PROSPECTS FOR COALBED METHANE DEVELOPMENT IN VIRGINIA

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INTRODUCTION

Contained in small coal seam fractures and released during mining, methane has long been the nemesis of underground mining operations, often creating hazardous, explosive conditions and requiring extensive mine ventilation. Out of necessity, underground coal operators have developed methods to degasify coal seams in order to ensure mine safety and productivity. Vast quantities of potentially usable methane gas are currently vented from deep coal mines in Southwest Virginia.

With the recent decline in domestic oil production, rising imports, imminent new environmental controls on utility coal emissions, and the halt in nuclear power development, many analysts look to natural gas as the incremental fuel of the 1990s. Advocates promote natural gas as a clean fuel -- readily available and relatively cheap. In response to expected markets for natural gas and the degasification needs of coal mining, U.S. energy firms are pursuing the commercial development of methane contained in coal beds. This development has been further stimulated by a federal tax credit for unconventional energy sources, available for coalbed methane through this decade, but only for wells completed before January 1, 1991.

Studies have shown that deep coal seams in Virginia's Buchanan and Dickenson counties are methane-rich. Prompted by these estimates; successful coalbed methane development in New Mexico and Alabama; and factors cited above, some gas and mining companies operating in the Southwest Virginia coalfields are looking seriously at commercial prospects. Indeed, one firm completed 12 commercial coalbed methane wells in 1989 and expects to develop an additional 30 to 50 wells in 1990.

However, certain barriers have stood in the way of widespread coalbed methane development in Southwest Virginia. A major issue is ownership -- is coalbed methane conveyed with coal ownership, with gas leases, or with surface land deeds? While this issue is complicated in other states, it has proven especially complex in Virginia. In a region dominated by severed estates, joint surface land ownership, and an often adversary relationship between surface owners and resource extraction industries, legal questions of ownership have been a serious constraint to large-scale coalbed methane development. Action by the 1990 Virginia General Assembly aimed to resolve some of these barriers, and has established a framework to expedite development within the time constraints of the tax credit.

This report reviews the prospects for commercial development of coalbed methane in Virginia. The first section summarizes recent studies on resource potential. The second describes production technologies and marketing options. The third discusses legal and institutional issues, including recent changes in the regulatory framework. The final section offers conclusions and recommendations for further study.

COALBED METHANE RESOURCE POTENTIAL

In 1977, the U.S. Department of Energy (DOE) established the Unconventional Gas Recovery Program to evaluate the potential for recovering gas resources from Devonian shales, tight gas sandstones, and coalbed reservoirs. A companion Methane Recovery from Coalbeds Project (MRCP) initiated in fiscal year 1978, was intended to determine the magnitude and distribution of coalbed methane, evaluate recovery potential, and generate interest in production and utilization by private industry (U.S. DOE, 1981). A major component of the project was the analysis of numerous sedimentary basins. Between 1979 and 1982, thirteen basins were analyzed by DOE contractor TRW Inc. in an attempt to determine the magnitude, distribution, and most favorable areas for potential coalbed methane production.[1] In many instances, this analysis included the first estimate of deep coal resources in individual basins; sampling and measurement of numerous coalbeds for gas content; and compilation of geological, hydrologic, and resource data to define areas of potentially high coalbed methane production (Rightmire, Eddy and Kirr, 1984).

The 13 basins (analyzed in separate "basin reports") are underlain by a coal-bearing strata covering a total of 235,420 sq. mi. Following the coal and coalbed methane resource assessment of these basins, high-potential areas were narrowed to 40,415 sq. mi., with a gas-in-place estimate ranging from 72 to 400 trillion cubic feet (Tcf) (Rightmire, Eddy and Kirr, 1984), compared to conventional U.S. gas reserves of 187 Tcf (U.S. EIA, 1988). The Methane Recovery from Coalbeds Project sparked considerable interest in methane recovery by the oil and gas industries, and provided much of the impetus for commercial development in the Warrior (Alabama), San Juan (Colorado), and Piceance (New Mexico) basins.

Recent studies conducted by ICF-Lewin Energy (Fairfax, VA) and sponsored by the Gas Research Institute (GRI) have provided more refined estimates of coalbed methane resources in the Warrior, Piceance, Northern Appalachian, Central Appalachian, and San Juan basins. Table 1 summarizes estimated coalbed methane resources in the 13 major U.S. basins.

The following section reviews the Central Appalachian Basin Report as well as the more recent ICF-Lewin study of Central Appalachia's coalbed methane potential, and concludes with summary comments on Virginia's resource potential.

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1 Basins included in the study are the Arkoma Basin (Arkansas and Oklahoma), Central Appalachian Basin (Maryland, West Virginia, Virginia, Kentucky, and Tennessee), Greater Green River Coal Region (Wyoming and Colorado), Illinois Basin (Illinois, Indiana, and Kentucky), Northern Appalachian Basin (Pennsylvania, Ohio, Maryland, West Virginia, and Kentucky), Piceance Basin (Colorado), Powder River Basin (Montana and Wyoming), Raton Mesa Coal Region (Colorado and New Mexico), San Juan Basin (Colorado and New Mexico), Uinta Basin (Utah and Colorado), Warrior Basin (Alabama and Mississippi), Western Washington Coal Region (Washington), and Wind River Basin (Wyoming).

Table 1: Estimated Coalbed Methane Resources in the Major U.S. Basins		
Basin	Area (in sq. mi.)	Estimated Gas-in-Place (in Tcf)
Arkoma	13,500	4
Central Appalachian*	5,000	5
Green River	21,000	31
Illinois	50,000	21
Northern Appalachian*	43,000	61
Piceance*	6,700	84
Powder River	25,800	30
Raton Mesa	2,200	30
San Juan*	19,000	88
Warrior*	6,000	20
Western Washington	6,500	24
Wind River	8,100	2
Unita	14,400	1
Total		**401**

* - Refined coalbed methane resource estimates provided by ICF-Lewin Energy studies; All other estimates provided by MRCP "basin reports."

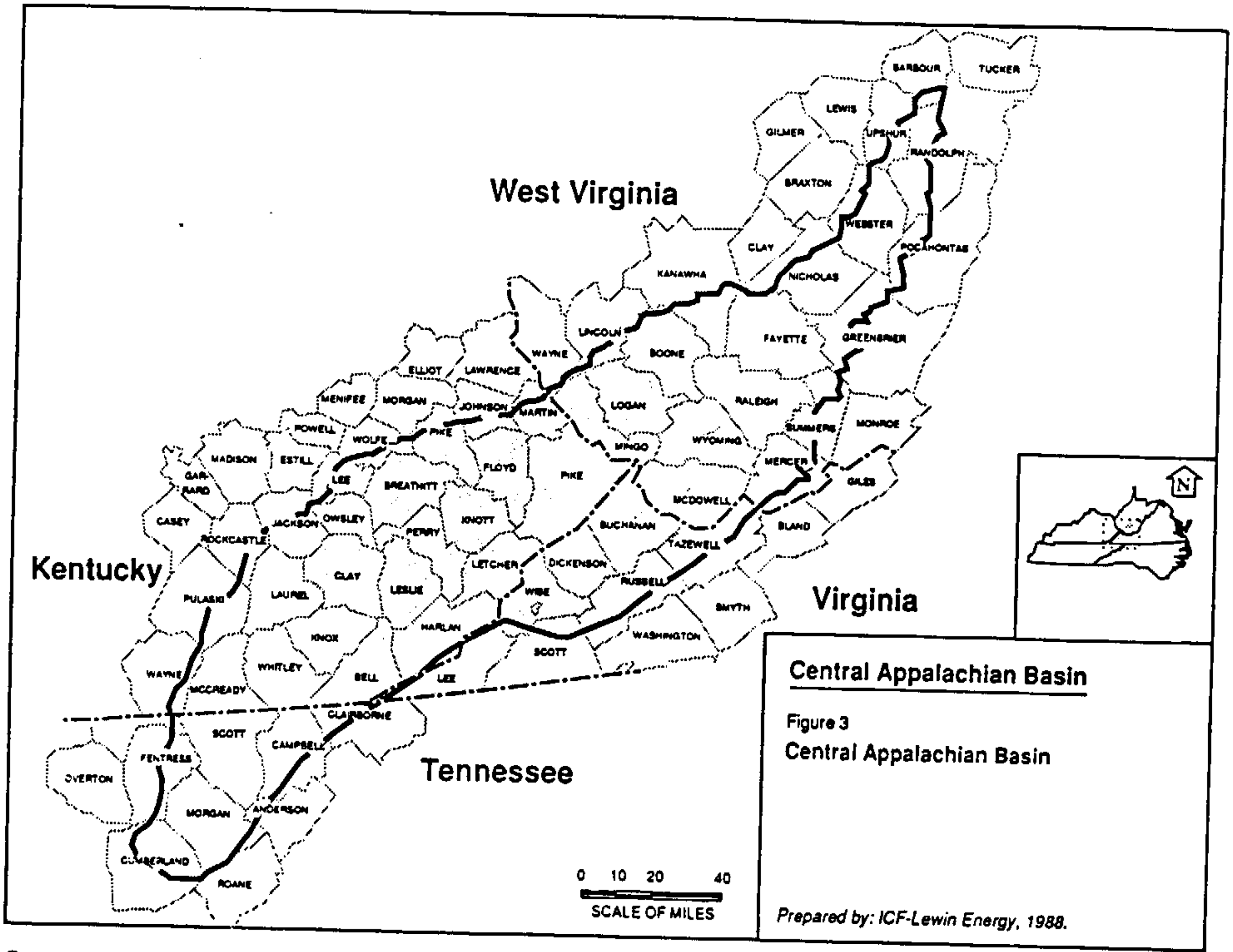
Source: *adapted from*: Ayers and Kelso, 1989

Central Appalachia Coalbed Methane Resources

The Central Appalachian Basin encompasses approximately 22,850 sq. mi., including portions of the Appalachian Plateau and the Valley and Ridge physiographic provinces. The region spans portions of eastern Kentucky, eastern Tennessee, Southwest Virginia, and southern West Virginia (Figure 1). Mississippian and Pennsylvanian strata underlying the basin claim numerous coalbeds that contain significant amounts of methane.

The MRCP report (Adams, 1982) was the first study of Central Appalachia's coalbed methane potential, estimating bituminous coal reserves at between 80 and 120 billion tons and in-place methane at 10 Tcf to 48 Tcf. A subsequent assessment by ICF-Lewin Energy Associates, Inc. (Fairfield, VA) (Kelfant and Boyer, 1988) estimated total in-place methane for six targeted Central Appalachian coalbeds at 5 Tcf.

Figure 1: Central Appalachian Basin



Source: Kelfant and Boyer, 1988

1982 Central Appalachian MRCP Report

The Central Appalachian Basin Report was completed in 1982 (Adams); a summary (Adams, 1984) appeared in a compilation of condensed versions of all thirteen MRCP reports (Rightmire, Eddy and Kirr, 1984). The information for analyzing and estimating coalbed methane was obtained from desorption data published in 1981 (Diamond and Levine); gas data from the USGS/R-9 well in Clay County, Kentucky; data from a horizontal borehole project at Island Creek Coal Co.'s Virginia Pocahontas No. 5 mine; Clinchfield Coal Co.'s Jawbone Coalbed Methane Drainage Project; and methane emission surveys from working mines made available by the U.S. Department of Labor's Mine Safety and Health Administration (MSHA).

According to the study, individual mines within five counties had total daily methane emissions of at least 1 million cubic feet (MMcf) in 1975. Citing a U.S. Bureau of Mines Information Circular (Irani, *et al.*, 1977), the study indicated that 57 mines in 18 counties recorded average measured methane emission rates of at least 0.1 million cubic feet per day (MMcf/d), and at least 10 mines within the basin were producing more than 1 MMcf/d from the Pocahontas #3 and #4 coal seams. Among these mines were five Island Creek Coal Co. mines in Buchanan County, Virginia, with combined methane emissions of more than 18 MMcf/d. Von Schonfeldt (1981) reported that seven Island Creek mines (Beatrice and Virginia Pocahontas #1 through #6) in the Pocahontas #3 seam (all in Buchanan County) emitted approximately 20 MMcf/d of methane from "gob"[2] gas vents and ventilation fans. This figure is astounding, considering that at that rate, emissions from Island Creek's mines alone totaled 7.3 billion cubic feet (Bcf) per year in the mid-1970s, or nearly half of Virginia's total 1988 natural gas production.

The MRCP report investigated desorption data published by Diamond and Levine (1981) that included 109 samples taken from 12 coalbeds within the basin. Significant amounts of methane were measured in 18 coal samples from the Pocahontas #3 seam in Wyoming County, West Virginia, and Buchanan County, Virginia. Gas content ranged from 285 to 573 cf/t, at depths between 778 and 2,143 ft.[3] Desorption tests performed on two core samples taken in 1978 from Clinchfield Coal Co.'s Jawbone Coalbed Methane Drainage Project indicated a gas content of approximately 280 cf/t.

Based on information published by Keystone (1980), Huddle, *et al.* (1963), USGS and USBM (1968), and other data, the MRCP report estimated Central Appalachian Basin bituminous coal reserves at between 80 and 120 billion tons. Emissions and desorption data indicated a methane content of coal from 125 cf/t to 400 cf/t. The in-place methane resource (coal reserves multiplied by methane content) was calculated at 10 Tcf to 48 Tcf. The estimate was based on in-place gas within the coalbed and does not consider gas influx from strata other than coal. Furthermore, the estimated range was derived from reserve estimates for all coal within the basin, irrespective of depth.

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[2] A "gob" is the caved-in portion of an underground coal mine created after coal is extracted.

[3] A more recent study reported methane concentrations greater than 600 cf/t for virgin coal from some Central Appalachian seams (Diamond, LaScola and Hyman, 1988).

Adams (1982) points out that coalbeds throughout the basin are numerous and generally discontinuous. These problems, in addition to limited gas content data, inhibit the accuracy and usefulness of the MRCP report's in-place gas estimates.

The MRCP report delineated a primary target area with the basin's greatest potential for coalbed methane development covering 4,000 sq. mi. in Southwest Virginia, eastern Kentucky, and southeastern West Virginia. The target area was based on emissions and desorption data that showed Pocahontas #3 and #4 seams having much higher methane content than other seams within the region.

1988 ICF-Lewin Energy Central Appalachian Study

A subsequent assessment by ICF-Lewin Energy (Kelfant and Boyer, 1988) of methane from coal seams in the Central Appalachian Basin differed from the MRCP report's methodology in two significant respects. First, specific gas content values were assigned based on the rank[4] and depth of individual coalbeds. Second, only those coalbeds estimated to contain significant quantities of producible methane were evaluated in detail. Two of the most important factors that influence the producibility of methane from coalbeds are gas content and reservoir pressure, both of which are depth dependent. Therefore, only coal seams consistently more than 500 feet below regional drainage were evaluated.

Figure 2 provides average methane content values (in cf/ton) for all counties within the boundaries of the Central Appalachian Basin. The figure shows that the deeper coalbeds of the Pocahontas and New River/Lee Formations in southeastern West Virginia and Southwest Virginia contain significantly more gas than other coalbeds within the basin. The study area in the ICF-Lewin report was confined to the areal extent of coalbeds that have a minimum of 86 cubic feet/ton of gas (for high-volatile coal) and a minimum reservoir pressure of 215 psi (hydrostatic gradient of .43 psi/ft multiplied by 500 ft). This methodology defined a study area covering portions of southeastern West Virginia and Southwest Virginia — approximately one-fourth of the Central Appalachian Basin. The study area encompassed six target coalbeds[5] with a total areal extent of 11,300 sq. mi., and a drillable area of 5,750 sq. mi. In terms of total coal volume, the study evaluated approximately 15 percent of the Central Appalachian Basin's estimated coal reserves (15 billion tons of an estimated total 80 to 120 billion tons), assuming that a major portion of reserves are shallow and do not meet the study's pressure criterion.

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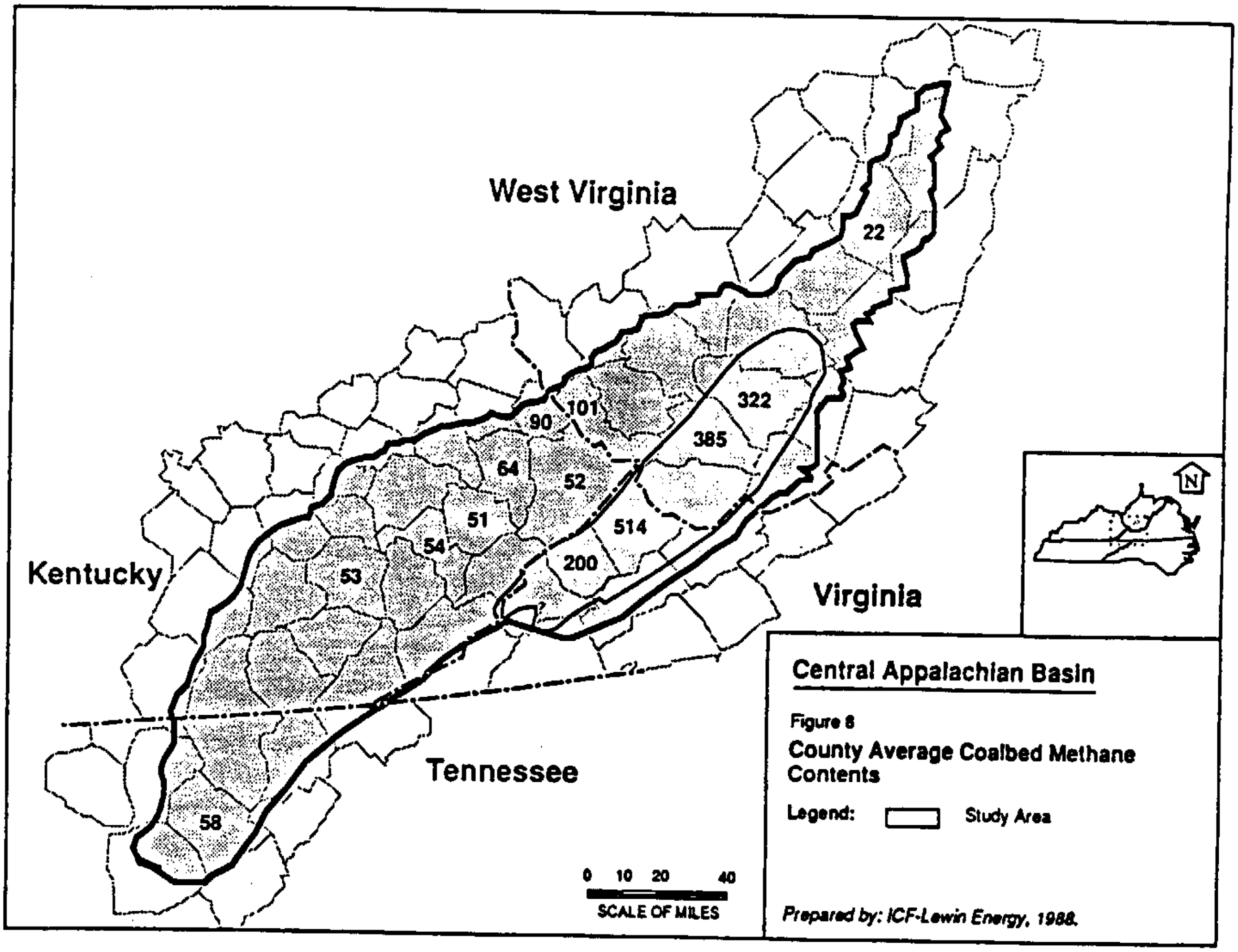
[4] The "rank" of coal is based on the extent of coalification, which is the process of coal formation from peat to lignite, progressing to sub-bituminous, high-volatile bituminous, medium-volatile bituminous, and low-volatile bituminous, and finally to semi-anthracite and anthracite coal. The greatest quantity of methane is generated during the transition from medium- to low-volatile bituminous coal. During this process, the coal may produce more methane than it can hold. Expelled gas may become trapped in conventional reservoirs adjacent to the coal seam, while the gas retained in the coal is coalbed methane. In general, the higher the rank of the coal, the lower its volatility, and the greater its methane content.

[5] Iaeger/Jawbone, Sewell/Lower Seaboard, Beckley/War Creek, Fire Creek/Lower Horsepen, Pocahontas No. 4, and Pocahontas No. 3.

Figure 2: County Average Gas Content Values in the Central Appalachian Basin (in cf/ton)



Source: Kelfant and Boyer, 1988

The total gas-in-place of the six target coalbeds was estimated at 5 Tcf. Based on possible errors in determining gas content, coal thickness, and drillable area, and using conventional statistical methods to determine variance, the range for gas-in-place was estimated at 4.2 to 5.4 Tcf, with a confidence interval of 80 percent.

The area of highest methane development potential (target area) is an elliptical expanse covering 3,000 sq. mi. in Southwest Virginia and southeastern West Virginia that is estimated to contain slightly more than 4 Tcf of in-place gas. The area coincides with the thickest target coalbeds that occur at depths of 1,000 to 2,000 feet (Kelfant and Boyer, 1988).

The Pocahontas #3 coal seam, stratigraphically the deepest evaluated, contains an estimated in-place methane resource of 1.6 Tcf, while the Pocahontas #4 seam, which lies approximately 75 feet above the Pocahontas #3, contains an estimated 1.1 Tcf. The Beckley/War Creek and Fire Creek/Lower Horsepen seams have estimated gas resources of 1.0 Tcf and 0.7 Tcf, respectively. The two shallowest coalbeds evaluated, the Iaeger/Jawbone and Sewell/Lower Seaboard seams, contain an estimated 0.2 Tcf and 0.4 Tcf, respectively (Kelfant and Boyer, 1988). The authors emphasized that the gas-in-place total of 5 Tcf represents only the target coalbeds described in their report. Other Pocahontas and New River/Lee Formation coal seams in the basin are generally thin and discontinuous, but in places are up to 5-feet thick, and may provide additional completion targets. The authors estimate that if these minor seams were included in their resource assessment, they would contribute an additional 0.6 Tcf of methane.

Comparison of Findings

The results of the two studies regarding the potential coalbed methane resources in the Central Appalachian Basin are summarized in Table 2.

Table 2: Comparison of Studies on Coalbed Methane Resources of Central Appalachia

	Kelfant and Boyer (1988)	Adams (1983)
Total Study Area	5,750 sq. mi.	22,850 sq. mi.
Total Coal Tonnage	15 billion tons	80-120 billion tons
Gas Content	86 to 650 cf/t	125 to 400 cf/t
Gas-in-place	5 Tcf	10-48 Tcf

Source: *adapted from*: Kelfant and Boyer, 1988

The ICF-Lewin report (Kelfant and Boyer, 1988) was more refined than the earlier MRCP report (Adams, 1982), thus providing more reliable results. While Adams did not consider depth, Kelfant and Boyer assumed a 500-foot minimum depth for producible seams based on pressure needs and reduced natural degassing. This factor reduced coal quantities available for methane production to about 15 percent of Adams' estimate. While Adams assigned gas content values to coal irregardless of depth, Kelfant and Boyer assigned values based on depth. Kelfant and Boyer thus argue that Adams' methodology greatly overestimated the basin's potential producible methane resources.

Resources in the Valley Coal Fields

A second potential area for coalbed methane production in Virginia is the Valley and Ridge Province of Pulaski and Montgomery counties, which contain the geologically oldest, commercially mined coals in North America. Reports of high gas content in Valley and Ridge coals led the Virginia Division of Mineral Resources (DMR, Charlottesville) to initiate an evaluation of the coalbed methane resource there. The project attempted to obtain reliable data on subsurface coal elevations, thickness, quality, and gas content. In 1982, three exploratory diamond core holes were drilled near Price's Fork, Sunnyside, and Merrimac in Montgomery County. Based on gas desorption tests of coal samples obtained during drilling, in-place gas was estimated at 3,220 Mcf/acre within the study area (Stanley and Schultz, 1983).

A preliminary economic feasibility analysis concluded that a coalbed methane resource potential exists for future development if one or more of the following criteria could be met: 1) discovery of thick coal-bearing intervals with similar gas contents in other parts of the Valley coalfields; 2) higher coalbed methane contents; and 3) significantly increased profit margin from reduced development costs and/or increases in gas prices (Stanley and Schultz, 1983). The DMR report noted that because of the complex geologic setting of the Valley coalfields, extreme variability of coal thickness, and paucity of subsurface data, further drilling would be necessary to accurately assess the economic potential of coalbed methane beyond the study area.

Since 1985, the New River Gas Co. and its affiliate, Valley Basin Gas Associates, have drilled four wells into the region's semi-anthracite coal. Given complex geological conditions, additional drilling is needed to define the structure and ultimate methane potential. Since termination of a joint venture with AMOCO, New River Gas Associates have been conducting virgin seam and post-stimulation testing, and produced-water analysis. Gas content (ash-free basis) exceeds 600 cf/t (Goldsmith, 1989).

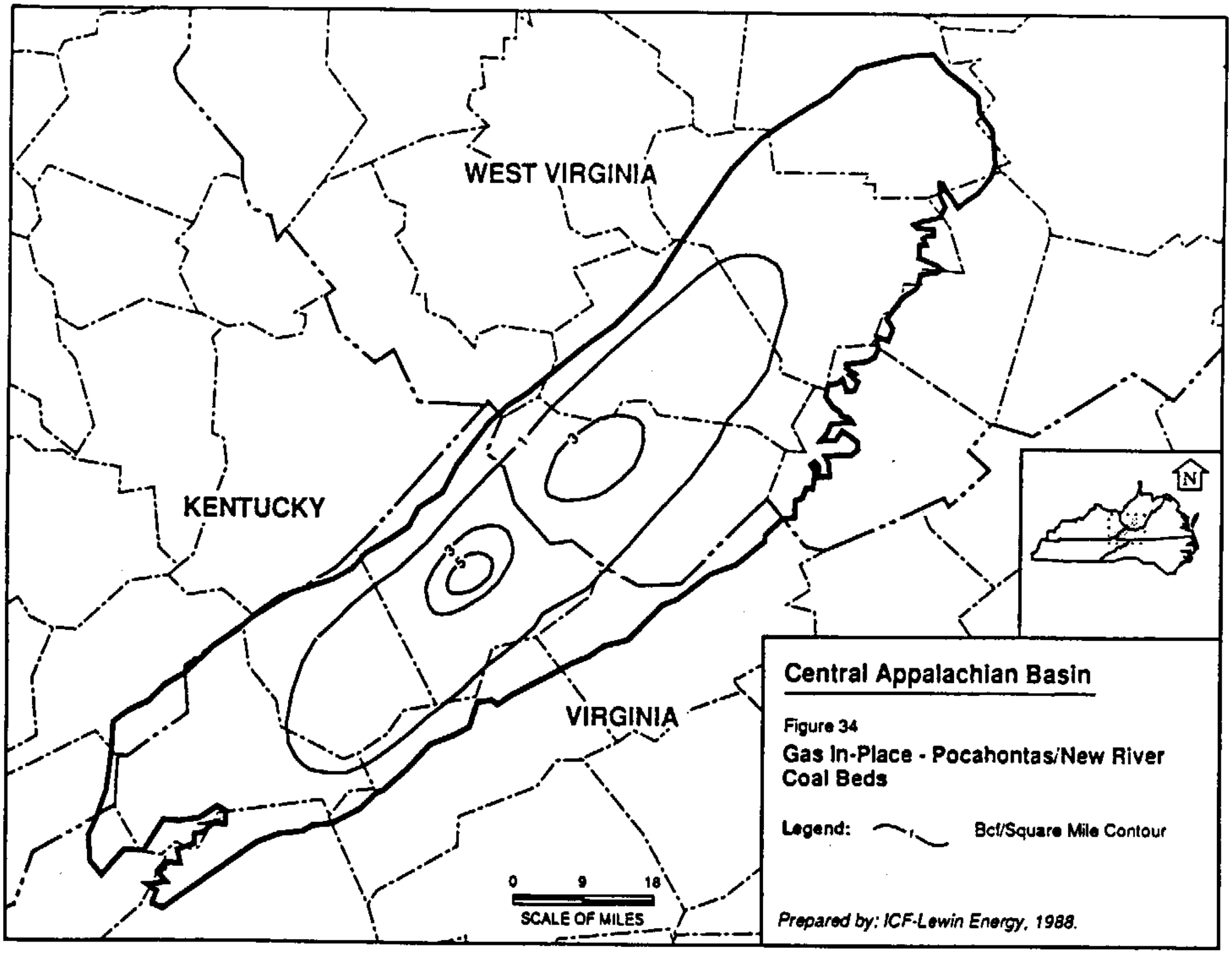
Summary of Virginia's Coalbed Methane Resource

The first study of coalbed methane production potential in the Central Appalachian Basin (Adams, 1982) estimated the in-place methane resource at 10 Tcf to 48 Tcf. A subsequent, more refined assessment conducted by ICF-Lewin Energy Associates, Inc. (Kelfant and Boyer, 1988) estimated the total in-place gas of the basin's six target coalbeds (an area one-fifth the size of Adams study area) at 5 Tcf.

The deeper coalbeds of the Pocahontas and New River/Lee Formations in southeast West Virginia and Southwest Virginia contain significantly more methane than other coalbeds in the basin. Figure 3 is a generalized contour map of the total in-place gas for the Central Appalachian Basin, showing that the area of highest methane concentration lies in Buchanan County, Virginia, and McDowell and Wyoming counties, West Virginia. The area represents that portion of the basin where target coal seams are thickest and between 1,000 and 2,000 feet below the surface -- depths comparable to those in Alabama's Warrior Basin, where commercial quantities of coalbed methane are being produced (Kelfant and Boyer, 1988). Figure 3 also shows that the highest concentration of coalbed methane is concentrated in Buchanan County, Virginia.

Finally, additional drilling in Virginia's Valley coalfields (Montgomery and Pulaski counties) may provide estimates of the coalbed methane resource that can be commercially recovered in that region.

Figure 3: Generalized Contour Map of Total Gas-in-place for the Central Appalachian Basin



Source: Kelfant and Boyer, 1988

COALBED METHANE EXTRACTION TECHNOLOGIES

This section describes several technologies involved in successful coalbed methane development. Development experience in New Mexico and Alabama continues to provide technical advances that are reducing costs and increasing the economic attractiveness of coalbed methane extraction. Included are basic methods for accessing coalbeds; drilling techniques; methods of stimulating gas flow; and pollution control of well water discharge.

Methods of Accessing Coalbed Methane

There are three ways to access coal seams for methane production. First are standard, vertical wells drilled from the surface. While they need not be associated with mining, they are commonly used to reduce methane levels in advance of underground operations. Second and third are "gob holes" drilled into mined-out areas; and in-mine, horizontal boreholes into coal seams. Both are associated with mining operations and are primarily degasification technologies, not development methods.

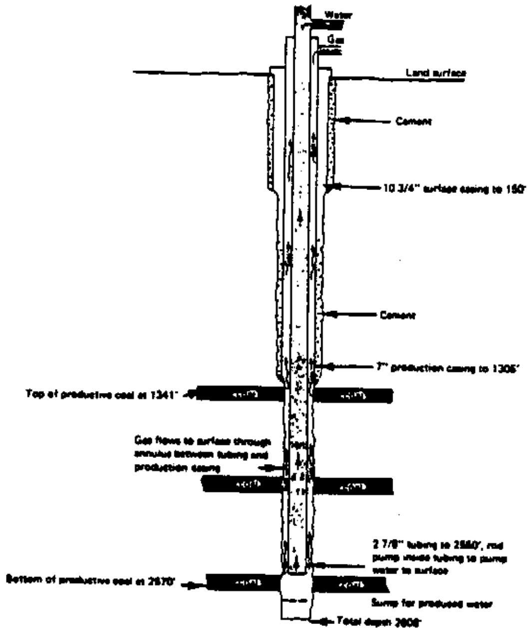
Standard Vertical Wells

Standard vertical wells provide the principal means of coalbed methane development. They can access coalbeds through "open-holes," "cased-holes," or a combination of the two. Open-hole wells to single or multiple seams are much like conventional natural gas production methods, and were preferred in early coalbed methane development. In these completions, the production casing is set, or cemented, in place immediately above the uppermost coalbed that is to be tapped for production. For example, Figure 4a shows the Reichhold Chemical 3-11 No. 2 well in Alabama's Warrior Basin, which has a production casing extending to 1,305 feet, leaving the well bore open to a total depth of 2,608 feet. The gas-producing horizon includes coalbeds from 1,341 to 2,570 feet. While open-holes work well in conventional natural gas development, they are less effective in the unique conditions of coalbeds, especially when attempting to access multiple seams. They do not provide the necessary isolation of productive zones, and can expose the well bore to damaging pressure and debris during stimulation (Lambert, *et al.*, 1989).

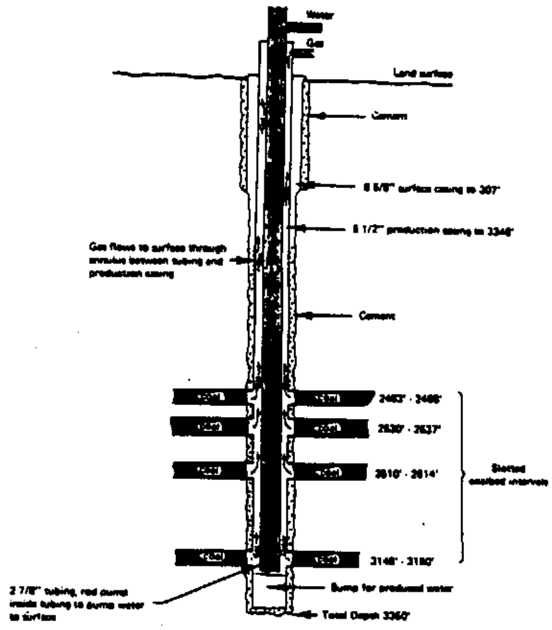
As a result, these first-generation wells have given way to more advanced methods of accessing multiple seams. In "cased-hole" completions, the production casing is set through the productive coalbeds penetrated by the well bore. The casing is selectively perforated or slotted to provide transmission paths between coalbed and well bore. Use of light-weight casing cement can reduce the potential for cement contamination of the coal seam (Graves, 1983). Figure 4b shows an example of a cased-hole completion, the AMPOCO 25-14 No. 5 well, where the production casing is set at a total depth of 3,350 feet and slotted to allow access to target coalbeds.

A variation is the "cased/open-hole" completion, in which at least one coalbed is completed through casing and at least one is completed in open-hole. Figure 4c shows the Alston No. 13-1-3 well. This cased/open-hole completion was drilled to a total depth of 2,955 feet and the production casing set at 2,850 feet. Three coalbeds were accessed through slots in the cased portion of the hole,

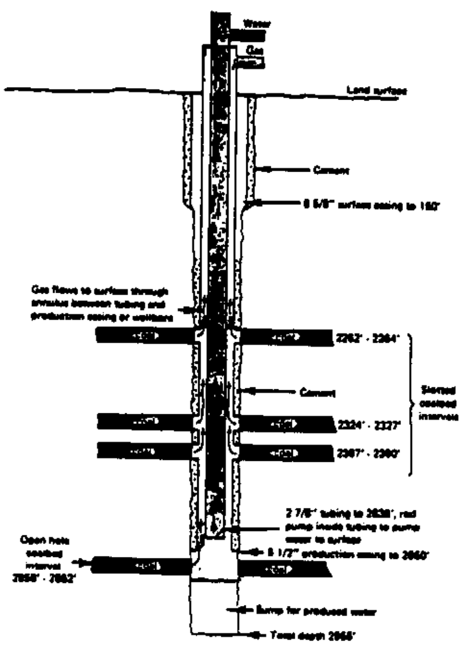
Figure 4: Examples of Well Completion Methods



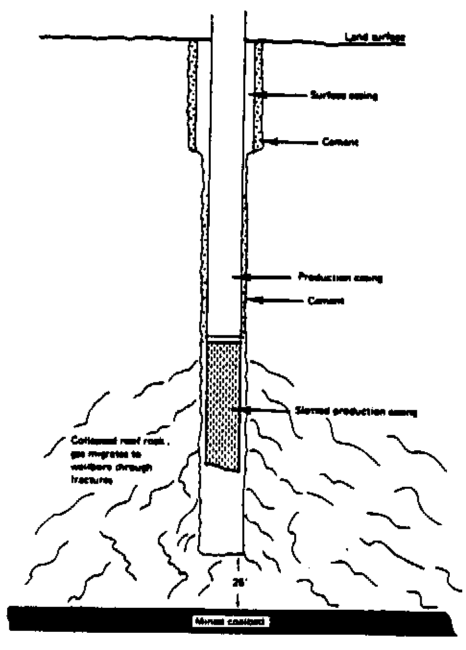
a) Open-hole Well Completion



b) Cased-hole Well Completion



c) Open/Cased-hole Well Completion



d) "Gob Hole" Well

Source: Sexton and Hinkle, 1985

while one coalbed was accessed in the open hole interval (Sexton and Hinkle, 1985).

Recent methane development experience in the Warrior Basin has demonstrated the advantages of "perforated" over "slotted" casing openings to coal seams. Though slots have larger openings to the seams and thus will not be as easily clogged or "screened-out" by loose coal, perforations provide greater flexibility and control during stimulation, fewer casing failures, and less movement of propping agent out of the seam after fracturing (see discussion on fracturing below). Lambert, *et al.* (1989) conclude that slotting is useful for initial test wells, while perforations are better suited for large development applications; open holes are not adequate for any multiple seam completions.

Before methane gas can be extracted, water contained in the coal seam must be removed (see discussion of water discharge control below). In all three examples of vertical well completions illustrated in Figure 4, the bottom of the well acts as a sump for water drainage from the coal seams. Water is pumped from the bottom of the well to the surface through a 2-7/8 inch tube.

Gob Holes and Horizontal Boreholes

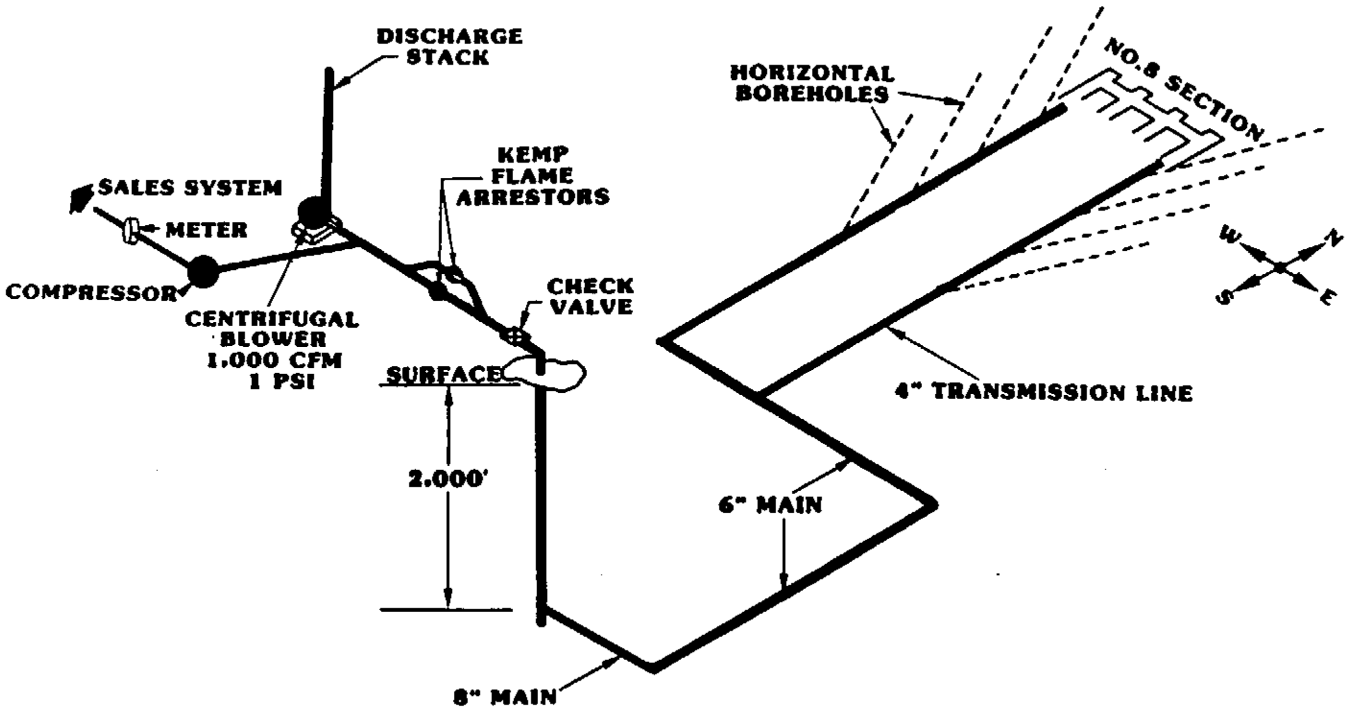
Gob holes are wells designed to draw off coalbed gas that accumulates in mined-out areas, especially gobs associated with complete extraction technologies such as longwalls. Gob hole wells are drilled into roof rock that has collapsed or will collapse as a result of underground mining. Fractures induced by the roof-fall liberate methane from the coalbeds and provide paths for gas migration through the collapsed material. Figure 4d shows an example of such wells at Jim Walter Resources No. 4 and No. 7 mines in Alabama (Sexton and Hinkle, 1985; Rodgers, 1989). Because methane is distributed by mine ventilation air, the gas produced from gob holes tends to have a lower Btu content than that from standard vertical wells and horizontal boreholes.

Horizontal boreholes provide another method for recovering coalbed gas associated with underground coal mining operations. Used extensively in major Appalachian mines to degasify coalbeds in advance of mining, horizontal boreholes can improve the efficiency of coalbed gas removal and reduce the number of vertical wells necessary for degasification. Boreholes are confined to the seam and do not penetrate strata immediately above or below the coal. Figure 5 illustrates horizontal boreholes drilled in Alabama's Oak Grove Field. Boreholes approximately 3-inches in diameter and from 200 to a few thousand feet in depth are drilled, then cased with slotted plastic pipes that allow methane to flow into the pipe. The gas is collected through an underground piping system connected to a vertical cased well that then transmits the gas to the surface (Sexton and Hinkle, 1985; Rodgers, 1989).

Drilling Techniques

Vertical coalbed gas wells are generally drilled with air-rotary rigs. Air is used to prevent drilling fluid contamination of the coalbeds, which could have adverse impacts on gas productivity. In fact, the low formation pressures and fracture gradients characteristic of coalbeds do not require drilling fluids for

Figure 5: Horizontal Borehole Degasification



Source: Rodgers, 1989

pressure control. Cost advantages of gas-rotary rigs include increased penetration rates and reduced drilling times (Sexton and Hinkle, 1985). However, when access water flows are encountered during drilling, penetration rates can be severely reduced, necessitating use of a booster air compressor or more conventional rotary techniques (Lambert, *et al.*, 1989).

Hydraulic Fracturing

After drilling and casing a coalbed methane well, the seam must be fractured to induce or stimulate gas flow. The major challenge in coalbed methane development is releasing the methane from the coal and prompting migration to the well bore. Some methane is present in bed voids and fractures; but the vast majority is adsorbed in a mono-molecular layer on the coal surfaces. Although the layer is micro-thin, coal is highly porous, with a tremendous total surface area (approximately 1 billion sq. ft. per ton); thus, a significant amount of methane can be held. To release the methane, hydrostatic pressure on the coal must be reduced to near atmospheric levels by removing water, with avenues provided for both water and methane to migrate from the coal seam.

Hydraulic seam fracturing involves injection of fluids (water, gels, or foams) and a propping agent or "proppant" (usually sand) into the coalbed; application of pressure widens natural fractures and creates new ones that are held open by the proppant after pressure is released. These fractures provide pathways for gas to migrate to the wellbore (Sexton and Hinkle, 1985). Because coal seams have relatively low permeability compared to conventional gas reservoirs, methane recovery requires low operating pressures. Hydraulic fractures must be designed for low pressure operations, and thus must provide greater induced fracture length and conductivity than conventional gas stimulation. If higher pressures are encountered during fracturing due to very low coal permeability, high stress, or "screenout," fractures will be wider but shorter, resulting in reduced methane release and production. Flexibility is important in the stimulation process, allowing the operator to change fracture design if high pressures are encountered (Lambert, *et al.*, 1989).

The coal industry in Virginia has raised concern that hydraulic fracturing may adversely affect the mineability of coal seams. However, citing Diamond and Oyler (1987), who showed that such problems have not materialized in Alabama, von Schonfeldt (1989) stated that this "major technical issue appears to be resolved." However, von Schonfeldt (1990) and Young (1990) caution that the experience in Alabama may not be directly applicable to Virginia's coalfield geology.

Production

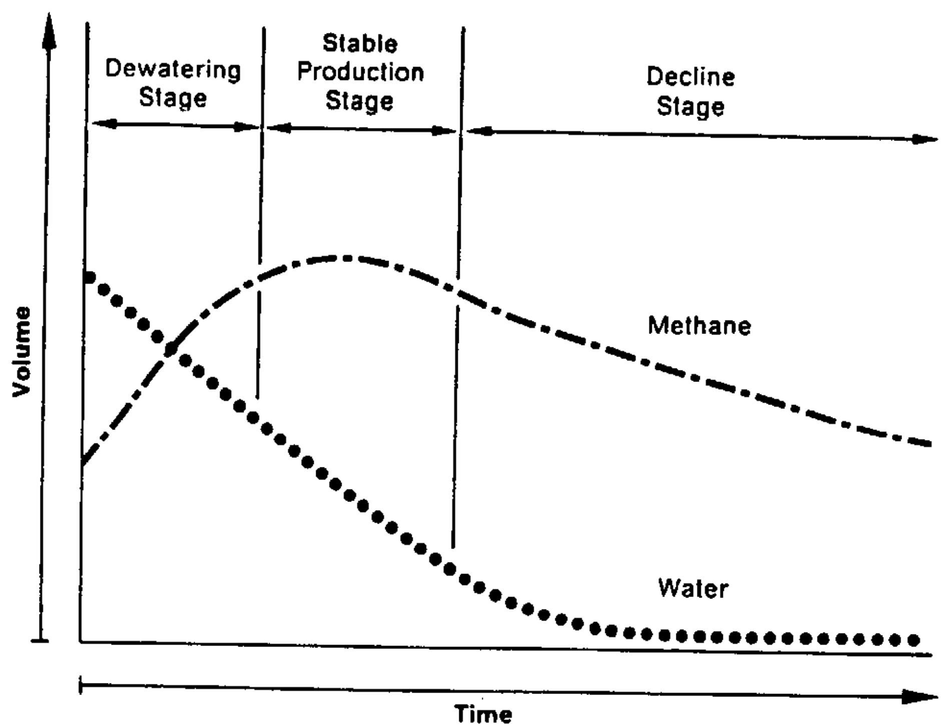
After a well has been drilled and the coal seam stimulated, it is prepared for production. Generally, the well must be cleaned out of back-filled sand (excess proppant from fracturing), and tubing string (for water removal) and pumps installed. As mentioned above, before significant volumes of gas can be recovered, the coalbeds must be dewatered. Because gas is trapped in coal by molecular adsorption, coalbed gas reservoirs behave differently from conventional reservoirs. In conventional natural gas reservoirs, hydrostatic pressure tends to move gas through the formation and into the well bore.

However, in coalbed reservoirs, hydrostatic pressure holds gas within the coalbed. As long as the water pressure is greater than gas pressure, only water will be produced (Kindley, 1982). Thus, coalbed water must be pumped out -- up the tubing string -- allowing gas to flow upward through the casing-tubing annulus (see Figures 4 a, b, and c).

Figure 6 illustrates the production stages of a coalbed methane well. The volume of water produced is usually highest during initial production, and generally decreases as production continues. In contrast, methane output is generally low during the initial stages and as dewatering of the coalbed progresses, gas production reaches a peak and then declines with time (Sexton and Hinkle, 1985; Kuuskraa and Brandenburg, 1989).

Coalbed methane is produced at low pressure, on the order of 15 psig. Gas-water separators are generally connected to individual wells to remove moisture from the gas upon reaching the surface. Subsequently the gas must be compressed to approximately 300 to 500 psig and additional moisture removed by a dehydrator before it can be introduced into a gas transmission line (Sexton and Hinkle, 1985). Lambert and Graves (1989) review specific production equipment options and those selected in the 144-well Taurus/Energen Alabama Methane (TEAM) Project.

Figure 6: Production Stages of a Coalbed Methane Well



Source: *adapted from*: Kuuskraa and Brandenburg, 1989

Well Water Discharges and Control Options

In most cases, after the effects of well drilling are overcome, the quality of water produced remains constant through the life of the well, and in general is no lower in quality than water produced from coal mining operations. While mining operations most often remove all water present in a coal seam and adjacent strata, coalbed methane production generally reduces water saturation of a stratum to no lower than 40 percent. Thus, only about 60 percent of coal seam water must be considered in methane development control options.

In cases of shallow coalbed methane, water produced in conjunction with the gas may be potable and used for irrigation and other agricultural purposes, or permitted to flow into nearby stream drainages with no detrimental effects on water quality at any time of the year. However, in areas where coalbeds are deeper, the water contains higher levels of total dissolved solids (TDS), such as chlorides (University of Alabama, 1983). Levels as high as 30,000 to 50,000 milligrams per liter (mg/l) are not uncommon. In Virginia, Equitable Resources Exploration (EREX) has encountered levels as high as 70,000 to 120,000 mg/l (Kelley, 1989). In addition to TDS, other constituents of methane-well produced water include iron, manganese, and other metals. Alternatives for handling this water include land application, release into surface streams, deep well injection, and treatment through reverse osmosis. Only land application and release to streams have been demonstrated to be cost-effective, but increasing attention has been given to deep-well injection (Simpson, 1989).

Land Application of Produced Water

In land application, partially treated or untreated effluent (produced water) is released into designated areas at specified rates. In some cases mutual benefits may be obtained by adding nutrients to the land area or enhancing ground water supplies, but the presence of metals and total dissolved solids, especially chlorides, may have detrimental effects. For example, chlorides upset the osmotic balance of plant root systems (preventing water and nutrient uptake from the soil) and alter soil chemistry, making soils unstable or spongy. While changes in vegetation and soil characteristics may occur during the life of a coalbed methane operation, these effects are generally localized. Furthermore, as observed in Alabama where water produced from AMPCO test wells was applied to land, these changes are often reversible, and may cause no lasting damage to vegetation or soils.

Experience in Alabama has shown that coalbed methane wells can produce several hundred barrels of water per day during initial production. Von Schonfeldt (1990) believes that while this may be true for some regions, quantities will be less for coalbed methane wells in Southwest Virginia. Whatever the initial water generation, quantities decrease as gas production increases. Thus, it may be feasible to alternate water release with periods of drying to allow maintenance of normal vegetation and soil conditions. Some consideration has also been given to wetland application of effluent (Simpson, 1989).

Release Into Surface Streams

Another option is release of discharged water into surface streams. In an Alabama case study of coalbed methane production on water quality, a worst-case combination of low-flow stream levels, mean rainfall, full development (3,500 wells), and chloride levels up to 5000 mg/l was considered. Even under this worst-case scenario, the study found that produced water could be allowed to flow into streams without adversely affecting water quality, with the exception that during periods of low flow it may be necessary to temporarily store produced water on-site (University of Alabama, 1983).

Recent field studies conducted in areas where surface water releases have been authorized for two years of well development found that areas with high concentrations of dissolved solids (chlorides) had high densities of aquatic insects and phytoplankton but low species diversity. However, as dissolved solids dropped to concentrations at or below 1,000 mg/l, species diversity and distribution approached levels typical for streams not receiving effluents (Simpson, 1989).

The studies indicate that instream concentrations not exceeding 1000 mg/l TDS do not significantly alter aquatic ecosystems. However, existing U.S. Enviromental Protection Agency (EPA) and Alabama standards call for maximum discharge concentrations of 230-250 mg/l. Such standards will likely restrict stream discharge of production water from coalbed methane wells.

Injection Wells

EPA regulations allow use of deep injection wells for wastewater disposal. Class II injection wells, i.e., those associated with oil and gas operations, apply to coalbed methane wells. Equitable Resources Exploration is currently discussing with EPA the prospects of a permit for such a well to dispose of production water from coalbed methane wells developed in Virginia. Deep, abandoned coal mines may also provide a location for well water disposal.

MARKETING OPTIONS AND PRODUCTION EXPERIENCES

Once production wells are completed, successful coalbed methane operations depend on effective gas marketing. This section discusses marketing options for Virginia's coalbed methane, and reviews the experiences of producers and marketers in Virginia and Alabama.

Markets for Coalbed Methane

Btu Content of Coalbed Gases

Gases derived from coal seams are of two types: high Btu (900-1000 Btu/cf) gas is mostly methane and compatible with pipeline-quality natural gas; low Btu (less than 900 Btu/cf, often 300-600 Btu/cf) gas contains methane and other gases such as carbon dioxide and air, and cannot be transmitted through conventional pipelines.

The type of gas produced depends on the coal source and on the extraction method. As discussed in the previous section on potential resources, coals vary in their methane content, obviously affecting Btu potential. Pure methane has a combustion heat value of 1000 Btu/cf. The higher the methane content of a coal, the higher the Btu content of gases extracted. Figure 2 showed that the methane content (cf/ton of coal) of Buchanan and Dickenson County seams is among the highest in Central Appalachia and the U.S. (Irani, *et al*, 1977). Therefore, the opportunities in Virginia for extracting high Btu gas are very good.

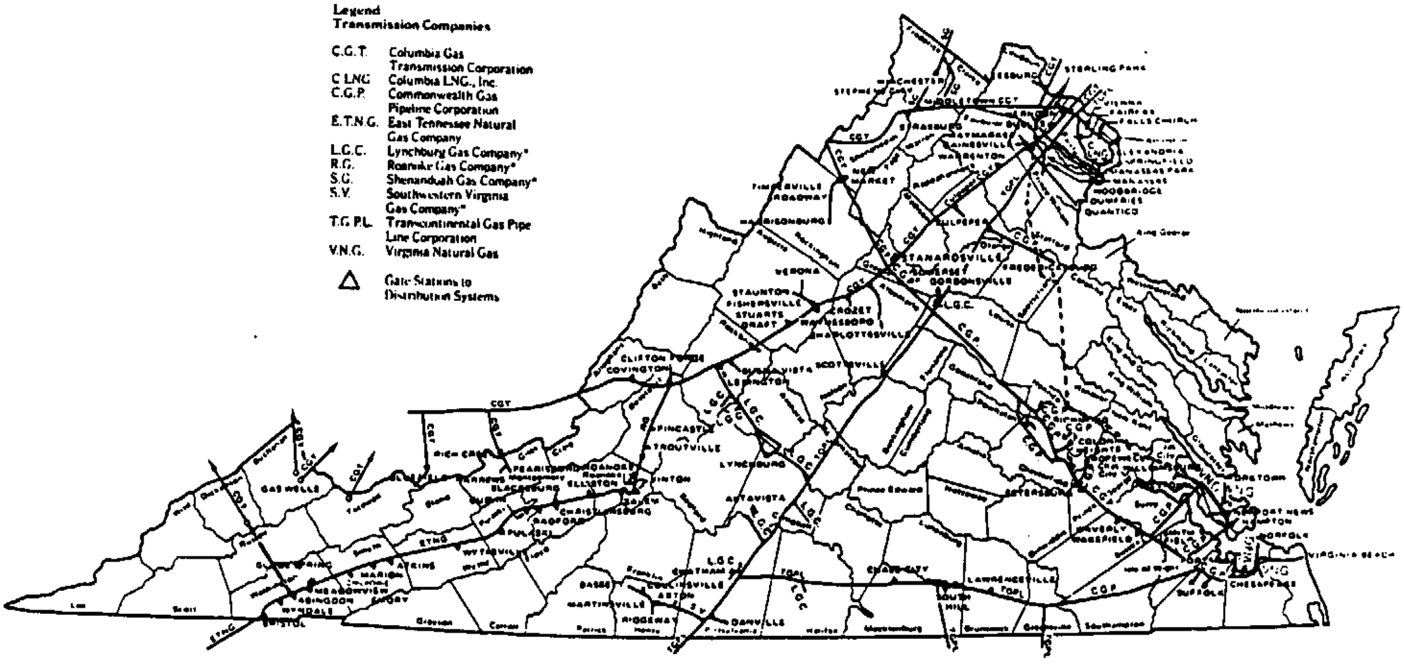
However, Btu content also depends on the extraction method. Standard vertical single and multi-seam well completions and in-mine horizontal bore holes can extract purer methane, and thus higher Btu gases, than gob holes. The massive fracturing within gob cavities as well as the presence of non-methane gases (mostly mine ventilation air), contaminates available methane and lowers Btu content (von Schonfeldt, 1989).

Markets for High-Btu Gases

Generally, the best market for coalbed methane is the intra- and inter-state natural gas pipeline system. The system for all of Virginia is shown in Figure 7. Figure 8 focuses on the state's coalfield region, showing existing pipelines as well as natural gas fields.

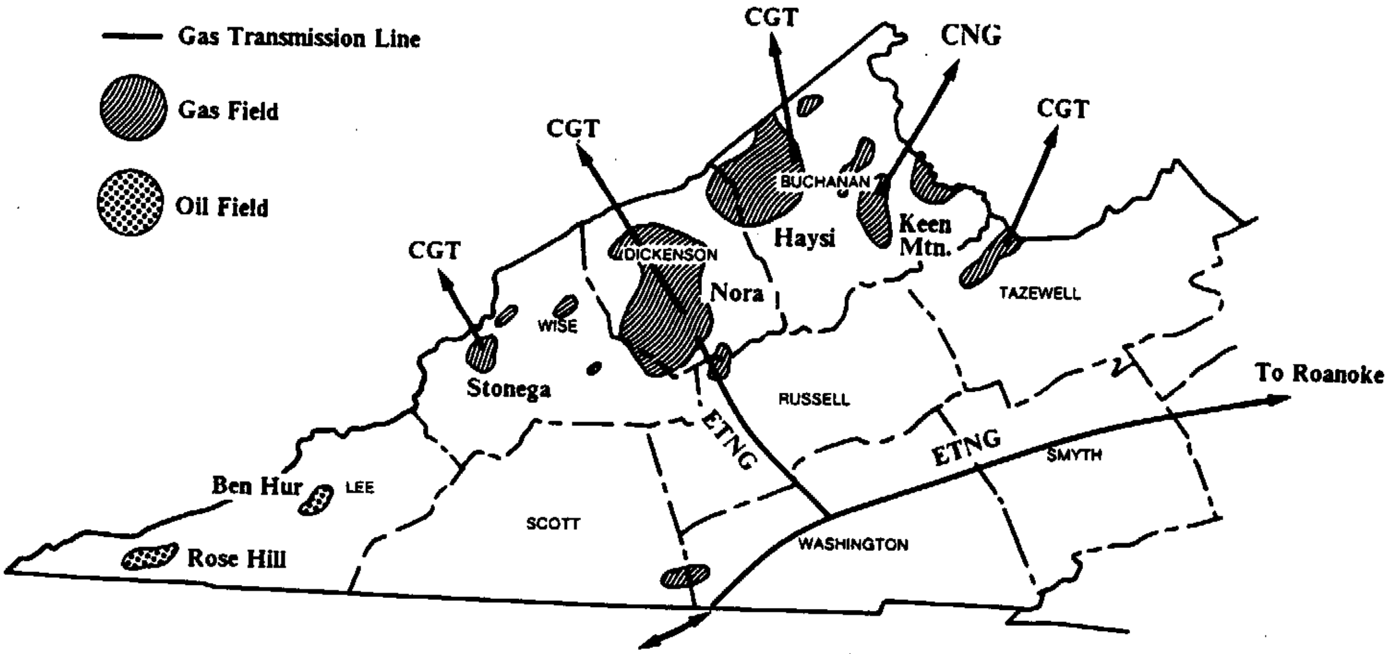
Three major gas transmission companies provide pipeline spurs into the coalfields. Columbia Gas Transmission Corporation (CGT) has spurs into Wise (Roaring Fork Field), Dickenson (Nora), Buchanan (Hurley, Haysi-Breaks), and Tazewell (Berwind) counties. East-Tennessee Natural Gas Company (ETNG) completed a spur to the Nora Field in Dickenson County in 1987. CNG Gas Transmission Corporation (formerly Consolidated Gas Transmission) has a spur to the Keen Mountain and Glick Fields in Buchanan County. Deliveries during 1988 to these pipeline companies is given in Table 3.

Figure 7: Natural Gas Lines in Virginia



*Distribution companies owning transmission lines.

Figure 8: Natural Gas and Oil Fields, and Gas Transmission Lines



Source: Randolph, 1988

Table 3: Deliveries to Pipeline Companies by Field (in cubic feet), 1988		
Columbia Gas Transmission (CGT)		
Roaring Fork (ANR)	4,755,986	
Berwind, Hurley, Haysi-Breaks (Col. N. R.)	2,841,249	
Other	422,704	
Total		8,019,939
East-Tennessee Natural Gas (ETNG)		
Nora (EREX)	9,171,211	
Early Grove (Penn-VA)	384,661	
Other	91,103	
Total		9,646,975
Consolidated Natural Gas (CNG)		
Keen Mountain, Glick (Ashland)	580,027	
Other	177,566	
Total		757,593
Total		**18,424,507**

Data source: Virginia Division of Gas and Oil, 1988

The spurs tie into main transmission pipelines that serve distant markets. The Columbia and CNG pipelines run through Kentucky and West Virginia and serve midwest and northeast markets. The ETNG spur connects at Abingdon, Virginia, with the main ETNG line, which runs north to Roanoke and extends to the southwest through Tennessee.

The ETNG spur provided a considerable new market for Dickenson County natural gas, with a resultant production surge in 1987. Because of excess capacity in this line, current and expected coalbed methane development in proximity to it will likely enjoy a ready market for some time to come.

Historically, the Columbia pipeline has had more limited capacity, and the northern markets it serves have not been expanding. As a result, conventional natural gas producers served by Columbia spurs have not enjoyed a growing market. These factors may constrain sale and production of coalbed methane in areas served by these spurs. The Consolidated pipeline has also been plagued by weak northern markets, but the company has been actively pursuing new opportunities. These include connecting to the new Virginia Natural Gas pipeline in northern Virginia to serve Richmond and Tidewater markets, and developing new delivery pipelines in Pennsylvania and New York.

Prospective coalbed methane developers in Buchanan County see connecting to CNG's spur as the most probable option for marketing gas. Other possibilities include new pipeline spurs to the ETNG line in Dickenson County or to Columbia's Buchanan County line, but distance and terrain would make construction of such spurs very costly (Crosby, 1990).

Another potential market for coalbed methane is local use. There are no existing large-scale natural gas users in the region, although a small market may exist in mining operations or community use. Considerable interest is currently developing in coalfield cogeneration and independent power development that could utilize locally produced gas (and coal) to generate electricity for sale to the utility grid. However, utilities serving the region (Appalachian Power and Old Dominion Power) offer extremely low rates for power purchases, thus reducing the cost-effectiveness of this option. Much higher rates for power purchases have been offered by Virginia Power through its competitive bidding process, but selling electricity to the utility would require wheeling over APCo transmission lines to Virginia Power's service area in the eastern part of the state. APCo has not been willing to offer transmission service to such facilities in the coalfields because of limited capacity. However, a Joint Subcommittee of the Virginia General Assembly has been studying the issue of wheeling capabilities from Southwest Virginia, prompting a joint study by APCo and Virginia Power, as well as other research on the subject (e.g., Randolph, *et al.*, 1990).

Prospective coalbed methane developers, however, do not perceive a local independent power industry as a strong market prospect. One developer believes that such local markets could provide opportunities in subsequent phases of coalbed methane development, but his firm would like to see demonstrated evidence of successful independent power facilities in the region before they would be considered seriously (Crosby, 1990). Most developers look to pipeline transmission companies as the principal market for coalbed methane produced in Virginia.

Markets for Low-Btu Gases

Because lower Btu gas (less than 900 Btu/cf) is not compatible with natural gas pipeline quality, its markets are limited to local uses. It has been suggested that low-Btu gases could be upgraded to pipeline quality by removing contaminating gases or mixing with high-Btu gas (Camp, 1989), but these measures require additional capital expense and may not be cost-effective. Local use of low-Btu gas is possible, but supplies, especially from mining operations, would likely be subject to interruptions.

Federal Tax Credit

A major factor influencing current coalbed methane development in Virginia and in other states is a tax credit originally enacted as part of the Crude Oil Windfall Profit Tax Act of 1980 (Pub. L. No. 92-223). The tax credits for the production of energy from unconventional sources aimed to encourage their development by decreasing production costs. These alternative energy sources typically involve new technology, and Congress felt a subsidy was necessary to encourage competitive development versus conventional fuels (McMurray, 1989).

Specifically, the Act created in the Internal Revenue Code, Section 29, a tax credit for a range of qualified fuels including coalbed methane. The gas had to be sold by a taxpayer to an unrelated person during the taxable year for which the credit is claimed, provided:

- gas production is attributable to the taxpayer;
- the gas is produced in the U.S.;
- the gas is sold at a "lawful price" (according to the National Gas Policy Act);
- there was no production of gas in marketable quantities from the property before January 1, 1980;
- there is no government financing; and
- the gas is produced from wells "drilled," or facilities placed in service before January 1, 1990, and the gas is sold after 1979 and before January 1, 2001. The Technical Corrections and Miscellaneous Revenues Act of 1988 amended the Section 29 tax credit, providing a one-year extension of the credit for well development. Qualified fuels are now eligible for the credit if they are produced from a facility placed in service or a well drilled before January 1, 1991.

The credit can be claimed for gas produced until January 1, 2001, but only for operations that are in place by January 1, 1991. The tax credit is a function of the barrel of oil equivalent of the qualified fuel in question, the rate of inflation, and the price of oil. Alegbraically, this computation may be expressed as follows:

$$\text{Available Credit} = \$3/\text{BOE} \times \text{I} \times \text{PH}$$

where:

- BOE equals the barrel of oil equivalent (5.8 MMBtu in the case of natural gas);
- I equals the inflation adjustment factor, determined annually by the Department of Energy and the Internal Revenue Service; and
- PH equals a phaseout factor which may also be algebraically determined, and is always less than or equal to 1 depending on the price of domestic crude oil. For example, 1990 oil prices have to exceed $41 a barrel to cause the tax credit to begin to phase out and be over $51 for it to completely phase out (Baker, 1988; McMurray, 1989).

The Section 29 alternative fuel production incentive is a bottom line credit, reducing tax liability on a dollar-for-dollar basis. In addition, there is no recapture of the alternative fuel production credit. Thus, once the credit has been taken, no subsequent taxes will be back-charged because of any credit recapture. The alternative fuel production credit is "freely transferable" if the underlying general interest or limited partnership that holds the interest in the production is transferred. Transfer must be done according to the partnership agreement and applicable securities laws. However, once an adequate transfer is made, the credit can be taken by the transferee owner of production (McMurray, 1989).

The tax credit is substantial, amounting in early 1990 to about 80-90 cents per Mcf, or nearly 40-50 percent of the wellhead price of natural gas in Virginia. This is a lucrative incentive for developers; indeed, it may tip the economic balance toward well development.

Coalbed Methane Production in Alabama

The success of Alabama's coalbed methane development during the past decade has been a major impetus for interest in Central Appalachia. All of Alabama's established coalbed methane fields are located in the Warrior Basin, which encompasses a 35,000 sq. mi. area astride the Mississippi-Alabama state boundary, with a resource estimated at 20 Tcf (Ayers and Kelso, 1989). The coalbed gas industry in Alabama has developed rapidly since the first drilling permit was issued in May 1980. Production grew to approximately 1.5 Bcf/month by the start of 1988 (*Oil and Gas Journal*, 1989). Nearly all produced methane is marketed as a high-Btu product through natural gas pipelines. A total of 869 wells had been permitted by 1988, more than doubling with an additional 900 wells permitted in 1989 (Wallace, 1989). At present, there are nine fields and six discoveries in various stages of development in the state (*Oil and Gas Journal*, 1989). The major reason for the recent growth in activity is the scheduled January 1, 1991 deadline for the federal tax credit.

It has been estimated that the Warrior Basin will have approximately 3,950 coalbed methane wells in production or in various stages of drilling and completion by the end of 1991. The number of new coalbed gas wells drilled are projected to decline to 400 per year in 1992, and then to a steady 200 wells/year through 1997. Some optimistic predictions put Warrior Basin 1993 production at a peak rate of 130-140 Bcf/year, about equal to Alabama's current production of natural gas from all sources (*Oil and Gas Journal*, 1989).

Using a substrate economic model, a study by the University of Alabama Center for Business and Economic Research estimated the economic impact of new coalbed methane development in Jefferson and Tuscaloosa counties in Alabama for the years 1989 to 1997 using the projections given above (Gunther and Ijaz, 1989). The study developed two impact scenarios.

The first scenario was based on the assumption that no part of total net revenues (total revenues minus taxes) generated from the sale of gas to end-line users remains within the region. Thus, new economic activity from coalbed methane is introduced mainly by the region's construction and mining sectors. For 1991, the study projected 3,950 producing wells, approximately $98 million in new construction, and $37 million in operating expenditures. This translates into approximately 8,500 jobs generating $186 million in total income and $49 million in new state and local tax revenues.[6]

The second alternative scenario for Alabama assumed that at least 50 percent of total revenues generated through methane gas sales would remain within the region. Total regional economic impact was expected to come not only from the construction and mining sectors, but also from increased total income. For 1989, the study projected approximately $98.5 million in construction expenditures, $37 million in operating expenditures, and $43.5 million in additional revenues from gas sales within the region. This translates

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[6] For 1997, the study projected 5,350 producing wells generating approximately $268 million in total income and $86 million in new state and local taxes.

into approximately 9,500 jobs, for an additional $251 million in total income and $61 million in new state and local tax revenues.[7]

Although these economic impacts are substantial, the data used in these projections were obtained from industry. Conceding that the economic picture in 1989 has not evolved to the extent projected in their study, the authors believe that the industry's "ambitious" data is the reason for the divergence between projected and actual economic impacts (Gunther, 1989 *quoted in* Kelly, 1989). Gunther also states that the issue of water disposal has slowed development in Alabama below optimistic projections. Development in Tuscaloosa and Shelby counties have been affected by lawsuits and other objections by environmental groups (Heine, 1989; Bruer, 1989).

Coalbed Methane Development in Virginia

With the high methane content of many of its deep coal seams, the Virginia coal industry has had to develop effective means of venting methane from its mines. In the late-1970s, Clinchfield Coal Co. (Pittston Coal Group) and Island Creek Coal Co. began to look into prospects for capturing this vented gas. Under a federal grant, Clinchfield initiated its Jawbone Coalbed Methane Drainage Project in 1978. The company drilled five vertical boreholes near its McClure No. 1 mine in Dickenson County, Virginia, to determine this system's feasibility for recovering methane gas from the Jawbone coal seam. As mentioned earlier, desorption tests performed on two cores from the first well indicated a gas content of approximately 280 cf/t. Gas production from this well, stimulated for production in June 1978, ranged from a maximum of 43.5 thousand cubic feet per day (Mcfd) in December 1978 to a minimum of 16 Mcfd in March 1980. Total cumulative production from June 1978 to September 1980 was 11.6 MMcf (Manilla, 1980).

While the project ended in 1980, this experience convinced Pittston management of the potential, and the firm is currently working with Equitable Resource Exploration, Inc. (EREX) to develop methane production from its coal seams. EREX drilled its first coalbed methane well on Pittston property in early 1989, and had twelve producing wells by the end of 1989. EREX had drilled another fifteen wells by early March 1990, well on its way to the 30-50 new wells expected by year's end (Camp, 1989; Stern, 1989).

EREX production is the only substantive, current coalbed methane development activity in Virginia. However, Island Creek owns portions of the Pocahontas #3 coal seam, some of the gassiest coal in the nation. Island Creek and its parent Occidental Petroleum, Inc., have been interested in capturing this gas since mid-1970s reports of 20 MMcfd of methane being vented from its Virginia mines. In 1979, under an agreement with DOE's MRCP, Occidental Research Co. conducted an experimental project at Island Creek's Pocahontas No. 5 mine in Buchanan County. In discussions about the state's legal framework for coalbed methane development (addressed in the next section), Island Creek's "corporate cousin," OXY USA, Inc., has actively pro-

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[7] For 1997, the study projected approximately 5,300 producing wells, generating approximately $102 million in operating expenditures and $19.17 million in construction expenditures. Approximately $547 million in total income and $117.72 million in new state and local tax revenues were projected.

posed modifications to accelerate development. These recommendations found favor with the 1990 General Assembly and have become law (see following section on Institutional Issues).

OXY anticipates the new law and regulations will allow expeditious development of new wells in Buchanan County. In early March, the company indicated plans to develop 125 wells before the January 1, 1991 deadline. Much needs to be done before that level of development can be realized, including permit applications, technical development, and marketing agreements. Although gas need not be marketed by January 1, 1991 to become eligible for the tax credit (wells need only to be put in place), OXY must be assured of available markets before securing and investing necessary capital.

The company believes its best marketing option is the CNG pipeline spur that runs to the Keen Mountain gas field. It sees CNG's market expansion efforts in Virginia and the northeast providing significant opportunities. Other options include a connector to the ETNG spur in Dickenson County or to the Columbia Gas Transmission compressor station at Conway.

1990 will be a year of substantial, perhaps frantic, coalbed methane development in Virginia, as developers race against the impending tax credit deadline. They were given a substantial boost in this effort by 1990 General Assembly which resolved some of the inhibiting institutional issues that have constrained past development. These issues and the legislative action are discussed in the next section.

LEGAL AND INSTITUTIONAL ISSUES IN VIRGINIA

The studies reviewed in this report indicate that Virginia's coalbed methane potential is substantial, and that some coal and gas companies operating within the state are poised to develop the resource. However, certain legal and institutional issues have posed considerable barriers to widespread and timely development. The most critical of these is the question of resource ownership.

In response to these barriers, the Virginia General Assembly passed emergency legislation that became law on March 4, 1990, to expedite coalbed methane development. The law provides a mechanism for development, but ownership questions remain. However, with less than ten months before the tax credit deadline, there is sufficient time to attain a meaningful level of development while the economic incentive is available.

This section reviews the legal and institutional issues in Virginia that have affected the development of coalbed methane, including ownership, the interests of various parties, and the regulatory framework both prior to, and after, the 1990 legislation.

Ownership Issue

When a land owner holds all surface and mineral rights, "fee simple," there is no question that he has title to underlying coalbed methane. However, when mineral rights are severed from the surface estate, and the coal estate is severed from the oil and gas estates, there are five possible claimants of methane contained in coal seams: the owner of the coal; the coal lessee; the oil and gas owner; the oil and gas lessee; and the surface owner (Patten, 1990). Courts in Pennsylvania[8] and Alabama[9] have ruled in favor of the coal owner for methane ownership. However, both cases were narrowly decided on the issue of deed construction, and while they would serve as precedent for subsequent cases with similar deeds, they are not broad declarations in favor of the coal owner (Patten, 1990). For federal lands, the U.S. Department of Interior has ruled that the methane is not owned by the coal lessee.[10]

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[8] *U.S. Steel Corp. V. Mary Jo Hoge, et al.* (Pa. 140, 468 A.2d 1380, 1983).

[9] *Rayburn, et al. v. USX Corp.* (U.S.D.C. N.D. Ala., Memorandum Opinion, July 29, 1987; appeal to 11th Circuit, August 17, 1987).

[10] The U.S. Department of the Interior Office of the Solicitor General, Solicitor's Opinion 88 I.D. 538 (1981) Memorandum M-36935, May 12, 1981. The Memorandum states that: (i) the Coal Reservations Acts of 1909 and 1910 included coal only - not ownership of the formation. All formations and other minerals pass to the surface owner; (ii) the Mineral Leasing Act - Coal refers to the coal mineral only - not the formation or container space, it does not include coalbed gas as leasable under 30 USC 221. However, the coal lessee has the right to ventilate methane gases for mining purposes; (iii) the Oil and Gas Researvation Act of 1914 conveyed surface (agricultural patents) only. Coalbed gas and all other gases were retained by the U.S.; and (iv) the Mineral Leasing Act - Oil and Gas refers to gas without qualification as to its origin, and considers coalbed gas as leasable under 30 USC 226.

The issue has been complicated in Virginia by the 1977 Migratory Gas Act, which vested certain rights to migratory gases with the surface owner. The law states:

> Except as otherwise provided by law, on or after January 1, 1978, all migratory gases, including but not limited to propane and methane, shall be conclusively presumed to be the property of the owner of the surface real property beneath which such migratory gases are or may be located (VA Code 55-154.1.A).

If coalbed methane is a migratory gas, this law grants ownership to the holder of the surface estate. Some argue that coalbed methane is not a migratory gas, as long as it is locked in the coal seam and extracted by a well into that seam. Others argue that the statute is unconstitutional, because it may "take" or transfer property rights (from the coal owner or gas lessee to the surface owner) without compensation.

There has been no judicial clarification of these arguments. However, they may be moot since the 1990 Virginia General Assembly repealed the 1977 Act in a move to help resolve at least part of the ownership question. Yet, how courts will respond to ownership claims based on the twelve years effective period of the Migratory Gas Act remains unclear. Property rights in specific cases depend on individual deeds, and in the multitude of severed estates in Southwest Virginia, there are an equal number of special conveyances of mineral rights from the surface owner to other interests.

Prior to the 1990 General Assembly action, the ownership issue was viewed by most parties as the major impediment to large scale and timely development of coalbed methane in the Commonwealth (Counts, 1990). To reduce this impediment, in addition to the Migratory Gas Act repeal, the Assembly passed legislation allowing well development and production, and forced pooling of potential interests with proceeds held in escrow *while* ownership questions are being resolved.

The specific provisions of this legislation are discussed later in this section. The following describes the expressed positions of parties having an interest in coalbed methane development.

Major Interests in Coalbed Methane in Virginia

Coal Industry

Some Virginia coal companies with ties to natural gas production,[11] and owners of coal with methane potential, want to see coalbed methane developed. The industry agrees with courts in Alabama and Pennsylvania that coalbed methane ownership is attached to coal mineral rights. However, the industry's foremost demand is that coalbed methane development not hinder opportunities for coal production. The principal concern is that coalbed methane

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[11] For example, ANR Coal Co., which is both a coal and gas owner and producer, and Island Creek Coal Co., a major coal producer whose parent company, Occidental Petroleum, has considerable interest in gas production.

fracturing and other gas stimulation methods, in advance of, or in conjunction with, coal operations may weaken coal seams and surrounding strata, adversely affecting existing or future mine roofs and floors. The industry is also concerned that once coalbed methane wells are developed, they may somehow inhibit mining operations either by delaying mine advance until gas is extracted or by constraining mine gas venting.

With regard to the former concern, von Schonfeldt (1989) refers to a recent study by Diamond and Oyler (1987), showing little adverse effect from stimulation of coal seams and related strata in Alabama. However, he (von Schonfeldt, 1990) and Young (1989) question whether these Alabama results would hold true within Virginia's differing coalfield geology. In response to this potential problem, negotiations between the Virginia Oil and Gas Association and the Virginia coal industry have been fruitful in resolving potential conflicts between these interests. They have agreed to a consent mechanism that would require prospective coalbed methane developers to receive approval from coal seam owners before well drilling or stimulation (Hudson, 1989a,b). As discussed later, this provision was included in coalbed methane legislation passed by the 1990 Virginia general Assembly.

Gas Industry

The gas industry in general believes that coalbed methane is a natural gas and rights should be included in gas ownership or leases. Still, the industry has conceded that the coal resource should be protected, and as mentioned above, the Virginia Oil and Gas Association has agreed to a requirement of consent from coal owners for drilling methane wells into coal seams.

The principal interest of gas companies involved in coalbed methane development is to produce the resource, and in particular, to develop drilling units before the scheduled deadline of the federal tax credit for unconventional sources. The cost-effectiveness of coalbed methane development depends substantially on the credit, which currently equates to an added value of 80 to 90 cents per MCF in Virginia (Camp, 1989). Drilling units not in place by January 1, 1991 will not be able to claim the credit. On the other hand, drilling units in place by that deadline can claim credit for gas produced until January 1, 2001.

The industry's principal concern has been that the complex legal and regulatory system in Virginia have made it very difficult to expedite well development. In cases where property is owned "fee simple," or where straightforward agreements can be made (such as between Pittston and EREX), permitting and development have proceeded unfettered.

However, where property estates are severed (the dominant situation in the Virginia coalfields), questions of coalbed methane ownership have muddled the permitting objections process under the 1982 Oil and Gas Act. Although the Migratory Gas Act provided for Circuit Court intervention in ownership disputes and for the court to allow continued production by a permitted operator until the dispute was settled, the provision was moot -- the gas industry never conceded that coalbed methane is a migratory gas.

During the Virginia Coal and Energy Commission's review of the 1982 Oil and Gas Act, OXY USA, Inc. and the Virginia Oil and Gas Association proposed a forced pooling and permitting provision for coalbed methane that aimed to expedite well development while ownership questions were being resolved. As discussed in the following section, the Commission recommended this provision to the General Assembly, which passed with little objection into law on March 4, 1990.

Surface Property Owners

Most surface owners believe coalbed methane is a migratory gas and that ownership granted to them under the Migratory Gas Act (assuming their deeds did not specifically cede those rights to others). With the repeal of the Migratory Gas Act in 1990, this argument is diminished; however, it is uncertain, given that the Migratory Gas Act was a standing law for twelve years, how the courts will respond to such claims in specific cases. The primary interest of surface owners is to protect their property from the effects of development, including surface disturbances and water discharges. In comments to the Coal and Energy Commission, the Dickenson County Citizens Committee voiced opposition to forced pooling of coalbed methane development without the surface land owner's approval. It recommended that a definitive method of discharge water disposal be approved by the appropriate state agency (Reilly, 1989).

There is also concern among property owners that in the haste to develop Virginia's coalbed methane resource, certain rights of surface owners may be circumvented. These include not only the rights to the methane (if indeed it is a migratory gas), but the right to object to development and the rights of due process (notice, objection, and hearing) -- a process they fear may be hindered for the sake of development.

The State

State officials want development of coalbed methane to stimulate economic development in the coalfields and to reduce the current waste of a potentially valuable resource. The state must also protect citizens' property rights and the environment through regulatory mechansims. While these interests are not mutually exclusive, they may pose certain trade-offs in expediting large-scale coalbed methane development, especially considering the time constraints presented by the federal tax credit deadline.

Regulatory Framework for Coalbed Methane Development in Virginia

The legal and institutional framework for coalbed methane development in Virginia changed dramatically as the result of actions by the 1990 General Assembly. The actions were prompted by a 1989 House Joint Resolution (HJR 364; sponsor: Del. Ford Quillen) that called on the Virginia Coal and Energy Commission to review the Oil and Gas Act and recommend any modifications deemed desirable or necessary.

Although coalbed methane was not mentioned in the resolution (or in the 1982 Act for that matter), the issue surfaced in the Commission's review, and the various parties discussed above advanced their perspectives on the need for, and concerns about, coalbed methane development. Under direction of the Commission, the Virginia Division of Legislative Services completed a draft of revisions to the Act on December 4, 1989. The draft contained little reference to coalbed methane beyond providing definitions. However, attached to the draft were proposals and comments submitted by various interests, allowing the commission to address coalbed methane provisions.

Although it did not address the issue at its December 21 meeting, the Commission met again on January 9, 1990 (a few days before the General Assembly convened) and decided to recommend emergency legislation for coalbed methane development, drawing heavily from proposals made by OXY USA, Inc. representatives at Commission hearings. The recommended bill was sponsored by all the legislative members of the Commission as Senate Bill 381. It was passed by the Senate and the House on February 23, signed into law, and made effective on March 4, 1990. Before discussing the provisions of this legislation, it is useful to outline the regulatory framework that existed prior to 1990.

Regulatory Framework Prior to 1990

Prior to 1990, the framework for regulating coalbed methane development in Virginia was based on the 1982 Oil and Gas Act and implementing regulations. Although the 1977 Migratory Gas Act never played a direct role in development, it placed a "cloud on title" of the resource and thus affected development (Patten, 1989). The 1982 Oil and Gas Act aimed to provide for efficient and effective development of the state's oil and and gas resources, and to consider the rights of parties affected by production operations. While the act did not specifically mention coalbed methane, it provided the basic framework for regulation of the resource. The act and implementing regulations established procedures for drilling unit permitting by the state Division of Oil and Gas and the Well Review Board. Pooling of production for oil and gas tracts was controlled by the Oil and Gas Conservation Board.

The following section discusses the permitting and pooling procedures provided by the Oil and Gas Act. It also describes possible effects of the Migratory Gas Act.

Permitting Drilling Units under the 1982 Oil and Gas Act

In order to develop a coalbed methane well, an operator first had to obtain a permit from the state Oil and Gas Inspector, under regulations provided by the Oil and Gas Act. The permitting procedure was the same as that used for conventional gas and oil wells. In the permit application, a prospective operator had to certify that he had the right to conduct all necessary operations, including road and pipeline construction, drilling, and other surface disturbances. The inspector relied on the certification as evidence that all legal arrangements had been made with affected property owners, but the regulations also provided for a "notice and objection" procedure to question the application.

The permitting process for two cases is illustrated in Figure 9. If the applicant holds all coal, oil, gas, and surface rights, the procedure was straightforward and a permit could usually be issued within 5 days. However, if surface rights were not fully held over the extent of the seam from which the gas was to be drawn, the notice and objections process would be triggered (Case II in Figure 9). Relevant land owners were notified; if there were no objections during a 15 day period, a permit could be issued. If not, the inspector could call an informal hearing; if no agreements were reached, the inspector rendered a decision not to issue a drilling permit. This decision could be appealed to the Well Review Board, which called an additional hearing that resulted in a written decision. If the process ran its entire course, it could take up to 105 days. Although the process could be lengthy, it aimed to preserve the rights of property owners by giving them an opportunity to question the legal certification included in the permit application.

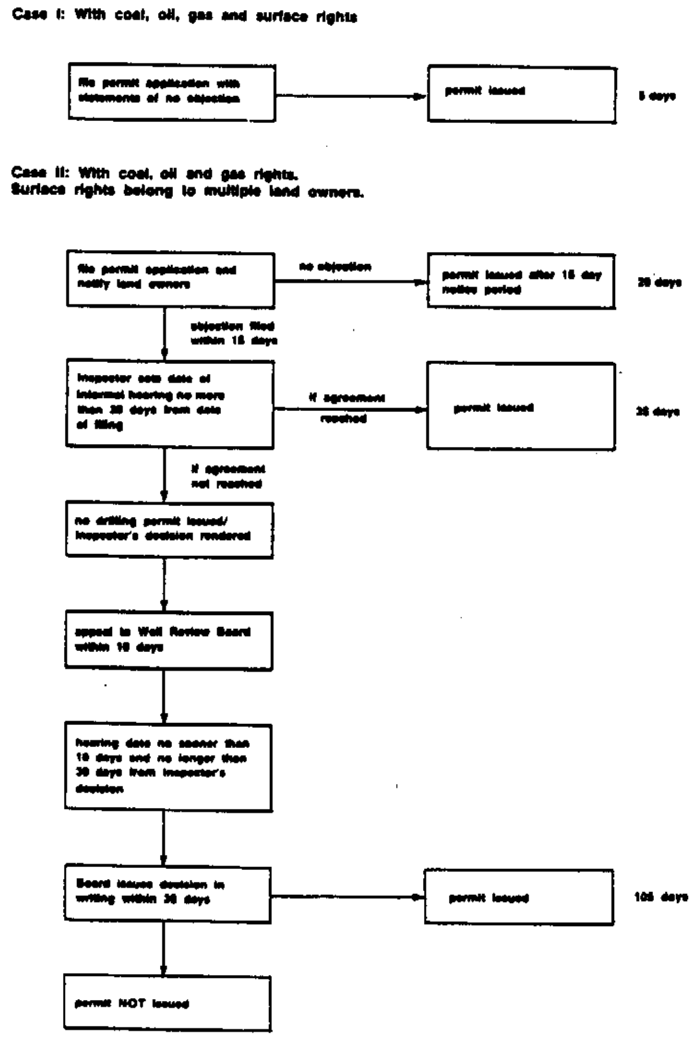
Pooling Resource Extraction under the 1982 Oil and Gas Act

In an effort to enhance the efficiency of oil and gas extraction, the 1982 Oil and Gas Act provided for resource pooling. A pool is an underground oil and gas reservoir in which different owners may have a stake, but cannot be tapped by one well without affecting the entire reservoir. Under the authority of the Oil and Gas Conservation Board, the act provided for pooling agreements between owners allowing well operation by one owner with proceeds shared among all owners. The act also provided for "forced pooling," or a board-issued pooling order in response to a well operator's request. Before such an order was issued, notice of the request and a hearing were required. The act spelled out sharing of costs and proceeds under pooling arrangements and defined different parties, such as "participating owners" (who share in operating costs during operation) and "carried interest operators" (who delay in their cost contribution but must pay before receiving their share of proceeds).

The pooling provisions of the act did not mention coalbed methane; thus, it was uncertain how pooling of this resource would be regulated under the act. A coalbed methane pool can be defined as the methane contained in several coal seams that can be accessed with one well. Thus, a multiple-seam well could pool the resources contained in a number of seams owned by different parties.

The Migratory Gas Act contained a provision[12] allowing continued extraction of migratory gases from wells where ownership was in dispute. The act vested authority for such disputes and this variation of forced pooling with the Circuit Court, instead of the Oil and Gas Conservation Board.[13] In a variation of forced pooling, the court could allow continued extraction with proceeds placed in escrow until gas ownership was determined by final court order.

Figure 9: Virginia Drilling Permit Time Scheduling



Source: Patten and Jones, 1989

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[12] "Litigation involving the legal construction of lease agreements entered into prior to the effective date of this section shall be governed by the applicable law in effect at the time the agreement or agreements were entered into. The Circuit Court in which such proceedings involving the construction of such leases are heard may permit, in the discretion of the court, commercial extraction of migratory gases; provided, however, that the court shall order reasonable royalties from the sale of such gases to be placed in an escrow account until the ownership of such gases is determined by final court order." (VA Code 55-154.1.B).

[13] The Migratory Gas Act (MGA) predated the Oil and Gas Act, so the Conservation Board had not been established when the MGA was enacted.

Regulatory Framework under 1990 Legislation

As discussed above, the 1990 Virginia General Assembly enacted bills repealing the Migratory Gas Act (HB 939), amending the 1982 Oil and Gas Act (SB 382), and establishing emergency procedures for coalbed methane development (SB 381). The emergency procedures became effective when Governor Wilder signed SB 381, March 4, 1990. They expire on July 1, 1990, when the Oil and Gas amendments become effective; the SB 382 amendments contain the basic provisions of SB 381 for coalbed methane.

In a memorandum issued March 9, 1990, Virginia Department of Mines, Minerals, and Energy Director Gene Dishner indicated that the new laws would be implemented in three steps. First, an emergency order under Section 45.1-293 was issued by the state Oil and Gas Inspector on March 7 to provide for timely coalbed methane development. It addressed certain technical issues, such as well casing and plugging, not included in SB 381. Second, since insufficient time is available to prepare new full regulations under SB 382 by its effective date, July 1, 1990, the inspector will issue emergency Oil and Gas Act regulations on that date to be in effect for one year. Third, in July 1990, the Department will commence a process to develop new full Oil and Gas Act regulations. The process will involve many parties having diverse interests and will take six to twelve months (Dishner, 1990).

The following sections describe the basic provisions of the new legislation for coalbed methane development.

Permitting Drilling Units under 1990 Legislation

Requirements for coalbed methane well permitting are specified under the Oil and Gas Act with special provisions contained in SB 381 and the inspector's emergency order of March 7, 1990. Beyond routine permitting requirements, the emergency law requires approval of each permit application from coal operators whose operations could be impacted by well stimulation. Specifically, the application must include a *signed consent* from the coal operator of each coal seam located within 750 horizontal feet of the proposed well, or within 100 vertical feet above or below coal-bearing strata that the applicant proposes to stimulate. In addition, the application must identify all coal owners and operators for seams more than 500 feet, but less than 750 feet, from the well location, and must specify the well stimulation method.

Wells must be placed at least 500 feet (or 250 feet in the case of gob wells) from the nearest tract not pooled in the operation; and at least 1000 feet (or 500 feet in the case of gob wells) from other coalbed methane wells. Drilling units must conform to coal mine development plans and operations.

Pooling Resource Extraction under 1990 Legislation

The most substantive provision of SB 381 concerns resource pooling. The pooling provision allows well permitting and development before conflicting claims of resource ownership are fully resolved. This separates the muddling questions of ownership (which require legal negotiations and possible court determination) from permit and pooling decisions (made by the Oil and Gas

Conservation Board and the Oil and Gas Inspector), and thus aims to expedite well development.

Under the provision, the Oil and Gas Conservation Board may order pooling when conflicting ownership claims exist in order to (a) avoid unnecessary well drilling, (b) protect correlative rights, and (c) promote coalbed methane development. The applicant for such a pooling order must identify prospective interests and list them as respondents in the application. The pooling order:

1. authorizes coalbed methane well drilling and operation;
2. designates the coalbed methane well operator;
3. prescribes the time and manner in which respondents may elect to participate subject to final legal determination of ownership;
4. provides that operating costs be borne, and production proceeds be received by the well operator on behalf of all respondents; and
5. provides for payment of reasonable fees to the operator by the respondents who choose to participate.

Respondents may elect among several alternative roles in the operation:

1. He may become a "participatory operator" and share in the risk and cost of the well. He must tender his share of costs to the well operator, who, if there are conflicting claims of ownership, must deposit these costs in an escrow account.
2. He may sell, lease, or assign his ownership or leasehold interest to the well operator. The board will determine the terms if the operator and respondent cannot agree.
3. He may do nothing, in which case, he will be deemed to have elected to lease or assign his interest.
4. He may share in the operation of the well as a "carried operator." In this case, he will not contribute his share of operating costs up front (as a participating operator does), but he will have his share of costs charged against his share of production proceeds from the well. Thus, the carried operator does not share in the risk of the operation, and his share of costs are covered by the operator. However, the carried operator cannot claim his share of proceeds from the operation until the well operator has received out of the well's production proceeds, an amount equal to 200 percent (for unleased tracts, 300 percent for leased tracts) of the carried operator's share of costs. This aims to compensate the operator for acting as lender and risk-taker for the carried operator.

An important part of the pooling provision is the board's authority to order the establishment of escrow accounts to hold production proceeds attributable to conflicting claims of resource ownership until a final legal determination of ownership is made. If there are conflicting claims, the well operator is required to place in escrow, one-eighth of the production proceeds attributable to the conflicting interests.

In such cases, participating operators will also place their share of estimated costs in escrow until ownership is determined. After final determination of ownership, participating operators are given thirty days to supplement this account as necessary to cover their share of operating costs, which are paid to the well operator. Likewise, the well operator must pay the participating operators their share of proceeds in excess of the proceeds held in escrow. As discussed above, the well operator is to pay carried operators their share of proceeds, less 200 percent of their share of costs for unleased tracts (300 percent for leased tracts).

Summary and Conclusions on Institutional Issues

The 1990 General Assembly took significant action to remove institutional and legal impediments to coalbed methane development in Virginia. The repeal of the Migratory Gas Act helped clarify the question of resource ownership. Still, the ownership issue is not fully resolved. First, the Migratory Gas Act was on the books for twelve years and may still have an effect on specific cases. Second, even if surface owners are removed as possible holders of coalbed methane rights, coal and natural gas owners and lessees are still left as prospective owners. Patricia Patten of OXY USA calls the situation a "goldmine" for lawyers as these parties battle in court over ownership (Kelley, 1990)..

Prior to the 1990 legislation, the ownership issue was the principal impediment to coalbed methane development where severed estates exist. The 1990 legislation attempted to remove this barrier by separating determination of ownership from well development. It did so by providing for forced pooling of prospective resource interests, thus allowing permitting and development of wells while proceeds are kept in escrow until final legal determination of ownership is made. This appears to provide a regulatory green light for Virginia coalbed methane developers in their race to put drilling units in place by the January 1, 1991, tax credit deadline.

SUMMARY AND CONCLUSIONS

This report has reviewed a range of issues affecting prospects for coalbed methane development in Virginia. During the past dozen years, significant issues have evolved from questions of resource potential to development technologies; institutional and legal issues; and finally, to market economics.

With regard to resource potential, mine ventilation experience in the mid-1970s made clear the vast volume and content of methane present in several Virginia coal seams. Several studies, culminating in a 1988 report by ICF-Lewin Energy, indicated a substantial Central Appalachian potential of 5 trillion cubic feet, with the greatest prospects centered in Virginia's Buchanan County. In comparison, Virginia's natural gas reserves totalled 189 billion cubic feet in 1988.

With the resource potential established, attention turned to technical issues of well completion. The technology needed proved to be much different from that used in natural gas development. However, experience in New Mexico's San Juan Basin and Alabama's Warrior Basin helped refine methods and equipment for coalbed methane development. Most of these technologies are directly transferable to Virginia.

As reports of these advances helped resolve technical questions, attention turned to legal and institutional issues. The major legal impediment was the question of ownership. Where the mineral estate is severed from the surface estate, do the rights to coalbed methane belong to the coal owner, the coal lessee, the gas owner, the gas lessee, or the surface owner (as the Migratory Gas Act seemed to imply)? Virginia courts provided little guidance on this issue.

Procedures for well permitting under the 1982 Oil and Gas Act required some resolution of ownership conflicts before permits could be issued. Developers were reluctant to enter into protracted legal forays over ownership with no guarantee of a permit.

The 1990 Virginia General Assembly responded with emergency legislation that, while not resolving the ownership question,[14] did provide a mechanism for prospective coalbed methane operators to proceed with well development during the time that claims of conflicting ownership would be resolved. This is especially important during 1990, the final year of eligibility for placing wells that can claim the lucrative federal tax credit. In fact, it is this tax credit deadline that in large part drove the political process for the legislation.

While the General Assembly did not resolve the ownership issue, it did repeal the Migratory Gas Act, which was a significant source of uncertainty. Conflicting claims of ownership will still likely abound, but with the new legislative mechanism for permitting and pooling, well development can proceed. And with each successive case involving determination of ownership, Virginia will establish a body of law on which to base subsequent decisions regarding conflicting claims.

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[14] In fact, legal questions of ownership and property rights are not legislative issues, but judicial ones.

The final major impediment to development involves the market economics of coalbed methane. The regulatory mechanism provided by the General Assembly now puts the prospects for development squarely in the hands of the private sector. Coalbed methane developers must now weigh the costs of development against prospective revenues to make investment decisions. Uncertainties exist on both sides of the equation. Technical advances elsewhere have reduced some of the cost uncertainties, but others remain, including well water disposal costs.

On the revenue side, production volumes are questionable until the well is completed. More importantly, satisfactory long-term markets must be developed. Although one developer in Virginia has access to a satisfactory market and has responded with an aggressive development program, others are not as fortunate. Some pipelines serving Virginia gas production have little potential for market growth. Others have potential, but are not easily accessible to prospective coalbed methane production sites.

A major factor in coalbed methane development and marketing is the federal tax credit. Most analysts agree that the current flurry of activity is driven by the credit and its impending deadline for well completion of January 1, 1991.

For Virginia, the main questions regarding future prospects for coalbed methane development are:

- How many wells, and with what production capacity, can be put in place before the end of 1990?
- If the tax credit is not extended, how many wells will be put in place after that date?

The answer to the first question depends on the pace of development the operators can achieve. This will likely approach 65 wells in Dickenson County, but activity in Buchanan County will be affected by level of investment, pipeline access and market development, as well as the process for forced pooling and permitting.

The answer to the second question depends on market factors, including the world price of oil, the east coast demand for natural gas, and development of local gas markets. If markets expand and prices go up (as many expect), prospects for post-1990 development of coalbed methane are good.

However, without substantial improvement in gas demand or prices, Virginia may see only those wells developed in 1990 for some time to come.

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