Chapter 10

Coalbed Methane

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Coalbed Methane

INTRODUCTION

Methane in coal seams traditionally has been viewed as a hazardous waste product of the mining operation, rather than an energy resource in its own right. In fact, gas in a coal seam only contains 1 to 2 percent of the energy capacity of the coal itself. As a consequence, an estimated 217 thousand cubic feet per day (MCF/D) or 80 billion cubic feet per year (BCF/yr) of methane is vented to the atmosphere from U.S. mines,[1] without thought of recovery, to increase mine safety. The search for additional natural gas resources in the 1970s fostered an interest in economically recovering this "wasted" gas. By removing this gas before mining begins and either using it on site or selling it to the natural gas market, energy conservation could be combined with increased mine safety. In addition, it was realized that a potentially large gas resource lies trapped in seams of coal that will likely never be mined because of their depth or physical characteristics.

[1]V. A. Kuuskraa and R. F. Meyer "Review of World Resources of Unconventional Gas," IIASA Conference on Conventional and Unconventional World Natural Gas Resources, Luxenburg, Austria, June 30-July 4, 1980.

Although it is widely acknowledged that the coal bed methane resource is large, early economic assessments suggested that it had little potential for economic recovery barring very high gas prices. More recent evidence from wells producing gas from coal seams at current prices suggests a more optimistic outlook is justified. It appears that in some areas with highly favorable geology, commercial volumes of gas are recoverable at current prices using existing technologies.

Current production efforts include nearly 100 producing wells drilled by various operators in Alabama's Black Warrior Basin, early efforts by Carnegie Natural Gas Co. and Equitable Gas Co. in Pennsylvania and West Virginia, a variety of wells in the San Juan Basin of New Mexico, and others.[2]

[2]J. L. Wingenroth, "Recent Developments in the Recovery of Methane From Coal Seams," Gas *Energy Review, vol.* 10, No. 9, September 1982, American Gas Association.

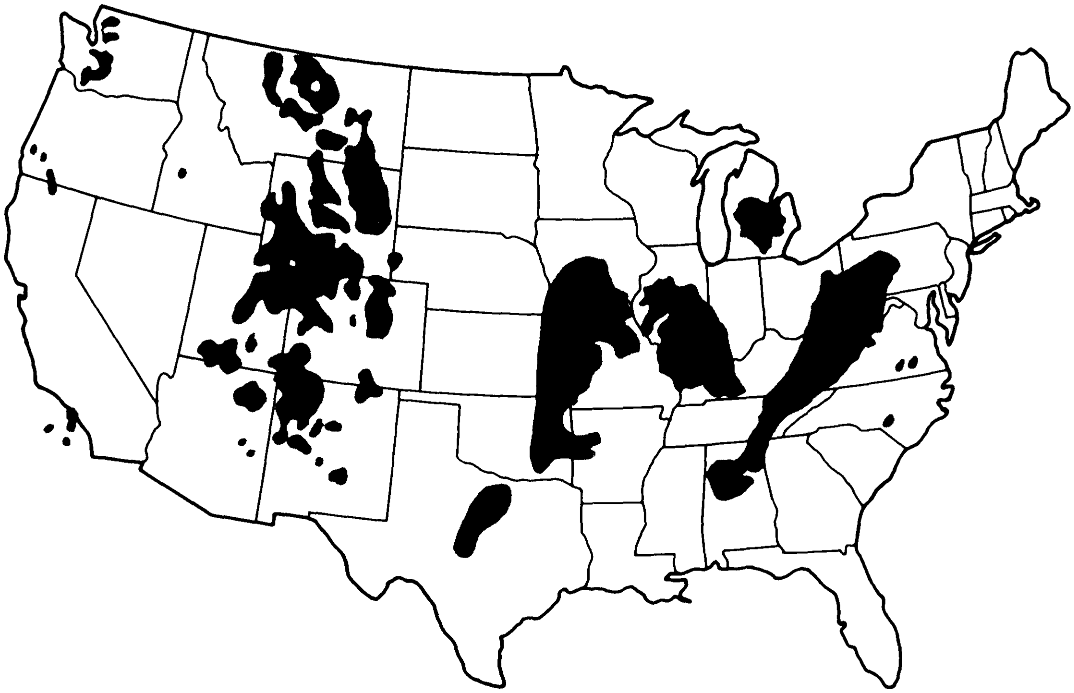
CHARACTERISTICS OF THE COALBED METHANE RESOURCE BASE

Coalbed methane is defined as natural gas trapped in coal seams. The location of the Nation's coal resources and associated methane accumulations are depicted in figure 43. Approximately two-thirds of the resource is located in the West and Midwest and the remainder is located in the Appalachian Basin.

Methane forms as a byproduct of the coalification process.[3] With increasing temperatures, the rank (carbon content) of the coal increases, and larger volumes of methane and other volatile constituents are produced (fig. **44).** As volatiles are driven off by the increasing temperatures, the coal shrinks, giving rise to a pervasive natural fracture system called the "cleat." Although much of the generated gas migrates out of the formation, some remains in the coal seam adsorbed to the coal pore surfaces, and some is trapped in the pore spaces and fracture system by the reservoir pressure. In sharp contrast to conventional gas reservoirs, where essentially all of the gas is trapped in the pores and fractures, the adsorbed gas is the dominant source of coal bed methane and plays the major role in production. The volume of adsorbed gas appears to be a function of depth (pressure) and coal rank, as shown in figure 45. Nevertheless, given the vagaries of

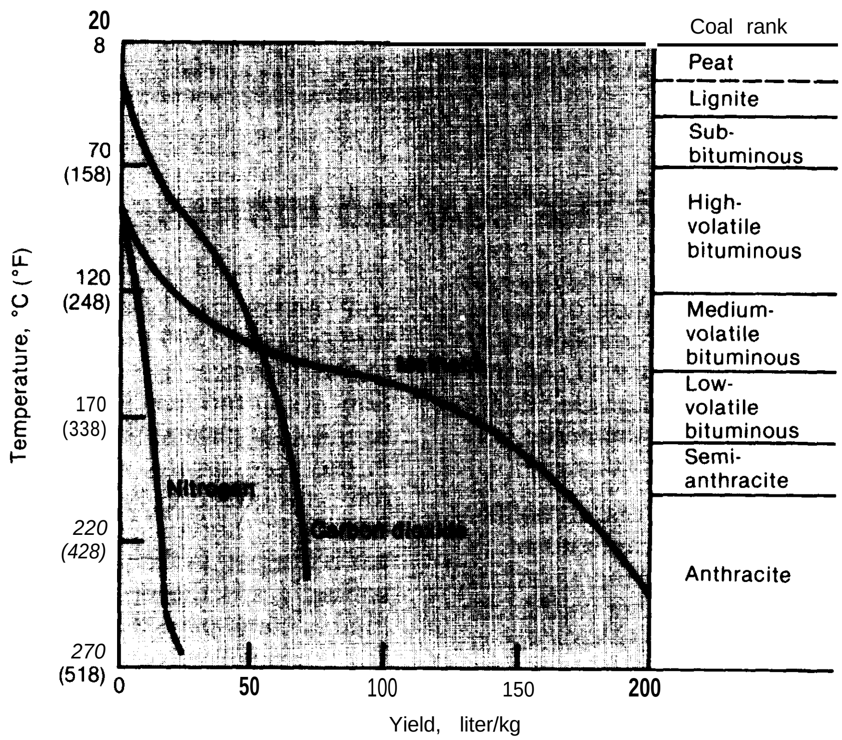
[3]Coalification: the formation of coal from organic-rich sediments, under intense heat and pressure.

Figure 43.—U.S. Coal Regions



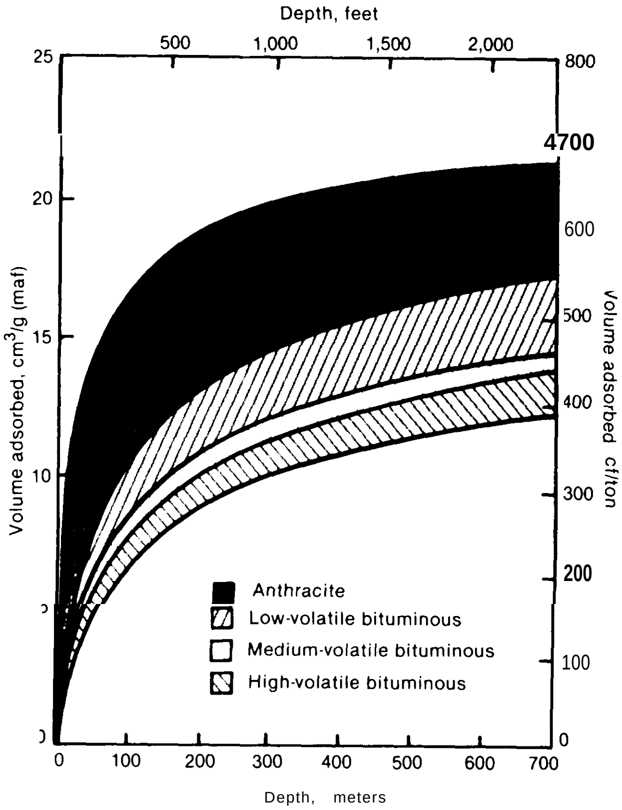
SOURCE: Department of Energy.

Figure 44.-Variation of Gas Content by Rank, Temperature



SOURCE: J. M. Hunt, *Petroleum Geochemistry and Geology* (San Francisco: W. H. Freeman & Co., 1978) (fig. 5-7, p. 165).

Figure 45.—Variation of Adsorbed Gas by Rank



SOURCES: A G Kim, “Estimating Methane Content of Bituminous Coalbeds From Adsorption Data,” BuMines RI 8245, 1977 c.f ; G. E. Eddy, C. T. Rightmure, and C. W. Bryer, “Relationship of Methane Content of Coal Rank and Depth, Theoretical vs Observed,” *SPE/DOE Unconventional Gas Recovery Symposium,* 10800, 1982

the geologic process, methane content in coal is highly variable from seam to seam and even within the same seam.

The quality of the gas present in coal seams is also somewhat variable, but generally is quite good. The heat of combustion ranges from 950 to 1,050 Btu per cubic foot. The gas has few impurities; carbon dioxide and water vapor are the primary undesirable components. Sulfur dioxide and hydrogen sulfide gases are absent even in the more sulfur rich coals.

Coal in itself is essentially impermeable. Bulk permeability of a coal seam depends on how well-developed the cleat is. Generally, there is a dominant system of vertical fractures, the so-called “face cleat, ” and a less developed system of vertical fractures perpendicular to the face cleat, the “butt cleat, ” the nature of the face cleat is critical to the coal’s production characteristics. The importance of the natural fracture system, together with the critical production role played by adsorbed gas, establishes a close parallel between coal seam methane and the Devonian shale gas resource.

Many coal seams contain water and thus the reservoir pressure is partially a hydrostatic pressure caused by groundwater. Although in some cases the water is the original product of the coal formation process, often the water infiltrates the coal from the surface or from overlying aquifers. The presence of this water has profound effects on gas production from the coal seams.

GAS-IN-PLACE

Existing gas-in-place estimates are summarized in table 56. These range from a low of 68 TCF to a high of about 850 TCF. Most estimates are based on the U.S. coal resource; differences arise from varying assumptions of gas content (volume of gas per cubic foot or ton) of the coal and criteria for defining coal seams as good targets for recoverable gas.[4] Several of the most recent estimates are discussed in more detail below.

[4]These criteria are important because gas-in-place estimates generally consider only gas found in formations that contain potentially recoverable gas.

Methodologies and Results

National Petroleum Council, Gas Research Institute, and Kuuskraa and Meyer

Among the more recent studies, the estimates by the National Petroleum Council (NPC), the Gas Research Institute (GRI), and Kuuskraa and Meyer (KM) are very similar in methodology and in results. The estimated resource in place ranges from 398 TCF (NPC) to 550 TCF (KM).

All of these studies use the 1974 U.S. Geologic Survey’s (USGS) coal resource data—an estimate

Table 56.—Coalbed Methane Resource Estimates

Study	Resource in place (TCF)
Department of Energy (1984)	68-395
Kuuskraa and Meyer (1980)	550
National Petroleum Council (1980) . .	398
Gas Research Institute (1980)	500
Federal Energy Regulatory Commission (1978)	300-850
Deul and Kim (1978)	318-766
Wise and Skillern (1978) ., ...	300-800
TRW	72-860
National Academy of Sciences (1976)	300

SOURCE: Adapted from AGA Gas Energy Review, September 1982; and C. W. Byrer, T. H. Mroz, and G, L. Covatch, "Production Potential for Coal-bed Methane in U.S. Basins," SPE/DOE/GRI Unconventional Gas Recovery Symposium, 12832, 1984.

of "minable" coal resources—as the basis for their estimates. The USGS assessment is broken down into identified and hypothetical resources at depths less than 3,000 ft and hypothetical resources at depths greater than 3,000 ft. The identified resources are further broken down by coal rank—anthracite, bituminous, subbituminous, and lignite. For the methane estimates, Kuuskraa and Meyer have subdivided the hypothetical resources by rank in approximately the same proportion as they occur in the identified resources.

The NPC, GRI, and KM analyses then multiply the coal resource by an assumed gas content to determine the gas resource in place. All assume that gas content varies with rank and depth. Assumptions are compared in table 57. Although the KM estimates disaggregate the gas content of coal to a greater extent than the GRI or NPC estimates, their assumed gas contents, averaged, are essentially the same as the GRI and NPC values. Consequently, the increased detail in their estimate does not contribute to a substantial difference in the calculated gas-in-place.

The **NPC estimate excludes all coal resources at depths less than 300 ft, assuming these coal seams contain essentially no recoverable gas.** The exclusion of shallow coals appears reasonable because the lower pressures may have allowed any gas originally contained in shallow seams to have escaped to the surface. However, the NPC also assumed that a full third of the identified and hypothetical coal resource between O and 3,000 ft occurs above 300 ft; also, the NPC apparently assumed that the bulk of this shallow coal is bituminous, with high gas content. Thus, the NPC analysis excludes from consideration a large percentage of the higher-gas-content coal. This conclusion appears to be the primary reason that the NPC estimates are 100 to 150 TCF lower than the GRI and KM estimates.[5] The exclusion appears overly pessimistic because it is the **lower rank**

[5] Although G RI also appears to exclude the coal resource at less than 300 ft from their gas-in-place calculations, in fact their total coal resource base is equal to the USGS coal resource base (3,968 X 10^9 tons) from O to 6,000 ft.

Table 57.-Coal Resource and Gas Content Assumptions

	Zero to 3,000 ft					Greater than 3,000 ft		
	Kuuskraa & Meyer							
Coal rank	<1,000	1,000-3,000	>3,000	NPC	GRI	Kuuskraa & Meyer	NPC	GRI
A) Coal resource assumptions (billion short tons):								
Anthracite (A)	845	739	1,584	46	60			
Bituminous (B)				1,001	1,300			
A + B	845	739	1,584	1,047	1,360	176		
Subbituminous	538	470	1,008	1,137	1,520	112		
Lignite	538	470	1,008	504	700	112		
Total			3,600	2,688	3,580	400	388	388
Total (all depths)			4,000	3,076	3,968			
B) Gas content assumptions-cubic ft/ton:								
Anthracite and bituminous	150	250	197[a]	200	200	500	200	200
Subbituminous	60	100	79[a]	80	80	200	200	200
Lignite	30	50	39[a]	40	40	100	200	200

[a] Weighted average.

SOURCE: Office of Technology Assessment.

(thus lower gas content) coals that tend to occur at shallower depths.

Department of Energy (DOE) —Methane Recovery From Coalbeds Project

The DOE Coalbed Methane Basin analysis is the first attempt to estimate the gas-in-place on a basin-by-basin level. The DOE approach targets the most likely gas-producing coal seams in each coal-bearing basin. Wherever possible, they have established a range of gas contents for the targeted coals in each basin and calculated a gas-in-place. Data were obtained from a variety of producing wells and test wells. They have completed studies of 14 basins with an estimated total gas-in-place of 68 to 396 TCF. Results for the 14 basin analyses are summarized in table 58. The high end of this range is essentially compatible with earlier estimates; the low end is very conservative, being the product of lower estimates of both target area and gas content.

DOE appears to have made a number of subjective judgments in delimiting its target areas. For example, DOE selected for inclusion in the resource base only those coal seams with high reported gas contents, high rank, and thick cumulative sections, without setting any quantitative criteria for the selection. In addition, assessments of several basins have not been completed. Thus, its estimate is conservative in terms of total gas-in-place. Because it focused on formations that are the most likely to contain recoverable gas, however, the gas-in-place estimates may represent a valid basis for an estimate of the technically recoverable resource.

Uncertainties

The wide range of gas content in coal seams, seen clearly in table 58, is the primary factor contributing to uncertainty in gas-in-place estimates. The range in the DOE gas-in-place estimates—over a factor of 5—may not be an unreasonable reflection of the true uncertainty at this time. The level of uncertainty will only be reduced as more data are obtained on gas content of specific coal seams. However, the impetus to obtain more data may only come as producers move to develop these resources.

The other major factor contributing to uncertainty is the lack of data on coal resources at depths greater than 3,000 ft. The USGS coal resource estimate is limited to potentially minable seams, and may substantially underestimate the gas-bearing resource. Very little information is available on the rank, reservoir characteristics,

Table 58.— DOE Gas-In-Place Estimates

Basin	Gas contents (CF/ton)	Estimated total gas-in-place (TCF)	
		Minimum	Maximum
Eastern:			
Northern Appalachian	30-420		61.0
Central Appalachian	125-400	10.0	48.0
Illinois	30-150	5.2	21.1
Warrior	7-600		11.0
Arkoma	70-700	1.6	3.6
Richmond	ND	0.7	1.4
Western:			
Piceance	1 -410+	30.0	110.0
Powder River	1.45	5.9	39.4
Greater Green River	13-539	0.2	30.9
San Juan	20-135 +	1.8	25.0
Western Washington	32-86	3.6	24.0
Raton Mesa	2-492	8.0	18.4
Wind River	a	0.5	2.2
Uinta	1-443	0.2	0.8
Total		67.7	395.8

ND—no data
aAssumes deep coals will contain some gas

SOURCE. C. W Byrer, T H. Mroz, and G L Covatch, "ProductIon Potential for Coal bed Methane in U.S Basin s," SPE/DOE/GRI Unconventional Gas Recovery Symposium, 12832, 1984 and gas content of the deep and unminable coals. Because deep coals are likely to be of higher rank and have higher gas content than shallower coals, b gas-in-place estimates that assign to the deep coals the same coal rank distribution found in the shallow coals may be too conservative. However, very low permeabilities, particularly in anthracites, may exclude some of these coals as sources of economically recoverable gas resources, absent significant advances in well stimulation technology.

‘Deeper coals are more likely to have been exposed to high temperatures, which in turn influence rank and gas content. See fig. 44.

To the extent that the deep coal seams are not considered to be viable targets for mining, many of the legal and institutional constraints to producing methane from minable coal seams will not be applicable to these deep seams. This may increase their attractiveness to gas producers. Refining the estimates of the deep gas resource, along with incorporating improved gas content data from the newly drilled basins, are the most important tasks remaining in establishing a more credible estimate of the coal bed methane gas-in-place.

PRODUCTION METHODS AND TECHNOLOGY

Production Methods

Producing coal seam methane is considerably different from producing natural gas in conventional reservoirs. Production rates in conventional reservoirs are primarily a function of permeability, whereas in coal seams, methane production is also dependent on the rate at which the adsorbed methane diffuses into the fracture network, or “cleat.” If the permeability of the coal’s fracture network is very low, then permeability will be the factor controlling production rates. However, when the fracture network is relatively permeable and is connected to the well bore, or when the fracture network is not well-developed (and thus the surface area for diffusion to take place is limited) production is more likely to be limited by the rate of diffusion of the adsorbed methane into the fracture network.

These different limiting factors have important implications for the probable effects of fracturing. If permeability is controlling, fracturing should increase production by enhancing the flow path from the fracture network to the wellbore. If diffusion is controlling, however, fracturing is unlikely to greatly affect production because it cannot add greatly to the surface area available for resorption, and any increased permeability it creates will not add to production.[7]

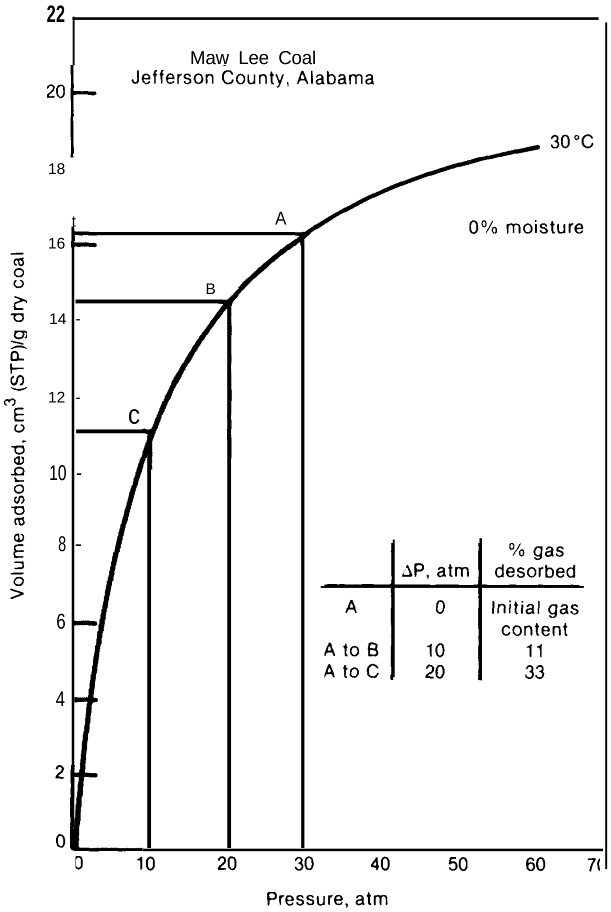
[7]Lewin & Associates, Inc., *Enhanced Recovery of Unconventional Gas, Volume ///: The Methodology,* U.S. Department of Energy report HCP/T2705-03, February 1979.

It is necessary to reduce the pressure in the fracture systems in order for gas to desorb from the coal and be available for production. Figure 46 shows how reducing the pressure will reduce the volume of gas adsorbed. The pressure/gas volume curve, which is typical of coal seams, is strongly nonlinear: a unit pressure drop has far less effect on resorption at high pressures than it does at low pressures. As a result of this nonlinearity, there may be little or no gas production until the pressure in the formation is reduced to the level where the rate of resorption per unit pressure drop begins to accelerate.

Because the reservoir pressure generally is a hydrostatic head associated with the groundwater in the coal seam, reducing the reservoir pressure means dewatering, i.e., pumping the water out of the seam. Water removal also increases the relative permeability of gas in the fracture network, allowing more gas to flow to the well bore. This also tends to reduce the pressure in the formation, further increasing the ability of gas to desorb from the coal,

As pumping the water from a well commences, the reservoir pressure is first reduced in the immediate vicinity of the wellbore, with the area of the pressure drop spreading overtime. The rate of gas production generally will increase with time as more and more area achieves the large pressure drop necessary to cause rapid resorption. This production increase with time is in

Figure 46.— Methane Gas Adsorbed on Coal as a Function of Pressure



	ΔP, atm	% gas desorbed
A	0	Initial gas content
A to B	10	11
A to C	20	33

SOURCE: S. C Way, et al , "Role of Hydrology in the Production of Methane From Coal Seams," Quarterly *Review of Methane From Coal Seams Tech. nology, vol* 1, No. 2, August 1983, Gas Research Institute,

sharp contrast to the more normal production de**cline** experienced in conventional gas wells. s

This model of gas production from coal seams may not apply to single, isolated wells. In coals with highly permeable, interconnected fracture systems, the effect of pumping over time will draw the pressure down in small increments over a wide and expanding area with little change in the pressure distribution near the wells.[9] Because resorption is strongly nonlinear, favoring a large pressure drop, the areal extension of a moderate pressure drawdown is likely to yield little additional gas. The solution to this problem is to somehow bound the drainage area of the wells so that larger pressure drops occur over time. One method is to drill a closely spaced pattern of wells and pump them simultaneously, deliberately creating interference between adjacent wells. Such interference will effectively halt or bound the areal spread of pressure drop from a single well. This practice is in sharp contrast to normal practice in conventional gas fields, where close spacing and well interference are avoided because they reduce average recovery per well.

Figure 47 shows pressure drawdown curves for a group of three wells. The broken lines represent the pressure curves associated with each well **in isolation;** the solid lines are the actual pressure curves that result from the three well system, reflecting the interference effects of the wells on each other. Close spacing of wells allows more of the formation to achieve the sharply reduced pressures necessary for maximum resorption and production of gas. The advantage of closer spacing is particularly apparent when water can infiltrate the formation. Pumping from isolated wells may simply be unable to remove the water faster than it can infiltrate, and thus such pumping will not successfully dewater the formation and produce the gas; simultaneous pumping from a group of wells generally can "outrun" the infiltration. In a formation where water infiltration is a problem, the **rate** of pumping also becomes critically important, since a higher pumping rate may be necessary to outrun the infiltration and successfully draw down the pressure.

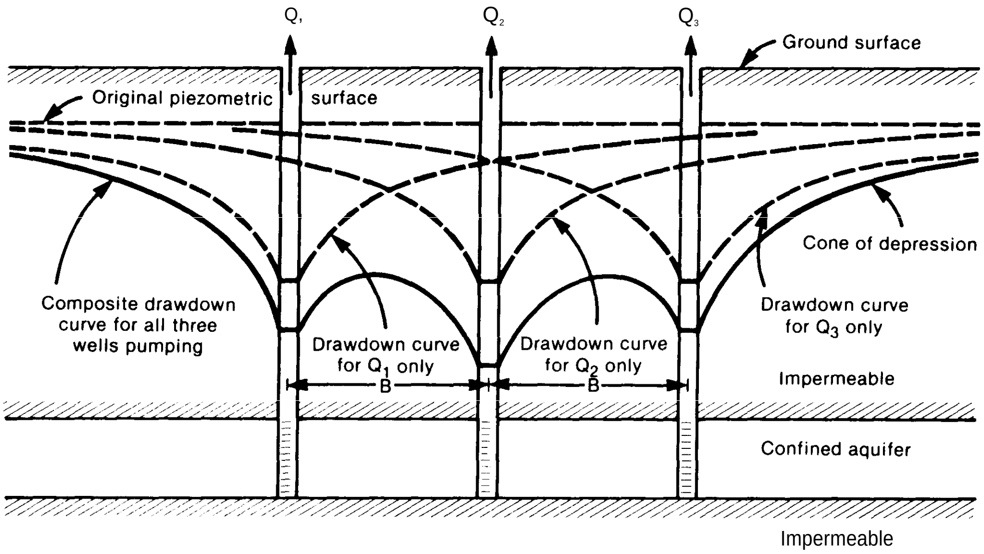
One well spacing pattern uses exterior wells to produce water and provide interference, while interior wells produce most of the gas.[10] Simulated production from this configuration predicts consistent high flow rates over a 20-year term, as shown in figure 48.

[8] S. C. Way, et al., "Role of Hydrology in the Production of Methane From Coal Seams," *Quarterly Review of Methane From Coal Seams Technology,* vol. 1, No, 2, August 1983, Gas Research Institute.

[9] "New Advances in Coalbed Methane, " Intercomp Resource Development & Engineering, Inc. (appears as app. C in K. L. Ancell, *Coal Degasification, An Unconventional Resource,* Dowdle Fairchild & Co., Inc., Houston, TX).

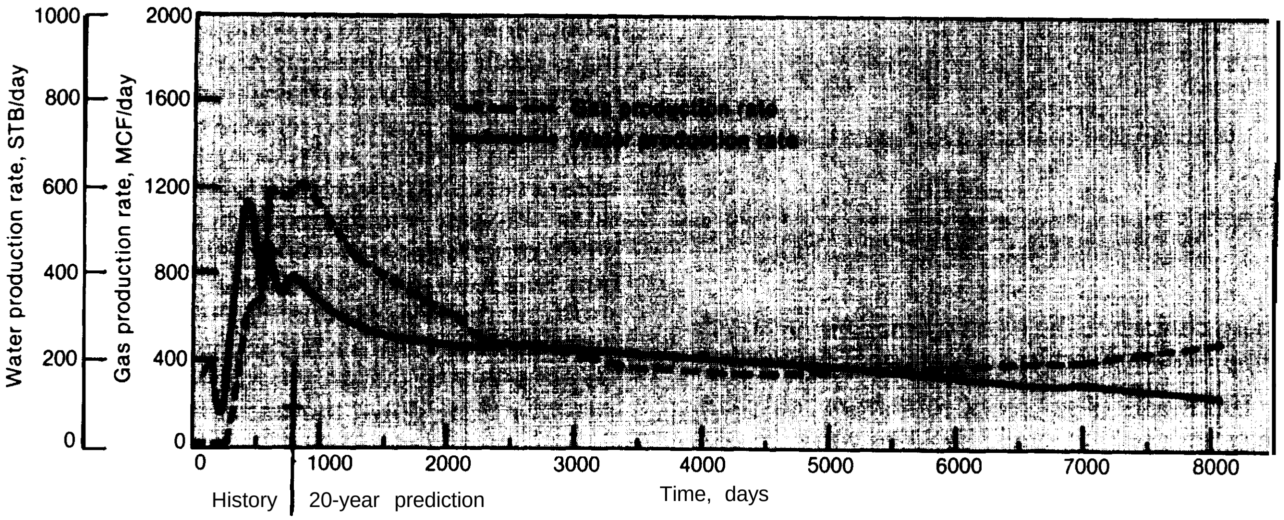
[10] Ibid.

Figure 47.—Pressure Drawdown Curves for Three Wells in a Line



SOURCE: S. C, Way, et al., "Role of Hydrology in the Production of Methane From Coal Seams," *Quarter/y Review of Methane From Coal Seams Technology, vol.* 1, No. 2, August 1983, Gas Research Institute.

Figure 48.—20-Year Production Prediction for Gas and Water Production From a Well Pattern Designed to Allow Rapid Water Removal



SOURCE: INTERCOMP Resource Development and Engineering, Inc.

Technologies

Increasing production, at least from shallow wells, does not depend primarily on the development of new technologies. The primary target for improved technologies are the deep coal seams. There we need better reservoir characterization techniques. New drilling and completion techniques also are required in deep wells where drilling fluids or cements used for completions are likely to cause extensive formation damage. Stimulation technologies also have not been highly successful in the lower permeability deep coal seams.

Drilling

Most current production of methane from both minable and unminable coalbeds uses vertical wells drilled through the coal seam. Major problems involve extensive formation damage induced by drilling fluids and by cements used to complete the holes. In shallower wells, air or water drilling and open hole completions[11] can counteract these problems. Improved production from multiple completions[12] and from deep coal seams where open hole completions may not be practical will require new technology developments. Current research programs sponsored by the Gas Research Institute are addressing these problems.

Another problem inherent in vertical drilling is the difficulty of intersecting the vertical fracture network, or face cleat. Well stimulation may be required to connect the wellbore with the natural fracture system and thus provide a pathway for gas to flow to the well. Another remedy is to slant or deviate the wells from the vertical to intersect the face cleats. Ideally, the well can be drilled parallel to the seam, as sketched in figure 49. This technology requires considerable improvement and cost reductions to be considered a realistic option for coal seam methane production. Keeping the wellbore in the coal seam is quite difficult, and drilling costs are significantly higher than for vertical wells. Dewatering deviated wells may also be a problem.

In minable coal seams, horizontal wells may be used. These wells usually are drilled from within the mine workings, perpendicular to the face cleat, and generally have high rates of gas drainage. The gas recovered from the boreholes is pumped through a separation unit to remove associated water before the gas is piped out of the mine.[13]

The main difficulty in drilling horizontal holes is keeping within the coal seam. Consolidated Coal Co. (Consol) has developed a mobile horizontal drilling system with special features for methane production. Three- to four-inch diameter holes may be drilled to lengths greater than 2,000 ft using a guidance system to keep the bit within the seam and methane is piped out through closed-loop plastic pipes.

Horizontal wells may partially escape dependence on the mining operation with a system that uses horizontal holes drilled radially from the bottom of a central vertical shaft. However, the expense of the shafts may dictate that the whole operation can succeed financially only if the shafts can be re-used later on for the mining operation; thus, it is not clear that this drilling system actually will sever the tie between mine and gas recovery operation. This method has not yet been tried in the United States.

Stimulation

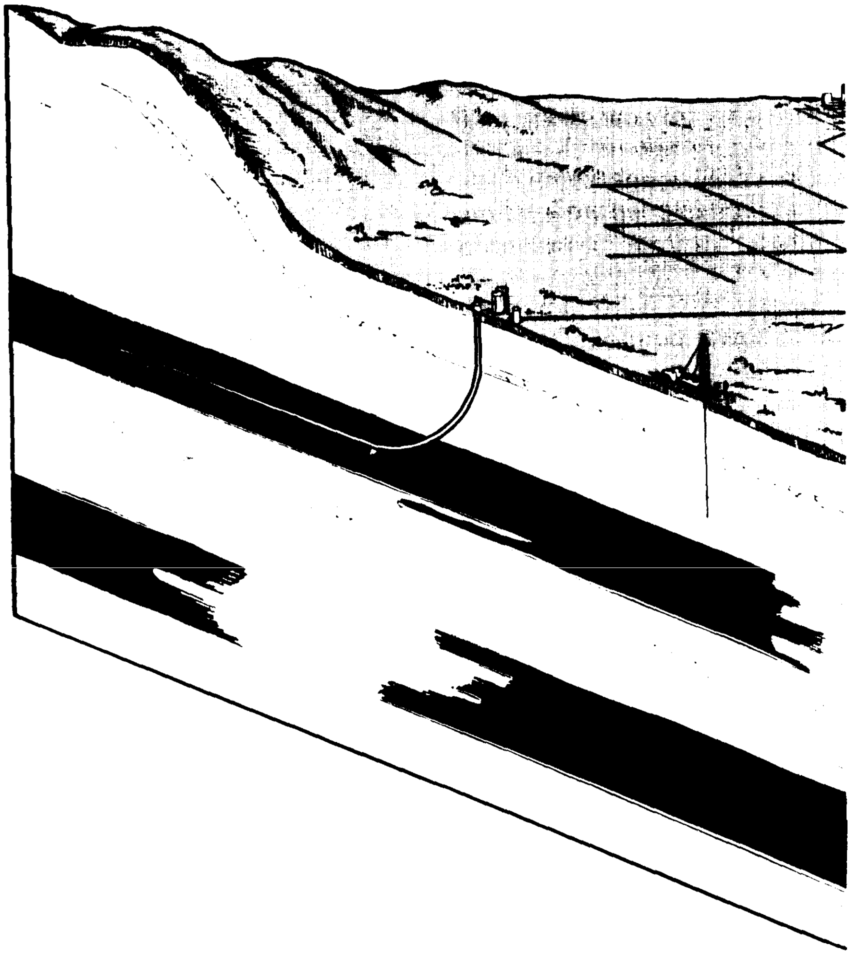
Where low permeabilities area problem, stimulation is used to increase the flow of gas to the well by increasing the area of the natural fracture system in contact with the wellbore. Hydraulic fracturing is the most common stimulation technique used. As with such treatments in the

[11] That is, completing the well by perforating the gas-bearing rock formation without first casing and cementing the wellbore in the vicinity of the formation.

[12] That is, producing from multiple seams with a single well.

[13] A major (but nontechnical) roadblock to substantial production of methane from these types of horizontal boreholes is that production may be dependent on the mine operation, If the mine were to close, the methane recovery operation might also be forced to cease. For example, at Kerr McGee's Choctau Mine in the Arkoma Basin, the coal seam methane production operation was completely set up, equipment installed, and approvals acquired when the mine was closed for lack of a coal market, Financing for a methane recovery project that is dependent on mine operation will tend to be difficult to obtain.

Figure 49.—Deviated Drilling Into a Coal Seam



SOURCE: Gas Research Institute.

Devonian shales, the most widely used fracturing fluids are nitrogen foam and water-based gel. A sized proppant may be included to hold open the newly formed fractures. The amount of each ingredient used **depends on the fracturing fluid pressure required, the coal seam thickness, the fracture length desired, and the cost. When the fluid injection is completed, the induced pressure is released and the well prepared for production.**

The effects of hydraulic fracturing may be entirely different in coals than in sandstone reservoirs. **An induced fracture** in sandstone will typically extend outward at substantial length from the well bore. Coal formation fractures are generally shorter and wider than sandstone fractures. The difference is attributed to the plasticity of the coal and dissipation of the compressional energy into the cleat system. [14]

Several problems may be encountered in stimulating coalbed wells. One is the tendency for proppant material to flow back into the well bore and create pump malfunctions during dewatering. Another problem is orienting the fracture to intersect rather than parallel the planes of the vertical fractures, or face cleat, in order to intersect as many fractures as possible. This may be difficult because the original stress field in the coal

[14] M. G. Doherty, "Methane From Coal Seams, " International Conference on Small Energy Sources, Los Angeles, CA, Sept. 9-18, 1981.

clearly favored fracture directions parallel to the face cleat. A third problem, pertaining to minable seams, lies in containing the fracture within the seam. Some mine operators feel that fracturing can cause structural damage to the roof rock, increasing the potential for mine collapse. Ongoing work by the U.S. Bureau of Mines is attempting to evaluate the extent to which this concern is valid.[15]

[15] M.A. Trevits, M.E. Hanson, and V. L. Ward, "Methane Drainage: Identification and Evaluation of the Parameters Controlling Induced Fracture Geometry," SPE/DOE Unconventional Gas Recovery Symposium, May 16-18, 1982.

Pumps

Water removal can in general be accomplished with existing pumping technologies, but the large amount of water that is produced during dewatering is a strain on pumping equipment and frequent maintenance is often required. pumps are also apt to become clogged with the coal fines remaining in the well after drilling. Dewatering deeper wells may require the development of larger capacity pumps. Nevertheless, solutions to these problems are more a matter of refinement of existing technology than radical innovation.

RECOVERABLE RESOURCES AND PRODUCTION POTENTIAL

The coalbed methane resource base is large but, like the other unconventional resources, the recoverable portion is significantly less than the gas-in-place. Economic and technological conditions are the primary factors governing the amount of the resource that will contribute to future supply. Other factors, such as legal and environmental issues, also are likely to influence coal bed methane production, particularly from minable coal beds. Even without the hard-to-predict effects of these other issues, however, the uncertainty associated strictly with technical issues is high. The NPC, in describing its estimates for the recoverable gas resource, calls them "a qualified and educated guess," and "nothing more than an order-of-magnitude projection based on current information."[16] Although the scientific understanding of coal bed methane production has improved in the last 4 years, no estimates of the economically recoverable resource have been made since the 1981 GRI estimate.

[16] National Petroleum Council, *Unconventional Gas Sources: Coal Seams*, June 1980.

Methodologies and Results

Estimates of the recoverable resource base have been made by the NPC (1 980), Kuuskraa and Meyer (1 980), and GRI (1 981). A variety of different economic and technology assumptions were used to obtain the estimates shown in table 59.

National Petroleum Council[17]

[n the NPC study, recoverable resources were calculated by identifying that portion of the resource that would yield sufficient production per well to cover the costs of an "average" well (with

[17] Ibid.

Table 59.—Comparison of Recoverable Resource Estimates

Technically or economically recoverable gas (TCF)					Assumptions
KM	40-60				30-45°/0 recovery of target resource of 135 TCF, no price constraints, but recoverable resource limited to bituminous seams >3.5 ft thick, subbituminous seams >10 ft thick
NPC	$2.50	$5.00	$9.00		Production costs define minimum production levels,
	5.0	25	45	10%\o ROR	which in turn define minimum economic thickness at 3
	2.5	20	38	150/0 ROR	MCFIDlft (bituminous), 1,2 MCF/D/ft and 0.6 MCF/D/ft
	2,0	17	33	200/0 ROR	(subbituminous and lignite, respectively) Gas is used onsite,
GRI	$3.00	$4.50	$9.00		Expert judgement
	10-30	15-40	30-60		Existing-advanced technologies

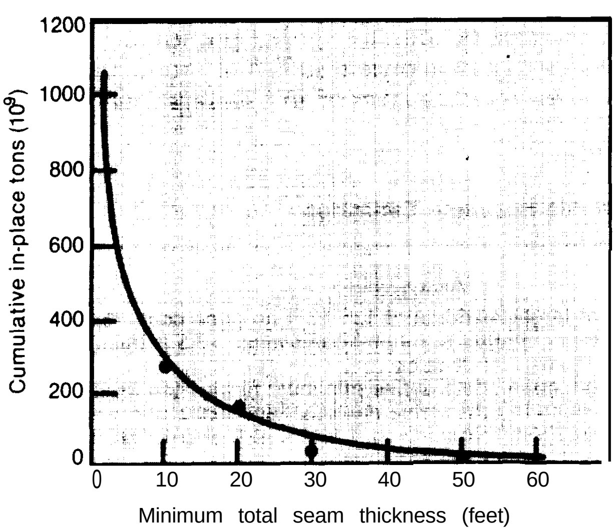
SOURCE Off Ice of Technology Assessment

a depth of 3,000 ft, 12-year well life, assumed 10 percent production decline rate, and 90 percent success rate). This was done by the following method:

1. Using county-by-county coal resource estimates, a distribution of the coal-in-place resource according to seam thickness was constructed for each grade of coal. The distribution for bituminous coal is shown in figure 50 as a plot of cumulative coal-in-place v. minimum total seam thickness.
2. By examining data on production rates per foot of seam thickness for existing wells, values of 3 MCF/D/ft (bituminous), 1.2 MCF/D/ft (subbituminous), and 0.6 MCF/D/ft (lignite) were estimated for the production rates per foot from the coal resource in place. Then, for each grade of coal, minimum total seam thickness was converted to minimum "per well" production rate. This rate can, in turn, be converted into minimum gas price necessary to pay for the well.
3. It is assumed that gas recovery will be 50 percent of the total gas-in-place in coal seams satisfying the minimum thickness criteria, and that a random 10 percent of the coal-in-place will not be available for drilling.[18] Using these values and the assigned values of gas content (200 cubic feet per ton for bituminous, 80 CF/t for subbituminous, and 40 CF/t for lignite), cumulative coal-in-place can then be converted to recoverable gas resource.
4. The final result is a relationship between the recoverable resource and gas price. The estimated recoverable gas resources for three gas prices, assuming the gas to be used onsite without compression, are shown in table 59.

[18]Neither of these values are further substantiated in the report.

Figure 50.—Estimated Distribution of Bituminous Coal by Seam Thickness



SOURCE: National Petroleum Council.

The report does not give results for the case where the gas is scrubbed, compressed, and gathered for delivery to a pipeline. However, comparison of plots of gas price v. necessary production rates for onsite use and pipeline sales (figs. 4 and 5 in the NPC report) imply that pipeline delivery will add approximately $1.00/MCF to production costs. The actual effect on producer incentives is not clear, however. On the one hand, it is not uncommon for pipelines to pay for gathering and compression costs, which reduces the gas price required by producers to make a profit. On the other hand, for existing coal bed methane projects, initial compression and gathering cost generally have fallen on the producers.[19]

Kuuskraa and Meyer[20]

A large portion of Kuuskraa and Meyer's gas-in-place estimate of 550 TCF was recognized as being within coal seams that were too thin or whose gas content per unit volume was too low to exploit. Assuming the favorable resource to occur only in bituminous coal seams greater than 3.5 ft thick and sub-bituminous seams greater than 10 ft thick, Kuuskraa and Meyer estimated that about 135 TCF of methane is present in the most favorable coal seams. The technically recoverable resource was determined to be 30 to 45 percent of the favorable resource, or 40 to 60 TCF, based on calculations of the amount of gas

[19]Vello Kuuskraa, Lewin & Associates, Inc., personal communication, 1984.

[20]V. A. Kuuskraa and R. F. Meyer, "Review of World Resources of Unconventional Gas," IIASA Conference on Conventional and Unconventional World Natural Gas Resources, Luxenburg, Austria, June 30-July 4, 1980.

that would desorb from the coal.[21] The KM estimate does not specify price constraints, but the thickness limits used to define the favorable resource do appear to imply a price range. Using basically the same methodology, a predecessor Lewin & Associates report[22] projected that 11 ft thick subbituminous seams in Colorado could be economically developed for gas production at $3.00 to $4.50/MCF in 1977 dollars, or about $5.00 to $7.00/MCF in 1983 dollars. Consequently, it seems likely that most of the 40 to 60 TCF of technically recoverable gas could be economically recovered at gas prices of $5.00 to $7.00/MCF (1983$).[23]

Gas Research Institute[24]

GRI estimated recoverable gas resources by polling experts to determine how much gas they thought was present at various price levels, using existing or advanced technologies. The results of this poll are given in table 59.

Estimate Comparison and Uncertainties

In general, the estimates of recoverable resources are quite similar, with the exception of the pessimistic NPC estimate for moderate priced gas (2.5 to 5.0 TCF at $2.50/MCF in 1979$ or $3.35 in 1983$). For high-priced gas, in the range of $5.00 to $10.00/MCF (1983$), a range of 20 to 60 TCF of recoverable gas would appear to agree well with all three studies.

In OTA's opinion, however, this apparent agreement should be viewed with caution. Of the three unconventional resources examined in this report, coal seam methane has the least production experience and the poorest data base to guide recoverable resource estimates. As a result, the two studies that used an analytical approach to estimating the recoverable resources—NPC and Kuuskraa and Meyer—use very broad assumptions and may be subject to considerable error,

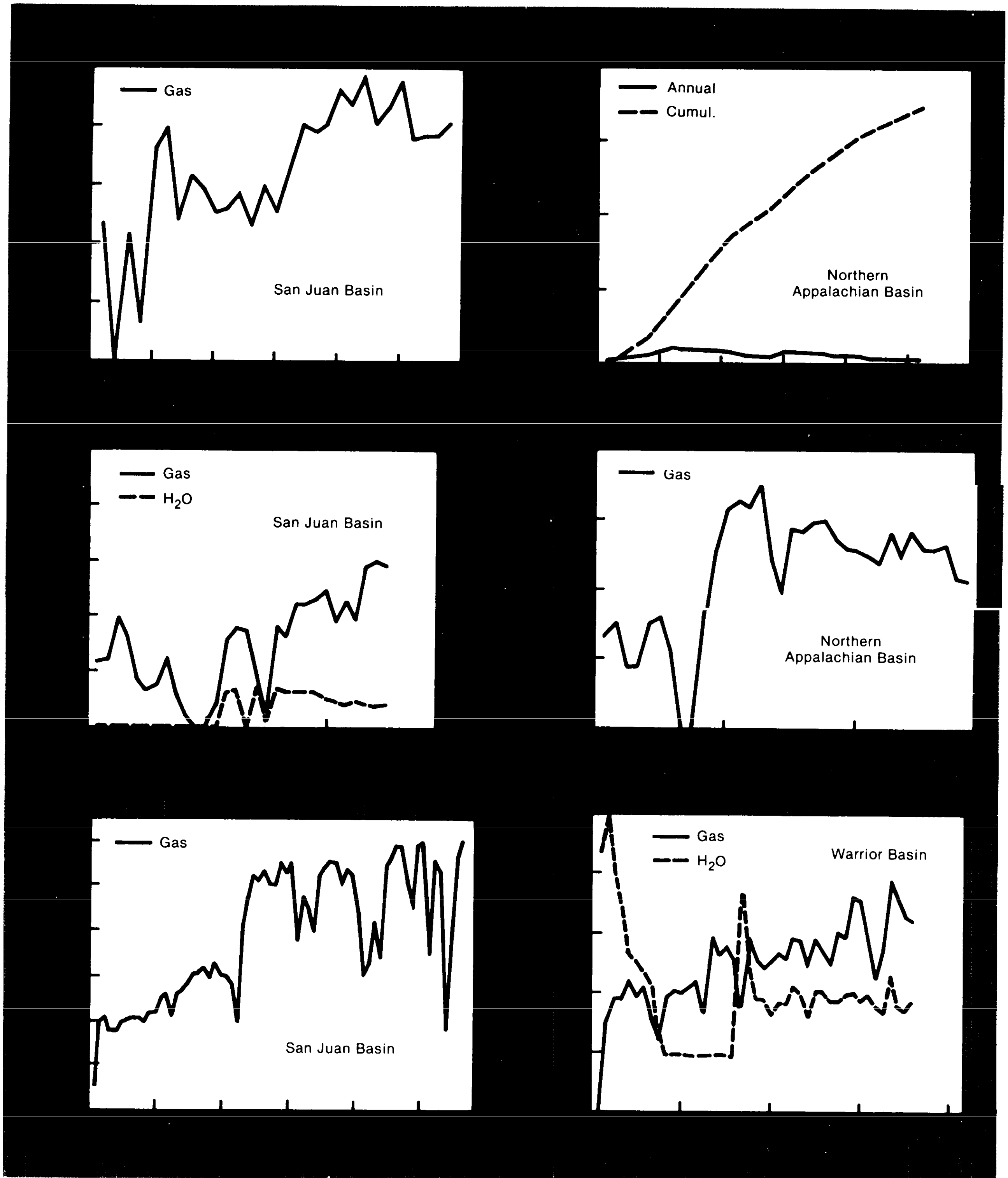
The NPC report has made several assumptions that appear vulnerable to error. For example, the assumption of a 50 percent average recovery of the gas-in-place appears to be unrealistically high. Seams in the Black Warrior Basin in Alabama currently being developed by U.S. Steel do appear to have a potential recovery of about 50 percent,[25] but this area is one of the **best** methane prospects at present. A second assumption, that historic values of production rates per foot of seam thickness can be used to project future production rates, is probably too pessimistic. The NPC report notes that they had been told that future close-pattern drilling will be more productive than existing wells, which for the most part are isolated and do not represent efficient gas recovery. Recent performance data and research results appear to verify this production behavior (see discussion on *Production Methods,* above). Another problem with the use of the historic data is that the values of production per foot of seam thickness vary widely and randomly both between and within separate coal beds. In the limited sample obtained by the NPC, production varied between O and 12.3 MCF/D/ft.[26] This wide variation implies that the use of an average can introduce substantial error into the calculation.

The NPC also has assumed that a well's gas production will experience an exponential decline from its initial flow rate. In reality, flow rates often have been observed to **increase over a period of time as water drawdown increases the reservoir** rock's relative permeability to gas and decreased pressure increases resorption from the coal surfaces. Figure 51 shows plots of production rates over time to illustrate this phenomenon.

The NPC calculations of minimum coal seam thicknesses for economic gas recovery at various prices appear to be conservative in comparison to their own data. For gas prices in the $2.50 to $5.00 (1 979$) range for onsite use (and, presumably, about, $3.50 to $6.00 for pipeline sale),[27] the estimated minimum coal seam thicknesses for

[21] Ibid.
[22] Lewin & Associates, Inc., *Enhanced Recovery of Unconventional Gas,* op. cit.
[23] Confirmed by Vello Kuuskraa, Lewin & Associates, Inc., personal communication, 1984.
[24] Gas Research Institute, *Position Paper; Unconventional Natural Gas,* May 1981.
[25] Vello Kuuskraa, Lewin & Associates, Inc., personal communication, 1984.
[26] National Petroleum Council, *Unconventional Gas Sources: Coal Seams,* June 1980, table 7.
[27] Because pipeline sale may require the producer to incur costs for compression, liquids removal, contaminants removal, etc.

Figure 51 .—Well Production Histories in San Juan and Other Basins



SOURCE: National Petroleum Council, *Unconventional Gas Sources: Coal Seams,* 1980.

bituminous coals range from 45 to 20 ft, corresponding to production levels of 135 to 60 MCF/D. The NPC data on actual wells, however, indicate that seam thicknesses in all cases examined were less than 25 ft and most were less than 10 ft, with production rates in all cases less than 70 MCF/D. Although the sales price of the produced gas and the profitability of the wells is not known, presumably some of these wells are profitable, and it does not seem likely that the prices paid for this gas could be much above the given range. This implies that the cost of these wells must have been lower than the NPC's calculated average well costs.

On balance, the examination of uncertain assumptions in the NPC study appears to indicate that their analysis may have been overly pessimistic.

The Kuuskraa and Meyer analysis differs substantially from the NPC analysis, especially because it **calculates recovery efficiency from an analysis of diffusion from the fracture network rather than assuming a recovery efficiency. This exposes the** KM analysis to some different kinds of uncertainties than those encountered by NPC. In particular, as noted in the earlier Lewin report,[28] the results are extremely sensitive to assumptions about the fracture intensity in the seams and the diffusion constant. For example, for Western coals, a change in the spacing between vertical fractures, from 1- to 5-ft intervals, reduces the 10-year recovery efficiency from 30 to 2 percent, essentially eliminating the economic recovery potential from these coals. Fracture intensity is not well-documented, especially for deeper coals.

Another potential problem with the KM analysis is that it is uncertain whether or not its simple diffusion model adequately represents the actual physical production mechanism in the coal seam. For example, the model and associated assumptions imply uniform production behavior across the seam, whereas in reality production behavior in existing coal seam methane projects (i.e., the Black Warrior development) has fluctuated widely from well to well.[29] This implies that we do not yet fully understand the gas production mechanism.

Because of the substantial remaining uncertainties and the lack of recent economic analyses that could take into account the latest understanding of the nature of the coal seam methane resource, OTA is reluctant to project a new estimate of the recoverable resource, However, in our opinion the NPC estimates for moderate prices–e.g., 2.5 TCF (at 15 percent rate of return) for gas prices of $2.50/MCF in 1979$ ($3.35/MCF in 1983$)—are overly pessimistic, and are based on past experience that does not reflect recent production capabilities associated with improved operating practices such as closer well spacing. What is critically needed is a reevaluation of the economics of recovering this resource given our better understanding of the resource and improved production methods. Information that would help such an estimate is a disaggregation of the resource base based on gas content as well as seam thickness. The data collected for the DOE basin analysis may be sufficient to provide the basis for a new analysis along these lines.

Annual Production Estimates

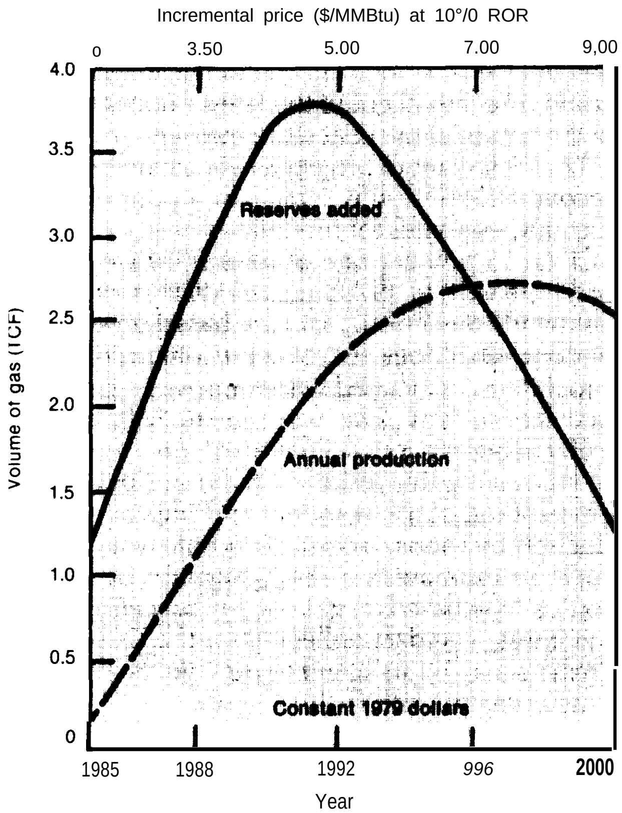
Both NPC and GRI calculated annual production estimates. NPC estimated annual production through the year 2000 for both production from vertical wells and from shafts with horizontal holes. The vertical well development scenario extends over a drilling period of 18 years with recovery of the resource for 28 years. The development schedule requires beginning with 80 rigs the first year and adding 80 rigs in each of the next 7 years, with each rig drilling 45 producing wells per year. The resulting annual production estimates are included in figure 52.

For production from shafts with horizontal holes, the NPC assumed that 50 shafts would be drilled in the first year, with a 20-percent increase in the rate of adding new shafts every year, At this drilling rate, a 22-year program would be required to recover the total projected gas resource

[28] Lewin & Associates, Inc., *Enhanced Recovery of Unconventional Gas*, op. cit.

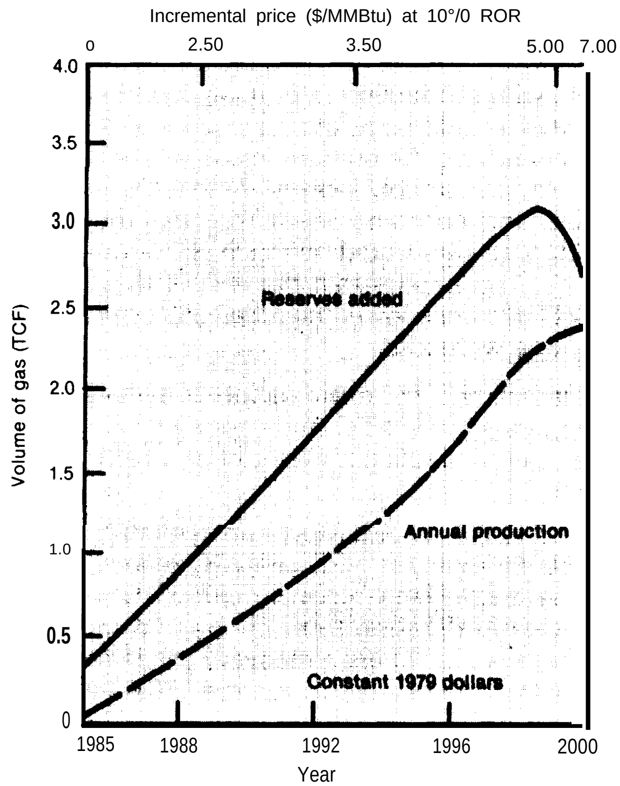
[29] Vello Kuuskraa, Lewin & Associates, Inc., personal communication, 1984.

Figure 52.—Annual U.S. Production Rates of Coalbed Methane as a Function of Time—Vertical Wells



SOURCE National Petroleum Council

Figure 53.-Annual U.S. Production Rates of Coalbed Methane as a Function of Time—Horizontal Wells



SOURCE: NPC.

in **a** period of 35 years. The annual **production** rates are depicted in figure **53.**

GRI used the recoverable resource estimates acquired from the poll and further assumed production and drilling rates. Production rates were estimated at 30 and 100 MCF/D for existing and advanced wells, respectively. The number of wells drilled per year was assumed to be 200 from 1983 to 1986 with a 10 to 15 percent increase per year thereafter. Utilizing the resource base as a limit, annual production estimates were calculated. The 1990 and 2000 production estimates are included in table 60.

The NPC study assumes that the gas price will increase steadily to $9/MCF (1 979$), Given current and expected future market conditions, this assumption appears unrealistic. On the other hand, if, as it appears, a majority of the recoverable resource can be recovered at prices on the order of $5/MCF (1979$), and if little is required in the way of technologic advances, increasing levels of production might still be expected. What is required is an increased level of producer interest-interest which at present is constrained by questions of ownership, mine safety, environmental concerns, and other institutional considerations. Some of these issues are discussed below.

Legal Constraints

Court decisions to date have attempted to resolve several legal questions associated with coal seam methane production, but without much success. Previous litigation has centered on the issue of resource ownership and whether the methane is a resource in its own right or an intrinsic part of the coal. The *U.S. Steel v. Hoge*

Table 60.–GRI Coalbed Methane Annual Production Estimates (TCF)

Market price (1979$/MCF)	*1990* Existing technology	Advanced technology	*2000* Existing technology	Advanced technology
$3.00	0.06	0.22	0.29	0.95
$4.50	0.07	0,23	0.35	1.2
$6.00	0.07	0.24	0.42	1.4

SOURCE GRI

case of March 1980 set a precedent on both these issues. Although lower court decisions determined that methane is a natural gas occurring in coal, and that the land owner owns the methane until the gas rights are released, in December 1983 the Pennsylvania Supreme Court reversed that decision, remanding ownership to the coal owner.

The recovery of coalbed methane on Federal coal lands also is burdened with unanswered legal questions. The current position of the Solicitor's Office of the Department of Interior is that ownership of a coal lease does not include rights to the coal bed gas, but that a reservation of gas does,[30] and that coalbed gas is leasable under the oil and gas leasing provisions of the Mineral Leasing Act. This position has not been tested in the courts, however. Drilling permits for coal seam methane recovery have been issued, although administrative delays are a problem.

Environmental Constraints

The primary environmental issue associated with coal seam methane production is disposal of the water produced with the gas in those coal seams characterized by high water contents. Since dewatering is a primary production requirement, large volumes of water must be pumped from the subsurface. The quality of the water varies from slightly acidic to slightly alkaline depending on the site location. The environmental regulations of the State determine whether the water must be treated, and such decisions will influence the economic viability of the recovery project.

[30]A detailed summary of the legal situation is presented in J. H. Kemp, "Coalbed Gas: Recent Developments in the Ownership and Right to Extract Coalbed Gas," *The Landman,* November 1982.

Institutional Barriers

There are other factors that will influence the contribution of coal bed methane to future supply. Institutional barriers characteristic of the coal industry will deter or possibly preclude production in some instances. A primary institutional barrier is the lack of interest exhibited by the coal companies. According to industry analysts, since the companies' primary interest is coal mining, they tend not to want to become involved in the more long-term nature of the methane production industry, particularly when the economics are marginal. Investment incentives may be required to create interest in producing the methane rather than venting. Alternatively, if new analyses demonstrate a real economic advantage to producing gas prior to mining, the coal industry may become more interested in overcoming problems created by the mining schedule. One problem with degassing prior to mining is the short time period between the beginning of gas production and the mine opening that has often been allowed. Numerous wells are required, incurring high capital costs which cannot be recouped without a longer production period.

Another institutional barrier to production is the strong concern with worker safety associated with coal mining. The issue of whether stimulation causes unacceptable damage to the mine ceiling has not been resolved. The Bureau of Mines initiated a program at four sites to determine the effects of stimulation. Due to various problems, however, work was completed at only one site. The site evaluation indicated that there were no adverse effects on the mining operation, but the limited extent of the test precludes extrapolation of the results to other sites. No firm evidence exists to link stimulation effects to mine collapse at numerous other operating facilities, but until the technique is proven not to cause damage, many companies will be reluctant to invest.

In OTA's opinion, the above uncertainties, coupled with the technical and economic uncertainties mentioned in the discussion of recoverable resources, imply that the current production projections are not adequate, and effort should be focused on establishing a new, more scientifically based estimate of the potential contribution of coal seam methane to future U.S. gas Supply.