./sk YIELD
4) PERFORATE WITH 4 SPF USING 3 1/8" HSC
5) LARGER SHOTS AND HIGHER DENSITY CAN MAKE ENTRY DIFFICULT DURING STIMULATION TREATMENT

EARLY COMPLETIONS

SHALLOW HARTSHORNE COALS SITUATED ON KINTA ANTICLINE. TREATMENTS CONSISTED OF STRAIGHT NITROGEN TREATMENTS UTILIZING APPROXIMATELY 150,000 SCF @ 8,000 SCFM. FLOWED BACK TO ATMOSPHERE.

THIS TREATMENT WAS FOUND TO BE INEFFECTIVE ON WELLS DRILLED OFF STRUCTURE OR IN THE SYNCLINES WHERE WATER WAS PRESENT IN THE CLEATS.

SEVERAL NITROGEN FOAM FRACS UTILIZING 20# AND 30# GELS WERE PERFORMED WITH NO SUCCESS. AT LEAST 16 WELLS WERE TREATED AND ALL COULD BE CONSIDERED FAILURES.

CORES FOUND TO BE EXTREMELY SENSITIVE TO ALL CHEMICALS, ESPECIALLY FOAMERS.

SAND/WATER TREATMENTS

TREATMENTS WERE BASED UPON SUCCESSFUL TREATMENTS PERFORMED IN THE APPALACHIAN COALS. TREATMENTS WERE "BULLHEADED" AND RATES OF 40 BPM WERE DESIRED. HIGH RATES WERE CONSIDERED NECESSARY TO OBTAIN PROPPANT TRANSPORT. WELLS WERE IMMEDIATELY FLOWED BACK AFTER TREATMENT WITH AVERAGE VOLUMES OF 1000 BBL RECOVERED. AFTER WASHING SAND FROM CASING, WELLS WOULD BE PUT ON PUMP. INITIAL RATES OF 70 TO 80 BPD WERE COMMON WITH FIRST SIGNS OF GAS AFTER 5 TO 7 DAYS. WELLS WERE ALLOWED TO PRODUCE GAS AT MAXIMUM RATES (NO BACKPRESSUE). RATES AS HIGH AS 300 MCFD WERE NOTED BUT HAD EXTREMELY HIGH DECLINE RATES. AFTER 2 WEEKS MANY WELLS WOULD DROP TO LESS THAN 20 MCFD.

INITIAL OBSERVATIONS

1) PROPPANT TRANSPORT. 63 WELLS WERE FRACED WITHOUT A SCREENOUT.
2) HIGH FRAC GRADIENTS. FG AVERAGED 1.55 psi/ft WITH SOME AS HIGH AS 2.0 psi/ft. RESEARCHERS INDICATED THAT THIS TREND IS NORMAL IN COALS DUE TO MULTIPLE FRACTURES AND MULTIPLE ORIENTATIONS. WELLS DID HAVE A FG OF LESS THAN 1.0 psi/ft EARLY IN TREATMENT, THOUGH. EXPLANATION WAS THAT OBTAINED RATES WERE NOT HIGH ENOUGH AT THAT POINT IN THE TREATMENT TO INITIATE A TRUE FRACTURE.
3) WELLS PRODUCED A TREMENDOUS VOLUME OF COAL FINES. FOUND TO BE DETRIMENTAL TO DOWNHOLE PUMPS.
4) WOULD TYPICALLY LOOSE 50% GAS PRODUCTION AFTER PUMP CHANGE. WATER RATES WOULD ONLY DROP 5 TO 10%.

INITIAL CONCLUSIONS

1) COAL FINE PLUGGING WAS RESPONSIBLE FOR HIGH DECLINE RATES AND POOR PRODUCTION.
2) FELT THAT COMBINATION OF HIGH WATER AND GAS RATES WERE PROVIDING THE MECHANISM FOR FINES TRANSPORT.
3) BACKPRESSURE WAS HELD IN ATTEMPT TO CONTROL FINES MOVEMENT BUT SUCCESS WAS LIMITED.
4) "ELIMINATE THE FINES, ELIMINATE THE PROBLEM."

   ASSUMED FINES WERE BEING CREATED FROM PROPPANT ETCHING COALFACE. OBSERVATIONS FROM STIMLAB INDICATED THAT THE FINES ARE CREATED BY THE TURBULENCE OF THE FLUID WITHIN THE FRACTURE. FOAMS AND GELLS HAVE A VELOCITY OF ZERO AT THE COALFACE. RECOMMENDED THAT LINEAR FOAM WITH MINIMAL FOAMER BE USED. TREATMENTS WERE TOTAL FAILURES.

DEVELOPMENT OF CONTROLLED VELOCITY FRAC

1) OBSERVED THAT FG'S ON FOAM AND GEL FRACS WERE CONSIDERABLY LOWER THAN THOSE FROM WATER FRACS.
2) FLOWBACKS DURING TWO FRACS YIELDED "COAL SLURRY".
3) SUSPECTED THAT FRACS WERE OUT OF ZONE. TAGGED SAND CONFIRMED FRAC HEIGHTS OF 45' AND 72' INTO UNPRODUCTIVE HARTSHORNE SAND.
4) FOUND TREND DURING REVIEW OF FRAC CHARTS INDICATING POINT OF COAL FAILURE. NORMALLY AROUND 20 BPM IN 5 1/2' COAL (FACTOR OF 3.5).
5) THEORY DEVELOPED THAT "CRITICAL VELOCITY" REACHED AT THAT POINT IN TREATMENT, PRODUCING COAL SLURRY AND SUBSEQUENT SCREEN-OUT.
6) SINCE PROPPANT CANNOT BE TRANSPORTED AT LOWER RATES, A METHOD TO DECREASE THE VELOCITY MUST BE DEVELOPED.
7) AN INCREASE IN FRAC WIDTH WOULD ULTIMATELY DECREASE THE VELOCITY WITHIN THE FRACTURE PROPORTIONATELY.
8) NORMALLY DONE BY INCREASING THE FLUID VISCOSITY WITH GELLS, BUT THAT PRODUCES SEVERE DAMAGE.
9) DEVELOPED "CONTROLLED VELOCITY FRAC" UTILIZING 100 MESH SAND TO INCREASE FLUID EFFICIENCY.
10) DRAMATIC DECREASE IN FRAC GRADIENT NOTED ON INITIAL TREATMENTS.
11) FURTHER REFINEMENTS MADE BY RUNNING CONTINUOUS SAND, AND CONTROLLING REDUCTION OF PUMP RATES AND RATE SURGES DURING GEAR CHANGES.
12) INDICATIONS OF LIMITED ENTRY INTO PERFORATIONS FROM STUDIES FROM THE BLACK WARRIOR AND CONFIRMED BY DOWNHOLE CAMERA LEAD TO THE ADOPTION OF ACID SPEARHEAD. ALTHOUGH DAMAGING TO THE COAL, THE IMMEDIATE SUCCESSION OF WATER WILL DILUTE THE ACID TO THE POINT OF NO DAMAGE, EXCEPT MAYBE NEAR WELL BORE.

INTRODUCTION TO NE OKLAHOMA

1) TYPICAL TREATMENTS CONSISTED OF 400 BBL 10# TO 30# GEL WITH 8,000# TO 12,000# PROPPANT. MULTIPLE SCREEN-OUTS NOTED AND FG'S RANGING FROM 1.6 psi/ft TO 3.0 psi/ft.
2) GOOD RATES NOTED DURING DRILLING OPERATIONS, BUT VERY POOR PRODUCTION AFTER FRACS.
3) DOWNSIZED "CONTROLLED VELOCITY" TREATMENT TO MATCH COAL THICKNESS.
4) DRAMATIC DECREASE IN FRAC GRADIENTS AND INCREASE IN GAS AND WATER RATES.
5) FAILED FRAC ATTEMPT RESULTED IN THE DISCOVERY OF THE ACID/WATER TREATMENT AND TRUE NATURE OF PERMEABILITY.

CURRENT COMPLETION PROCEDURE

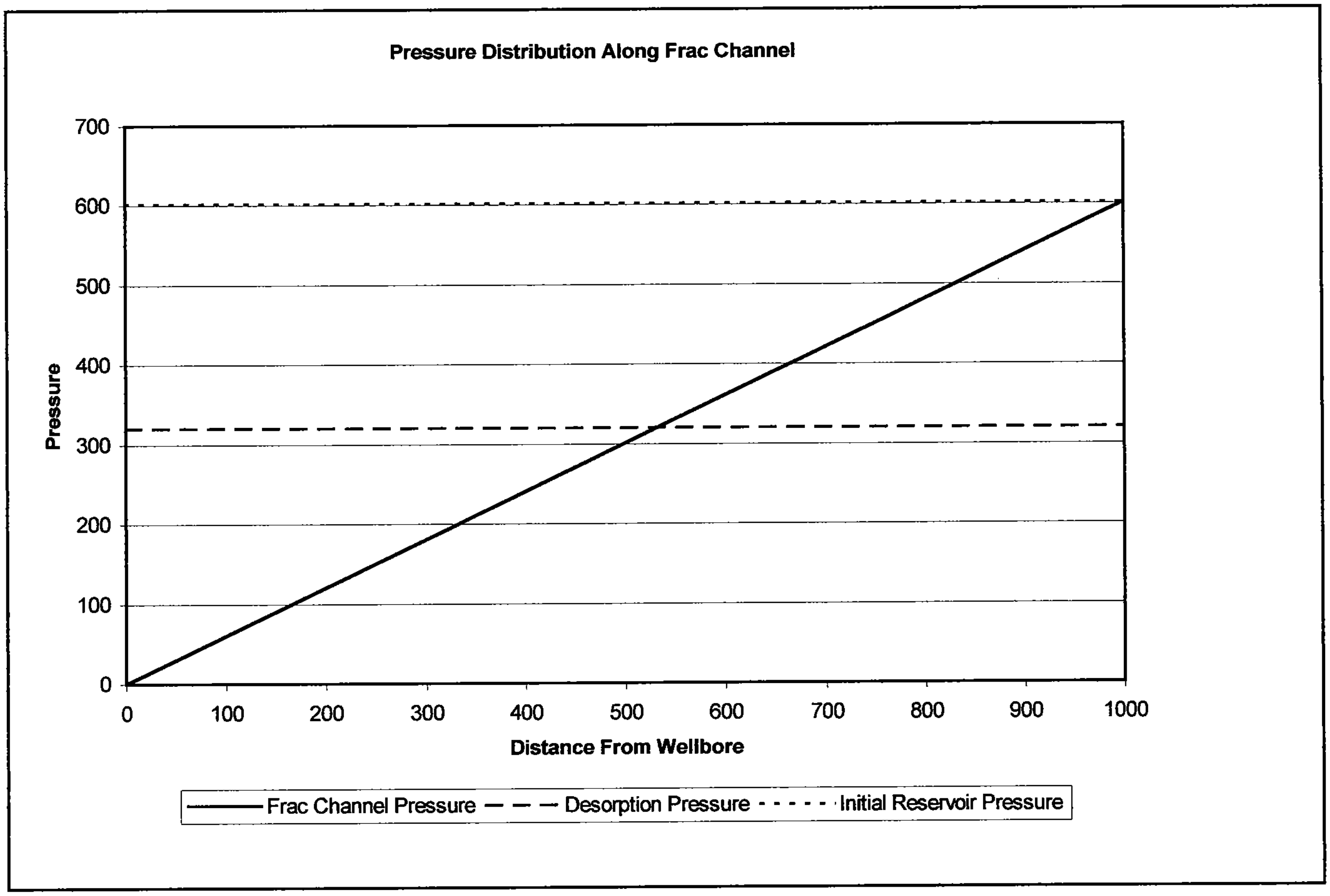
PROCEDURE:

1) SWAB WELL DOWN.
2) START ACID & LOAD HOLE.
3) BREAKDOWN FORMATION @ <3 BPM.
4) PUMP ½ VOLUME OF ACID THROUGH PERFORATIONS.
5) SHUT DOWN. SOAK ACID FOR 5 minutes.
6) RESUME PUMPING @ 5 BPM.
7) INCREASE RATE IN 2 BPM INCREMENTS EVERY 30 TO 50 BBL IF PRESSURE IS STABLE OR FALLING. HOLD RATE IF PRESSURE IS INCREASING AFTER 30 BBL.
8) LIMIT MAXIMUM RATE TO 3.5 TIMES COAL THICKNESS.
9) SHUT WELL IN FOR MINIMUM OF 48 HRS.
10) RUN TUBING, PUMP AND RODS.
11) TEST WELL. IT IS NOT NECESSARY TO HOLD BACKPRESSURE TO RESTRICT GAS VOLUME.
12) IF NEED FRAC WELL WITH CONTROLLED VELOCITY FRAC TREATMENT MINUS ACID SPEARHEAD.

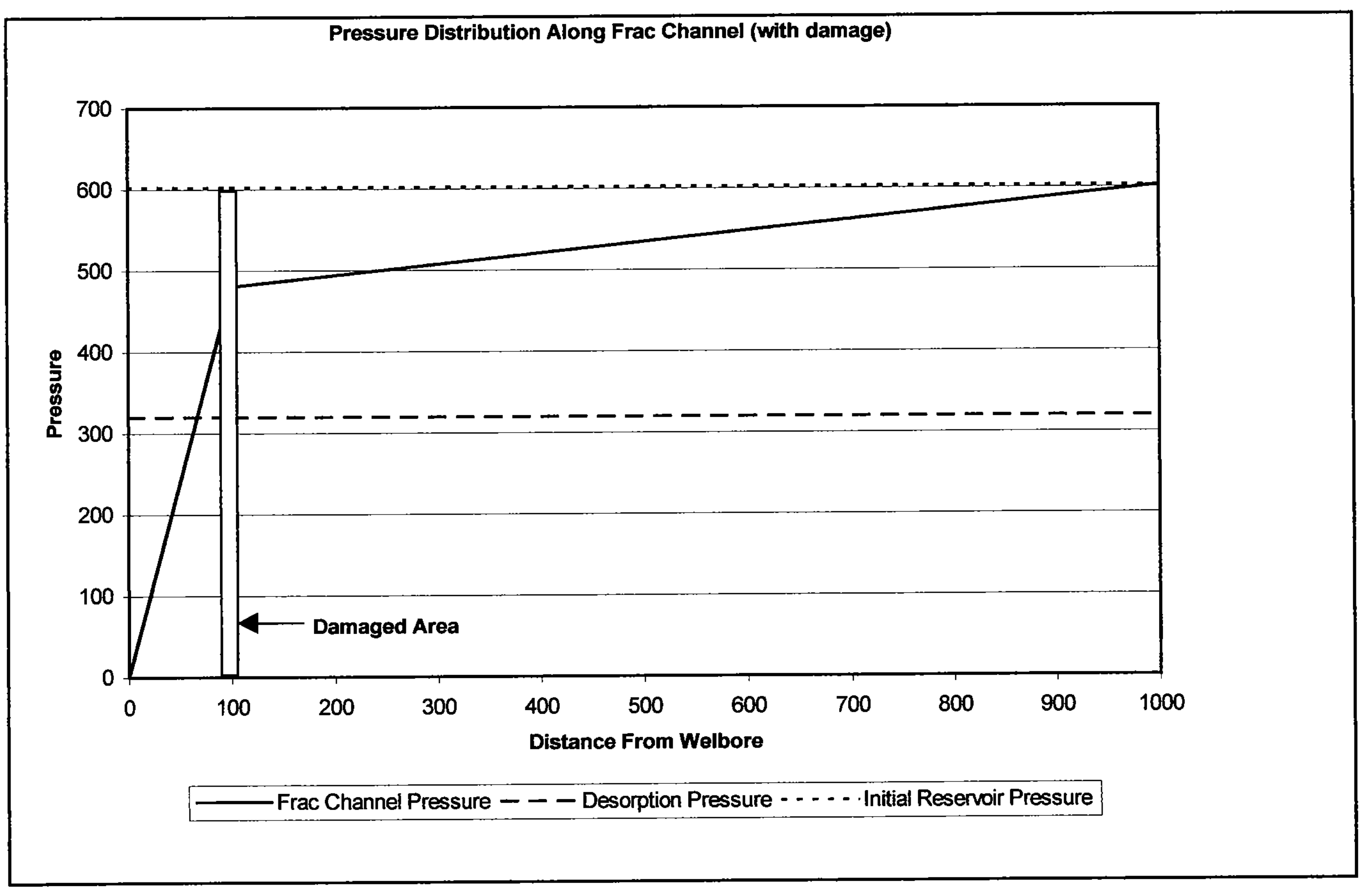
TYPICAL EARLY HARTSHORNE COAL FRAC TREATMENT

STAGE	VOLUME	TOTAL	DESCRIPTION	GALLONS	SAND STG	SAND TOT
1	500	500	PAD	21000	0	0
2	300	800	1# 100 MESH	12600	12600	12600
3	100	900	PAD	4200	0	12600
4	100	1000	1# 20/40	4200	4200	16800
5	75	1075	PAD	3150	0	16800
6	200	1275	1# 20/40	8400	8400	25200
7	100	1375	PAD	4200	0	25200
8	75	1450	1.5# 20/40	3150	4725	29925
9	75	1525	PAD	3150	0	29925
10	100	1625	1.5# 20/40	4200	6300	36225
11	100	1725	PAD	4200	0	36225
12	125	1850	1.5# 20/40	5250	7875	44100
13	100	1950	PAD	4200	0	44100
14	100	2050	1.5# 20/40	4200	6300	50400
15	100	2150	PAD	4200	0	50400
16	100	2250	1.5# 20/40	4200	6300	56700
17	50	2300	PAD	2100	0	56700
18	75	2375	1.5# 20/40	3150	4725	61425
19	75	2450	PAD	3150	0	61425
20	75	2525	1.5# 20/40	3150	4725	66150
21	75	2600	PAD	3150	0	66150
22	100	2700	1.5# 20/40	4200	6300	72450
23	50	2750	PAD	2100	0	72450
24	100	2850	1.5# 20/40	4200	6300	78750
25	200	3050	PAD	8400	0	78750
26	150	3200	1.5# 20/40	6300	9450	88200
27	25	3225	PAD	1050	0	88200
28	150	3375	1.5# 20/40	6300	9450	97650
29	175	3550	PAD	7350	0	97650
30	200	3750	2# 12/20	8400	16800	114450
31	150	3900	PAD	6300	0	114450
32	100	4000	2# TO 8# 12/20 RAMP	4200	21000	135450
33	50	4050	FLUSH	2100	0	135450

4500 BBL FLUID ON LOCATION (NINE TANKS)
TREATMENT PUMPED @ 40 BPM
IMMEDIATE FLOWBACK OF TREATMENT
TREATMENT BULLHEADED (no acid)

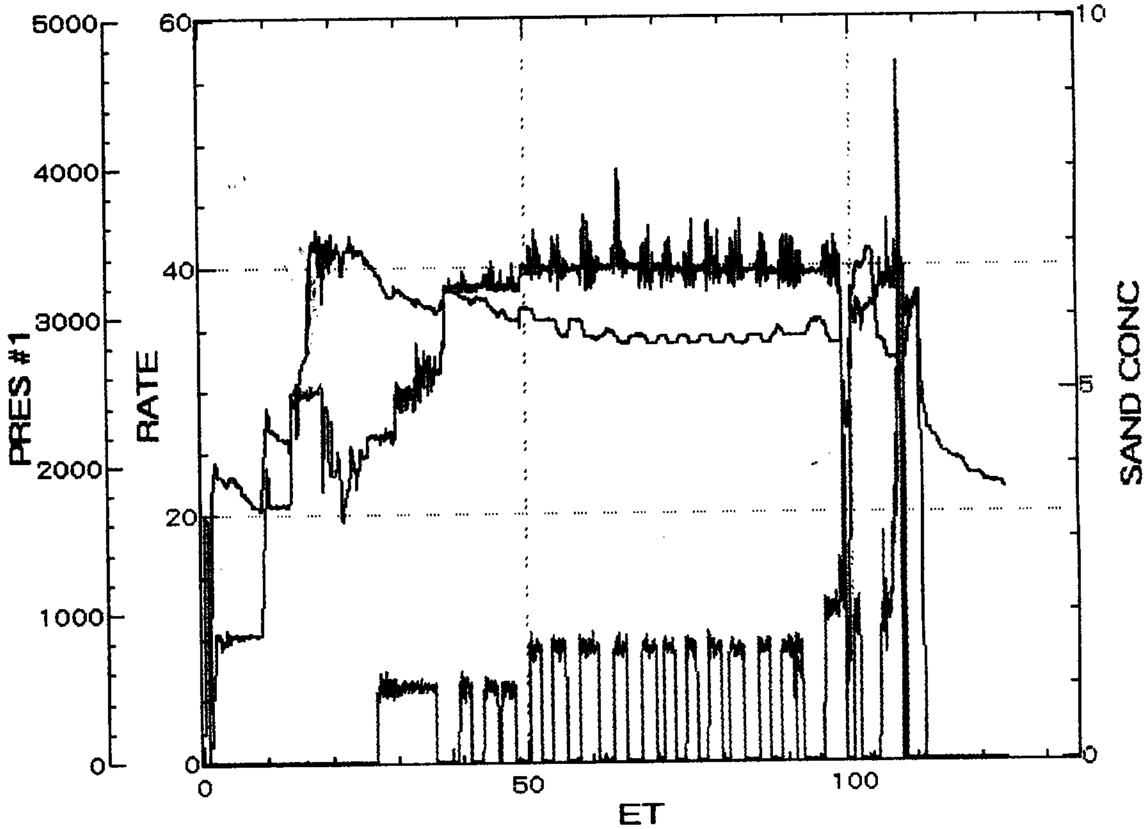


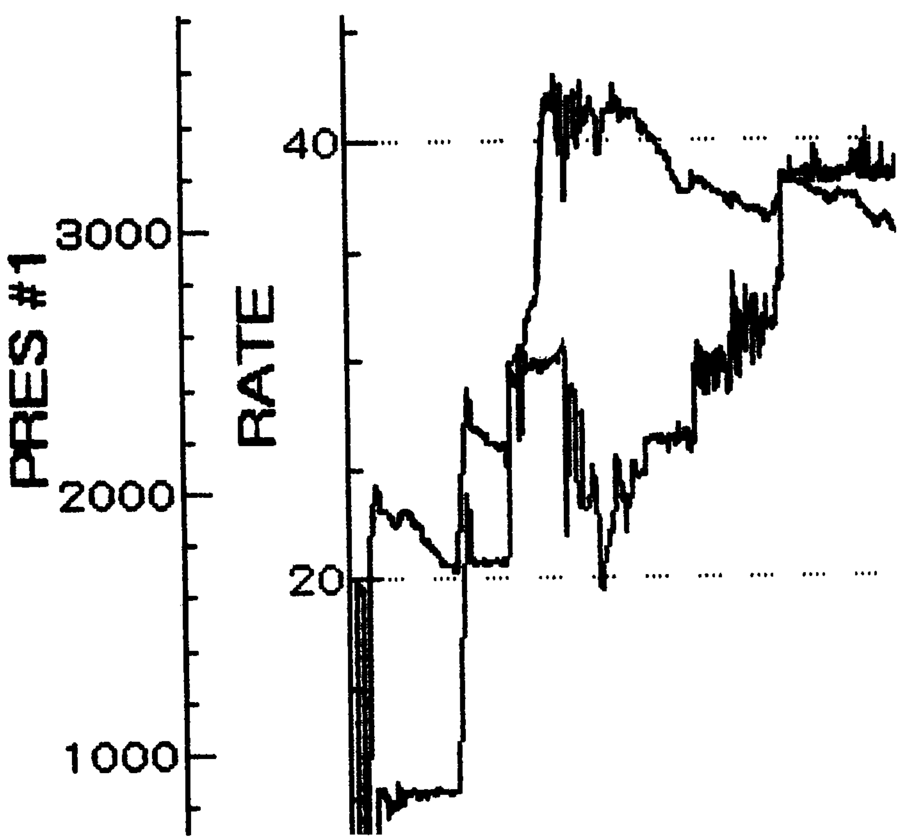
Pressure Distribution Along Frac Channel
Pressure
700
600
500
400
300
200
100
0
0
100
200
300
400
500
600
700
800
900
1000
Distance From Wellbore
Frac Channel Pressure
Desorption Pressure
Initial Reservoir Pressure



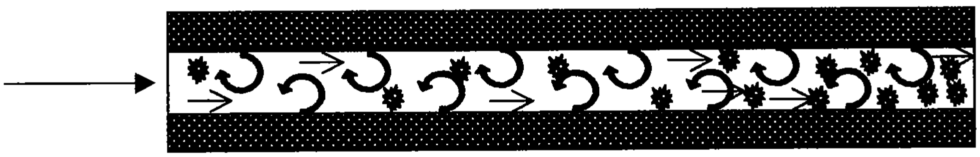
Pressure Distribution Along Frac Channel (with damage)
Pressure
700
600
500
400
300
200
100
0
Damaged Area
0
100
200
300
400
500
600
700
800
900
1000
Distance From Welbore
Frac Channel Pressure
Desorption Pressure
Initial Reservoir Pressure

FRAC COMPUTER CHART
HARTSHORNE COAL TREATMENT

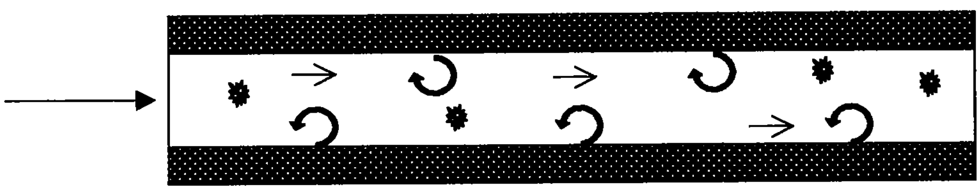




VELOCITY ILLUSTRATION



PUMP RATE = 17.5 BPM
HEIGHT = 5'
FRAC WIDTH = 0.20"
VELOCITY = 19.65 ft/sec (CRITICAL VELOCITY)



PUMP RATE = 17.5 BPM
HEIGHT = 5'
FRAC WIDTH = 0.30"
VELOCITY = 13.10 ft/sec
RATE @ CRITICAL VELOCITY = 26.25 BPM (with 0.30" frac width)

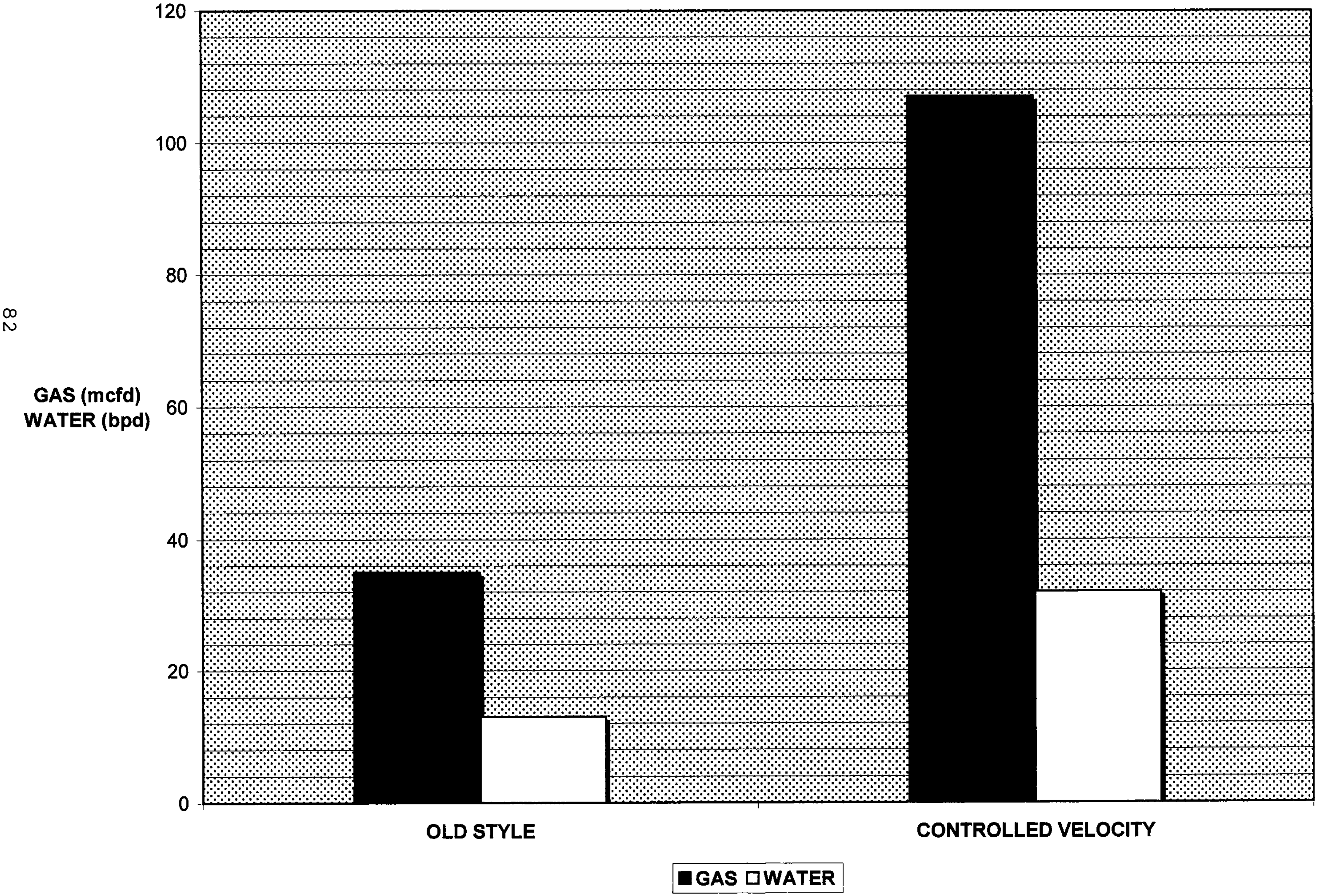
CONTROLLED VELOCITY
FRAC TREATMENT
HARTSHORNE COAL

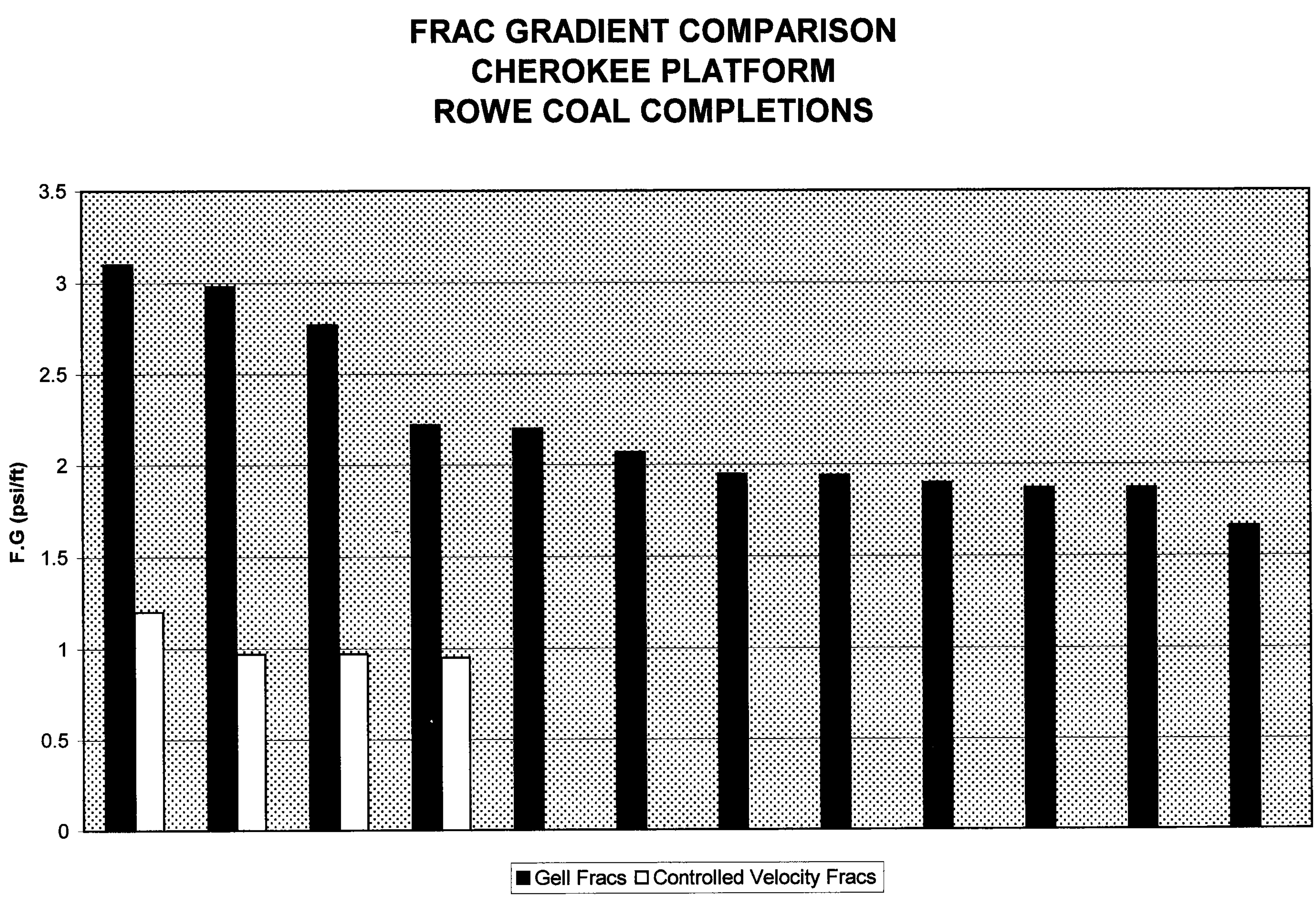
STAGE	VOLUME	TOTAL	DESCRIPTION	GALLONS	SAND STG	SAND TOT
1	24	24	1000 gal. 15% HCl ACID	1008	0	0
2	300	324	PAD @ 10 to 15 BPM	12600	0	0
3	300	624	PAD @ 15 BPM	12600	0	0
4	110	734	3/4# 100 MESH	4620	3465	3465
5	225	959	1# 100 MESH	9450	9450	12915
6	200	1159	1# 20/40 (15-20 BPM)	8400	8400	21315
7	200	1359	1# 20/40 (20-25 BPM)	8400	8400	29715
8	200	1559	1# 20/40 (25-30 BPM)	8400	8400	38115
9	820	2379	1.5# 20/40	34440	51660	89775
10	300	2679	PAD	12600	0	89775
11	925	3604	1# 12/20	38850	38850	128625
12	75	3679	1# to 3# 12/20 RAMP	3150	6300	134925
13	50	3729	FLUSH	2100	0	134925

4000 BBL FLUID ON LOCATION (EIGHT TANKS)
TREATMENT PUMPED @ 30 BPM
WELLS SHUT IN FOR MINIMUM OF 7 DAYS
1000 gal. 15% HCl SPEARHEAD

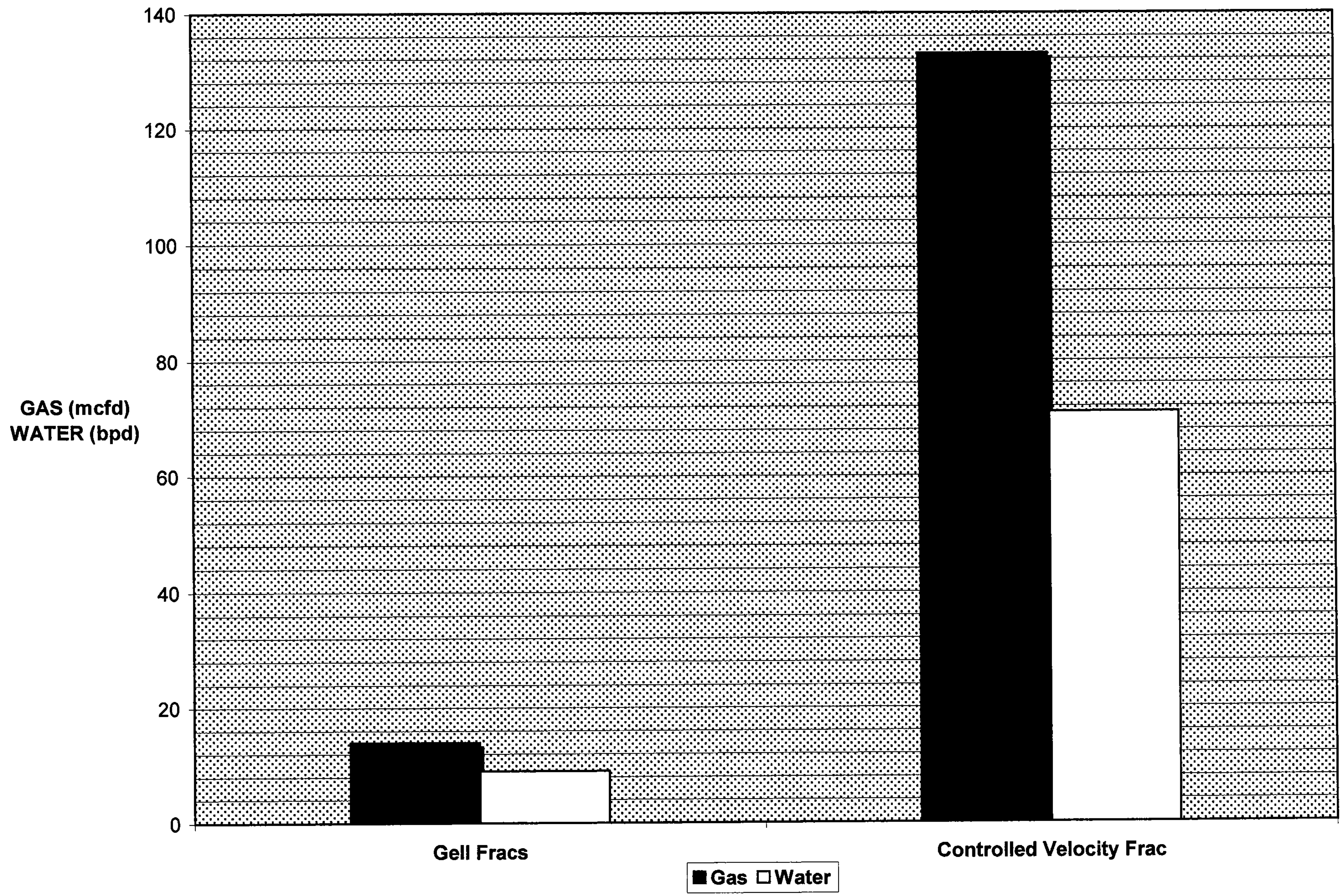
FRAC GRADIENT COMPARISON
ARKOMA BASIN
HARTSHORNE COMPLETIONS

PRODUCTION COMPARISON
HARTSHORNE COAL COMPLETIONS




FRAC GRADIENT COMPARISON
CHEROKEE PLATFORM
ROWE COAL COMPLETIONS
F.G (psi/ft)
3.5
3
2.5
2
1.5
1
0.5
0
Gell Fracs
Controlled Velocity Fracs

PRODUCTION COMPARISON
ROWE COAL COMPLETIONS



CONTROLLED VELOCITY
FRAC TREATMENT
ROWE COAL

STAGE	VOLUME	TOTAL	DESCRIPTION	GALLONS	SAND STG	SAND TOT
1	18	18	15% HCl ACID	756	0	0
2	125	143	PAD @ 8 BPM	5250	0	0
3	125	268	PAD @ 10 BPM	5250	0	0
4	125	393	PAD @ 12.5 BPM	5250	0	0
5	100	493	3/4# 100 MESH	4200	3150	3150
6	100	593	1# 100 MESH	4200	4200	7350
7	75	668	1# 20/40 (12.5-15 BPM)	3150	3150	10500
8	100	768	1# 20/40 (15-20 BPM)	4200	4200	14700
9	100	868	1# 20/40 (20-25 BPM)	4200	4200	18900
10	100	968	1.5# 20/40	4200	6300	25200
11	75	1043	PAD	3150	0	25200
12	75	1118	1# 12/20	3150	3150	28350
13	100	1218	2# 12/20	4200	8400	36750
14	50	1268	FLUSH	2100	0	36750

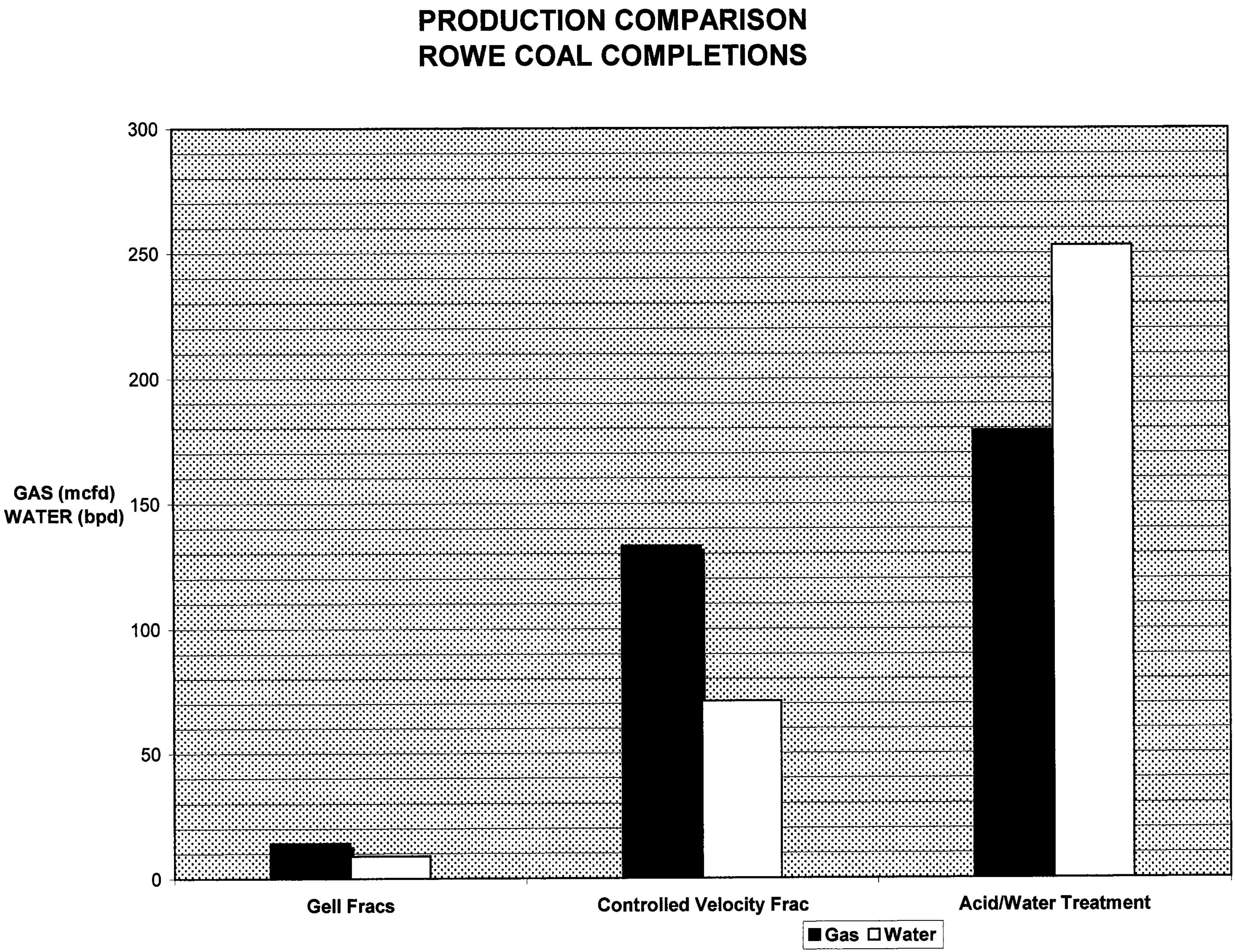
1500 BBL FLUID ON LOCATION (THREE TANKS)
TREATMENT PUMPED @ 30 BPM
WELLS SHUT IN FOR MINIMUM OF 7 DAYS
750 gal. 15% HCl SPEARHEAD

ACID/WATER FRAC TREATMENT

STAGE	VOLUME	TOTAL	DESCRIPTION	RATE	GALLONS
1	18	18	15% HCL ACID	<3 BPM	756
2	35	53	FRESH WATER	5 BPM	1470
3	40	93	FRESH WATER	7 BPM	1680
4	45	138	FRESH WATER	9 BPM	1890
5	50	188	FRESH WATER	11 BPM	2100
6	70	258	FRESH WATER	13 BPM	2940

PROCEDURE:

1) SWAB WELL DOWN.
2) START ACID & LOAD HOLE.
3) BREAKDOWN FORMATION @ <3 BPM.
4) PUMP ½ VOLUME OF ACID THROUGH PERFORATIONS.
5) SHUT DOWN. SOAK ACID FOR 5 minutes.
6) RESUME PUMPING @ 5 BPM.
7) INCREASE RATE IN 2 BPM INCREMENTS EVERY 30 TO 50 BBL IF PRESSURE IS STABLE OR FALLING. HOLD RATE IF PRESSURE IS INCREASING AFTER 30 BBL.
8) LIMIT MAXIMUM RATE TO 3.5 TIMES COAL THICKNESS.
9) SHUT WELL IN FOR MINIMUM OF 48 HRS.
10) RUN TUBING, PUMP AND RODS.
11) TEST WELL. IT IS NOT NECESSARY TO HOLD BACKPRESSURE TO RESTRICT GAS VOLUME.
12) IF NEED FRAC WELL WITH CONTROLLED VELOCITY FRAC TREATMENT MINUS ACID SPEARHEAD.


PRODUCTION COMPARISON
ROWE COAL COMPLETIONS
GAS (mcfd)
WATER (bpd)
300
250
200
150
100
50
0
Gell Fracs
Controlled Velocity Frac
Acid/Water Treatment
Gas
Water

OKLAHOMA GEOLOGICAL SURVEY
OPEN-FILE REPORT OF 6-99

7

Hartshorne CBM play in Oklahoma: selected production and economic viability

Matthew A. Biddick
Fractal Oil Company
Norman, OK

Biddick, M.A., 1999, Hartshorne CBM play in Oklahoma: selected production and economic viability, in Oklahoma coalbed-methane workshop: Oklahoma Geological Survey, Open-File Report OF 6-99, p. 88-114.

Hartshorne CBM Play in Oklahoma: Selected Production And Economic Viability

Matthew A. Biddick
Fractal Oil Company

Abstract

The modern coalbed- methane play in the Hartshorne coal of the Arkoma basin, Oklahoma has been ongoing since 1988 with the advent of Bear Productions, Inc.s' pioneering efforts at the Kinta Anticline in Haskell County. Other operators are now conducting projects around the basin which have wells with several years of production. We can now evaluate a little more clearly the economic viability of the Hartshorne CBM play in Oklahoma. This paper will take a cursory look at some of the considerations operators face in this play and at a few of the older, targeted projects in the Arkoma basin.

Introduction

Production of methane from coal seams in Oklahoma via vertical wells dates back to the 1920's with gas production from the "Fears Coal" at the Canadian Dome in Pittsburgh County (Section 5-8N-16E & Section 32-9N-16E). At about the same time and into the 1930's at the Kinta Anticline, gas production from the Hartshorne Formation was initially attributed to "broken sand & coal" of the Hartshorne. All wells were completed openhole; later wells did not drill the entire Hartshorne section and were stopped just below the coal. Modern drilling in the 1980's and 1990's would show, through openhole logs, that no quality sand reservoir was present in the original producing area.

Several of the 1930's vintage wells at the Kinta Anticline (8N-20E, Haskell County) have documented sales of gas. It is in this locale that Bear Productions, Inc. began the modern era of coalbed- methane production in Oklahoma. The principals of Bear were born and raised for two generations in the immediate vicinity of the apex of the Kinta Anticline. They had first-hand knowledge of several of the original wells, which had remained unplugged, emitting gas on an intermittent basis since cessation of commercial gas sales. The fact that it was methane being emitted was substantiated through the lighting of the gas flow from time-to-time when things were a little slow for the teenage population of the area. One well in particular is said to have flowed gas continuously, and could be lit anytime, since at least 1950 (Johnson #1 W/2 W/2 NW/4 Section 26-8N-

20E). It was this well that the principals of Bear flow tested in 1987 at approximately 40 MCFGPD at 20 psi. This well is said to have had a shut-in pressure of approximately 180 psi. The original bottomhole pressure in the Hartshorne, as reported in the 1920's, was as high as 295 psi. This particular well's initial shut-in pressure was reported at 245 psi in 1927. The Johnson #1 has reported cummulative gas sales of 69,000 MCF. It is known that it was abandoned and venting gas since at least 1950. It seems almost too fantastic to think that this well possibly vented over 500,000 MCF in the intervening years between its abandonment and 1987 when Bear personnel tested it.

Economic Considerations

With any gas, or oil, production, profitability depends upon production rate, ultimate volume, competitive costs, and a reliable, cost effective market for the gas. Another important consideration for CBM production is to achieve an economy of scale, whereby the operator realizes cost savings and lowers his cost per MCF produced. Economy of scale is vital to the success of a CBM project in the Hartshorne coal. Proper reservoir development requires multiple wells per section in order to drop the pressure in the coal and desorb the gas. An economy of scale is realized when the coal is adequately developed. For any prospective CBM project in the Hartshorne coal(s), an operator must be ready to commit the resources necessary to get the project off the ground. A well density of 4 wells/section is a good beginning with 8 wells/section deemed to be the optimum density.

An operator of a CBM project can calculate production costs on a per MCF of gas produced basis. Because of high water handling costs (especially early in the life of a well), usually mandatory compression costs, normal transportation and marketing fees, and typically low production volumes relative to conventional gas reservoirs, the lease operating expenses (LOE) of a CBM well are high on a per MCF of gas produced basis. A net gas price worksheet follows in this paper that illustrates these costs along with the "bite" per MCF that royalty and the severance tax take when beginning with a $2.00/MMBTU price. This worksheet attempts to account for normal LOE. Workovers for other problems such as pump failures, motor failures, electrical problems, etc., are not taken into consideration. Such problems are "lumps" that will extend payout of the well in which they occur by a month or two for each occurrence. An illustration of payout scenarios is provided for three different completed well costs ($40,000.00; $50,000.00; $60,000.00). These costs are deemed to be achievable for wells drilled and completed in a single Hartshorne coal at depths from 800' - 1,200'. A second payout scenario is provided using a price of $2.50/MMBTU which illustrates the dramatic impact just a 50 cent increase in price has on the payout of a CBM well.

Production Overview of Selected Projects

As of September, 1999, approximately 318 completions in the Hartshorne coal were catalogued in the coalbed methane database maintained by Brian Cardott at the Oklahoma Geological Survey. It is known that operators over the years have perforated and tested the Hartshorne coal from time-to-time when completing in the Hartshorne sand. The coal was not considered a target in and of itself. Even today, Hartshorne coal production is being commingled with gas production from other zones. It is safe to say that the Hartshorne coal is being produced from more than 318 wells in the Arkoma basin. However, there are probably no more than a half dozen "projects" where the Hartshorne coal is the primary target and where the production of gas from the coal is the primary business motivation. At this time other projects are just gathering steam, including the first attempt at CBM production from the Hartshorne coal primarily via horizontal wells. Four of the projects with the longest production history are Bear Productions, Inc. at the Kinta Anticline, Redwine Resources at the north flank of the Kinta Anticline, Continental Resources in 7N & 8N- 16E, Pittsburgh County, and SJM, Inc. at the Canadian Dome in 8N & 9N-15E & 16E, Pittsburgh County.

FOUR KEYS TO ECONOMIC CBM PRODUCTION:

1. Gas Production Rate & Ultimate Volume

2. Competitive Costs

3. Reliable & Cost Effective Market

4. Economies of scale

GAS PRODUCTION RATE / ULTIMATE VOLUME

- Production rate should be in proportion to drill depth and payout period desired;
- Ultimate reserves proportionate to drill costs

COMPETITIVE COSTS

1. ACREAGE COST
   - lease Hartshorne rights only
   - farm-ins (CBM is NRI sensitive)

2. COST OF DRILLING/DRILL DEPTH
   - ultimate reserves limit depth

3. COMPLETION TECHNIQUE: COST/SIZE OF FRAC
   - straight nitrogen with better inherent permeability
   - sand/water frac for rest but don't overdo it

4. PROXIMITY TO MARKET & ATTENDANT LINE PRESSURE
   - ultimate recoverable reserves must support all gathering system costs

5. LIFTING COSTS
   - handling load water is large initial cost; typically declines
   - get an excellent pumper
   - use electric motors on pumping units - less down time

RELIABLE & COST EFFECTIVE MARKET

- In current environment, reliability not usually a problem, but can be

- CBM cannot sustain pipeline piracy, i.e., gathering/transportation costs must be reasonable.

ECONOMIES OF SCALE

1. Allows operator to lower cost per MCF produced and sold.

    a. Put pumper on salary

    b. Spread compression cost

    c. Better prices on equipment/services due to centralized location and multiple orders

    d. Less travel time and consequent work time loss

    e. Justify lower admin. & overhead charges

NET GAS PRICE WORKSHEET

GIVEN \$2.00/MMBTU [\$2.00/MCF FOR CBM]
FOR A 10-WELL, 500 MCFGPD PROJECT
COSTS PER MCF PRODUCED

	\$2.00	Wellhead Price/MCF
-	.14	Severance Tax
-	.25	Pipeline Gathering
-	.30	Royalty
-	.10	Compression (\$1500/mo.)
-	.12	Pumper (\$175/well)
-	.22	Water Disposal (hauling) 1 BW / 7.5 MCF
-	.10	Electricity, Overhead, Charts
	.77	Net \$/MCF

PAYOUT SCENARIO

FOR A 1000' HARTSHORNE CBM WELL WITH THREE DIFFERENT COMPLETED WELL COSTS

$40,000 / .77/MCF = 51,948 MCF TO PAYOUT

51,948 MCF / 50 MCFGPD = 1039 Days [2.85 yrs.]

$50,000 / .77/MCF = 64,935 MCF TO PAYOUT

64,935 MCF / 50 MCFGPD = 1299 Days [3.55 yrs.]

$60,000 / .77/MCF = 77,922 MCF TO PAYOUT

77,922 MCF / 50 MCFGPD = 1558 Days [4.3 yrs.]

EVERY $10,000 SPENT TAKES 9 MONTHS TO RECOVER.

PAYOUT SCENARIO II

USING $2.50/MMBTU (MCF)

$40,000 / $1.14/MCF = 35,088 MCF TO PAYOUT

35,088 MCF / 50 MCFGPD = 701 Days [1.9 yrs.]

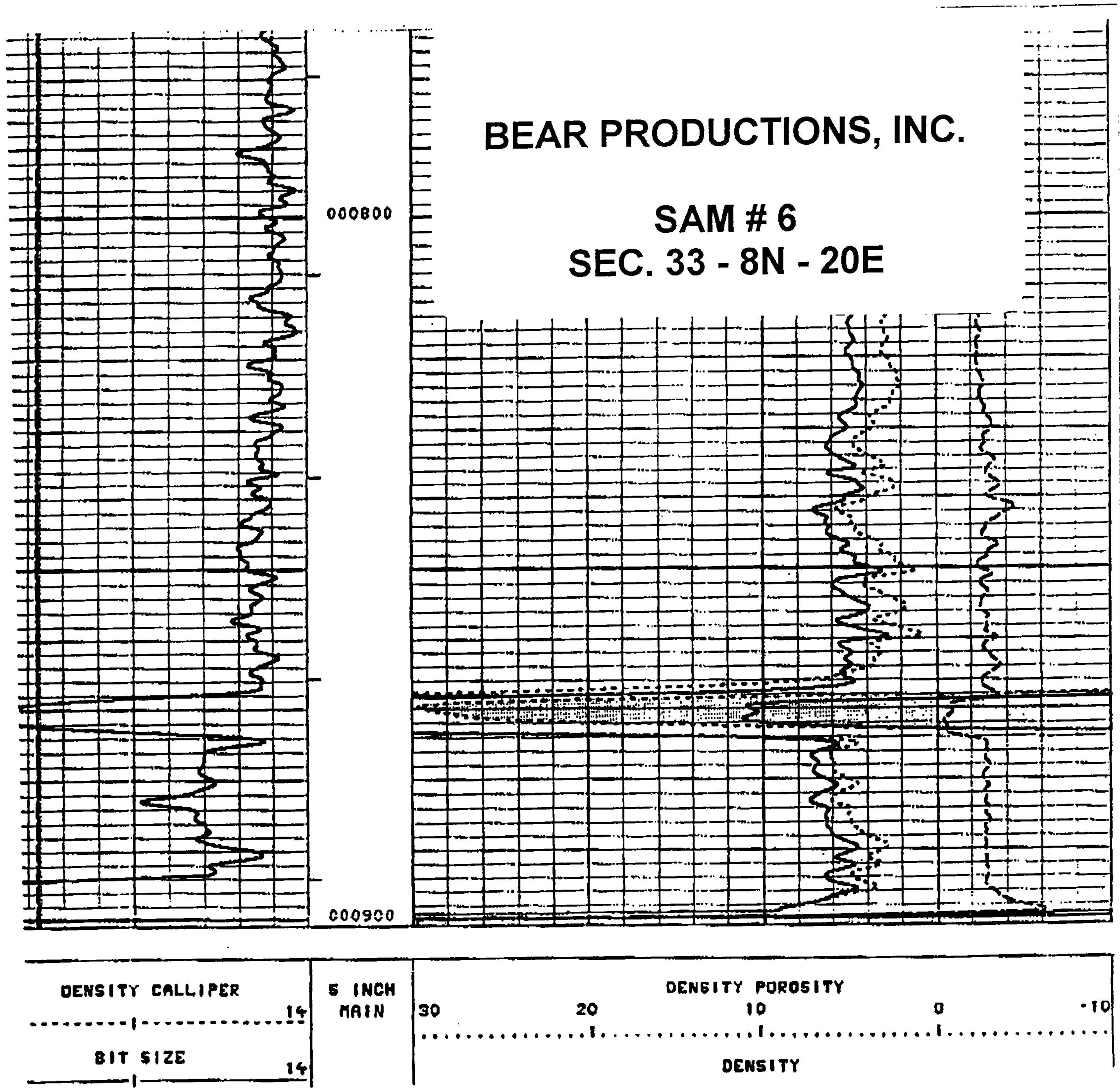
$50,000 / $1.14/MCF = 43,860 MCF TO PAYOUT

43,860 MCF / 50 MCFGPD = 877 Days [2.4 yrs.]

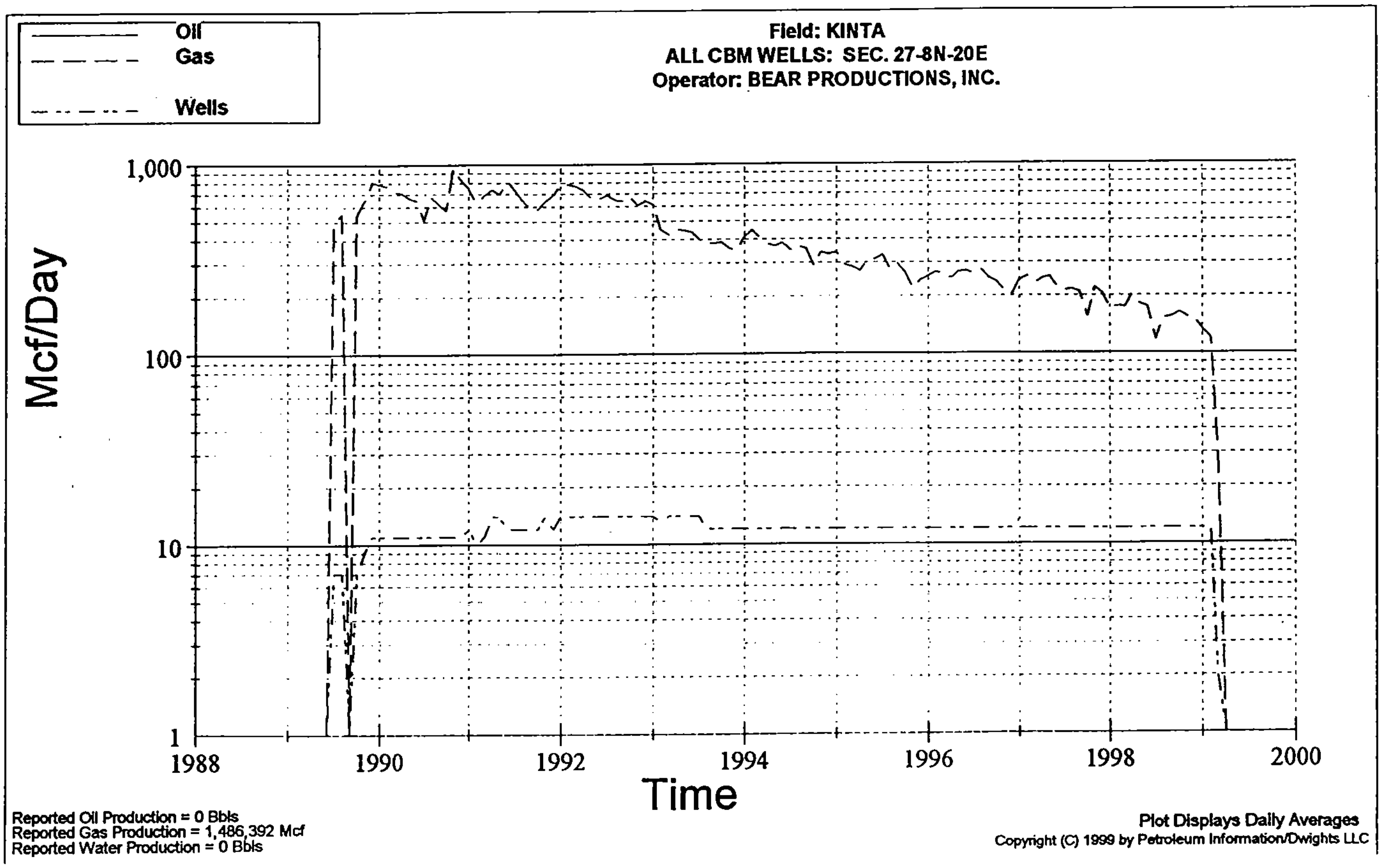
$60,000 / $1.14/MCF = 52,632 MCF TO PAYOUT

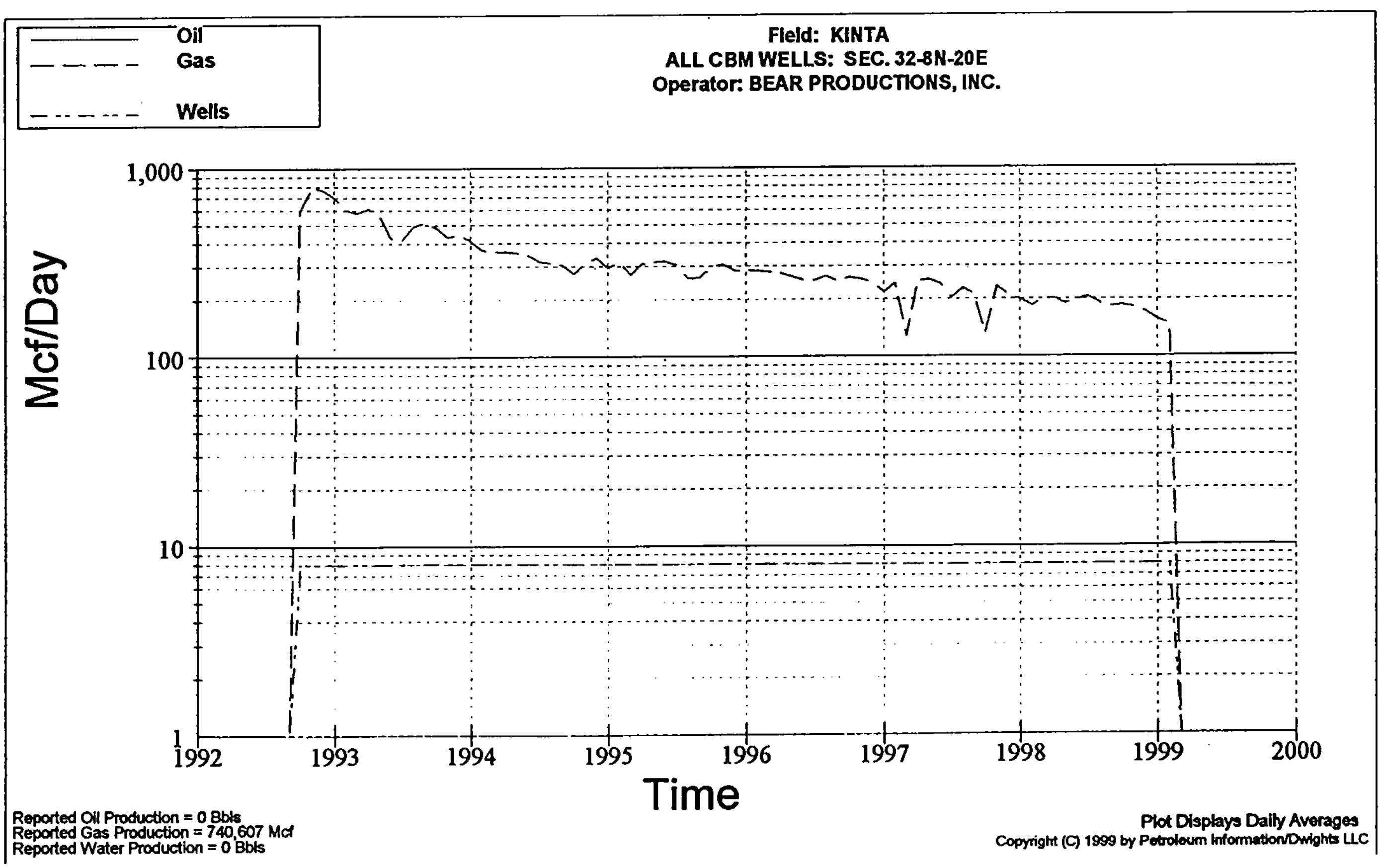
52,632 MCF / 50 MCFGPD = 1053 Days [2.9 yrs.]

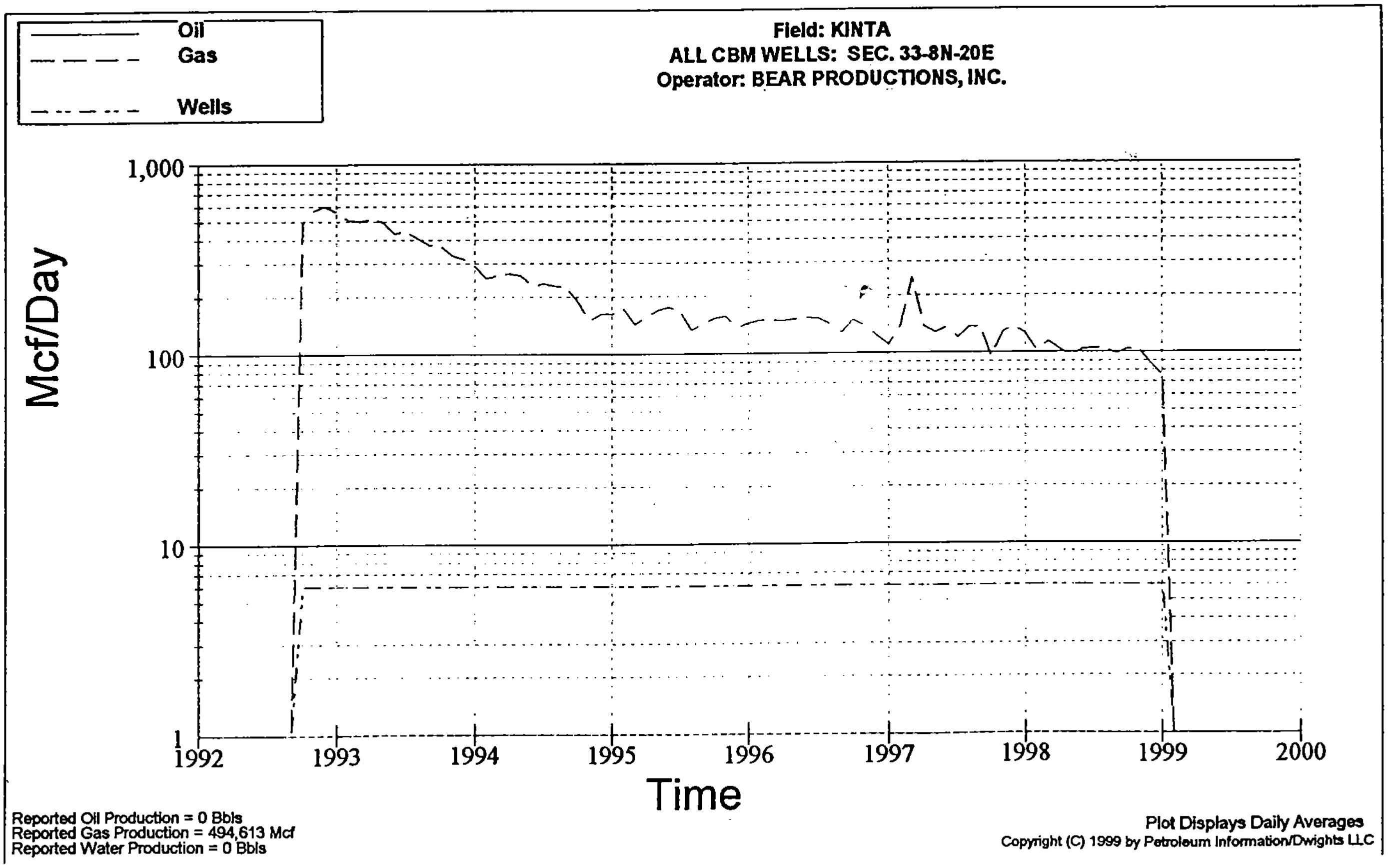
EVERY $10,000 SPENT TAKES 6 MONTHS TO RECOVER.

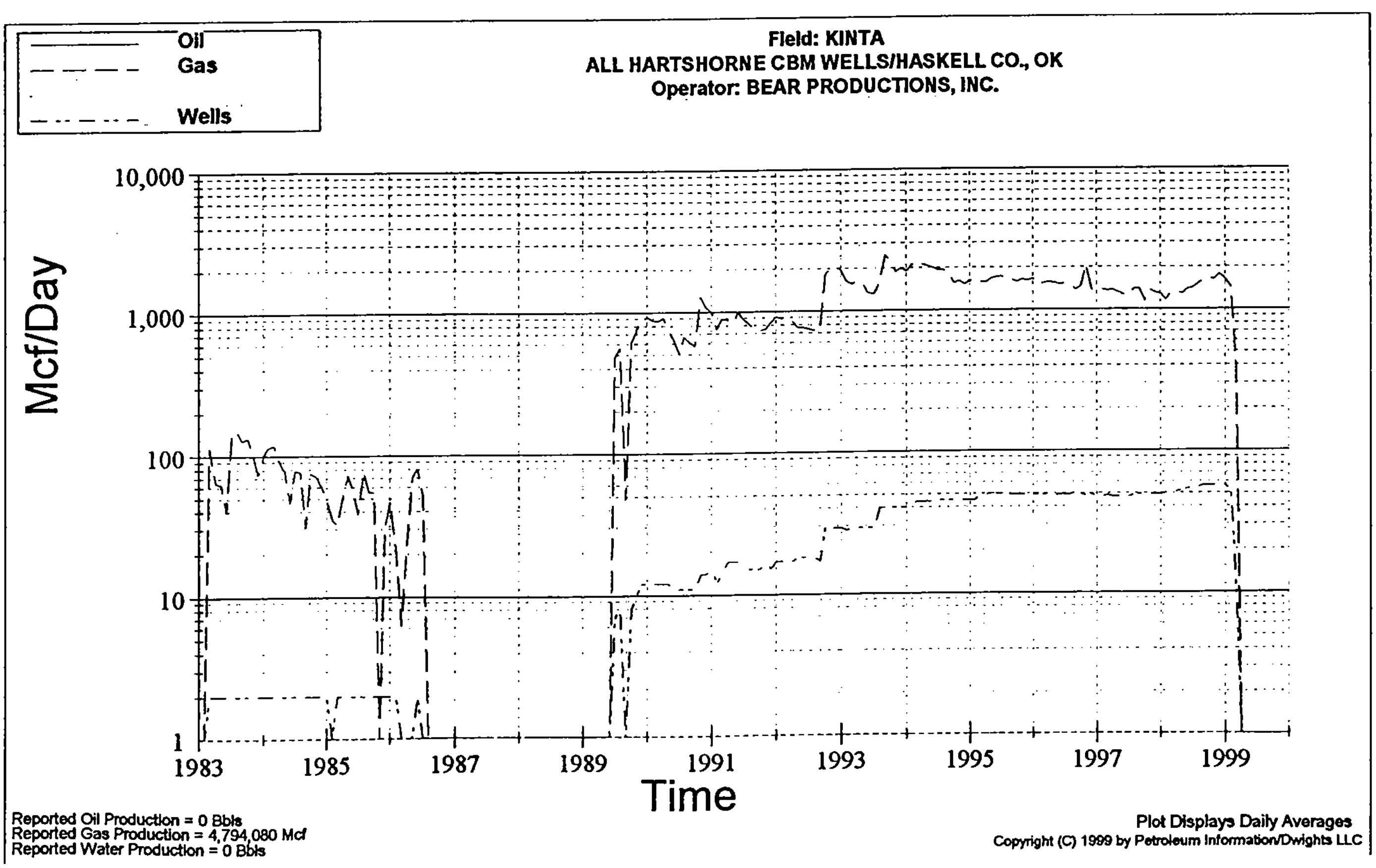


BEAR PRODUCTIONS, INC.
SAM # 6
SEC. 33 - 8N - 20E
000800
000900
DENSITY CALLIPER
14
BIT SIZE
14
5 INCH
MAIN
DENSITY POROSITY
30
20
10
0
-10
DENSITY


Oil
Gas
Wells
Field: KINTA
ALL CBM WELLS: SEC. 27-8N-20E
Operator: BEAR PRODUCTIONS, INC.
1,000
100
10
1
Mcf/Day
1988
1990
1992
1994
1996
1998
2000
Time
Reported Oil Production = 0 Bbls
Reported Gas Production = 1,486,392 Mcf
Reported Water Production = 0 Bbls
Plot Displays Daily Averages
Copyright (C) 1999 by Petroleum Information/Dwights LLC


Oil
Gas
Wells
Field: KINTA
ALL CBM WELLS: SEC. 32-8N-20E
Operator: BEAR PRODUCTIONS, INC.
1,000
100
10
1
Mcf/Day
1992
1993
1994
1995
1996
1997
1998
1999
2000
Time
Reported Oil Production = 0 Bbls
Reported Gas Production = 740,607 Mcf
Reported Water Production = 0 Bbls
Plot Displays Daily Averages
Copyright (C) 1999 by Petroleum Information/Dwights LLC


Oil
Gas
Wells
Field: KINTA
ALL CBM WELLS: SEC. 33-8N-20E
Operator: BEAR PRODUCTIONS, INC.
Mcf/Day
1,000
100
10
1
1992
1993
1994
1995
1996
1997
1998
1999
2000
Time
Reported Oil Production = 0 Bbls
Reported Gas Production = 494,613 Mcf
Reported Water Production = 0 Bbls
Plot Displays Daily Averages
Copyright (C) 1999 by Petroleum Information/Dwights LLC


Oil
Gas
Wells
Field: KINTA
ALL HARTSHORNE CBM WELLS/HASKELL CO., OK
Operator: BEAR PRODUCTIONS, INC.
Mcf/Day
10,000
1,000
100
10
1
1983
1985
1987
1989
1991
1993
1995
1997
1999
Time
Reported Oil Production = 0 Bbls
Reported Gas Production = 4,794,080 Mcf
Reported Water Production = 0 Bbls
Plot Displays Daily Averages
Copyright (C) 1999 by Petroleum Information/Dwights LLC

PROJECT SUMMARY: BEAR PROD.

DATE OF FIRST PRODUCTION: 1989

LOCATION: 7 & 8 N - 19, 20, & 21 E

COUNTY: HASKELL

COAL THICKNESS: 3 - 4 FEET

DEPTH RANGE: 600 - 1,120 FEET

NUMBER OF WELLS: 65

COMPLETION METHOD: NITROGEN FRAC

PRODUCTION RANGE (IND. WELL): UP TO 150 MCFGPD

AVG. DAILY PROD. PER WELL: 20 MCF

AVG. DAILY PROD. /FIELD: 1,279 MCF

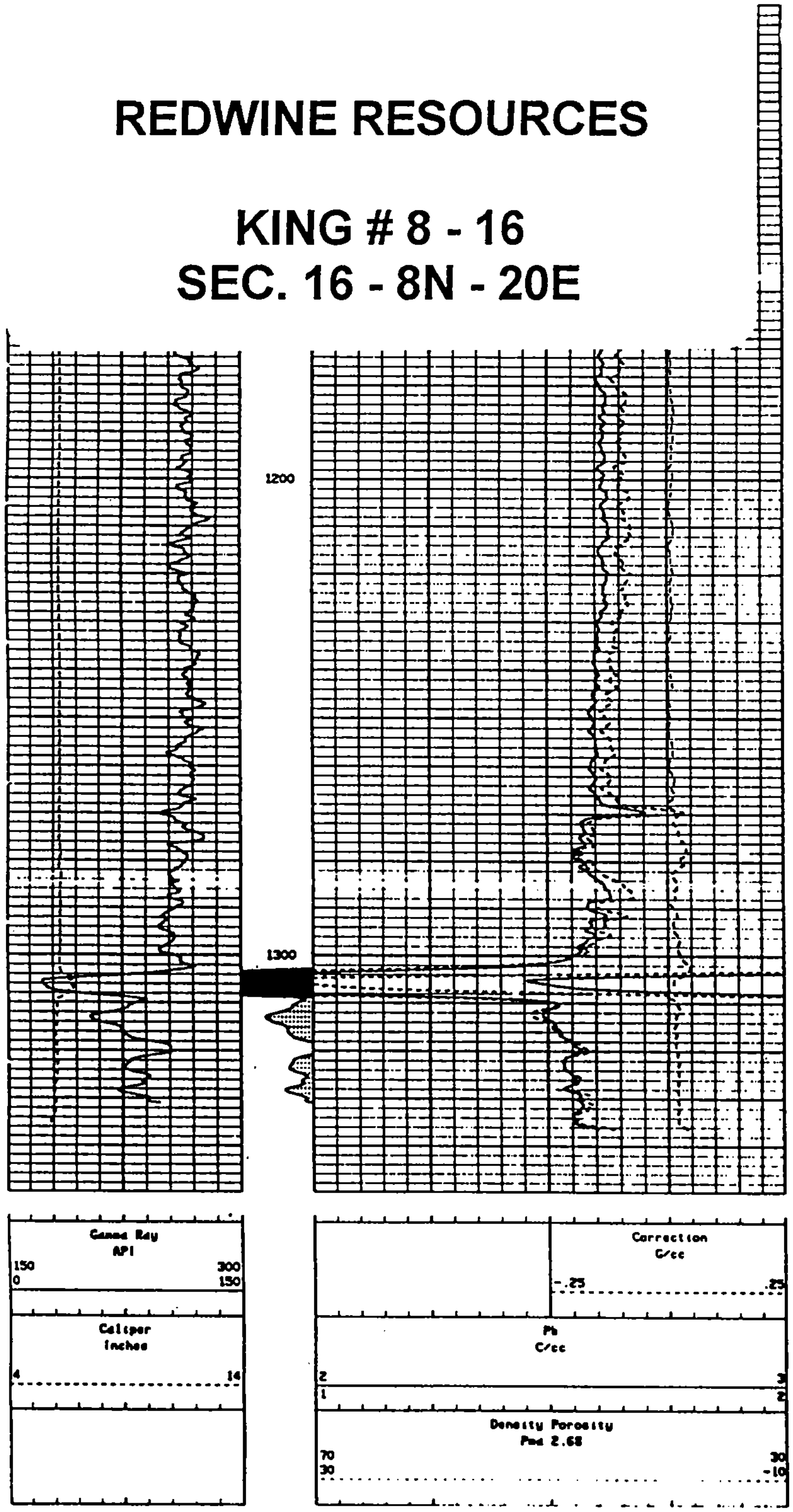
CUMULATIVE PRODUCTION: 4,923,029 MCF

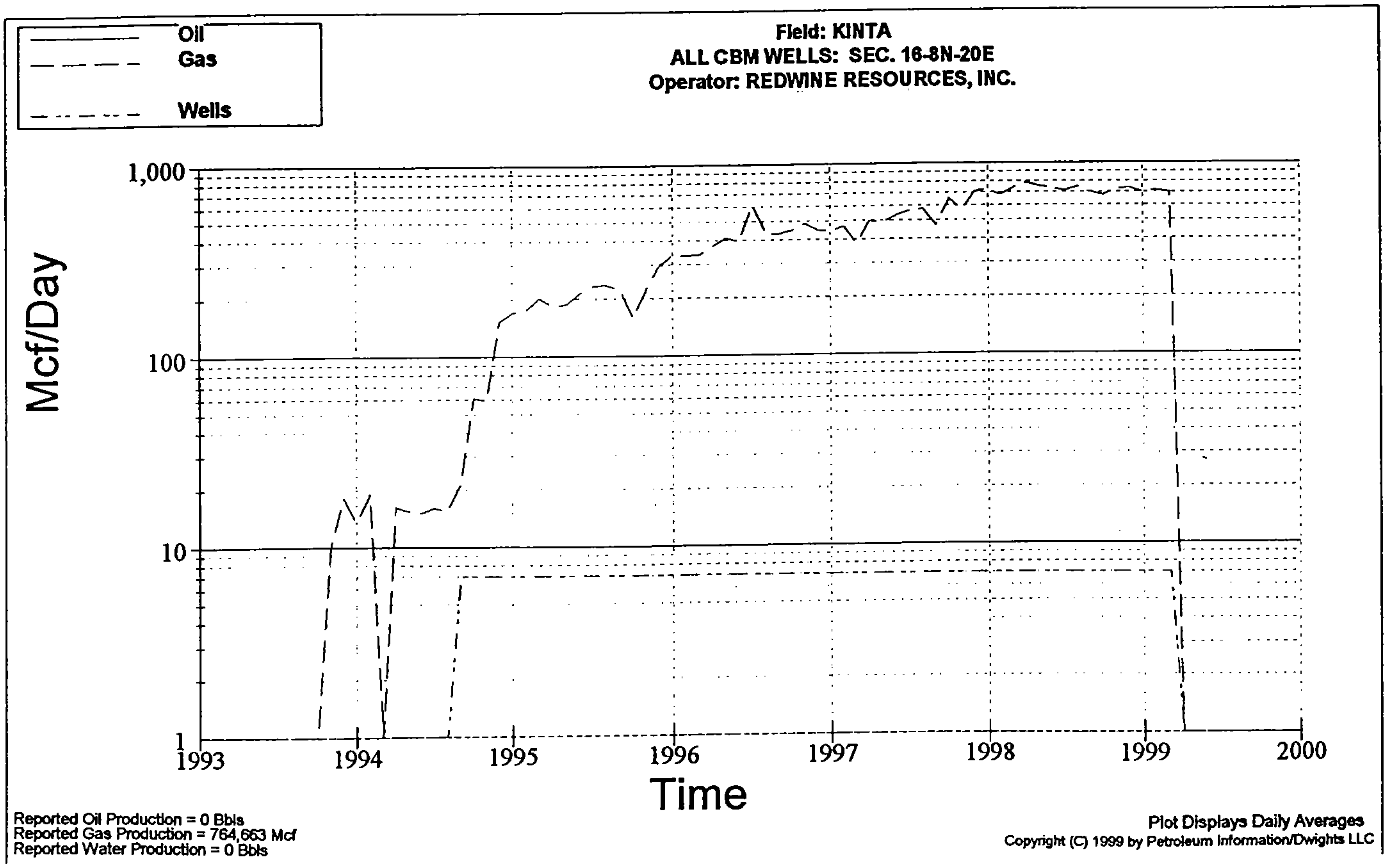
CUM. PROD. RANGE (IND. WELL): UP TO 159 MMCF

AVG. CUM. PROD. PER WELL: 75,739 MCF

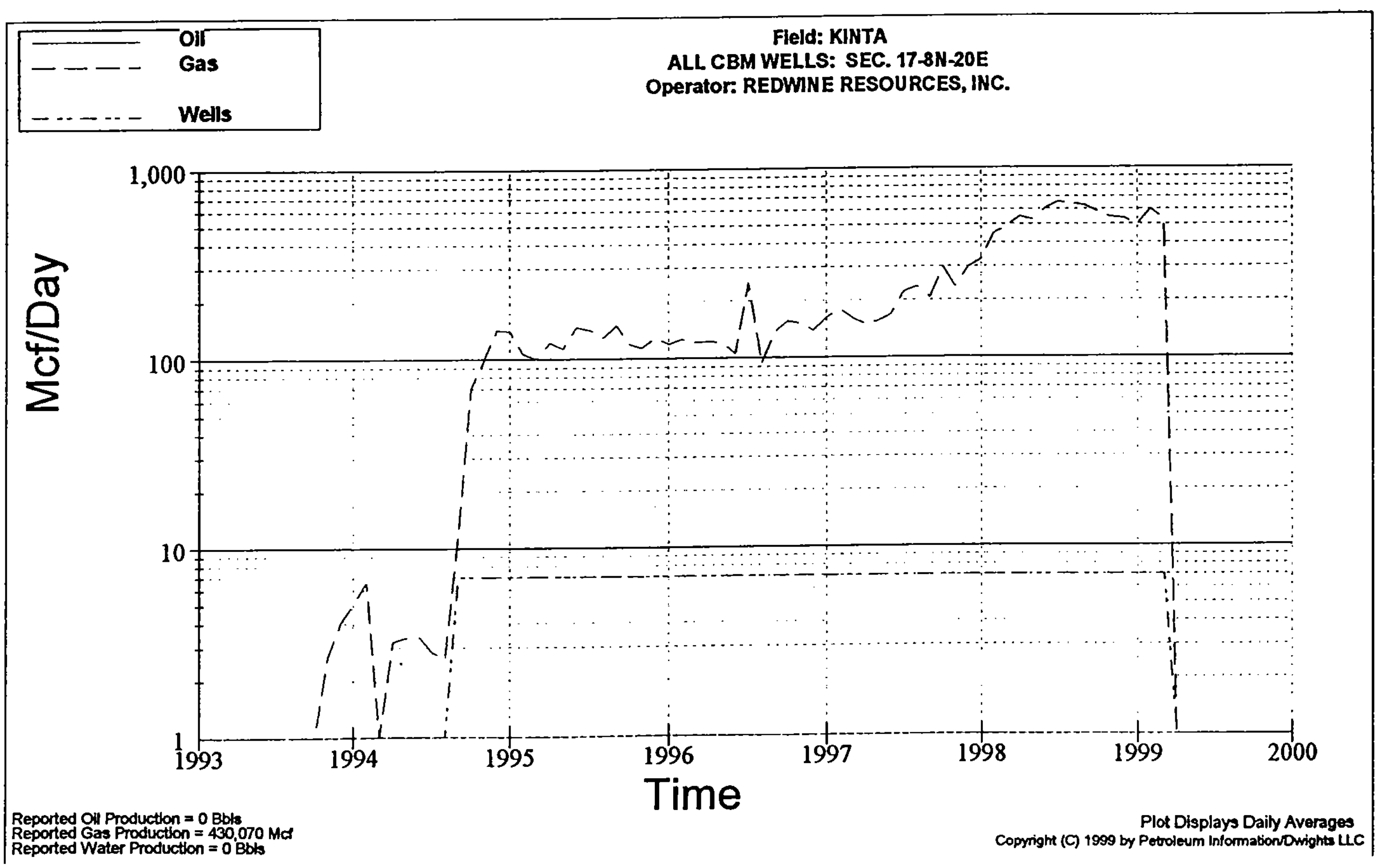
REDWINE RESOURCES

KING # 8 - 16
SEC. 16 - 8N - 20E

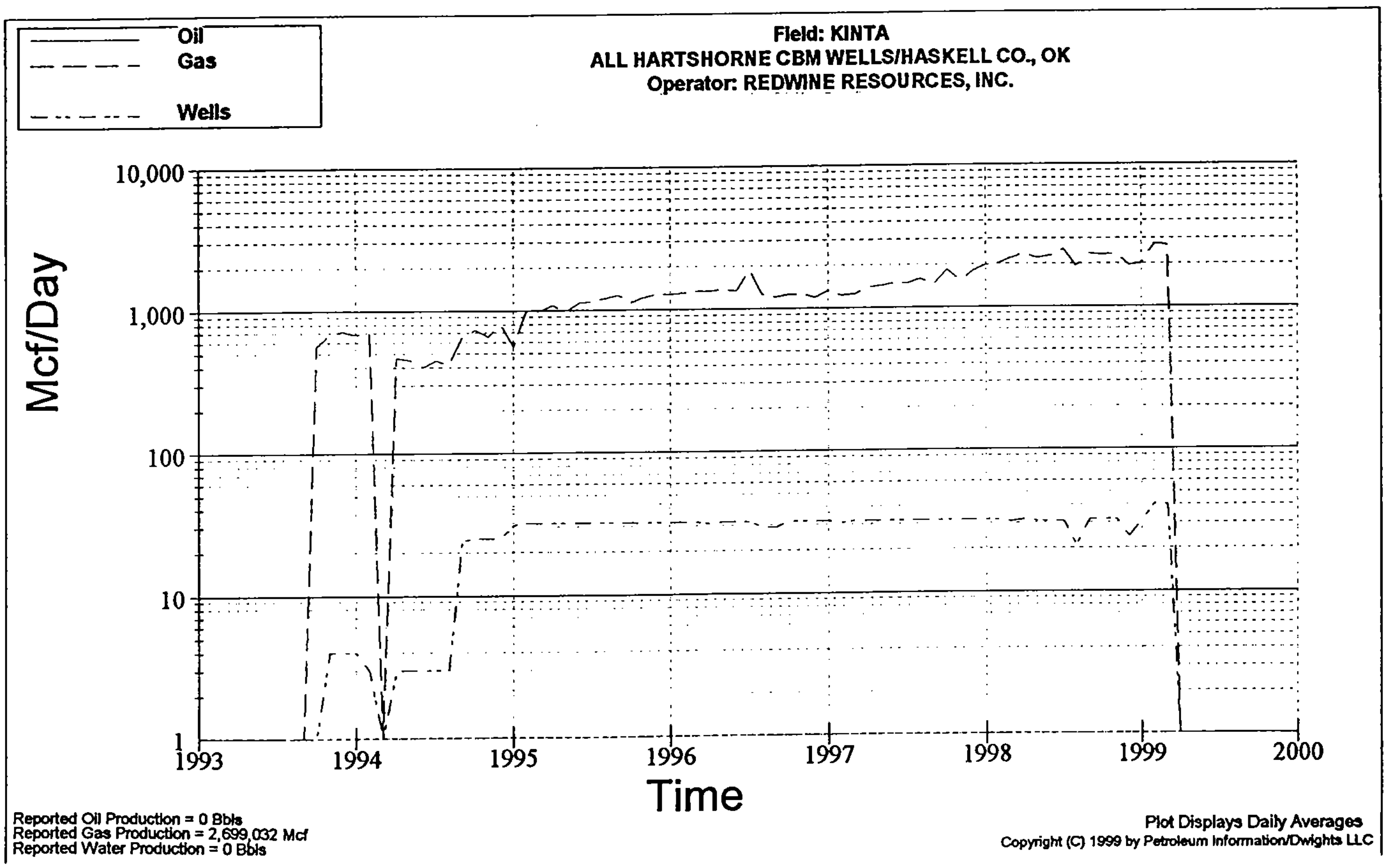




Oil
Gas
Wells
Field: KINTA
ALL CBM WELLS: SEC. 16-8N-20E
Operator: REDWINE RESOURCES, INC.
Mcf/Day
1,000
100
10
1
1993
1994
1995
1996
1997
1998
1999
2000
Time
Reported Oil Production = 0 Bbls
Reported Gas Production = 764,663 Mcf
Reported Water Production = 0 Bbls
Plot Displays Daily Averages
Copyright (C) 1999 by Petroleum Information/Dwights LLC



Oil
Gas
Wells
Field: KINTA
ALL CBM WELLS: SEC. 17-8N-20E
Operator: REDWINE RESOURCES, INC.
Mcf/Day
1,000
100
10
1
1993
1994
1995
1996
1997
1998
1999
2000
Time
Reported Oil Production = 0 Bbls
Reported Gas Production = 430,070 Mcf
Reported Water Production = 0 Bbls
Plot Displays Daily Averages
Copyright (C) 1999 by Petroleum Information/Dwights LLC



Oil
Gas
Wells
Field: KINTA
ALL HARTSHORNE CBM WELLS/HASKELL CO., OK
Operator: REDWINE RESOURCES, INC.
Mcf/Day
10,000
1,000
100
10
1
1993
1994
1995
1996
1997
1998
1999
2000
Time
Reported Oil Production = 0 Bbls
Reported Gas Production = 2,699,032 Mcf
Reported Water Production = 0 Bbls
Plot Displays Daily Averages
Copyright (C) 1999 by Petroleum Information/Dwights LLC

PROJECT SUMMARY: REDWINE

DATE OF FIRST PRODUCTION: 1993

LOCATION: 8N - 20 & 21 E

COUNTY: HASKELL

COAL THICKNESS: 3 - 5 FEET

DEPTH RANGE: 700 - 1650 FEET

NUMBER OF WELLS: 57

COMPLETION METHOD: SAND/WATER FRAC

PRODUCTION RANGE (IND. WELL): UP TO 200 MCFGPD

AVG. DAILY PROD. PER WELL: 46 MCF

AVG. DAILY PROD. /FIELD: 2,656 MCF

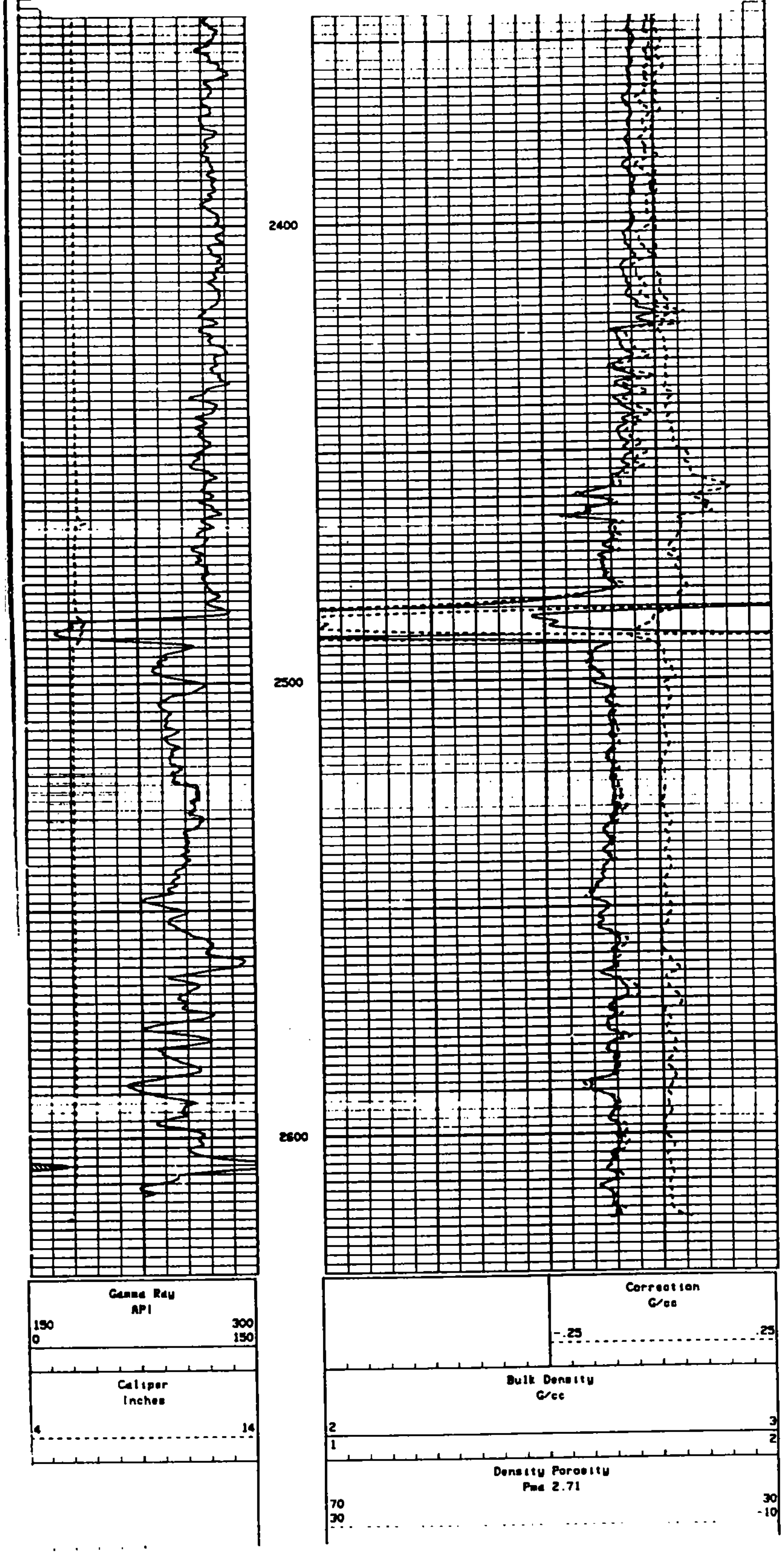
CUMULATIVE PRODUCTION: 2,974,022 MCF

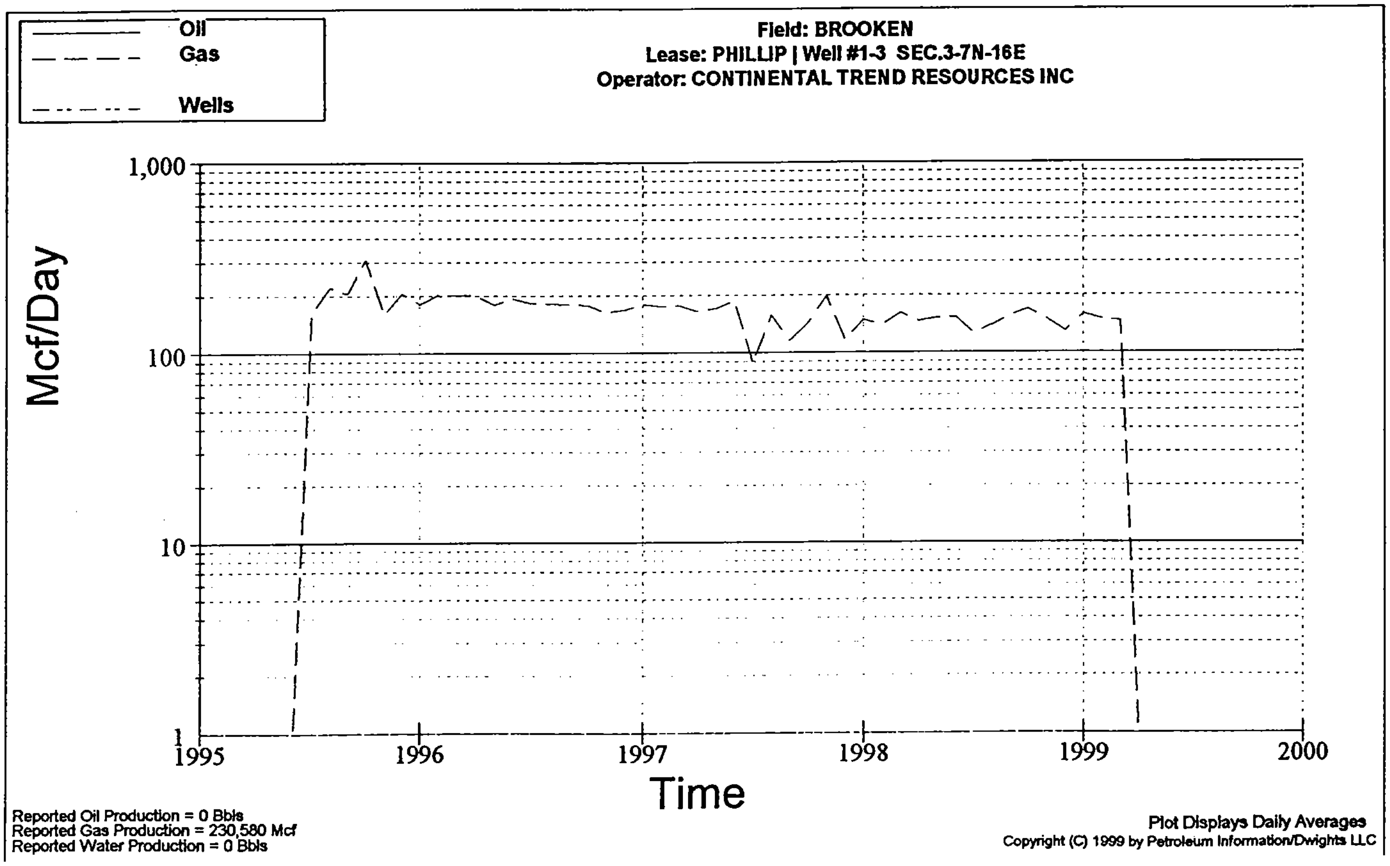
CUM. PROD. RANGE (IND. WELL): MTR'D BY LSE.

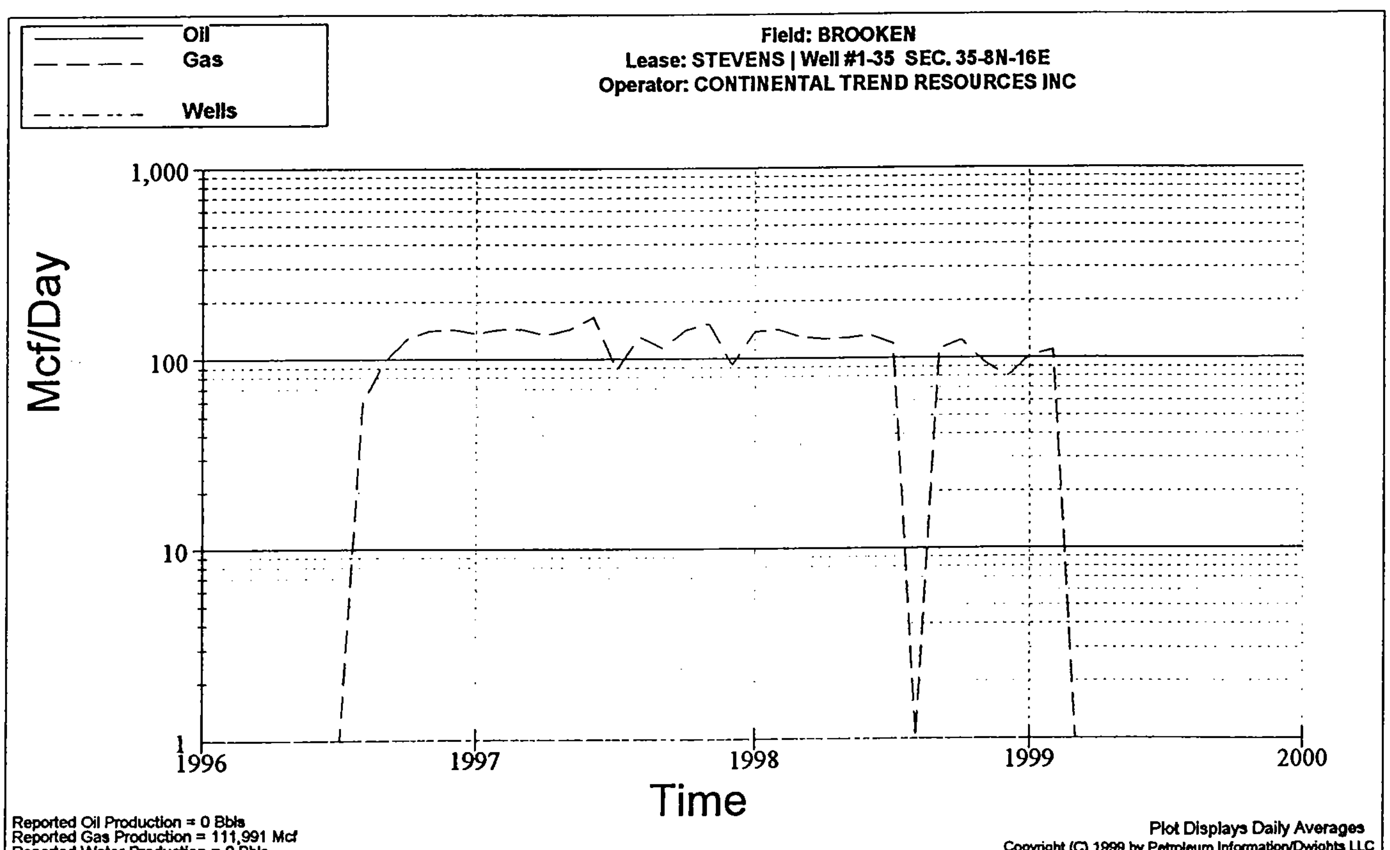
AVG. CUM. PROD. PER WELL: 52,175 MCF

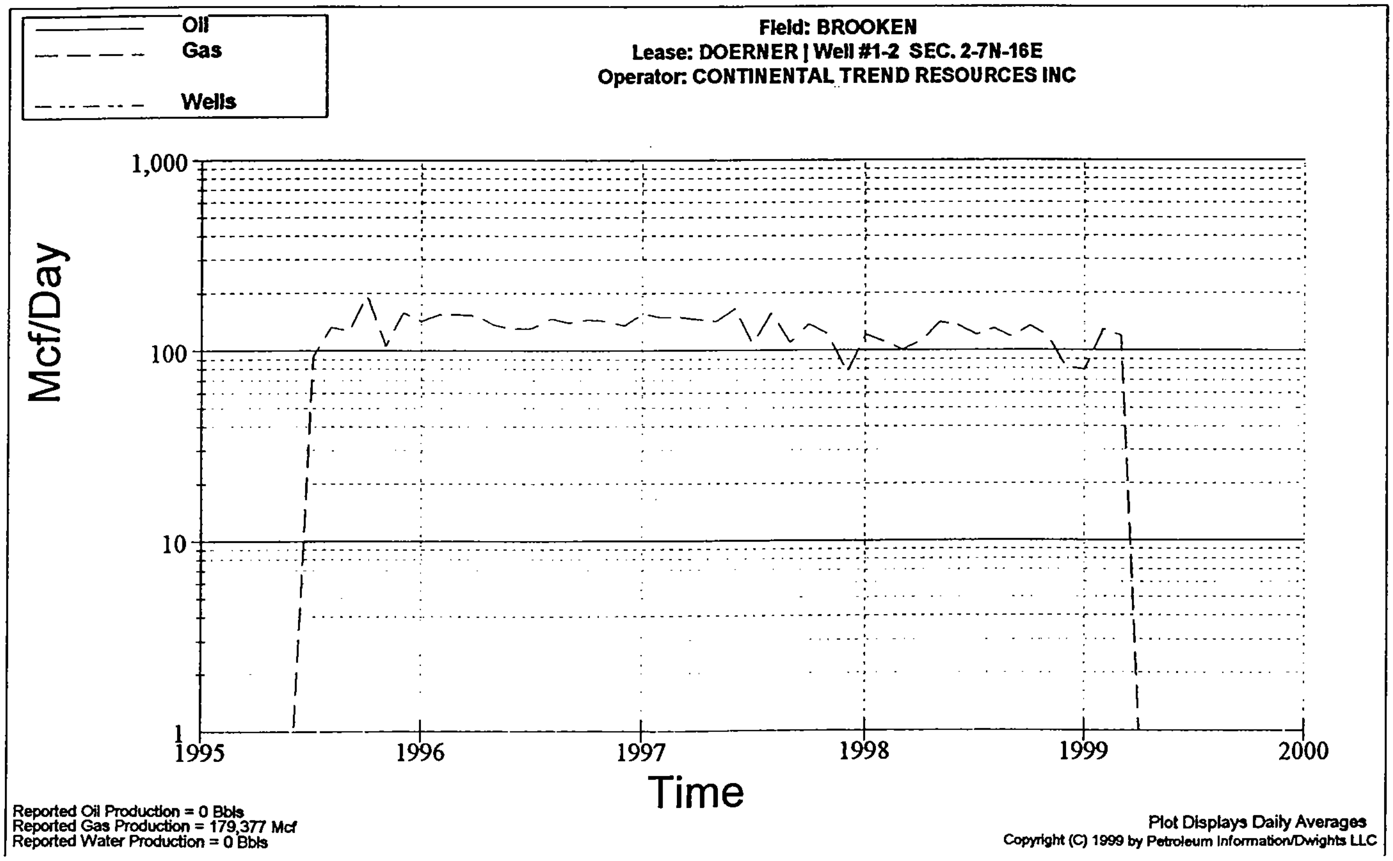
CONTINENTAL RESOURCES

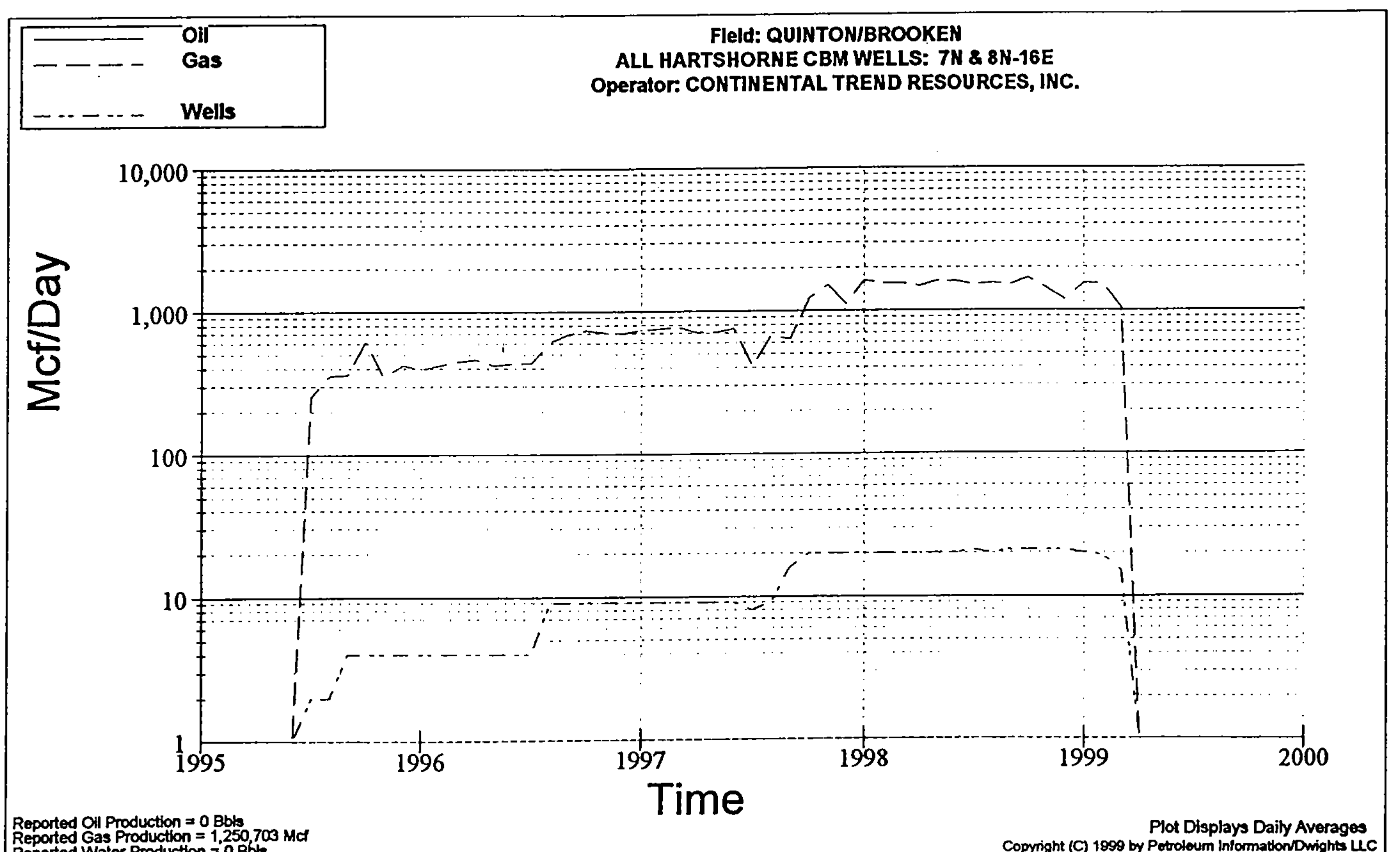
PHILLIP # 1 - 3
SEC. 3 - 7N - 16E




Oil
Gas
Wells
Field: BROOKEN
Lease: PHILLIP | Well #1-3 SEC.3-7N-16E
Operator: CONTINENTAL TREND RESOURCES INC
1,000
100
10
1
Mcf/Day
1995
1996
1997
1998
1999
2000
Time
Reported Oil Production = 0 Bbls
Reported Gas Production = 230,580 Mcf
Reported Water Production = 0 Bbls
Plot Displays Daily Averages
Copyright (C) 1999 by Petroleum Information/Dwights LLC


Oil
Gas
Wells
Field: BROOKEN
Lease: STEVENS | Well #1-35 SEC. 35-8N-16E
Operator: CONTINENTAL TREND RESOURCES INC
1,000
100
10
1
Mcf/Day
1996
1997
1998
1999
2000
Time
Reported Oil Production = 0 Bbls
Reported Gas Production = 111,991 Mcf
Reported Water Production = 0 Bbls
Plot Displays Daily Averages
Copyright (C) 1999 by Petroleum Information/Dwights LLC


Oil
Gas
Wells
Field: BROOKEN
Lease: DOERNER | Well #1-2 SEC. 2-7N-16E
Operator: CONTINENTAL TREND RESOURCES INC
Mcf/Day
1,000
100
10
1
1995
1996
1997
1998
1999
2000
Time
Reported Oil Production = 0 Bbls
Reported Gas Production = 179,377 Mcf
Reported Water Production = 0 Bbls
Plot Displays Daily Averages
Copyright (C) 1999 by Petroleum Information/Dwights LLC


Oil
Gas
Wells
Field: QUINTON/BROOKEN
ALL HARTSHORNE CBM WELLS: 7N & 8N-16E
Operator: CONTINENTAL TREND RESOURCES, INC.
Mcf/Day
10,000
1,000
100
10
1
1995
1996
1997
1998
1999
2000
Time
Reported Oil Production = 0 Bbls
Reported Gas Production = 1,250,703 Mcf
Reported Water Production = 0 Bbls
Plot Displays Daily Averages
Copyright (C) 1999 by Petroleum Information/Dwights LLC

PROJECT SUMMARY: CONTINENTAL TREND RESOURCES

DATE OF FIRST PRODUCTION: 1995

LOCATION: 7 & 8 N - 16 E

COUNTY: PITTSBURGH

COAL THICKNESS: 5 - 8 FEET

DEPTH RANGE: 1,892 - 3,081 FEET

NUMBER OF WELLS: 21

COMPLETION METHOD: SAND/WATER FRAC

PRODUCTION RANGE (IND. WELL): UP TO 149 MCFGPD

AVG. DAILY PROD. PER WELL: 70 MCF

AVG. DAILY PROD. /FIELD: 1,465 MCF

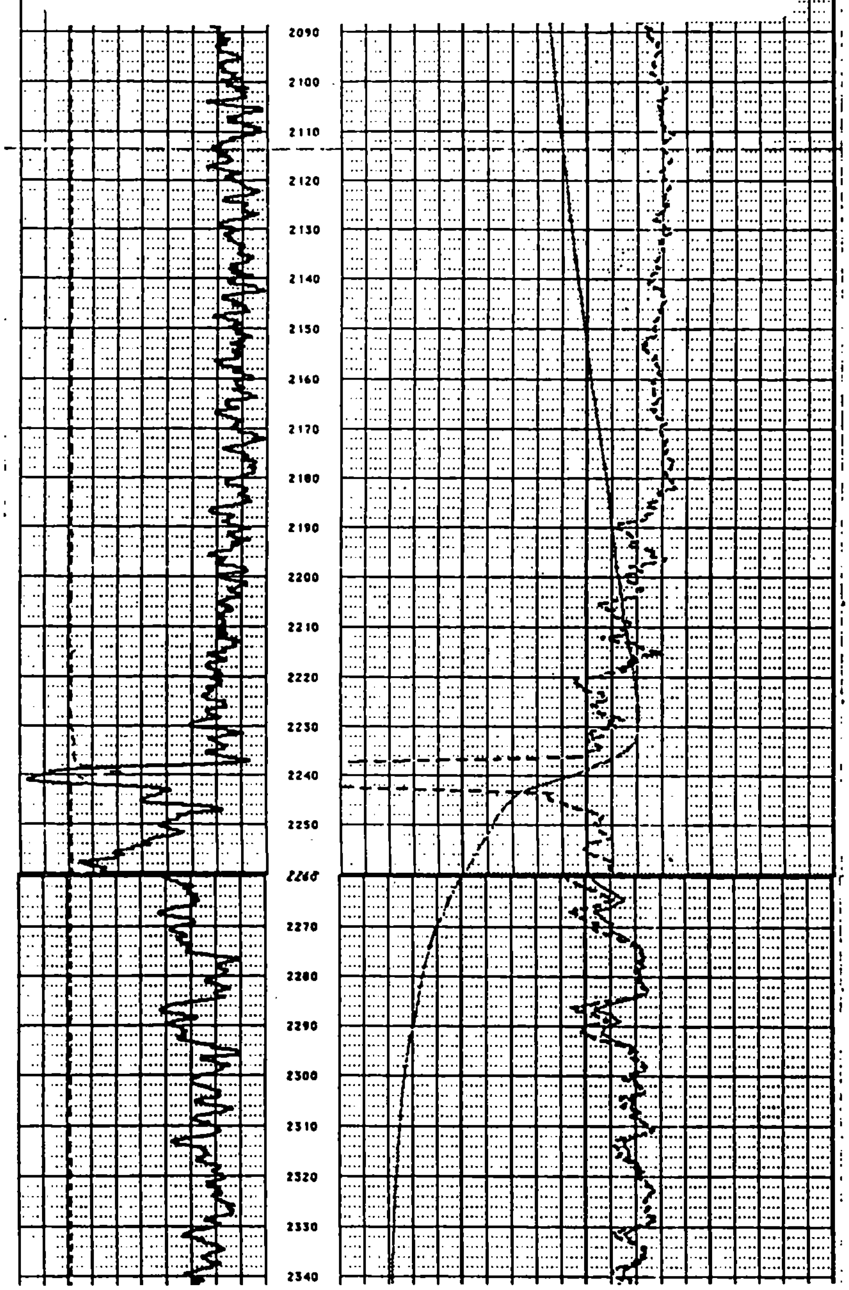
CUMULATIVE PRODUCTION: 1,392,465 MCF

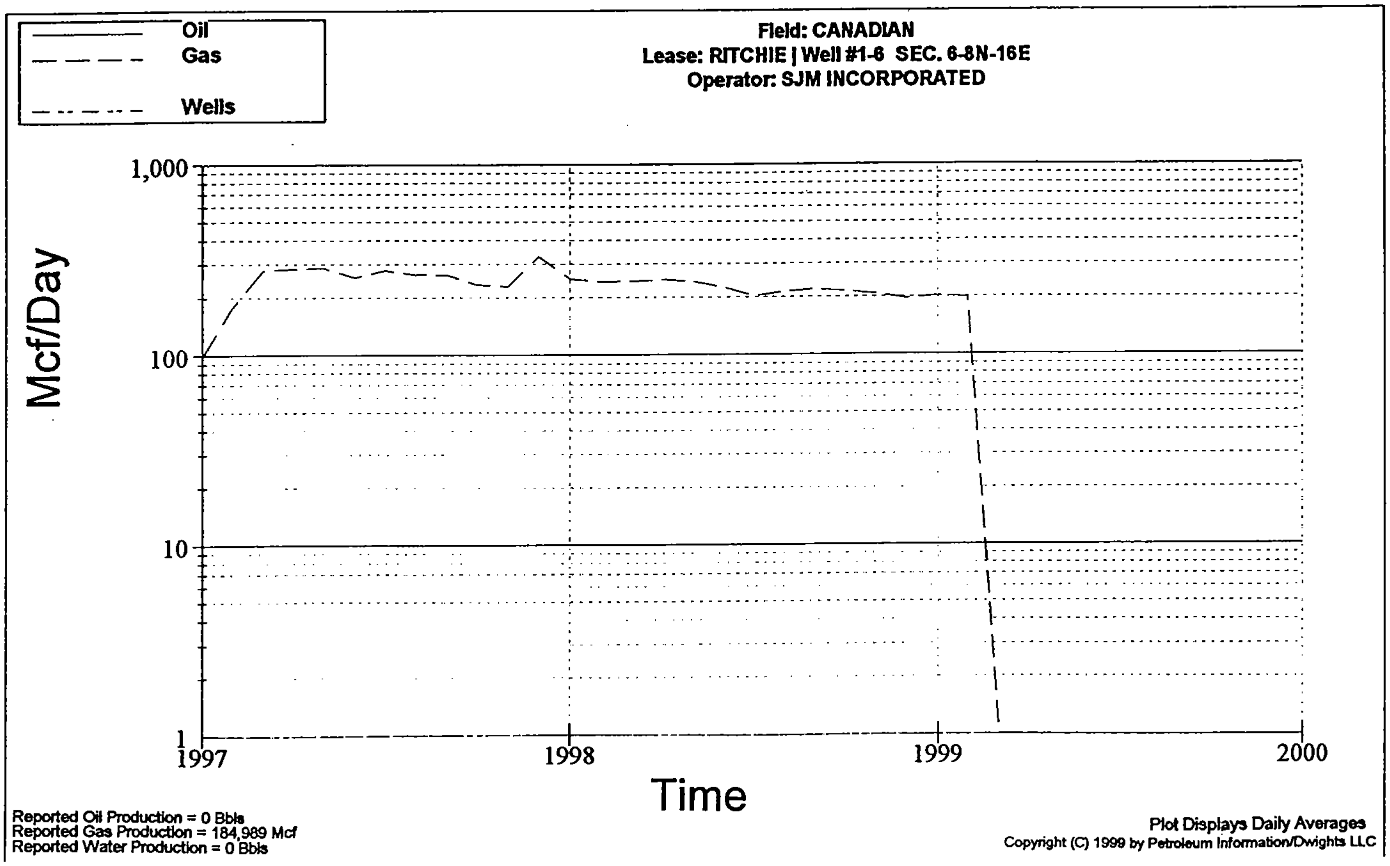
CUM. PROD. RANGE (IND. WELL): UP TO 244 MMCF

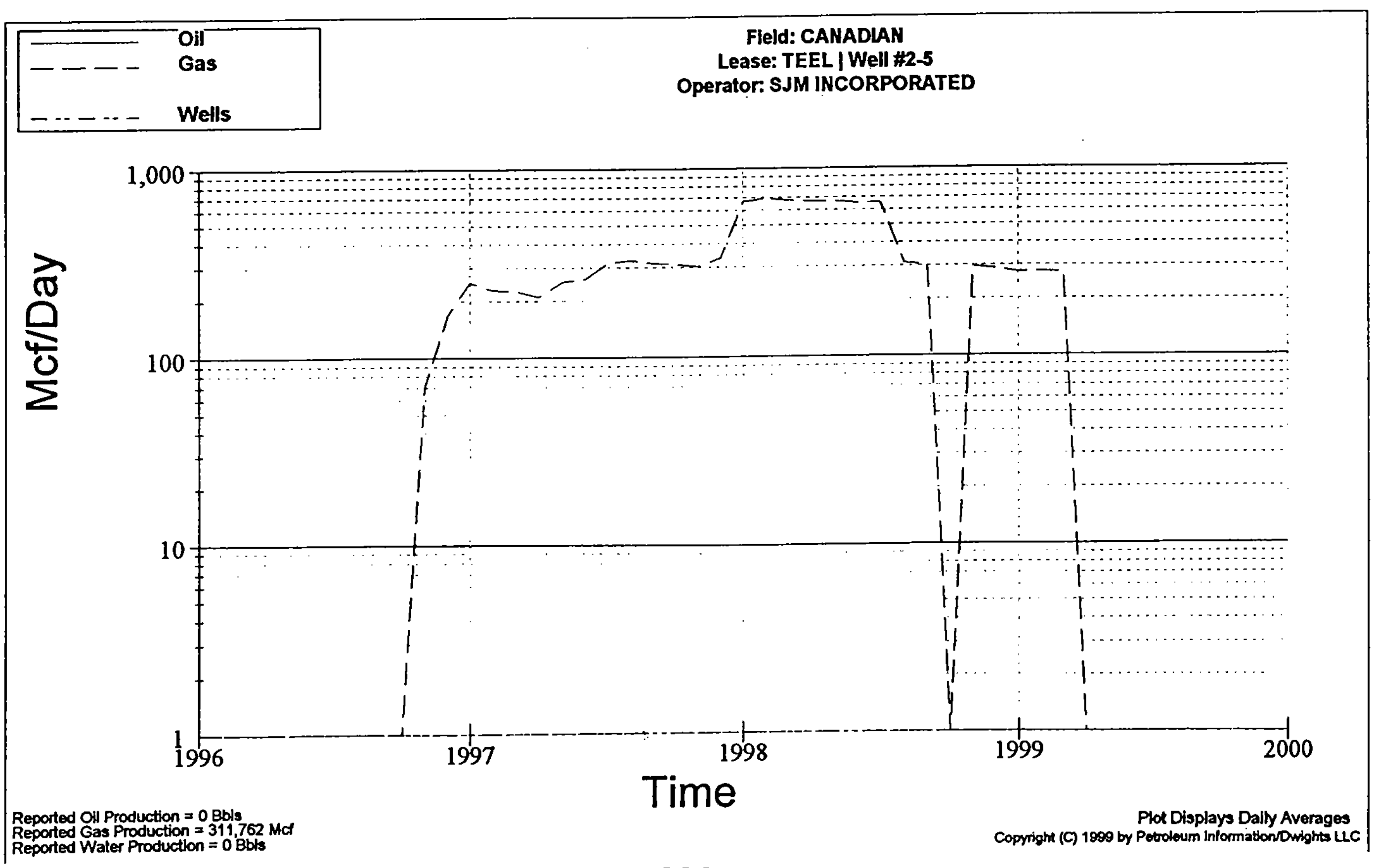
AVG. CUM. PROD. PER WELL: 66,307 MCF

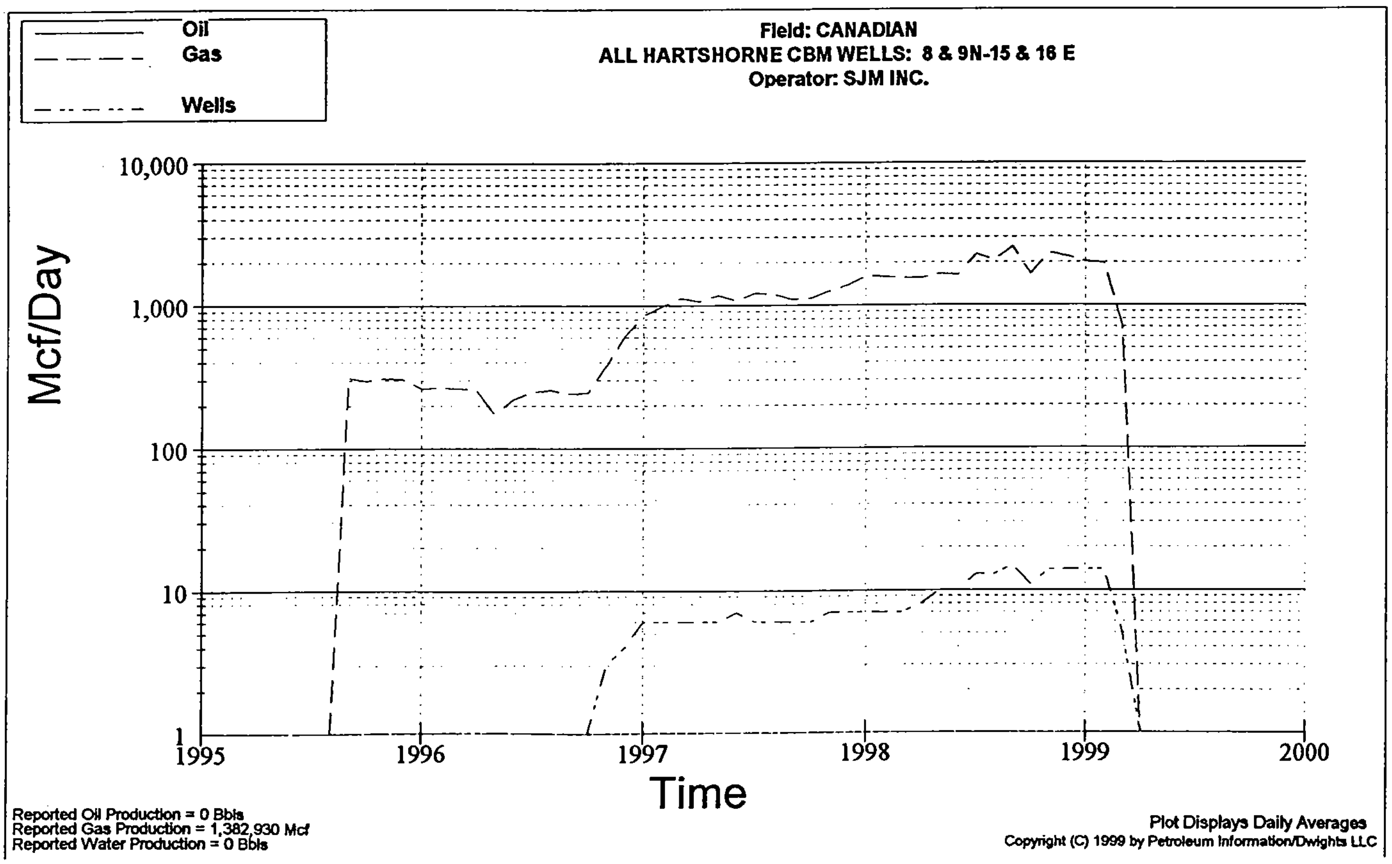
SJM, INC.

RITCHIE # 1 - 6
SEC. 6 - 8N- 16E




Oil
Gas
Wells
Field: CANADIAN
Lease: RITCHIE | Well #1-6 SEC. 6-8N-16E
Operator: SJM INCORPORATED
1,000
100
10
1
Mcf/Day
1997
1998
1999
2000
Time
Reported Oil Production = 0 Bbls
Reported Gas Production = 184,989 Mcf
Reported Water Production = 0 Bbls
Plot Displays Daily Averages
Copyright (C) 1999 by Petroleum Information/Dwights LLC


Oil
Gas
Wells
Field: CANADIAN
Lease: TEEL | Well #2-5
Operator: SJM INCORPORATED
1,000
100
10
1
Mcf/Day
1996
1997
1998
1999
2000
Time
Reported Oil Production = 0 Bbls
Reported Gas Production = 311,762 Mcf
Reported Water Production = 0 Bbls
Plot Displays Daily Averages
Copyright (C) 1999 by Petroleum Information/Dwights LLC



Oil
Gas
Wells
Field: CANADIAN
ALL HARTSHORNE CBM WELLS: 8 & 9N-15 & 16 E
Operator: SJM INC.
10,000
1,000
100
10
1
Mcf/Day
1995
1996
1997
1998
1999
2000
Time
Reported Oil Production = 0 Bbls
Reported Gas Production = 1,382,930 Mcf
Reported Water Production = 0 Bbls
Plot Displays Daily Averages
Copyright (C) 1999 by Petroleum Information/Dwights LLC

PROJECT SUMMARY: SJM, INC.

DATE OF FIRST PRODUCTION: 1995

LOCATION: 8 & 9 N - 15 & 16 E

COUNTY: Pittsburgh

COAL THICKNESS: 4 - 6 Feet

DEPTH RANGE: 1940' - 2420'

NUMBER OF WELLS: 17

COMPLETION METHOD: Sd/Wtr. Frac; Nitrogen Frac

PRODUCTION RANGE (IND. WELL): up to 270 MCFGPD

AVG. DAILY PROD. PER WELL: 99 MCF

AVG. DAILY PROD. /FIELD: 1,680 MCF

CUMULATIVE PRODUCTION: 1,547,980 MCF

CUM. PROD. RANGE (IND. WELL): up to 336,000 MCF

AVG. CUM. PROD. PER WELL: 91,057 MCF