UGR-371

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SPE 8922

SPE Society of Petroleum Engineers of AIME

GAS INDUSTRY ESTIMATES OF UNCONVENTIONAL GAS PRODUCTION 1980-2000

by G.H. Lawrence, O.C. Davis, H.R. Linden, B.S. Lee, B. Schlesinger, W.T. McCormick, Jr., R.B. Kalisch

ABSTRACT

The authors of this paper prepared a series of analyses of the supplemental supply sources of natural gas. This study was developed for the use of the Gas Supply Committee of the American Gas Association. The authors operating as a task force prepared a series of individual studies which were then integrated into a single report which will be published as the proceedings of the Gas Supply Committee Workshop II. This SPE-DOE paper has been taken from the broader study. It emphasizes the unconventional or non-conventional sources of natural gas and provides sufficient summary data on other supplies of natural gas to facilitate a review of the major findings of the task force with respect to the relative importance of unconventional sources of gas.

This paper provides a review of unconventional sources of gas from western tight sands, Devonian shale, gas from coal seams, SNG from peat, SNG from oil shale, gas from geopressured aquifers, gas from urban waste and animal residues and gas from biomass. The potential gas supplies from all sources are compared for four specific scenarios to illustrate the variability of the gas supply because of different national energy policies.

WESTERN TIGHT SANDS

The so-called tight formation in the West occur in two types of formations, blanket and lenticular sands. At one extreme are single, relatively thin (10 to 100 feet) gas-bearing zones of generally uniform thickness (blanket sands) which extend over a large area. At the other extreme are the lenticular formations composed of relatively thick sections (possibly 1,000 or more feet) containing multiple lenses scattered throughout the section, as in non-marine formations of the Rocky Mountain basins. There are 20 known geologic basins that have reservoir rocks with properties such as permeability and porosity of such value that they must be considered as unconventional (less than 0.03 millidarcies permeability and less than 10 percent porosity).

The Lewin 13-basin estimate of gas in place was 400 tcf. Although numbers are not available yet from the National Petroleum Council Task Force on tight sands, indications are that their estimates will be much higher than those in the Lewin Report perhaps more closely approximating the National Gas Survey.

The National Gas Survey and the National Petroleum Council study for the DOE is based on a lesser number of basins but includes speculative and very tight rock not included in the Lewin survey. The National Gas Survey estimate of gas in place for Unita, Piceance, and Green River Basins is 600 Tcf. When the National Gas Survey reviewed their 1973 estimates in their 1978 report to the DOE, they added 193 Tcf for parts of the San Juan Basin and the Northern Great Plains Province with no change for the original 3-basin estimate.

There are several incentive pricing packages under consideration. However, considering one proposed definition for tight sands (.03 millidarcy), it is anticipated that no significant production will be available until 1984. The primary factors affecting these projections are: 1) the unknowns associated with incentive packages and pricing consideration; 2) the lack of data in many basins; 3) the time and financial requirements for gathering and transmission systems.

Production estimates for the existing technology case are based on 100 wells being drilled in 1984, 200 wells in 1985 and then 200 additional wells each year until 1988 where 800 new wells are projected to be drilled. Estimates for the advanced technology case are based on 200 wells being drilled in 1984 and then an additional 200 wells each year to 1987 then 800 wells would be drilled. Projections beyond these initial years for both cases are based on constant growth rates of drilling wells ranging from 10 to 15% depending on price level.

For existing technology, success rates for production wells vary from 40 to 50% depending on price level. The assumed average production for a 12 year well life is 500 Mcf/day. Advanced technology has assumed success rates of 50 to 60% with average production of 1,000 Mcf/day for the same well life.

Using the above assumptions, estimates of the annual production to the year 2000 were calculated. One additional constraint was imposed. That is that any year's annual production cannot exceed 1/10 of the remaining recoverable gas. The annual production did not exceed the required recoverable gas values before the year 2000.

The 1990 and 2000 production estimates for western tight gas sands are tabulated below and represent increments above conventional lower 48 production estimates. These estimates do not include current tight sands production which is about 0.8 Tcf per year and which is treated as if it were conventional gas.

ANNUAL PRODUCTION (TCF)

	1990	
Market Price*	Existing Technology	Advanced Technology
$3.12	0.28	0.83
$4.50	0.32	1.00
$6.00	0.37	1.12

*1979 Dollars

	2000	
Market Price*	Existing Technology	Advanced Technology
$3.12	1.36	3.73
$4.50	1.81	4.99
$6.00	2.40	6.63

*1979 Dollars

DEVONIAN SHALE

The FERC has clarified the definition of "natural gas produced from Devonian Shale" to mean "natural gas produced from the fractures, micropores and bedding planes of shales deposited during the Paleozoic Devonian Period." The only significant body of data that relates to the shales of this period comes from the Appalachian Basin.

Of the 160,000 square miles in the Appalachian Plateau, about 40 percent (64,000 square miles) are underlain at depths of less than 4,000 feet by the Devonian brown shales, more than 50 percent (80,000 square miles) at depths between 4,000 and 8,000 feet, and less than 10 percent (16,000 square miles) at depths greater than 8,000 feet. Most of the deeply buried brown shale lies in the vicinity of the anthracite coal mines in Northeastern Pennsylvania. These latter shales show a high degree of thermal maturation. The high degree of maturation indicates a low potential gas productivity from more deeply buried shales. Similarly, most of the brown Devonian shales in the Valley and Ridge Province do not appear to have as much potential as the less thermally mature brown shale to the west under the Appalachian Plateau.

Assuming about 0.23 to 0.41 cubic feet of gas per cubic foot of brown shale, DOE estimates 234 Tcf to 1,157 Tcf of gas in place. If the leaner grey shales are included in the resource base, the upper end of the range can be put at nearly 2,000 Tcf.

Starting with a total area of approximately 210,000 square miles in the Appalachian Basin, the Lewin Study eliminated approximately 148,000 square miles as being "Speculative." Of the 62,000 square miles remaining they eliminated 5,000 square miles as already being developed, leaving only 57,000 square miles as potential for development. This does not include any of the older Ordovician shales nor any of the shales of the Michigan and Illinois Basins. A review of the Lewin work by the Columbia Gas System indicated that much of the eliminated area was discarded without adequate justification. On the same resource basis, the Columbia analysis showed the potential to be approximately 104,000 square miles, or about twice Lewin's estimate.

If one takes the larger resource size and considers limiting factors such as town sites, lakes, land withdrawn from mineral development for other reasons, etc., the remaining exploration target is reduced to about 60,000 square miles. The probable range of technically recoverable gas from the Appalachian shales is about 60 to 600 trillion cubic feet. As Columbia Gas pointed out, secondary shale targets -- of which little currently is known -- could more than double this estimate.

There are approximately 200 Devonian Shale wells planned for drilling in 1980. With incentives provided by decontrol, it is likely that a significant percentage of the now-active drilling capacity aimed at Eastern targets will be dedicated to shale development. GRI assumed a 100 percent growth in wells drilled in 1981, with declining growth in subsequent years down to 20 percent in 1985. The growth in wells drilled beyond 1985 was assumed at a constant rate between 10 and 15% depending on the economic case considered.

For existing technology, GRI assumed that an average shale well would produce 75 Mcf/day. Technology goals included both increased production rates and the ability to economically exploit more currently nonproductive resources. GRI assumed that the average production rate would be 100 Mcf/day per well for the advanced case. In both cases a 30 year well life and 90% success rates were assumed.

Based on estimates for recoverable resources the number of average wells required to produce the various quantities of recoverable resource were calculated. For example, the total 30 year production for an average advanced technology well was estimated to be 1.1×10^9 cu. ft. Since the recoverable resource estimate for a $3.00 market price with advanced technology was 20 Tcf, the number of average wells required to produce this resource is 18,000 wells. With an assumed 4,200 new shale wells in production by 1985 and a constant growth of 10 percent per year for drilling activity thereafter, the 18,000 wells would have been drilled before 1993 and would have annual production of about 0.7 Tcf. Since hypotnetically wells have a life of 30 years, wells drilled in 1980 would be abandoned in 2010 with a corresponding drop in annual production.

The 1990 and 2000 production estimates for Devonian Shale are tabulated below. These estimates do not include current production which is about 0.1 Tcf per year and do not include those small quantities in lower 48 conventional production forecasts.

ANNUAL PRODUCTION (TCF)

	1990	
Market Price*	Existing Technology	Advanced Technology
$3.00	0.31	0.38
$4.50	0.36	0.46
$6.00	0.40	0.51

*1979 Dollars

	2000	
Market Price*	Existing Technology	Advanced Technology
$3.00	0.31	0.70
$4.50	0.55	1.00
$6.00	0.82	1.50

*1979 Dollars

GAS FROM COAL SEAMS

The United States Geological Survey (USGS) reports about 1.73 trillion tons of identified, and 1.85 trillion tons of hypothetical, coal resources as of 1974. Another 0.39 trillion tons are reported as hypothetical resources in deeper structural basins (3,000 to 6,000 feet).

The limited data available on methane content, mostly from mineable bituminous coals, show considerable variability; and little, if any, data are available for sub-bituminious coal and lignite. It is generally agreed, however, that the gas content of these lower rank coals is likely to be less than that of bituminous coal on a per ton basis. Most studies to date use a gas content of 200 cu. ft./ton of coal for bituminous and anthracite coal seams. Extrapolating this value to sub-bituminous and bituminous coals based on moisture content differences yields a value of 80 cu. ft./ton for sub-bituminous coals and 40 cu. ft./ton for lignites.

Recoverable resources estimates have been made by a number of experts. These estimates generally range between 10 and 60 Tcf -- the lower end of the spectrum being associated with existing technology and lower prices, the upper end with advanced technology and prices in the $6.00 per MMBtu range.

Given the anticipated size of the recoverable resource and the anticipated productivity per well, the industry does not become resource limited by 2000. Production estimates for 1990 and 2000 are shown below. Conventional production forecasts for the lower 48 do not contain any coalbed methane production.

ANNUAL PRODUCTION ESTIMATES (TCF)

	1990	
Market Price	Existing Technology	Advanced Technology
$3.00	0.06	0.22
$4.50	0.07	0.23
$6.00	0.07	0.24

	2000	
Market Price	Existing Technology	Advanced Technology
$3.00	0.29	0.95
$4.50	0.35	1.2
$6.00	0.42	1.4

SNG FROM PEAT

Peat, geologically the youngest form of coal, consists of vegetation which has been deposited in bogs at the land surface under conditions of moderate to high rainfall and partical isolation from local drainage systems. As a result, peat generally occurs at the ground surface with little or no overburden material. A small amount of peat is mined commercially in the United States, primarily for horticultural uses, but it is not used commercially as a source of energy at the present time.

Peat can be converted to SNG by either thermal or biological methods. Both the thermal and biological processes have advantages and disadvantages. The primary advantage of thermal processes is faster reaction rates, while the primary advantage of biological conversion processes is that feedstock peat de-watering is not required. The primary disadvantage of thermal processing is the requirement of high temperature, and sometimes, elevated pressure. Two major disadvantages of the biological converison processes are the requirements for pre-treating peat to increase the biologically digestible portion, and the de-watering required for the solid by-products.

Peat resources are found in all 50 states; more than half of the peat resources of the nation are located in parts of Alaska (outside of the permafrost regions).

Current economic studies show that the cost of SNG from peat will be competitive with the cost of SNG from other fossile feedstocks.

The maximum potential production estimate is based on one demonstration plant (80 million cubic feet per day) on-stream in 1985, two commercial size (250 million cubic feet per day) plants in operation by 1990, three additional commercial plants by 1995, and five additional commercial plants by the year 2000, for a total of ten commercial plants in operation by that time.

The most likely annual production would be one demonstration plant on-stream in 1985, expansion of the demonstration plant to commercial size by 1990, two commercial plants in operation by 1995 and one additional commercial plant added by the year 2000.

The pessimistic estimate reflects a time delay of five years from the most likely case with one demonstration plant coming on-stream in 1990, expansion of the demonstration plant to full-scale commercial plant in 1995, and one additional commercial plant by the year 2000.

A summary of the production estimates in Bcf per year is as follows:

	1990	2000
Maximum Potential	180	900
Most Likely	90	270
Pessimistic	30	180

SNG FROM OIL SHALE

Oil shale is a fine-grained sedimentary rock containing an organic material known as kerogen. Upon heating, the kerogen will decompose to yield liquid oil, gases and residual carbon. The crude oil product is similar to conventional petroleum and by further processing can be converted into liquid and gaseous fuels.

Culbertson and Pitman (U.S. Geological Survey) reviewed U.S. oil shale resources and estimated that 420 billion barrels of oil occur in U.S. shales that yield at least 30 gallons per ton, 85% of this being in western Colorado. They gave total U.S. resources to a depth of 20,000 feet as 26 trillion barrels in low-yield shales and 1.3 trillion barrels in high-yield shales. Averitt (U.S. Geological Survey) currently estimates 125 billion barrels of reserves and 1.23 trillion barrels of resources.

Parent and Linden, in a recently published IGT study of U.S. fossil fuel resources, evaluated U.S. shale oil reserves as 74 billion barrels proved and currently economically recoverable, based on the most accessible and better defined deposits in the Green River formation in the Piceance and Uinta basins that are at least 30 feet thick and average 30 gallons of oil per ton by Fischer assay, as reported in the NPC study, and assuming 60% recovery of shale in the mineable seam and oil recovery corresponding to 96% by Fischer assay. Parent and Linden also evaluated the total remaining recoverable shale oil resources based on the total quantity of oil shale in the Green River formation ranging down to 15 gallons per ton by Fischer assay, as reported in the NPC study, and assuming 60% recovery of shale in the mineable seam and oil recovery corresponding to 96% by Fischer assay; this amounts to slightly over 1 trillion barrels.

The U.S. Geological Survey estimates the total "known resources" of Devonian oil shale in the Eastern United States at 400 billion barrels and the "probable extensions of known resources" at an additional 2600 billion barrels. Experimental work has indicated that up 250% of the yield from the conventional method of assay can be recovered from Eastern shales. Therefore, the actual magnitude of the oil present in "known resources" of Eastern oil shales could be as high as 1000 billion barrels. Estimated resources of shale oil recoverable by aboveground processing using recently developed technology in the Appalachian-Illinois and Michigan basins is estimated to be 423 billion barrels.

Based on recent economic studies, the cost of SNG from oil shale will be competitive with the cost of SNG from other fossil feedstocks.

The maximum potential production estimate is based on one demonstration plant (125 million cubic feet per day) on-stream in 1985, expansion of the demonstration plant to commercial size (250 million cubic feet per day) by 1990, four commercial size plants on-stream by 1995, and an additional four commercial plants by the year 2000.

The pessimistic estimate is based on a smaller (75 million cubic feet per day) demonstration plant on-stream in 1990, expansion of the demonstration plant to 150 million cubic feet per day by 1995, and an additional 150 million cubic foot per day plant by the year 2000.

A summary of the production estimates in Bcf per year as follows:

	1990	2000
Maximum Potential	90	720
Most Likely	45	360
Pessimistic	25	100

NATURAL GAS FROM GEOPRESSURED ZONES

The geopressured zones in the U.S. Gulf Coast Basin are Cenozoic sedimentary deposits containing trapped water at higher than normal (hydrostatic) pressure. The water trapped by both faulting and shale barriers in these formations is believed to contain significant quantities of dissolved methane, and, possibly, to be saturated with methane under reservoir conditions. The geopressured zones underlie a large portion of the northern Gulf of Mexico coastal region in a strip 200-300 miles wide. Sedimentary deposits in this area are up to 50,000 feet thick and the geopressure zones are contained in these formations, beginning from 5,000-15,000 feet below the surface and probably averaging about 10,000 feet in overall depth below that level.

Estimates of the gas-in-place and ultimately recoverable gas vary widely. A review of recent estimates showed gas-in-place estimates ranged from 860 to 100,000 Tcf. Recoverable gas quantities ranged from 42 to 5,000 Tcf.

Estimation of future gas production from geopressured brine is subject to large uncertainties because:

1. Although it was initially assumed that the brine would be saturated with natural gas at reservoir conditions, results from the four wells drilled to date show that three were undersaturated with gas.

2. Capital and operating costs are not well-defined due to the limited number of wells drilled to date and uncertainties concerning disposal of the produced brine.

A representative finanical analysis was performed using a calculated constant gas price of $5.43/Mcf for brine containing 35 Scf methane per barrel and $7.62 for brine with 25 Scf methane per barrel. The lower price is competitive with SNG produced from coal using currently available technology and the higher price will be competitive with refined products from petroleum at the time wells are put into commercial production. For the maximum potential case, it was assumed that gas saturation of the produced brine would be 35 cubic feet per barrel. Twenty-five wells were assumed completed by 1985, building up to 1,600 wells by the year 2000.

For the most likely case, as gas saturation of 25 cubic feet per barrel of brine was assumed. Ten wells were assumed productive in 1985, building up to 500 wells by the year 2000.

For the pessimistic case, the same gas saturation and flow rate was taken as used in the most likely case, but the number of wells producing was assumed to be 10 in 1990 and 50 by the year 2000. A summary of the production estimates in Bcf per year is as follows:

	1985	1990	2000
Maximum Potential	15	100	1000
Most Likely	5	20	200
Pessimistic	-	5	20

GAS FROM URBAN WASTES AND ANIMAL RESIDUES

Urban waste and animal residues include: urban refuse, sewage, animal manures and industrial waste. Urban refuse is the daily accumulation of garbage that is generated each day by society. About 75% of this refuse is organic matter. Projects for processing animal manures into biogas are feasible but economically limited to operations where substantial numbers of animals are confined to a relatively small area. In contrast, industrial wastes and sewage can not be economically transformed into high-Btu biogas today. The problem is primarily one of too much water and too little recoverable organic solids.

Urban refuse was estimated by EPA in 1976 to be generated at the rate of 3.5 pounds per person per day, or a national total of 135 million tons per year. EPA further estimated that 225 million tons would be generated in 1990. Extrapolating this trend and using the estimate that 75% is organic matter, the total annual production of organic urban waste by the year 2000 is 200 million tons. If 60% of generated urban waste is collectible, about 120 million tons organic matter would be available. Since approximately 75% of the population live in urban areas, about 90 million tons of the 120 million is generated in areas large enough to warrant an energy recovery system. Estimates for the Btu value of organic waste range from 7,000 Btu/lb to 9,000 Btu/lb. (This is comparable to lignite or brown coal at 7,200 Btu/lb, peat and sawdust at 9,000 Btu/lb, or wood (pine) at 11,000 Btu/lb). Using the lower estimate, a potential recovery of 1.3 quads could be predicted.

Organic solids of cattle manure are generated at approximately 250 million tons a year. Most of this manure, however, remains in the field. The manure generated at feedlots with over 1,000 head of cattle is about 35 million tons a year. The Btu value of this cattle manure, about 7,500 Btu/lb, is .5 quads. If the anaerobic digestor efficiency is between 30%-60%, the amount of biogas that could be produced is between .2 and .3 quads.

Sewage is over 99% water. The amount of organic solids suspended in sewage was estimated in 1976 to be 200 million tons about .5 lbs per person per day. Of this amount 10% was estimated to be recoverable. Based on projected population growth, the resource size could reach 30 million tons by the year 2000. Statistics derived from reports filed with the EPA under the Clean Water Act of 1977 indicate that recovery rates could increase about 50% by the year 2000, or about 15 million tons.

Estimates of the production potential of gas from urban and livestock wastes are 75 to 220 Bcf per year in 1990 and 230 to 800 Bcf per year in 2000. In order to calculate future production of biogas from cattle manure a timetable based on an estimate of 25 years to full commercialization from date of first commercialization (1978) was used to set the upward limit for the high production potential in the year 2000.

To achieve the high case projections, a concerted national effort to produce methane will be necessary. Improved technology for landfill recovery systems allowing production of biogas from small landfills which are currently not economic to develop will be necessary. A national effort to use more efficient anaerobic digestors is also assumed.

The low estimates are derived by assuming that only existing technologies, (current landfill recovery methods and current anaerobic digestor technology), will be used. Under an existing technology scenario, significant portions of the collectable resource will be used for other purposes. Cattle manure, for example, appears at this time to be more likely used to produce feed supplementals and fertilizer. Any gas produced may be used to dry the feed supplement rather than being upgraded to pipeline quality gas. See Table 1.

Sewage and industrial waste are assumed to provide no pipeline quality gas. Even under a high technology scenario, it appears that fertilizer value or on-site use will be more economic. The most likely sewage or industrial waste to gas route would be to grow water hyacinths, algae, or other plants to treat the water, then use anaerobic digestion to convert excess plant matter into biogas.

GAS FROM BIOMASS

Biomass formed by solar radiation and plant growth in the past now is being produced as fossil fuels, e.g., coal, oil and natural gas. In fact, throughout man's history biomass in the form of firewood has been a basic fuel source. However, modern developing technology and the national need to develop new energy sources have now given new incentives to find new means of using biomass as a supplement to fossil fuel sources.

Biomass, in a universal sense, includes all growing plant life. Aquatic biomass provides a means to use the vast ocean coastal waters as an energy resource. A project off southern California is testing the feasibility of growing giant kelp planted on submerged platforms which would then be harvested and converted by anaerobic digestion or other means to form methane. Onshore aquatic biomass is also a possible fuel source. One possible source currently being investigated is the conversion of water hyacinths, used to biologically treat sewage and industrial wastes, through anaerobic digestion to methane. Terrestrial biomass such as trees and other plants and crops including wastes from harvesting and processing, can also be converted to methane.

Estimates of the potential production capability for aquatic biomass are shown below. No estimates are projected for terrestrial biogas production due to the likelihood that the limiting factors enumerated previously will constrain land biomass to either a medium-Btu biogas or as direct-use fuel.

Major assumptions for estimating annual production capability are based on conversion efficiencies of anaerobic digestors ranging between 30-60 percent. The low production estimates for onshore aquaculture project a growth rate such that the 25% of the population currently not served by sewage treatment facilities will be served by new facilities designed for hyacinths. This low case will require only the refinement and application of newly developing existing technology. The high case estimates assume that in addition to the low case volumes, there are new facilities constructed to serve the expanding new population and that existing systems are modified to use water hyacinths. Technology for sustaining year round plant growth would need to be developed to meet the high case projections. Since this source of biogas is potentially available in every community, if technical and economic feasibility is proven, fairly rapid development can be expected reaching full commercial development in 25-35 years.

Marine kelp farming represents a longer term, large scale approach towards biomass energy. Estimates for marine biomass project no commercial production until 1990. The low case assumes construction of a 1 sq. mile farm in 1990 with an expansion of 5 sq. miles annually thereafter. The high case assumes rapid technology advancement and the construction of 5 sq. mile farm in 1990 expanding by 25 sq. miles annually thereafter. Projections are that full commercialization of marine biomass will take 80-100 years after first commercialization in 1990.

Summed together the low case estimates reach 35 Bcf by the year 2000 which represents a volume achievable with the refinement of existing and developing technology. The high case reaches 135 Bcf by the year 2000 and represents a volume achievable with the rapid implementation of improved, new technology.

PRODUCTION CAPABILITY OF AQUATIC BIOMASS GAS
(Bcf Equivalent)

	Onshore Aquaculture (Water Hyacinths)	Marine Biomass (Giant Kelp)
1990	1-.5	2-.4
2000	35-15	100-20

	Total		
	High	Most Likely	Low
1990	3	2	1.5
2000	135	110	35

CONCLUSIONS

This analysis has been integrated with studies of the other supplemental sources, i.e., Alaskan gas; Canadian, Mexican and LNG imports; SNG from liquid hydrocarbons and coal gasification. The overall integrated result is a total gas supply estimate.

For each supplemental source there is a wide range of uncertainty in the volumes of gas which could be available. Such estimates are, by their very nature, imprecise. To reflect this lack of precision, high and low estimates have been made for each individual source. However, since the assumptions which maximize one source may reduce the supply potential of another, the individual high estimates for these various supplement gas supplies cannot be added together for a single total supply estimate. Evaluation of several different future supply and policy scenarios showed that different combinations of supplies result from major changes in the scenarios. Broadly speaking, the total natural gas supplies from all sources for most scenarios fall in the range of 23 to 32 Tcf (trillion cubic feet) per year.

The range of gas supplies have been developed for four specific scenarios. These estimates illustrate the variability of each supplemental source as a function of both national policy and the rate of technological advancement.

Table 2 shows the volumes of gas supplies estimated for four scenarios. These results indicated that under limited technological development and government restrictions on new supply initiatives, natural gas supplies in the year 2000 would range from 23 to 26 Tcf. On the other hand, aggressive technology programs and government encouragement could increase supplies to about 30 Tcf (28-32 Tcf).

The four specific scenarios shown in Table 2 were developed to illustrate how the range of supplies for each source might vary. These scenarios represent neither policy recommendations nor are they attempts to characterize current policy. Rather, the scenarios represent future situations which demonstrate how supplemental gas volumes are non-uniformly affected. Hopefully, these scenarios will clarify the impact of national policy on the production from a particular source of gas. These estimates show how dependent each supplemental source of gas is on national policy and regulatory attitudes.

Generally, a high and low forecast is presented. The high forecast implies that there is a vigorous national R & D effort to improve the technologies related to gas production. In addition the high estimate assumes that, subject to the scenarios description, federal policy and regulatory decisions support increasing gas supplies.

The low estimate is based on an indifferent national R & D program with dilatory federal and regulatory policy decisions. It is important note that such conditions could occur by neglect or by failure to maintain policy continuity or by a poorly conceived set of programs.

The self-sufficiency scenario is based on a strong national policy to minimize energy imports. Estimated volumes by source are shown in Figure 1. Alaskan gas, coal gasification and tight formations are sources whose production would be maximized; Canadian, Mexican, and LNG imports and imported feedstocks for SNG plants would be minimized. The scenarios includes a high and low technology option. It is not surprising that the low technology, self-sufficiency case is one of the lowest supply scenarios identified, since it contemplates restrictions on imports without a strong technology program.

The World Conventional Gas scenario is based on the "world gas option" which recognizes that only ten percent of the world's gas and over 20 percent of the world's oil have been consumed. Most of the world's gas resources are in regions of the world far from the major industrial consumption centers. Although the same is true of the oil resource, the ease of shipping oil by tanker and pipeine has largely offset this geographic problem. The world gas option recognizes the growing need for fuel world wide and accepts the idea that world wide trading of natural gas by pipeline and LNG will increase significantly in the next two decades.

This scenario emphasizes the development of conventional gas resources and the transmission of that gas to wherever fuel is needed. As a result, all of the conventional production from supplemental supplies are maximized but the higher cost tight formations and non-conventional sources are not developed as rapidly as possible. Also, coal gasification plants are built at a rate well below the national capability.

Industrial nations throughout the world are vulnerable to political, military or religious instabilities and to natural catastrophes which might disrupt the flow of oil from the Persian Gulf. The scenario titled "Persian Gulf Crisis," assumes that the U.S. plans to minimize the effect of such a crisis and that the crisis occurs late in this century.

North American sources of gas receive the emphasis in this scenario. Lower 48, Alaskan, Canadian, Mexican, coal gasification and to a lesser extent the non-conventional sources are the major sources of gas in this scenario in that each of these supplies could be developed independent of the middle Eastern nations.

The level of LNG imports would be very sensitive to the specific type of instability in the Persian Gulf. Nevertheless, for illustrative purposes, this scenario is based on severely restricted new LNG imports and on the assumption that operational LNG projects are not affected by the Persian Gulf Crisis.

A new concept developed during the past year is the "Least Energy Cost Strategy." Roger Sant, Director of the Energy Productivity Center of Mellon Institute, is responsible for this concept which is based on comparing the cost of energy services actually provided to the ultimate consumer and which considers conservation on an equivalent basis with supply. Using some of Sant's concepts GRI developed a scenario called the "GRI Least Energy Cost Strategy." The scenario is intended to represent an all-encompassing least energy cost strategy model which would indeed develop the optimum mix of energy supply sources in terms of consumer cost. In its ideal form it would reflect fully internalized marginal costs for each individual energy supply as a function of time and production rate in conjunction with projections of the characteristic of each of the competitive utilization systems.

Analysis of these scenarios reveals that there is likely to be an increasing dependence on supplemental sources of gas in the remaining twenty years of this century. Of the new technology supplemental sources the tight formations has the greatest potential for production in the year 2000. In fact by 2000 renewable resources, tight formations, synthetics and geopressured gas could provide as much as 25 percent of the nation's gas supply. A total national gas supply by 2000 could be in the 23-32 Tcf range with supplemental sources of gas providing over half of the supply.

Table 1

Gas Production Capability of Urban & Livestock Wastes (Bcf equivalent)

	Urban Waste (Landfills and Digestors)	Livestock
1990	75-160	0-60
2000	230-520	0-280

	Total		
	High	Most Likely	Low
1990	220	100	75
2000	300	300	230

Table 2

Total Natural Gas Supply in 2000 For Four Scenarios

	Gas Supply in Tcf[4]	
Scenario	Low[1]	High[2]
National policy of energy self-sufficiency	23	30
Maximum Use of World Conventional Gas	28-30[3]	
Persian Gulf Crisis	26	32
GRI Least Energy	28[3]	

[1]Low Technology described a national attitude of limited investment in technology dependent programs and general reluctance to initiate new gas supply programs.

[2]High technology describes a national attitude of aggressive technological growth combined with a willingness to accept a higher degree of risk in some of the new gas supply programs.

[3]These scenarios do not provide for high and low technology supply options.

[4]These estimates include gas supplies from conventional production in the U.S.; Canadian, Mexican and LNG imports; SNG from Liquid Hydrocarbons; coal gasification; and unconventional sources.