Natural Gas

Natural gas is the fastest growing primary energy source in the IEO2004 forecast. Consumption of natural gas is projected to increase by nearly 70 percent between 2001 and 2025, with the most robust growth in demand expected among the developing nations.

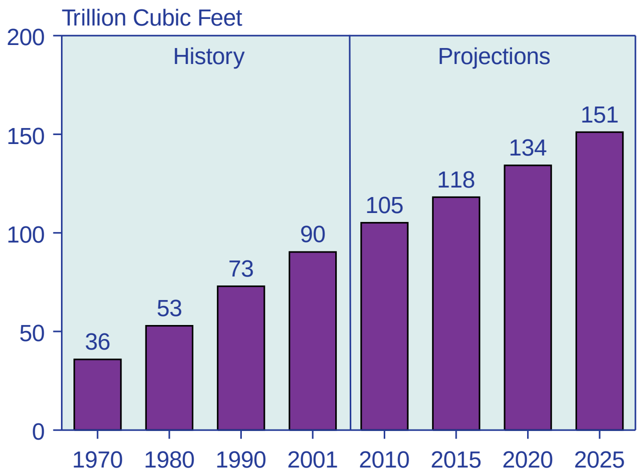
Natural gas is expected to be the fastest growing component of world primary energy consumption in the *International Energy Outlook 2004* (*IEO2004*) reference case. Consumption of natural gas worldwide is projected to increase by an average of 2.2 percent annually from 2001 to 2025, compared with projected annual growth rates of 1.9 percent for oil consumption and 1.6 percent for coal. Natural gas consumption in 2025, at 151 trillion cubic feet, is projected to be nearly 70 percent higher than the 2001 total of 90 trillion cubic feet (Figure 35). The natural gas share of total energy consumption is projected to increase from 23 percent in 2001 to 25 percent in 2025.

The most robust growth in natural gas demand is expected among the nations of the developing world, where overall demand is projected to increase by an average of 2.9 percent per year from 2001 to 2025 in the reference case. Natural gas use in the developing world in 2025 is projected to be double the 2001 level (Figure 36). Most of that increase is expected to be for electricity generation. In the industrialized countries, where natural gas markets are more mature, consumption of natural gas is projected to increase by an average of 1.8 percent per year from 2001 to 2025, with the largest increment projected for North America, at 13 trillion cubic feet (Figure 37).

IEO2004 also includes projections for natural gas production (Table 11), which are new to this year's forecast. The largest increase in production is projected for the Middle East—from 8.3 trillion cubic feet in 2001 to 18.8 trillion cubic feet in 2025. The smallest increase is projected for the industrialized countries—from 39.3 trillion cubic feet in 2001 to 46.8 trillion cubic feet in 2025, an average increase of 0.7 percent per year over the forecast period.

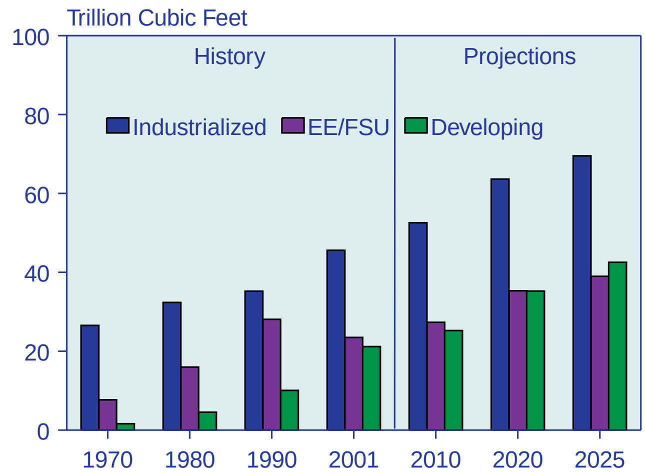
The disparity between the increase expected for natural gas consumption in the industrialized nations and the much smaller increase expected for their gas production indicates that they will rely on other parts of the world for more than 30 percent of their natural gas supply in 2025. In the developing world, gas production is expected to exceed consumption by 16.3 trillion cubic feet in 2025; and in the former Soviet Union, production is projected to exceed consumption by 11.7 trillion cubic feet. As a result, those two regions are expected to be the major source of exports to the rest of the world.

Figure 35. World Natural Gas Consumption, 1970-2025



Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 2001*, DOE/EIA-0219(2001) (Washington, DC, February 2003), web site www.eia.doe.gov/iea/. **Projections:** EIA, System for the Analysis of Global Energy Markets (2004).

Figure 36. Natural Gas Consumption by Region, 1970-2025



Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 2001*, DOE/EIA-0219(2001) (Washington, DC, February 2003), web site www.eia.doe.gov/iea/. **Projections:** EIA, System for the Analysis of Global Energy Markets (2004).

The amount of natural gas traded across international borders continues to grow, having increased from 19 percent of the world's consumption in 1995 to 23 percent in 2002 [*1*]. Pipeline exports grew by 46 percent between 1995 and 2002, and trade in liquefied natural gas (LNG) grew by 62 percent. In 2002, the Middle East accounted for 22 percent of the world's international LNG trade and 6 percent of international trade in natural gas. Qatar accounted for 56 percent of the gas exported from the Middle East in 2002.

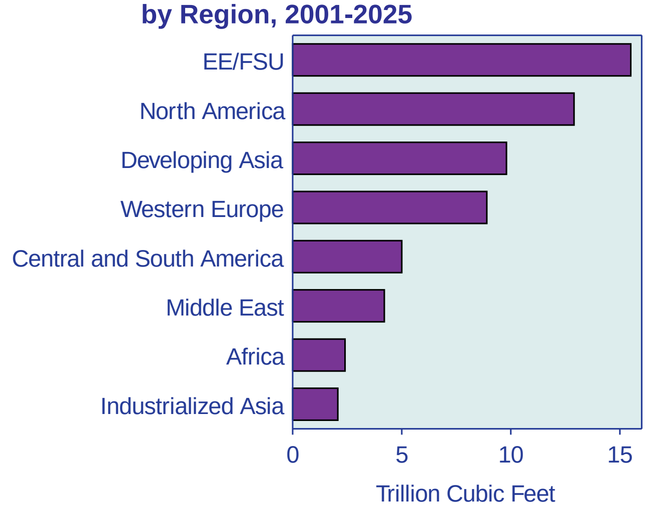
The increases in world natural gas consumption projected in the *IEO2004* reference case will require bringing new gas resources to market, and a number of international pipelines are either planned or already under construction. In addition, because many of the natural gas assets of the developing world are remote from major consuming markets ("stranded"), much of the increment in international trade is expected to be in the form of LNG. The fact that many sources of natural gas are far from demand centers, coupled with cost decreases throughout the LNG chain, has made LNG increasingly competitive, contributing to the expectation of strong worldwide growth in LNG trade.

The economics of transporting natural gas to demand centers currently depends on the market price, and the pricing of natural gas is not as straightforward as the pricing of oil. Almost 60 percent of the world's oil consumption is supplied by imports, whereas natural gas markets tend to be more isolated, with prices varying considerably from country to country. In Asia and Europe, LNG markets are more strongly influenced by oil product prices than by natural gas prices. As the use and trade of natural gas continue to grow, it is expected that pricing mechanisms will continue to evolve, facilitating international trade and paving the way for a global natural gas market.

Reserves and Resources

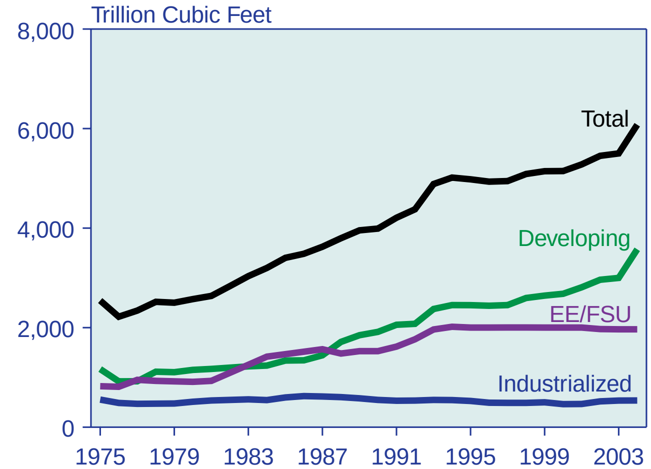
Since the mid-1970s, world natural gas reserves have generally trended upward each year (Figure 38). In 2004, worldwide reserve estimates increased for the ninth consecutive year. As of January 1, 2004, proved world natural gas reserves, as reported by *Oil & Gas Journal*,[9] were estimated at 6,076 trillion cubic feet—575 trillion cubic feet (10 percent) more than the estimate for 2003 [**2**]. The developing world accounted for virtually all the increase in proved reserves. Qatar, where the estimate of proved gas reserves grew from 508 trillion cubic feet for 2003 to 910 trillion cubic feet for 2004, accounted for most of the increment. Smaller but still substantial increases in estimated gas reserves were reported for Iran (an increase of 128 trillion cubic feet) and Nigeria (35 trillion cubic feet). Almost three-quarters of the world's natural gas reserves are located in the Middle East and Eastern Europe and the former Soviet Union (EE/FSU) (Figure 39), with Russia, Iran, and Qatar combined accounting for about 58 percent of the total

Figure 37. Increases in Natural Gas Consumption by Region, 2001-2025



Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 2001*, DOE/EIA-0219(2001) (Washington, DC, February 2003), web site www.eia.doe.gov/iea/. **Projections:** EIA, System for the Analysis of Global Energy Markets (2004).

Figure 38. World Natural Gas Reserves by Region, 1975-2004



Sources: **1975-1993:** "Worldwide Oil and Gas at a Glance," *International Petroleum Encyclopedia* (Tulsa, OK: PennWell Publishing, various issues). **1994-2004:** *Oil & Gas Journal* (various issues).

[9]Proved reserves, as reported by the *Oil & Gas Journal*, are estimated quantities that can be recovered at current price levels, using the production technology available now. 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. Significant gas discoveries made during 2003 are not likely to be reflected in the reported reserves.

(Table 12). Reserves in the rest of the world are fairly evenly distributed on a regional basis.

In the industrialized world, reserves increased by 0.7 trillion cubic feet between 2003 and 2004. While North America recorded growth of 8.6 trillion cubic feet, Western Europe's reserves declined by 6.1 trillion cubic feet. In North America, reserves in Mexico increased by 6.2 trillion cubic feet in 2004, after they had been reduced by more than 50 percent in 2003 following Mexico's adoption of the U.S. Securities and Exchange Commission definitions for reserves [*3*]. In Western Europe, the decrease in reserves is attributed to production in 2003. In the EE/FSU, reserves contracted by 0.4 trillion cubic feet, entirely attributable to a revision of the reserve estimate for Croatia.

Despite high rates of increase in natural gas consumption, particularly over the past decade, most regional reserves-to-production ratios have remained high. Worldwide, the reserves-to-production ratio is estimated at 60.7 years [*4*]. Central and South America has a reserves-to-production ratio of 68.8 years, the FSU 75.5 years, and Africa 88.9 years. The Middle East's reserves-to-production ratio exceeds 100 years.

The U.S. Geological Survey (USGS) periodically assesses the long-term production potential of worldwide petroleum resources (oil, natural gas, and natural gas liquids). According to the most recent USGS estimates, released in the *World Petroleum Assessment 2000*, a significant volume of natural gas remains to be discovered. The mean estimate for worldwide undiscovered gas is 4,258

Table 11. World Natural Gas Production by Region, 2001-2025
(Trillion Cubic Feet)

Region/Country	2001	Projections				Average Annual Percent Change, 2001-2025
		2010	2015	2020	2025	
Industrialized Countries						
North America	**27.6**	**29.6**	**30.6**	**32.8**	**33.6**	**0.8**
United States[a]	19.7	20.5	21.6	23.8	24.0	0.8
Canada	6.6	7.6	7.5	7.1	7.5	0.5
Mexico	1.3	1.5	1.6	1.9	2.1	2.0
Western Europe	**10.2**	**9.0**	**9.0**	**8.9**	**9.8**	**-0.2**
Industrialized Asia	**1.5**	**2.3**	**3.0**	**3.2**	**3.4**	**3.5**
Japan	0.1	0.1	0.1	0.1	0.1	-1.0
Australia/New Zealand	1.4	2.3	2.9	3.1	3.4	3.7
Total Industrialized	**39.3**	**40.9**	**42.6**	**44.9**	**46.8**	**0.7**
EE/FSU						
Former Soviet Union	25.7	30.2	34.9	39.6	44.5	2.3
Eastern Europe	0.9	0.9	0.8	0.8	0.8	-0.5
Total EE/FSU	**26.6**	**31.0**	**35.7**	**40.4**	**45.3**	**2.2**
Developing Countries						
Developing Asia	**8.8**	**10.2**	**11.2**	**13.1**	**15.4**	**2.4**
China	1.1	1.6	1.9	2.3	3.1	4.5
India	0.8	0.9	0.9	1.2	1.5	2.6
South Korea	0.0	0.0	0.0	0.0	0.0	—
Other Developing Asia	6.9	7.7	8.3	9.6	10.8	1.9
Middle East	**8.3**	**9.8**	**12.1**	**15.6**	**18.8**	**3.5**
Africa	**4.6**	**8.1**	**9.9**	**11.9**	**14.1**	**4.8**
Central and South America	**3.6**	**5.5**	**7.1**	**8.6**	**10.6**	**4.6**
Total Developing	**25.2**	**33.5**	**40.2**	**49.2**	**58.9**	**3.6**
Total World	**91.1**	**105.5**	**118.5**	**134.5**	**151.0**	**2.1**

[a]Includes the 50 States and the District of Columbia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Totals may not equal sum of components due to independent rounding.

Sources: **2001:** Energy Information Administration (EIA), *International Energy Annual 2001*, DOE/EIA-0219(2001) (Washington, DC, February 2003), web site www.eia.doe.gov/iea/. **Projections:** EIA, System for the Analysis of Global Energy Markets (2004).

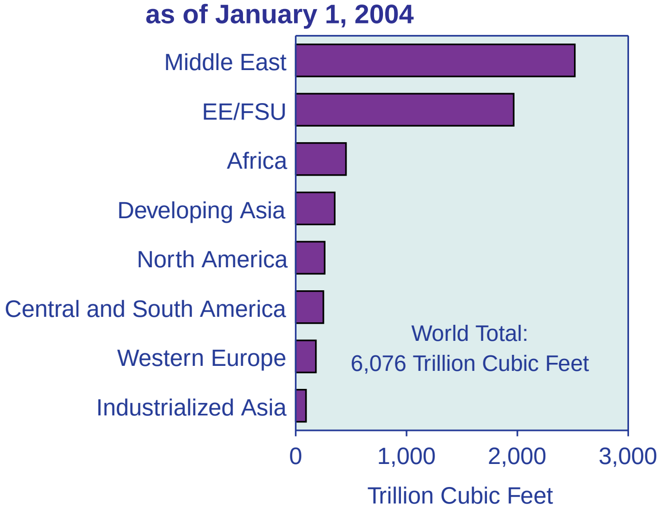
trillion cubic feet (Figure 40), which is approximately double the worldwide cumulative consumption forecast in *IEO2004*. Of the total natural gas resource base, an estimated 3,000 trillion cubic feet is in "stranded" reserves, usually located too far away from pipeline infrastructure or population centers to make transportation of the natural gas economical. Of the new natural gas resources expected to be added over the next 25 years, reserve growth accounts for 2,347 trillion cubic feet. More than one-half of the mean undiscovered gas estimate is expected to come from the FSU, the Middle East, and North Africa; and about one-third (1,169 trillion cubic feet) is expected to come from a combination of North, Central, and South America. It is estimated that about one-fourth of the undiscovered natural gas reserves worldwide are in undiscovered oil fields.

Table 12. World Natural Gas Reserves by Country as of January 1, 2004

Country	Reserves (Trillion Cubic Feet)	Percent of World Total
World	**6,076**	**100.0**
Top 20 Countries	**5,449**	**89.7**
Russia	1,680	27.6
Iran	940	15.5
Qatar	910	15.0
Saudi Arabia	231	3.8
United Arab Emirates	212	3.5
United States	187	3.1
Algeria	160	2.6
Nigeria	159	2.6
Venezuela	148	2.4
Iraq	110	1.8
Indonesia	90	1.5
Australia	90	1.5
Malaysia	75	1.2
Norway	75	1.2
Turkmenistan	71	1.2
Uzbekistan	66	1.1
Kazakhstan	65	1.1
Netherlands	62	1.0
Canada	59	1.0
Egypt	59	1.0
Rest of World	**628**	**10.3**

Source: "Worldwide Look at Reserves and Production," *Oil & Gas Journal*, Vol. 101, No. 49 (December 22, 2003), pp. 46-47.

Figure 39. World Natural Gas Reserves by Region as of January 1, 2004



Source: "Worldwide Look at Reserves and Production," *Oil & Gas Journal*, Vol. 101, No. 49 (December 22, 2003), pp. 46-47.

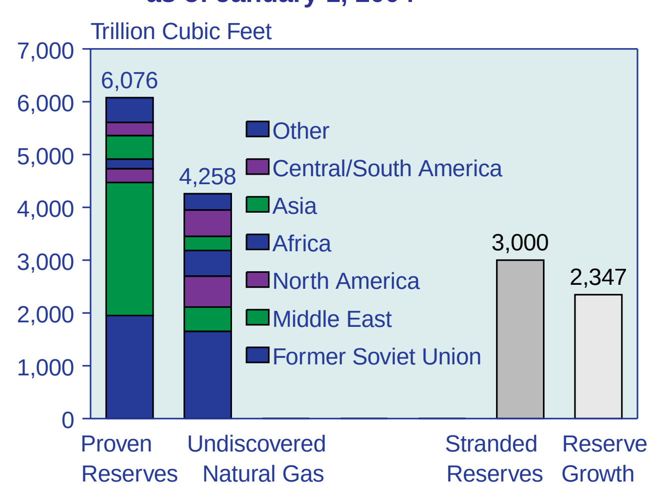
Although the United States has produced more than 40 percent of its total estimated natural gas endowment and carries less than 10 percent as remaining reserves, in the rest of the world reserves have been largely unexploited. Outside the United States, the world has produced less than 10 percent of its total estimated natural gas endowment and carries more than 30 percent as remaining reserves.

Regional Activity

North America

Natural gas consumption in North America is projected to grow at an average annual rate of 1.6 percent between 2001 and 2025 in the *IEO2004* reference case (Figure 41). The highest growth rate in the region—an average annual rate of 3.9 percent—is projected for Mexico, where demand is projected to more than double over the forecast period, from 1.4 trillion cubic feet in 2001 to

Figure 40. World Natural Gas Resources by Region as of January 1, 2004



Source: U.S. Geological Survey, *World Petroleum Assessment 2000*, web site http://greenwood.cr.usgs.gov/energy/WorldEnergy/DDS-60; "Worldwide Look at Reserves and Production," *Oil & Gas Journal*, Vol. 101, No. 49 (December 22, 2003), pp. 46-47; and Energy Information Administration estimates.

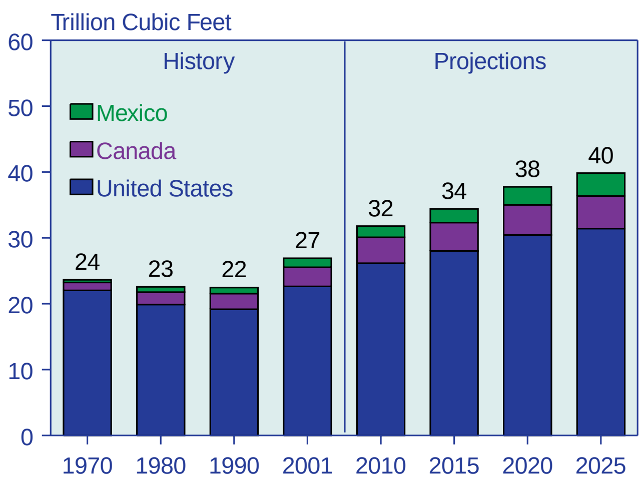
3.5 trillion cubic feet in 2025. Canada's natural gas consumption is projected to increase at an average rate of 2.2 percent per year, increasing by 70 percent over the forecast period.

The United States is by far the largest consumer of natural gas in North America, with consumption projected at 31.4 trillion cubic feet in 2025. Growth in U.S. natural gas use is expected to be strong in the early years of the forecast but to slow after 2020, when projected higher prices erode the advantage of natural gas over coal for electricity generation. As a result, even with continued growth in other sectors, overall consumption of natural gas in the United States is projected to increase at an average annual rate of only 1.4 percent.

The North American natural gas market is tightly integrated, with Canada supplying the bulk of U.S. imports and the United States supplying imports to Mexico. That trade structure is expected to change, however, as LNG imports from other regions begin to play a more prominent role. Imports of LNG into the United States are projected to surpass pipeline imports from Canada by 2015, and LNG imports into Mexico are projected to reduce Mexico's dependence on the United States as early as 2007.

At present, North America produces approximately as much natural gas as it consumes. In 2010, however, the region's consumption is projected to exceed its production by 2 trillion cubic feet, and the gap between production and consumption is projected to increase to almost 5 trillion cubic feet in 2020 and 6 trillion cubic feet in 2025. LNG from other regions will be needed to bridge the gap.

Figure 41. Natural Gas Consumption in North America, 1970-2025



Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 2001*, DOE/EIA-0219(2001) (Washington, DC, February 2003), web site www.eia.doe.gov/iea/. **Projections:** EIA, System for the Analysis of Global Energy Markets (2004).

United States

Although the United States holds only 3.1 percent of the world's natural gas reserves, it consumed more than any other country in 2001, and its natural gas production was exceeded only by Russia's. With U.S. production projected to grow more slowly than its consumption, it is expected to import more natural gas, most of which is expected to be in the form of LNG.

Until 2001, the United States had only two active receiving terminals for LNG, at Everett, Massachusetts, and Lake Charles, Louisiana. When domestic spot market prices for natural gas climbed above $10 per thousand cubic feet in the winter of 2001, however, plans were announced for the reopening of mothballed LNG terminals in Maryland (Cove Point) and Georgia (Elba Island), and plans for the construction of additional new facilities were discussed. The Cove Point and Elba Island terminals were reopened in 2001 and 2003, respectively. In addition, four new LNG terminals are expected to open on the U.S. Atlantic and Gulf Coasts between 2007 and 2010. The first new LNG terminal in more than 20 years is projected to open on the Gulf Coast in 2007, and another facility, expected to serve Florida, is projected for construction in the Bahama Islands [**5**], with the gas to be transported through an underwater pipeline to Florida (Figure 42).

Total net imports are projected to supply 21 percent of total U.S. natural gas consumption in 2010 (5.5 trillion cubic feet) and 23 percent in 2025 (7.2 trillion cubic feet), compared with recent historical levels of around 15 percent. Nearly all of the increase in net imports, from 3.5 trillion cubic feet in 2002, is expected to consist of LNG. LNG imports already have doubled from 2002 to 2003, based on preliminary estimates that show LNG gross imports at 540 billion cubic feet in 2003, compared with 228 billion cubic feet in 2002. Strong growth in LNG is expected to continue throughout the forecast period, with LNG's share of net imports growing from less than 5 percent in 2002 to 39 percent (2.2 trillion cubic feet) in 2010 and 66 percent (4.8 trillion cubic feet) in 2025 [**6**].

Existing U.S. LNG plants are expected to be at, or close to, full capacity by 2007, importing 1.4 trillion cubic feet annually, and new plants are projected to import a total of 812 billion cubic feet in 2010. In addition, a new terminal in Baja California, Mexico, is expected to start moving gas into Southern California in 2007, with volumes reaching 180 billion cubic feet by 2008. Additional capacity in Baja California is expected to be added in 2012, increasing annual deliveries into Southern California to 370 billion cubic feet per year from 2014 through 2025. Other new terminals are expected to be constructed in the Mid-Atlantic and New England regions by 2016, and significant additional capacity is expected along the Gulf Coast by 2025, including expansions of existing terminals and construction of new ones. Imports into new

Gulf Coast terminals are projected to total nearly 2.5 trillion cubic feet in 2025 [7].

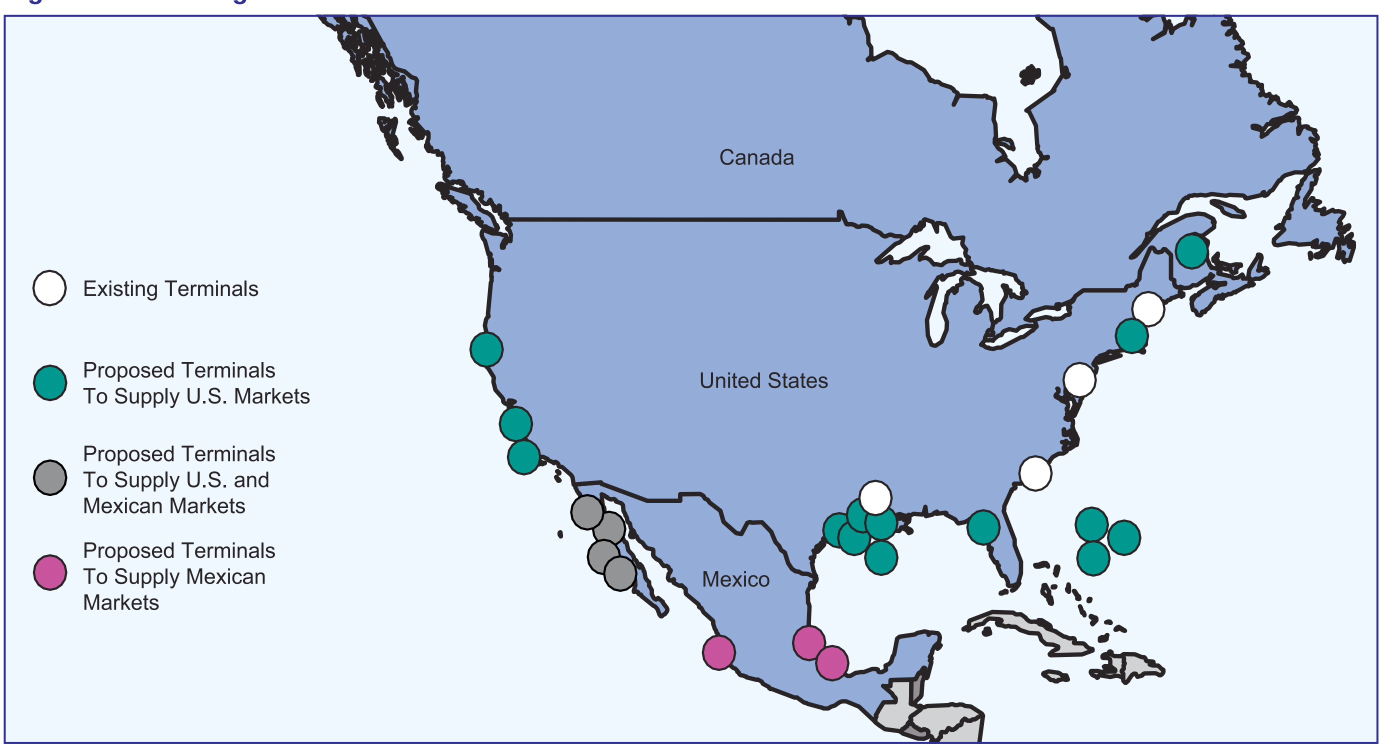
As of August 2002, there were 16 active proposals to construct new LNG regasification terminals in North America to serve U.S. markets (or partially serve, as in the case of three proposed terminals in Baja California, Mexico), with total annual capacity slightly over 5 trillion cubic feet. As of December 1, 2003, there were 32 active proposals for new terminals: 21 in the United States, 4 in Baja California, Mexico (to serve both Mexico and U.S. markets), 2 in Mexico (to serve Mexican markets exclusively), 3 in the Bahamas (to serve U.S. markets), and 2 in Canada (to serve Canada and possibly also U.S. markets). Three proposals to construct terminals in the onshore Gulf of Mexico have been filed with the U.S. Federal Energy Regulatory Commission, and one, Cameron LNG (formerly Hackberry), has received preliminary approval. Two more proposals for the offshore Gulf of Mexico have been filed with the U.S. Coast Guard.

The increase in proposed capacity between 2002 and 2003 includes both additional terminals and increases in capacity for many of those previously proposed. Proposed projects active during the summer of 2002 were primarily for terminals with a capacity of 1 billion cubic feet per day or less, whereas 9 of the current proposals are for terminals with a capacity of 1 to 2 billion cubic feet per day. If all the U.S. LNG facilities currently being proposed were completed, they would add more than 15 trillion cubic feet to annual U.S. import capacity. In addition, two proposed terminals in Mexico to serve Southern Mexican markets would have the indirect effect of reducing U.S. natural gas exports to Mexico.

Global developments are contributing to the domestic emphasis on LNG in the United States, as new liquefaction facilities proliferate around the world and potential supply sources expand. Until 1995, almost all U.S. LNG imports were from Algeria. More recently, shipments have also been received from Nigeria, the United Arab Emirates, Oman, Qatar, Malaysia, Australia, and Trinidad and Tobago. Additional sources of supply exist throughout the world where liquefaction facilities are either being developed or are in the planning stages.

Current worldwide liquefaction capacity and LNG consumption are roughly equivalent, at slightly over 6 trillion cubic feet per year, indicating that supply constraints are contributing to the current underutilization of U.S. regasification capacity. The equivalency of capacity and consumption is changing, however, with an additional annual capacity of 2 trillion cubic feet under construction and scheduled to come on line by 2006 and an additional 8.5 trillion cubic feet of capacity planned to come on line by 2011. Trinidad and Tobago, with current annual capacity of approximately 300 billion cubic feet, has now surpassed Algeria as the primary source of supply for U.S. markets. With an additional 157 billion cubic feet scheduled to come on line by 2006 and 570 billion cubic feet under consideration for development by 2011,

Figure 42. Existing U.S. LNG Terminals and New Terminals Planned in North America



Source: Energy Information Administration.

Trinidad and Tobago (located in relative proximity to the U.S.) is an important player in the future growth of the U.S. LNG market.

As the global market evolves, LNG is becoming an increasingly important energy source for many countries. A number of European and Asian nations already rely heavily on LNG. Japan, in particular, depends on LNG to meet its power generation needs, and the United States has been exporting LNG to Japan for more than 30 years from a liquefaction plant in Kenai, Alaska. As the world market for LNG continues to expand, natural gas is expected to become more of a global commodity, and the world natural gas market is expected increasingly to affect the U.S. market.

An important aspect of globalization is expansion of the LNG spot market. Internationally, most LNG currently is traded under long-term contracts. In recent years, however, the short-term market has played a more significant role, especially in the United States. Most of the LNG imported at the Everett terminal in Massachusetts remains under long-term contract at relatively stable quantities, but short-term deliveries at Lake Charles, Louisiana, have risen and fallen dramatically over the past few years, primarily in response to domestic natural gas prices.

Recent developments in Japan and South Korea illustrate the potential impact of global developments on the U.S. LNG market. In Japan, the forced closing of more than a dozen nuclear reactors in 2001 and 2002 because of reporting discrepancies led to greater reliance on fossil fuels for electricity generation. The result was a significant increase in Japan's demand for LNG, so that the majority of world spot cargoes were delivered to the Japanese market. Japan's increased reliance on LNG probably contributed to the reduction in short-term deliveries of LNG to the United States during the winter of 2001-2002, although low natural gas prices also played a role. In South Korea, an unusually cold winter in 2002-2003 led to the diversion of many spot cargoes to that country to meet unusually high demand for heating. The increase in shipments to South Korea may in part explain the low level of U.S. LNG imports during the winter of 2002-2003, when natural gas spot prices were spiking. These examples suggest that an assessment of future U.S. LNG consumption patterns cannot be based solely on the economics of the U.S. natural gas market.

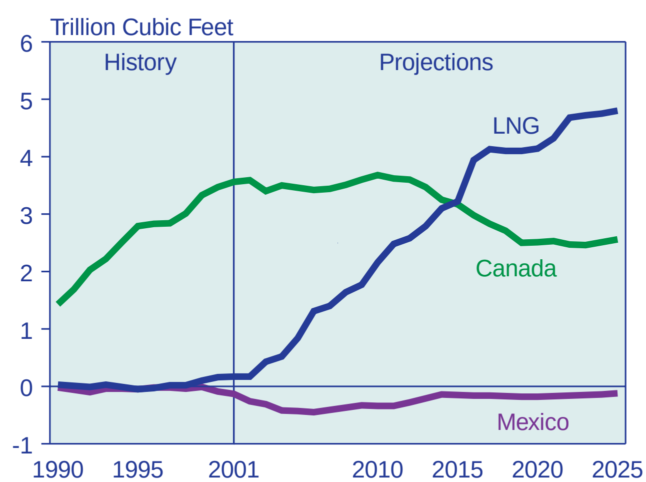
Canada

Canada is expected to continue producing more natural gas than it consumes; however, the amount of excess production available for export is expected to decrease. Like the United States, Canada has a growing need for natural gas for domestic use, while its supply basins are maturing, causing the pace of production increases to slow. In the *IEO2004* reference case, Canada's production is projected to grow at an average annual rate of 0.5 percent, while its consumption grows by 2.2 percent annually. In 2001, natural gas production in Canada exceeded consumption by 3.7 trillion cubic feet. In 2025 its excess production is projected to be 30 percent less, at 2.6 trillion cubic feet, most of which is expected to be exported to the United States.

Until recently Canada was expected to remain the primary source of natural gas imports for the United States through 2025, but it is currently projected that net U.S. imports of LNG will exceed its net imports from Canada by 2015 (Figure 43). The primary reason for the change is a significant downward reassessment by the Canadian National Energy Board (NEB) of expected natural gas production in Canada. In 1999, the NEB estimated that Canada's total production would be in a range of 8.1 to 9.0 trillion cubic feet in 2015 and 7.7 to 9.9 trillion cubic feet in 2025. In contrast, its 2003 estimates are 5.9 to 7.1 trillion cubic feet in 2015 and 4.3 to 6.1 trillion cubic feet in 2025.

Additional reasons for the downward reassessment of projected natural gas exports from Canada are declining natural gas production in the province of Alberta, which accounts for more than 75 percent of Canada's natural gas production, and increasing use of natural gas for oil sands production. In its most recent annual reserve report, the Alberta Energy and Utilities Board expects gas production in the province to decline at an average rate of 2 percent per year from 2003 to 2012, while its oil sands production could triple. Because natural gas is one of the fuels used in producing oil sands, such a dramatic increase could divert significant amounts of gas

Figure 43. Net U.S. Imports of Natural Gas, 1970-2025



Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 2001*, DOE/EIA-0219(2001) (Washington, DC, February 2003), web site www.eia.doe.gov/iea/. **Projections:** EIA, *Annual Energy Outlook 2004*, DOE/EIA-0383(2004) (Washington, DC, January 2004), Table A13.

from the U.S. import market. Other factors that could contribute to a decline in Canadian gas exports include higher projections for domestic natural gas demand in Canada and recent disappointments in Canadian drilling results, including smaller discoveries with lower initial production rates and faster decline rates.

Some major gas finds in recent years had contributed to the belief that Canada would continue to supply both its own needs and the bulk of U.S. import needs, but the discoveries are proving to be much less prolific than initially expected. One such find was the Ladyfern field in northeastern British Columbia. Production from the Ladyfern field, heralded as Canada's largest find in 15 years, peaked at 700 million cubic feet per day in 2002 and is declining rapidly. Current production is about 300 million cubic feet per day, and many expect the field to be depleted by the end of 2004. Another recent disappointment was the Scotian Shelf Deep Panuke field. In February 2003, EnCana (Canada's second largest oil company), initially highly optimistic about the field, requested that the regulatory approval process for developing it be placed on hold while it reassesses the economics of development.

The decline in Canada's exports of natural gas to the United States is expected to be mitigated by the construction of a pipeline that would bring MacKenzie Delta gas into Alberta. The gas would then be available both to serve Canada's internal needs and to provide exports to U.S. markets. Initial flows from the pipeline are expected in 2009, with annual throughput reaching approximately 675 billion cubic feet in 2012 and remaining at that level through the end of the forecast period.

Mexico

In Mexico, natural gas consumption is expected to far outstrip production over the forecast period. In the *IEO2004* reference case, Mexico's demand for natural gas is projected to grow at an average annual rate of 3.9 percent from 2001 to 2025, while production grows by 2.0 percent per year. The projected growth in demand is primarily to fuel natural gas combined-cycle electricity generation, but as infrastructure to serve residential and commercial users continues to grow, requirements for natural gas in all sectors is growing. Mexico thus faces an increasing dependence on imports, which is projected to grow from 7 percent in 2001 to 40 percent in 2025. This would leave Mexico in a precarious position, given that its only current source of imports is the United States, which is a net importer itself. Mexico is striving to remedy the situation in two ways, by developing LNG import facilities and by attracting foreign capital to help develop its own resources. The administration of Mexico's President Vincente Fox strongly supports both avenues of development.

LNG facilities have been proposed at Altamira on Mexico's Gulf coast and at Lazaro Cardenas on its Pacific coast. Five facilities have been proposed in Baja California, Mexico, to serve both Mexican and U.S. markets. As of late November 2003, the Mexican Energy Regulatory Commission had granted some of the required permits for the Altamira terminal and for three Baja California terminals—those proposed by Marathon Oil, Sempra Energy, and Shell. Mexico is not immune to local opposition, however, and concerns have been raised by citizens' groups in Baja California about health and safety issues that could slow (or even stop) progress on some projects.

Pemex, Mexico's state-owned oil and gas company, has to date concentrated its exploration and development efforts on oil, finding it to be more profitable than gas. As a result, a vast potential still exists for development of its indigenous gas resources. According to the Mexican government, only 10 percent of its onshore resources have been explored, 4 percent of offshore regions considered to have good potential have been explored, and no exploration has occurred in the deep offshore. Pemex wants to place a stronger emphasis on gas, but it lacks funds to finance the development.

Approximately 2 years ago, the government began a campaign to attract foreign investment through Multiple Service Contracts (MSCs), under which a contractor would handle multiple phases of development, such as arranging financing for a project to develop and produce reserves in a given block, produce the gas, build any needed pipeline infrastructure to deliver the gas, and deliver the gas to Pemex. MSCs were shunned by potential bidders when they were first proposed because of terms deemed unfavorable to investors: the Mexican constitution prohibits foreign ownership of any of its oil and gas assets and also stipulates that payment for help in developing its oil and gas resources must be for services rendered and cannot be linked in any way to the level of production. Accordingly, foreign companies would be prohibited from booking reserves, and their profit margins would be limited, even when gas prices rose, making the contracts economically unattractive. The situation is further complicated by the fact that elements of the Mexican government are declaring that the MSCs, even with all their stipulations, violate the Mexican constitution and are thus illegal and subject to being overturned.

After numerous revisions to the terms of the contracts, attempts to attract foreign investment through MSCs have finally begun to show some progress. Out of seven MSC tenders for help in developing natural gas reserves in the Burgos Basin in northwestern Mexico, four contracts were awarded. The contracts, hopefully, will lead to an additional 400 million feet per day of production, still far short of the 1,000 million cubic feet per day that Pemex had hoped the contracts would yield by 2006. The hoped-for 1,000 million cubic feet per day would have satisfied 15 percent of the domestic demand projected by the Mexican government and lessened reliance on imports, which have averaged around 700 million feet per day for most of 2003. Some large oil companies, including ExxonMobil and Total, purchased tender documents but later decided not to proceed; most international oil companies showed no interest at all.

Pemex has announced that it will accept feedback from bidders on how to make the contracts more acceptable while still complying with Mexican constitutional law before re-offering the blocks that were not bid on. It is anticipated that this will happen in early 2004. In the middle of 2004, Pemex plans to offer a second round of tenders to develop resources along its Gulf coast and in the south near the Bay of Campeche. It is hoped that some combination of production developed under the MSCs and LNG imports will allow Mexico to become more self-sufficient and less dependent on the United States for its gas requirements in the future.

Western Europe

Natural gas is expected to be the fastest growing fuel source in Western Europe, with demand projected to grow at an average annual rate of 2.0 percent, from 14.8 trillion cubic feet in 2001 to 23.7 trillion cubic feet in 2025. Western Europe currently holds less than 4 percent of the world's proved natural gas reserves, and its production is projected to decline from 10.2 trillion cubic feet in 2001 to 9.8 trillion cubic feet in 2025 (see Table 11). As a result, the region is expected to become increasingly dependent on imports, especially toward the end of the forecast period, when growth in natural gas consumption is expected to accelerate. In 2001, 31 percent of Western Europe's natural gas supply was imported from outside the region; *IEO2004* projects that in 2025 Western Europe will need to import 59 percent.

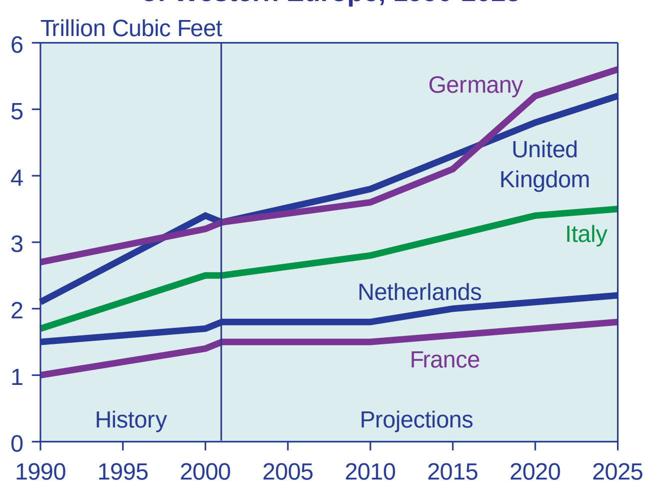
Western Europe's largest consumers, in order of amount consumed in 2002, are the United Kingdom, Germany, Italy, the Netherlands, and France (Figure 44). Between 2015 and 2020, Germany is expected to replace the United Kingdom as Western Europe's largest natural gas consumer and remain there through the rest of the forecast period, in part due to its commitment to phase out nuclear power over the next 20 years. In 2025, Germany is projected to consume 5.6 trillion cubic feet of natural gas and the United Kingdom 5.2 trillion cubic feet.

The United Kingdom, with an estimated 26.0 trillion cubic feet of natural gas reserves, is at present both Western Europe's largest producer and largest consumer of natural gas. Until the mid-1990s, it was a net importer of gas, shifting to a net exporter after 1997 when its production began to increase as deregulation and privatization of the U.K. gas industry progressed. A major milestone in the process was the passage of the 1995 Gas Act, which split up British Gas, at the time the monopoly supplier to the interruptible market, and brought in competition. The privatization of the gas industry led to increased gas supply at reduced prices, which lowered the United Kingdom's reliance on coal for electricity generation. The U.K. natural gas market has continued to grow, as has its share of electricity generation. The natural gas share of utility fuels, which was 1 percent in 1988 [*8*], is projected to increase to almost 50 percent by 2010.

Natural gas consumption in both the Netherlands and France is projected to grow modestly over the forecast period, to 2.2 and 1.8 trillion cubic feet, respectively, in 2025. France is expected to remain the smallest of Western Europe's top five consumers, in part because the French natural gas market is controlled by the state gas company, Gaz de France. The French government was slow to liberalize its natural gas market to conform to the mandates of the European Gas Directive, which did not become national law until almost 3 years after the EU deadline. The French Electricity Regulation Commission contends that the market limits competition because of an overabundance of long-term contracts with foreign groups. Gaz de France currently dominates supply, but this will change when the Commission takes regulatory control of the natural gas market as scheduled in 2004. At that time it intends to introduce more flexibility into contractual terms and foster competition. In the meantime, growth in natural gas consumption is slow and is expected to show little increase until after 2010.

In the other Western European countries, natural gas consumption is projected to grow at a combined average

Figure 44. Natural Gas Consumption in Countries of Western Europe, 1990-2025



Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 2001*, DOE/EIA-0219(2001) (Washington, DC, February 2003), web site www.eia.doe.gov/iea/. **Projections:** EIA, System for the Analysis of Global Energy Markets (2004).

rate of 3.3 percent per year. Some of the most rapid growth in natural gas consumption is occurring in Spain and Portugal, where gas markets have only recently begun to flourish. Between 2001 and 2002, Portugal saw a 21.0-percent increase in consumption and Spain saw a 14.4-percent increase. In 1998, Portugal's gas consumption increased from less than 10 billion cubic feet to 28 billion cubic feet; in 1999, consumption again increased dramatically, to 80 billion cubic feet.

Although virtually all of Portugal's natural gas comes by pipeline from Algeria, Portugal began importing LNG in 1998 and in 1999 entered into a contract to purchase LNG from Nigeria for 20 years beginning in 2002. The LNG was regasified initially in Spain and piped into Portugal until Portugal's own regasification terminal at Sines became operational in October 2003. The Sines terminal, operated by Gas de Portugal, has an annual capacity of 146 billion cubic feet, more than twice Portugal's 61 billion cubic feet of consumption in 2002. Almost all of the natural gas consumption in Portugal is for electricity generation.

Spain is considered one of the world's most rapidly growing natural gas markets. Consumption over the past 10 years has more than tripled. The country is in the process of phasing out its older nuclear and coal-fired power plants in favor of gas. Almost entirely dependent on imports to satisfy demand, Spain currently has three LNG receiving terminals operated by state-owned Enagas—in Barcelona, Huelva, and Cartagena. The terminals became operational in 1969, 1988, and 1999, respectively, and all are being expanded. A fourth terminal in the port of Bilboa in the northwestern Basque region, operated by a consortium of BP, Iberdrola, Repsol YPF, and EVE, came on line in August 2003. There are also two new terminals currently under construction at El Ferrol and Sagunto, both scheduled to come on line in 2006-2007. Both will be operated by consortia. In 2002, Spain received 59 percent of its gas imports as LNG and the remainder as pipeline imports from Norway and Algeria.

The major producing countries in Western Europe are, in order of amount produced in 2002, the United Kingdom, Norway, and the Netherlands. In 2002, they together produced 8.0 trillion cubic feet of gas and consumed 4.9 trillion cubic feet, exporting all but a small amount of the remainder to other Western European countries. These three countries contain most of Western Europe's indigenous natural gas resources. Most of the reserves in the United Kingdom and the Netherlands are in mature gas fields considered to be in decline, and the likelihood of major new finds is small.

Norway also has maturing gas fields, but it has extensive offshore reserves. Norway's proved reserves at the end of 2002 showed more than a 75-percent increase over proved reserves at the end of 2001, primarily because of the discovery of the offshore Ormen Lange field, estimated to contain 13.3 trillion cubic feet of recoverable reserves. Production from Ormen Lange is expected to begin in 2007, with most of the gas destined for the United Kingdom. Norway itself consumes only about 150 billion cubic feet of natural gas per year and exports the rest.

Western Europe's dependence on natural gas imports from other regions has been growing for some time. The Western European natural gas market was relatively self-contained until the early 1970s, when consumption first began to exceed production. The gap was filled by LNG imports that started arriving from Algeria and Libya and pipeline imports that started flowing from the Soviet Union. Over the years, additional pipeline capacity from the Soviet Union and north Africa was added. Currently, the primary sources for imports of natural gas to all of Western Europe are pipeline imports from Russia and Algeria and LNG from numerous sources, including Algeria. In 2002, the region imported more than 35 percent of its supplies. Russia provided 43 percent of the imported gas, Algeria provided 16 percent as pipeline imports and an additional 31 percent as LNG, and the remaining 10 percent was imported as LNG from Algeria, Nigeria, Qatar, Oman, Libya, Trinidad and Tobago, the United Arab Emirates, Australia, and Brunei.

Germany, Italy, and France are Western Europe's biggest natural gas importers. Germany received 38 percent of its supplies from Russia, with the remainder coming from within the region. Italy received 30 percent of its supplies by pipeline from Russia, 32 percent by pipeline from Algeria, and 9 percent as LNG from Algeria and Nigeria. France, Spain, and Italy are Western Europe's biggest importers of LNG. Together, the three countries in 2002 imported 23 percent of their total consumption as LNG and 45 percent as pipeline imports from Russia and Algeria.

The *IEO2004* forecast expects Western Europe's LNG consumption to grow strongly over the projection period. Western Europe currently has 10 operating LNG import facilities—4 in Spain, 2 in France, 1 in Belgium, 1 in Greece, 1 in Italy, and 1 in Portugal—with a combined capacity of about 2,000 billion cubic feet per year. Considerable infrastructure development is planned to increase LNG import capacity (Figure 45). Expansion is underway at 3 of Spain's 4 facilities, and 2 new ones are under construction, adding 526 billion cubic feet of annual capacity by 2007. In the United Kingdom, plans are in the works for 161 billion cubic feet of annual capacity. In addition to projects already underway, an additional 2,100 billion cubic feet of capacity has been proposed for completion before 2010. The added capacity proposed is for Belgium, France, Italy, the Netherlands, and the United Kingdom.

In addition to its plans to import LNG, the United Kingdom is in the process of developing other sources of supply to meet the projected future needs. Centrica (formerly British Gas), a major energy supplier, has negotiated import agreements scheduled to start in 2005 with Statoil of Norway and Gasunie of the Netherlands. Proposals for new import pipelines are also being considered to transport offshore gas (likely to include gas from Norway's Ormen Lange field) to the United Kingdom; and plans have been announced to add compression by 2005 that will almost triple the capacity of the Interconnector at Bacton, one of two major pipelines used to bring gas into the United Kingdom.

Norway is entering the LNG market as an exporter. Gas from the Snohvit and other fields in the Barents Sea will be processed in what will be the largest sub-sea LNG project in the world for the international Snohvit Group, a consortium of oil companies that includes the Norwegian Statoil ASA, Norsk Hydro, and French TotalFinaElf S.A. The plant, now under construction on Melkoye Island, will have a capacity of 200 billion cubic feet per year. It is expected to go into production by 2006, with exports targeting markets in Spain, France, and the United States. In November 2002, Statoil purchased capacity rights at the Cove Point, Maryland, import terminal, gaining 20-year access to one-third of the terminal's capacity. This will be the first time that Western European LNG exports have targeted the United States.

Russia is the largest supplier of natural gas imports to Western Europe, and the second largest supplier is North Africa (primarily Algeria), delivering supplies by pipeline to Italy, Spain, and Portugal and by LNG tanker to France, Spain, Italy, Belgium, Greece, and Portugal. Algeria is increasing its exploration efforts and encouraging foreign investment in the further development of its natural gas transmission and export activities. Egypt is also expected to become a supplier of gas to Western Europe. A two-train LNG liquefaction facility is currently under construction at Idku, with an expected completion date of 2005. The first train has already been committed to Gaz de France, and the second train has been committed to Centrica for delivery to Italian and U.S. markets.

Industrialized Asia

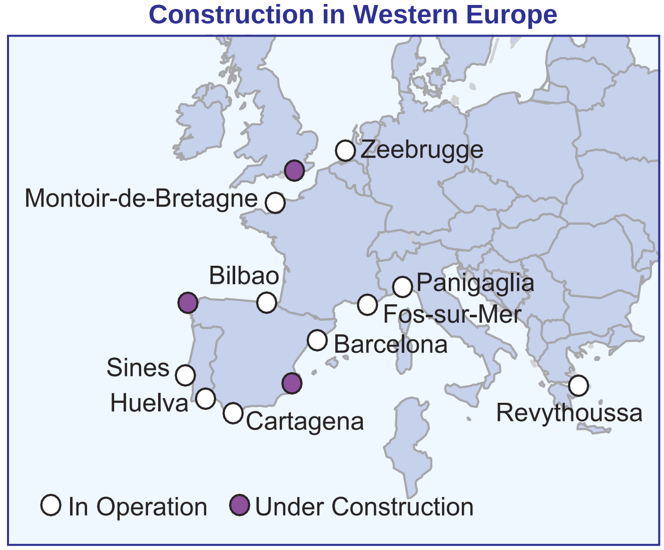
In the three countries of industrialized Asia—Japan, Australia, and New Zealand—annual natural gas consumption grew by 50 percent over the 1991-2001 period, from 2.6 trillion cubic feet to 3.9 trillion cubic feet. In the *IEO2004* reference case, their combined demand is projected to grow by 1.8 percent per year on average, to 6.0 trillion cubic feet in 2025. Australia and New Zealand account for about one-third of the projected increase. Australia began to exploit its sizable natural gas resources relatively recently, and in both Australia and New Zealand increased natural gas consumption is projected to accompany strong economic growth over the forecast period.

Japan

Japan's natural gas consumption is projected to grow from 2.8 trillion cubic feet in 2001 to 4.2 trillion cubic feet in 2025, at an average rate of 1.6 percent per year—about the same rate as Japan's projected economic growth rate over the period. As the world's largest LNG importer, Japan plays a key role in the Asia-Pacific natural gas trade. From 1990 to 2001, Japanese gas consumption grew 47 percent. Japan's proved natural gas reserves are estimated at 1.4 trillion cubic feet [***9***], and about 97 percent of natural gas demand in Japan is met by LNG imports. Most of Japan's 2,567 billion cubic feet of imports in 2002 was purchased under long-term contracts and around 1 percent on the spot market.

In 2003, Japanese companies continued to pursue new contracts for natural gas imports to replace expiring contracts and to increase supply. Japan had 23 LNG importing terminals on line in 2003 [***10***]. Its three major gas companies succeeded in signing a joint agreement with Malaysia's MLNG Tiga project in 2002, to begin delivery in 2004. The agreement gives the importer a level of flexibility uncommon in LNG contracts. Tokyo Gas and Toho Gas signed a contract on more traditional terms in October 2001 for LNG purchases from Australia's North West Shelf LNG project, also to begin in 2004. Shell's Sakhalin-2 project in Russia also signed contracts early in 2003 with both Tokyo Electric Power (TEPCO) and Tokyo Gas, to begin delivery in 2007 [***11***]. The expiration of several long-term contracts between Japan and Indonesia in the next few years has generated competition from suppliers. While price issues are important in such contracts, the Japanese companies are also focusing on

Figure 45. LNG Terminals in Operation and Under Construction in Western Europe



Source: Energy Information Administration.

reliability of deliveries in arrangements that will last for as long as 20 years.

Japan's national gas grid currently serves 25 million residential consumers. Japan has 1,400 miles of transmission line, 17,600 miles of medium-distance pipeline and 127,000 miles of low-pressure pipeline [*12*]. The Japanese government has slowly begun to deregulate the natural gas industry, leading to the increased domestic competition. Gas prices are linked to the Japan Customs Cleared Crude price [*13*]. In 2001, 72 percent of natural gas utilization was for power generation [*14*]. City gas consumption has increased by more than 70 percent in the past decade due to a 25-percent increase in natural gas customers and also to a large rise in consumption by industry (Figure 46).

Australia/New Zealand

Australia and New Zealand consumed a combined 1.1 trillion cubic feet of natural gas in 2001, and their consumption is projected to increase at an average annual rate of increase of 2.2 percent, to 1.8 trillion cubic feet by 2025. Relative to neighboring Australia, New Zealand has modest natural gas resources: its proved natural gas reserves were estimated at 1.3 trillion cubic feet in 2004 [*15*]. New Zealand's largest natural gas field, the Maui field, supplies 80 percent of the country's gas needs, but it has lost production capacity in recent years and is likely be exhausted by 2007. Several companies have proposed developing LNG import facilities rather than expend additional resources on exploration, which has returned poor results in recent years. Two new fields, Pohokura and Kapuni, have failed to yield the same low-cost production as the Maui field. New Zealand's largest power companies are partnering with Shell on the construction of regasification infrastructure.

Australia is the third largest LNG exporter in the Asia-Pacific region, after Indonesia and Malaysia. The Australian government has worked to streamline project approval and certification to allow the country's producers to compete in what has been a buyer's LNG market in Asia until recently. Australia's North West Shelf venture owns the country's only liquefaction plant, the Withnell Bay LNG facility, which has three trains and a total capacity of 7.5 million metric tons per year. A fourth train is scheduled to come on line in mid-2004, and a fifth train is under consideration.

The Darwin liquefaction plant, currently under construction, is scheduled for completion in 2004. All 3.6 million metric tons of LNG from the Darwin project has been contracted to Tokyo Electric/Tokyo Gas. Two additional projects have been proposed. Greater Sunrise, located on the Timor Sea, would have a capacity of 5.3 million metric tons per year. The project could be completed by 2009. The Gorgon LNG project, proposed by ChevronTexaco, ExxonMobil, and Shell, would have a capacity of 10.0 million metric tons per year and could be on line in 2008. The Gorgon project has signed a memorandum of understanding with China for 5 million metric tons per year and another to supply 4 million metric tons per year to a potential terminal on the U.S. West Coast [*16*].

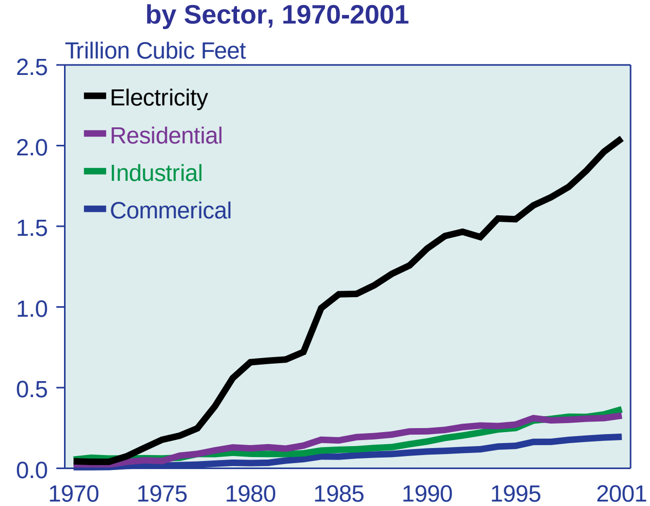
Eastern Europe and the Former Soviet Union

The EE/FSU region holds more than 35 percent of the world's natural gas reserves and accounts for 28 percent of global production [*17*]. In 2002, Russia produced 78 percent of the gas brought to market in the region and 22 percent of the gas marketed globally, surpassing production in the United States [*18*]. In the *IEO2004* reference case, natural gas consumption in the EE/FSU region is projected to reach 39.0 trillion cubic feet in 2025, growing at an average annual rate of 2.1 percent over the forecast period. Consumption is expected to grow by 3.6 percent per year in Eastern Europe and 1.9 percent per year in the FSU. Overall production in the FSU is projected to grow at a rate of 2.1 percent per year, which would assure its status as a major exporter through 2025 (Figure 47).

Changes in the pattern of natural gas use between 1991 and 2001 varied among the EE/FSU nations. In Turkmenistan, Uzbekistan, Hungary, and the Czech Republic there were marked increases in gas use, and in Georgia, Albania, and Azerbaijan there were significant decreases. Since the fall of the Soviet Union in the early 1990s, both economic growth and natural gas consumption have rebounded faster in Eastern European than in the FSU.

In 2001 the FSU countries produced 4.9 trillion cubic feet more gas than they consumed, and in 2025 they are

Figure 46. Natural Gas Consumption in Japan by Sector, 1970-2001



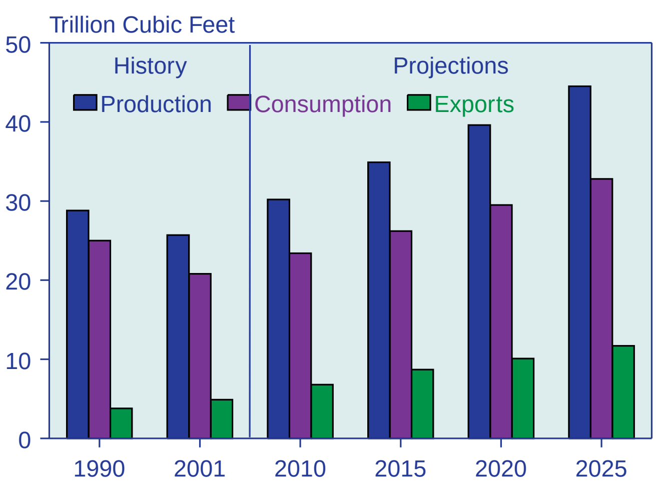
Sources: International Energy Agency, *Energy Balances of OECD Countries* (Paris, France, various issues); and Energy Information Administration, International Statistics Database.

projected to produce 11.7 trillion cubic feet more than they consume, more than double the 2001 amount. Infrastructure expansion will be required for the FSU to be able to market additional gas, and some expansion is already underway.

Recent developments in the EE/FSU natural gas market include completion of major pipeline projects, the signing of new international trade agreements, and progress on several infrastructure expansion proposals to facilitate international trade. One notable project is a pipeline linking Turkmenistan to Afghanistan and Pakistan. On February 27, 2004, President Niyazov instructed the Turkmen Oil and Gas Ministry to determine the extent of its actual reserves as part of its planning for the $3.5 billion Trans-Afghanistan pipeline. Originally proposed in 1997, the project was put on hold because of tensions between Afghanistan and Pakistan; however, since the fall of the Taliban regime in Afghanistan it has drawn strong international (including U.S.) support. Turkmenistan is also pursuing long-term arrangements to provide gas to both Russia and Ukraine and has already signed a 25-year deal to provide gas to Russia.

In 2002, natural gas production increased in Russia, Georgia, Uzbekistan, Poland, and Kazakhstan and fell in most of the other EE/FSU countries. The main exporters of gas were Russia, Kazakhstan, Turkmenistan, and Uzbekistan. Belarus, the Czech Republic, Slovakia, and Hungary were among the region's largest importers in 2002. Kazakhstan, a net importer, also exported about 70 billion cubic feet of gas to other countries in the region. Overall gas production in the EE/FSU has been increasing over the past few years, but consumption still remains well below the levels of the early 1990s.

Figure 47. Natural Gas Production, Consumption, and Exports in the FSU Region, 1990-2025



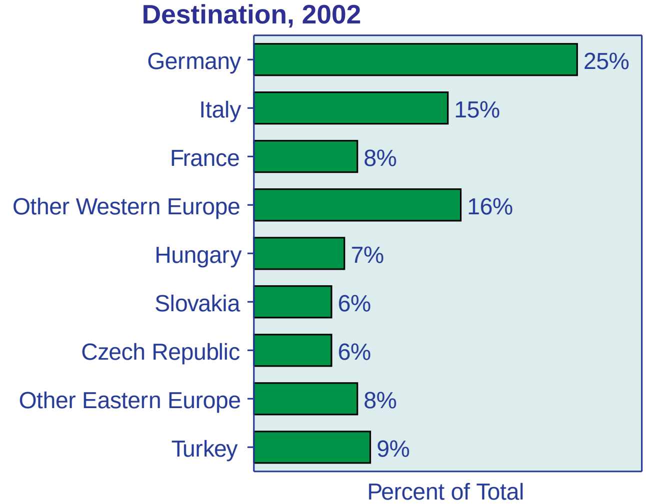
Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 2001*, DOE/EIA-0219(2001) (Washington, DC, February 2003), web site www.eia.doe.gov/iea/. **Projections:** EIA, System for the Analysis of Global Energy Markets (2004).

Russia is a preeminent force in global natural gas trade. In 2002, it exported 4.5 trillion cubic feet of gas to other European countries (Figure 48) and to Turkey, accounting for 29 percent of global pipeline trade [***19***]. The only other significant regional participant in the pipeline trade was Turkmenistan, with a 1.1-percent market share consisting of deliveries to Iran. Russia's total exports were flat from 2001 to 2002, with slightly lower exports to Western Europe and slightly higher exports to Eastern Europe. In 2002, Western Europe received 64 percent of Russia's exports.

Russia is exploring options to export natural gas to China and South Korea. Gazprom, Rusiya Petroleum, South Korea's state-owned Korea Gas Corporation (KOGAS), and the Chinese National Petroleum Company (CNPC) have started negotiations on the construction of a pipeline that would connect Russia's Kovykta field to South Korea and provinces in Northeast China. The pipeline, with a capacity of 706 billion cubic feet per year, would deliver about two-thirds of its gas annually to China and the remainder to South Korea. It is expected to come on line as early as 2008.

Europe is Russia's primary export market, but Turkey has long been seen as a potential outlet for Russian gas. Currently Russia's fastest growing export market, Turkey jumped ahead of France to become Russia's third largest foreign customer in 2002. Exports to Turkey are expected to continue to grow with the opening of the Blue Stream pipeline in October 2002. Shortly after it began commercial shipments, however, Turkey ceased accepting Russian gas through the Blue Stream, claiming that the price was too high and that by the terms of its contract it could cease acceptance for 6 months

Figure 48. Russian Natural Gas Exports by Destination, 2002



Source: Cedigaz.

without penalty. A new price agreement was reached several months later, and Russia expects to send record supplies to Turkey in 2004, in part because a recent boiler explosion at Algeria's Skidka facility is expected to have a severe impact on exports to Turkey in the near term.

Russia is anticipating that Turkey will become a future transit route to Europe, bypassing Ukraine, Romania, and Bulgaria. All Russian supplies entering Turkey transited those three countries before the Blue Stream was opened, and Russia has long sought alternate routes. The Blue Stream is just one of Russia's attempts to bypass Ukraine; the recently completed second line of the Yamal-Europe pipeline transports gas from Russia's Yamal Peninsula to Germany via Belarus and Poland. The first Yamal-Europe line transits Belarus and Ukraine.

Relations between Russia and Ukraine regarding the transport of Russian gas have been under strain. Tensions arose from Ukraine's failure to keep current in its payments for gas imported from Russia and from Russia's accusation that Ukraine was siphoning gas during transit. Relations between the two countries are improving, however. On August 29, 2003, Russia and Ukraine entered into an agreement under which Russia will ship 4.5 trillion cubic feet to and through Ukraine in 2004, 3.9 trillion cubic feet of which will be destined for export to various European countries. Part of the transit fee will be paid in kind and the rest in cash. As part of the same agreement, Gazprom guaranteed the transport of 1.3 trillion cubic feet of gas, primarily from Turkmenistan, through Russia to Ukraine. Additional stipulations will allow Ukraine to export limited amounts of its own gas under Gazprom's export contracts and to re-export limited amounts of the gas it buys from Gazprom.

Russia is currently Poland's major source of natural gas. In addition to attempting to diversify import sources, the Polish government continues to talk of increasing its own production to assure stability of supply at reasonable prices. In 2002, a long-term natural gas supply agreement between Norway's Statoil and Poland was reached, with Statoil agreeing to begin sending supplies in 2008 through a dedicated pipeline to be constructed from the North Sea to Poland. Plans were aborted in late 2003 at the urging of Polish Prime Minister Leszek Miller because of lower estimates of Poland's gas requirements and the availability of cheaper Russian gas. Shortly thereafter, in the wake of Gazprom's curtailment of supplies because of transit problems in Belarus, Poland entered into a memorandum of understanding with Statoil to increase supplies and diversify import options.

There are still issues to be resolved before EE/FSU natural gas markets are fully developed and open, but the state of the market today is far superior to that of the early to mid-1990s, when gas markets in most EE/FSU countries were almost completely controlled by national governments, and efforts at privatization and foreign involvement were just beginning to develop. The climate for foreign investment in the EE/FSU, particularly Russia, continues to improve, fostered by the region's vast energy resources and recent continued economic growth.

Russia, in particular, is attracting record investment from major Western companies. A good example is Sakhalin Island, where five oil and gas projects are separately operated by unique international consortia [***20***]. Sakhalin I and II are expected to bring oil and gas supplies on line in the next 5 years. The Sakhalin I project is expected to begin piping gas to Japan in 2008. Sakhalin II, which involves the development of Russia's first natural gas liquefaction facility, is expected to begin supplying exports to Japan (and possibly the United States) in 2007. As another example, in June 2003 Germany's Wintershall joined with Gazprom in a joint venture for the production of natural gas from Russia's Urengoi field, with initial development to begin in 2004 and full production in 2008.

Central and South America

Although the natural gas industry in Central and South America is still at an early stage of development, expanding exploration and infrastructure activities in several countries have yielded promising results. Natural gas markets in the region constituted 3.9 percent of world natural gas consumption in 2001. At the beginning of 2004, Central and South America held 4.1 percent of the world's proved natural gas reserves, about 250 trillion cubic feet [***21***]. Natural gas consumption in the region increased from 2.0 trillion cubic feet in 1990 to 3.5 trillion cubic feet in 2001 and is projected to grow at an average annual rate of 3.8 percent per year to 8.5 trillion cubic feet in 2025.

The region's largest natural gas reserves are in Venezuela (148 trillion cubic feet). Trinidad and Tobago, Bolivia, and Argentina also hold reserves of more than 20 trillion cubic feet, and Brazil and Peru have reserves of about 8 trillion cubic feet. Currently, production of natural gas in Central and South America is sufficient to meet regional demand, but only Trinidad and Tobago exports natural gas to other regions, including 187 billion cubic feet of LNG marketed to the United States in 2002 [***22***].

Brazil

From 1991 to 2001, as a result of rapid economic growth and favorable government energy policies, Brazil's natural gas consumption rose from 119 billion cubic feet to 339 billion cubic feet, accounting for 12 percent of regional consumption in 2001 [***23***]. In 2002, Argentina and Bolivia exported 16.9 billion cubic feet and 139.4 billion cubic feet of natural gas to Brazil, respectively. Brazil's own reserves stood at 8.5 trillion cubic feet at the beginning of 2004 [*24*]. Brazil imports 44 percent of its natural gas. The state-controlled energy company, Petrobras, dominates upstream production in Brazil, while distribution falls to the states.

Brazil's largest natural gas reserves are off its south central coast. The recent discovery of an additional 14.8 trillion cubic feet in the Santos basin nearly tripled Brazil's natural gas reserves, moving Petrobras closer to its goal of Brazilian energy self-sufficiency [*25*]. The discovery of unanticipated reserves is particularly important with regard to the Bolivia-Brazil Gasbol pipeline, which was built as part of a 20-year take-or-pay agreement signed in June 1999 [*26*]. Brazil's 1999 plan to expand gas-fired electricity generation capacity was curtailed in 2002, however, as a result of federal and state budget woes stemming from volatility in currency and debt markets. Of the 16 gas-fired electricity plants envisioned in 1999, only 10 are likely to be constructed in the foreseeable future [*27*]. In light of lower investment in electricity generation capacity and recent domestic natural gas discoveries, Brazil is attempting to reduce its import obligations with Bolivia.

The push for an increase in gas infrastructure by the previous presidential administration also aimed to reduce Brazil's dependence on hydropower, after a drought in 2001 led to electricity rationing and blackouts and contributed to Brazil's economic downturn. In 2003, however, favorable weather conditions created an energy surplus, and the new administration has announced an initiative to meet the nation's growing electricity needs largely through expansions of hydroelectric capacity. The Brazilian Basic Infrastructure and Industry Association has estimated that increases in generating capacity on the order of 5 gigawatts annually will be needed to prevent shortfalls after 2007 [*28*].

Other Central and South America

Argentina's natural gas sector continues to be affected by reduced consumer and investor confidence following a 2002 economic crisis that was set off by a 30-percent devaluation of the Argentine peso. The country's natural gas sector is entirely privately held, dominated by privatized former state enterprises now largely owned by major international players. Argentina has 23 trillion cubic feet of proved reserves [*29*]. In 2001, it produced 1,098 billion cubic feet of natural gas and exported 206 billion cubic feet to Chile, Brazil, and Uruguay [*30*]. In Argentina, unlike many other Latin American countries, natural gas has permeated beyond industrial and utility applications to commercial and residential use. One noteworthy example is that 11 percent of road transportation is fueled by compressed natural gas, constituting 5 percent of Argentina's natural gas usage [*31*].

Venezuela has proved natural gas reserves of 148 trillion cubic feet [*32*], and the USGS estimates that about 67 trillion cubic feet remains to be discovered [*33*]. Venezuela's reserves account for 58 percent of South America's total, but Venezuela lacks adequate infrastructure to take advantage of its natural gas abundance. Although Venezuela brought 960 billion cubic feet to market in 2000, because its reserves are mostly associated gas, another 159 billion cubic feet was flared or vented and 752 billion cubic feet was reinjected [*34*]. Venezuela's petroleum industry was troubled by political unrest in 2003, but its natural gas production contracted by only 3 percent in the first half of the year, when disruptions were at their worst [*35*]. The largest part of Venezuelan gas reserves is offshore, near its border with Trinidad and Tobago. In addition, a recent onshore discovery of 2.5 trillion cubic feet presents another opportunity for development [*36*]. At current consumption levels, Venezuela's proved reserves would satisfy 101 years of domestic demand [*37*]. Its transmission and distribution system serves to supply gas mainly to industrial consumers, and only the five largest metropolitan areas have notable distribution networks for residential consumption [*38*].

Petróleos de Venezuela (PDVSA), the state-run energy company, dominates the natural gas sector; however, Venezuela did begin opening the sector for foreign investment in 1999 and offered the first licenses to private participants for nonassociated gas exploration in 2001. The current administration of President Hugo Chavez hopes to increase gas production and generate export opportunities, but continued political unrest and general strikes by PDVSA employees have diminished the potential interest of investors.

Venezuela is considering exporting natural gas as LNG. PDVSA, Royal Dutch/Shell, and Mitsubishi signed a preliminary development agreement to begin a feasibility study for an LNG plant that would process natural gas off the Paria peninsula, but the venture is also weighed down by the political instability of the current regime. Trinidad and Tobago and Venezuela signed a memorandum of understanding regarding the utilization of the natural resources on their shared border. The agreement is the first of its kind in the Western Hemisphere. Venezuelan reserves are larger than the reserves of Trinidad and Tobago, which has a more developed infrastructure. Under the terms of the memorandum, British Petroleum Platforma Deltana will use Trinidad and Tobago's infrastructure to help transport Venezuelan reserves [*39*].

Trinidad and Tobago exported 151 billion cubic feet of LNG to the United States in 2002, 80 percent of its annual LNG production. Another 11 percent went to Puerto Rico and 9 percent to Spain. Trinidad and Tobago has a cost advantage over other LNG exporters targeting the

U.S. market because its proximity to the United States significantly reduces the cost of transporting LNG.

Bolivia is considering exporting LNG, but the gas would have to be piped to the coast through either Peru or Chile. Although building the pipeline through Chile makes more economic sense, a 117-year-old territorial feud between Bolivia and Chile makes the idea politically unpopular. The project, backed by Total, Repsol, BG, and Sempra, is now on hold following public protests and the resignation of President Gonzalo Sanchez de Lorzado [***40***].

There is also a proposal in Peru that would export gas from the Camisea field to markets along the U.S. and Mexican west coasts [***41***]. An export agreement has been reached between U.S.-based Hunt Oil, which is building the Peruvian liquefaction terminal, and Belgium's Tractabel, which hopes to build regasification facilities in western Mexico. The project faces opposition on environmental grounds, because the pipeline would run through sections of the Peruvian rain forest, and the liquefaction facility would be situated near a wildlife sanctuary. The Camisea consortium approached the U.S. Export-Import Bank for a loan, but the request was rejected because of the environmental sensitivity of the project; however, despite the abstention of its U.S. representative, the Inter-American Development Bank approved a loan for the project. The Andean Development Bank also granted a loan for the project.

Developing Asia

The *IEO2004* reference case projects continued rapid growth in natural gas consumption among the countries of developing Asia. Regional natural gas consumption between 2001 and 2025 is projected to increase by 3.5 percent on average per year, about twice as fast as the rate projected for the countries of the industrialized world (Figure 49). Underlying causes include countries' desire for fuel source diversification, particularly for electricity generation, and environmental concerns, particularly in large urban centers.

As the region's largest producers, Indonesia and Malaysia play an important role in natural gas markets; however, the pace is likely to be set by the region's fastest growing energy consumers, China and India. Both have continued their efforts to increase natural gas supplies and develop the infrastructure needed to bring gas to market. China and India together account for 57 percent of the expected regional increment in natural gas use, with projected average annual increases of 6.9 percent and 4.8 percent, respectively.

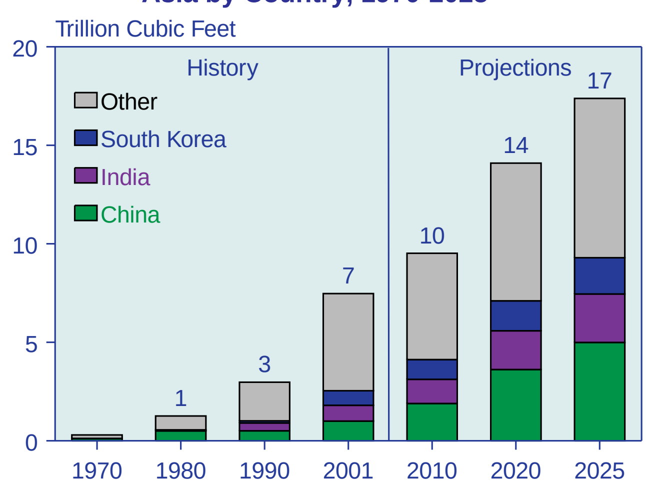
China

Although natural gas use accounted for only 3 percent of China's energy mix in 2001, the Chinese government has recently taken aggressive steps to develop natural gas production, transportation, and import capacity. The government aims to reduce Beijing's dependence on coal by bringing the city's natural gas infrastructure to full operational capacity by 2008 as part of a $12 billion program to clean up the city before it hosts the Olympic games in 2008. In addition, Shanghai province has stopped construction of coal-fired generation facilities in anticipation of inclusion in the nation's developing natural gas transportation system.

China's natural gas reserves were estimated at 53.3 trillion cubic feet in 2002. In 2001, it consumed 1.0 trillion cubic feet of natural gas. China's three gas producers are state-controlled companies, each of which focuses its operations in a different part of the country. Petrochina/Chinese National Petroleum Corporation (CNPC), which concentrates in the north and west of the country, is China's largest producer [***42***]. Sinopec concentrates on southern basins and works with CNPC in some fields in Sichuan province. A large part of Sinopec's business includes refining operations that lack the profitability of the upstream work of the other national oil companies. China National Offshore Oil Corporation (CNOOC) concentrates on offshore production; it produced 128 billion cubic feet of natural gas in 2003 [***43***].

China's natural gas infrastructure is growing quickly. Given that natural gas can help provide electricity and meet environmental objectives, the Chinese government is encouraging the development of gas-fired electricity generation. The distribution system in Sichuan province already has 5,400 miles of pipeline serving industrial and residential customers. In September 2003, Petrochina started building a 454-mile pipeline with a capacity of 116 billion cubic feet per year, connecting

Figure 49. Natural Gas Consumption in Developing Asia by Country, 1970-2025



Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 2001*, DOE/EIA-0219(2001) (Washington, DC, February 2003), web site www.eia.doe.gov/iea/. **Projections:** EIA, System for the Analysis of Global Energy Markets (2004).

Zhongxian field in Sichuan to the Hubei province with the potential of an extension to the eastern coast [*44*]. In August 2003, CNOOC completed construction on a pipeline from the South China Sea to the east coast as part of a drive to increase access to offshore resources in the area.

Petrochina is building a 2,500-mile-long west-to-east pipeline from the Tarim basin in Xinjiang to Shanghai and Beijing with an annual capacity of 706 billion cubic feet. The pipeline connects gas fields in China's sparsely populated west to urban markets in the east. The eastern section of the pipeline, from the Ordos basin to Shanghai, came on line in October 2003, and the western portion is scheduled to come on line in October 2004.

China is also increasing its potential to import natural gas. Several pipelines from eastern Russian fields in Sakhalin or Irkutsk are being considered to deliver gas into Shenyang in northeastern China. The countries have already negotiated a connection from Russia's Kovytka field to flow into the west-to-east pipeline after 2008.

There are also plans to introduce facilities for LNG in China. BP won a contract with CNOOC to build China's first LNG terminal, in Guangdong province, to be completed in 2006 with a capacity of 3.3 million metric ton per year. The Guangdong LNG terminal is currently under construction. Australia LNG, part of North West Shelf LNG, won the long-term supply contract worth more than $10.6 billion for 3 million tons per year of LNG for 25 years, starting in 2005. CNOOC has also broken ground on another LNG terminal at Fujian, which will begin operations in 2007 with an initial capacity of 2.6 million tons per year [*45*].

India

In 2001, India consumed 0.8 trillion cubic feet of natural gas, all of which was domestically produced. The *IEO2004* reference case projects that India's consumption will grow by 4.8 percent per year on average, to 2.5 trillion cubic feet in 2025. In 2001, about 40 percent of the gas consumed was used for electricity generation, and most of the remainder was used by the petrochemical industry [*46*]. Proved reserves in India at the beginning of 2004 were estimated at 30 trillion cubic feet, up from about 27 trillion cubic feet at the beginning of 2003 [*47*].

Much of India's production comes from fields in its western offshore area. On land, the provinces of Assam, Andhra Pradesh, and Gujarat are other major producers. Smaller quantities of gas are produced in Tripura, Tamil Nadu, and Rajasthan. Around 60 percent of the natural gas produced in 2002 was associated gas. Nonassociated gas comes mostly from the western offshore fields of South Bassein and Tapti, the gas fields in Tripura, and the K.G. Basin in Andhra Pradesh. The main natural gas producers are the Oil and Natural Gas Corporation Limited (ONGCL), which concentrates on the western offshore, and the Oil India Limited (OIL), which focuses on Assam and Rajasthan. Urban centers in producing states, as well as in Gujarat and Maharashtra in northwest India, consume most of the natural gas produced. A gas pipeline grid in the south is also being considered [*48*].

The Ministry of Petroleum and Natural gas has plans for dramatic transmission growth in the near future [*49*]. The Gas Authority of India Limited (GAIL) is the government's transmission and distribution operator, with 2,700 miles of natural gas pipelines. Because production of associated gas exceeds the existing transportation capacity, ONGCL and OIL are setting up special transportation facilities to prevent flaring, which has already been reduced from 30 percent of gross production in the early 1990s to 7 percent in 2002. Domestic pipelines now in the works include a 373-mile pipeline from Visakhapatnam to Secunderabad in Andhra Pradesh, a 435-mile pipeline from Mangalore in Karnataka to Madurai in Tamil Nadu, 357 miles of pipeline to connect the Cochin LNG terminal to Kerala's infrastructure, and an extension of the 1,429-mile Hazira-Bijapur-Jagdishpur pipeline [*50*]. India recently refused to participate in a potential Middle Eastern pipeline, which would have entered India through Pakistan, for political reasons. The Qatar-Oman Dolphin pipeline project may later extend to India by an undersea route.

Over the next decade, India's demand for natural gas is projected to exceed supply. To reduce the supply gap, India has negotiated a 25-year import agreement for 7.5 million metric tons of LNG annually from Rasgas of Qatar [*51*]. Rasgas will supply the first two regasification terminals in India, at Dahej and Hazira. Both are expected to come on line in 2004, with capacities of 5.0 and 2.5 million tons per year, respectively [*52*]. Shell, BG, and other companies are competing to enter India's LNG market, negotiating innovative pricing deals with the National Thermal Power Corporation to accommodate current political difficulties involved in setting end-user tariffs. A breakdown of agreements on Enron's Dabhol project halted the completion of an LNG facility that was to begin operation in 2001. The Dabhol fracas illustrated the political risks of investing in public utilities in India [*53*].

South Korea

South Korea is the world's second largest LNG importer, after Japan. The country produces negligible amounts of natural gas domestically and in 2001 consumed 0.7 trillion cubic feet, mostly obtained through long-term import contracts. Natural gas demand in South Korea has increased markedly since the country's recovery from the 1997-1998 Asian economic crisis and is projected to increase to 1.0 trillion cubic feet in 2010 and 1.8

trillion cubic feet in 2025 in the *IEO2004* reference case, at an average annual rate or 3.9 percent. LNG demand is expected to climb as the industrial sector shifts to electric power and direct natural gas use, a trend that gained momentum from the high oil prices of 1999 [***54***]. Industrial demand makes up about 17.6 percent of South Korea's total natural gas demand, residential demand 41.4 percent, electricity generation 35.4 percent, and miscellaneous uses the remainder [***55***].

In 2003, South Korea began offshore production from Ulchin at the Donghae-1 field, which contains 200 billion cubic feet of gas [***56***]. The Korea National Oil Corporation is a substantial partner in more than a dozen gas projects around the world. In 2002, Korea's contracted sources of gas imports included Qatar (237 billion cubic feet), Indonesia (232 billion cubic feet), Oman (187 billion cubic feet), and Malaysia (106 billion cubic feet), with smaller amounts from Australia, Brunei, and the United Arab Emirates [***57***]. Following deregulation of the country's energy sector, KOGAS limited its pursuit of long-term import contracts in 2002, leaving it in part reliant on spot markets for LNG in 2003. KOGAS purchased 1.36 million metric tons of LNG on the spot market in 2002, about 9 percent of South Korea's total gas consumption [***58***].

The Korean distribution network consists of 820 miles of pipelines covering the west coast near and around Seoul, with connections to LNG terminals at Incheon and Pyongtaek. KOGAS has built an 832-mile pipeline system serving the central and west coast regions. South Korea has no international pipelines, but the government hopes to negotiate a route from Russia by 2007. China and Russia are interested in a natural gas pipeline that would run through North Korea to South Korea, which would help resolve the geopolitical issues facing North Korea, particularly concerning its use of nuclear power.

Other Developing Asia

A number of countries and companies across Asia have taken an interest in the development of natural gas markets, and several are going ahead with international agreements to access resources. In 2002, Indonesia and Malaysia were the largest natural gas producers in developing Asia, exporting 1,108 and 741 billion cubic feet of natural gas, respectively [***59***]. They accounted for about 70 percent of Asia's gas trade, both by way of pipeline (small amounts to Singapore) and as LNG (to Japan, South Korea, and Taiwan). Indonesia alone exported 22 percent of the world's traded LNG in 2002.

Indonesia, the world's largest LNG exporter, produced 2.4 trillion cubic feet of natural gas in 2001 while consuming only 1.3 trillion cubic feet [***60***]. In 2002, Indonesia exported 729 billion cubic feet of LNG (66 percent of LNG exports) to Japan, 232 billion cubic feet (21 percent) to Korea, and 147 billion cubic feet (13 percent) to Taiwan. It also piped natural gas to Singapore. LNG is processed at the country's two liquefaction plants, PT Arun LNG and Bongtang LNG. A third plant is being developed by BP at Tangguh to supply China with LNG for its Fujian regasification terminal beginning in 2007.

Like Indonesia, Malaysia has substantial natural gas reserves. At the beginning of 2004, Malaysia's proved reserves were estimated at 75 trillion cubic feet [***61***]. About 60 percent of its marketed gas production is consumed domestically, three-quarters of which is used for electricity generation. The country's largest gas field is Kinabalu, in eastern Malaysia, and its gas infrastructure includes more than 1,000 miles of transmission and distribution pipelines. Malaysia is the region's second largest LNG exporter, accounting for 14 percent of the total world trade in LNG in 2002, with exports to Japan, South Korea, Taiwan, and occasionally the United States [***62***].

Malaysia is also seeking to increase its production of natural gas. The Malaysia-Thailand Joint Development Authority administers a region that is contested by the two countries and is now being explored by Petronas and the Petroleum Authority of Thailand (PTT) as well as Amerada Hess and BP. The two countries are building a pipeline linked to a gas-fired electricity generation plant in Thailand near a connection in the two countries' grids, with plans for a future gas pipeline to Malaysia. Malaysia also has offshore fields in the South China Sea, which are being developed by ExxonMobil. Malaysia exports 9.2 billion cubic feet per year to Singapore via pipeline. In a move to position itself as Southeast Asia's gas hub, Malaysia also has begun imports of Indonesian gas from the Natuna offshore field through a connection to Malaysia's Duyong field pipeline.

Thailand developed its natural gas market rapidly in the 1990s, more than doubling its production between 1991 and 2001. Its gas reserves were estimated at 13 trillion cubic feet as of the beginning of 2004 [***63***]. In 2001, the last year of a national drive to increase gas-fired generation, 76 percent of Thailand's natural gas was used to generate electricity [***64***]. Its largest natural gas field, Bongkot, is 400 miles south of Bangkok in the Gulf of Thailand, and the government plans to expand the natural gas distribution network to reach more power plants and industrial consumers. Thailand also imports 55 billion cubic feet a year from Myanmar through the Yadana-Ratchaburi pipeline.

In Taiwan, a major regional consumer of natural gas, consumption grew significantly from 1990 to 2000. Of the total gas supplied to the market, 68 percent of Taiwan's natural gas supply is used for electricity generation. Taiwan imported 91 percent of its gas supply in 2002, obtaining LNG mainly under long-term agreements with Indonesia (147 billion cubic feet) and

Malaysia (100 billion cubic feet) [*65*]. Taiwan currently has one LNG import facility, Yung An. Another facility, Taoyuan, has been proposed but has not yet secured a contract with Taipower, the national utility.

Middle East

Natural gas consumption in the Middle East rose sharply in the 1990s, from 3.7 trillion cubic feet in 1990 to 7.9 trillion cubic feet in 2001, and is projected to increase to 12.1 trillion cubic feet in 2025 (Figure 50). The average annual growth rate over the forecast period is projected to be 1.8 percent. Oil-exporting countries in the Middle East are seeking to expand natural gas use domestically so that as much oil as possible can be exported.

After Russia, Iran has the world's second largest proven natural gas reserves, at 940 trillion cubic feet. Qatar ranks third in world reserves with 910 trillion cubic feet and is becoming an important LNG supplier (see box on page 66). Despite its abundant reserves, Iran has imported natural gas for the past several years, because its major population centers are in the north, far from its reserves in the Persian Gulf. The government of Iran is working aggressively to address this discrepancy and begin monetizing its assets. Natural gas consumption in Iran grew from 883 billion cubic feet in 1992 to 2.3 trillion cubic feet in 2001. About 2.2 trillion cubic feet of natural gas was brought to market in 2002, and an additional 1.5 trillion cubic feet was flared or reinjected [*66*].

Natural gas supplies about half of Iran's total energy consumption, and the government hopes to increase gas-fired electricity generation to free other petroleum products for export. Of Iran's total marketed natural gas consumption, 36.1 percent is used for electricity generation, 22.8 percent goes to industrial uses, 28.8 percent to the residential sector, and 3.8 percent to the commercial sector. The remainder is accounted for by autoconsumption and distribution losses [*67*].

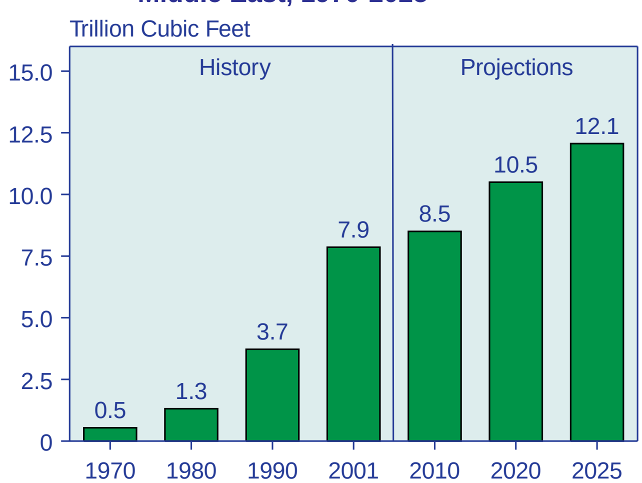
The South Pars field is geologically divided between Qatar and Iran. The Iranian Oil Ministry estimates that South Pars eventually will produce up to 8 billion cubic feet per day and can earn Iran $11 billion annually for 30 years. TotalFinaElf, Malaysia's Petronas and Russia's Gazprom are key developers of South Pars. Petronas spent $8 billion on the development of South Pars in 2003, but expansion plans have lagged due to technical and commercial obstacles. Russian contractors are building a 56-inch, 300-mile pipeline to feed into Iran's national gas grid [*68*]. Currently, South Pars gas runs to onshore refining facilities at Asaluyeh, where Hyundai is building four gas-processing trains for LNG exports.

The government and private investors are working to build LNG facilities in Iran. Currently there are four proposals, ranging in size from 8.0 to 10.0 million metric tons of LNG exports per year. The Oil Ministry expects to begin supplying the domestic market by 2007 and to begin LNG exports by 2008. The Iranian government is hoping to boost gas production from 3.9 trillion cubic feet in 2000 to 10 trillion cubic feet in 2010 [*69*]. Although no firm commitments have yet been made, Iran has the potential to become a major supplier of natural gas to Europe in the future. At least four two-train LNG liquefaction projects are being evaluated by the Iranian government, each with a capacity of 390 to 490 billion cubic feet per year. Iran has also recently completed a pipeline link to Turkey, which it hopes is the first step toward providing supplies to Europe.

A gas pipeline between Iran and Turkey was inaugurated in January 2002. While the pipeline could carry as much as 350 billion cubic feet by 2007, there are concerns as to the robustness of future Turkish demand in light of potentially competing imports from Russia, Algeria, and Nigeria.

Saudi Arabia has the world's fourth largest proved gas reserves, after Russia, Iran, and Qatar. About 40 percent of Saudi Arabia's 231 billion cubic feet of gas reserves consists nonassociated gas. The Saudi government and the state-controlled national oil and gas company, Aramco, are developing the domestic gas market—particularly to fuel the growing petrochemical industry—in order to free oil resources for export. The government has chosen this strategy to mobilize its natural resources rather than actively joining the race to export LNG. Industrial centers fed by the Saudi gas system include Yanbu on the Red Sea and Jubail, which supply 10 percent of the world's petrochemical production. The Hawiyah natural gas processing plant produces 1.5

Figure 50. Natural Gas Consumption in the Middle East, 1970-2025



Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 2001*, DOE/EIA-0219(2001) (Washington, DC, February 2003), web site www.eia.doe.gov/iea/. **Projections:** EIA, System for the Analysis of Global Energy Markets (2004).

Qatar LNG: Status and Developments

By 2010 Qatar is expected to be one of the world's leading producers of LNG. The country has been very successful in finding new markets. In 2002, Qatar earned around $3.7 billion from exporting 15 million metric tons of LNG.[a] At the LNG Ministerial Summit in December 2003, sponsored by the U.S. Department of Energy, Qatar's energy minister announced that his country will invest some $25 billion in LNG projects by 2010, quadrupling its export capacity.[b]

Qatar is a relatively new supplier of LNG, shipping its first LNG to Japan in 1997. Its focus is the Asian market, the proximity of which has been strategic to profitability. As technology has reduced the cost of liquefaction and shipping by almost a third in the last few years, Qatar has become the focus of attention as it negotiates projects that will expand its market share in Asia and allow it to enter the Western market.

With proven reserves of over 900 trillion cubic feet, Qatar's natural gas resources rank third in size behind Russia's and Iran's.[c] Most of the country's reserves are located in the North Field, to date the largest known non-associated gas field in the world. Qatar began developing the North Field gas reserves in 1984, for the most part producing condensates.[d] In addition, the Dukhan field and smaller associated gas reserves in the Id al Shargi, Maydan Mahzam, Bul Hanine, and al-Rayyan oil fields are estimated to contain 10 trillion cubic feet of gas.

For the last few years the Qataris have opted to diversify their gas portfolio by investing in regional gas pipeline projects, gas-to-liquid technology, and the expansion of their liquefaction capacity. The most ambitious regional pipeline project to date is the $4 billion Dolphin Gas project that will pipe gas over 260 miles from Qatar to the United Arab Emirates (UAE) and Oman, delivering an estimated 2 billion cubic feet per day by 2006.[e] Though these importing countries have their own reserves, and export LNG themselves, they find it less costly to import Qatari gas than to develop and treat their own non-associated gas supplies. Kuwait and Bahrain, two other Gulf States, have also approached Qatar with a view to follow suit.

Qatar has also invested in gas-to-liquid technology (GTL). This approach, developed at great cost, converts natural gas into high-grade gasoline and distillates. Qatar has already drawn up plans to produce 174,000 barrels per day. It is expected that its project with *Sasol*, the South African oil company, will produce 34,000 barrels per day by 2005; according to current estimates another venture with Shell International will produce 140,000 barrels per day by 2007.[f]

Currently, Qatar has two LNG export projects that serve mainly the Asian market:

- *Qatar Liquefied Gas Company Limited (QatarGas).* The first of this three-train project went on stream in 1996. Partners comprise the state-owned Qatar Petroleum (QP), which has a majority interest, ExxonMobil, Total, Marubeni, and Mitsui. At present, the project has a capacity of around 8 million metric tons per year; after debottlenecking is completed in 2005, it will reach 9.5 million metric tons per year. In addition, QatarGas has long-term contracts for the sale of 4 million metric tons per year to Chubu Electric Company in Japan and another 2 million metric tons per year to seven other Japanese electric and gas utilities. It also delivers spot cargoes to Europe and the United States.
- *Ras Laffan Liquefied Natural Gas Company Limited (RasGas).* With a current capacity of 6.6 million metric tons per year, RasGas sells 4.8 million metric tons per year to Korea Gas under a long-term contract. Two more trains are presently under construction, each with a 4.7 million metric tons per year capacity. Of this, 7.5 million metric tons per year will go to India under a 25-year contract, with additional volumes available for spot sales. Participants in the first phase of RasGas are QP, ExxonMobil, Itochu, and LNG Japan, though only QP and ExxonMobil are involved in the expansion phase.[g]

(continued on page 67)

[a]World Market Research Centre, "Country Reports—Qatar" (December 2003), web site www.wmrc.com.
[b]Personal communication with Abdullah bin Hamad Al-Attiyah, Minister of Energy & Industry, State of Qatar (Washington, DC, December 18, 2003).
[c]Embassy of Qatar, *Qatar: The Modern State* (Washington, DC, November 2003).
[d]Condensate is a light hydrocarbon liquid that is suspended in natural gas reservoirs and can be recovered by condensation of hydrocarbon vapors. After it is separated from the gas, it remains liquid without pressurized or refrigerated containment.
[e]Personal communication with Khaldoon Al Mubarak, Executive President of Dolphin Energy Limited (Washington, DC, December 18, 2003).
[f]Energy Information Administration, *Country Analysis Brief: Qatar* (November 2003), web site www.eia.doe.gov/emeu/cabs/qatar.html.
[g]Personal communication with Colleen Taylor-Sen, Senior LNG Advisor, Gas Technology Institute (Washington, DC, December 18, 2003).

Qatar LNG: Status and Developments (Continued)

Other projects have also been proposed. In 2003, Qatar signed two agreements: one with ExxonMobil, to provide the United Kingdom with 15 million metric tons per year by 2006-2007; and a second, with ConocoPhillips, to provide 9.2 million metric tons per year by 2008-2009, 7.5 million metric tons of which is to be destined for the United States. Total is negotiating a similar volume (9.2 million metric tons per year) with QatarGas, also for delivery by 2008-2009; ExxonMobil too is working on providing an additional 15 million metric tons per year for the United States by 2010.[h] In all of these projects, Qatar intends partnering international companies across the entire spectrum, ranging from production to liquefying, transporting, regasifying, distributing, etc.

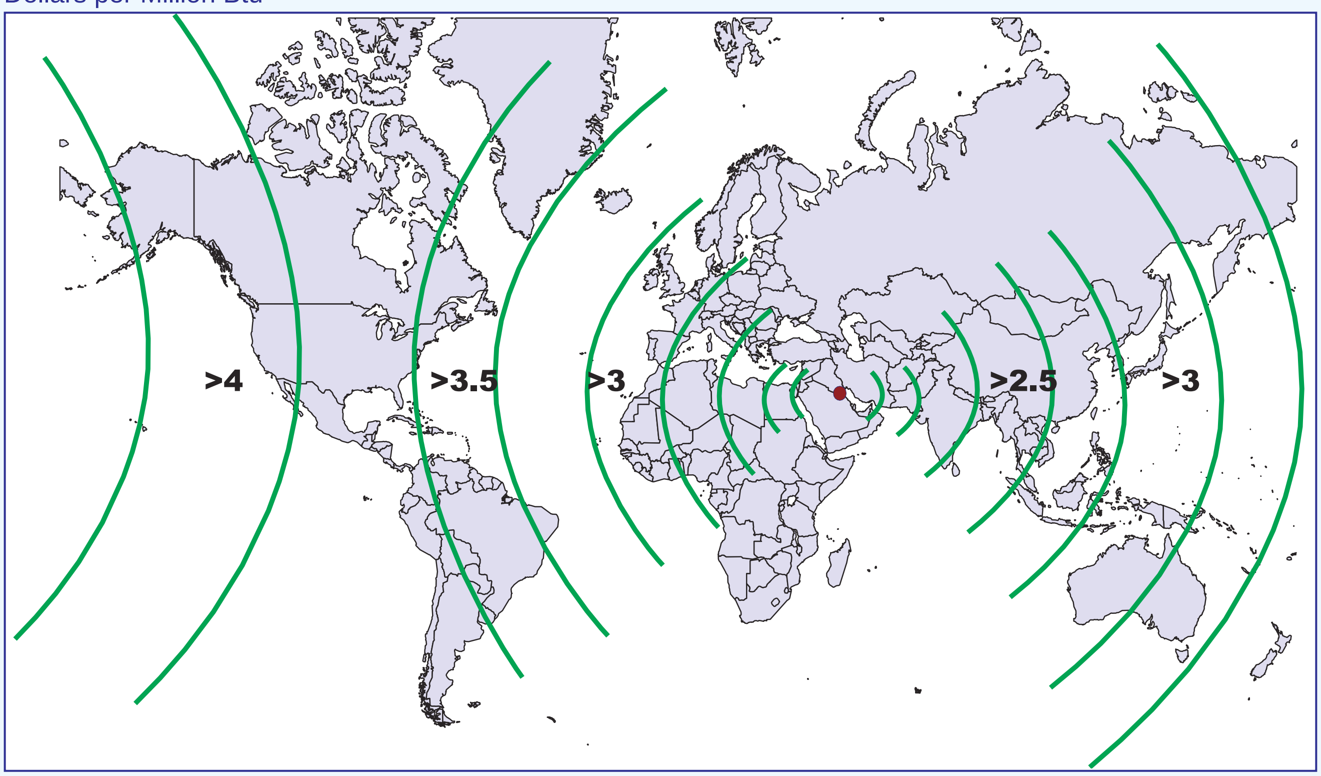
Qatar LNG is expected to occupy a leading position in the United States market over the next two decades. For the next 6 years, with the U.S. average annual wellhead price of gas not expected to be lower than $ 3.50 per million Btu, Qatar will be in a position to recover its costs in the U.S. market (see map below).

The Middle East has the lowest exploration and development costs for gas of any region in the world, with capital costs estimated at less than $0.20 per million Btu.[i] Even though most of Qatar's gas is offshore, the transmission pipelines to connect the gas fields to the LNG liquefaction plants are relatively short, comprising only a small share of the overall cost. An added bonus is that most of the proposed liquefaction projects are in Ras Laffan Industrial City, where they take advantage of existing infrastructures and large amounts of land available for development, additional factors that keep spending down. Technological advances are such that the capacity of the new trains might reach 7 million metric tons per year (prior to this the limit was 2 to 3 million metric tons). Once economies of scale are factored in, the competitiveness of Qatar's LNG should continue to increase.

In order to finance its current projects, Qatar maintains and enjoys a strong credit rating, despite regional

(continued on page 68)

Benchmark Price Requirements for LNG Shipments from Qatar
Dollars per Million Btu



Source: Adapted from Cambridge Energy Research Associates.

[h]Energy Information Administration, *The Global Liquefied Natural Gas Market: Status & Outlook*, DOE/EIA-0637(2003) (Washington, DC, December 2003), web site www.eia.doe.gov/oiaf/analysispaper/global/pdf/eia_0637.pdf.
[i]International Energy Agency, *World Energy Investment Outlook 2003* (Paris, France, 2003), p. 228, web site www.worldenergyoutlook.org.

Qatar LNG: Status and Developments (Continued)

unrest.[j] Qatar's infrastructure is safer than in most nearby countries because it hosts U.S. military bases.[k] Costs for Qatar's new liquefaction facilities will therefore remain stable, despite the region's strife.

Although LNG imports in 2002 comprised only about 1 percent of the U.S. market, this amount will increase substantially over the next two decades. At present there are four terminals in the continental United States that receive LNG, with a total capacity of about 3 billion cubic feet per day. By 2025 the projected increase is estimated at 14 billion cubic feet per day, necessitating at least 10 more terminals. In fact the major challenge regarding the future of LNG in the United States is not the availability of terminals (a need that is slowly being met), rather it is the reliability of supply. Equally important, there is also the matter of transparent and sustainable rules governing the gas business per se.[l]

A major concern to a supplier such as Qatar is the uncertainty regarding U.S. restructuring of the gas and electric power industries. LNG suppliers see deregulation as a disadvantage, because it is likely to result in changes to the business environment, such as the insistence on shorter contracts, the removal of the take-or-pay clauses and fixed destination from future contracts, and requiring third-party access to regasification facilities. These changes force suppliers to shoulder a greater portion of the risk, which might hinder the development of liquefaction facilities.

The U.S. regulatory body, the Federal Energy Regulatory Commission (FERC), has lately eased its requirement for open access to regasification capacity. This development has encouraged potential suppliers such as Qatar and its major partners to consider investing in new terminals. At present, many LNG investors who have been monitoring the Henry Hub index of natural gas prices are eager to capture what appears to be a high margin of profitability in supplying LNG to the U.S. market. Although Henry Hub index prices have been higher than the cost of LNG imported to the United States for the past 4 years, some observers believe that the index does not reflect market realities, and may encourage over-investment in LNG that will not be economically sustainable.

LNG projects are multi-billion-dollar undertakings, and at this point it is unclear whether Qatar will be willing to accept the high financial risks associated with increasing its LNG capacity to supply the North American market.

[j]International Energy Agency, *World Energy Investment Outlook 2003* (Paris, France, November 4, 2003), p. 231.
[k]World Market Research Centre, "Country Reports—Qatar" (March 2004), web site www.wmrc.com.
[l]Personal communication with Ibrahim B. Ibrahim, Chairman of Marketing and Vice Chair of the Board of Qatar RasGas Company (Washington, DC, December 18, 2003).

billion cubic feet of gas per day, enough to displace 260,000 barrels per day of Arabian light crude oil from domestic consumption. The Haradh processing plant, which came on line in 2003, increased the country's natural gas processing capacity by 20 percent, to 9.5 billion cubic feet per day [***70***].

Starting in 1999, Aramco has been developing a 25-year, $45 billion initiative to expand Saudi Arabia's upstream gas industry. Aramco's exploration aims to increase reserves by 3 to 5 trillion cubic feet per year to meet growing domestic demand for natural gas. One-quarter of the country's gas production goes to petrochemical producers (fuel gas and feedstock for producing plastics and industrial chemicals for export), one-fifth to desalination plants, and one-fifth to the oil industry in support of the expanding Master Gas System capacity [***71***].

The Saudi government has been in talks with major international energy companies to open the country to upstream development as part of the Saudi Gas Initiative. The aim of the program is to integrate upstream gas development with downstream petrochemicals, power generation, and water desalination, in part through greater foreign investment. Talks broke down in the summer of 2003, however, over issues of access to reserves and potential rates of return to investors. Saudi officials hope to have 1,200 miles of transmission pipeline in place by 2006 and to raise natural gas output to 15 billion cubic feet per day by 2009 [***72***].

Oman's natural gas consumption totaled 224 billion of cubic feet in 2001, an 80.5-percent increase from a decade earlier. In the same period, its natural gas production doubled [***73***]. Oman has 29 trillion cubic feet of proved reserves [***74***], and the government is aggressively pursuing growth in its gas industry, in part to diversify its economic dependence on oil exports; however, much of its gas reserves are trapped in complex geologic structures near oil fields [***75***].

The Oman Gas Company runs the national transmission network, consisting of one 500-mile trunk line and several pipelines connecting gas fields to an electricity facility in Salalah, which came on line in 2004. A second pipeline, scheduled to open in 2006, will transport gas from a site near Muscat to a new refinery in Sohar [***76***]. Enbridge, BC/Terasen Gas International, and Oman

Holding International won a 5-year, $23 million contract to run the nation's 1,100-mile distribution system. Oman is also participating in the $3.5 billion deepsea Dolphin pipeline [*77*], which will link Qatar with Oman and the United Arab Emirates and eventually with the South Asian subcontinent.

Oman LNG, another public-multinational partnership, which includes Shell, Total, and Korea LNG, runs the liquefaction plant at Qalhat with a capacity of 7.3 million metric tons per year [*78*]. Ongoing efficiency improvements are expected to increase production by 15 percent per year. Gas is delivered through three major LNG contracts: an agreement with KOGAS for 4.1 million metric tons per year; a contract with Osaka Gas Company for 0.7 million metric tons per year; and a contract with Metgas to supply India's Dabhol project with 1.6 million metric tons per year. The last two agreements are not yet in effect, and Oman is selling LNG on the global spot market [*79*].

In recent years Turkey has moved to preempt expected increases in international and domestic natural gas demand by fostering international pipeline infrastructure, which may eventually connect producers in the Middle East and northern African to Europe's natural gas grid. In February 2003, as part of an effort to integrate hydrocarbon transport networks in the region, Greece and Turkey signed an agreement to construct a 176-mile pipeline, to begin operation in 2005 with an initial capacity of 17.6 billion cubic feet [*80*].

Turkey's gas demand has climbed rapidly over the past decade, from 164 billion cubic feet in 1992 to 563 billion cubic feet in 2001. Turkey's April 2001 passage of a gas market reform program has brought it closer to accord with EU market practices and closer to a competitive gas market intended to encourage private investment. Almost all the natural gas consumed in Turkey is imported from four countries: Russia, Iran, and LNG from Algeria and Nigeria. Turkey's LNG imports come in from Ereglisi on the Sea of Marmara, which received 172 billion cubic feet of LNG in 2002 [*81*]. In 2002, Turkey imported 621 billion cubic feet of gas [*82*].

Africa

Natural gas consumption in Africa is projected to increase from 2.3 trillion cubic feet in 2001 to 4.6 trillion cubic feet in 2025, at an average rate of 3.0 percent per year (Figure 51). Africa is a net exporter of natural gas, primarily from Algeria, Nigeria, and Libya. In 2002, LNG exports from those three countries accounted for about 23 percent of the natural gas traded in the world and 52 percent of Africa's natural gas production. More than 85 percent of Africa's gas exports went to Western Europe, with some LNG exports also going to the United States. Many countries in Africa have significant untapped production and export potential, and with Western European demand rising, international energy companies are rapidly expanding investment in the region.

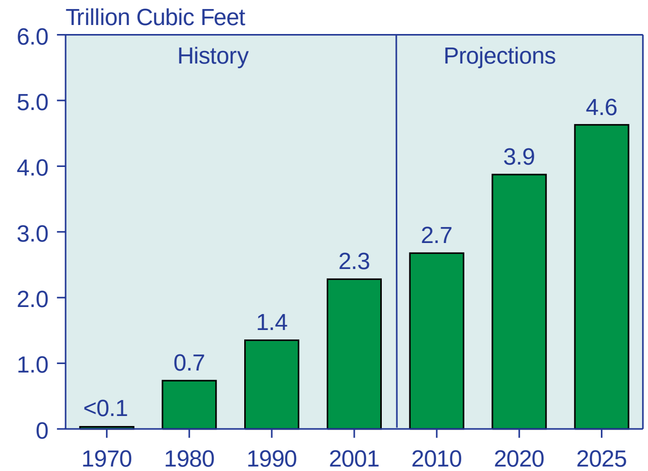
Algeria

Algeria is the world's second largest LNG producer, after Indonesia, and the fourth largest exporter of natural gas, after Russia, Canada, and Norway. In 2001, Algeria produced 2.84 trillion cubic feet of natural gas, while its consumption totaled 788 billion cubic feet. Its consumption has grown moderately since the beginning of the 1990s, fluctuating between 650 and 800 billion cubic feet [*83*]. Algeria holds 35 percent of Africa's proved reserves, about 160 trillion cubic feet [*84*]. In 2002, Algeria exported 2 trillion cubic feet of gas through pipelines and as LNG.

About 72 percent of Algeria's gas exports go to southern European and Mediterranean countries and 23 percent to the rest of Europe. Sonatrach, Algeria's state-owned oil and gas company, is responsible for overseeing gas production and sales to foreign buyers and domestic industries. One-fourth of Algerian natural gas comes from the Hassi R'Mel field, which produces 1.4 billion cubic feet per day. The remainder comes from the southeast and the southern In-Salah region.

Sonatrach's management and labor unions have blocked petroleum market proposals that would have removed Sonatrach's monopoly or changed its regulatory status. As a result, foreign companies may find it easier to make investments to export large quantities of natural gas in the near term, because they will be able to continue to

Figure 51. Natural Gas Consumption in Africa, 1970-2025



Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 2001*, DOE/EIA-0219(2001) (Washington, DC, February 2003), web site www.eia.doe.gov/iea/. **Projections:** EIA, System for the Analysis of Global Energy Markets (2004).

negotiate with only one partner. Had the reform proposals been passed, the foreign companies would have had to negotiate with several successor companies formed by divesting Sonatrach; however, the prices charged to foreign companies for natural gas might have been reduced if the transition to competition had been completed [*85*].

Algeria has a well-developed transportation infrastructure, including 4,300 miles of domestic pipeline and 1,460 miles of international pipeline. The two largest international pipelines are the Trans-Mediterranean (Transmed) pipeline, at 900 billion cubic feet per year, and the Maghreb-Europe Gas (MEG) pipeline, at 350 billion cubic feet per year. The Transmed comprises segments through Algeria, Tunisia, and under the Mediterranean to Sicily and mainland Italy, with an extension into Slovenia. Tunisia purchases about 39 billion cubic feet per year, Slovenia's Sozd Petrol is committed to 21 billion cubic feet, and Italy's main gas utility, Snam, is under contract to buy 680 billion cubic feet until 2018 [*86*]. Planned upgrades would increase the capacity of the Transmed pipeline to 1.0 trillion cubic feet per year [*87*].

The MEG pipeline runs from Hassi R'Mel to the Iberian Peninsula via Morocco, carrying 350 billion cubic feet per year for 1,013 miles. It runs 168 miles across the Strait of Gibraltar, sometimes at a depth of 1,312 feet, to Cordoba, Spain, and ties into the Spanish and Portuguese transmission networks. Planned upgrades will augment MEG's transmission capacity to 460 billion cubic feet per year in late 2004. The Medgaz consortium also has plans to build a new 279-mile pipeline between Algeria and Spain, to come on line in 2006, which would carry 282 billion cubic feet of gas per year, with the possibility of future expansion to 420 billion cubic feet.

In addition, Algeria has two LNG plants with a combined annual liquefaction capacity of 23 million metric tons of LNG, or 1,125 billion cubic feet of gas. In 2003, BP won a contract to partner with Sonatrach to supply 5 percent of the United Kingdom's LNG market starting in 2005 [*88*].

Nigeria

Nigeria is the second largest LNG exporter on the African continent and the fifth largest in the world. The country produced 394 billion cubic feet of natural gas in 2002. Its domestic consumption increased from 168 billion cubic feet in 1991 to 277 billion cubic feet in 2001, an increase of 65 percent [*89*]. At the beginning of 2004, Nigeria's proved reserves were estimated at 159 trillion cubic feet [*90*].

One-half of Nigeria's gross natural gas production is flared, and another 12 percent is reinjected to improve oil production operations. The development of the Bonny LNG facility and the 40-percent increase in gas usage by the petrochemical industry over the past decade are beginning to generate a market for natural gas resources [*91*].

Nigeria's LNG plant at Bonny Island currently has three trains with a capacity of 9.5 million metric tons per year. Two additional trains under construction will add an additional 8.2 million metric tons in 2005, and a sixth train has been proposed for mid-2006. Three new LNG plants—West Niger Delta, Brass River LNG, and a floating LNG plant—have been proposed. If funded, they would come on line between 2008 and 2010 [*92*].

Egypt

Egypt will soon emerge as a major African exporter fueling Europe's expanding demand for natural gas. The Western Desert, the Nile Delta, and offshore regions hold significant potential for natural gas development. Egypt's proved natural gas reserves total 59 trillion cubic feet, and its expected reserves are much larger. Egypt produced about 3 billion cubic feet of gas per day in 2002 and expects to produce 5 billion cubic feet per day by 2007.

To develop private investment and joint venture deals, the government set up the Egyptian Natural Gas Holding Company, splitting it from the Egyptian General Petroleum Company (EGPC) in April 2001. The International Egyptian Oil Company, a subsidiary of the Italian energy group Eni-Agip, is Egypt's leading gas producer. BG, BP, Shell, and Apache also produce gas in Egypt.

Spain's Union Fenosa and EGPC are building Egypt's first LNG facility at the port of Damietta, to be completed by the end of 2004. It is slated for a single train with a capacity of 5.0 million metric tons and potential for additional trains [*93*]. The project will purchase gas from the EGPC grid and ship LNG to Union Fenosa's associate power plants. A second Egyptian LNG facility at Idku is being built by EGPC, BG, Gaz de France, and Petronas. The first train is set to come on line in 2005 and is contracted to deliver 3.6 million metric tons per year to Gaz de France for 20 years. The Idku complex can house up to six trains, and the second train, funded by EGPC, BG, and Petronas, is already under construction and slated to open in 2006. The entire capacity of the second train is contracted to BG through 2007 [*94*].

Egypt is also beginning to export natural gas via pipeline to the Middle East. The first phase of the Middle East Gas Pipeline Project was completed in January 2004, linking the city of Aqaba in Jordan to Egypt's gas distribution network. The second phase will extend approximately 230 miles from Aqaba to a power plant in northern Jordan by 2005. The pipeline could be extended to Syria and Lebanon by 2006 [*95*].

Other Africa

Libya's reincorporation into the international community in 2003 has created the potential for it to become another large African exporter of natural gas. It has been exporting LNG to Spain since 1970 from its Marse el-Brega facility, but lack of technical capacity and capital has limited its exports to around 30 billion cubic feet per year. Libya's proved natural gas reserves were estimated at 46 trillion cubic feet in 2004, but it is likely that its actual resources are far greater.

Despite a 1,000-mile pipeline network, the Libyan grid is inadequate to serve growing demand. The network has a cumulative capacity of 353 billion cubic feet of gas, with the largest capacity contribution, 144 million cubic feet per day, from the Costal pipeline that runs from Marse el-Brega to Bukkamash. There are plans to build additional transmission capacity to serve power generation in Khoms, Benghazi, Zueitina, and Tripoli.

Engas, the Spanish Utility, is the only current major foreign consumer of Libyan gas. Eni and the government energy company have started developing the $5 billion Western Libyan Gas Project (WLGP). In June 2002, an Eni affiliate won a $500 million contract to build an offshore facility near Tripoli. The WLGP is expected to export 280 billion cubic feet of gas per year from Melitah to Italy and France beginning in 2006 via a 370-mile pipeline under the Mediterranean Sea. Gaz de France and Italy's Edison Gas and Energia have signed agreements to receive 140 billion cubic feet of the exported gas, mostly for power generation.

While Angola is a major international oil producer, it lacks the infrastructure to harness much of its natural gas resources. Currently, 59 percent of the gross associated gas produced in Angola is flared and 31 percent is reinjected for oil production [***96***]. The government aims to spend $2 billion to end flaring from offshore facilities, including plans to build a new LNG plant near Luanda in the South Lower Congo Basin in order to develop its natural gas resources for domestic and external use [***97***]. The state-owned oil company, Sonangol, has partnered with ChevronTexaco to develop an LNG facility capable of exporting 4 million metric tons per year by 2005. TotalFinaElf, Norsk Hydro, BP, and ExxonMobil will participate in the project, contributing gas from their deepwater facilities. The government of Namibia and Shell are considering similar investments from Shell's offshore Kudu gas field [***98***].

Other natural gas producers in Africa with noteworthy marketed quantities in 2002 include Tunisia (79.4 billion cubic feet), South Africa (74.1 billion cubic feet), Ivory Coast (47.7 billion cubic feet), and Equatorial Guinea (44.8 billion cubic feet). Gabon, Cameroon, and Congo produce significant amounts of natural gas as a byproduct of oil operations but flare or reinject almost all of it [***99***].

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