MERC/CR-77/4(Vol.2)
Distribution Category UC-95e

# Systems Studies of Energy Conservation
# Methane Produced from Coalbeds

January 1977 • Volume II

prepared for
Morgantown Energy Research Center
under Contract E(46-1)-8042

by

TRW
ENERGY SYSTEMS GROUP
ENERGY SYSTEMS PLANNING DIVISION
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U.S. Bureau of Mines
U.S. Geological Survey
Pennsylvania Department of Environmental Resources, Bureau of Land Protection, Division of Mines
Pennsylvania Geological Survey, Gas and Oil Division
West Virginia Geological Survey
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West Virginia Department of Natural Resources, Industrial Waste Section
Ohio Geological Survey, Coal Division
Ohio Department of Industrial Relations, Division of Mines
Bethlehem Mines
Lykes Resources
Jones and Laughlin Steel Co.
Eastern Associated Coal Corp.
Clean Air Combustion Systems Ltd.
C&I Girdler
United Technology Corp.
Hope Natural Gas
Youghiogheny and Ohio Coal Co.
Valley Camp Coal Co.
Mathies Coal Co.
Republic Steel
Buckey Coal Co.
Mid-Atlantic Oil Field Service Co.
Halliburton Services
Paramount Exploration
Don Holbert, Consulting Petroleum Engineer
Dyna Drill
Sperry Sun Co.
Humphrey Instrument, Inc.
Kennedy Engineering
Solar Division of International Harvester
Scientific Drilling Controls
Eastman-Whipstock
Equitable Gas Co.

## Contributors

The study described in this report represents the combined effort of various members of the TRW technical staff whose contributions are acknowledged herein. The resource definition was researched by Dr. P. Protopapas with the support of Mr. A. A. Lee. The definition of subsystems and acquisition of the subsystem data base was performed by Dr. S. Sareen with the support of Dr. K. Durai-Swamy and Mr. R. Parekh. The cost-benefit analysis was performed by Mr. R. Dawley and supported by Dr. H. Leon. The preliminary program plan was prepared by the Assistant Project Manager, Mr. K. Lewis.

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# APPENDIX A

# COAL RESERVES

## TABLE 3-1. UNDERGROUND BITUMINOUS COAL RESERVE BASE BY STATE, COUNTY, BED THICKNESS AND SULFUR RANGE, JANUARY 1, 1974, MILLION SHORT TONS

**WEST VIRGINIA** COUNTY

| THICK NESS | BED | RESERVES BY SULFUR RANGE, PERCENT ≤ .4 | .5-.6 | .7-.8 | .9-1.0 | 1.1-1.4 | 1.5-1.8 | 1.9-2.2 | 2.3-2.6 | 2.7-3.0 | > 3.0 | UNKNOWN | TOTAL | NO. OF ANAL | AVG S % |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **BARBOUR** | | | | | | | | | | | | | |
| 28-42 | 036 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 361 | 3.2 |
| > 42 | | .00 | .00 | .00 | .00 | .00 | 1.62 | 6.48 | 13.13 | 19.61 | 40.04 | .00 | 81.07 | | |
| TOTAL | | .00 | .00 | .00 | .00 | .00 | 1.62 | 6.48 | 13.13 | 19.61 | 40.04 | .00 | 81.07 | | |
| | | **BRAXTON** | | | | | | | | | | | | | |
| 28-42 | 036 | .00 | .00 | .00 | .09 | .44 | 1.28 | 2.82 | 3.52 | 2.24 | .89 | .00 | 11.30 | 25 | 2.4 |
| > 42 | | .00 | .00 | .00 | .31 | 1.52 | 4.45 | 9.76 | 12.18 | 7.77 | 3.08 | .00 | 39.07 | | |
| TOTAL | | .00 | .00 | .00 | .40 | 1.96 | 5.73 | 12.58 | 15.70 | 10.01 | 3.97 | .00 | 50.37 | | |
| | | **BROOKE** | | | | | | | | | | | | | |
| 28-42 | 036 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 44 | 2.6 |
| > 42 | | .00 | .00 | .00 | .00 | 11.54 | 16.78 | 21.11 | 22.55 | 20.19 | 39.08 | .00 | 131.15 | | |
| TOTAL | | .00 | .00 | .00 | .00 | 11.54 | 16.78 | 21.11 | 22.55 | 20.19 | 39.08 | .00 | 131.15 | | |
| | | **CLAY** | | | | | | | | | | | | | |
| 28-42 | 036 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 1.99 | 1.99 | | |
| > 42 | | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 3.03 | 3.03 | | |
| TOTAL | | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 5.02 | 5.02 | | |
| | | **DODDRIDGE** | | | | | | | | | | | | | |
| 28-42 | 036 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 19.32 | 19.32 | | |
| > 42 | | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 219.90 | 219.90 | | |
| TOTAL | | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 239.22 | 239.22 | | |
| | | **GILMER** | | | | | | | | | | | | | |
| 28-42 | 036 | .00 | .00 | .00 | .00 | .00 | .53 | 3.79 | 7.59 | 3.62 | .69 | .00 | 16.27 | 106 | 2.4 |
| > 42 | | .00 | .00 | .00 | .00 | .00 | 4.54 | 32.11 | 64.37 | 30.74 | 5.92 | .00 | 137.85 | | |
| TOTAL | | .00 | .00 | .00 | .00 | .00 | 5.07 | 35.90 | 71.96 | 34.36 | 6.61 | .00 | 154.12 | | |
| | | **GRANT** | | | | | | | | | | | | | |
| 28-42 | 036 | .00 | .00 | .00 | .00 | .00 | .00 | 00 | .00 | .00 | .00 | .00 | .00 | | |
| > 42 | | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .04 | .04 | | |
| TOTAL | | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .04 | .04 | | |
| 28-42 | 038 | .00 | .00 | .00 | .06 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .06 | 1 | 1.0 |
| > 42 | | .00 | .00 | .00 | .04 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .04 | | |
| TOTAL | | .00 | .00 | .00 | .10 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .10 | | |

## TABLE 3-1. UNDERGROUND BITUMINOUS COAL RESERVE BASE BY STATE, COUNTY, BED THICKNESS AND SULFUR RANGE, JANUARY 1, 1974, MILLION SHORT TONS

**WEST VIRGINIA** COUNTY **(CONTINUED 2)**

| THICK NESS | BED | RESERVES BY SULFUR RANGE, PERCENT ≤ .4 | .5-.6 | .7-.8 | .9-1.0 | 1.1-1.4 | 1.5-1.8 | 1.9-2.2 | 2.3-2.6 | 2.7-3.0 | > 3.0 | UNKNOWN | TOTAL | NO. OF ANAL | AVG S % |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **HANCOCK** | | | | | | | | | | | | | |
| 28-42 | 036 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .02 | .07 | .00 | .11 | 3 | 3.3 |
| > 42 | | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .07 | .15 | .58 | .00 | .82 | | |
| TOTAL | | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .07 | .17 | .65 | .00 | .93 | | |
| | | **HARRISON** | | | | | | | | | | | | | |
| 28-42 | 036 | .00 | .00 | .00 | .00 | .13 | .54 | 1.25 | 2.51 | 3.93 | 10.39 | .00 | 18.76 | 2448 | 3.1 |
| > 42 | | .00 | .00 | .00 | .00 | 2.21 | 9.17 | 21.19 | 42.38 | 66.42 | 175.23 | .00 | 316.30 | | |
| TOTAL | | .00 | .00 | .00 | .00 | 2.34 | 9.71 | 22.44 | 44.89 | 70.35 | 185.62 | .00 | 335.06 | | |
| | | **KANAWHA** | | | | | | | | | | | | | |
| 28-42 | 036 | .00 | .36 | .48 | .62 | 1.67 | 2.00 | 1.86 | 1.34 | .81 | .73 | .00 | 9.90 | 19 | 2.0 |
| > 42 | | .00 | 1.25 | 1.66 | 2.13 | 5.73 | 6.88 | 6.37 | 4.61 | 2.78 | 2.51 | .00 | 33.92 | | |
| TOTAL | | .00 | 1.61 | 2.14 | 2.75 | 7.40 | 8.88 | 8.23 | 5.95 | 3.59 | 3.24 | .00 | 43.82 | | |
| | | **LEWIS** | | | | | | | | | | | | | |
| 28-42 | 036 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 10.20 | 50.30 | .00 | 60.39 | 89 | 3.3 |
| > 42 | | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 32.72 | 161.31 | .00 | 193.66 | | |
| TOTAL | | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 42.92 | 211.61 | .00 | 254.05 | | |
| | | **MARION** | | | | | | | | | | | | | |
| 28-42 | 036 | .00 | .03 | .06 | .10 | .37 | .56 | .48 | .25 | .10 | .05 | .00 | 2.05 | 438 | 1.8 |
| > 42 | | .00 | 19.39 | 32.66 | 52.06 | 187.84 | 281.76 | 242.96 | 127.61 | 51.04 | 25.52 | .00 | 1020.88 | | |
| TOTAL | | .00 | 19.42 | 32.72 | 52.16 | 188.21 | 282.32 | 243.44 | 127.86 | 51.14 | 25.57 | .00 | 1022.93 | | |
| | | **MARSHALL** | | | | | | | | | | | | | |
| 28-42 | 036 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 40 | 4.6 |
| > 42 | | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 1924.67 | .00 | 1924.67 | | |
| TOTAL | | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 1924.67 | .00 | 1924.67 | | |
| | | **MASON** | | | | | | | | | | | | | |
| 28-42 | 036 | .00 | .00 | .00 | .00 | .00 | .00 | .70 | 3.68 | 7.37 | 8.36 | .00 | 20.15 | 70 | 3.0 |
| > 42 | | .00 | .00 | .00 | .00 | .00 | .00 | 3.33 | 17.42 | 34.85 | 39.52 | .00 | 95.24 | | |
| TOTAL | | .00 | .00 | .00 | .00 | .00 | .00 | 4.03 | 21.10 | 42.22 | 47.88 | .00 | 115.39 | | |
| 28-42 | 038 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .12 | .12 | | |
| > 42 | | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 1.15 | 1.15 | | |
| TOTAL | | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 1.27 | 1.27 | | |

## TABLE 3-1. UNDERGROUND BITUMINOUS COAL RESERVE BASE BY STATE, COUNTY, BED THICKNESS AND SULFUR RANGE, JANUARY 1, 1974, MILLION SHORT TONS

(CONTINUED 3)

WEST VIRGINIA COUNTY

| THICK NESS | BED | RESERVES BY SULFUR RANGE, PERCENT ≤ .4 | .5-.6 | .7-.8 | .9-1.0 | 1.1-1.4 | 1.5-1.8 | 1.9-2.2 | 2.3-2.6 | 2.7-3.0 | > 3.0 | UNKNOWN | TOTAL | NO. OF ANAL | AVG S % |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **MINERAL** | | | | | | | | | | | | | |
| 28-42 | 036 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 8 | .9 |
| > 42 | | .00 | .00 | 3.96 | 7.14 | 3.96 | .00 | .00 | .00 | .00 | .00 | .00 | 15.08 | | |
| TOTAL | | .00 | .00 | 3.96 | 7.14 | 3.96 | .00 | .00 | .00 | .00 | .00 | .00 | 15.08 | | |
| | | **MONONGALIA** | | | | | | | | | | | | | |
| 28-42 | 036 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 1659 | 2.9 |
| > 42 | | .00 | .00 | .00 | .00 | .00 | 26.84 | 102.00 | 301.98 | 472.43 | 437.53 | .00 | 1342.14 | | |
| TOTAL | | .00 | .00 | .00 | .00 | .00 | 26.84 | 102.00 | 301.98 | 472.43 | 437.53 | .00 | 1342.14 | | |
| | | **OHIO** | | | | | | | | | | | | | |
| 28-42 | 036 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 29 | 3.8 |
| > 42 | | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 16.12 | 256.61 | .00 | 273.29 | | |
| TOTAL | | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 16.12 | 256.61 | .00 | 273.29 | | |
| | | **PRESTON** | | | | | | | | | | | | | |
| 28-42 | 036 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 7 | 1.4 |
| > 42 | | .00 | .00 | .32 | .61 | 2.26 | 2.03 | .00 | .00 | .00 | .00 | .00 | 5.24 | | |
| TOTAL | | .00 | .00 | .32 | .61 | 2.26 | 2.03 | .00 | .00 | .00 | .00 | .00 | 5.24 | | |
| | | **PUTNAM** | | | | | | | | | | | | | |
| 28-42 | 036 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 3.24 | 12.09 | 9.24 | .00 | 24.58 | 43 | 3.0 |
| > 42 | | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 15.42 | 57.48 | 43.92 | .00 | 116.83 | | |
| TOTAL | | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 18.66 | 69.57 | 53.16 | .00 | 141.41 | | |
| 28-42 | 038 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .23 | .23 | | |
| > 42 | | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .90 | .90 | | |
| TOTAL | | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 1.13 | 1.13 | | |
| | | **ROANE** | | | | | | | | | | | | | |
| 28-42 | 036 | .00 | .00 | .00 | .34 | 1.15 | 1.95 | 2.49 | 2.24 | 1.48 | 1.13 | .00 | 10.81 | 4 | 2.1 |
| > 42 | | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | | |
| TOTAL | | .00 | .00 | .00 | .34 | 1.15 | 1.95 | 2.49 | 2.24 | 1.48 | 1.13 | .00 | 10.81 | | |
| | | **TAYLOR** | | | | | | | | | | | | | |
| 28-42 | 036 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 258 | 2.2 |
| > 42 | | .00 | .00 | .00 | .00 | 1.80 | 3.81 | 5.99 | 6.22 | 4.19 | 3.35 | .00 | 25.40 | | |
| TOTAL | | .00 | .00 | .00 | .00 | 1.80 | 3.81 | 5.99 | 6.22 | 4.19 | 3.35 | .00 | 25.40 | | |

## TABLE 3-1. UNDERGROUND BITUMINOUS COAL RESERVE BASE BY STATE, COUNTY, BED THICKNESS AND SULFUR RANGE, JANUARY 1, 1974, MILLION SHORT TONS

### (CONTINUED 4)

| WEST VIRGINIA COUNTY | | RESERVES BY SULFUR RANGE, PERCENT | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| THICKNESS | BED | < .4 | .5-.6 | .7-.8 | .9-1.0 | 1.1-1.4 | 1.5-1.8 | 1.9-2.2 | 2.3-2.6 | 2.7-3.0 | > 3.0 | UNKNOWN | TOTAL | NO. OF ANAL | AVG S % |
| | | | | | | | | | | | | | | | |
| **TUCKER** | | | | | | | | | | | | | | | |
| 28-42 | 038 | 00 | 00 | 00 | 01 | .00 | 00 | 00 | .00 | .00 | .00 | .00 | .01 | 1 | 1.0 |
| > 42 | | 00 | 00 | 00 | 05 | .00 | 00 | 00 | .00 | .00 | .00 | .00 | .05 | | |
| TOTAL | | 00 | 00 | 00 | 06 | .00 | 00 | 00 | .00 | .00 | .00 | .00 | .06 | | |
| **UPSHUR** | | | | | | | | | | | | | | | |
| 28-42 | 036 | 00 | 00 | 00 | 00 | .00 | 00 | 00 | .92 | 1.06 | 5.01 | .00 | 7.00 | 16 | 3.5 |
| > 42 | | 00 | 00 | 00 | 00 | .00 | 00 | 00 | .89 | 1.02 | 4.84 | .00 | 6.76 | | |
| TOTAL | | 00 | 00 | 00 | 00 | .00 | 00 | 00 | 1.81 | 2.08 | 9.85 | .00 | 13.76 | | |
| **WETZEL** | | | | | | | | | | | | | | | |
| 28-42 | 036 | 00 | 00 | 00 | 00 | .00 | 00 | 00 | .00 | .00 | .00 | 51.27 | 51.27 | | |
| > 42 | | 00 | 00 | 00 | 00 | .00 | 00 | 00 | .00 | .00 | .00 | 534.38 | 534.38 | | |
| TOTAL | | 00 | 00 | 00 | .00 | .00 | 00 | 00 | .00 | .00 | .00 | 585.65 | 585.65 | | |
| **PENNSYLVANIA BITUMINOUS** | | | | | | | | | | | | | | | |
| **ALLEGHENY** | | | | | | | | | | | | | | | |
| 28-42 | 036 | 00 | 00 | 00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 433 | 1.8 |
| > 42 | | 00 | 00 | 07 | .11 | .38 | .58 | .60 | .40 | .20 | .13 | .00 | 2.50 | | |
| TOTAL | | 00 | .00 | .07 | .11 | .38 | .58 | .60 | .40 | .20 | .13 | .00 | 2.50 | | |
| **ARMSTRONG** | | | | | | | | | | | | | | | |
| 28-42 | 036 | 00 | 00 | 00 | 00 | .00 | 00 | .00 | .00 | .00 | .00 | .00 | .00 | 1 | 1.7 |
| > 42 | | 00 | 00 | 00 | 00 | .00 | 5.09 | .00 | .00 | .00 | .00 | .00 | 5.09 | | |
| TOTAL | | 00 | 00 | .00 | .00 | .00 | 5.09 | .00 | .00 | .00 | .00 | .00 | 5.09 | | |
| **BEDFORD** | | | | | | | | | | | | | | | |
| 28-42 | 036 | 00 | .00 | 00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .19 | .19 | | |
| > 42 | | 00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | | |
| TOTAL | | 00 | 00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .19 | .19 | | |
| **FAYETTE** | | | | | | | | | | | | | | | |
| 28-42 | 036 | 00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 552 | 1.7 |
| > 42 | | 00 | 3.48 | 5.66 | 8.93 | 32.67 | 53.15 | 54.67 | 34.85 | 16.11 | 7.84 | .00 | 217.83 | | |
| TOTAL | | 00 | 3.48 | 5.66 | 8.93 | 32.67 | 53.15 | 54.67 | 34.85 | 16.11 | 7.84 | .00 | 217.83 | | |
| **GREENE** | | | | | | | | | | | | | | | |
| 28-42 | 036 | 00 | .00 | .00 | .00 | .05 | .17 | .44 | .67 | .51 | .26 | .00 | 2.13 | 74 | 2.6 |
| > 42 | | 00 | .00 | .00 | .00 | 91.98 | 290.11 | 732.35 | 1128.60 | 856.18 | 442.24 | .00 | 3537.94 | | |
| TOTAL | | 00 | .00 | .00 | .00 | 92.03 | 290.28 | 732.79 | 1129.27 | 856.69 | 442.50 | .00 | 3540.07 | | |

## TABLE 3-1. UNDERGROUND BITUMINOUS COAL RESERVE BASE BY STATE, COUNTY, BED THICKNESS AND SULFUR RANGE, JANUARY 1, 1974, MILLION SHORT TONS

(CONTINUED 5)

PENNSYLVANIA BITUMINOUS

| THICKNESS | BED | ≤ .4 | .5-.6 | .7-.8 | .9-1.0 | 1.1-1.4 | 1.5-1.8 | 1.9-2.2 | 2.3-2.6 | 2.7-3.0 | > 3.0 | UNKNOWN | TOTAL | NO. OF ANAL | AVG S % |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | RESERVES BY SULFUR RANGE, PERCENT | | | | | | | | | | | | | |
| COUNTY | | | | | | | | | | | | | | | |
| INDIANA | | | | | | | | | | | | | | | |
| 28-42 | 036 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 109 | 1.2 |
| > 42 | | .00 | .00 | .00 | .00 | 3.08 | .83 | .04 | .00 | .00 | .00 | .00 | 3.97 | | |
| TOTAL | | .00 | .00 | .00 | .00 | 3.08 | .83 | .04 | .00 | .00 | .00 | .00 | 3.97 | | |
| SOMERSET | | | | | | | | | | | | | | | |
| 28-42 | 036 | .00 | .00 | .05 | .12 | .75 | 1.80 | 1.46 | .31 | .00 | .00 | .00 | 4.50 | 69 | 1.7 |
| > 42 | | .00 | .00 | .07 | .17 | 1.10 | 2.65 | 2.15 | .45 | .00 | .00 | .00 | 6.63 | | |
| TOTAL | | .00 | .00 | .12 | .29 | 1.85 | 4.45 | 3.61 | .76 | .00 | .00 | .00 | 11.13 | | |
| 28-42 | 038 | .00 | .00 | .64 | .90 | .37 | .00 | .00 | .00 | .00 | .00 | .00 | 1.92 | 3 | .8 |
| > 42 | | .00 | .00 | .92 | 1.28 | .52 | .00 | .00 | .00 | .00 | .00 | .00 | 2.74 | | |
| TOTAL | | .00 | .00 | 1.56 | 2.18 | .89 | .00 | .00 | .00 | .00 | .00 | .00 | 4.66 | | |
| WASHINGTON | | | | | | | | | | | | | | | |
| 28-42 | 036 | .00 | .00 | .05 | .08 | .31 | .55 | .71 | .61 | .36 | .29 | .00 | 3.02 | 529 | 2.1 |
| > 42 | | .00 | .00 | 56.85 | 86.78 | 311.22 | 553.62 | 709.24 | 607.49 | 365.09 | 296.26 | .00 | 2992.59 | | |
| TOTAL | | .00 | .00 | 56.90 | 86.86 | 311.53 | 554.17 | 709.95 | 608.10 | 365.45 | 296.55 | .00 | 2995.61 | | |
| WESTMORELAND | | | | | | | | | | | | | | | |
| 28-42 | 036 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 554 | 1.3 |
| > 42 | | .00 | 6.18 | 9.51 | 12.93 | 30.34 | 21.78 | 9.60 | 3.32 | 1.04 | .38 | .00 | 95.13 | | |
| TOTAL | | .00 | 6.18 | 9.51 | 12.93 | 30.34 | 21.78 | 9.60 | 3.32 | 1.04 | .38 | .00 | 95.13 | | |
| OHIO | | | | | | | | | | | | | | | |
| ATHENS | | | | | | | | | | | | | | | |
| 28-42 | 036 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 1.12 | 24.33 | .00 | 25.51 | 27 | 4.3 |
| > 42 | | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 4.84 | 104.94 | .00 | 110.01 | | |
| TOTAL | | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 5.96 | 129.27 | .00 | 135.52 | | |
| BELMONT | | | | | | | | | | | | | | | |
| 28-42 | 036 | .00 | .00 | .00 | .00 | .00 | .00 | 1.04 | 4.19 | 16.27 | 503.44 | .00 | 524.97 | 329 | 4.0 |
| > 42 | | .00 | .00 | .00 | .00 | .00 | .00 | 3.81 | 15.25 | 59.09 | 1828.12 | .00 | 1906.28 | | |
| TOTAL | | .00 | .00 | .00 | .00 | .00 | .00 | 4.85 | 19.44 | 75.36 | 2331.56 | .00 | 2431.25 | | |
| CARROLL | | | | | | | | | | | | | | | |
| 28-42 | 036 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .03 | .03 | | |
| > 42 | | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .02 | .02 | | |
| TOTAL | | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .05 | .05 | | |

## TABLE 3-1. UNDERGROUND BITUMINOUS COAL RESERVE BASE BY STATE, COUNTY, BED THICKNESS AND SULFUR RANGE, JANUARY 1, 1974, MILLION SHORT TONS

### (CONTINUED 6)

OHIO

| THICKNESS | BED | ≤ 4 | 5-6 | 7-8 | 9-10 | 11-14 | 15-18 | 19-22 | 23-26 | 27-30 | > 30 | UNKNOWN | TOTAL | NO. OF ANAL | AVG S % |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | RESERVES BY SULFUR RANGE, PERCENT | | | | | | | | | | | | | |
| | | **GALLIA** | | | | | | | | | | | | | |
| 28-42 | 036 | .00 | .00 | .00 | .00 | .00 | .00 | 1.38 | 1.97 | 2.58 | 11.89 | .00 | 17.80 | 13 | 3.6 |
| > 42 | | .00 | .00 | .00 | .00 | .00 | .00 | 8.19 | 11.66 | 15.23 | 70.19 | .00 | 105.08 | | |
| TOTAL | | .00 | .00 | .00 | .00 | .00 | .00 | 9.57 | 13.63 | 17.81 | 82.08 | .00 | 122.88 | | |
| | | **GUERNSEY** | | | | | | | | | | | | | |
| 28-42 | 036 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 32.96 | .00 | 32.96 | 13 | 4.9 |
| > 42 | | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 25.25 | .00 | 25.25 | | |
| TOTAL | | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 58.21 | .00 | 58.21 | | |
| | | **HARRISON** | | | | | | | | | | | | | |
| 28-42 | 036 | .00 | .00 | .00 | .00 | .00 | .00 | 3.12 | 7.47 | 13.66 | 34.74 | .00 | 58.89 | 321 | 3.1 |
| > 42 | | .00 | .00 | .00 | .00 | .00 | .00 | 10.60 | 25.40 | 46.40 | 118.00 | .00 | 200.01 | | |
| TOTAL | | .00 | .00 | .00 | .00 | .00 | .00 | 13.72 | 32.87 | 60.06 | 152.74 | .00 | 258.90 | | |
| | | **JEFFERSON** | | | | | | | | | | | | | |
| 28-42 | 036 | .00 | .00 | .00 | .64 | 2.43 | 5.32 | 10.14 | 14.37 | 13.92 | 17.26 | .00 | 64.19 | 324 | 2.9 |
| > 42 | | .00 | .00 | .00 | 2.63 | 10.01 | 21.87 | 41.63 | 59.03 | 57.18 | 70.88 | .00 | 263.53 | | |
| TOTAL | | .00 | .00 | .00 | 3.27 | 12.44 | 27.19 | 51.77 | 73.40 | 71.10 | 88.14 | .00 | 327.72 | | |
| | | **MEIGS** | | | | | | | | | | | | | |
| 28-42 | 036 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .33 | 9.86 | .00 | 10.18 | 12 | 4.1 |
| > 42 | | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .29 | 8.72 | .00 | 9.00 | | |
| TOTAL | | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .62 | 18.58 | .00 | 19.18 | | |
| | | **MONROE** | | | | | | | | | | | | | |
| 28-42 | 036 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 69.10 | 69.10 | | |
| > 42 | | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 344.23 | 344.23 | | |
| TOTAL | | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 413.33 | 413.33 | | |
| | | **MORGAN** | | | | | | | | | | | | | |
| 28-42 | 036 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 6.88 | .00 | 6.88 | 8 | 5.0 |
| > 42 | | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 17.16 | .00 | 17.16 | | |
| TOTAL | | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | 24.04 | .00 | 24.04 | | |
| | | **MUSKINGUM** | | | | | | | | | | | | | |
| 28-42 | 036 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .53 | .53 | | |
| > 42 | | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .45 | .45 | | |
| TOTAL | | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .00 | .98 | .98 | | |
| | | **WASHINGTON** | | | | | | | | | | | | | |
| 28-42 | 036 | .00 | .00 | .00 | .00 | .00 | .00 | .06 | .20 | .37 | 6.32 | .00 | 6.97 | 3 | 4.4 |
| > 42 | | .00 | .00 | .00 | .00 | .00 | .00 | .07 | .23 | .43 | 7.26 | .00 | 8.00 | | |
| TOTAL | | .00 | .00 | .00 | .00 | .00 | .00 | .13 | .43 | .80 | 13.58 | .00 | 14.97 | | |

COALBED CODE NUMBERS 036 PITTSBURGH 038 FIRST LITTLE PITTSBURGH

# APPENDIX B

# COAL ANALYSIS

## TABLE 3-2. AVERAGE ANALYSES OF COAL BY STATE, COUNTY AND BED

**WEST VIRGINIA**

| COUNTY | BED | MOISTURE A.R. | ASH A.R. | ASH DRY | SULFUR A.R. | SULFUR DRY | SULFUR M&AF | BTU A.R. | BTU DRY | BTU M&AF | NO. OF ANAL |
|---|---|---|---|---|---|---|---|---|---|---|---|
| BARBOUR | 036 | 2.1 | 9.9 | 10.2 | 3.1 | 3.2 | 3.5 | 13,380 | 13,670 | 15,220 | 361 |
| BRAXTON | 036 | 2.6 | 8.1 | 8.4 | 2.3 | 2.4 | 2.6 | 13,190 | 13,540 | 14,780 | 25 |
| BROOKE | 036 | 6.2 | 11.5 | 12.3 | 2.3 | 2.5 | 2.8 | 11,940 | 12,730 | 14,510 | 45 |
| CALHOUN | 036 | 1.2 | 6.9 | 7.0 | 3.3 | 3.4 | 3.6 | 13,740 | 13,910 | 14,960 | 2 |
| GILMER | 036 | 3.5 | 8.9 | 9.3 | 2.2 | 2.3 | 2.5 | 13,030 | 13,500 | 14,880 | 106 |
| GRANT | 038 | .9 | 5.3 | 5.4 | .9 | 1.0 | 1.0 | 14,760 | 14,890 | 15,740 | 1 |
| HANCOCK | 036 | 3.4 | 8.1 | 8.4 | 3.1 | 3.3 | 3.6 | 12,780 | 13,230 | 14,440 | 3 |
| HARRISON | 036 | 2.2 | 8.6 | 8.8 | 3.0 | 3.1 | 3.3 | 13,470 | 13,780 | 15,100 | 2451 |
| KANAWHA | 036 | 2.8 | 6.2 | 6.4 | 1.8 | 1.9 | 2.0 | 13,580 | 13,970 | 14,930 | 19 |
| LEWIS | 036 | 3.1 | 8.8 | 9.1 | 3.0 | 3.2 | 3.5 | 13,050 | 13,480 | 14,830 | 89 |
| MARION | 036 | 2.2 | 7.8 | 8.0 | 1.6 | 1.7 | 1.8 | 13,630 | 13,940 | 15,150 | 440 |
| MARSHALL | 036 | 2.5 | 8.8 | 9.1 | 4.3 | 4.5 | 4.9 | 13,220 | 13,560 | 14,920 | 42 |
| MASON | 036 | 6.6 | 12.4 | 13.3 | 2.8 | 3.0 | 3.4 | 11,560 | 12,380 | 14,280 | 70 |
| MINERAL | 036 | 2.1 | 6.8 | 7.0 | .8 | .9 | .9 | 13,890 | 14,190 | 15,260 | 8 |
| MONONGALIA | 036 | 2.2 | 9.3 | 9.6 | 2.7 | 2.8 | 3.0 | 13,460 | 13,760 | 15,220 | 1662 |
| OHIO | 036 | 3.2 | 9.3 | 9.7 | 3.6 | 3.8 | 4.2 | 12,920 | 13,350 | 14,780 | 31 |
| PRESTON | 036 | 4.2 | 7.6 | 8.0 | 1.2 | 1.3 | 1.4 | 13,010 | 13,600 | 14,780 | 7 |
| PUTNAM | 036 | 3.7 | 9.2 | 9.6 | 2.8 | 3.0 | 3.3 | 12,690 | 13,180 | 14,580 | 43 |
| ROANE | 036 | 1.1 | 6.8 | 6.9 | 1.9 | 2.0 | 2.1 | 13,560 | 13,710 | 14,720 | 4 |
| TAYLOR | 036 | 2.1 | 8.2 | 8.4 | 2.1 | 2.2 | 2.4 | 13,680 | 13,970 | 15,250 | 258 |
| TUCKER | 038 | .9 | 5.3 | 5.4 | .9 | 1.0 | 1.0 | 14,890 | 15,030 | 15,880 | 1 |
| UPSHUR | 036 | 2.2 | 9.2 | 9.5 | 3.3 | 3.4 | 3.7 | 13,400 | 13,700 | 15,140 | 16 |

KEYNOTE

A.R As Received

M&AF Moisture & Ash Free

## TABLE 3-2. AVERAGE ANALYSES OF COAL BY STATE, COUNTY AND BED (CONTINUED-2)

| COUNTY | BED | MOISTURE A.R. | ASH A.R. | ASH DRY | SULFUR A.R. | SULFUR DRY | SULFUR M&AF | BTU A.R. | BTU DRY | BTU M&AF | NO. OF ANAL |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **PENNSYLVANIA** | | | | | | | | | | | |
| **ALLEGHENY** | 036 | 3.2 | 8.4 | 8.7 | 1.5 | 1.6 | 1.7 | 13,210 | 13,650 | 14,950 | 627 |
| **ARMSTRONG** | 036 | 2.3 | 9.4 | 9.7 | 1.6 | 1.7 | 1.8 | 13,450 | 13,760 | 15,240 | 2 |
| **BEDFORD** | 036 | .7 | 17.9 | 18.1 | 2.3 | 2.4 | 2.9 | 12,250 | 12,340 | 15,070 | 1 |
| **FAYETTE** | 036 | 2.7 | 9.8 | 10.1 | 1.5 | 1.6 | 1.7 | 13,270 | 13,640 | 15,170 | 552 |
| **GREENE** | 036 | 3.1 | 9.5 | 9.9 | 2.9 | 3.0 | 3.3 | 13,230 | 13,670 | 15,170 | 188 |
| **INDIANA** | 036 | 2.9 | 12.5 | 12.9 | 1.1 | 1.2 | 1.3 | 12,870 | 13,250 | 15,220 | 109 |
| **SOMERSET** | 036 | 4.6 | 12.3 | 12.9 | 1.6 | 1.7 | 1.9 | 12,710 | 13,330 | 15,300 | 69 |
| | 038 | 3.7 | 9.4 | 9.8 | .7 | .8 | .8 | 13,490 | 14,010 | 15,530 | |
| **WASHINGTON** | 036 | 3.6 | 9.8 | 10.2 | 2.0 | 2.1 | 2.3 | 12,850 | 13,330 | 14,840 | 531 |
| **WESTMORELAND** | 036 | 3.4 | 9.7 | 10.1 | 1.1 | 1.2 | 1.3 | 13,180 | 13,650 | 15,180 | 554 |
| **OHIO** | | | | | | | | | | | |
| **ATHENS** | 036 | 5.8 | 9.4 | 10.0 | 3.9 | 4.2 | 4.6 | 12,070 | 12,810 | 14,230 | 27 |
| **BELMONT** | 036 | 3.6 | 10.1 | 10.5 | 3.7 | 3.9 | 4.3 | 12,660 | 13,130 | 14,670 | 335 |
| **GALLIA** | 036 | 6.9 | 10.9 | 11.8 | 3.2 | 3.5 | 3.9 | 11,650 | 12,520 | 14,190 | 14 |
| **GUERNSEY** | 036 | 4.5 | 10.3 | 10.8 | 4.6 | 4.9 | 5.4 | 12,420 | 13,000 | 14,580 | 13 |
| **HARRISON** | 036 | 5.4 | 10.5 | 11.1 | 2.9 | 3.1 | 3.4 | 12,250 | 12,950 | 14,570 | 322 |
| **JEFFERSON** | 036 | 4.8 | 10.1 | 10.7 | 2.7 | 2.9 | 3.2 | 12,510 | 13,140 | 14,710 | 327 |
| **MEIGS** | 036 | 7.7 | 11.6 | 12.6 | 3.6 | 4.0 | 4.5 | 11,360 | 12,300 | 14,080 | 12 |
| **MORGAN** | 036 | 6.1 | 11.6 | 12.4 | 4.6 | 5.0 | 5.7 | 11,550 | 12,300 | 14,040 | 8 |
| **WASHINGTON** | 036 | 4.8 | 12.8 | 13.5 | 4.1 | 4.4 | 5.0 | 11,480 | 12,060 | 13,940 | 3 |

KEYNOTE

A.R. As Received

M&AF Moisture & Ash Free

# APPENDIX C

## COMPANIES POSSESSING COAL MINING RIGHTS IN THE PITTSBURGH COALBED

## TABLE 3-4. COMPANIES POSSESSING COAL MINING RIGHTS IN THE PITTSBURGH COALBED

### WEST VIRGINIA

**BARBOUR COUNTY**

BARBOUR COAL CO
BETHLEHEM MINES CORP
C&W COAL CO
DEXCAR QUEEN COAL CO., INC
MCCOY BROS. INC
OHIO MINING CO
PETITTO BROS., INC
QUEEN BROS. COAL CO., INC
TUCKAHOE MINING CO., INC

**BROOKE COUNTY**

BOLOGNA MINING CO
HILLTOP MINING CO., INC
STARVAGGI IND. INC
WINDSOR POWER HOUSE COAL CO

**GILMER COUNTY**

GILMER FUEL CO., INC
ORLANDO MINING CO

**HARRISON COUNTY**

CONSOLIDATION COAL CO., MOUNTAINEER DIV
ERAN COAL CO
FRESA CONSTRUCTION CO
GALLOWAY LAND CO
GRAFTON COAL CO
KING KNOB COAL CO
PITTSBURGH & REDSTONE FUEL CO
THOMPSON COAL CONST. INC
UNITED COALS INC
WESGIN MINING CO

**JEFFERSON COUNTY**

WEIRTON CONSTRUCTION CO

**LEWIS COUNTY**

QUEEN BROS. COAL CO., INC.
WHITE CONTRACTING CO., R. N.

**MARION COUNTY**

BETHLEHEM MINES CORP
CONSOLIDATION COAL CO., CHRISTOPHER DIV
CONSOLIDATION COAL CO., MOUNTAINEER DIV
EASTERN ASSOC. COAL CORP

**MARSHALL COUNTY**

CONSOLIDATION COAL CO., OHIO VALLEY DIV
VALLEY CAMP COAL CO

**MINERAL COUNTY**

D&L COAL CO

**MONONGALIA COUNTY**

CONSOLIDATION COAL CO., BLACKSVILLE DIV
CONSOLIDATION COAL CO., CHRISTOPHER DIV

**OHIO COUNTY**

VALLEY CAMP COAL CO

**PRESTON COUNTY**

MAURICE JENNINGS

**TAYLOR COUNTY**

BUCK RUN COAL CO., INC.
C&P COAL CO

**UPSHUR COUNTY**

B&B COAL CO
DEXCAR QUEEN COAL CO., INC.

**WASHINGTON COUNTY**

PENNWEIR CONSTRUCTION CO.

### PENNSYLVANIA

**ALLEGHENY COUNTY**

ALOE COAL CO
CONSOLIDATION COAL CO., PITTSBURGH DIV
ROSINIS INC

**ARMSTRONG COUNTY**

DONALD K. ANKENY
RAYMOND SCHALL COAL CO

**FAYETTE COUNTY**

BETTY LOUISE COAL CO
NATIONAL MINES CORP
US STEEL CORP

**GREENE COUNTY**

BUCKEYE COAL CO
DUQUESNE LIGHT CO
GATEWAY COAL CO
JONES & LAUGHLIN STEEL CORP
THE EMERALD MINES CORP
US STEEL CORP

**SOMERSET COUNTY**

SANNER BROS. COAL CO

**WASHINGTON COUNTY**

BETHLEHEM MINES CORP
BOLOGNA MINING CO.
CONSOLIDATION COAL CO., PITTSBURGH DIV
CRESCENT HILLS COAL CO
JONES & LAUGHLIN STEEL CORP
MATHIES COAL CO.
MIDWAY COAL CO
REPUBLIC STEEL CORP
ROSINI'S, INC
TREMONT MINING INC
US STEEL CORP.

**WESTMORELAND COUNTY**

EIDEMILLER, INC., ADAM
OLD HOME MANOR INC
REPUBLIC STEEL CORP

### OHIO

**BELMONT COUNTY**

BANNOCK COAL CO
CONSOLIDATION COAL CO., CENTRAL DIV
CRAVAT COAL CO
NACCO MINING CO
NORTH AMERICAN COAL CORP CENTRAL DIV
R&F COAL CO
SPEIDEL FUEL CORP
YOUGHIOGHENY OHIO COAL CO

**GUERNSEY COUNTY**

OHIO RIVER COLLIERIES CO
R&F COAL CO

**HARRISON COUNTY**

CONSOLIDATION COAL CO., CENTRAL DIVISION
R&F COAL CO.

**JEFFERSON COUNTY**

ANTHONY MINING CO., INC
BOICH MINING CO
CONSOLIDATION COAL CO., CENTRAL DIVISION
HUBERTA COAL CO., INC
OHIO COAL & CONST. CORP
OHIO EDISON CO
POLEN COAL CO
S&D CONSTRUCTION CORP
STRAUS COAL CO.
TERAMANA BROS. COAL MINING CO.
ZIMNOX COAL CO.

**MONROE COUNTY**

QUARTO MINING CO

### MARYLAND

**ALLEGHENY COUNTY**

GINNIMAN COAL CO
JET FUEL COAL CO., INC
WINNER BROS. COAL CO., INC

**GARRETT COUNTY**

GINNIMAN COAL CO
MORAN COAL CO., INC

# APPENDIX D

## CURRENTLY ACTIVE UNDERGROUND MINES IN THE PITTSBURGH COALBED

(Contents of this Appendix, Table 3-5, are in envelope accompanying this report)

# APPENDIX E

## MINE AND PIPELINE MAPS OF NORTHERN APPALACHIAN BASIN

(Contents of this Appendix, Figures 3-18, 3-19, and 3-20 are in envelope accompanying this report)

# APPENDIX F

## COMPOSITION OF GOB COALGAS FROM PITTSBURGH COALBED MINES

TABLE 3-16. COMPOSITION OF GOB COAL GAS FROM PITTSBURGH COALBED MINES

| | | MONONGALIA COUNTY | | | | |
|---|---|---|---|---|---|---|
| SAMPLE | | NO. 1 | NO. 2 | NO. 3 | NO. 4 | NO. 5 |
| RIKEN RESPONSE | | 56% | 86.5% | 45% | 86.5% | 45% |
| PULLING Hg VACUUM | | 7.1" | 9" | 10.2" | 9" | 10.2" |
| POSITIVE FLOW | | | | | | |
| CONSTITUENT | | % | | | | |
| HYDROGEN | $H_2$ | – | – | – | – | – |
| OXYGEN | $O_2$ | 3.42 | 0.37 | 1.80 | 0.09 | 2.93 |
| NITROGEN | $N_2$ | 38.45 | 1.68 | 51.54 | 0.71 | 55.32 |
| CARBON MON. | CO | – | – | – | – | – |
| METHANE | $CH_4$ | 56.22 | 96.73 | 40.91 | 98.05 | 37.31 |
| ETHANE | $C_2H_6$ | 0.02 | 0.07 | 0.33 | 0.08 | 0.25 |
| CARBON DIOX. | $CO_2$ | 1.91 | 1.14 | 5.34 | 1.05 | 4.10 |
| ETHYLENE | $C_2H_4$ | | | | | |
| PROPANE | $C_3H_8$ | TRACE | 0.01 | 0.08 | 0.02 | 0.07 |
| ISO-BUTANE | $IC_4H_{10}$ | TRACE | TRACE | 65.3 PPM | TRACE | 0.01 |
| BUTANE | $C_4H_{10}$ | TRACE | TRACE | 94.9 PPM | TRACE | 0.01 |
| | $H_2S$ | 1 PPM | 1 PPM | 1 PPM | 0 | 0 |
| | $CH_3SH$ | 0 | 0 | 0 | 0 | 0 |

TABLE 3-16. COMPOSITION OF GOB COAL GAS FROM PITTSBURGH COALBED MINES (CONTINUED – 2)

| | | MONONGALIA COUNTY | | | | |
|---|---|---|---|---|---|---|
| SAMPLE | | NO. 6 | NO. 7 | NO. 8 | NO. 9 | NO. 10 |
| RIKEN RESPONSE | | 93% | 93% | 76.5% | 76.5% | 79% |
| PULLING Hg VACUUM | | | | | | |
| POSITIVE FLOW | | X | X | X | X | X |
| CONSTITUENT | | % | | | | |
| HYDROGEN | $H_2$ | – | – | – | – | – |
| OXYGEN | $O_2$ | 0.34 | 0.29 | 1.53 | 0.92 | 0.30 |
| NITROGEN | $N_2$ | 2.02 | 2.00 | 21.85 | 21.02 | 2.93 |
| CARBON MON. | CO | – | – | – | – | – |
| METHANE | $CH_4$ | 97.41 | 97.47 | 71.29 | 72.82 | 95.88 |
| ETHANE | $C_2H_6$ | 0.10 | 0.13 | 0.55 | 0.52 | 0.80 |
| CARBON DIOX. | $CO_2$ | 0.11 | 0.10 | 4.74 | 4.68 | 0.03 |
| ETHYLENE | $C_2H_4$ | | | | | |
| PROPANE | $C_3H_8$ | 0.02 | 0.01 | 0.04 | 0.04 | 0.06 |
| ISO-BUTANE | $IC_4H_{10}$ | 24 PPM | TRACE | 41.6 PPM | TRACE | 59.40 PPM |
| BUTANE | $C_4H_{10}$ | TRACE | TRACE | 54.5 PPM | 23.0 PPM | 44.44 PPM |
| | $H_2S$ | 1 PPM | 0 | 1 PPM | 0 | 1 PPM |
| | $CH_3SH$ | 0.5 PPM | 0.1 PPM | 0 | 0 | 0 |

TABLE 3-16. COMPOSITION OF GOB COAL GAS FROM PITTSBURGH COALBED MINES (CONTINUED – 3)

| | | MONONGALIA COUNTY | | | | |
|---|---|---|---|---|---|---|
| SAMPLE | | NO. 11 | NO. 12 | NO. 13 | NO. 14 | NO. 15 |
| RIKEN RESPONSE | | 78% | 78% | 76% | 76% | 89% |
| PULLING Hg VACUUM | | | | | | |
| POSITIVE FLOW | | X | X | X | X | X |
| CONSTITUENT | | % | | | | |
| HYDROGEN | $H_2$ | – | – | – | – | – |
| OXYGEN | $O_2$ | 0.65 | 0.52 | 0.63 | 1.05 | 0.67 |
| NITROGEN | $N_2$ | 21.57 | 21.30 | 20.29 | 19.38 | 4.33 |
| CARBON MON. | CO | – | – | – | – | – |
| METHANE | $CH_4$ | 70.70 | 70.98 | 72.07 | 72.60 | 93.86 |
| ETHANE | $C_2H_6$ | 0.64 | 0.70 | 0.77 | 0.75 | 0.73 |
| CARBON DIOX. | $CO_2$ | 6.34 | 6.42 | 6.16 | 6.15 | 0.35 |
| ETHYLENE | $C_2H_4$ | | | | | |
| PROPANE | $C_3H_8$ | 0.67 | 0.07 | 0.07 | 0.07 | 0.06 |
| ISO-BUTANE | $iC_4H_{10}$ | 0.02 | 69.56 PPM | 0.01 | 73.04 PPM | 30 PPM |
| BUTANE | $C_4H_{10}$ | 0.01 | 0.01 | 0.01 | 76.10 PPM | 20 PPM |
| | $H_2S$ | 1 PPM | 0 | 1 PPM | 0 | 1 PPM |
| | $CH_3SH$ | 0.5 PPM | 0 | 0 | 0 | 0.5 PPM |

TABLE 3-16. COMPOSITION OF GOB COAL GAS FROM PITTSBURGH COALBED MINES (CONTINUED – 4)

| | | MONONGALIA COUNTY | | | MARION COUNTY | |
|---|---|---|---|---|---|---|
| SAMPLE | | NO. 16 | NO. 17 | NO. 18 | NO. 19 | NO. 20 |
| RIKEN RESPONSE | | 56% | 77% | 77% | 90% | 90% |
| PULLING Hg VACUUM | | 7.1" | 10" | 10" | | |
| POSITIVE FLOW | | | | | X | X |
| CONSTITUENT | | % | | | | |
| HYDROGEN | $H_2$ | – | – | – | – | – |
| OXYGEN | $O_2$ | 3.15 | 3.25 | 2.35 | 0.49 | 0.17 |
| NITROGEN | $N_2$ | 38.40 | 14.51 | 11.49 | 3.90 | 3.01 |
| CARBON MON. | CO | – | – | – | – | – |
| METHANE | $CH_4$ | 56.83 | 73.08 | 77.50 | 94.77 | 96.38 |
| ETHANE | $C_2H_6$ | 0.02 | 0.07 | 0.08 | 0.46 | 0.45 |
| CARBON DIOX. | $CO_2$ | 1.60 | 8.26 | 8.58 | 0.33 | 0.39 |
| ETHYLENE | $C_2H_4$ | | | | | |
| PROPANE | $C_3H_8$ | TRACE | TRACE | TRACE | 0.05 | 0.05 |
| ISO-BUTANE | $iC_4H_{10}$ | TRACE | TRACE | TRACE | 63 PPM | 33.04 PPM |
| BUTANE | $C_4H_{10}$ | TRACE | TRACE | TRACE | 16.2 PPM | 19.46 PPM |
| | $H_2S$ | 0 | 1 PPM | 0 | 1 PPM | 0 |
| | $CH_3SH$ | 0 | 0 | 0 | 0 | 0 |

APPENDIX G

TOPOGRAPHIC MAPS WITH

WOODLAND OVERPRINTS

(Contents of this Appendix, Figures 3-32, 3-33, and 3-34 are in envelope accompanying this report)

# APPENDIX H

## ENVIRONMENTAL REGULATIONS FOR INDUSTRIAL PROCESS WASTES

There are no definitive regulations covering coalgas extraction or coalgas utilization plants in West Virginia. The code simply applies to all industrial process wastes in either the liquid, solid, or gaseous forms.

The main sources of environmental regulations in West Virginia, pertinent to this project, are:

- Water Pollution Control Act, Chapter 20 - Article 5A (as amended in 1974)
- Administrative Regulations of the State of West Virginia for Water Quality Criteria on inter- and intrastate streams (1974)

Both publications are available from the Department of Natural Resources, Division of Water Resources, Charleston, West Virginia 25305.

# APPENDIX I

## QUESTIONNAIRE ON MINING AND DRAINAGE PRACTICES CIRCULATED TO THE MINING INDUSTRY

MINE:

OWNER CO.:

OFFICIAL:

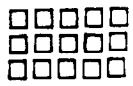
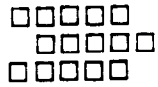
TELEPHONE:

DATE:

MINING PRACTICE DATA:

1. No. of Mains:
2. Headings per Main:
3. No. of Sub-mains:
4. Headings per Sub-main:
5. No. of Butt Sets:
6. Headings per Butt Set:
7. Height x Width of Headings:
8. Length of Mains:
9. Length of Sub-mains:
10. Length of Butt Sets:
11. Arrangement of Main Headings: (Example: RRRII|B|T|IRRR, where: R=Air Return, I=Air Intake, B=Belt, T=Track)
12. Function, Length, Diameter of Shafts: (Functions: Air Intake, Air Return, Coal transport, men & equipment transport, double-compartment of two of the above, etc.)
13. Function, Length, Diameter of Slopes: (Functions: Air Intake, Belt, Track, Stairs, etc.)

14. Pillar Pattern, Width, Length, Height:

(Patterns: Normal:  Staggered:  )

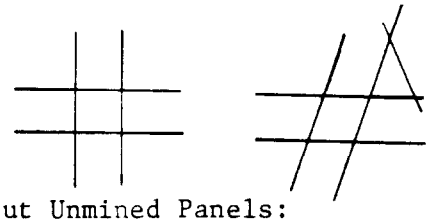
15. Barrier Pillar, Width x Length x Height:

16. Number of Levels, Number of Benches: (Bench-mining: When the two levels are directly one on top of the other; the floor of the upper level is the roof of the lower level. Multiple-level mining: When the levels are hundreds of feet apart, one under the other.

17. Method of Pillaring Retreat: (Methods: Pocket-and-Wing, Split-and-Fender, Open-End, etc.):

18. Width x Length of Room Panels:

19. Width x Length of Longwall Panels:

20. Angle Between Mines and Cross-Cuts: 

21. Number, Width, Length of Developed but Unmined Panels:

22. Location & Spacing of Air Return Shafts (with reference to the mains).

23. Total Length of Headings:

24. Methods of Stabilizing Mined-out stopes. (Methods: Open stopes supported by timber or hydraulic props or not supported at all, forced to cave-in stopes, refilled stopes with tailings from the surface)

25. Methods of Roof Support in Roadways and Return Airways: (Methods: Timber, Steel rings, etc.)

26. Advancing or Retreating Longwalls:

27. Heading Rate of Advancement: (ft/hr)

28. Room Rate of Advancement: (ft/hr)

29. Longwall Rate of Advancement: (ft/hr)

30. Room Mining Rate: (tons/hr)

31. Longwall Mining Rate: (tons/hr)

32. Total Surface of Mining Lease:

33. Room-to-Pillar Surface Ratio in Advancement:

34. Percent of Pillar Recovery During Retreat:

DRAINAGE PRACTICE DATA:

35. Number & Type of Drainage Boreholes:

36. Location of Drainage Boreholes:

37. Dimensions of Drainage Boreholes:

38. Equipment & Features of Drainage Boreholes:

39. Number of Stopes Sealed & Tapped for Drainage:

40. Number of Stopes Sealed but not Tapped for Drainage:

41. Number of Open Gobs, Drained Through Conventional Ventilation:

42. History of Accidents due to Coalgas Explosion:

43. Ownership of Coal Gas (Oil and Gas) Rights (major companies own coal gas rights over the acreage of the mine)

# APPENDIX J

## PROJECTED WELL PERFORMANCE AND WELL SPACING REQUIREMENTS

APPENDIX J

PROJECTED WELL PERFORMANCE AND WELL SPACING REQUIREMENTS

## 1. GENERAL

This appendix describes projected well production rates and well spacing requirements used for the cost-benefits analysis. The gas production rates used are based primarily upon rates achieved by the Bureau of Mines which have been extrapolated to other coalbeds of interest, using simplified gas well performance equations.

The simplified equations are based upon assumptions that gas flow is due primarily to the flow through larger pores and fracture joints in the coal (i.e., Darcy's Law, see Section 3.3.5) and do not account for flows through the micropores. Extrapolation of data obtained by the Bureau of Mines is based upon the supposition that coal seam permeabilities and water flow effects will be approximately the same for Eastern coal beds, and, in the case of stimulated vertical wells, that the same effective fracture patterns would be achieved. While the projections remain to be proved - for average wellbores developed for actual operation - the assumptions are believed to be conservative, in that larger gas volumes could be recovered and shorter drawdown times realized.

## 2. STIMULATED VERTICAL BOREHOLE PROJECTIONS

Based upon the simplifying assumption that gas flow will be governed primarily by Darcy's Law, the two dimensional gas flow state equation in cylindrical coordinates is

$$\frac{\partial P}{\partial T} = C \frac{P}{R} \frac{\partial P}{\partial R} + \frac{\partial}{\partial R} P \frac{\partial P}{\partial R} \qquad \text{Equation J.1}$$

P = Pressure at the Point 'R' distance R from the borehole

T = Time

R = Distance from the borehole

C = Constant for the coal seam between the borehole and Point 'R'

The quantity of gas contained in the segment of the area surrounding the wellbore containing the Point R is

$$\rho_o V_\theta = S \bar{\rho} R^2 d\theta \qquad \text{Equation J.2}$$

$\rho_o$ = Density of gas at standard conditions

$V_\theta$ = Volume of gas at standard conditions in the segment of the area

S = Porosity factor for the area

$\bar{\rho}$ = Average density of gas in the area

R = Distance from the borehole

$d\theta$ = Angle defining the segment

Gas flow into the wellbore from the area is obtained by differentiating Equation J.2. The flow is

$$\rho_o \, q_\theta = S(\dot{\bar{\rho}}) \, R^2 \, d\theta + 2S \, \bar{\rho} \, R \, \dot{R} \, d\theta \qquad \text{Equation J.3}$$

$q_\theta$ = Gas flow rate from the segment

$\cdot$ = Indicates differences with respect to time

Based upon the assumption that flow into the well is due primarily to flow from the region in which the pressure gradient is nearly uniform, Equation J.1 reduces to

$$\frac{\partial P}{\partial T} = 2C \frac{P^*}{R_P} \qquad \text{Equation J.4}$$

$P^*$ = Pressure difference between the Point R and the wellbore

$R_P$ = Distance into the seam at which the pressure would be equal to the seam pressure assuming a linear pressure gradient.

Assuming that pressure in the wellbore is small compared to the seam pressure using the relationship that $\partial P/\partial T = \partial P/\partial R \; \partial R/\partial T$ , and assuming the perfect gas laws apply for relating gas density and pressure, gas flow into the wellbore from the area defined by $R_P$ and $d\theta$ will be

$$q_\theta = K \nu_o P^* d\theta \qquad \text{Equation J.5}$$

K = Constant for the coal seam between the wellbore and $R_p$ in the direction of $\theta$

$\nu_o$ = Specific gas content of the area

P* = The seam pressure (approximately)

As indicated, Equation J.5, a constant flow rate will occur. Since the pressure gradient is assumed to be linear, the average pressure or gas density in the area being drained will be equal to one-half the original pressure or density at any given time, and as such one-half the gas originally contained in the area will have been withdrawn through the borehole. The well's total flow rate is obtained by integrating Equation J.5 over the total area being drained.

Results of the Bureau of Mines' demonstrations have indicated that the permeability factors of the coal seams are highly directional. Based upon this factor the constant K in Equation J.5 must necessarily be defined as the average value for the seam. With this definition the total flow would be given by

$$q = k' \nu_o P^* \qquad \text{Equation J.6}$$

$K'$ is the effective constant appropriate for the seam and would be established by using results of the Bureau of Mines' demonstrations.

$K'$ will also depend upon the actual fracture patterns that would be obtained when stimulating the gas flow and upon the water quantity withdrawn from the coal seam from the bottom of the borehole. As such, gas flows from stimulated vertical wells cannot be expected to remain constant during the initial drawdown time. As such, Equation J.6 will be used to indicate average flow rates to be expected.

If a large number of degasification boreholes are uniformly spaced to drain a large area, flow rates from the wells would remain approximately constant until the time that mutual interference occurs. For these conditions R in Equation J.3 becomes equal to zero, $R_p$ in Equation J.4 becomes a constant, P* is equal to the actual pressure at point $R_p$, and $\rho$ is proportional to the pressure of point $R_p$. With these conditions the flow into the borehole will decrease with time according to

$$q' = \frac{q_o}{\left(2 \frac{Q_o}{V} + 1\right)^2} \qquad \text{Equation J.7}$$

$q'$ = Flow rate after mutual interference occurs

$q_o$ = Flow rate during the time before mutual interference occurred

V = Total gas initially contained in the area

T = Time measured from when mutual interference occurred

The time T* that mutual interference will occur is given by Equation J.8 (i.e., one-half the gas contained in the area will be withdrawn).

$$T^* = \frac{V}{2q_o} \qquad \text{Equation J.8}$$

The gas flows given by Equation J.7 indicate the flow will decrease rapidly. During this time, pressure in the seam will also decrease and consequently gas contained in micropores of the coal and from the less permeable overburden will also drain into the coal seam and into the wellbore, tending to increase the gas production rate. For the remainder of this analysis these additional flow rates are excluded.

Results of demonstrations (Ref. 11.3) conducted at the Federal #2 mine by the Bureau of Mines have indicated that the effective permeability is highly directional and varies by a factor of four or more in directions parallel and normal face cleat. The directionality of the permeability will result in draining an area that is roughly elliptical with axes that are about 4:1.

Based upon Equation J.5, the initial gas flow will be proportional to permeability factors of the coal seam, the initial gas content, and the seam pressure. Using results of the stimulated well established in the Mary Lee seam (approximately 1050 feet depth, 396 PSIG seam pressure, and 435 SCF gas/ton of coal), and assuming that the same effective permeability and stimulation factors exist for the other beds, gas flows for the other areas may be projected. Projected flow rates, using the seam pressures that have been measured, are shown in Figure J-1. These rates are shown as the ratio of the flow rate over the gas content versus depth, to facilitate estimating flows at specific locations.

Based upon projected flow rates in which the flow is approximately constant until the time mutual interference occurs, and upon the flow rates given by Equation J.7 for the time after mutual interference occurs, approximately 80% of the gas contained in the area to be drained will be withdrawn after three T* time periods (i.e., Equation J.8). The times required to drain the seams are illustrated in Figure J-2. As indicated, due to the higher seam pressures, the time required decreases as the coal seam depth increases.

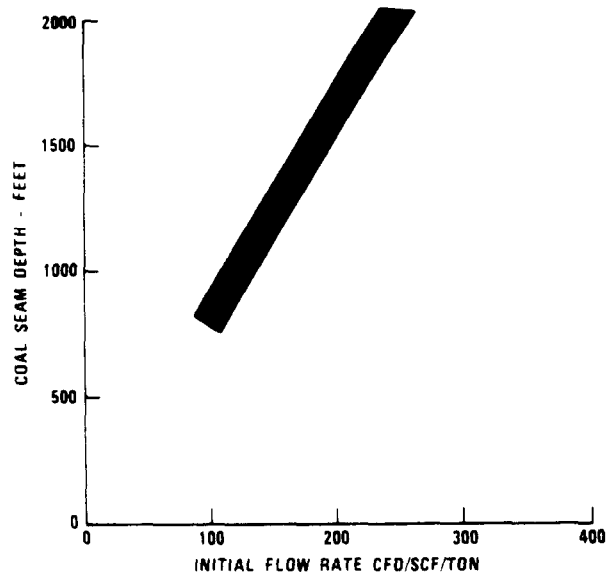



FIGURE J-1. PROJECTED GAS PRODUCTION RATES, STIMULATED VERTICAL BOREHOLES; WELLBORE FRACTURED IN COAL SEAM; COAL SEAM THICKNESS – 7 FEET

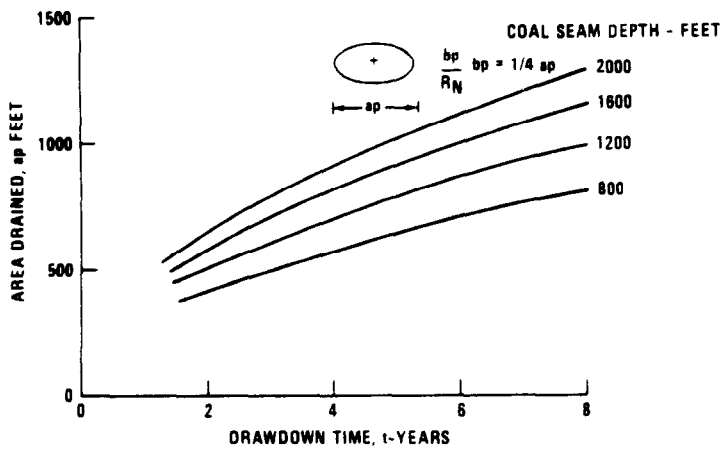



FIGURE J-2. STIMULATED VERTICAL WELL, AREA DRAW DOWN REQUIREMENTS; GAS RECOVERED = 80% OF ORIGINAL VOLUME; UNIFORMLY SPACED WELLS

## 3. HORIZONTAL BOREHOLE PROJECTIONS

Using the same simplifying assumptions used for vertical boreholes, the state equation for the one dimensional gas flow is

$$\frac{\partial P}{\partial T} = C \frac{\partial}{\partial X} \; P \frac{\partial P}{\partial X} \qquad \text{Equation J.9}$$

P = Pressure at point 'X' distance from the borehole

T = Time

C = Permeability and viscosity factor for the seam in the direction of X

The gas contained in the area (for a one-foot width) is given by

$$\rho_o \; V = S \; \bar{\rho} \; X \qquad \text{Equation J.10}$$

S = Porosity factor for the coal seam

$\bar{\rho}$ = Average gas density in the area

The flow rate into the borehole is obtained by differentiating Equation J.10. The flow rate is

$$\rho_o \; q = S \; \dot{\bar{\rho}} \; X + S \bar{\rho} \; \dot{X} \qquad \text{Equation J.11}$$

q = Flow rate

With the simplifying assumption that flow into the wellbore is due primarily to gas contained in the area in which the pressure gradient is nearly uniform, and using the relationship that $\rho P/\rho T = \rho P/\rho X \; \rho X/\rho T$ , the gas flow into the wellbore from the area on one side of the borehole would be given by

$$q = c \frac{\nu_o}{2} \; \frac{P^*}{X_p}$$

$$X_p = (2C \; P^* \; T + X_o^2)^{1/2} \qquad \text{Equation J.12}$$

where C is the appropriate factor for the coal seam.

As indicated by Equation J.12, the flow rate will decrease as the area drained ($X_p$) increases. The constants for the equation are difficult to evaluate using experimental data and tend to result in gas production rates that decrease much faster than those obtained by the demonstration conducted by the Bureau of Mines. Additionally, Equation J.12 does not account for the flow of gas from surrounding areas. Accordingly, the gas flows for the horizontal boreholes are assumed to be described by exponentially decreasing functions, as follows

$$Q = Q_o \, \ell^{-\beta \, T/T^*}$$

Based upon demonstrations conducted at the Federal #2 mine, T is about one year and $\beta = .68$. For these conditions the flow rate may be expressed as

$$Q = 1.36 \, \bar{Q} \, \ell^{\,.68T/T^*} \qquad \text{Equation J.13}$$

where $\bar{Q}$ is the average flow during the first year.

As before, $\bar{Q}$ is proportional to the seam pressure and initial gas content and about one-half the gas contained in the area will be withdrawn after any time T. The flow given by Equation J.13 is compared with flows obtained from well #3, at the Federal #2 mine demonstration in Figure J-3.

If the horizontal boreholes are located so as to drain a specified area, then the exponentially decreasing flow will persist until mutual interference occurs. At this time, X in Equation J.11 will be zero and $\partial P/\partial X$ in Equation J.9 becomes approximately equal to the pressure at X divided by $X_p$. The resulting gas flow then takes the same form as indicated by Equation J.7 in which the initial gas flow $q_o$ in Equation J.7 is equal to the gas flow just prior to the time that mutual interference occurred. This is

$$q = q' \frac{1}{\left(\frac{2q'}{v} T + 1\right)^2} \qquad \text{Equation J.14}$$

$q'$ = Flow rate at the time mutual interference occurred.

T = Time measured after mutual interference occurred.

The time T* that interference will occur is obtained by integrating Equation J.13 and assuming that one-half the gas will be withdrawn from the area.

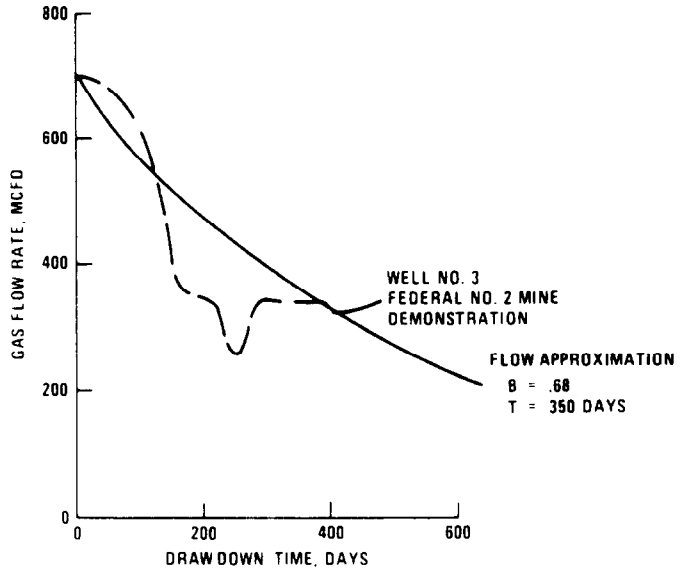



FIGURE J-3. HORIZONTAL WELLBORE PERFORMANCE; PITTSBURGH SEAM CHARACTERISTICS; WELLBORE NORMAL TO CLEAT

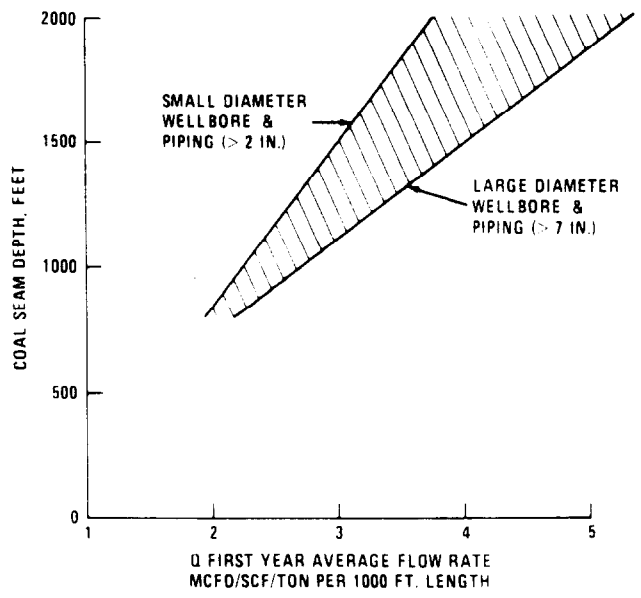



FIGURE J-4. PROJECTED GAS PRODUCTION RATES, HORIZONTAL BOREHOLES – NORMAL TO CLEAT; COAL SEAM THICKNESS – 7 FEET

$$T^* = -514 \ell_n (1 - \frac{\nu_o X_p}{1400Q} \qquad \text{Equation J.15}$$

The projected first year average flow rates for the different coal seams - expressed as the average flow/initial gas content - is provided in Figure J-4. The time required to drain the area defined by $X_p$ is provided in Figure J-5. As indicated, large areas will be drained over relatively short time periods, and due to the increase of pressure with depth deeper coal seams could be drained more rapidly.

4. VERTICAL BOREHOLE STIMULATION FACTORS

Gas production rates projected for vertical wells and the related drawdown time periods described in Section 2 are based upon achieving nominal coal seam fracture patterns in which it is presumed that fractures will extend further in the direction parallel to the face cleat (East-West) than parallel to the butt cleat (North-South). This basic supposition leads to short vertical hole spacing requirements for draining virgin coalbeds rapidly.

It is anticipated that when establishing an array of vertical holes, fracturing could result in achieving longer fractures than those observed for single borehole experiments. Should the results of continued development indicate that long fracture planes normal to the cleat are usually established, then production rates and proper wellbore spacings could be adjusted accordingly. Under these conditions, the optimum solution for spacing will depend upon the cost to achieve longer fracture planes as compared to establishing additional wells. It is, however, projected that the required well spacings described in Section 2, are conservative and that substantial improvements will be realized as the technology matures.

5. PROJECTED RATES FOR EASTERN COALBEDS

Projected initial gas flow rates for stimulated vertical wells vary from about 100 to 250 SCFD/SCF/Ton of coal depending upon the coalbed depth, i.e., the in situ gas pressure. Projected gas flow rates for Eastern U.S. coalbeds are illustrated in Figure J-6.

The projected first year average flow rate for 1000-foot long horizontal boreholes ranges from 2 MSCFD/SCF/Ton of coal for coalbeds at about 800-foot depths to about 4 MSCFD/SCF/Ton for coalbeds at about 2000-foot depths depending upon the size of the boreholes. Projected gas flow rates (first year average) for the smaller diameter boreholes for Eastern U.S. coalbeds are illustrated in Figure J-7. As described earlier, the initial flow rate will likely be about 36 percent higher than the indicated average, depending upon the water production rates, and 30 percent higher flows could possibly be achieved by using larger diameter boreholes.

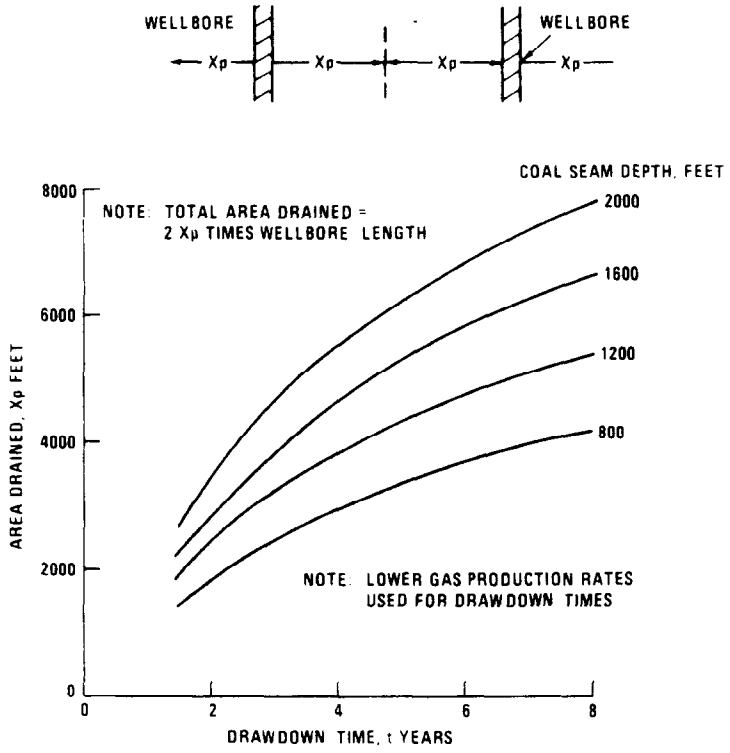



FIGURE J-5. HORIZONTAL WELLBORES, AREA DRAWDOWN TIME REQUIREMENTS; GAS RECOVERED = 80% OF ORIGINAL VOLUME; UNIFORMLY SPACED WELLS NORMAL TO CLEAT

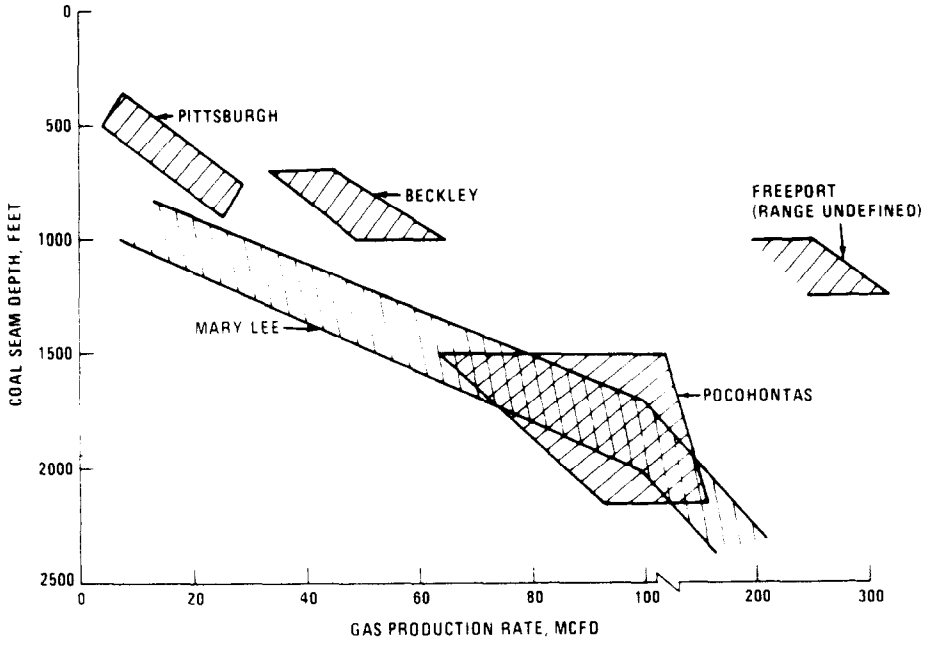



FIGURE J-6. PROJECTED GAS PRODUCTION RATES, STIMULATED VERTICAL WELLBORES

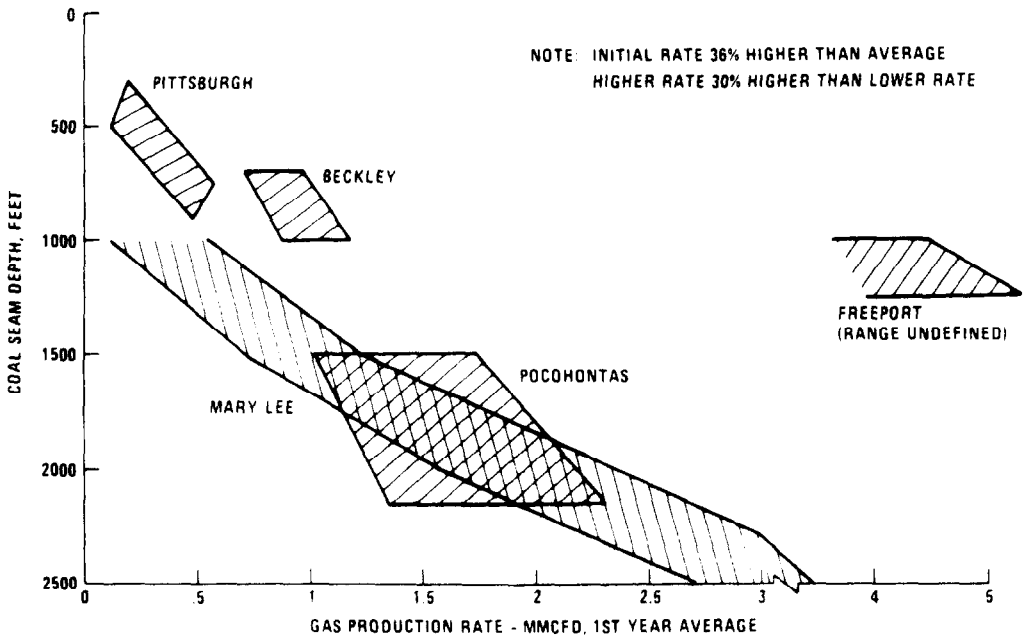



FIGURE J-7. PROJECTED GAS PRODUCTION RATES, 1000-FT. HORIZONTAL BOREHOLE (LOWER RATE PROJECTION)

# APPENDIX K

# METHANE RECOVERY INVESTMENT ANALYSIS

# APPENDIX K

## METHANE RECOVERY INVESTMENT ANALYSIS

### 1. GENERAL

This appendix describes investment opportunities for recovering and using methane contained in coal seams and surrounding areas. The cost of the wells, collection systems, and plants and projected gas production rates are described in Section 4.4.4 and Appendix J. The basic technique towards defining profitability of the different possible ventures is based upon the conventional "constant dollar" (no inflation effects) discounted cash flow approach. For those investments representing low risk, the minimum acceptable rate of return (before taxes) is set at 15 percent. For investments associated directly with recovering and using the methane, the minimum acceptable rate of return is set at 20 percent (before taxes).

In cases where the after tax rate of return is provided, the equipments were depreciated using the straight line method and the tax rate was set at 50 percent. Salvage value of the equipments and the end of period cost to restore the areas were not specifically included in the cash flow analysis.

The cost of the individual system elements to recover and use the methane, gas production rates of the wells, value of the methane or product that is formed, and the specific plan for installing degasification boreholes represent the primary variables used in the venture analyses. Where use of the ranges of the variables is required, profitabilities are provided for the appropriate range. In certain cases, value of the gas or product is insufficient to meet the minimum acceptable rates of return that are required. In these cases, the after tax rates of return are provided as a function of the coal mining cost savings that would accrue due to degasifying the coal seam.

The remainder of this appendix is structured as follows to describe the economics of different possible system configurations:

Section 2. General Economics associated with draining the coal seam in advance of mining with the gas sold to a commercial distributor or used to produce liquefied natural gas (LNG) or ammonia.

Section 3. General Economics associated with recovering gob gases with gas used to produce LNG, ammonia, or electrical power or used locally for general heating purposes.

Section 4. Specific Investment Economics for logical system combinations with specific applications for the Pittsburgh seam.

## 2. PREDRAINAGE INVESTMENT ANALYSIS

The profitability of recovering methane contained in the coal seam and surrounding areas - based on the value of the gas alone - is based upon cost of the equipments required, the rate and quality of gas recovered, and the gas value. In those cases where it is practical to establish a pipeline from the area being drained to a commercial pipeline, selling the gas directly represents the simplest approach to its effective use.

Where such lines are impractical - because of distance or other obstacles - converting the gas to LNG or ammonia represents practical options. These options are described in the following text.

### 2.1 Direct Methane Sales Option

This option requires establishing and operating the following major system components:

- The pipeline from the area being drained to the connection point at the commercial pipeline
- The primary collection system required to manifold the outputs of the individual wells into the main pipeline
- The degasification boreholes

Costs of the pipeline, costs of the primary collection system, and costs of the degasification boreholes are provided in Section 4.4.2. Projected gas production rates are provided in Appendix J. For this analysis, it is assumed that a large area will be drained, resulting in producing at least 4 MMCFD of high quality gas for a period of 10 years and requiring piping the gas four miles to the connection point. The cost of the pipeline (with the $CO_2$ scrubber) is estimated to be approximately $1.284 million with annual operating costs of $109 thousand. Based upon the 20 percent discount rate, these costs translate into a cost of $.30/MCF of gas.

The cost of the primary collection system depends upon the gas production rate for each wellbore and upon the well spacings involved. Based upon the spacings described in Appendix J and assuming that individual wells are located so as to drain the individual areas in six years, the vertical wells will be spaced from 1400 to 2200 feet apart in a direction parallel to the face cleat, depending upon the coalbed depth. The spacing parallel to the butt cleat would be from 350 to 550 feet. For the same conditions, horizontal boreholes established using slant hole technology would be spaced from 8000 to 14,000 feet apart in a direction parallel to the face cleat.

For draining large areas, the cost of the primary collection system should be somewhat less than that described in Section 4.4.2. Assuming

that 20 percent cost reductions can be achieved, the cost of the primary collection system for vertical wells would be given by Equation K.1.

$$\text{Cost}_{(\$1000)} = (2.5 + \frac{Q}{20}) \qquad \text{Equation K.1}$$

Q = gas flow rate MCFD (Cost in $000)

O & M Cost = $700 + 8.5 Q (Cost in dollars)

The primary collection system cost for slant hole wells would be given by Equation K.2.

$$\text{Cost}_{(\$1000)} = 25 + \frac{Q}{200} \quad \text{(Cost in \$000)} \qquad \text{Equation K.2}$$

O & M Cost = 5000 + 10 Q (Cost in dollars)

The costs of the degasification holes described in Section 4.4.2 provide high and low estimates for vertical and slant hole wells. The costs for vertical wells are given by Equation K.3.

High Cost = 13,000 + 30 depth (Cost in dollars) Equation K.3

Low Cost = 8000 + 20 depth

O & M Cost = $750/year

The costs of slant hole wells are given by Equation K.2.

High Cost = 107,000 + 40 depth (Cost in dollars) Equation K.4

Low Cost = 55,000 + 22 depth

O & M Cost = $2500/year + $5000 for cleaning (1st year)

Based upon a six-year drawdown and upon the projected gas production rates described in Appendix J, the wells will produce approximately one-half the gas in the area being drained during the first two years of operation, one-fourth the gas in the area during the next two years, and one-eighth the gas during the last two years of operation.

Using these drawdown characteristics, the costs described above, and the projected flow rates described in Appendix J, the required selling

price of the gas (given the flow rate) or the required well production rate (given the selling price) may be defined.

### 2.1.1 Required Production Rate

The required production rate to realize a 20 percent return rate before taxes is established by present valuing the cash flows over the six years of operation. The cash flows are represented by the gas sales, the O & M costs, and the initial cash outlays. The appropriate equation is:

$$\sum_{N=1}^{6} \frac{Q_n P}{(1+i)^n} - \sum_{N=0}^{5} \frac{O \& M}{(1+i)^n} = \text{Cost of system} \qquad \text{Equation K.5}$$

$i$ = rate of return required = 20 percent

$P$ = selling price of the gas less pipeline cost and any royalties

$Q_n$ = yearly gas production rate - year n

O&M = total yearly O&M cost

Based upon the projected flow rates, the first term in Equation K.5 - for vertical wells - is given by Equation K.6, and for horizontal wells by Equation K.7.

$$\text{PV Methane} = 700\ Q_o\ P \qquad \text{Equation K.6}$$

$Q_o$ = initial production rate MCFD

$$\text{PV Methane} = 560\ Q_o\ P \qquad \text{Equation K.7}$$

$Q_o$ = first year average production rate MCFD

The values of the second term are given by the O&M costs given by Equations K.1 through K.4 as follows:

$$PV_{\text{O\&M Cost Vertical Wells}} = \$5800 + 34\ Q \qquad \text{Equation K.8}$$

$$PV_{\text{O\&M Cost Slant Holes}} = \$35{,}000 + 40\ Q \qquad \text{Equation K.9}$$

Solutions for these equations, based upon the selling price of $1.50/MCF and pipeline cost of $.30/MCF, are provided in Figures K-1 and K-2. These data are superimposed upon the projected rates for different coalbeds. As indicated, the required flow rates to recover the equipment cost are greater than those projected for the Pittsburgh seam, but deeper, gasier seams would provide adequate flow rates to recover the capital costs.

### 2.1.2 Required Selling Price

The required methane selling price is determined in the same manner. For these calculations, the projected flow rates are used together with the costs established above, and $.30 is added to cover the cost of a pipeline to the connection point. The required selling prices for the different seams obtained by associating high cost and low production rates, and low cost with high production rates are illustrated in Figures K-3 and K-4. As indicated, the required selling price of gas from the Pittsburgh seam using vertical wells at about 750-foot coal seam depth is about $2-$3/MCF. This price is higher than the currently regulated price for interstate gas but might be obtained in some locations for local use. When using slant hole wells, the gas cost is generally lower than the currently regulated price.

### 2.1.3 Use of Vent Shafts

The use of horizontal boreholes established from the bottom of vent shafts that would normally be established to support mining operations may also be used to drain virgin coal seams by installing the vent shaft ahead of schedule. Due to high cost of the shafts (see Section 4.4.2), this method is not considered practical for draining coal seams well in advance of mining operations. The estimated required selling price of methane, using vent shaft technique in the Beckley Seam, for example, would be about $2.50/MCF. In circumstances wherein the coal seam would be drained as mining progresses, horizontal degasification boreholes may be used in conjunction with vertical or slant holes to degasify the coal seam so long as the drawdown times are kept short. The specific economic projections for use of vent shaft technique in the Pittsburgh seam are described in the next section.

### 2.1.4 Application to the Pittsburgh Seam

As indicated in Section 2.1.2, predraining the Pittsburgh seam would not be economically practical - based on methane sales alone - when using vertical degasification boreholes - but would be economically practical in many areas when using slant hole technology. It has been projected that degasifying the Pittsburgh seam in advance of mining would result in improved mining productivity and reduced mining costs. The cost reductions are generally attributed to reduced ventilation air requirements, reduced costs for establishing the headings, reduced lost time due to gas buildups in the mine workings, and improved mining rates due to reduced methane emissions at the face.

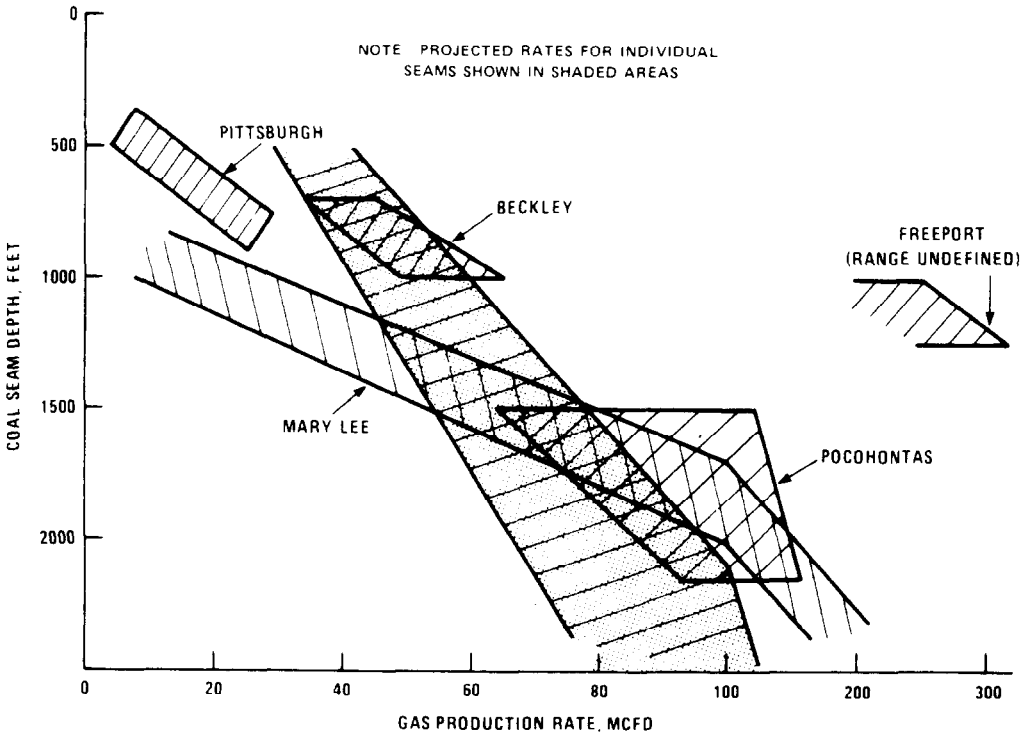



FIGURE K-1. REQUIRED GAS PRODUCTION RATES, STIMULATED VERTICAL WELLBORES

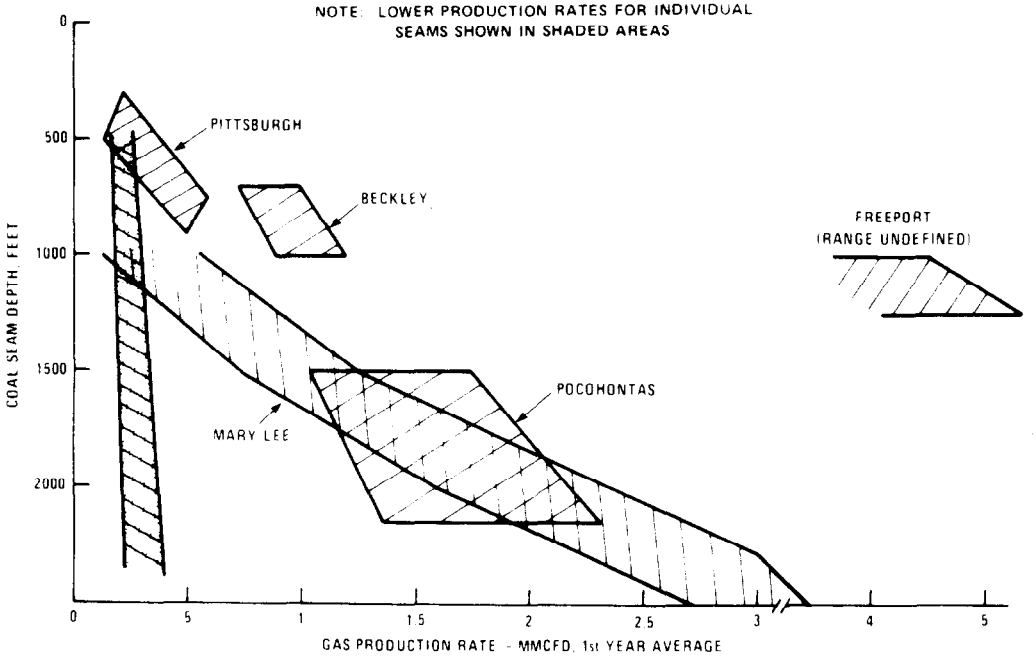



FIGURE K-2. REQUIRED GAS PRODUCTION RATES, 1000-FT. HORIZONTAL BOREHOLE

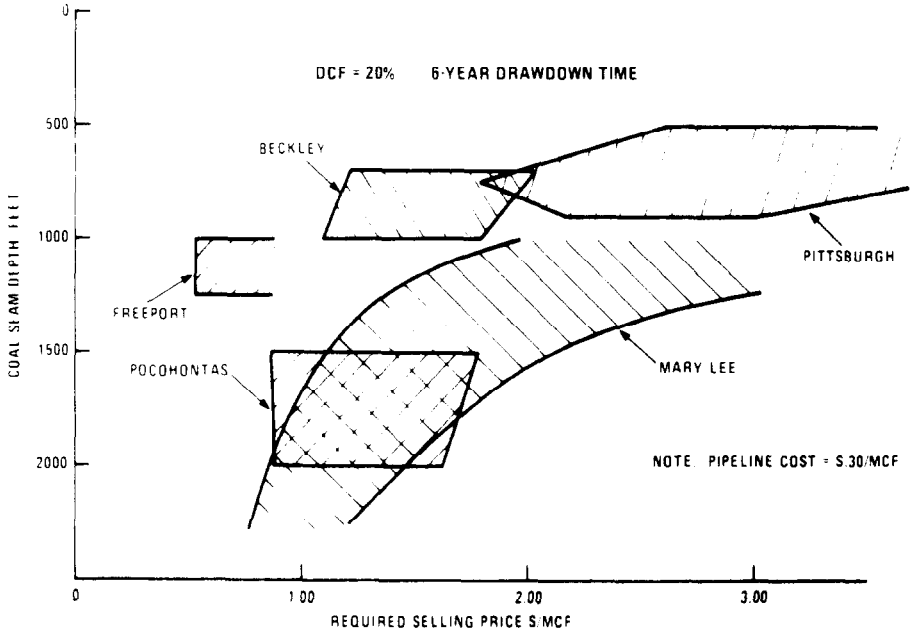



FIGURE K-3. REQUIRED GAS SELLING PRICE, STIMULATED VERTICAL WELLS

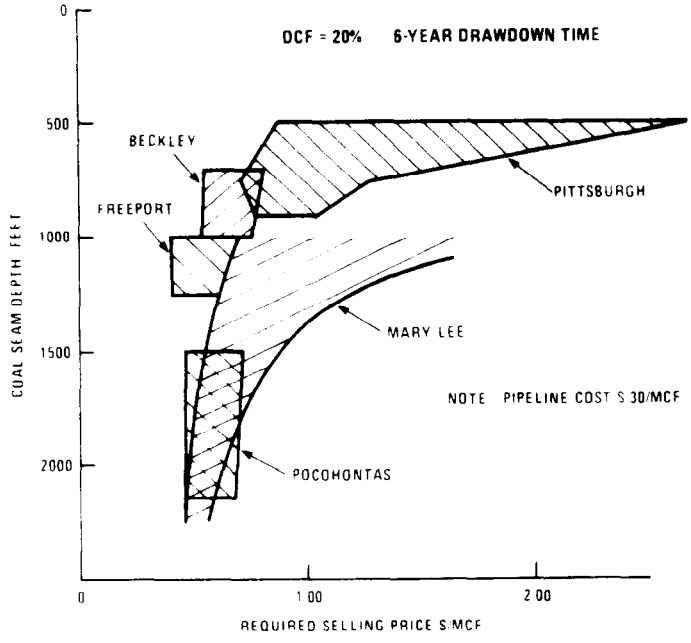



FIGURE K-4. REQUIRED GAS SELLING PRICE, SLANT HOLE WELLS

When degasifying the coal seam in advance of mining to reduce mining costs, the coal seam would be drained at a rate compatible with the planned mine production rate, and degasification boreholes would be spaced so as to obtain the highest practical investment return rate. Under such conditions, proper spacing is dependent upon relative value of the gas, value of the mining cost savings that would be realized, and costs of establishing and operating the wells and for piping the gas to a commercial pipeline.

One process that may be used is to seek the proper spacing that maximizes the after tax investment rate of return. In this process, the cash flows include initial capital outlay, revenues from gas sales and reduced mining costs, costs of operating the wells and collection system, and taxes. Assuming a 50 percent tax rate and that coal in the drained area would be mined directly after the area was drained, the process reduces to seeking the proper drainage time according to Equation K.10.

$$\sum_{N=1}^{N} \frac{Q_n P}{(1+i)^n} - \sum_{N=0}^{N} \frac{O \,\&\, M}{(1+i)^n} - \qquad \text{Equation K.10}$$

$$\sum_{N=1}^{N} \frac{\text{Tax}}{(1+i)^n} + \frac{\text{Coal Value}}{2(1+i)^n} = \text{Cost}$$

$Q_n$ = volume of gas sold in year N

P = gas value = selling price less piping cost

O&M = total O&M cost for wells and collection system

Tax = income tax on revenues, credit taken if negative

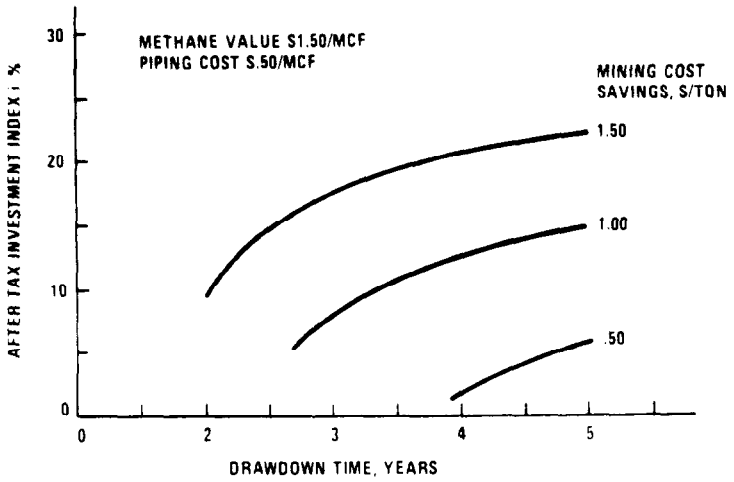
Coal Value = coal mined in the area drained times the cost savings/ton realized

Cost = cost of the wells and collection system

In this equation, the coal value depends upon the area drained and the coal amount that would normally be recovered from the area. For this example, it is assumed that in room-and-pillar mining operations, 50 percent of the coal would be recovered and in longwall mining methods, 80 percent of the coal would be recovered. The area drained depends upon drainage time as described in Appendix J.

Solutions to Equation K.10 are illustrated in Figures K-5 and K-6, using vertical and slant hole wells to gasify the coal seam. Rates of return

RATES, PITTSBURGH SEAM, NOMINAL WELL COST
ROOM-AND-PILLAR MINING



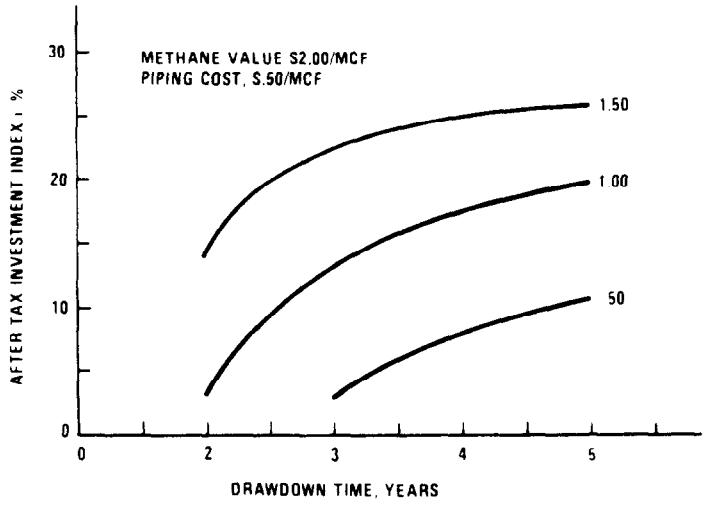




FIGURE K-5. PREDRAINAGE INVESTMENT RETURN, VERTICAL WELLS

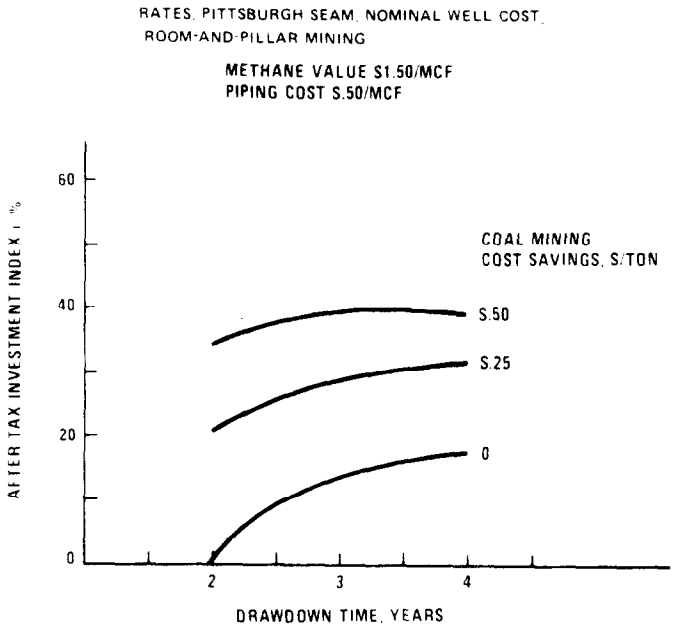



FIGURE K-6. PREDRAINAGE INVESTMENT RETURN, SLANT HOLE WELLS

are based upon the cost and gas flow parameters listed in Table K-1 and are shown as a function of the drawdown time (area drained) allowed for degasifying the coal seam. As indicated, the appropriate times depend upon coal mining cost savings that would be realized, and in general short drawdown times are desirable.

TABLE K-1. PITTSBURGH SEAM DEGASIFICATION IN ADVANCE OF MINING: INVESTMENT PARAMETERS

| | VERTICAL WELLS | SLANT HOLE WELLS |
|---|---|---|
| GAS PRODUCTION RATE/WELL MCFD | 25 | 500 |
| COST/WELL 200 FOOT DEPTH $000 | 31 | 107 |
| COLLECTION SYSTEM COST/WELL $000 | 4.6 | 61 |
| O&M COST $000/YEAR | 1.7 | 12.3 |
| PIPELINE COST $/MCF | .50 | .50 |
| GAS VALUE $1.50/MCF, $2.00 MCF<br>PIPING COST $.50/MCF<br>COAL VALUE = ROOM & PILLAR .14 X AREA ($FT^2$) X VALUE/TON<br>(7 FT SEAM) LONGWALL .23 X AREA ($FT^2$) X VALUE/TON<br>GAS CONTENT - 245 SCF/TON = 69 SCF/$FT^2$ | | |

After tax rates of return for using vertical holes with room-and-pillar mining methods are illustrated in Figure K-7. These data are based upon using a three-year drawdown time and are shown as a function of the mining cost savings that would be realized. For the case shown in which no methane value is taken, the collection system was not established. These data indicate that to be economically practical, coal mining cost savings of about $1/ton would be required and that sale of the methane improves the profitability. Since longwall mining methods result in removing about 60 percent more coal from the area drained, the required savings to break even are about 60 percent of the savings required for room-and-pillar methods or about $.60/ton. Referring to Figure K-5, at the low coal mining savings of $1/ton, longer drawdown times of the order of four or five years would be more appropriate and improved after tax rates of return could be realized. As indicated when using a five-year drawdown time, the rate of return when saving $1/ton would be from 15 to 20 percent, depending upon the methane value.

As indicated in Figure K-6, the proper drawdown time when using slant hole wells is about three years if the expected coal mining cost savings exceeds $.25/ton of coal. The projected cost of using horizontal wells from the bottom of a vent shaft established three years ahead of schedule is given in Section 4.4.2 as $262,000. The cost of the collection system is given as about $93,000 (1 MMCFD production rate). Total operation and maintenance cost is estimated to be about $20,000/year. These costs are approximately twice those estimated for the nominal slant hole well, approximately twice as much methane would be drained, and approximately twice as much coal could be recovered form the drained area. Consequently, the effective investment returns indicated for using slant hole wells would also be realized using vertical vent shafts.

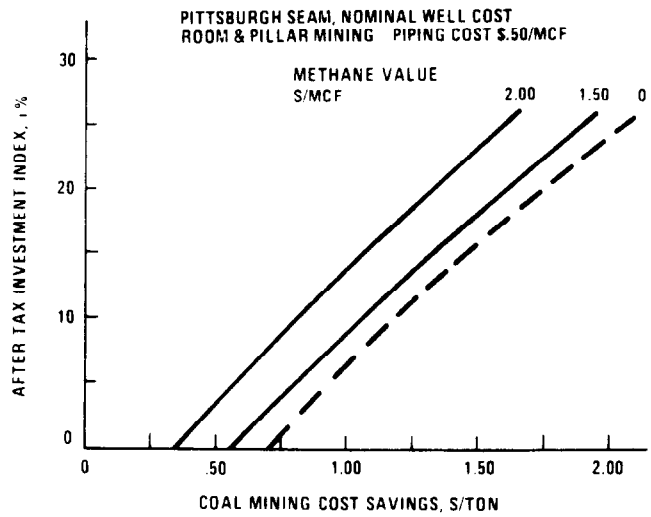



FIGURE K-7. PREDRAINAGE INVESTMENT RETURN, VERTICAL WELLS (3-YEAR DRAWDOWN)

## 2.2 Ammonia and LNG Production Options

In cases where it is impractical to establish a pipeline connecting degasification boreholes to a commercial pipeline, the gas may be used to produce LNG or ammonia. When coal seams are drained well in advance of mining, which could be the case if slant hole technologies are developed, then large quantities of methane would be produced and large commercial size plants could be used to produce LNG or ammonia. In this case, the economic practicality of converting gas to LNG or ammonia depends upon the methane price as compared to prices that must be paid by other competing plants. When using slant hole wellbores, the required methane selling price is generally less than $1.50/MCF, the projected price that would be paid by a competing plant. Based upon this comparison, converting gas to LNG or ammonia could be economically practical depending upon the market for the product. When using vertical wells, the required selling prices are higher and practicality of the investment depends heavily on market forces.

When draining the coal seam is coupled directly to coal production, the required methane selling price is less, but smaller, more expensive plants are needed to convert the gas to LNG or ammonia. Consequently, the required product selling price - if methane prices are the same - will be higher when using smaller plants. Since it is the required selling price that would require coupling gas production to coal production, the required selling price, based upon revenues realized from sale of the product alone, will be higher than that required by a commercial plant to realize an acceptable profit.

As such is the case, the economic practicality of converting gas to LNG or ammonia is considered as an option to establishing a connecting pipeline from degasification boreholes to a commercial pipeline. The most appropriate option would depend upon specific market conditions in the general area affecting the products' selling prices.

### 2.2.1 Required Selling Prices

The required selling price of LNG or ammonia depends upon the cost of the methane recovered and upon costs of establishing and operating the plants. The required selling prices of the products to realize a 20 percent rate of return - before taxes - are provided in Figure K-8. These prices are based upon a 10-year plant operation using the plant cost provided in Section 4.4.2, and are shown as a function of the gas cost. As indicated, the required LNG selling price would be competitive if gas costs are less than $1.40/MCF for the larger plant and less than $1.15/MCF for the smaller plant. For ammonia, the required selling price would be competitive if gas costs are less than $1.50/MCF for the larger plant and less than $.25/MCF for the smaller plant. In general, the LNG plant would represent the most practical option, but since the market for LNG is highly localized, the ammonia plants could be required for many specific locations, i.e., no LNG market. The specific choice would depend upon actual market conditions. The most appropriate choice is indicated in Figure K-9. This data is based upon equating the required selling prices of the LNG or ammonia shown in Figure K-8 for equal gas costs. If higher LNG or ammonia prices are realized, then the rates of return will be higher than 20 percent.

### 2.2.2 Application to the Pittsburgh Seam

As indicated in Section 2.1, it will generally not be economically practical to predrain the Pittsburgh seam using vertical wellbores unless the methane can be sold for at least $2.10/MCF, or if coal mining cost savings - for room-and-pillar mining - of about $1.00/ton are realized. When using slant holes or vent shaft technologies, the required selling prices are generally less than $1.50/MCF. For the vertical wellbore case, a coal mine cost savings of about $1.00/ton will be sufficient to recover the cost of the wells and collection system. For slant holes, a cost savings of about $.40/ton is required to recover the cost of the wells and collection system.

Assuming that these cost savings are realized, the effective cost of the methane for conversion to LNG or ammonia would be zero. Using these criteria as a basis for comparisons, the relative economic merits of the LNG or ammonia plants expressed in terms of the after tax rates of return are provided in Figures K-10 and K-11. As indicated at the projected selling prices in the area, LNG plants would represent the most practical option. Additionally, the high cost of ammonia plants requires that the plant be used only where large volumes of methane would be drained.

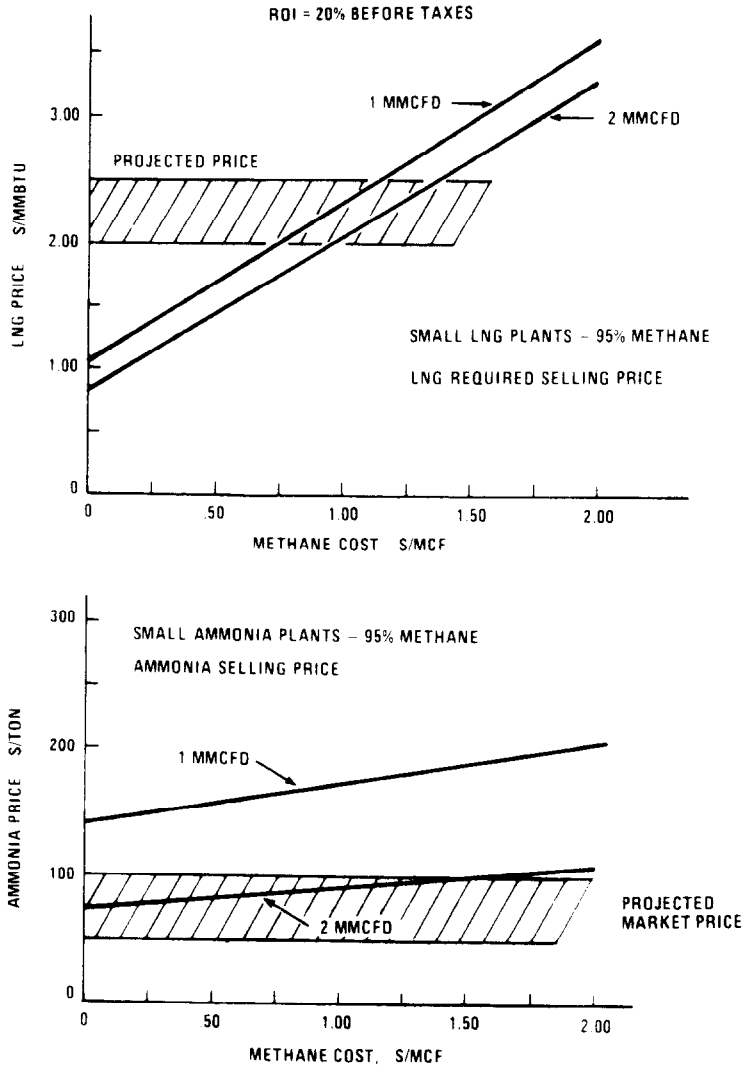



FIGURE K-8. REQUIRED SELLING PRICE FOR AMMONIA AND LNG

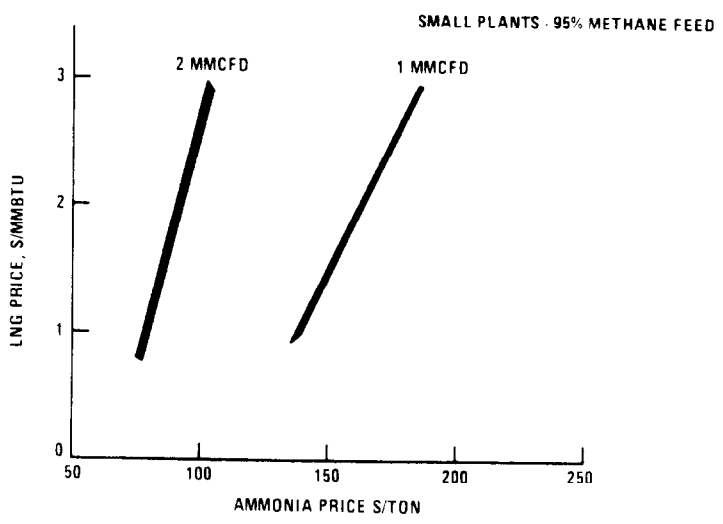



FIGURE K-9. EQUIVALENT SELLING PRICES, LNG AND AMMONIA

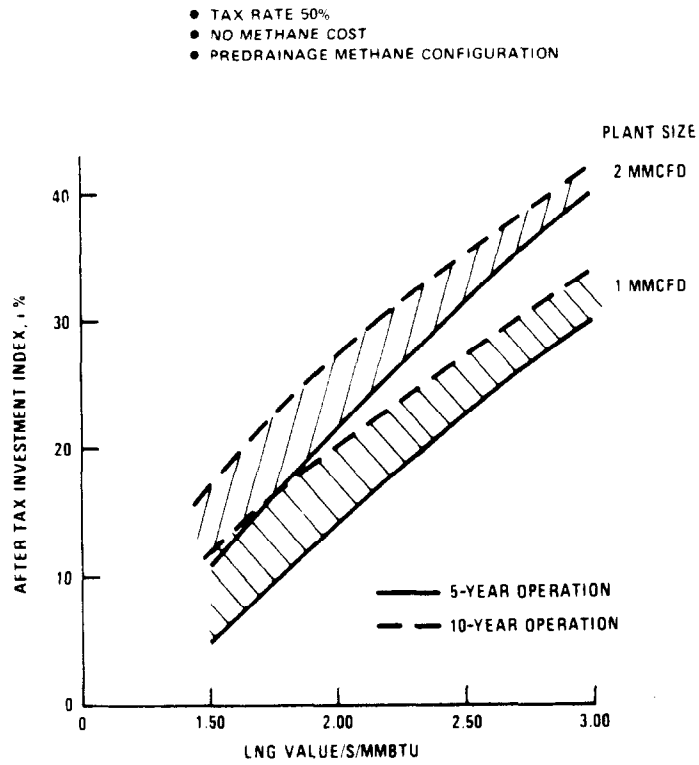



FIGURE K-10. LNG PLANT INVESTMENT RETURN

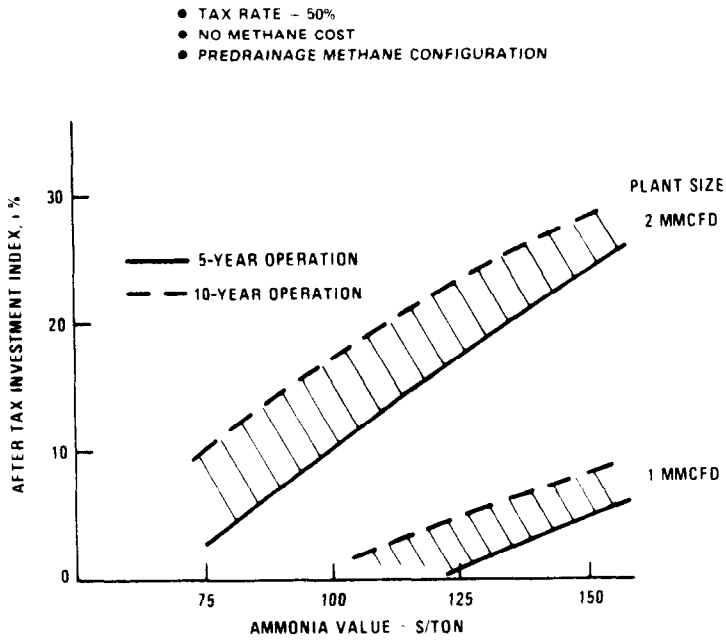



FIGURE K-11. AMMONIA PLANT INVESTMENT RETURN

On the average, the Pittsburgh seam contains 245 SCF of methane per ton of coal. Based upon room-and-pillar mining methods and recovering 80 percent of the methane within the coal, a mine producing one million tons of coal per year would also produce by predraining about one million SCF of gas per day. Thus, use of the large ammonia plant would be compatible with only very large mines or for a combination of two or more smaller mines.

## 3. GOB GAS RECOVERY SYSTEMS

Gas recoverable from the gob areas varies in quality, depending upon how well the areas are sealed to ventilation air in the mine workings. For this analysis, quality of the gob gases is taken to be about a 50 percent methane-50 percent air mixture. Upgrading these gases to pipeline quality and selling them at pipeline prices is impractical. As such, the basic options for using the gas are either to convert it to LNG or ammonia, use it to produce electrical power, or employ it for local heating purposes as a substitute for natural gas or coal.

Techniques for recovering gob gases include drilling vertical vent boreholes from the surface and establishing ducts within the mine workings, with gas brought to the surface through a ventilation shaft. The costs of establishing the ducts required for collecting gob gases within the mine are difficult to establish due to mining safety regulations and, as such, an economic analysis for such systems is not included in this report. In those cases wherein the coal seam is drained before mining, the wellbores established may also be used to recover gob gases. Economic projections for this case are provided in Section 4.

### 3.1 General Economic Factors

The cost of establishing a vertical borehole from the surface to a gob area is taken to approximately the same level as for establishing a vertical borehole for predraining virgin coal. For such boreholes, the dewatering pump and the stimulation cost are of course not required. The collection system cost depends upon the rate at which gas will be removed from the mine, upon pressure that would be maintained in the gob area, and upon the distance gas must be piped to the point where it is to be used. At present, there is insufficient data to accurately project the quantity of gas recoverable from gob areas. Conceptually, recoverable gas would be that draining into the area from the ribs, floor, and overburden areas. In most cases, the gas would be that draining from the overburden which generally has low permeability and porosity, resulting in relatively slow gas production rates. For room-and-pillar mining methods, individual rooms may be interconnected, providing large effective drainage areas. In long-wall mining methods, the mined areas are large and collapse of the overburden should generally result in larger gas flows into the gob area.

In the Cambria No. 33 mine, the Bureau of Mines succeeded in removing large quantities of methane by installing high capacity vacuum pumps (1 MMCFD to 1.6 MMCFD) and allowing methane concentrations to diminish with

time. At the end of the nine-month period, after mining progressed past the hole, methane concentration fell from 89 percent to 30 percent as the gas production rate was increased from about 1 MMCFD to 1.6 MMCFD.

For this analysis, the conservative estimates of producing 100 MCFD/well (which would be associated with room-and-pillar mining) to 200 MCFD/well (which would be associated with longwall mining) are considered typical for the general area. Further, it is assumed that this gas production rate would extend over a three-year period and that the methane concentration would average about 50 percent.

For the Pittsburgh seam (800-foot depth), cost of the vertical wellbore and vacuum pump is estimated from $20,000 to $30,000 per well installation for gas production rates between 50 and 200 MMCFD. For a coal seam at 1500 feet, the cost would be approximately $35,000 to $56,000. The required mining cost savings to recover well costs are provided in Figure K-12. These savings are expressed in $/ton of coal mined per MMCFD of methane produced, based on a mine producing one million tons of coal annually. As indicated, small mining cost savings will result in recovering the wellbore costs. If these small savings are not actually realized, the gob gas must necessarily be used profitably to recover the well costs. For these conditions, it is necessary to compress and pipe the gases to the point where they will be used.

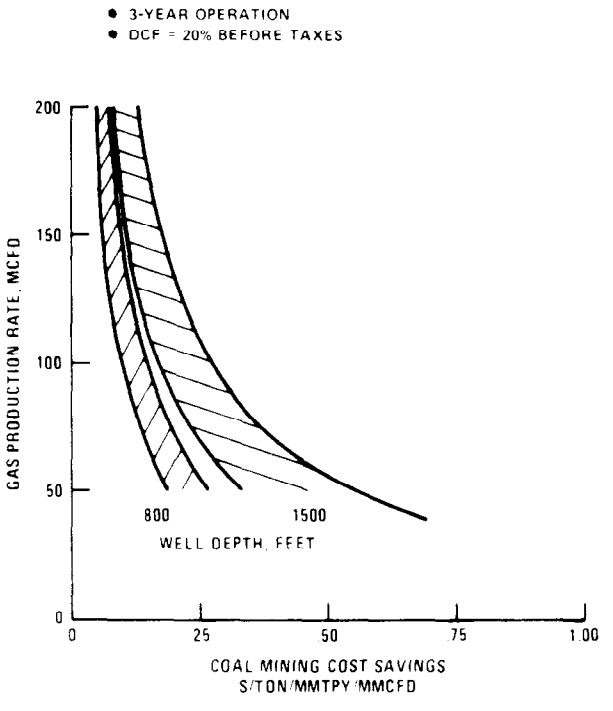



FIGURE K-12. REQUIRED MINING COST SAVINGS TO RECOVER GOB GAS VENT HOLE COST

Costs of a typical collection system and pipeline to the using point are provided in Table K-2. These costs are based upon average wellbore spacings and upon locating the using system 5000 feet from the initial degasification boreholes with an additional 5000 feet added every three years.

TABLE K-2. GOB GAS PRODUCTION AND COLLECTION SYSTEM COSTS

| | SYSTEM COSTS $000 TOTAL GAS PRODUCTION RATE MMCFD | | | |
|---|---|---|---|---|
| | 1 WELL PRODUCTION RATE MCFD | | 2 WELL PRODUCTION RATE MCFD | |
| | 100 | 200 | 100 | 200 |
| BOREHOLES | 240 - 300 | 100 - 150 | 400 - 600 | 200 - 300 |
| PRIMARY COLLECTION SYSTEM | 118 | 95 | 236 | 190 |
| PIPELINE (5000 FEET) | 89 | 89 | 144 | 144 |
| TOTAL | 407 - 507 | 284 - 334 | 780 - 980 | 534 - 634 |
| OPERATION & MAINTENANCE | | | | |
| PRIMARY | 14 | 12 | 28 | 24 |
| PIPELINE | 17 | 17 | 24 | 24 |
| TOTAL | 31 | 29 | 52 | 48 |

The resulting gas value based upon a rate of return of 20 percent before taxes is provided in Figure K-13. These data are shown as a function of coal mining cost savings that would be realized and for recovering 1-2 MMCFD of 50 percent methane gas. As indicated, the gas value is less than $.50/MMBtu for the higher production rate if mining cost savings are more than $.20 per ton/MMCFD. The gas value if no mining costs are realized ranges from $1.00 to $1.50/MMBtu, which would be competitive with natural gas for heating purposes if required burner modifications are small. The gob gas value due only to the collection system cost is provided in Table K-3. As indicated, the cost of collecting and piping the gas to a central location ranges from $.49 to $.62 MMBtu.

## 3.2 Gob Gas Utilization Options

The relative economics of converting gob gas to LNG or ammonia, to produce electrical power, or for use in local heating applications, are described in this section. The relative economics are based upon the plant costs provided in Section 4.4.2, upon the gas cost being from 0 to $.50/MMBtu, and upon recovering 1 to 2 MMCFD of gob gas averaging 50 percent methane. Operational lives of the LNG and ammonia plants - before major overhaul - are assumed to be 10 years. Operational lives of the gas turbines are presumed to be 40,000 hours (five years) before major overhaul. When used for local heating applications, operational lifetimes are assumed to be 10 years, although lifetimes for the specific combustion equipments may be much longer.

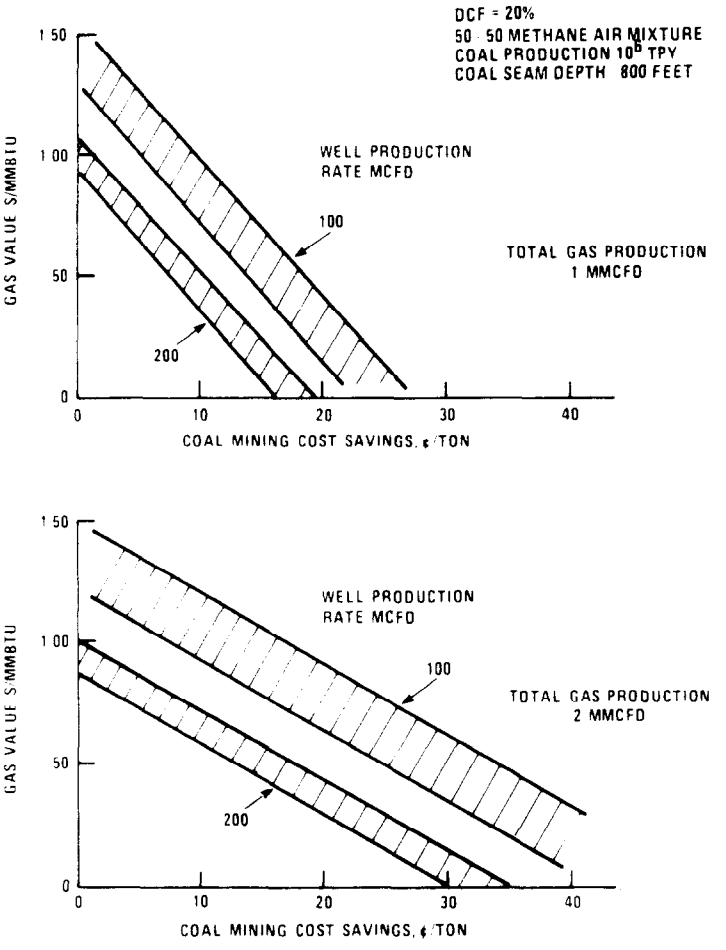



FIGURE K-13. GOB GAS VALUE

TABLE K-3. GOB GAS COLLECTION SYSTEM COST: 50% METHANE - 50% AIR MIXTURE

| | GOB GAS VALUE $/MMBtu TOTAL GAS PRODUCTION – MMCFD | |
|---|---|---|
| INDIVIDUAL WELL PRODUCTION RATE-MCFD | 1 | 2 |
| 100 | .62 | .57 |
| 200 | .54 | .49 |

### 3.2.1 LNG Plant Option

Costs of the plants to convert 50 percent methane gas to LNG are provided in Appendix J. The required LNG selling price based upon the costs and a 20 percent rate of return for 10 years' operation is provided in Table K-4. As indicated, if the gas value is $.50/MMBtu, for larger plants the required price is $2.69/MMBtu, and for smaller plants the required price is $3.60/MMBtu. These costs are higher than the projected selling price of $2.25/MMBtu. Actual rates of return after taxes for using gas to produce LNG are provided in Figure K-14. These data are shown as a function of the selling price and indicate this option is marginally practical for larger plants unless higher than projected selling prices can be realized.

### 3.2.2 Ammonia Plant Option

The costs of plants to convert 50 percent methane gas to ammonia are provided in Section 4.4.2. The required ammonia selling price based upon these costs and a 20 percent rate of return for 10 years' operation are provided in Table K-5. As indicated, if the gas value is $.50/MMBtu the required selling price is $194/ton, and for the smaller plants the price is $325/ton. These costs for larger plants are higher than the projected selling price of $100/ton. Actual rates of return after taxes for converting gob gas to ammonia are provided in Figure K-15. These data are shown as a function of the selling price and indicate this option is marginally economic for larger plants unless higher than projected selling prices can be realized.

### 3.2.3 Power Generation Option

Costs of small gas turbine power plants suitable to burn gob gas are provided in Section 4.4.2. These costs are based upon consuming the power locally and using short power transmission distances. Values of the generated power based upon these costs and a 20 percent rate of return for five years' operation are provided in Table K-6. As indicated, if gob gas costs $.50/MMBtu, the power value is about 30 mills/kwh, then support and housing facilities are required. If not, the value is 20 mills/kwh. These lower costs are about the expected 20 mills/kwh rates, and the power generation option could represent a practical investment. After tax rates of return for the power generation option are provided in Figure K-16.

### 3.2.4 Local Heating Options

The value of using gob gas for local heating applications depends upon cost of the alternative fuel. If used for space heating applications, the displaced fuel would usually be natural gas or oil. Substituting gob gases for such fuels will reduce the heating cost by a factor of about three, and large savings could result if substantial quantities of fuel are required. If the gas is used for coal drying applications, then

TABLE K-4. REQUIRED LNG SELLING PRICE: GOB GAS CONVERSION SYSTEM

| | PLANT CAPACITY MMCFD | |
|---|---|---|
| | 1 | 2 |
| PLANT COST $000 | 1273 | 1917 |
| OPERATING & MAINTENANCE COST | 112 | 207 |
| LNG COST ($/MMBtu) | | |
| GOB GAS VALUE 0 | 2.97 | 2.38 |
| $/MCF $.50/MBtu | 3.60 | 2.69 |
| PLANT PRODUCTION MMCFD LNG | 0.4 | 0.8 |

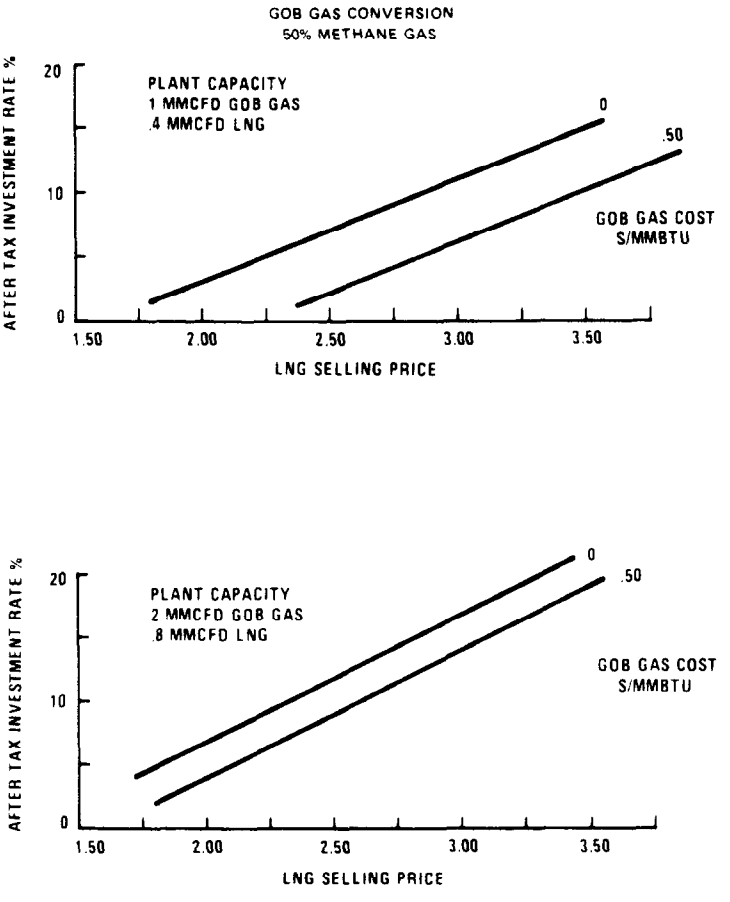



FIGURE K-14. REQUIRED LNG SELLING PRICE

TABLE K-5. REQUIRED AMMONIA SELLING PRICE: GOB GAS CONVERSION

| | PLANT CAPACITY MMCFD | |
|---|---|---|
| | 1 | 2 |
| PLANT COST | 5705 | 6380 |
| OPERATION & MAINTENANCE | 248 | 327 |
| AMMONIA COST (S/TON) | | |
| GOB GAS VALUE 0 | 308 | 177 |
| (S/MBtu) S.50 | 325 | 194 |
| PLANT PRODUCTION TONS/DAY | 15 | 30 |

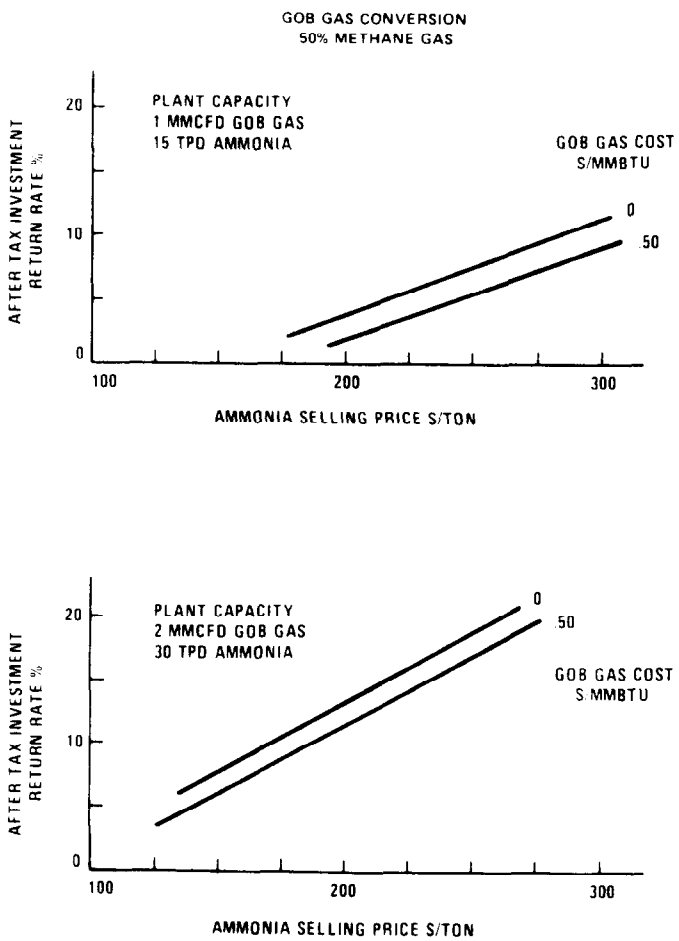


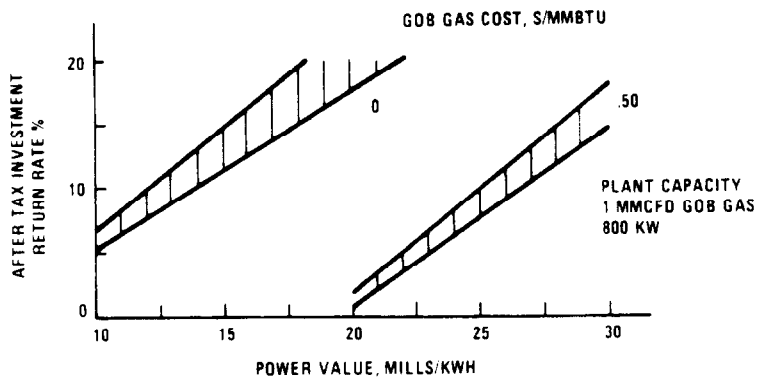

FIGURE K-15. REQUIRED AMMONIA SELLING PRICE

TABLE K-6. GENERATED POWER VALUES, GAS TURBINE OPTION: GOB GAS CONVERSION SYSTEM, FIVE-YEAR OPERATION

| | COST $000 PLANT CAPACITY MMCFD | |
|---|---|---|
| | 1 | 2 |
| PLANT COST WITH FACILITIES | 350 | 620 |
| WITHOUT FACILITIES | 290 | 560 |
| OPERATION & MAINTENANCE | 23 | 31 |
| POWER GENERATED | 800 KW | 1600 KW |
| POWER VALUE[1] (WITH FACILITIES) | 21 | 18 |
| (NO GAS COST) (WITHOUT FACILITIES) | 18 | 16 |
| POWER VALUE (WITH FACILITIES) | 34 | 31 |
| (GAS COST $.50 MMBtu) (WITHOUT FACILITIES) | 31 | 29 |

[1]POWER VALUE IN MILLS/KWH

- GAS TURBINE OPTION
- GOB GAS CONVERSION SYSTEM
- RANGE SHOWN FOR INSTALLATION WITH AND WITHOUT SUPPORT FACILITIES



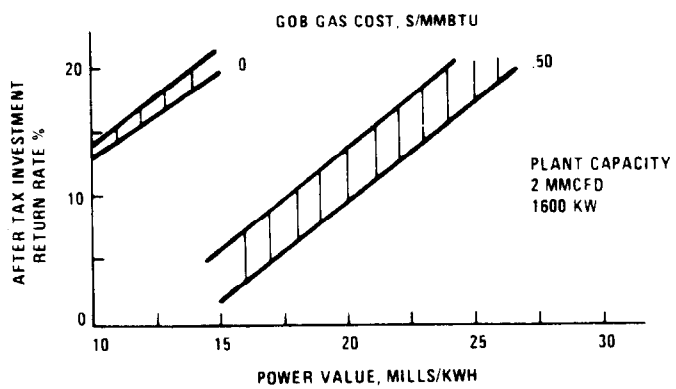




FIGURE K-16. REQUIRED POWER VALUES

the displaced fuel will usually be boiler quality coal with a nominal selling price of about $.40/MMBtu. This price represents the approximate cost of establishing the collection system and pipeline. As such, this investment would represent a practical option, depending upon the specific cost involved in establishing a pipeline to the coal drying facility.

## 4. OPERATIONAL SYSTEM CONFIGURATIONS

As indicated in Section 2, relative economics favor draining coal seams in advance of mining, with the gas either being sold to a commercial supplier or used to produce LNG or ammonia. As indicated in Section 3, providing systems to recover and use gob gases are marginally economic. In actual practice, if the systems are properly designed, degasification boreholes and collection piping established to drain virgin coal may also be used to recover gob gases. Generally, since the gob gas production rate (50 percent methane) will usually be higher than the gas production rates when draining virgin coal, larger pipe sizes will be required and, when gob gases are to be collected, larger vacuum type compressors should be installed.

When establishing the initial system, allowances for well production rate uncertainties and gas quality uncertainties should be factored into the system design and contracts for sale of the products. In general, production of individual wells may be adjusted so that the total production rate would remain below the maximum rate at which the gas could be used or sold. If a large number of wells are used, the throttling process may be selective and the coal seam could be properly degasified so as to enhance mining.

A typical system that could be configured to utilize both high quality gas recovered from virgin coal and lower quality gas recoverable from gob areas would necessarily include a LNG or ammonia plant or gas turbine to use the gob gases. An appropriate system design safety factor would provide for a 25 percent uncertainty in average gas production rates.

For a mine producing 1 million tons of coal annually from the Pittsburgh seam, approximately 1 MMCFD of gas would be drained from virgin coal and 1 MMCFD of gob gas (50 percent methane) could be recovered from gob areas. Using stimulated vertical wellbores to drain virgin coal, the system would require that approximately 60 wells be in continuous operation to drain virgin coal, with about 20 new wells added each year. For the basic safety margin of 25 percent, an agreement to sell about .75 MMCFD to a commercial supplier would be appropriate. The LNG or ammonia plant would be sized to handle a maximum of 1.25 MMCFD of gob gas and .5 MMCFD of high quality (95 percent methane) gas. The minimum feed rate to the plants would be .75 MMCFD of gob gas. For these conditions, sales agreements would require selling from 11 to 36 tons/day of ammonia, or from .3 to .9 MMCFD of LNG. If such flexible sales agreements cannot be reached, and if higher rates are actually realized, gas production could be reduced initially, and agreements for higher minimum supply rates negotiated.

A typical system to be established would locate the LNG or ammonia plant in the general vicinity of degasification boreholes so as to minimize overall system costs. The initial primary collection piping system would be sized to handle maximum expected gob gas flow rates, and the system established so as to facilitate either piping predrainage gas to a commercial pipeline or to an ammonia or LNG plant. With such a concept, the plant would be installed three to four years after degasification was started, the appropriate vacuum type compressors added to the proper boreholes and LNG or ammonia production would commence. As mining progresses, degasification boreholes are systematically disconnected from the pipeline, proper compressors are added, and gob gases are piped to a plant using the established collection system, i.e., reversed flow. Individual wells draining gob gases would remain connected to the system as long as gas flow (primarily gas quality) is adequate for economic system operation. In those circumstances wherein gas flow from virgin coal is higher than expected, gas from the predrainage system would be diverted into an LNG or ammonia plant and, if necessary, the least economic gob gas well would be disconnected.

## 4.1 System Costs

The estimated cost of the system described above is based upon cost projections provided in Section 4.4.2 for the appropriate system elements. For this system, 20 new degasification wells would be added annually (initial well production rate of 25 MMCFD). The primary collection system is sized to handle a gob gas production rate of 50 MMCFD/well. The pipeline to the commercial pipeline is sized to handle 1 MMCFD and is assumed to require 5000 feet of piping and upgrading of the gas before sale. The plant size is based upon handling gob gases with a maximum input feed stream of 1.25 MMCFD of gob gas and .5 MMCFD of methane from the origin coal. Costs of the system components are provided in Table K-7.

TABLE K-7. PROJECTED PLANT COST FOR COMBINED 95% AND 50% METHANE FEED OPTION

| | CAPACITY | CAPITAL COST $1000 | O&M COST $000/YEAR |
|---|---|---|---|
| LNG PLANT | 1.8 MMCFD | 1535 | 105 |
| AMMONIA PLANT | 34 TPD | 5315 | 239 |
| WELL COSTS (20 WELLS)* | 1 MMCFD | 600-1000 | 40** |

*REPRESENTS NUMBER OF NEW WELLS REQUIRED EACH YEAR TO SUSTAIN MINING RATE. 60 WELLS REQUIRED IN OPERATION TO COMPLETE DEGASIFICATION OVER 3 YEARS.

**O&M COST FOR EACH 20 WELL ARRAY

- MAXIMUM FEED OF 95% $CH_4$ - .5 MMCFD
- MAXIMUM FEED OF 50% $CH_4$ - 1.25 MMCFD
- ROOM-AND-PILLAR MINING

## 4.2 Economic Projections

For this analysis, it is assumed that pipeline and plants are to be amortized over a 10-year period, individual wells and primary collection systems amortized over three years, no salvage values are associated with the equipments, and that the tax rate is 50 percent on income. Table K-8 provides projected cash flows for the LNG system configuration based upon achieving nominal gas production rates, saving $1.00/ton of coal during mining, selling the natural gas at $1.50/MCF, and LNG at $2.25/MMBtu. As indicated, at these prices the coal mine savings recover the cost of the wells and LNG sales recover the cost of the plant. Gas sales then provide a small profit. Investment returns for other sale prices and well costs are provided in Figure K-17. The range of expected investment returns for the ammonia plant option is provided in Figure K-18. For these projections, the coal production rate was set at 2 MMTPY since the ammonia plants are only marginally economic for smaller plants.

**TABLE K-8. CASH FLOW SUMMARY, TYPICAL OPERATIONAL SYSTEM; NOMINAL COST AND SALES PROJECTION**

| YEAR | PIPELINE COST | LNG PLANT | WELLS | PRIMARY COLLECTION SYSTEM | TOTAL CAPITAL | GAS SALES | LNG SALES | COAL MINING SAVINGS | TOTAL REVENUE (GROSS) | O&M | D&P | AFTER TAX INCOME (GROSS) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 289 | - | 620 | 180 | 1089 | 262 | - | | 262 | 41 | 295 | 258 |
| 2 | - | - | 620 | 180 | 800 | 440 | - | | 440 | 59 | 561 | 471 |
| 3 | - | 1535 | 620 | 180 | 2335 | 525 | - | | 525 | 77 | 829 | 638 |
| 4 | - | - | 620 | 180 | 800 | 525 | 105 | 1000 | 1630 | 182 | 983 | 1215 |
| 5 | - | - | 620 | 180 | 800 | 525 | 210 | 1000 | 1740 | 204 | 983 | 1260 |
| 6 | - | - | 620 | 180 | 800 | 525 | 315 | 1000 | 1840 | 226 | 983 | 1298 |
| 7 | - | - | 620 | 180 | 800 | 525 | 315 | 1000 | 1840 | 226 | 983 | 1298 |
| 8 | - | - | 620 | 180 | 800 | 525 | 315 | 1000 | 1840 | 226 | 983 | 1298 |
| 9 | - | - | 620 | 180 | 800 | 525 | 315 | 1000 | 1840 | 226 | 983 | 1298 |
| 10 | - | - | 620 | 180 | 800 | 525 | 315 | 1000 | 1840 | 226 | 983 | 1298 |
| TOTALS AFTER 10 YEARS | 289 | 1535 | 6200 | 1800 | 9824 | 4902 | 1890 | 7000 | 13792 | 1693 | 8566 | 10335 |
| 11-20 | - | - | 620 | 180 | 800 | 525 | 315 | 1000 | 1840 | 226 | 954 (3)<br>800 (7) | 1284 (3)<br>1207 (7) |
| TOTALS AFTER 20 YEARS | 289 | 1535 | 12400 | 3600 | 17824 | 10152 | 5040 | 17000 | 32192 | 3953 | 17028 | 22636 |

LINEAR DEPRECIATION
TAX RATE 50%
20-YEAR OPERATION
3-YEAR WELL DRAWDOWN
1 MMTPY COAL PRODUCTION, ROOM & PILLAR
STIMULATED VERTICAL WELLBORES
PITTSBURGH SEAM CHARACTERISTICS

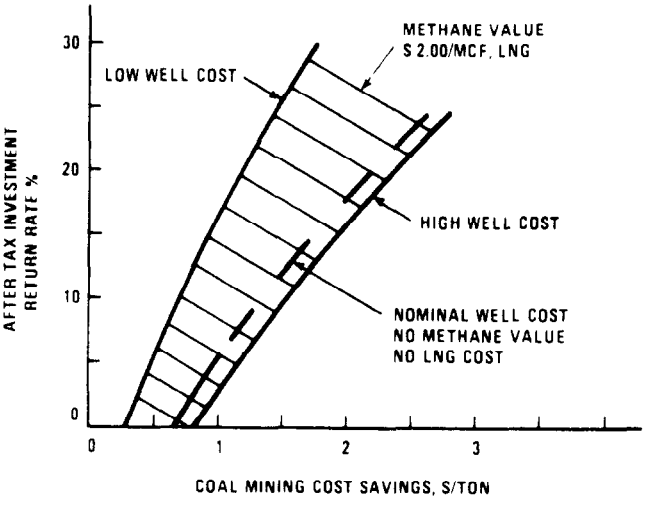



FIGURE K-17. OPERATIONAL SYSTEM: LNG OPTION

- 10-YEAR OPERATION, LINEAR DEPRECIATION
- TAX RATE 50%
- 2 MMTPY COAL PRODUCTION - ROOM & PILLAR
- 3-YEAR DRAWDOWN TIME
- STIMULATED VERTICAL WELLBORES
- GAS VALUE - $2.00 1 MMCFD
- AMMONIA VALUE $100/TON

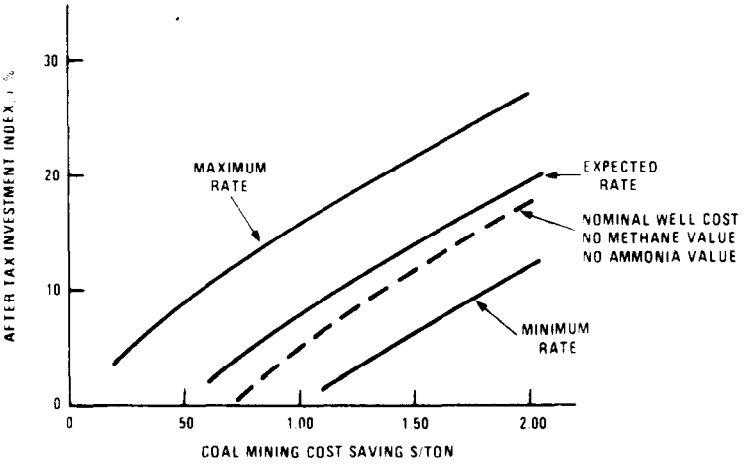



FIGURE K-18. COMBINED PREDRAINAGE AND GOB SYSTEM: OPTION - AMMONIA PLANT