3.
Future Gas Availability and Use

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Policy alternatives related to future liquefied natural gas (LNG) imports can only be evaluated in the context of the possible ranges of gas availability and use over the duration of a supply contract. Although such projections are highly speculative, this chapter presents the results of a review of the relevant literature.

On examining the forecasts from several econometric demand models, one observes that projected U.S. gas use falls between 14 and 25 quadrillion Btu (Quads) in 1990 depending on such factors as future fuel prices, energy productivity, and public policy. Table 1 indicates by sector what portions of expected demand are "basic" in the sense that alternatives are costly or unlikely, and what are "marginal," i.e., possible if supplies are available at attractive prices and policies are favorable.

Since LNG is just one of many possible sources from which to meet demand, this chapter also includes a survey of North American gas and oil production potential. As shown in table 2, domestic production, now at a level of about 19.6 trillion cubic feet per year (Tcf/yr) in 1979, may decline to as low a level as 14.6 Tcf/yr by 1990, barely enough to meet '(basic" demand. It could also possibly satisfy "marginal" demand, but only at high prices. Furthermore, Mexico and Canada will probably not significantly alter the balance, and oil production in the continent is not likely to increase either,

In the rest of the world, large gas reserves occur particularly around the Persian Gulf and in the Soviet Union. However, for political or economic reasons, most of these resources either would not be exported or would flow to closer markets, in Japan and Europe, for example. Thus, only perhaps 0.5 to 1 Tcf/yr could presently be committed to future LNG sales to the United States beyond those imports already approved. These remaining available volumes are located in Nigeria, Southeast Asia, and South America.

Table 1.—Projected Levels of Potential Gas Demand in 1990 by Consuming Sector Under Alternative Policies and Prices (quadrillion Btu)

Sector	Basic[a]	Marginal[b]	Total
Buildings	5	3	8
Industry	8	2	10
Utilities	.5	4	4.5
Other	.5	3	3.5
Total	14	12	26

[a]Basic demand includes applications for which alternatives are relatively costly or unlikely.
[b]Marginal demand includes other economical uses that are Possible if supplies are available at attractive prices, and policies are favorable
SOURCE: Office of Technology Assessment, based on data from several separate studies (see text for assumptions).

Table 2.–Potential Gas Supply in 1990 (trillion cubic feet; approximate quadrillion Btu)

	NPGA prices[a]	Over $3/Mcf[b]	Over $5/Mcf[b]
Domestic			
Conventional	12.5-16.6	12.5-16.6	12.5-16.6
Alaska North Slope	—	—	1.6
Unconventional	2.3	3.6-8.4	3.6-8.4
Synthetics	—	—	0.3-1.4
Subtotal	14.8.18.9	16.1 -25.0	18.0-28.0
North American imports			
Canada	—	0.6	0.6
Mexico	—	0.7-1.2	0.7-1.2
Subtotal	—	1.3-1.8	1.3-1.8
LNG imports			
Present & approved	—	0.8	0.8
Possible additions	—	0.5-1.0	0.5-1.0
Subtotal	—	1.3-1.8	1.3-1.8
Total	14.8-18.9	18.7 -28.6	20.6 -31.6

[a]Prices specified in the Natural Gas Policy Act of 1978 (Public Law 95-621)
[b]1978 dollars per thousand cubic feet.
SOURCE: Office of Technology Assessment.

U.S. gas demand

This section presents a survey of recent studies of energy and natural gas demand, particularly those that emphasize the tradeoffs between gas use and efficiency improvement technologies in the residential, commercial, industrial, and powerplant sectors. The resulting range of estimates of likely demand for natural gas in the next 10 to 20 years is then contrasted with projections of available gas supplies.

The projections analyzed here were performed by the Energy Information Administration, American Gas Association (AGA), Brookhaven National Laboratory, Dale Jorgenson Associates, Energy and Environmental Analysis, Inc., Jensen Associates, and the National Academy of Sciences Committee on Nuclear and Alternative Energy Systems (CONAES). The underlying models and analytical methods, described in the *Background Reports* volume of this report, generally account formally for potential changes in end-use efficiency and technology, consistent with assumed energy prices, economic growth rates, and Government policies,

As the differences among the projections listed below illustrate, analytical modeling is an imprecise art, requiring judgment as well as logic and facts. The inclusion of many studies here is intended to indicate how varying assumptions affect the results, and to dramatize the uncertainty associated with any given projection. As a result, the premises underlying the individual studies are not necessarily mutually consistent, although in most cases the long-term real economic growth is assumed to be 3.5 percent per year. Direct comparisons, such as those that follow, must be tempered with these considerations in mind.

Comparisons of projection results

The level of gas demand predicted in any particular study is a function of both the structure and data input to the demand-side model, and the exogenous inputs to the model such as price and economic growth. Generally, models with more detail on the demand side may be expected to capture a higher degree of consumer response to price increases, provided the costs and efficiencies of end-use technologies are represented accurately. In addition, the higher the assumed price of fuels and the economic growth rate, the lower the predicted demand for gas and other fuels, all else being equal.

Because of the importance of world oil prices as a pacing variable for energy prices generally, the summary gas demand for the studies considered are presented in two separate tables. Table 3 presents the gas demand for the projections that assume little or no increase in the real price of world oil. Table 4 presents the results of several projects that begin with assumptions of between 50- and 150-percent real increases in world oil prices between 1978 and 1990.

Effect of prices

Since imported oil is the principal alternative fuel for many uses, the price of substitutes will tend to rise to world oil price levels, absent regulation. In a theoretical free market, the price of natural gas might be expected to rise to the price of distillate oil refined from foreign crude. Most world oil price projections fall in the range between no real price increase ($15 to $20/bbl in constant 1978 dollars)* and increases to approximately $4o to $50/bbl by 1990.

Gas demand projections assuming nearly constant world oil prices, fall fairly consistently in the range of 7 to 9 Quads in buildings and 8 to 11 Quads in industry, if gas prices are limited to no more than the Btu equivalent of imported oil. In the high world oil price cases, however, the difference between gas prices at Btu equivalency with oil and at lower regulated levels is striking. The projections by Jensen Associates and Brookhaven assume gas to be priced well below Btu parity. Gas demand for buildings and industry in these cases is not very different from the projections shown in table 3, indeed, gas demand may be slightly higher due to substitution for oil. A more dramatic contrast is between the CONAES scenarios, in which gas is priced at a slight premium over oil due to its

*This lower limit has become outdated in recent months.

Table 3.—1990 Gas Demand for Low Oil Price Cases (quadrillion Btu)'

Report	EIA(l) A	EIA (1) B	EIA(l) C	EIA(l) D	EIA(l) E	AGA (2) low supply	AGA (2) high supply	BNL (3) DJA L	BNL (4) BECOM L
Oil									
Imported									
1978 $/bbl	16.00	23.50	18.50	15.60	21.00	19.06	19.06	15.83	16.59
Gas									
Well head									
1978 $/Mcf	1.99	3.27	2.40	2.01	2.79	2.05	2.05b	2.50	2.74
Residential ., .	5.57	5.33	5.41	5.48	5.35	5.80	5.80 1	(6.80 space heat)	6.91
Commercial. , .	2.75	2.38	2.37	2.45	2.29	3.20	3.20	16.80 1	
Industry.	8.24	8.60	9.98	9.60	7.97	13.50	10.90 ~	(3.95 process heat)	N/S
Utilities	0.52	0.54	0.51	0.52	0.60	2.20	2.20	3.10	NIS
Other	0.47	0.48	0.53	0.47	0.45	3.00	3.10	N/s	N/S
Total.	17.55	17.33	18.80	18.52	16.66	27.70	25.20	19.90	N/S

N/S Not specified
[a]10[15] Btu = 0.98 Tcf of gas = 1 Quad
[b]Supplemental priced comparable to world oil.

SOURCES: 1. Energy Information Administration, *Energy Supply and Demand* in *the Midterm 1985, 1990, and 1995, 1979.*
2 American Gas Association, *A Forecast of the Economic Demand for Gas Energy in the* U.S. *Through* 1990, 1979.
3 R J Goettle, E. A Hudson, and J. Lucachinski, *A Comparative Assessment of Energy-Econorrry Interactions: Price Versus Growth,* BNL 50923, Upton N Y , 1978
4 S C. Carhart, S S. Mulherker, and J. Schwam, *Energy, Employrrrent, and Environmental Irnpact of Accelerated Investment in Conservation and Solar Technologies m Buildings,* BNL 50918, Upton, N.Y.,1978

Table 4.—1990 Gas Demand for High Oil Price Cases (quadrillion Btu)[a]

	JAI (1)	BNL/DJA-H (2)	BNL BECOM-H(3)	CONAES A(4)	CONAES B(4)	CONAES B' (4)
World oil price.	42.00	29.12	49.20	45.09	25.15	25.15
Gas wellhead price.	2.50	3.49	3.46	9.76	4.78	4.78
Residential	5.32	16.55	6.14	4.6 [b]	5.1[b]	5.7[b]
Commercial.	2.77					
Industry.	9.37)		N/S	8.0[b]	7.1 [b]	8.4[b]
Utilities , ...	4.80	1.75	N/S	N/S	N/S	N/S
Other	2.48	N/S	N/S	N/S	N/S	N/S
Total.	24.74	18.30	N/S	N/S	N/S	N/S

N/S Not specified
[a]10[15] Btu = 098 Tcf of gas = 1 Quad
[b]Adjusted for 3.5 percent per *year* GNP growth for comparability with other forecasts.

SOURCES 1 Jensen Associates, Inc., *Imported Liquefied Natural Gas, 1979 (vol.* II of this report).
2. R. J Goettle, E. A. Hudson, and J. Lucachinski, *A Comparative Assessment of Energy-Economy Interactions Price Versus Growth,* BNL 50923, Upton N Y , 1978
3. S. C. Carhart, S. S. Mulherker, and J. Schwam, *Energy, Employment, and Environmental Impact 01 Accelerated Investrmen! in Conservation and Solar Technologies in Buildings,* BNL 50918, Upton, N. Y,,1978.
4 National Academy of Sciences, Committee on Nuclear and Alternative Energy Systems, *Alternative Energy Demand Futures,* Report of the Demand/Conservation Panel, 1980.

ease of use and cleanliness, and the other high oil price cases. The results are substantial reductions in gas demand—to 5 Quads in the buildings sector and to 8 Quads in industry.

The implication of the latter figures, while preliminary and not strictly comparable, is that substantial conservation in buildings and industry is economically justified between the $2,05 per thousand cubic feet (Mcf) price contemplated in the AGA high-demand case and the $5 to $10 Mcf assumed by CONAES. On the basis of these studies taken together, one concludes that 1990 buildings and industry demand will probably lie in the 12- to 14-Quad range if gas is priced on a Btu equivalency basis with higher priced oil, in contrast with 16 to 20 Quads for the lower gas price cases.

Effect of public policy

The range of demand for utilities and miscellaneous uses falls between 1 and 7 Quads. The main difference in these projections arises from varying interpretations of the Power Plant and Industrial Fuel Use Act, which calls for negligible levels of natural gas use in powerplants by 1990, but provides for numerous exemptions and exceptions. Regulatory interpretation of the law over the next decade will be a key factor in resolving this uncertainty.

Another major element of Government policy concerns incremental pricing and use of natural gas for the generation of steam. The AGA study, which explores what type of energy service in industry would absorb marginal supplies of gas, illustrates the effect of these policies. A "high supply" case assumes that supplemental supplies, such as LNG, will be used by, and priced incrementally to, industrial users. In the "low supply" case, no supplemental gas is included, and prices stay at the average level for conventional supplies. The effect of incremental pricing in industry is to reduce demand by 2.6 Quads, the bulk of which would have raised steam, largely through displacement of other fuels, as shown in table 3. The incrementally priced high-supply case projection of 10.9 Quads in industry is quite comparable with other projections. However, if all gas to industry is incrementally priced, and world oil prices are in the $40 to $50/bbl range, CONAES case A suggests that total demand in industry might be expected to fall to around 8.0 Quads.

Domestic supplies

This section reviews U.S. gas and oil resources and potential supplies in terms of quantity, time of availability, and cost. In the context of projected demand, this discussion is designed to aid in assessing the need for imports. The method of analysis draws heavily on numerous available supply forecasts. The results, presented in greater detail in the *Background Reports* volume, rely on secondary resources and do not represent yet another supply projection,

Table 5 summarizes U.S. gas production from all sources. The ranges in estimates are indicative of the uncertainty associated with each source. Production is principally dependent on the rate at which new reserves can be added, and Alaska's contribution also hinges on the construction of the Alaska gas pipeline. Realization of the potential of unconventional gas sources will require time and technological progress, and coal gasification also will require large capital outlays.

Maintaining current levels of U.S. liquid petroleum production over the next decade or two will be extremely difficult. Natural gas liquids production may decline with declining production of natural gas, and conventional oil production from proved reserves will continue to decline. At the same time, enhanced oil recovery (EOR) processes and new discoveries may not add enough to reserves in time to offset declin-

Table 5.—U.S. Gas Supply Conventional, Unconventional, Coal Gas (trillion cubic feet)

	Lower-48 NGPA-prices[a] Low	Med	High	Alaska $5.00-$6.00 1978$	Unconventional $1.75 1972	$3.00	$3.00 High	Coal gas $5.00-$6.00 1978$
1980	18.8	18.8	18.8	—	.3	.5	.5	—
1985	14.7	16.3	17.8	.8	1.3	1.9	4.1	.2-.7
1990	12.5	14.5	16.6	1.6	2.3	3.6	8.4	.3-1.4
1995	11.4	12.4	13.6	2.5	2.8	4.4	8.4	2.4
2000	10.8	11.6	12.2	3.6	2.8	4.4	9.0	4.0

[a]According to the Natural Gas Policy Act of 1978 (Public Law 95-621).
SOURCE: Office of Technology Assessment.

ing production from older fields. Progress in developing oil shale and coal will be slow, and synthetics production on a large scale is not anticipated before the mid-1990's) even if potential environmental problems are resolved.

Future U.S. liquid petroleum production could consist of the components in table 6. In spite of the inherent uncertainty, the forecast does suggest that domestically produced liquid petroleum will not be available to substitute for shortfalls in gas or other energy sources. Indeed, large quantities of imported oil will continue to be required to meet liquid petroleum demand in the foreseeable future.

Conventional natural gas

Five forecasts of conventional gas production, summarized in table 7, have been examined in this study, representing a range of institutional perspectives. They were chosen in part to represent the widely different levels of optimism expressed by analysts in this field, but all forecasts (except one by AGA) project a decrease in U.S. conventional natural gas production from about 19.6 Tcf in 1979 through the end of the century.

As of year-end 1978, U.S. proved reserves of natural gas totaled 200.3 Tcf, including approximately 30 Tcf of North Slope, Alaskan gas for which no transportation and delivery system is available, at least for the next 5 years. Estimates of indicated and inferred reserves range from 52 to 202 Tcf, reflecting differences in the definitions of categories, less certain geology, and lack of interest in exploration (particularly for nonassociated gas) due to Government price regulations. Estimates of undiscovered, recoverable natural gas resources varying from 361 to 920 Tcf, are even more speculative. Estimates of remaining recoverable U.S. conventional gas resources are summarized in table 8.

Proved reserves are the most significant determinant of production in the immediate future, since the ratio of reserves to production, 8.5 to 1 in the United States, excluding Alaska, is close to its technical limit. In the lower 48 States, proved reserves have declined every year since 1968 as production has exceeded additions. With no net additions to reserves, a lower reserve-to-production ratio, even if technically feasible, would delay but not reverse the decline in natural gas production which began in 1973.

Over a period of several years, however, additions to production potential would arise from revisions and extensions of existing fields, new discoveries, and Alaskan reserves. Since 1970,

Table 6.–Possible Future U.S. Liquid Petroleum Production
(million barrels per day; 25.381978 dollars/bbl)

	1985	1990
Conventional liquid petroleum known fields	5.6	4.2
Enhanced recovery	1.0	1.8
New discoveries	2	2
Shale oil	—	.1-.4
Coal liquids	—	.1-.5
Total	8-9	8-9

SOURCE Office of Technology Assessment

Table 7.—Forecasts of U.S. Conventional Natural Gas Production
(trillion cubic feet)

	American Gas Association[a]	EXXON	Shell	Lewin[c]	Tenneco
1980	18-19	17.0	17.0	17.0	18.0
1985	16-18	15.3	14.0	14.0	16.0
1990	15-17	14.3	13.0	13.0	15.0
1995	14-15	NA	NA	NA	14.0
2000	12-14	NA	NA	11.0	12.0

[a]The higher estimate assumes gas price deregulation.
[b]Excludes Alaska.
[c]Including developments of unconventional gas already underway.
SOURCE: Office of Technology Assessment.

Table 8.–Potential Supply
(trillion cubic feet)

Year of estimate	Source	Old fields	New fields	Proved	Total
1974	Hubbert	135	361	200	696
1974/5.	Mobil	52	485	200	737
1975	National Academy of Sciences	118	530	200	848
1975	Institute of Gas Technology	(633-1,138)		200	833-1,338
1975	U.S. Geological Survey	202	322-655	200	724-1,057
1978	EXXON	(202-860)		200	400-1,060
1978	Potential Gas Committee	199	820	200	1,219

SOURCE: Office of Technology Assessment

additions to reserves outside Alaska have averaged 9.3 Tcf/yr, consisting mostly of new reservoir discoveries in old fields and revisions and extensions of presently producing fields. The contribution of new field discoveries to this total has averaged only 1.8 Tcf/yr since 1971. To maintain current production at the 8.5:1 reserves to production ratio, additions to proved reserves would have to equal current production, about **20** Tcf/yr, so an additional 10 Tcf above historical reserve additions would have to be found to maintain current production levels.

Optimism or pessimism in the forecasts cited above turns on the likelihood of large additions to reserves in the future, in the light of uncertain geology and the unknown effect of higher prices of drilling rates.

Alaska contains an estimated 225 Tcf of potential gas, including indicated and inferred reserves and speculative resources, representing perhaps 23 percent of the U.S. total. Of the 31.8 Tcf of proved reserves within the State, the major portion is located in the Prudhoe Bay field of northern Alaska, and gas resulting from oil production there is being reinfected into the gas cap. None of this gas will be available until an Alaska pipeline project is completed, in 1984 at the earliest, and the financing for the venture is still problematic. When completed, the pipeline would have a nominal design capacity of 0.9 Tcf/yr. When a west coast LNG terminal is built, 50 billion cubic feet (Bcf) of Alaskan gas from southern Alaska, which is currently shipped to Japan, could come to the United States.

Conventional oil

The United States has already reached the 1:10 production-to-reserves technical limit. To maintain current production levels, additions to reserves, whether through enhanced recovery or new discoveries, would have to equal current production—about 3 billion barrels per year (bbl/yr). In fact, the United States has been adding to reserves at a rate of about 1.8 billion bbl/yr (excluding Prudhoe Bay). For this reason the United States will probably be unable to maintain current production levels over the next decade, since enhanced recovery and new discoveries are not likely to offset the decline in older producing fields.

Five domestic oil production forecasts appear in table 9. Although difficult to compare because of inconsistent and inexplicit assumptions, most forecasts project no increase before 1990 in U.S. liquid petroleum production from the 10.3 million barrels per day (MMbbl/d) level achieved in 1978. Indeed, EXXON and Shell project a decline from current levels, and in general, the more recent the forecast the lower the projected production figures. *

The extent to which any of these forecasts are borne out depends on petroleum reserves, recovery factors, and the rate at which resources are discovered. The following analysis examines each of these factors.

At the end of 1978, U.S. proved crude oil reserves stood at 27.8 billion bbl. Typically, as exploration and development work yields greater information on a field, inventories of proved reserves will change, and estimates of additional oil include 4 billion bbl of indicated reserves and 23 billion bbl of inferred reserves. The importance of these potential additions to proved reserves is their near-term availability (1 to 3 years).

Table 9.— Forecasts of U.S. Conventional Liquid Petroleum Production
(millions of barrels per day)

	Energy Information Agency/ DOE 1978	Petroleum Industry Research Foundation 1978	EXXON 1978	CIA 1978	Shell 1978
1980. .	NA	9.8	9.6	10.4	9.8
1985. .	10.8	10.3	8.5	10.2	9.7
1990. .	10.4	10.4	7.2	10.3	9.9

NA = Not available.
[a]Including natural gas liquids.
SOURCE: Office of Technology Assessment

*These estimates may not fully reflect more recent large world oil price increases and the President's decision to deregulate domestic oil production,

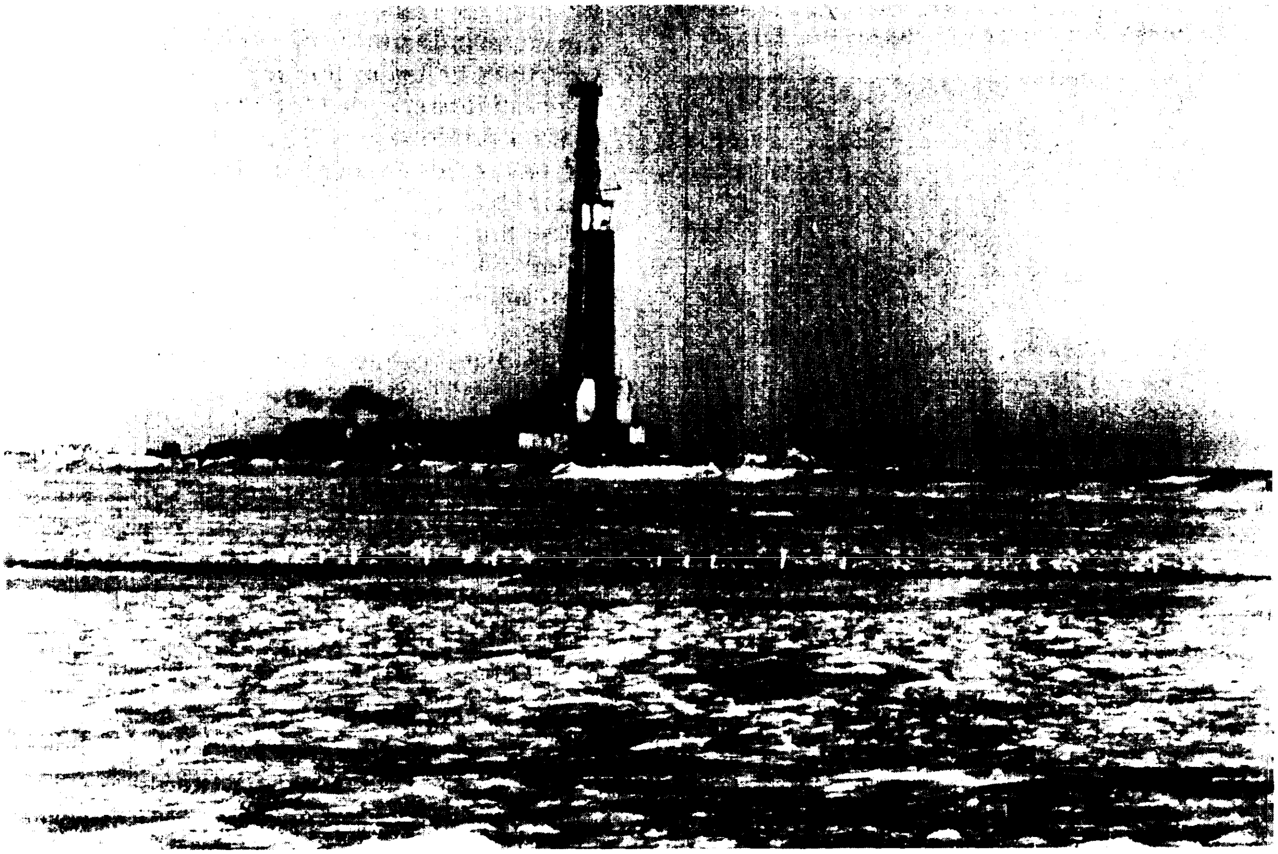


Photo credit Courtesy of American Gas Association

Alaska's North Slope contains new reserves of natural gas. At Prudhoe Bay, this rig is typical of initial exploratory and production efforts

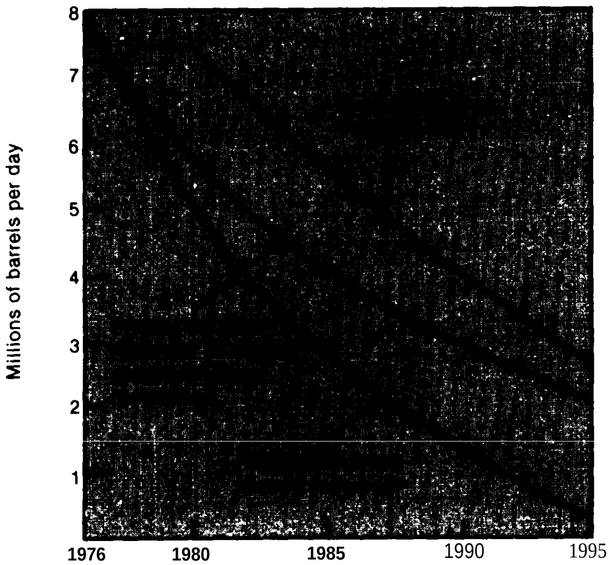
In the lower 48 States, annual production has exceeded additions to reserves since **1970.** Also, as indicated in figure 3, the addition of Prudhoe Bay reserves will permit only a temporary increase in production, after which North Slope's contribution will be insufficient to offset the decline in older producing fields. The extent to which production can be maintained or increased depends on the existence and availability of additional reserves represented by EOR and new discoveries.

Primary oil recovery takes advantage of the natural flow of oil in a reservoir to a producing well, and the application of secondary recovery techniques, water flooding and gas injection, increases the proportion of oil-in-place that can be recovered and accounts for approximately 50 percent of the current U.S. oil production discussed above. These established techniques leave significant quantities of oil in the ground, and the future availability of this remaining oil depends on the development and application of EOR technology, including thermal, chemical, and miscible processes.

Predictions of the quantity of oil to be recovered by enhanced recovery technology and potential production rates are beset with uncertainty. While interest in EOR is longstanding, most of the processes, with the exception of steam injection, remain unproved. Nevertheless, the results of three production estimates appear in table 10, reflecting varying assumptions about future price and process performance.

Further additions to production will have to come from new discoveries, and estimates of

Figure 3.—Projected Oil Production by Conventional Methods From Known U.S. Reservoirs, 1976-95



NOTE: The decline curves for proved reserves do not include enhanced oil recoveries recorded within these categories.

SOURCES: [a]Federal Energy Admintstration, *National Energy Outlook,* 1976.
[b]us, Geological Survey, *Circular* 725, 1975.
[c]American petroleum Institute, *Reserves* of *Crude 0il, Natural Gas Liquids, and Natural Gas m the u.S. and Canada* as of *December 30, 1975,* Lewin & Associates, Inc., for Federal Energy Administration, *Decline Curve Analysls, 1976.*

Table 10.—Estimated Potential Production From Enhanced Recovery (millions of barrels per day, $10-$25/barrel[a])

	OTA[b]	Lewin[c]	NPC[d]
Poor process performance			
1985	.4- .9	.5- .7	.4-1.0
1990	.5-1.8	.5- .9	.8-1.9
1995	.5-2.3	.5-1.0	.8-1.9
High **process** performance			
1985	.5-1.3	1.7-2.5	1.6-2.3
1990	1.1-2.3	2.6-4.3	2.9-3.9
1995	1.7-6.0	2.8-4.5	3.3-4.6

[a]1976 dollars.
[b]Enhanced 01/ *Recovery Potential m the United States,* Office of Technology Assessment, 1978.
[c]Research and *Development in Enhanced Oil Recovery, Lewin and Associates, 1976.*
[d]*Enhanced 01/ Recovery,* National Petroleum Council, 1976.

undiscovered resources vary widely, converging in recent years around a figure of 60 to 100 billion bbl (figure 4). Recent exploration results in south Alaska and the Baltimore Canyon generally confirm the downward trend. Since undiscovered resources, to the extent that they exist, must be found and developed before they can contribute to U.S. oil supply, their potential contribution lies in the longer term, and most forecasts assume that by 1990, 25 percent of U.S. oil production will have to come from reserves not yet discovered. Since 1970, 10.8 billion bbl of oil have been discovered in new fields, but if Prudhoe Bay is excluded only 1.0 billion bbl of this category of discovery have been added to reserves in the entire **1970-7?** period. If undiscovered resources are to contribute significantly to U.S. oil supply, the finding rate will have to increase.

Unconventional domestic oil and gas sources

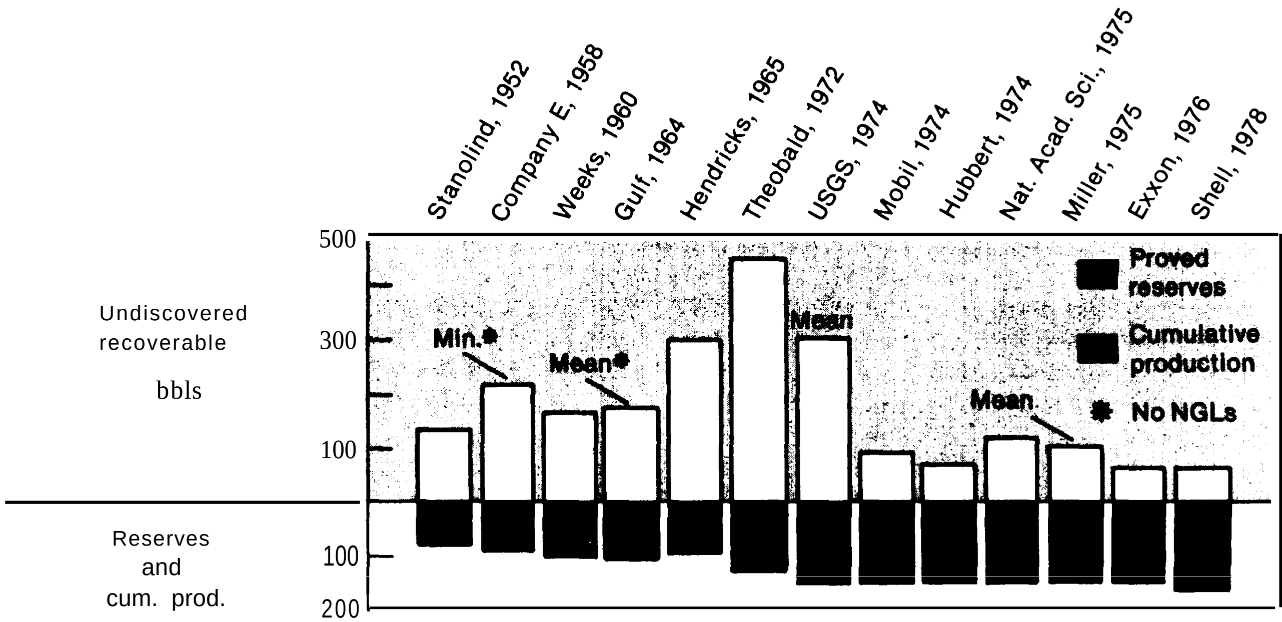
In addition to conventional supplies, oil and gas may be available from other sources including unconventional gas, synthetic fuels from coal, and oil shale. This section evaluates these potential sources.

UNCONVENTIONAL GAS

In addition to conventional natural gas, significant quantities of methane are found in Devonian shales of the Appalachian Basin, low-permeability formations in the Western and Northwestern United States, coal seams in the Eastern and Western United States, and geopressured aquifers located primarily near the coast of Louisiana and Texas. Although gas is known to be present in each of these locations, its extent and commercial recoverability are uncertain. Nevertheless, for the purposes of this analysis, the projections by Lewin and Associates presented in figure 5 are representative of a reasonable range of expectations. The contributions of individual resource categories appear in table 11, based on varying technology and price assumptions. The President's 1979 energy message suggests that 1990 unconventional gas production could be between 1 and 2 Tcf/yr.

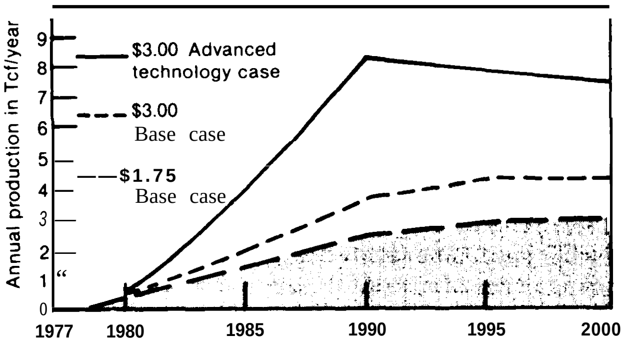
Devonian shales are low-permeability, sedimentary rocks present throughout an area of 210,000 square miles stretching from New York to Alabama. The low permeability of the shale restricts gas production to very slow rates, albeit for long periods of time, and requires artificial stimulation to enhance recovery. Thus, while the total resource base is large, the recov-

Figure 4.—Comparative Estimates of Undiscovered Recoverable Resources of Crude Oil and Natural Gas Liquids (NGLs) in the United States as of Date of Estimate



SOURCE: Charles Masters, "Recent Estimates of U.S. Oil and Gas Resource Potential," U.S. Geological Survey, Open File Report 79-236, 1976.

Figure 5. —Annual Production From Unconventional Sources to the Year 2000 at $1.75 and $3.00/Mcf (except geopressured aquifers)



SOURCE. Lewin and Associates, *Enhanced Recovery of Unconventional Gas,* February 1978

erable resource may be no more than 1 to 10 percent of the gas-in-place. Estimates of recoverable resources range from 3 to 285 Tcf, and studies by OTA[1] and Lewin and Associates[2] agree that production is unlikely to reach 1 Tcf in the next 20 years.

Natural gas is also present in tight basins of low-permeability sandstone, siltstone, and chalk formations located primarily in the Western United States, the northern Great Plains, and parts of Texas and Louisiana. Although the gas in these formations cannot be recovered economically using conventional technology, it may contribute about 1 Tcf to U.S. annual gas production already and appears to hold the greatest near-term potential for contributing significantly to U.S. gas supply, depending on progress in resource characterization, stimulation technology, and higher gas prices. Estimates of total gas-in-place for tight basins range from 400 to 1,200 Tcf. In some places, recoverability may approach 70 to 80 percent, but in most, recoverability will be in the 40- to 50-percent range. At $3.00 (1977) per Mcf, production could reach 7 to 8 Tcf/yr in the 1990's given technological advances from Federal and industry R&D efforts.

Methane in coal mines constitutes a major safety hazard, and research in the United States

[1]Gas *Potential From Devonian Shales of the Appalachian Basin* (Washington, D.C.: Office of Technology Assessment, November 1977).

[2]Lewin and Associates, *Enhanced Recovery of Unconventional Gas,* October 1978.

Table 1 1.—Annual Production From Unconventional Sources to the Year 2000 at $1.75 and $3.00/Mcf[a] (trillion cubic feet)

	1985			1990			2000		
	$1.75	$3.00	$3.00 Advanced	$1.75	$3.00	$3.00 Advanced	$1.75	$3.00	$3.00 Advanced
Devonian shale	.05	.1	.3	.1	.3	.6	.04	.3	.5
Tight gas	1.2	1.8	3.8	2.2	3.2	7.7	2.7	4.0	7.0
Coalbeds	.02	.02	.02	.04	.05	.05	.05	.07	.08
Geopressured aquifers				(Uncertain)					(l-2?)
Total	1.3	1.9	4.1	2.3	3.6	8.4	2.8	4.4	9.0?

[a]1977 constant dollars.
SOURCE: Data from Lewin and Associates, *Enhanced Recovery of* Unconventional Gas, October 1978.

has concentrated on disposing of the gas. However, several European countries—notably the United Kingdom, Belgium, the Netherlands, and West Germany—have recovered and utilized methane from coal seams as a fuel. In the period 1971-75, 200 bituminous coal mines emitted about 80 Bcf/yr, mostly in the Appalachian region. Further development of methane recovery from minable coal is hampered by difficulties of resource definition, economic uncertainties and high costs, institutional questions involving ownership of the gas, and conflicting economic interests of mine operators and gas producers. In spite of these problems, a small amount of gas, about .05 Tcf/yr, could be produced from mines in the Appalachian Basin by 1990. Recovery of an additional but uncertain small amount of gas may be possible from coalbeds that are too deep or thin to sustain mining.

Geopressured aquifers contain methane dissolved in water trapped at higher than normal pressures in sedimentary deposits underlying a large portion of the northern shorelines of the Gulf of Mexico. Estimates of gas-in-place vary widely reflecting geological uncertainty and inconsistent analytical techniques. Also, the recoverability of natural gas depends on the amount of water that can be produced by wells tapping these reservoirs, and the requirement of high flow rates limits the number of geopressured aquifers that might be suitable for recovery of methane. The economics of natural gas recovery from geopressured aquifers might be improved by the simultaneous exploitation of hydraulic and geothermal energy. However, water production may be limited by declining pressure to about 2 to 5 percent of a reservoir's capacity over a 30-year period. Institutional and environmental constraints on the recoverability of natural gas from geopressured aquifers include: questions of ownership of the gas, possible land subsidence problems, and problems of water disposal. Less than 5 percent of the gas-in-place may be recoverable even assuming favorable reservoir properties and high methane extraction efficiency, and estimates of recoverable resources range from **42** to 1,146 Tcf. Although Lewin and Associates considered the uncertainties too great to forecast production potential, other sources indicate that geopressured aquifers may yield 1 to **2** Tcf/yr of natural gas by 1995-2000, assuming gas prices of $3.00 to $4.50/Mcf (1977 dollars).

SYNTHETIC FUELS FROM COAL

Coal is the Nation's most abundant fossil energy resource, and coal conversion technology is not new. Gas from coal was distributed as town gas in the United States before the advent of an extensive natural gas pipeline network. Coal liquefaction processes are also well-known. Germany produced synthetic oil from coal in the 1930's and South Africa currently produces coal liquids on a limited scale. Nevertheless, coal conversion does not overcome all of the safety and environmental problems associated with conventional coal use and has yet to result in oil or gas that is competitive with alternative sources in terms of price. Further development may improve the efficiency of individual processes and the economics of coal conversion generally, but only in time.

Estimates of potential coal gas production have been repeatedly scaled down. In 1973, the Federal Power Commission (FPC) National Gas Survey estimated 1985 production at 0.7 to 1.9

Tcf. By 1975, FPC announced that the lower end of the range appeared more realistic. Other projections of coal gas production (table 12) agree that coal gasification's most significant contribution to U.S. energy supply will probably be after 1990. Even the realization of these forecasts would require Government incentives, advanced technology, and possibly some relaxation in environmental regulations.

Coal liquefaction is presently thermally inefficient and costly. It also poses the same environmental problems as coal mining and introduces some new ones, The promise of significantly greater efficiencies of future liquefaction technologies may make investors reluctant to apply present technology on a large scale. Given long leadtimes associated with the development of improved technology, high plant costs, and heavy capital investments, the need to scale-up pilot plants to commercial size, greater interest in oil exploration and enhanced recovery on the part of the oil companies, and water availability problems, rapid development of a substantial synthetic fuel industry is not anticipated. AIthough the President's July 1979 energy message suggested that gas and liquids from coal could contribute between 1.0 and 1.5 MMbbl/d to domestic fuel supplies in 1990 at a cost of $38 bbl, recent forecasts, shown in table 13, indicate that production will be significantly less than this amount, at least without massive Government participation.

OIL SHALE

Oil shales are fine-grained sedimentary rocks containing significant quantities of an organic material, which, when heated, yields gas, residual carbon, and a highly viscous liquid oil product. With the addition of hydrogen, shale oil is upgraded to become a synthetic crude feedstock, which can be refined to produce conventional fuels. While oil shale resources are widespread throughout the United States, attention has focused on the extensive and rich deposits in the Green River formation of Colorado, Utah, and Wyoming. Although estimates of shale oil resources recoverable with currently available mining technology and aboveground processing are in terms of billions of barrels, potential large-scale shale oil production will be constrained by environmental considerations, water availability, construction logistics, Federal leasing policies, land title conflicts, leadtimes needed to scale-up and construct commercial plants, and the marginal economics of shale oil vis-a-vis natural crude oil. Estimates of potential shale oil production have been consistently scaled down since 1974 (see table 14).

Table 12.—Projections of Coal Gas Production (trillion cubic feet)

	1985	1990	1995	2000
American Gas Association (1977)	.1	.6	1.8	3.3
Department of the Interior (1975)	.4	N/A	N/A	4.7
Shell Oil Company (1978)	.6-.7	1.4	N/A	N/A
Frost and Sullivan (1976)	.2	.6	N/A	N/A
Congressional Research Service (1978)	N/A	.3-.5	N/A	N/A
EXXON (1978)	.5	.7	N/A	N/A

N/A = Not available
SOURCE Off Ice of Technology Assessment

Table 13.—Potential Syncrude Production From Coal (million of barrels per day)

	1985	1990	1995	2000
DOE	.09	.5	1.5	4.0
Shell	.04	.3	N/A	N/A
NPC	.08-.9	N/A	N/A	N/A
EXXON	—	.1	N/A	N/A

N/A = Not available.
SOURCE: Off Ice of Technology Assessment

Table 14.—Shale Oil Production (thousands of barrels per day)

	1980	1985	1990
Project Independence (1974)	50-100	250-1,000	450-1,600
Synfuels interagency task force	NA	100-830	NA
Shell (1978)	0	40	300
EXXON (1978)	0	0	100
President Carter (July 1979)	NA	NA	400

NA = Not available.
SOURCE Office of Technology Assessment

Canada and Mexico

Pipeline imports from neighboring countries in North America represent another potential source to meet projected demand for gas and oil. Under present Canadian policy, which may change in the future, gas exports to the United States would increase from a present level of 1 Tcf to a peak of 1.8 Tcf before declining to about 0.6 Tcf/yr by 1990, reflecting depletion of reserves and a policy of self-reliance. Mexico could have 0.7 to 1.2 Tcf/yr of gas available for export by that time to make up for reduced supplies from Canada, depending on how attractive sales to the United States are compared to domestic consumption. Prospective oil imports from these two nations will not alter the situation. Mexico could increase petroleum exports as much as 0.5 MMbbl/d by 1990 if markets are found for associated gas, but under official Mexican policy, the United States would receive no more than 60 percent of this amount. Also, Canadian production is not as likely to increase, and given domestic requirements, exports will probably be small in volume, interruptible if Canadian demand requires, and tied to exchange agreements. Selling to the United States at substantially less than competing fuel prices in the world market is not in the interest of either country.

Canada

Throughout the decade of the 1960's and into the early 1970's, Canada was a major energy supplier to the United States. By 1970, the United States was importing 760,000 bbl/d of liquid petroleum from Canada, and in 1978 the United States purchased approximately 1.0 Tcf of Canadian gas,

In the early 1970's however, a deteriorating domestic resource position, higher international oil prices, and concern with the security of foreign oil supplies led Canada to adopt a policy of self-reliance which was reaffirmed by the recent conservative government.

Balanced against the self-reliance policy and arguing in favor of Canadian energy exports are domestic economic and political considerations. Energy resources are concentrated in western Canada, and the provincial governments exercise a great deal of power over their resources. Western provinces, eager to encourage further exploration and development and concerned with controlled domestic prices, favor exports as a means of earning greater revenue. The quid pro quo for lower domestic energy prices is often some level of allowable exports. Finally, given the distances involved in moving western resources to eastern markets, economics often favor exports to closer U.S. markets, since payments for crude imports for eastern Canada are more than offset by earnings on western exports.

Generally, only oil and gas supplies surplus to Canadian needs will be available for export. In assessing Canada's energy potential, one must rely heavily on the projections prepared by Canada's National Energy Board (NEB), which is responsible for forecasting Canadian energy supply and requirements and for recommending export policy for Government approval. Thus, projections from this source have a major impact on the volumes available for sales to the United States quite apart from their technical validity.

Higher Canadian gas prices have led to expanded drilling activity in recent years, and a decline in proved reserves in 1972 and 1973 was followed by increases beginning in 1974. The NEB gas production capability forecast for conventional areas (table 15) is based on established reserves, historic finding rates and reserves-to-production ratios, and estimated leadtimes for the construction of gas delivery systems. While the frontier areas appear promising in terms of gas resources, NEB does not include potential production from them in its forecast of producing capability, since no delivery system has been built or approved to bring frontier gas to market.

NEB has devised three tests all of which must be satisfied if new export licenses are to be granted, in order to protect Canadian requirements. NEB anticipates that gas exports already contracted will be fulfilled, and it recently approved an additional total of 3.75 Tcf of gas for

Table 15.-Canadian Gas Potential
(trillion cubic feet per year)

Year	Producing capability, conventional areas	Total Canadian demand
1980	4.1	1.9
1985	4.6	2.4
1990	3.8	2.6
1995	3.0	2.9
2000	2.3	3.3

SOURCE. Canadian National Energy Board, November 1979.

export to the United States in the period 1980-87. Under the new decision, total exports are expected to reach a peak of about 1.8 Tcf/yr in 1982, declining to about 1.0 Tcf by 1987. After that time, only gas under existing contracts would continue to be delivered, at volumes declining rapidly to 0.6 Tcf/yr in 1990 and zero shortly thereafter, unless new exportable surpluses are identified.

The NEB projections of exportable surplus are conservative in that estimated demand is high and supply is low. Demand is inflated by the inclusion of eastern Canadian markets, while hearings still are underway to determine the economic advisability of expanding the transmission system beyond Montreal. Supply excludes the frontier areas, even though the Alaskan highway gasline and the proposed Dempster lateral could bring Mackenzie Delta-Beaufort Sea gas to market by the mid-1980's. Some Arctic Islands gas might also be available for export to the U.S. east coast if a proposed LNG project is approved.

The price of Canadian gas exports is not tied to the price of any particular oil product, but instead to the cost of alternative fuels in selected U.S. markets and the cost of imported oil in Toronto. A new official price of $4.47/Mcf took effect on February 17, 1980.

Potential Canadian liquid hydrocarbon supply derives from conventional producing areas, oil sands, and frontier areas. The conventional areas include those already producing oil. Proved reserves total about 6 billion bbl, and Alberta and Saskatchewan account for approximately 95 percent of the total. Since 1970, annual production has exceeded yearly additions to reserves. As in the United States, Canadian production potential depends on the existence of additional resources and the rate at which they are found and developed. NEB estimates that 4.9 billion bbl of reserves might be added from enhanced recovery, revisions and extensions of known fields, and new discoveries. Nevertheless, production in conventional producing areas is forecast to decline through 1995.

While the resource potential of heavy oil and oil sands deposits is large, technological and economic considerations will slow development. NEB projects 155,000 bbl/d of oil sands production in 1980, increasing to 255,000 bbl/d in 1985 and 755,0OO bbl/d in 1995. Although representing over 50 percent of prospective Canadian oil supply in 1995, oil sands production will merely offset the decline in production anticipated for conventional producing areas.

The frontier areas—the Mackenzie Delta-Beaufort Sea region, the Arctic Islands, the Labrador Shelf, and the Atlantic Shelf South—are characterized by their distance from markets and harsh environments. The existence of oil resources in these regions and the economic attractiveness of production are both uncertain. Important recent discoveries have involved natural gas more often than oil. Even if large discoveries occur in the next few years, Ieadtimes associated with production in hostile environments are long. Indeed, NEB does not anticipate any production from the frontier regions at least until 1995.

NEB oil demand and base case supply forecasts project imports of 300,000 bbl/d in 1980, 700,000 bbl/d in 1985, and 900,000 bbl/d in 1990 and 1995, assuming no exports. Given the Canadian oil supply/demand situation and the official policy of self-reliance, large volumes of Canadian crude are unlikely to be sold to the United States. Small quantities may be available as further development of indigenous resources requires temporary access to the larger U.S. markets, and considerations of logistics, crude quality, and refining capacity also may argue for some exports to the United States. However, under Government policy, light crude exports are to be phased out completely by 1981, and heavy crude exports are determined quarterly.

Mexico

Estimates of Mexico's resource and production potential are uncertain. Since the 1938 ejection of foreign oil companies and the nationalization of the petroleum industry, Mexican hydrocarbon development has been the sole responsibility of the national oil company, PEMEX, which considers the information necessary for independent resource and production estimates to be proprietary. Moreover, the PEMEX monopoly may constrain petroleum development. While the company has a long operating history and a core of highly skilled personnel, the scale of present developments may strain its manpower and equipment resources. The strength of nationalist sentiment and the petroleum workers' union militate against heavy reliance on foreigners, although some have been hired for work in highly technical areas. Finally, uncertainty as to Mexico's potential relates also to the fact that only 10 percent of Mexico's potential hydrocarbon-bearing areas have been explored.

Domestic and international politics are also important in determining Mexico's production potential and export policy. A domestic concern is that oil revenues should be consistent with Mexico's ability to absorb the added income for balanced economic growth without major social and political dislocations. Mexicans are also convinced that their oil and gas resources are to be exploited for their own benefit and not prematurely exhausted for the benefit of foreigners. Finally, Mexico can avoid increasing dependence on the United States by diversifying its export markets.

On the other hand, transportation costs are lower to the United States than to other markets, especially for gas, and U.S. reliance on Mexican fuels could counter Mexican dependence on the United States as a major purchaser. Also, increased production provides the opportunity to gain international prestige as a major oil exporter and to alleviate pressing internal economic problems and a heavy foreign debt burden. While resources and domestic demand place outer limits on availability of imports from Mexico, political and economic factors will determine the actuality. However, the available evidence suggests that while Mexico may become a major hydrocarbon exporter, that nation alone does not represent an answer to U.S. energy problems.

Mexico's official estimates of proved oil and gas reserves have increased steadily from 5.8 billion bbl oil equivalent at the end of 1974 to 40.2 billion bbl as of January 1979. Depending on assumed associated gas/oil ratios and the fields included in the estimates, this figure could include 26 to 32 billion bbl of oil and 45 to 80 Tcf of gas. In addition, PEMEX estimates 44.6 billion bbl oil equivalent of probable reserves (34.4 billion bbl of liquids and 72,4 Tcf gas) and 200 billion bbl of potential hydrocarbon resources. The resource base appears sufficient to sustain increased levels of production.

Mexican oil production has increased rapidly from 0.5 MMbbl/d in 1973 to over 1.4 MMbbl/d in 1978, and gas production reached 0.9 Tcf in 1978. PEMEX development plans call for oil production of 2.25 MMbbl/d and gas production of 1.5 Tcf/yr by the early 1980's. While official plans do not extend beyond the early 1980's, available forecasts suggest that, on the basis of resources alone, Mexico could continue to increase oil production after that time, but unofficial reports suggest that oil production will be limited to less than 3.8 MMbbl/d.

In a 1978 study,[3] the Congressional Research Service (CRS) developed two cases for potential Mexican oil and gas production. Case I assumed that gas would not be exported and oil production would be constrained by the inability to utilize associated gas. Case II assumed that oil production would not be constrained, and gas would be available for export. In a later study,[4] Lewin and Associates developed three scenarios of Mexico's oil and gas potential. Their base case assumed development of already discovered fields, and alternative cases included assumptions regarding future exploratory success. CRS Case I projects somewhat lower levels of oil production than does the Lewin base case assess-

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3Congressional Research Service, *Mexico's Oil and Gas Policy: An Analysis* (Senate Foreign Relations Committee and Joint Economic Committee, December 1978).

4Lewin and Associates, *The Potential of Mexican Oil and Gas*, May 1979.

ment, reflecting in part a lower resource estimate. However, both studies note that even their lowest cases are likely to strain Mexico's technical and managerial capabilities, and in the light of expected 1979 production estimates of 1.5 MMbbl/d official targets may be missed. Interviews with industry sources also suggest that Mexican oil production is more likely to resemble CRS Case I, with the Lewin base case an upside possibility.

With regard to gas production potential, Lewin's figures are lower, particularly after 1985, reflecting lower associated gas-oil ratios than those used in the CRS study. The high gas-oil ratios of 1,200 to 2,000 cf/bbl prevailing in the Reforma field are not obtained in the fields of Campeche or Chicontepec as CRS assumes, so the Lewin assessment represents a more reasonable range of potential Mexican gas production than the CRS study. However, given the greater likelihood of lower oil production figures than those assumed by Lewin even the base case may prove to be high.

Adding to the uncertainty of export projections are trends in Mexico's domestic energy consumption, in terms of both aggregate level and fuel types, and domestic energy policy still is undefined. For example, the greater use of gas domestically would leave less available for export but might free additional oil for foreign purchasers. Also, oil production may be limited by the ability to export or to utilize associated gas internally.

Based on the preceding analysis of production potential, CRS oil estimates and Lewin gas estimates are assumed to be the most reasonable to derive the potential export 1evels shown in table 16.

The Lewin gas production figures are somewhat overstated, and gas exports to the United States would probably be less than those indicated in the table. Mexico could readily convert enough industries to use gas to absorb 1.5 Tcf annually, thereby precluding gas exports at least in the near term. Presumably, gas could also be exported as LNG, but the return would be quite low, on the order of $0.27/Mcf. Mexico also has some discretion in gas production. The estimates presented above include 0.4 Tcf of production from the Northern, nonassociated gasfields, which could be shut in without constraining oil production. In addition, Mexico might elect to develop oilfields with less or more associated gas depending on domestic needs and export opportunities.

On the other hand, Mexico does have somewhat less than 1 Tcf of gas for export to the United States within a short period of time if the conditions are advantageous. In 1977, six U.S. interstate natural gas companies signed a letter of intent for the purchase of Mexican gas, and a pipeline was to be constructed linking Mexican gasfields with the U.S. gas transmission system in Texas. The entire line from the southern fields to the north was to cost $1 billion and

Table 16.—Mexican Oil and Gas Export Potential

Year	Oil					Gas		
	Production	Domestic demand		Exports		Production	Domestic demand	Exports
	(M Mbbl/d)					(Tcf)		
		1	2	1	2			
1980	2.2	2.2	1.1	1.1	1.5	1.5	.7	.8
1981	2.3	1.1	1.2	1.2	1.1	1.5	.7	.8
1982	2.4	1.1	1.3	1.3	1.1	1.5	.8	.7
1983	2.5	1.2	1.4	1.3	1.2	1.6	.8	.8
1984	2.6	1.2	1.5	1.4	1.1	1.6	.8	.8
1985	2.7	1.2	1.5	1.5	1.2	1.6-1.8	.9	.7-.9
1986	2.8	1.2	1.5	1,6	1.3	1.6-1.9	.9	.7-.9
1987	2.9	1.3	1.6	1.6	1.3	1.7-2.0	1.0	.7-1.0
1988	3.0	1.4	1.8	1.6	1.2	1.7-2.2	1.0	.7-1.2

1 = no gas exports.
2 = with gas exports
SOURCES Congressional Research Service; Lewln and Associates

would have eventually carried 0.7 Tcf/yr to the United States.

The gas deal met domestic opposition in Mexico from the political left and *campesinos*, who resented the land confiscations required to build the pipeline. Moreover, a public debate surrounded the proper rate of exploitation of Mexican hydrocarbon reserves, particularly if the United States was to be the main beneficiary of rapid development.

To secure domestic agreement on gas exports the Mexicans drove a hard bargain, demanding a take-or-pay contract, gas prices tied to distillate fuels delivered in New York harbor ($2.60/Mcf at the time and $3.00/Mcf in May 1979), and the option to lower or halt exports as required by domestic needs. The U.S. Economic Regulatory Administration failed to approve the terms, and the Mexican Government allowed the agreement to lapse.

Intergovernmental negotiations were renewed in 1979 resulting in a limited agreement involving about 0.1 Tcf/yr at $3,625 /Mcf. It now seems that Mexico will make every effort to utilize the gas domestically, and barring a change in political relations, Mexico may be satisfied to free up additional oil for export.

Gas from overseas

Natural gas constitutes 42 percent of the known proven world supply of gaseous and liquid hydrocarbons. While natural gas resources are widely scattered around the globe, the largest proven reserves are in North America and the Persian/Arabian Gulf. The amount of gas that can be dedicated to LNG projects is far less than the total reserves. Most gas, such as that found in Europe, is dedicated to local markets, and other resources are too remote or too small to support a world-scale LNG project. Additional exportable supplies, such as those in Canada and Mexico, are likely to move to consuming markets by pipeline rather than as LNG. Table 17 summarizes, by geographic area, the important LNG export countries and the amount of LNG that might come to the United States from operating, approved, and possible projects.

Algeria is currently the only supplier of LNG to the United States, but as her remaining gas reserves have now been committed to European buyers, additional Algeria-U.S. projects are not likely in the near future. Moreover, the prospect of a higher netback price to the Algerian natural gas wellhead because of the expected

Table 17.—Availability of Foreign LNG to the United States Beginning in the 1980's (trillion cubic feet per year)

	Operating and approved projects	Exportable surplus as of 12/31/78	Possible projects	
Algeria	0.63	8	—	Existing reserves are committed to Europe.
Nigeria	—	33	0-0.59	Europe a strong competitor. Possible political problems.
Southeast Asia	0.2	41	0.15	Japan a strong competitor.
Western Hemisphere	—	19	0.39	Scattered small potential projects. Four are anticipated including the Arctic Island project from Canada.
Persian/Arabian Gulf	—	231 plus	—	Locational disadvantage relative to Europe and Japan. No projects to United States likely before 1990.
U.S.S.R.	–	439	—	No shipments to United States *like/y* before 1990.
Total	0.83		0.54-1.13	

SOURCE: Jensen Associates, Inc

success of the trans-Mediterranean pipeline, combined with the heavy capital costs of LNG and the apparent concern in Algeria with the allocation of large amounts of capital to hydrocarbon development, raise strong doubts about additional LNG trade with the United States before 1990, However, as is the case of Russian gas, if the U.S. Government were to seek Algerian LNG aggressively and provide substantial financing, additional Algerian LNG is a possibility, most likely from new gas discoveries. Russian LNG trade is possible before 1990 but will also require financing and the encouragement of the U.S. Government. Otherwise, imports of Russian LNG before 1990 seem unlikely.

Gas from additional LNG projects in Southeast Asia is expected to flow mostly to Japan, but Australia may sell perhaps 0,15 Tcf/yr to the United States. Nigeria will probably develop one or two large LNG projects, and the resulting supplies are likely to flow either to Europe or to the United States, or both. Anticipated projects in the Western Hemisphere, principally in Trinidad, Colombia, and Chile could bring LNG to the United States, and a Canadian Arctic Island LNG project may be developed. Projects likely to be approved in the next 5 to 7 years could bring an additional 0.54 to 1.13 Tcf/yr to the United States. The higher figure is less probable because Europe will be a strong competitor for Nigerian LNG. It is also possible that Japan will take all of the LNG that Australia has thus far approved for export.

Worldwide natural gas reserves and exportable surpluses

Estimated proved reserves of natural gas as of the end of 1978 amounted to 2)5575 Tcf, constituting 42 percent of the energy content of the world's combined proved reserves of oil and gas. Since the oil embargo of 1973, worldwide additions to proved gas reserves reported by the Oil and *Gas Journal* have amounted to 55 percent of combined oil and gas additions. Growth in gas reserves should continue, since the lack of a market outlet in many cases has relegated gas discoveries to the noncommercial category, and the amount of gas that has been found or indicated probably substantially exceeds the proved reserve figure.

Despite the magnitude of worldwide reserves, the role of gas in international trade is quite small, and worldwide consumption is less than 30 percent of the total of oil and gas combined. In 1978, international oil trade, primarily in tankers, was at a level of 33.8 MMbbl/d while gas trade was only 2.9 MMbbl/d of oil equivalent, of which only about 470,000 bbl/d moved in LNG tankers instead of pipelines. Thus, despite the major worldwide gas reserve base and optimism about gas discoveries, LNG tanker trade represents only 1.4 percent of oil trade.

The reasons for this disparity involve the high cost of gathering and transporting natural gas compared with oil. Oil valuation almost anywhere in the world can be related through quality differentials and transportation costs to the price of the marker crude, Arab Light f.o.b. Ra's at Tannurah. Gas generally competes with other fuels, predominantly oil, so in determining whether natural gas will be sold in any given location, one estimates the equivalent oil value and determines whether it covers distribution, transportation, gathering, and production of natural gas. If the answer is no, as is often the case, the gas will not be marketed. For example, the U.S. Bureau of Mines estimates that in 1976 over 12 percent of world natural gas production was disposed of by flaring.

Determining the outlook for world LNG trade requires looking beyond the gross numbers representing reserves or production to identify those special combinations of large uncommitted gas reservoirs, geographic location, and political stability that will form a basis for a viable project. Viewed in this light, less than one-third of total world gas reserves (less than one-quarter of free-world reserves) appear favorably situated for international trade.

Gas reserves may be either associated/dissolved or not associated with oil. Production of nonassociated gas is discretionary in the sense that the discovery can be shut-in and not developed until the economic climate is appropriate. Associated/dissolved gas is produced along with

[54] **Oil** *and* Gas *Journal,* American Gas Association, Canadian Gas Association, **PEMEX.**

oil. Unless it can be sold or reinfected for EOR or for later withdrawal, it has to be flared. Some associated gas is contained in large gas caps in oilfields where its premature extraction will deplete reservoir pressures and reduce ultimate recovery of the oil. While one usually cannot delay production of dissolved gas, one often cannot practically accelerate the production from associated gas caps. An estimated 28 percent of world gas reserves are associated/dissolved while the remainder are nonassociated.

While the flaring of dissolved gas often focuses attention on the potential availability of "free" gas as a basis for international trade, the costs of gathering and compressing it, together with difficulties of controlling its rate of production, often make it less desirable as a basis for export projects than large, high-pressure, nonassociated gasfields. With the exception of projects in Libya and Abu Dhabi, all LNG projects to date have been based on nonassociated rather than associated gas.

A gasfield's location relative to markets is important, as mentioned earlier, because of the high cost of transportation. Figure 6 shows estimates of world proved gas reserves as of December 1978, subdivided both geographically and by political grouping, including proportions of associated and nonassociated gas. Political categories include the developed world as the Organization for Economic Cooperation and Development (OECD), the Sine-Soviet countries, and the less developed nations subdivided into OPEC and NOPEC (or non-OPEC) groups. In this table, the U.S.S.R. appears in Europe, despite the fact that large portions of its substantial gas reserves are physically located in Asia. Note that the role of OPEC is much less dominant in gas than in oil. Whereas OPEC constitutes 77 percent of total world proved oil reserves and 90 percent of free-world oil reserves, it represents only 38 percent of world gas reserves and 60 percent of free-world gas reserves.

Estimates of gas reserves are much less reliable than those for oil. Where gas has no commercial value, either because it will be flared or because the size of the deposit does not justify marketing it, discoveries have often not been included in the figures. The amount of gas that remains to be discovered from future exploration is also very large. Some recent estimates place the undiscovered gas resource base in the vicinity of 6,500 Tcf of natural gas or roughly 2.5 times present proved reserves.[6]

The development of a new outlet for gas reserves, such as a pipeline or LNG project may generate specific field development or even exploration. Proved reserves can therefore increase rapidly to provide a basis for an export project where present estimates do not suggest such a potential. The figures reported for Trinidad, for example, are significantly lower than those which would be required to justify a world-scale export project of 500 MMcf/d or more. However, there is considerable optimism in Trinidad that additional exploration and development will generate more than enough reserves to support such a project.

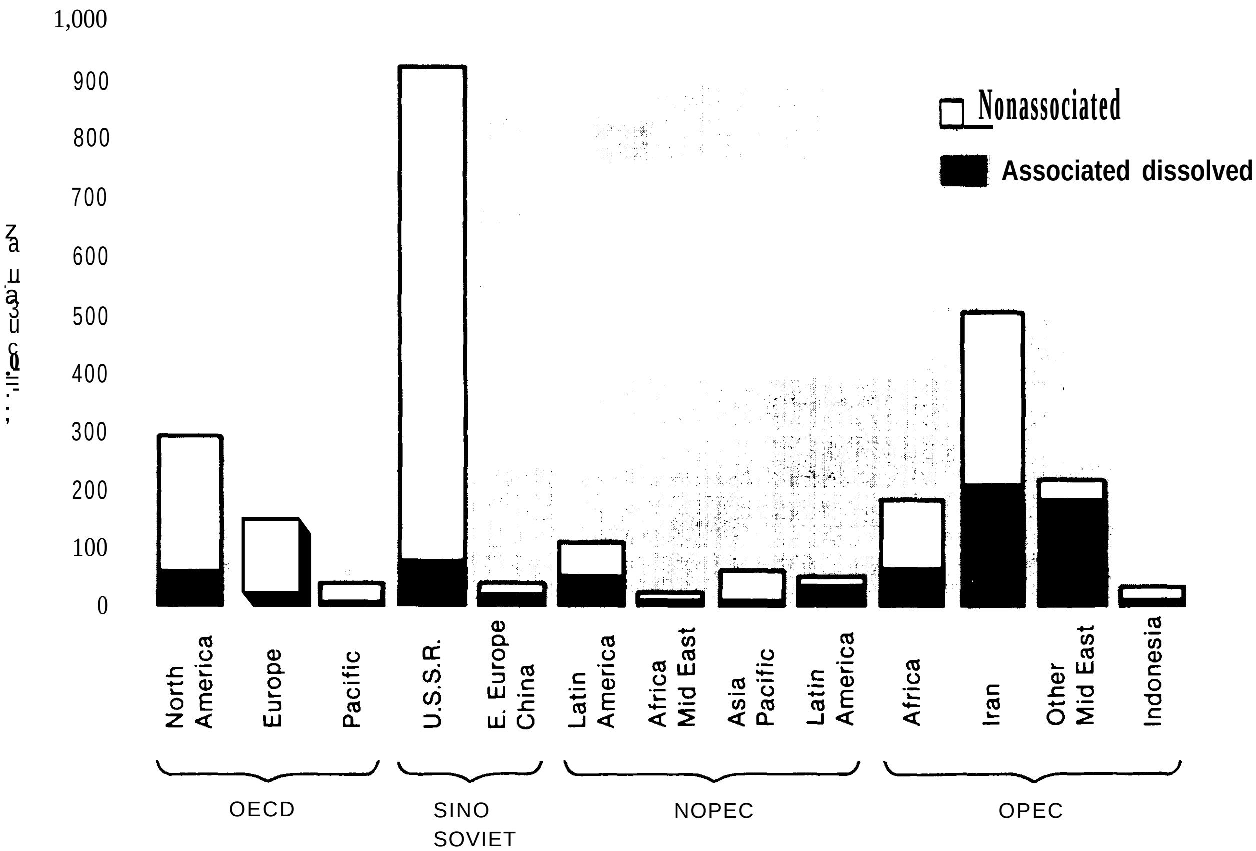
Without local markets, recovery of dissolved gas is difficult to justify, and flaring is likely to continue. Similarly, many small nonassociated fields are too remote to warrant the gathering and transmission expense of moving the gas to market. Thus, a significant portion of reserves might be considered as noncommercial because they are either inaccessible or likely to be flared.

In order to determine the extent to which gas reserves are potentially available to support LNG trade in the future, they have been analyzed country-by-country to determine those potential blocks of reserves that are not presently committed and are large enough to support LNG and pipeline export projects. * The basis of this analysis is the proved reserves figures just mentioned, subdivided into six different categories of commercial status as follows:

1. */accessible or flared:* gas reserves that are too small or remote either to justify recovery of flared gas or full field development of nonassociated gas.
2. *Deferred reserves:* reserves in large gas caps or undergoing gas injection for oil recovery that are unlikely to be committed to markets until future time.

[6]For example, see *Energy Topics, Dec. 5, 1977.*
**For* further discussion, see the *Background Reports* volume of this report.

Figure 6.—World Natural Gas Reserves (trillion cubic feet)



SOURCE Jensen Associates, Inc , based on *Oil and Gas Journal,* American Gas Association, Canadian Petroleum Associatlon, and PEMEX Reserve Estimates

3. *Committed to domestic markets:* gas reserves that either are contracted to domestic markets or set aside to assure that domestic requirements will be met. Without detailed information about many such set-asides, a modified Canadian formula, which provides for 30-year coverage of present domestic consumption has been applied.

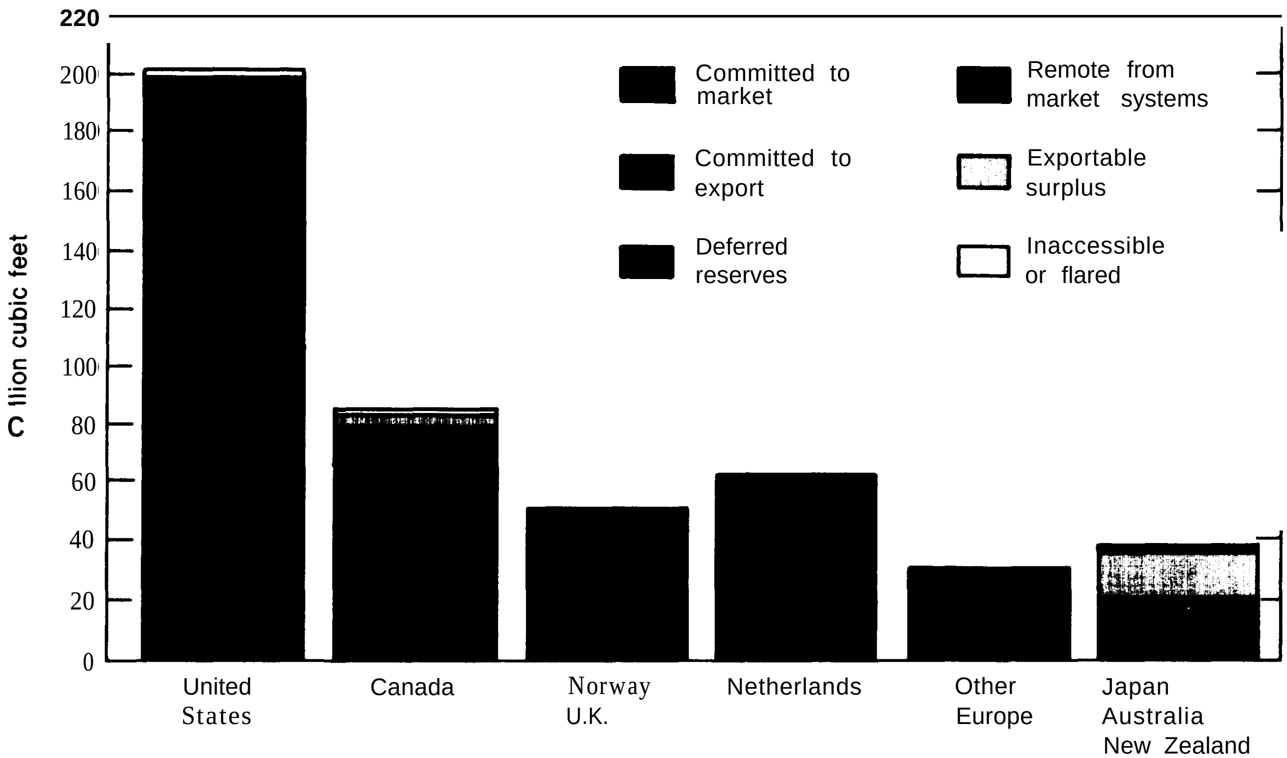
4. *Remote from existing market systems:* gas reserves that are clearly destined for a major industrial market, but whose remoteness from this market raises questions about the feasibility of commercialization. Examples would include North Slope and Arctic Island gas in North America and some North Sea gas reserves in Europe. Some of this gas will prove feasible for commercialization and thus may later belong to the "committed to market" or "exportable surplus" classifications.

5. *Committed to export markets:* gas reserves usually in firm export contracts covering the deliveries over the life of the contract.

6. *Exportable surplus:* blocks of gas reserves that are large enough and well-located enough to support export projects, In a limited number of cases, current national policy suggests that this gas will not be exported and, in other cases, discussions to commit the gas have proceeded to the point where it is no longer available.

Figures 7 through 10 show these market status estimates in somewhat greater detail for the

Figure 7.—Market Status OECD Gas Reserves



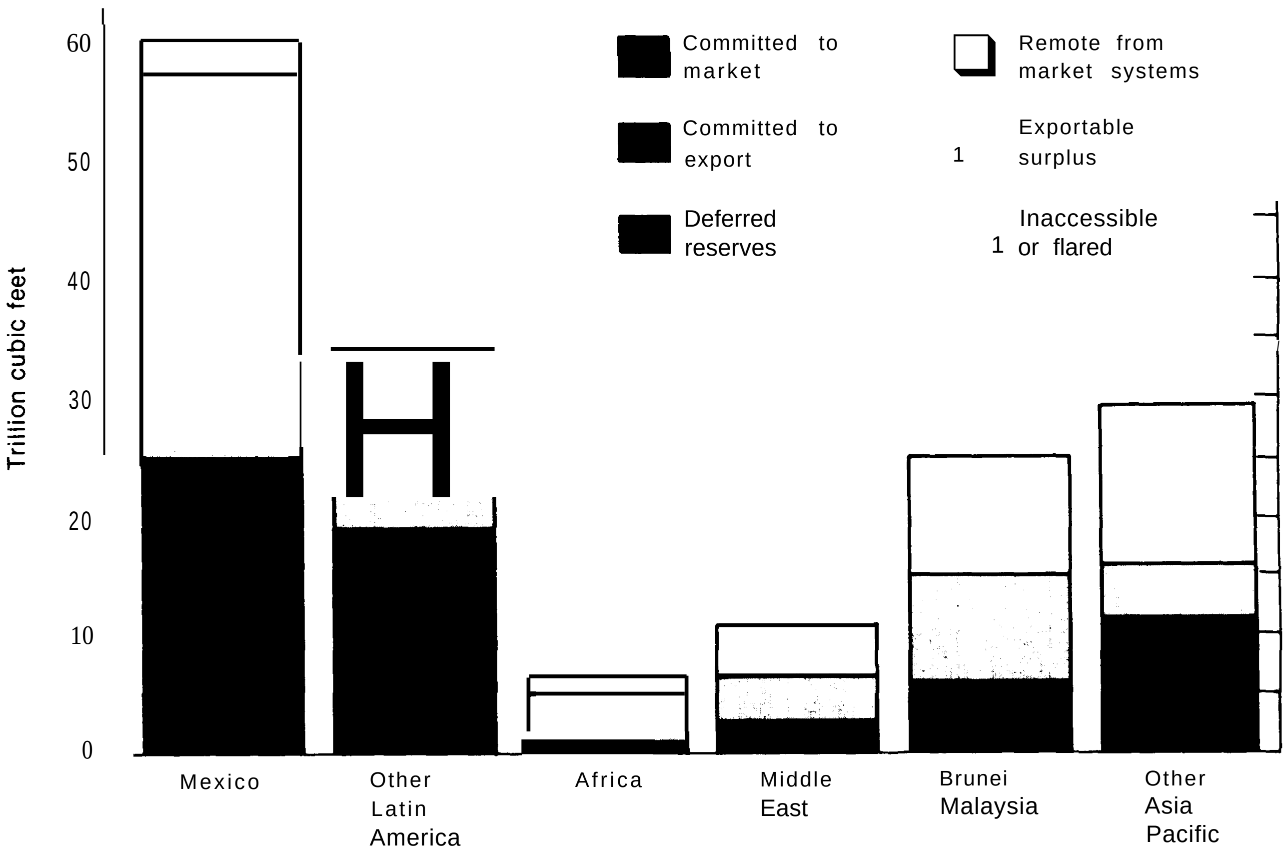
SOURCE: Jensen Associates, Inc.

OECD, NOPEC, OPEC (excluding Iran and Algeria), and for the large gas export areas of the U. S. S. R., Algeria, and Iran. (It is important to note that the scale on each bar chart varies with the relative magnitudes of reserves typical of the group,) An estimated 812 Tcf of world reserves are in the exportable surplus category, representing about 32 percent of the world total. Three-quarters of the exportable surplus is concentrated in the Soviet Union and Iran. The failure of Iran to be able to deliver associated gas to the Soviet Union through the IGAT system during the Iranian revolution and the resulting inability of the Soviet Union to honor some of its export commitments to Europe have focused attention on supply security from these two countries. With Iranian and Russian reserves out of the exportable surplus category, only 7.2 percent of the world proved gas reserves remain. Figure 11 shows where the major exportable volumes are concentrated. About 32 Tcf of reserves worldwide are likely to be exported by pipeline, including the 2 Tcf which NEB in Canada has deemed surplus to Canadian requirements, as well as the 25 Tcf of Mexican gas reserves (consistent with the January 2, 1979, PEMEX gas reserve estimate of 65.1 Tcf proved) which is in excess of Mexican domestic commitments. The U. S. S. R., Iran, and Algeria have all operated or considered both pipeline and LNG export schemes.

U.S.S.R.

Out of the total exportable surplus of 812 Tcf, 635 is located in the U. S. S. R., Iran, and Algeria. The Soviet Union has 35 percent of the world's gas reserves. Although the Soviet reserve estimates are somewhat less conservatively stated than those in much of the rest of the world, including not only proved and probable but some possible resources, they are, nonetheless, impressive in magnitude. Earlier, Russian oil and gas exploration was concentrated in the south near the Black Sea and Caspian Sea. The major

Figure 8.— Market Status NOPEC Gas Reserves

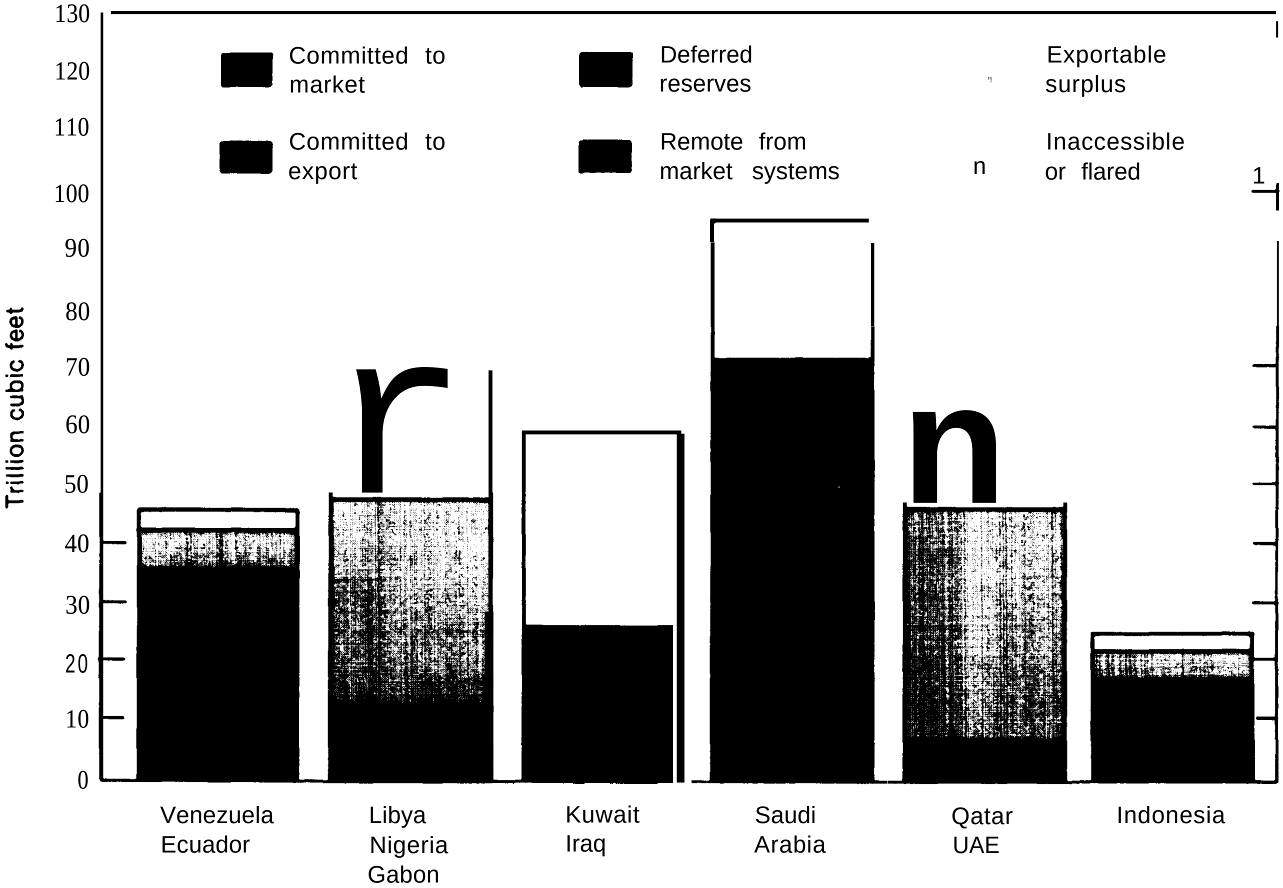


SOURCE Jensen Associates, Inc

gas discoveries of more recent vintage are located in west Siberia, particularly in the giant fields of the Ob Peninsula, such as Urengoy, Yamburg, and Zapolyarnoe. Approximately 75 percent of Russian reserves are concentrated in West Siberia. Areas to the south and west, such as Turkemenistan, Uzbekistan, and the Volga-Urals region, constitute another 20 percent, The rest of the gas is scattered throughout the country in several producing basins.

The Soviet Union currently imports small quantities of gas by pipeline from Afghanistan. It also has been supplementing its more limited southern reserves by importing about 1 billion C/d from Iran through the IGAT- 1 pipeline system, while at the same time delivering 1.45 billion cf/d to West Germany, Italy, and Austria from its northern reserves. While not a formal exchange agreement as IGAT-2 was intended to be, the arrangement has similar effects. Iranian shipments under the IGAT-1 contract ceased during the winter of 1978-79 and have still not returned to contractual levels as of July 1979. Also, the Iranian Government has publicly announced the cancellation of all planning on IGAT-2, which would have delivered an additional 1.65 billion cf/d ultimately to Europe via the Russian exchange route. Since Russian deliveries to Europe were reduced to compensate for the loss of Iranian gas, the question of the future level of European reliance on the very large Soviet gas reserves as well as the reliability of Iran is being reevaluated. While most immediate plans for utilization of Russian gas contemplate pipeline expansions, LNG projects have been discussed both for the U.S. east coast from west Siberia reserves and to the U.S. west coast

Figure 9.—Market Status OPEC Gas Reserves



SOURCE: Jensen Associates, Inc.

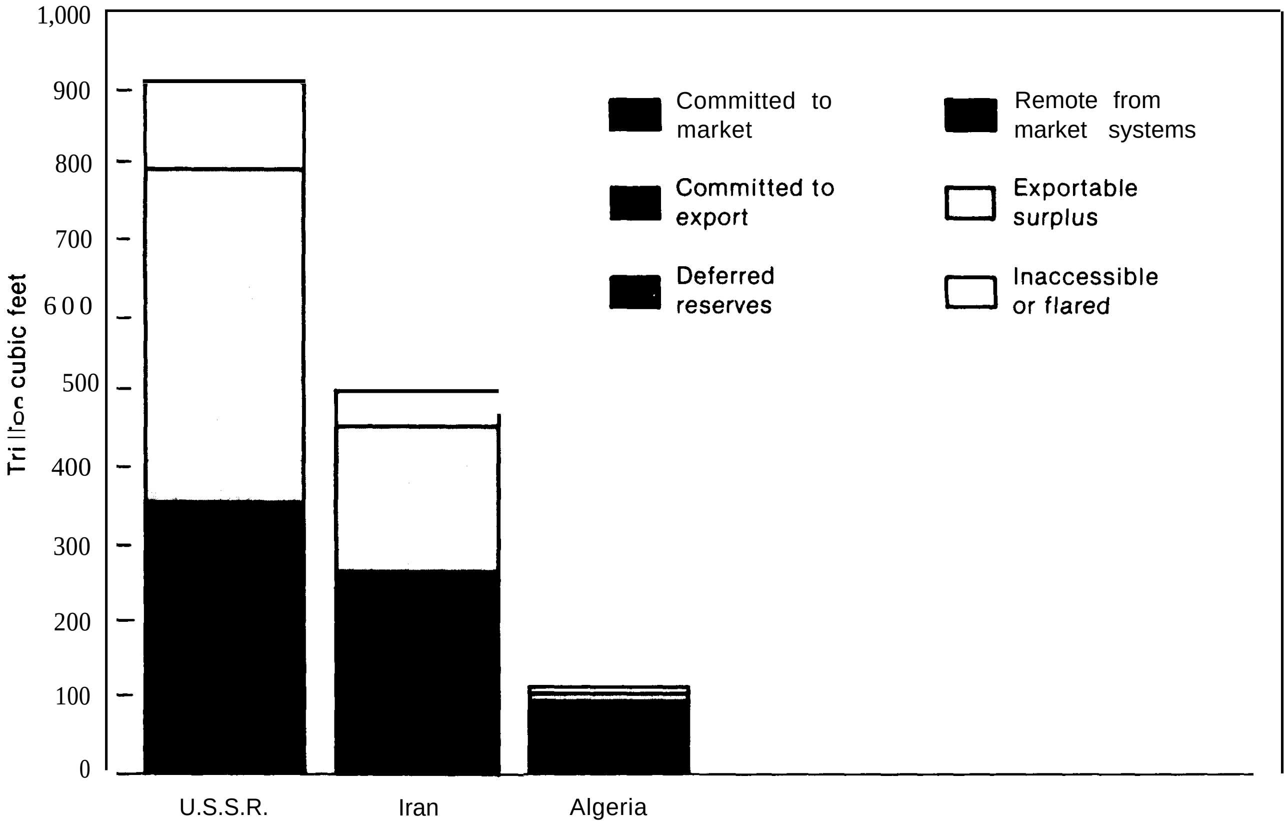
and Japan from the Yakutsk area of eastern Siberia. 'None of these projects appear particularly active at present.

IRAN

Iranian gas reserves are second only to those of the Soviet Union. Approximately 210 Tcf of the 500 Tcf of Iranian gas reserves are associated/dissolved, and a large portion of these are concentrated in the very large gas caps of some of the Khuzestan oilfields. About half of the Iranian gas reserve is contained in very large nonassociated gasfields, both onshore near Kangan and extending out into the central Persian Gulf. Smaller quantities are located near the Straits of Hormuz, around Bandar Abbas, and scattered throughout the country.

Oil recovery in the Khuzestan fields is particularly sensitive to bottom-hole pressure decline. Before the overthrow of the Shah's government, the National Iranian Oil Company was experimenting with a major gas injection program which, if successful, was to be extended to virtually all of the Khuzestan fields. The program, designed to increase oil production, would not only have postponed production from the gas caps but would have reinfected significant quantities of dissolved and nearby nonassociated gas into the oil formations for later recovery. Injecting gas in this way would have deferred production of almost half of the Iranian reserves, so Iran represents the largest single volume in the deferred reserve category worldwide. Iran had also planned to export gas to Europe via the

Figure 10.—Market Status: U. S. S. R., Iran, and Algeria



SOURCE Jensen Associates, Inc.

planned IGAT-2 pipeline and had discussed a large LNG project from the Kangan area to Japan and the United States. The reserves that would have been dedicated to IGAT-2 and the Kangan LNG project would probably have amounted to almost 21 Tcf.

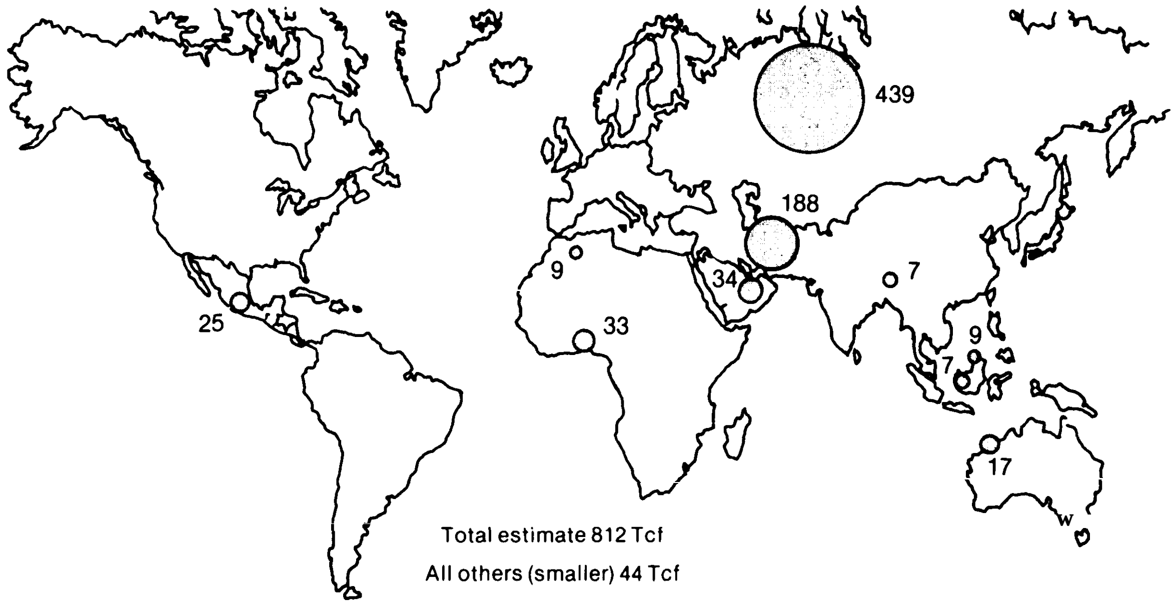
However, the uncertainties surrounding future Iranian gas policy call into question whether any of these projects will come to fruition in the foreseeable future. Both IGAT-2 and the Kangan project are now canceled, and contract commitments under IGAT-1 may not be honored. The future of the major gas injection scheme also is in doubt. Thus, in spite of an estimated 188 Tcf of exportable surplus for Iran, new projects are not likely to be initiated soon.

Had Iran gone ahead with its earlier plans, many of the large gasfields, which are most economically situated to support export, would have been committed to the gas injection program instead. The remaining exportable" reserves, including the very large "E," 'I F," and "G" structures, which are quite far out in the Gulf, together with some of the "C" structure (or Pars gas reserves) both onshore and offshore near Kangan, would have been more expensive to commercialize than some of the onshore gas. However, they might lend themselves well to barge-mounted LNG facilities in the future if Iran is prepared to discuss exports again.

ALGERIA

Algeria was the first country to export I.NG on a commercial scale and has the most extensively developed programs for LNG export. Figures 6 and 10 are based on Algerian proved reserves of 105 Tcf. Approximate}' another 25 Tcf are classed by the Algerians in the "possible" category, and the 25-year master Algerian gas devel-

Figure 11 .—Major Uncommitted Gas Reserves Exportable to World Markets (trillion cubic feet)



SOURCE: Jensen Associates, Inc.

opment program is designed to handle all of the proved plus a portion of the possible resources. The program is designed to be scaled down if possible reserves fail to materialize. Firm commitments for 11 LNG projects and the pipeline across the Mediterranean to Italy account for nearly 60 Tcf. Local markets are expected to take about another 30 Tcf, and a certain amount of oil well gas flaring would leave an estimated 8 Tcf in the exportable category. Most of this surplus has already been virtually committed. This volume includes the provisions for the Algeria 11 and Tenneco St. John's projects, and when these projects were disapproved by the U.S. Government, a scramble in Europe developed to take over these contract commitments. The Italian pipeline and negotiations with several potential European LNG purchasers now appear to have accounted for all of the available volumes, and Algeria is essentially sold out, barring further discoveries in the future. The 8 Tcf of exportable surplus shown in figure 10, though not yet firmly contracted for and approved, is spoken for.

OTHER SOURCES

A remaining 116 Tcf of reserves are located in countries that could be considering world-scale LNG export schemes, projects of a thousand-cubic-feet-per-day export capacity or greater. The map in figure 11 indicates where some of these projects might be located. Qatar has discovered Permian Khuff gas in the Northwest Dome offshore, reported at 34 Tcf. Although it is too early to estimate reserves with any accuracy, the field could range up to 100 Tcf when fully developed. Clearly, this large block of reserves could serve a major LNG trade, although its location well out in the Gulf may make it expensive. The Permian Khuff formation is deeper than the typically oil-productive zones on the Arabian Peninsula. The number of Permian Khuff tests to date has been limited, but geologists have expressed optimism that the formation could provide Saudi Arabia, Kuwait, and the Emirates with large future reserves of nonassociated gas.

Nigeria has been anxious to develop gas markets for its associated gas to reduce the level of flaring. A number of earlier proposed LNG projects have been consolidated into one large export scheme with Phillips as the operator, and discussions are being held with a number of U. S. and European companies about possible markets for the gas. The project, if it materializes, could require approximately 14 Tcf to support the large volume of planned exports. Nigeria also has large reserves of nonassociated gas, which could support further LNG exports, if an initial project with associated gas were successful.

Australia has discovered large volumes of nonassociated gas in the Northwest Shelf region, remote from limited Australian markets, and promoters have attempted to organize projects for both Japan and the U.S. west coast from an exportable surplus on the order of 17 Tcf. Smaller projects have been considered from Malaysia (Sarawak), which would move the gas to adjacent Brunei for export, and from Bangladesh, which could have about 7 Tcf of exportable gas available.

Indonesia has an estimated 7 Tcf remaining of exportable surplus. Indonesian market commitments include both Badak I and the Japanese portion of the Arun project. Badak 11 still requires additional reserve development. The Pac Indonesia portion of the Arun project is included with Badak II in the 7 Tcf of exportable surplus.

Abu Dhabi has discussed a second project for Japan based on the estimated 5 Tcf of onshore gas reserves of Bu Hasa and the Bab Dome (the old Abu Dhabi Petroleum Co. producing area). Also, Bahrain could support a small project with 4.4 Tcf of excess exportable reserves in a deep gas reservoir.

In a number of other areas, the size of the individual discoveries together with commitments to protect local markets, prevent the assembly of enough reserves to support a 500 MMcf/d export project worldwide, approximately 28 Tcf may be concentrated in these small blocks.

Trinidad, which currently falls into this category, has been anxious to utilize gas for local industrial development in fertilizer plants and a steel mill, and to protect its local market with a 40-year reserve coverage. Developing enough gas reserves to support LNG exports has therefore been difficult. Nonetheless, the Government has expressed great optimism that further exploration and development will provide reserves sufficient to support a project of between 600 and 750 MMcf/d.

Although possible U.S. imports from Colombia, Chile, Ecuador, and Venezuela have been mentioned in the past, none of these countries have exportable surplus great enough to support a major project now. Venezuela has retreated from extensive earlier plans for LNG export and now plans to keep all of its gas at home, although the country could export at a level of about 350 MMcf/d. Chilean reserves are small and remotely located in Tierra Del Fuego, at the southern end of South America. Argentinian exploration in the San Sabastian area, also in Tierra Del Fuego, is discovering nonassociated gas in excess of Argentinean requirements, and the possibility of some type of joint venture appears at least technically possible.

Tunisia has discovered offshore Mediterranean gas, which it may provide for LNG export in the future, and exploration offshore in Thailand has resulted in some gas which could conceivably form the basis for a future project to Japan. Libya has gas in excess of current market requirements, which might not justify an expansion of present LNG facilities but might enable Libya to negotiate the extension of contracts with Italy and Spain in the future.

Thus, despite the extent of world gas reserves, the number of countries that could export LNG to the United States is quite limited. Algeria appears to be sold out and is not prepared to make further commitments to the United States in the immediate future. The next most likely alternative sources would appear to be Nigeria and Trinidad. Gas from the Middle East will probably be expensive. Much of the gas in South America is in such small blocks that world-scale projects are not likely without some form of integration.

Competitive importers of LNG—Europe and Japan

International trade in LNG began abroad, from North Africa to Western Europe, in the

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mid-1960's. Japan, too, was importing its first cargos (of American LNG from Alaska) by 1969, about 2 years before deliveries under the first U.S. import contract (by Distrigas in Boston from Algeria) commenced. In 1980, the United States will be importing nearly as much LNG as Europe (approximately 0.5 Tcf/yr) but much less than Japan (0.79 Tcf annually), in spite of the fact that the total American gas market is nearly 3 times as large as Europe's and 30 times as large as Japan's.

Historically, demand for gas imports into Western Europe has developed as a complement to the successive discoveries of large-scale gas reserves there (notably in the Netherlands and the North Sea), and the decline of traditional coal-gas making. In 1977, local output was over 6 Tcf, covering about 90 percent of consumption. But since production from most of the known reserves is now peaking or leveling off, European utilities are actively seeking further imports, both as LNG from Algeria and by pipeline from the U.S.S.R.

Japan has been unable to discover significant reserves of natural gas (or of any other fuel), so it is planning much greater imports of LNG during the 1980's and 1990's, particularly as its nuclear prospects have been revised downwards. Its main imports so far are from Southeast Asia (Brunei, Indonesia, and in the future, from Malaysia), and it will compete strongly for LNG from Australia and possibly New Zealand.

Japan has also begun the only LNG import scheme yet developed from the Middle East (of associated gas in Abu Dhabi). All of the several projects put forward in recent years for LNG exports to Japan from Iran's huge nonassociated gas reserves now appear to have been canceled (along with the European contracts for substantial "indirect imports" of Iranian gas through trades with the U.S.S.R.). Notwithstanding this setback for Middle East gas exports, soaring oil prices may now be approaching the levels at which exports as LNG of associated gas produced with Gulf crude will begin to become commercially viable.

If so, Japan and Europe would again have a transport advantage over the United States, as they each have from Southeast Asia and Africa respectively. In addition, they experience fewer administrative delays in governmental approval of gas import projects. Initially, both regions paid delivered prices for LNG related to local market values for fuel oil. But in Europe, where low-sulfur content had little value, prices were significantly lower than in Japan, where LNG commanded high premiums along with low-sulfur crudes and fuel oils, U.S. premiums for low-sulfur, and hence landed values for LNG, came in-between those in Europe and Japan. So even allowing for higher transport costs, the netback value to Algeria from landed prices under U.S. contracts could be higher than Europe was paying. Since the mid-1970's, however, European buyers appear to have paid Algeria prices representing comparable netback values to those from American contracts.

European and Japanese markets for gas will never compare with the sheer volume of the U..S. market. But for LNG from Africa, Southeast Asia, and the Pacific, and potentially from the Gulf, both regions may offer strong competition to U.S. importers.

WESTERN EUROPE

Natural gas imports into Western Europe have been forecast to rise from their recent annual level of 0.83 Tcf (1977) to around 4 to 5 Tcf by 1990 (see table 18). How much of that gas will be brought in as LNG will depend on the amounts available by pipeline, which are at the moment liable to particular uncertainties (table 19).

In 1977, Western Europe imported about 0.5 Tcf of natural gas annually from the U.S.S.R. That amount represented about one-half of total Soviet gas exports, which account for about 9 percent of total Soviet production. The rest of Russian gas exports go to Eastern Europe, As mentioned earlier, the U.S.S.R. has been importing about 0.3 Tcf annually (1977) of Iranian gas through the IGAT-1 pipeline to the Caspian Sea region.

Implementation of plans to formalize and expand this indirect export of Iranian gas to Europe now seems unlikely. In 1975, a trilateral deal for a second, parallel IGAT-2 pipeline

Table 18.—Natural Gas Supply/Demand Projections for 1985 and 1990, European Economic Community (trillion cubic feet)

	1985			1990		
	Production	Imports from outside Europe	Consumption	Production	Imports from outside Europe	Consumption
EEC	6.12	2.84	9.75	5.25	3.45	10.41
Belgium	—	.23	.50	—	.24	.55
France	.22	.77	1.40	.14	1.20	1.66
Germany	.61	.89	2.61	.53	.87	2.66
Italy	.55	.72	1.47	.42	.97	1.67
Netherlands	2.89	.15	1.47	2.16	.16	1.45
United Kingdom	1.70	— [a]	2.12	1.80	— [a]	2.23

NOTE These import figures exclude imports from Norway, which is within OECD Europe but outside EEC Community governments in fact expect to import some 1 15 tcf from Norway in 1985, and perhaps about 1.40 tcf by 1990 (though that would imply higher gas exports than Norway is yet counting on to make by then) Also, for particular EEC countries, the import figures also exclude intra- EEC trade in natural gas, essentially Dutch exports to Belgium, France, Germany, and Italy

[a]United Kingdom projections do not include Imports from Algerla under its orlglnal LNG contract, which may be renewed

SOURCE. Jensen Associates, Inc , from EEC member governments estimates, 1978 (made before Iran announced to cancel IGAT-2 plpellne exports)

Table 19.—LNG and Pipeline Gas Import Projects to OECD Europe (trillion cubic feet per year)

	Startup	Form of import	Contracted delivery volumes	Notes
Operational				
Algeria-United Kingdom	1964	LNG	.04	Due to end 1979: renewable?
Algeria-France	1965	LNG	.02	
U.S.S.R.-Austria	1968/80	Pipeline	.09	
Libya-Italy	1969	LNG	.11	
Libya-Spain	1971	LNG	.04	
Algeria-France	1972	LNG	.14	
Algeria-Spain	1974	LNG	.18	
U.S.S.R.-Germany	1974/78	Pipeline	.36	
U.S.S.R.-Italy	1974/78	Pipeline	.27	
U.S.S.R.-Finland	1974	Pipeline	.11	
U.S.S.R.-France	1976/80	Pipeline	.15	Starting up to 1980
Total			1.51	(.53 LNG) (.98 pipeline)
Possible before 7985				
Algeria-France	1980	LNG	.20	
Algeria-Italy	1981	Pipeline	.45	
Algeria-Belgium	1982	LNG	.20	
Algeria-Germany	1984	LNG	.41	
Algeria-Netherlands	1984	LNG	.15	
Total			1.41	(.96 LNG)
Possible before 1990				
Algeria-Germany	1985	LNG	.15	
Algeria-France	1985	LNG	.18	May be alternatives
Algeria-Spain/France	?	Pipeline	.54	
Iran/U.S.S.R.-Germany	?	Pipeline	.20	Exchanges via U.S.S.R.
Iran/U.S.S.R.-Germany	?	Pipeline	.13	Iran plans to cancel, 1979
Iran/U.S.S.R.-Austria	7	Pipeline	.07	
U.S.S.R.-France	?	LNG	.18	Linked with U. S. S. R.-U.S.A.
Total			**1.45**	
Nigeria-Europe	?	LNG	**up to .59**	Or to U S. A.?

NOTE Projects are also being discussed for Algerian LNG to Sweden, Switzerland, and Yugoslavia

SOURCE Jensen Associates Inc.

would have raised the system capacity to 1.0 Tcf/yr, and would have enabled Russia to export another 0.4 Tcf/yr to Germany, Austria, and France, beginning in the early 1980's. However, the new authorities in Tehran have announced that the contract for deliveries through IGAT-1, halted for a time during the Iranian revolution and since reported to be running below the volumes planned for this period, might not be renewed when it expires in 1985. They also said they would cancel the IGAT-2 line, jeopardizing the exchange supplies onward to Western Europe. The German and French gas utilities involved hope that the original contracts with Iran will finally be honored, perhaps with inevitable delays to the earlier timetable. As an alternative, they might hope to secure extra deliveries from Russia, eventually to restore the whole planned volume, without the Iranian backup. (The Economic Commission for Europe currently reckons that natural gas availability for net export from the U.S.S.R. might reach 1.8 Tcf/yr by 1990.) Russian reserves are ample, but the development of additional reserves, pipeline capacity, and infrastructure would probably strain Soviet engineering resources, even though the investment might be financed from Western Europe.

The uncertainty about further pipeline supplies from the East may increase Europe's demand for LNG supplies from Africa, notably from Nigeria. European utilities have also recently contracted for much of the gas remaining available for export from Algerian reserves so far developed, about 1.4 Tcf/yr by 1985 in added projects over and above the 0.45 Tcf/yr due for Europe by then under earlier contracts. However, 0.44 Tcf/yr of these extra imports are now planned to move from Algeria by pipeline across the Mediterranean to Italy and north into the European gas grid. Another pipeline across the Mediterranean might move up to 0.5 Tcf/yr of Algerian gas to Spain and perhaps from there to France. Recently, however, new gas discoveries onshore in northern Spain and offshore in the south could be sizable in relation to the country's consumption. The resulting addition to Spanish energy may increase the uncertainty of this second European pipeline import project. If the pipeline links to Italy are completed successfully, it may eventually prove more economical to double those up. In any case, tying Algerian supply by one pipeline or two into the European gas network may secure for European customers some continuing advantage in access to additional reserves of uncommitted gas that Algeria may find and develop in the future.

Much of the gas Europe expects to begin importing in the 1980's was originally to be shipped as LNG to the United States. European buyers took advantage of administrative and regulatory delays over American LNG projects to negotiate alternative standby contracts with Algeria's Sonatrach for the same supplies, to take effect if the U.S. purchasers could not meet agreed timetables. Because only three of the U.S. contracts were eventually approved by the regulatory authorities, Algeria has allotted the gas covered by the others to Europe. Algeria reasons, therefore, that all of its planned gas production for export in the 1980's, some 2.6 Tcf/yr, is committed.

Europe appears now to have contracts for some 1.9 Tcf/yr of LNG and pipeline gas from North Africa by 1985, possibly reaching 2.5 Tcf/yr by 1990. It might be able to secure up to 1.4 Tcf/yr from Russia with or without exchanges of Iranian gas, but to meet total import requirements of perhaps 4 to 5 Tcf by 1990, it will still remain interested in further LNG imports during the later 1980's, possibly the 0.59 Tcf that may become available as LNG from Nigeria.

During the 1990's, local production may decline more rapidly, even allowing for North Sea fields not yet discovered. Projections assuming that natural gas will provide 15 percent of total energy requirements, and that growth in OECD Europe's gross domestic product will continue at 3 percent annually (which may be optimistic), call for total LNG imports of perhaps 7 Tcf/yr at the end of the century. In contrast, gas consumption may not grow at all if European production falls sharply, and even to hold consumption level would require increasing imports or rapid development of synthetic natural gas. '(Near-in" sources of LNG for Europe seem hardly able to offer larger volumes by then on a continuing basis, though even heavier import dependence on gas pipelined from Russia may be possible. By that time the only other major potential source of extra gas supplies, as LNG or by pipeline, may be the Middle East for *all* importers.

JAPAN

Relative to its total energy use, gas consumption in Japan is small. In 1977, only 4 percent of Japan's total energy requirements were served by gas, compared with 26 percent in the United States. Japanese consumption is concentrated in residential, commercial, and electric power generation sectors, while in the United States, industry is the largest consumer.

The oil embargo of 1973 and subsequent rapid increase in crude oil prices in world markets increased Japan's attraction to LNG. In 1973, imported petroleum comprised 75 percent of the energy used in Japan, compared with 58 percent of the energy used in OECD Europe and, even though oil imports have increased dramatically since then, only 16 percent of the total energy requirement of the United States. During the 17-year period, from 1960 to 1977, the growth rate of industrial energy consumption in Japan was 8 percent per year, far higher than in the United States and in Europe. The remarkable growth in Japanese industry during this period was fueled largely by imported oil. Because most petroleum flows to Japan from relatively few countries in the Middle East, the Japanese economy and society are heavily dependent, more so than the United States and Europe, on stable oil supplies from that part of the world. But the oil embargo of 1973, the 1979 revolution in Iran, and rapid price increases have caused the Japanese to look for ways to diversify their fuel supplies. Importing LNG is one route they are taking.

A report entitled "Japan's Energy Strategy Toward the Twenty-First Century" states,

> Liquefied gas has many advantages: among others, the volume of natural gas deposits is more comparable to that of petroleum, natural gas is relatively more widely distributed than petroleum, and liquefied gas is a clean energy. Therefore, natural gas is considered as an energy source Japan should actively try to introduce as a petroleum substitute.[7]

To implement these objectives, the report continues,

> In promoting the introduction of LNG, Japan needs to construct liquefied gas plants and LNG carriers, locate receiving terminals and other receiving facilities, prepare a pipeline network, and organize users. These preparatory activities need to be supported through measures such as financial assistance by the national government.[8]

Substantial quantities of nonassociated gas are located outside of the Middle East in Indonesia, Brunei, Malaysia, the U. S. S. R., Australia, and New Zealand. Japan imports LNG from the United States, Indonesia, Abu Dhabi, and Brunei; and projects from other nations including Iran and Qatar are being considered, as shown in table 20.

Table 20.—Japanese LNG Import Projects
(trillion cubic feet per year)

	Startup date	Contracted delivered volumes	Total
Operations			
United States (Alaska)	Nov. 1969	0.05	
Brunei	Dec. 1972	0.26	
Abu Dhabi (Das Island)	May 1977	0.10	
Indonesia (Badak)	Oct. 1977	0.16	
Indonesia (Arun)	Aug. 1978	0.22	
Total operations		0.79	O.G[b]
Possible additions by 1985			
Indonesia (Badak) expansion	1983	0.16	
Malaysia (Sarawak)	1983	0.31	
Indonesia (Arun) expansion	1984-85	0.12	
Australia (NW Shelf)	1984-85	0.17-0.32	
Abu Dhabi (inland)	mid-1980's	0.25	
Qatar	mid-1980's	0.31	
Total additions		1.32-1.47	
Total			2.11-2.26
Possible addition before 1990			
Iran	?	0.13	
U.S.S.R.	?	0.38	
Thailand	?	?	
Bangladesh	?	?	
China	?	?	

[a]At 52 MM Btu/tonne and 1,020 Btu/cf.
bActual receipts year ending Mar 31, 1979

SOURCE Office of Technology Assessment

7 "Report of the Advisory Committee for Energy Conference on Fundamental Issues-March 1979" [Background Information, Ministry of International Trade and Industry BI-33), p.7.

8 Ibid., p. 24.

If all possible projects were to come to fruition by 1985, Japan would have nearly quadrupled its LNG imports and would have exceeded the planned import levels for 1985 as shown in table 21. The Advisory Committee for Energy sets targets for energy development, and the Institute of Energy Economics has forecast imports based on its perception of Japan's ability to absorb LNG. Both the targets and the forecast are exceeded by the volumes represented by existing and possible projects.

Table 21.—Comparison of LNG Import Project Volumes and Planned Import Levels—Japan (trillion cubic feet)

	1985	1990
Operating and possible LNG import projects (table 20)	2.1 1-2.26	
Advisory Committee for Energy?.	1.53	2.24
Institute of Energy Economics.	1.33	1.79

[a]"Japan's Energy Strategy Toward the 21st Century," a report of the Advisory Committee for Energy, Conference on Fundamental Issues. Published by the Ministry of International Trade and Industry, BI-33, March 1979.
[b]"Energy in Japan," report No. 44, March 1979, by The Institute of Energy Economics, Tokyo.

The 1979 OPEC price increases for crude oil, as well as agreements among the leaders of the industrial nations at the 1979 Tokyo summit meeting, heightened Japan's need to reduce oil imports from the Middle East. In 1977, Japanese industry consumed oil which would be the equivalent of 8 Tcf of gas. If industry would switch to LNG, considerably more could be imported. But historically, gas has been too expensive for industry, and distribution systems for the regasified LNG would have to be developed, and processes and appliances adapted for natural gas.

A factor which favors industrial use of LNG is that a large segment of Japanese industry is located within a few miles of existing LNG import terminals, and new pipelines to serve large industrial customers could be built quickly. With the financial support of the government for pipelines, expanded terminals, and conversion equipment, Japan could easily accept all the LNG available by 1985, shown in table 20, i.e., 2.1 to 2.4 Tcf. Industry would need only to increase its LNG consumption from .05 Tcf to between 0.8 and 1.0 Tcf. To meet its goals of geographical and political diversity of energy sources, one would expect Japan to give priority to LNG from Southeast Asia.

Foreign LNG potentially available to the United States

LNG must be carried further to the United States from major export points than to either the European or Japanese markets. Table 22 shows the distances between major sources of LNG and ports of northwest Europe, the U.S. east coast, and Japan. Algerian LNG will travel less than half the distance to Europe than to either the U.S. east or gulf coast. The relative advantage of Europe is less for Nigerian LNG, but Europe still has a 800- to 1)800-nautical-mile advantage. Both Japan and Europe are closer to Iran and other Arabian Gulf ports than is the United States, and Japan is far closer than the United States to the gas deposits in Southeast Asia.

Table 22.—Distances Between LNG Liquefaction Ports and Typical Import Locations (nautical miles)

Europe and United States

	Arzew Algeria	Bonny Nigeria	Bushehr Iran via Cape of Good Hope	Bushehr Iran via Suez
Rotterdam.	1,637	4,390	11,222	6,469
Philadelphia.	3,594	5,185	11,906	8,426
Lake Charles, La. .	4,961	6,102	12,479	9,793
Yokohama.			6,624 (east from Arabian Gulf)	

Japan and United States

	Lhakseumawe[a] Sumatra Indonesia
Yokohama.	3,369
Los Angeles	8,347

[a]Lhakseumawe is the liquefication port for the Arun field gas.
SOURCE: Jensen Associates, Inc.

This locational disadvantage influences the availability of LNG to the United States from outside the Western Hemisphere. In order to compete with Europe and Japan by offering the same price at a liquefaction plant, the United States must accept a higher landed price for the LNG because of the increased distance and shipping costs. Table 23 summarizes the possible

Table 23.—Potential Availability of Foreign LNG to the United States Before 1990
(trillion cubic feet per year)

Country	Remarks	Tcf/year
Algeria	Operating and approved projects	0.63
	Additional amounts only from new reserves, if any	?
Nigeria		0.0-0.59
Western Hemisphere		**0.3**
Southeast Asia		**0.35**
Persian/Arabian Gulf	Not likely before late 1980's	?
U.S.S.R.	Not likely before 1990	0.04
Canada (Melville Island)		?
		0.1

SOURCE Jensen Associates, Inc.

supplies of LNG to the United States in light of this limitation, and individual sources are discussed below.

ALGERIA

Algeria has become the world's largest exporter of LNG and seems likely to remain so for the rest of the century. It has perhaps the most elaborately coordinated master plan for optimized joint development of all its petroleum resources—natural gas, crude oil, condensates, and liquid petroleum gas (LPG)—of any producer. Its pricing policies are also the most fully spelled out. It is becoming a significant supplier of LNG to the United States (0.63 Tcf by 1985), but for the present, it has no more gas to offer. The State company, Sonatrach, says it has already committed in long-term contracts the 2.6 Tcf/yr* of exports that it plans to build up by 1985 and maintain until after 2000. Under these contracts, a total of about 60 Tcf would be exported over the period 1976-2004.

In the past, some Algerian authorities have suggested that the country might have an additional 30 Tcf "available for export, " but the Government has given no sign that it wishes to contract for this amount. It is making any further negotiations conditional on the results of exploration, which can only be uncertain and delayed. The effort and investment required to implement present contracts are enormous.

Algeria's Valorization Hydrocarbon Development Plan (VALHYD) aims at

> . . . maintaining a level of gas sales volume as high and as stable as possible during the longest period of time while taking into account gas needs for cycling operation, re-injection in oil-fields, and gas lift.

Covering the period 1976-2005, at a capital cost of $33.4 billion (1976 dollars), the plan provides for national production rising to about 4 Tcf/yr by 1985, and thence to nearly 5 Tcf by 2000, from 130 Tcf of reserves. Of these volumes, a plateau level of about 2.6 Tcf/yr will be exported from about 1985 to about 1998. Exports theoretically return to nil before 2005, because VALHYD does not count any "potential and possible" reserves in known and other basins, nor does it allow for the uprating of reserves in fields recently discovered.

One of the VALHYD objectives is "re-injection of gas, particularly associated gas, whenever this will lead to a better oil reserves recovery. " Moreover, losses in the recovery, gathering, transmission, and processing of gases for export from fields far from coastal terminals, will represent a sizable debit against total gas production, approaching 1 Tcf/yr at the plateau level. Thus, the total gas for disposal under this plan, for home use and export, will be around 4 Tcf/yr. Algeria's own domestic consumption of gas, which was only about 0.35 Tcf in 1977, is expected to treble by 1985, and to reach about 1.5 Tcf/yr around 2005. By that time about 60 percent of the reserves for development under VALHYD may have been used up, unless more of this gas is released for export in the meantime.

After the cancellation of the Tenneco and Algeria 11 projects, the United States will have difficulty obtaining more Algerian LNG. Europe is even more interested in Algerian LNG with the cancellation of the Iranian IGAT-2 contract and a reduction in Russian gas last winter. Further, the Netherlands is refusing to extend long-term contracts, and the amount of gas that Europe

* Some 2.2 Tcf will move as LNG and 0.4 Tcf by pipeline. The pipeline contract across the Mediterranean to Italy (which was at 01)() t ime replaced by an I, NC; plan, then changed hark) does not appear to be included in this 2.6 Tcf yr. The second pipeline project, to move gas to Spain and France, is not included, nor are the American Algeria II and Tenneco projects. All three are classified as depending on the results of further exploration

believes it needs in 1990 exceeds what appears to be available. Although Algeria seeks to diversify its markets and feels over committed to Europe, the United States should expect vigorous competition for the remaining Algerian gas. Even if Algeria proves up additional reserves, Europe will remain competitive, especially if the trans-Mediterranean pipeline is completed.

Since 1975, Sonatrach has sought to obtain a base f.o.b. price of $1.30/MMBtu, calculated to yield a return on investment in gathering and trunk pipelines, liquefaction facilities, and export terminals, plus a commodity value of $0.30 to $0.40 /MMBtu for gas at the wellhead. That f.o.b. price escalates automatically with the prices of competing oil products in the import market concerned, and contracts provide for additional review of the base price every 4 years. The specific price escalation formula in each contract has depended on individual negotiations, and for U.S. contracts, as Sonatrach soon discovered, on their approval by Federal regulatory bodies.

Algeria has recommended a similar pricing formula based on a minimum wellhead commodity value, to other OPEC gas exporters, but it has never recommended uniform OPEC prices for LNG. Its objective for the price of LNG regasified in final markets would be comparability with the cost of incremental alternative fuels, which it recognizes, will depend on the prices that OPEC has the power to set for crude, not on any leverage through LNG supply per se. The Algerian Government has consistently been a "hawk," supporting the highest possible level of basic OPEC prices. Its own low-sulfur crudes enjoy quality and often freight differentials over the OPEC base level, and its sales contracts provide for quarterly adjustment of these differentials.

Algeria participated in the 1973-74 oil embargo against the United States. If the occasion were to arise, it would probably do so again. At the time, its only LNG shipments were to France and the United Kingdom, and those destinations were not embargoed. Interruptions of LNG shipments to the United States (Distrigas in Boston) were ascribed to problems in the liquefaction lines and the contract with Distrigas, which provided only for LNG which was surplus to the United Kingdom and French commitments. Sonatrach argues that producers are as dependent on uninterrupted revenues as purchasers are on secure supplies:

> When a country has earmarked over half' of its largest natural resource for export, entailing the investment of half of its current GNP while raising its debt burden to the limit, there can be little reason for consumer concern over security of supplies. [9]

Although its Government remains committed to revolutionary Arab nationalism, Algeria is also perhaps the most businesslike and sophisticated technically and commercially of the OPEC governments from whom importers can presently hope to buy LNG.

NIGERIA

Although LNG from Nigeria has been discussed for many years without result, negotiations with potential buyers have begun for a new project with Phillips Petroleum as operator. Reserves are ample, and a large project of 0.59 Tcf/yr (1,500 MMcf/d) able to serve more than one receiving terminal is being considered. This LNG is available to U.S. buyers but they will face aggressive competition from Europe, which enjoys a small distance advantage. Politics may intervene, as well. Nigeria is allocating oil to those nations that adhere to its African policies and has recently reduced British Petroleum's (BP) offtake by 100,000 bbl/d. The U.S. Government may not allow energy availability to influence U.S. foreign policy, and U.S. gas buyers and investors will be exposed to clear political perils to an LNG supply. In fact, U.S. antiboycott legislation may make contracting with Nigeria difficult.

Proposals to export Nigerian gas go back as far as the mid-1960's, before the country's civil war, and before the British, then the most likely prospective customer, discovered its own natural gas in the southern North Sea. Nigeria has **large, never** fully measured, known reserves of gas far exceeding likely domestic consumption during the rest of this century, Perhaps two-

[9] M. Belguedj, Director, Gas Exports, Sonat rach, *Petroleum Economist*, December 1978

thirds of the reserves maybe nonassociated, but Nigeria would probably first gather associated gas for export, to avoid the visible waste of flaring. Two parallel proposals were being considered until last winter, when they were amalgamated. The combined scheme would now be owned 70 percent by the Nigerian National Oil Company (since BP, with 10 percent, has been nationalized), and the other 30 percent would be shared among American, Anglo-Dutch, French, and Italian companies.

Nigeria's crude oil is of a high gravity and low-sulfur content now in very strong demand in the United States. The Nigerian Government has always sought to maximize the price differentials that it can secure for this quality, and it is reported recently to have sought higher than the OPEC "official selling prices" from its contractual customers for all except "equity" crude. *

Politically, Nigeria, like most other OPEC members, is committed to an embargo of oil to South Africa. This year, stricter application of that embargo, regarding tankers, first threatened to embroil two of the non-American companies operating there with U.S. laws against compliance with such restrictions, and then, after reports that the United Kingdom might indirectly sell North Sea crude to South Africa, led to the nationalization of BP's Nigerian interests. A further serious political conflict could arise for all companies operating in Nigeria and prospective customers for gas and oil as well, if the United States, the United Kingdom, and other European countries lift economic sanctions against Rhodesia and recognize its newly reconstructed government. Such an action could affect deliveries of Nigerian crude and the tenure of the American and Anglo-Dutch companies producing oil there, including most of those involved in promoting LNC exports. The most important government in Black Africa, a conservative military regime planning to hold elections and hand power over to a civil government, is unlikely to ignore the political attitudes towards African sovereignty that its most important customers for petroleum choose to adopt.

* Equity crude is what Nigeria receives in proportion to the 45 percent that it retains ()! equity ownership in former concessionary opt lolls.

WESTERN HEMISPHERE

LNG from Trinidad, Colombia, and Chile, which could total about 0.3 Tcf/yr, would nor-really flow to the United States, which is much closer than Europe and Japan. The lower shipping costs would give the LNG exporters better prices than they would obtain from the more distant markets.

In addition, a project to ship LNG from the Arctic Islands of Canada to Savannah, Ga., has been suggested. This gas might flow alternatively to the Maritime Provinces in Canada or through pipelines to other Canadian and U.S. markets. Canadian policy about shipping the Arctic Island gas south and supplying gas to eastern Canada has not yet been resolved.

In 1972, Peoples Gas of Chicago contracted with the Standard Oil Company of Indiana (AMOCO) to import LNG from AMOCO's gas finds offshore to the east of Trinidad. However, the Government of Trinidad canceled the project in 1974, because it wanted the gas for internal industrial development, especially for fertilizer and ammonia plants and a steel mill at Point Lisas on the western coast. By 1973, oil production in Trinidad had risen to 159,000 bbl/d from reserves that were thought to amount to 2.2 billion bbl. 10 By the first of 1979, oil reserve estimates had been revised downward to 500 MMbbl. At the 1978 production level of 240,000 bbl/d, the reserves to production ratio had fallen to about 6, and exports are expected to decline. At the same time, gas reserves had increased to an estimated 8 Tcf by January 1979, and two strikes to the north of Trinidad led many observers to think that this figure could be understated. Proved gas reserves now represent more than 21/2 times the energy content of the oil reserves, and LNG exports appear to be the only way in which Trinidad can maintain the income stream from hydrocarbon exports as oil production declines. Existing reservoirs are more than ample to meet the 40 years of internal requirements that Trinidad requires before permitting exports.

Trinidad is not a member of OPEC, and the number of rigs drilling in Trinidad has in-

[10] *Oil and Gas Journal* estimates.

creased steadily over the past few years. While the Government is participating in some new ventures, its take from some production is still in the form of royalty and income tax.

The Government is likely to buy the natural gas from a producer and to maximize the price it receives for the LNG. However, Trinidad will not easily be able to shut down an operating LNG project to force the price up, The revenues would represent a significant part of GNP, which the people, having become accustomed o a rising income, might be unwilling to forgo.

Both Chile and Argentina have discovered oil and gas on the very southern tip of South America, bordering the Straits of Magellan and on the Tierra Del Fuego Islands. Argentina pipelines gas up the length of the country, serving Buenos Aires and towns along the way. Chile is actively developing its oil reserves and producing liquefied petroleum gas to relieve heavy imports at rising prices. For example, in 1977 Chile imported 77 percent of its total petroleum needs. " During the mid-1970's, the nation faced a serious decline in oil production and increased dependence on expensive imported oil, so in 1974, it ended a 50-year Government monopoly in the oil industry by a constitutional reform and invited foreign companies to assist in the exploration and development of oil through service contracts. Resulting new discoveries in the Straits of Magellan have increased production. Although Chile has substantial gas reserves in this region, the Andes Mountains make pipelining to population centers uneconomic.

In the early 1970's, a project to liquefy approximately 0.08 Tcf/yr for delivery to two LNG terminals elsewhere in Chile was proposed but dropped. Another LNG project to California of about the same size is currently being formulated, since receiving terminals on the Chilean coast appear uneconomic. Chile's need for foreign exchange and the absence of markets for the gas would reduce the likelihood of supply interruption once exports began. On the other hand, Chile, which was once considered one of the most stable democracies in Latin America, has undergone political turmoil during the 1970's and is experiencing rising inflation and other economic problems.

At the end of 1978, Colombia had an estimated 750 MMbbl of oil and an equivalent amount (4.8 Tcf) of gas in its hydrocarbon reserves. Until 1976, the Colombian Government kept petroleum prices low. Consumption was high, oil production declined over a 10-year period, and Colombia ceased exporting oil and became a net importer. With financial incentives, exploration improved in 1977.

Natural gas reserves are sufficient for internal use plus 0.05 Tcf/yr of exports. If Colombia wants to sell gas abroad, LNG shipments to the United States are the only possibility. Since not enough gas is available to support an independent project, Colombian LNG would need to share a receiving terminal with gas from some other source.

SOUTHEAST ASIA

Although Pacific nations appear to have more gas than Japanese markets can absorb, Japan has a strong incentive to buy LNG in Southeast Asia to diversify its energy supply geographically and politically. The Japanese have also demonstrated the ability to take action quickly and could utilize all gas from this region as industrial fuel. In addition, the greater distances from Southeast Asia LNG sources to the U.S. west coast allow Japan to offer better prices and other terms. However, the countries of Southeast Asia may prefer to diversify their markets and sell to the United States as well as Japan as long as they suffer no significant economic penalty.

Indonesia, Australia, and Malaysia together have considered LNG exports totaling 1.,1 Tcf/yr, most of which would flow to Japan. The United States could probably obtain 0.35 Tcf/yr, including 0.2 Tcf from the recently approved Pac-Indonesia project.

Indonesia is now supplying Japan with LNG under two projects, and the Pac Indonesia proposal for shipments to the United States has been approved but awaits a west coast terminal. Together, these exports should eventually reach a level of about 0.6 Tcf/yr from the large Arun

" U. S. Department of Energy, Energy Informat ion Agency, *International Petroleum Annual 1977,* June l", 1979.

and Badak gasfields in Sumatra and Kalimantan, remote from Indonesia's main centers of population and energy consumption in Java. Exports have been described as a second-best option:

> If we have the gas in such huge quantities and in such remote locations that there will be no significant domestic uses in the near future, then export may be the more beneficial alternative. 12

In general, however, Indonesia would rather use gas for local development and maximize exports of oil, which fetches much higher f.o.b. prices with less local investment. Moreover, gas reserves, if located close to markets, can be developed for domestic consumption more quickly.

Indonesia is a huge country with by far the largest population in OPEC, and rapidly rising local energy consumption, Its oil production is modest by OPEC standards and can perhaps be maintained around 1.6 to 1.8 MMbbl/d throughout the 1980's. Gas, along with coal, will have to provide a much larger share of domestic energy supply as consumption increases. Exploration may still discover large gasfields far from practicable markets that might offer further LNG possibilities. However, Indonesia is hardly eager to develop gas exports beyond present schemes,

Indonesia maintains closer and more amicable relations with its production-sharing operators, which are mainly American companies, than do most OPEC governments. Its relationships with customers, primarily in Japan, are also close, and Indonesia has never participated in an oil embargo. Political considerations, indeed, appear to influence petroleum operations less there than in most OPEC countries.

Approximately 12.2 Tcf of gas are located about 80 miles off the northwest coast of Australia at 400 to 450 ft. A consortium of Australian and foreign companies is considering whether to proceed with a project, estimated to cost $2.8 billion to $3.3 billion (1977 dollars) to export up to 0.33 Tcf/yr as LNG and to supply the city of Perth by pipeline. Although the Northwest Shelf project is almost certain to be approved by the consortium, its prospects have not always seemed assured. At various times, Australia's opposing political parties have expressed sharply contrasting views generally about the development of natural resources, including Northwest Shelf gas, and particularly about export policy and the participation of foreign companies.

Concerned about the high level of foreign investment in Australia's resources, the Labor governments of 1972 to 1975 introduced several measures to "buy back the farm. " They imposed restrictions on the level of foreign equity in new projects and established a "variable deposit rate" whereby a high proportion of foreign loan capital had to be deposited at zero interest in the Federal Reserve Bank. Even if the participants in the Northwest Shelf venture at that time had met these restrictions, the Labor government opposed the export of gas with a view to tying the reserves into a proposed national pipeline system to supply Sydney and the eastern states.

Following the December 1975 election, a Liberal and National Country Party coalition government removed restrictions on overseas borrowing for projects costing more than $615 million. A target of 50-percent Australian equity in new projects (and 75 percent in uranium developments) was announced, but not strictly applied. In any event, the Northwest Shelf project could virtually meet this target, because the Broken Hill Proprietary Co. purchase of Burmah Oil's interest, in 1976, raised the Australian equity share to about 48 percent.

In the August 1977 budget, the Federal Government announced its approval in principle of the export of LNG and condensate from the Northwest Shelf. In so doing, it acknowledged the consortium's view that gas could not be delivered economically to the eastern states, nor could reserves be developed for the market in Western Australia without LNG exports. The Government's approval covered 6.5 Tcf of gas (53 percent of proven reserves), equivalent to exports of up to 0.33 Tcf/yr for 20 years.

The guiding principle of the Liberal government's gas export policy is that exports will be permitted "subject to satisfactory evidence that

[12] Wijarso, Director-General of Pertamina, IPA convention, Jakarta, May 1977.

every reasonable effort has been made to market the product in Australia. " This principle was confirmed by the Minister for National Development.

Should a Labor government be elected to office in the future, it would be unlikely to reverse the approval of gas exports from the Northwest Shelf. In its last months in office, the 1975 Labor government relaxed or abandoned many of its restrictive policies relating to the development of natural resources. It also conceded that some gas exports may be necessary to make the Northwest Shelf project viable. Nevertheless, some of the tax allowances granted to the project by the Liberal government could be reduced, and the disposition of gas reserves discovered in the future may be restricted.

Export prices for Northwest Shelf LNG will be commercially negotiated within long-term (20-Year), take-or-pay contracts. All but one of the participants have appointed Mitsui/Mitsubishi "seller's helpers" in negotiating contracts with Japanese buyers. However, the participants have also met recently with the U.S. west coast utilities, Pacific Gas & Electric and Southern California Gas Company.

The Northwest Shelf participants are expected to sell their LNG at the price which, when netted back from a particular market, provides the highest value for gas at the wellhead. In the Japanese market, they will probably seek a price for delivered LNG that is equivalent on a heating-value basis to the price of competing fuels, such as low-sulfur fuel oil, LPG, or even LNG from alternative sources. Thus, in order to be competitive, potential U.S. buyers would need to offer a price for LNG equivalent on a netback basis to the Japanese market price.

PERSIAN/ARABIAN GULF

Although the nations in this area possess large reserves of gas, the gulf is farther from all three of the main regional markets for imported gas than Africa or Southeast Asia. Netback values for gas exports from there might in many cases be negative, or at best, miniscule in comparison with the high economic rents that exporters can exact for their oil. Both Europe and Japan are closer than the United States to the Arabian Gulf and thus have a competitive commercial advantage. Abu Dhabi currently is exporting LNG, and Iran has canceled proposed projects with the United States and Japan. The only uncommitted gas, other than in Iran, is in Abu Dhabi and Qatar, where the Japanese are discussing LNG purchases. Some gas from additional reserves may be available to the United States eventually, but projects are not likely in the near future.

In June of 1979, the Iranian Government announced that it expected to cancel the second IGAT scheme for pipeline exports of gas to the U. S. S. R., even though a considerable mileage of the large-diameter pipeline involved is reported to have been laid. The immediate direct effect of this indication of the revolutionary government's attitude towards gas exports would be on the Soviet gas system, but indirectly, it would also affect Western markets for gas imports substantially.

As mentioned earlier IGAT-2, feeding up to 1 Tcf/yr into the Russian network by the early 1980's, would have enabled the U.S.S.R. to export 0.4 Tcf/yr to Western Europe and 0.4 Tcf/yr to Czechoslovakia in the mid- to late-1980's. If European countries are deprived of these pipeline imports, they may become even stronger competitors for available supplies of Eastern Hemisphere LNG.

A restrictive policy of the Iranian Government could represent official adoption of an attitude expressed by some of the country's petroleum authorities in the past. They argued that Iran can afford to wait to develop what may ultimately be its more important petroleum resource, gas, until its oil reserves are closer to depletion. Earlier LNG export schemes, for example, were postponed for that reason.

The new Islamic revolutionary government, in any case, appears to look forward to slower depletion rates for oil than in the past. It has cut its oil exports sharply and canceled some of the arms and industrial development projects that drew heavily on foreign exchange earnings. It is even reported to be cutting back on exploration and development drilling in the oilfields. * Initially, denouncing Western-style materialistic ambitions, the Islamic regime appears ready to accept substantial reductions in oil income. The surge of international prices that its cuts in production set off, however, may indeed now provide Iran with higher total oil revenues in current dollars, and perhaps even in real terms, than its larger export volumes in 1978. If so, financial incentives to invest large sums in gas exports will diminish.

The Iranian Government has also announced that it will place extra emphasis on conversion of the country's industrial, commercial, and domestic usage to gas, and it is cutting back nuclear energy plans. These actions will accelerate domestic demand beyond the considerable growth planned already, but local consumption increases can hardly take up more than part of the gas that had been committed earlier to injection in the oilfields. More associated gas may therefore be flared and lost, but nonassociated gas can be left in the ground.

So long as Government policy is against gas exports even by pipeline, LNG projects appear unlikely. Questions about Iranian pricing policy become academic. As to political security, recent months have demonstrated how insecure what once looked like the strongest and most stable governrnent of any gulf exporter really turned out to be. It is too early yet to guess whether and when any settled pattern of commercial and contractual practice in foreign trade under the Islamic regime will emerge.

Elsewhere in the gulf region, the present small-scale Abu Dhabi LNG trade with Japan, when first planned in the early 1970's, appeared likely to yield an exceptionally low netback value for the contracted ().1 Tcf/yr of associated gas. By the time deliveries began in 197'7, prices in Japan had roughly doubled, and though construction costs had inflated too, much of the liquefaction and terminal facilities had been constructed on fixed-price contracts. Thus, Abu Dhabi, in spite of technical problems in its early operations, may achieve an acceptable return on investment, and LNG exports from there may increase. However, the experience hardly offers much commercial precedent for other LNG exports from the gulf.

Qatar has very large reserves of nonassociated gas in the deep Permian Khuff strata which extends, and may also contain gas, underneath the Kuwait oil reservoirs). It has also less opportunity than neighboring gulf exporters to expand oil production, which has remained at around .500, ()()()" bbl/d for some years. If the Government wants to increase petroleum exports, development of this gas offers an alternative opportunity, but whether and when this tiny and rich State will decide to proceed with LNG remains uncertain.

Kuwait has been drilling deep wells to ascertain whether the Khuff strata under its territory, too, contains gas but has reported 110 finds. Any gas found would first severe local consumption, and then exports of' LPGs and natural gas liquids (NGLs). At present, Kuwait limits oil production to 2.2 MMbbl/d and associated gas appears at times insufficient to meet local demand. Also, the LPG/NGLs facilities that Kuwait brought into operation this year were designed to accommodate 3 MMbbl/d of crude production. The Kuwait Government is perhaps the firmest exponent in the gulf of the policy of keeping petroleum in the ground for the benefit of future generations, SO even if it **now** finds new reserves of nonassociated gas, early development of LNG exports is unlikely.

Saudi Arabia is estimated to possess the second largest gas reserves in the gulf, primarily in the associated category. Some nonassociated gasfields have also been discovered there, but none have been developed. However, the country has never shown an interest in exporting any of this gas as LNG. Government spokesmen, on the basis of technical studies, have consistently dismissed both I. NC, and methanol as too costly ways of exporting their abundant energy.

"It ith 101$(11" oil product Ion) less associated gas w ill be produced. The N, ii ional Iranian ( )11 Compaimay ii lso cut back the large-scale plans f ( )1' re-injection of ii ssociated ga s Into some of" t 11(' oil reservoirs in the Khuzestan Province Those plans had been designed 10 maintain reservoir })1'['ss11 resand increase total I'('('()\'('l'}' by stretching out the 1)(' riod during which Iranian capacity (() pro- (111('(' at the ('ill' lier level of ()\'('I' 6MM 1)1)1 (1 per (iii\' could be maintained Abandonment may III('ill) accepting ('ill' Ii('I' declines in a number of Iran Iii n fields a t ter production peaks, as against prolonging the peak product ion ()\ er sev ('I'ill years

Instead, Saudi Arabia is committed to huge investments in gathering most of its associated gas, using the methane and ethane inside the country for petrochemical and other industrial purposes and for domestic fuel supplies, and stripping out the LPGs and NGLs for export. This effort is likely to transform the world market for LPGs by the mid-1980's, and may offer supplementary supplies for the gas utilities of Europe and Japan. Even assuming changes in governmental attitudes, early development of LNG exports is not probable in the light of this major component of the Saudi industrialization program.

No proposals for LNG exports from Iraq have been publicized, either. The limited indications are that this country too, may be adopting a policy, comparable with those of Saudi Arabia and Kuwait, to use the dry gas from its northern oilfields for internal consumption, and to strip out LPGs for export from its southern operations.

Notwithstanding those negative signs, changing oil prices must be shifting the balance of economics for gulf LNG projects. In 1977, Sonatrach of Algeria reckoned that the market price for OPEC crudes, then $12.70/bbl, would need to rise 50 percent in real terms to about $19/bbl, to make the gathering, processing, and export of associated gas in the gulf as commercially worthwhile. The market price applied for most OPEC crudes had reached $20/bbl by mid-1979. Construction costs in the gulf have continued to rise since 1977, and the dollar has fallen, but OPEC crude prices have risen sharply in the past year in real terms and could reach the threshold of economic viability for LNG exports from the gulf well before 1985. *

U.S.S.R.

The U.S.S.R. is a substantial exporter of gas (about 1 Tcf in 1977) from the largest reserve base in the world. Only about half its exports go to Eastern Europe. Exports to the non-Communist world are rising and could possibly be trebled by 1990. So far, all exports have moved by pipeline, but couId be available to the United States as LNG in the future. Two projects have been proposed, but international politics may be more important than commercial feasibility in determining their success. Any export of Russian LNG to the United States is unlikely to start before 1990.

Details of the border prices charged for Russian gas exports to Western European customers are not known. But the delivered prices have had to compete with Dutch gas, and hence with fuel oil values. The U.S.S.R. needs foreign exchange, so in the past its gas exports, moving very long distances, must have returned relatively low-commodity values at the wellhead. From now on, as Dutch supplies decline, and the prices of competing oil products rise, the U.S.S.R. can raise its tariffs. It is also seeking financial and possibly technological support from prospective customers for field development and pipeline construction, including pipe to supplement its own production.

Proposals for LNG exports of Siberian gas to the United States and France, or the United States and Japan, have not progressed in recent years. Western Europe may prefer to seek additional supplies by pipeline, with or without the backup of Iranian gas.

Politically, Western exports of gas run the same strategic risks, no more and no less, as imports of other goods from the U.S.S.R. The European community has always monitored the level of energy imports from Eastern Europe and is likely to be vigilant about possible excessive dependence on Russian gas. On the other hand, in the mid-1990's) unless very large-scale LNG exports from the Middle East develop, gas moving from or through Russia may be the only major source of incremental supply to Western Europe and perhaps Japan. However, that the United States would ever develop sufficient imports of LNG from Russia to become significantly dependent on that one source seems hardly conceivable.

* NIP, Ait [aoussine 0! Sonatrach has suggested a steady 1 5-percent rise yearly in OPEC prices, which with 10-percent inflation would mean a 50-1 percent increase in real terms by 1985.