Natural Gas

Natural gas is the fastest growing primary energy source in the IEO2001 forecast. The use of natural gas is projected to nearly double between 1999 and 2020, providing a relatively clean fuel for efficient new gas turbine power plants.

Natural gas is expected to be the fastest growing component of world energy consumption in the *International Energy Outlook 2001* (*IEO2001*) reference case. Gas use is projected to almost double, to 162 trillion cubic feet in 2020 from 84 trillion cubic feet in 1999 (Figure 38). With an average annual growth rate of 3.2 percent, the share of natural gas in total primary energy consumption is projected to grow to 28 percent from 23 percent. The largest increments in gas use are expected in Central and South America and in developing Asia, and the developing countries as a whole are expected to add a larger increment to gas use by 2020 than are the industrialized countries. Among the industrialized countries, the largest increases are expected for North America (mostly the United States) and Western Europe (Figure 39).

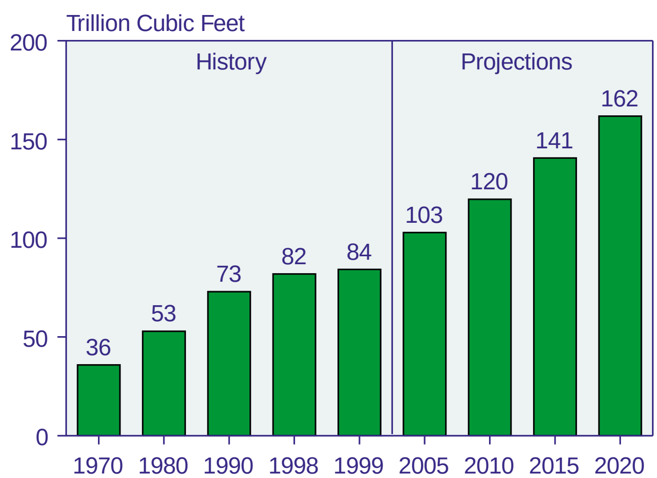
In the *IEO2001* reference case, the world share of gas use for electricity generation is projected to rise to 26 percent in 2020). Natural gas accounts for the largest projected increment in energy use for power generation, at 32 quadrillion British thermal units (Btu) between 1999 and 2020, as compared with an increment of 19 quadrillion Btu projected for coal. As a result, a growing interconnection between the gas and power industries is expected (see box on page 52).

The projections for natural gas consumption in the industrialized countries show more rapid growth and a larger share of the total expected increase in energy consumption than are projected for any other energy fuel. Gas use is projected to grow by 2.4 percent per year in the industrialized countries (compared with 1.1 percent for oil) and to account for 49 percent of the projected increase in their total energy use. Natural gas is projected to provide 25 percent of all the energy used for electricity generation in the industrialized countries in 2020, up from 14 percent in 1999.

The *IEO2001* projections for the developing countries show similar trends for natural gas use, starting from a smaller share of total energy used in 1999 (16 percent for the developing countries, compared with the world average of 23 percent). In the reference case, natural gas consumption is projected to grow more rapidly than the use of any other fuel in the developing countries from 1999 to 2020, by an average 5.2 percent per year, compared with 4.9 percent per year for nuclear energy, 3.7 percent for oil, 3.1 percent for coal, and 2.8 percent for renewable energy (primarily hydropower).

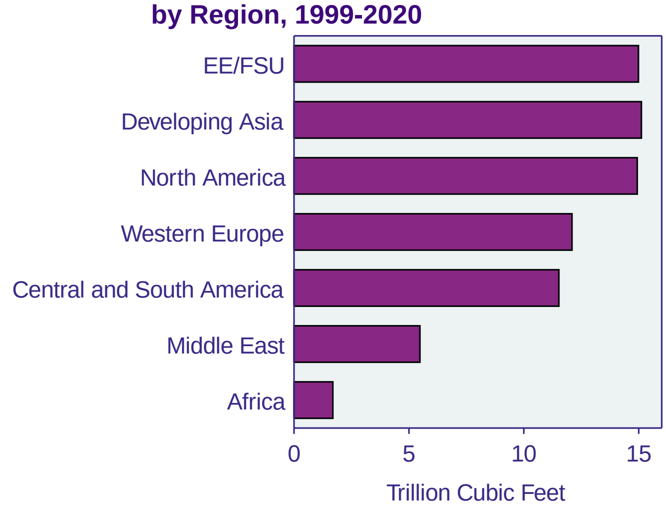
Around the world, gas use is increasing for a variety of reasons, including price, environmental concerns, fuel

Figure 38. World Natural Gas Consumption, 1970-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, January 2001). **Projections:** EIA, World Energy Projection System (2001).

Figure 39. Increases in Natural Gas Consumption by Region, 1999-2020



Sources: **1999:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, January 2001). **2020:** EIA, World Energy Projection System (2001).

diversification and/or energy security issues, market deregulation (for both gas and electricity), and overall economic growth.[6] In many countries, governments hold equity in natural gas companies, and this can be used as a policy instrument. In Asia, examples include Kogas (Korea), Petronas (Malaysia), Pertamina (Indonesia), China National Petroleum Corporation, and Gas Authority of India Ltd. In the Middle East and Africa, examples include Oman LNG, Adgas (subsidiary of Abu Dhabi National Oil Company), National Iranian Oil Company, Sonatrach (Algeria), Nigerian National Petroleum Corporation, Egyptian General Petroleum Company, and Mossgas in South Africa.

Barely 20 percent of the natural gas that the world consumed in 1999 was traded across international borders, as compared with 50 percent the oil consumed. Trade of both fuels grew steadily in the late 1990s, but natural gas is more complex to transport and generally requires larger investments. In addition, many gas resources are located far from demand centers.

Future world gas consumption will require bringing new gas resources to market. Currently, the economics of transporting natural gas to demand centers depends on the market price, and the pricing of natural gas is complicated by the fact that it is much less traded than oil. In Asia and Europe, for example, markets for liquefied natural gas (LNG) are strongly influenced by oil and oil product markets. As the use and trade of gas continue to grow, it is expected that pricing mechanisms for natural gas will continue to evolve, facilitating international trade.

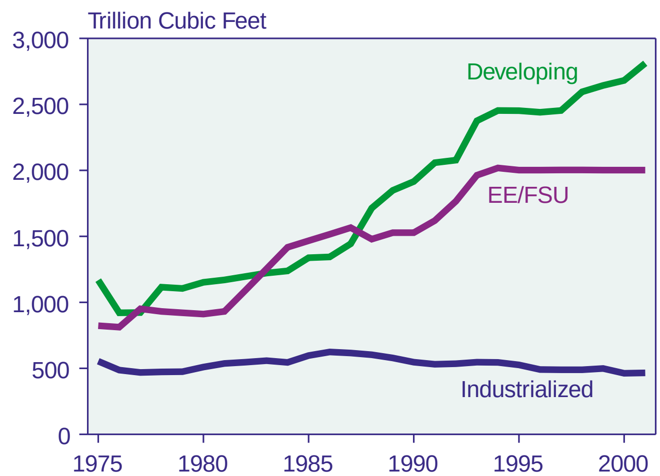
Reserves

Global natural gas reserves doubled over the past 20 years, outpacing growth in oil reserves over the same period. Gas reserve estimates have grown particularly rapidly in the former Soviet Union (FSU) and in developing countries in the Middle East, South and Central America, and the Asia Pacific region (Figure 40). The *Oil & Gas Journal* estimated proven world gas reserves as of January 1, 2001, at 5,278 trillion cubic feet, an increase of 132 trillion cubic feet over the 2000 estimate (see box on page 46).[7]

The largest increases in estimated reserves in 2000 were in the Middle East and in Central and South America. In the Middle East, where reported reserves grew by more than 100 trillion cubic feet, additions were concentrated in Saudi Arabia and Israel. In Central and South America, gas reserves reported by Bolivia grew fourfold, and reserve additions were also reported for Venezuela, Argentina, and Trinidad and Tobago. Other regions reported either very small changes in reserves or no change at all. New reserves in Norway played a large role in the small increase for Europe, and a small increase for developing Asia reflected reserve additions in Papua New Guinea.

World gas reserves are somewhat more widely distributed among regions than are oil reserves. For example, the Middle East holds 65 percent of global oil reserves but only 35 percent of gas reserves (Figure 41). Thus, some regions with limited oil reserves hold significant gas stocks. The FSU accounts for around 6 percent of world oil reserves but roughly 35 percent of proven gas reserves. Most of the gas (32 percent of world reserves) is located in Russia, which has the largest reserves in the world—more than double those in Iran, which has the second largest stocks. In the Middle East, Qatar, Iraq, Saudi Arabia, and the United Arab Emirates also have significant gas reserves (Table 16). Reserve-to-production (R/P) ratios exceed 100 years for the Middle East and are nearly as high for Africa (about 98 years) and the FSU (about 82 years). The R/P ratio for Central and South America is also high (about 66 years), as compared with only 10 years for North America and about 18 years for Europe. For the world as a whole, current average R/P ratios are 61.9 years for natural gas and 41 years for oil [***1***].

Figure 40. World Natural Gas Reserves by Region, 1975-2001

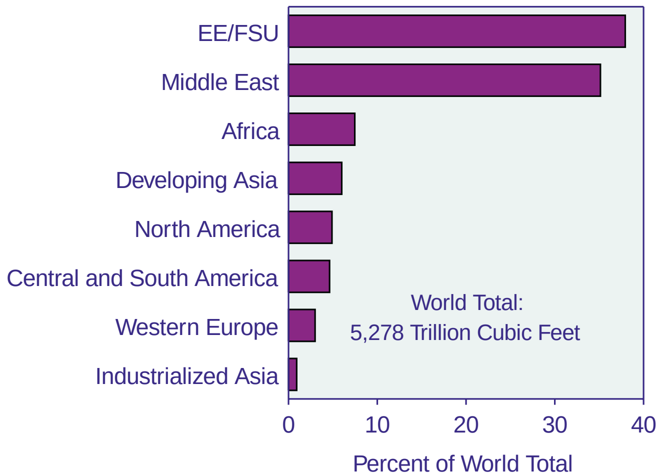


Sources: **1975-1993:** "Worldwide Oil and Gas at a Glance," *International Petroleum Encyclopedia* (Tulsa, OK: PennWell Publishing, various issues). **1994-2001:** *Oil & Gas Journal* (various issues).

[6] In some places, such as Japan, deregulation policies could lead to less gas use; in the United States, deregulation is expected to increase gas use.

[7] Proven reserves, as reported by the *Oil & Gas Journal*, are estimated quantities that can be recovered under present technology and prices. Figures reported for Canada and the former Soviet Union, however, include reserves in the probable category. Natural gas reserves reported by the *Oil & Gas Journal* are compiled from voluntary survey responses and do not always reflect the most recent changes (see box on page 46 for discussion of reserves). Significant gas discoveries made during 2000 are not likely to be reflected in the reported reserves.

Figure 41. World Natural Gas Reserves by Region as of January 1, 2001



Source: "Worldwide Look at Reserves and Production," *Oil & Gas Journal*, Vol. 98, No. 51 (December 18, 2000), pp. 121-124.

Table 16. World Natural Gas Reserves by Country as of January 1, 2001

Country	Reserves (Trillion Cubic Feet)	Percent of World Total
World	**5,278**	**100.0**
Top 20 Countries	**4,678**	**88.6**
Russia	1,700	32.2
Iran	812	15.4
Qatar	394	7.5
Saudi Arabia	213	4.0
United Arab Emirates	212	4.0
United States	167	3.2
Algeria	160	3.0
Venezuela	147	2.8
Nigeria	124	2.3
Iraq	110	2.1
Turkmenistan	101	1.9
Malaysia	82	1.6
Indonesia	72	1.4
Uzbekistan	66	1.3
Kazakhstan	65	1.2
Canada	61	1.2
Netherlands	63	1.2
Kuwait	52	1.0
China	48	0.9
Mexico	30	0.6
Rest of World	**600**	**11.4**

Source: "Worldwide Look at Reserves and Production," *Oil & Gas Journal*, Vol. 98, No. 51 (December 18, 2000), pp. 121-124.

Regional Activity

North America

The countries of North America continue to move toward an integrated natural gas market. Cross-border natural gas pipeline capacity between the United States and its neighbors, Canada and Mexico, is increasing, export/import activity is growing, and prices in the three countries are converging. The most significant additions to cross-border capacity since 1998 have been between the United States and Canada, with the expansion in 1998 of the Northern Border system through Montana into the Midwest (650 million cubic feet per day); the December 2000 opening of the Alliance Pipeline through North Dakota into Chicago (1,325 million cubic feet per day); and the opening of the Maritimes and Northeast system on December 31, 1999 (400 million cubic feet per day). The Northern Border and Alliance projects provide access to Western Canadian natural gas, and the Maritimes and Northeast project transports supplies from Sable Island in the North Atlantic to New England markets. U.S. net imports from Canada in 1999 increased by 8.9 percent over 1998 levels, mainly because of the Northern Border expansion from Iowa to Illinois just south of Chicago.

Pipeline capacity between the United States and Mexico has increased by 70 percent since 1998, from 1,150 billion cubic feet per day to 1,970 billion cubic feet. The increase resulted from three projects: the September 1999 opening of the Tennessee Pipeline near Alamo, Texas (220 million cubic feet per day); the October 2000 opening of the Coral Energy pipeline between Kleburg County and Hidalgo County, Texas, to the border that will serve the state oil company, Pemex, at Arguelles, Mexico (300 million cubic feet per day); and the April 2000 opening of the Rosarito pipeline from San Diego County to Rosarito, Baja California (300 million cubic feet per day). The Tennessee and Coral Energy pipelines are bidirectional. (Although most capacity between the United States and Canada flows into the United States, approximately 75 percent of the capacity between the United States and Mexico is bidirectional.) A number of additional projects have been proposed and may proceed if the trend of increased trade with Mexico continues. Current plans include two El Paso Natural Gas projects, one that will add 130 million cubic feet per day of capacity at the Arizona/Mexico border and the other a project to increase compression on the Samalyuca pipeline, which will add 60 million cubic feet per day at the Texas/Mexico border.

Although North America accounted for 5.0 percent of the world's total natural gas proved reserves at the end of 1999, it accounted for 31.8 percent of the world's total production, most of which was consumed internally. The United States accounted for 23.2 percent of the world's total production, second only to Russia's 23.7 percent. Canada was the world's third largest natural gas producer, accounting for 7.0 percent of the total.

World Natural Gas Resources: A 30-Year USGS Perspective

The U.S. Geological Survey (USGS) periodically assesses the long-term production potential of worldwide petroleum resources (oil, natural gas, and natural gas liquids) resources. The most recent USGS estimates, released in the *World Petroleum Assessment 2000* (*WPA2000*),[a] are the culmination of a 5-year effort based on extensive geologic information from Petroconsultants, Inc.[b] and NRG Associates.[c] Previous analyses by the USGS[d] and the U.S. Minerals Management Service[e] were used for the purpose of including U.S. estimates in the world totals.

The *WPA2000* is the fifth in a series of assessments that began in 1981. Two aspects of the *WPA2000* analysis represent departures from the methodology used in previous assessments. First, the current assessment adopts a 30-year forecast period (1995-2025), whereas earlier USGS assessments assumed an unlimited forecast span. The use of a finite forecast span allows for a more detailed evaluation of petroleum-related activities whose availability during the forecast period is uncertain. For example, certain political (ecologically sensitive areas) or physical (extreme water depths) attributes might preclude some fields from being developed over the next 25 years.

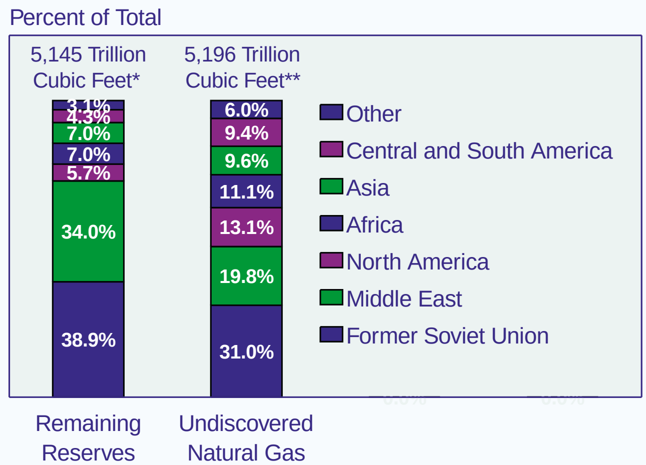
Second, the current assessment segregates future petroleum resources into two categories: undiscovered and reserve growth. Previous USGS assessments defined future petroleum only in terms of ultimately recoverable resources and did not separately address the concept of reserve growth. This concept refers to an increase in estimated field size due mainly to technological factors that enhance a field's recovery rate. As sophisticated technologies become more transferrable worldwide, reserve growth will become an increasingly important component of ultimate resource estimates. The methodologies employed in the *WPA2000* are considered important refinements to those used in previous assessments.

Highlights of the *WPA2000* projection for worldwide natural gas resources include:

- A significant volume of natural gas remains to be discovered. The mean estimate for worldwide undiscovered gas is 5,196 trillion cubic feet, or 886 billion barrels of oil equivalent. This mean estimate is more than double worldwide cumulative production but is less than the sum of remaining reserves and reserve growth estimates. About one-fourth of worldwide undiscovered gas resides in undiscovered oil fields.

- More than half of the mean undiscovered gas estimate is expected to come from the former Soviet Union, the Middle East, and North Africa. An additional 1,169 trillion cubic feet is expected to come from a combination of North, Central, and South America. The figure below shows the regional distribution of existing gas (remaining reserves) and potential gas (undiscovered).

World Natural Gas Resources by Region



*As of January 1, 2000.
**Through 2025.
Source: U.S. Geological Survey, *World Petroleum Assessment 2000*, web site http://greenwood.cr.usgs.gov/energy/WorlEnergy/DDS-60.

- Of the new natural gas resources expected to be added over the next 25 years, reserve growth accounts for 3,660 trillion cubic feet.

- The United States has produced more than 40 percent of its total estimated natural gas endowment and carries less than 10 percent as remaining reserves. Outside the United States, the world has produced less than 10 percent of its total estimated natural gas endowment and carries more than 30 percent as remaining reserves.

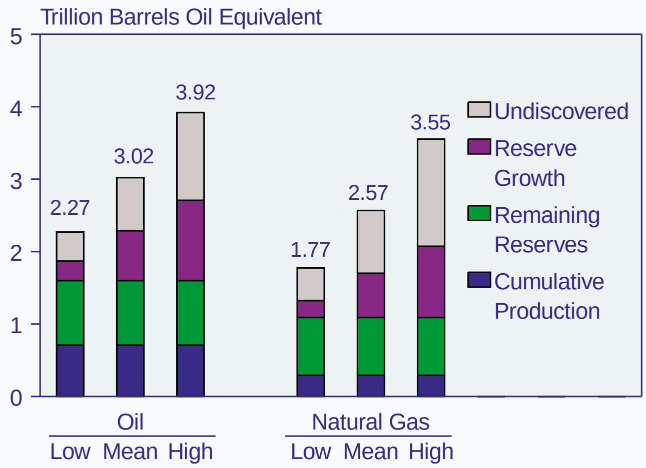
(continued on page 47)

[a]U.S. Geological Survey, *World Petroleum Assessment 2000*, web site http://greenwood.cr.usgs.gov/energy/WorlEnergy/DDS-60.
[b]Petroconsultants, Inc., *Petroleum Exploration and Production Database* (Houston, TX, 1996).
[c]NRG Associates, Inc., *The Significant Oil and Gas Pools of Canada Data Base* (Colorado Springs, CO, 1995).
[d]D.L. Gautier et al., *National Assessment of United States Oil and Gas Resources: Results, Methodology, and Supporting Data,* U.S. Geological Survey Data Series DDS-30, Release 2 (Denver, CO, 2000).
[e]U.S. Department of Interior, Minerals Management Service, *An Assessment of the Undiscovered Hydrocarbon Potential of the Nation's Outer Continental Shelf,* OCS Report MMS 96-0034 (Washington, DC, 1996).

World Natural Gas Resources: A 30-Year USGS Perspective (Continued)

Many energy analysts are more familiar with worldwide statistics for oil than they are with those for natural gas. For comparison, the USGS gas estimates can be expressed in terms of equivalent volumes of conventional oil. The figure below shows world oil and gas estimates out to 2025 in terms of trillion barrels of oil equivalent, including mean estimates as well as high and low estimates to indicate a range of uncertainty for reserve growth and undiscovered resources. Cumulative production and remaining reserves are also included.

World Oil and Gas Resources, 1995-2025



Source: U.S. Geological Survey, *World Petroleum Assessment 2000*, web site http://greenwood.cr.usgs.gov/energy/WorlEnergy/DDS-60.

The following relationships between oil and gas resources are derived from the USGS mean estimates:

- Almost one-quarter of estimated worldwide oil resources have already been produced, compared with only slightly more than 10 percent of worldwide gas resources.
- The amount of oil expected to be either discovered or added to reserves as a result of enhanced recovery is approximately equal to the amount of gas expected to be discovered or added to reserves. For both oil and gas, the bulk of the resource that has yet to be produced resides in fields that have already been discovered.
- On an energy equivalent basis, world oil consumption over the next 25 years is expected to be almost double world consumption of natural gas.
- Whereas the estimates of undiscovered oil volumes in *WPA2000* are 20 percent greater than those in the previous (1994) USGS assessment, the estimates of undiscovered gas volumes are 14 percent smaller as a result of reduced estimates for the former Soviet Union, China, and Canada.

While the analytical rigor and information depth of the *WPA2000* are impressive, it is important to recognize that all long-term assessments are imperfect. The USGS acknowledges that petroleum economics and technological improvements are critical unknowns whose evolution over time will have a profound impact on the world's petroleum resource potential. In addition, the USGS assessments are limited to conventional resources only, excluding trillions of barrels of oil equivalent from the resource base. Estimates of worldwide heavy oil and tar sands exceed 3.2 trillion barrels, with Canada and Venezuela accounting for most of the deposits.[f] The range of estimates for worldwide shale oil resources is staggering, running from a conservative 12 trillion barrels to a considerably more optimistic 2.1 quadrillion barrels.[g] Coalbed methane deposits are estimated to hold more than 1 quadrillion cubic feet of gas, with most of the resource located in the United States, Canada, and China.[h]

The USGS petroleum assessments will continue to provide an important foundation for additional geologic, economic, geopolitical, and environmental studies. With many of the world's economies intrinsically linked to energy resource availability, such studies also provide essential long-term strategic guidance.

[f]About Oil/Gas, *Heavy Oil and Tar Sands–A Present and Future Resource*, on-line version web site http://petroleum.about.com/industry/petroleum/library/weekly/aa032999.html (March 29, 1999).
[g]W. Youngquist, *Shale Oil—The Elusive Energy*, Newsletter No. 98/4 (Golden CO: M. King Hubbert Center for Petroleum Supply Studies, Fourth Quarter 1998).
[h]D.D. Rice, *Coalbed Methane—An Untapped Energy Resource and An Environmental Concern*, U.S. Geological Survey Fact Sheet FS-019-97 (Denver, CO, 1997).

Mexico produced only slightly more gas than it consumed in 1999, whereas Canada produced more than twice as much as it consumed [*2*]. Almost all the excess production in both Canada and Mexico was exported to the United States to fill the widening gap between U.S. production and consumption. U.S. exports to Canada from the United States were negligible, but exports to Mexico—primarily to satisfy demand in areas where Mexico did not have the infrastructure to get its own domestic supplies to market—exceeded imports by 12.5 percent. In 1999, U.S. net imports of natural gas represented 15.8 percent of consumption, and in EIA's *Annual Energy Outlook 2001* (*AEO2001*), imports are projected to make up 16.7 percent of U.S. consumption in 2020.

Canada, which supplied 95 percent of U.S. natural gas imports in 1999, is expected to continue to be the primary source of U.S. imports.

A growing source of U.S. imports is liquefied natural gas (LNG). Four LNG receiving terminals exist in the United States, but two (Cove Point, Maryland, and Elba Island, Georgia) have been mothballed for many years. Higher natural gas prices, reductions in the costs of producing and transporting LNG, and the development of new sources have caused renewed interest in LNG, and there are plans to reopen both the Cove Point and Elba Island facilities by 2002 [***3***]. In conjunction with the reopening, Willams, the owner of the Cove Point facility, has announced plans to add a fifth storage tank to the four existing tanks. When it is open, Cove Point will be the largest of the four U.S. terminals.

Algeria was once the only source of LNG supply for the United States, but Trinidad and Tobago has now become the primary source of supply, with cargos coming also from Qatar, Nigeria, Australia, Oman, and the United Arab Emirates. In addition, spot market sales are now becoming routine. For the first 9 months of 2000, 36 out of 74 cargoes received were spot sales, with long-term contract sales only with Trinidad and Tobago and Algeria.

All indications are that LNG imports will grow in the future. The aggregate existing sustainable capacity of the four U.S. facilities is 840 billion cubic feet per year, and their capacity could be expanded. CMS Trunkline LNG Company, owner of the Lake Charles, Louisiana, facility, is considering expanding the facility to add 110 billion cubic feet per year of deliverability. CMS is currently conducting an open season through February 15, 2001, to assess interest in long-term contracts starting in early 2002, and will base its decision on the outcome. Although LNG is not expected to become a major source of U.S. gas supply, it does play an important role in regional markets, including New England. In the *AEO2001*, gross LNG imports are projected to grow from 90 billion cubic feet in 1998 to 810 billion cubic feet in 2020 [***4***].

Although Mexico has the resource base needed to become a source of increasing future imports for the United States, the country's own consumption is rapidly increasing, and its indigenous production is not expected to increase sufficiently to meet the growing demand. Pemex is anticipating demand growth of approximately 9 percent per year over the next 10 years. To meet rising demand, Pemex is actively promoting the expansion of cross-border capacity to allow increased imports. Over the longer term, Pemex hopes to develop more of its own resources, both to reduce Mexico's dependence on imports and to increase its exports to the United States. It is unclear, however, whether Mexico will be able to increase production significantly, and it is likely that Mexico will remain a net importer of natural gas for the foreseeable future.

The *IEO2001* reference case projects average annual growth in natural gas consumption in North America between 1999 and 2020 of 2.2 percent and annual growth rates of 1.5 percent in Canada, 2.3 percent in the United States, and 2.2 percent in Mexico. The driving force behind the growth in all three countries is the increased consumption of natural gas for electric power generation. In the United States, natural gas consumption for electricity generation (excluding cogenerators) is projected in the *AEO2001* to triple from 3.8 trillion cubic feet in 1999 to 11.3 trillion cubic feet in 2020.

Partly as a result of increasing demand for natural gas with new gas-fired power plants coming on line, and partly due to the decline in drilling that resulted from low natural gas prices over the past few years, natural gas prices rose sharply in 2000 in all of North America, with prices at the U.S. Henry Hub more than quadrupling from those seen just a year earlier. Consumers have seen, and will most likely continue to see, substantial increases in natural gas costs. In California, where insufficient pipeline capacity both at the border and within the State has severely limited the availability of supply to meet rapidly growing demand, border prices that exceed the New York Mercantile Exchange (NYMEX) price more than sixfold have been seen [***5***].

California's electricity transmission has recently been plagued with rolling blackouts in portions of the State (see box on page 126), and electric utilities have been encouraging consumers to limit usage in order to prevent repeat occurrences. The prices have taken their toll on industry both in California and in other parts of the country. There have been cutbacks and closures at aluminum smelting plants in the Pacific Northwest, and the ammonia, urea, and methanol industries are also cutting back. Several manufacturers that have hedged their gas supplies have found that it is more profitable to either shut down or cut back and sell the gas at considerable profit margins. Examples are Terra Nitrogen, which shut down its Arkansas fertilizer plant and cut back its Oklahoma plant, and Mississippi Chemical, which halted fertilizer production. Both companies are selling their natural gas futures contracts. High gas prices have precipitated high electricity prices, causing companies such as Kaiser Aluminum and Chemical to close plants in Mead and Tacoma, Washington and Georgia Pacific to close a paper mill in Bellingham, Washington [***6***].

The high prices that have caused problems for natural gas consumers have also spurred considerable interest and investment in exploration and development. EIA's February 2001 *Short-Term Energy Outlook* projects that domestic natural gas production in 2001 will exceed the

2000 level by about 1 trillion cubic feet (5.4 percent). The U.S. natural gas rig count grew from 371 in April 1999 to 840 as of November 10, 2000. Thus, although wellhead prices are projected to rise from an estimated $3.73 (nominal dollars) per thousand cubic feet in 2000 to $4.95 in 2001, they are expected to retreat in 2002 to $4.52.

Canada

Rig counts in Canada have also grown, and preliminary estimates indicate that more than 7,000 new gas wells were drilled there in 2000. Considerable investment has already been made in expansions of export capacity from Canada to the United States. For example, the 1,875-mile Alliance Pipeline that recently began operation required an investment of $2.5 billion. In addition, the *AEO2001* preliminary estimates indicate that investment on interstate pipeline expansion within the United States in 1999 exceeded $2 billion and that investment in 2000 will reach approximately the same level.

Both the United States and Canada are seeing a revival of interest in an Arctic pipeline, which was considered and subsequently shelved in the 1970s as uneconomical. Combined Alaskan and Canadian proved reserves in the Alaska North Slope, McKenzie Delta, and the Beaufort Sea are approximately 40 trillion cubic feet, with the potential for far more. The Alaska, Yukon, and Northwest Territory governments all support different routes, however, and it is estimated that the earliest completion date for any of the proposed routes would be 2007 [***7***].

High gas prices have also caused industry to be hard hit in Canada and Mexico. The impact has been especially severe in Western Canada—where abundant supplies priced considerably below U.S. levels had long been available—because excess gas production could not be moved to markets in other regions. With recent increases in pipeline capacity to move Western Canadian gas to the United States, the price differential from U.S. gas has narrowed to the point that many consider them to be on a par. Between 1998 and 1999 alone, the differential between NYMEX-based gas prices and the Canadian benchmark AECO-C prices decreased from an average of $1.14 per thousand cubic feet to $0.42 [***8***].

The increase in natural gas prices for many Canadian consumers has been more pronounced than the increase to U.S. consumers. A number of Western Canadian companies, with plants close to sources of natural gas that had been available at prices considerably below U.S. prices before the opening of new pipeline capacity between Canada and the United States, have closed plants and rethought spending plans. Prominent producers of specialty chemicals and fertilizers made from natural gas have been forced to shut plants in Western Canada and increase production at overseas plants where gas is relatively cheap. Methanex Corporation, the world's largest producer of methanol (a natural gas derivative used to make industrial chemicals), mothballed its original plant in British Columbia in July 2000, and Sherritt International Corporation suspended fertilizer production at its Fort Saskatchewan facility in October 2000 [***9***].

Mexico

In Mexico, where the price of natural gas is set by Pemex based on U.S. benchmarks (specifically, Houston ship channel prices plus transport costs to Mexico), industrial consumers are facing similar problems. On September 21, 2000, Mexico's second largest steel manufacturer, Hylsa, announced the partial suspension of operations at three iron mines and their related ore-processing plants, stating that the high gas prices had made them uneconomical [***10***]. Facing additional layoffs, production cutbacks, and possible closings, many industrialists, particularly in the glass, mining, and steel industries in northern Mexico's Monterrey, have been pressuring Pemex to revise the pricing mechanism or provide some other form of relief [***11***]. While Pemex did announce plans to develop resources more aggressively and increase cross-border pipeline capacity, the only immediate relief it has offered major consumers has been a willingness to finance a portion of their natural gas costs.

Mexico's Energy Regulatory Commission (CRE) took steps in August to ameliorate the situation in the longer term by announcing plans to begin a restructuring of the gas industry in order to reduce the effects of price volatility. The initiative, which will allow private investors to participate in the development of transportation, storage, and distribution infrastructure, has resulted in commitments of $2.2 billion to build about 24,000 miles of pipeline [***12***]. On October 4, 2000, the CRE issued a call for a public consultation to solicit proposals on how to open the market to more private sector suppliers [***13***]. Proposals relating to the public consultation were due in November, and they are scheduled to be published in January 2001, followed by an issuance in March of the CRE's proposals based on the suggestions.

The CRE also implemented a month-long program during August 2000 in which industrial customers who could show proof of either having purchased futures contracts or put some other form of hedging instrument in place were offered a 25-percent discount on natural gas prices. Approximately 355 companies, representing 85 percent of Mexico's natural gas consumption, took advantage of the 25-percent discount offer [***14***]. The primary purpose of the offer was to promote the use of hedging instruments, and the CRE president at that time, Hector Olea, initially indicated that it would not be repeated and other subsidies would not be introduced.

In subsequent discussions, Olea did not rule out future subsidies that might be implemented by the incoming Vicente Fox administration after Fox took office on December 1, 2000. Olea, at the end of his 5-year term as chairman, resigned in November. While the incoming administration favors restructuring Mexico's energy markets, Fox may have difficulty implementing any sweeping reform, because his party lacks a majority in Congress.

President Fox would in particular like to encourage an opening of the upstream portion of the market to competition so that Mexico's natural gas resources could be developed at a more rapid pace. The distribution segment of the industry has been opened to private investment since 1995, but Pemex by constitutional mandate still controls exploration and production. Mexico remains the only North American country in which a segment of the natural gas market is directly controlled by the government.

Pemex has announced plans to develop gas reserves in a number of areas, including the northern Burgos basin, in an effort to increase gas production and reduce imports to zero by 2004. The Pemex program calls for $12 billion in spending, according to a September 26, 2000, statement by Energy Undersecretary Mauricio Toussaint [***15***]. Heavy industry has still been clamoring for a loosening of Pemex control, however, indicating that the current plans will not develop resources rapidly enough to meet rising demand or to alleviate the current short-term situation. If the government is slow to act, Mexico could be facing serious obstacles to meeting internal demand at acceptable prices.

U.S. President George Bush during his election campaign expressed concern over the future of Mexico's gas market and called for a "hemispheric energy policy where Canada and Mexico and the United States come together." He indicated that he and President Fox had discussed expediting gas exploration in Mexico for transport to the United States [***16***]. In September, a delegation from the Texas Railroad Commission met with CRE members to discuss ways the agencies could cooperate to encourage the construction of more cross-border capacity between South Texas and northern Mexico [***17***].

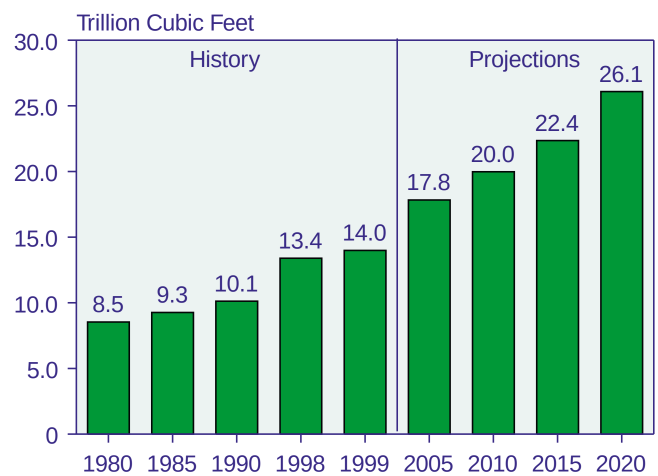
Western Europe

Western Europe's natural gas reserves are limited (less than 5 percent of global resources) and are concentrated along with gas production in the Netherlands, Norway, and the United Kingdom. Nearly one-third of the region's gas demand is met by pipeline imports from the former Soviet Union and Algeria and LNG from North Africa. Recent demand increases reflect rising gas use for power generation as well as in the industrial sector. *IEO2001* projects that the demand for natural gas in Western Europe will grow at an average annual rate of 3.0 percent from 1999 to 2020, reaching 26.1 trillion cubic feet in 2020 (Figure 42).

The year 2000 was important for natural gas in Western Europe because the European Union (EU) had set a deadline of August 10, 2000, for members to have an arrangement in place for third-party access to gas infrastructure (see box on page 52). The European Parliament and Council Directive 98/30/EC of June 22, 1998, set common rules for the EU's internal market in natural gas. By August 10, 2000, all gas-fired power generators and customers using more than 883 million cubic feet of gas per year were to be "eligible" to choose a gas supplier. The EU distinguishes between "eligibility," or the legal right to choose a supplier, and truly competitive markets in which customers have a real choice. Under the directive, further deadlines expand eligibility, first to customers of at least 530 million cubic feet per year by 2003 and then to those using at least 177 million cubic feet per year by 2008. The directive also gives the emerging markets in Portugal and Greece more leeway [***18***].

Not all member countries met the August 10, 2000, deadline because of the many issues and politics of the EU and the gas industry there. Spain and Belgium are partly compliant, with some third-party access to gas infrastructure, and have plans to become completely compliant over the next 10 or so years. The United Kingdom, on the other hand, is already 100 percent compliant with the EU directive. France, Portugal, and Luxembourg were sent warning letters about their failure to comply by the EU Energy Commissioner, Loyola De Palacio, and have also received formal "infringement notice"

Figure 42. Natural Gas Consumption in Western Europe, 1980-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, January 2001). **Projections:** EIA, World Energy Projection System (2001).

from the European Commission, which could lead in theory to legal action by the Court of Justice. The EU has also scrutinized and questioned German compliance, but no formal action has been taken. Germany has struggled with setting fees to exit points in its transportation system, which involves more than 700 operators.

The ultimate impact of the EU directive on creating a "single European gas market" is uncertain, but the EU has not ruled out taking further measures, and EU energy ministers have discussed tougher draft amendments [***19***]. Other catalysts for change in the European gas market may also come from growing trading opportunities (such as via the Interconnector pipeline between the United Kingdom and continental Europe) or from forces of abundant supply.

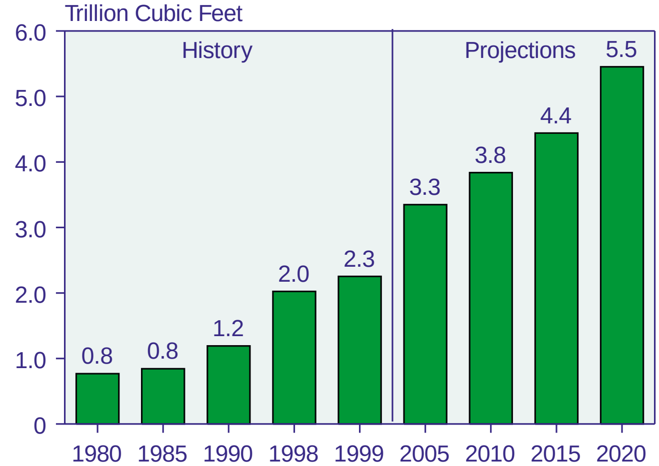
In the *IEO2001* outlook, the projected 3.0-percent annual growth rate for natural gas consumption in Western Europe is not particularly rapid in comparison with other regions. However, excluding five of the largest countries in the region (France, Germany, Italy, the Netherlands, and the United Kingdom), gas use in the other countries of Western Europe is expected to grow by 4.3 percent per year between 1999 and 2020 (Figure 43). Rapid expansion in gas use is readily apparent in Spain, Italy, and Portugal, where there were numerous important gas industry developments during 2000, and the investment plans of some industry players may be accelerated or become more aggressive as governments announce timetables for deregulation [***20***].

In Spain, plans to expand LNG imports continue with two new receiving terminal projects. One terminal is scheduled to begin operations in 2003 in the northern Basque region in the newly expanded port of Bilbao. The project involves the company Bahia de Bizkaia Gas (BBG), owned by BP Amoco, Iberdrola, Repsol YPF, and Ente Vasco de la Energia (the Basque energy authority). Gas imports would initially be delivered to an 800-megawatt power plant in addition to Repsol and the Basque gas distributor (Gas de Euskadi). A turnkey contract for the terminal was awarded in summer 2000 to a consortium led by SN Technigaz [***21***].

Another Spanish LNG terminal project involves Spain's third largest power company, Union Fenosa, which has signed a deal with Egyptian General Petroleum Corporation (EGPC) for LNG supply. Providing Fenosa with its own gas source from 2004, the agreement calls for Fenosa to invest $1 billion in a liquefaction terminal, shipping arrangements, and participation in regasification. The project would help Fenosa compete with Repsol-Gas Natural as a supplier in the newly opening market [***22***].

During the spring of 2000, Union Fenosa and a Spanish subsidiary of U.S. energy company Enron were awarded gas supply licenses for the Spanish market. More than

Figure 43. Natural Gas Consumption in Other Western Europe, 1980-2020



Note: Other Western Europe includes all the countries of Western Europe except France, Germany, Italy, the Netherlands, and the United Kingdom.

Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, January 2001). **Projections:** EIA, World Energy Projection System (2001).

eight other licenses for capacity in the pipelines of Gas Natural were awarded in the preceding months [***23***]. Gas Natural also moved up investment plans for extending its pipeline network following a government decision to take only 10 years (not 14) for the transition to an open market [***24***].

The projects planned and the jockeying of various companies to compete in Spain reflects the type of battles or issues being raised in parts of Europe as the EU's plans for electricity and gas industry deregulation move forward. Repsol YPF, Spain's premier oil and gas group, has sought entrance to the electricity market, but electric utilities initially fought the move, arguing that it would not be reciprocal (providing unfair advantage to Repsol) until the gas market also opened and offered similar access [***25***].

Elsewhere in southern Europe, Portugal's state gas distribution company, Transgas, began receiving Nigerian LNG via the regasification terminal at Huelva in southern Spain. Portugal is also constructing its first LNG terminal at Sines (55 miles south of Lisbon) in conjunction with a 1-gigawatt combined-cycle gas turbine power plant. Transgas Atlantico (TA), a joint venture between Transgas and state gas company Gas de Portugal, would like LNG to meet half of the country's growing gas needs by 2010 [***26***]. Under the EU gas directive, Portugal is considered an emerging natural gas market (having only begun using gas in 1998) and is not required to open its domestic gas market to full competition until 2008.

Natural Gas and Electricity in Western Europe

The natural gas and electric power industries in Europe are becoming increasingly interconnected. Both industries have been set on a course of change by parallel directives from the European Union (EU) calling for deregulation. Growing availability of natural gas supplies, efforts to introduce greater competition in energy supply, and improvements in natural gas turbine technology are driving the convergence of natural gas and electricity in Western Europe.

Until the early 1970s, gas supplies in Europe came predominantly from sources within the region. Around that time, however, supplies started to come from other sources as well, with the beginning of liquefied natural gas (LNG) deliveries from North Africa (Algeria and Libya) and pipeline gas from the Soviet Union. Also at that time, the United Kingdom (UK) and later Norway began to develop North Sea hydrocarbon resources. Gas demand, along with economic growth, waned in the early 1980s just when earlier investments in gas transportation infrastructure were adding capacity—particularly the Trans-Mediterranean pipeline (from Algeria to Italy), pipelines from Norway, and additional pipeline capacity from the Soviet Union. As gas demand grew stronger in the late 1980s and 1990s, the supply mix continued to reflect growing pipeline imports with a smaller share of imported LNG.[a] Growth in the more separated UK gas market was especially strong, supplied by rising domestic from the North Sea and eventually imports from Norway. Only with the 1998 commissioning of the UK-Belgium Interconnector pipeline has a more integrated, cross-channel European gas market become possible.

Currently, pipelines transport more than three-quarters of the natural gas imported by EU members. About 40 percent of those pipeline imports arrive from the Russian Federation and 15 percent from North Africa (predominantly Algeria).[b] Intra-EU trade, primarily in gas from the Netherlands, accounts for just about 20 percent of the pipeline imports; however, when exports from Norway are included, the countries of Western Europe obtain nearly 45 percent of their pipeline gas imports from other countries in the region.

Gas fields in the Netherlands are beginning to near depletion, which will constrain future exports. Norwegian gas discoveries have also dropped off, limiting current export possibilities to known resources (although the region is believed to still have gas potential, particularly in the offshore Norwegian Sea).[c] Thus, future incremental gas supplies are expected to arrive primarily from North Africa, the Middle East, and Russia.

As in the United States, energy policies have had an important effect on the availability of natural gas in Western Europe and its development as a fuel for electricity generation. In the 1970s, gas availability issues led to intervention in the industry by the European Community (EC, predecessor to the EU). In 1975, a perceived scarcity of gas resources led to an EC directive restricting the use of gas in power plants, which eventually was revoked in the early 1990s, when perceptions about the availability of gas resources and the competitiveness of gas turbine technologies had changed.[d] In contrast, the European Parliament and

(continued on page 53)

[a]J. Estrada, H.O. Bergesen, A. Moe, and A.K. Sydnes, *Natural Gas in Europe: Markets, Organisation and Politics* (New York, NY: Pinter Publishers, 1988).

[b]BP Energy, *World Energy Statistics 2000*, web site www.bp.com.

[c]U.S. Geological Survey, *World Petroleum Assessment 2000*, web site http://greenwood.cr.usgs.gov/energy/WorldEnergy/DDS-60/.

[d]P. Soderholm, "Fuel for Thought: European Energy Market Restructuring and the Future of Power Generation Gas Use," *International Journal of Global Energy Issues* (forthcoming).

In Italy, projects, plans, and proposals for new LNG terminals are also linked with deregulation. Italy now has one LNG receiving terminal in operation. Edison/Exxon Mobil's plan for a terminal in the Adriatic Sea around the Po River delta (offshore Rovigo) received several first-stage approvals in 1999, and in early 2000 the Italian environment ministry approved the environmental impact study. The project is targeted for completion in 2003 [***27***]. Rivaling the Edison/ExxonMobil plans is a British Gas (BG) proposal to build a terminal in the southern city of Brindisi, for which there is already local clearance [***28***]. A major potential customer could be Enel, the state power company, which seeks to challenge the state gas player Snam as the gas market opens.

Snam, which is owned by Italy's state gas company Eni, controls 90 percent of the country's gas imports and 85 percent of its gas transport. Legislation to open the gas market was passed by the Italian senate in early summer 2000. Eni will not have to relinquish its gas transport network, but its share of gas imports will be capped at 75 percent and its share of gas sales limited to 50 percent of the market. This type or level of deregulation faces less opposition in Italy's high-growth gas market, because it is unlikely that Eni will have to cut or limit gas sales under the market share limits. In addition, Eni plans to generate power with some of its gas, which would then be counted as "self consumption" rather than sales of natural gas [***29***].

Natural Gas and Electricity in Western Europe (Continued)

Council Directive of June 22, 1998 (with an implementation deadline of August 10, 2000) was not about safeguarding supplies, but about promoting market-based development of the gas industry.

The 1998 gas directive—part of a regulatory trend worldwide in which (among other changes) both gas and power transmission systems are being made available to multiple users—seeks to end monopoly control of national gas transmission systems, which were once viewed as natural monopolies. Not all EU member countries have met the deadline for implementing the directive, however, and its effectiveness has been limited as a result. EU officials are continuing to focus on compliance while drafting further guidelines in case they are needed to promote an EU-wide gas market.

The increasing use of gas for power generation in Western Europe has played a central role in prompting the dual EU directives to alter gas and power market regulations. In turn, the current regulatory changes are having an important effect on corporate strategies and structures. European gas transmission companies, which increasingly must allow third-party access to their pipelines, are now seeking to move into both upstream and downstream businesses, expanding their profit base beyond the deregulating gas transmission market. Gas de France, for example, has bought offshore Dutch production assets from TransCanada. Some companies may have sought growth in order to compete more internationally. Others may have sought to protect their domestic markets from foreign investors.[e] Some of the mergers have involved corporations that hold extensive assets in both the gas and power industries, such as the combining of Germany's Veba and Viag to become E.ON. If the current trends in gas-fired generating technology, improving access to natural gas supplies, and EU regulation continue, further interconnection of the natural gas and electricity industries in Western Europe can be expected.

[e]P. Carpentier and A. Tagheghi, "Commercial Opportunities in European Gas Markets," in *World Power 2000* (London, UK: Isherwood Production Ltd., 2000).

In France, although the government has been slow to enact legislation complying with the EU gas directive, the state company Gaz de France volunteered to comply and undertook reorganization to facilitate its compliance. Access to the French gas infrastructure could be tested, however, by four big industrial gas users (Pechiney, Rhodia, St. Gobain, and Solvay) that have announced a tender to buy gas. The four companies account for about 4 percent of France's gas consumption [***30***].

Eastern Europe and the Former Soviet Union

At the end of 1999, natural gas deposits in the former Soviet Union (FSU) accounted for 2003 trillion cubic feet, or 38.7 percent of the world's proved reserves. While Russia continued to lead all other countries in total reserves, with 1,700 trillion cubic feet of proved reserves, or 32.2 percent of the world's total, Turkmenistan, Uzbekistan, and Kazakhstan each accounted for between 1 and 2 percent of the total.

Russia is both the world's largest natural gas producer and its largest exporter, with all the country's excess production going to exports. Russia far surpassed all other countries in gas production in 1999, providing 23.7 percent of the world's total supply, only slightly ahead of the U.S. share of 23.2 percent. Russia's 1999 gas production varied only slightly from 1998, at 19.5 trillion cubic feet. Russia provides Turkey with more than 75 percent of the gas it consumes and the EU with almost one-third of the gas consumed by its member countries. Major EU consumers of Russian gas are Germany, Italy, and France, each of which imported more than 400 billion cubic feet in 1999. Other major importers of Russian gas were the Czech Republic, Hungary, Slovakia, and Poland, each receiving more than 250 billion cubic feet. Most EE/FSU countries depend almost solely on Russia for their natural gas supplies.

Although neither Russia's natural gas production nor its consumption increased in 1999, largely because of its internal economic problems, production increases occurred throughout the remainder of the FSU, accompanied by increased consumption in all the major gas-consuming countries of the FSU. The major producing countries, in order of amount produced in 1999, were Uzbekistan, Turkmenistan, Ukraine, Kazakhstan, and Azerbaijan. Production from other FSU countries was negligible. Of particular note were production increases of 71.4 percent in Turkmenistan and 20.7 percent in Kazakhstan.

Outside Russia, Turkmenistan is the only significant exporter of natural gas in the EE/FSU, producing approximately 70 percent more gas than it consumed in 1999. Most of the excess production was exported to other EE/FSU countries, and about one-third went to Iran. Turkmenistan's sizable increase in production in 1999 resulted mainly from a resumption of exports to Ukraine, which Turkmenistan had cut off in 1997 and 1998 in response to Ukraine's nonpayment for previous deliveries.

Gas markets in the EE/FSU region face a number of complex issues, including curtailments, nonpayment, declining Russian production, transit disputes, and economic and political conditions that have not been conducive to foreign investment. Nevertheless, the *IEO2001* reference case projects significant future growth in the region's natural gas consumption. Consumption in the EE/FSU as a whole is projected to grow at an average annual rate of 2.5 percent per year between 1999 and 2020. Consumption in the FSU is projected to grow at a rate of 1.8 percent a year, with slower growth in the early years of the forecast. The projected increase in Eastern Europe is considerably higher, at an overall rate of 5.9 percent per year. FSU consumption is projected to grow from 20.1 trillion cubic feet to 29.5 trillion, and EE consumption is projected to more than triple, from 2.4 trillion cubic feet in 1999 to 8.0 trillion in 2020.

Between 1997 and 1999, consumption declines in Eastern Europe outweighed increases, with consumption in Bulgaria, Romania, and Poland declining by 34 percent, 25 percent, and 5 percent, respectively, over the 2-year period. Countries posting gains included the Czech Republic and Hungary, but all the gains were modest (less than 2.0 percent).

Along with posting the highest gains in gas production among the FSU countries, Turkmenistan showed the highest consumption increase from 1997 to 1999, at 27 percent. Ukraine consumed more than 4 times what it produced and was thus, like the nonproducing countries, heavily dependent on Russian supplies. The other producing countries produced approximately what they consumed, and any dependence on imports in those countries resulted from a lack of infrastructure linking their producing areas with their demand centers [***31***]. The highest level of consumption in a nonproducing FSU country in 1999 was in Belarus.

Although Russia's gas production remained steady in 1999 and its reserves are plentiful, there is considerable talk of an impending gas shortfall. Russia has been forced to tap into its reserves, and its major active natural gas fields have been depleted by more than one-third, to the point of declining output. Gazprom does not have the capital needed to either develop new fields or pursue the upgrades desperately needed in the domestic gas industry, and government policy that holds down domestic gas prices and prevents independent producers from exporting gas discourages growth in production [***32***]. According to Gazprom's own figures, the country's natural gas shortfall will reach 388 billion cubic feet in 2000, 1,300 billion cubic feet in 2001, and 2,400 billion cubic feet in 2002. Russia's Deputy Energy Minister Valery Garipov has indicated that production could drop by almost 10 percent within the next 3 to 5 years. The situation has caused Gazprom to announce drastic cuts in gas sales to domestic power plants (the Russian Unified Power System) in 2001, citing its need to first honor agreements with foreign purchasers.

So far, Russia has not breached any of its supply contracts with its European buyers, but it has recently been unable to meet contractual obligations to supply gas to Azerbaijan. Deliveries to Azerbaijan were stopped at the beginning of the 2000/2001 heating season, forcing power plants supplying heat to operate at less than full capacity. As a result, Azerbaijan has announced plans to negotiate with Iran for future gas supplies [***33***]. Turkey, a major consumer of natural gas, despite its voiced concerns about too much dependence on Russia, seems to be increasing its dependence. At risk of a power shortage, Turkey has negotiated an increase of 15 to 20 percent in imports from Russia beginning in November 2000. The Blue Stream pipeline project, which will move natural gas under the Black Sea to Turkey, currently is scheduled for completion in the fall of 2001. With the pipeline in operation, Turkey will receive 60 percent of its natural gas imports from Russia [***34***].

Because the Russian government has mandated artificially low domestic prices for natural gas, Gazprom must cover its domestic losses with profits from the sale of gas at considerably higher prices in foreign markets [***35***]. Gazprom has indicated that domestic gas prices might have to double in order for Russian gas producers to stop losing money, and that increases of at least 50 percent would be needed to attract needed investment [***36***]. Russian president Vladimir Putin has indicated a desire to reform Gazprom (which is partially owned by the government). His success could allay many of the fears that currently keep potential investors at bay, and a better managed, more efficient Gazprom could attract the investment that is so sorely needed. Putin is working on a series of energy contracts with EU leaders that will benefit all parties. Russia would obtain the capital investment it needs to overhaul its out-of-date producing and exporting infrastructure, and Europe would obtain attractively priced gas supplies to meet increasing demand and diversify supply sources.

If Gazprom goes ahead with planned reductions in supply to Russia's Unified Power System, the power company will be forced to turn to Turkmenistan for natural gas at considerably higher prices. Although Gazprom's year-to-date gas exports are down from 1999 figures, profits are up by 60 percent because of the rise in foreign gas prices [***37***]. Gazprom has also talked of raising prices to a number of foreign customers, including Poland and Lithuania.

In addition to receiving lower prices domestically for its gas, Gazprom still struggles with the issue of nonpayment both domestically and within the EE/FSU. In one recent example of domestic nonpayment problems, Gazprom stopped supplies to a number of regions on September 30, 2000, just before the start of the heating season, because of consumers' nonpayment of bills. Included were the Siberian city of Omsk and the southern region of the North Caucasus republic of North Ossetia. Supplies to homes in North Ossetia had dwindled to the point that it was taking more than an hour to bring a kettle of water to a boil on a gas stove. If debts for gas already consumed can be rescheduled, North Ossetia hopes to see the resumption of deliveries for the winter [***38***]. During the 1999/2000 winter, supplies to Moldova were shut off twice by Gazprom for nonpayment. As of the end of September 2000, Moldova was hundreds of millions of dollars in debt to Gazprom [***39***].

In other countries, payment arrangements and/or barter deals continue to help satisfy the huge debt owed Gazprom. In December 2000, Russia and Ukraine worked out a restructuring of Ukraine's debt under which Ukraine has been given an 8-year grace period, with the debt to be repaid by the Ukrainian government in cash. In turn, Ukraine has provided Russia with some security guarantees on the transit of Russian gas to Europe through Ukraine, and Russia has guaranteed the supply of necessary quantities of gas to Ukraine [***40***].

These agreements are important to both Russia and Ukraine. Ukraine is the transit route for approximately two-thirds of Russian gas destined for European markets, and Russia contends that Ukraine has been siphoning off gas during transit for both internal use and resale. The agreement, if upheld, will put an end to that practice and could soften Russia's objections to the construction of a pipeline through Ukraine to deliver Russian supplies to Western Europe. Russia has instead supported a less direct route through Belarus, Poland, and Slovakia that bypasses Ukraine. Slovakia is already the world's second largest conveyor of natural gas, with up to 25 percent of the natural gas consumed in Western Europe crossing Slovakian territory [***41***]. The choice of routes has been contentious, with Poland until recently being opposed to a route that bypasses its strategic ally, Ukraine.

In an attempt to lessen its dependence on Russia, Ukraine intends to satisfy a portion of its gas demand with imports from Turkmenistan. Turkmenistan had ceased supplying Ukraine with gas in May 1999, because of mounting debt, but agreed to resume supplies in October 2000 after receiving $16 million in cash toward the debt. Payment for the resumed supplies will initially consist of 40 percent cash and 60 percent goods and services for the expansion and updating of Turkmenistan's oil and gas infrastructure [***42***]. Ukraine has agreed to make weekly advance payments of $7 million in cash and $9 million in goods and services to ensure timely payment [***43***]. While on the surface this agreement will diversify Ukraine's gas sources, some are concerned about the fact that the Turkmen gas still must pass through Russia en route to Ukraine, with transit fees under the control of Gazprom.

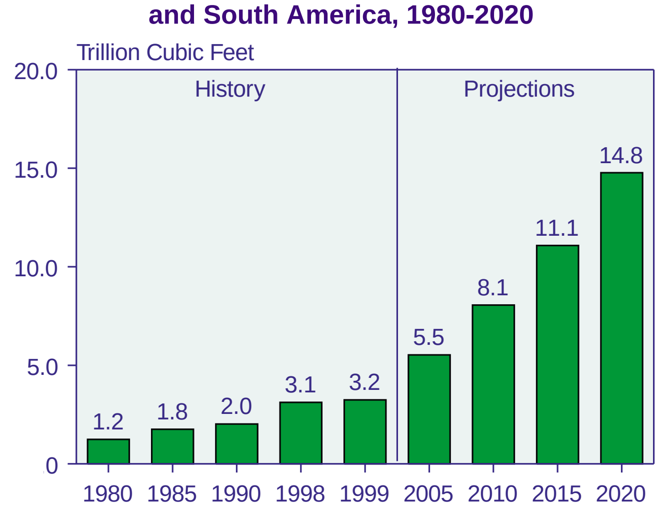
The move continues among other countries dependent on Russia to diversify their sources of supply, especially in light of Russia's looming shortfall. Poland has announced plans to cut imports from Russia by more than one third. Warsaw maintains that European suppliers are more reliable than Russia, and a new Polish law mandates that no one natural gas supplier may provide more than 49 percent of the country's natural gas supply. Poland's plans are to replace Russian supplies with Norwegian supplies transported via the Baltic Sea [***44***].

Central and South America

Natural gas reserves in Central and South America represent less than 5 percent of the world total; however, much of the region remains to be explored for gas, and new discoveries have accompanied recent exploration activity. The region continues to be an area of rapid gas development, and *IEO2001* projects that its gas use, facilitated by additional pipelines, will grow to 14.8 trillion cubic feet by 2020, at an average annual growth of 7.5 percent (Figure 44).

A great deal of gas market activity is occurring in the area referred to as the Southern Cone, or Mercosur (from *Mercado Comun del Sur*, the Southern Common Market

Figure 44. Natural Gas Consumption in Central and South America, 1980-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, January 2001). **Projections:** EIA, World Energy Projection System (2001).

involving Brazil, Argentina, Paraguay, and Uruguay, with Chile and Bolivia as Associated Members), which is becoming a significant pipeline gas market. Further north, the approval of expansion plans for Atlantic LNG, located in Trinidad and Tobago and new gas finds there are also important events. Activity throughout the region underscores the changing dynamics of international natural gas trade (Figure 45).

Two developments in Latin America highlight the potential for increased use of imported LNG in smaller markets. In July 2000, Atlantic LNG began natural gas deliveries from Trinidad and Tobago to Puerto Rico, where the gas is used largely for power generation. Also in the summer of 2000, an AES (Applied Energy Services) subsidiary and BP Amoco signed an agreement to send LNG from Trinidad to the Dominican Republic. The deal involves 720,000 metric tons of LNG per year arriving in the Dominican Republic via a new LNG import terminal (reportedly now under construction) from as early as the end of 2002. A second terminal and associated power project were announced by Union

Figure 45. Major International Natural Gas Pipelines in South America

Source: Adapted from "South America: A Flair for Gas," *Petroleum Economist*, Vol. 67, No. 5 (May 2000), pp. 30-34.

Fenosa and Enron in October 2000, with construction expected to begin in the first part of 2001. Gas demand in the Dominican Republic may not be sufficient, however, to support two LNG import terminals [***45***].

The Trinidad and Tobago Atlantic LNG facility is initiating new trade routes with contracts that cover smaller volumes than have been common in the Asian dominated LNG trade. The Atlantic LNG export project is also set to expand, having received formal approval from the Trinidad and Tobago government in the first part of 2000. Plant capacity is set to increase by 6.5 million tons per year to nearly 9.5 million tons per year. Of the expanded production, 55 percent will supply the Spanish market (via Enagas) and 45 percent will go to Southern Natural Gas (Sonat) of Georgia. The expansion, due for completion in 2003, will cost $1.1 billion and will lead to projected tax revenues for the Trinidad government of $240 million annually over a 20-year period [***46***]. Ongoing exploration continues to delineate more gas resources in the area, including two major finds reported by BP Amoco. BP's second discovery, announced in September 2000, could turn out to be the largest yet made in Trinidad and Tobago (on the Red Mango prospect), with an estimated 3 trillion cubic feet of gas and 90 million barrels of condensate [***47***].

Proposals for two more LNG export facilities in the American Atlantic basin, both in Venezuela, were discussed during 2000. Venezuela's government has decided to emphasize gas business via the state company, Petroleos de Venezuela (PDVSA). PDV Gas and Enron signed a memorandum of understanding (MOU) to construct a single-train LNG plant near San Jose with a capacity of 2 metric tons per year. Despite a targeted startup in 2003-2004, arrangements for the project are not yet finalized. The other proposal is a resurrection of the previously canceled Cristobal Colon project involving ExxonMobil, Royal Dutch / Shell, and Mitsubishi, using gas from the Gulf of Paria. The companies signed an MOU with PDVSA regarding an LNG plant with a capacity of 4 metric tons per year, which is intended to export gas to U.S. and Caribbean markets from the state of Sucre. This project, now called Project Venezuela Liquefied Natural Gas (PVLNG), has been targeted for a 2005 startup. Industry experts are skeptical, however, that either project will find a market to take the gas before 2010 [***48***].

In Peru, government actions are having a different impact on gas development. The government awarded a contract for development of the Camisea gas fields (300 miles east of Lima) in February 2000 after many delays. The winning consortium included Argentina's Pluspetrol Resources (holding a 40-percent equity share), Hunt Oil's Peru subsidiary (40 percent share), and South Korea's SK Sucursal Peruana (20 percent share). Argentine Pluspetrol, which will operate Camisea production, offered the highest royalty in its bid (37.24 percent) and narrowly beat the only other offer (35.5 percent by France's Elf). The royalty offers in both bids were substantially higher than the 10-percent minimum set by the government. The contract awardees are considered small players in the industry (relative to the giants like Shell and Mobil, which withdrew from the project after negotiations with the government failed), and there is some speculation that field development will proceed slowly and include difficulties in securing financing. The winning consortium, which has a 40-year concession to develop the reserves, expects to meet a government goal of transporting gas to Lima by 2003.

The award of a related transportation-distribution contract was also delayed repeatedly by the Peruvian government during 2000. Political instability in Peru has played a large role in the delays. This second contract was awarded in October 2000 to the one and only bidder, a consortium involving Argentina's Techint, Algerian Sonatrach, a Peruvian construction firm (Grana y Montero), and the members of the Argentine Pluspetrol upstream consortium named above. The government guarantees a 12-percent return on investment for transportation and distribution to and within Lima [***49***].

Brazil, like Venezuela, has a large and powerful state hydrocarbons company, Petrobras. In March 2000 the president of Petrobras signed a contract for increased gas deliveries from Bolivia by 2004. For the first half of 2000, however, the Bolivia to Brazil (BTB) gas pipeline remained underutilized, partly because of slow and delayed power plant construction. Petrobras, which is under contract to pay for imports from the line whether or not it uses the gas, opposed requests from other companies seeking third-party (open) access to the pipeline capacity [***50***].

Petrobras also signed an MOU regarding a proposed pipeline it would underwrite in Bolivia. Recent discoveries have increased Bolivia's reserves, and the planned pipeline would link Yacuiba in gas-rich Tarija to the existing BTB pipeline. The new pipeline would run parallel to the existing Yabog line operated by Transredes (controlled by Shell and Enron), and thus it is not surprising that concerns were raised over the MOU, which may favor one investor over others [***51***].

Delivering Argentine gas to Brazil, the Transportadora de Gas del Mercosur (TGM) pipeline began operations in the second half of 2000, providing the first direct interconnection of Brazilian and Argentine gas networks. The 24-inch line from Aldea Brasilera in the northern Argentine province of Entre Rios to Brazil will supply gas to a new 600-megawatt power plant at Uruguaiana, Rio Grande do Sul [***52***]. Transportadora SulBrasileira de

Gas (TSB), which connects TGM to Uruguaiana in Brazil, is now planning a second phase for completion in 2001 involving an extension from Uruguaiana to Porto Alegre, including interconnection with the Bolivia-Brazil pipeline. Gasoducto Cruz del Sur is also pursuing a connection with Porto Alegre via extension from Colonia, Uruguay [***53***]. Plans for an LNG terminal in Brazil have also been announced, although there is no clear timetable for development. Gaspetro of Petrobras and Shell have announced plans to build an import terminal at Suape, the deepwater port and industrial complex in northeast Brazil [***54***].

Asia

Gas market activity in Asia during 2000 reflected ongoing, if uneven, recovery from the economic crisis that affected the region from 1997 to 1999. Many oil and gas importers in the region were adversely affected by high oil prices during 2000. Although LNG prices in Asia are generally linked to crude oil prices, LNG trade is also dominated by long-term contracts, and high oil prices did not slow the LNG movements that currently dominate gas trade in the region. It is important to note what did not happen in the region: plans for additional LNG imports did not move forward rapidly, nor did 2000 become an important year for the signing of long-term sales agreements that would solidify future LNG trade.

The *IEO2001* reference case projects that natural gas consumption in the whole of Asia (both industrialized and developing) will grow by an average of 5.0 percent per year, increasing Asia's consumption to 26.6 trillion cubic feet in 2020 from 9.6 trillion cubic feet in 1999. The growth in developing Asia is expected to far outpace that in the industrialized countries of the region (Figure 46).

Industrialized Asia

For the countries of industrialized Asia, natural gas consumption is expected to rise from 3.6 trillion cubic feet in 1999 to 5.4 trillion cubic feet in 2020. Australia—which has large, expanding gas reserves and further resource potential—continued to pursue supply projects during 2000, including a proposal for a gas-to-liquids project. Japan, with recent power sector deregulation, has not moved to fully renew LNG contracts that will be expiring in a few years.

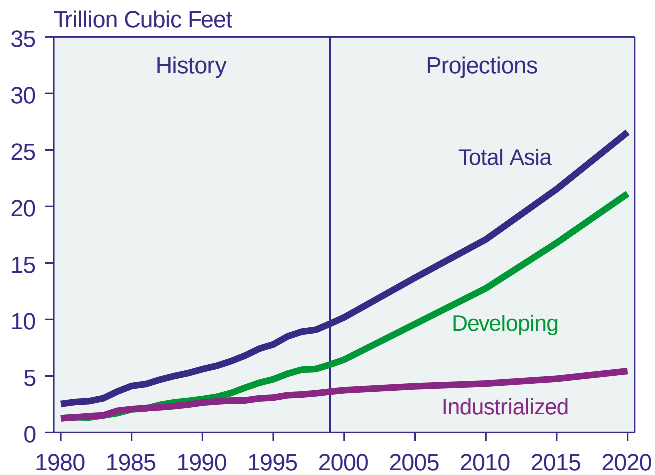
Australia, Asia's third largest producer of natural gas in 1999, also has large undeveloped gas resources, some in remote areas. During 2000, Australia continued to make discoveries of significant gas resources in the remote northwest. For example, discoveries by the West Australian Petroleum (WAPET) consortium in the Gorgon gas fields could eventually add several trillion cubic feet of gas to existing reserves [***55***].

Many of the gas-related developments in Australia during 2000 were aimed at bringing Australian gas to markets. There is more than one ongoing effort to build additional LNG production facilities, although developers have not yet secured buyers for the volumes of LNG that would enable them to move forward. Marketing efforts continue, particularly those oriented toward China and Taiwan. For example, Australia LNG has signed an MOU with Tuntex Gas Corporation for LNG trade, but it depends on the ability of Tuntex to secure buyers for the gas in Taiwan [***56***].

In addition to LNG, new proposals were made in 2000 to use Australia's northwest gas domestically. Austeel announced that it is planning to build a major iron and steel plant in the region and that it has signed an initial MOU to use gas from the Northwest Shelf. If completed, this would be the biggest gas supply deal for Western Australia in 20 years [***57***]. The Sweetwater gas-to-liquids project[8] planned by Syntroleum would also use Northwest Shelf gas domestically, converting it to liquid products. To be located on the Burrup Peninsula in Western Australia's Pilbara, the 10,000-barrel-per-day Sweetwater project now includes Clough engineering as a local partner, with German Tessag INA as the contractor for engineering, procurement, and construction [***58***].

Because Australia's abundant gas resources are concentrated in the remote northwest, some developers are

Figure 46. Natural Gas Consumption in Asia by Region, 1980-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, January 2001). **Projections:** EIA, World Energy Projection System (2001).

[8]For more information about gas-to-liquids technology and proposed projects, see Energy Information Administration, *International Energy Outlook 2000*, DOE/EIA-0484(2000) (Washington, DC, March 2000), p. 59.

continuing to promote a pipeline project to import gas from Papua New Guinea to gas-poor northeastern Australia (the province of Queensland). Chevron and its partners in the pipeline project have asked the Australian government to review and clarify applicable fiscal and tax conditions, which could affect the project's financial viability. (Developers said the project was potentially threatened by a debated tax change in the cutoff for accelerated depreciation.)

During summer 2000, the Queensland government announced a new "cleaner energy strategy," which could help the Chevron pipeline project succeed. The government strategy requires 15 percent of power needs to be met from gas-fired or renewable energy by 2005. The Queensland government also announced that no new licenses would be issued to coal-fired power plant projects unless absolutely necessary. In addition, the government is said to be in talks with the consortium building the PNG-Queensland pipeline (involving AGL and Petronas) about possibly taking an equity share in a portion of that project [***59***].

In Japan, as in Europe and the United States, deregulation is changing both the gas and power industries as gas companies move into the power sector and power companies pursue gas ventures. Chubu Electric and Iwatani announced plans for a joint venture to sell retail LNG to large industrial plants, using tank trucks for transportation from the LNG terminal next to their Kawagoe power plant in Mie Prefecture, central Japan. They anticipate that sales could begin by April 2001. In mid-March 2000, Tokyo Gas, Osaka Gas, and Nippon Telegraph and Telephone (NTT) said that they were thinking of forming a new large-scale joint venture to supply electricity [***60***]. Also, many of Japan's power companies now have plans that call for reductions in the natural gas share of power generation and increases in the nuclear and coal shares.

Developing Asia

Developing Asia includes the first, second, and fourth most populous countries in the world—China, India, and Indonesia. As a region, developing Asia accounts for more than 50 percent of the world's population, roughly 10 percent of its GDP, and about 7 percent of its natural gas consumption. Strong growth in both GDP and gas use are expected for the region, which could account for about 13 percent of global gas use by 2020. Much of the gas that will be used in developing Asia is expected to cross international borders to reach markets, thus contributing to growing international gas trade. Major gas trade developments during the past year involve pipeline projects in Southeast Asia, prospects for LNG import terminals in China and India, and plans for additional LNG export facilities in Malaysia, Australia, and Indonesia. Countries with significant development of gas resources for domestic use include Australia, China, Malaysia, Pakistan, the Philippines, and Thailand.

China

At the beginning of January 2000, the Chinese government formally approved its first plan to import LNG, into Guangdong in the south. With a targeted startup date of 2005, the LNG project will involve China National Offshore Oil Corporation (CNOOC), holding a likely 36-percent equity share. An additional 34-percent share in the project would be held by local parties including Guangzhou Gas Company, Dongguan Gas, Foshan Gas, Guangdong's Provincial Power Bureau, and Shenzhen Investment Management Company. The remaining stake probably will be offered to foreign private investors [***61***].

Toward increasing domestic gas supply, Shell, BP Amoco, and Enron all have agreements to develop gas resources and infrastructure in China [***62***]. Expansion and integration of pipeline infrastructure will be important to increasing gas use in China (Figure 47). China also announced during 2000 the discovery of what it is calling the country's biggest natural gas field. Located in the northern part of the Tarim Basin in Xinjiang Province, the find is estimated by China to hold more than 7 trillion cubic feet of gas.

India

India, developing Asia's other giant, is another country where rapid growth in gas consumption is expected (Figure 48). Many LNG import schemes are proposed for the country, and there are frequent announcements about them, but few are under construction or making concrete progress. To facilitate gas development, India needs and continues to pursue comprehensive policies for natural gas and, specifically, LNG. However, related policymaking and reform (particularly in the natural gas and power sectors) are proceeding slowly in India's complex democracy.

In the first half of 2000, a committee was established to formulate a comprehensive LNG policy for India, and by August 2000 a draft policy had been issued. Some proposals in the draft policy call for the central government to take a much stronger role in coordinating LNG imports. The draft also contains guidelines to ensure that foreign investors in Indian LNG shipping will maintain Indian involvement and technology transfer. It is not yet clear how the government would handle existing contracts and agreements that are not aligned with the new guidelines [***63***].

Meanwhile, Enron's project to build an LNG terminal at Dabhol is under construction, and Petronet moved forward in 2000 toward finalizing aspects of its first LNG

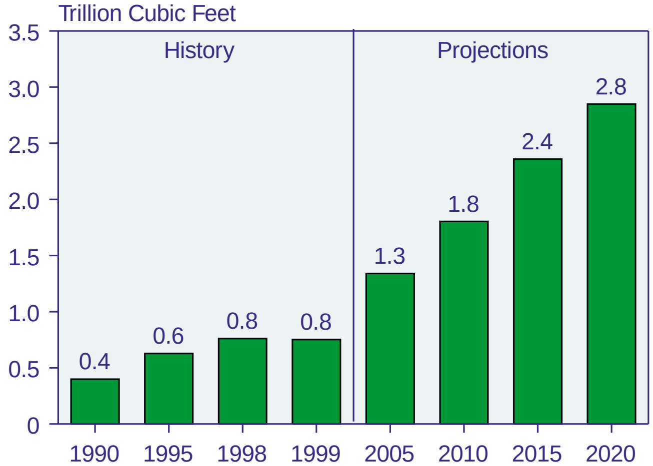
Figure 47. China's Major Natural Gas Pipelines

Source: Fesharaki Associates Consulting and Technical Services and East-West Consultants International, Ltd., *China's Natural Gas to 2015*, Multi-Client Study (Honolulu and Singapore, October 2000), p. 4-10.

import scheme. The evolution of Petronet in India is significant because it is a government-led undertaking with substantial state participation in an arena where private companies are competing fiercely. Rasgas, the Qatari LNG supplier, is taking a cross-investing share in Petronet, and several Indian public-sector companies will have a total of 50 percent equity [***64***]. In October 2000, Petronet and Rasgas agreed to postpone until December 2003 the first LNG deliveries under a sale purchase agreement (SPA) [***65***]. One state company, the National Thermal Power Corporation, has promoted a private-sector proposal for a terminal at Pipavav in Gujarat, and it is ready to take equity in the project, which also involves British Gas [***66***].

India's LNG import schemes tend to involve gas sales to power producers as a critical component; however, many of India's state electricity boards (utilities) are in poor financial condition, in part because of their practice of selling power at subsidized rates. Until power reform issues are resolved, LNG projects in India will struggle to secure gas buyers and project financing in a subsidized environment. For example, in Tamil Nadu on India's southernmost east coast, efforts have continued to solidify a project involving the Dakshin Bharat Energy Consortium and its Ennore terminal. The Ennore project appeared to be in trouble at one point during 2000 because of the financial status of the Tamil Nadu Electricity Board (TNEB). TNEB could not provide

Figure 48. Natural Gas Consumption in India, 1990-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, January 2001). **Projections:** EIA, World Energy Projection System (2001).

escrow cover for power purchase payments, let alone purchase the entire output as earlier promised. Time was also running out on a deadline for locking in the LNG price with its Middle Eastern supplier.

Before the end of September 2000, investors in the Tamil Nadu project (including CMS Energy) announced that they had concluded a joint development agreement with the Power Trading Corporation of India. The agreement includes a government commitment to institute a "payment security mechanism" to guarantee firm purchase of power from the associated 1,850-megawatt gas-fired power plant. The agreement also has a noteworthy diplomatic element, having been concluded in Washington, DC, and involving as signatories U.S. Commerce Secretary Norman Mineta and Indian Finance Minister Yashwant Sinha [***67***].

Other Asia

While China and India are on the verge of becoming key LNG importers in Asia, Malaysia is proceeding in a somewhat unusual manner with plans to build the country's third LNG plant (known as MLNG III or MLNG Tiga). Sponsoring consortium members including a Petronas subsidiary, and Kellogg Brown & Root of the United States have signed an engineering, procurement, construction, and commissioning contract for the plant without yet having contracts from buyers for all the LNG that will be produced. The ability to finance and build LNG plants without purchase commitments is new in the LNG industry [***68***].

In Malaysia and other parts of Southeast Asia, including Thailand, Indonesia, and Singapore, plans continue to expand cross-border natural gas pipelines. However, the timing of a proposed pipeline to deliver gas from a Malay-Thai joint development area (JDA) to both countries now seems to be in question. First, it is unlikely that Thailand will be able to take its commitment for gas from the JDA for several years due to a lack of domestic demand. Second, Malaysia, which was expected to take Thailand's share of JDA gas, has decided to buy gas from Indonesia's south Natuna resources beginning in 2002 [***69***].

Elsewhere, Singapore Power and Indonesia's Pertamina have initialed a contract confirming their plans to proceed with a pipeline from Sumatra to Singapore, where delivered gas will be used primarily for power generation in Singapore's deregulating electricity market [***70***]. Another pipeline is already under construction and ahead of schedule to begin delivering gas to Singapore from Indonesia's Natuna West gas field sometime during 2001. Indonesia, also an LNG exporter, continues to both deplete and add to its gas resources. Two trains at the Arun LNG export facility were shut down during 2000 due to field depletion, while Unocal reported a significant gas discovery, estimated by investors at 2 to 3 trillion cubic feet.

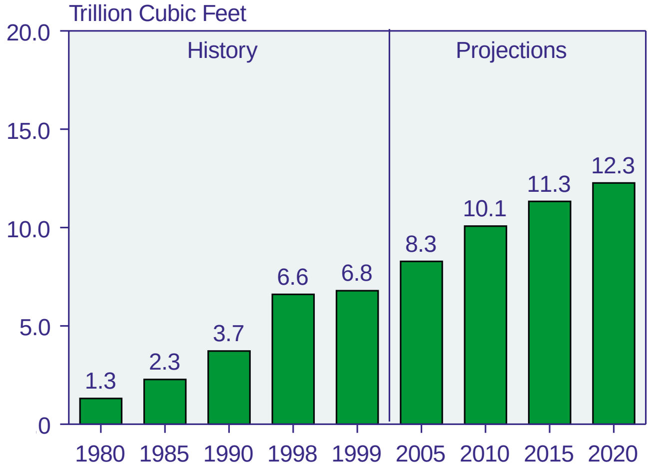
Middle East

The Middle East region has the second largest natural gas reserves after the FSU, amounting to 1,855 trillion cubic feet as of January 1, 2001. Iran, Qatar, Saudi Arabia, and the United Arab Emirates (UAE) have the second, third, fourth, and fifth largest reserve holdings in the world, respectively, following Russia. Already a strong producer and growing exporter of natural gas, the Middle East increasingly seeks to develop domestic gas markets. The *IEO2001* reference case projects a near doubling of Middle East gas consumption between 1999 and 2020, from 6.8 trillion cubic feet to 12.3 trillion cubic feet (Figure 49).

Estimates of gas resources in the Middle East also continue to grow. Iran's IRNA news agency has reported the discovery of a new gas field, known as Homa, containing an estimated 6.7 trillion cubic feet (and 82 million barrels of gas liquids). The onshore field is located about 30 miles north of the port of Asaluya (Bandar-e-Asulayeh) on the Persian Gulf in the southern Fars province. Nearby, another gas field, Tabnak, was found earlier in the year, with estimated reserves of 15.7 trillion cubic feet of gas and 240 million barrels of condensate [***71***].

During 2000, Iran's National Iranian Oil Company (NIOC) signed an agreement with Italy's Eni for the fourth and fifth development phases of the giant South Pars field, a deal worth about $3.8 billion [***72***]. British Gas (BG) signed a joint venture agreement with Iran's Oil Industries Engineering and Construction (OIEC) to pursue both domestic gas projects and LNG export from

Figure 49. Natural Gas Consumption in the Middle East, 1980-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, January 2001). **Projections:** EIA, World Energy Projection System (2001).

Iran using gas from South Pars at the country's southern border. BG would export LNG to its receiving terminal planned for Pipavav in northwest India starting around 2006 [***73***]. Iran may also seek further gas development with other foreign investors, including Shell or BP.

Across the border from Iran's South Pars, the extraordinarily large gas resources extend to Qatar's North Field. Another plan to increase gas use in the Middle East, the Dolphin project, involves piping gas from Qatar to Abu Dhabi, Dubai, and eventually to Oman. Although the developer (UOG, or the United Arab Emirates Offsets Group) had hoped to start construction on the Dolphin project in 2000, it did not reach agreement with Qatar on a transfer price for the gas. In March 2000, UOG agreed to share equity in the project with Enron of the United States and the Franco-Belgian group, Total Fina Elf, which will split a 49-percent share [***74***]. Abu Dhabi, itself an LNG exporter, did agree in early 2000 to the construction of a 67-mile gas pipeline to Dubai's free trade zone, Jebel Ali. Abu Dhabi's gas company, Atheer (a subsidy of the national oil company), announced that work would be completed in early 2001 [***75***].

Saudi Arabia also has plans to develop domestic natural gas use by restarting foreign direct investment in its gas sector. In August 2000, a number of short-listed companies submitted bids for upstream and integrated gas projects, followed by high-level meetings with the Saudis. The Saudi negotiating team hopes to sign initial agreements with investors and begin detailed negotiations in 2001 [***76***]. Saudi Aramco also signed a contract with Foster Wheeler at the beginning of 2000 to provide preliminary work on the Haradh gas project. Set to begin operation in 2004, the facility will produce 1.4 billion cubic feet of gas per day for domestic use [***77***].

In early 2000, the first commercial gas deposit was discovered offshore Israel by British Gas with two local partners, Isramco and Delek. In April, Samedan (operating in partnership with Avner, Delek, and RB Mediterranean) made another important gas discovery about 15 miles off Israel's southern coast. Samedan is estimating that reserves at the Mari-B structure will exceed 1 trillion cubic feet. Israel aims to increase gas-fired power generation to avoid a looming electricity crisis. As part of a related gas development effort, four consortia have submitted bids to build Israel's natural gas system [***78***].

During 2000, both Qatar and Oman brought new LNG export facilities on stream and pursued domestic gas development. In Qatar, RasGas began production from its second LNG train, doubling capacity at the Ras Laffan facility to 5 metric tons per year. Most of the gas will go to Korea under a long-term contract, but excess LNG will also be available for sale. On the domestic front, Qatar signed a contract with ExxonMobil to develop North Field gas for local industry and a planned independent power plant. Gas may also be piped from Qatar to Kuwait for domestic use [***79***].

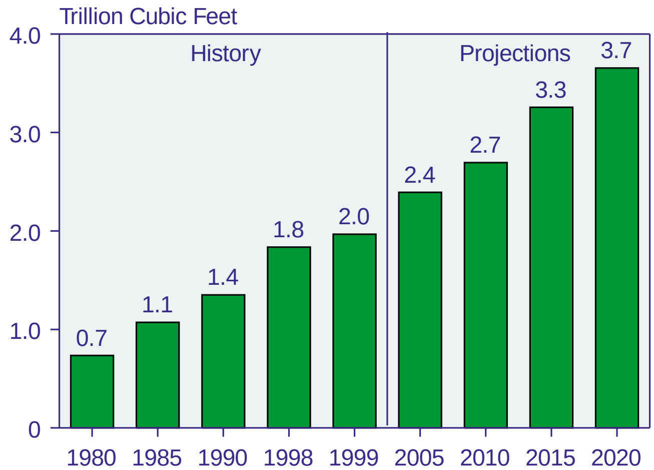
Oman, which produced its first LNG in December 1999, began production at the second train of its facility in the second quarter of 2000. LNG exports will go to Korea, Japan, and India (Dabhol). Also in Oman, seven companies have submitted bids to build two new gas pipelines from inland gas fields to the coastal cities of Sohar and Salalah. The companies include U.S.-based Willbors, Italy's Saipem / Snamprogetti / CCC, Technip Germany, India's Dodsal, Argentina's Techint, and South Korea's LG / Hyundai and SK / Daewoo [***80***].

Africa

Africa's gas reserves, estimated at 394 trillion cubic feet, account for nearly 8 percent of global reserves. Egypt, Algeria and Nigeria have a combined 319 trillion cubic feet of reserves or about 80 percent of the total. Gas production activity is concentrated in north and west Africa, where proposed export projects and plans for domestic use are also accumulating. In the western part of Africa, especially Nigeria, production of associated gas has risen with development of crude oil resources and reductions in gas flaring.

The *IEO2001* reference case projects that natural gas consumption in Africa will increase by 7.5 percent per year on average from 1999 to 2020. Total gas use in Africa is projected to rise from 2.0 trillion cubic feet in 1999 to 3.7 trillion cubic feet in 2020 (Figure 50).

Figure 50. Natural Gas Consumption in Africa, 1980-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, January 2001). **Projections:** EIA, World Energy Projection System (2001).

In Algeria there are new plans for gas development to monetize the gas reserves and resources that grew in the 1990s with successful exploration. During the first quarter of 2000, BP Amoco and Sonatrach (in a 50:50 joint venture) agreed to proceed with the $2.5 billion development of the In Salah gas fields in the central Algerian Sahara Desert, which contain more than 7.5 trillion cubic feet. First deliveries are due in 2003 to Italy, where the gas has already been assigned to Enel in an earlier Sonatrach deal. Edison Gas, the independent marketer in Italy, may purchase additional volumes and already has an agreement in principle [***81***].

In the summer of 2000, a noteworthy new type of contract was signed for a $1 billion development project in eastern Algeria's Ohanet gas/condensate fields, which contain more than 3.4 trillion cubic feet. A consortium led by BHP (known earlier as Broken Hill Proprietary Company) signed a "risk service contract" (RSC) with Sonatrach. The RSC states partner entitlements in monetary terms, in contrast to a production sharing contract, which involves monetary and volume terms. (BHP, for example, has no entitlement to pipeline gas or associated revenue, although it does have entitlement to a share of the LPG and condensate produced.) Sonatrach will export the natural gas via the Mediterranean pipeline and as LNG [***82***].

Algeria's government is considering privatization of domestic electricity and gas distribution, and a law to privatize mining has already been approved. The measures are in part a response to economic and financial difficulties in the country, which currently suffers from a 30-percent unemployment rate and uses 40 percent of its total export revenue to service foreign debt. In September 2000, Algerian Prime Minister Ahmed Benbitour resigned, reportedly because President Bouteflika was dissatisfied with the slow pace of Benbitour's economic reform efforts [***83***].

Both Egypt and Angola have plans to develop large gas resources for LNG export, but firm buyers for their exports are still needed. Egypt has signed an agreement with Union Fenosa of Spain, which would invest in the facility. At the same time, gas resources are growing in Egypt, where British Gas announced a significant gas and condensate discovery made together with Edison in the West Delta Deep Marine Concession, located 40 miles northeast of Alexandria [***84***].

In addition to developments in north and west Africa, South Africa has had an important gas find and reached agreement to develop offshore gas. An estimated 2.5 trillion cubic feet of natural gas was discovered about 50 miles off of South Africa's west coast by Forest Oils and Anschutz. The gas lies at relatively shallow depths, with the potential for oil still to be found, and is the most important find since the Mossgas discoveries of the early 1980s [***85***]. The Mossgas resources will be further developed by British-based Dresser Kellogg Energy Services, which will drill wells and provide transport and process systems for the gas. The official export credit agency of the United Kingdom, Export Credits Guarantee Department (ECGD), has reported that it will underwrite the financing for the project [***86***].

References

1. BP Amoco, *Statistical Review of World Energy 2000* (London, UK, June 2000), pp. 4-26.
2. BP Amoco, *Statistical Review of World Energy 2000* (London, UK, June 2000), pp. 23-26.
3. "Big Gas Find Puts Spotlight on Trinidad as Major Player," *Natural Gas Week* (October 2, 2000), p. 6.
4. Energy Information Administration, *Annual Energy Outlook 2001*, DOE/EIA-0383(2001) (Washington, DC, December 2000), p. 83.
5. "California Haunted by Neglect of Infrastructure," *Natural Gas Week* (December 18, 2000), p. 11.
6. "California Haunted by Neglect of Infrastructure," *Natural Gas Week* (December 18, 2000), p.10.
7. Energy Information Administration, *Canada Country Analysis Brief* (Washington, DC, October, 2000), pp 4 -5.
8. *Oil and Gas Investor*, Bell and Howell Information and Learning, ABI/INFORM (Hart Publications, Inc., October, 2000).
9. *The Montreal Gazette*, from the *Wall Street Journal* (December 28, 2000), Business Section, p. E5.

10. "Newsbriefs," *Platt's Oilgram News*, Vol. 78, No. 184, p. 6.
11. *Mexico Country Briefing*, The Economist Intelligence Unit Ltd., EIU ViewsWire (November 3, 2000).
12. "Mexico Calls for Proposals To Open Gas Industry," *The Energy Report*, Vol. 28, No. 42 (October 16, 2000).
13. "Mexico Offers Discounts to Natural Gas Hedgers," *Platt's Oilgram News*, Vol. 78, No. 148, p. 4.
14. "Newsbriefs," *Platt's Oilgram News*, Vol. 78, No. 180, p. 6.
15. "Mexico Sees Gas Imports Ending by 2004," *Platt's Oilgram News*, Vol. 78, No. 186 (September 27, 2000), p. 3.
16. "Mexico Calls for Public Proposals on Gas Industry," *Gas Daily*, Vol. 17, No. 193 (October 9, 2000).
17. "Mexico Calls for Proposals To Open Gas Industry," *The Energy Report*, Vol. 28, No. 42 (October 16, 2000).
18. "A Liberating Experience," *Petroleum Economist*, Vol. 67 No. 10 (October 2000), pp. 10-12.
19. "EC Adopts Wait and See Approach," *FT Gas Daily Europe*, Vol. 2.150 (August 4, 2000), p. 2; and "Brussels Will Add Teeth to EU Gas Directive," *World Gas Intelligence* (September 28, 2000, internet edition.
20. "Gas Natural Plans New Pipeline Expansion," *FT Gas Markets Week*, Vol. 34 (January 10, 2000), p. 3.
21. "$550 Million LNG Terminal and Power Project Planned for Northern Spain," *LNG Express*, Vol. 10, No. 8 (August 2000), p. 9; and "Bouygues Offshore Subsidiary Wins LNG Import Terminal Contract in Spain; Total Amount: 203 Million Euros, Bouygues Offshore Portion: 81 Million Euros," *Business Wire* (June 20, 2000), internet edition.
22. "Spain's Union Fenosa Seals Egypt LNG," *Financial Times International Gas Report*, Vol. 404 (August 4, 2000), pp. 2-3.
23. "Union Fenosa and Enron Awarded Supply Licenses," *Financial Times Gas Markets Week*, Vol. 43 (March 13, 2000), p. 3.
24. "Gas Natural Plans New Pipeline Expansion," *Financial Times Gas Markets Week*, Vol. 34 (January 10, 2000), p. 3.
25. "Spain Gas / Power Battle Mounts," *Financial Times International Gas Report*, Vol. 393 (March 3, 2000), pp. 4-6.
26. "Portugal Takes First Nigeria LNG via Spain," *Financial Times Gas Markets Week*, Vol. 35 (January 17, 2000), p. 12; and "Portugal Looks to Growing LNG," *Financial Times International Gas Report*, Vol. 393 (March 3, 2000), pp. 12-13.
27. "Italy Sees First 'Private' Russian Deal," *Financial Times International Gas Report*, Vol. 391 (February 4, 2000), pp. 3-4; and "Edison-Mobil LNG Terminal Plan Clears Another Hurdle," *Financial Times Gas Markets Week*, Vol. 37 (January 31, 2000), p. 3.
28. "BG Continues Brindisi LNG Probe," *Financial Times International Gas Report*, Vol. 402 (July 7, 2000), pp. 13-14.
29. M. Wildt, "Gains Are Projected for ENI Stock," *Wall Street Journal* (August 3, 2000); and D. Lane, "Liberalisation Turns up the Heat in Italian Power Market," *Financial Times London* (August 1, 2000).
30. "Big Buyers Test French 'Liberalisation'," *Financial Times International Gas Report*, Vol. 406 (September 1, 2000), p. 5; and "Gas de France Reorganises Ahead of Liberalisation," *Financial Times Gas Markets Week*, Vol. 50 (May 2, 2000), p. 9.
31. Statistics from BP Amoco, *Statistical Review of World Energy 2000* (London, UK, June 2000), pp. 23-26.
32. "Critical Situation in Natural Gas Industry," Feature Stories Section, The Russian Oil and Gas Report, *Rossiyskaya Gazeta* (November 23, 2000).
33. "Azerbaijan Republic Turns to Iran for Natural Gas," National Financial News Section, *Asia Pulse* (December 18, 2000).
34. "Turkish Protest at Russian Gas Dependence," *Energy Day*, Business Section (November 20, 2000, p. 12.
35. "Gas Wars: Putin Imposes a Truce for the Winter," *Current Digest of the Post-Soviet Press*, Vol. 52, No. 43, p. 8.
36. "Russian Natural Gas Producer Urges Higher Domestic Prices," *Associated Press Worldstream*, International News, Moscow (October 17, 2000).
37. "Russian Gas Exports Edge Down But Profits up 60 Percent," *BBC Monitoring Former Soviet Union—Economic*, Interfax News Agency, Moscow (November 14, 2000).
38. "Gazprom Cuts Gas Supplies to North Ossetia," *BBC Sumary of World Broadcasts*.
39. "Moldovan PM in Russia for Visit on Tough Issues," *Associated Press Worldstream*, International News (September 25, 2000).
40. "Russia and Ukraine Sign Natural Gas Agreement," *The Russian Oil and Gas Report*, Contracts and Concessions Section (December 22, 2000).
41. "Daily Reports Data on Natural Gas Imports, Consumption," *BBC Summary of World Broadcasts*, *Narodna obroda*, Bratislava (September 18, 2000), p. 13.

42. "Leonid Kuchma Visits Saparmurad Niyazov and Finds Alternative Source of Natural Gas," *Current Digest of Post-Soviet Press*, News of the Week Section, Other Post-Soviet States, Vol. 52, No. 41 (October 7, 2000), p. 3.

43. "Turkmenistan Turns Gas Back on to Ukraine," *Associated Press Worldstream*, International News Section, Ashgabat, Turkmenistan (November 1, 2000).

44. "Eni To Buy into Gazprom," *The Russian Oil and Gas Report*, *Izvestia*, Corporate Dynamics Section (December 1, 2000).

45. "Dominican Republic Set as Second LNG Terminal in Caribbean," *LNG Express*, Vol. 10, No. 8 (August 2000), p. 5; and "Enron, Union Fenosa Target Second LNG Terminal for Dominican Republic," *LNG Express*, Vol. 10, No. 11 (November 2000), p. 1.

46. "Repsol YPF Gains LNG Expansion Approval," *Financial Times Gas Markets Week*, Vol. 36 (January 24, 2000), p. 12; and "Atlantic LNG Gets Go-Ahead for Two Extra Trains," *Financial Times Gas Markets Week*, Vol. 40 (February 21, 2000), p. 3.

47. *Oil & Gas Journal Online's Upstream This Week* (May 12, 2000), e-mail edition; and *Oil & Gas Journal Online's Upstream This Week* (September 29, 2000), e-mail edition.

48. "Venezuela Pushing LNG Projects Despite Economic Questions," *Latin America Energy Alert*, Vol. 7, No. 8 (April 6, 2000), p. 8; "Enron Joins Enlivened Venezuelan LNG Race?" *World Gas Intelligence* (February 25, 2000); "Venezuela Inks Paria LNG Deal," *World Gas Intelligence* (March 30, 2000); and *Oil & Gas Journal's Downstream This Week* (January 31, 2000), e-mail edition.

49. "Group of Small Players Wins Camisea Bid," *Oil Daily*, Vol. 50 No. 32 (February 17, 2000), pp.1-2; "Peru Sets Minimum Royalty for Camisea Gas at 10%," *Latin American Energy Alert*, Vol. 7 No. 5 (January 20, 2000), p. 6; "Argentine Group Breaks Camisea Ice," *Financial Times Power in Asia*, Vol. 56 (February 2000), pp. 2-3; "Peru Has Yet To Set Date for Camisea Pipeline Concession," *Latin American Energy Alert*, Vol. 7 No. 9 (March 23, 2000), p. 4; and "What's New Around the World," *World Gas Intelligence* (October 26, 2000), internet edition.

50. "Brazil Ties Up Increased Deal With Bolivia," *World Gas Intelligence* (March 31, 2000), internet edition; and "Companies Considering Getting Around Petrobras' Control of Gas Pipeline," *Latin American Energy Alert*, Vol. 7, No. 5 (January 20, 2000), pp. 1-2.

51. "Bolivian Riches: Probable Reserves of 31 Trillion," *Brasil Energy*, Vol. 21, No. 335 (July 2000), p. 27.

52. "IDB Backs Argentina / Brazil Pipe Link," *Financial Times Power in Asia*, Vol. 56 (February 2000), p. 8; "Argentina Set To Start Gas Exports to Brazil," *Oil Daily*, Vol. 50, No. 113 (June 13, 2000), p. 5; and "New Gasline Officially Opened," *Financial Times International Gas Report*, Vol. 407 (September 15, 2000), p. 24.

53. "Argentina Set To Start Gas Exports to Brazil," *Oil Daily*, Vol. 50 No. 113 (June 13, 2000), p. 5.

54. "Gaspetro / Shell Set for Brazil LNG Launch," *FT International Gas Report*, Vol. 388 (December 10, 1999), p. 6; and "Petrobras Unit, Shell Form Partnership for Brazil's First LNG Terminal," *LNG Observer*, Vol. 10, No. 6 (November-December 1999), p. 2.

55. *Oil & Gas Journal's Upstream This Week* (April 24, 2000), e-mail edition.

56. "South Asia Holds Key to Greenfield LNG Projects, Gas Market Expansions," *LNG Express*, Vol. 9, No. 12 (December 1999), p. 4.

57. "What's New Around the World," *World Gas Intelligence* (August 24, 2000), internet edition.

58. Syntroleum press release (August 8, 2000); *Oil & Gas Journal's Downstream This Week* (February 28, 2000), e-mail edition; and *Oil & Gas Journal's Upstream This Week* (March 20, 2000), e-mail edition.

59. "Pipe Partners in Tax Plea," *Financial Times International Gas Report*, Vol. 388 (December 10, 1999), p. 29; and "New Policy Boosts PNG Line," *Financial Times International Gas Report*, Vol. 400 (June 9, 2000), p. 27.

60. "Chubu in LNG retail J-V," *Financial Times Power in Asia*, Vol. 303 (May 30, 2000), p. 13; and "Currents of Change," *Financial Times Asia Gas Report*, Vol. 34 (March 2000), pp. 2-5.

61. "China Approves First LNG Import Project" *World Gas Intelligence* (January 27, 2000), internet edition; and *Oil & Gas Journal Online's Downstream This Week* (May 19, 2000), e-mail edition.

62. "China $3bn Changbei Project Moves Ahead," *Financial Times International Gas Report*, Vol. 394 (March 17, 2000), pp. 2-3; and " What's New Around the World," *World Gas Intelligence* (June 16, 2000), Vol. 11, No. 11, p. 11.

63. "India Awards Further LNG Project, As Delhi Defines Shipping Policy," *World Gas Intelligence* (August 24, 2000), on-line edition.

64. "Rasgas Seals 10% in Petronet," *Financial Times International Gas Report*, Vol. 405 (August 18, 2000), p. 14.

65. “India: Qatar To Begin LNG Supply in Gujarat from End-2003,” *BBC Monitoring South Asia—Economic* (October 18, 2000), on-line edition.

66. *Oil & Gas Journal Online’s Downstream This Week* (May 19, 2000), e-mail edition.

67. “CMS, Birla Sign $1.6 bn LNG Deal,” *Financial Times Power in Asia*, Vol. 311 (September 19, 2000), p. 8.

68. “Malaysia Awards $1.5 Bn LNG Contract,” *Financial Times International Gas Report*, Vol. 391 (February 4, 2000), pp. 4-5.

69. “What’s New Around The World,” *World Gas Intelligence* (September 28, 2000), internet edition.

70. “What’s New Around The World,” *World Gas Intelligence* (September 14, 2000), internet edition.

71. “What’s New Around The World,” *World Gas Intelligence* (August 24, 2000), internet edition.

72. “Italy’s Eni Lands $3.8 bn Iran Project,” *Financial Times International Gas Report*, Vol. 404 (August 4, 2000), Pp. 3-4.

73. “BG Signs Joint LNG Venture in Iran,” *World Gas Intelligence* (September 28, 2000), internet edition.

74. “Enron / Total Fina Elf Join UOG,” *FT International Gas Report*, Vol. 393 (March 3, 2000), pp. 18-19; and “UOG’s Dolphin Project Awaits Agreement on Transfer Price and Other Issues,” *Middle East Economic Survey*, Vol. 43, No. 36 (September 4, 2000), pp. A11-A12.

75. “Abu Dhabi Signs 84 Million Dollar Dubai Gas Pipeline Deal,” *C-afp@clari.net (AFP)* (February 22, 2000), internet news service.

76. “Saudi Upstream Talks Hang in Balance,” *World Gas Intelligence* (March 16, 2000), internet edition; and “Crown Prince ‘Abd Allah To Meet US Bidders For Saudi Gas Initiative,” *Middle East Economic Survey*, Vol. 43 No. 37 (September 11, 2000), p. A11.

77. *Oil & Gas Journal’s Downstream This Week* (January 17, 2000), e-mail edition.

78. *Oil & Gas Journal’s Upstream This Week* (April 24, 2000), e-mail edition; “What’s New Around the World,” *World Gas Intelligence* (February 25, 2000), internet edition; and “Israel Accelerates Gas Proposals in Response to Pressure Over Electricity Shortfalls,” *Middle East Economic Survey*, Vol. 43, no. 33 (August 14, 2000), p. A11.

79. *Oil & Gas Journal’s Downstream This Week* (April 17, 2000), e-mail edition; “ExxonMobil / QGPC Ink Gas Deal,” *Financial Times International Gas Report*, Vol. 398 (May 12, 2000), pp. 17-18; and “Kuwait Signs MOU With Qatar and ExxonMobil for North Field Gas Supply,” *Middle East Economic Survey*, Vol. 43, No. 31 (July 31, 2000), p. A14.

80. *Oil & Gas Journal’s Downstream This Week* (May 12, 2000), e-mail edition.

81. “Go-Ahead for In Salah Gas Project,” *Financial Times Gas Markets Week*, Vol. 41 (February 28, 2000), pp. 1, 3; “Green Light for Algeria’s In Salah Gas,” *Financial Times International Gas Report*, Vol. 393 (March 3, 2000), pp. 2-3; and *Oil & Gas Journal’s Upstream This Week* (February 28, 2000), e-mail edition.

82. “BHP / Sonatrach Ink US$1bn Algeria Gas Deal,” *FT International Gas Report*, Vol. 402 (July 7, 2000), pp 5-6; and “$1.03 Billion Ohanet Fields in Algeria Will Supply Gas for LNG Export,” *LNG Express*, Vol. 10, No. 9 (September 2000), p. 3.

83. “Algerian PM Resigns Over Pace of Privatization, Oil Minister Retains Portfolio,” *Middle East Economic Survey*, Vol. 43, No. 36 (September 4, 2000), p. A12.

84. “What’s New Around the World,” *World Gas Intelligence* (September 28, 2000), internet edition.

85. “Large Gas Well Discovered off S. Africa’s West Coast,” *C-afp@clari.net (AFP)* (March 31, 2000).

86. “UK Funds SA Gasfield Project,” *Financial Times International Gas Report*, Vol. 388 (December 10, 1999), p. 21.