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Economics and coalbed gas in the 1995 National Assessment of U.S. oil and gas resources

by

Emil D. Attanasi and Dudley D. Rice

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Table of conversion to SI units

multiply unit	by	to obtain metric unit
barrel	0.159	cubic meter
cubic foot	0.02832	cubic meter
foot	0.3048	meter

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ABSTRACT
This report summarizes results of the economic analysis of the coalbed gas assessment of the U.S. Geological Survey's1995 National Assessment of U.S. Oil and Gas Resources. Of the more than 700 trillion cubic feet (Tcf) of coalbed gas in-place in the lower 48 States, Rice and others (1995) estimated 49.9 Tcf of gas as technically recoverable in undrilled coalbed gas bearing areas at depths of 6000 feet or less. Results of the economic analysis show that 4.8 Tcf of the technically recoverable coalbed gas can be commercially found and produced at $1.50 per thousand cubic feet (Mcf) while 21 Tcf is commercially producible at a cost of $3.00 per Mcf. For gas contained in confirmed plays, the lowest cost gas is located in the San Juan Basin.

INTRODUCTION

This report summarizes the basic results of the economic analysis of the coalbed gas assessment of the U.S. Geological Survey's 1995 National Oil and Gas Assessment. The economic component of the National Assessment is intended to place the geologic resource assessment into an economic context which is more accessible and more easily understood by industry and government decision and policy makers. One goal of the economic analysis is to estimate the incremental costs of transforming undiscovered conventional resources and selected unconventional resources into additions to proved reserves. Incremental cost functions show cost-resource recovery possibilities and are not supply functions as strictly defined by economists. However, the basic data used to construct the functions could serve as input into more complicated oil and gas supply models.

In the following section, the method and results of the geologic coalbed gas assessment are briefly reviewed. Then the method and data used in estimating the incremental costs of finding, developing, and producing the assessed coalbed gas are discussed. Results and interpretation of the economic analysis are presented in the concluding section.

REVIEW OF GEOLOGIC ASSESSMENT OF COALBED GAS

This section briefly summarizes the geologic assessment of the technically recoverable coalbed gas. Appendix A provides definitions for technical terms used in the discussion that follows. A detailed description of the geologic characteristics of the plays assessed is presented in Rice (1995). Rice and others (1995) presents a description of the method of estimating the technically recoverable quantity of coalbed gas for each play. The geologic assessment was prepared at the play level because important play characteristics such as estimated ultimate recovery (EUR) distributions, drilling risks, and gas and water production profiles of coalbed gas wells vary significantly across plays in the same province. Figure 1 shows the approximate locations of the areas assessed in provinces containing plays that were assessed.

Outlines of individual plays were drawn and the area of each play was partitioned into 'cells' that generally corresponded to the State permitted or "authorized" coalbed gas well spacing in each area. From examination of available geologic data, including the drilling record, from the coal-bearing interval, the assessor estimated the median, maximum, and minimum number of remaining untested cells. A point estimate of the drilling success ratio and estimates of the minimum, maximum and median depths of undrilled cells were also made. Plays were classified as "confirmed" , if the play had produced coalbed gas. Alternatively, if the play had no cells that produced coalbed gas, the play was classified as " hypothetical". For those plays classified as hypothetical a play probability was estimated. The play probability is the probability that at least one untested cell in the play will have a minimum (threshold) quantity of producible gas. The EUR probability distribution of untested cells is the distribution of estimated ultimate recoveries judged by the assessor to be representative of a play's potentially productive, untested cells. Confirmed plays were used as analogs for hypothetical plays for the purpose of estimating the EUR distributions of untested cells as well as their production schedules.

Because of the relative infancy of coalbed gas resource development, available data on well recoveries were insufficient to completely fill out an empirical EUR distribution with historical well recoveries. For nearly all of the confirmed plays, Advanced Resources International (ARI) prepared a series of studies that used the PC-COMET well-simulation model (Sawyer and others, 1990) to match production histories of wells thought to be representative of the plays that were assessed. Production well-history matching allowed calibration of the reservoir simulation model for the play. The calibrated simulation model was used to generate a number of well-production forecasts or scenarios while underlying model parameters were varied. The model calibration procedures used only data generated from vertical wells that conformed to the State authorized well spacing for the play. Consequently, the economic analysis was based on the assumptions that all wells were vertical and that cells corresponded to the State authorized or permitted drill spacing.

The well-simulation forecasts and corresponding well recoveries provided some guidance for estimation of the values of the EUR distribution of untested cells for the play. The well-production forecasts also provided the basis for estimating well production schedules required for the economic analysis. In order to fill in the EUR distribution, the assessor began by choosing two EUR values, one for the 50th fractile and one for the10th fractile of the EUR distribution judged to be representative of the potentially productive untested cells within the play. With these values and given the assumption that the EUR distribution is lognormal, the remaining fractiles of the EUR distribution were calculated.

With the assessed distribution of the number of untested cells, the EUR distribution of untested cells, the play probability, and a point estimate of the success ratio, the distribution of expected technically recoverable coalbed gas resources for the play was computed. Table 1 summarizes the expected value of the quantity of technically recoverable coalbed gas. Overall, the largest quantities were assigned to the Appalachian Basin, the Uinta-Piceance Basin and the San Juan Basin. The table also shows the quantities that are derived from confirmed and hypothetical plays.

DATA. ASSUMPTIONS, AND PROCEDURES FOR ECONOMIC ANALYSIS

The purpose of the economic analysis is to estimate the incremental costs of transforming undiscovered resources into additions to proved reserves. The cost functions include the costs of finding, developing, and producing currently undeveloped resources. The incremental cost functions are not the same as the economist's market price supply predictions for the following reasons. At any given price, the oil and gas industry will allocate funds over a number of provinces and supply sources in order to meet market demand at lowest costs. An observed price-supply relationship represents the culmination of numerous supplier decisions over many projects and regions. The incremental cost functions represent costs that are computed independently of activities in other areas. Furthermore, the incremental cost functions are assumed to be time independent and should not be confused with the firm supply functions that relate marginal cost to production per unit time period. Because of the time-independent nature of the incremental cost functions and the absence of market demand conditions in the analysis, user costs or the opportunity costs of future resource use are not computed. However, the incremental cost functions and the data which underlie the functions can be used as basic input data for models which predict market supply and demand.

Data

Geologic and descriptive data were taken from the coalbed gas assessment forms that were completed by the assessment geologist (Rice and others, 1995, and Gautier, and others, 1995- CD-ROM). These data included the type of the play (confirmed or hypothetical); play probability; fractiles of the cell EUR distribution; median, minimum and maximum number of undrilled cells and depth; a point estimate of the success ratio; the average and maximum thickness of the coal; and other data such as carbon dioxide levels, water treatment method, and well stimulation practices if known. From the well-simulation studies prepared by ARI, two well production schedules were chosen to characterize production profiles of cells representing the 50th and the 5th fractiles of the play's EUR distribution of untested cells.

Economic and engineering cost data include certain pre drilling costs; well drilling, completion, and stimulation costs; production equipment costs, water treatment equipment costs; annual production costs; production-related taxes; and federal income taxes. Cost of drilling coalbed wells were based on data presented in the Joint Association Surveys (JAS) of Drilling Cost for 1991 and 1992 (American Petroleum Institute, 1992, 1993). Well-stimulation cost estimates were based on data from working papers prepared by Energy and Environmental Analysis Inc. (1992) for the 1992 National Petroleum Council study entitled *The Potential for Natural Gas in the U.S.* (working papers are available from the National Petroleum Council). Estimates of production equipment costs were based, in part, on gas well equipment costs published by the Energy Information Administration (1994). Cost data that were originally based on development of conventional gas resources were adjusted to compensate for the special factors which increase costs in coalbed gas development. These cost factors were computed using data from the literature (American Petroleum Institute, 1992, 1993, Kuuskra and Boyer, 1993). The cost algorithm for estimating costs of treating produced water to meet state regulations was based on water-treatment cost functions prepared by Remediation Technologies, Inc, (1993). State taxes, including State severance and income tax, were the estimated regional tax rates used in the 1993 update of the Gas Research Institute's Hydrocarbon Supply Model (Vidas and others, 1993). The Federal corporate tax rate used in the project analysis was 35%. The estimated costs were assumed to represent costs that prevailed in the beginning of 1993.

Assumptions

Calculations were prepared in terms of constant 1993 dollars. The discounted cash flow (DCF) analysis was specific to individual projects and ignored minimum taxes and tax preference items that might be important from a corporate accounting stance. The DCF analysis used a 12% required rate of return. A DCF analysis was prepared for representative cells for the EUR size classes shown in table 2. For each play, these cell EUR size classes were evaluated at the expected depth of undrilled cells in each successive depth interval of 5000 feet. Plays with maximum depths greater than 5000 feet are in the Uinta-Piceance, Wind River, and Southwestern Wyoming (Greater Green River) basins. For calculating the incremental cost functions, it was assumed that the industry was rational and would not explore a given depth interval in a play unless the aggregate expected returns, represented by the expected aggregate after-tax net present values of all commercially developable cells, was sufficient to compensate for all costs, including exploration, development and production as well as a specified return to capital.

The assessment forms showed the following plays having gas with high carbon dioxide; Book Cliffs (Uinta), White River Dome, Western Basin Margin, and Divide Creek Anticline (Piceance), and the Overpressured Play (San Juan). It was assumed that the purchaser of the coalbed gas would discount the wellhead gas price by $0.15 per thousand cubic feet (Mcf) in these plays. Wellhead gas prices were also assumed to be discounted by $0.10 per Mcf by the purchaser to compensate for downstream compression costs. The assessment play forms indicated that production well stimulation was required in all plays except the Arkoma Anticline, the Illinois Basin, and the Northern Appalachian Anticline.

In all plays except those in the Powder River, the Black Warrior and the Appalachian basins produced water was assumed to be discharged into deep injection wells. In these other areas produced water is aerated, treated and then discharged as surface water. The quantities of produced water for sizing and treatment system design were based on data developed by ARI. Costs were estimated from models developed by Remediation Technologies, Inc.(1993). It was assumed that, depending on representative gas well produced-water rates, investment and operating costs of a disposal well or treatment facility could be shared by up to 25 production wells.

Procedure

The EUR distribution of undrilled productive cells and the distribution of the number of untested cells and success ratio were used to calculate a discrete frequency-size distribution of the productive cells at 5000 foot depth intervals of the play. Here, cell size refers to the quantity of recoverable hydrocarbons, that is, the cell EUR. Table 2 shows the cell-size classes used in the analysis. A DCF analysis was prepared for each size class at a given price (assuming a 12% rate of return) to determine what part of the frequency-size distribution is commercially developable. The industry will not initiate exploration of the play at the depth interval unless the aggregate of the after-tax net present value of the developable cells would at least pay for the cost of exploration of the entire depth interval where such costs include the cost of drilling dry holes and noncommercial cells. If the aggregate after-tax net present value of the commercially developable cells was sufficient to cover such costs, the aggregate resources in the commercially developable cells would be added to the incremental cost function. The calculations were repeated assuming progressively higher prices and results were aggregated to the play level and then to the province level to arrive at province incremental cost functions.

INCREMENTAL COSTS OF COALBED GAS: RESULTS AND INTERPRETATION

The aggregate incremental cost function for the lower 48 States is presented in figure 2. The graph shows that 4.8 Tcf of coalbed gas can be commercially found and produced at $1.50 per Mcf. Similarly, at $3.00 and $5.00 per Mcf 21 Tcf and 32 Tcf can be added to reserves. The right y-axis of the figure shows the number of cells that will have to be drilled in order to find and develop the associated additions to reserves. At $1.50 per Mcf, 2,678 wells are required , at $3.00 per Mcf; 48,318 wells are required, and at $5.00 per Mcf, 70,632 are required. This analysis assumed constant costs. However, the drilling industry is an increasing cost industry in that efforts to suddenly accelerate drilling could approach capacity constraints and lead to increasing cost. According to the Joint Association Survey (American Petroleum Institute, 1992, 1993) there were 1749, 1659, and 740 coalbed gas wells drilled in 1990, 1991, and 1992, respectively. The precipitous decline in 1992 was the result of nearing the expiration of the Section 29 tax credits for coalbed gas development. At its peak in 1981, the natural gas industry drilled nearly 20,000 gas wells per year. In 1993, it drilled about 8800 gas wells.

Even if the coalbed gas drilling rate were to increase to 2,000 wells per year without increasing costs, it would take beyond 20 years to add to reserves the 21 and 32 Tcf associated with the $3.00 and $5.00 costs. Obviously, the coalbed gas drilling rate could increase significantly without increasing costs if the drilling industry were characterized by excess capacity, were to increase capacity, or if drilling for other resources were to decline. Over such a time frame perhaps technology will be developed to screen sites without drilling. Moreover, the accumulated knowledge about the resource would probably lead to the refinement of plays allowing the a highgrading of the resource. For immediate planning purposes the resources of interest are those available at costs below $5.00 per Mcf.

The rule for determining whether a play (or part of a play at a given depth interval) would be explored by the industry required that the aggregate expected after-tax net present value of the play's commercially developable cells be sufficient to compensate for all costs, including all exploration, development, and production costs. Table 3 shows the minimum entry level incremental costs at which each play (or part of the play) starts to contribute resources to the incremental cost function in figure 2. The table also denotes plays where the entry level price is greater than $9.00 per Mcf. According to the table, plays with at least 0.5 Tcf that have a maximum entry cost of $2.00 per Mcf are the Overpressured and Underpressured Discharge plays (San Juan), the Williams Fork

(Southwestern Wyoming), Southern Raton (Raton) and the Central Appalachian plays (Appalachian).[1]

In actual practice, individual operators often have special knowledge about specific sites that allows them to profitably enter higher cost plays to explore and develop the superior locations. Some of the reported coalbed gas production in the high cost plays such as the Cherokee comes from recompletions of old gas wells in the coal interval. In such cases the gas producing infrastructure is already in place and operator costs are a small fraction of the new development costs listed in the table 3. Also, some production in higher cost areas results because of drilling associated with coal mining and past tax credits. Where there is sufficient drilling and production experience, geologists can refine plays and play boundaries to allow selective drilling of the province. The table shows that the delineation of plays in the San Juan roughly corresponds to their incremental costs. Because production experience in the Southern Raton play has been limited, the San Juan production profiles were used by the assessor as analogs.

Figures 3 a thru l show the incremental cost functions and table 4 shows the associated cost reserve additions data by province. The province incremental cost functions were drawn with the same horizontal axis to emphasize the few provinces where most of the resource is found. The table shows that for the lower 48 States, $1.50 per Mcf nearly 80% of the gas is in confirmed plays. As the incremental costs increase to $5.00 per Mcf the share of gas coming from hypothetical plays increases to 40% of the total. The largest quantities of coalbed gas in confirmed plays are in the San Juan, Appalachian (in particular, the Central Appalachian play), Uinta-Piceance and Black Warrior provinces. The cost functions show the San Juan to be the low cost area.

The assumption that the industry would incur costs of drilling each cell in a depth interval amounts to assuming grid drilling of that part of the play occurring in that depth interval. The sensitivity of the results to this assumption was tested by recomputing the incremental cost functions based on the alternative assumption that the industry would be able to selectively drill and "avoid" drilling half of the dry cells. At $1.50 per Mcf there is no difference with the "no selectivity" case, but at $3.00 per Mcf the commercially producible quantity of gas under "selectivity" is 4.3 Tcf greater than that obtained earlier. At $5.00 per Mcf the difference is only 1.8 Tcf.

[1] The Norhthern Appalachian Anticline play appears to be an anomoly but it has low costs because of extemely shallow wells (less than 1000 feet), no well stimulation, and no water production.

In 1993, gas that was formally classified as coalbed gas accounted for 6% of U.S. gas production and proved reserves. In particular production was 732 Bcf and year-end reserves were 10.2 Tcf. The San Juan accounted for a least 80% of this production. To place the numbers in this report in prospective, in 1993 U.S. gas consumption was 20.3 Tcf. The assessed quantities of coalbed gas that could reasonably be expected to be commercially developed at prevailing prices suggests that coalbed gas will continue to contribute to future gas supply. However, the quantities that can be added to reserves within a short term period may be limited by the drilling required to evaluate the resource.

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APPENDIX A. NOMENCLATURE

Continuous-type deposit.- a hydrocarbon accumulation that is pervasive throughout a large area, and for which the standard methodology for assessment of sizes and numbers of discrete accumulations is not appropriate. Sandstone continuous deposits are not significantly affected by hydrodynamic influences.

Play.- is a set of known or postulated oil or gas accumulations sharing similar geologic, geographic, and temporal properties, such as source rock, migration pathway, timing, trapping mechanism, and hydrocarbon type. For continuous type deposits or accumulations, such as coalbed gas , so-called "tight sandstone" reservoirs, and auto-sourced oil- and gas-shale reservoirs the continuous accumulation is identified as a play.

Coalbed gas play- a class of continuous-type gas deposits occurring in widespread accumulations. A play may be an area within an accumulation where similar conditions exist for the generation, accumulation, and recovery of the gas. Although the accumulation is widespread, well recoveries can be highly variable within a single play. For this assessment coal seams within a basin (province) were generally grouped together and plays were defined by changes taking place in a group of coals laterally and not vertically.

Cell.- is a subdivision of a coalbed gas play the area of which is generally equal to the coalbed gas well spacing permitted or authorized by the State regulatory agency at the time of the assessment. A productive cell has at least one well with reported production. The number of cells in a play is equal to the area of the play divided by the cell size.

Hypothetical play.- is a defined coalbed gas play that has yet no cells reporting production.

Confirmed play.- is a defined coalbed gas play that has at least one cell with demstrated production.

Success ratio.- fraction of untested cells in a coalbed gas play that are anticipated to produce gas.

Play probability.- the probability that one or more of the untested cells in the play will recover at least a threshold minimum amount of gas assigned by the assessor to the 100th fractile of the EUR distribution for the play.

Estimated Ultimate Recovery (EUR) probability distribution.- a probability distribution of ultimate recoveries of gas, in millions of cubic feet, that characterizes the distribution of gas recoveries in productive cells within a play. The EUR distribution for untested cells is judged by the assessor to represent the distribution of recoveries from potentially productive, but as of yet untested cells within the play.

Table 1. Estimates of technically recoverable coalbed gas as of January 1, 1994 *

Province (Basin)	Total (Tcf)	Confirmed (Tcf)	Hypothetical (Tcf)
Western Oregon - Washington	0.70	0.00	0.70
Uinta - Piceance	10.70	3.42	7.29
San Juan	7.53	7.53	0.00
Powder River	1.11	0.68	0.43
Wind River	0.43	0.43	0.00
Southwestern Wyoming	3.89	0.00	3.89
Raton	1.78	1.78	0.00
Forest City	0.45	0.00	0.45
Cherokee	1.91	1.91	0.00
Arkoma	2.64	0.39	2.26
Illinois	1.63	1.63	0.00
Black Warrior	2.30	2.24	0.06
Appalachian	14.85	4.43	10.41
Total lower 48 States	49.91	24.43	25.48

* Based on data in Gautier and others (1995).

Table 2.--Cell EUR size classes

Class	Cell Size BCF
0	.0938 - .1875
1	.1875 - .375
2	.375 - .750
3	.75 - 1.5
4	1.5 - 3.
5	3 - 6.
6	6 - 12
7	12 - 24
8	24 - 48
9	48 - 96
10	.96 - 192

Table 3. Provinces, play names, threshold price at which play is commercially developable with associated reserves and required drilling

Province	Play No.	Play Name	Threshold Price ($/Mcf)	Initial Reserves (Bcf)	Cells Drilled
W. Oregon-Washington	450	Bellingham*	------		
W. Oregon-Washington	451	W. Cascade Mountains	3.75	329	730
W. Oregon-Washington	452	Southern Puget Lowlands*	-----		
Uinta-Piceance	2050	Uinta - Book Cliffs	3.00	1225	1523
Uinta-Piceance	2051	Uinta - Sego*	-----		
Uinta-Piceance	2052	Uinta - Emery	3.75	552	1088
Uinta-Piceance	2053	Piceance - White River Dome	3.50	183	344
Uinta-Piceance	2054	Piceance - Western Basin Margin	2.25	4228	4215
Uinta-Piceance	2055	Piceance - Grand Hogback	3.75	194	104
Uinta-Piceance	2056	Piceance - Divide Creek Anticline	2.50	259	332
San Juan	2205	Overpressured	1.00	3328	1300
San Juan	2252	Underpressured Discharge	2.00	2098	1939
San Juan	2253	Underpressured	4.00	1035	2243
Powder River	3350	Shallow Mining Related	2.25	534	5653
Powder River	3351	Central Basin	7.50	389	5339
Wind River	3550	Mesaverde	2.50	349	360
Southwestern Wyoming	3750	Rock Springs	2.75	576	665
Southwestern Wyoming	3751	Iles	5.25	267	959
Southwestern Wyoming	3752	Williams Fork	1.50	983	809
Southwestern Wyoming	3753	Almond	5.00	567	1900
Southwestern Wyoming	3754	Lance*	-----		
Southwestern Wyoming	3755	Fort Union*	-----		
Raton	4150	Northern Raton	3.25	860	700
Raton	4151	Purgtoire River	2.00	254	230
Raton	4152	Southern Raton	1.50	527	569
Forest City	5650	Central Basin*	-----		
Cherokee Platform	6050	Central Basin	6.75	1277	20000
Arkoma	6250	Anticline	2.25	272	2844
Arkoma	6251	Syncline	3.00	1753	8272
Illinois	6450	Central Basin	4.50	1335	9710
Black Warrior	6550	Recharge	5.25	232	929
Black Warrior	6551	Southeastern Basin	3.25	1200	2923
Black Warrior	6552	Coastal Plain	5.50	584	1781
Black Warrior	6553	Central and Western Basin*	-----		
Appalachian	6750	Northern Appalachian Anticline	2.00	448	11020
Appalachian	6751	Northern Appalachian Syncline	6.00	8190	68910
Appalachian	6752	Central Appalachian	2.00	2539	8418
Appalachian	6753	Canhaba Field	5.25	119	814

* Indicates that play is not commercially developable at cost of $9.00 per Mcf or less

Table 4. Coalbed Gas: incremental costs of additions to reserves for provinces and the lower 48 States

Province Name	Cost	Plays Total	Plays Confirmed	Plays Hypothetical
	$/Mcf	Tcf	Tcf	Tcf
W. Oregon - Washington	0.00	0.00	0.00	0.00
	1.50	0.00	0.00	0.00
	2.00	0.00	0.00	0.00
	2.50	0.00	0.00	0.00
	3.00	0.00	0.00	0.00
	3.50	0.00	0.00	0.00
	4.00	0.33	0.00	0.33
	4.50	0.33	0.00	0.33
	5.00	0.33	0.00	0.33
Uinta-Piceance	1.00	0.00	0.00	0.00
	1.50	0.00	0.00	0.00
	2.00	0.00	0.00	0.00
	2.50	4.49	0.26	4.23
	3.00	5.77	1.54	4.23
	3.50	7.76	2.05	5.71
	4.00	9.07	2.86	6.21
	4.50	9.39	2.87	6.53
	5.00	9.49	2.95	6.54
San Juan	1.00	3.33	3.33	0.00
	1.50	3.33	3.33	0.00
	2.00	5.97	5.97	0.00
	2.50	5.97	5.97	0.00
	3.00	5.97	5.97	0.00
	3.50	6.23	6.23	0.00
	4.00	7.27	7.27	0.00
	4.50	7.42	7.42	0.00
	5.00	7.42	7.42	0.00
Powder River	1.00	0.00	0.00	0.00
	1.50	0.00	0.00	0.00
	2.00	0.00	0.00	0.00
	2.50	0.53	0.53	0.00
	3.00	0.65	0.65	0.00
	3.50	0.65	0.65	0.00
	4.00	0.65	0.65	0.00
	4.50	0.65	0.65	0.00
	5.00	0.65	0.65	0.00

Wind River	1.00	0.00	0.00	0.00
	1.50	0.00	0.00	0.00
	2.00	0.00	0.00	0.00
	2.50	0.35	0.35	0.00
	3.00	0.35	0.35	0.00
	3.50	0.40	0.40	0.00
	4.00	0.40	0.40	0.00
	4.50	0.40	0.40	0.00
	5.00	0.42	0.42	0.00
Southwestern Wyoming	1.00	0.00	0.00	0.00
	1.50	0.98	0.00	0.98
	2.00	1.09	0.00	1.09
	2.50	1.09	0.00	1.09
	3.00	1.83	0.00	1.83
	3.50	1.83	0.00	1.83
	4.00	1.91	0.00	1.91
	4.50	1.91	0.00	1.91
	5.00	2.57	0.00	2.57
Raton	1.00	0.00	0.00	0.00
	1.50	0.53	0.53	0.00
	2.00	0.78	0.78	0.00
	2.50	0.83	0.83	0.00
	3.00	0.83	0.83	0.00
	3.50	1.71	1.71	0.00
	4.00	1.71	1.71	0.00
	4.50	1.72	1.72	0.00
	5.00	1.72	1.72	0.00
Arkoma	1.00	0.00	0.00	0.00
	1.50	0.00	0.00	0.00
	2.00	0.00	0.00	0.00
	2.50	0.28	0.28	0.00
	3.00	2.10	0.35	1.75
	3.50	2.11	0.36	1.75
	4.00	2.11	0.36	1.75
	4.50	2.11	0.36	1.75
	5.00	2.56	0.36	2.21

Illinois	1.00	0.00	0.00	0.00
	1.50	0.00	0.00	0.00
	2.00	0.00	0.00	0.00
	2.50	0.00	0.00	0.00
	3.00	0.00	0.00	0.00
	3.50	0.00	0.00	0.00
	4.00	0.00	0.00	0.00
	4.50	1.34	1.34	0.00
	5.00	1.35	1.35	0.00
Black Warrior	1.00	0.00	0.00	0.00
	1.50	0.00	0.00	0.00
	2.00	0.00	0.00	0.00
	2.50	0.00	0.00	0.00
	3.00	0.00	0.00	0.00
	3.50	1.20	1.20	0.00
	4.00	1.20	1.20	0.00
	4.50	1.20	1.20	0.00
	5.00	1.20	1.20	0.00
Appalachian	1.00	0.00	0.00	0.00
	1.50	0.00	0.00	0.00
	2.00	2.99	2.99	0.00
	2.50	3.06	3.06	0.00
	3.00	3.48	3.48	0.00
	3.50	3.51	3.51	0.00
	4.00	3.53	3.53	0.00
	4.50	3.93	3.93	0.00
	5.00	3.94	3.94	0.00
Lower 48 States	1.00	3.33	3.33	0.00
	1.50	4.84	3.86	0.98
	2.00	10.83	9.74	1.09
	2.50	16.59	11.27	5.32
	3.00	20.98	13.17	7.81
	3.50	25.40	16.10	9.30
	4.00	28.18	17.97	10.21
	4.50	30.40	19.88	10.52
	5.00	31.65	20.00	11.65

* Expected incremental costs of Forest City and Cherokee Platform exceed $5.00 per Mcf

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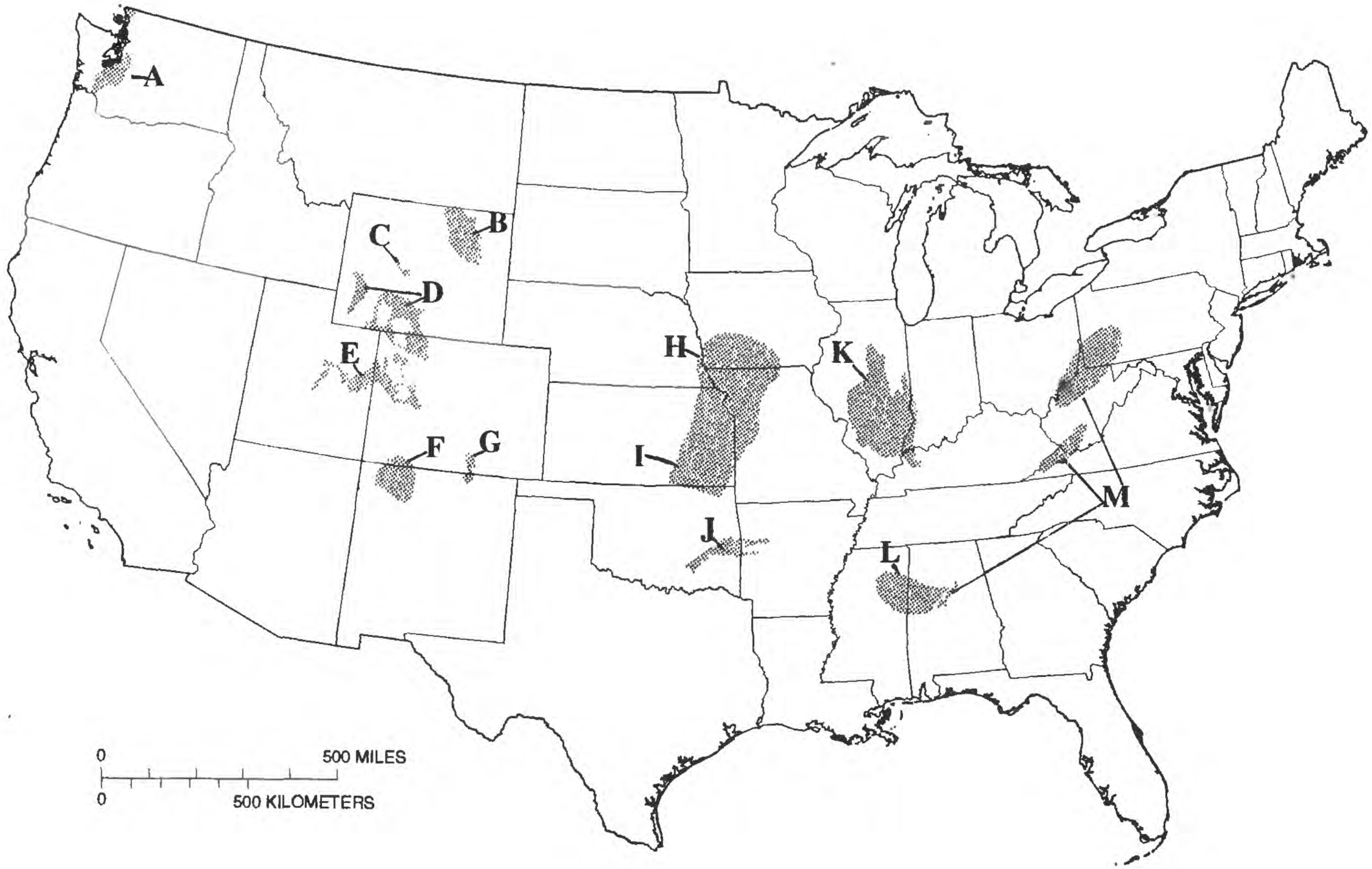


Figure 1. Locations of the provinces showing areas of coalbed gas plays assessed. Provinces and corresponding letters are: Western Oregon-Washington (A), Powder River (B), Wind River (C), Southwestern Wyoming (D), Uinta-Piceance (E), San Juan (F), Raton (G), Forest City (H), Cherokee Platform (I), Arkoma (J), Illinois (K), Black Warrior (L), Appalachian (M).

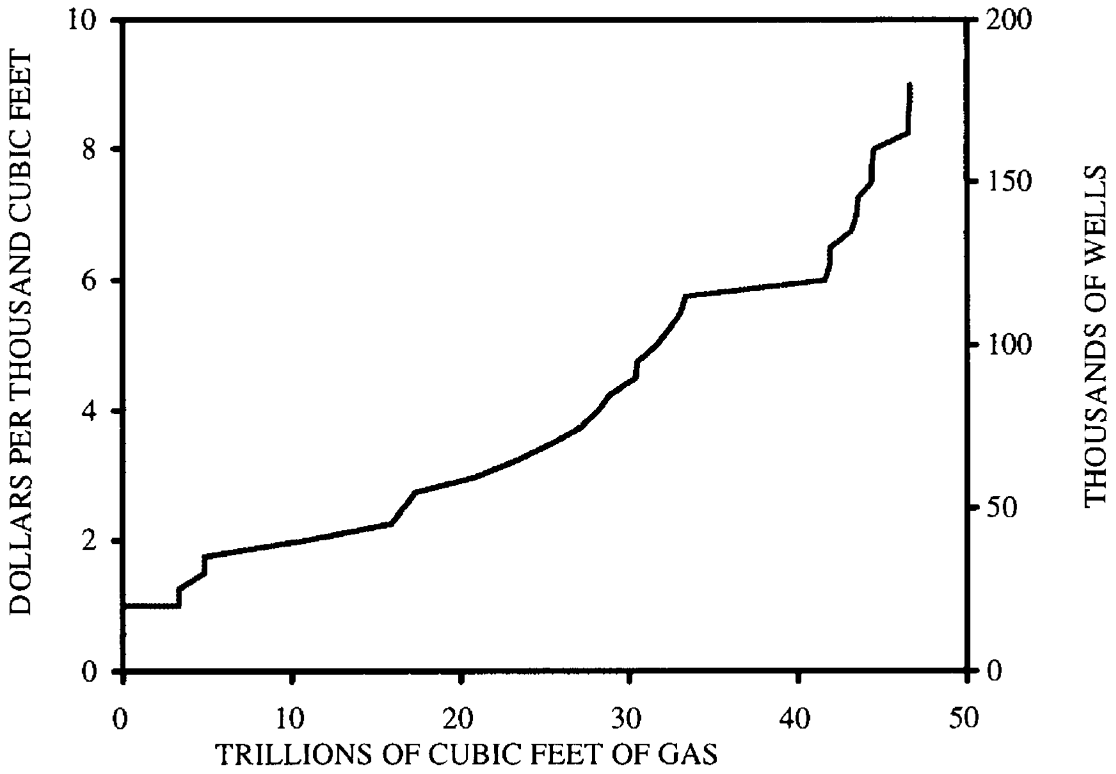


Figure 2. Incremental costs of finding and producing coalbed gas in the conterminous United States

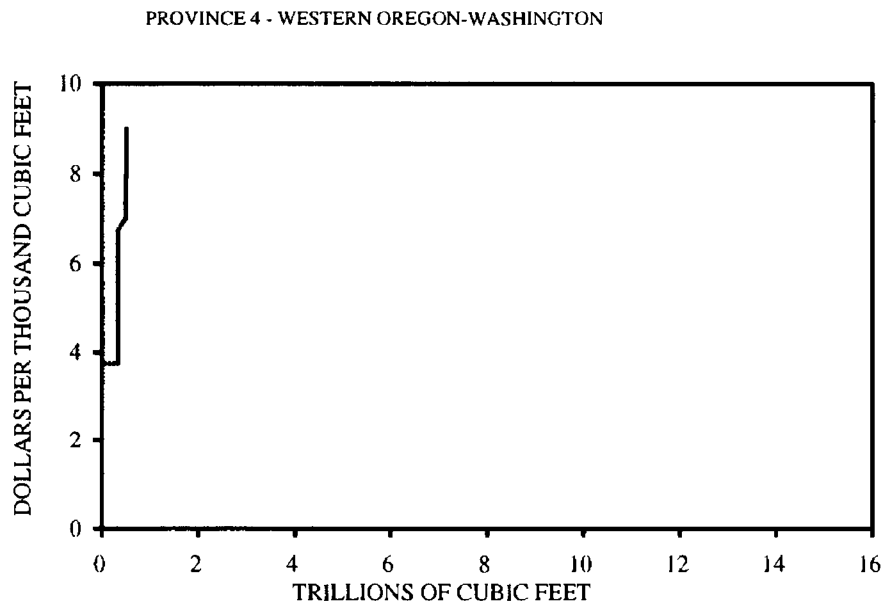


FIGURE 3A. Incremental costs of finding and producing coalbed gas in W. Oregon Washington.

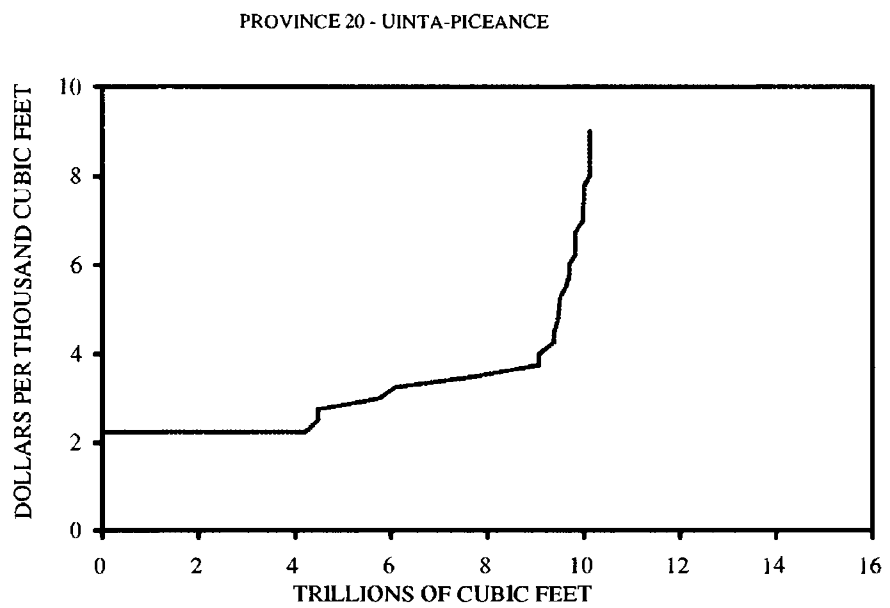


FIGURE 3B. Incremental costs of finding and producing coalbed gas in Uinta-Piceance.

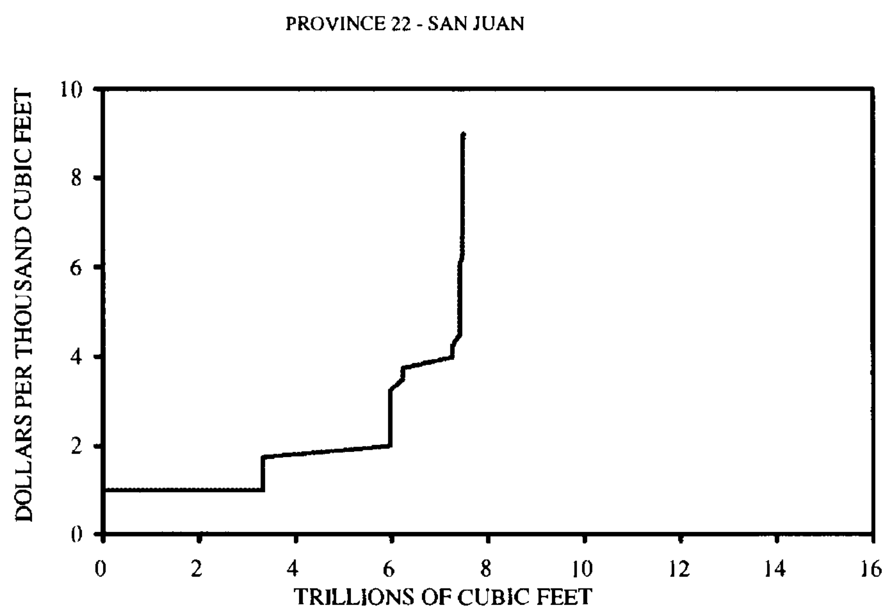
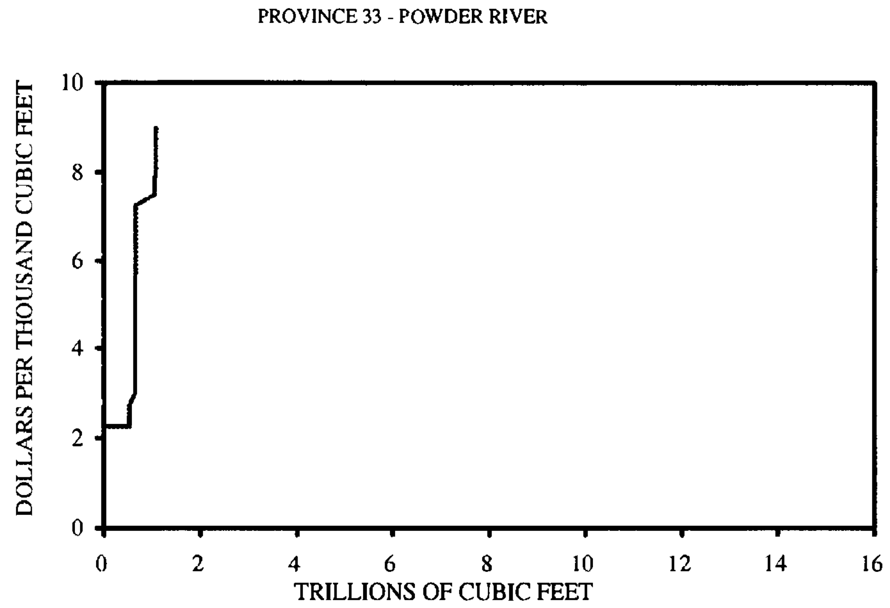


FIGURE 3C. Incremental costs of finding and producing coalbed gas in the San Juan.



FIGUR 3D. Incremental cost of finding and producing coalbed gas in the Powder River.

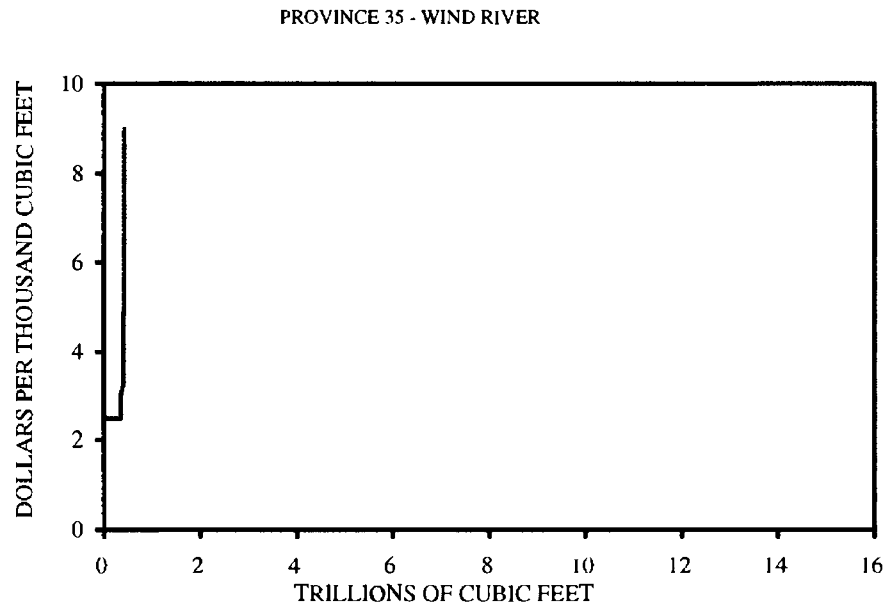


FIGURE 3E. Incremental costs of finding and producing coalbed gas in the Wind River.

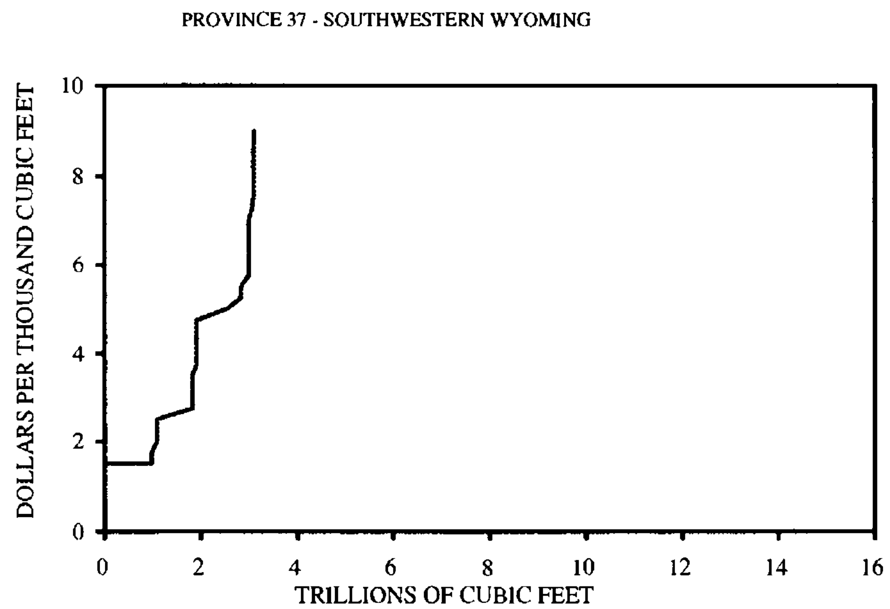


FIGURE 3F. Incremental costs of finding and producing coalbed gas in Southwestern Wyoming.

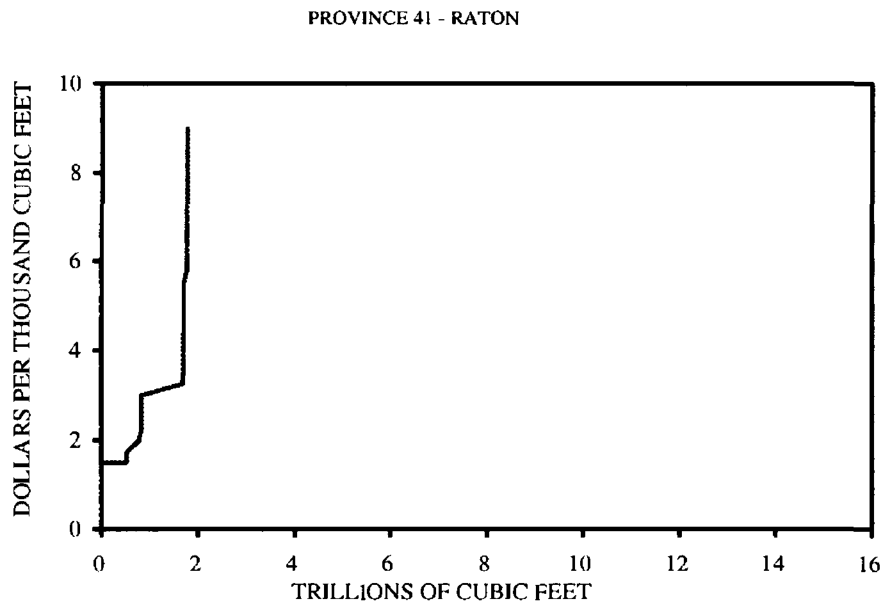


FIGURE 3G. Incremental costs of finding and producing coalbed gas in the Raton.

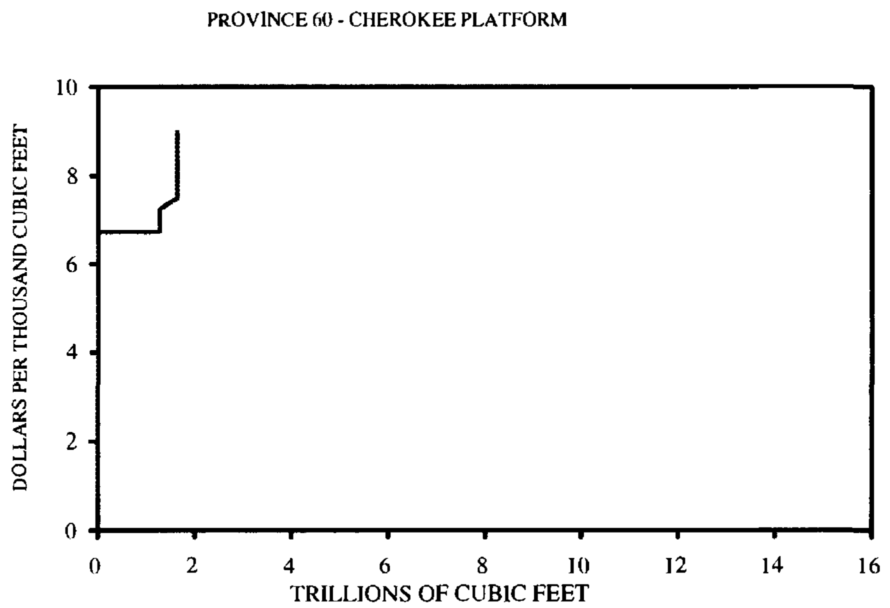


FIGURE 3H. Incremental costs of finding and producing coalbed gas in the Cherokee Plaform.

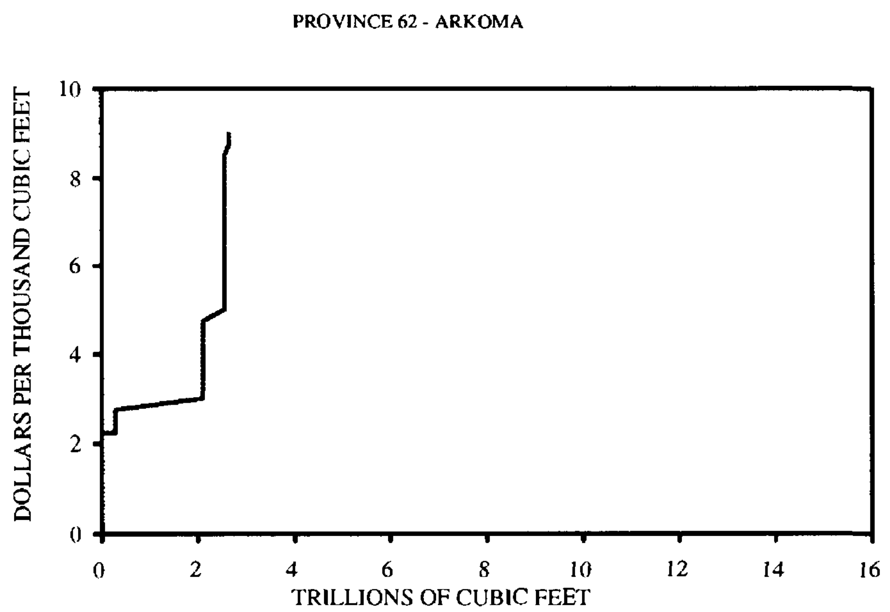


FIGURE 3I. Incremental costs of finding and producing coalbed gas in the Arkoma.

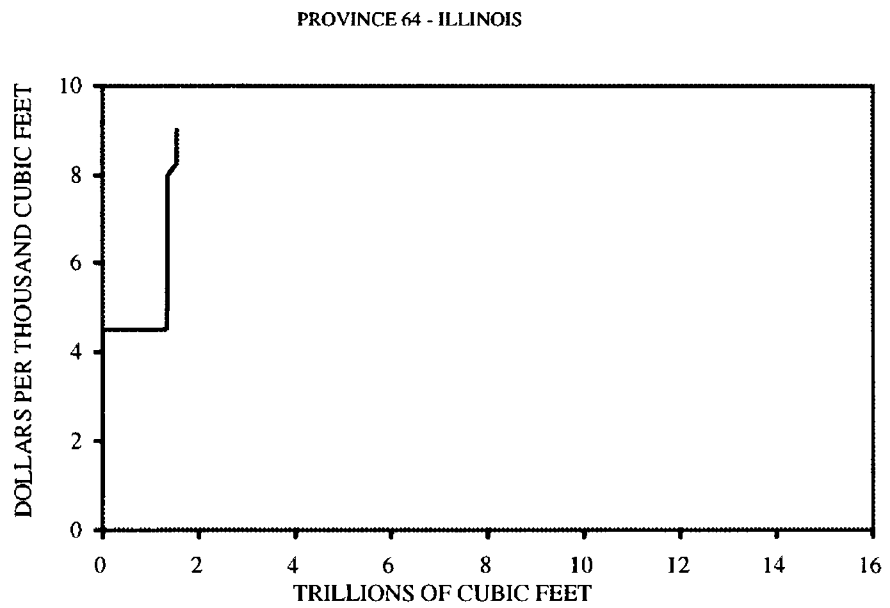


FIGURE 3J. Incremental costs of finding and producing coalbed gas in the Illinois.

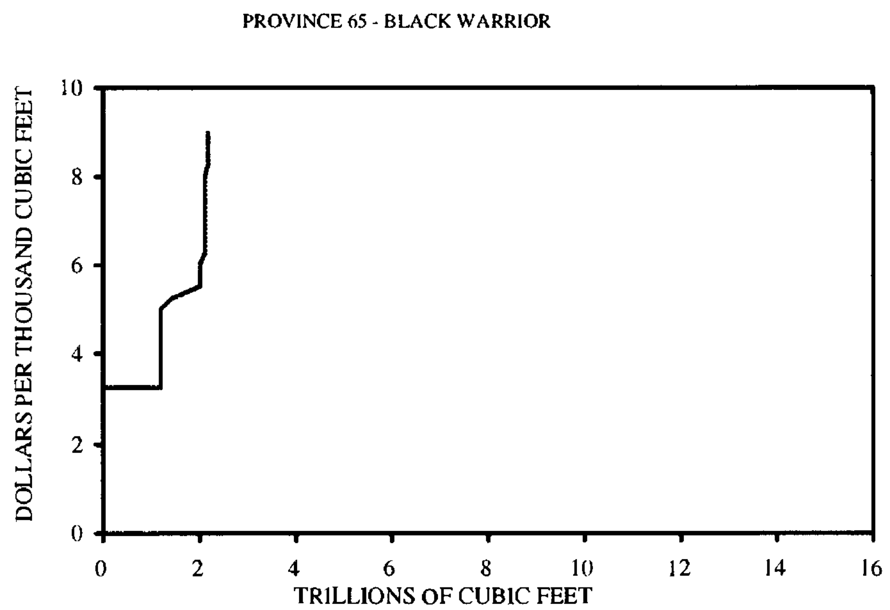


FIGURE 3K. Incremental costs of finding and producing coalbed gas in the Black Warrior.

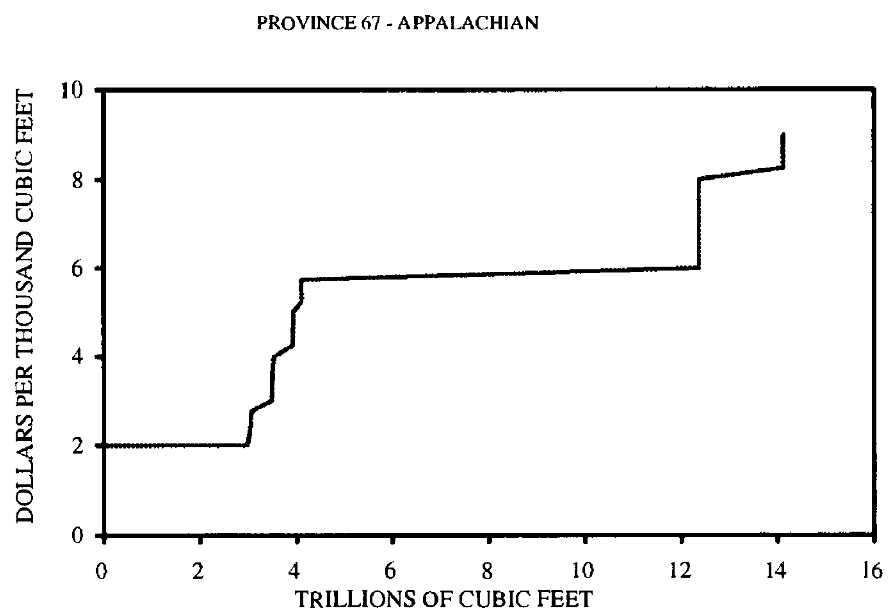


FIGURE 3L. Incremental costs of finding and producing coalbed gas in the Appalachian.