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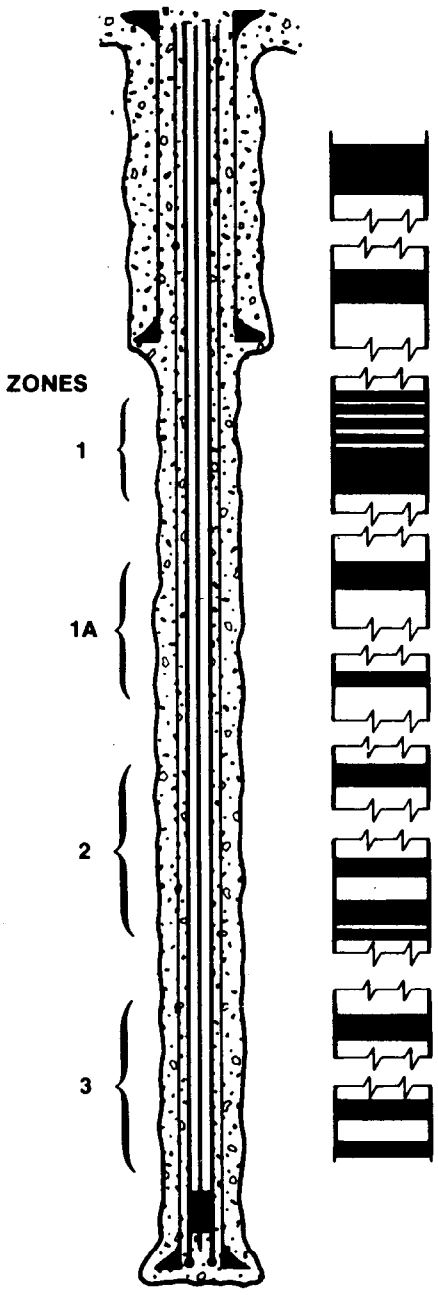

Economic Analysis of Vertical Wells for Coalbed Methane Recovery

Prepared for
Methane Recovery from Coalbeds Project
Contract Number DE-AC21-78MC08089
United States Department of Energy

UGR FILE # 98

March 1981

By
TRW ENERGY ENGINEERING DIVISION
8301 GREENSBORO DRIVE, McLEAN, VIRGINIA 22102

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ABSTRACT

Previous economic studies of the recovery and utilization of methane from coalbeds using vertical wells were based on drainage in advance of mining where a single seam is drained with well spacing designed for rapid predrainage. This study extends the earlier work and shows that methane recovery costs can be reduced significantly by increasing well spacing and draining multiple coalbeds. A favorable return on investment can be realized in many geologic settings using this method. Sensitivity of recovery economics to certain development costs and parametric variations are also examined as are the economics of three methane utilization options.

This work was funded in part by the TRW effort under U.S. DOE contract DE-AC21-78C08089. Dr. Harold D. Shoemaker is the Technical Project Officer for this contract. The sponsoring organization is the Methane Recovery from Coalbeds Project, John R. Duda, Manager. This study was conducted under the direction of Alex Gillies by Arnold Snygg and William Fox.

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1. EXECUTIVE SUMMARY

BACKGROUND

Previous economic studies relating to the drainage of methane from coalbeds, conducted by TRW and the National Petroleum Council, focused primarily on techniques associated with mining operations. In that scenario rapid drainage of methane from coal is required; for vertical wells a spacing of 20 acres or less is typical. Additionally, only the coalbed being mined is drained.

This study extends the earlier work to techniques dictated by production economics--multiple wells spaced to reduce the initial investments and producing gas from several coalbeds. The economics of three utilization options sized for relatively low production rates expected from coalbeds were also examined to provide a complete economic picture of recovery and utilization of coalbed methane.

MAJOR FINDINGS

For the purposes of comparison to previous studies and to highlight the impact of systems designed for economic effectiveness, a baseline system or field configuration of closely spaced wells draining a single seam or pay zone was assumed. This baseline assumes 32 wells with 20-acre spacing draining a single 7-foot coalbed with a specific gas content of 250 cubic feet per ton. The effects of well spacing and the recovery of methane from the other coalbeds that are frequently present in many areas were determined using the required selling price to provide a reasonable return on investment (20 percent). The discounted cash flow analysis was performed on the conceptual system designs using the TRW ECONGAS model. The major findings are:

- The cost of the recovery of coalbed methane can be substantially reduced by the increases in well spacing and the multiple zone production possible at many sites. The 20 percent return required selling price for the baseline case can be reduced from $9.89/Mcf to $6.34/Mcf by using 80-acre spacing. If the number of coalbeds drained can be increased to four, the selling price can be further reduced to $2.16/Mcf. Similar results can be obtained with various combinations of wider spacing, multiple zone drainage, and higher specific gas content.

- For mine operators, the cost of draining methane before or along with mining can be eliminated or substantially reduced by using longer drainage times to reduce the number of wells and by using revenues from the sale of gas recovered from the mined seam and other coalbeds in the field area. This method of production pays off even when the rights to drain gas must be purchased.

CONFIGURATIONS AND COST VARIATIONS

The following parameters were varied to show their individual impact on gas price at the field:

Variable	Sensitivity or Impact on Required Selling Price
Specific gas content	Price is inversely proportional to gas content. (Only added costs are for larger compressors and additional power.)
Intangible costs (site preparation, rig mobilization, drilling, and services)	A 50% variation results in approximately a 30% change in required selling price (intangible costs are approximately 70% of initial costs).
Production lifetime	A 50% variation in production lifetime results in a 20% change in price when lifetime is decreased; 5% when lifetime is increased.
Drilling and casing costs	A 50% variation results in a 20% change in price for the baseline configuration (20 acres/well) and 10% change in price for all other configurations (80 acres/well)
Depreciable costs	A 50% variation in depreciable costs results in approximately a 10% change in price (depreciable costs are approximately 25% of initial costs).
Required return on investment	A change in ROI to 15% and 25% results in approximately 8% change in price for the baseline configuration and 14% for all other configurations.
Operations and maintenance	A 50% variation results in an average 2% change in price for the baseline configuration and 7% for the other configurations. (O&M yearly costs are approximately 5% of initial costs.)

UTILIZATION ECONOMICS

The increases in selling price required to produce a rate of return of 20% on small-scale utilization systems are:

Option	Added Price
Gas cleaned, compressed, and transmitted to a pipeline	.81 to $4.14/Mcf (dependent on cleaning requirements)
Electricity generated and transmitted to the power grid	1.59 to 1.88/Mcf
Gas liquefied and trucked to market	4.2 to $6.5/Mcf

CONCLUSIONS AND RECOMMENDATIONS

The results of this study show that coalbed methane can be recovered economically by designing the recovery systems to maximize the return on investment rather than designing the system to drain a single seam in the period just prior to mining. This system designed for economic effectiveness can be employed by mine operators for predrainage by allowing for longer drainage times. Even if mine operators do not desire to drain other coalbeds in the field because of institutional or legal issues, wider spaced, longer drainage time wells reduce costs significantly.

Further economic studies of other drainage methods and comparisons to vertical wells should be conducted. These studies should also consider the loss of methane resources which occur when all of the coalbeds in an area are not drained. Vertical wells of course provide direct access to these multiple coalbeds.

2. INTRODUCTION

2.1 BACKGROUND AND ECONOMICS

Methane is generated during the natural process of coal formation and frequently is trapped in the coalbeds and associated strata. There is general agreement that the total magnitude of the coalbed methane resource is significant with estimates from various sources ranging from 260 to 860 trillion cubic feet (Tcf). Estimates of the methane content of the Pittsburgh Seam in the Northern Appalachian Basin alone range from 0.6 to 4 Tcf. Little of this resource is currently utilized, although it has been estimated that approximately 300 Tcf are recoverable using current technology (ref. 1). In general, methane recovery technology has been driven by the need to predrain gassy coal mines rather than by the need for gas, and the recovered gas is typically vented to the atmosphere. This low rate of utilization of coalbed methane also stems from the traditional abundance and low cost of natural gas produced domestically.

Increases in high-cost gas imports, although lagging those of liquid products, have focused attention on unconventional gas resources, including methane from coalbeds. As shown in Figure 1, natural gas has historically been inexpensive in absolute terms and in relation to the price of liquid petroleum. Even at regulated prices supplies from domestic sources met demand, and gas imports lagged far behind imports of liquids. In 1975 about 4 percent of U.S. gas consumption was imported, and a trend to higher prices was evident (data from Los Alamos Survey).

In order to stimulate domestic production of natural gas, the Natural Gas Policy Act of 1978 (Public Law 95-621) was enacted. Under Title 1, Subtitle A, Section 107 of this law, "occluded natural gas produced from coal seams" was classified as a "high-cost natural gas", and its price was in effect deregulated. Thus the current gas market differs radically from that existing before 1973 or 1974. In 1979 a total of 283.4 trillion Btu of liquefied natural gas was imported from Algeria at prices ranging from $3.50 to $4.42 per MMBtu regasified into east coast transmission lines.*

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*From "Gas Energy Review", March 1980

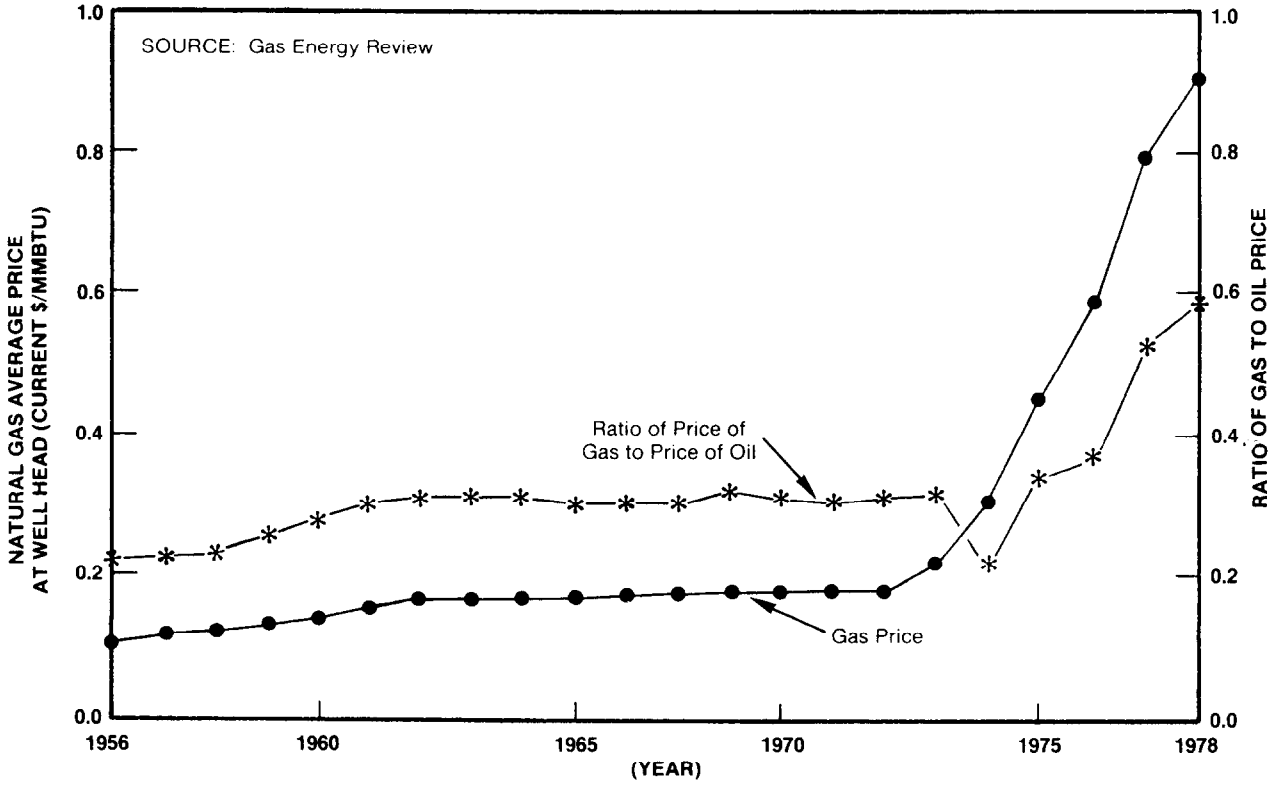


Figure 1. Gas Price History

In March of 1980 Algeria doubled the price of its gas to bring it into parity with crude oil (at $38 per barrel). As a result, gas imports from that country ceased, but imports from Canada and Mexico continue at $4.47 per MMBtu.

Domestically produced gas from deep conventional wells is also exempted from price ceilings by the Natural Gas Policy Act and is increasing in cost. Recent contracts at prices of $5.00 per MMBtu are reported in the Wall Street Journal. However, these high prices for domestic gas are being paid only for large volumes of gas over long periods of time, and short-term contracts for small quantities of gas such as coalbed methane supplies do not command as high a price (Wall Street Journal, June 10, 1980). Additionally, significant quantities of natural gas have been discorered in 1980, and prices of both imported and domestic gas are apparently stabilizing (Gas Energy Review and Oil and Gas Journal). The price of coalbed methane gas can be expected, therefore, to exhibit the same stabilization in price.

2.1.1 Previous Studies

A study conducted by TRW (ref. 2) in 1977 for the U.S. Department of Energy's Morgantown Energy Technology Center (METC) examined the recovery of the methane contained in coalbeds using various extraction techniques and utilization options. The extraction options considered stimulated vertical and horizontal wells drilled into the coalbeds from within the mine or directionally drilled from the surface. The concept of drilling holes from the mine considered holes both drilled immediately in advance of mining and from a vent shaft sunk into the coalbed several years in advance of when it was required for mine operations.

In that study the economics of vertical wells to extract methane in advance of mining did not compare favorably with in-mine drilling, principally due to the higher costs of the wells and the close well spacing typical of the short time desirable for drainage for mine safety purposes (approximately 3 to 5 years). The wells were typically spaced at 20 acres or less and drained only the coalbed associated with the mining. For typical installations associated with mine predrainage, the required gas selling price for a favorable return on investment was 2 to 3 times the price for horizontal wells drilled from within the mine and was in excess of the then-regulated market price for the gas by 30 to 100 percent.

A later study conducted by the National Petroleum Council (ref. 3) in 1980 made the following projections of economically recoverable methane from coalbeds.

PROJECTED ECONOMIC RESERVES OF COALBED GAS

(Raw Gas On Site With No Compression)

(Constant 1979 Dollars)

Price Level	ROR	Recoverable Reserves (TCF)
$2.50/MCF	10%	5.0
	15%	2.5
	20%	2.0
$3.50/MCF	10%	13.1
	15%	9.9
	20%	7.1
$5.00/MCF	10%	25.4
	15%	19.9
	20%	16.7
$7.00/MCF	10%	33.9
	15%	30.7
	20%	24.3
$9.00/MCF	10%	44.7
	15%	38.4
	20%	33.2

These projections were also made on the basis of draining a single bed of coal.

2.1.2 Current Commercial Developments

Due in part to projects conducted in cooperation with the Department of Energy, and in part to gas price increases, private industry has become active in some fairly large-scale operations with varying degrees of success. Some of these projects are:

- Mid-Continent Resources, Carbondale, Colorado, operates a project in the Piceance Basin. Daily production is 1.5 MMcfd and the gas is compressed and supplied to a coal dryer system.

- Kerr-McGee produces 300 Mcfd from the Arkoma Basin and injects into a pipeline. This project is located in Haskell County, Oklahoma.

- A private developer in the San Juan Basin produces 600 Mcfd from five wells. The gas is injected into a pipeline.

- Sun Gas and partners (Tuscoal Project) planned to drill 96 wells in the Warrior Basin, but the project was terminated because the property contained too little coal.

- Algas Resources Limited is planning a project in the Newfoundland coal fields. Estimated production is 10 million cubic feet per day.

2.2 OBJECTIVES AND APPROACH

The purpose of this study is to examine the economics of recovering methane from coalbeds via multiple vertical wells, each producing from all coalbeds available at the site with well spacing dictated by economic factors rather than the need to drain the methane rapidly in advance of mining. Economic benefits to mining operations realizable from predraining the methane were not included in this study.

2.2.1 Approach and Assumptions

Economic analyses were conducted for a baseline case and a set of variations to the baseline. The baseline scenario consisted of five configurations:

- 20-acre well spacing, a single coalbed, and a field life of 3 years (the rapid drawdown configuration associated with mining operations)

- 80-acre well spacing and a life of 10 years (methane is drained from one coalbed for comparison to the above case)

- 80-acre well spacing and a field life of 10 years with methane drained from 2 seven foot zones (14 feet of coal)

- 80-acre well spacing and field life of 10 years with methane drained from 4 zones (28 feet of coal)

- 80-acre well spacing and a field life of 10 years with methane drained from 6 zones (42 feet of coal).

Sensitivity analyses included the effects of variations of specific gas content, well spacing, tangible and intangible costs, depletable costs, production lifetime operating and maintenance expenses, return on investment, production drawdown, and drilling and casing costs.

The costs associated with developing a gas property were grouped on a unit basis (cost per foot of well bore, for a set of wellhead equipment, etc.) and into the following categories:

- Items basically independent of field size
- Items mainly dependent on well spacing and site area
- Costs per well that are nearly independent of well depth
- Costs dependent on well depth.

A sequential ordering of costs, as incurred during normal field development, was also assumed. The unit costs are averages and are considered best estimates for 1980/81.

In addition, economic analyses of three utilization systems were considered: direct injection of coalbed methane into a nearby natural gas distribution pipeline, electric generation, and liquefaction of natural gas.

2.2.2 Report Content

The magnitude, distribution, and quality of the coalbed methane resource is discussed in Section 3; well performance data and assumptions in Section 4; and site development and well costs in Section 5.

Economic analyses were conducted using and TRW ECONGAS Model. This model is described in Section 6; economic analyses results are discussed in Section 7; and utilization economics are discussed in Section 8.

3. RESOURCE CHARACTERISTICS

Characteristics of the coalbed methane resource described in this section are the quantity of the resource, its geographic distribution, its geologic or stratigraphic characteristics and its quality. This data forms the basis for well and reservoir performance assumptions. Data on other physical parameters affecting recovery of this resource (formation hydrology and permeability of coal to gas flow) are very limited or site-specific and are addressed only in general terms in the following sections. Legal considerations such as constraints on recovery of the gas are not addressed in this study.

3.1 QUANTITY OF METHANE IN COALBEDS

Estimates of the total gas content of coalbeds from various sources are as follows:

Source	Estimate (Tcf)
National Petroleum Council "Unconventional Gas Sources - Coal Seams", June 1980	398
Federal Energy Regulatory Commission, U.S. DOE, Nonconventional Natural Gas Resources", June 1978	850
Wise and Skillern "Coalbed Methane Recovery and Utilization", Nov. 1978	300-800
M. Deul and A. Kim, "Methane Drainage - Update", July 1978	258-629
DOE, "Semi-Annual Report for the Unconventional Gas Recovery Program", March 1980	700
TRW, "Systems Studies of Energy Conservation--Methane Produced from Coalbeds", January 1977	72-860

3.2 GEOGRAPHIC DISTRIBUTION OF THE RESOURCE

On the basis of work conducted on the Department of Energy Methane from Coalbeds Project, TRW estimates the methane content and concentrations of important coal basins and their principal formations to be as shown in Table 1. The variation in methane content for some of the better understood coalbeds is shown in Figure 2. Anthracite and bituminous coals typically have a higher concentration of methane than other coals, and the deeper beds typically contain more gas than the shallow beds. More data are available on eastern than on western coal basins. The location of these basins is shown in Figure 3.

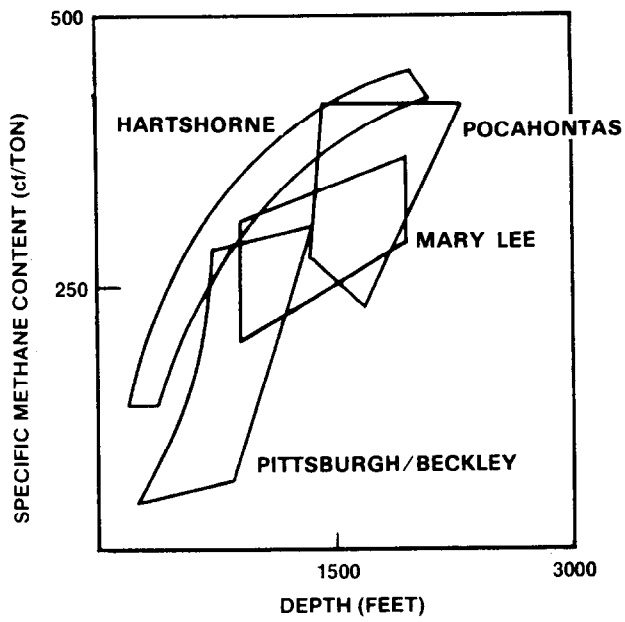


Figure 2. Methane Concentration as a Function of Depth

3.3 STRATIGRAPHIC DISTRIBUTION

Typical aggregate thicknesses of coal deposits in eastern and western coal basins as a function of depth are shown in Figure 4. Coal deposits typically occur in a number of beds or in zones of closely spaced beds or partings. For example, in tests being conducted by Mountain Fuel Gas Company in the Book Cliffs coal fields in central Utah, seven coalbeds, ranging in thickness from 3 to 15 feet, were encountered at depths of from 2,880 to 3,150 feet and specific gas content was 200 to 400 cf/ton. The areal extent of this

Table 1. Principal Coalbed Methane Resource Concentrations

Basin and Principal Coal-Bearing Formations	Gas Resource (TCF)*	Gas Content (cf/ton)
ARKOMA	1.6 - 3.6	200 - 450
McAlester	0.3 - 0.7	
Hartshorne Undivided	0.3 - 0.7	
Upper Hartshorne	0.1 - 0.3	
Lower Hartshorne	0.6 - 1.4	
GREATER GREEN RIVER	1.0 - 31	10 - 540
Hams Fork Region	.01 - 1.7	
Rock Springs Uplift	0.3 - 5.7	
Great Divide Basin	0.2	
Washakie Basin	0.2	
Sand Wash Basin	0.1 - 23	
ILLINOIS	14.6 - 54.8	40 - 150
Danville	0.5 - 1.7	
Herrin	2.5 - 3.4	
Springfield - Harrisburg	2.2 - 9.9	

*Since all formations are not included, the resource in formations listed does not necessarily equal resource in basins.

Table 1. Principal Coalbed Methane Resource Concentrations (Cont'd)

Basin and Principal Coal-Bearing Formations	Gas Resource (TCF)	Gas Content (cf/ton)
NORTHERN APPALACHIANS	6.8 - 87.3	30 - 420
PICEANCE	.06 - 20.3	1 - 340
POWDER RIVER	5.9 - 65	15 - 100
Wyodak-Anderson	1.5 - 10	
RATON MESA	8 - 18.4	25 - 490
Vermejo Formation	5 - 11.6	
Raton Formation	3 - 6.8	

Table 1. Principal Coalbed Methane Resource Concentrations (Cont'd)

Basin and Principal Coal-Bearing Formations	Gas Resource (TCF)	Gas Content (cf/ton)
SAN JUAN		10 - 135
Fruitland Formation	1.8 - 25	
Menefee Formation	.007 - .09	
WARRIOR	5 - 10	7 - 600
Mary Lee Group	0.9 - 3.5	150 - 550
WESTERN WASHINGTON	2.6 - 24	65 - 440

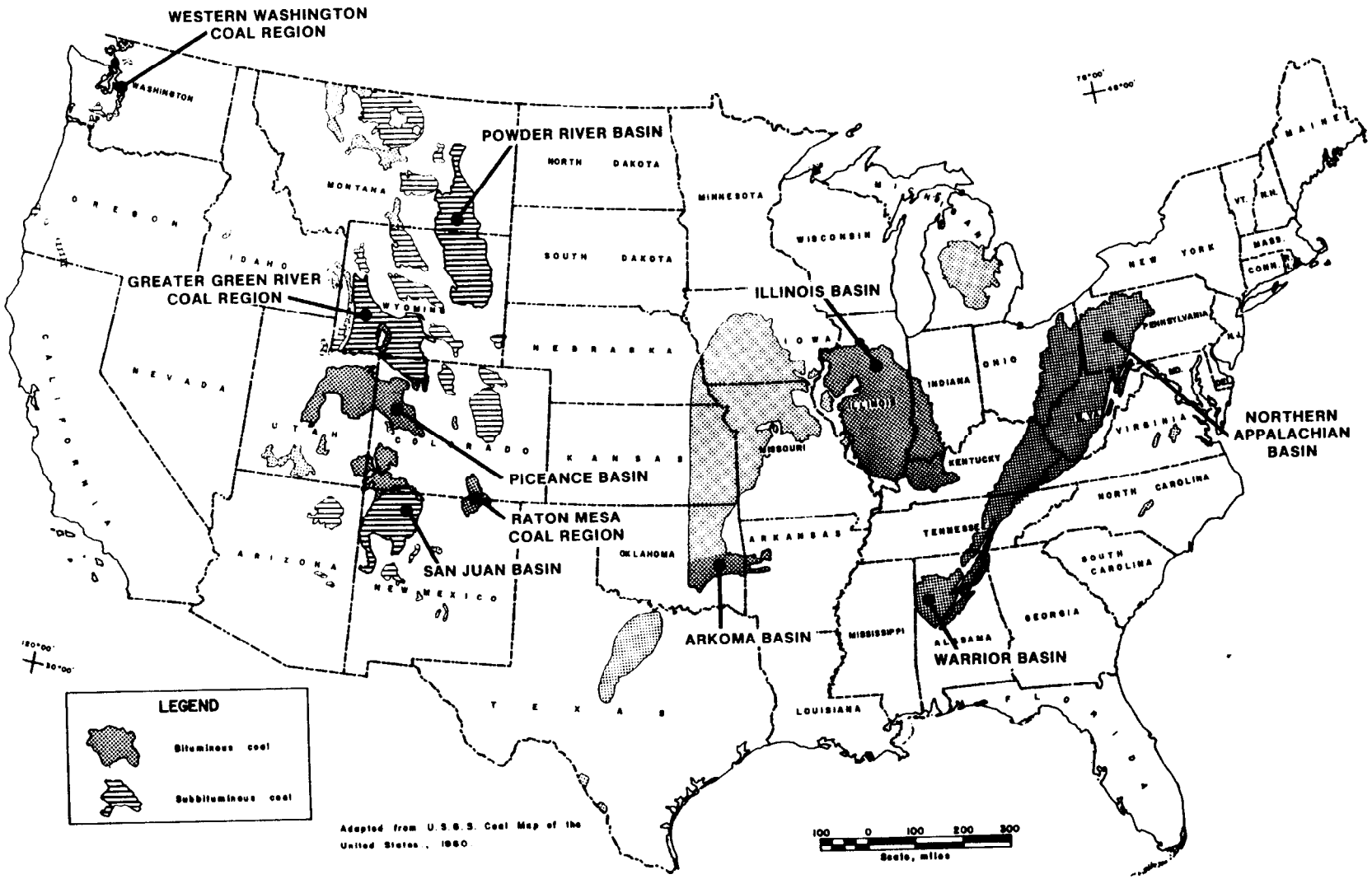


Figure 3. Locations of Coal Basins

field is 180,000 acres and the gas-in-place is estimated to be 0.2 to 0.4 Tcf. The stratigraphic distribution of coal and gas content in two areas, one in the Northern Appalachian Basin and one in the Green River Basin, is shown in Figures 5 and 6, respectively.

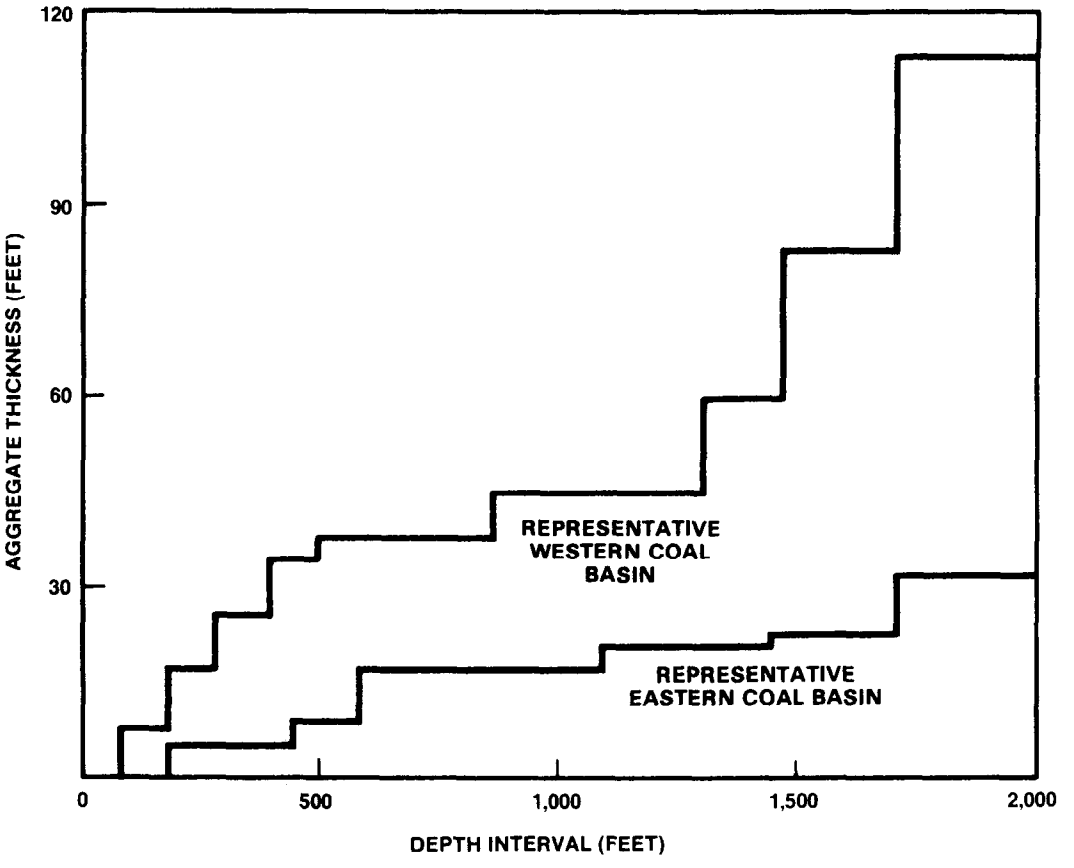


Figure 4. Multiple Coal Seam Occurrences

3.4 GAS QUALITY

The heat of combustion and constituents of gas from virgin coalbeds are summarized in Table 2 for several coalbeds. While this gas is often comparable to natural gas, its composition is not constant, and variations sometimes exist even for different locations in a single coalbed. Of the heavier hydrocarbons, ethane typically contributes up to 2 percent, and propane, butane, and pentane less than 1 percent each. The principal undesirable component is carbon dioxide, but it is not present in significant amounts except in the Pittsburgh Coalbed in West Virginia.

BASIN: NORTHERN APPALACHIAN

WELL(S): AAA, AAB

COAL HORIZON	DEPTH, FEET	THICKNESS, FEET	GAS CONTENT, cf/ton	GAS-IN-PLACE MMcf/acre
Waynesburg Coal	140-340	5-10	70-93	0.61-1.62
Sewickley Coal	370-540	2-4	154	0.54-1.08
Pittsburgh Coal (including riders)	480-645	8-12	134-180	1.87-3.76
Bakerstown Coal	885-1064	3-6	138	0.72-1.44
Upper Freeport Coal	1080-1230	2-4	115	0.40-0.80
Upper Kittanning Coal	1180-1350	1-3	154-198	0.27-1.03
Middle Kittanning Coal	1235-1400	1-3	99	0.17-0.52
Lower Kittanning Coal	1290-1430	1-3	141	0.26-0.78
Brookeville-Clarion Coal	1400-1490	1-3	200	0.35-1.05
		Total Thickness 24 to 48 Ft		Total Gas-in-Place 5.2 to 12.1 MMcf/acre

LEGEND:

SANDSTONE
SILTSTONE
LIMESTONE
SHALE
COAL
CLAY

Figure 5. Typical Stratigraphic Distribution of Coal - Northern Appalachian Site

BASIN: GREEN RIVER

WELL(S): GAA, GAB

COAL HORIZON		DEPTH, FEET	THICKNESS, FEET	GAS CONTENT, cf/ton	GAS-IN-PLACE, MMcf/acre
Williams Fork Formation		3480-3482 394-3496 3526-3675	2-3 1-2 1-2	416-467 496-512 256-461	1.5-2.4 0.86-1.78 0.44-1.61
Upper Coal Zone		3923-3925	1-2	121	0.21-0.42
Middle Coal Zone		?	?	?	?
Lower Coal Zone		4649-4662 4704-4706	10-13 1-2	270-323 336-376	4.7-7.31 0.58-1.31
			Total Thickness 16 to 24 Ft		Total Gas in Place 8.29 to 14.8 MMcf/acre

LEGEND:

SANDSTONE
SILTSTONE
LIMESTONE
SHALE
COAL
CLAY

Figure 6. Typical Stratigraphic Distribution of Coal - Green River Basin

Table 2. Analysis of Gas from Various Virgin Coalbeds

Coalbed and Location	Heat of Combustion Btu per cf mine run (raw) gas	CH_4, %	H_2 & heavy hydrocarbons, %	CO_2, %	Other, % (inc. O_2)
Pocahontas #3, Dismal Creek Buchanan County, VA	1,058	97.07	1.27	0.20	1.46
Pocahontas #3, Keen Mountain Buchanan County, VA	1,053	95.93	1.60 (H_2 unknown)	0.57	1.90
Pocahontas #3, Grundy Buchanan County, VA	689*	63.1*	0.855	0.06	36.00*
Pocahontas #3, Van Sant Buchanan County, VA	1,066	97.61	1.32	0.30	0.77
Pittsburgh, Bobtown Greene County, PA	949	88.91	0.04	10.97	0.08
Pittsburgh, Marianna Washington County, PA	1,043	95.86	1.08	2.54	0.52
Pittsburgh, Fairview Marion County, PA	1,001	93.85	0.04	4.75	1.36
Pittsburgh, Fairview Marion County, PA	900	84.4	nil	14.75	0.85
Upper Kittanning, Ebensburg Cambria County, PA	1,019	95.47	nil	0.10	4.43

*This analysis results from two samples taken near a gob area.

Table 2. Analysis of Gas from Various Virgin Coalbeds (Continued)

Coalbed and Location	Heat of Combustion Btu per cf mine run (raw) gas	CH_4, %	H_2 & heavy hydrocarbons, %	CO_2, %	Other, % (inc. O_2)
Upper Kittanning, Ebensburg Cambria County, PA	1,059	99.17	0.02	0.18	0.63
B Seam, Mesaverde Formation, Carbondale Pitkin County, CO	938	87.84	0.06	11.99	0.11
Lower Hartshorne, Heavener LeFlore County, OK	1,058	99.22	0.01	0.06	0.71
Mary Lee Oak Grove, AL	1,204	96.05	0.01	0.10	3.84
Anthracite, Swatara Coal Track Schuylkill County, PA**	951	93.7	nil	0.1	6.2***
Anthracite, Swatara Coal Track Schuylkill County, PA**	1,003	99.0	nil	nil	1.0

**From BuMines Circular IC8717, 1976. All other data from Analyses by Kim.
***Principally nitrogen.

4. WELL PERFORMANCE

4.1 PERFORMANCE DATA

Production histories of 33 successful coalbed methane wells, documented by the Department of Energy and the U.S. Bureau of Mines (ref. 4) were examined. Initial flow from these wells, following stimulation, was as follows:

Range of flow, Mcfd per foot of coal seam	Number of wells producing in that range
0 to 4	9
4 to 8	3
8 to 16	14
16 to 30	5
30 to 50	2

Most of the above data are from two test projects: the Emerald Mine #2 at Waynesburg, Pennsylvania and the U.S. Steel project at Oak Grove, Alabama. At the Emerald Mines project, flow following stimulation varied from a few hundred to 100,000 cfd from seven wells producing from one 6-foot-thick coalbed. The specific gas content at this location in the Pittsburgh coal averages about 200 cf/ton. Flows from the 17 wells at the U.S. Steel project were as high as 170 Mcfd and averaged 86 Mcfd after 8,400 well days. This flow was realized from one 5-foot-thick coalbed with a specific gas content of 380 to 510 cf/ton.

Performance of these wells, related to total gas-in-place at their locations, is shown in Figure 7. Gas-in-place (GIP) per acre was computed on the basis of a coal density of 80 lbs per cubic foot. The curve on this figure assumes Darcy flow.

Flow rates tabulated in the National Petroleum council study (ref. 3) ranged from 100 to 12,300 cfd per foot of coalbed and the NPC used a fixed production rate of 3,000 cfd per foot of coalbed for their analysis. In this study production rates were allowed to vary within limits compatible with the experience documented above.

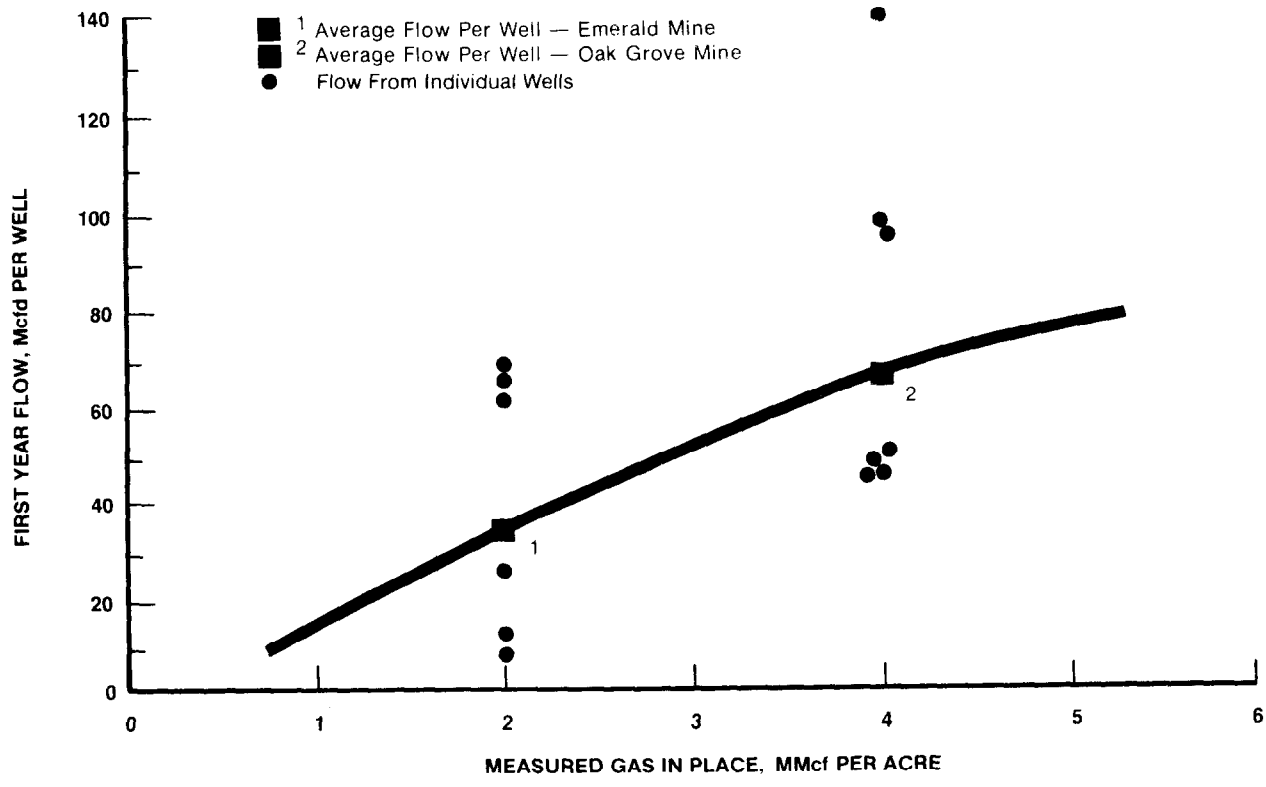


Figure 7. Initial Flow as a Function of Gas In Place

Long-term well performance data is not available but examination of limited production histories of coalbed methane wells indicates that several mechanisms affect flow rates:

- The depletion of gas in fractures near the wellbore
- Dewatering of the coalbeds--this increases relative permeability of the formation to gas flow
- Desorption of methane from the coal as pressure is reduced
- Influx of gas from surrounding formations.

These mechanisms are related to typical flow histories in Figure 8. After an initial period of high flow following stimulation and dewatering, flow generally declines in manner approximating exponential decline.

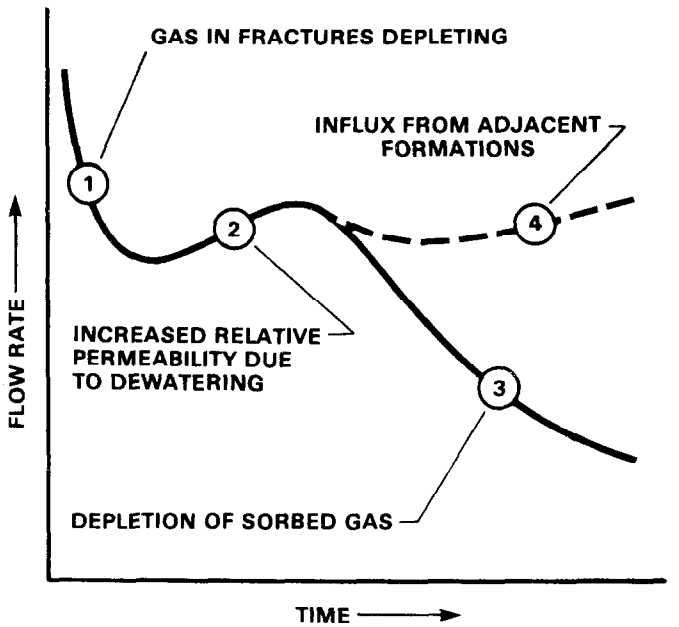


Figure 8. Typical Decline Curve, Coalbed Methane Well

4.2 PERFORMANCE ASSUMPTIONS

In this study it is assumed that gas flow starts at a value as shown in Figure 7 and then declines exponentially as shown in Figure 8, until 50 percent of the total GIP has been recovered. The decline curve is expressed as

$$Q = Q_i \, e^{-kt}$$

where

Q is flow in Mcf per year at a time t, in years

Q_i is the initial flow in Mcf per year following stimulation

and

k is the exponential decline factor.

The area under the curve, Q_r, is the quantity of gas recovered during the life of the field or well.

$$Q_r = \frac{Q_i}{k} (1-e^{-kt})$$

At a recovery ratio of 50 percent Q_r is ½ the total measured GIP and for a field life of 5 years k = 0.14. For a field life of 10 years k = 0.07 and for a life of 20 years k = 0.035. The 50 percent recovery ratio is lower than that indicated in other studies (references 2 and 5) but it includes risks due to dry wells, stimulation failures, and other problems typical of gas production ventures. Similar problems have been experienced on coalbed methane wells and the 50 percent recovery ratio, while possibly conservative, is considered an expected value for the multiple well and multiple zone cases. Other assumptions used in development of the base case economic analysis are:

- The specific gas content is treated as an independent variable baselined at 250 cf/ton of coal. It is assumed to be uniform for multiple zone cases, and at a coal density of 80 lbs per cubic ft. the GIP is approximately 440 Mcf per acre-ft. of coalbed.
- Each coalbed or zone is assumed to be 7 feet thick.
- The field size is 640 acres or one section.

These production estimates and assumptions, compatible with well spacings of 20 and 80 acres and 1, 2, 4, and 6 producing zones, are summarized in Table 3. Case I is typical of that used to drain coalbeds in advance of mining. Well performance that would result from specific gas contents of 125 and 500 cf/ton are also tabulated in Table 3.

Table 3. Well Spacing and Field Production Estimates for a 640-Acre Field, 50% of Gas Recovered

Variable \ Case	Case I (Rapid draw down)	Case II	Case III	Case IV	Case V
Well spacing, acres per well	20 (32 wells)	80 (8 wells)	80 (8 wells)	80 (8 wells)	80 (8 wells)
Number of producing zones	1	1	2	4	6
Coal thickness, feet	7	7	14	28	42
Total gas in place at 125 cf/ton, MMcf	1,000	1,000	2,000	4,000	6,000
Total gas in place at 250 cf/ton, MMcf	2,000	2,000	4,000	8,000	12,000
Total gas in place at 500 cf/ton, MMcf	4,000	4,000	8,000	16,000	24,000
Field life, years	3 (K=0.23)	10 (K=0.07)	10 (K=0.07)	10 (K=0.07)	10 (K=0.07)
Initial flow, Q_i, MMcf/yr. from 125 cf/ton coal	280	70	140	280	420
Initial flow per well per ft. of coal seam from 125 cf/ton coal, Mcfd	3.35	3.35	3.35	3.35	3.35
Initial flow, Q_i, MMcf/yr. from 250 cf/ton coal	560	140	280	560	840

Table 3. Well Spacing and Field Production Estimates for a 640-Acre Field, 50% of Gas Recovered (Continued)

Variable \ Case	Case I (Rapid draw down)	Case II	Case III	Case IV	Case V
Initial flow per well per ft. of coal seam from 250 cf/ton coal, Mcfd	6.7	6.7	6.7	6.7	6.7
Initial flow, Q_i, MMcf/yr. from 500 cf/ton coal	1120	280	560	1120	1680
Initial flow per well per ft. of coal seam from 500 cf/ton coal, Mcfd	13.4	13.4	13.4	13.4	13.4

5. SITE DEVELOPMENT AND WELL COSTS

5.1 UNIT COSTS

Field development costs are presented in Table 4 on a unit basis (per section, well, and foot), and are the basis for estimating initial costs used in each case. These costs are grouped into the following categories:

- Items basically independent of field size or production rates including site investigations, permits, and an initial exploratory well
- Items mainly dependent on well spacing and total site area including site preparation, surveying, roads, fences, mineral leases, land use or damages, and gathering systems
- Items for each well, but basically independent of depth, including wellheads, pumps, electrical equipment, meters, compressors, and the stimulation cost for each zone
- Items directly dependent on well depth including drilling and casing.

Drilling costs were adapted from the American Petroleum Institute's Joint Association Survey on Drilling Costs (1978). The basis of other costs is data from the U.S. Steel Oak Grove Project, the Mountain Fuel Company Brook Cliffs Project, the TRW Waynesburg College Project, articles in technical and trade journals, and engineering cost buildup data from TRW files.

As indicated in Table 4 several cost items including gas lease, site investigation, proof well, surface damages, roads, and surface systems would be incurred prior to developing the remainder of the field. A decision to terminate the project or proceed with further development would be made after dewatering and testing the proof well. Costs incurred up to that decision point would be approximately $360,000.

5.2 FIELD DEVELOPMENT COSTS

The costs of developing the baseline 640-acre field are summarized in Table 5 for several configurations. The base case (configuration I) is typical of that employed in projects using vertical wells in advance of mining operations to rapidly reduce the methane content of the coalbed. These wells are closely spaced - 20 acres per well - and only one seam is drained. In configuration II only one seam is drained, but the well spacing is increased

Table 4. Unit Costs for Site Development and Well Drilling/Completion

ITEM	COST	SOURCE/COMMENTS
1.0 ITEMS WITH COSTS BASICALLY INDEPENDENT OF FIELD SIZE OR NUMBER OF WELLS		
1.1 Pinpoint areas with high production potential (consulting)	$10,000	
1.2 Assess Area	$50,000	
a. Determine land availability for leasing purposes		
b. Determine accessibility to blocks of leasable land including topography		
c. Identify site specific permitting requirements (Use TRW study "Permit Requirements for the MRCP")		
d. Conduct first-cut production economics analysis for accessible and available blocks considering distance to market for pipeline or power line, drilling cost, recoverable resource, cleanup requirements, etc.		
e. Select block for detailed geologic investigation via workshop meeting or equivalent		
1.3 Site support facility rental (one year)	$9,000	
1.4 Proof or wildcat well (same as production well + $20,000 mobilization charge and $6,000 for coring	$185,000 for a 2,000 ft. well w/one zone frac	

Table 4. Unit Costs for Site Development and Well Drilling/Completion (Continued)

ITEM	COST	SOURCE/COMMENTS
2.0 ITEMS WITH COSTS DEPENDENT ON AREA		
2.1 Land lease for high risk or modest resource	$15/acre or $9,600/section lease bonus	Conversation w/independent oil/gas operators and TRW Staff experience
2.2 Estimate based on worth of one crop (east)	$30/acre or $20,000/section	Estimate based on worth of one crop
2.3 Roads, power lines, fences. Costs vary as square root of area.	$180,000/section	From Oak Grove project
2.4 Gathering system. 4" PVC pipe partially buried. Costs vary as square root of area.	$135,000/section	From Westinghouse on-site power generation project and O&G Journal pipeline cost data
3.0 ITEMS WITH COSTS INDEPENDENT OF WELL DEPTH		Composite from Oak Grove, Book Cliffs, and Waynesburg projects and NOSR quotes. These costs vary by ± 50% from the nominal. Depth limited to approximately 2000 feet.
3.1 Site preparation, leveling and clean-up	$18,000/well	
3.2 Water pump	$21,000/well	
3.3 Wellhead equipment, valves, meters	$15,000/well	
3.4 Stimulation and Perforation	$17,000/well per zone	
3.5 Logging	$8,000/well	
3.6 Coring	$6,000/well	

Table 4. Unit Costs for Site Development and Well Drilling/Completion (Continued)

ITEM	COST	SOURCE/COMMENTS
4.0 DRILLING AND CASING	$40/foot	Adapted from 1978 Joint Association Survey, API, February 1980, Table 4, page 10. $40 per foot is the mean cost of drilled and cased holes for U.S. onshore gas wells drilled from 0 to 4,999 feet. Cost was also adjusted to 1980 dollars with Independent Petroleum Association of America indices of cost of drilling and equipping new wells in the U.S.

Table 5. Field Development Costs, 640-Acre Field
(cost in thousand $)

Cost Item \ Case	I one zone 7 ft. coal 3 yr. life 20 acres/well	II one zone 7 ft. coal 10 yr. life 80 acres/well	III two zones 14 ft. coal 10 yr. life 80 acres/well	IV four zones 28 ft. coal 10 yr. life 80 acres/well	V six zones 42 ft. coal 10 yr. life 80 acres/well
1. Land lease (depletable)	9.6	9.6	9.6	9.6	9.6
2. Surface damages (intangible)	20.0	20.0	20.0	20.0	20.0
3. Site investigation (permits legal work, geologic surveys, etc.) (depletable)	60.0	60.0	60.0	60.0	60.0
4. Trailer rental & Misc. (intangible)	9.0	9.0	9.0	9.0	9.0
5. Proof well (includes coring and single well mobilization costs) (tangible and intangible)	185.0	185.0	206.0	248.0	290.0
6. Roads, power lines, fences, etc. (tangible and intangible)	180	180	180	180	180
7. Gathering system (tangible and intangible)	135	135	135	135	135

Table 5. Field Development Costs, 640-Acre Field
(cost in thousand $) (Continued)

Cost Item \ Case	I one zone 7 ft. coal 3 yr. life 20 acres/well	II one zone 7 ft. coal 10 yr. life 80 acres/well	III two zones 14 ft. coal 10 yr. life 80 acres/well	IV four zones 28 ft. coal 10 yr. life 80 acres/well	V six zones 42 ft. coal 10 yr. life 80 acres/well
8. Additional wells to complete the field (includes 100 ft. extra depth drilling for each zone) (tangible and intangible)	4,929 (31 wells)	1,113 (7 wells)	1,260 (7 wells)	1,582 (7 wells)	1,876 (7 wells)
a. Site preparation	(18/well)	(18/well)	(18/well)	(18/well)	(18/well)
b. Water pump	(21/well)	(21/well)	(21/well)	(21/well)	(21/well)
c. Wellhead equipment	(15/well)	(15/well)	(15/well)	(15/well)	(15/well)
d. Logging	(8/well)	(8/well)	(8/well)	(8/well)	(8/well)
e. Fracing, per well	(17)	(17)	(34)	(68)	(102)
f. Drill & case at $40/ft	(80/well to 2000 ft.)	(80/well to 2000 ft.)	(84/well to 2100 ft.)	(96/well to 2400 ft.)	(104/well to 2600 ft.)
g. Per well cost	(159)	(159)	(180)	(226)	(268)
9. Engineering and unforeseen (20% of items 6, 7, and 8) (tangible and intangible)	1,048	285	315	379.4	438.2
TOTAL INITIAL COSTS	6,575.6	1,996.6	2,194.6	2,623	3,017.8

to 80 acres, and the field life increased from 3 to 10 years. Increasing the well spacing reduces the total initial costs from approximately $6,600,000 to $2,000,000.

In configurations III, IV, and V the well spacing is retained at 80 acres per well, but multiple coalbeds are produced - two for configuration III, four for configuration IV, and six (or 42 feet of coal) for configuration V. It is also assumed that multiple coalbeds or production zones are separated by 100 feet and costs are increased to reflect the increased depth. The cost of developing each added zone in the 640-acre, 8-well field (additional stimulation and drilling) is on the order of $200,000. The majority of the development costs is basically fixed by field size and number of wells.

The costs of site investigation, site development and leasing, and drilling and completion for 640- and 1280-acre fields are plotted in Figure 9. The effects of well spacing on field development costs for a 640 acre field are shown in Figure 10.

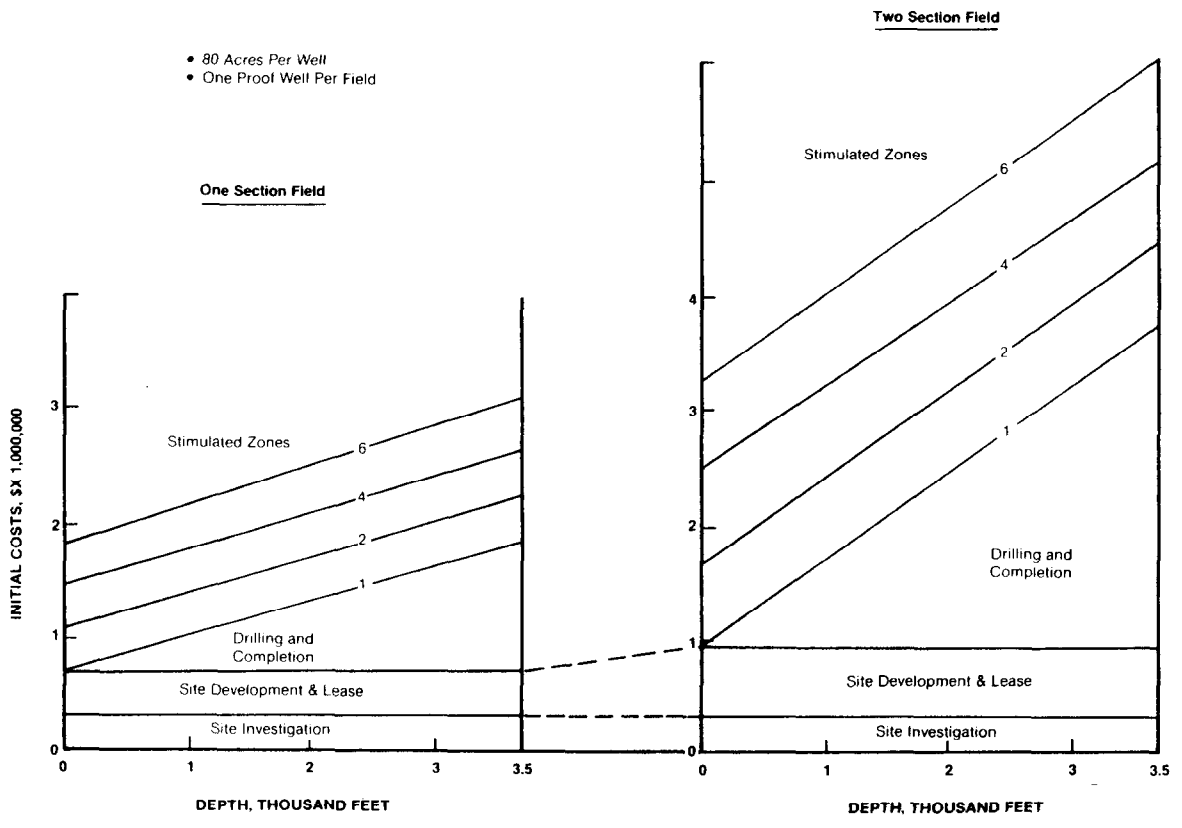


Figure 9. Field Development Costs for a 640-Acre and 1280-Acre Field

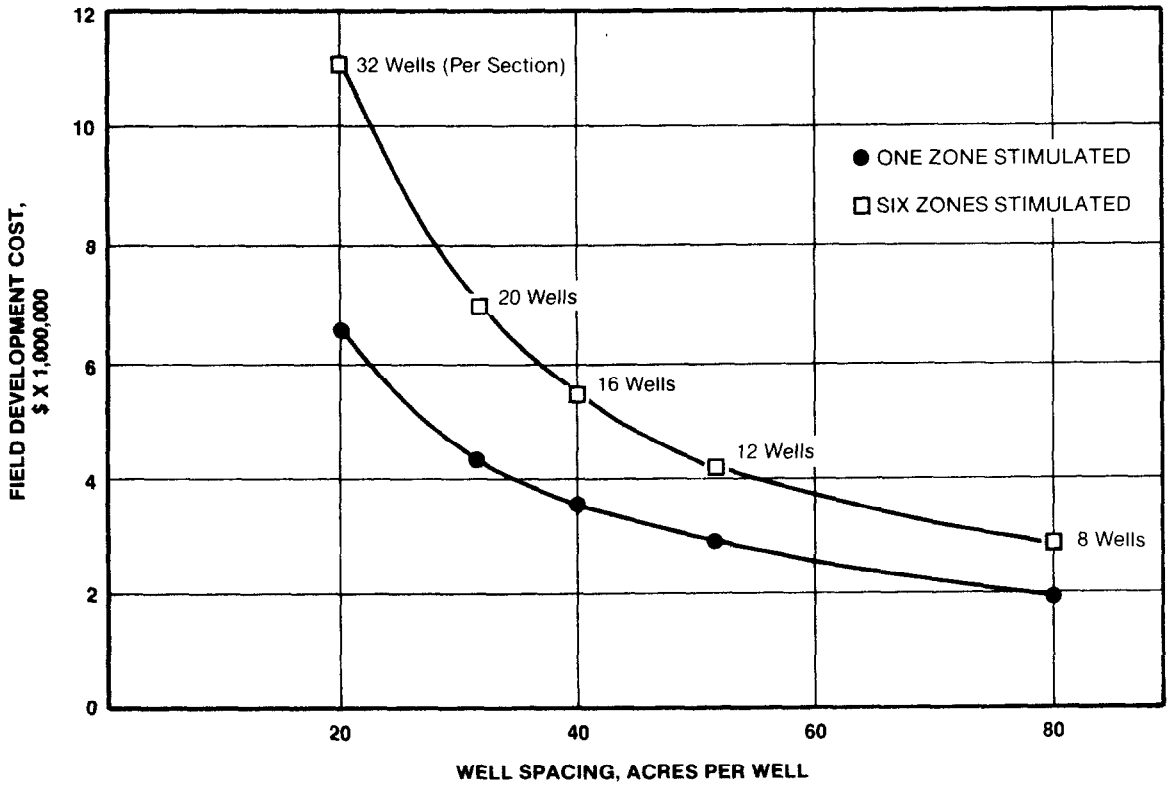


Figure 10. Field Development Costs as a Function of Well Spacing in a 640-Acre Field

6. ECONOMIC MODEL

The model used in the analyses is the TRW ECONGAS Model. ECONGAS is a discounted cash flow (DCF) model of the life cycle economics of a gas well(s). The basic equation is:

Annual DCF =

$$\frac{(\text{Revenues}_t - \text{Expenses}_t) * \text{Tax Retention Rate} + \text{Credits}_t}{(1. + \text{Return})^t}$$

where

t = "time" and the subscript "t" indicates a time based function

This model was developed initially in 1976 in support of the Economic Analysis of Natural Gas Stimulation Applied to the Eastern Devonian Shales study for the Division of Oil, Gas and Shale Technology, of the United States Energy Research and Development Administration. Since that time, the model has been enhanced and used in several studies for the Gas Research Institute (GRI), including the analysis of benefits for research and development projects for unconventional gas resources and the analysis of tight formations projects.

The ECONGAS program has a moderate number of input data elements by which the user specifies the desired scenario. The data elements fall into the following categories:

- Price or return
- Production
- Operations and maintenance expenses
- Annual expenses or credits
- Initial expenses
- Taxes and depreciation
- Other revenue and expenses
- Cost and/or percentage depletion.

The program also is capable of several mutually exclusive data options. For example, the program may determine either price or return on investment, but not both in the same execution. Other data options are listed below:

- Percent or annual price increment

- Direct input of production or either exponential or generalized hyperbolic production decline

- Direct input or inflationary operation and maintenance expenses

- Annual or production-tied condensate revenue

Currently, the model reflects four years of enhancement and development by TRW in various economic analyses. An updated description of the model is further detailed within the TRW ECONGAS USER's MANUAL. An example of the program output is shown below:

Case No. 21, Compute Price, Given R O I = 20.00
10/29/80. 06.23.35. ECONGAS Version: GAS8H- 17 June 80

Price = 2.363

ANNUAL CASH FLOWS

Year	Undiscounted	Discounted	Total
0	-2350700.00	-2350700.00	-2350700.00
1	716491.63	597076.36	-1753623.64
2	637253.25	442536.98	-1311086.66
3	588924.82	340812.97	-970273.68
4	544912.25	262785.61	-707488.07
5	504714.04	202833.25	-504654.82
6	467904.56	156700.29	-347954.53
7	434120.49	121155.06	-226799.47
8	403049.92	93736.53	-133062.93
9	374423.51	72565.78	-60497.15
10	374582.40	60497.15	-.00
TOTAL	2695676.89	-.00	

7. ECONOMIC ANALYSIS OF THE BASELINE SCENARIO

A DCF analysis of the five field configurations presented in Section 5.2 was conducted using the TRW ECONGAS Model. The basic physical assumptions used in this analysis were:

- Field size is 640 acres
- Each zone contains 7 feet of coal
- No utilization systems are included
- Specific gas content is 250 cf/ton
- Fifty percent of the gas is recovered
- Initial flow per well is 17.5 MMcf per year per zone

Other inputs and model inputs were:

- Royalties are 12.5 percent
- Tax retention rate is 50 percent
- Prices are computed on a 1980 basis
- Investment tax credit is 10 percent for the first $25,000 and is decreased to 5 percent of the investments greater than $25,000
- Depreciation method is double declining balance
- Tangible drilling costs are depreciated
- Intangible drilling costs are expensed
- Depletion method is cost depletion.

Configuration I represents the predrainage of methane ahead of mining where the basic objective is the rapid removal of methane. The production well is completed in a single zone. Well life is 3 years, and spacing of the 32 wells is 20 acres. The initial cost for this configuration is $6.57 million and annual operations and maintenance (O&M) costs are $150,000. The required gas sales price for a 20-percent ROI is 9.89 per Mcf for this configuration.

Configuration II is similar to the predrainage case (I) except the objective is to decrease initial investment and extend field life. Well spacing is increased to 80 acres with each well still producing from a single

zone. Well life is 10 years. The initial cost is $2.0 million, with a $75,000 annual O&M cost. The required selling price is reduced to $6.34 per Mcf.

Configurations III, IV and V are identical to the single zone cases except for the additional gas production, changes in well depth, and completion costs. Initial cost is $2,2 million for the two zone configuration (IV), and $3.0 million for the six zone case (V). Annual O&M costs are $100,000, $150,000, and $200,000, respectively. The required gas sales prices per Mcf are $3.54 for the two-zone configuration, $2.16 for the four-zone configuration, and $1.69 for the six-zone configuration. The required selling prices for the various configurations are compared in Figure 11 and development costs are shown in Table 6.

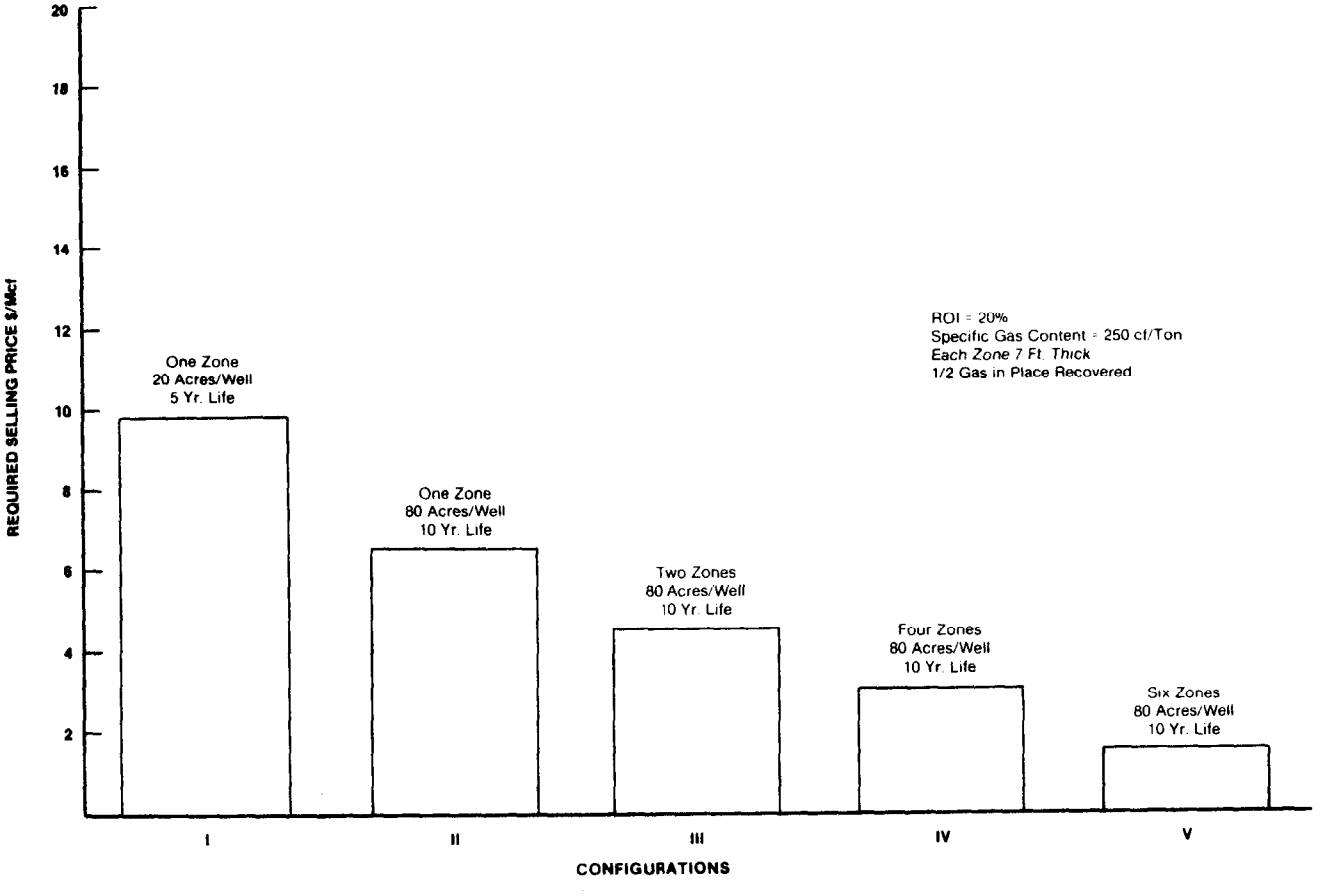


Figure 11. Required Selling Price of Raw Gas at the Wellhead for Selected Configurations

Table 6. Costs of Development for each Configuration

Cost Item \ Configuration	I one zone 7 ft. coal 3 yr. life 20 acres/well		II one zone 7 ft. coal 10 yr. life 80 acres/well		III two zones 14 ft. coal 10 yr. life 80 acres/well		IV four zones 28 ft. coal 10 yr. life 80 acres/well		V six zones 42 ft. coal 10 yr. life 80 acres/well	
	Thousand $	%	Thousand $	%	Thousand $	%	Thousand $	%	Thousand $	%
Amount Depletable	69.6	1	69.6	3	69.6	3	69.6	3	69.6	2
Amount Depreciable (tangible costs)	1431	22	567	29	567	26	567	22	567	19
Amount Initially Expensed (intangible costs)	5075	77	1360	68	1558	71	1986.4	75	2381.2	79
Total Initial Investment	6575.6	100	1996.6	100	2194.6	100	2623	100	3017.8	100
Operating and Maintenance (per year)	150		75		100		150		200	

7.1 SENSITIVITY ANALYSIS

The following input variables were systematically varied to show their individual impact on wellhead price:

- Specific gas content
- Intangible costs
- Production lifetime
- Drilling and casing costs
- Depreciable costs
- ROI
- O&M
- Depletable costs.

Variation of the above input variables for single-zone and multiple-zone configurations are shown in Figures 12 and 13. The impacts of these variations as related to the base case scenario are summarized in the following sections.

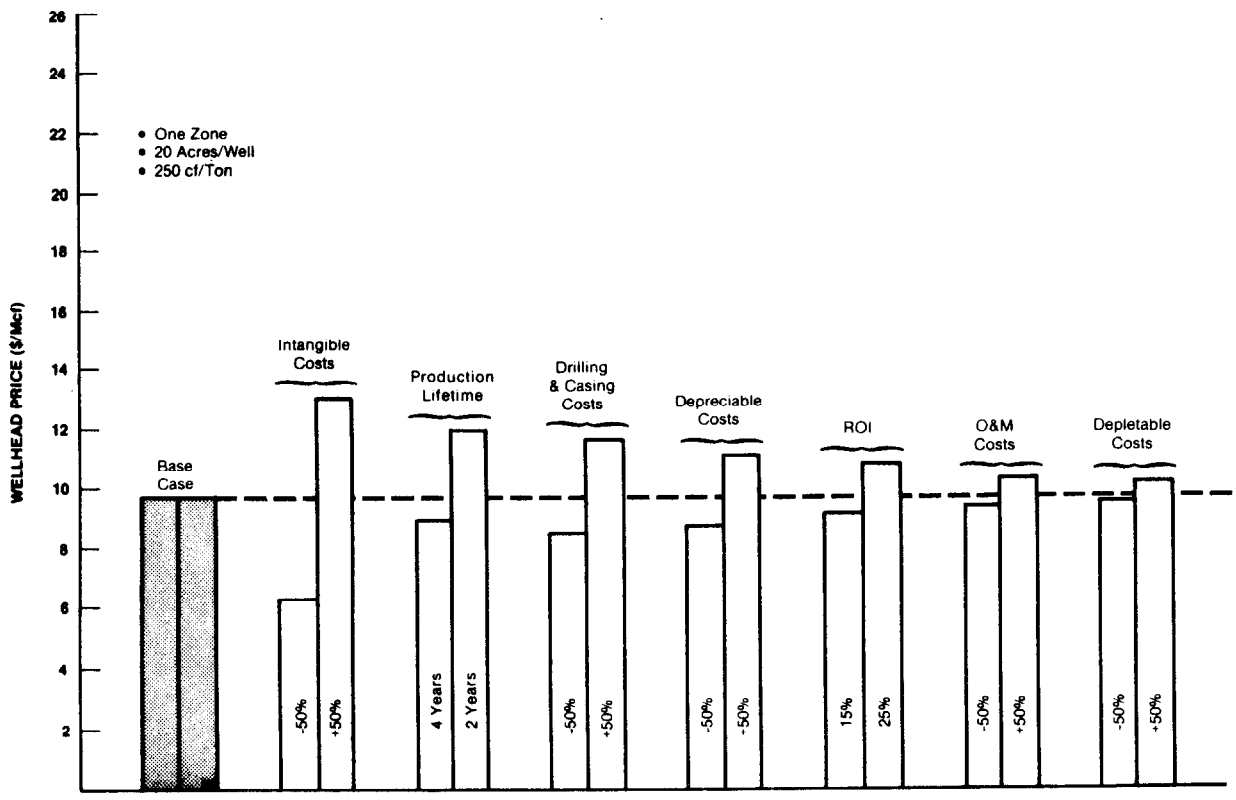


Figure 12. Configuration I Sensitivity Analyses Summary

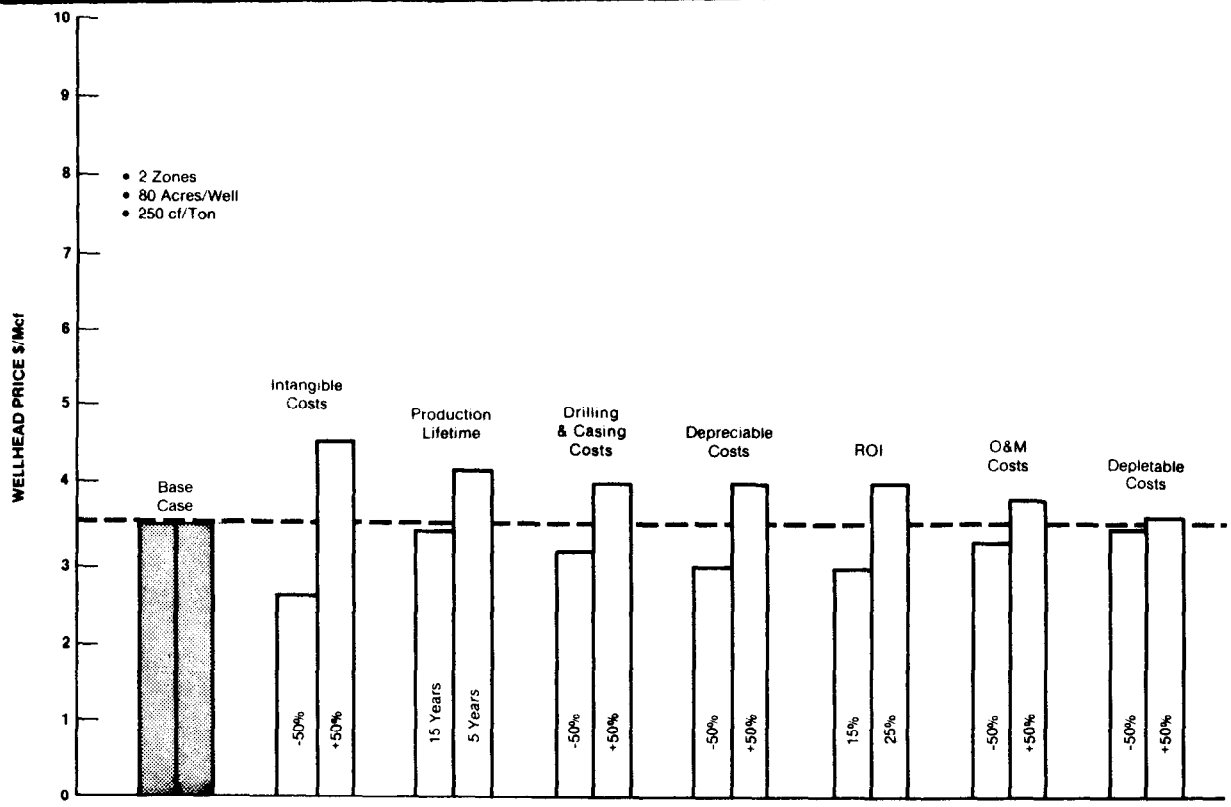


Figure 13. Configuration III Sensitivity Analyses Summary

7.1.1 Specific Gas Content

The effects of changes in specific gas content on selling price were computed for all configurations of the base case scenario. As shown in Figure 14, wellhead price decreases by approximately 50 percent when the specific gas content is doubled.

7.1.2 Intangible Costs

Intangible drilling costs include such items as site preparation, mobilization, labor, fuel, repairs, hauling and supplies (Items 2, 4, 5, 8a, d, e, f and 9 of Table 5). These costs contribute to drilling and developing the field but do not create tangible depreciable assets. These costs were expensed against revenue in the year incurred.

Variations in the intangible drilling costs, which account for 68 to 79 percent of the initial site preparation result in a large change in the wellhead price. The results of a 50 percent variation for all configurations are shown in Figure 15. Configurations II through V are shown to be less

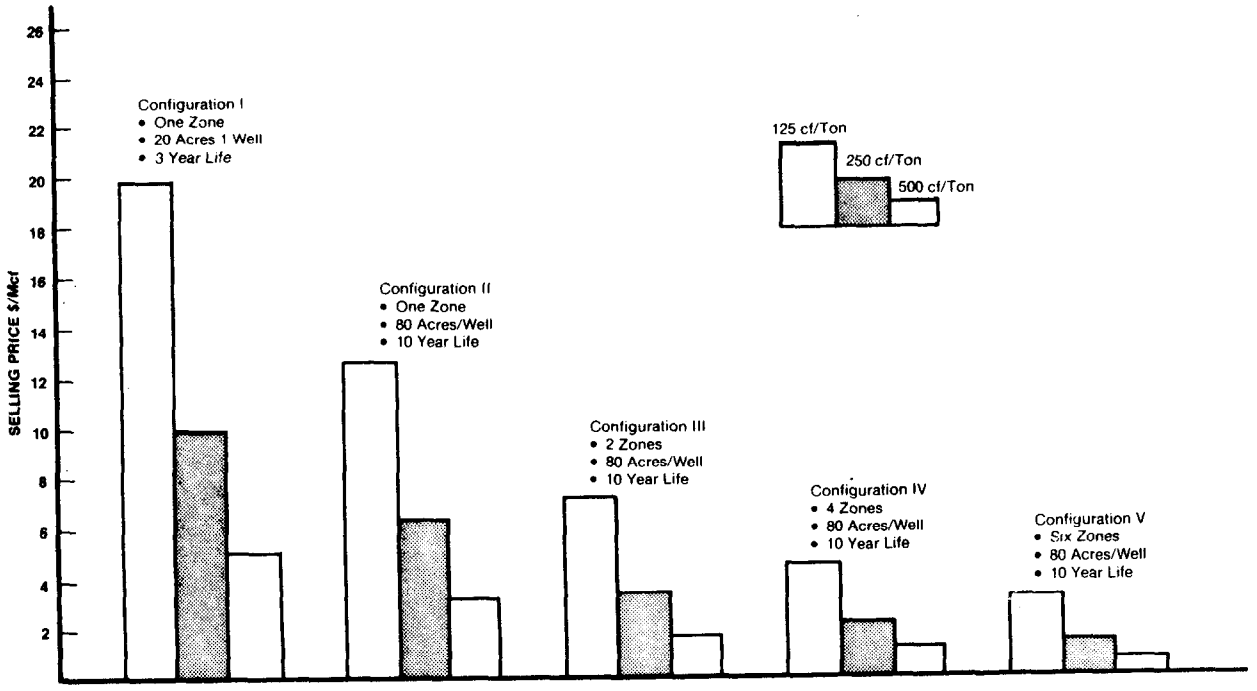
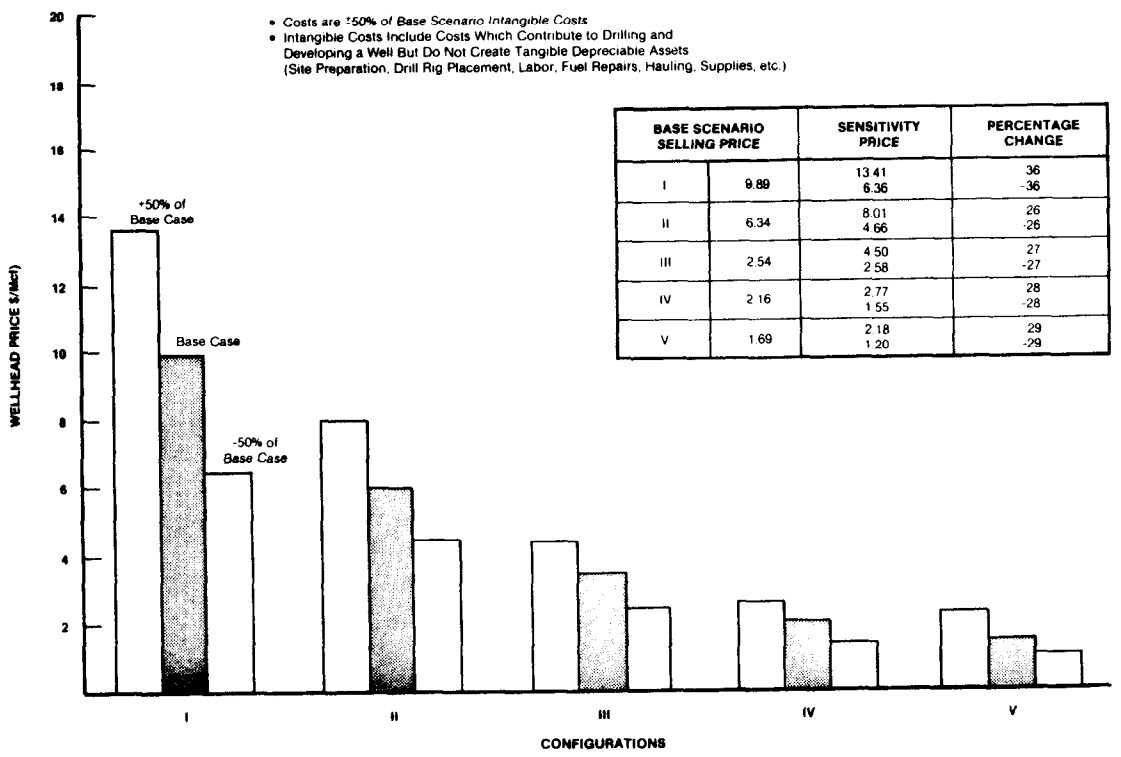


Figure 14. Sensitivity of Selling Price to Specific Gas Content



BASE SCENARIO SELLING PRICE		SENSITIVITY PRICE	PERCENTAGE CHANGE
I	9.89	13.41 6.36	36 -36
II	6.34	8.01 4.66	26 -26
III	2.54	4.50 2.58	27 -27
IV	2.16	2.77 1.55	28 -28
V	1.69	2.18 1.20	29 -29

Figure 15. Sensitivity of Selling Price to Intangible Costs

sensitive to the variation in intangible drilling costs than the rapid draw-down configuration I.

7.1.3 Production Lifetime

Production lifetime was varied by 1 year for configuration I and by 5 years for configurations II through V. Yearly production is assumed to follow the decline curve based on the initial flow value; however, the total cumulative production level would deviate from the assigned 50 percent level of the base case scenario.

The results of the variations are similar for all of the configurations. Furthermore, each configuration shown a greater change in wellhead price for a decrease in production lifetime than for an increase in production lifetime as shown in Figure 16.

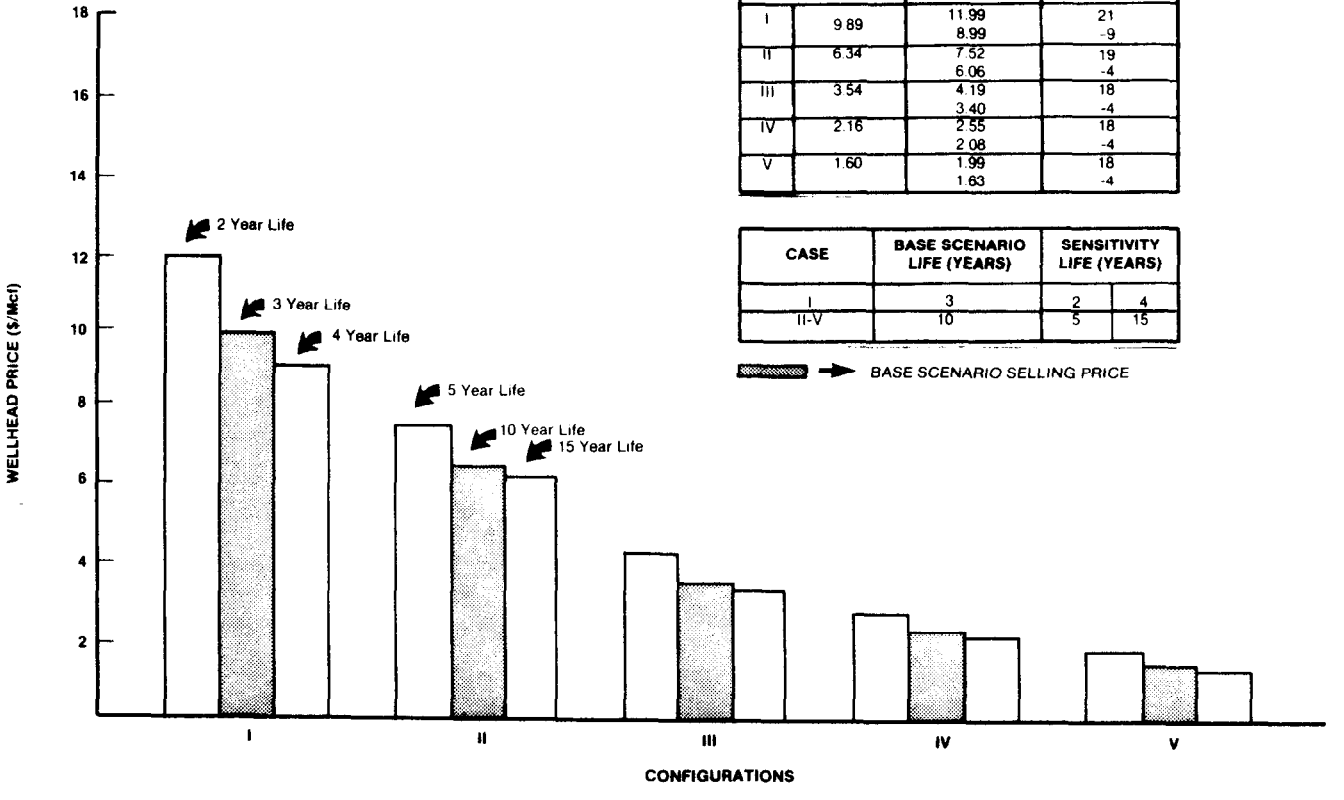
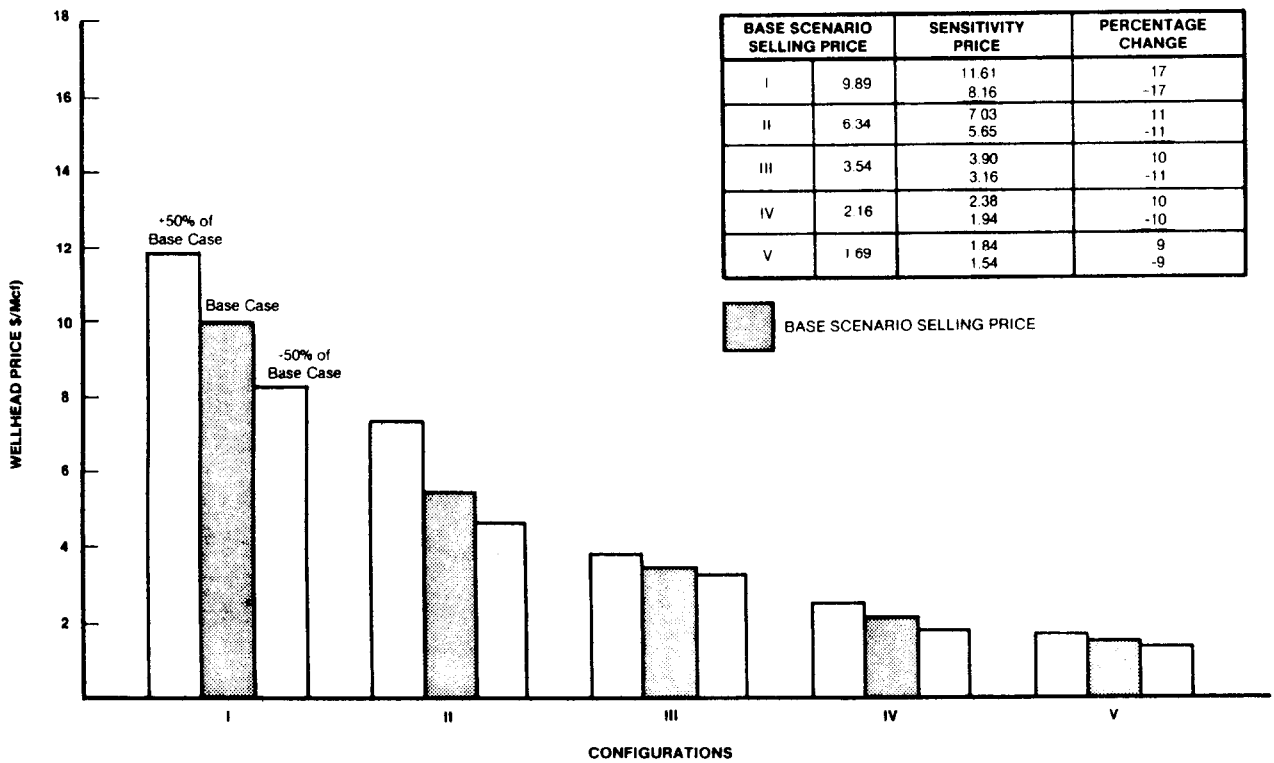


Figure 16. Sensitivity of Selling Price to Production Lifetime

7.1.4 Drilling and Casing Costs

Drilling and casing costs were varied by 50 percent from their estimated value of $40 per foot. In all configurations, tangible and intangible costs are changed to reflect each particular configuration's drilling scenario. Figure 17 shows similar results for all configurations from the variations.



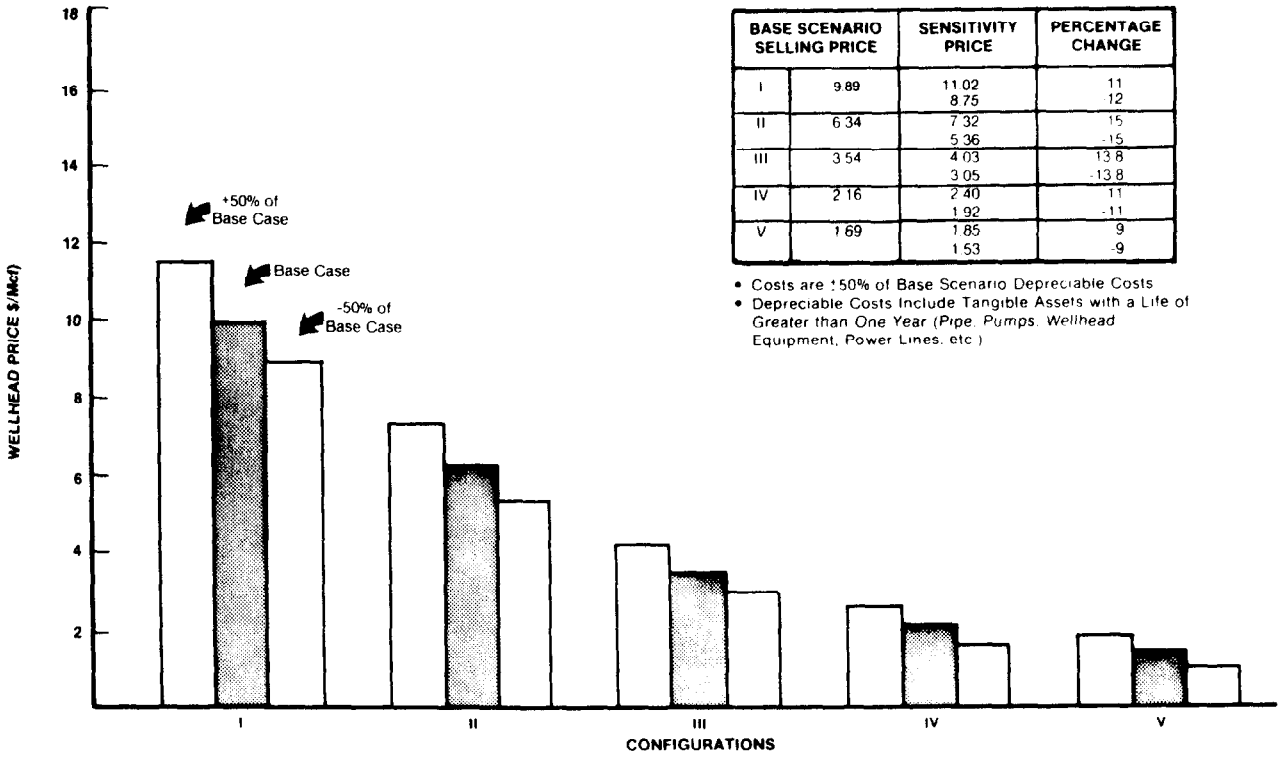
BASE SCENARIO SELLING PRICE		SENSITIVITY PRICE	PERCENTAGE CHANGE
I	9.89	11.61 8.16	17 -17
II	6.34	7.03 5.65	11 -11
III	3.54	3.90 3.16	10 -11
IV	2.16	2.38 1.94	10 -10
V	1.69	1.84 1.54	9 -9

Figure 17. Sensitivity of Selling Price to Drilling and Casing Costs

7.1.5 Depreciable Costs

Capital items such as pipe, pumps, wellhead equipment, power lines, etc., are tangible assets with a life greater than one year and are thus included as depreciable items (items 6, 7, 8b, c, Table 5, Section 5.1). The cost of these items is recovered in before-tax dollars through allowable tax deductions over a useful lifetime of 10 years.

Figure 18 shows the results of variations in depreciable costs. The effects of the variations are similar for all of the configurations.



BASE SCENARIO SELLING PRICE		SENSITIVITY PRICE	PERCENTAGE CHANGE
I	9.89	11.02 8.75	11 -12
II	6.34	7.32 5.36	15 -15
III	3.54	4.03 3.05	13.8 -13.8
IV	2.16	2.40 1.92	11 -11
V	1.69	1.85 1.53	9 -9

- Costs are ±50% of Base Scenario Depreciable Costs
- Depreciable Costs Include Tangible Assets with a Life of Greater than One Year (Pipe, Pumps, Wellhead Equipment, Power Lines, etc.)

Figure 18. Sensitivity of Selling Price to Depreciable Costs

7.1.6 Return on Investment

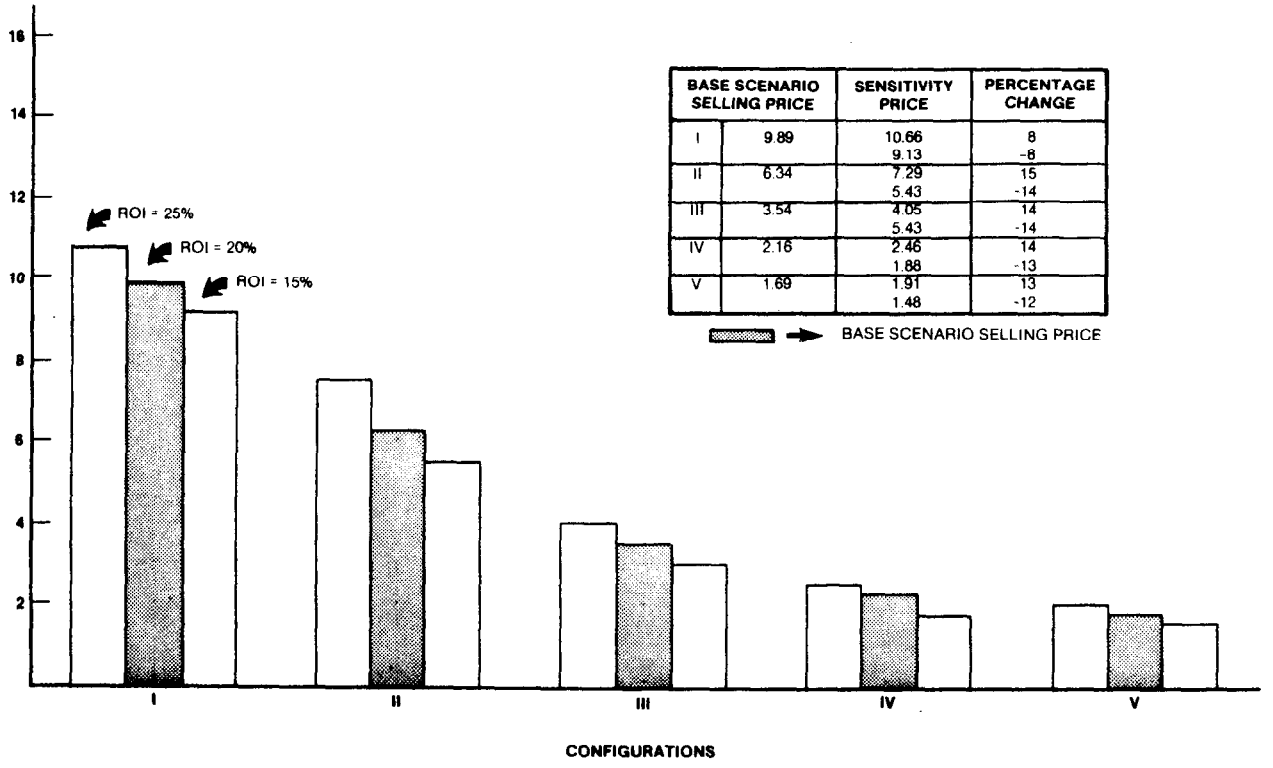
The minimum acceptable rate of return on investment associated directly with recovering the methane was set at 20 percent for the baseline scenario. The effects on wellhead price for returns on investment of 15 and 25 percent are shown in Figure 19.

7.1.7 Operating and Maintenance Expenses

The annual costs of O&M are expensed against revenues in the year that they are incurred. Variations of ± 50 percent in O&M expenses are shown in Figure 20 to result in less than 11 percent variation in wellhead price.

7.1.8 Depletable Costs

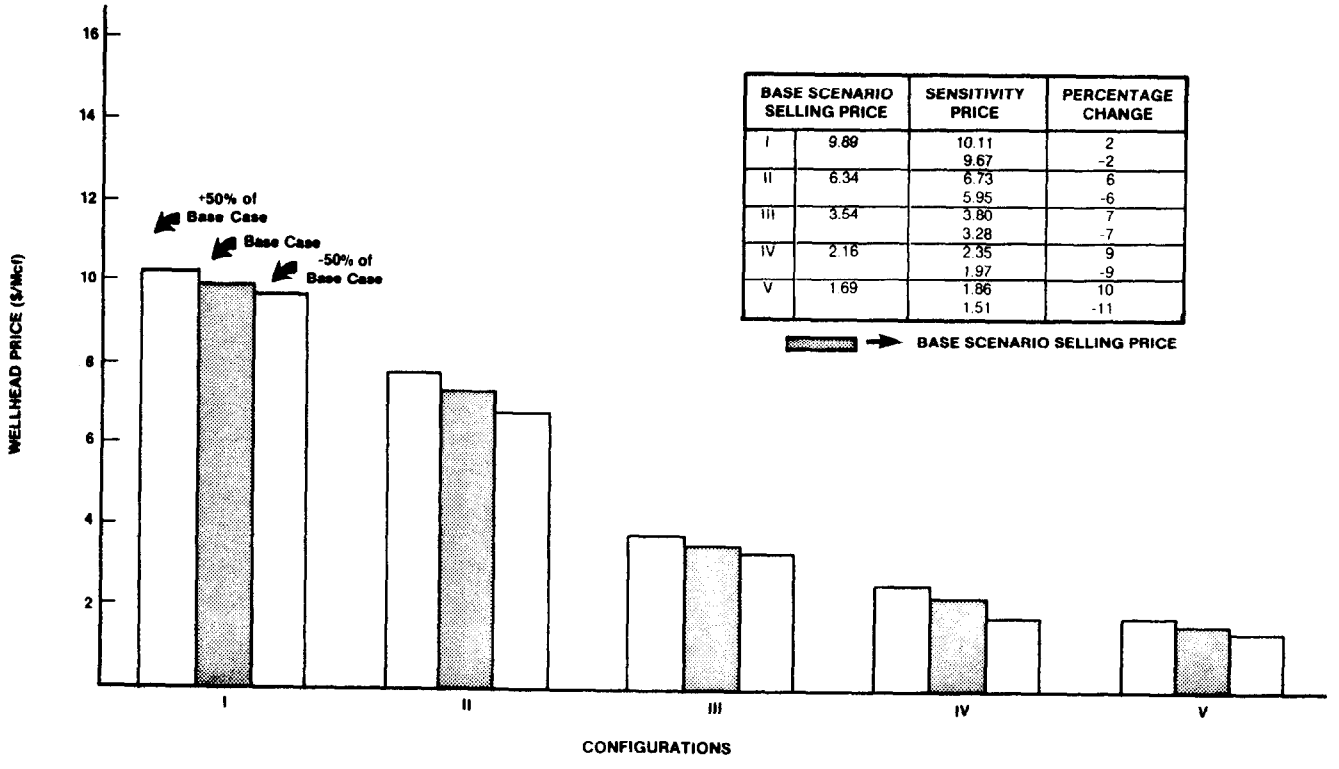
Depletable costs include costs for mineral rights acquisition and/or lease bonuses. Land lease and site investigation costs (items 1 and 3, Table 5, Section 5.1) were treated as cost depletable items in this analysis. A ± 50 percent variation in depletable costs is shown as having minimal impact on wellhead price in Figures 12 and 13.



BASE SCENARIO SELLING PRICE		SENSITIVITY PRICE	PERCENTAGE CHANGE
I	9.89	10.66	8
		9.13	-8
II	6.34	7.29	15
		5.43	-14
III	3.54	4.05	14
		5.43	-14
IV	2.16	2.46	14
		1.88	-13
V	1.69	1.91	13
		1.48	-12

BASE SCENARIO SELLING PRICE

Figure 19. Sensitivity of Selling Price to ROI



BASE SCENARIO SELLING PRICE		SENSITIVITY PRICE	PERCENTAGE CHANGE
I	9.89	10.11	2
		9.67	-2
II	6.34	6.73	6
		5.95	-6
III	3.54	3.80	7
		3.28	-7
IV	2.16	2.35	9
		1.97	-9
V	1.69	1.86	10
		1.51	-11

BASE SCENARIO SELLING PRICE

Figure 20. Sensitivity of Selling Price to O&M Costs

8. UTILIZATION SYSTEM ECONOMICS

Variables associated with production rate, distance to existing transmission systems, quality of the gas, rate structure (peak demand applications), and regulatory constraints will dictate the method by which the gas from a field will be utilized. The utilization options considered in this study were:

- Gas compressed, processed, and transmitted to an existing pipeline
- Electricity generated by gas turbines and transmitted to the power grid
- Gas liquefied and trucked to market.

Additions to required selling price were computed for each option using the ECONGAS model described in Section 5.3 and the following general assumptions and guidelines:

- The gas is received from the field at one to two atmospheres with some water knocked out by a separator (see Table 2)
- The life of the field is 10 years
- Production is sensitive to interruptions in flow rate and the utilization systems are thus operated in a steady-state mode
- Movable skid-mounted equipment has salvage value but is not considered in the model. The other equipment (pipelines, transmission lines, mounting slabs, etc.) has no salvage value.
- No royalties or cost depletion allowances were taken
- Costs were computed for systems compatible in size with expected production rates from coalbed methane fields (0.3 to 2.0 MMcfd) to illustrate the economics of scale inherent in small systems. Utilization systems are "sized" to initial flow rates.

8.1 OPTION 1 - GAS CLEANED AND PIPED TO EXISTING PIPELINE

In order to inject methane gas directly into commercial pipelines, the gas must meet certain specifications established by the pipeline gas companies. Specifications on quality of purchased gas set by the Equitable Gas Company and typical of other gas companies are:

- Gas must be free from dusts, gums, gum-forming constituents, or other liquid or solid matter which might become separated from the gas in the course of transportation through pipelines

- Gas must not contain more than three-tenths (0.3) of a grain of hydrogen sulfide (H_2S) per 100 cubic feet

- Gas must not contain more than 30 grains of total sulfur per 100 cubic feet

- Gas must not contain more than four percent by volume of a combined total of inerts such as carbon dioxide, nitrogen, argon, and helium; provided, however, that the total carbon dioxide content shall not exceed three percent by volume

- Gas must not contain more than one percent of oxygen by volume

- Gas must have at least 950 Btu per cubic foot calculated as the gross saturated value at 14.73 psia and 60°F

- Water content must be less than seven pounds of water per million cubic feet of gas measured at the purchase base of 14.73 psia and 60°F.

A design study (Reference 6) was conducted to define a system or class of systems to upgrade the raw gas to pipeline quality and compress it to pipeline pressures. As a result of this study, four systems were postulated as shown schematically in Figure 21. In all cases the raw gas must be dried. In addition to drying, the following systems were defined:

- A minimum system to compress gas to 60 psig without scrubbing. (Removal of CO_2 will be required in relatively few applications)

- A system to remove CO_2 and compress the gas to 60 psig

- A system to compress the gas to 200 psig without scrubbing

- A system to remove CO_2 and compress the gas to 200 psig.

In all cases, liquid ring- or vane-type compressors are used for the first stage of compression and in the low-pressure configurations as the only stage of compression. The liquid ring-type compressor requires approximately 70 percent more power than a centrifugal compressor, but it can operate from very low inlet pressures or serve as a vacuum pump. This type of compressor, using water as the compression medium, also removes impurities such as particulates, gum-forming compounds, tars, and some CO_2 from the raw gas. Dehydration requirements are also reduced as water in the gas stream is condensed and partially separated during compression. The maximum outlet pressures attainable by liquid ring compressors are about 135 psig, and a booster compressor is thus required to reach standard pressures of 200 psig.

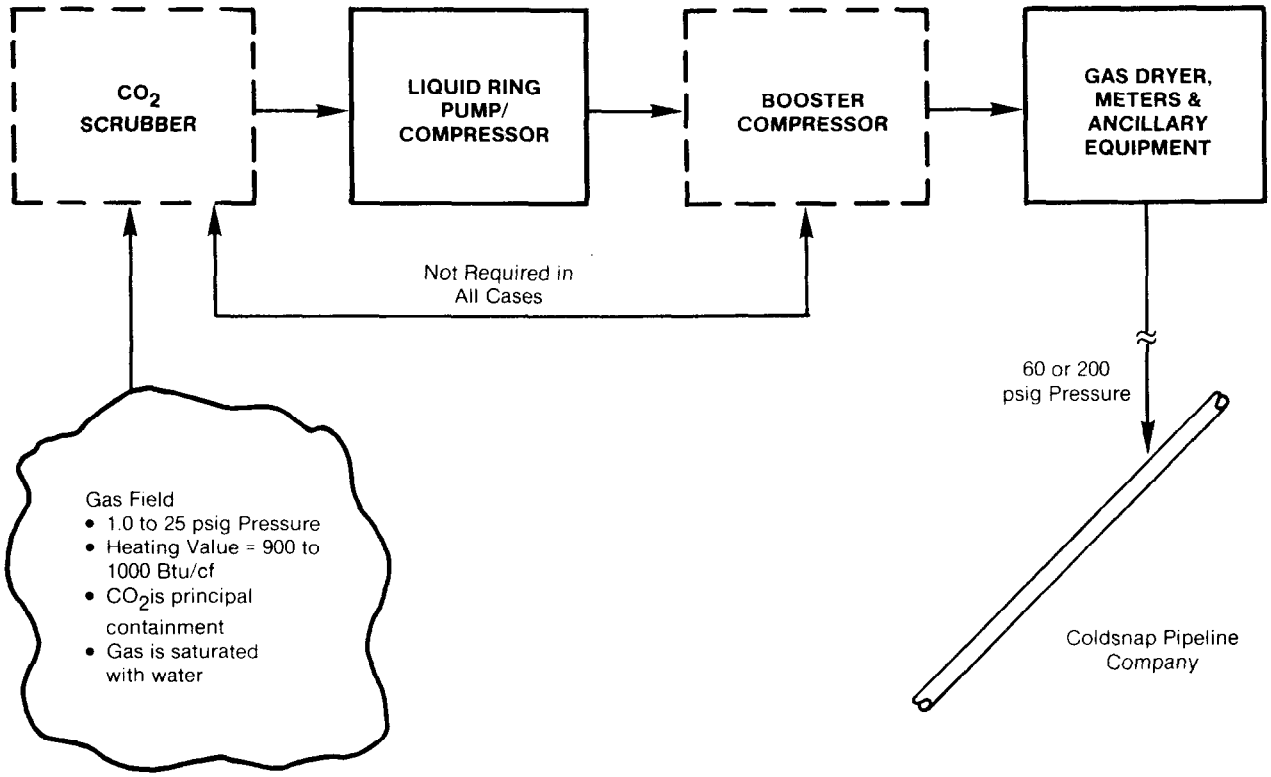


Figure 21. Schematic--Gas Cleaning and Compression System

The costs of small gas-cleaning and compression systems are tabulated in Table 7 and plotted in Figure 22. These costs include hookup to an existing pipeline via a nominal one-mile pipeline. In all cases there is excess compressor capacity for up to approximately 10 additional miles of pipeline at costs indicated in Table 7.

Assuming a gas transmission or distribution pipeline is available - a nominal distance (one mile) from the field manifold or gathering point - the add-on cost per Mcf for gas processing compression and transmission for the small scale systems would be:

Table 7. Costs of Treating & Compressing Raw Gas
($ X 1000)

Item \ System	0.3 MMcfd System		1.5 MMcfd System	
	60 psig	200 psig	60 psig	200 psig
Wellhead interface	5.0	5.0	5.0	5.0
Liquid ring pump/compressor	41.0	41.0	102.0	102.0
Booster Compressor	---	60.0	---	122.0 *
Dryer, solid desiccant type	7.0	7.0	35.0	35.0
Odorizer	9.0	9.0	9.0	9.0
Flare	5.5	5.5	32.0	32.0
Metering and controls including valves	15.0	15.0	50.0	50.0
Equipment slab	6.0	6.0	9.0	9.0
Water subsystem for cooling	---	30.0	---	45.0
Electrical equipment	50.0	60.0	250.0	300.0
One mile pipeline	15.6 (1-1/4" pipe)	15.6 (1-1/4" pipe)	105.6 (4" pipe)	80.0 (3" pipe)
Other piping and valves	5.2	5.2	16.8	16.8

* includes a standby compressor

Table 7. Costs of Treating & Compressing Raw Gas (Cont'd)
($ X 1000)

Item \ System	0.3 MMcfd System		1.5 MMcfd System	
	60 psig	200 psig	60 psig	200 psig
Subtotal w/o CO_2 scrubber	159.3	219.3	614.4	781.4
Subtotal cost per unit capacity	(531/MMcfd)	(731/MMcfd)	(410/MMcfd)	(521/MMcfd)
Engineering start-up and unforseen costs	40 (≈ 25% of subtotal)	50 (60 psi system + 10)	123 (≈ 20% of subtotal)	140 (60 psi system + 17)
Total for system w/o CO_2 scrubber	199.3	269.3	737.4	921.4
Cost per unit capacity	(664/MMcfd)	(898/MMcfd)	(490/MMcfd)	(614/MMcfd)
CO_2 scrubber add-on	160	160	315	315
Total for system w/ CO_2 scrubber	359.3	429.3	1,052	1,236
Cost per unit capacity	(1,200/MMcfd)	(1,430/MMcfd)	(700/MMcfd)	(824/MMcfd)
Maintenance and Repair (equivalent of 1 man with tools)	30/year	30/year	30/year	30/year
Compressor Power ($.50 per kwh)	30/year (75 hp)	40/year (105 hp)	100/year (450 hp)	200/year (550 hp)
Capital Cost per mile of additional pipeline	16	16	105	80

	0.3 MMcfd	1.5 MMcfd
Compression to 60 psi without CO_2 scrubbing	$1.38	.81
Compression to 60 psi with CO_2 scrubbing	1.73	.91
Compression to 200 psi without CO_2 scrubbing	2.70	1.24
Compression to 200 psi with CO_2 scrubbing	4.14	1.38

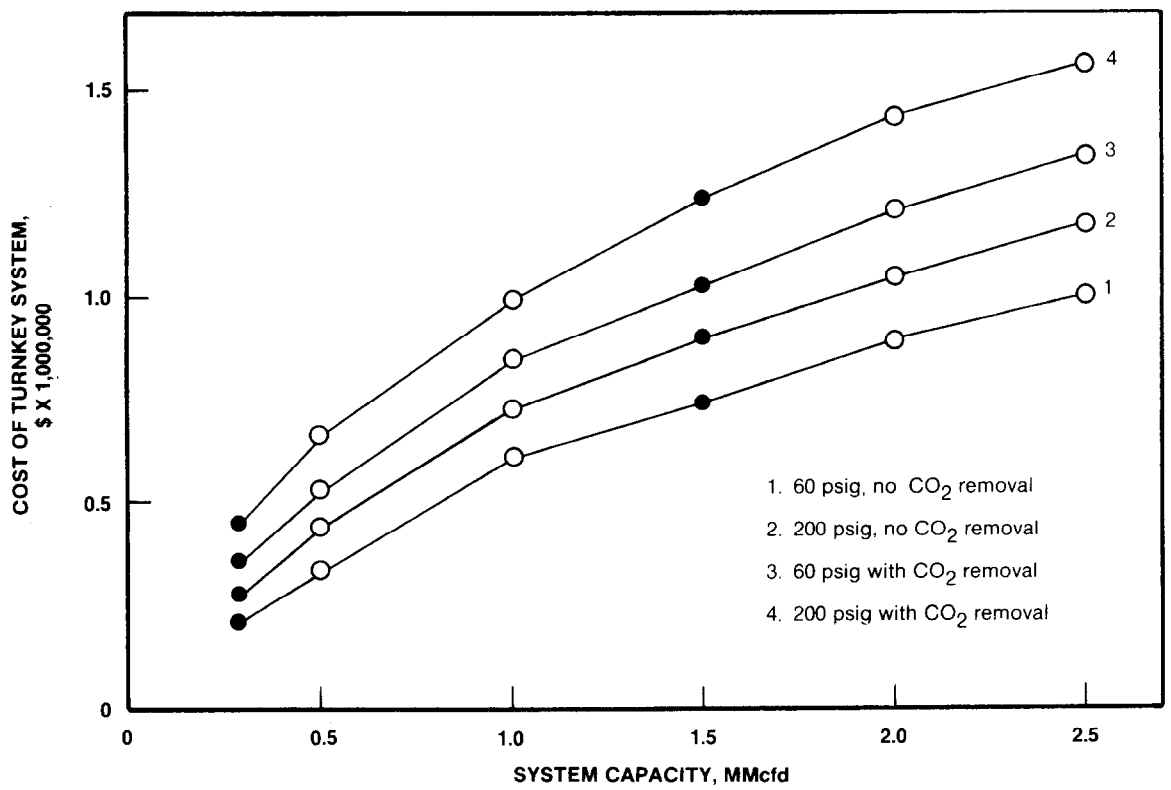


Figure 22. Initial Cost of Gas Cleaning and Compression Facility

8.2 OPTION 2 - ELECTRICITY TRANSMITTED TO THE POWER GRID

Since gas turbines are tolerant to variations in gas quality, the option of generating electrical power may be preferable to treating gas and piping it to market. Distance to the customer hookup and relative cost of electric power lines and pipelines would also be important (if not principal) factors effecting the choice of utilization options.

The conversion efficiencies of turbo generators applicable to the production rates under consideration and the system schematic for this utilization option are shown in Figure 23. Equipment and O&M costs are tabulated in Table 8. Cost estimates of turbo generators are based on discussion with representatives of Solar International, and Detroit Allison. Cost estimates of transmission lines are based on data from MIT. As in the previous discussion, cost data are presented in terms of equipment needs without a transmission line and in terms of transmission line costs on a per-mile basis.

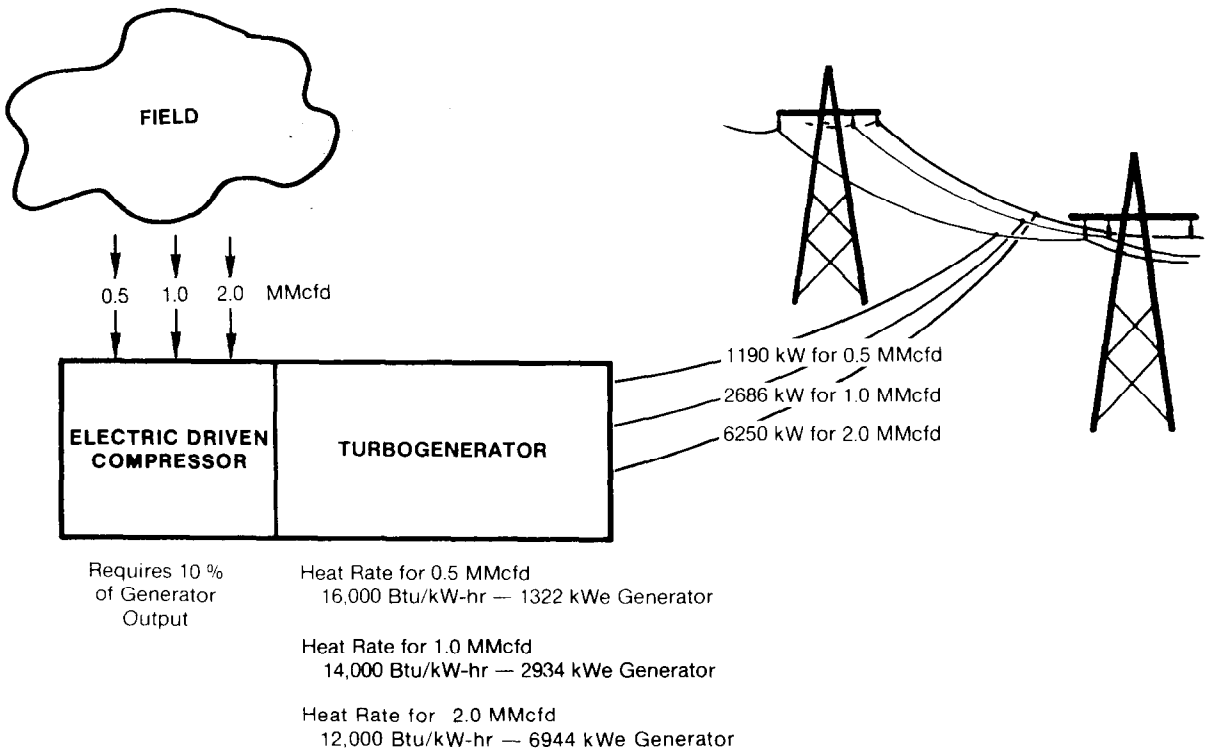


Figure 23. Schematic and Heat Rates - Electric Power Generation Option

Assuming a 1-mile transmission line, the add-on cost per Mcf, of generating electricity at the field is:

- 0.5 MMcfd.....$1.88
- 1.0 MMcfd.....$1.67
- 2.0 MMcfd.....$1.59

Table 8. Costs for Gas Turbine/Electric Generation
(cost in thousand $)

Item \ System	0.5 MMcfd	1.0 MMcfd	2.0 MMcfd	Source, Basis, Assumptions
Land	0	0	0	Generator located on lease
Turbogenerator -- Turnkey installation on slabs. Controls needed for parallel operation with power network.	675 (1350 kw)	1,200 (3000 kw)	2,625 (7000 kw)	Data from Solar International, Detroit Allison, and Westinghouse i.e. $500/Kw---800 Kw $400/Kw--2500 Kw $375/Kw--7500 Kw
Transmission Line (per mile)	55	55	55	Data adapted from MIT study
Turbine Overhaul	108	240	560	Required every 3.5 years at an estimated cost of $80/Kw (50% of original cost of turbine)
Operation/Tending ($/yr)	20	20	20	1/2 man (shared with field operations)
Transmission Line Maintenance	5	7	12	Based on MIT report

8.3 OPTION 3 - LNG PRODUCTION

On a direct comparison basis with the other options, liquefying the gas and trucking it to market is a high-cost operation. However, it may be feasible for the peak demand market where the supply could negate the need for a utility customer to build a liquefaction facility. Another market for the liquid product may be automotive fleets equipped to burn it. The Atlanta Gas Light Company is currently operating a fleet of 27 trucks and 46 sedans and light trucks on a dual LNG/gasoline system.

The system postulated for this option assumes that the facility will have access to electrical utility hookup and that water pumps, cooling towers, etc., will be powered by electricity. Cost estimates for a turn-key facility were based on data from discussions with a LNG plant contractor (Chicago Bridge and Iron) and are dependent to a large extent on the degree of CO_2 scrubbing required. O&M costs are relatively high and essentially independent of plant size as an operator is required on a round-the-clock basis. O&M requirements are based on discussions with operators of peak shaving plants in the Boston area (Boston Gas Co. and Fall River Gas Co.). Equipment costs and O&M costs are shown below in Table 9 for three production rates.

Table 9: LNG Utilization System Costs
(cost in thousand $)

Items \ System	.5 MMcfd	1.0 MMcfd	2.0 MMcfd
LNG PLANT	2,500	4,000	6,300
Transportation Equipment	200	200	300
Total	2,700	4,200	6,600
Annual O&M Costs	183	205	250
Annual Transportation Costs (100 miles)	36	73	146

The add-on cost of this utilization option is:

- 0.5 MMcfd plant.....$6.5/Mcf
- 1.0 MMcfd plant.....$5.4/Mcf
- 2.0 MMcfd plant.....$4.2/Mcf

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