EMERGING ENERGY SECURITY ISSUES

Report Series No. 4

Natural Gas in the Gulf Nations:

An Overview of Middle East Resources,
Export Potentials, and Markets

Program on Resources: Energy and Minerals
East-West Center
Honolulu, Hawaii

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Introduction

The growth of the global natural gas industry has been striking over the past 10-15 years. Between 1978 and 1993, worldwide production grew 58 percent, then it grew 41 percent between 1983 and 1993. These increases correspond to average annual growth rates of 3.1 percent and 3.5 percent, respectively. This growth is expected to continue well into the next century. While North America, Europe, and the Former Soviet Union have dominated total volumes and will continue to dominate well into the future, Asia's thirst for natural gas is growing rapidly. This is derived from both domestic and foreign sources.

While their gas resource base is huge, the Gulf nations of the Middle East have so far played a relatively minor role in the global natural gas industry. Most internationally traded natural gas has moved among countries via pipelines, with a much smaller share transported as liquefied natural gas (LNG). The LNG trade, while relatively small, has been around for nearly 30 years and began with exports from Algeria and Alaska in the late 1960s.

The single largest source of LNG is and will continue to be Indonesia, even though natural gas resources of the Gulf nations will enter the global trade in ever increasing volumes. For example, the Gulf's share of LNG supplies to the Asia-Pacific region in 1993 was just 5 percent, but could account for as much as 26 percent by 2010, based on the firm and likely additions to existing facilities. The increase from 5 percent to 26 percent will take place as the total Asia-Pacific supply doubles, from 49.0 million tonnes to nearly 100 million tonnes. While Indonesia's exports may increase from 23.8 million tonnes in 1993 to 28.1 million tonnes in 2010, its share of the region's LNG supplies will fall from 48 percent to 28 percent.

Natural gas from the Gulf will typically enter regions that do not have well defined natural gas markets. While natural gas is used extensively in many parts of the

world, there are few examples of markets with many suppliers and many buyers actively involved in the business of making a market for natural gas. North America provides the best example of this type of well defined, integrated market for natural gas. The norm is a single seller and a single buyer with a wholly proprietary delivery and receiving system. While there may be some competitive activity in the very early phases of developing a delivery and receiving system, once agreements have been signed, there has been little room for competition.

The natural gas sold from the Gulf will typically be priced through long-term contracts, with prices tied to prices of another energy resource, such as a basket of crude oils or fuel oil. The nature of the regions to be served will permit little opportunity for gas from one source to compete with gas from some alternative source, i.e., there will be no gas-on-gas competition because proprietary delivery and receiving systems are involved.

While several pipeline projects have been proposed to move Gulf natural gas, the primary means for transporting this gas to end-users, for the foreseeable future, will be as LNG. Each proposed pipeline has technical or political problems, or both.

Planned target markets for Gulf natural gas include India, Pakistan, Japan, South Korea, Taiwan, Thailand, and China. There is a possibility that Qatari LNG will be sold to Israel, and occasional spot shipments to Europe are likely.

The paper proceeds with a presentation of the natural gas resource base of the Gulf nations of the Middle East. The resource base is put in the context of the world natural gas resource and trade flows. This is followed by a discussion of the existing and planned project to move Gulf natural gas to consuming regions. Then a discussion of the source of demand in the likely target markets for the Gulf resource follows. Next, the nature of LNG pricing is discussed. A brief summary concludes the paper.

Reserves

Natural gas reserves worldwide represent a substantial inventory of an energy resource. Table 1 reports estimated world natural gas reserves, annual production, and annual consumption by region, for 1985-1993. At the end of 1993, estimated total reserves were 5,014 trillion cubic feet (tcf). Natural gas reserves for the world at the end of 1994 have been estimated at 4,980 tcf.¹ The smallest reserve base, 260 tcf, is found in North America (United States and Canada; Mexico is under Latin America), and the largest reserve base, 1,996 tcf, is found in the Former Soviet Union (FSU).

Table 2 shows that world reserves are not evenly distributed by region, nor is the distribution of reserves in balance with production and consumption patterns. North America accounted for just 5.2 percent of worldwide reserves in 1993 (a decline in share from 8.5 percent in 1985), yet it was responsible for 31.4 percent of production and 32.6 percent of consumption in 1993. Reported production and consumption levels for North America have been relatively stable over the period. The FSU accounted for 39.8 percent of world reserves at the end of 1993 (a decline from 43.5 percent in 1985), while producing 33.8 percent and consuming 30.1 percent of the world totals.

The Middle East's share of world reserves has increased from 24.6 percent in 1985 to 31.5 percent in 1993. The Middle East region, as defined in the *BP Review of World Gas*, includes Bahrain, Iran, Iraq, Israel, Jordan, Kuwait, Oman, Saudi Arabia, Syria, United Arab Emirates (UAE), and Yemen. The nearly 7 percent gain in share was the largest increase in any of the region, and mirrors the 7 percent decrease for North America and the FSU combined. The 2.1 percent increase in production share amounted to a 55 percent increase over 1985. Nevertheless, at just under 6 percent of total world production, the Middle East is still a relatively small player in world natural gas activity.

Combining data in Table 1 for reserves and annual production yields estimates of the regional reserve-to-production (R/P) ratios over the period. The R/P ratios provide an

¹ See *Oil and Gas Journal*, December 26, 1994, p. 43.

Table 1. World Natural Gas Reserves, Production, and Consumption by Region, 1985-1993

	1985	1986	1987	1988	1989	1990	1991	1992	1993
Reserves (Tcf)									
North America	297	283	285	282	259	264	266	263	260
Latin America	189	190	227	236	234	242	238	259	268
Europe	226	230	218	200	192	194	195	213	212
Former Soviet Union*	1,515	1,565	1,479	1,528	1,527	1,599	1,749	1,941	1,996
Middle East	855	925	1,084	1,182	1,226	1,324	1,319	1,519	1,580
Africa	198	201	249	253	267	290	310	347	343
Asia & Australasia	201	229	255	272	283	302	299	341	354
Total	3,483	3,622	3,795	3,954	3,987	4,215	4,376	4,883	5,014
Production (bcf/y)									
North America	19,487	18,870	19,710	20,601	21,052	21,655	21,736	22,262	23,243
Latin America	2,674	2,799	2,850	3,006	3,099	3,314	3,408	3,489	3,568
Europe	7,937	7,899	8,059	7,564	7,756	7,637	8,011	8,037	8,444
Former Soviet Union	21,172	22,594	23,951	25,358	26,214	26,825	26,614	25,653	25,017
Middle East	2,231	2,652	2,910	3,332	3,666	3,650	3,672	4,090	4,328
Africa	1,668	1,722	2,016	2,078	2,244	2,368	2,481	2,596	2,716
Asia & Australasia	3,915	4,336	4,615	4,878	5,241	5,672	6,020	6,319	6,646
Total	59,084	60,874	64,113	66,817	69,271	71,121	71,941	72,445	73,963
Consumption (bcf/y)									
North America	19,386	18,118	19,155	20,409	21,416	21,254	21,603	22,258	23,001
Latin America	2,573	2,582	2,610	2,696	2,797	2,823	2,903	2,898	3,116
Europe	10,500	10,741	11,260	10,975	11,535	11,670	11,950	11,659	12,379
Former Soviet Union	19,206	19,807	20,775	21,908	22,372	23,883	23,495	22,396	21,223
Middle East	1,778	2,016	2,227	2,630	2,905	2,856	2,698	2,960	3,202
Africa	1,018	1,087	1,114	1,176	1,288	1,313	1,283	1,340	1,392
Asia & Australasia	3,538	3,832	4,145	4,473	4,870	5,233	5,591	5,926	6,150
Total	57,999	58,182	61,286	64,266	67,182	69,033	69,523	69,436	70,463

Source: BP Review of World Gas, 1994.

* Includes reserves for other centrally planned economies for 1985-1989.

Table 2. Regional Shares of World Natural Gas Reserves, Production, and Consumption, 1985-1993
(% of totals)

	1985	1986	1987	1988	1989	1990	1991	1992	1993
Reserves									
North America	8.5%	7.8%	7.5%	7.1%	6.5%	6.3%	6.1%	5.4%	5.2%
Latin America	5.4%	5.2%	6.0%	6.0%	5.9%	5.7%	5.4%	5.3%	5.4%
Europe	6.5%	6.3%	5.7%	5.1%	4.8%	4.6%	4.5%	4.4%	4.2%
Former Soviet Union	43.5%	43.2%	39.0%	38.7%	38.3%	37.9%	40.0%	39.8%	39.8%
Middle East	24.6%	25.5%	28.5%	29.9%	30.7%	31.4%	30.1%	31.1%	31.5%
Africa	5.7%	5.6%	6.5%	6.4%	6.7%	6.9%	7.1%	7.1%	6.8%
Asia & Australasia	5.8%	6.3%	6.7%	6.9%	7.1%	7.2%	6.8%	7.0%	7.1%
Production									
North America	33.0%	31.0%	30.7%	30.8%	30.4%	30.4%	30.2%	30.7%	31.4%
Latin America	4.5%	4.6%	4.4%	4.5%	4.5%	4.7%	4.7%	4.8%	4.8%
Europe	13.4%	13.0%	12.6%	11.3%	11.2%	10.7%	11.1%	11.1%	11.4%
Former Soviet Union	35.8%	37.1%	37.4%	38.0%	37.8%	37.7%	37.0%	35.4%	33.8%
Middle East	3.8%	4.4%	4.5%	5.0%	5.3%	5.1%	5.1%	5.6%	5.9%
Africa	2.8%	2.8%	3.1%	3.1%	3.2%	3.3%	3.4%	3.6%	3.7%
Asia & Australasia	6.6%	7.1%	7.2%	7.3%	7.6%	8.0%	8.4%	8.7%	9.0%
Consumption									
North America	33.4%	31.1%	31.3%	31.8%	31.9%	30.8%	31.1%	32.1%	32.6%
Latin America	4.4%	4.4%	4.3%	4.2%	4.2%	4.1%	4.2%	4.2%	4.4%
Europe	18.1%	18.5%	18.4%	17.1%	17.2%	16.9%	17.2%	16.8%	17.6%
Former Soviet Union	33.1%	34.0%	33.9%	34.1%	33.3%	34.6%	33.8%	32.3%	30.1%
Middle East	3.1%	3.5%	3.6%	4.1%	4.3%	4.1%	3.9%	4.3%	4.5%
Africa	1.8%	1.9%	1.8%	1.8%	1.9%	1.9%	1.8%	1.9%	2.0%
Asia & Australasia	6.1%	6.6%	6.8%	7.0%	7.2%	7.6%	8.0%	8.5%	8.7%

estimate of the remaining life of the identified reserves. Table 3 shows that after 1993 world reserves would last 68 years at the 1993 production rate of 74 tcf/y. Because of the slight decline in estimated reserves between year-end 1993 and year-end 1994, the R/P ratio (at the 1993 production rate) fell to 67 years.

The lowest R/P ratio (on a regional basis) is in North America, where during 1993 there 23.2 tcf were produced, compared with 1994 year-end reserves estimated at 259.7 tcf. This implies an R/P ratio of just 11 years. The North American R/P ratio has declined steadily for about 15 years, since the deregulation of the industry in both Canada and the United States in the early 1980s. The current ratio is, however, comparable with the ratios from the mid-1970s and might reflect incentives to identify reserves rather than actual reserves.

The largest regional reserves estimates are found in the Former Soviet Union, which had 1,996 tcf in 1993; Russia dominates with over 85 percent of these reserves. Because annual production for 1993 was 25.0 tcf, the R/P ratio is 80 years. While this ratio is small relative to the Gulf, it still constitutes a substantial natural gas inventory. Figure 1 provides a graphical comparison of the regional and worldwide reserves-to-production ratios.

Figure 1 highlights the size of the Middle East natural gas resource endowment where the regional R/P ratio is by far the largest at 365 years. Middle East reserves are estimated to be 1,580 tcf at the end of 1993, while production for 1993 was 4.3 tcf. When the analysis is limited to the Gulf states of the Middle East, i.e., the Middle East minus Israel, Jordan, and Syria, the ratio for 1993 rises to 375 years.

Table 4 presents the Gulf's share of world reserves, production, and consumption. The Gulf's share of world reserves was 31.4 percent at the end of 1993 and 31.9 percent at the end of 1994. There has been a relatively steady increase in the Gulf's share over the period, with a slight dip in 1991 and 1992, coinciding with Gulf War. The region's reserve share is significantly larger than the production and consumption shares. The

Table 3. World Natural Gas Reserves-to-Production Ratios by Region, 1985-1993

Region	1985	1986	1987	1988	1989	1990	1991	1992	1993
North America	15	15	14	14	12	12	12	12	11
Latin America	71	68	79	79	75	73	70	74	75
Europe	29	29	27	26	25	25	24	26	25
Former Soviet Union*	72	69	62	60	58	60	66	76	80
Middle East	383	349	372	355	334	363	359	372	365
Africa	119	117	123	122	119	122	125	134	126
Asia & Australasia	51	53	55	56	54	53	50	54	53
Total	59	60	59	59	58	59	61	67	68

* Includes reserves for other centrally planned economies for 1985-1989.

Table 4. Middle East Share of World Natural Gas Reserves, Production, and Consumption, 1985-1995 (% of world totals)

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
Reserves	24.5%	25.4%	28.5%	29.5%	30.6%	31.3%	30.0%	31.0%	31.4%	31.9%
Production	3.8%	4.3%	4.5%	5.0%	5.2%	5.0%	4.9%	5.5%	5.7%	na
Consumption	3.1%	3.5%	3.6%	4.1%	4.3%	4.1%	3.9%	4.2%	4.5%	na

Figure 1. World and Regional Natural Gas Reserves-to-Production Ratios, 1985-1993

1993 share of worldwide production was just 5.7 percent while its share of consumption was just 4.5 percent. Figure 2 shows that, but for the Gulf War, all three categories have steadily increased over the period.

The distribution of natural gas resources within the Gulf, like that for the global regions, is uneven and not in balance with production and consumption activity. Tables 5 and 6 report the reserves, production, and consumption for each of the nine Gulf states, for 1985-1993. The *Oil and Gas Journal* estimates for year-end 1994 reserves are also included. Iran, with by far the largest reserves in the region, has sufficiently large reserves to rank second in the world, behind Russia. A distant second, for the region, goes to Qatar.

The largest regional producer and consumer of natural gas is Saudi Arabia. This is largely the result of the 8 million barrel per day Saudi crude oil production (largest volume in the world), which brings with it large volumes of associated natural gas. This gas is used to fuel field operations as well as electricity generation, and as feedstock to thriving petrochemical industry. Large volumes are also reinjected to maintain oil field pressures. Thus, while Saudi Arabia had 11.8 percent of the region's natural gas reserves at the end of 1993, it accounted for over 30 percent of the production and over 31 percent of the consumption.

The United Arab Emirates (UAE) is the only current LNG exporter of natural gas in the region; Iran exports small quantities of gas into the FSU via pipeline. The UAE held 13 percent of the region's reserves at the end of 1993 and 1994, a sharp increase from its 3.8 percent share in 1985. Nevertheless, it has steadily produced about 20 percent of the region's output over the period.

Yemen's reserves have grown rapidly from virtually nothing in 1985 to 15 tcf by the end of 1993. While this amounts to only 1 percent of the region's reserves, Yemen is catching up with Oman, and both are moving aggressively toward a future emphasizing natural gas exports.

Figure 2. Middle East Share of World Natural Gas Reserves, Production, and Consumption, 1985-1994

Table 5. Middle East Natural Gas Reserves, Production, and Consumption by Country, 1985-1994 (billion cubic feet)

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
Reserves										
Bahrain	7,100	6,997	6,897	6,697	6,473	6,247	6,007	5,808	5,898	5,295
Iran	469,800	449,809	489,192	494,190	499,788	600,095	600,095	698,903	729,690	741,609
Iraq	28,988	27,988	26,289	94,960	94,960	94,960	94,960	109,454	109,454	109,500
Kuwait	36,590	41,182	42,532	48,629	54,577	53,577	48,479	52,878	52,878	52,900
Oman	5,997	7,497	9,496	9,316	9,256	7,197	9,896	16,893	19,991	22,248
Qatar	147,937	151,935	156,634	156,634	163,031	163,131	161,931	226,903	249,894	250,000
S. Arabia	125,052	130,135	145,988	151,933	187,268	185,276	184,470	183,022	185,781	185,900
UAE	32,786	104,555	203,413	201,430	200,715	200,315	199,215	204,513	204,513	204,600
Yemen	-	600	1,599	3,698	5,498	6,997	6,997	13,894	14,994	15,000
Total	854,250	920,698	1,082,040	1,167,487	1,221,564	1,317,796	1,312,051	1,512,268	1,573,092	1,587,052
Production										
Bahrain	163.8	156.4	153.9	185.0	194.2	210.0	223.1	256.3	270.0	na
Iran	515.7	536.9	565.2	706.4	764.6	844.4	909.0	882.5	955.6	na
Iraq	30.0	54.7	132.4	202.3	215.0	141.2	61.4	80.1	90.0	na
Kuwait	148.3	202.3	168.7	229.1	288.0	191.0	17.7	92.5	157.8	na
Oman	49.8	50.5	53.7	73.1	80.1	77.7	81.9	91.1	98.1	na
Qatar	192.7	204.7	198.0	206.2	215.0	222.0	276.4	445.5	476.6	na
S. Arabia	663.6	902.3	946.0	1,027.6	1,052.6	1,077.7	1,129.6	1,200.2	1,267.3	na
UAE	460.3	537.3	667.5	683.4	776.6	781.5	855.0	913.6	881.1	na
Yemen	-	-	-	-	-	-	-	-	-	na
Total	2,224.3	2,645.0	2,885.4	3,312.9	3,586.1	3,545.5	3,554.0	3,961.7	4,196.5	na

Table 5 (continued)

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
Consumption										
Bahrain	114.0	134.1	177.2	188.1	195.6	205.1	195.6	206.5	218.5	na
Iran	515.4	536.6	564.8	706.0	783.7	801.3	802.7	882.5	937.6	na
Iraq	31.4	39.2	33.2	88.3	96.0	68.5	37.4	55.1	62.8	na
Kuwait	127.4	172.6	243.2	306.1	390.4	235.5	17.7	94.3	156.7	na
Oman	62.1	72.4	81.2	81.9	84.7	91.8	92.8	101.7	105.9	na
Qatar	142.6	158.1	144.4	189.6	189.6	191.3	191.3	195.2	200.2	na
S. Arabia	564.8	650.9	702.1	761.1	819.7	878.6	929.4	949.2	1,003.9	na
UAE	215.0	246.0	273.6	300.8	332.2	371.0	410.2	451.1	490.3	na
Yemen	-	-	-	-	-	-	-	-	-	na
Total	1,772.8	2,010.0	2,219.7	2,621.7	2,891.8	2,843.1	2,677.2	2,935.5	3,175.9	na

Source: BP Review of World Gas 1994

Note: The year-end 1994 reserves estimates are drawn from the Oil And Gas Journal, December 26, 1994.

Production and consumption estimates are not yet available for 1994.

Table 6. Country Shares of Middle East Natural Gas Reserves, Production, and Consumption, 1985-1994 (% of totals)

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994*
Reserves										
Bahrain	0.8%	0.8%	0.6%	0.6%	0.5%	0.5%	0.5%	0.4%	0.4%	0.3%
Iran	55.0%	48.9%	45.2%	42.3%	40.9%	45.5%	45.7%	46.2%	46.4%	46.7%
Iraq	3.4%	3.0%	2.4%	8.1%	7.8%	7.2%	7.2%	7.2%	7.0%	6.9%
Kuwait	4.3%	4.5%	3.9%	4.2%	4.5%	4.1%	3.7%	3.5%	3.4%	3.3%
Oman	0.7%	0.8%	0.9%	0.8%	0.8%	0.5%	0.8%	1.1%	1.3%	1.4%
Qatar	17.3%	16.5%	14.5%	13.4%	13.3%	12.4%	12.3%	15.0%	15.9%	15.8%
Saudi Arabia	14.6%	14.1%	13.5%	13.0%	15.3%	14.1%	14.1%	12.1%	11.8%	11.7%
UAE	3.8%	11.4%	18.8%	17.3%	16.4%	15.2%	15.2%	13.5%	13.0%	12.9%
Yemen	0.0%	0.1%	0.1%	0.3%	0.5%	0.5%	0.5%	0.9%	1.0%	0.9%
Production										
Bahrain	7.4%	5.9%	5.3%	5.6%	5.4%	5.9%	6.3%	6.5%	6.4%	na
Iran	23.2%	20.3%	19.6%	21.3%	21.3%	23.8%	25.6%	22.3%	22.8%	na
Iraq	1.3%	2.1%	4.6%	6.1%	6.0%	4.0%	1.7%	2.0%	2.1%	na
Kuwait	6.7%	7.6%	5.8%	6.9%	8.0%	5.4%	0.5%	2.3%	3.8%	na
Oman	2.2%	1.9%	1.9%	2.2%	2.2%	2.2%	2.3%	2.3%	2.3%	na
Qatar	8.7%	7.7%	6.9%	6.2%	6.0%	6.3%	7.8%	11.2%	11.4%	na
Saudi Arabia	29.8%	34.1%	32.8%	31.0%	29.4%	30.4%	31.8%	30.3%	30.2%	na
UAE	20.7%	20.3%	23.1%	20.6%	21.7%	22.0%	24.1%	23.1%	21.0%	na
Yemen	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	na

Table 6 (continued)

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994*
Consumption										
Bahrain	6.4%	6.7%	8.0%	7.2%	6.8%	7.2%	7.3%	7.0%	6.9%	na
Iran	29.1%	26.7%	25.4%	26.9%	27.1%	28.2%	30.0%	30.1%	29.5%	na
Iraq	1.8%	1.9%	1.5%	3.4%	3.3%	2.4%	1.4%	1.9%	2.0%	na
Kuwait	7.2%	8.6%	11.0%	11.7%	13.5%	8.3%	0.7%	3.2%	4.9%	na
Oman	3.5%	3.6%	3.7%	3.1%	2.9%	3.2%	3.5%	3.5%	3.3%	na
Qatar	8.0%	7.9%	6.5%	7.2%	6.6%	6.7%	7.1%	6.6%	6.3%	na
Saudi Arabia	31.9%	32.4%	31.6%	29.0%	28.3%	30.9%	34.7%	32.3%	31.6%	na
UAE	12.1%	12.2%	12.3%	11.5%	11.5%	13.0%	15.3%	15.4%	15.4%	na
Yemen	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	na

* The year-end 1994 reserves estimates are drawn from the Oil and Gas Journal, December 26, 1994.

Production and consumption estimates are not yet available for 1994.

The huge size of the reserves in the region, along with relatively low production and consumption levels, results in very large R/P ratios. Table 7 reports the R/P ratios by country and their history during 1985-1994. The 1994 estimate is based on the OGI reserves estimates and the BP Review 1993 production estimates. The smallest R/P ratio is found in Bahrain, at 20 years. Bahrain's use of natural gas for industrial fuel, electricity generation, and as a petrochemical feedstock is growing rapidly, thus the 20-year life (based on 1993 production levels) might be shortened considerably if new reserves are not found.

The next lowest R/P ratio (Saudi Arabia's) is seven times larger at 147 years. Iraq's huge R/P ratios (in excess of 1,000 years) largely result from the U.N. sanctions, which prohibit exports of crude oil (and other goods). This constraint on crude oil production limits the volumes of natural gas that can be produced; Iraq has only one nonassociated natural gas field. In fact, one argument put forward earlier in the year, in response to claims that Iraq's "over-production" implied cheating on the sanctions, was that Iraq had to produce more oil than it could use to satisfy its natural gas requirements. The claim was that the excess crude oil was reinjected back into the reservoirs to maintain pressures. Nevertheless, even if Iraq returned to pre-Gulf War production levels, its R/P ratio is still likely to exceed 400 or 500 years.

Kuwait's ratio rocketed to over 2000 years in 1991 as result of production cuts incurred during the Gulf War. It has not yet returned to the pre-war levels of around 200 years. The ratio stood at 335 years for both 1993 and 1994. Figure 3 shows that the R/P ratios for both Iraq and Kuwait pushed above 1,000 years in 1991. While Kuwait's ratio returned into the figure area, Iraq's ratio remains well above 1,000 years.

The R/P ratio for the region has been relatively stable over the period, holding between 341 and 384 years. If the Yemeni reserves are excluded to examine the R/P ratio for the region's active producers, the ratio hovers at the 370 year level. This is an enormous amount of natural gas that may be available for export.

Table 7. Middle East Natural Gas Reserves-to-Production Ratios by Country, 1985-1994

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994*
Bahrain	43	45	45	36	33	30	27	23	22	20
Iran	911	838	866	700	654	711	660	792	764	776
Iraq	966	512	199	469	442	673	1,546	1,366	1,216	1216
Kuwait	247	204	252	212	189	281	2,747	572	335	335
Oman	120	149	177	127	116	93	121	185	204	227
Qatar	768	742	791	760	758	735	586	509	524	525
Saudi Arabia	188	144	154	148	178	172	163	152	147	147
UAE	71	195	305	295	258	256	233	224	232	232
Yemen	na	na	na	na	na	na	na	na	na	na
Total	384	348	375	352	341	372	369	382	375	378

* The 1994 R/P ratio estimate is based on year-end 1994 estimated reserves and 1993 annual production.

Note that the R/P ratio for the region ("Total" row) includes Yemeni reserves but no Yemeni production.

If the Yemeni reserves are excluded, the 1993 "Total" R/P = 371, and the 1994 "Total" R/P = 375.

Figure 3. Middle East Natural Gas Reserves-to-Production Ratios by Country and Total, 1985-1994

Reserve Life: The World

A question of interest is, with growing demand for natural gas, how long will these reserves actually be available to contribute to the energy requirements of the economies of the world? One way to answer this question is to project both future additions to reserves and future production. Following this approach, it is useful to evaluate the growth rates over the recent past. Table 8 reports, in the upper half, year-to-year growth in reserves, production, and consumption. The table also provides average annual growth rates for 1985-1993. For the world, reserves grew at an annual average of 4.6 percent. During the same period, production grew at an annual average of roughly 2.8 percent. If both reserves and production are extrapolated at these historical rates, by the year 2005 there would be 8,558 tcf of reserves and annual production of 103 tcf. This would imply an R/P ratio of 83 years compared with the current 68 years.

The upper half of Table 9 reports three projection scenarios. The first, just mentioned, is represented by "R/P Ratio I". This may be considered a relatively aggressive projection with respect to the rate of reserve additions. This is especially aggressive in light of estimates of the world's natural gas reserves that show a small decline (0.7 percent) between the end of 1993 and the end of 1994.² The existing very large reserves base would appear to provide very little incentive for further investment in reserves. Nevertheless, because natural gas endowments are uneven and unbalanced among the several Gulf states, there remains some incentive to discover new reserves to satisfy export plans.

A more conservative projection would hold reserve levels constant at current levels, but account for growth in production at recent historical levels. This approach, represented in the upper half of Table 9 by "R/P Ratio II," holds the level of reserves constant over the projection period to 2005. R/P Ratio II assumes that annual additions to reserves are sufficient to replace the projected annual production. Under these conditions, R/P Ratio II in 2005 falls to 49 years.

² See *Oil and Gas Journal*, December 26, 1994, p. 43.

Table 8. Levels and Growth of Natural Gas Reserves, Production, and Consumption: World versus Middle East, 1985-1994

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994*
World Levels										
Reserves (Tcf)	3,483	3,624	3,795	3,954	3,987	4,215	4,376	4,883	5,014	4,980
Production (bcf/y)	59,084	60,874	64,113	66,817	69,271	71,121	71,942	72,446	73,962	na
Consumption (bcf/y)	57,999	58,182	61,286	64,267	67,182	69,033	69,524	69,436	70,463	na
										Average Annual Growth
World Growth (year-to-year annual averages)										
Reserves		4.1%	4.7%	4.2%	0.9%	5.7%	3.8%	11.6%	2.7%	4.6%
Production		3.0%	5.3%	4.2%	3.7%	2.7%	1.2%	0.7%	2.1%	2.8%
Consumption		0.3%	5.3%	4.9%	4.5%	2.8%	0.7%	-0.1%	1.5%	2.4%
Middle East Levels										
Reserves (Tcf)	854	920	1,082	1,167	1,222	1,318	1,312	1,512	1,573	1,587
Production (bcf/y)	2,224	2,645	2,885	3,313	3,586	3,546	3,554	3,962	4,196	na
Consumption (bcf/y)	1,773	2,010	2,220	2,622	2,892	2,843	2,677	2,936	3,176	na
										Average Annual Growth
Middle East Growth (year-to-year annual averages)										
Reserves		7.7%	17.6%	7.9%	4.6%	7.9%	-0.4%	15.3%	4.0%	7.6%
Production		18.9%	9.1%	14.8%	8.2%	-1.1%	0.2%	11.5%	5.9%	7.9%
Consumption		13.4%	10.4%	18.1%	10.3%	-1.7%	-5.8%	9.7%	8.2%	7.3%

* The year-end 1994 reserves estimates are drawn from the *Oil and Gas Journal*, December 26, 1994.

Production and consumption estimates are not yet available for 1994.

The average annual growth rates are for the period 1985-1993.

Table 9. Projection of World and Middle East Natural Gas Reserves, Production, and Reserves-to-Production Ratios:
Three Scenarios, 1993-2005 (reserves in trillion cubic feet; production in trillion cubic feet per year)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
World													
Reserves I	5,014	5,243	5,481	5,731	5,992	6,265	6,551	6,849	7,161	7,487	7,829	8,185	8,558
Production	74.0	76.0	78.2	80.4	82.6	84.9	87.3	89.8	92.3	94.9	97.6	100.3	103.1
R/P Ratio I	68	69	70	71	73	74	75	76	78	79	80	82	83
Reserves II	5,014	5,014	5,014	5,014	5,014	5,014	5,014	5,014	5,014	5,014	5,014	5,014	5,014
R/P Ratio II	68	66	64	62	61	59	57	56	54	53	51	50	49
Reserves III	5,014	4,940	4,864	4,786	4,706	4,623	4,538	4,451	4,361	4,269	4,174	4,076	3,976
R/P Ratio III	68	65	62	60	57	54	52	50	47	45	43	41	39
Middle East													
Reserves I	1,573	1,693	1,822	1,961	2,111	2,272	2,446	2,632	2,833	3,050	3,282	3,533	3,802
Production	4.2	4.5	4.9	5.3	5.7	6.1	6.6	7.2	7.7	8.3	9.0	9.7	10.5
R/P Ratio I	375	374	373	372	371	370	369	368	367	365	364	363	362
Reserves II	1,573	1,573	1,573	1,573	1,573	1,573	1,573	1,573	1,573	1,573	1,573	1,573	1,573
R/P Ratio II	375	347	322	298	276	256	237	220	203	189	175	162	150
Reserves III	1,573	1,569	1,564	1,559	1,554	1,549	1,542	1,536	1,529	1,521	1,512	1,503	1,494
R/P Ratio III	375	346	320	296	273	252	232	214	198	182	168	155	142

Reserves I uses the 1993 estimate as its base and grows at an average annual rate of 4.6% for World and 7.5% for Middle East Gulf (see Table 8).

Production uses the 1993 estimate as its base and grows at an average annual rate of 2.8% for World and 7.9% for Middle East Gulf (see Table 8).

Reserves II uses the 1993 estimate in each year, i.e., annual production is exactly replaced each year.

Reserves III uses the 1993 estimate as its base, and reserves are reduced each year by production in that year, i.e., no reserve additions occur.

R/P Ratio I = Reserves I / Production; R/P Ratio II = Reserves II / Production; and R/P Ratio III = Reserves III / Production.

A final, even more conservative projection, assumes that no further additions are made to reserves, while production continues to increase at the historical rate. This is represented by "R/P Ratio III," under which the reserves diminish each year by the volume produced, and no reserve additions occur. Under these conditions, by 2005 worldwide reserves fall to 3,976 tcf. With annual production projected to grow to 103 tcf (i.e., 2.8 percent annually), the R/P Ratio III would drop to 39 years. While this level of reserves-to-production is quite lower than the current 68 years, it is nonetheless still a substantial inventory. Even under these restrictive conditions, a decade from today the world would still have nearly four decades of reserves. Four decades of reserves exceeds the very restrictive reserves requirements that were imposed on producers of natural gas in both the United States and Canada, during the period prior to industry deregulation.

Reserve Life: The Gulf Nations of the Middle East

Comparable analysis can be conducted for the Gulf states as a group. For the nine Gulf states, the average annual growth of reserves was 7.6 percent, for 1985-1993, while production grew at 7.9 percent; this is reported in the lower half of Table 8.

Extrapolating through 2005, the lower half of Table 9 shows that the Gulf would have reserves of 3,802 tcf and annual production at 10.5 tcf. Since production has been growing faster than reserves, R/P Ratio I declines to 362 years, compared with the current 375 years.

If the growth in production is offset by reserve additions, such that the reserves in each year equal current levels, R/P Ratio II drops to 150 years. With an R/P ratio as large as that found in the Gulf, there is little incentive to find additional resources. The estimate of the growth between the end of 1993 and the end of 1994 was 0.8 percent, sufficient to replace production during 1994 and add a little to the reserve inventory. Nevertheless, while the large current inventory of natural gas may provide a disincentive to add reserves, several of the countries in the region (Qatar, Oman, and Yemen) have

implemented aggressive programs to locate more natural gas and to increase productive capacity.

Even if there are no additions to reserves over the next decade, the production life of natural gas resources in the Gulf states remains long indeed. When annual production is subtracted from the 1993 base-year reserves (with no additions), the region's reserve base falls from 1,573 tcf to 1,494 tcf in 2005. This is based on extrapolating the 7.9 percent grow rate for production through 2005. The result is an R/P Ratio III of 142 years. Thus, if no reserves are added to the resource base and production grows annually at the rate of 7.9 percent, a decade from now the Gulf states will still have over 140 years of reserves in inventory.

Figure 4 provides a graphic representation of the three natural gas reserves projection scenarios for the Gulf. It is reasonable to assume that the actual outcome will lie somewhere between the bounds set by these projections. There is a relatively small probability that reserve additions will continue at the pace of the recent past, but there is also little probability that no new reserves will be added over the next decade. The primary reason for not expecting reserve additions to keep pace with the recent past growth is that the financial incentives are relatively low. While several countries are moving aggressively to expand their reserves for exports, these countries are starting from a relatively small base.

The projected growth in production, based on the recent past, may be conservative, given the many plans for new export projects plus expected internal growth in demand for natural gas by most Gulf states. Under these conditions, the Gulf would account for roughly one-tenth of world production in 2005, up from the current 5.7 percent. Moreover, that would more than double the current production, increasing from 4.2 tcf/y in 1993 to 10.5 tcf/y.

Year-to-year growth rates for each Gulf country, and average annual growth rates between 1985 and 1993, are presented in Table 10. The fastest reserve growth was

Figure 4. Projections of Middle East Natural Gas Reserves: Three Scenarios, 1993-2005

Table 10. Middle East Natural Gas Reserves, Production, and Consumption: Year-to-Year and Average Annual Growth, 1985-1994

	1986	1987	1988	1989	1990	1991	1992	1993	1994	Average Annual Growth Rates	
										1985-	1985-
										1993	1994
Reserves											
Bahrain	-1.4%	-1.4%	-2.9%	-3.3%	-3.5%	-3.8%	-3.3%	1.5%	-10.2%	-2.3%	-3.3%
Iran	-4.3%	8.8%	1.0%	1.1%	20.1%	0.0%	16.5%	4.4%	1.6%	5.5%	5.1%
Iraq	-3.4%	-6.1%	261.2%	0.0%	0.0%	0.0%	15.3%	0.0%	0.0%	16.6%	14.8%
Kuwait	12.6%	3.3%	14.3%	12.2%	-1.8%	-9.5%	9.1%	0.0%	0.0%	4.6%	4.1%
Oman	25.0%	26.7%	-1.9%	-0.6%	-22.2%	37.5%	70.7%	18.3%	11.3%	15.0%	14.6%
Qatar	2.7%	3.1%	0.0%	4.1%	0.1%	-0.7%	40.1%	10.1%	0.0%	6.6%	5.8%
S. Arabia	4.1%	12.2%	4.1%	23.3%	-1.1%	-0.4%	-0.8%	1.5%	0.1%	4.9%	4.4%
UAE	218.9%	94.6%	-1.0%	-0.4%	-0.2%	-0.5%	2.7%	0.0%	0.0%	22.9%	20.3%
Yemen	-	166.7%	131.2%	48.6%	27.3%	0.0%	98.6%	7.9%	0.0%	46.0%	40.2%
Total	7.8%	17.5%	7.9%	4.6%	7.9%	-0.4%	15.3%	4.0%	0.9%	7.6%	6.9%
Production											
Bahrain	-4.5%	-1.6%	20.2%	5.0%	8.2%	6.2%	14.9%	5.4%		6.2%	
Iran	4.1%	5.3%	25.0%	8.2%	10.4%	7.7%	-2.9%	8.3%		7.7%	
Iraq	82.4%	141.9%	52.8%	6.3%	-34.3%	-56.5%	30.5%	12.3%		13.7%	
Kuwait	36.4%	-16.6%	35.8%	25.7%	-33.7%	-90.8%	424.0%	70.6%		0.8%	
Oman	1.4%	6.3%	36.2%	9.7%	-3.1%	5.5%	11.2%	7.8%		8.5%	
Qatar	6.2%	-3.3%	4.1%	4.3%	3.3%	24.5%	61.2%	7.0%		11.3%	
S. Arabia	36.0%	4.9%	8.6%	2.4%	2.4%	4.8%	6.3%	5.6%		8.1%	
UAE	16.7%	24.2%	2.4%	13.6%	0.6%	9.4%	6.9%	-3.6%		8.1%	
Yemen	-	-	-	-	-	-	-	-		-	
Total	18.9%	9.1%	14.8%	8.2%	-1.1%	0.2%	11.5%	5.9%		7.9%	

Table 10 (continued)

	1986	1987	1988	1989	1990	1991	1992	1993	1994	Average Annual Growth Rates	
										1985- 1993	1985- 1994
Consumption											
Bahrain	17.6%	32.1%	6.2%	3.9%	4.9%	-4.6%	5.6%	5.8%		8.1%	
Iran	4.1%	5.3%	25.0%	11.0%	2.3%	0.2%	9.9%	6.2%		7.5%	
Iraq	24.7%	-15.3%	166.0%	8.8%	-28.7%	-45.4%	47.2%	14.1%		8.7%	
Kuwait	35.5%	40.9%	25.8%	27.6%	-39.7%	-92.5%	434.0%	66.3%		2.6%	
Oman	16.5%	12.2%	0.9%	3.4%	8.3%	1.2%	9.5%	4.2%		6.7%	
Qatar	10.9%	-8.7%	31.3%	0.0%	0.9%	0.0%	2.0%	2.5%		4.2%	
S. Arabia	15.3%	7.9%	8.4%	7.7%	7.2%	5.8%	2.1%	5.8%		7.2%	
UAE	14.4%	11.2%	9.9%	10.4%	11.7%	10.6%	10.0%	8.7%		10.3%	
Yemen	-	-	-	-	-	-	-	-		-	
Total	13.4%	10.4%	18.1%	10.3%	-1.7%	-5.8%	9.7%	8.2%		7.3%	

Note: The average annual growth rates for production and consumption are for the period 1985-1993.

The average annual growth for Yemeni reserves begins with 1986.

recorded by Yemen at an average annual rate 46 percent, but Yemen started from a very low base. UAE recorded an average annual growth in reserves of nearly 23 percent, followed by Iraq with 16.6 percent, and Oman with 15 percent.

For production, Iraq recorded the fastest growth at 13.7 percent, followed by Qatar at 11.3 percent. Kuwait's average annual growth of less than 1 percent reflects that fact that it had not yet recovered from the devastation of the Gulf War. UAE lead the group in increased consumption.

Export Availability

The export availability of natural gas is related to the level of reserves and to the relationship between the growth in production and domestic consumption. Production and consumption data are not always easy to reconcile, because a good share of the natural gas produced results from crude oil production, which might not add to the market supply of natural gas. Historically, much natural gas produced as a by-product of oil production has been used as a field fuel, reinjected into the reservoir, flared, or vented. Because of differences in reporting requirements, it is often impossible to account for these activities from outside of the operation, and these activities are typically not accounted as consumption. Generally, consumption accounts for gas delivered to consumers who use the gas after it has left the lease property. Moreover, consumption statistics for a country will not typically include volumes that have been exported.

If regional or domestic consumption grows faster than production, the availability of export quantities might be pinched. But, if consumption represents a relatively small share of the volumes produced, capturing previously flared or vented volumes might meet both growing internal demand and a growing or prospective export industry. Similarly, more efficient use of natural gas as a field fuel or as a reinjectant might free additional volumes for domestic or export needs.

Both reserves and production have generally increased faster than consumption in the Gulf. The growth in regional gas consumption since 1985 averaged 7.3 percent, compared with 7.6 percent for reserves and 7.9 percent for production, as reported in the lower half of Table 8. On an individual country basis, three countries have seen faster consumption growth than production growth. UAE had 10.3 percent growth in consumption compared with 8.1 percent in production, for 1985-1993. However, UAE's reserves grew 22.9 percent for the same period. The UAE's exports (LNG from Abu Dhabi) have increased at an average annual rate of 1 percent during the period.

Kuwait has experienced 2.6 percent growth in consumption compared with 0.8 percent growth in production. Kuwait is clearly a special case, owing to the Gulf War and the significant damage done to oil and gas production facilities. Nevertheless, even accounting for declines in reserves in 1990 and 1991, the average annual growth of reserves was 4.6 percent.

The third country with slower growth in production than consumption is Bahrain. Bahrain has by far the smallest resource endowment of the nine countries. Not only did consumption growth (8.1%) outstrip production growth (6.2%), but also reserves declined on an annual average by 2.3 percent for the period. At the end of 1994, Bahrain had an R/P ratio of 20 years (seven times smaller than the next lowest R/P ratio for the region). Bahrain's growing industrial base will become more reliant on its neighbors for its energy requirements as its relatively small resources are depleted.

Comparisons of production versus consumption is difficult with the available data. Table 11 shows that, for several countries and for different years, recorded consumption exceeded production. If trade took place between countries, it could provide an explanation. But, with the exception of trade between Iraq and Kuwait before the Gulf War, this does not appear to be the case. Natural gas pipelines do not exist among the countries in the region, at this time.

Table 11. Middle East Natural Gas Consumption as a Percentage of Production by Country, 1985-1993

	1985	1986	1987	1988	1989	1990	1991	1992	1993
Bahrain	69.6%	85.8%	115.1%	101.7%	100.7%	97.6%	87.7%	80.6%	80.9%
Iran	99.9%	99.9%	99.9%	100.0%	102.5%	94.9%	88.3%	100.0%	98.1%
Iraq	104.7%	71.6%	25.1%	43.6%	44.7%	48.5%	60.9%	68.7%	69.8%
Kuwait	86.0%	85.3%	144.1%	133.6%	135.5%	123.3%	100.0%	101.9%	99.3%
Oman	124.8%	143.4%	151.3%	112.1%	105.7%	118.2%	113.4%	111.6%	107.9%
Qatar	74.0%	77.2%	72.9%	92.0%	88.2%	86.2%	69.2%	43.8%	42.0%
S. Arabia	85.1%	72.1%	74.2%	74.1%	77.9%	81.5%	82.3%	79.1%	79.2%
UAE	70.6%	65.0%	56.2%	60.4%	56.9%	61.9%	62.2%	62.6%	69.1%
Yemen	-	-	-	-	-	-	-	-	-
Total	84.6%	79.9%	80.4%	82.5%	83.7%	83.4%	78.8%	77.1%	78.5%

Based on data from Table 5, plus UAE exports.

The inconsistencies might be the result of reporting anomalies, such as incomplete coverage of all producers or possible double counting on the consumption side. Nevertheless, it is clear that available reserves are sufficiently large, relative to any speculated demand, that enough natural gas will be made available to meet both internal and external regional requirements well into the next century.

Proposed Natural Gas Export Projects

Currently most natural gas produced in the Gulf is consumed domestically. The gas is used to fuel crude oil recovery, electricity generation, and industry, and it is used as a feedstock for the region's rapidly growing petrochemical industry. The only exceptions to this pattern are Abu Dhabi (the largest of the seven United Arab Emirates) and Iran. Nevertheless, plans are in place to develop several export projects throughout the region. Several of these plans are now in the construction phase.

Current Exports

Abu Dhabi has exported LNG since 1977 from facilities on Das Island, which are operated by Abu Dhabi Gas Liquefaction Company (ADGAS). These facilities have recently doubled in capacity—from 2.5 million tonnes per year to 5.0 million tonnes per year (121.75 bcf/y to 243.5 bcf/y). All of these LNG exports are sold to the Tokyo Electric Power Company under several long-term contracts. Export volumes account for about 24 percent of total UAE reported natural gas consumption in 1993 and about 13 percent of reported production. The doubling of export LNG volumes should increase the share to over 45 percent of consumption. Nearly two-thirds of UAE's primary energy usage is satisfied with natural gas.

While its capacity is contractually obligated to its single Japanese customer, ADGAS has shown aggressiveness and flexibility by arranging to export spot LNG

cargoes to Belgium and France. The deal was made with France's Gaz de France and Belgium's Distrigaz for the export of 8.4 bcf of LNG, to be delivered during the 1994-1995 winter. The LNG price per million Btu was somewhere between the c.i.f. Europe (\$2.80) and c.i.f. Japan (\$3.10) prices.

Iran exports natural gas to the Former Soviet Union via pipeline. The export pipeline enters the FSU through a connection on the western side of the Caspian Sea, at the border with Azerbaijan. During 1993, the total exports amounted to 17.65 bcf.

Planned Export Projects

Several Gulf countries plan to develop their natural gas resources with a focus on exports. These include in Qatar, Oman, UAE, Iran, and Yemen. Target markets are South Asia (Pakistan and India), the Far East (Japan, Korea, China, and Taiwan), and potentially Southeast Asia (Thailand).

Qatar

Qatar's primary focus is on the world LNG market. It plans to export as much as 16 mn tonnes/year (t/y), or 780 billion cubic per year (bcf/y), by 2010. This is over 15 percent of the world LNG export capacity that is existing, firm, or likely to be on line by 2010. The size of Qatar's natural gas resource is sufficient that even the increment 780 bcf/y, added to its 1993 level of production, would result in an R/P ratio of nearly 200 years.

Three LNG projects are planned. The Qatar Gas Liquefaction Company (Qatargas) is scheduled to come on line in October 1996, with a capacity of 6 mn t/y. Partnership shares differ between the upstream and downstream portions of the project, though both are well represented by foreign investors. Upstream shareholdings are Qatar General Petroleum Corporation (QGPC, 65%), Total (20%), Mobil (10%), Marubeni

(2.5%), and Mutsui (2.5%). Liquefaction and downstream shareholdings are QGPC (65%), Total (10%), Mobil (10%), Marubeni (7.5%), and Mitsui (7.5%).

Chubu Electric, Japan, signed a 25-year agreement in 1992 for 4 mn t/y of LNG from Qatargas, with first delivery in January 1997. Chubu holds an option for an additional 2 mn t/y. The remaining 2 mn t/y were contracted for by seven Japanese electricity and gas utilities, including Tokyo Electric Power Company. They signed a 25-year agreement in January 1995, and by so doing precluded Korea Gas Corporation's involvement in the project. This might have been a move on the part of the Japanese to dedicate the entire output of the Qatargas project to Japan.

Two additional LNG projects are under consideration. The joint-venture project, Ras Laffan LNG (Rasgas), was established in August 1992 under the ownership of QGPC (70 percent) and Mobil (30 percent). The agreement contained the proviso that the venture would have the exclusive rights to Qatar's next 10 mn t/y of LNG export capacity. So far, Mobil has entered into no sales or purchase agreements for any of this capacity. There are signed memoranda of understanding (MOU) with Korea Gas Corporation, Taiwan's Chinese Petroleum Corporation, China, Turkey's Botas, and India's Essar. These MOUs are not binding, and without firm sale and purchase contracts, financing will not be forthcoming.

In January 1995, Enron, another U.S. energy company, signed a letter of intent with QGPC to develop a 5 mn t/y LNG facility, also at Ras Laffan, to serve Mediterranean and Indian markets. Because of the exclusivity clause in the QGPC-Mobil Rasgas agreement, QGPC has requested Mobil to waive this right. The Enron project would deliver LNG to an Indian power station at Dabhol in which it holds a majority equity interest. Enron also plans to export LNG to Israel and Jordan. Mobil was reluctant to relinquish its exclusive right for two reasons. First, Mobil was concerned that a third LNG project would overexpose Qatar within the international financial markets. Second, it was concerned that Enron would encroach on its market in India and Turkey.

Mobil has, however, come to an agreement with Enron under which Enron would sell LNG only to projects in India in which Enron holds an equity position. In the Mediterranean Enron is limited to Israel and Jordan, with Turkey specifically excluded. However, Enron's Dabhol project is now in question: the State of Maharashtra canceled the project in July, although there are ongoing discussions that might revive the project. Enron asserts that even if the Dabhol project dies, it will still go forward with the LNG export development.

Exports to Israel are permitted, under Mobil agreement. It is likely, however, that this proposed project might change somewhat. The initial plan was for the LNG to be delivered to Eilat on the Gulf of Aqaba (an arm of the Red Sea). The Israelis now want the deliveries from the Mediterranean, for security reasons. It is not yet clear how such an alteration will affect the viability of the project.

An additional export option for Qatar is via pipeline. There are discussions between Qatar and Crescent Petroleum (a private Sharjah company) to develop a natural gas pipeline to supply Pakistan. The 1,600 km line would originate in Qatar and pass through UAE before reaching Pakistan. The system would draw gas at the rate of 3.8 bcf/d from the North Field. The gas would be distributed 2.4 bcf/d to Pakistan, 0.8 bcf/d to Dubai, and 0.4 bcf/d to northern UAE.³ This system appears to compete with the proposed Iran-Pakistan pipeline project, as well as possibly competing with Iranian gas sales to Dubai from the Sirri fields.

An additional export scheme is to develop a Gulf Cooperation Council (GCC) gas grid. The idea is to develop a regional natural gas grid, which will provide Qatar with a avenue to sell more of its gas though most GCC might prefer domestic to imported gas. This idea is in the concept stage and is unlikely to materialize any time soon.

³ That is, the UAE excluding Abu Dhabi and Dubai.

Oman

Oman is currently designing both an LNG project that targets Far East markets and a subsea pipeline to serve India. In the near term, these proposed projects are probably mutually exclusive. It is possible that only one will be chosen, in the near term, and that will most likely be the LNG option. The LNG project is designed to produce 6.2 mn tonnes/year (302 bcf/y), with planned start-up in 2000. In February 1995, the Korea Gas Company signed a letter of intent with the Oman Liquefied Natural Gas Company (OLNGC) to purchase 3 mn tonnes/year for 25 years, with initial deliveries to begin with project start-up. OLNGC is a joint venture made up of the Omani government (51%), Shell (34%), Total (6%), Mitsubishi (3%), Mitsui (3%), Partex (2%), and Itochu (1%). The upstream portion of the project will be wholly owned by the Omani government.

The Omani-Indian pipeline project is considered technologically difficult and expensive. It is one of three Gulf pipeline export proposals; the other two are the Qatar-Crescent and one from Iran. Oman's continued pursuit of gas export projects like this emphasizes its firm intent to find the best markets possible for its growing natural gas resource. The Omani-Indian pipeline, if completed, would be an engineering marvel. The project calls for a two-phase development program to lay a 24 inch, 1 bcf/d undersea line at depths reaching 3,500 meters. The project will include an onshore pipeline to deliver natural gas from Central Oman to the Omani coast, where a compressor station will boost the line pressure to 6,000 psi to move the gas 1,130 kilometers to India. The first phase is to be completed by mid-1999, with a second 24 inch line being brought into service by 2001. The first phase is projected to cost \$2.7 billion, and the total project cost is estimated at \$5 billion. However, no such line has ever been constructed before. Sub-sea pressures will be greater than ever encountered in previous pipeline projects. Many innovations will be required to complete the project, and costs can only rise.

The three proposed Gulf pipeline projects targeting South Asia face possible competition from Turkmenistan. There are plans to build a pipeline across Afghanistan to bring Turkmen gas to Pakistan and produce LNG in Pakistan for exports. The pipeline

may move perhaps further south to India. An alternative pipeline route for the Turkmen gas runs through Iran. Political instability in Afghanistan may preclude the shortest route, and U.S.-stimulated reluctance on the part of the international financial community may forestall development through Iran.

The Omani government claims that both the LNG and the subsea pipeline projects can be physically supported. This is based on recent (mid-1995) claims of increased proved reserves, i.e., 24 tcf compared with the 20 tcf reported in Table 5 for year-end 1993 and 22.2 tcf for 1994. However, financial requirements for both are substantial. This is especially true given the costs of financing Oman's nationwide privatization program. It is expected that if a choice has to be made between the two projects, the LNG project will be preferred. It will enhance the domestic economy much more than the pipeline project.

United Arab Emirates

There are no known plans to expand the Das Island facility, which was recently doubled in size. There is, however, participation in a pipeline originating from Qatar and extending across the Strait of Hormuz if possible. This project was mentioned above in the section on Qatar. The Qatar-Crescent project would pass through Iranian territory on its way to Pakistan and possibly on to India. An alternative to this route is to avoid Iranian territory and instead interconnect with the proposed Omani pipeline system that would serve India.

Iran

Iran has discussed building an export pipeline to serve both Pakistan and India. There is also interest in expanding pipeline exports, through the FSU interconnection, to Europe. Iran is also investigating exports to Dubai, which lacks the gas resources of its neighbors, Abu Dhabi and Sharjah. Iran recently awarded a contract to Total to develop its Sirri-E

and Sirri-A fields, after Conoco was forced to withdraw. Dubai requires natural gas for a miscible gas injection project to maintain crude oil production. The Sirri fields are just across the offshore demarcation line in the Gulf from Dubai's Fateh Field and constitute a natural source for the gas. Current talks are for approximately 100 mcf/d, while under the Conoco structure to be talked were in the 400 mcf/d range.

Plans to export natural gas to Pakistan and India rely on production from Iran's South Pars field, which is connected to Qatar's North Field. The Pakistan plan calls for a 1,000 mile long overland pipeline to ship up to 1.6 bcf/d. This project could cost \$8.5 billion or more and requires India's agreement to take gas from Iran via Pakistan. India remains reluctant.

Iran has also engaged in talks with Turkmenistan with respect to a pipeline to supply gas to Europe. The project would require a 2,000 mile long pipeline, originating in Turkmenistan and passing through Iran and Turkey on its way to Europe. The project might provide Iran with another avenue for exports and an alternative route to Europe.

Major project development originating in Iran or requiring passage through Iran may face significant hurdles. Iran appears to be weathering the U.S. embargo, with respect to both the crude oil export volumes and prices, but its ability to draw on the international financial community to raise significant funding for export oriented projects has not yet been tested. The size of the proposed projects will require external financing, and without it, the projects will likely languish while others progress.

Yemen

Yemen's natural gas resource base and transportation infrastructure is in its infancy. Nevertheless, it has been moving aggressively to develop this sector.

The Yemeni government is developing a 5 million tonnes per year LNG project, with the plan to supply Asian markets. Yukong Ltd. leads a Korean group that holds a

24.5 percent equity interest in the Marib gas reserves, along with Hunt and Exxon. The downstream marketing of the project is the responsibility of Total. The \$5 billion dollar project will not go forward until the Hunt/Exxon/Yukong group comes to an acceptable agreement with Total and Yemen's General Gas Corp., but recent advances in discussions suggest that the project will move ahead.

The Markets

General

Both India and Pakistan have a tendency of overcommitting their use of natural gas beyond available supplies. This has led them to have to curtail investments in natural gas based industries in recent years. Both nations would prefer to develop domestic natural gas resources before they import natural gas, mainly because these should be less expensive than imports by pipeline or as LNG. Both now realize that domestic natural gas reserves are not likely to be fully adequate for their development ambitions. Further, imports of raw materials are now easier into each nation than formerly was possible, because governments now realize that foreign competition and foreign supply of raw materials can have a beneficial impact on domestic industry and competing raw material suppliers in general.

Supply options are limited for each nation if natural gas pipelines are to be used. Distance would favor eastern Middle East supplies to Pakistan, with Central European supplies apparently remote, even though Turkmenistan would like to supply gas to South Asia. Surprisingly little discussion has taken place regarding Bangladeshi supplies of natural gas to India, even though any pipeline from Bangladesh would be the shortest possible gas route to Indian territory. The two nations might require yet further time to develop the trust required to share natural gas resources, and further development would require resolution of water disputes. In any case, pipeline gas from Bangladesh would serve a different (northeastern Indian) market than would natural gas from the Middle

East (northwestern India). Further it would compete with possible natural gas supplies from Assam.

India

Natural gas is used in most major regions of India, though roughly two-thirds of consumption takes place in the Western Region that includes the industrial areas of Gujarat and Maharashtra, which are near the natural gas sources of the offshore Bombay High hydrocarbon province. Also consuming natural gas from the Bombay High (and onshore Gujarat) are northern areas including Delhi, Uttar Pradesh, and Rajasthan that have access to the natural gas by pipeline. During 1992/3 (the fiscal year from April 1992 through March 1993), the North and the West consumed 1,083 million standard cubic feet of natural gas per day. The North Eastern Region of India, dominated by Assam, consumed 100 million scf/d from locally produced sources. Some natural gas is also produced in the South, notably in Tamil Nadu, which consumed 56 million scf/d in 1992/3.

India uses natural gas in a variety of industries. During 1992/3 31 percent of natural gas use was in the power generation industry, and 41 percent was used to produce fertilizer. The 4 percent of natural gas reported used in the petrochemical industry might include either ethane used at olefin plants or possibly methane used in methanol production, both of which occurred in India at the time at low levels. Much of the remaining 24 percent of natural gas consumption included sponge iron production at integrated and secondary steel units in the western and northern regions

India's domestic production has been stable if not declining since 1990. This reflects the maturity of both the Bombay High and the Assam hydrocarbon provinces. With the liberalization of India's investment climate, foreign and domestic oil firms are showing a new interest in exploration within India. Since the nation is in some senses "underexplored," new discoveries cannot be ruled out, though it is premature to expect

substantial finds. Natural gas reserves in neighboring Bangladesh are substantial and close to India but have proven to be inaccessible owing to endemic distrust between the two nations. Potential markets for this gas would be in eastern India—a market different from the potential markets for natural gas originating in the Middle East.

The potential consumption of natural gas in western and possibly northern India can be expected to grow if supplies permit. The most recent energy outlook of the International Energy Agency (IEA) projected that gas based electricity generation in India would grow from 3.1 GW in 1992 to 15.0 GW in 2010. We do not know where India will find this gas. Currently more than 60 percent of India's electricity generating capacity is coal based, most of which is domestically produced. India's conventional coal fields are located in the eastern and interior regions of the country, while there are also exploitable lignite deposits in Tamil Nadu and elsewhere. The western and northern regions have relatively little identified coal resources, necessitating imports by rail or sea. The distance of these shipments, coupled with environmental concerns with coal fired power generation, imply a potential for alternative forms of power generation, including gas firing.

Plans for electricity production in the eastern and northern regions of India now include an expectation that natural gas will become available in the area, based on either importation as LNG from the Middle East or through a pipeline. In many cases power plant construction is proceeding with the intention of initially using naphtha or heavier oil products until gas supplies are available. The most widely publicized example of this is the 2,015 MW Dabhol power plant in Maharashtra, which is sponsored by Enron and other American firms. Dabhol is divided into two phases. The first phase is a 695 MW unit currently under construction that will initially burn distillate oil but will be converted to LNG when it becomes available. The gas would come from Qatar, where Enron is developing LNG production facilities. The second phase would burn LNG from its beginning. Construction at the Dabhol plant has recently been halted owing to political and financial concerns. Its status is now uncertain.

Other power projects in western India are being undertaken on the basis of plans to import gas from Oman. This includes a proposal by a unit of Steel Tubes of India to build a 330 MW power plant at Guna in Madhya Pradesh, which would initially burn naphtha but which would be converted to natural gas when the pipeline is completed. (Such plants could presumably switch to gas based on LNG if this alternative is pursued.) Two other 330 MW plants have also been proposed near existing pipelines in the area, with similar intentions of switching eventually from naphtha to natural gas. For similar reasons a proposed 400 MW power plant in Kerala has also been redesigned for naphtha to gas conversion instead of earlier coal firing plans.

Petrochemical and fertilizer use of natural gas also has a higher potential than is currently possible because of insufficient natural gas supplies. India is rapidly increasing its ammonia based fertilizer production, but has been forced to use naphtha and fuel oil feedstocks rather than methane because of constrained supplies. Allocations of methane within India give fertilizer a lower priority than other methane uses. Some fertilizer plants have been forced to use heavier feedstocks, even after they received contractual commitments for methane deliveries that exceeded actual receipts. Similarly, India's methanol production levels are still relatively low, owing partly to a shortage of preferred methane feedstocks.

Olefin petrochemical plants, in the traditional market environment, have generally favored lighter feedstocks such as ethane because of the higher ethylene yield. During the past few years propylene prices in eastern Asia have exceeded ethylene prices, diminishing the attractiveness of this natural gas based feed. It remains to be seen if this change is permanent or also if the trend might also appear in other olefin markets. The attractiveness of ethane as a feedstock, of course, is also a reflection of the relative prices of feedstocks as well as of output products. The attractiveness of gas imports to India might depend on ethane content and price.

Several of India's olefin construction plans appear to have been based on at least some ethane input. This includes Reliance Industries' unit at Hazira (750,000 tonnes/year

ethylene capacity in two phases), Indian Petrochemicals Company Ltd.'s (IPCL) Gandhar unit (300,000 tonnes/year), and the Gas Authority of India Ltd.'s (GAIL) Auraiya plant (320,000 tonnes/year). In some cases, the "gas" feed of these plants includes liquefied petroleum gas, and in others (e.g., Hazira) naphtha also is included in plans. The Gandhar facility's olefin unit has been deferred to a second phase specifically owing to the failure of IPCL and its gas supplier (GAIL) to come to terms that would assure adequate feedstock supplies. Access to ethane might change the plans and timing of these and other projects.

Pakistan

Pakistan has several natural gas deposits in its central area which includes the southern Punjab Province and parts of northern Sindh Province. Pakistan has more current options for electricity generation than India as a whole, with electricity production now dominated by hydroelectric facilities, oil, and gas. Substantial coal deposits have been located in the Thar region of Sindh Province but have not yet been exploited. Other, less attractive, coal deposits have also been found, and those at Lakhra are being exploited for power generation. A large project east of Karachi could involve as much as 5,280 MW of coal fired electricity, though initially the coal involved will be imported. Hydroelectric resources are also continuing to expand, with a 1,425 MW project at Ghazi-Barotha being among the largest planned. Large power projects in the south involve traditional oil fired plants.

The potential to develop a natural gas based power industry in Pakistan is thus limited by the large number of alternative resources that can be brought to the task. Each alternative fuels has its drawbacks, however. Coal in Pakistan is often of poor thermal quality, and many sites have excessive overburden. This raises questions regarding the commercial viability of Pakistani coal. Large hydroelectric projects in Pakistan, beyond Ghazi-Barotha, might involve the displacement of large populations. An excessive dependence on hydroelectric power has also resulted in nationwide seasonal power

shortages. If gas were available in Pakistan at a commercially reasonable rate, additional power generation using gas might be attractive. Pakistan's relative proximity to the Middle East would make any gas supplies in the form of LNG unexpected. Pipeline supplies, however, would also be unusual because of the still long distance that would exist between major markets and gas sources. (These distances are even greater for India, of course.)

The IEA's recent world energy outlook expects that gas based electricity generation capacity in South Asia (outside of India) will rise from 4.7 GW in 1992 to 12.2 GW in 2010. Current gas based capacity among these nations is confined to Bangladesh and Pakistan. No gas production is expected by us for Nepal by 2010, and gas fired production is not certain in Sri Lanka by this time, though LNG shipments by 2010 cannot be ruled out. We credit Bangladesh with 2.1 GW of gas fired plants and Pakistan with 2.8 GW in 1993, though some of these facilities might not have been in actual operation, especially in Bangladesh. One hundred MW were added at Kot Addu in 1992 and might not have been included in the IEA numbers. Subtracting our own, highly tentative gas plant figures for Bangladesh from the IEA figures, we convert their forecast to a Pakistan forecast of 2.7 GW in 1992 and 5.8 GW in 2010. Much as is the case with India, we cannot identify domestic gas sources that would permit a doubling of gas capacity in Pakistan, though this cannot be ruled out. The IEA figures appear to include the 2.4 GW Kalabagh Dam hydro project and perhaps other uncertain hydro schemes that might not materialize. If so, power requirements for gas might be even higher, if the gas is available.

Commercial usage of natural gas in power generation is not expected to expand rapidly without foreign based supplies. The existing Kot Addu power plant (1,400 MW) was scheduled for partial privatization, but the process has been hindered by the inability of local gas firms to guarantee supplies. (Less than a third of gas requirements could be promised by the government.) New gas fired power projects such as the 586 MW Uch

plant are based on the usage of low calorie natural gas that might not otherwise be marketable.

Pakistan's petrochemical industry is at present poorly developed. A small refining sector and inadequate natural gas supplies have generally stalled the petrochemical industry's growth, despite a high potential for domestic petrochemical consumption. Adequate feedstocks are not available domestically. Plans for at least two long-planned large ammonia-urea plants have been deferred if not canceled because of a lack of natural gas resources.

Pipelines

Potential natural gas suppliers in Qatar, Iran, Oman, and Turkmenistan have each proposed the supply of natural gas to India and Pakistan by pipeline. The Qatar and Iran pipelines would transit Pakistan with the eventual extension of pipelines to India, while the Oman route would be subsea, terminating in Gujarat state in westernmost India. The Turkmenistan route is less clear but would have to transit Afghanistan (or circuitously Iran) to Pakistan before any extension to India.

Pakistan and India have a history of not trusting each other and have gone to war several times since independence, though not since 1971. (There have been subsequent cases when war appeared possible.) India would have to trust Pakistan's intentions to accept natural gas piped through Pakistani territory for its power and industrial sectors. Further, if sufficient redundant capacity were not available in any pipeline, growing Pakistani demand for natural gas might threaten to displace supplies to India. Much of this might imply a need for an orderly pricing mechanism for the gas, but risks might occur if transit tariffs through Pakistan discouraged Indian consumption.

The subsea pipeline proposed between Oman and India has been challenged on the grounds that it might not be technically feasible. Gas pipeline pressures are nominally quite high on the surface, but subsea pressures at proposed depths for the

Omani pipeline are greater still. This increases the risk of ruptures in pipelines that are not specially designed for the deep subsea conditions. Further, pipeline laying vessels have not previously been designed to handle the depths that would be encountered in the Indian Ocean, thus equipment and vessels might have to be built or reengineered to handle new and potentially adverse conditions.

Gas from Turkmenistan appears to be only a remote possibility. To the political difficulties of Pakistan-Indian interrelationships would be added either the transit of habitually unstable Afghanistan or negotiating a circuitous and longer route through Iran. Iran would be a competitor with Turkmenistan in any South Asia gas market, but has proven willing to allow the potential pipeline transit of gas from Qatar and the UAE through Iranian littoral regions.

While the various gas pipeline schemes are still in the planning stage, the possibility is open for combining the various pipeline plans emanating from the Middle East. This might lie behind Iran's cooperativeness on the transit of the pipeline from Qatar and the UAE. Iran's high level of international debt might require the nation to seek acceptable foreign partners, if it were to finance any ambitious investment scheme.

The pipeline from Iran to India would be 2,200 km long and would be capable of supplying 50 million cubic meters of gas to India each year. Additional gas would of course flow to Pakistan. The target for completion is 2000. The Omani pipeline is scheduled to deliver 56 million cubic meters of gas each year to India with no flow expected to Pakistan, which would be bypassed. Oman has recently appeared to favor the shipment of LNG to the subcontinent in preference to piped gas. Pakistan has promised Turkmenistan that it will permit the transit of its gas through Pakistani territory into India. Transit terms are not clear. The pipeline would under current plans be 1,500 km long and would cross Afghanistan. This is the shortest of proposed routes. Deliveries would be 20 billion cubic meters of gas each year, with initial delivery targeted for 2002.

Demand in East Asia

Japan

Japan's government policies have generally favored power generation using nuclear, hydro, and indigenous unconventional energy sources. The Japanese government has announced plans to increase capacity by 40 GW of nuclear generated electricity by the year 2010. Even MITI officials now acknowledge that this goal was ambitious and will not be met in the face of increased siting problems for nuclear plants and of low yen prices for fossil fuels. Hydroelectric facilities also face siting problems and domestic unconventional sources of energy have only a limited potential. This leaves fossil fuels as Japan's alternative. Concern with clean air standards and lower plant construction costs would favor LNG based generation, while fuel cost might favor coal. Convenience of delivery and new technologies that improve oil's competitive position would also permit some continued oil fired electricity production.

Japan's policymakers currently favor replacing the nuclear capacity that will not be built with natural gas based power generation, ostensibly for environmental reasons. Some of this is already reflected in LNG contracts, which must be negotiated well in advance, but the possibility remains that additional gas might be required for power generation. Some of this might come from the Middle East. Alternative potential gas supplies are also located attractively nearby on Sakhalin Island. Use of this gas is, however, restricted by continuing disagreements between Russia and Japan over the Soviet seizure of what was formerly Japanese territory on Sakhalin and the Kurile Islands. Also inhibiting exploitation is the absence of either pipelines connecting Sakhalin to Japan or an extensive gas pipeline system within Japan. Such issues are not likely to be resolved in the near future and thus might not affect seriously Japan as a possible market for Middle East originated LNG.

Japan, has only recently developed a program to encourage independent power production. Details of the plan remain unclear. The switch to independent power has generally led to changes in fuel use at new power plants in other countries, and the same

might eventually be expected in Japan. We believe that this might favor coal over gas, but options remain for such fossil fuel.

The use of natural gas as a fertilizer and petrochemical feedstock is limited in Japan. Most petrochemical facilities are based on naphtha. Further, Japan's petrochemical facilities were built to meet export markets in Asia that are now increasingly being served by either domestic or regional facilities or by Korea. Japanese petrochemicals are thus expected to fill increasingly specialized and technically advanced niches. Japan's petrochemical industry is thus not expected to require significant new quantities of natural gas.

Much of Japan's current natural gas usage is used to meet residential and commercial requirements. This market could grow, though its growth will depend partly on the relative costs of electricity compared with gas based household energy. Household formation should not grow rapidly in Japan, as the population continues to stabilize and as the age structure of the population levels out.

Korea

Korea is increasingly turning to independent power producers for the generation of its future electricity needs. The national utility, Korea Electric Power Corporation (Kepco), will continue to also produce electricity and the national commitment to nuclear generated power has yet to abate. Proposed IPP based power projects to date have had their fuel use identified by Kepco and the government, thus the IPP program has not yet served the role of directing power generation to the most effective power sources. As Korea becomes familiar with more competitive power sourcing this centralized control of the industry can be expected to relax. Also, while nuclear is less controversial in Korea than in other Asian nations, public opposition to plant citing and expansion can be expected to increase as it has in Japan and Taiwan. The relative high cost of nuclear compared to fossil fuel power can also be expected to affect policies.

What can be expected would be a potential for more fossil fuel based power in Korea than is currently planned. The opportunities for LNG from the Middle East are thus no worse than official plans would project and might in fact be better. The same alternative sources for Korea exist as for Japan, with the exception that Korea has no territorial disputes with Russia. The nation is thus potentially more receptive to potential supplies from Sakhalin, be they LNG or eventually piped. Korea's domestic gas reticulation system is more developed than Japan's, but its capacity to accept piped gas from Russia is inhibited by the territorial interposition of North Korea.

Korea's petrochemical industry has been constrained by its limited access to inexpensive natural gas feedstocks. It is also dependent on exports of (naphtha based) petrochemicals. Korea's markets for petrochemicals continue to grow rapidly, but demands for natural gas should not be significant.

Domestic commercial and residential use of natural gas is accepted in Korea and continues to have the potential to grow.

Taiwan

Official Taipower forecasts of electricity supplies have generally argued for the provision of most new baseload power from nuclear energy. These have run into popular roadblocks to nuclear energy based on both citing, safety, and political concerns. If the new independent power producer (IPP) program promises more and cheaper electricity than had been scheduled by Taipower, the program might be expected to expand. We also expect that additional cogeneration schemes might readily raise the amounts of power from private sources above the government target.

Petrochemical facilities in Taiwan have a low dependence on natural gas. Gas based petrochemical facilities are not expected to expand significantly. There is a potential for increased household and residential gas use. Taiwan does not have any

nearby sources of potential piped natural gas, thus any increase in gas use would be likely in the form of LNG. The Middle East is a potential source of this gas.

Taiwan's IPP program is more advanced than that of either Korea or Japan. Plans call for the provision of 7,260 MW of privately produced power by 2002. The first bidding process for providing this electricity included offers for almost 34 GW in 25 projects. Electricity capacity in these projects that can be identified by potential fuel include gas (15,560 MW), oil (14,280 MW), and coal (3,740 MW). The relatively poor showing for coal was surprising and might have represented a combination of concerns for the environmental impact of power plants and an unwillingness on the part of IPPs to build the support facilities that coal might require. When the final projects were identified however, coal had a disproportionately large share.

China

China is generally not viewed as a major potential market for imported natural gas primarily because of the nation's reluctance to support its economy by means of imported energy. Energy in China primarily means coal and hydroelectric power. Ambitious nuclear energy plans are not expected to match schedules, but the importance of nuclear (a new and still minor energy source) can be expected to grow. China is now a net importer of oil and this condition is expected to increase. Natural gas use is minor because of limited domestic resources. China's large size, however, makes "small" in China "large" in the view of overall global markets.

There has been continuing talk of importing LNG primarily to fuel domestic power plants. Currently power is produced mainly by coal, and also by hydroelectric sources. Excessive use of not very clean coal technology has resulted in environmental problems that will inhibit future coal use if no abatement procedures are adopted. This has increased the attractiveness of gas, and several gas projects have been proposed. These include a number of coastal LNG based projects that have been proposed by a

consortium now owned jointly and in part by the Wing Group and Mobil Oil, both of the United States. The recent involvement of Mobil in these projects hints that the firm might wish to tie the plants to its LNG projects located in Qatar.

China has recently been very hesitant to permit the construction of large foreign owned power plants within its territories. Within the past three years, no large foreign managed facilities have received complete central government approval, though some smaller local projects have advanced without central government guarantees. This near halt to foreign power investments has been attributed in part to efforts to fight inflation, which by implication implies that the policy is temporary. Since few sources of domestic natural gas are expected, LNG would be the most likely source. Since domestic coal reserves are remote from energy consumption centers on the coast, these coastal centers are the most likely centers for potential gas based power production.

China's petrochemical industry has used almost everything but natural gas feedstocks, although a few exceptions exist. This situation is not expected to change in the near future, and many petrochemicals normally produced from natural gas will be produced from either oil or coal sources. Nonetheless, 65 percent of total gas output in China is currently used by the fertilizer industry. There has in fact been a recent tendency to convert these plants to naphtha feed when possible.

Similarly, the absence of domestically available natural gas in most parts of the nation has limited household and commercial usage of gas. Only 10 percent of China's natural gas production is used by residential and commercial consumers. Industrial uses of gas are expected to have priority over these uses.

Demand in Western Europe

The possibility of marketing natural gas from the Middle East into Western Europe is more affected by the availability of alternatives to a Middle Eastern supply. Europe now has three major sources of natural gas. Its gas comes from (1) Russia, (2) North Africa,

and (3) domestic sources. Domestic sources include primarily the North Sea and a scattering of locations distributed around the continent. These sources are mainly mature gas provinces which cannot be expected to expand much further and which might contract. Russian and North African (Algeria) gas is available by pipeline, including two pipelines that cross the Mediterranean to the Italian and Iberian peninsulas, respectively. LNG is also available from Algeria. Additional gas supplies might be expected to be available from either North Africa (Algeria, Libya) or from Russia (whose potential supplies are barely tapped).

If Middle East gas were to become available to Western Europe, it would have to arrive either in the form of LNG or by pipeline. LNG could be produced either in the producing nation or on the Mediterranean. Possible pipeline routes include either a linkage to existing and planned pipelines in Russia and Central Asia or a new "southern" route to Europe, which would have to cross Turkey and the Balkans and might eventually find developing markets in Mediterranean Europe as well as in Western Europe itself. In any case, pipeline routes would have to cross many national borders. These borders are not all amicably maintained, and relations of each nation with Western Europe would need to be a matter of concern to gas shipping and buying nations. The political instability in the regions to be crossed from the Middle East can be overemphasized, since the Russian and North African routes also involve politically unstable regions. Access to either potential pipeline route to Western Europe would in any case be easier for more northerly suppliers of gas in the Middle East (Iran and potentially Iraq), for reasons of both distance and politics.

Access to gas markets in Europe through Russia would be a particular problem. Russia believes that it holds adequate reserves to meet Europe's foreseeable needs and would thus be a competitor with the Middle East. Central Asia also is natural gas rich and would claim second priority in the task of attaching its gas supplies to Russia's pipeline system. This would leave the Middle East disadvantaged in access to Western Europe by way of Russia, standing third on a crowded list of regional suppliers.

The view is then that while the Middle East is not excluded from European markets, others have distinct advantages to serving this market. The rewards for shipping gas to Europe would be diminished by the very existence of these advantages, and the Middle East would probably not find the market very lucrative.

Pricing LNG

The pricing terms for LNG are rarely made public. Nevertheless, there is general agreement on the nature of the terms. Typically, LNG entering the Asian market is tied to the price of a "basket" of crude oils. This is in contrast to, say, Europe where LNG prices are normally tied to fuel oil prices. Moreover, the lack of transparency of the price for LNG implies that the price is not being determined in a competitive environment.

The pricing mechanisms in the natural gas markets of both Asia and Europe differ from that found in the United States. Over the past decade, the structure of the North American natural gas market has been significantly altered as the result of deregulation. The deregulation has worked its way from the wellhead through the interstate pipeline systems, and in some cases well into the intrastate systems. The driving force for the reforms has been the Federal Energy Regulatory Commission. The pipeline deregulation has led to interstate pipeline transporters operating only as third-party shippers of natural gas, while they were forced to terminate their role as natural gas merchants. As a result, the interstate pipeline systems are open access.

This structure has led to a natural gas market, on a continental level, that is characterized by a high degree of competition. Where the price of natural gas was once determined on a "cost plus" regulatory basis, it is now the result of a highly transparent interaction between the supply of and the demand for natural gas. The earlier regulated price of natural gas went from being far too low to stimulate sufficient production to being far too high to compete with alternatives like fuel oil. The artificially low prices led to overheated demand and insufficient supply, while the relatively high prices both

stimulated supply and led to an exodus by the marginal users who could switch to alternative fuels. Both situations were driven by a regulatory structure that flew in the face of underlying energy market fundamentals, and thus neither situation was sustainable in the long run.

The transition from wellhead-to-burner total price control to transparent, competitive pricing moved through a phase whereby the price of natural gas was closely linked to the Btu-parity price of fuel oil, the nearest switchable substitute. This was much like the current situation in Europe and Asia. As the market became more and more competitive, with the removal of regulation, the linkage weakened, until the price of fuel oil constituted merely a ceiling. As a ceiling, the price of fuel oil now plays a role only when the competitively determined price of natural gas approaches the Btu equivalent price for fuel oil (or perhaps its Btu equivalent plus some factor to account for an environmental preference and the cost of switching). The price of natural gas in the United States is effectively determined by the interaction between natural gas supply and demand, without concern for the price of alternative fuels until the Btu-parity value is approached. This pricing structure is the result of what has become known in North America as gas-on-gas competition.

Effectively, the price of natural gas in the North American market falls somewhere between the cost of producing and delivering it and the ceiling price established by the marginal substitute fuel source. In general, the higher the degree of competition the closer will be the price to the cost of producing and delivering. Moreover, as long as there is a differential between the cost of producing and delivering natural gas and the Btu-parity price of the alternative fuel(s), there will be an incentive to expand the production of natural gas and to expand the energy-market share held by natural gas vis-à-vis alternative fuels. This cost of producing and delivering includes a reasonable rate of return.

What should be asked and answered is whether or not the pricing of natural gas leaving the Middle East will continue to be couched in terms of Btu equivalence with

alternatives, or whether it will face gas-on-gas competition leading to a pricing structure resembling that in the United States. The short answer is that it is unlikely that a gas-on-gas pricing structure will develop in either Europe or Asia in the foreseeable future. The ownership arrangements of reserves and infrastructure are such that competition of the sort now found in North America is quite unlikely to occur. Where the reserves in North America are found in thousands of producing formations, the reserves in Europe and Asia are much more highly concentrated. Moreover, these reserves are often controlled by either state-owned monopolies or by a relatively small group of majors. This is also the case with the industry infrastructure. Since the regional market prices will not likely reflect gas-on-gas competition, there is no reason to expect the Mideast gas entering these regions to be faced with gas-on-gas competitive-style pricing. However, the pricing formulas will likely differ between gas destined for Europe and that destined for Asia.

The difference in the LNG linkages to crude oil versus fuel oil, however, is not without a market justification. The reasoning behind pricing LNG against fuel oil is that it is typically fuel oil that LNG will replace. There is no active global market for natural gas with transparent pricing based on supply and demand conditions. In other words, the international market for LNG does not exhibit characteristics of what has become known as gas-on-gas competition. When gas-on-gas competition exists, the price of gas will be determined primarily as the result of the interaction between the supply of gas and the demand for gas, with the price of alternatives acting only to establish upward bounds for the price. As has been the experience in the United States, once competition arises, the upper bounds set by alternatives are rarely binding, and the price falls between the price of the alternative and the cost of supplying the gas.

Recent revelations by Qatar's oil minister, Abdullah al-Attiyeh, shows that current LNG pricing regimes fall into the indexed framework, rather than one representative of a competitive gas-on-gas structure. While few specifics were revealed, the minister noted that a minimum FOB price of \$2.50 per million Btu will be charged

for LNG from the Ras Laffan project, and that this minimum will be indexed to inflation.⁴ Emphasizing that this is just the minimum price, it was noted that the actual price will be "indexed to both inflation and energy prices." On a strictly Btu-equivalent basis, the \$2.50 per million Btu implies a crude oil price of roughly \$14.50 per barrel, f.o.b.

The May 1995 crude-oil formula price for Qatari Dukhan was \$17.86, and for Marine it was \$17.72. These crude oil prices would imply an LNG price of a little over \$3.00 per million Btu, f.o.b. While this does not represent the crude oil basket to which LNG prices have been tied, it represents a sense of the opportunity cost to Qatar of selling its natural gas instead of its oil.

Australia has recently established an LNG pricing mechanism that is referred to as an "S-curve." The formula is based on the weighted average price of crude oil delivered to Japan, but the c.i.f. LNG price is constrained by both an upper and lower bound. The upper bound is \$26.95 per barrel, and the lower bound is \$16.95 per barrel. This implies an upper bound of \$4.65 and a lower bound of \$2.92 per million Btu, delivered. This upper- and lower-bound aspect accounts for 90 percent of the price, while the remaining 10 percent of the price is dependent upon currency exchange rates and changes in Japanese inflation.⁵

Natural gas, unlike crude oil and many petroleum products, has no integrated international market. The lack of a well defined, integrated market, implies that there will continue to be a lack of transparent prices. The regions into which the Gulf states will be selling their natural gas will continue to suffer from the lack of gas-on-gas competition. The norm will continue to be one-on-one arrangements between a seller and a buyer that will utilize proprietary delivery and receiving facilities, with little or no opportunity for competition from spot (short term) transactions.

⁴ See "Rarely-Discussed Gas Price Revealed," *Platts Oilgram News*, June 7, 1995, Vol. 73, No. 109, p. 3.

⁵ See *World Gas Intelligence*, February 10, 1995, p. 10.