Promoting Energy Security in APEC through Improved International Fuel Market Operations

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Executive Summary

Energy security has become a watchword for energy policymakers since at least the 1970s, when the first of a series of "oil crises" occurred. Over the years that have followed since the energy security concept was first enunciated, the idea has changed and mutated to fit the current needs of particular times and economies. To some, energy security is a short-term issue related to the crisis of the day, while to others it has become a question of sustainability of energy supplies. Energy security has also meant different things to energy consumers than it has meant to energy producers. In recent years the concept of energy security has also received diminished focus, because economies have found that energy resources have remained available, for a price of course, and that once-anticipated energy supply shortages have not materialized.

This document takes the view that the concept of energy security is still with us, even if energy needs appear at the moment to be met. Energy security is addressed here primarily in its longer-term sustainable context, even if short-term crises remains possible. "Crises," so far, have proven to be of short duration, while market structures that have emerged over the past two decades or more have proven able to adapt to such events. Broader energy security issues, such as competing interests of producers and consumers, have often devolved to a status of business relations rather than rivalries. What entangles the concept of energy security now is competing ambitions for economic efficiency and for mitigating nonmarket concerns, such as managing environmental damage or abuse and promoting domestic economic evolution. Even more recently, issues have emerged regarding the interrelationship of energy policies with the financial condition of an overall economy. Such concerns are very much the topic of this document.

Chapter 1 summarizes the issue of energy security as it applies to APEC regional economies. We find that energy transactions are becoming divided into zones within which most general energy demands are met. Within this development, Asia has become more dependent than ever on oil and, to an extent, gas supplies from the Middle East. While concerns about the political security of Middle East oil and gas supplies remain, supply disruptions from that region have so far proven to be transient. Meanwhile, the Americas have become more reliant on their own oil supplies, supplemented by resources located in the North Sea. As a result, the key interaction between the Middle East and the United States by 2010 might come to emphasize strategic interests over oil trade.

Chapter 2 deals specifically with the topic of electricity. Electricity markets are now undergoing considerable industrial reform stimulated by the increased market liberalization within most APEC area economies. This has resulted in either the breakup of many regional power utilities or at the minimum a promise of increased competition in the area of power generation. In some cases the distribution and even the transportation of electricity has become the subject of heightened competition. This has meant changes in market structure of a continuing and perhaps disruptive nature, as APEC regional power systems pass through the stages in development from an original utility system to a system of contract-based power provision. In many economies there is now a promise of developing competition-based electric power provision systems in which markets set prices. These changes have been further spurred on by technological changes that have increased the efficiency of many power generating fuels and have improved an economy's ability to monitor the transit and delivery of electric power to ultimate consumers. Yet another development in the power industry has been the growth of national and even international power grids. These promise to make the trade in externally generated electricity competitive in some cases with the importation of primary fuels.

Chapter 3 examines the competitiveness of particular energy resources within the APEC region. Competitiveness can mean many things. When one examines the characteristics of oil, gas, coal, and nuclear fuels, many markets are limited by the physical characteristics of the fuels themselves. Interfuel competition is in reality an issue for only a limited number of particular fuels within many markets, but is of particular importance primarily in power generation where managing heat and converting heat and mechanical power into electricity are the main concerns. Technological changes, pricing patterns, and market structures can seriously alter the competitiveness of primary fuels within the power industry. Oil in recent decades has lost ground within the power industry because (1) prices are relatively high and (2) there are many alternative uses to which oil resources might be put. Also declining in importance has been nuclear energy, which has suffered from (1) the high capital costs associated with nuclear capacity creation, (2) expenditures arising from general concerns regarding nuclear plant and fuel safety, and (3) the relatively high uncertainty of plant completion. Natural gas on the other hand might be termed the "favorite of the day," because of (1) the increased popularity of liquefied natural gas (LNG), especially in Asia, (2) technological trends that enhance the competitiveness of gas in the electricity industries, and (3) the attractiveness of natural gas, among the fossil fuels, in meeting environmental goals. In much of Asia, which depends on LNG shipments, the gas industry has been among the last of the major primary fuel markets to liberalize. In the Americas, where gas pipeline systems are extensive, the liberalization process in the gas industry is essentially complete in North America and promises to be rapid in Latin America.

Chapter 4 looks at trends in energy industry regulation. Generally, regulators have come to apply a lighter hand, as energy markets have liberalized and as fears of global energy supply shortages have receded. Markets are increasingly being relied on to set prices and to identify which customers are to receive energy supplies. Exceptions to this trend arise primarily from environmental issues that are now of growing concern, as many APEC economies seek to make their cities and industrial communities more livable. The appropriate application of environmental or other forms of regulation can vary markedly under a liberalized market structure, compared with the apparently more controlled markets of what were once considered "natural monopolies."

Chapter 5 deals with financial issues that concern APEC economies and their energy interests. Finance is becoming increasingly important, as the issue of the appropriate allocation of credit supplies among domestic and foreign resources has now come to the fore so visibly. Failure to give appropriate consideration to financial issues can lead to the delay or even the cancellation of power and other energy projects on which so much of an economy's development depends. This is thus becoming an area where the interests of energy ministers and the interests of finance ministers often converge.

Chapter 1

Energy Security and the International Fuel Markets

Energy security has long been a fundamental cornerstone of economic policy for the APEC economies. Today's energy importers are not the only ones who have been concerned about security of supplies. Even many energy exporters fear a future when they might become energy importers. Both governments and private businesses have worked hand in hand to establish legislation and procedures to ensure energy-supply security.

1.1. Structure of Energy Consumption in APEC Economies

The characteristics of APEC energy consumption structures differ from those of the world as a whole. As shown in Figure 1, the world depends on oil for 39% of total energy demand, coal for 27%, and natural gas for 24%. Nuclear power and hydro make up 10% of global energy use. The share of oil within APEC is similar to the world's total energy share, as is also the case for hydroelectricity and nuclear power. However, the shares of coal and natural gas differ greatly. The share of coal within APEC (32% of energy demand) is 5% higher and the share of gas (only 19%) is 5% lower than the respective global energy consumption shares of these fuels.

An important factor in APEC's unique position is the predominance of China's coal consumption within the APEC energy picture. If we exclude China from APEC energy consumption, the pattern looks very different. APEC without China has a coal dependence of only 22% and an oil dependence of 44%. Natural gas consumption within APEC then becomes almost identical with the global picture. Moreover, excluding China, the APEC energy structure shows a 9% dependence on nuclear power.

1.1.1. Oil

APEC economies possess approximately 122 billion barrels of proven oil reserves, corresponding to 12% of global oil reserves (see Table 1). In contrast, oil consumption within APEC economies is around 50% of global oil demand. Mexico alone accounts for one-third of APEC's total proven reserves. The United States and China are in the second and third positions, though both are net oil importers. Indeed, together Mexico, the United States, and China account for well over 80% of APEC oil reserves.

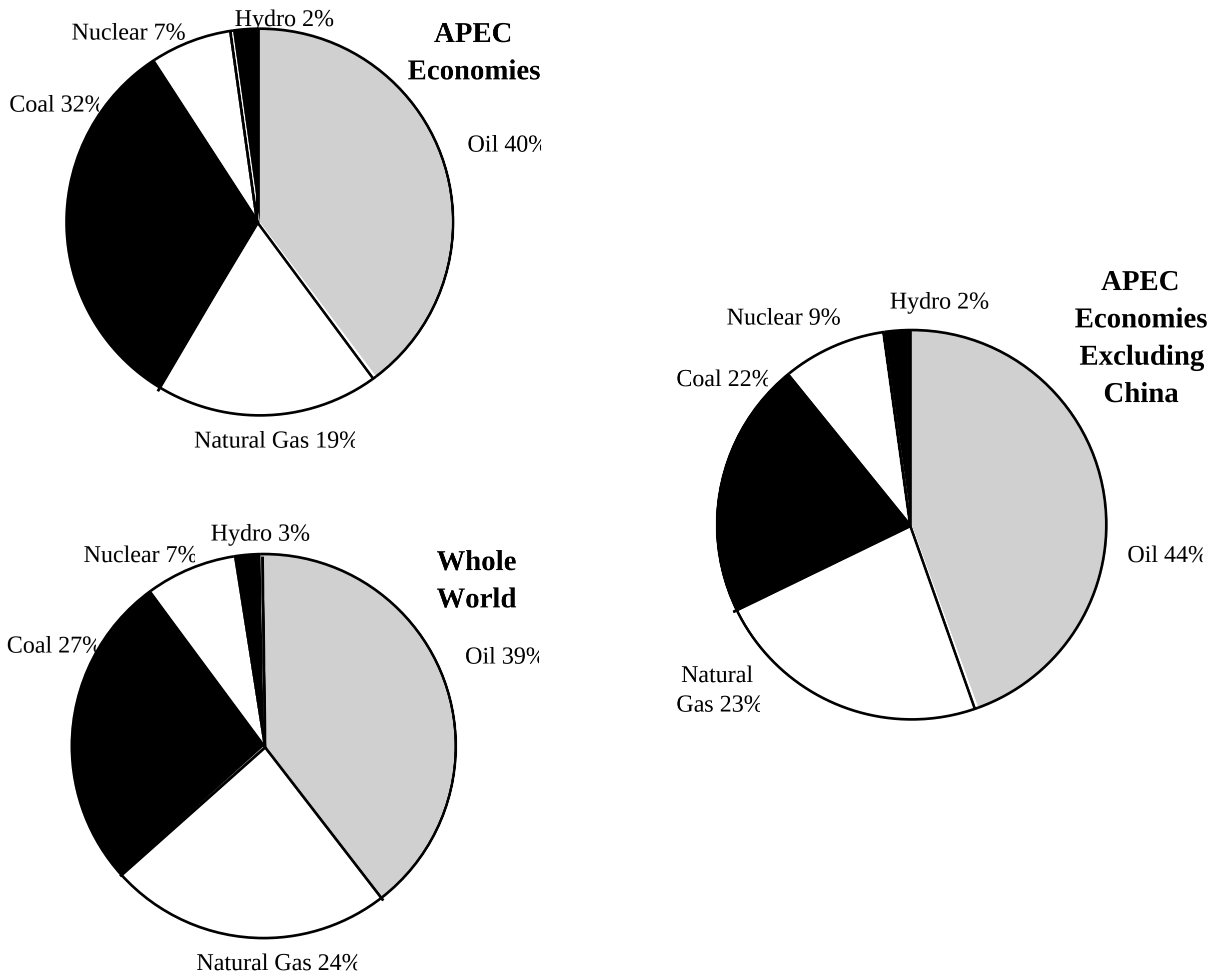

Figure 1. APEC and World Primary Energy Consumption by Source, 1996

Table 1. Proven Oil Reserves by APEC Economy, 1996

Economy	Reserves (billion barrels)	Share of World Reserves (%)
Australia	1.8	0.2
Brunei Darussalam	1.4	0.1
Canada	6.9	0.7
China	24.0	2.3
Indonesia	5.0	0.5
Malaysia	4.0	0.4
Mexico	48.8	4.7
Papua New Guinea	0.3	0.0
United States	29.8	2.9
Total APEC	122.0	11.8
Total World	1,036.9	100.0

1.1.2. Natural Gas

APEC's proven reserves of natural gas in 1996 were 537 trillion cubic feet (tcf). That was 11% of the world total. The United States has the greatest reserves of natural gas, accounting for 30% of total APEC gas reserves (see Table 2). Malaysia, Indonesia, Mexico, and Canada also occupy important positions in the ranking. However, all APEC natural gas reserves combined are less than the gas reserves in Iran!

Table 2. Proven Natural Gas Reserves by APEC Economy, 1996

Economy	Reserves (trillion cubic feet)	Share of World Reserves (%)
Australia	19.4	0.4
Brunei Darussalam	14.1	0.3
Canada	68.1	1.4
China	41.4	0.8
Indonesia	72.3	1.5
Malaysia	80.2	1.6
Mexico	67.7	1.4
Papua New Guinea	1.5	0.0
Thailand	7.1	0.1
United States	165.1	3.3
Total APEC	536.9	10.8
Total World	4,991.1	100.0

1.1.3. Coal

APEC economies are giant players in the world energy scene when it comes to coal. They possess nearly 500 billion tonnes of reserves or just under one-half of global coal reserves (see Table 3). Nearly half of APEC coal reserves are in the United States, while China accounts for approximately another quarter of the APEC total. Australia and Indonesia rank third and fourth, respectively.

1.1.4. Electricity Output

APEC economies produced nearly 1,100 TWh of hydroelectric/other electricity in 1995, amounting to nearly 43% of world hydro/other output. The United States and Canada produce approximately one-third of APEC hydropower each (see Table 4), followed by China (over 17%). APEC economies produced nearly 7,100 TWh or 53.5% of total 1995 world electric power output. The United States is the largest producer (50% of APEC production), while China is a distant second (nearly 15%), closely followed by Japan (see Table 5). These three ecomomies (the United States, China, and Japan) account for nearly 79% of APEC's electricity output.

Table 3. Coal Reserves by APEC Economy, 1996

Economy	Reserves (million tonnes)	Share of World Reserves (%)
Australia	90,940	8.8
Canada	8,623	0.8
China	114,500	11.1
Indonesia	32,063	3.1
Japan	821	0.1
Korea	183	0.0
Mexico	1,211	0.1
New Zealand	117	0.0
Chinese Taipei	99	0.0
United States	240,558	23.3
Total APEC	489,115	47.4
Total World	1,031,610	100.0

Table 4. Production of Hydro/Other Electricity by APEC Economy, 1995

Economy	Output (TWh)	Share of World Output (%)
Australia	16	0.6
Brunei Darussalam	0	0.0
Canada	334	13.1
Chile	18	0.7
China	191	7.5
Hong Kong, China	0	0.0
Indonesia	11	0.4
Japan	91	3.6
Korea	5	0.2
Malaysia	6	0.2
Mexico	28	1.1
New Zealand	28	1.1
Papua New Guinea	0	0.0
Philippines	9	0.4
Singapore	0	0.0
Chinese Taipei	9	0.3
Thailand	7	0.3
United States	338	13.3
Total APEC	1,091	42.8
Total World	2,548	100.0

Source: International Energy Agency.
Note: The IEA data include nonthermal and nonnuclear power with hydroelectric power in a category termed “hydro/other electricity.”

Table 5. Production of Electricity by APEC Economy, 1995

Economy	Output (TWh)	Share of World Output (%)
Australia	174	1.3
Brunei Darussalam	2	0.0
Canada	552	4.2
Chile	28	0.2
China	1,008	7.6
Hong Kong, China	28	0.2
Indonesia	61	0.5
Japan	990	7.5
Korea	185	1.4
Malaysia	45	0.3
Mexico	153	1.2
New Zealand	36	0.3
Papua New Guinea	1	0.0
Philippines	30	0.2
Singapore	22	0.2
Chinese Taipei	123	0.9
Thailand	80	0.6
United States	3,582	27.0
Total APEC	7,098	53.5
Total World	13,263	100.0

1.1.5. Oil Production and Import Dependence

Patterns of oil production, consumption, and oil dependence vary radically among APEC economies. As shown in Table 6, APEC economies in 1996 produced 20.3 million barrels per day (b/d) of oil, but consumed 36.9 million b/d. APEC economies thus imported a massive 16.6 million b/d. Indeed, APEC economies imported more oil than was exported by all Middle East producers combined. Oil import dependence within APEC was 45% of consumption in 1996, including some trade among APEC economies. Surprisingly, the APEC region's dependence on Middle East oil supply was only 28%. But if we examine only the Asian members of APEC, the picture is quite different: import dependence on the Middle East was 55%.

Table 6. APEC Regional Oil Production, Consumption, Imports, and Import Dependence, 1996

Volume of oil (kb/d)	
Production	20,287
Consumption	36,894
Imports	16,607
Import dependence (%)	
Overall dependence of APEC economies	45
APEC's dependence on the Middle East	28
Asian APEC members' dependence on the Middle East	55

Another way to measure the resource and usage balance in the region is to apply reserve/production (R/P) ratios as shown in Table 7. The R/P ratios for oil and gas are 16 to 17 years, whereas the R/P ratio for coal is nearly 350 years. This clearly demonstrates that the APEC region has adequate coal supplies for many years to come.

Table 7. APEC Regional Resource/Production Balance, 1996

Oil	
Proven Reserves	122 billion barrels
Production	20.3 million barrels per day
R/P Ratio	16.5 years
Gas	
Proven Reserves	13.9 billion tonnes of oil equivalent
Production	814.9 million tonnes of oil equivalent
R/P Ratio	17.1 years
Coal	
Proven Reserves	489.1 billion tonnes
Production	1,408.6 million tonnes
R/P Ratio	347 years

Source: British Petroleum.

Table 8 shows APEC oil production, consumption, and net imports in 1996. The United States produced 8.3 million b/d of crude oil in 1996 (over 40% of APEC production) and accounted for 47% of APEC consumption. The second largest oil producer in APEC was Mexico, followed very closely by China. Canada was in fourth place. Japan and China followed the United States on the consumption side, with Korea in fourth place. Among APEC economies, Mexico is by far the largest net oil exporter. Canada and Indonesia occupy second and third positions, respectively. Japan, the United States, and Korea dominate oil import volumes.

Table 8. Oil Production, Consumption, and Net Import Requirements by APEC Economy, 1996 (kb/d)

Economy	Production	Consumption[a]	Net Imports
Australia	575	755	180
Brunei Darussalam	158	10	(148)
Canada	2,460	1,735	(725)
Chile	9	225	216
China	3,145	3,321	176
Hong Kong, China	-	201	201
Indonesia	1,494	870	(624)
Japan	14	5,654	5,640
Korea	-	2,079	2,079
Malaysia	650	416	(234)
Mexico	3,280	1,605	(1,675)
New Zealand	34	118	84
Papua New Guinea	107	19	(88)
Philippines	1	355	354
Singapore	-	579	579
Chinese Taipei	1	752	751
Thailand	59	801	742
United States	8,300	17,400	9,100
Total	20,287	36,894	16,607

a. Consumption of petroleum products; includes direct crude burning.

Table 9 indicates oil imports from the Middle East (specifically the Persian Gulf) in 1996. The largest importers of Mideast crude in the APEC region are Japan, Korea, and the United States. The Philippines and Thailand, followed by Japan, are the APEC economies most dependent on Mideast oil. Indeed, the level of dependence of Asian APEC economies is very different from that of non-Asian economies. US dependence on Mideast oil is only 9%, whereas overall APEC dependence on Mideast oil is 28%. In contrast, Asian APEC members are 55% dependent on imports from the Middle East.

Table 9. Share of Mideast Oil in Total Oil Consumption by APEC Economy, 1996

Economy	Consumption[a] (kb/d)	Imports from Middle East (kb/d)	Share of Middle East in Demand (%)
Asian Member Economies			
Brunei Darussalam	10	-0	0.0
China	3,321	242	7.3
Hong Kong, China	201	0	0.0
Indonesia	870	115	13.2
Japan	5,654	4,221	74.7
Korea	2,079	1,693	81.4
Malaysia	416	27	6.4
Papua New Guinea	19	0	0.0
Philippines	355	334	94.0
Singapore	579	1,208	208.7
Chinese Taipei	752	38	5.1
Thailand	801	431	53.8
Subtotal, Asian Member Economies	15,057	8,309	55.2
Other Member Economies			
Australia	755	185	24.5
Canada	1,735	112	6.5
Chile	225	50	22.2
Mexico	1,605	0	0.0
New Zealand	118	20	17.3
United States	17,400	1,641	9.4
Subtotal, Other Member Economies	21,838	2,008	9.2
Total APEC	36,894	10,317	28.0

a. Consumption of petroleum products; includes direct crude burning.

1.1.6. The Resource/Consumption Imbalance

In examining the resource base as well as supply and demand for the key fuels¾oil, gas, and coal¾it is clear that the imbalances between APEC reserves and APEC use are very *severe* in the case of oil, *manageable* in the case of gas, and *comfortable* in the case of coal.

APEC proven oil reserves were nearly 12% of global reserves in 1996 (see Figure 2). APEC economies produced 29% of world oil output, but were responsible for 53% of total global demand. The imbalance is clear. First, APEC's share of oil reserves is much smaller than APEC's share of production. Second, consumption is much greater than production, resulting in long-term sizable imports of oil into APEC. The imbalance is so large that the APEC economies will have to formulate their long-term economic and foreign policies with widening oil imbalances in mind.

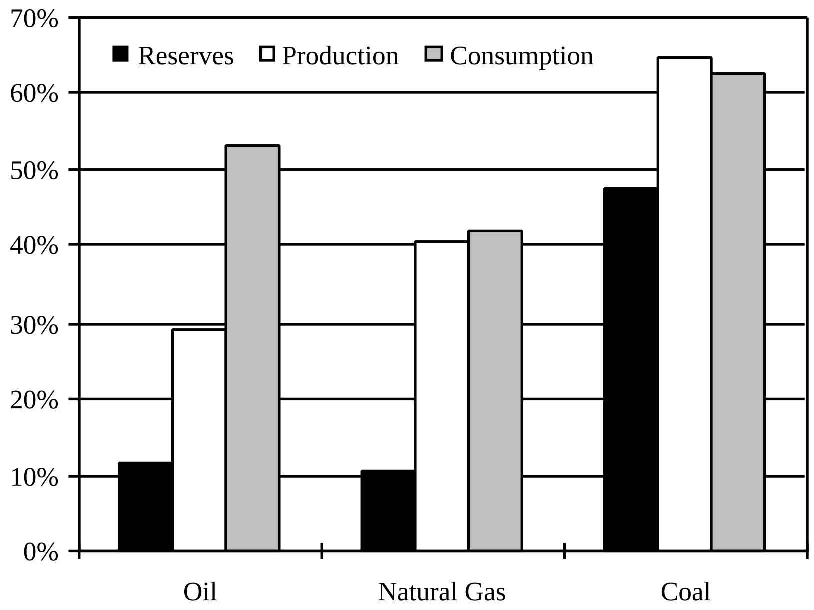

Figure 2. APEC Shares of World Reserves, Production, and Consumption of Oil, Natural Gas, and Coal, 1996

The picture is somewhat different for gas. APEC economies have 11% of world gas reserves, but are responsible for just over 40% of total world production and consumption. Supply and demand are therefore presently in a rough balance, even though the growth in APEC gas reserves has not kept pace with production growth. The Asian APEC economies are also large importers of liquefied natural gas (LNG) from the Middle East. Given the fact that many APEC members now focus their attention on gas discoveries and development, there is a sense of optimism that proven gas reserves will rise dramatically in the near future.

The regional picture is far more balanced insofar as coal is concerned. APEC coal reserves are a little less than half of world reserves, whereas production and consumption are both a little over 60% of world totals. Proven reserves are more than adequate to meet anticipated demand. This indicates a comfortable balance in APEC's coal outlook.

Clearly, oil is the key issue of APEC's energy security concerns. APEC's dependence on oil demand and oil imports is dramatic. The long-term outlook for oil imports from the Middle East only accelerates the trends. Australia, New Zealand, and Asian APEC members will become more and more dependent on Mideast oil, whereas non-Asian members will reduce their dependence on the Middle East and rely increasingly on the Atlantic Basin or Latin America for their oil supplies. Indeed, by 2010 Asia might depend on the Middle East for more than 90% of its oil imports, while US dependence on the Middle East might drop below 5%. Dependence on the Middle East for oil imports thus affects the energy security visions of different APEC subregions in different ways.

1.2. The Governments' Perspectives: Oil Security vs. Energy Security

1.2.1. The Oil Importers

Oil supply security is a predominant feature of energy policy within the oil importing APEC economies. The initial concept of energy security was based on several key criteria:

(i) Maximize the use of domestic energy resources.

(ii) Increase energy efficiency through use of taxes and legislation that reduce energy intensity.

(iii) Diversify away from oil dependence to multiple energy resources.

(iv) Minimize oil imports.

(v) Minimize oil imports from the Middle East.

The concept of energy security also includes financial commitments of a large and enduring nature that were seen to be essential. These took a variety of shapes:

(i) Overinvest in certain facilities to ensure redundant capacity in case of supply interruptions.

(ii) Subsidize freight costs of imports from certain economies.

(iii) Implement policies to utilize more renewable resources.

(iv) Raise taxes on oil imports to make competing fuels more economical.

(v) Require the private sector or state oil companies to purchase oil from the so-called "G-to-G" (government-to-government) contracts without regard to economics or quality.

(vi) Develop informal *administrative guidance* systems by governments (such as the case in Japan).

(vii) Establish *oil funds* as commodity price stabilization programs to try to smooth out violent price movements (used by Korea, the Philippines, Thailand, and others).

Among the most novel ideas in the 1980s was the concept of the *flexible switching system* developed by Japan's Ministry of International Trade and Industry (MITI). The concept provided for excess capacity in the power sector so that if any one fuel source (oil, gas, or coal) was interrupted, the power sector might continue to function.

Some of the other most spectacular programs were the synthetic fuels programs in the United States in the late 1970s and the "Think Big" programs of New Zealand. The US program sought to use windfall profit tax revenues resulting from the deregulation process to fund an ambitious synthetic fuels program costing around $100 billion. The New Zealand program contained multibillion-dollar projects to convert natural gas to gasoline and to use compressed natural gas for highway transportation.

Such original concepts of energy security did not take market forces adequately into account. Indeed, the market was seen to work inefficiently and to respond too swiftly to oil price movements and supply disruptions. Many held that *it was a government's duty to intervene in the market to protect the consumer.*

Among APEC members, Mexico's long-term production output is very bright. New reforms attracting advanced drilling technology raised Mexico's oil production to 2.85 million b/d of crude and 430,000 b/d oil equivalent of natural gas liquids in 1996¾some 130,000 b/d greater than 1995. Mexico's production is likely to inch up for some time with most supplies going to the Americas. With a domestic oil demand of only 1.6 million b/d, Mexico will remain a key international player in the oil trade well into the future.

China has been a net oil importer since 1994. However, China will remain an exporter of some crude and oil products for several more years, mainly to Japan, while net imports escalate to over 1 million b/d by the turn of the century. Indonesia, a major oil exporter and an APEC member, faces problems similar to those of China, in that Indonesia will also soon become a net oil importer. Indonesia's oil production (nearly 1.5 million b/d today) is expected to slowly decline, while oil demand has been rising rapidly. This has reduced exportable oil supplies. Meanwhile, subsidized domestic oil pricing has been abolished in China, but continues in Indonesia. Higher prices in Indonesia would certainly reduce oil demand levels or demand growth.

The present Asian economic and currency crisis will certainly affect oil demand in the APEC region, but it is too early to measure its impact. We estimate that 1997 demand growth declined by some 100,000 b/d. If the crises and the consequent economic slowdown continue for 2-3 years, as we anticipate they might, the result would be a decline in expected demand in the year 2000 to more than 500,000 b/d below the level expected before the financial crisis. Clearly, the economic crisis will not resolve the key issues relating to oil security, but it might mitigate the pressure slightly.

1.2.2. The Oil Exporters

The APEC oil exporters' view of the situation has differed from that of the importers. Exporters benefited from the once high oil prices, but found that the new oil wealth did not always positively affect their long-term economic outlook. Many chose not only to subsidize domestic fuel prices, but also to use their oil revenues to subsidize uneconomic investments and large social welfare projects and sometimes to live beyond their means. Indeed, fundamental economic reform programs were often delayed because of the high oil income generated by the price movements. The oil importers, on the other hand, were motivated to institute economic reforms rapidly, though often not fully appreciating the consequences of the reforms.

1.3. The Private Sector

The oil shocks of the 1970s and early 1980s and the inflationary pressures and economic recession that often followed in oil consuming economies had a major impact on thinking regarding the private sector. The usual calls for the free market and nongovernment intervention in the industrialized economies of APEC were muted by a fear that oil crises might lead to severe worldwide depression. Indeed, in most cases, the private sector dutifully followed government guidelines and became willing partners in government intervention programs. The US private industry began to push for deregulation by the late 1970s. Deregulation there began to take effect by the early 1980s. In many other APEC economies, complete oil industry deregulation has taken much longer (e.g., Australia 1987, Japan 1997, and Korea 1999).

The private sector found itself in difficulty as governments began to reconsider the concept of energy security and moved slowly away from market intervention. This move jeopardized large private-sector projects built at the behest of the governments. Withdrawal of government support meant financial hardships for many private companies. Some private companies even found incentives to lobby for continued regulation. A good example of such projects is the Syngas Project in New Zealand. The project would have converted natural gas to gasoline via a methanol route at a massive cost and a huge subsidy. When the government decided this was not economically viable, the private sector's investment was put at risk. Legal action has forced the government to continue subsidies even today.

In short, the private sector went along with government out of concern for economic security. Later, when the deregulation process took place in some economies it had an uneven impact on the private sector¾benefiting some, but hurting others.

1.4. New Concept of Energy Security

The long period of intervention and regulation has taught APEC economies many important lessons. The most important new lesson was that energy security can be achieved through the efficient operation of market forces, both at home and abroad.

Following initial deregulation, oil prices retreated from the highs of the early 1980s, demand for oil fell, rationalizations began to take effect in many economies, and non-OPEC oil became available in greater volumes than had been expected. By the early 1990s the real price of oil had fallen to pre-1973 levels. As the demand for oil began to grow, it became clear that many cornerstones of previous energy security arguments were no longer critical. Many government-to-government deals slowly disappeared, though some are still in effect. Policies designed to ensure the diversity of sources of oil supply were given less priority. Indeed, by the late 1980s, economies such as Japan found themselves more dependent on the Middle East than during the prediversification era. The urgency for big projects that diversify away from using oil disappeared, as have the freight subsidies for fuel transportation. The private sector has become more active in the international scene. Power companies now look abroad to secure economic fuel supplies, though severe restrictions might still be in effect, blocking independent overseas negotiations by the fuel users. While Japan's utilities are free to engage in LNG import negotiations, Korean buyers must still go through the state monopoly (Korea Gas Corp., or KGC), and Chinese Taipei buyers must go through the Chinese Petroleum Corporation (CPC). The Japanese experience has demonstrated the importance of individual negotiations in achieving the most efficient and reliable sources of supply at market prices.

A second new concept in energy security relates to the environment. The original concept of energy security was so heavily influenced by fears of supply interruption that environmental concerns played only a minor role. A rising dependence on fossil fuels and a new awareness of the greenhouse effect and of local and regional pollution problems made environmental considerations a key part of the energy policy debate within governments by the late 1980s. As such, environment and sustainable development have become buzzwords underlying the new concept of energy security.

The first reaction of some APEC governments was to reduce fossil fuel consumption by using either more nuclear power or more gas and by reducing the use of coal and oil. Once the power sector fuel substitutions were put in effect, the next step proved difficult, particularly in the transportation sector. Indeed, opposition to nuclear power in Japan, Chinese Taipei, and to a much lesser extent Korea has been quite effective in limiting the number of new nuclear power stations. This still results in large additions to coal and oil consumption in the APEC region.

The Asian currency crises are likely to have an impact on energy demand in the region, though demand growth is expected to resume. Indeed, the equivalent of one year's oil demand growth might be lost over the next five years¾that is, the oil demand that was forecast for 2003 might not be reached until 2004.

1.5. Energy Security Revisited: Old Stories, New Fears

After dying down since the late 1980s, new energy security concerns have been expressed in the past year or two regarding the implications of Asia's oil demand growth. Oil-hungry Asia and oil imports from the Middle East have assumed a new importance in the energy security picture. Scholars such as Kent Calder of Princeton University (now an adviser to the US Ambassador to Japan) have argued that Asia's oil demand could set off rivalries among Asian economies for access to oil as well as rivalries among the United States, Europe, and Asia over Mideast oil supplies. Such rivalries might shift economic and political alliances and detrimentally affect broader security issues.

When we talk about energy security in general and oil supply security in particular, do we mean that we are concerned with the resource base? Or are we just worried about transportation issues? The answer to these questions is rather simple. Oil and other energy sources might run out one day, though not in the near future. New drilling technologies have significantly reduced offshore production costs. Average finding and development costs in the North Sea have declined from $10 per barrel in the late 1980s to $3-4 per barrel in 1996. This, combined with privatization and better terms offered to investors, has resulted in a big boom in oil production efforts. Lower production costs permit investors to live with lower oil prices. It is no longer necessary to have $20-30 oil prices to make investment worthwhile. A price of $10-15 per barrel justifies 90% of the investments in the world today.

Two decades ago, who would have believed that Norway would export more oil than Iran or Kuwait, or that North Sea oil production could approach that of Saudi Arabia? Over the next 15 years and probably much longer, resource supply issues are not a likely cause for concern. OPEC oil production capacity could easily rise by 15 to 20 million b/d between 1996 and 2010, while non-OPEC oil supplies might grow by another 10 million b/d. According to IEA/EIA, the massive Asian growth will make up 50-60% of new demand, which is estimated at 15 to 20 million b/d. There are ample supplies of oil and, as a result, it is highly unlikely that large price increases will be seen in the market. If for some reason oil prices increase because of political turbulence, the problem will not last long, as higher prices would unleash significant new production.

In short, the market has recognized the value and importance of new capital and technologies. Even in somewhat apprehensive Asia, there is a clear understanding that the resource base is there and that, if you can *afford* it, there will be oil to buy. Fears that domestic political interruptions in Saudi Arabia or the Gulf will affect oil markets appear rather exaggerated. Any radical government would require more money to do the *right things* and would sell oil cheaper and at easier terms. It is indeed the conservatives who hold the reins of OPEC, not the radicals.

The key issue in the supply of oil is the concentration of proven reserves in the Persian Gulf. With their small populations, the highly prolific Gulf oil economies lack the manpower to defend themselves. Abu Dhabi, with a citizen population of some 100,000 people, has as much proven oil reserves as Iran (with a population of 70 million) and more oil reserves than Russia, Central Asia, and the Caucasus combined. Are these economies reliable suppliers of oil to Asia?

For totally economic reasons, the oil market has become divided into several zones. The Pacific zone (including large flows of oil from the Middle East to Asia), the Atlantic zone (including Africa, Europe, and parts of the East Coast of the United States and Canada), and the Caribbean zone (involving the Gulf and West Coasts of the United States and Latin America). This demonstrates the new order. Persian Gulf exports of oil will decline in *absolute terms* for destinations in the United States and Europe for an indefinite future. Gulf oil supplies will instead increasingly move toward Asia as their "natural" market. This new East-of-Suez zone will dominate the world oil trade over the next 10-15 years.

How much should we be concerned about the emergence of the new East-of-Suez zone? From an economic perspective, this is a natural evolution that must be encouraged, not discouraged. It is, after all, market forces¾not government policies¾that have produced the zones.

Asian economies have a good understanding of the new structure. Is there rivalry among them? Yes, there is, but it is a sensible rivalry, not a destructive one. There is no stampede to sign contracts at any price or to offer unjustifiable terms. In today's transparent oil market, prices are based on futures markets or other formulas. Indeed, no major producer in the Persian Gulf sets its own prices anymore. The Asian rivalry is based on an economic mandate to form strong economic and energy bonds with the Middle East and to create interlinkages that ensure the smooth flow of oil. This is a two-way street. Key Mideast suppliers recognize that Asia is the best market and try to ensure good credibility and consumer satisfaction. The Asians seek to negotiate the best deals, but do not wish to depend solely on one economy or region.

Asian economies are keen to undertake exploration and refining investments in the Middle East. Asian and Mideast investments are planned by Malaysia and China. Malaysia now has one of the world's best organized state oil companies: Petronas. Petronas has acquired rights to acreage for oil exploration in Iran that was previously assigned to American firms. Many more such concessions are anticipated for Malaysia. China's state oil company was the first company to sign a new contract for oil exploration in Iraq and to receive the approval of the Iraqi Parliament. Conversely, Middle East economies have targeted Asia for refinery and marketing investments to ensure reliable outlets for their oil. Saudi Arabia now has over 650,000 b/d of joint venture refining capacity in Korea and the Philippines, compared with 600,000 b/d in the United States and only 100,000 b/d in Europe. Eventual Saudi investments in refining in India and China are a certainty. Kuwait, Abu Dhabi, Oman, and Iran also have ambitious investment plans in Asia. These are sensible policies designed to enhance economic linkages and to assure markets. It is something that the American and European firms would also do, if their economic circumstances permitted them.

One hears a great deal about internal Asian rivalries over access to offshore resources or competition for access to Sakhalin Island or the Spratly Islands oil reserves. Asia actually has very few large geological structures containing oil and gas. There is no reason to expect that large reserves are hiding under the Spratlys. We expect to see only minor reserves. In all of the South China Sea and East China Sea, peak production is expected to be 300,000 b/d each, barely enough to supply one year of China's incremental demand. Even then, production in China has been procured at a cost of $5 billion of capital investment and 15 years of exploration. Sakhalin Island can produce potentially 150,000 b/d in the next century. All of this new oil will still not be enough to supply the Russian Far East, which alone has an oil demand of 250,000 b/d.

The new energy security arguments thus boil down to the security of shipping routes. Some 8.5 million b/d of oil were shipped from the Persian Gulf to Asia in 1996. The volume might increase to 19 million b/d by 2010. Today, the United States has a convergence of three key interests in the Middle East: strategic, economic, and oil supplies. By 2010, the key strategic interest will remain, but Mideast oil supplies to the United States will become less important, and economic ties between the Middle East and Asia will surpass those with the United States. The Mideast supply is too far from US markets. US oil imports will come from short-haul crude suppliers in the Atlantic Basin and the Americas. This means US oil dependence on the Middle East will decline in both percentage and absolute numbers. Meanwhile, rising economic relations between the Mideast and Asian economies will likely become more significant than US-Mideast trade. As such, the most important link between the Middle East and the United States by 2010 will be strategic interest rather than oil or general trade.

In short, energy markets do work, and the economic pragmatism of the APEC economies has overcome the energy security concerns. This has mitigated some fears regarding Asia's energy security problems. If tanker transportation is secured, other problems become manageable. The issue of reserve base is no longer a critical energy security issue concern, because there are enough identified oil and gas resources in the Middle East. However, transportation of oil and, to an extent, gas from the Middle East to Asia will remain a key concern. The transportation issue relates to several potential problems: (1) possible naval interference by forces within or outside of the region, if there is no security umbrella in the region, and (2) there could be congestion problems in the Malacca Strait or serious environmental problems emerging from oil spills or leakages. Tankers using these waterways by 2010 will be two to three times more numerous than they are today.

The key factor for APEC economies remains a solid and continuous movement toward open and free access to fuels in a globalized energy industry. We have seen that while government intervention may be inevitable or even necessary at times, the best mechanism to ensure energy security is a watchful eye over the market and a consistent, collective effort to ascertain that energy markets function properly, that information flows are not blocked, that access of buyers to sellers is open, and that short-term market disruptions can be resisted without damage to the member economies.

1.6. Summary

Energy markets have proven to be a much more reliable source of energy security than was imagined during the 1970s, when energy security increased in importance as a topic in energy policy debates. Projected supply shortages have not emerged, despite the dire forecasts of the past. Efforts to project policy goals into energy markets have more often than not either had to be abandoned as energy markets have evolved or have created as many problems as they have attempted to solve. Energy markets have devolved into regional spheres of activity that are relatively self-sufficient regarding the balance of available supplies and regional demand. These spheres of activity do have implications regarding the security of shipment routes and the ability of these routes to handle the increased volumes of shipments, especially oil and gas shipments, that are expected in the near future.

Chapter 2

Fuel Supply to the Power Industry

The power supply industry is being rapidly liberalized, deregulated, and privatized on a global basis. This activity widely replicates reforms that have already taken place or are taking place in other industries such as telephone and telecommunications services, airlines, banking, television, natural gas transmission and distribution, and oil marketing. The trend in the electric power industry does not, however, determine the degree to which individual economies ultimately seek to liberalize, deregulate, or privatize their power supply systems.

2.1. Power Industry Structure

2.1.1. Emerging Power Industry Structure

Based on experience in industries that have liberalized and in particular on experience within the power industry, three phases of evolution of the power industry organization might be identified:

1. Utility Organization
2. Contract-Based Organization
3. Competitive Power Provision

Utility Organization. The term "utility organization" refers to a market structure under which power provision is regarded as a "natural monopoly" either on an economy-wide basis or within a geographically defined territory. While it has become customary to define a power utility monopoly as extending from power generation through high voltage transmission to low voltage distribution and finally to the ultimate consumer, this has not always been the case for all APEC economies. In many economies, including New Zealand, Australia, Thailand, the Philippines, and Canada's Ontario Province, the distribution and customer service portions of the industry have long existed as entities separate from the generation and transmission functions. The large and complex power systems of China, the United States, and Canada (as a whole) also never fully met this utility organization definition, though they had many elements of the system.

A second error in interpretation of the utilities is that they were publicly owned. In Japan, in most of the larger utilities in the United States, and for many utilities in Canada, private ownership was the general rule. In the Philippines the larger distribution companies often had a high private share ownership, while generation and transmission systems were publicly owned. In parts of many APEC member economies, such as Australia, New Zealand, the Philippines, and the United States, rural and in some cases regional and urban power distribution was structured under cooperative or local-government ownership patterns.

Contract-Based Organization. Contract-based power provision has existed in one form or another in most APEC member economies, though often the contract involved only a generation facility and a major consumer. The structural change that has taken place most consistently across APEC economies during the 1990s, and in some economies much earlier, has been the increased provision of power to a specific customer or group of customers by firms or entities other than the original utility. Generally this has consisted of contracts between the utility responsible for electricity transmission (high voltage over distances) and privately held owners of power generation facilities. A second class of contracts has been between individual power consumers and a nearby power generating plant. The generating firms that sell power under such contracts are often referred to as independent power producers (IPPs).

In many economies the power generator will distinguish between the provision of electricity to the transmission system and the production of steam or heat to industrial clients or to local communities. Less publicized has been the reorganization of power distribution systems to allow customers to buy power directly from power producers, to generate their own power, or to institutionally separate the regional power distribution function from the generation and transmission function. Long-term contracts with power suppliers and customers would then characterize the activity of the distribution concern.

Contract-based power provision is often poorly defined and seldom encompasses an economy's entire power industry as well as did the descriptive concept of utility organization. Usually the former utility retains much of its former function under a contract system. This poor distinction (between what is a contract-based power provision system and what is a utility system) is often due to the fact that some APEC economies' policy organizations have viewed contract provision as an intermediate step on the way to fully competitive power provision, while other economies maintain a policy preference to retain many characteristics of utility organization. Terms of contract have thus often been long term, but experience tends to reveal an inherent instability of the contract-based pricing system when confronted with unstable energy markets and political policy change.

Competitive Power Provision. Truly competitive power provision is not a universal target among APEC member economies, but it is a policy goal within many economies. Much as was the case with the previous market classifications, no example of a purely competitive market exists today, though significant elements of competitive power provision have been introduced in New Zealand, Chile, Victoria State in Australia, and (on 1 April 1998) in California in the United States. Increased introduction of elements of competition, including open access to transmission systems, have been broadly introduced. Among the elements that define competitive power systems are (1) a degree of open access to power transmission and distribution systems, (2) no commercial restrictions on who may provide power to a given customer (retail and wholesale wheeling), (3) no dominant owner of power generation systems within a grid, (4) a wholesale market into which power may be sold prior for delivery to intermediate and final customers through a separate market transaction, and (5) a central and impartial power dispatching system.

Two distinctive resulting characteristics of competitive power supply systems are (1) the separation of the ownership of local distribution systems (i.e., wire ownership) and the right to sell to final customers and (2) the division of the task of transmission into an energy market or exchange, dispatching, and wire ownership functions. Because both spot markets and long-term contracts can exist within a competitive system, the direct role of regulation over the setting of power prices is abandoned, though a regulatory function over the fairness of the system would remain. Likewise, directly imposed environmental rules might prove to be impossible to enforce, though environmental and other industry policies might be asserted through evenly applied systems of incentives or disincentives, including taxes and the exchange of pollution rights. A competitive system might also designate a “supplier of last resort” function for customers who might not otherwise be able to purchase market-provided power. A power plant built to provide electricity only to the wholesale market would be called a “merchant power plant”¾a concept that differs from an IPP, which seeks contract sales of power.

The preceding is an overview of possible power provision systems. Nowhere within the APEC area does the power provision system fall fully within one of these classifications, and it is not expected that any power delivery system ever will. The diverse array of power provision organizations among APEC member economies ranges across this spectrum and reflects differing cultures and economic concepts. Fairly consistently within the power industry classification, however, it can be said that power provision as recently as five or ten years ago was most accurately described by the “utility organization” structure. It can also be accurately said that most APEC member economies have moved or are moving toward the provision of a portion of their power production through a contract-based power system. This change usually includes the concept of the IPP. In many cases, it has included increased privatization or deregulation of the power distribution sector, as well as frequent incorporation of the transmission system as either a separate entity from the former utility or utilities or as a semi-autonomous unit of the utility system. Such an arrangement might include direct access by contract between an IPP and at least larger consumers.

The competitive structure has been less widely accepted among the APEC economies, though competitive elements have already been implemented or soon will be implemented, in degrees, within large portions of New Zealand, Australia, Chile, and the United States. Elements of a competitive system are components of the declared policy objectives of the governments of Thailand, the Philippines, Malaysia, Singapore, and Japan, among many others. In some economies, notably the Philippines, there have been fundamental disagreements among executive, legislative, and judicial functions regarding the degree of reform that will ultimately be sought.

It can, however, be fairly accurately stated that most, if not all, APEC member economies have moved in the direction of deregulation of elements of their former utility structures and that in those cases where an original publicly owned utility structure remains, there has been a tendency to sell shares of the utility to the public or to domestic and foreign private concerns. Even when private shares have not been made available, private firms have been allowed into sectors of the power industry from which they were formerly excluded. Thus it can also be said that elements of privatization are also nearly universal within the power sectors of APEC economies.

2.1.2. Regulatory Environment and Power Industry Structure

Curiously, deregulation and regulation are not contradictory terms. In fact, as power sectors have evolved through the three stages, government interests in power provision have continued. Each industry structure, however, has unique elements that affect efforts to implement public policy. Such elements can negate policies that are not imposed with the industry structure in mind. Moreover, because the evolution of most economies’ power sectors is continuing, appropriate policies toward the power sector can be expected to continue to evolve. Given this interpretation, the following discussions will, when necessary, distinguish among power sectors that are in the utility, contract, and competitive phases of development.

The preceding discussion is included because the degree and character of deregulation that is feasible differ among the three types of electricity markets. Regulatory intervention in the pricing system is quite common within both the utility and the contract-based industry structures. Under these systems, prices for the delivery of power are set through the interaction of power-providing institutions and regulatory authorities. The prices received can vary among power producers. Competitive power systems have their basic prices set by a “market” and, if one excludes contracts that would continue in operation, prices are thus generally uniform at any given moment, though locational and scale advantages might be enjoyed by large consumers and producers.

The change in industry structure from utility to contract to market-based power provision will change the advantages of each power producing and distributing entity, often to the disadvantage of the original utility. Thus a shift from a utility system to a contract system will often leave the original utility operator with the least desirable or least profitable portions of the market and possibly with a commitment to serve a greater portion of peak demand than base load. A shift from contract or utility systems to competitive systems often illustrates how older plants and facilities that were built under previous policies or contract terms become competitively disadvantaged. In the United States such original facilities are the source of “stranded-cost” claims, which have proven to be one of the major discouraging elements in policy changes toward a more competitive power supply system. Such stranded cost claims have mounted into the billions-of-dollars range in many states.

An economy that experiences the dynamics of changing its power sector’s organizational structure will generally institute regulations to protect the owners of facilities that have become stranded. These policies, as long as they are enforced, will inherently discourage power sector investments and will often alter the cost structure of the industry. This in turn will inhibit interfuel competition in a major market (power generation) for primary fuels and potentially would halt other industrial sector innovations.

Quite often under the utility and contract-based power systems, governments might seek to enforce energy and foreign exchange policies through the control of contracts for fuel acquisition. Thus, when the utility or transmission body issues a tender for power plant producers, the contract will often specify the location of the plant to be built and the type of fuel to be used. Alternatively, some fuels might receive preferential treatment under contracting procedures. Reasons for these specifications can vary. For example, location restrictions might be issued to meet either technical conditions on the existing power grid or to meet zoning requirements. Fuel use policies might be associated with environmental or port limitation concerns. Renewable energy sources are often favored. The impact of such policies is, however, to restrict the power producers’ choice of primary fuels and plant location: thus, within the context of energy policies, interfuel markets might become less competitive than they would otherwise be. In short such policies do not take advantage of the full imagination of the power provider.

2.2. Long-Term Energy Development and Supply Contracts

Most primary energy resources are developed and produced under long-term contracts, because the extraction of energy resources often involves high risks, large levels of capital expenditures, and a need for operational continuity. The trading of some primary energy resources, notably natural gas, also requires long-term contracts to ensure stable fuel supplies to consumers and a reasonable guarantee of a market for producers. The linkage between energy development and trading is that long-term supply or trading contracts for primary energy in the world market are often incorporated with the development and financing of the resources, especially natural gas and coal. The market for crude oil in contrast is largely globalized. That is, there are more buyers and sellers of oil than can be found in the gas and coal markets.

Although resource tenure and long-term energy contracts appear to be essential for exploration, development, production, and international trading of many primary energy resources, the implications regarding energy security differ between producing and consuming economies. Today, the ownership of primary energy resources usually lies in the hands of governments, especially in the developing economies. Governments thus have great influence over how energy resources might be extracted and where the markets for resources might be developed. Levies on energy resource extraction also often play a key role in the raising of government revenues. When energy security became a primary economic concern, many governments formed state energy companies to invest in and manage domestic primary energy production. These companies also played central roles in revenue collection and distribution. Greater sovereignty was also asserted over domestic and foreign private firms that participated in exploration and production activities. However, for economies that did not possess surplus primary energy resources, international energy markets became indispensable and supply availability and stability became major concerns. Thus, long-term international trading contracts became important measures by which energy-consuming though resource-poor economies secured their energy supply. These contracts also assured energy producers a seemingly certain source and pattern of future government revenues.

The concept of energy security itself also changes continuously to reflect the world's evolving political and economic condition. A well-functioning market, in which normal energy developments are adequately compensated and in which buyers are free to select energy supply sources, is perhaps an alternative guarantee for long-term energy supply. Long-term energy development and supply contracts might thus be designed in ways that avoid becoming major barriers to market operations. If long-term contracts have rigid terms, force other traders to follow, or are biased against noncontract buyers and sellers, then they can constitute serious barriers to competitive market operations. Under this situation, energy security policies might receive emphasis at the cost of market efficiency. Over longer periods of time, such energy security policies might defeat the purposes for which they were created and in fact block the facile availability of energy supplies.

Fuel developers can commit investment funds only if their access to potential energy resources can be secured. Such access might be obtained through concessions from governments. Long-term contracts are usually sought prior to the development of any primary fuel resource because of high capital costs, risk management requirements, and the need to ensure the continuity of operations. There are many types of contracts, including concession contracts, production-sharing contracts, joint-venture contracts, and service contracts. At the exploration stage, the terms for primary energy contracts usually cover duration, relinquishment, and exploration obligations. At the production stage, a host economy's control and the payment system (including royalties, income taxes, and foreign exchange repatriation rules) are key elements of the contract. For state energy companies, exploration and production represent the government's direct commitment to the energy development. Many governments in both developing and developed economies often commit significant funds to energy development because of energy security concerns.

In many ways, the international energy trade is of greater concern regarding energy security than are development contracts. This is because many economies hold that they cannot effectively control events beyond their borders. Under these circumstances, long-term energy supplies guaranteed by contract might be seen as an important means to meet energy needs. Despite the variations, nearly all long-term supply contracts for primary energy resources specify the duration of the contract, the price mechanism, the quantity traded, and quality specifications. Differences in the nature of international markets have led to variations in the importance of supply contracts among individual fuels such as oil, coal, and gas. Long-term contracts are most important for natural gas and least important for oil, with coal lying somewhere in the middle.

Oil's globalized market is now characterized by three trading zones under which the volume of trading within each zone is greater than cross-zone trading. Crude oil and refined products are physically traded either by contract or by spot transaction. Oil futures markets emerged during the late 1970s and now are used by traders for hedging and commodity risk transfer. Contracts are sometimes referred to as term sales. Under contract sales, buyers and sellers commit to the deal within a set period of time and often at fixed quantity. Prices may be fixed or determined under a mechanism that sets the price. Spot deals, on the other hand, refer to short-term trading under which each individual transaction is concluded at a price struck by sellers and buyers based on international markets. Today, except for state oil companies, few oil companies can supply all of the needs of their downstream refineries with their own crude. Very often, refineries must purchase a substantial part of their crude intake from international crude oil markets. Even integrated international majors frequently do not sell their equity oil to their refineries but rather to those buyers who will pay the highest price. Under these circumstances, oil trading through spot deals and term contracts becomes very important to unite suppliers with buyers and producers with consumers.

Even though oil is traded under both spot and term contracts, spot transactions did not gain prominence until the 1980s. During the 1970s, spot deals were normally residual or marginal factors in oil markets. Now term oil contracts ranging from one to three years allow their prices to adjust based on spot prices. What is left in the term contracts are the quantity and quality of oil supplies. On the surface, term contracts still dominate oil markets and pure spot deals account for only 30-40% of oil traded. In reality, spot and spot-related deals account for over half of the market. This reflects the fact that oil trading is largely globalized with sellers and buyers in the market. Securing oil supplies today relies more on ability to pay than on contractual guarantees of prices and quantities supplied. The future trend for spot deals is uncertain, however, because spot trading depends on market conditions. At times when oil prices become volatile, term contracts are favored to ensure trading stability.

There are fewer participants in coal trading than in oil trading. Among the APEC economies, Australia is the largest coal exporter, followed by the United States, China, Indonesia, and Canada. These five economies are expected to continue to export coal through at least 2010. Japan is the leading coal importer in the APEC area, followed by Chinese Taipei, Korea, and Chile. Other economies also import various amounts of coal, including China, the United States, and Indonesia, which are net coal exporters though they also import small amounts of coal. About 90% of international trade in steam and coking coal takes the form of long-term contracts, with the remainder as spot deals. As was the case with oil, the interaction between long-term contracts and spot deals has increased during the 1990s. Coking coal contracts between the leading coal exporter (Australia) and the chief buyer (Japan) have traditionally been the model for contracts among other APEC area economies. The resulting prices are regarded as the benchmark price.[1]

For steam coals, the two economies also have long-term agreements that affect regional steam coal prices under other contracts. Unlike gas contracts, one-year contracts are very popular in the coal trade, though contracts for five and ten years have also been widely used. Pricing mechanisms are also important features in coal contracts. Prices can be fixed or adjustable to reflect a producer's costs, or they may be based on a reference price.[2] Because coal qualities vary widely among producers, quality specifications are usually spelled out in the contract. The function of using term contracts for coal is to reduce transaction costs, including the need for frequent bargaining. Traditional contracts, however, are heavily influenced by the export policies in Australia and by trade and industrial policies in Japan. As new economies enter the regional coal market as buyers, the APEC area coal market is rapidly evolving. While the model coal contracts between Japan and Australia should continue to outline prices or price adjustment mechanisms, prices have increasingly been linked to spot coal prices. Coal futures markets are also seriously being considered. Contract terms are expected to become more flexible, though markets will continue to be dominated by long-term contracts.

International trade in natural gas, either through pipelines or as liquefied natural gas (LNG), is mainly conducted on the basis of long-term contracts. Short-term transactions or spot deals account for a small share of the market, especially in Asia. Long-term LNG contracts commit buyers and sellers for periods of 20 years or more. An elaborate sophisticated pipeline network exists between the United States and Canada, and a number of gas pipelines also connect the United States to Mexico. More such pipelines have been proposed. For Chile, pipelines are planned to obtain gas supplies from Argentina, Bolivia, and possibly Peru. Asian APEC members, however, have no operational gas pipelines connecting economies, except for a short one between Malaysia and Singapore. Another connecting Hong Kong to China is not truly international because the two APEC members are now politically integrated. Future cross-border pipelines are planned in the Gulf of Thailand, between Thailand and Burma (Myanmar), and between Singapore and Indonesia.

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1. See Kazuya Fujime and Koji Morita, "The Coal Pricing System in Asia: Status Quo and Issues," *The Fourth APEC Coal Flow Seminar Proceedings* (Honolulu: published by the East-West Center's Program on Resources for the APEC Energy Working Group, February 1998), pp. 215-224 (APEC publication no. 98-RE-04.1).

2. See Chuanlong Tang, "Structure and Price Adjustment in Long-Term Contracts: The Case of Coking Coal Trade in the Asian-Pacific Markets," *Energy Policy*, Vol. 21, No. 9, September 1993, pp. 944-52.

Nearly all of Asia's gas trade thus takes place in the form of LNG. The Asian LNG trade is either among APEC economies or originates in the Middle East. So far, Asia has dominated global LNG production, though recently the Middle East has increased its production share in regard to Asia. The role of the Middle East in the LNG trade should grow, because proven natural gas reserves in the Middle East are about three times as large as Asia's comparable reserves.

LNG supply contracts, many of which are between Japan's utilities and LNG suppliers, traditionally include terms related to supply security, regularity of shipments, and gradual changes in price terms. The traditional LNG contract is designed for the long term, with a typical contract duration of 20 years during the 1980s and about 25 years during the 1990s. Because of special requirements for LNG manufacturing, transportation, receiving, regasification, and storage, buyers and sellers are protected by the contract terms. Buyers are assured of specific volumes to be delivered within tight time frames, while sellers are guaranteed take-or-pay clauses. LNG pricing in contracts is determined by low-sulfur crude oil in the case of Japan, though with a premium related to volume.

Should this type of LNG contract continue, further development of Asia's gas markets will certainly be constrained. Asia's gas demand and supply situation has already evolved rapidly during the 1990s. The traditional contract terms for LNG have been challenged, following the rise of Korea and other economies as major LNG importers. Korean contracts have altered many of the basic assumptions behind LNG contracting, giving contracts more flexibility by placing more risk on the side of buyers. Korea has consequently obtained a contract with Oman that has loosened many of the traditional terms. LNG demand continues to grow in Korea and Chinese Taipei, while additional Asian economies, notably China, are expected to join the APEC region's LNG importers. LNG contract terms and conditions will evolve further as this occurs. The potential for spot LNG deals or short-term LNG shipments is debatable, however, even though such arrangements increased during the 1990s. Long-term contracts are expected to continue to dominate LNG trading, while spot deals will remain supplementary. However, future long-term contract terms may become more flexible, and new trading patterns might develop.

Thus, long-term energy development and supply contracts form an important foundation for energy security, but contract terms can either facilitate or hinder the functioning of free markets. Traditional long-term contracts for energy trading can become too rigid in today's evolving energy markets and can be barriers to efficient market operation and entry. Because of rapidly changing market conditions and energy security concepts, the core features of the long-term contracts for oil, coal, and gas have changed and evolved during the 1980s and 1990s. Further changes in contract terms are expected in the future. While the pure form of spot transactions cannot overtake long-term contracts for the trading of most primary fuels, spot prices as well as futures prices will certainly play a greater role in shaping long-term energy supply contracts.

2.3. Potential for Electricity Trade among APEC Economies

Electricity trade among APEC economies is presently an important issue only in North America, where transfers between the United States and Canada are commonplace and transfers between Mexico and the United States are increasing. Under the new environment of open access to US transmission lines, electricity trade between Canada and Mexico is technically possible.

Chile will see increased electricity trade with its neighbors, though its energy markets must determine whether electricity trade is more economical than primary fuel trade. Presently, there are natural gas pipelines being built or planned that will transfer gas to Chile from Argentina, Bolivia, and perhaps Peru. Much of that gas will be transferred to Chile for the purpose of power generation, while additional Argentine gas will be used to generate electricity in Argentina for transfer to Chilean markets. There are also schemes to develop hydroelectric power facilities in Bolivia near Chile’s border for export to Chile’s northern grid.

Southeast Asia is also developing a regional power grid. A large share of this regional power system is centered on Thailand and western Malaysia, where regional power consumption is concentrated. Thailand now has existing power purchase contracts with Laos, which send hydroelectric power from Laos to Thailand’s grid. Agreements have also been signed to deliver further hydroelectricity and to send lignite-fueled power from Laos to Thailand. Arrangements are also in varying degrees of completion to sell power to Thailand from Burma (Myanmar), China’s Yunnan Province, Cambodia, and Malaysia. Such power trade in the cases of Burma (Myanmar) and Malaysia competes with possible pipeline provision of natural gas for power stations located in Thailand. Also competing with such power transfers might be natural gas sales from Indonesian fields, notably Natuna, to Thailand.

The electricity trade between Singapore and Malaysia has long been established, though each of those economies is basically self-sufficient in electricity. A subsea electrical cable from Bakun in Malaysia’s Sarawak State to western Malaysia was proposed to cross offshore Indonesian territory. This project has faced delays and might either be reorganized from its original form or canceled. Proposals have also been advanced to sell electricity generated near coal mines in Sumatra to Malaysia. Vietnam, which is in the APEC region geographically and will formally join APEC in November 1998, sells some electricity to neighboring communities in Laos and Cambodia. Proposals to sell gas to Singapore from Sumatra and neighboring Indonesian islands or from the Natuna field must compete with proposals to sell electricity from plants located in Indonesia itself.

China also conducts limited electricity trade with its neighbors. Hong Kong, China, now politically integrated into China, though still a separate economy within APEC, has for some time exchanged electricity across the common border of the two economies. Arrangements also exist to share electricity generated along China’s border rivers with North Korea, and a small amount of electricity has been transferred from the Russian Far East into northeastern China. Power lines also connect parts of China to the Central Asian republics. Hydroelectric projects in Yunnan Province are intended to transmit power along lines that will cross Laos into Thailand.

There has been particular attention in recent years to the possibility of setting up a regional power grid among the ASEAN economies¾Vietnam, Thailand, Laos, Myanmar (Burma), Malaysia, Singapore, Indonesia, Brunei Darussalam, and the Philippines¾but also including economies that are not now part of ASEAN, such as Cambodia and China's Yunnan Province. Benefits asserted to derive from such interconnections would include balancing of seasonal and daily peak loads and providing alternatives to primary energy imports in forms such as natural gas, oil, and coal. (Uranium is not a primary energy source in the ASEAN region and is not scheduled to become a power source there in the near term.)

Plans to interconnect the ASEAN economies face many hurdles that make a completely interconnected ASEAN system unlikely in the short run. Not all ASEAN economies lie on the same land mass. Large portions of the region consist of archipelagos, and grids within some ASEAN economies are not yet fully integrated. This does not preclude the possibility that, in some circumstances, cross-border interconnections in the archipelagos might be more cost effective than some domestic interconnections. Power demand in Southeast Asia remains concentrated in a few urban and industrial centers. The load demand in many intervening areas remains relatively low, thus the costs of interconnecting load centers might be prohibitive. Finally, financial constraints in the region have recently become more stringent, limiting the ability to raise funds for interconnections.

Despite such barriers to the integration of Southeast Asian power grids, the fact exists that the integration of power and gas supply grids have both been proposed for the region. It is likely that both gas and power system integration efforts will proceed simultaneously and will seek to meet energy needs in very much the same areas. Presently, it appears that the electricity systems will be most thoroughly integrated prior to the integration of the gas systems.

Japan, Korea, Chinese Taipei, Australia, New Zealand, Papua New Guinea, the Philippines, and portions of Indonesia are perhaps presently too geographically isolated to anticipate direct interregional power connections in the near term. Long-term suggestions have been made for electric power interconnections involving Korea, Japan, the Philippines, and even Chinese Taipei with mainland markets. At present, such suggestions appear to be too expensive, though investigations continue and some local progress on components of such systems might be anticipated. Any entire integrated system would thus be most likely to develop on a piecemeal basis over considerable periods of time.

Given the preceding environment, cross-border electricity sales have become an alternative to meeting interregional primary energy sales. Most clearly this has been the case for the transfer of gas and electricity, where proposed transit routes for exchanging the two energy sources often follow similar paths. On an income distribution basis, the selling economy would most often receive the highest value added, if it controlled the process from energy production to electricity generation. The consuming economy would normally be expected to receive the greater income share, buying the primary fuel and generating its own power. The issue would become more complex if the primary fuel or electricity transited a third economy, such as would be the case in the proposed Yunnan-Thailand power interconnection. The economic efficiency of the transaction would then be a more complex issue, heavily affected by the regulations applied to the power transfer and to primary fuel transfers within each economy.

Electricity generation permits the separation of the location of primary fuel use from the location of energy consumption. This is a different circumstance from most primary fuel use. One very clear advantage to electricity consumption is the fact that environmental regulations affecting power generation can be geographically separated from the relatively low environmental impact of the actual use of power. Thus policies such as demand-side management (DSM) exhibit their environmental benefits at the point of generation, even though they address power at the point of consumption. This ability to relocate environmental costs gives electricity production a distinct advantage over primary fuels consumption.

From a primary-fuels-liberalization vantage point, electricity interconnections among economies are alternatives to primary fuel transfers. If the liberalization and preferential financing or “ground rules” among primary fuels and electricity are not balanced, one energy source or the other might effectively be subsidized, thereby unequally affecting interfuel competition.

2.4. Summary

The power supply industry has become characterized in recent years by rapid liberalization, deregulation, and privatization on a global basis. This has generally resulted in decreased prices for electricity and increased supplies to consumers. Along with this has come a growing demand for funding, often international funding, which has become a crucial issue regarding power in many APEC member economies.

More competitive power provision has meant that a power producer’s primary concern is the control and timing of his costs. This places rather direct pressure on fuel markets in regard to power plant design and construction. Most fuels that provide heat or mechanical energy might be selected for electricity generation, but the fuel that producers would most willingly select is the fuel that meets cost requirements. This desire on the part of the power producer often conflicts with energy security goals of a particular economy. One of the more continuing sources of difficulty in recent power plant implementation has been the setting of fuel choice by the leadership of the power-purchasing economy. These goals might at times conflict with the financial interests of power-producing enterprises.

The development of economy-wide and international power grids has been moving apace within the APEC region. This has changed the character of many regional economies, as cross-border electricity transfers become competitive alternatives to domestic energy supplies and to international shipments of primary fuels. Presently, among Asian and Latin American APEC power producers, these cross-border electricity transfers have been primarily from energy supply sources to energy consuming markets. Among North American producers, this characteristic also exists, though the potential is stronger for routine balancing differences in interregional demand patterns.

During an APEC Energy Working Group workshop of 3-4 February 1998 in Honolulu, Table 10 was presented regarding the desirability of fuel options for the power industry.

Table 10. Ranking of Power Industry Fuel Options

	Technical	Supply	Environmental	Eco-	Finance-

Option	Complexity	Security	Concern	nomics	ability
Nuclear	3	5	?	1	1
Hydro	3	4	?	2	2
Coal	4	3	2	3	3
Gas	5	4	5	5	1-5
Oil	5	2	3	3	5

Source: World Bank.
Ranking: 1 = least desirable; 5 = most desirable.

The accuracy of each evaluation on Table 10 would of course vary by project. Local conditions are always overriding. The range of financeability ratings for gas occurs because pipeline-based gas projects are relatively easy to finance, whereas LNG-based projects are comparatively difficult to finance. We also believe that coal-fired generation economics are better than oil-fired generation economics though often less than gas economics. The table does, however, lead to a fairly clear conclusion that gas-fired projects have definite advantages over most other major fuels. Coal and oil would lie somewhere in the middle, depending heavily on the environmental criteria applied, while hydroelectric projects and, even more so, nuclear generation projects usually start out from a disadvantaged position.

2.5. Recommendations

1. Policies directed toward power industry fuel choice should be flexible enough to allow not only for the present structure of the industry, but also for the potential future structure of the industry. This is one way to avoid stranded costs.

2. Movement toward a more competitive electricity market should not preclude the continued use of long-term contracts within the electric power supply industry. It is anticipated that as the electricity industry evolves, long-term electricity supply contracts should increasingly adapt their pricing mechanisms to changes in market (spot) prices. This should be anticipated within the present contracting process.

3. Trade of electricity should be fostered among APEC economies. Electricity sales across borders should be viewed as an often viable alternative to primary fuel sales and as a means to enhance energy security.

4. Organizations that generate electricity should be allowed to choose freely among alternative fuels and plant within the context of the availability of sites and the cost of the fuel, including the costs of the fuel's environmental impact.

5. Any power investment should have a sound international financial basis.

6. Reasons for strict controls on enriched nuclear fuels (and on highly radioactive nuclear wastes) are too strong to permit liberalization within the nuclear industry to a degree comparable with the liberalization taking place in other fuel industries. (This topic is discussed further in Chapter 3).

Chapter 3

Operations of International Fuel Markets

International market operations for primary fuels such as oil, gas, coal, and uranium differ substantially from each other, mainly because of the unique physical properties of each fuel. The worldwide distribution of individual energy resources and the distances between the energy resources and markets also significantly affect market operations for individual fuels. Generally, oil is more widely traded than coal and gas. Each economy in the APEC region trades oil and refined products though many might not trade significant volumes of coal or gas. Because oil is indispensable for any modern economy and because some large APEC economies produce far less oil than they need, large volumes of oil imports are required. This results in a sizable flow of oil shipments among APEC economies and with economies outside of the APEC region.

International trade in coal is also important, though coal is produced and used as an indigenous fuel in many economies. Perhaps half of the world's coal reserves are located in the APEC region. The United States, China, Indonesia, Australia, and Canada are major coal exporting economies. Many other APEC economies have some domestic coal reserves, though the quality is usually not as good as that of coals found in the exporting economies or the coal is poorly located relative to potential markets. Many economies that do not export coal, when they chose to use coal as a power fuel, must therefore decide whether lower quality domestic or premium imported coal resources best meet their needs.

International transactions in natural gas often require the construction of long-distance pipelines or special facilities to transport gas in the form of liquefied natural gas (LNG). Trading natural gas in small volumes but over long distances is rare, if not impossible, because of the high costs involved in building gas related facilities.

The uninhibited trade in uranium as a power fuel is limited by differences in policies toward "natural uranium" compared with "enriched uranium." Natural uranium is sold under both term and spot arrangements, much as is any other power fuel. Enriched uranium or plutonium transfers are made complex by the association of sales with nonproliferation and safety policies. Because many commercial reactor designs require enriched uranium fuels, only a portion of the actual nuclear fuels sales are transacted in relatively liberalized markets.

While almost all primary fuels are traded under term or spot contracts, the dominant characteristics of trade for each individual fuel differ from each other. Despite dissimilarities, market operations of all primary energy fuels are interrelated in many ways. They are all affected by the energy-economic links, technological development, and overall energy policies within individual economies. Primary fuels also compete in several markets, with the power sector being the most notable and sizable arena of interfuel competition.

One important result of differences among market operations for individual fuels is that there may be different types of barriers within individual fuel markets as well as among fuel markets. The fact that interfuel competition exists in industrial sectors makes it even more important to improve the market operations for individual fuels, thus increasing fuel substitutability and efficiency within the overall energy market.

3.1. Interfuel Competition

There is a school of thought that interfuel competition evolves primarily because of changes and improvements in technology. Activities that were once considered natural monopolies, such as natural gas distribution and electricity, are now considered areas where greater market competition is possible. One of the reasons for the change in perception has been the increased ability to monitor and regulate flows of gas or electricity within their distribution systems. It is now possible to track at least notional amounts of natural gas or electricity from their point of origin to their point of sale. This monitoring capacity allows not only identification of the product, but also more accurate segregation and pricing of the product than was previously imagined possible. Gas pipelines and power transmission and distribution lines can thus become common carriers for energy, much as a highway is a common carrier for motor vehicles. Products using such systems can be sold to separate markets and differentially priced. The only remaining "natural monopoly" is the wire or the pipe itself and not the service that each provides.

A second influence on the ability to improve the operation of international fuel markets has been the considerable investment that has taken place over the past century. In many cases the investments are the product of the last decade or two. The consequence is that more alternative routes for delivering competing primary energy sources are available than ever before, and potential alternatives in regard to fuel consumption are everywhere increasing. This allows fuels to compete more directly with each other in markets where a single primary fuel once dominated the economy. Electricity grids now cover entire economies rather than isolated subregions, while alternatives such as natural gas are now often available where previously they were not.

A third influence that has enhanced interfuel competition was the oil price crises of the 1970s and 1980s. These crises made investors acutely aware that individual primary energy resources are subject to market conditions that permit price gyrations of both a transient and a sustained nature. Such gyrations in their turn alter the relative advantages of individual fuels. One reaction to this condition was an increased concern in many economies with energy security and energy independence. That is, an increasing desire arose to depend on either domestic primary energy resources or on those resources that an economy might control. Many of the investments that have permitted interfuel competition have been the result of government policies and encouragement. There is a fad to point out the mistakes that have arisen from misdirected government policies. Less effectively heralded benefits have also arisen from the better conceived government policies of the past decades.

There has also been an increased interest in energy diversity as a means to promote energy security. This has taken the form of vigorous efforts to spread energy resource requirements among many primary resources rather than just one or two. Part of energy diversity has been an increased capacity to switch among fuels. This has permitted energy consumers to shop around among energy sources, especially before facilities are built, and to switch from one resource to another whenever prices change the relative advantages of individual primary energy sources. Such flexibility is of course not free, and the capital costs of building a flexible facility often exceed the costs of a single-fuel-based unit. Switching among fuels also involves operating costs and fuel-contract-based costs. Also, long-term relative prices of fuels change more slowly than is often anticipated. Thus, for example a power plant might be able to burn several alternative fuels, though in practice such switching might be rare and often transitory.

3.2. Oil

Oil in its initial form differs from other primary fossil fuel in that petroleum refineries are almost the only entities that actually consume crude oil. While coal and natural gas are used directly for power generation and by industrial, residential, and commercial sectors,[3] few power plants (notable exceptions are in Japan, China, and the Middle East) use crude oil directly to generate power. Some crude oil is also used in the industrial sector on a very limited scale, but commercial and residential usage of crude oil essentially does not exist. At the point of final consumption, there is little demand for crude oil, but rather a demand for energy and nonenergy products: for petroleum products and petrochemicals that might themselves also be directed toward intermediate uses rather than to final consumer items.

3.2.1. Quality of Crude Oil

Crude oils are naturally occurring hydrocarbon mixtures that occur in the liquid range under atmospheric conditions. Differences in composition among crude oils can make dramatic differences in the yields of oil products (e.g., gasoline, jet fuel, diesel, fuel oil), in the price of the crude oil, and in the environmental consequences of using the oil. Though crude oil qualities vary in many ways, crude oil markets often concentrate on two key indicators: sulfur and crude density.[4]

Sulfur is measured as the percentage of sulfur by weight in oil. When oil is burned, most sulfur in the oil is combusted to form sulfur oxides. When sulfur oxides combine with moisture in the atmosphere, sulfuric acid is formed, which then can precipitate as a component of “acid rain.” Almost all crude oil contains some sulfur. Most crudes contain considerable amounts—0.5-3.0% by weight—and some may contain in excess of 5% sulfur. Most sulfur in crude oil can be removed as the oil is refined, though this involves expensive equipment and high operating costs, and greatly increases energy consumption within a refinery.

Another obvious difference among crude oils is their density (or specific gravity). Most crude oils are lighter than water, though crude densities vary substantially. Crude oil density is often expressed as “API gravity.” (API is the acronym for the American Petroleum Institute, which originated the measure.) API gravity is derived from the specific gravity by the formula: API gravity = $(141.5/g_s) - 131.5$, where g_s is the specific gravity. Although most specific gravity measures increase with density, API gravity works the opposite way around. The higher the API gravity, the less dense, or “lighter” the material. By definition, a gravity of 10° API is as dense as water. An oil of 30° API gravity is more dense than an oil of 40° API gravity but less dense than a crude of 20° API. Because less dense oil products, such as gasoline, kerosene/jet fuel, and diesel, generally have higher market values than more dense oil products, such as fuel oil or bitumen, a

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3. Of course in many economies coal has to be properly cleaned before it is burned. The standards for clean coal, however, vary from economy to economy.

4. Much of the discussion in this section is derived from the *Hawaii Energy Strategy Project 2: Fossil Energy Review, Task I: World and Regional Fossil Energy Dynamics*, prepared by the East-West Center’s Program on Resources for the State of Hawaii, December 1993.

high API value crude generally sells for a higher price. Similarly, crude oils with lower sulfur content have higher market values because they present less refining difficulties and expenses.

API gravity and sulfur content do not tell the whole story, though a refiner can make a good guess about what a crude is worth in product yields, based on the two figures. Gravity and sulfur are also indicators for examining trends in world oil reserves and production. Knowing the direction that API gravity and sulfur might move in the future tells a great deal about the costs of meeting environmental regulations and the costs of different refined products made from oil. For Japanese power utilities, anticipating the future supply availability and price of low-sulfur crude oil is important in deciding how much crude oil might be burned directly for power generation.

There has been general agreement that the long-term trend is for crude quality to deteriorate in both API gravity and sulfur content. This trend runs counter to the trends in world demand where lighter products (gasoline, jet fuel, and diesel) are increasingly in demand while denser products (notably fuel oil) are in declining demand. Additionally, concern about the environment has led the world to demand lower sulfur content in oil products. The sulfur content of refined oil products can be most readily reduced by starting with a low-sulfur crude oil.

Nonetheless, there is presently no oil quality crisis in the oil market. Some detailed studies suggest that, although the crude slate might become higher in sulfur in the near-term, available crudes might actually move to slightly higher API gravities. The crude slate in the longer term, however, will definitely resume its trend toward both higher sulfur and lower API gravity, if only because of the vast reserves of extremely high-sulfur, low-API material in the Western Hemisphere, notably in Venezuela and Mexico.

3.2.2. Uses of Petroleum Products

There are many grades of petroleum products, ranging from asphalt to gasoline, from propane to Vaseline. The most diverse products are lubricating oils and greases, though the greatest sales volume is in five general product categories. These, ranked from the least to the most dense, are liquefied petroleum gas (LPG), gasoline/naphtha, kerosene/jet fuel, gasoil (diesel), and fuel oil. These five categories account for 92% of oil product demand, while the thousands of other product categories and subcategories account for a mere 8%.

Liquefied petroleum gas (LPG) has the most varied uses among the major oil products. LPG is composed of propane, butane, and some propylene. Statistically, LPG occasionally also includes a gas, ethane. The term LPG can also refer to propane or butane alone or to a mixture of the two. LPG is often used for cooking, especially in remote areas, and as an illuminating fuel. LPG is also a feedstock for the petrochemical industry, a boiler fuel, and, rarely, a fuel for power generation. In some locations, LPG is used as an automotive fuel, especially for fleet vehicles. New Zealand, Thailand, and others have extensive programs using LPG as a vehicle fuel, and propane-powered cars have also been promoted in California because of a lowered pollutant output compared with gasoline.

The distinction between gasoline and naphtha can be confusing. All gasoline is also naphtha, but not all naphtha is gasoline. Naphtha is simply material that separates out from crude in a specified temperature range during the refining process. For naphtha to be sold as gasoline, it must meet a list of performance criteria that vary from economy to economy and among areas. Such criteria are constantly being tightened to control automotive-originated pollution and to raise gasoline performance. Most naphtha is used to make gasoline, but not all naphtha can "make the grade." Some naphtha is thus used to make solvents, paint thinners, and various minor products. Naphtha's greatest end-use, beyond gasoline feedstock and as a raw material in aromatics chemical plants, is as feed to olefin crackers, one of the most fundamental processing facilities in the petrochemical industry. After further manufacturing, the output of olefin crackers can be used to produce polyethylene, polypropylene, synthetic rubbers, and other plastic and many petrochemical products. Ethane, LPG, and other oil products can replace naphtha in the cracking process, but naphtha is the critical feedstock for the manufacture of petrochemicals in most Asian APEC economies. Ethane is more important in North America, Australia, Mexico, and in a few Asian APEC economies. Until recently, almost all military aircraft used naphtha-based jet fuels, though many military agencies have begun phasing out these fuels for safety reasons.

Commercial jet fuel is based on kerosene, which is less volatile (explosive) than naphtha. All commercial jet fuel is kerosene, but not all kerosene is jet fuel, though the grade dual-purpose kerosene (DPK), which meets the requirements for most kerosene uses including jet fuel, has become most common. Very little kerosene is used in the United States and Canada other than for jet fuel. Kerosene is a major fuel for cooking and lighting in many developing economies. In some instances, increases in the price of kerosene have led to riots due to the impact of kerosene prices on low income groups. This has made the removal of restrictions and subsidies on the price of kerosene difficult in many economies. In Japan, kerosene is an important fuel for home heating. Kerosene consumption in Japan therefore varies significantly between summer and winter. A cold winter in Japan can cause dramatic increases in the international price of kerosene and jet fuel.

Diesel fuel is often referred to as "gasoil" or "light gasoil." There are many grades of diesel/gasoil. The most important specifications for diesel are cetane number, sulfur content, and viscosity. The cetane number is best thought of as comparable with the octane rating of gasoline, though technically the two ratings measure nearly opposite fuel burning characteristics. Sulfur in gasoil is broadly controlled for emissions reasons. There are also maximum viscosity requirements to ensure that the diesel fuel will flow smoothly. Heavier, higher-viscosity, higher-sulfur grades include marine diesel, railroad diesel, and industrial diesel. Specifications for these diesel products vary widely. Some economies, such as Japan and the United States, are fairly strict regarding diesel qualities, whereas in other economies industrial and railroad diesel containing up to 1.8% sulfur may be burned.

Fuel oils are the "bottom of the barrel," unless one gives that title to asphalt or coke. That is, fuel oils constitute liquid oil products that are left after distillation and processing ceases in the refining process. Fuel oils are thus often called "residual fuel" or "residuum." There are many grades of fuel oil and there is also a large market in "off-spec" fuel oil that does not meet particular specifications. Specifications usually govern sulfur content and viscosity. The most important use of fuel oil is for electric power generation, though large volumes are also used in industrial boilers, mining, and smelting, and as an international shipping fuel. Unlike the transportation fuels (gasoline, kerosene and jet fuel, and diesel) where a liquid is specifically required, fuel oil is usually used simply as a source of high-temperature heat. Thus in most uses, natural gas, coal, biomass, and many other petroleum products might be substituted for fuel oil. Fuel oil is used when price, storage, and technical conditions are favorable. In the case of electric power, each of these alternatives to fuel oil has been used, as well as nonthermal energy sources such as hydroelectric power, wind and solar power, geothermal energy, and nuclear energy. Fuel oil has often been preferred among oil products for power generation, primarily for its relatively low market price.

Interfuel competition varies according to sector. There are few ready alternatives to oil for the transportation fuels, though differing grades and classes of oil products do compete with each other. Similarly, there are few alternatives to the use of ethane, LPG, naphtha, and some middle distillates in petrochemical manufacturing, though ethane is a preferred petrochemical feedstock in the United States, Canada, Malaysia, Thailand, and Australia where it is available in quantities. Petroleum products such as lubricants, asphalt, and needle coke are also relatively difficult to displace with other materials. In these cases, it is not just energy that is demanded, but rather an energy or chemical form. On the other hand, power generation (the largest energy-consuming sector) offers considerable flexibility for interfuel competition.

3.2.3. Oil Market Operations: Global Demand and Supply Trends in APEC Economies

Oil trading has long been globalized. When oil prices plus freight provide the incentive, oil can be and is moved anywhere in the world. Oil price movements on the world market ultimately determine the import and export incentives and, often, governmental subsidy levels that an economy will face, even in the face of domestic price controls and elaborate cross-subsidy schemes in some economies. However, freight charges can be a very important determinant for the volume of oil flows. Because long-haul oil shipping is usually much more costly than short-haul shipping, actual world oil trading tends to occur within regional zones that are relatively close to each other. The United States was highly dependent on crude from the Middle East during the 1970s and early 1980s, because oil supplies from the North Sea and Latin America were insufficient to meet domestic demands. Oil production outside of the Persian Gulf has increased rapidly since the late 1980s. While the United States still imports oil from the Gulf, Latin America has become a more important supply source. Additionally, the North Sea and Canada are now also significant oil suppliers to the United States.

Three regional oil trading zones have emerged during the 1990s¾the Atlantic Basin, the Middle East and Asia, and the Western Hemisphere. Oil is still traded among these zones, but the existence of the zones is based on the fact that most oil that zonal markets require is available within each zone. Cross-zone trading is still significant because of the need to supplement specific qualities and quantities of crude oil. Thus, the United States still imports oil from the Persian Gulf. Asia's special appetite for low-sulfur crudes at many refineries prompts purchases from Western Africa (part of the Atlantic Basin) for crudes that are not available in adequate volumes within the Middle East and Asia zone.

The world's proven reserves were slightly over 1 trillion barrels at the end of 1996¾ up from 710 billion barrels at the end of 1986 and 607 billion barrels in 1976.[5] The world's oil reserves-to-production (R/P) ratio was 42 years in 1996, up from 32 years in 1986. The R/P ratio is a widely used measure of oil depletion, largely because it is easy to explain: "here's how much we have and here's how fast we're using it." Unfortunately, the R/P ratio is a very volatile measure. Because changes in how much oil we have found and how fast we are using oil move in opposite directions (upward and downward, respectively) in response to increased prices, the R/P ratio changes faster than either of the indicators that govern it. The R/P ratio is thus "highly leveraged." When prices go up, the oil industry does not immediately find more reserves and consumers do not immediately invest in energy conservation. But, within a matter of years, there are moves in these directions and the R/P ratio increases sharply.

If the R/P ratio were recalculated to reflect total remaining resources rather than proven reserves, then evaluating the whole oil resource gives nearly 90 years at present consumption levels. Of course, undiscovered and unproven oil reserves have higher production costs than do proven reserves. Oil prices will rise as reserves are depleted. This would brake consumption, slowing its growth in the coming decades. The world might never run out of oil, but oil would gradually become more scarce and more costly. Oil would be reserved for more specialized uses that have fewer substitutes, such as petrochemicals and transportation fuels, and would be phased out of lower-value-added uses such as electricity generation as alternative fuels become more economical. This might extend oil resources considerably. Barring major technological breakthroughs or a fundamental restructuring of the world economy, oil will most likely continue its important role in the world's energy supply well into the twenty-first century. But, oil would supply less and less of the world's total energy requirements, becoming instead a more critical fuel whose use would be devoted to relatively unique functions.

Total world oil consumption was 71.8 million b/d in 1996, up from 70.1 million b/d in 1995, 66.3 million b/d in 1990, and 60 million b/d in 1985. The share[6] of total world oil demand originating in non-OECD (Organization for Economic Cooperation and Development) economies was about 42% in 1996. On the supply side, OPEC (Organization of Petroleum Exporting Countries) accounted for 39% of the world oil supply in 1996, up from 30% in 1985, but near to the 37% level registered in 1990. OPEC economies produced 25.8 million b/d of crude oil and 2.6 million b/d of natural gas liquids (NGLs) in 1996.

APEC economies represent the world's largest oil consuming area and exhibit a high oil import dependence because of the inclusion of the United States and Japan. APEC economies consumed a total of 36.9 million b/d of petroleum products in 1996, accounting for more than half of the world total (Table 11). During the past seven years, annual oil consumption growth in the APEC area averaged 2.7%, more than twice the average annual growth of world oil consumption. Korea had the highest annual oil demand growth rate (12.8% during 1990-1996), followed by Thailand (11.5%), Chile (8.2%), the Philippines (7.6%), Malaysia (7.4%), China (7.1%), and Indonesia (6.5%). Faster growth was seen among Asian member economies than among the Western Hemisphere economies. Oil demand growth averaged 5.3% per year for Asian member

5. See *BP Statistical Review of World Energy*, June 1997.

6. See IEA, *Annual Statistical Supplement to the Monthly Oil Market Report*, 9 October 1997.

economies from 1990 to 1996, nearly twice the rate for the whole APEC area. Except for Chile, Western Hemisphere member economies demonstrated low oil demand growth during the 1990s. Altogether, oil demand in the APEC economies grew by 5.5 million b/d from 1990 to 1996, roughly the same as the total consumption addition for the entire world. That is, net oil demand growth was almost nil for non-APEC economies, largely due to the demand decline in the former Soviet Union. Of the 5.5 million b/d additional oil consumption of APEC economies from 1990 to 1996, Asian members accounted for nearly 4 million b/d.

APEC accounts for less than one-third of world oil production. Production in the area has grown only slightly since 1990, owing to the production declines in the United States, Australia, New Zealand, and Chile. Annual oil production growth in the APEC region during 1990-1996 was about half of the world average annual growth of 1.2% (Table 12). Production among Asian members, however, increased at a faster rate than the world average during 1990-1996, though Asian production accounted for only 29% of APEC output. The largest APEC producer is the United States with 8.3 million b/d in 1996, followed by Mexico (3.3 million b/d), China (3.1 million b/d), Canada (2.5 million b/d) and Indonesia (1.5 million b/d). Smaller producers include Malaysia, Australia, Brunei Darussalam, and Papua New Guinea. Papua New Guinea’s oil production jumped from 3,000 b/d in 1990 to 127,000 b/d in 1993, but has since declined slightly. Canada increased its production by 495,000 b/d from 1990 to 1996, followed by China at 379,000 b/d and Mexico at 305,000 b/d.

Table 11. Petroleum Product Demand by APEC Economy, 1990-1996

Economy	Product Demand (kb/d) 1990	1991	1992	1993	1994	1995	1996	Average Annual Growth Rate, 1990-96 (%)
Australia	662	656	668	689	726	746	755	2.2
Brunei Darussalam	9	9	10	9	9	10	10	3.0
Canada	1,690	1,630	1,625	1,680	1,720	1,665	1,735	0.4
Chile	140	150	160	175	190	210	225	8.2
China	2,205	2,340	2,545	2,818	2,937	3,117	3,321	7.1
Hong Kong, China	139	130	166	174	187	199	201	6.3
Indonesia	598	649	714	752	759	814	870	6.5
Japan	5,199	5,312	5,405	5,322	5,623	5,621	5,654	1.4
Korea	1,008	1,222	1,481	1,632	1,781	1,930	2,079	12.8
Malaysia	271	281	292	325	344	374	416	7.4
Mexico	1,455	1,520	1,545	1,550	1,685	1,560	1,605	1.6
New Zealand	100	101	101	100	110	114	118	2.7
Papua New Guinea	17	17	17	18	18	18	19	1.7
Philippines	228	225	255	278	291	338	355	7.6
Singapore	406	444	471	478	528	567	579	6.1
Chinese Taipei	576	580	603	641	704	756	752	4.5
Thailand	416	447	509	577	639	735	801	11.5
United States	16,305	16,000	16,260	16,470	16,950	16,950	17,400	1.1
Totals								
All APEC	31,424	31,712	32,825	33,688	35,200	35,724	36,894	2.7
Asian Members	11,072	11,655	12,466	13,024	13,819	14,479	15,057	5.3
World Total (kb/d)	66,280	66,740	67,290	67,710	68,620	70,060	71,760	1.3
APEC Share of World Total (%)	47.4	47.5	48.8	49.8	51.3	51.0	51.4	

The APEC area's net oil imports jumped from 11.9 million b/d in 1990 to 16.6 million b/d in 1996 because of rapid demand growth and flat regional production (Table 13). During this period, China switched from being a net oil exporter to a net importer, while Indonesia and Malaysia saw a decline in their net oil exports. Canada is the only APEC member that had a rapid increase in net oil exports; Mexico and Brunei Darussalam registered small increases, while Papua New Guinea switched from being a net oil importer to a net oil exporter. Net oil imports for other economies have increased at average rates, ranging from 1.4% per annum in Japan and 3.5% in the United States to 12.1% in Thailand, 12.8% in Korea, and 16.5% in Australia. The APEC region has an overall oil import dependence of about 45%. For Asian member economies,

Table 12. Crude Oil Production by APEC Economy, 1990-1996

Economy	Production (kb/d)							Average Annual Growth Rate, 1990-96
	1990	1991	1992	1993	1994	1995	1996	(%)
Australia	576	544	539	496	540	510	540	-1.1
Brunei Darussalam	134	145	159	156	162	159	158	2.7
Canada	1,965	1,980	2,060	2,185	2,275	2,400	2,460	3.8
Chile	18	16	13	13	12	10	9	-10.5
China	2,766	2,820	2,842	2,905	2,922	3,001	3,145	2.2
Hong Kong, China	0	0	0	0	0	0	0	-
Indonesia	1,462	1,592	1,505	1,530	1,506	1,510	1,494	0.4
Japan	10	15	17	16	15	15	14	6.1
Korea	0	0	0	0	0	0	0	-
Malaysia	623	652	661	650	640	693	650	0.7
Mexico	2,975	3,125	3,120	3,130	3,140	3,065	3,280	1.6
New Zealand	56	55	46	46	40	33	34	-7.8
Papua New Guinea	3	4	40	127	121	100	107	81.5
Philippines	7	6	10	10	5	3	1	-25.5
Singapore	0	0	0	0	0	0	0	-
Chinese Taipei	2	2	1	1	1	1	1	-10.9
Thailand	42	45	49	52	54	51	59	5.9
United States	8,915	9,075	8,870	8,585	8,390	8,320	8,300	-1.2
Totals								
All APEC	19,554	20,076	19,932	19,902	19,822	19,871	20,253	0.6
Asian Members	5,049	5,281	5,284	5,447	5,425	5,533	5,630	1.8
World Total (kb/d)	66,920	66,790	67,240	67,450	68,640	70,150	72,060	1.2
APEC Share of World Total (%)	29.2	30.1	29.6	29.5	28.9	28.3	28.1	

Source: East-West Center Energy Data Files.

the overall oil import dependence was 63% in 1996 (see Table 13). The Middle East is also the dominant supplier of crude oil and oil products to Asia, while in the Western Hemisphere the only net oil importing member economies (the United States and Chile) rely primarily on oil from their hemispheric neighbors, though Mideast exports to the United States are still large.

Table 13. Net Oil Imports by APEC Economy, 1990-1996

Economy	Imports (kb/d) 1990	1991	1992	1993	1994	1995	1996	Average Annual Growth Rate, 1990-96 (%)
Australia	86	112	129	193	186	236	215	16.5
Brunei Darussalam	-125	-136	-149	-147	-153	-149	-147	2.7
Canada	-275	-350	-435	-505	-555	-735	-725	17.5
Chile	122	134	147	162	178	200	216	9.9
China	-561	-480	-297	-87	15	116	176	-
Hong Kong, China	139	130	166	174	187	199	201	6.3
Indonesia	-864	-943	-792	-778	-747	-696	-624	-5.3
Japan	5,189	5,297	5,388	5,306	5,608	5,606	5,640	1.4
Malaysia	-352	-371	-369	-325	-296	-319	-234	-6.6
Mexico	-1,520	-1,605	-1,575	-1,580	-1,455	-1,505	-1,675	1.6
New Zealand	44	46	55	54	70	81	83	11.2
Papua New Guinea	14	13	-23	-110	-103	-81	-89	-
Philippines	221	219	245	268	286	335	354	8.1
Singapore	406	444	471	478	528	567	579	6.1
Korea	1,008	1,222	1,481	1,632	1,781	1,930	2,079	12.8
Chinese Taipei	574	578	602	640	703	755	751	4.6
Thailand	374	402	460	525	585	684	742	12.1
United States	7,390	6,925	7,390	7,885	8,560	8,630	9,100	3.5
Totals								
All APEC	11,870	11,637	12,893	13,786	15,378	15,853	16,641	5.8
Asian Members	6,023	6,375	7,182	7,577	8,394	8,947	9,427	7.8
Net Imports: Share of Oil Demand (%)								
All APEC	37.8	36.7	39.3	40.9	43.7	44.4	45.1	
Asian Members	54.4	54.7	57.6	58.2	60.7	61.8	62.6	

Source: East-West Center Energy Data Files.

The global oil market is largely a free market in which the market sets the price. Attempts to control and manipulate local oil markets have always existed and continue. While the fundamentals of global oil demand and supply determine long-term oil prices, short-term market disturbances caused by wars, leadership change within large oil exporters, and other political factors persist. Such disturbances result in daily fluctuations of oil prices and have created risk and uncertainty for long-term energy planning.

OPEC is the most apparent example of such attempts at market control. One purpose of OPEC is to serve as a loose international cartel that maintains world oil prices above minimum levels. During the past two decades, OPEC's influence over world oil prices has, however, declined. One reason is that the OPEC economies' reliance on oil revenue is as great as the world's reliance on OPEC-originated supplies. Dependence on oil revenues to maintain domestic economic development and welfare systems in many OPEC economies has greatly increased. Because today's world oil market is largely driven by demand, many OPEC economies are often willing to produce more than their OPEC production quota shares to meet the world oil demand. Nonetheless, present world oil prices remain considerably above the extraction costs for most Mideast producers. This differential still brings sizable profits to the lower-cost oil producers in OPEC.

Some argue that at least two useful purposes are served when oil prices are maintained at a level that is significantly above extraction costs. First, many high-cost oil producers (for example in the United States) benefit when prevailing price levels allow high-cost domestic operators to remain in business. And second, a high oil price saves energy by encouraging the development of relatively easy energy conservation technologies that suppress oil demand. However, high oil prices also impose an economic burden on importing economies through greater oil import bills. These bills undermine development efforts in the poorest economies in particular. If oil prices are allowed to rise to a too-high level, additional energy or oil conservation technologies might become costly, and either the global economy might contract or growth rates would be reduced, owing to a lack of access to oil supplies.

While OPEC members and other oil exporting economies seek the maximum overall benefit from their oil resources, importing economies desire energy supply security. Term contracts have been used to partly offset the risk of oil supply. An oil futures market also emerged during the late 1970s and early 1980s to provide buyers and sellers a potential avenue to defuse price risks. As far as market operations are concerned, if long-term supply contracts stipulate too stiff a term and prevent other buyers from freely trading oil, then the contracts will amount to a barrier to the market operations. Term contracts signed between Saudi Arabia and Japan might have once had such an impact on the market, but the oil market has evolved rapidly since the 1980s, and the spot market's role has grown substantially. Contract terms have become more flexible in Asia, the Americas, and elsewhere.

3.2.4. Technical and Regulatory Barriers in Oil Markets

Other barriers to world oil market operations are technical and regulatory. Inadequate petroleum infrastructure (pipelines, ports, carriers, and port depth) in some areas and government regulations on the types and ownership of crude carriers and pipelines can be major factors hindering crude oil flows. The operation of domestic oil markets within the APEC region also differs widely among economies. Import regimes (tariffs, licensing, quotas), domestic taxes, government controls on domestic oil prices, and other government regulations are important factors shaping the domestic oil markets.

Within the APEC region, the United States; Canada; Australia; New Zealand; Singapore; and Hong Kong, China, have basically free regimes for oil trade and marketing. The export of all indigenous crudes was banned in the United States until 1995, when the export of Alaskan North Slope (ANS) crude was permitted. Japan had one of the toughest import regimes and regulated oil markets among all OECD economies. Until April 1996, imports of major refined products to Japan were largely restricted under the Provisional Law on the Importation of Specific Petroleum Products (*Tokuseki-ho*). This law was enacted in 1986. In April 1997, Japan lifted another virtual ban on refined product exports. While such deregulation measures help to open Japan's markets to foreign investors and traders, it will take some time to see the full impact. Japan's strict rules for land use, its complicated financial system, and its tough requirements for stockpiling make the entry into domestic retail oil market or even product exports to Japan a daunting task.

Private oil companies are free to import crude oil into the Philippines and Korea, though product pricing in domestic markets is subject to government regulations. While each economy is undertaking deregulation measures, the process is subject to fierce debate, especially now that Asia's currency and stock market crisis has spread to the two economies. Fear of soaring oil prices in the Philippines has delayed the full implementation of oil price deregulation. The latest deregulation law was passed in the Philippines in February 1998 with the intention of implementation over the course of a five-year period. It remains to be seen whether the political and judicial process will allow the new law to stand.

Oil market deregulation in Korea was delayed in late 1997 because of the economic turmoil associated with the won devaluation and with presidential elections. The $57 billion program to rescue Korea's troubled economy was the largest such bailout package ever offered by the International Monetary Fund (IMF) for any single economy. The bailout plan might, however, speed up oil market deregulation, as the newly elected Korean government must impose tough fiscal and financial measures to revitalize domestic markets under conditions negotiated with the IMF.

The publicly-owned Chinese Petroleum Corp. (CPC) in Chinese Taipei officially ended its retail market monopoly in 1994. Imports and wholesale markets for refined products will soon be liberalized.[7] CPC itself is likely to be partly privatized before 2000. In Indonesia, publicly-owned Pertamina still holds a monopoly on the import of crude oil and on refined product marketing, including the setting of retail prices. Competing privately owned facilities have been proposed. Malaysia's oil market is much more competitive than Indonesia's, and the state oil company, Petronas, is striving to become a competitive international corporation. Foreign investment has always been allowed in Malaysia's upstream, downstream, and retail sector. However, the terms offered by Malaysia to foreign investors in the oil sector are among the toughest in the region.

The government in China gradually opened oil markets during the 1980s and early 1990s, but since 1994 oil import regulations have been strengthened in the face of inflation fears. Permission for foreigners to compete in oil product wholesaling and retailing investments has been limited, though foreign firms have been allowed to operate several dozen private service stations in association with Chinese partners. The view that some further deregulation is inevitable is one motivation behind recent and continuing mergers in the oil and petrochemical industry. These

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7. As a new policy in Chinese Taipei, any refinery now can provide wholesale products to the market. CPC will be, however, the only operating refiner in the economy until 1999, when the first of two slated private refineries becomes partially operational.

mergers are intended in part to create large and strong domestic firms that will be able to compete with international rivals.

Mexico’s position with regard to its oil sector is one of the most nationalistic among both APEC and Latin American economies. This position is firmly grounded in Mexico’s twentieth century history. The constitution explicitly bans direct foreign equity in the upstream oil sector, refineries, and basic petrochemicals. The state oil company, Pemex, plays a monopolistic role in crude oil exploration and production, refining, wholesaling, and oil trading. Foreign investment is allowed in the retail service station operations, but ownership must be Mexican and products must be wholesaled by Pemex. Most refined products sold in domestic markets, except gasoline, are subsidized by the government at prices below international market prices. The government prices gasoline at a relatively high level to control automobile use and to combat air pollution in the Valley of Mexico (which is among the worst in Latin America if not the world). While Pemex does not intend to privatize, some restructuring is under way¾such as establishing regional subsidiaries and allowing these subsidiaries control over more decisions in oil production and marketing. The goal is to increase the competitiveness of Pemex. The government also intends to privatize some petrochemical firms, though there is very strong public resistance to the effort. Gas distribution and marketing in Mexico has been opened to domestic private and foreign investment on a build-operate-transfer (BOT) basis with long-term contracts.

In comparison, Chile has perhaps one of the most open economies in Latin America. By law, foreign and private investments are allowed in all sectors of the oil and energy business. Refineries in Chile are primarily owned by domestic private firms. Domestic and foreign companies own and operate most of Chile’s wholesale and nearly all of its retail oil business. Refined oil products are competitively priced, based on international markets. Chile imports nearly all of its crude oil needs for its refineries and about 20% of its refined product requirements. The government has vowed to privatize the state oil company, ENAP, under a plan that was initiated in the early 1990s. The most recent privatization plan was finalized in May 1997. If implemented, 20-30% of ENAP’s assets will be sold to international investors and 20-30% to domestic institutions and company workers while the remainder would stay in government hands.

For APEC as a whole, deregulation, increased competition, and privatization are the trend for the oil industry during recent years, though the extent of such reforms differs widely among economies. Moreover, each economy has encountered unique problems and difficulties in completing the deregulation process as targeted. Some setbacks have occurred. The recent financial crisis facing many Asian APEC economies might slow down the deregulation process in some member economies, as the preservation of jobs grows among public policy requirements. Deregulation and privatization can be painful processes that will not solve all the problems of an economy, though they are often needed steps, along with a variety of other reform measures, to establish well functioning markets within each APEC member.

As we move into the next century, oil demand should continue to grow rapidly among the developing APEC economies. Many developed economies among APEC members (the United States, Canada, Japan, Australia, and New Zealand) will see a more moderate oil demand growth. Mexico and Korea anticipate that their oil demand might grow more rapidly than will the demand of other OECD members. Many economies in the APEC region, including the United States, will see flat or declining crude oil production levels. Mexico and China—the second and third largest oil producers in APEC—should, however, increase crude production steadily, though slowly in the case of China. Oil production is most likely to be flat for APEC as a whole, while overall oil demand will continue to grow over the next ten to fifteen years.

The overall oil import dependence of APEC, especially among Asian members, is projected to grow, with particular dependence on the Middle East during the coming decades. In contrast, the United States has diversified its oil supply sources to include Latin America, the Middle East, the North Sea, and Canada to meet its growing oil import needs. Many Asian APEC economies may need to improve their trade regimes, petroleum infrastructure, and domestic oil market operating systems, under these circumstances, to accommodate the increased oil trade and the globalization of oil and other markets. China will need to build additional terminals and pipelines to move imported oil to refineries in eastern and southern regions as it increases oil imports. A major pipeline connecting the eastern part of China with the Tarim Basin would also help, if the resources in West China and Central Asia are to be accessed in the future.

3.2.5. Oil for Power Generation

Oil yields many benefits in power plant usage. Oil is widely available on world markets and is much more easily handled than most other primary energy resources such as coal, natural gas, or enriched uranium. This is one reason why many economies still retain some oil-fired capacity even after much substitution away from oil. Such plants, which are often older facilities that are used primarily under peak load conditions, add flexibility and convenience to the power system, but many of these plants are also being phased out as new power industry investments are completed. Diesel (gasoil) generation is often selected for remote areas that are not connected to an integrated grid. The use of oil in base-load power plants must be evaluated within the context of the long-term global oil and oil-product price scenarios. The suitability of oil for power plants also depends considerably on the location of an economy and the location of the plant within an economy.

The many products that are simultaneously produced in refineries complicate the use of oil as a fuel in power generation. These products are sought for several activities in addition to power production. Petroleum product demand growth in most APEC economies is characterized by demand patterns that skew toward more expensive middle distillates (kerosene, jet fuel, and diesel) and by increasingly tight product specifications. The prices of most oil products are determined outside of the power sector, even though the same products might be burned in power plants. This has generally raised the cost of oil products relative to many other energy resources. As a consequence, many economies have now increased the use of fuels other than oil in their power sector mix. Thus, while oil consumption in the power sector remains substantial, the primary incentive in designing and operating a refinery is seldom to fulfill power demand but rather to supply transportation and chemical markets.

If crude oil is burned directly to generate power, any potential gain from refining the crude oil into more valuable products is lost. Only Japan and China among APEC economies use significant amounts of crude oil to generate power. Japan burned around 300,000-350,000 b/d of low-sulfur crude oil in 1995. Low-sulfur crude was selected to meet environmental standards for sulfur emissions. For China, crude oil used to generate power was over 300,000 b/d during the 1970s but fell to under 20,000 b/d in 1995. If we include Saudi Arabia (which burns about 170,000 b/d), the three economies account for most of the crude oil used for power generation. For the world as a whole, power generation consumed approximately 560,000 b/d of crude oil in 1995, compared with nearly 4.5 million b/d of various refined products used in power generation.

Fuel oil is the refined product most commonly used to generate power. Often over half of domestic fuel oil consumption is for power generation, if international marine bunker fuel use is excluded. For example, Singapore's domestic fuel oil consumption in 1995 was 145,000 b/d (about 70% for power generation). Among APEC economies, Japan is the largest user of fuel oil for power generation, consuming 457,000 b/d in 1995 (65% of domestic fuel oil consumption, excluding international bunkers). The second largest consumer, Mexico, used 318,000 b/d of fuel oil for power generation (66% of domestic fuel oil consumption). Fuel oil consumption for power production in 1995 was 239,000 b/d in the United States, 197,000 b/d in China, 154,000 b/d in Korea, 110,000 b/d in Chinese Taipei, 91,000 b/d in Thailand, 52,000 b/d in the Philippines, 34,000 b/d in Malaysia, 30,000 b/d in Canada, and 19,000 b/d in Indonesia.

Because of the relatively high returns from upgrading fuel oil to light and middle distillate oil products, the share of fuel oil in power generation is expected to continue to decline in most economies, if current technologies remain unchanged. The most apparent source of potential technological change would be further development of fuel oil gasification technologies, which might allow greater production of power from a given volume of fuel oil. Such power generation is becoming very popular when applied to the heaviest product output (an otherwise undesirable type of fuel oil) of vacuum distillation units when the power plant is located at a refinery. Such power facilities are being built at refineries within many APEC member economies. A second refinery "waste" product, petroleum coke, has also been targeted for gasification at refineries around the world.

Diesel (gasoil) is also used to generate electricity, mainly in internal combustion plants though it can be and is used in other forms of generation. The proportion of diesel used for power generation is significantly less than the proportion for fuel oil, because diesel has many other important uses in most economies. The United States is perhaps the largest user of diesel for power generation (41,000 b/d in 1995) in the APEC area, though China's consumption was nearly the same. Indonesia used 39,000 b/d in 1995. Other economies, including Japan and Korea, used well under 20,000 b/d.

Few economies in the APEC area use significant volumes of other petroleum products for power generation, though a non-APEC member, India, has long used naphtha to produce electricity. Naphtha is particularly suitable from a technical standpoint for use in combined-cycle gas turbine power plants. Naphtha for power generation has been particularly popular as a fuel to be selected when it is anticipated that even more cost-effective fuels, such as natural gas, might become available in the near future. Wider use of naphtha to generate power, however, might adversely affect the potential availability of naphtha for the expanding petrochemical industry. If the relative price of naphtha rises over the next decade or so, as many anticipate, the power industry will probably be the first to be priced out of the naphtha market. This situation adds uncertainty to the suitability of naphtha in the power sector.

Oil, as a whole, is not a favored choice for power for many economies. Many developing economies see oil as too precious to be used for power generation. For Japan, environmental emission targets have prompted the government to seek to limit future oil use for power generation, though efforts to reduce total oil consumption in Japan have not been particularly effective.

Additionally, low-sulfur fuel oil should become more expensive as the crude pool becomes more sour and as specifications for fuel oil become more stringent.

China's government has spent billions of renminbi (RMB) yuan[8] since the 1970s to convert generation units that once burned fuel oil to burn coal. The official policy is to restrict the use of fuel oil further in the future. In some cases, China's utilities and independent power producers have found it advisable to install internal-combustion diesel-fired generation sets to meet immediate generation needs. Over the longer term, however, this policy has been discouraged by the government, which prefers to see power generated by using domestic resources that are more abundant (notably coal and hydroelectric power), even though in many cases it might be more economical to use diesel generators or imported fuels.

With combined-cycle generation and gasification technology, the thermal efficiency of using fuel oil can increase to the 40-50% range, compared with the 35-40% attainable in the very best steam turbine plants. New technologies promise that well operated combined-cycle plants will become even more efficient in the future. This might increase the value of fuel oil as fuel for power generation. As far as greenhouse gases are concerned, emissions of oil-fired power plants lie between those fired by coal and natural gas. Increasing the thermal efficiency of a fuel will reduce the greenhouse impact of any particular volume of that fuel. The ultimate choice of fuels for power plants will become more complex as technologies proliferate, diversify, and specialize.

3.2.6. Environmental Considerations Regarding Petroleum Products

The major environmental objective in petroleum product specification is to reduce air pollutants, including volatile organic compounds. This objective can be achieved by reducing (1) the sulfur content of all fuels, (2) the aromatics (notably benzene) content in gasoline and middle distillates, (3) the lead content in gasoline, and (4) the vapor pressures of gasoline. Such reductions are difficult to accomplish without sacrificing fuel "performance." Octane and cetane numbers, vapor to liquid ratios, smoke points, pour points, and similar measures must be maintained within specified limits if fuels are to meet performance requirements.

Petroleum product specification have been improved in the power sector primarily by reducing the sulfur content of diesel (gasoil) and fuel oil, though it is also possible to control sulfur emissions after combustion. However, a fuel that is more environment-friendly is just one of many complex and interrelated issues involved in fuel selection. "Cleaner" fuels can reduce harmful emissions, but, for example, a greater reduction in total net pollution might actually be achieved by increasing a power plant's thermal efficiency rather than improving fuel quality. Progress in this area has been substantial over recent decades, with the energy efficiencies of many newer combined-cycle types of power plants now attaining as much as 50% increases over the power once obtained from the same volume of fuel using traditional steam generation technologies. There are strong signs that further thermal efficiencies will be found in combined-cycle power plants in the near future.

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8. The average exchange rate for 1997 was approximately US$1.00 = 8.3 RMB yuan.

While the trend has been toward cleaner fuels, plans for future fuel specifications within the APEC region vary widely among economies. Not surprisingly, an economy's progress toward tighter product specifications is strongly related to income levels. Environmental standards related to fuel specifications are tightening rapidly throughout the APEC region. Standards developed for the California Air Resources Board (CARB) are widely held to be the world's most stringent specifications. CARB was the first to introduce the strict specifications that led to fuel reformulations to improve California's air quality. Although not as strict as CARB, the rest of the United States is also adopting strict petroleum product specifications. Developed economies in the APEC region, such as Japan and Canada, have followed the US example. Japan has always applied the strictest standards among Asian APEC economies, followed closely by Korea and Chinese Taipei. Some economies that have only recently experienced rapid industrial growth are now strengthening their environmental standards more rapidly than many developed economies.

Japan and Chinese Taipei moved during 1997 from 0.2% weight sulfur to 0.05%, a standard adopted earlier for most diesel formulations in the United States and Canada. Korea and Thailand will apply the same standards in 1998 and 1999, respectively. Singapore and New Zealand presently set limits as high as 0.3% sulfur, while Malaysia and the Philippines will reduce permitted sulfur in diesel to 0.5% in 1998 and by 2000, respectively. Malaysia, Singapore, and New Zealand will move toward 0.1% or 0.2% sulfur by 2000. Similarly, Australia will move from 0.5% sulfur to a range of 0.2% to 0.05% for some uses by 2000. Other economies still apply 0.5% sulfur standards, but many plan to reduce the content to 0.2% or 0.3% by 2000.

Tighter sulfur specifications for fuel oil have been applied to the power sector and to a lesser extent to industry. Japan has always limited its fuel oil sulfur specification below 0.3%. Korea has recently applied the same specification for power sector use in urban areas and to 0.5% for other uses and for power production outside of the cities. Chinese Taipei has reduced fuel oil sulfur levels from 1% to 0.5% while Thailand's fuel oil sulfur specification is now 2% (1% in urban areas) and will be dropped further to 1% (0.5% urban) by 2000. Australia has a strict emission limit that has required power plants to install flue gas desulfurizers (FGD) and to use low-sulfur (usually 1-2%) fuel oil. (The use of FGD is also mandated in several other APEC area economies.) Some other economies still consume 3.5% sulfur fuel oil but will progressively move toward 2% or 1% limits.

Unfortunately, APEC area economies have not extensively consulted with each other regarding tighter fuel specifications. This failure to consult might disrupt the international fuel market, because specification differences can alter price differentials among crude oils, between crude oil and oil products, among alternatives to oil products, and among grades of the same product. Economies may benefit through coordinated fuel specification policies, because such coordination would permit the oil industry to adjust more easily to new product standards. This would facilitate more efficient product trading, giving stronger signals to investors in such activities as refinery expansion and upgrading. For example, economies might announce a clear timetable for future specification changes after such a consultation process. This would help to smooth any transition, given industry readiness in such a move.

3.2.7. LPG and Its Supply Potential

Liquefied petroleum gas (LPG) is any of a variety of propane-butane mixes. (Some LPG data include ethane and some propylene as part of LPG for statistical purposes.) LPG is a product whose characteristics lie between oil and gas. It is a gas under ambient conditions but liquefies when pressure is increased or temperature is lowered. LPG can easily be confused with the term natural gas liquid (NGL). There is some overlap between the two concepts, because NGL also contains propane and butanes. In a broad sense, NGL refers to hydrocarbons heavier than methane, thus it includes both true LPG and other light oil products.

LPG can compete with naphtha and other middle distillates for petrochemical production and with natural gas, coal, liquefied coal gas, and even electricity in the residential and commercial sectors. Because LPG is relatively easy to store, transport, and use, it can be supplied to markets in either large or small volumes. This contrasts with natural gas, which requires a rather large minimum market scale to be available at low costs. While LPG can be used for power generation, few economies actually do that because of the higher value of LPG in other uses. LPG thus is more expensive than alternative power fuels. In developing economies where energy substitutability is low, LPG can greatly enhance interfuel competition and improve energy market efficiency in urban areas.

The APEC area, especially Asia, constitutes a large LPG market. Most Asian APEC economies are net importers of LPG, with the exception of Singapore and Indonesia. Japan is the largest LPG importer in the APEC region, with an actual import of 473,000 b/d in 1996, followed by Korea at 151,000 b/d and China at 113,000 b/d. The LPG market is growing rapidly in China, where it is used for cooking and other residential and commercial purposes. Indonesia is the largest LPG exporter among the Asian APEC economies (74,000 b/d in 1996), followed by Singapore (23,000 b/d). New Zealand is a small LPG importer, while Australia exported 37,000 b/d in 1996. Most Australian LPG comes from gas processing plants and not from refineries.

More LPG is consumed in the United States than in all other APEC economies combined. The United States consumed slightly over 2 million b/d of LPG in 1996. More than 99% comes from domestic gas processing plants and from refineries. Canada also trades some LPG, though Canada's 1996 LPG consumption (222,000 b/d) was mainly from domestic sources. Both Canada and the United States have a sizable LPG potential from their gas resources. Mexico imported 41,000 b/d of LPG in 1996 but also exported 28,000 b/d. Mexico's overall LPG consumption was 387,000 b/d. Chile imports more than half of its LPG needs.

The Middle East dominates the international LPG trade¾not just the East-of-Suez market, but also the world trade. The Middle East accounted for over 60% of the world's large-cargo LPG exports in 1995 and over 80% of the seaborne LPG trade in the East-of-Suez market. The Middle East produced slightly over 1 million b/d of LPG in 1995, 80% of which was exported. Saudi Arabia alone accounted for nearly 500,000 b/d of Mideast LPG exports. The reserves-to-production (R/P) ratio of the Middle East remains the highest worldwide. Gas processing is the major source of LPG production in the Middle East, as it is in the United States. Saudi Arabia has the largest gas processing capacity in the Middle East, but Saudi Arabia's LPG-based petrochemical industry is expanding. It is not clear whether Saudi Arabia's LPG export availability will be maintained in the future. However, LPG supplies from Iran and Kuwait should increase, adding to total Mideast LPG export capacity. LPG expansion projects in Qatar and Abu Dhabi will also ensure the Middle East's position as the world's most important LPG exporting region.

Latin America also has substantial gas reserves. Mexico, Venezuela, and Argentina are the region's three largest gas producers, and each has substantial gas processing capacities. Gas processing plants play a significant role in LPG production in these three economies as well as in Bolivia. Gas processing plants account for over 90% of Venezuela's LPG production and over 60% of Argentina's. Presently, Latin America's gas trade operates mainly on a regional basis. There are several plans to expand gas processing and refinery capacities. However, growing environmental concerns in the region imply that most of the future gas production will be absorbed by domestic markets. Thus the amount of LPG available for trade outside the region might not increase sharply, despite the expansions.

Russia and Central Asia may hold some of the world's largest natural gas reserves. This region is a large LPG producer, even though gas processing facilities are still relatively underdeveloped. A major consideration is the high economic cost associated with the development of gas resources in Russia and Central Asia. With the exception of the Russian Far East, which includes producing fields on Sakhalin Island and offshore, the transportation costs from Central Asia and Russian Siberia to the Pacific puts the region in last place among possible LPG suppliers to the APEC area.

LPG imports, sales, and prices are not regulated in most APEC economies. Although LPG is supplied by Pertamina in Indonesia, the LPG price is set by the market. Other large economies such as China, where LPG markets are expanding rapidly, have opened their LPG sectors to foreign and private investment. In Mexico, however, LPG is supplied exclusively by Pemex, and Mexican domestic LPG prices are set at about one-third of the international prices¾an implicit government subsidy to domestic users.

Because of Saudi Arabia's dominant role in the LPG market, the Saudis have traditionally been a market price setter. Price formulas set by Saudi Arabia have, however, been changing. Saudi Arabia has discontinued the SP (selling price) formula that linked LPG price to crude oil since October 1994 and embraced a new system based on the CP (contract price) formula. CP is still set by Saudi Arabia, but it is based on spot tenders, with prices of crude and other oil products taken into consideration. The Saudi CP is followed by most other Mideast LPG exporters and used as a reference by Asia-Pacific buyers. The CP formula is used for term contracts that range from one to five years in duration and account for about 90% of Mideast LPG exports.

Only 10% of Mideast cargoes are traded on a spot basis, though the future trend is uncertain. While the Middle East will still dominate Asia's LPG market in Asia, it is uncertain how fast the Persian Gulf economies can increase LPG exports to meet the growing demand in the Asia-Pacific region. Several Mideast economies, including Saudi Arabia, plan to use LPG to produce petrochemical products, which are seen to add more value to the region's export streams. Saudi Arabia's power to set benchmark prices might therefore be challenged, if the kingdom fails to hold its share of LPG exports. The evolution of the price system established by Saudi Arabia has already shown increased flexibility. Spot prices might soon play a bigger role in shaping LPG contract prices, though markets may become more volatile. An LPG futures market might also emerge, as traders and buyers seek ways to disperse risks.

3.3. Natural Gas, Including LNG

Most issues concerning the choice of natural gas for the power industry and most barriers to the operation of the gas market stem from the fact that natural gas is a gas and thus performs and handles differently from a liquid like oil or a solid like coal. Gases present particular complications in terms of transportation and storage. Also affecting natural gas markets are the size and maturity of gas markets, how gas is priced, and how many players are active in the market.

3.3.1. Technical Issues

Gas is a bulky fuel in its natural state. About 1,000 cubic meters of marketed gas have the energy equivalence of about 7 barrels of crude oil or 1 tonne of oil equivalent (toe). But because natural gas also lacks ash (nonflammable material), its combustion is cleaner and more efficient. Gas produces far lower emissions of sulfur dioxide, nitrogen oxides, and carbon dioxide than either oil or coal. Many barriers related to the transportation and trade of gas have been surmounted by technology. Primarily, the cost of available gas technologies affects the competitiveness of natural gas compared with other fuels.

Internationally traded natural gas is shipped today either by pipeline or as liquefied natural gas (LNG) in specially designed tankers. Pipeline trade limits the transport and delivery of gas to destinations along the pipeline system. Some geographic features, such as deep-sea routes or mountain ranges, can make pipelines prohibitively expensive, if not technologically impossible. For example, in the deep-sea case, the problem of increased water pressure on a pipeline has not yet been economically overcome. Thus, a proposed deep-sea pipeline from Oman to India was tabled for cost and technology reasons. Geopolitical barriers are an even greater obstacle to pipeline trade, particularly in Asia, Central Asia, and the Middle East. For example, in APEC, geopolitics have significantly influenced plans for pipelines to Thailand from Burma (Myanmar) and to Korea and Japan from Russia through North Korea. The Western Hemisphere APEC member economies have experienced comparatively few geopolitical problems regarding their pipeline interconnections. Such pipelines in North America are extensive and growing. The southern Latin American pipeline system is also expanding rapidly.

LNG trade requires additional expensive infrastructure, including liquefaction plants and receiving terminals, as well as special tankers to handle the low temperatures required to maintain LNG as a liquid. LNG tankers have, however, a much better safety record than oil tankers, with no major spills or accidents having occurred since trade began in the 1960s. Because natural gas in its gaseous state is lighter than air, a leak at an LNG facility generally does not present severe dangers beyond the immediate site of the LNG facility itself. The technical success of avoiding accidents affects public opinion, which can influence costs and acceptability of LNG trade. The expense of liquefying gas has been made economic only by building large plants that yield economies of scale. These economies of scale are a significant market barrier.

The range of technologies available for using gas also affect the gas market. The high efficiency of gas-fired power plants, for example, improves the competitiveness of gas. Also, it is not only the economics, but the acceptance and spread of technologies, such as gas-fueled cooling, that can influence demand and pricing of gas. In this manner, technological breakthroughs might dramatically alter natural gas markets¾for example, economic conversion of natural gas to synthetic liquid fuels (such as middle distillates for transportation) using new catalysts.

3.3.2. Natural Gas Market Overview

Natural gas is the most rapidly growing major source of energy in the world today. Yet compared with oil, international trade of gas is a much newer and more limited phenomenon. While more than half of the world's oil is traded internationally in comparatively transparent physical and paper markets, over 80% of world gas production is consumed in its economy of origin. This significantly influences how gas markets operate.

The United States was the world's largest consumer and second largest producer (after Russia) of natural gas in 1996. US production reached 547 billion cubic meters (bcm) or 25% of the world total, while consumption (632 bcm) accounted for 29% of the world total (Table 14). Canada alone produced slightly less gas (153 bcm) than all of the Asian APEC economies combined during 1996. The largest producers among APEC's Asian members are Indonesia, Malaysia, and Australia. Each of these producers exports gas, but also consumes gas domestically. China presently neither imports nor exports gas except to Hong Kong which is now politically integrated with China. The United States, Canada, and Japan are APEC's largest gas consumers, with the United States and Japan the largest importers. The next largest consumers in APEC are Mexico, Indonesia, Australia, and China. Chile will soon be importing natural gas by pipeline from Argentina and perhaps also from other neighboring economies.

Table 14. Natural Gas Production, Consumption, Imports, and Exports by APEC Economy, 1996 (billion cubic meters)

Economy	Production	Consumption	Imports	Exports
Australia	29.8	19.1	0	10.1
Brunei Darussalam	11.6	n.a.	0	8.7
Canada	153	73.7	1.3	80.1
Chile	n.a.	1.7	0	0
China	19.9	17.7	0	0
Indonesia	66.5	30.2	0	35.9
Japan	n.a.	66.1	63.8	0
Korea	n.a.	13.5	13	0
Malaysia	35.4	16.2	0	19.2
Mexico	31.2	31.2	0.9	0.4
New Zealand	n.a.	4.7	0	0
Philippines	n.a.	< 0.05	0	0
Singapore	0	1.5	1.5	0
Chinese Taipei	n.a.	4.5	3.4	0
Thailand	11.2	11.2	0	0
United States	546.9	632.4	81.7	4
APEC Total	905.5	923.7	165.6	158.4

n.a. = complete data not available.

Three-quarters of international gas trade takes place through pipelines, with the United States and Western Europe the major consumers. The remaining quarter of the trade is in the form of LNG. Within APEC, about half of gas trade is among American economies, predominantly by pipeline. The other half of the international trade takes place among Asian economies and is dominated by LNG sales to Japan, Korea, and Chinese Taipei. The Asian region accounts for over 75% of the world's LNG trade, thereby constituting, with North America and Western Europe, one of the three main regional gas markets. The international gas trade among economies in southern South America promises to become yet another gas trading block over the next decade, with most of the trade taking place through pipelines.

Trade in North America is dominated by pipeline shipments from Canada to the United States (over 80 bcm in 1996), while smaller amounts of gas are exported to Canada from the United States (1.3 bcm). Gas trade between the United States and Mexico (now less than 1 bcm) promises to grow. North American trade constitutes about 25% of world pipeline trade, or 20% of total world gas trade. Gas prices are variously linked to gas transactions in the extensive, deregulated pipeline network of North America as well as to fuel oil, the primary competing fuel for natural gas. With the deregulation of the US pipeline transmission system there is technically no reason why Canadian gas could not be sold in Mexico. Regional and seasonal imbalances contribute to price fluctuations. There are small volumes of LNG imports to the United States on the east coast and in Louisiana. On the US Pacific coast LNG has been exported from Alaska to Japan since 1970 (about 1.8 bcm per year). Much larger LNG projects have been promoted in both Alaska and Canada for export to Asia, but these projects are likely to take another 10-15 years.

Chile inaugurated its first international gas pipeline in mid-1997, importing gas from Argentina. More pipelines are slated for both northern and central Chile. Elsewhere in South America, another existing pipeline annually moves about 2 bcm of gas from Bolivia to Argentina. The southern South American system will also be enhanced by a planned gas pipeline linking Brazil and Bolivia. Additional pipelines are promised in the area and will also include Uruguay. This southern South American gas market is smaller in size than either the Asian or the North American markets, but is expected to grow over the coming decades.

Gas imports into the European regional market (including Eastern Europe but not the former Soviet Union) account for over 50% of Europe's gas consumption. Europe's gas supplies are dominated by pipeline shipments from the former Soviet Union, the Netherlands, Norway, and North Africa. Ten percent of Europe's imports arrive as LNG. Prices in Europe are primarily indexed to petroleum products. While Europe imports nearly three times as much gas by pipeline as North America does, markets there are still regulated, and those firms involved in the market are fewer and more integrated.

APEC economies in Asia have a small but growing pipeline system, though there has also been recent discussion regarding a grand pipeline network, much of which presently appears unrealistic and uneconomical. Only one international pipeline now exists in the Asian APEC region. This line moves gas (1.5 bcm per year) from Malaysia to Singapore. Another recently completed line brings gas from China's fields in the South China Sea to Hong Kong, China. China and Hong Kong, China are now politically united, though separate units of the APEC community, thus this pipeline is not truly international. A pipeline being built between Burma (Myanmar) and Thailand is slated for completion during 1998. Additional pipelines may follow, including a pipeline from the Natuna gas fields in Indonesia to Thailand and another from Sumatra, also in Indonesia, to Singapore. Gas pipelines from Malaysian territories to Thailand have also been suggested. A pipeline has also been proposed to connect Papua New Guinea gas supplies with northern Queensland in Australia. The planned pipeline from Natuna to Thailand might experience some delay due to the recent economic crisis and alternative gas resources discoveries in areas nearer to Thailand. Most gas pipelines in Asia involve monopoly ownership and control, though Australia has recently opened its domestic pipeline system to third-party, though not competitive, access.

Asia's individual gas pipeline projects will result in a slow and small increase in Asia's gas trade by pipeline and promise to create eventually a regional pipeline network at least within much of Southeast Asia. A more extensive gas grid will not materialize by design but will emerge only if and as the system's components become economical. Other individual projects under discussion, such as pipelines from Turkmenistan to China or Pakistan or from the Russian Far East to East Asia, have also not yet proven to be economical. In one or two instances, such as with Russia's Irkutsk gas, a heads-of-state agreement has been signed. It is possible that government policies will succeed in pushing such projects forward, even if the projects themselves are commercially uneconomical.

3.3.3. LNG Markets

LNG trade among Asian APEC economies has recently shown strong growth. This growth should continue through 2010 and most likely beyond. Commercial LNG trade began during the mid-1960s in Europe. Japan pioneered Asia's trade a few years later when it signed a long-term contract for Alaskan LNG. Though Europe's LNG trade has grown slowly, as has North America's, the 1970s saw dramatic increases in Japan's LNG imports, including contract deliveries from Brunei Darussalam, Abu Dhabi, and Indonesia (Figure 3). Japan's first ten years of imports saw annual shipments grow to over 16 million tonnes (mt) in 1980. Imports more than doubled to 35 mt per year by 1990. This rapid development of the LNG trade was a result of Japan's energy diversification program, which was initiated after the oil price shocks of the 1970s and early 1980s. Korea began importing Indonesian LNG in late 1986. Imports into Korea grew in their first ten years to over 10 mt annually. Chinese Taipei's first LNG imports arrived only in 1990, but rose to 2.5 mt per year by 1996.

Most of the exporters who dominate the LNG market are Asian APEC members: Indonesia, Malaysia, Australia, and Brunei Darussalam. US exports from Alaska also go to Asian APEC importers. Additional LNG production projects, targeted toward Asian APEC markets, are envisioned in the United States and Canada. Such interregional exports will have to compete with LNG facilities that are now being built in the Middle East. Asian APEC buyers are likely to become more numerous over the coming decades, because projects are proposed in China and possibly in Thailand and the Philippines. At the same time buyers are likely to face increased rivalry for Mideast supplies, if elaborate proposed LNG import schemes in India come to fruition.

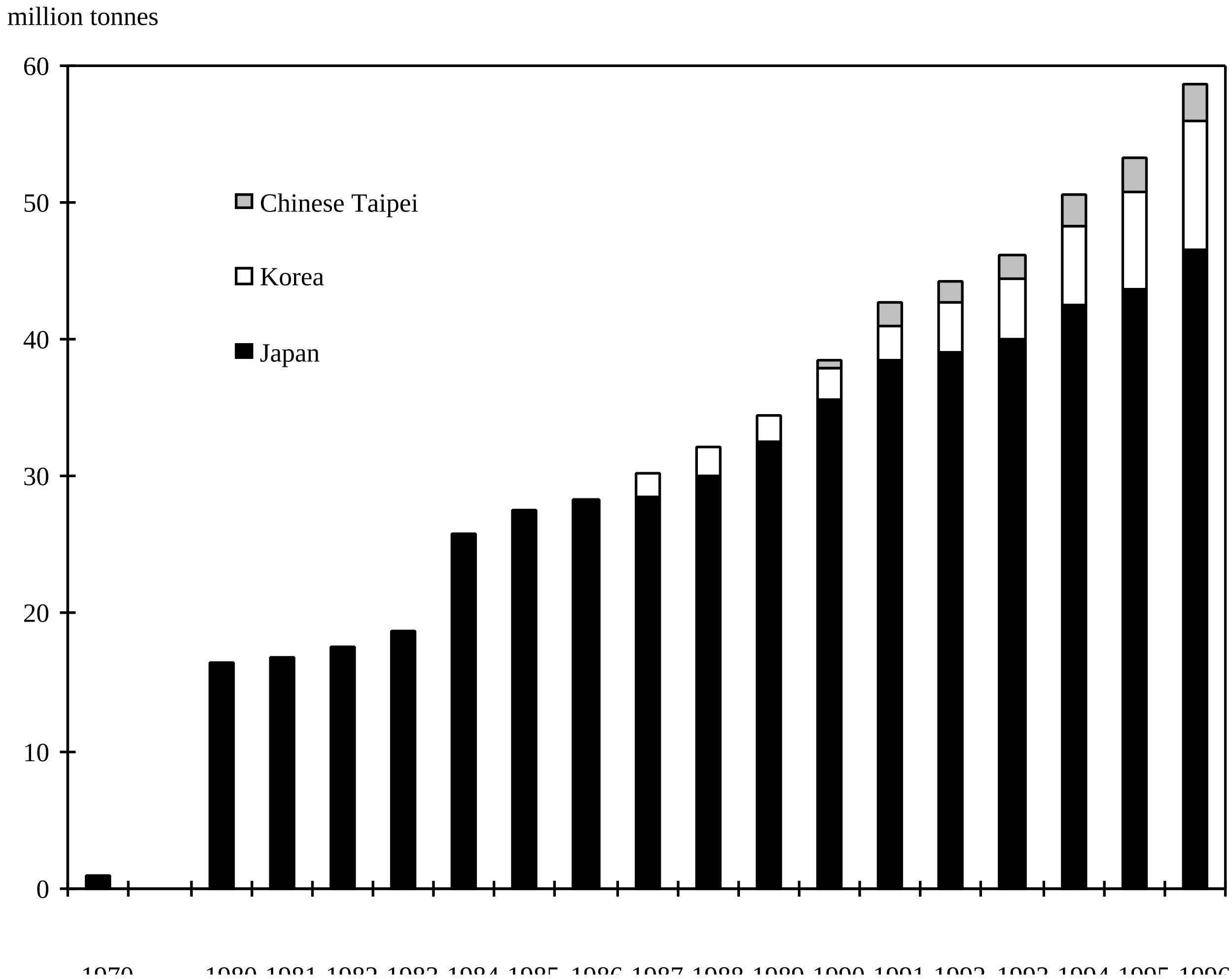

Figure 3. LNG Imports to Asia, 1974-1996

3.3.4. LNG Contracts and Pricing

Despite the rapid growth in imports to Japan, Korea, and Chinese Taipei, Asian LNG markets still involve only a few buyers and sellers. One reason is that LNG projects are economic only if they take advantage of large economies of scale. Investment costs are generally measured in billions of dollars and thus require long-term contracts (20 years or more). Such contracts were first developed during the sellers' market of the 1970s and early 1980s, when buyers were anxious to diversify their energy imports. Sellers emphasized financial security in their first contracts to ensure financing for their investments. In particular, floor (but not ceiling) prices were set, and buyers agreed to "take or pay" arrangements under which they paid for all LNG specified in the contract, whether or not they accepted each cargo.

Formula pricing in Indonesian contracts through the late 1980s was typically based on average f.o.b. prices for Indonesian export crude oils. Both the appeal of LNG and the price linkage to crude oil followed the oil crises of the 1970s and early 1980s and were associated with high oil prices. The collapse of oil prices in 1986 and the relatively low levels of oil prices that followed led to the renegotiation of LNG contracts, a direct result of the failure of the pricing formulas that had been used. Thus far, successful renegotiations have been possible, partly owing to the limited number of buyers and sellers in the market.

Plans for new LNG projects in the Middle East have recently led to several innovations in pricing formulas. A ground-breaking contract was reported in 1996 between Korea Gas Corp. (KGC) and Oman's LNG project. There is no floor in the price formula. Such floors were previously held essential to secure project financing. There is also no ceiling to the LNG price. (The existence of both ceiling and floor LNG prices has been called an "S-curve" band.) Such contract developments reflect what is increasingly a buyer's market. Shell, a participant in the Oman project, reportedly wanted to have one firm LNG greenfield project under way, while KGC used the contract as a precedent to renegotiate its earlier contract price formulas from Qatar.

Shifts in buyer and seller leverage have so far brought many new components to LNG contracts, though contracts continue to base LNG prices on crude oil prices. The persistent reliance on crude-oil-based formulas is partly due to the lack of a spot LNG market. Expensive projects involving long-term contracts has meant that new buyers and sellers cannot easily enter the market and that most of the LNG is designated for purchase before it is produced. Even so, a limited surplus capacity has led to a still small but growing number of spot transactions as well as a few shorter-term contracts (1-5 years). It remains to be seen whether the potential expansion of the LNG trade to several potential sites in India and elsewhere in Asia might lead to further evolution of the world LNG market.

Spot LNG volumes were just over 1.5 mt in 1994 but had grown 20% over the previous year to represent about 2% of world LNG trade. Spot liftings in 1995 and 1996 were heavily influenced by maintenance and refurbishing in Algeria, a key supplier. Algeria's recent entry into the supply of gas to Europe by pipeline might affect its willingness to participate in the spot LNG trade. An increase in surplus LNG capacity is also anticipated in the supply system, particularly with the completion of new production units worldwide. It is possible that as buyers and sellers multiply, they will contribute to a growing spot market and lead to LNG prices that do not rely on a crude oil price index. One suggestion that has been repeatedly proposed is to include fuels other than crude oil in the price formula, especially those against which LNG might compete. Thus, a now suspended Thai proposal to buy Omani LNG reportedly included a basket of alternative power fuels, primarily coal, in the price formula.

Shifts in buyer and seller leverage and expansion of the minute LNG spot market both reflect an growing number of participants and a consequent increase in competition in the LNG trade. Nonetheless APEC's three Asian buyer economies¾Japan, Korea, and Chinese Taipei¾have not changed in number since 1990. Neighboring India is likely to sign contracts and enter the market between 2000 and 2005. China is also another source of potential new LNG demand. Thailand and the Philippines are additional potential LNG buyers, though not realistically until closer to 2010.

On the supply side, Qatar has recently brought an LNG project on stream and plans at least two more such projects. Oman is also building an LNG facility. A number of additonal projects proposals include facilities in APEC members Australia, Papua New Guinea, Canada, and the United States, as well as projects in Yemen and Russia. While new participants might increase competition in the LNG market, the high capital cost of large-scale projects remains a potent barrier to market entry and to the operation of the LNG market. This condition limits developments within LNG market operations to a slowly evolving process. However, the potential for dramatic changes in the operation of the LNG and overall natural gas markets is dramatic, as the result of the development of new gas-to-liquids technologies that might economically transform natural gas into tradable liquid fuels utilizing much smaller-scale projects.

Governments have always played a very important role in Asia’s LNG markets. The importing companies of Korea and Chinese Taipei are publicly-owned monopolies that respond directly to government policies. This has been further facilitated by publicly-owned monopolistic electricity utility companies in the two economies. While market organization is now evolving in Korea and Chinese Taipei, the development of private, third-party importers of LNG has not been finalized, and they will not be operational until after 2000. Unless or until publicly-owned importers allow third-party use of existing import terminals, new importers will have to build their own facilities. The separation of the gas importing utility or firm from the electricity utility in Korea and Chinese Taipei has permitted the development of third-party independent power producers (IPPs) in both economies as the electricity sector in each is gradually privatized.

Such changes would eventually introduce new buyers into LNG markets and might raise imports above government targets. The impact would, however, be greatest in the operation of domestic markets. Under existing market conditions, independent power producers who plan to purchase LNG-based gas directly will not only require import terminals and possibly connecting pipelines, but will also have to commit to the long-term LNG contracts, unless they succeed in developing attractive purchasing structures such as an LNG toll purchasing scheme. A number of buyers in Japan (there are now about 20) have successfully formed a consortium. LNG buyers in Japan are, however, primarily gas and electric power utilities. This appears to have affected the access of third-party IPPs to gas for their own, competing power generation projects.

The two largest Asian APEC producers (Indonesia and Malaysia) operate their LNG export projects through large publicly-owned corporations (Pertamina and Petronas) that also oversee oil development and export. Pertamina and Petronas operate in consortia with private oil companies, though in each case, as well as in Brunei Darussalam, it is the state company that sells the LNG. One of the most important ways that state oil companies influence the market is by bringing to fruition projects that are of government interest (i.e., for their export earnings or for more political reasons). State companies are seen as having the potential to provide coordination among multiple projects that might otherwise compete. Australia, in contrast, has pursued private-sector LNG export projects to develop its substantial gas reserves. Multiple corporate interests there are vying to promote such projects. It is disputed within the LNG industry exactly how much government involvement on both the supply and buyer sides is required for an LNG project to be completed successfully.

The North American gas market provides a strong contrast to the Asian gas market. The United States and Canada, with deregulated domestic markets, also have substantial private-sector gas trade by pipeline. Mexico and Chile are also rapidly integrating their gas pipeline systems with their neighbors. Nonetheless, outside of the Americas, Australia, and perhaps Southeast Asia, APEC’s gas trade will continue to be dominated by LNG for at least the next one or two decades. As this trade continues to evolve slowly, the most pronounced barrier to gas industry development will remain the substantial investments required to expand supply and the accompanying long-term contracts that use crude-oil-based pricing formulas. Such projects have been successfully financed only when several components of the project come together simultaneously.

3.4. Coal

Table 15 contains data on hard coal production, net trade, and supply for ten APEC member economies. China is the largest coal producer in the area. Its domestic coal production exceeds the next two largest producers¾the United States and Australia¾combined. China's coal market is, however, primarily domestic, and net international trade is rather minor. Australia and the United States are the APEC region's primary coal exporters, while Japan is the most important regional coal importer. Korea and Chinese Taipei are also important coal importers. Demand for coal in those two economies is growing relatively rapidly, primarily owing to rapid increases in electricity production. While the coking coal industry is growing in much of Asia, requirements for coking coal are globally seen as growing much more slowly than the demand for steam coal. Steam coal thus drives the coal industry.

Table 15. Hard Coal Production, Net Trade, and Supply by APEC Economy, 1995 (million tonnes of coal equivalent)

Economy	Local Production	Net Trade	Supply
United States	759	71	679
Japan	5	(113)	118
Australia	183	126	54
China	972	29	940
Korea	4	(41)	40
Chinese Taipei	0	(27)	25
Indonesia	36	28	9
Canada	58	24	36
Mexico	6	(2)	8
Hong Kong, China	0	(8)	8
Total of Ten APEC Members	2,023	87	1,917

Source: International Energy Agency.
Note: Inventory adjustments are not included with data.

3.4.1. Technical Issues

Coal is not a homogenous product. It varies by class (bituminous, anthracite, lignite, etc.), by mineral content (sulfur, metals, etc.), by ash content, and by thermal content. Measurements of the sulfur content vary across the spectrum of available thermal contents of coals. Thus if it takes twice as much 1% sulfur lignite to produce the same thermal effects as it takes of 1% sulfur bituminous coal, the lignite is in fact the equivalent (on the issue of sulfur produced during use) of 2% sulfur bituminous.

Coal that is traded can be measured in "coal equivalent" values based on an assumed 7,000 kcal/kg heat content. There is in fact little coal available with this relatively high heat value, thus a more typical heat content for internationally traded bituminous coal would be 6,700 kcal/kg. Lignites tend to have around half this heat value and their heat values can be considerably lower. Some coals have such low heat value that they must be mixed with better quality coals to be usefully burned. Desired characteristics of coal will vary with the type of power generation that takes place.

3.4.2. International Coal Trade

An international steam coal market has developed over the past twenty-five years. At present the trade accounts for only about 12% of the coal produced in the world. Local production continues to predominate, however, in most economies. The success of the coal trade is partly related to the availability of natural gas alternatives within economies. Imported coal is more likely to be accepted when natural gas is not available in adequate quantities by pipeline. Thus the coal trade has grown in Asia but fallen in Europe, where natural gas has become more readily available. Such trends often reflect basic market conditions, supply costs, and environmental policies.

Internationally traded coal can be divided among steam coals and coking coals. Each type of coal is valued for different properties. Steam coal is valued for its heat content and coking coal for its chemical properties, most notably in the steel industry. Steam coal markets are growing rapidly in Asia and Latin America. Steam coal growth is slower in North America, owing primarily to competition from natural gas, but also to relatively slow electricity demand growth. Coking coal markets are growing more slowly than steam coal markets, primarily because of the relatively slow growth of the steel industry and the more rapid growth of the power sector. The recent growth of coking coal markets has been more rapid in Asia than in North America.

Coal is sold internationally on either term or spot bases. There is virtually no international market for steam coals of low heat value. Such coals tend to be commercially usable only when it is possible to set up a power plant at or near the coal source. The weight and volume of coal that must be shipped increases in proportion to the decrease in the heat value of the coal. Anthracite coals have different and generally lower heat values than globally traded bituminous coals. There is some international trade in anthracite, but not much. Generally, power plants designed to burn anthracite are technically unsuited for burning other forms of coal.

There are effectively only five coal exporting economies within the APEC community: Australia, the United States, Indonesia, China, and Canada. Canada’s coal trade is weighted more toward coking coals than steam coals, but demand for steam coal from Canada is growing slowly. Coal deposits in South Africa also influence APEC steam coal markets, especially in Asia, but because of APEC’s large coal reserves, APEC’s coal market is largely self-contained. Indian coals are not a major factor in the global steam coal trade, though India has the potential to become a steam coal importer in some coastal areas. Mexico is the second largest coal producer in Latin America after Colombia. Mexico is largely self-sufficient in coal and requires only small volumes of imports. Chile’s coal market has unique, local characteristics and is affected by domestic supplies that are becoming scarcer. Some of Chile’s market for steam coal might be displaced by imports of natural gas from neighboring economies.

The coal exporters within APEC are among the geographically largest member economies, thus some economies export coal from some regions and import coal into others. This is especially true of the United States and Canada but also to a limited extent China. A large number of the APEC economies have domestic coal supplies, though these generally have too low thermal content or too high sulfur content, or are too inopportunely located for export potential. Low thermal quality coal can be exported in the form of electricity. Thus lignite in Laos is scheduled to generate power that will be consumed in Thailand.

Coal in Australia and Indonesia is especially well located for export markets. Actively mined reserves are near the coast and coal port terminals are located near the reserves. This situation is expected to evolve, however, as export coal demand increases and as better located reserves are consumed. It is expected that future expansions of coal export capacities in Australia and Indonesia will be located further inland. New terminals would also have to be built.

Coal reserves in the United States and Canada are generally located in more inland locations, though rail systems in each are extensive. The United States also has an extensive inland river system that has likewise been developed for coal transportation. While coal deposits are scattered through both economies, deposit locations are often more suited for domestic consumption or for export into the Atlantic Basin. Nevertheless both Canada and the United States export coal into the Pacific area as well.

China's coal deposits are also located well inland. China is now the world's largest coal producer and consumer. China's extensive commitment to coal-fired power production has forced it to dedicate substantial portions of its growing rail system to coal transportation. Coal deposits are dispersed, though the best reserves are in Shaanxi, Shanxi, western Inner Mongolia, and Xinjiang.

Other APEC economies that mine coal include Thailand, Malaysia, New Zealand, Korea, Mexico, Chile, the Philippines, and Japan. Coal qualities vary considerably among these economies, as do transportation facilities. Generally these economies do not possess substantial volumes of export quality coals, though the coals might be suitable for some power production. The allocation of coal reserves presents many member economies with an economic and policy choice between promoting domestic coals of lower thermal quality (or higher sulfur or ash content) or using higher quality imported coals. Japan and Korea, for example, mandate the use of an amount of locally mined coal in their power plants. The option of using fuels other than coal is, of course, also available. Quite often, competition among coal sources is local within an economy, thus domestic coal might receive market preference in inland locations, while the choice between imported or domestic resources might be important in coastal areas. In some cases, such as the Philippines, where domestic coals are particularly poor in thermal quality, imported and domestic coal markets are complementary, because of the incentive to mix both types of coals prior to burning.

Because coal is expensive to develop and transport, international steam coal trade depends heavily on ready access to coastal port facilities and in some cases to river and canal transportation at both production and consumption ends of the power industry. Economies such as China, India, and the United States, which have inland coal deposits, have found that power production or coal exports at locations remote from coal supplies can tie up considerable portions of their rail, road, river transportation, and port systems. China in particular plans to build a number of rail lines primarily to deliver coal to power plants. In some cases the choice is made to generate the electricity at the mine and to transport the energy from the coal as electricity by transmission wire. This is especially the case for low thermal quality coal or when the coal is located at a great distance by land from its power market.

The trade of coal is restricted heavily by the size of ship that a port can handle and by the route the coal must take. Coal in much of the world must either transit the Cape of Good Hope in South Africa (Capesize vessels) or the Panama Canal (Panamax size). The terms, however, frequently refer to vessel size and not to transit routes taken. Panamax vessels are the smaller size. Freight rates cycle considerably over a year, generally being lower during the northern hemisphere's summer. Rates also cycle over a number of years. Typically Panamax rates are 160-180% of the Capesize rates, because the Panama Canal cannot handle larger vessels. In the case of Chinese Taipei, the power utility, Taipower, owns a large coal fleet. This particular fleet is generally of Panamax size, though rates are held below commercial Panamax rates. This makes it economically possible for Taipower to use a much higher percentage of Panamax vessels than would otherwise be expected. It also precludes foreign shipping from being used for much of the Chinese Taipei coal trade.

3.4.3. Trade Barriers

It would be difficult to establish that direct impediments dominate the world coal trade, though impediments are widespread. Something of a global market for coal has emerged. If there is a bias that affects the trade of coal, it is tariffs, which by their nature are designed to protect local interests. These interests can reflect domestic revenue requirements, environmental policies, and the desire to protect local interests over international ones. The general trend in tariffs has been downward, as liberalization progresses in most economies. In the case of some regional agreements such as NAFTA and ASEAN, tariffs and trade arrangements favor regional (member) economies over the APEC region as a whole. Another impediment to liberalized coal trade is the licensing and contract approval systems that exist within many APEC economies. Such licenses include import licenses and contracts to supply coal to particular customers, generally power plants. Tariffs by their nature put importers at a disadvantage. These carry with them the possibility of favorable treatment for domestic producers at the cost of imports. There has been a region-wide tendency to relax or eliminate such policies to the extent that they are discriminatory.

3.4.4. Environmental Considerations

Coal also presents environmental concerns that can seriously curtail access to markets. Steam coal consumption produces the highest volume of carbon dioxide in proportion to fuel consumed among the fossil fuels. Coal mining can also result in the release of quantities of methane, another potent greenhouse gas. (Coal bed methane is now proving to be a separately marketed product of coal fields, when present in sufficient volumes.) Policies designed to curtail global warming thus contain a bias against coal mining, consumption, and trade.

The coal industry has responded to such concerns primarily through technological improvements such as pressurized circulating fluidized bed (PCFB) combustion and integrated gasification combined-cycle (IGCC) plants that are beginning to receive industrial acceptance. Generally, if the thermal efficiency of a coal plant is improved (most clearly the case for IGCC plants), the carbon required to generate a given volume of power will decline.

Coal consumption is also associated with acid gas (carbon, sulfur, and nitrogen oxides) production. Sulfur and acid gas production are also associated with the sulfur content of particular coals, while nitrogen oxide production is attributed to the types of burners used in power plants. Acid gases can also be reduced after combustion or through the technology used in generating power. Such technologies include scrubbers, flue gas desulfurization (FGD), and the new power plant types, such as PCFB and IGCC. Such technologies can reduce acid gas production for coal to levels competitive with other fuels, but often do so at a cost. That cost can in some cases change the competitive position of steam coal, making it less attractive relative to other fuels such as piped natural gas, liquefied natural gas, and some oil products.

Coal is also associated with high particulate and solid waste production. Some of the newer coal technologies also involve increased levels of solid waste production. Such solid waste products often have higher concentrations of some heavy metals which have also come under growing, recent regulatory scrutiny. These problems vary with the type of power plant technology used and with the quality of coal consumed. In some cases secondary markets have developed for some of the solid waste by-products of the coal-fired power industry.

An array of technologies have been developed to reduce the production of particulate matter, acid gases, and greenhouse gases from the consumption of coal in power plants. Generally included with these technologies must also be added technologies that increase the thermal efficiency of coal burning to produce electricity. These technologies, collectively called "clean coal technologies," have gone a long way toward mitigating the adverse effects of coal consumption on the environment. There are also certainly promises that further technological improvements in the area of coal will occur.

Despite the improvements in coal consumption technologies, coal is the fuel that is most likely to be severely affected under the Kyoto Protocol on global warming that was written in November 1997. Under the protocol, developed economies (called Annex I parties in the protocol) are required to reduce their production of greenhouse gases below agreed 1990 levels that were set during the negotiations of the protocol. Six greenhouse gases are defined under the protocol, the most notable being carbon dioxide, methane, and N_2O. Some exchange of greenhouse gas emission levels is permitted under the protocol. Annex I economies within the APEC region are Australia, Canada, Japan, New Zealand, and the United States. This right to exchange emission rights tends to favor Annex I nations in the former Soviet Union (Russia and the Ukraine specifically) where energy consumption has markedly declined during the 1990s. The remainder of the world's nations (Annex II parties) were not placed under specific greenhouse gas emissions standards. It remains to be seen whether a sufficient number of Annex I nations will accept and ratify standards set under the protocol. If they do accept the standards, Annex I parties will most likely have to reduce their coal consumption, though such reductions might be partly offset by Annex II increases.

Additional environmental policies toward coal vary markedly among APEC member economies, but generally the environmental concerns related to coal have led to regulatory environments that are sometimes discriminatory against coal. The primary concern regarding the promotion of an equitable coal trade is thus that (1) comparable rules are applied to domestic and international coal and (2) competition among fuels is governed by cost differences in meeting criteria such as environmental performance standards.

3.5. Nuclear Fuels: Uranium and Other Nuclear Fuels Market Issues

Seven economies in the APEC region have commercial nuclear power reactors: Mexico, the United States, Canada, Japan, Korea, China, and Chinese Taipei. Several other APEC economies have also looked at establishing commercial nuclear power programs, including Indonesia, the Philippines, and Thailand. These last three economies are, however, still several years away from a full commitment to nuclear power programs. New Zealand has committed itself to never having a nuclear power program, while Australia, which once cleared a site for a nuclear power plant, appears to no longer consider nuclear power desirable for its power program.

3.5.1. Planned Nuclear Market Developments

Several economies in APEC have committed themselves to vastly expanding their nuclear power capacity by 2010. Targets for 2010 include 70 GW in Japan, 26 GW in Korea, and 20-22 GW in China. Chinese Taipei also hopes to complete at least two additional nuclear power reactors during the next decade. These reactors are, however, a politically sensitive issue in Chinese Taipei, and there is vocal parliamentary and private opposition to their completion. The United States and Canada, in contrast, are no longer building nuclear power plants on their own territory. Canada's largest nuclear utility, Ontario Hydro, has recently investigated mothballing seven of its twenty-two nuclear reactors on the grounds that Ontario Hydro does not have adequate personnel to safely manage all of its reactors. It is at the moment uncertain whether these reactors will be permanently closed or whether changes will be made in their management. Construction schedules in economies committed to building additional plants by 2010 often run behind targets, with Japan's nuclear program particularly delayed. Korea generally finishes its projects before scheduled completion dates, while China completed its three operating reactors roughly on schedule.

Nuclear construction schedules are relatively easy to project into the near future, because it takes around eight years to build a nuclear power plant, if all goes well. (Some plants have been built in as few as six years, but this has not been a universal experience.) An even longer period of time is needed to plan for the building of nuclear power plants. The projection of Asian nuclear capacities shown in Table 16 is based on ongoing plant by plant analysis conducted at the East-West Center. There is some judgment involved in the numbers to allow for anticipated delays in construction and site selection schedules and a very small number of plant closings. Numbers generated by agencies such as the International Atomic Energy Agency would be somewhat higher. The period 2008 to 2010 must be regarded as particularly tentative, because construction has not yet begun and in some cases public announcement of site selection has not occurred. The data do not include North American nuclear plant capacities, which should decline by 2010 because no new reactors are being built and several reactors will be retired.

Table 16. Projected Nuclear Energy Capacities in Selected APEC Economies, 1997-2010

Economy	Nuclear Capacity (MW) 1998	2008	2010	Average Annual Growth, 1998-2008 (%)
Japan	45,362	52,230	54,680	1.4
Korea	12,016	20,716	22,716	5.6
China	2,100	10,670	11,670	17.7
Chinese Taipei	5,148	7,848	7,848	4.3
Total	64,626	93,464	96,904	3.7

Source: East-West Center

3.5.2. Nuclear Fuels

Three radioactive elements (thorium, uranium, and plutonium) have been proposed for use in power reactors.[9] Of these, only uranium is significant in commercial plant operations. Plutonium (other than plutonium generated within a power reactor) has been widely proposed as a component of nuclear fuel, and India has plans to use thorium widely. Uranium as it is found in nature is not suitable for use in most power reactors, thus there is a distinction between "natural uranium" used in gas cooled reactor (GCR) and pressurized heavy water reactor (PHWR)[10] designs and the "enriched uranium" used in the more common pressurized water reactor (PWR) and boiling water reactor (BWR) designs. PWRs and BWRs are sometimes grouped as light water reactors (LWR). Several other classes of reactors have been developed, though most are not presently important in the energy sectors of APEC economies. There are also several experimental reactor types that might eventually become important in the power reactor business, but are not presently significant.

"Natural uranium" is uranium as it is found in nature. The key defining component of natural uranium is the ratio of the two principal naturally occurring isotopes of uranium, U-235 and U-238. In natural uranium only about 0.72% of the uranium is U-235. Because of its fission characteristics, U-235 provides most of the energy used to produce power in a commercial nuclear reactor.[11] If the share of U-235 is more than 0.72%, then the fuel is called "enriched uranium." If there is less than 0.72% U-235, it is called "depleted uranium." Uranium used in an LWR is enriched to 2-5% U-235, with variations depending on the particular reactor design. The enrichment of uranium (or any other nuclear fuel) is an expensive manufacturing undertaking. Because of the handling properties of uranium, pure uranium is not usually used in reactors. Generally uranium is used within nuclear reactors in the form of uranium oxides, though other uranium compounds might be used.

9. Research reactors are not discussed in detail in the following presentation.

10. PHWR and GCR reactors amount to only about 10 percent of world power reactor capacity.

11. Some of the U-238 in the uranium fuel is converted to plutonium in the reactor. This plutonium can provide as much as 40% of the energy used in a nuclear reactor.

Uranium is not a scarce material and is found in minable quantities at many locations around the world. Among the APEC economies that mine uranium are Australia, Canada, the United States, and China. Globally Namibia, Niger, Russia, Kazakhstan, and South Africa are also major uranium suppliers. The uranium export industry has generally faced low prices because of the relative abundance of ores. It is not anticipated that prices will rise significantly in the future. The industry has recently faced competition in the form of uranium produced from weapons-grade uranium and plutonium obtained from dismantled nuclear weapons from the Russian Federation and the United States. This weapons-grade material is of course heavily diluted prior to sale.

Success in the uranium mining industry depends heavily on the cost of production and on domestic and international regulations that include or exclude uranium supplies from the world market. Generally shipments of natural uranium are not regulated, and natural uranium can be transferred under spot or term contracts. Enriched uranium transfers are extensively regulated. Several APEC economies, notably Australia and Canada, are among the lower cost producers and thus play a major role in the world uranium trade. The United States also exports uranium. China's uranium market is primarily domestic. There is also a history of antidumping procedures in the United States and import limitations in the European Union taken against nondomestic uranium suppliers. Such actions have been directed notably against suppliers in the former Soviet Union.

Nuclear fuels (specifically enriched uranium) are generally regarded as low in cost, owing to the low price of natural uranium. This is, however, only one of the many costs involved in processing uranium ores. The International Atomic Energy Agency estimates that uranium feed constitutes only 25-30% of the cost of enriched uranium costs. Other major sources of costs are enrichment (30-35% of costs) and fuel fabrication (15-20%). Reactor designs that use natural uranium do not have to incur the high costs of enrichment.

With the notable exception of an anomaly in Gabon, plutonium is not known to occur in more than trace amounts in nature. Thus all plutonium used in nuclear power production is a by-product of nuclear reactor operations. One potential source of the plutonium is power reactors, though other reactor types also produce plutonium, often in greater quantities. In an LWR, the U-235 content declines as the nuclear fuel produces electricity. That is, the uranium is "depleted" as the share of U-235 declines.[12] Some of this depletion takes the form of lighter elements originating in the fission process that leads to the reactor's energy output, while neutron capture in U-238 transforms the U-238 into the heavier element plutonium. The total volume of fissile material (U-235 and plutonium) declines during the power creating reaction, though the level of plutonium in the spent fuel will increase from an initial level of near zero. For example a typical fresh LWR fuel starts with 3.5% U-235 content and normally ends as spent fuel with 0.9% U-235 and 0.6% plutonium in the spent fuel. The U-235 and plutonium content of the spent fuel can of course vary according to operating procedures at the plant. U-235 content in the spent fuel is typically in the 0.6%-1.0% range. The energy content of the used fuel would be roughly 30% of what the fresh fuel initially contained.

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12. Depletion here refers to the decline in U-235 content.

Plutonium is physically more difficult to handle than uranium, thus it is not used separately from uranium in power reactors. (The weapons potential of plutonium also makes direct availability of plutonium for commercial power reactors undesirable.) Instead, plutonium oxides are usually mixed with enriched uranium oxides into a fuel known as mixed oxide (MOX). MOX is much more readily handled than plutonium. Plutonium produced in the power reactor as it operates does contribute to the fission-based energy generated by the reactor. Thus technically all reactors use mixed oxides. Manufactured MOX fuels are generally considered more expensive and less efficient power reactor fuels than enriched uranium-based fuels, thus MOX fuels have not become widely popular among commercial reactor operators. MOX fuels are usable in most reactor types including GCRs and PHWRs that were originally designed for natural uranium. MOX can also be used in LWRs. The use of MOX fuels based on reprocessed material would result in a net decrease in the net volume of fissile material in spent reactor fuels. For this reason, MOX fuels based on reprocessed spent fuels have been proposed as a means of reducing the content of high level radioactive wastes coming from LWRs. This would also increase the energy derived from a given initial volume of enriched uranium fuel.

The economics of MOX fuels is generally considered adverse because of the low cost of competing uranium fuels and the high cost of reprocessing plutonium. This economic situation has become more adverse to spent-fuel-based plutonium in recent years, because economies that are reducing their weapons-grade plutonium and enriched uranium stockpiles (the United States, the Russian Federation, the United Kingdom, and France) are increasingly making this plutonium available, in diluted form, as a source of MOX fuel. Such former weapons-grade plutonium would be available at lower costs than plutonium originating from spent reactor fuels and would have the added benefit of reducing the world's present stockpile of weapons-grade nuclear materials. Thus the production of plutonium for MOX use is presently highly discouraged by basic economics as well as by an absence of sufficient capital-intense reprocessing facilities.

3.5.3. Nuclear Fuel Cycles

If an economy is committed to recover and use both plutonium and uranium generated in spent fuels as a source of power for its commercial nuclear reactors, the economy is said to operate its nuclear power system on a "plutonium cycle." Among the APEC members, only Japan is firmly committed to developing a plutonium cycle for its commercial power program. Plutonium cycle programs are usually associated with "fast breeder reactors" (FBRs), a class of reactor which can generate more plutonium and U-235 in their spent fuel than they consume in their power reaction. This occurs primarily through the conversion of U-238 into plutonium during the irradiation process. Many anticipate that breeder reactors will become important in the future, though, apart from the Russian BN 600 reactor, no breeder reactor has yet attained large-scale commercial status for a sustained period of time.

Japan's plutonium cycle commits it to reprocessing the spent fuels from its commercial and research reactors. There is not presently sufficient reprocessing capacity in Japan to handle the spent fuels that have been selected for upgrading to plutonium/MOX status. Japan therefore sends a volume of spent fuels to France and England to be reprocessed. For safeguard and safety reasons, unique controls have been placed over the transportation and processing of enriched uranium and plutonium. Safety and health risks have also been suggested as reasons for controls over nuclear fuels shipments, though this is a topic that has raised much controversy.

Japan is building a reprocessing center at Rokkasho-mura that it hopes will reduce the need for long-distance shipping of nuclear materials. Published reports place the cost of Rokkasho-mura as high as $20 billion, though this has been denied by its sponsors. This plant has been subject to considerable delay. Thus much of any cost would be interest during construction, which might not have been incurred if schedules had not been interrupted.

There are alternatives to the plutonium cycle. Most are considerably less expensive. The United States generally follows a "once-through" policy under which most spent fuels (primarily derived from enriched uranium) from nuclear reactors are disposed of after they are removed from a commercial reactor. There is thus essentially no reprocessing. (If some reprocessing of spent fuels occurs, the fuel cycle is called a "closed fuel cycle"¾yet another approach to spent fuels that is popular in many economies.) The US policy intends to bury most such wastes underground in a site at Yucca Mountain. This program has also been delayed through the political process and is now ten years behind the original schedule of opening during 1998. Costs of implementing the Yucca Mountain project have also been enormous.

The US policy is in the process of being somewhat modified, in that diluted weapons-grade plutonium from dismantled weapons have been proposed for inclusion in commercial nuclear fuels. The initial power reactor fuel would thus include MOX fuel in addition to enriched uranium-based fuels. The United States and the Russia Federation have agreed to dilute 500 tonnes of highly enriched uranium (HEU) from Russia for use in the world power market over the next fifteen years.

Candu type PHWR reactors and GCR reactors can and do accept fuels that include plutonium. In the APEC region, Canada and Korea both have Candu reactors, and China is considering building some. Korea is investigating using its Candu reactors as a means of burning part of the remaining fissile material from spent fuels produced in its more numerous PWR reactors. Several economies in APEC beyond Japan are investigating building further reprocessing facilities, which might convert their fuel systems to a closed fuel cycle, while Japan has temporarily closed its FBR at Monju and portions of its small reprocessing plant at Tokkai-mura following accidents.

3.5.4. International Nuclear Fuel Policies and Regulations

It has become the practice of the international nuclear community to subject all nuclear technology transfers and nuclear materials markets to full scope safeguards as a means to avoid any link between nuclear power generation and the production of nuclear weapons. The two most conspicuous examples of this policy association, India and Pakistan, lie outside the APEC region. Similar concerns by the United States (and others) that China (and others) might be exporting nuclear weapons technology were used as a basis for curtailing the transfer of nuclear power technologies between those two economies. This particular policy example has recently been reversed, though such policies are likely to be imposed by economies suspecting others of similar asserted evasions of international nuclear weapons safeguards.

Nuclear fuels require careful handling, including at their disposal stage. The major health and safety hazards are radioactivity, criticality (i.e., the potential for uncontrolled and unintended radioactive reaction, including explosion), and their chemical reactivity. These issues plus the threat of diversion of nuclear materials to weapons activities have led to strict controls over the international shipment and storage of nuclear fuels (enriched uranium, spent fuels, plutonium, and

MOX fuels) and many other nuclear materials. Natural uranium is not included under most of these regulations and is transacted in relatively competitive markets.

Civil plutonium inventories are monitored under guidelines set through the International Atomic Energy Agency (IAEA). The issue of plutonium and enriched uranium shipments has been a particular concern in Japan, where the reprocessing facilities now available are inadequate for present and anticipated requirements under nuclear industry development plans. This has led to careful controls over the shipment of plutonium and other nuclear fuels that are reprocessed for Japan in facilities located in the United Kingdom and France. Economies adjacent to the shipment routes have set strict conditions for the transit of such fuels, in some cases extending to the banning of shipments through their waters. The exact trend in Japan's plutonium inventory is now an active issue of debate, though it is known to be growing, owing partly to delays in the scheduling of components of Japan's nuclear program.

There are also strict international standards for the use and monitoring of nuclear materials in power reactors. Under the Nonproliferation Treaty (NPT) these standards are overseen by the IAEA, by local and regional nuclear agencies and associations, and through cooperative agreements. Some disagreement (mostly outside the APEC region) has occurred in some economies over a division of IAEA monitoring functions between power and research reactors. Most economies that control nuclear power technologies insist that international monitoring procedures and agreements include both power and research reactors, while some economies would prefer to confine international monitoring to power reactors. Because of the higher level of enrichment that is used in fuels for many research reactors (as high as 20% U-235) and because of the high cost of enrichment, most weapons material is produced at "research" reactors rather than at power reactors. A general, though not universal, criterion that has been applied is that nuclear technology transfers are withheld if an economy does not permit the inspection and monitoring of nuclear materials at both power and research reactors.

Nuclear power plant design is subject to safety controls. Such controls can have both domestic and international origins. These include power plant design requirements, the operating procedures at nuclear power plants, and the disposal of the various grades of radioactive wastes produced at such plants. The heart of the debate over nuclear power "safety" rests on the perception of adequacy of such requirements. Because such requirements often involve considerable expense, the safety issue is intimately related to the commercial viability of nuclear power plants.

Assessments of safety requirements vary among economies. Generally, present safety requirements along with relatively low fossil fuel prices have contributed to making "safe" nuclear power plants commercially unviable in most economies worldwide. Capital costs of building a given capacity of nuclear power plants are generally two to four times the costs of building equivalent fossil-fuel-based power capacity. Construction times for nuclear power plants also take from two to four times as long as is required to build a fossil fuel plant. This is partly due to safety requirements. Interest incurred during construction is consequently a large portion of the cost of building a nuclear power plant.

While nuclear fuel costs are generally much below the fuel costs in a conventional fossil-fuel-based power plant, this cost advantage can be largely offset, owing to the high operation and maintenance costs required by safety standards applied at a nuclear power plant. Moreover, further cost advantage of nuclear fuels might be lost if an economy implements expensive reprocessing procedures to handle spent fuels.

While nuclear power might presently not meet most commercial criteria for construction, nuclear plants continue to be built in the APEC region and will continue to be built into the future. Justifications for building nuclear power plants range from energy security arguments (which maintain that nuclear power reduces dependence on offshore energy resources) to environmental arguments (which point out that nuclear energy has no greenhouse gas, acid gas, or particulate disposal problems). It has been pointed out that compliance with greenhouse gas levels set under the Kyoto protocol of late 1997 will be difficult to attain in many economies without a simultaneous commitment to nuclear power. The environmental benefits are of course partially offset by concerns related to radioactive materials produced at nuclear plants, which are an entirely different family of environmental concerns. Generally nuclear power alternatives are favored when these noncommercial considerations are seen as offsetting the financial or commercial disadvantages of nuclear energy investments.

Nuclear fuels provide an example of a regulatory environment that might not be improved through deregulation or liberalization. A “best practice” in the handling of nuclear fuels is thus arranged through domestic and international policy-setting procedures, with the understanding that any imposition of regulation might commercially disadvantage nuclear fuels compared with other primary fuels. International regulatory practices have been used to exclude certain economies from developing nuclear power options, though this is generally not the case among APEC economies, where the extent of nuclear power activities is heavily the product of policy decisions and of the basic economics for and against building nuclear power plants.

3.5.5. The Future of Nuclear Energy

It would be easy to misunderstand the summary of the problems related to nuclear power in the preceding discussion. Nuclear fuels have a considerable number of commercial and risk-based disadvantages relative to other primary energy products. These are likely to leave nuclear-based power relatively unpopular during the first decade or more of the coming century. This is not to say that all nuclear investment will stop. Nuclear also has many advantages, particularly if energy security is a major policy concern. Many technological, safety, political, and cost based problems related to nuclear energy will continue to be addressed over the coming period. At some point growth in nuclear energy use is likely to be restored, even if the share of nuclear power in the immediate future is likely to decline.

3.6. Choice of Fuels from an Environmental Perspective

Environmental considerations influence the fuel choices of parties within APEC in several different ways. Publicly-owned power utilities such as Taipower in Chinese Taipei and KEPCO in Korea and regional power utilities such as those of Japan are often more directly influenced by environmental policies than are power producers that operate within a more competitive environment. Today, many power providers operate in a contract-based production environment that lies somewhere between these two extremes. These power producers seek to maximize financial rewards, but are still rather directly subject to policy influence. When power producers can make fuel choices that are not entirely profit driven, concerns about the environment and energy security can be intertwined and difficult to distinguish.

3.6.1. Environmental Considerations

Some environmental considerations are incorporated into markets via prices, affecting all players similarly and making decisions clearer and more financially based. For example, cleaning emissions when higher-sulfur coal or oil are used might be more or less expensive than meeting the same standards when low-sulfur coal or oil is used. Price differences have thus become associated with sulfur levels of coal or oil products, partly owing to environmental standards regulating the volume of sulfur that may be released into the environment or contained in the fuel. Table 17 shows emission standards for new coal-fired power plants in APEC economies,

Table 17. Emissions Standards for New Coal-fired Power Stations in APEC Economies (milligrams per cubic meter)[a]

Economy	Particulate Matter	SO_2	NO_2
Australia (guidelines)	100	ambient only	860
Canada (guidelines)	130	700	460
Chile	ambient only	ambient only	
China[b]	200-600	1,200-2,100	650-1,000
Hong Kong, China	50	200	670
Indonesia	250	1,500	1,700
from 2000	125	750	850
Japan	100	K-value method	410
Korea	100	1,430	720
from 1 January 1999	50	770	720
Malaysia	400	ambient only	ambient only
Mexico	475	7,610	840
from 1 January 1998	380	6,440	785
New Zealand	ambient only	ambient only	ambient only
Philippines	160-220	1,090	1,090
from 1 January 1998	160-220	760	1,090
Chinese Taipei	29	1,430	720
Thailand	400	ambient only	940
United States	40[c]	1,480	560-620

Source: Study on Atmospheric Emissions Regulations in APEC Economies and Their Compliance at Coal-Fired Plants (January 1997, APEC publication no. 97-RE-01.1).

a. Adjusted to gas volumes based on dry flue gas at standard temperature (0 degrees Celsius) and pressure (101.3 kPa) and 6% dioxide.

b. New plants built or examined and approved for construction after December 31, 1996.

c. PM-10.

Table 18. Diesel and Fuel Oil Sulfur Specifications for Selected APEC Economies (sulfur % wt)

	High Speed Diesel			Power Plant Fuel Oil		
Economy	1995/96	1997	2000	1995/96	1997	2000
Australia	0.5	0.5	0.05-0.2	2	1.5	1.5
China[a]	0.2-0.5	n.a.	0.2-0.5[b]	n.a	n.a	n.a
Indonesia	0.5	0.5	0.5	3.5	3.5	3.5
Japan	0.2	0.05	.05	0.25	0.25	0.25
Korea	0.1	0.1	0.05 ('98)	1.6/1.0[c]	1.0/0.5[c]	0.5/0.3[c]
Malaysia	0.5	.5 (.3 in '98)	0.2	n.a	n.a	1.0
New Zealand	0.3	0.3	0.1	n.a	n.a	n.a
Philippines	0.5	0.5	0.3	3.5	3.5	3-1
Singapore	0.5	0.3	0.2	n.a	n.a	n.a
Chinese Taipei	0.3	0.3-.05	0.05	1	0.5	0.5
Thailand[d]	0.5	0.25[d]	0.05 ('99)	2	2	2-0.5

a. The split of gasoil into industrial and transport is not expected in China before 1999. Imports generally have higher (45) cetane index. The 1995/96 sulfur content is the average of different grades used, weighted by share consumed.
b. Sinopec plans to produce all of its diesel with a sulfur content of no more than 0.2% by 2000.
c. Varies by area; generally urban areas have stricter specification.
d. Bangkok now requires 0.05% wt sulfur.

while Table 18 shows regulated sulfur content for diesel (gasoil) and fuel oil in selected APEC economies. With sulfur emission regulations, a coal-fired power plant operator might make choices between burning low-sulfur coal and burning high-sulfur coal with installed emission control equipment, such as flue gas desulfurizers (FGD).

Other environmental issues affecting the choice of fuels can be more complex. Nuclear and hydroelectric power plants are usually more expensive to build than fossil-fuel-based plants. Such plants also usually take longer to build. The decision to build a nuclear or a hydroelectric plant is nonetheless sometimes preferred, if an economy wishes to increase power production without raising fossil-fuel imports or consumption. Such plants also do not have the emissions associated with fossil fuels. However, concern about storing radioactive waste and fears of potential nuclear incidents have often led to public opposition to nuclear plants and at times halted or delayed nuclear plant construction. Environmental problems associated with hydroelectric power include damage to ecosystems that will be inundated and with the need to relocate the often substantial populations residing in river basins to be flooded.

3.6.2. Economic Tradeoffs

When competitive power producers chose among fuels, the decision is complicated by the economic tradeoffs among capital outlay, construction time, plant operating efficiency, and fuel costs. A number of independent power producers in Korea and Chinese Taipei now plan to build natural-gas-fired power plants. This suggests that as such economies tighten emission regulations, gas-fired power is becoming more competitive relative to coal. Otherwise coal might be viewed as the lower-cost fuel, especially when gas must be imported in the form of LNG.

There has been, so far, little or no regulation of carbon dioxide (CO_2) emissions. Thus, it is not surprising that coal still costs much less per million Btu than does natural gas, even though natural gas emits far less CO_2 during power generation. International agreements in Rio de Janeiro in 1992 and Kyoto in 1997 have sought to reduce CO_2 emissions but, because the agreements lack convincing means of enforcement, compliance is in doubt. This comparison does not include the relationship of thermal efficiency to CO_2 production. An increase in thermal efficiency, for any fossil fuel, would reduce the carbon dioxide output per unit of power produced by the fuel.

The United States promoted a plan at Kyoto to share emissions requirements through a system of trading emission permits, similar to the program that has been introduced for other pollutants within the United States. A permit system would enable economies that emit less than their designated volume of CO_2 to sell emission rights to economies that emit more than their designated amount. The price of the permits would be set by a market for the permits. This type of system assumes that it is impossible to precisely evaluate the environmental costs of all fuel choices and that it is difficult to incorporate such costs in the price of a fuel. Environmental costs of fuel use are thus now "externalities"¾that is, external to the fuel's market price determining process. This is the issue underlying the choice of fuels from an environmental perspective. Thus, as environmental concern grows, the evaluation of the external impact of fuel choice increases.

3.7. Summary

International fuel markets are becoming more competitive as new infrastructure is completed. Such competition is not confined to fuel markets defined by terms such as oil, natural gas, coal, or nuclear fuels. Competition among fuels is also increasingly important. This is especially the case for power generation, where heat and the ability to convert heat or mechanical energy into electricity is the primary concern and the physical condition of the fuel is of lesser interest.

The nature of interfuel competition has been directed extensively by the evolution of the market structure within each industry. Markets for coal and oil are now quite competitive on a global basis, even though cost considerations have kept deliveries of oil and coal regional. If prices were to deviate significantly among regions, coal and oil are deliverable to anywhere in the world from any major supplier.

The natural gas industry has been constrained by the difficulties of delivering fuel in the form of a gas. In eastern Asia where international pipelines are few, international gas deliveries have been primarily in the form of LNG. LNG is an expensive proposition, which by its character must involve large buyers of gas produced in large processing plants. Moreover building LNG facilities takes considerable time. Such considerations have slowed the liberalization of the gas industry within Asian APEC economies. The Americas present a contrasting picture with their extensive networks of natural gas pipelines. Large outlays still limit the development of pipelines to large enterprises, but the final supply of gas to North American customers has become quite competitive. There is also a promise of increasingly competitive supply of natural gas among southern Latin American APEC members.

Nuclear fuels other than natural uranium operate in the most constrained markets within the APEC and global arenas. This has proven to be necessary because of the global concern about the security of weapons-capable material, because of safety concerns regarding the operation of nuclear power plants, and because of concern over the radioactive nature of nuclear fuels and waste materials. The nuclear power industry is not expected to see much liberalization, but will rather face the effects of liberalization because its primary product, electricity, is being provided within a more competitive environment.

3.8. Recommendations

1. Reduce or eliminate energy market distortions, particularly within the power sector, where the largest degree of interfuel competition is possible. This includes an equitable taxation regime so that fuel choices are not distorted.

2. Pursue a well planned and transparent energy market deregulation process.

3. Improve existing regional information-exchange networks and create new institutions, as required, to address the environmental issues in the energy sector on a consistent basis across APEC member economies.

4. Promote clean coal, natural gas utilization, renewable energy, and other appropriate technologies when they are cost-effective means to combat energy-related environmental problems.

5. Assess the potential to reduce air emissions from electricity generation using market-based mechanisms, including emissions trading.

Chapter 4

Regulatory and Technical Issues

4.1. Resource Tenure

A primary resource delivery system would not function without some degree of contractual tenure over the resource. Investments in the energy industry would not be financeable if the party or firm buying the raw material did not have an enforceable right to acquire his raw materials and to sell his manufactured energy product. An equivalent to a contract for selling a product would, of course, be a captive distribution system, such as gasoline stations affiliated with an oil refining firm.

Another exception would be a competitive market which would not require explicit contracts, though in practice contractual markets have existed side by side with competitive ones and competitive agreements must be enforceable for the competitive system to flourish. Sellers in a competitive system would have an ability to choose whether they sold in the competitive market or term contracts. A competitive system requires either a large number of sellers and buyers of the primary energy resource or sufficient competition among fuels, so that the seller cannot influence the price of the product. Because there are a large number of suppliers, diversity of potential supply provides an alternative to fixed-term contracts or “tenure” over the resource.

4.2. Distortions and Constraints of Interfuel Competition

The issue of interfuel competition relates to more than the comparison of fuel price per unit of energy provided. The total cost per unit of energy (e.g., electricity) generated over time must also be identified. Comparison includes capital costs, operating and maintenance costs, efficiency, a facility’s economic life, and environmental costs. Competition among fuels can be achieved if there are:

1. no distortions in the supply and demand sides (i.e., competitive supply of energy resources vis-à-vis competitive demand in the consuming sectors),

2. no barriers in the access of technology or entry into the industry, and

3. environmental regulations that are efficient, transparent, predictable, consistent, and cost effective.

APEC economies apply differing regulations, which might distort each of the above conditions. These regulations extend to trade among economies. Thus price arbitrage is created not only owing to transportation differentials, but also owing to differing domestic regulations. Indeed, distortions come from market intervention, directly and indirectly, in the form of subsidies, taxes, tariffs and nontariff barriers, and other regulatory conditions, which are derived from an economy’s regulatory policies.

Distortions in the energy sector come from two biases. The first relates to indigenous resources. There are no distortions when indigenous resources generate the lowest-cost energy.

Problems arise when an economy seeks to use domestic energy resources that are more costly than those that might be acquired on world markets. Essentially, an economy must often decide whether to use a subsidized domestic energy resource or to import resources from more economical, though foreign, suppliers. When an economy subsidizes a resource, this creates distortions on the supply side. If the supply is not subsidized, but consumers are mandated to use a specific fuel at a higher-than-market price, the distortion is on the demand side. Subsidies on domestic energy prices for the purpose of helping lower income groups also create demand-side distortions.

A second bias comes from supply security consideration designed to protect domestic energy industries, mandate strategic reserves, require diversification of energy supplies or impose long-term contracts by means of paying premiums to preferred suppliers. It might be argued that protecting domestic industry can yield some economic benefits. Similarly, supply security might provide some economic values. But each of these objectives is achieved at the price of lost efficiency in the provision of energy. Eliminating distortions and other barriers promotes more efficient resource allocation, through cost related signals to supply and demand activities, including international trade.

Deregulation has become the theme of the day, owing to anticipated gains from more efficient resource utilization. This has been achieved mostly in the power sector and in domestic oil markets. The advent of private power sector investment has yielded efficiency gains to the power sector. The electricity sector can indeed accommodate many types of fuels; thus ideally a power provider might choose any fuel that would maximize his profits, subject to environmental and other public policy constraints. Deregulation is intended to encourage private participation in the power sector. Ideally, deregulation policies in the energy sector include pricing policies that conform with free market costs, reduce and eliminate duties, and facilitate fair bidding processes in the procurement of required energy resources.

The pricing of domestic petroleum products can distort domestic energy prices in general. Until the end of the 1980s, most APEC economies regulated their domestic oil markets, primarily through price controls. (The United States was an exception, having deregulated its oil industry in 1980.) During the 1990s many APEC members completed domestic oil industry deregulation, while others are still doing so or are about to begin. Most deregulation processes seek to (1) free market prices allowing them to conform with the international markets, (2) eliminate unnecessary monopolies and abolish barriers to market entry, and (3) relax export and import controls regarding petroleum products.

Many economies have sought to slowly deregulate their markets. APEC members that have completely deregulated domestic oil markets include the United States, Canada, Chile, New Zealand, Singapore, and Thailand. Australia, Japan, and Korea are completing the deregulation process, while most other APEC member economies are just starting the process. The Philippines presents a unique situation. A well planned deregulation process began in 1996 and would have been completed in 1997. However the Philippine Supreme Court in November 1997 annulled the deregulation law. The ruling occurred amid political pressure brought about by dissatisfied consumers who had to pay higher prices due to the peso's depreciation against the US dollar. If the Philippine economy returns to a price regulated state, it will be the first recent re-regulation case in APEC. The Philippine government would have to subsidize petroleum product prices, if it intends to keep prices low. In February 1998 the Philippine legislature again passed an oil deregulation bill that seeks to deregulate the industry over a period of five years. It remains to be seen if this new policy will survive the local political and judicial processes.

Prior to deregulation, most APEC economies subsidized or cross-subsidized petroleum products prices. Prices of petroleum products in Indonesia are still well below international levels, though Indonesia intends to deregulate by allowing competing firms (in addition to the state oil company, Pertamina) into domestic markets. Moreover, Indonesia also cross-subsidizes product prices by making gasoline prices much more expensive than kerosene and gasoil. It has been very common in many APEC economies, notably in Asia, to cross-subsidize prices between gasoline and diesel (gasoil) and kerosene prices. That is, relatively low prices are maintained for kerosene (because low income people use it for cooking and lighting) and for industrial fuels (mainly diesel but sometimes also fuel oil) to promote development. At the same time prices are much higher for gasoline and jet fuel (because they are associated with perceived luxuries, automobile or air travel). This practice is partly responsible for the relatively strong consumption growth of some subsidized products, notably the sizable demand for diesel that has emerged in many Asian APEC economies. Japan’s oil industry has now become financially troubled following deregulation, because the industry has had difficulty raising the price of the middle distillates, while it faces competition from relatively cheap gasoline imports.

Domestic oil market deregulation usually realigns energy prices to give more accurate price signals to users of energy resources. The current trend in the APEC region is to reduce regulations that inhibit such market signals. Some of the more developed economies, such as the United States, Canada, Australia, New Zealand, and Chile, already rely on such market pricing systems. Japan has made substantial moves toward market policies as well. Thailand, Korea, Singapore, and Malaysia also determine their energy prices based upon international prices, while most energy prices in Mexico, China, Chinese Taipei, and Indonesia are still regulated or subsidized.

While regulations can constrain the acquisition and use of fuels that generate electricity, other physical constraints are often present, such as a lack of infrastructure. In this case, an economy might have to pursue, at least temporarily, less desirable energy options. Such infrastructure needs to be included in any long-term energy program, because fuel prices are only one aspect in a whole chain of resource utilization that determines the suitability of a particular resource. For example, the initial investment required for most natural gas uses is enormous, though necessary, if natural gas is to be economically competitive.

Because such physical constraints are usually related to funding, governments often provide incentives in the provision of infrastructure when such facilities are not otherwise available. Economies that once allowed only state oil companies to operate within their economies now encourage the private sector to build and operate as a result of the deregulation process. Indonesia, for example, now encourages energy transportation facilities such as natural gas pipelines by private parties. In contrast, Korea’s domestic natural gas trunk line is still dominated by one firm, Korea Gas Corp. (KGC).

Another possible constraint arises from the differing environmental impacts of particular fuels. While many costs are relatively straightforward, environmental costs are harder to assess. Impacts range from immediate health effects or crop losses to less immediately tangible issues such as global warming. Economies with limited resources might readily address visible environmental problems, but might lack the incentive to address the less tangible. When emission limits and other environmental impact regulation are clearly specified, energy providers might select the appropriate fuel that optimizes their interests, subject to all attainable constraints.

4.3. The Impact of Government-Controlled Fuel Prices on Electricity Supply

Long-term contracts also play a role in power industry developments. Under a contract-based power production system, there are several contracts that determine the feasibility and financeability of a given power project. These include the power purchase agreement (PPA), the operations and maintenance (O&M) contract, and the fuel supply agreement (FSA). Contracts also exist for the engineering, procurement, and construction (EPC) activities that take place while a plant is being built. Such contracts generally determine how incomes and responsibilities are divided among project sponsors and set the viability of the project itself. These contracts also set the competitiveness and flexibility of access to fuels at a given power plant.

Under a contract-based system, the regulatory function of government changes from that under a utility system. Contracts will generally be less determined by government policy, and will increasingly be determined through bidding processes that identify the lowest-price (not lowest-cost) producer among the qualified bidders. Policies of economies vary as to the degree of government involvement in setting the rules for the bidding process, though the utility that manages the transmission system is often the principal purchaser of power that is not sold directly to a final end user.

The FSA is likewise a matter of contract between the IPP and the available fuel providers. The number of fuel suppliers available in a given economy will vary considerably by type of fuel sought and by the industry policies of the individual economy. As a general rule, those economies with elaborate gas pipeline systems are often deregulating the provision of gas supplies, opening gas markets to an increased number of suppliers. The number of suppliers of coal will vary markedly among economies and by location. Generally, economies that favor domestic coal supplies will have fewer suppliers than economies that permit and encourage international competition.

Environmental regulations generally direct power purchases to fuels that meet criteria for emissions standards, given available and anticipated technologies. While particulates and solid waste disposal are serious issues in the power industry, much recent attention has been focused on "acid gases" such as sulfur and nitrogen oxides and "greenhouse gases," notably carbon dioxide and methane. Policies concerned with acid and greenhouse gases in general favor low- or no-emissions power generation forms such as nuclear, hydroelectric, or some renewable technologies. Among the fossil fuels, there also is an environmental hierarchy, with the least dense (lowest carbon and sulfur content) fuel, natural gas, being favored over the densest fuel, coal, and with a hierarchy of oil products lying somewhere in the middle. This is because of the higher carbon content of the denser fuels and because of a tendency, which varies considerably when dealing with specific fuel sources, for denser fuels to have higher sulfur contents. The effective "carbon" content of a power fuel is, of course, also related to the thermal efficiency of a power plant. Thus a power plant that gets more power production from a given volume of fuel, effectively has a lower carbon content in its fuels. The important issue is then the carbon consumed for a given amount of energy production.

Under the three types of power industry structure¾utility, contract, and competitive¾ only the competitive system fully discourages customer subsidies that are not directly imposed by government. Under the contract system, prices may still be administered within the limits of contract and law, but the cost of the subsidy is more clearly focused on the distribution activity where the subsidy actually occurs. A utility-based power provision system integrates the power industry often from generation to distribution and marketing, and thus obscures any subsidies or regulations within the system.

Most APEC economies enforce or seek to enforce regulations on environmental standards, including the implementation of a variety of environmental impact assessments prior to the implementation of an industrial investment, including power generation. "Best practices" procedures for environmental policies were the subject of the APEC Energy Working Group report, Apogee Research et al., *Environmentally Sound Infrastructure in APEC Electricity Sectors*, submitted at the August 1997 APEC Energy Ministers Meeting in Edmonton, Canada. The core finding of the report was that environmental policies should be (1) efficient, (2) transparent, (3) predictable, (4) consistent, and (5) cost effective. These findings were discussed in detail within that report. The study also noted that APEC member economies have opted to assert environmental policies that meet (1) ambient environmental quality standards, (2) point source discharge standards, (3) technological standards, or (4) fuel quality standards. More typically policies involve a combination of these procedures.

Rather clearly, environment policies have within them a capacity to discriminate, if they do not meet the five criteria. Environmental policies could, for example, prevent the importation and use of high-sulfur coal for power generation purposes, even if it were more cost effective to reach sulfur emission standards by cleaning emissions after the coal is burned rather than by setting standards on the sulfur content of the coal. If environmental policies violate the five principles, environmental policies might be structured to favor domestic energy resources over imported energy resources, even if the stated objective is environmental. Oil- and coal-producing economies have asserted that such motivation lies behind "carbon tax" policies in many consuming economies and trade blocks.

The possibility also exists for biases among primary fuel consumption patterns and environmental policies. Rather clearly there are a variety of environmental standards that might be applied to various sectors such as automotive transportation and power generation. Clearly the five environmental criteria could be applied to each sector. Also clearly, policies might be structured to be less strict on, say, automobile transportation than on the power sector, or the other way around. Indeed, it is a frequent case for power production managers to complain that environmental regulations are more stringently enforced on their activities than on the transportation system. Such discrimination might be partly justified, if it is more effective to implement a policy in a power plant than a policy in a vehicle. But the economic impact would be to subsidize the other sectors, which might soon become an increasing portion of overall environmental problems.

For the most part the regulatory function in the power sector has been separated from the function of providing power. In those economies where the two functions are still nominally combined, the functions are in the process of being separated. This was not always the case in many economies. As recently as five years ago, economies including Australia, New Zealand, Thailand, Singapore, and China combined the regulatory and operating functions of their power systems. A failure to separate the regulatory and the operating functions can create conflicts of interest within power systems that have moved beyond the basic utility stage of activity. This is particularly so, as policy focus moves toward the issue of fair and open access to markets.

Under the contract and competitive systems for electric power, there is also an incentive to separate transmission, generation, and distribution functions into at least separate corporate entities. Under the competitive system, there is yet further incentive to divide transmission into power markets, dispatching, and wire management activities. There is also a parallel separation of distribution between the act of actually marketing power to customers and the management of the local grid. The argument for the separation of these functions is basically a “level playing field” position, which permits all market participants equitable access to their markets. In many APEC regional economies, it has been found necessary to institute a “grid code” that identifies the conditions for the fair access to and management of the transmission and distribution systems. Effectively established, such disintegration of the utility structure in the power industry would posit that the only natural monopoly in the power industry is the transmission or distribution wire itself and not the service provided along the wire. Even then, competing and perhaps parallel transmission and distribution wire systems might be possible.

“Wheeling”¾the process of permitting open access to wholesale and retail power markets¾is a necessary component to a limited extent under contract systems and to a thorough extent under competitive systems. An effective wheeling system would allow equitable access to transmission and distribution systems (wires) under competitive, price-based criteria. Wholesale wheeling would permit access to a common power pool or transmission service from which retailing organizations might acquire their power supplies. Retail wheeling allows any seller of electricity access to the lines that deliver their power to their customers.

Under the contract system, there is necessarily a requirement that the tendering process be fairly operated. Within economies that operate their power system on a contract basis, there has been a continuing conflict in the choice between competitive bidding and unsolicited proposals. Which should dominate efforts to expand the power production sector? Generally, there has been a tendency to prefer competitive bidding through tenders, because this allows power purchase agreements to be set at the lowest price for which power services might be provided. Competitive bidding, however, requires the tender issuing authority to specify a minimum power supply that is sought. Very frequently the tender will also specify how the power is to be generated (including fuel choice) and the load patterns that must be met.

Unsolicited proposals have the benefit of permitting greater leeway for the imagination of the bidder, which should eventually lower the effective cost of providing power. Unsolicited bids for long-term contracts can, however, take many grid management decisions out of the hands of the grid operator. Unsolicited bids often reallocate the least attractive portion of demand, leaving these less vital submarkets in the hands of previously existing power generation facilities or utilities. This process has at times been called “cherry picking,” because of the tendency of unsolicited bidders to take these best markets. Unsolicited bidding also carries an enhanced requirement that the tender managing agency be fair in its project-selecting process. Such fairness is difficult to obtain.

It is the difficulties of the tendering process within a dynamic market environment that have generally led many economies that initially selected contract-based power provision systems to gradually move toward more competitive power market systems. Competitive power provisions systems have an advantage over contract-based systems. The selection of power provider is based solely on price, and in a large portion of the power market there is little or no reliance on long-term contracts that might be expensive in a power market characterized by changing technologies and unstable primary fuel prices. Contract systems require elaborate and rule-bound tendering procedures that competitive systems allow to be handled through market operations. Contract-based power provision requires that each contract have its own pricing agreement. Two contracts are seldom alike, and there is no single market price for power. If an old contract is set significantly above or below current prices, either the contract must be met at great expense to one of the contracting parties or the difficult process of contract renegotiation must be undertaken. The 1997 currency instability in Southeast Asia has illustrated the instability of power and fuel supply contracts under times of changing basic market conditions.

The competitive system has the cost of decreasing central authority control over production decisions¾be that authority a utility or a government. Prices are, however, unitary across the power pool, allowing for cost differences passed on to large customers or to customers whose location is advantageous. Because the typical competitive system provides power on the basis of uniform half hourly contracts, contract renegotiation is built into the power market. The risks of market changes are born entirely by the power provider, and the provider is forced to make efficient decisions regarding how he generates and supplies his product.

Economy-wide long-term planning becomes very difficult under a competitive power provision system. Because prices can vary as often as each half hour of service provided, the relative advantage of particular fuels or generation techniques might also often vary. Economy-wide planning, however, normally covers long periods such as five years or even decades. Such planning requires a certainty that markets might not be able to provide. A frequent criticism of competitive power provision is thus that the long term is not adequately accounted for and any system development occurs without an underlying strategy.

A truly competitive power supply system exists nowhere. Even in those systems that are approaching a competitive structure, it has been found that often long- and medium-term power production and supply arrangements are advantageous to arrange side by side with the power that is competitively supplied. Power pricing under those contracts that exist in otherwise competitive power markets would, however, have to be more flexibly arranged than under the “contract-based” power system described above.

4.4. Technical Barriers

Interfuel competition may be limited by available technology as well as by physical limits within a market, because of failure to use a technology, usually for economic reasons. Technical barriers can affect the operation of individual fuel markets as well as how competitive one fuel is relative to others. Generally speaking, technical barriers affect the production, handling, transport, trade, and consumption of fuels. Often, it is the presence or lack of infrastructure that is the greatest barrier in the operation of fuel markets.

The greater the supply of a fuel, the lower its price, and the more competitive it becomes relative to other fuels. Thus, new technologies that facilitate the exploration and production of fuels are removing technical barriers and increasing fuel competitiveness. Offshore, deep-sea, and horizontal drilling techniques, for example, have improved the competitiveness of oil, as have field development techniques such as gas reinjection.

As a solid, coal is the easiest to handle of the fossil fuels and the first to develop a widespread market and consumption. Coal can be mined, transported, and traded with little or no technical expertise, which affects its relative consumption level. Trade and consumption of all fossil fuels have been affected by lack of infrastructure. In China, coal consumption has been constrained by the lack of rail lines and the physical inability of existing lines to transport more coal, while oil imports in India have been impeded by clogged ports. In contrast, an extensive pipeline network facilitates trade and consumption of natural gas in the United States. Similarly in Korea, gas distribution pipelines and efforts to construct trunklines have contributed to expanding gas consumption as town gas. The individual safety and engineering specifications of different economies with regard to fuel handling can also be a technical barrier in markets. In the case of nuclear power, technologically or politically imperfect solutions for handling spent fuel have been a major barrier in the market.

At the point of consumption, innovations in technology continue to reduce technical barriers affecting fuel markets. Vehicles using electricity stored in batteries and compressed natural gas facilitate substitution of fuels for transportation, although these particular procedures are not yet, in most cases, economically competitive. Still, one of the greatest technical barriers with fuels remains: they are generally not directly substitutable for one another at the point of consumption. Coal cannot be burned in automobiles; in fact, even diesel cannot fuel a gasoline engine. In the electricity sector, some thermal power plants might be able to switch fuels, from naphtha to natural gas, for example; but many power plants remain similarly constrained in their fuel substitutability. Technical barriers such as these will continue to have a large impact on the operation of fuel markets.

4.5. Ocean Fuel Transport

World oil trade by tanker represents about 15% of the value of total world trade and about 40% of total seaborne tonnage. The shares for coal and gas are much smaller, but still represent sizable amounts of energy resources traveling by ship: annually more than 435 million tonnes of coal and over 75 million tonnes of LNG.

Within the maritime transport industry, a ship obeys the laws of the economy whose flag it flies as well as the laws of the ports that it enters. For this reason, many ship owners register their ships in locations such as Liberia and Panama, which have favorable employment and tax laws. However, the Jones Act of the United States restricts freight and passenger traffic between American ports to US-built, US-crewed, and US-citizen-owned vessels. Although such restriction of purely domestic cargo shipments have a long history worldwide, this has often been interpreted as creating a barrier in fuel transport markets. The US government has also subsidized its domestic shipbuilding industry to ensure the availability of ships that meet Jones Act requirements.

Such rules restricting maritime transport are not confined to the United States, though in many economies the impact is less explicit than the written statute of the Jones Act. For example, Chinese Taipei encourages its power utility to own the ships that are used to supply coal to its power plants. Coastal trade within any economy is almost always confined to vessels bearing the economy's flag. Several oil producing economies (most outside of the APEC region) give preferential treatment to own-flag vessels when they export crude oil. Rules favoring domestic carriers on domestic routes also exist for road, river, and air transit, though in many cases such rules are in the process of weakening.

In addition to the Jones Act, the United States also enforces the Oil Pollution Act of 1990 (OPA90). While the provisions are complex, OPA90 essentially stipulates that aged tankers and those tankers with a single hull design are to be phased out of US trade. This process began in January 1995. Moreover, the maximum age allowed for a single hull tanker (28 years in 1995) is to be reduced by one year each year until 2000, when the maximum allowed age will be 23 years. Single hull tankers over 30,000 deadweight tonnes (dwt) will not be allowed to trade in US waters after 2010. Vessels involved in US trade must now also obtain a certificate of financial responsibility (COFR), proving that they can meet the costs of possible pollution cleanups.

International shipping industry regulation designed to reduce pollution and increase safety has also been undertaken by the International Maritime Organization (IMO) as well as by the International Association of Independent Tanker Owners (Intertanko). An IMO convention initiated in 1993 requires all new tankers to have double hulls or be equally protected by an alternative design. Although there are over 95 signatories to the convention, many APEC members and Persian Gulf economies have not yet signed. The IMO also proposed regulations in 1996 on safety design features for double hull tankers, which industry analysts claim might increase the cost of double hull shipbuilding by 5%. As IMO conventions gain international acceptance, laws aimed at pollution control in individual economies, such as OPA90, become more like the international norm and less like barriers to international shipping. In contrast, laws like the Jones Act and practices in other economies that limit the entry of nondomestic vessels, remain barriers to open markets for ocean fuel transport.

4.6. Summary

Energy security interests often summarize to a desire by consuming economies to be assured of reliable access to energy resources. This often has meant a desire for enforceable contractual controls over access to the energy resources of other economies and, at times, over the development of those resources. The liberalization of many energy markets, however, has meant that access to many energy resources has become market led rather than contract guided. Market-based supplies are thus, to an extent, in conflict with energy security, unless one is confident that the market would actually function. So far, the functioning of liberalized markets has been reassuring with regard to the availability of most energy supplies.

Interfuel competition has proven to be most severely disrupted by policies that seek to promote domestic energy resources over imports or that promote domestic industries. Generally, such policies have been successfully implemented only at the cost of the overall competitiveness of particular economies.

Regulation has often seen a diminished or (more accurately) an altered role with the introduction of market liberalization. One notable exception to this, however, has been in the area of environmental controls, which have generally become more explicit and more strict, as APEC economies have seen ambient conditions in many of their urban and industrial areas deteriorate. Regulations in general have proven to be most effective when they are tailored to the industrial structures of particular energy or power industries and to the structure of an economy as a whole. Increasingly the required regulation has been one that ensures the fairness of markets rather than explicitly channeling market activities.

4.7. Recommendations

1. Governments should implement legal, fiscal, and regulatory frameworks that facilitate:

    a) the development of energy resources at a member-wide level and a local level

    b) investment in energy infrastructure

    c) efficient use of energy

    d) diversification of energy supply and use, subject to practical commercial and environmental criteria

    e) economically efficient allocation of scarce resources, including capital.

2. Regulations designed to address environmental or similar costs should be efficient, transparent, predictable, consistent, and cost effective.

3. Deregulation policies that change market structures should seek to balance the impact on parties that are disadvantaged owing to compliance with earlier policies (sunk or stranded costs). Such processes should be applied in a manner to ensure the protection of consumers' interests in reliable and affordable energy supplies.

4. The present economic climate in many APEC member economies should be used as an opportunity to promote a more efficient regulatory framework.

Chapter 5

Financial Barriers and Their Implications

5.1. Discussion

Much of Asia is presently undergoing a period of widespread currency devaluation and exchange rate fluctuations. Economies including the Philippines, Indonesia, Thailand, and Korea are now seeking the assistance of the IMF, the World Bank, the Asian Development Bank, and others to overcome difficulties with their balances of payments, to stabilize exchange rates, and to bring stability to their international credit standings. Moreover, there have recently been periods of weakness with the Japanese yen brought about partly by excessive levels of bad debt in the banking system.

The present situation in Asia mirrors many of the problems that arose earlier in the 1990s with the devaluation of the Mexican peso and even earlier in the late 1970s and early 1980s with Latin American currencies in general. Such financial instability has a significant bearing on the ability of an economy to fund its trade and investment and to continue vibrant economic growth. A large portion of the capital investment taking place in the Asia-Pacific region is related to energy requirements, and a large portion of the Asia-Pacific's energy investments involves the construction of power plants.

An economy has the option in financing energy investments of either seeking internally generated funds (savings) or seeking funds from abroad. This decision is heavily influenced by the availability of funds from domestic financial institutions and the extent to which a given project requires imported components. Much of the Asia-Pacific region has been characterized as having a high domestic savings rate: over 30% of GDP in much of Asia. Thus a potentially large source of domestic funds for investment does exist. A large portion of the investment increases that have recently occurred in Asia has come from investors finding new ways to tap this high savings rate. Criticism has, however, been leveled on the management of many economies' financial institutions regarding the equity of access to domestic credit in regard to both comparative access to domestic funds between the public and private sector and comparative access within the private sector.

However, there has also been a simultaneous rapid increase in external funds sought to finance domestic investment within many Asia-Pacific economies. This has proven to be a source of financial insecurity due to the resulting potential for currency stability. Additionally, international balance within credit markets has proven to be particularly difficult to obtain in regard to electricity and energy borrowing in general. Quite often, energy borrowing and investment requires substantial international funds to develop markets where potential earnings come primarily in the form of domestic revenues.

Recent devaluations and currency instability in Indonesia, Thailand, the Philippines, and Korea have meant that it now takes a larger portion of domestic economic activity and trade revenues to fund foreign debts. This increased debt service requirement has been a primary cause of (1) the recourse by Asian APEC economies to funds provided through the IMF and (2) the domestic financial reforms required under the conditionality standards negotiated within the IMF assistance process.

It is easy to look only at the weakness of particular currencies and to ignore the fact that devaluations are by their nature two-sided events, especially when many other currencies do not devalue. Thus, in the Asia-Pacific region, the devaluations of many Southeast and East Asian currencies have in effect been the simultaneous revaluations of the currencies of other APEC economies such as the United States, China, and Chinese Taipei within APEC and, outside the APEC region, much of Europe. The devaluation of one set of currencies has made the financing of the energy trade more expensive for the devaluing economies, while it has decreased the effective cost of the energy trade for many “revaluing” economies. Energy prices and currencies are, of course, often quoted in dollars, but the dollar price itself determines whether the “revalued” US currency raises or lowers energy prices in the United States. In Asia itself, the devaluations of neighboring currencies will be a component of any decision by the government of China when it comes to setting the international value of the yuan.

The availability of lending and equity for energy investments becomes a more complex issue in a period of currency instability. A continued availability of funds will depend a good deal on the level of lender-economy apprehensions regarding the future value of regional currencies and on the level of interest rates. This effectively means that investors must have confidence in the stabilization reforms that a particular economy institutes.

The entire issue of currency stability relates to the issue of energy security and energy trade liberalization. Liberalization by its nature requires an increase in openness to foreign-supplied funds, investments, and energy resources. This means an increased domestic economic sensitivity to currency and financial markets and policies. International lending institutions such as the World Bank and the Asian Development Bank have increasingly pointed out that the development of domestic financial institutions, including domestic bond markets and futures markets, must go hand in hand with economic liberalization. Recent and still local exchange and interest rate difficulties call into question whether this has in fact yet occurred. Successful development of domestic lending institutions would of course minimize the impact of currency fluctuations, especially if the development permits the free and efficient flow of funds from foreign exchange generating institutions to foreign exchange consuming institutions. While there was an impressive expansion of such institutions during the 1980s and early 1990s, the recent devaluations and attendant disruptions indicate that in many cases there might not have been sufficient development of this sort within many APEC area economies.

Financing primary fuel consumption consists not only of trade financing but also investing in facilities that consume fuels. Both types of funding normally involve domestic financing and often some form of international lending and equity to manage attendant international costs, including financial risks. From a commercial standpoint, financing primary fuel consumption is a direct result of competition among economies for international funds. Commercial viability is a matter of risk and returns. Commercial lending will generally flow in the direction of the most favorable risk-and-return combination. This need not mean toward the project with the highest financial risk, though generally investments and expenditures involving higher risks must be compensated through higher returns. This flow of funds will involve all areas of possible investment and international expenditure and will not be confined to the energy sector. In short, the energy sector competes with other sectors and ambitions within an economy.

Perceived and actual risks of lending are heavily governed by shifts in the anticipated stability of currencies relative to each other. The mid- to late-1997 devaluations of many Asian currencies created an increased perception of risk in the concerned economies. This in turn has resulted in a severe contraction of available private international funds facilitating energy developments within the region. To an extent, recent conditions have also dried up international credit availability for Asian economies in general. A parallel situation occurred in the Americas following the Mexican peso "crises" of the mid-1980s and of 1995. Experience has shown that with correct financial adjustment procedures, the fears of currency instability are often transitory, though the transition period might last several years even with the implementation of the most optimal policies.

Typically, an IPP or a primary energy investment project might seek to get as much as 80% of its investment costs financed through domestic and international debt, though the debt share is frequently and now usually lower. This is especially the case when lenders see a high level of risk in the project. In those economies with well developed financial markets, the local component of this debt would increase. Likewise, if uncertainties rise regarding the stability of a currency area, the availability of international, and perhaps also local, credit facilities might decline and in some cases virtually vanish. Policies that thus increase a currency's instability, discourage long-term energy sector investments.

The experience of Mexico in 1995 and parts of Asia in 1997 indicates that unanticipated devaluations of a currency have the potential to delay energy market deregulation and privatization, if the economy whose currency is devalued depends heavily on imported equipment in its investment program. The devaluation process and the follow-up recovery program might require a curtailment of foreign exchange expenditures, including a renegotiation of debt service schedules. Rather clearly, if a thriving domestic capital market evolves concurrently with the energy investment program, the effects of a devaluation on private investment would be considerably lessened.

Commercial financing of energy investments is often based on the allocation of risks among the project participants. Increasingly, large energy projects are cooperative arrangements among many domestic and foreign investors and creditors that allocate responsibilities to obtain raw materials, sell products, operate and maintain the plant, obtain financial support, manage political and policy changes and risks, and engineer and build the facility. Ideally, participants in an energy project allocate the risks and returns among each other in a manner that allows the participant who can best handle a particular risk to handle that risk. Appropriate distribution of such responsibilities would thereby decrease the overall project risk and increase the project's financeability.

Understandably, the returns on a given energy project are more than just the returns to the venture or joint venture that actually owns the facility. Operations and maintenance, fuel supply contracts, and engineering, procurement, and construction responsibilities each entail incomes that are not directly included in the venture's profit and loss statement. This is one reason why increasingly partnerships in investments often include in the process explicit financial roles for engineering and government-managed entities. Similarly, the role of financing an energy project will also increasingly entail the direct involvement of the lead financial agencies. Equity and debt can, in the process, thus become blurred distinctions.

This process is part of the risk-allocating function. Rather clearly, economies do set up rules for investment within their economies. Among the most frequently encountered are limits on the foreign versus domestic investment permitted in a project. Such rules are often seen as necessary to maintain domestic control over an economy. Equity rules also limit the financeability of projects, because they limit the allocation of risks among investors.

Among the most widespread barriers to investment in the energy industry are limitations on the investment of foreign equity in the energy sector of an economy. Caps are often placed on the equity share of an investment that might be held by foreign entities, especially if the energy activity is seen as related to economic sovereignty or security. In some cases, the caps on investment are not matters of statute but of policy as it is enforced. A decades-old example from outside of the APEC region occurred when the government of the United Kingdom set a limit on the amount of equity Kuwait Petroleum was allowed to acquire in British Petroleum, even though statutory restrictions on equity purchases might have been few or nonexistent.

Within the APEC region, examples exist in Chinese Taipei or Korea (in power plant investments) and in China (in petroleum refineries and petrochemical plants) where foreign equity is restricted. Caps on foreign equity are, of course, also limitations on financing in general, which will decrease the ease with which a particular project might be financed. The policy of an economy on the issue is thus a tradeoff between optimizing investments and ensuring the interests of the participants within the economy.

5.2. Recommendations

1. Economic reforms to eliminate domestic economic distortions and to provide transparency and cost effectiveness in financial activities must continue. Energy institutions should have access to capital under criteria comparable with those for all other institutions, including government. No distinction should be made in the borrowing costs faced by energy institutions beyond those distinctions based on financial risks, taking into account macroeconomic considerations.

2. Expand and improve domestic sources of capital such as basic banking institutions, stock exchanges, bond markets, and other lending, financial, and risk management institutions.

3. Lower financial risks through increased equity investment, broadened financial participation (including potential buyers), and price (including foreign exchange) hedging.

4. Financial instruments should complement the terms of borrowing and risk requirements. Thus long-term bonds and other financial instruments should be available for investments yielding long-term returns. Short-term instruments should be available to meet short-term credit needs.

5. Capital markets should be encouraged to provide commercial discipline to the credit process.

Chapter 6

Conclusions

"Energy security" and "improved international fuel markets" are ideas that are defined by the party that chooses to use the terms. As such, there are naturally a variety of definitions. Time and short memories also affect our concepts of energy security and improved markets. There were times in the 1970s when many oil consumers were seriously concerned whether they would be able to acquire even a portion of their oil needs. The 1990s are more accurately characterized as a period when concerns are directed toward the prospects that a period of abundance and economic liberalization might lead to the disappearance of earlier conservation efforts, to reluctance in the full observation of environmental controls, and to the complete failure of energy planning.

Despite the globalization of most energy markets, energy policies and decisions remain local matters, directed by local interests and made possible by the scarcities of resources and infrastructure that characterize the locality. Natural gas is a policy option only if a pipeline or an LNG terminal or a nearby reserve is available. Coal likewise requires ports and transportation facilities. Oil, despite the price declines of the past decade, remains relatively expensive as an energy source, even though it is usually convenient to ship and store. Each of these energy sources is now available in what might be called a market, even if the Asian gas market lacks many of the traits of competition. Markets mean that efforts to control prices are difficult, if not impossible, and that such efforts are often costly, diverting economic actors into efforts to evade the regulatory function.

The localization of the energy environment has gone hand in hand with the liberalization of the business community as a whole and with the strengthening of regional governments within economies. While efforts might be growing to establish one-stop locations at which construction and investment clearances might be obtained, localities are increasingly exercising or claiming both advocacy and veto rights over plans that affect their communities. This is an environment under which energy planning becomes increasingly difficult and in which short-term interests often prevail.

Technology also changes what can and cannot be done within energy markets. We can now package items such as gas in a pipeline and electricity on a wire in ways that allow sellers to distinguish among customers. This allows for greater degrees of competition in energy areas that were once labeled "natural monopolies." Industries that were viewed as a whole, such as electricity, are now divided up into submarkets and profit centers such as production, transmission, distribution, and marketing. Crossovers are occurring within energy industries, such that electricity suppliers are also becoming providers of communications, transportation, finance, or even home and business security services.

At the same time that the importance of the locality is growing, borders are crumbling. Electricity and natural gas grids are no longer confined within the borders of an economy or within subregions of an economy. They are becoming international. Regions and economies can thus compete with or complement each other in the provision of energy resources. Independence from energy imports does not make much sense in this environment. Nor does reliance on a single set of domestically provided energy resources. Lowering the cost of energy becomes the most important target. That is possible only when markets work efficiently and freely.