INTERIM SUMMARY

UNCONVENTIONAL GAS SOURCES

NATIONAL PETROLEUM COUNCIL • JUNE 1980

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John F. Bookout, Chairman—Committee on Unconventional Gas Sources

NATIONAL PETROLEUM COUNCIL

U.S. DEPARTMENT OF ENERGY

Charles W. Duncan, Jr., *Secretary*

The National Petroleum Council is a federal advisory committee to the Secretary of Energy.

The sole purpose of the National Petroleum Council is to advise, inform, and make recommendations to the Secretary of Energy on any matter requested by the Secretary relating to petroleum or the petroleum industry.

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INTERIM SUMMARY

PREFACE

By letter dated June 20, 1978, the National Petroleum Council, an industry advisory committee to the Secretary of Energy, was requested to prepare an analysis of potential natural gas recovery from coal seams, Devonian Shale, geopressured brines, and tight gas reservoirs. In requesting the study, the Secretary stated that:

> ...Your analysis should assess the resource base and the state-of-the-art of recovery technology. Additionally, your appraisal should include the outlook for cost and recovery of unconventional gas and should consider how government policy can improve the outlook. (See Appendix A for complete text of the Secretary's letter and a further description of the National Petroleum Council.)

To aid it in responding to this request, the National Petroleum Council established the Committee on Unconventional Gas Sources under the chairmanship of John F. Bookout, President and Chief Executive Officer, Shell Oil Company. R. Dobie Langenkamp, Deputy Assistant Secretary for Resource Development & Operations, Resource Applications, U.S. Department of Energy, served as Government Cochairman of the Committee. A Coordinating Subcommittee and four task groups, by source, were formed to assist the Committee. (Rosters of these study groups are included in Appendix B.)

The National Petroleum Council's report, Unconventional Gas Sources, is being issued in five volumes:

- Volume I - Executive Summary
- Volume II - Coal Seams
- Volume III - Devonian Shale
- Volume IV - Geopressured Brines
- Volume V - Tight Gas Reservoirs.

The Coal Seams, Devonian Shale, and Geopressured Brines volumes are being issued in June 1980 and are summarized below. The Executive Summary and Tight Gas Reservoirs volumes are to be issued later in 1980. This Interim Summary provides an overview of the three volumes issued in June and a discussion of the status of the tight gas reservoir analysis. Preliminary analysis indicates that reserve additions for tight gas reservoirs will be the largest and most significant of the unconventional sources.

RESULTS

Within each volume, the resource base, state-of-the-art of recovery technology, potential reserves and production, constraints, and uncertainties associated with each source are examined. The report presents estimates of what could happen under certain assumed technical and economic circumstances and is not intended to represent a forecast of what will occur.

Resource

In this report, the in-place gas resource of coal seams and Devonian Shale is estimated to be very large. The National Petroleum Council makes no independent estimate of the in-place gas of geopressured brines since published estimates are so large that total resource size is not considered a constraint to development. Even though only a small percentage of these sources' in-place resource is estimated to be economically recoverable, unconventional gas could be a significant addition to the nation's future gas supply.

The resource estimates depend heavily on the extrapolation of limited data. The coal seams estimate is based on available limited gas content data which pertain mostly to known gassy bituminous coals. The Devonian Shale estimate is also based on rather limited gas content data. Although there is already significant shale gas production in some portions of the Appalachian basin, most of the resource is in undrilled and unproved areas.

Reserve Additions

For each source, reserve additions and producing rates are calculated as functions of five gas prices ($2.50, $3.50, $5.00, $7.00, and $9.00 per million Btu [MMBtu]), three rates of return (10, 15, and 20 percent),[1] and at least two levels of technology. Constant January 1, 1979, dollars are used in all analyses. Reserve additions for conventional technology shown on Table 1 are cumulative additions through the year 2000, and the prices give a 10 or 20 percent discounted cash flow rate of return (ROR) to the producer on the highest cost (last) increment of production.

Gas prices of $5.00 and $9.00 per MMBtu are equivalent to $29.00 and $52.00 per barrel of crude oil and bracket present decontrolled crude oil prices. Unconventional gas production from coal seams, Devonian Shale, and geopressured brines qualifies for decontrolled high-cost gas prices.

[1]These rates of return are real rates of return on investment, after tax, and take risk into account. They do not reflect inflation.

TABLE 1

Cumulative Reserve Additions to the
Year 2000 -- Conventional Technology
(TCF)

Source	Gas Price (Constant 1979 Dollars)					
	$2.50/MMBtu		$5.00/MMBtu		$9.00/MMBtu	
	10% ROR	20% ROR	10% ROR	20% ROR	10% ROR	20% ROR
Coal Seams	5	2	25	17	45	33
Devonian Shale	7	0.3	20	11	27	21
Geopressured Brines	0	--	0.1	--	0.6	--
	12	2	45	28	72	54

The above estimates may be optimistic because when faced with a choice on a critical parameter, the study participants usually made the optimistic choice.

INTERIM CONCLUSIONS

The potential for recovery from unconventional gas sources involves complex relationships among resource base, technology, economics, and government policy, making generalizations difficult. From its study, however, the National Petroleum Council draws the following interrelated conclusions:

- Natural gas from coal seams and Devonian Shale could make a significant contribution to future U.S. gas supply. Conventional natural gas reserve additions have been 10-14 TCF annually in recent years. At the $5.00 per MMBtu gas price level and a 10 percent real ROR after tax, the total unconventional reserve additions through 2000, if achieved between 1985 and 2000, would average 3 TCF per year. Because of the difficulty of properly assessing risk, anticipated rates of return higher than 10 percent may be required to attract investment, at least initially. Maximum annual production could be about 2.5 TCF from coal seams and 1 TCF from Devonian Shale, with negligible production from geopressured brines. Potential reserves and production from tight gas reservoirs will be additive to the above estimates. Preliminary analysis indicates that tight gas has the largest potential of the unconventional gas sources examined.

- There is considerable uncertainty in the estimates of reserve additions and producing rates. An indication of this uncertainty is shown by the range of estimates in Table 1. The geologic and technical uncertainties for most sources are so great that resource base assessments as well as reserve addition and producing rate estimates for any specified economic condition may be substantially in error. Further resource characterization studies, research and development, and field experience will be required to improve prediction capabilities.

- <u>The rate of development of unconventional sources will be highly dependent on economic conditions</u>. These sources contain high-cost gas which generally was not produced at past gas prices. As mentioned previously, these sources now qualify for decontrolled or incentive gas prices; however, current levels of gas supplies are suppressing field prices in certain areas. Estimates in this report assume that markets will exist for the producible gas. Thus, government actions affecting gas usage could significantly impact the rate of unconventional gas development. The resolution of legal questions as to the ownership of coal seams and geopressured brines gas will also impact their development.

  Significant risk and capital requirements are also associated with the development of these resources. Achievement of the reserve additions estimated for coal seams and Devonian Shale will involve capital needs in excess of $100 billion. Such projects will have to compete for available funds with other energy activities, including conventional oil and gas exploration and production as well as other emerging technologies (synfuels, shale oil, etc.). Gas will also have to compete with other fuels for its share of the market.

COAL SEAMS

RESOURCE

Description

Coal-bed gas is a natural byproduct of coal formation and can be found in varying quantities in coal seams lying below drainage. Although a large portion of the gas thus formed has escaped to the atmosphere, a portion has been trapped and remains in place. Coal-bed gas molecules exhibit a high affinity for their parent material which enables larger volumes of the gas to be stored in coal than in porous media (sandstones, etc.) at the same conditions. Methane is the primary component and generally comprises 85 to 99 percent of the volume. Its calorific value varies from 850 to 1,050 Btu per cubic foot; a value of 1,000 was assumed for this study.

Coal-bed gas contains only a slight portion (less than 2 percent) of the total energy contained by the coal that hosts it.

Magnitude

The coal gas resource is intimately related to the coal resource base itself. Only limited coal seam gas content data are available and they pertain mostly to known, gassy bituminous coals.

Table 2 presents coal gas resources which have been projected from published U.S. Geological Survey (USGS) resource data and from study participant deliberations on the gas content of coals.

EXPLORATION REQUIRED TO LOCATE THE BETTER RESOURCE

A considerable amount of information pertaining to the gas-producing potential of coal seams exists and has already been evaluated during the course of oil and gas drilling activity.

METHODS OF RECOVERY

The major techniques for recovering coal-bed gas are:

- Hydraulically stimulated vertical wells
- Unstimulated horizontal holes from vertical shafts
- Unstimulated horizontal holes from mine access
- Slant holes that terminate with long horizontal in-seam segments.

In order to meet near-term, economically sensible energy needs, the viable alternatives have been reduced to either hydraulically

TABLE 2

Estimated In-Place Resource of Coal-Bed Gas

Coal Category	Estimated Coal Resource (Billions of Short Tons)	Estimated Gas Content (Ft^3/Ton)	Projected Gas Resource (TCF)
1. 300-3,000 feet deep (identified and hypothetical)			
A. Anthracite	46	200	9
B. Bituminous	1,001	200	200
C. Subbituminous	1,137	80	91
D. Lignite	504	40	20
2. 3,000-6,000 feet deep (hypothetical)	388	200	78
Total			398

stimulated vertical wells or to unstimulated horizontal wells from vertical shafts. Many experienced coal mine operators have expressed concern over the possibility that hydraulically induced fractures can impose additional risk to safe and efficient mining operations. Some of the few hydraulic fractures that have been mined through and visually inspected tend to support the contentions of the unpredictable nature of hydraulically induced fractures.

The measured gas production from horizontal holes is substantially greater than that of hydraulically stimulated vertical wells completed in the same seam. Gas productions of up to 30 thousand cubic feet per day (MCF/D) per 100 feet of horizontal hole length and hole lengths in excess of 1,000 feet have been reported. The U.S. Bureau of Mines has already demonstrated the technical feasibility of unstimulated horizontal holes drilled from a shaft into the gassy Pittsburgh coal seam in northern West Virginia.

STUDY METHODOLOGY

In order to relate gas production on a uniformly applicable basis, it was decided to project likely gas production per foot of coal seam thickness. This approach lends itself to an economic evaluation dictated by the total thickness of coal-bearing strata at any given location.

The average coal thickness for each coal-bearing county was calculated from published USGS total in-place coal tonnage, published areal extent of the county, and the coal density upon which the USGS data were based.

Thirty percent of the in-place reserves lying at depths of 1,000 feet or less were eliminated based on the assumption that shallow coals would contain little, if any, producible coal-bed gas. The total resource for each coal rank as a function of seam thickness was plotted on a graph. Hypothetical scenarios for multiwell projects, including water handling, small wellhead compressors, piping, etc., were employed for cost-estimating purposes. An annual rate of production decline of 10 percent and a 90 percent drilling success ratio were employed. A production life of 12 years and an overall project life of 20 years were used in the economic evaluations.

Gas production at six different rates, ranging from 10 to 150 MCF/D per well, were used. Costs for add-on items, such as scrubbing, high-pressure compression, etc., were calculated and presented separately for each case ($0.60-$2.00 per MCF). A discounted cash flow analysis based on the different gas production scenarios was generated using the financial guidelines established for the study.

RESULTS

The cumulative additions to ultimate recovery to the year 2000 that are likely to evolve during the next 20 years were projected for both stimulated vertical wells and horizontal holes from vertical shafts. It should be pointed out that the productions from these two scenarios are mutually exclusive. The results are difficult to present concisely in tabular form and are thus presented in graph form in Figures 1 and 2.

CONSTRAINTS

Legal

The coal-bed gas ownership issue is unresolved and will have to await final court decision. A need exists to review state and other local regulations that may also be of importance.

Environmental

The most significant environmental constraint relates to the disposal of produced water. The composition of coal-bed water varies from slightly acidic to slightly alkaline and only minimal knowledge of the mineral makeup is available. Where water availability is an issue (as in some western locales), the water table drawdown becomes an issue in itself.

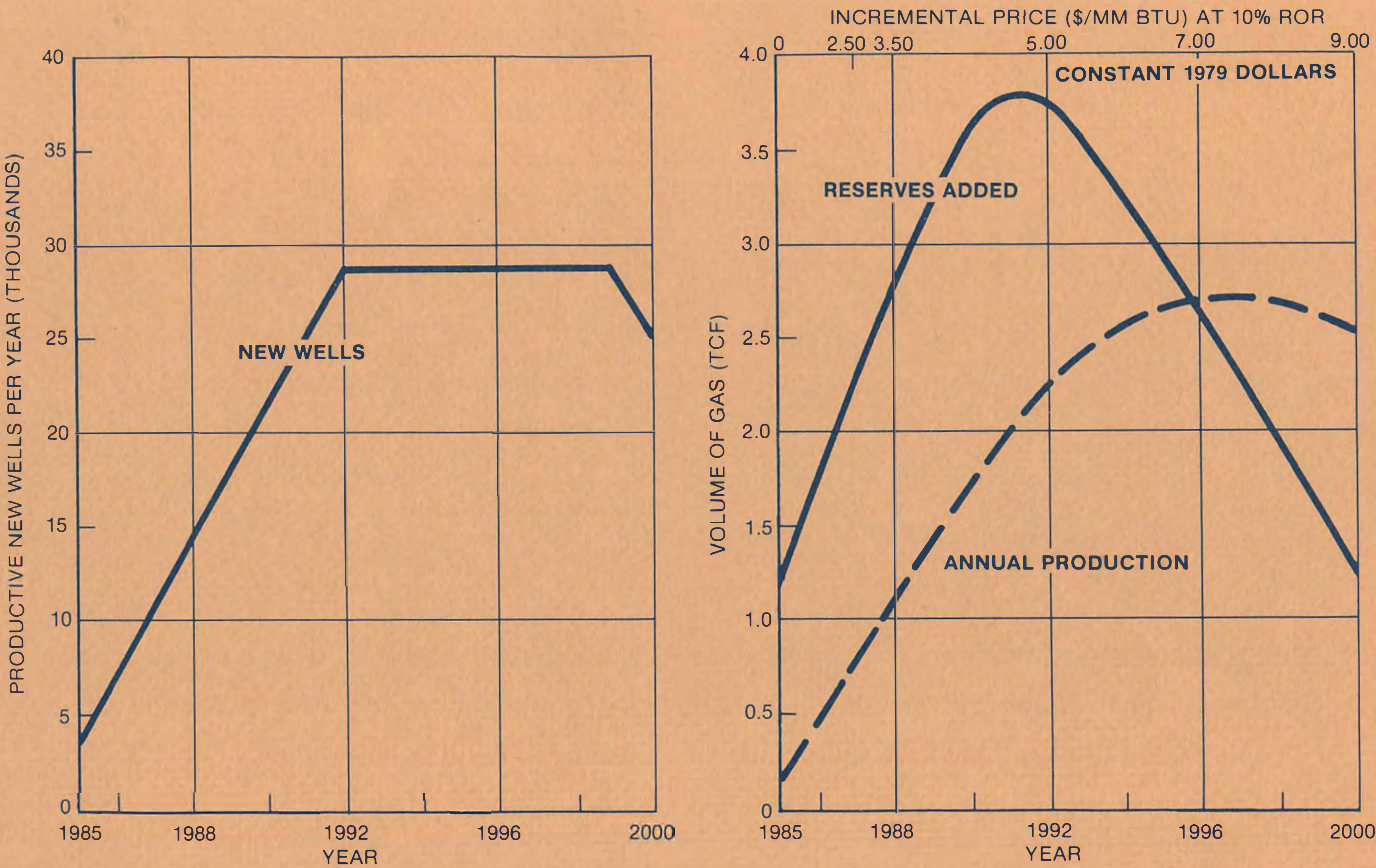

Figure 1. Annual Rates as a Function of Time--
Vertical Wells Projects (Raw Gas on Site).

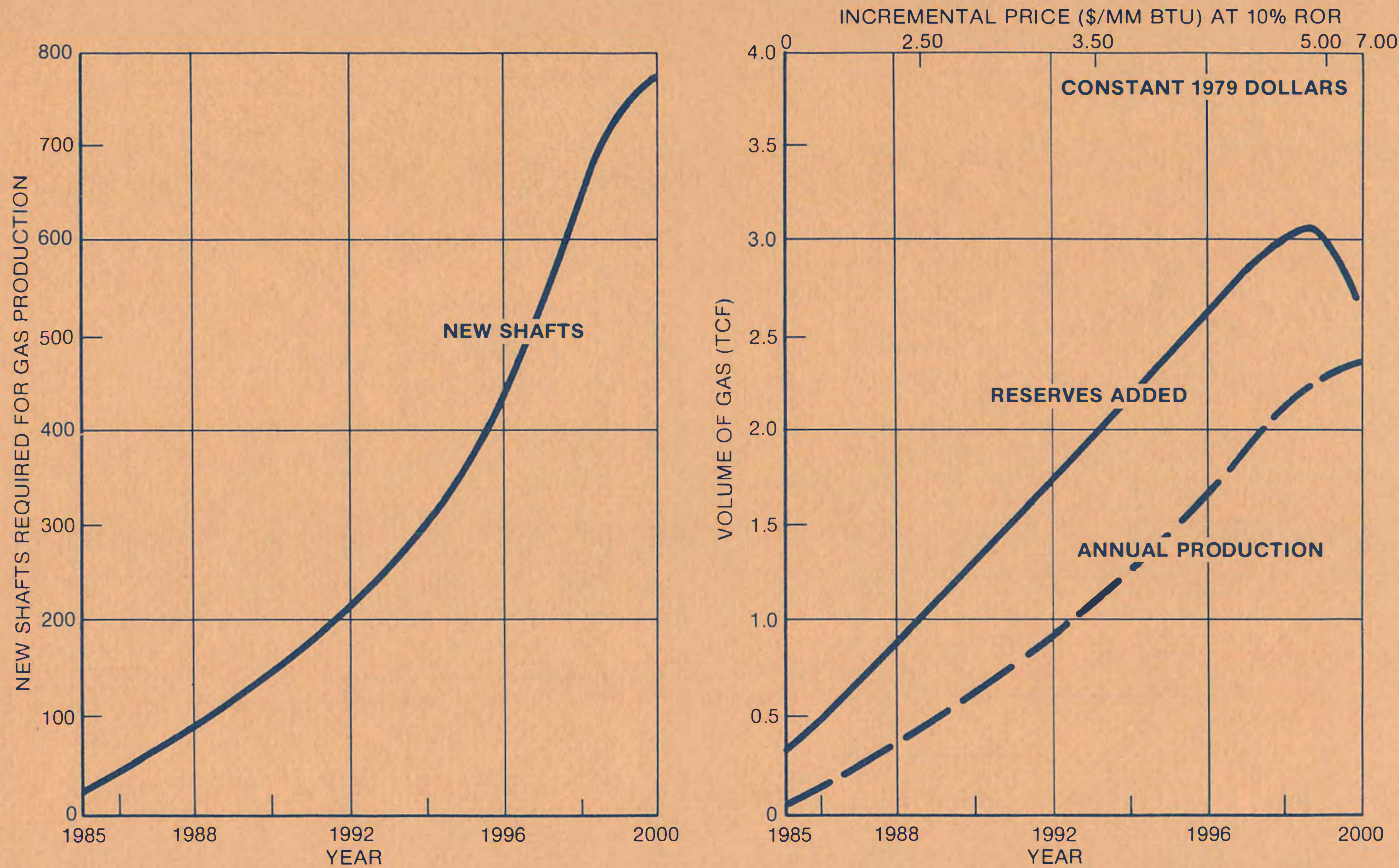

Figure 2. Annual Rates as a Function of Time--
Shafts with Horizontal Holes (Raw Gas on Site).

Commercial

Uncertainties in the rate and decline of coal-bed gas are likely to deter the finalization of gas purchase agreements. Impurities such as water and carbon dioxide are also of concern because of their corrosive potential when combined. Gas produced from projects coupled with active mining must be free to flow unencumbered to prevent gas "backup" into the mines.

Technological

A need exists to obtain additional baseline information on the gas-producing characteristics of coal reservoirs. Gas production rates cannot be predicted for extended periods with any degree of certainty. Adequate equipment (production, handling, etc.) appears to be commercially available. A new generation of directional surveying and drill guidance hardware is evolving. The further development of these items is essential to the success of routine in-seam long horizontal hole drilling operations.

MAJOR UNCERTAINTIES

The major uncertainties in coal seam gas development are:

- Long-term gas and water producing characteristics from coal seams (rates, declines, compositional changes)
- Environmental constraints pertaining to the effect of and to the disposal of ground water
- Coal seams being rendered economically unmineable by hydraulically created fractures
- Gas content of nonbituminous coal
- Gas-producing potential of most coal seams
- Coal-bed gas ownership.

DEVONIAN SHALE

RESOURCE

The principal known deposits of Devonian Shale gas are concentrated in the Appalachian, Michigan, and Illinois basins in the eastern United States. The study recognized differences in the thickness and gas content values of the deposits by delineating the black and gray shale horizons. The black shales have a higher gas content than the gray shales and are generally believed to be the predominant source beds of the natural gas found in the shales. Although the average total thickness of the shale deposits in the Appalachian basin is many times greater than that found in the other two basins, a large part of the deposit consists of the poorer quality gray shales.

The in-place gas resource was calculated on a volumetric basis using the appropriate gas content values for the gray and black shales. Among the three basins, the Appalachian basin has the greatest resource potential, varying from 225 TCF if only the black shale as determined by log analysis is considered, to 1,861 TCF if both black and gray shales based on sample thickness are used. Estimates for the Michigan and Illinois basins were 76 TCF and 86 TCF, respectively. The in-place gas is not a recoverable resource, but rather provides a means of ranking the shale gas potential of the three basins.

EXPLORATION REQUIRED TO LOCATE THE BETTER RESOURCE

If future Devonian Shale exploration does occur on a large scale, it would probably expand in the Appalachian basin as there is already significant shale gas production; therefore, for the purpose of this study, the projections of the potential for recoverable gas were confined to the Appalachian basin. Although similar projections could have been made for the Illinois and Michigan basins, estimates based on such limited data would be highly speculative.

METHODS OF RECOVERY AND STUDY METHODOLOGY

Historical production data from approximately 2,700 out of some 9,000 Devonian Shale wells in the four-state area of Kentucky, West Virginia, Ohio, and New York provided a substantial data base in developing the methodology for future production. A production model using a hyperbolic decline configuration allowed well performance to be represented by a single variable. The black shale thickness and well performance provided the correlation to predict potential production from estimates of the black shale thickness in the undrilled areas, taking into account such parameters as well spacing, success ratio, and lands accessible for future drilling. The predicted well performance, extracted from historical data, represents the proven state-of-the-art "traditional" technology. This technology could be considered more certain than the other two higher levels of technology presented in the study. Conventional technology represents the next level beyond traditional and is defined as improvements in technology which could reasonably be expected to occur. This was achieved by upgrading the traditional well performance based on well stimulation results published by E. O. Ray (1976). The source of well data in Ray's analysis was the primary shale-producing areas and it remains to be determined whether similar improvements can be achieved in the other shale areas. The third level of technology, identified as the advanced technology case, was developed from very limited stimulation and exploration research results. From this data it was assumed that advanced technology would double the improvement of conventional technology over traditional technology. This achievement would in all likelihood require significant breakthroughs in either or both production and exploration techniques.

RESULTS

The potential additions to reserves that may possibly be developed at various price levels, ranging from $2.50 to $9.00 per MMBtu, were determined as a function of rate of return (ROR) and technology in constant January 1, 1979, dollars. At a 10 percent rate of return, the estimated recoverable reserves under traditional technology at a price of $2.50 per MMBtu is 3 TCF; this increases to 39 TCF at the maximum price of $9.00 per MMBtu with advanced technology.

The prices at which supplies could be developed represent the field price paid to the producer exclusive of compression and suction pipeline facilities. If these facilities are taken into consideration, the incremental add-on cost would range between $0.49 and $0.68 per MMBtu at the $2.50 and $9.00 price levels, respectively.

Possible production volumes available from the estimated potential reserves were derived as a function of the drilling activity. The moderate drilling scenario assumed that the number of rigs would increase at a rate of 12 percent per year; this reflects the rig growth rate experienced in the Appalachian basin between 1973 and 1979. Under this drilling schedule, 9,000 productive shale wells would be in place by 1990 with annual production of 140 billion cubic feet (BCF) assuming conventional technology. By the year 2,000, there would be 36,000 wells producing at a yearly rate of 470 BCF. Considering the same drilling schedule but different technologies, production in the year 2000 would be 380 BCF for traditional technology and 600 BCF for advanced technology.

A second drilling schedule (high rig growth) was developed to illustrate the required drilling activity to develop essentially all of the Devonian Shale reserves priced up to and including $9.00 gas during the next 20 years. With conventional technology, production in 1990 would be 550 BCF from 37,000 producing wells and would increase to 1,000 BCF per year from 126,000 wells by the year 2000.

CONSTRAINTS

Significant portions of the presently economically competitive Devonian Shale areas are under lease and demand will dictate when the gas will be produced, irrespective of price. Other areas lack immediately available pipelines. These two constraints are barriers to the immediate development of Devonian Shale. Several economic factors represent additional constraints: the 10 percent ROR, which is considered representative of low-risk production, may not be sufficient for drilling in the unproven areas, and current supplies of gas are suppressing field prices for natural gas. Also, the gas pricing structure under the Natural Gas Policy Act has not been in effect long enough for production buildup, and production will probably come first from the tight sandstone formations rather than from the more risky Devonian Shale.

Environmental and legal constraints are not major problems and can be dealt with in the normal course of exploration with a minimum of delay. Socioeconomic considerations are beneficial to a region which is economically depressed, although some temporary delays in obtaining adequately trained personnel may develop. If historical trends are realistic predictors, neither rig availability nor investment capital would constrain development.

MAJOR UNCERTAINTIES

The major uncertainties to the rapid development of Devonian Shale are primarily technical in nature. Exploration procedures for locating natural fractured shale are poor, conventional stimulation techniques have not been demonstrated with certainty, and present logging techniques often give ambiguous results when identifying potential producing zones. There is considerable uncertainty as to the amount of technically recoverable gas since much of the Devonian Shale resource is not only unproved but not drilled. Whether the projected estimates of gas can be produced will depend upon the demonstration of feasible extraction and exploration technology.

GEOPRESSURED BRINES

RESOURCE

Geopressured brine reservoirs are underground reservoirs which contain hot salt water at a pressure gradient greater than .465 pounds per square inch (psi) per foot of depth. The resource base is huge. Geopressured brine reservoirs are known to exist in the Tertiary deposits of the Louisiana-Texas Gulf Coast; the Mississippi Salt basin of Mississippi and Alabama; deep Mesozoic formations of the San Joaquin Valley of California; the Wind River, Piceance, Green River, Uinta, and Big Horn basins of the Rocky Mountain area; and the Tuscaloosa-Woodbine formation along the Gulf Coast.

Based upon extensive geologic data, the Louisiana-Texas Tertiary trend has by far the most potential and provides the best opportunity for resource development. This trend exists in a band approximately 50 to 70 miles wide straddling the coastline from southern Texas to the mouth of the Mississippi River. The sediments are known to exist to a thickness of 50,000 feet; however, the actual prospective reservoir thickness would be from 500 to 1,000 feet. In this study, these brines are assumed to be saturated with natural gas.

EXPLORATION REQUIRED TO LOCATE THE BETTER RESOURCE

The large existing data base for Tertiary sandstone reservoirs in the Gulf Coast area has enabled geologists to locate the best prospects for development. This data base, which results from more than 10,000 penetrations to explore for and develop geopressured oil and gas reservoirs, has provided knowledge of:

- Reservoir temperature
- Reservoir pressure
- Reservoir quality
- Cost data.

Several factors critically important to commercial development and production of geopressured brines are not known and must be resolved. These factors are:

- Continuity of the reservoir within a fault block
- Amount of natural gas and minerals in solution in the brine
- Recovery factor.

The Department of Energy wells of opportunity and design test wells programs have in the past and will continue to obtain data in these uncertain areas.

METHODS OF RECOVERY

Development of a geopressured brine reservoir would consist of drilling and then producing, by natural flow, the hot salt water from deep wells; conversion of the geothermal energy to electricity (when economic); separation of the methane from the water; sale of the methane; and underground disposal of the produced water.

STUDY METHODOLOGY

The study participants made a detailed engineering appraisal of the 11 best prospects identified by the University of Texas and Louisiana State University under the funding of the Department of Energy.

These prospects were examined in detail to determine the following:

- Reservoir performance
- Drilling programs
- Production and water disposal methods
- Geothermal and hydraulic energy potential
- Producing rates and recoverable reserves
- Cost estimates and economics of field development.

RESULTS

Based upon the 11 best prospects and on an extrapolation of their data, it was concluded that it is possible to develop and produce some geopressured brine reservoirs at gas prices ranging from $4.00 to $9.00/MCF at a 10 percent (real) rate of return on investment.

The most optimistic case predicted gas rates of 54 MMCF per day in 1990 and 81 MMCF per day by the year 2000. Ultimate recovery for this case would be 568 BCF.

The less optimistic, "Lower Median Case," which appears to be the most likely from tests conducted thus far on two Department of Energy wells of opportunity and one design test well, predicts sales gas rates of 18 MMCF of gas per day by 1990 and 23 MMCF of gas per day by the year 2000. Ultimate recovery from this case would be 240 BCF.

CONSTRAINTS

No technical constraints to drilling and producing geopressured reservoirs were found. Locating large fault blocks containing sands of high permeability is the major problem in achieving significant production.

MAJOR UNCERTAINTIES

The major uncertainties in geopressured brine development are:

- Reservoir continuity within a fault block
- Reservoir quality
- Recovery factor
- Possibility that the geopressured brines are saturated with methane
- Sand production
- Corrosion
- Scale.

The current Department of Energy test program is aimed at resolving some of these uncertainties.

RESULTS

This progress report deals with a study of undiscovered tight gas. The following preliminary estimates have not received final approval of the study participants. The study participants have studied 12 tight gas basins out of the 113 U.S. basins and provinces that produce gas. The tight gas in these 12 basins is contained in 80 sub-basins. Of these, 69 have been evaluated.

As shown in Table 3, the study group reported potential reserves for these 69 sub-basins, for a 15 percent rate of return rather than the 10 and 20 percent rates shown for the other three unconventional gas sources in Table 1.

TABLE 3

Recoverable Tight Gas
(Constant 1979 Dollars)

Price ($/MCF)	Base Case (TCF)	Advanced Case (TCF)
2.50	114	150
5.00	164	220
9.00	184	249

There are 3 1/2 million sections in the 113 U.S. gas-producing basins. The percentage of the basin area containing tight gas varies from 2 to 50 percent of the basin area. If 3 percent of this area produced tight gas at 5 billion cubic feet per section, there could be over 500 TCF of recoverable tight gas at world energy prices.

The preliminary results strongly indicate that gas reserve increases are about equally dependent on price increases and a successful research and development program.

PRELIMINARY CONCLUSIONS

- The amount of recoverable tight gas is large, probably in the range of 200-500 TCF.
- Tight gas is technically recoverable using large hydraulic fractures, 1,000-4,000 feet long from well to tip.

- Production of some tight gas can begin at current Federal Energy Regulatory Commission (FERC) incentive price.

- Production of most of the tight gas could begin within five years at world energy prices.

- The first new supplies of tight gas will come from basins now producing declining amounts of conventional gas.

- Increased pipeline capacity will be required to produce the large potential tight gas reserves in the western basins.

STUDY METHODOLOGY

The method of study was to identify formations containing tight gas in each basin; in most basins there are several of these. In many areas, several of these formations occur together in the sedimentary section. Where practical to do so, wells were assumed to be completed in multiple formations, thus improving the economics.

Formations considered productive had very low permeabilities, in the range of 0.3 to 0.00001 millidarcies. The production from gas wells completed in such tight sands declines rapidly. Also, close spacing, from four to 12 wells per section, was usually required to recover a substantial part of this gas.

PIPELINE CONSTRAINTS

A rough estimate of excess pipeline capacity in the various regions was made. Excess capacity is substantial in the older producing areas of Louisiana, Texas, and New Mexico. All of the tight gas presently estimated by the study participants to be producible in these areas (7 TCF at $2.50/MCF and 15 TCF at $5.00/MCF) could flow out in 10 years. Naturally, it could not be discovered or produced this fast, but plenty of excess pipeline capacity exists.

Over 90 percent of the low-priced gas (107 TCF at $2.50/MCF and 149 TCF at $5.00/MCF) is expected to come from the Montana and Rocky Mountain regions and not more than 0.4 TCF per year could be delivered through pipelines available before 1985. For the Montana and Rocky Mountain regions, new pipelines will be required.

If major behind-the-pipe tight gas reserves, not included in the 12-basin estimate, are discovered in the southwest in the near future, the pipeline capacity exists to deliver up to 1.5 TCF per year of additional gas.

Department of Energy
Washington, D.C. 20585

June 20, 1978

Dear Mr. Chandler:

An objective of the energy supply initiatives of the President's energy policy is to promote domestic energy production from unconventional sources as well as from conventional sources. One of the areas to be encouraged is the recovery of natural gas from unconventional sources.

In the past, the National Petroleum Council has provided the Department of the Interior with appraisals on the extent and recovery of the Nation's oil and gas resources through such studies as Future Petroleum Provinces, U. S. Energy Outlook, Ocean Petroleum Resources, and Enhanced Oil Recovery.

Therefore, the National Petroleum Council is requested to prepare, as an early and important part of its new relationship with the Department of Energy, a study on unconventional sources of natural gas to include deep geopressured zones, Devonian shale, tight gas sands, and coal seams. Your analysis should assess the resource base and the state-of-the-art of recovery technology. Additionally, your appraisal should include the outlook for costs and recovery of unconventional gas and should consider how Government policy can improve the outlook.

For the purpose of this study, I will designate the Deputy Assistant Secretary for Policy and Evaluation to represent me and to provide the necessary coordination between the Department of Energy and the National Petroleum Council.

Sincerely,

James R. Schlesinger

James R. Schlesinger
Secretary

Mr. Collis P. Chandler, Jr.
Chairman, National Petroleum
Council
1625 K Street, N. W.
Washington, D.C. 20006

DESCRIPTION OF THE NATIONAL PETROLEUM COUNCIL

In May 1946, the President stated in a letter to the Secretary of the Interior that he had been impressed by the contribution made through government/industry cooperation to the success of the World War II petroleum program. He felt that it would be beneficial if this close relationship were to be continued and suggested that the Secretary of the Interior establish an industry organization to advise the Secretary on oil and natural gas matters.

Pursuant to this request, Interior Secretary J. A. Krug established the National Petroleum Council (NPC) on June 18, 1946. In October 1977, the Department of Energy was established and the Council's functions were transferred to the new department.

The purpose of the NPC is solely to advise, inform, and make recommendations to the Secretary of Energy on any matter, requested by him, relating to petroleum or the petroleum industry. The Council is subject to the provisions of the Federal Advisory Committee Act of 1972.

Matters which the Secretary of Energy would like to have considered by the Council are submitted as a request in the form of a letter outlining the nature and scope of the study. The request is then referred to the NPC Agenda Committee, which makes a recommendation to the Council. The Council reserves the right to decide whether or not it will consider any matter referred to it.

Examples of recent major studies undertaken by the NPC at the request of the Department of the Interior and the Department of Energy include:

- Petroleum Resources Under the Ocean Floor (1969, 1971)
  Law of the Sea (1973)
  Ocean Petroleum Resources (1974, 1975)
- Environmental Conservation -- The Oil and Gas Industries (1971, 1972)
- U.S. Energy Outlook (1971, 1972)
- Emergency Preparedness for Interruption of Petroleum Imports into the United States (1973, 1974)
- Petroleum Storage for National Security (1975)
- Potential for Energy Conservation in the United States: 1974-1978 (1974)
  Potential for Energy Conservation in the United States: 1979-1985 (1975)
- Enhanced Oil Recovery (1976)

- Materials and Manpower Requirements (1979)

- Petroleum Storage & Transportation Capacities (1979).

The NPC does not concern itself with trade practices, nor does it engage in any of the usual trade association activities.

Members of the National Petroleum Council are appointed by the Secretary of Energy and represent all segments of petroleum interests. The NPC is headed by a Chairman and a Vice Chairman who are elected by the Council. The Council is supported entirely by voluntary contributions from its members.

NATIONAL PETROLEUM COUNCIL
MEMBERSHIP

1980

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