SPE 8739

RECOVERY AND USE OF COALBED METHANE

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1.0 INTRODUCTION

Interest in the so called unconventional gas sources is currently in a period of rapid growth. One of these sources, coalbed methane, is known to exist in large quantities within and around most coal seam formations. Numerical estimates of the extent of this resource have been placed as high as 800 trillion cubic feet, with perhaps 300-400 trillion cubic feet recoverable. At today's prices for conventional energy sources, and projected escalations of those prices, coalbed methane is becoming a strong candidate, in many cases, for actual recovery and use as an auxiliary energy source. Historically methane has been recovered and used extensively for many years in other countries;' particularly in con.-junction with coal mining operations. These uses have included pipeline injection, industrial process heat generation and gas turbine-generator conversion to electricity. The technology for converting methane to useful energy forms, then, is not a limiting factor, and has, in fact, been around for many years. The principal factors which appear to influence the extent to which this resource can be recovered and used in this country include:

- Institutional barriers; particularly the question of methane ownership.
- Conflicting philosophies on how to recover. collect and use the resource.
- Economic considerations.

The question of methane ownership has already been discussed this morning. To what has already been said I would only add that the ownership issue isinmany cases, apparently the single most important factor in delaying the application of existing technology to the actual recovery and use of this resource.

In the case of the second point noted above, a coalbed methane resource of several hundred trillion cubic feet can quickly suggest a large scale, regionally oriented recovery approach with interconnecting pipeline systems for collecting and delivering large gas flows to the users. This approach would seem to be an unlikely candidate for success with coalbed methane. On the contrary, technological, institutional and economic factors ll weigh heavily in favor of a relatively small, indi 'idual site development approach.

'inally, economic viability has, and will most likely :ontinue, to control the extent to which the private ›usiness sector is willing to make the necessary inves ıents required to recover and use the coalbed methane 'esource. On this basis the system requirements will include:

- Predictable gas flows which can be sustained for long periods of time.
- Recovery, collection and conversion equipments which are reliable, safe, and environmentally acceptable to operate.
- Initial investment and operation/maintenance costs which are compatible with reasonable system payback periods and acceptable returns on investment.

ith this background, Iwould now like to present a ;ummary of two programs now underway at Westinghouse. he Department of Energy, through the Morgantown Energ Technology Center, is the primary sponsor for both pro grams, with additional support provided by the United States Army Corps of Engineers, Bethlehem Mines Corporation and the Commonwealth of Pennsylvania. These programs are both based on the concept of recovering, collecting and using the methane within a relatively small geographic area.

In one case, the methane is being extracted from virgi coal which is considered too thin to be mined. The en use of the methane in this case is gas fired boilers used to make industrial process and habitable space heat. In the second case, methane recovered from an active coal mining operation is intended to serve as the primary fuel for gas turbine-generator conversion to electricity for use by the mining operation. In what follows, these programs are referred to as Case No. 1 and Case No. 2, respectively.

2.0 CASE NO. 1

This program is underway in Westmoreland County, Penn. Sylvania, at an 850 acre site which is owned (including mineral and gas rights) by Westinghouse. *Site* operations include a Westinghouse industrial plant

References and illustrations at end of paper.

hich normally uses seventy-five to one-hundred million ubic feet of gas annually for industrial process and abitable space heating. The area is underlaid by coals n the Allegheny group from *the* Freeport seam down to he Sharon seam. Overburden depths range from 600 to 100 feet throughout the site. Coal formations are not onsidered to be suitable (economically) for mining.

lork at this site has been organized into three phases. t present we are near the end of the second phase, and hat work can be sunarized as follows:

- Core analysis has been completed at four sites within the 850 acre area.
- Drill stem tests have been completed at two of the four sites.
- One of the four sites has been completed to the point of a gas producing well, and the gas is being consumed on site as an energy source for gas fired industrial boilers.
- Based on core analysis results, the coalbed methane resource has been placed at 2623 MCF/ acre over the 850 acre site, for a total in-place resource of 2.125 x 10^9 cubic feet of gas. Drill stem tests and well performance to date indicate that 60% of this resource can be recovered with six interconnected, hydraulically stimulated vertical wells located throughout the site.

igures 2-l through 2-4 summarize the history for the roducing well to date, and Figure 2-5 shows the overall lan for the multiple well system for complete develop-ment of the site. Table 2-l shows the results of a laboratory analysis of the gas produced. The heating alue exceeds 1000 Btu/SCF, and the gas is now being sed as a direct substitute for commercial grade natural jas.

igure 2-1, which summarizes the *core* analysis, shows a elatively low value of gas content, averaging about 1.15 cc/gram, or 37 cubic feet of methane/ton of in-lace coal. As expected, the methane content of the oal tends to increase with the depth of the coal forma-ion. Core samples from the three additional sites hich have been cored show increased amounts of methane in the coal, and the average methane content of the site, based on the four samples, is between 65 and 75 ubic feet of methane per ton of in-place coal.

rhe production well (Figure 2-2) was hydraulically stimulated with a water/sand mix on October 30/31, 1979. The details of the stimulation treatment are shown in Figure 2-3. Only three of the planned four zones shown were hydrofractured (zone #l did not fracture).

Interconnection of the gas well to the local gas distri-bution system was completed early in 1979, and Figure 2-4 shows the surface installation as it now exists. Early gas and water production by the well (open hole) were as high as 100,000 cubic feet/day and 13 gallons per minute, respectively. These values today are show-ing signs of stabilization. Over the past forty-five days the well is averaging gas flows of about 37,000 cubic feet/day and water production of a little over five gallons/minute. Total gas recovered and consumed at the site now exceed two million cubic feet.

3.0 CASE NO. 1 ECONOMICS

Projection of the economic viability of the complete development of this site ultimately requires estimates of:

- Total number of wells required to drain the 850 acre site.
- Total gas production and longevity of the site as a fuel reservoir.
- Projected value of the gas and specifica-tion of the investment and operating costs for the complete system.

Overall site design has been greatly facilitated by a computerized model developed by INTERCOMP Resources, Inc., of Houston, Texas. This model operates on input data from the core analysis completed at this site and actual flow data from the existing well. Using this approach the projected plan for the site, well produc-tion, and longevity are as follows:

- Six wells on 120 acre spacing are required.
- Longevity is estimated to be between ten and fifteen years.
- Daily production of gas is projected to average *about* 35,000 SCF/Day/well.
- A local waste water well will be required to handle water recovered from the system.

Based on *cost* experience to date at this site the investment required for the complete six well system is \$991,000. Table 3-l summarizes the total cost/10^6 Btu for the development and operation of the system based on a twelve year lifetime. The total cost/10^6 Btu as shown in Table 3-l represents about 50% of the present cost of commercial grade natural gas at this site.

The economic analysis can be extended somewhat by set-ting up a table of future revenues and operating/main-tenance costs over the twelve year lifetime. From thi! exercise cash flow can be estimated. The difference betweentheintegrated value of cash flow and theinitia investment then corresponds to the present worth of the system. This type of analysis applied to this case produced the following results:

- The payback period is five years.
- The system will earn 15% on the investment.
- The system will provide an average cash income of about \$30,000/year, i.e., system present worth exceeds \$300,000 for a twelve year system life and a demand return of 15%.

These results are based on fixed escalations of both the price of gas (8%/year) and operation/maintenance costs (7.5%/year) over the twelve year lifetime.

4.0 CASE NO. 2

This programhasbeenunderwaysomewhatlongerthan Case No. 1, but system operating experience has been slower in coming; for several reasons. As previously noted, we are attempting to adapt existing gas turbine generator designs to operate from methane flows devel-oped by mine gasification programs. Figure 4-l shows portion of the Revloc #32 mining operation. This mine is one of several mines operated by Bethlehem Mines Corporation in this area of Pennsylvania. Effective control of methane concentration levels underground includes direct venting of methane from the undergroun areas through a series of vertical wells drilled into active sections where the coal has been extracted. This creates methane flows which are partially diluted with mine ventilation air. In many cases the amount o air present in the Methane/Air mixture is relatively small, and the mixture can be used as fuel in the continuous burning gas turbine. The lower limit for the mixture is determined from safety considerations established[2] by the Mine Safety and Health Administration, and these require no more than 10% oxygen and no less than 52% methane, by volume, in the methane/air mixture. Figures 4-3 and 4-4 show the two major components of the system which we have planned to operate at this mine. The turbine-generator (Figure 4-3) is rated at 800 kW. It is produced by SOLAR Turbines International, of San Diego, California, and has been manufactured in large quantity for several years. The model shown in Figure 4-3 was designed for the United States Army for Use in portable, emergency power applications. The unit will operate on either pure methane or methane which is partially diluted with mine ventilation air; down to a lower limit of 60/40 methane/air, or approximately 600 Btu/SCF.

Figure 4-4 shows the other major component of the system. This equipment interfaces the gas turbine to the source of coalbed methane. The equipment is portable and provides the following overall system functions:

- Particulate filtering of the input coalbed methane flow.
- Moisture removal from the coalbed methane.
- Continuous monitoring of the methane/oxygen mixture levels in the fuel with automatic shutdown instrumentation.
- A pressurized (150 psig) source of fuel for turbine combustion up to flows of 500 standard cubic feet per minute.
- A Nitrogen purge system used only for initial start-up on coalbed methane fuel.

With operation on medium Btu fuels (e.g., 600 Btu/cubic foot) the system will always be initially started on conventional liquid hydrocarbon fuels and switched to coalbed methane operation. The switchover is a push buttom operation and can be executed with the system under full electrical load.

From an equipment readiness point of view we could have been in operation at the Revloc X32 mine some time ago. However, events underground at this mining operation have delayed our access to a suitable source of coalbed methane generated by the mining process. Specifically, an underground fire required a year to bring under control. Fire control procedures included the flooding of a relatively large area of the mining operation. Our planned fuel source (degasificafion Well No. 32-10) was within the flooded area. In an attempt to avoid program delay we drilled into an area of virgin coal and hydraulically stimulated the coal fonnationsformcthane recovery. Figure 4-2 shows the design of this well. The stimulation procedures used were similar to the Case NO. 1 well described earlier. We were hopeful of achieving a sufficiently high rate of flow to permit reduced power operation of the Saturn gas turbine-generator system. Gas production by this well since recent completion is less than 30,000 cubic feet per day, which is substantially below the level needed for turbine operation. Our efforts to develop operating experience with this type of system will now require movement of the system to an alternate site. We are currently negotiating with Bethlehem for permission to locate the system at the Marianna #58 Mine near Washington. Pennsylvania. This mining operation is in the Pittsburgh seam and the coal is being degasified by horizontal holes drilled into the coal as the mining operation advances. A manifolding of four horizontal holes into the coal, an underground collection system, and a single vertical well currently vents to the atmosphere near pure methane at a rate of about 250,000 cubic feet per day. One additional horizontal hole will be added underground. The additional total flow is expected to be about 350,000 cubic feet per day which will permit sustained operation of the gas turbine-generator at maximum power. By this time next year we hope to have accumulated several months of actual operatingexperience with this type of system.

Figure 4-5 summarizes the performance, waste heat generation, and fuel consumption data for two gas turbine-generator configurations. The smaller unit (800 kW) is the Saturn model we are currently using with the Bethlehem Mines Corporation program (Figure 4-3). The other model shown in the Centaur system which is rated at 2600 kW. Both systems will operate on coalbed methane with a heating value down to 600 Btu/cubic foot and both equipments output 3-phase 60 Hertz power at either 240d volts or 4160 volts. This power is normall transformed to either 7200 volts or 12,480 volts for mixing with the mine power grid. Both engines are manufactured by SOLAR Turbines International of San Diego, California. They have been manufactured in large quantity and are in service all over the world. The range of 800 - 2600 kW represents practical limitations on individual installations developed around coal mining degasification programs. In some cases associated with larger mining operations, installations as large as 780 kW (multiole Centaur) are beinq considered. At such power levels, the methane fueled gas turbine-generator can often supply much of the mine power needs. Figure 4-6 and 4-7 show some of the operational concepts for this type of installation. Portability in the equipment is generally required since the system will ultimately be relocated to keep pace with the planned coal degasification program. In cases where the turbine- enerator can be located close to other mine facilities 4e.g., the bath house or coal processing plant) the possibility exists for utilizing waste heat from the turbine stack to resolve related mining heating needs. In such cases the overall efficiency of the gas turbine process is dramatically increased resulting in substantial cost savings above and beyond the electrical energy produced

4.1 CASE NO. 2 ECONOMICS

Since we have not yet developed an extensive experimental data base with this type of system, the economics evaluation is limited. Table 4-1 is a summary of estimated annual revenues from the two types of systems discussed based on power values of 30, 40 and 50 mills/kWH. The values shown reflect allowances for normal system losses. the local use[3] of turbine supplied Power and reasonable system down time for maintenance. The values shown in Table 4-l do not include potential additional revenue from using waste turbine heat. Wher site geometry will permit the use of this waste heat, the potential exists for an additional 25% to 35% in revenues.

The capital investment requirements for these systems are quite sensitive to actual site conditions, particularly with regard to right-of-way problems, local fuel collection problems and distance to the mine Power grid For the cases we have looked at in some detail the investment required is less than $900/kW of installed capacity. On this basis the larger (Centaur) system always costs less. This figure includes not only the cost of the basic equipment -it includes also those necessary peripheral costs such as site preparation, protective fence enclosures and power conversion components required to mix turbine supplied power with the line power grid. Using this figure, the cost of generating power with these systems can be estimated:

$$G_C = \frac{C_C \times F_{CR}}{8.76\ (1 - R_O)} + \frac{H_R \times F_C}{10^5} + OM$$

where

G_C = Bus bar cost of generating power, Mills/kWh

C_C = Cost (initial) of the system, \$/kW of capacity

F_{CR} = Fixed charge rate, including return on investment, insurance, and taxes, (%)

R_O = Turbine outage rate, (%)

H_R = Turbine incremental fuel consumption rate, Btu/kWh

F_C = Fuel cost, cents/10^6 Btu

OM = Operating and maintenance costs, Mills/kWh

To estimate the power cost in a specific case, we substitute the following values into the model:

C_C = \$900/kW

F_{CR} = 20% (assumed)

R_O = 4%

H_R = 16,250 Btu/kWh

F_C = Zero, on the basis that the mine degasification program supplies the fuel

OM = 5 mills/kWh

The cost of power with these values computes to 21.6 mills/kWh which is substantially below present power costs in many areas.

References

[1]See, for example, R.A. Swift, "Methane Drainage in Great Britain" - Coal Age, February 1970.

[2]U.S. Department of Labor, Mine Safety and Health Administration, Information Report, IR 1094, dated 1978.

[3]Turbine supplied power as used locally to operate the gas compressor.

TABLE 2-1: GAS COMPOSITION

Constituent	Mol. %
Methane	99.22
Oxygen	
Carbon Dioxide	-.-51
Hydrogen	.04
Nitrogen	.22
Argon	.01
Water	--
TOTAL	100.00

TABLE 3-1: FUEL COSTS

Cost Element	$/10^6 u
Wells (six)	.76
Wellhead Equipment	.06
Collection System (3 miles of pipeline)	.05
Waste Water Handling	.18
Operation and Maintenance	.20
TOTAL	1.25

TABLE 4-1: ESTIMATED ANNUAL REVENUES

	30 Mills	40 Mills	50 Mills
Saturn (800 kW)	\$157,500	\$210,000	\$262,500
Centaur (2600 kW)	6580,000	\$772,800	\$966,000

COAL SEAM	SEAM DEPTH FEET	SEAM THICKNESS INCHES	GAS CONTENT cc g
UPPER FREEPORT	187-189.3	28	.376
LOWER FREEPORT	237.243	74	, 4581 (.648)(821
UPPER KITTANNING	324.326	25	.807
LOWER KITTANNING	384.389	62	II.6691 (1 6281
CLARION	432-435.5	46	723
BROOKVILLE	458459.5	18	.878
UPPER MERLER	477.5479	15	1 976
MIDDLE MERLER	517.518	14	.966
LOWER MERLER	552-554	24	1482
OUAKERTOWN	589	5	1441
UPPER SHARON	818	4	1646
LOWER SHARON	628.5	8	3 245

Fig. 2-1 - Core Data Summary

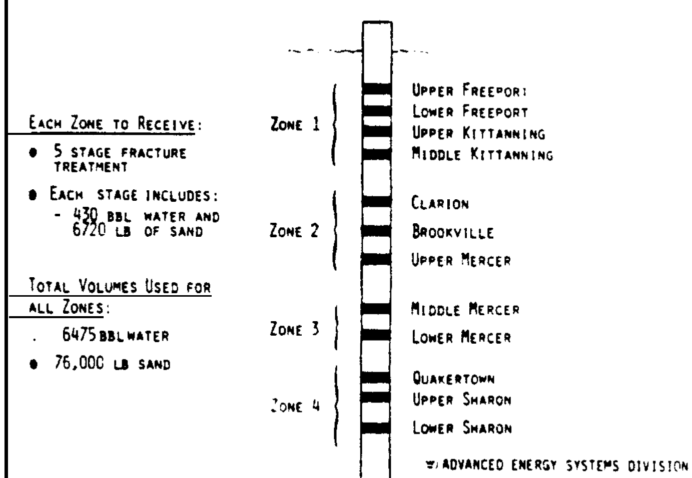

Fig. 2-2 - Perforation/Stimulation Detail

ie	Perforations Depth	Number of Holes	Number of Stages	Sand lb	Volume Pumped bbl	Rate bpm	Pressure psig
	657-58	2	1	0	145	8	3800
	652-53	2					
	645-47	3					
	614-16	5					
	570-72	4	5	26000	2105	26	2100
	530-32	4					
	490-92	4					
	449-52	6	5	26000	2145	30	1200
	385-88	6					
	333-35	4	5	24000	2080	32	1200
	256-58	4					
	193-95	4					
OTAL				76000	6475		

Fig. 2-3 - Stimulation Treatment Detail

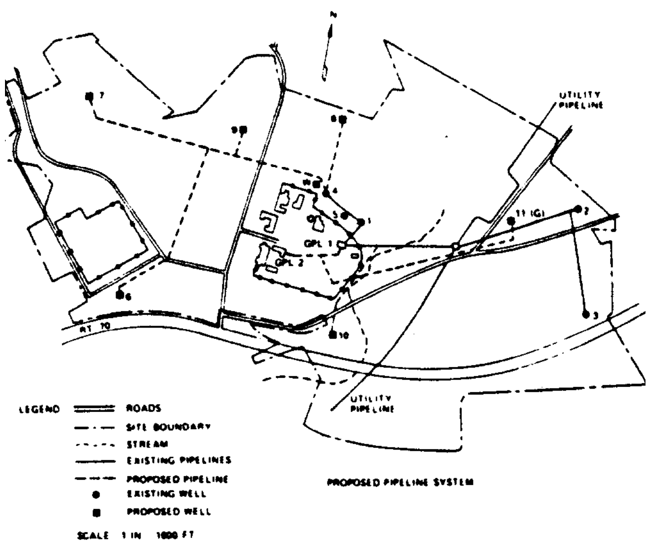

Fig. 2-5 - Site Development Plan

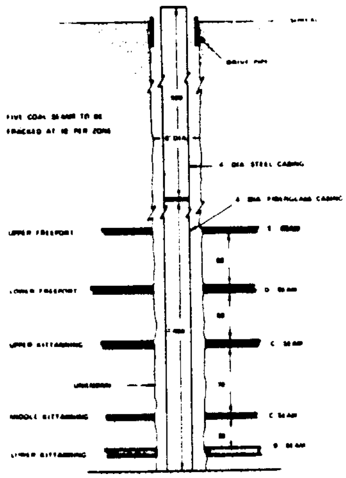

Fig. 4-2 - Design of Borehole for Hydrofracture

% Power	Incremental Fuel Consumption (Btu/kWh)		Fuel Flow Requirements[3] (Cubic Feet/24 Hours)		Waste Heat[4] Produced 10^6 Btu/Hour	
	Saturn[1]	Centaur[2]	Saturn	Centaur	Saturn	Centaur
100	16,250	14,925	312,000	931,200	6.61	17.2
75	18,000	15,897	259,200	743,976	4.9	12.75
50	21,750	19,231	208,800	600,000	3.4	8.72

NOTES:
1. Saturn rated at 800 kW
2. Centaur rated at 2600 kW
3. Based on pure coalbed methane
4. At maximum power, stack exhaust temperatures exceed 800°F

g. 4-5 - Saturn/Centaur Performance at Sea Level and 59°F

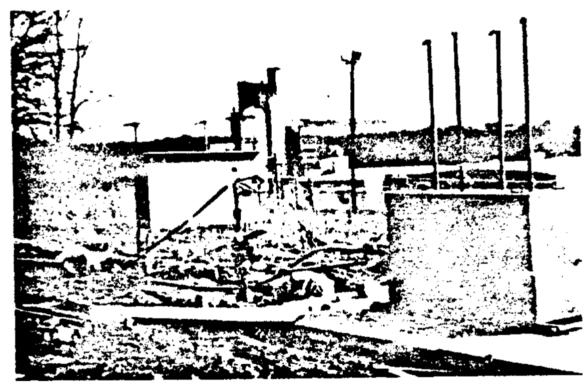

Fig. 2-4 - Production Well Today

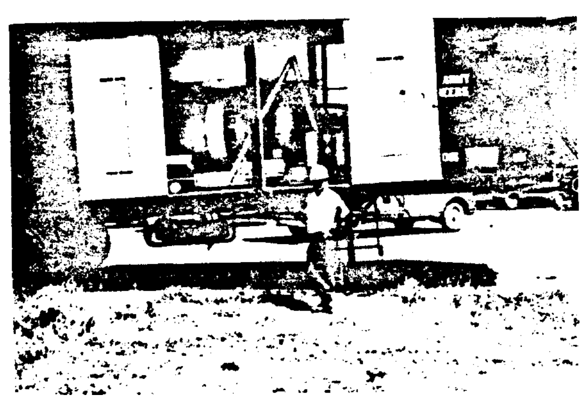

Fig. 4-3 - 800 kW Saturn Turbine-Generator

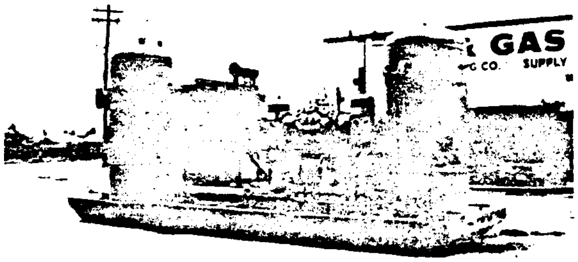

Fig. 4-4 - Gas Compressor Skid

Fig. 4-1 - Revloc #32 Mine, Ebensburg, Pennsylvania

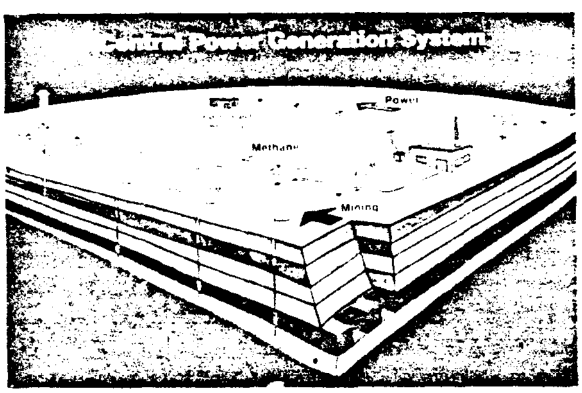

Fig. 4-6 - Centralized Power Concept

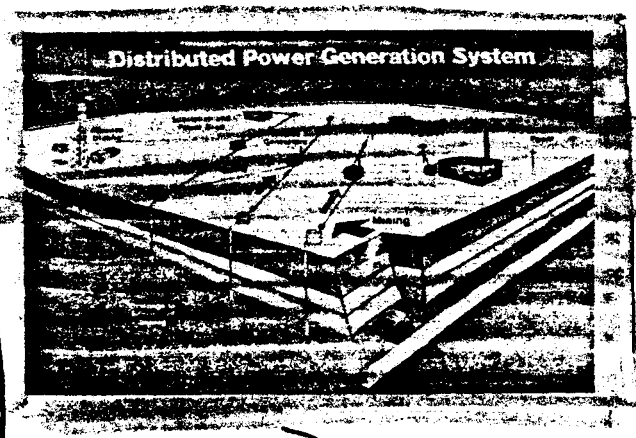

Fig. 4-7 - Distributed Power Concept