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Hawaii Energy Strategy Project 2:
Fossil Energy Review

TASK I

WORLD AND REGIONAL FOSSIL ENERGY DYNAMICS

Prepared for

State of Hawaii
Department of Business, Economic Development & Tourism,
Energy Division

by

The East-West Center
Program on Resources: Energy and Minerals

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Task I. World and Regional Fossil Energy Dynamics

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Abbreviations, Acronyms, and Measures

AAGR	average annual growth rate in percentage terms
ADO	automotive diesel oil
AES	Applied Energy Services (Hawaii)
ANS	Alaska North Slope (crude oil)
API	degrees of API (American Petroleum Institute); API gravity.
ASEAN	Association of South East Asian Nations
bcf	billion cubic feet
b/d	barrels per day
boe	barrels of (crude) oil equivalent
Btu	British thermal unit
BTX	benzene, toluene, xylene; BTX raffinate: the material remaining after aromatics extraction
CAT REF	catalytic reformer
CDU	crude distillation unit
cf	cubic feet
cf/d	cubic feet per day
c.i.f.	cost, insurance, freight
CIS	Commonwealth of Independent States (former Soviet Union)
CNG	compressed natural gas
CPE	centrally planned economies
d	day
dwt	deadweight tons
EC	European Community
ETBE	ethyl tertiary butyl ether
FBC	fluidized bed combustors
FCC	fluid catalytic cracker
FGD	flue gas desulfurization
f.o.b.	free on board (f.o.b.t.: free on board and trimmed)
gPB/l	grams of lead (Pb) per liter
GSP	gross state product
GW	gigawatts (1,000,000 kilowatts)
HDC	hydrocracker
HGI	Hardgrove grindability index
HGO	heavy vacuum gasoil (also HVVGO)
HSFO	high-sulfur fuel oil
HVAC	heating, ventilating, and air-conditioning
HVVGO	heavy vacuum gasoil
IDO	industrial diesel oil
IEA	International Energy Agency (Paris)

IGCC	integrated gasification combined cycle
kg	kilogram (2.205 pounds)
km	kilometer (0.62 miles)
kW	kilowatt (1,000 watts)
kWh	kilowatt-hours
l	liter (1.057 U.S. quarts)
lb	pound
LCO	light cycle oil
LNG	liquefied natural gas
LPG	liquefied petroleum gas
LRG	liquefied refinery gas
LSFO	low-sulfur fuel oil
LSWR	low-sulfur waxy resid
LTVGO	light vacuum gasoil
m	thousand
mb	thousand barrels
mb/d	thousand barrels per day
MDO	marine diesel oil
MITI	Ministry of International Trade and Industry (Japan)
mm	million
mmb	million barrels
mmb/d	million barrels per day
mmcf/d	million cubic feet per day
mmt	million tons
mmtoe	million tons of oil equivalent
MON	motor octane number
MTBE	methyl tertiary butyl ether
MW	megawatts (= 1,000 kW)
NGL	natural gas liquids
OECD	Organisation for Economic Cooperation and Development
OPA 90	Oil Pollution Act of 1990 (U.S.)
OPEC	Organization of Petroleum Exporting Countries
OTEC	ocean thermal energy conversion
PADD-V	Petroleum Administration for Defense District V (Alaska, Arizona, California, Hawaii, Nevada, Oregon, and Washington)
PCF	pulverized coal fired (power plant)
PCI	pulverized coal injection
PNG	Papua New Guinea
RCC	resid catalytic cracker
RDS	resid desulfurizer
resid	residual oil; also called heavy oil, bunker fuel, bottoms, etc.
RON	research octane number
RP ratio	reserves-to-production ratio
RVP	Reid vapor pressure

RVPBI	Reid vapor pressure blending index
t	ton (U.S. short ton)
tcf	trillion cubic feet
TEL	tetraethyl lead
TFI	transport fuels index (East-West Center)
toe	tons of oil equivalent
UAE	United Arab Emirates
VB	vacuum bottoms
VDU	vacuum distillation unit
VGO	vacuum gas oil
VR	vacuum resid
y	year

I. Fossil Energy Characteristics

Although energy comes in many forms, there are really only three forms available for human use: solar energy, nuclear energy, and geothermal energy. Nuclear energy is the heat released when atoms lose mass by combining (fusion) or breaking into smaller elements (fission). Geothermal energy is the heat of the planet, most of which is residual compressional heat from the original condensation of the planetary mass (but some of which derives from nuclear decay in the earth's crust).

It is typical to think of solar energy in terms of photovoltaic cells or solar water-heating panels, but most of the forms of energy that we are familiar with—wind power, fossil fuels, hydroelectricity, OTEC, and the calories in the food we eat—derive from the sun. The principal difference between fossil fuels and the so-called "renewable" energy sources is that fossil fuels are solar energy stored from millions of years ago.

Most of the renewable energy sources are "flow" resources. Hydropower, windpower, and direct use of solar insolation rely on capturing energy from a fluctuating, passing source, and these sources are easiest to use on an instantaneous basis, to generate electricity or deliver immediate heating. It is difficult for current technologies to store energy from fluctuating sources for any length of time; rechargeable batteries are expensive and bulky, and storage of heat for any length of time requires large masses and excellent insulation. The only widespread method of storage from flow resources is storage of water behind a dam, either by capturing current flow or by using a fluctuating source (such as wind-generated electricity) to pump water uphill to a reservoir.

Today, the only really effective technologies for storing solar energy on a long-term basis are not even human technologies; they are the photosynthetic technologies developed by plants. For most of human history, even this storage was treated as a flow resource. Plants store solar energy in complex compounds, which can be eaten by humans, eaten by animals that work for humans, or burned to produce heat. Human civilization revolved around an annual cycle driven by the flows of solar energy on the globe, in the temperate zone mainly by the winter/summer harvest cycle, and in the tropics by the moisture cycles such as the monsoons.

Over millions of years, a tiny fraction of the energy captured by plants (which in turn was a tiny fraction of the energy arriving from the sun) was buried in situations where it did not degrade normally. Heat and pressure in sedimentary layers gradually transformed this material into fossil fuels—peat, coal, oil, and natural gas. Most oil and natural gas, being fluid, was squeezed out of the ground as fast as it was generated, or, over the millennia, found its way to fractures and leaked to the surface. Only an infinitesimally small amount of the energy originally captured by plants found its way into "structural traps" in the ground where the oil or gas accumulated and was stored.

Like life itself, the fossil fuels are carbon-based. Peat is not far from the original structure of the plant materials from which it formed. Coal is largely carbon, with smaller amounts of hydrogen and other elements than peat. Oil is almost exclusively hydrogen and carbon, with hydrogen exceeding carbon by a ratio of more than two to one. As the ratio of hydrogen to carbon increases to its limit of four to one, the compounds become smaller and lighter, until they are gases at ambient temperature—so-called natural gas. Oil and natural gas are called the "hydrocarbons" because of their composition; coal is usually excluded from this group.

Although many writers assert that human knowledge of fossil fuels is a very recent phenomenon, dating from the industrial revolution, human knowledge of and use of fossil fuels extends back into the mists of prehistory. In some areas, such as northern Persia, natural gas seeps accidentally ignited and burned perpetually; these were naturally sites of great religious significance to the surrounding peoples. Pitch was gathered from tar seeps in both the Americas and Asia for the caulking of reed boats and canoes long before the advent of written records, and exports of pitch from Burma to China were important 2000 years ago. The "Greek fire" used in early naval battles is generally believed to have been a compound based on naphtha collected from oil seeps in the

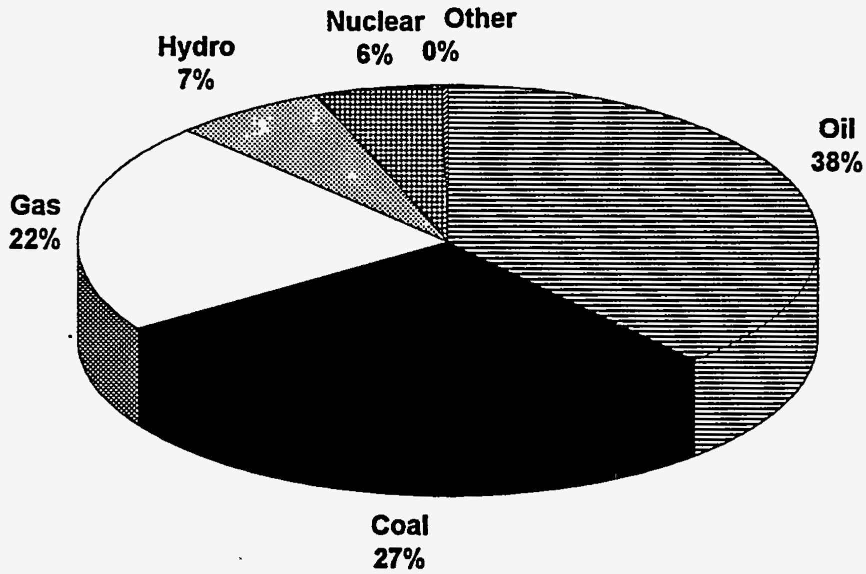
Mideast, and there are some indications that oil was gathered for a wide variety of purposes when it was available.

The transformation of plant matter into fossil fuels has a number of consequences. One is that most of the oxygen in the original plant matter is lost. The carbon and hydrogen—the combustible fractions—are thereby concentrated. On a weight basis, coal contains 140 percent of the energy found in wood, 230 percent of that found in oil, and about 290 percent of that found in natural gas. Thus a great deal more energy is available in fossil fuels than in the plant matter from which they are derived. Moreover, millions of species of organisms have specialized in breaking down plant matter to obtain the energy it has stored. Most organic matter decays fairly rapidly in nature, and even tough materials like wood have termites, fungi, and a wide variety of bacteria to attack them. Fossil fuels are rarer, so few organisms have learned to eat them (although there are a surprising number of microbes that can attack some or all of the compounds in oil under the right conditions). Thus, fossil fuels not only store energy at unusually high concentration, but they also store it in a form where it can be preserved almost indefinitely (on a human span of time). No other naturally occurring form of energy offers these advantages.

The burning of peat for heating and cooking in various parts of the world goes back as far as records exist. Coal has always been known from various outcroppings, but it was really the deforestation of major urban areas in Europe and Asia that led to widespread mining and use of coal. With the industrial revolution in Britain, and the invention of the steam engine, the demand for energy expanded far beyond what could be provided from local forests and watermills, and coal use burgeoned. The development of oil-drilling technologies and systematic structural geology in the late 1800s expanded fuel possibilities even further.

From a world in which wood, wind, and water were the only important sources of motive power and heat, by 1990, as Figure 1 shows, 87 percent of the world's

Figure 1. World Energy Supply by Source, 1990



Note: "Other" includes fuelwood, peat, charcoal, and bagasse.

energy was provided by fossil fuels, with oil taking the dominant position. Use of renewable sources of energy—mostly hydropower, with smaller amounts of fuelwood, charcoal, and agricultural residue—was less than 8 percent of supply, and nuclear energy accounted for a mere 6 percent.

Figure 2 shows world energy supplies by source from 1955 to the present. The "other" category includes estimates of fuels such as fuelwood and bagasse—the most recent comprehensive data for which is 1990. Consumption is represented in million barrels per day of oil equivalent. The growth over less than forty years has been tremendous. The amount of oil alone used in 1992 was larger than the total amount of energy used in the world in 1960. Although non-fossil sources of energy (hydro, nuclear, and others) have expanded at a rapid pace, the total growth in energy demand has been so large that their share has expanded only slightly.

This is a strange and remarkable transition. Two-thirds of today's energy comes from sources that were negligible (oil and gas) or unheard of (nuclear) one hundred years ago. There are people alive in the United States today who can remember when wood was a more important energy source than oil. In countries such as Korea, where wood provided more than 50 percent of energy demand in 1960, the transition has been even more rapid.

This pattern of reliance on fossil fuels is neither a matter of industrialization alone, nor of lifestyle or economic system. As Figure 3 shows, the similarities in energy use patterns are greater than the differences between the industrial countries of the Organisation for Economic Cooperation and Development (OECD), the former communist countries of the Commonwealth of Independent States (CIS), Eastern Europe, and the diverse mixture of economies of the less-developed countries (LDCs). Nuclear is a major source only in the OECD; the former communist states use more than a typical share of gas, while the LDCs use only a small amount of gas; the OECD is more dependent on oil relative to other sources, largely because of the private automobile and air travel. But in every case, as Figure 4 shows, the fossil fuels are

Figure 2. World Energy Supply By Source, 1955-92

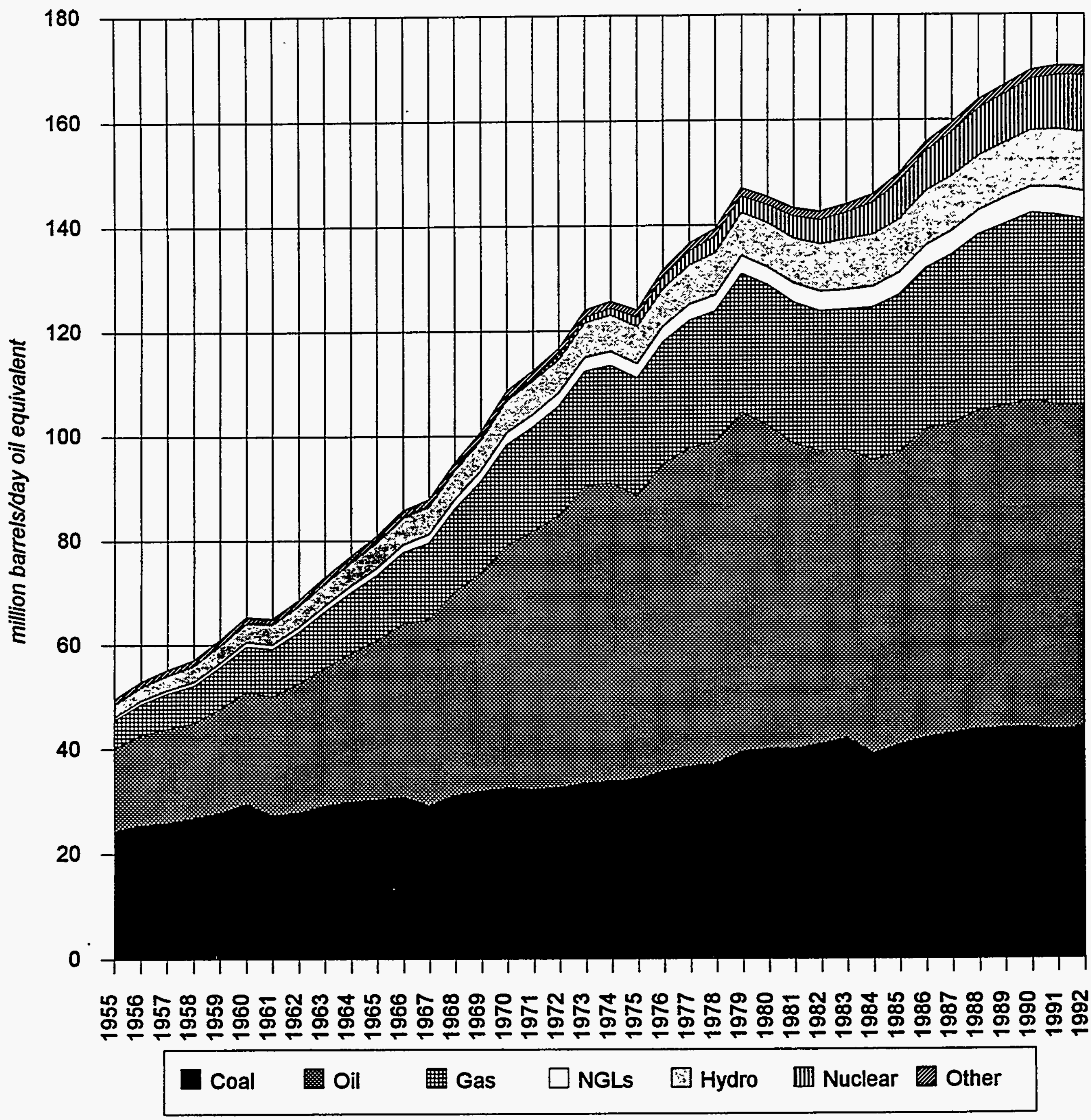
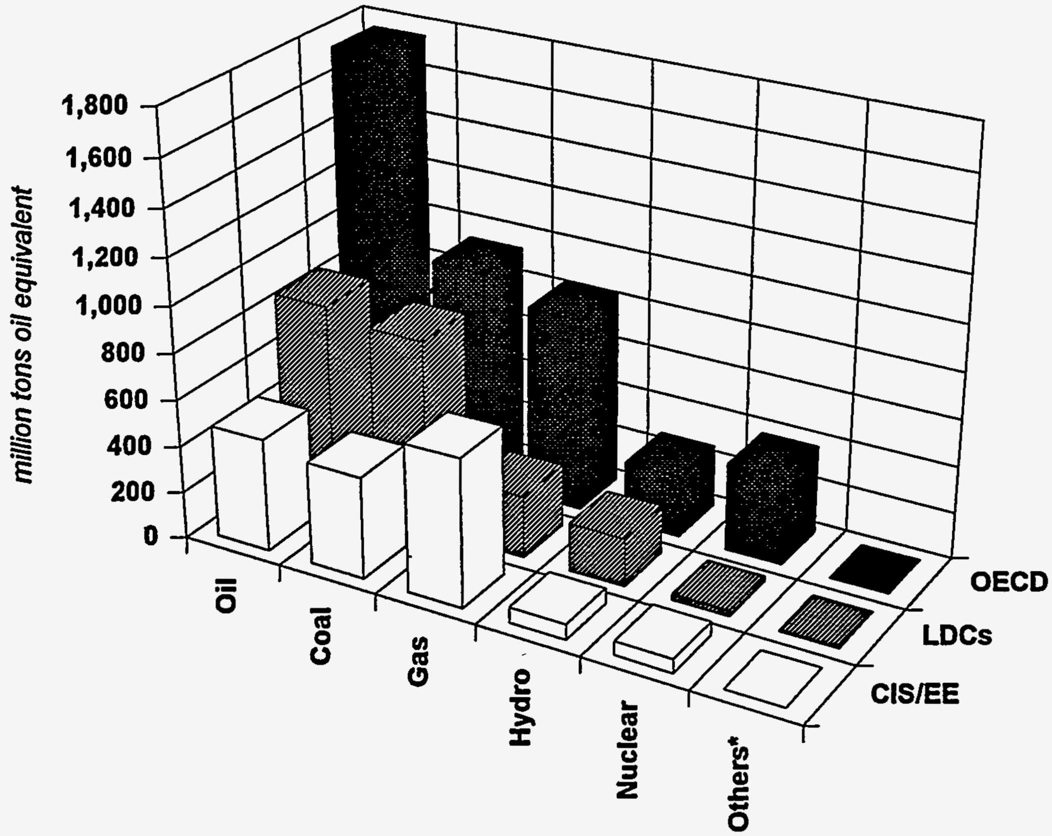
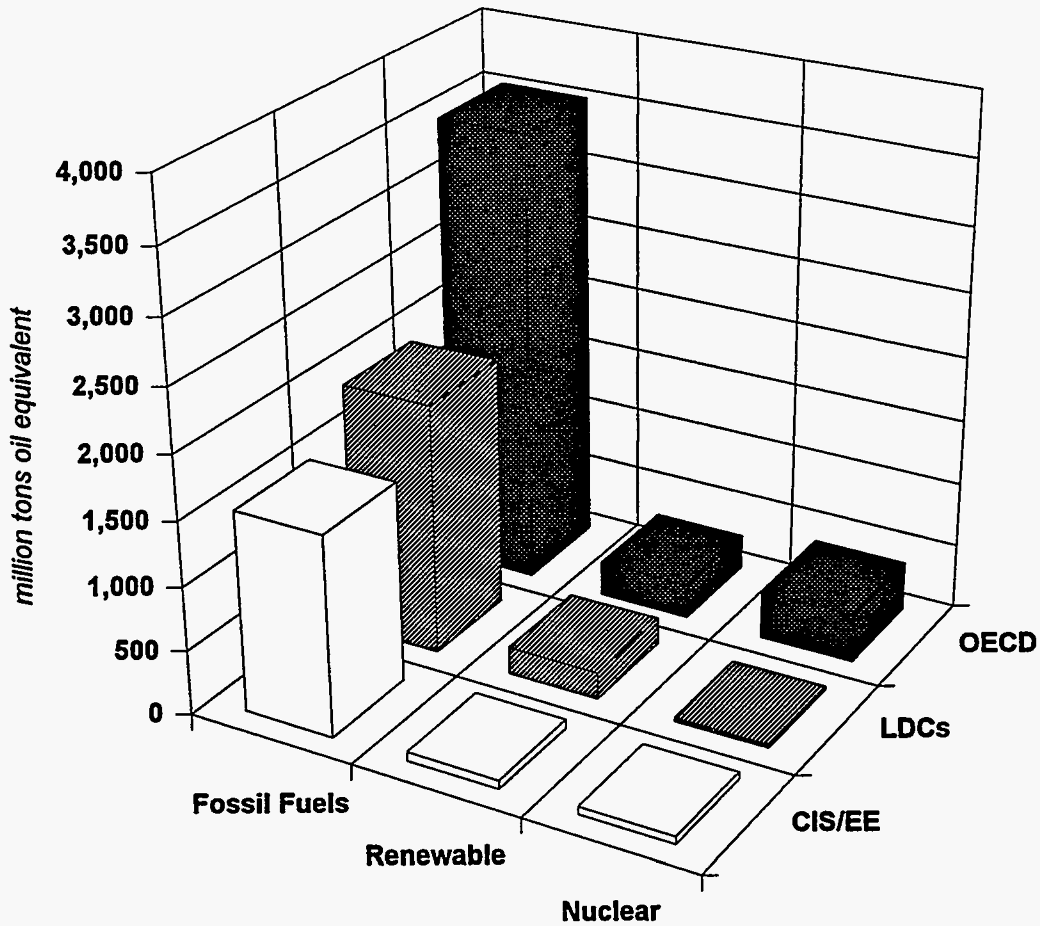


Figure 3. Composition of Energy Demand, 1990



Note: "Other" includes wood, charcoal, peat, and bagasse.

Figure 4. Energy Supplies by Type, 1990



dominant in all three economic groupings to an extent that dwarfs the contribution of other energy sources.

As Figure 5 shows, all three of the groupings rely on fossil fuels for more than 80 percent of their energy needs. Somewhat surprisingly, it is the industrial nations of the OECD that have the lowest dependence on fossil fuels, largely because of the substantial nuclear industry, combined with fairly intensive development of major hydropower projects. At the other end of the scale, the former communist nations have the highest reliance on fossil fuels as a consequence of centralized production and planning; large-scale energy supply schemes are more suited to centralized management than small-scale, diverse sources. The largest percentage use of renewable energy is in the LDCs, but this is not so much a matter of strategy as traditional uses that have not yet been supplanted by fossil fuels.

Why are fossil fuels so dominant? In part, it is just their energy density; they are extremely convenient compared to most other energy forms. But the biggest issue is one of cost; the energy in fossil fuels has been stored and concentrated over millions of years into small, localized pockets that can, for a short while, be tapped at amazingly low prices.

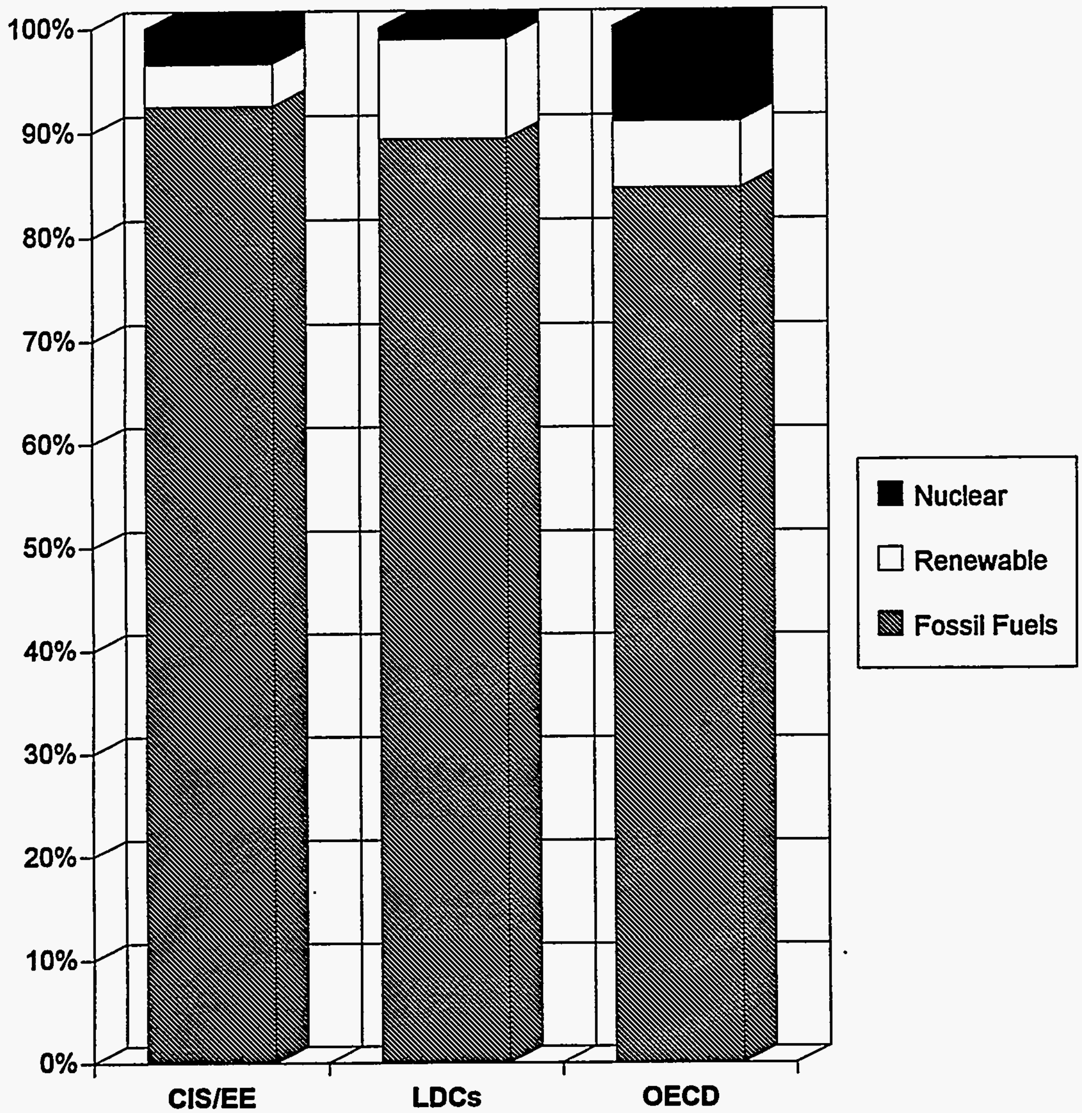
Table 1 gives some basic characteristics of fossil fuels in comparison with stored renewable energy in the form of wood, methanol (wood alcohol), and ethanol (grain alcohol). (It is difficult to draw comparisons between fossil fuels and hydroelectric, windpower, or direct solar in terms of costs, because they do not typically produce a stored form of energy.)

Ethanol's energy density is comparable to the fossil fuels on a weight basis, though it is much lower than oil or gas, but it is far less energy dense than oil on a per gallon basis. Methanol and wood score poorly relative to fossil fuels on energy density both per pound and per gallon. Oil strikes a very convenient balance between its relatives, having more energy per volume than gas, but more energy per weight than coal.

Table 1. Characteristics of Fossil and Renewable Fuels

	Coal	Oil	LPG	Natural Gas	LNG	Methanol	Ethanol	Wood
Energy Density								
Btu/lb	11,524	18,981	13,867	23,856	23,856	9,152	11,500	8,135
Btu/cf	990,402	1,010,690	473,662	1,002	616,566	449,864	524,132	140,069
Btu/gal	132,407	135,119	63,324	134	82,429	60,142	70,071	18,726
Energy Capture								
$/mmBtu, typical	$0.78	$0.26	$0.85	$0.52	$2.25	$25.61	$21.85	$1.12
$/mmBtu, high	$1.08	$2.41	$3.50	$3.15	$5.50	$32.76	$43.96	$3.35
$/mmBtu, low	$0.43	$0.09	$0.40	$0.03	$1.20	$3.82	$17.96	$0.00
Energy Transport								
$/mmBTU, typical:								
Land, 500 miles	$0.39	$0.28	$0.67	$0.39	$0.39	$1.01	$0.89	$0.55
Sea, 3,000 miles	$0.48	$0.22	$0.52	$1.38	$1.38	$0.81	$0.70	$3.37
Storage Costs								
Typical $/mmBtu/month	$0.01	$0.04	$0.17	$0.35	$0.35	$0.10	$0.08	$0.08
Uses	**(Lim. = Limited Uses; Exp. = Experimental)**							
Heating	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Power Generation	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Motor Fuel	No	Yes	Yes	Yes	No	Yes	Yes	No
Air Travel	No	Yes	No	No	**Exp.**	No	No	No
Chemicals	**Lim.**	Yes	Yes	**Lim.**	**Lim.**	No	**Lim.**	No
Environmental as % of *weight Sulfur*								
Typical	**0.80%**	**1.50%**	0.00%	**0.10%**	0.00%	0.00%	0.00%	0.00%
High	**3.50%**	**6.00%**	**0.10%**	**3.40%**	0.00%	0.00%	0.00%	0.00%
Low	**0.10%**	**0.03%**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Metals	**Yes**	**Yes**	No	No	No	No	No	No
Lbs CO2/mmBtu	206	165	139	115	115	141	149	211
Is fuel a greenhouse gas?	No	**Slight**	**Yes**	**Yes**	**Yes**	**Yes(?)**	**Yes(?)**	No
Emissions from extraction?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes(?)**	**Yes(?)**	No
Evaporative?	No	**Yes**	**Highly**	**Highly**	**Highly**	**Highly**	**Highly**	No
Renewable?	No	No	No	No	No	**Yes**	**Yes**	**Yes**
CO2 balance?	No	No	No	No	No	**possible**	**possible**	**possible**

Figure 5. Shares of Fuel Types in Energy Demand, 1990



Solid fuels have the convenience of not requiring containment; they can be stored in piles without leaking out or evaporating. The great drawback of solids is that they are difficult to handle; it is far cheaper to pump a gas or liquid through a pipe than to move solids about with steam shovels, particularly during loading and unloading of ships, rail cars, or trucks. Solids are also not homogeneous like liquids or gases, and can require extensive preprocessing before use. There is usually substantial residue or ash that does not burn away.

Gas is easy and cheap to move, and conforms to the shape of any container. Unless it is liquified to LNG, however, its energy density per unit volume is low. Oil's energy density per gallon is 1,000 times that of natural gas at normal pressures. This means that gas is fairly easy to move (through pipelines) and process, but very difficult and expensive to store.

Oil is both easy to transport and easy to store. It needs to be kept enclosed, since it contains volatile components that would otherwise escape, but it need not be kept under unusual pressure. Although oils vary substantially in their composition, any given barrel of oil is thoroughly mixed, yielding a material with a fairly homogeneous response to most processes. It is easy to design engines and boilers to run on gaseous or liquid feeds; it is difficult, unfortunately, to design sufficient storage for gaseous fuels. This has made oil the fuel of choice for most modern transport purposes, and most approaches to finding substitutes for oil in the transport sector likewise seek a liquid energy carrier.

The most important thing about fossil fuels, however, is that these desirable energy densities are available at very low prices. The complaints about "high oil prices" over the last twenty years tend to mask the fact that the average *cost* of producing oil is almost unimaginably low—only about 26 cents per million British thermal units (mmBtu). This is only about 20 percent of the cost of the same amount of wood energy, and oil is far more useful for most purposes other than carpentry. Typically, oil costs only about half as much as a unit of natural gas energy, only a third as much as a unit of coal, only a fifth of the cost of a unit of wood—and only about 1 percent of the cost of an alcohol biofuel like ethanol. Oil has attained its prominence among fossil fuels because it is both cheaper and more useful than its relatives; the fossil fuels dominate the energy scene because they are hugely cheaper than the nonfossil fuel competition in most situations. They are cheaper to transport, cheaper to store, and cheaper to produce or gather.

Consider the section of the table labelled "uses." Only oil is found in every niche. The solid fuels (coal and wood) are the most limited in their repertoire, and gas and alcohols cover a range of uses, but not with oil's versatility. There are those who attribute oil's dominance of the modern energy scene to plots by the oil companies, or even just to people's stubbornness. But the simple facts are undeniable: oil is the most useful and versatile of our fuels, and it is capable of becoming very cheap on short notice—cheap enough to destroy the economics of production of other fuels, as many energy entrepreneurs learned to their regret in the 1980s.

The problem is that the cost of producing oil is not related to its value, and oil is extremely valuable. It costs about $63 to produce enough ethanol to equal a barrel of oil, even with generous assumptions. An economist would say that, all other things being equal (they aren't), if ethanol is the next-best substitute for oil, then oil is a bargain at anything less than $63/barrel (b). The *value* of the oil is what it costs to do the same thing by other means; the *cost* of the oil is the expense incurred in bringing it out of the ground; and the *price* of the oil is usually somewhere in between these two. The difference between the price and the cost is the "rent," a profit that accrues to the resource because of its scarcity. Some of this rent accrues to the explorer for the large investments it may (or may not, if the explorer was lucky) have taken to find the deposit; more accrues to the owner of the resource, which, in every country other than the United States, is the government. (The United States is the only country in which an individual can own the mineral resources themselves, rather than merely a right to extract them.)

As the 1980s showed, even oil *prices* at today's level of $18-22/b are cheap. Oil at $34/b did result in significant conservation, and some degree of fuel switching, but the fact of the matter is that, for many uses of oil (such as transport fuels), doubling oil prices today would still leave oil a competitive edge against most other fuels. Optimists talk in terms of ethanol at $1.50/gallon, which might sound competitive with gasoline; but 46 cents per gallon of current gasoline prices is tax, meaning that today's typical gasoline price on Oahu excluding tax is $1.02/gallon. Furthermore, it takes about 1.6 gallons of ethanol to provide as much energy as a gallon of gasoline. Thus, the energy equivalent of a gallon of ethanol would be an amount of gasoline that sells today on Oahu for about 62 cents. In other words, ethanol, at what most people would call a reasonable price, costs almost two-and-a-half times as much as ex-tax gasoline prices in 1993.

The dangerous element in this is that $1.50/gallon for ethanol is a price at which the producer makes money—not huge profits, but profits high enough to encourage investment. A typical oil producer still makes money at 20 cents per gallon: Not enough money to pay back all the risks taken by all the explorers, not enough money to encourage new investment, not enough to run huge offices that administer the national oil company, but enough to get the oil out of the ground, refine it, and make a small profit. More oil would never be found at such prices (about $4/b), but the floor on oil production costs is lower than that for any other energy source. The huge deposits of the Mideast are the marvels of the world; for the price of drilling a hole into the ground, unimaginable volumes of energy flow out, virtually for free. There has never been a source of energy like this in human history, and we are unlikely to see another in the future.

The purpose of this discussion is not to sing the praises of oil, but rather to put things into perspective. The oil deposits of the planet are like a huge inheritance, valuable and utterly unearned. Like a large fortune, it can be squandered in a few generations; at present rates, we have at best 50-70 more years of present behavior. The way that the fortune is split up between governments, oil companies, and consumers varies from year to year, but all of us are spending out of our savings, and despite the complaints about high prices, what we pay for fossil fuels today is nothing compared to what we would pay to conduct the same activities if we had to rely entirely on the annual energy income from the sun. Oil's production cost today is so cheap that it can readily undercut any other energy source, but its price is quite likely still below its real value.

There are side effects to living off this stored wealth, one of which is environmental contaminants. Oil retains some of the sulfur originally found in the plant matter from which it derives. Sulfur levels can amount to more than 6 percent by weight in some fossil fuels, giving rise to sulfur dioxide and acid rain upon combustion. In addition, storing energy in the ground exposes it to a number of other elements and compounds that can become linked into the oil molecules, such as nickel, vanadium, and sometimes arsenic. The metals in oil tend to be found in concentrations of a few parts per million. Even so, they can be serious pollutants and can also damage machinery, catalysts, and other materials they come into contact with. Users of fossil fuels all suffer from such contamination to one degree or another, whereas renewable sources of energy are typically free of such problems.

Furthermore, the bulk of the energy stored in the ground in fossil fuels has been stored in the form of unoxidized carbon. By burning this stored carbon, we release carbon dioxide into the atmosphere at a far greater rate than the biosphere can lock it back up. A typical car emits about a pound of carbon dioxide for every mile it is driven. Most drivers thus produce 5 or more tons of carbon dioxide a year. Table 1 lists the emissions of carbon dioxide for each of the fuels under discussion. This increased carbon dioxide load is the main contributing element of the greenhouse effect that many fear will produce global warming (see Chapter V of this report).

Some of the fuels are themselves greenhouse gases if emitted into the atmosphere. The most notorious is methane, which is the main component of natural gas. Liquefied petroleum gas (LPG), some components of oil, and possibly the alcohols are direct contributors to the greenhouse effect if they enter the atmosphere by evaporation.

Extraction of the resources can also emit greenhouse gases, the classic example being coalbed methane. Most fuels can emit some greenhouse gases, but the extent to which they do depends greatly on the precautions taken.

Although the renewable fuels have substantial carbon dioxide emissions per unit of energy, they hold the potential for maintaining a carbon balance with the atmosphere; that is, if fuels are grown renewably, they can extract as much carbon dioxide from the air as is released by burning them. This is something no fossil fuel can achieve. When fossil fuels are burned, we are not only releasing stored energy, but releasing stored carbon as well. Although it is hard to attach a price to externalities, good arguments can be made that the current price of fossil fuel use is below the actual cost of their use when all factors (environmental damage, maintaining military presence near key energy exporting areas, foreign trade deficits, etc.) are accounted for. The assumptions involved in such a calculation are myriad, and enthusiasts can prove almost anything they desire in this arena. What cannot be doubted, however, is that there are major environmental, social, and economic costs in current uses of fossil fuels that are not accounted for in the pricing of such fuels. The debate focuses on the magnitude of these external costs; some maintain that the costs are actually far less than the estimates used by proponents of alternative fuels.

If fossil fuels are brought under competitive pressure from other energy sources, they can easily fall back to lower prices. The oil industry did this in the 1980s, and the shutdown of capacity outside the United States (where thousands of 2- to 30-b/d stripper wells were shut down) was fairly minimal. A price of $10/b was painful to industry but did little to curtail production potential in the short term. Any strategy that contemplates large-scale substitution of other energy sources for fossil fuels has to be prepared for a day of severe price competition. Moreover, while coal and gas can easily be displaced by a wide variety of fuels, there is no renewable fuel on the horizon that will offer a substitute for oil's ubiquity. A successful strategy for reducing oil dependence will have to take an integrated approach, with different fuels or conservation measures attacking different parts of the barrel. Any strategy that does not consider all of the roles of fossil fuels could easily reduce the absolute level of consumption, but leave the state just as vulnerable to disruption of one or two strategic uses of oil products.

II. The World Oil Industry

Oil is a single world market. Even with domestic price controls in some countries, and elaborate cross-subsidy schemes, it is ultimately the movement of prices on the world market that determines the import and export incentives and governmental subsidy levels that a nation faces. Centrally planned economies, such as China's, have had to come to terms with the world market despite ideological preconceptions about the price of oil, if for no other reason than the fact that the external market price is the amount of income that is lost if the oil is consumed in the country instead. Even the largest exporter, Saudi Arabia, found in the mid-80s that prices could not be set by fiat, but rather had to follow the values of petroleum products in major consuming centers.

Given the integrated nature of the market, the organization of any reports on the subject is arbitrary. This report stresses the fundamentals of the industry and the developments in the global and regional market. It is essential background to the discussion of the specifics of the Hawaiian situation in the report of Task II (*Fossil Energy in Hawaii*) of this project. Many features of the Hawaiian oil situation are unique. To appreciate the implications of these features, it is necessary to understand the structure of the market elsewhere. Furthermore, the global trends that are emerging will make themselves felt everywhere, but the impacts on Hawaii may in many cases differ from generalizations about the overall market. The more important differences between Hawaii and other markets are highlighted in this report where appropriate, but the details and policy implications are generally reserved for the more precise evaluations provided in the Task II report.

A. Prologue: "The Rule of 20"

At the beginning of the 1990s, there are about 200 countries in the world. About 80 of them produce oil; about 100 of them have known oil reserves; about 120 have oil refineries; all 200 use oil. It can take years of study to become familiar with the international oil industry and all of the players.

Fortunately, a good overview of the global situation can be obtained by appeal to the "Rule of 20." The Rule of 20 states that, for no particular theoretical reason, the top 20 countries in any aspect of oil will account for at least three-quarters of the total activity. Oil is often described as a volatile commodity, and in price terms this is certainly correct. In terms of where oil is found and where it is produced, consumed, imported, and exported, however, there is considerable stability. This section provides a glance at the "big picture" in oil, based on the Rule of 20.

1. Oil Reserves

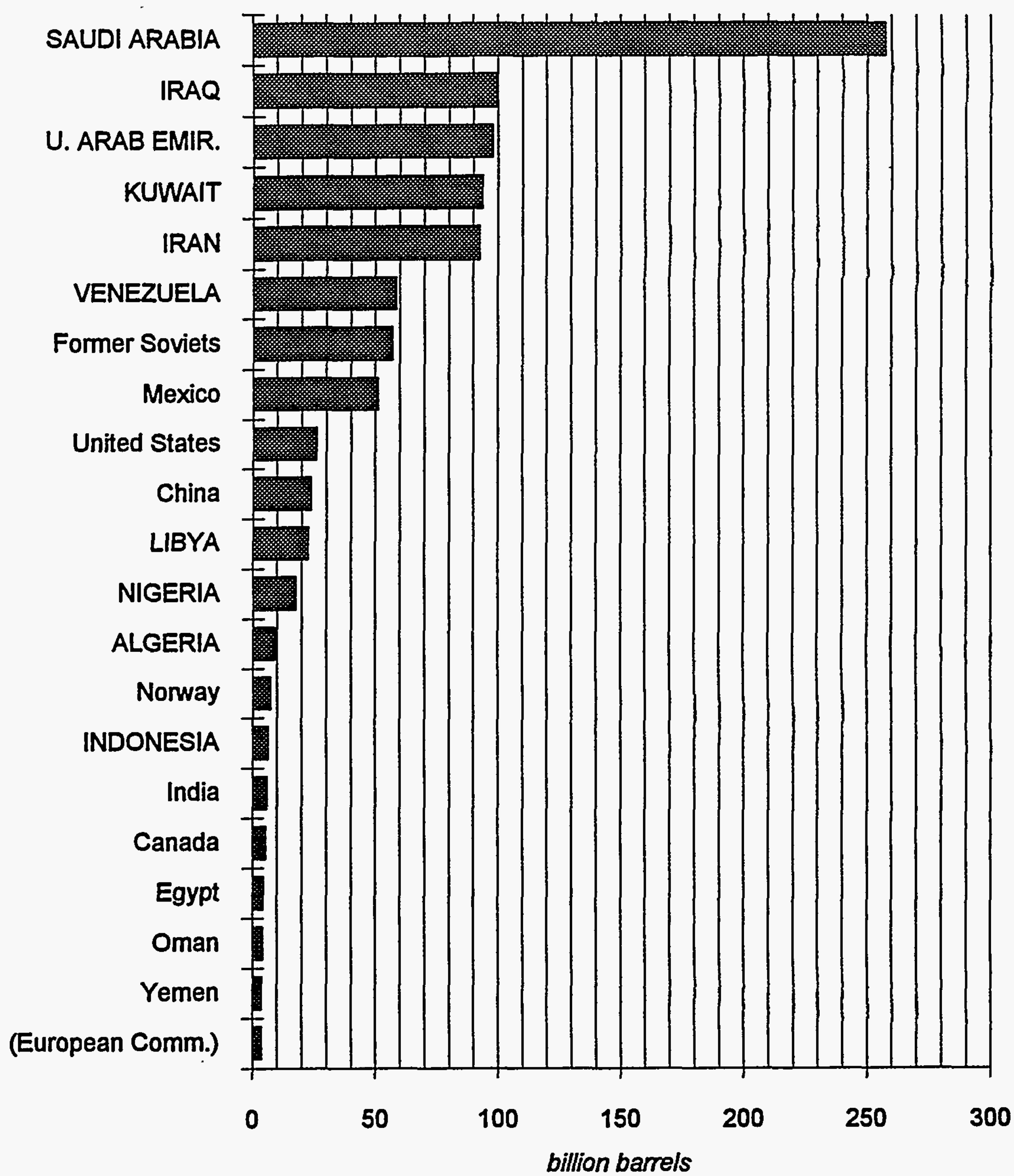
Figure 6 shows the proven crude oil reserves of the "Top 20" countries in 1991. These 20 countries account for 96 percent of the world's known reserves of oil. The top 6 are OPEC members. The top 5 are OPEC members in the Persian Gulf. Half the countries shown on the figure are OPEC members, and of the 13 members of OPEC, only three—Gabon, Ecuador, and Qatar—are not in the Top 20. OPEC accounts for 77 percent of world oil reserves, and all but a tiny fraction is represented on this chart.

Following the top 6 comes the former Soviet Union with 57 billion barrels; there are obvious political questions about the future composition of the Commonwealth of Independent States (CIS), but the former Soviet Union should continue to be rated as one, and possibly two or three, of the Top 20 in oil reserves.

Mexico has formidable reserves of about 50 billion barrels of oil. After Mexico, the next contenders—the United States and China—drop by half, to less than 25 billion barrels. All of the oil in China or the United States amounts to only 10 percent of the reserves in Saudi Arabia.

Behind China come three more OPEC countries: Libya, Nigeria, and Algeria. None have particularly large reserves. Algeria takes us below the 10 billion barrel mark, after

Figure 6. Top 20 Oil Reserves, 1991



Notes: Names of OPEC members are in uppercase. OPEC accounts for 77% of world reserves. Top 20 account for 96% of world reserves. EC shown for comparison.

which we begin to encounter countries that many people may not even realize are oil producers, such as Norway, India, and Yemen.

2. Oil Production

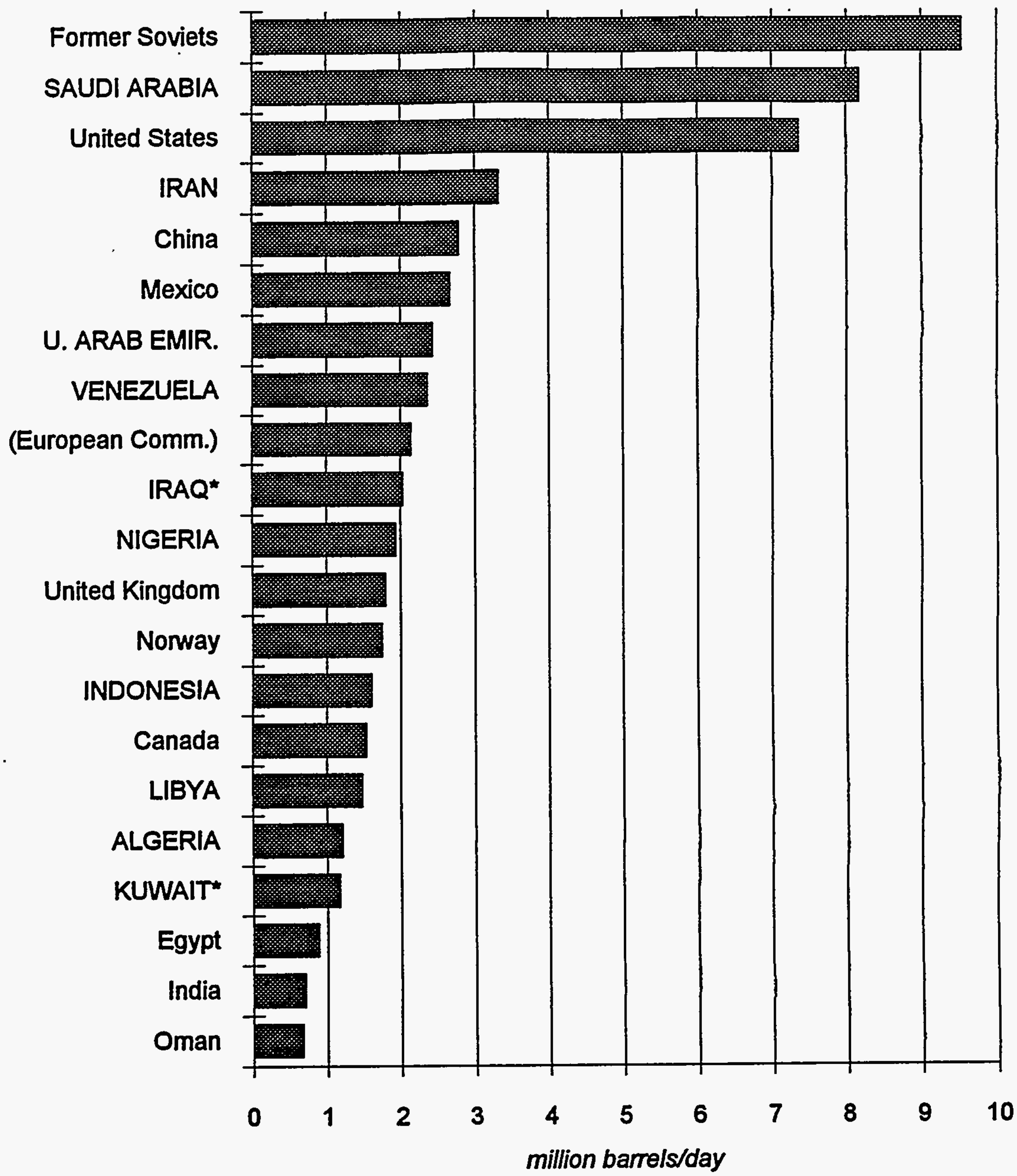
Figure 7 shows the Top 20 oil producers. Naturally, the names on the list are essentially the same as on the list of crude reserves, but the ordering is different. The former Soviet Union is the leader in production; the United States is number three, right after Saudi Arabia. (Until the late 1980s, the United States was traditionally number two, after the Soviet Union; declining production has put the United States roughly on par with the Saudis).

Only one country (Yemen) falls off the Top 20 list, and the United Kingdom climbs up to take its place. Some of the switches, however, are instructive. Kuwait (shown at prewar levels), with the fourth-largest oil reserves in the world, is only the 17th-largest producer. This is a matter of policy, not of capability. Kuwait plans to be producing oil 150 years from today.

Although the Top 20 countries shown on Figure 7 account for 92 percent of all oil production, OPEC—with 77 percent of the reserves—accounts for only 38 percent of total production. Non-OPEC countries are depleting their reserves of oil at a more rapid rate than the OPEC countries, which naturally means that we can expect for OPEC to have an even greater share of world reserves in coming years.

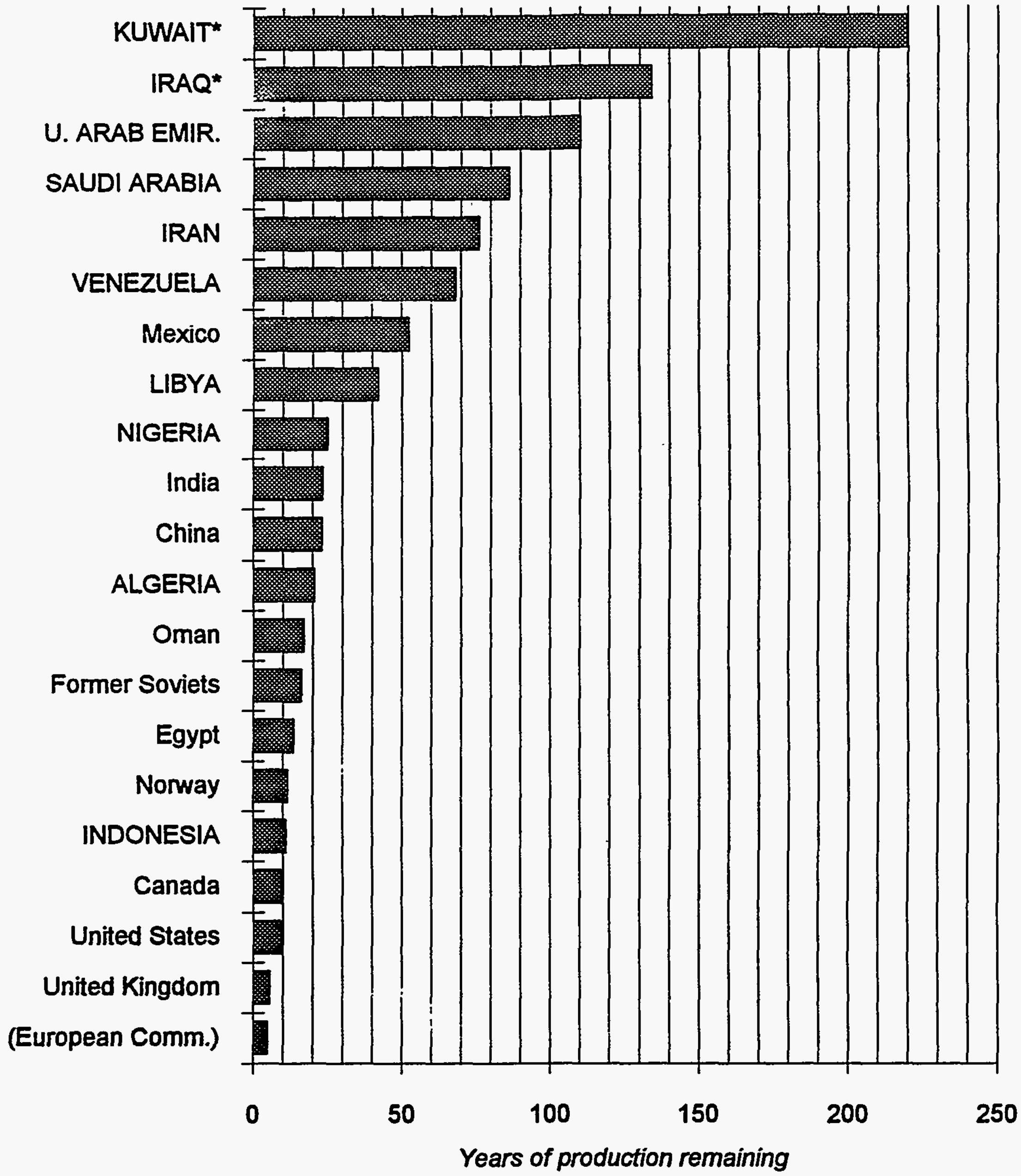
The fact that OPEC is depleting its reserves more slowly than non-OPEC countries is for some OPEC members a matter of strategy, and for others, the simple result of the fact that most countries will produce their own (often more expensive) oil rather than import. The ratio of reserves to production, the RP ratio (shown in Figure 8), has many faults in predicting when a producer will "run out of oil," but it is still a good indicator of relative rates of depletion: The higher the RP ratio, the slower the rate at which the country is depleting its oil reserves.

Figure 7. Top 20 Crude Producers, 1991



Notes: Names of OPEC members are in uppercase. Kuwait and Iraq are shown at prewar levels. OPEC accounts for 38% of world production. Top 20 countries account for 92% of world production. EC shown for comparison.

Figure 8. RP Ratios of Top 20 Oil Producers, 1991



Notes: Names of OPEC members are in uppercase. Kuwait and Iraq are shown at prewar levels. EC shown for comparison.

Not surprisingly, the most rapid depletion is in the industrial world, with the United States, the UK, and Canada all having RP ratios of 10 years or less. At the other end of the scale, Kuwait has about 200 years, Iraq 140 years, Saudi Arabia 85 years, and both Iran and Venezuela about 70 years. Unless alternative resources are developed and deployed, the drive for "self-sufficiency" in oil in importing countries merely means a higher level of foreign dependence in future years.

3. Oil Consumption

Figure 9 shows the Top 20 consumers of oil. The Top 20 account for 82 percent of all world oil demand. In the case of oil demand, however, OPEC countries account for only 6 percent of the total. Only 3 OPEC countries—Saudi Arabia, Iran, and Indonesia—are among the top consumers of oil, and each uses less than 1 million barrels per day (mmb/d).

At the other extreme is the United States, with almost 17 mmb/d of oil demand. This dwarfs even the total demand of the European Community at 11 mmb/d. Number two after the United States is the former Soviet Union at 9 mmb/d and falling.

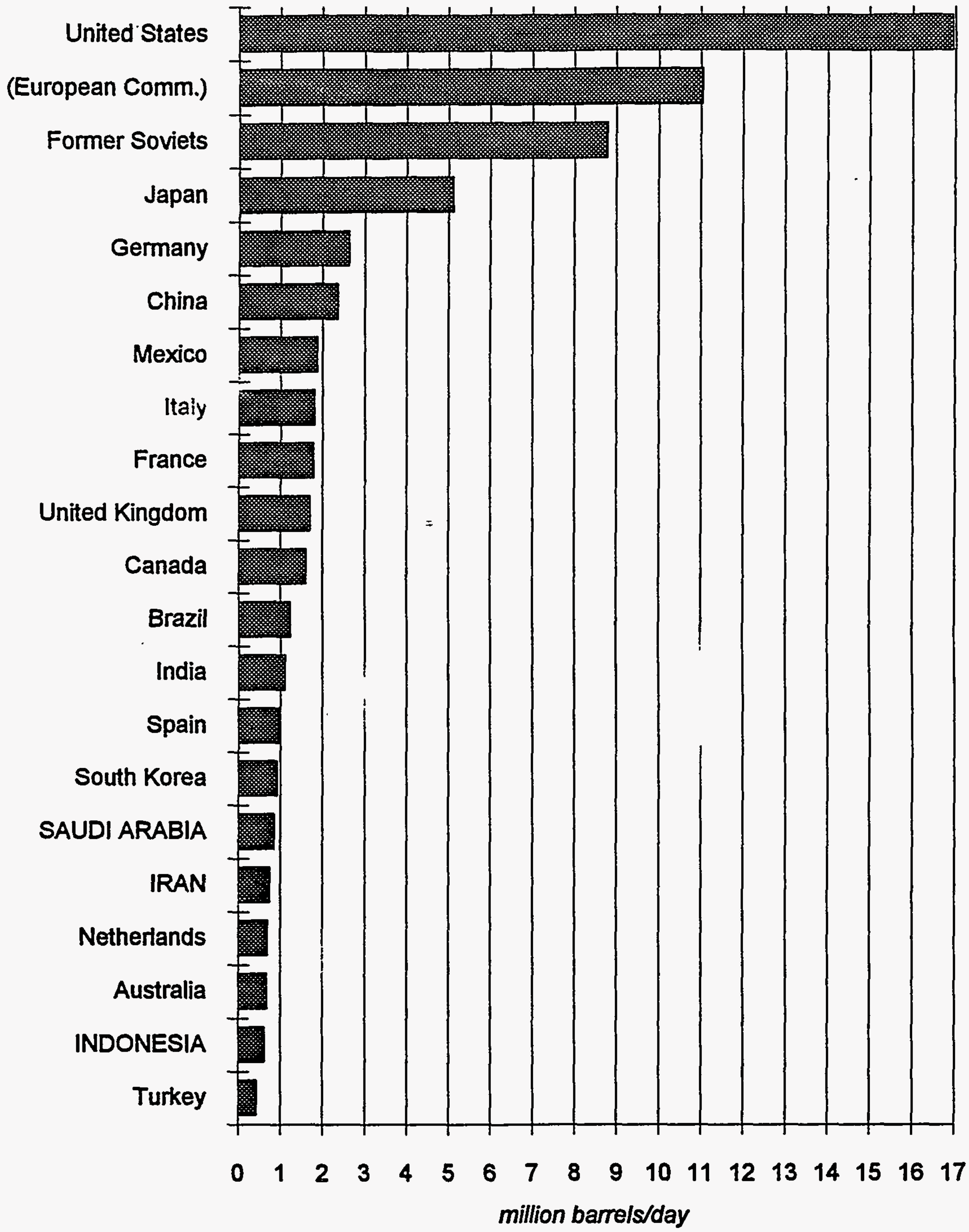
Japan, with virtually no oil reserves, is the third largest consumer at 5 mmb/d. Below Japan, Germany and China both register in the 2-3 mmb/d category, after which there is a host of industrial and newly industrializing countries in the 0.5-2.0 mmb/d range. Although oil is consumed everywhere, a few big users account for a disproportionate share of demand.

4. Oil Exporters

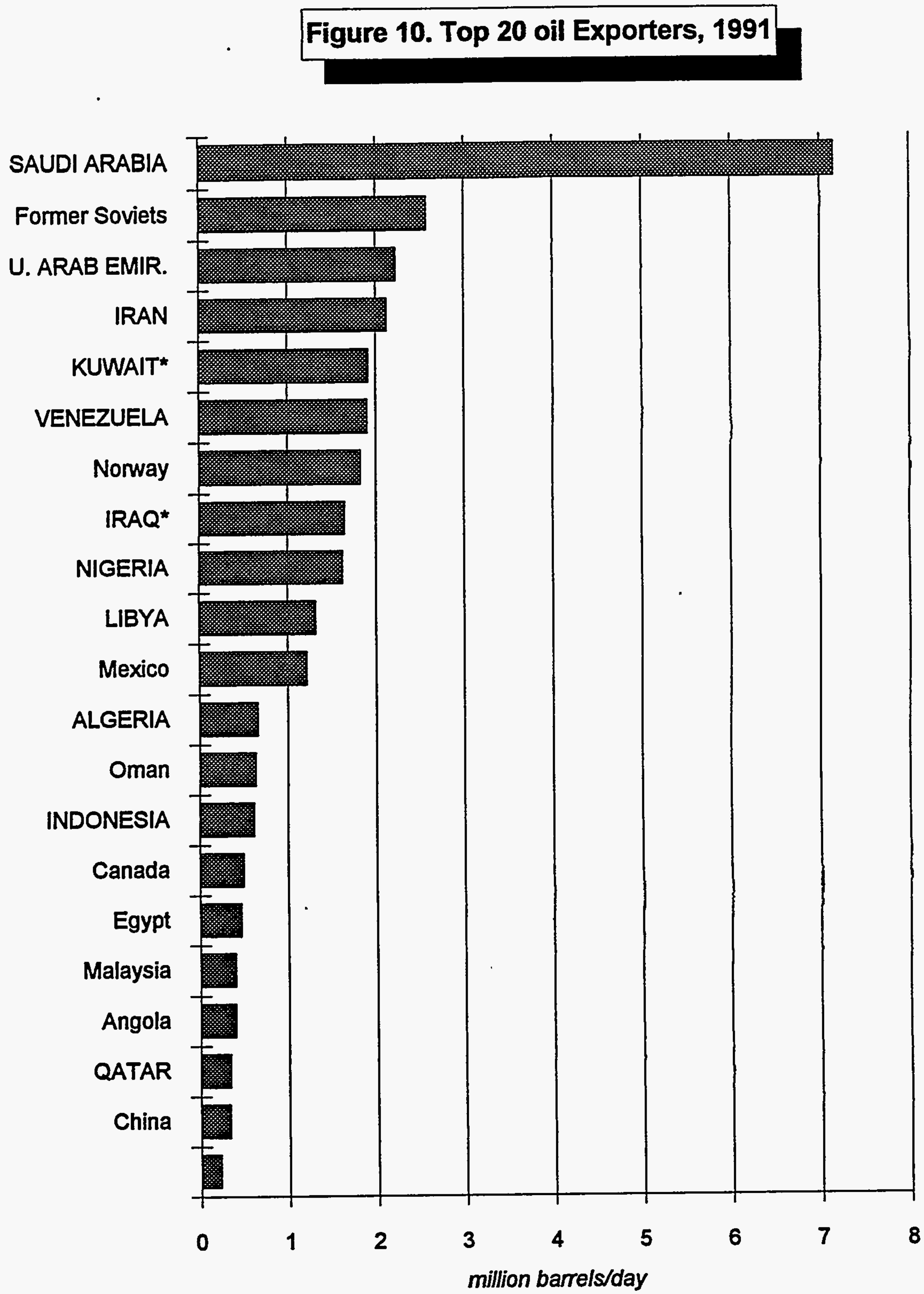
Figure 10 shows the Top 20 exporters of crude oil. These 20 account for 92 percent of exports. It surprises some to find that OPEC accounts for only 67 percent of all exports in a typical year; a few big exporters (the former Soviet Union, Norway, and Mexico), and dozens of tiny ones, make up a substantial share of world trade.

At over 7 mmb/d, the Saudis are more than double the nearest competitor, the former Soviet Union, at 2.5 mmb/d (and falling). Most of the countries from Figure 6 are on the

Figure 9. Top 20 Oil Consumers, 1991



Notes: Names of OPEC members are in uppercase. OPEC accounts for only 6% of world consumption. Top 20 account for 82% of world consumption. EC shown for comparison.



Notes: Names of OPEC members are in uppercase. Kuwait and Iraq are shown at prewar levels. OPEC accounts for 67% of world exports. Top 20 countries account for 92% of world exports. EC shown for comparison.

list, with the very notable exception of the United States, which is a large producer with larger reserves and large imports as well. There are, however, a few possible surprises among the Top 20 exporters, such as Malaysia and Angola. The lesson to be learned is that important exporters do not necessarily have large reserves, or even large production; what they have is production capabilities in excess of their own demand. Many new producers coming onstream in the 1990s, such as Papua New Guinea or Vietnam, will not have large outputs of oil, but they will have an effect on the market because the bulk of what they produce will be traded.

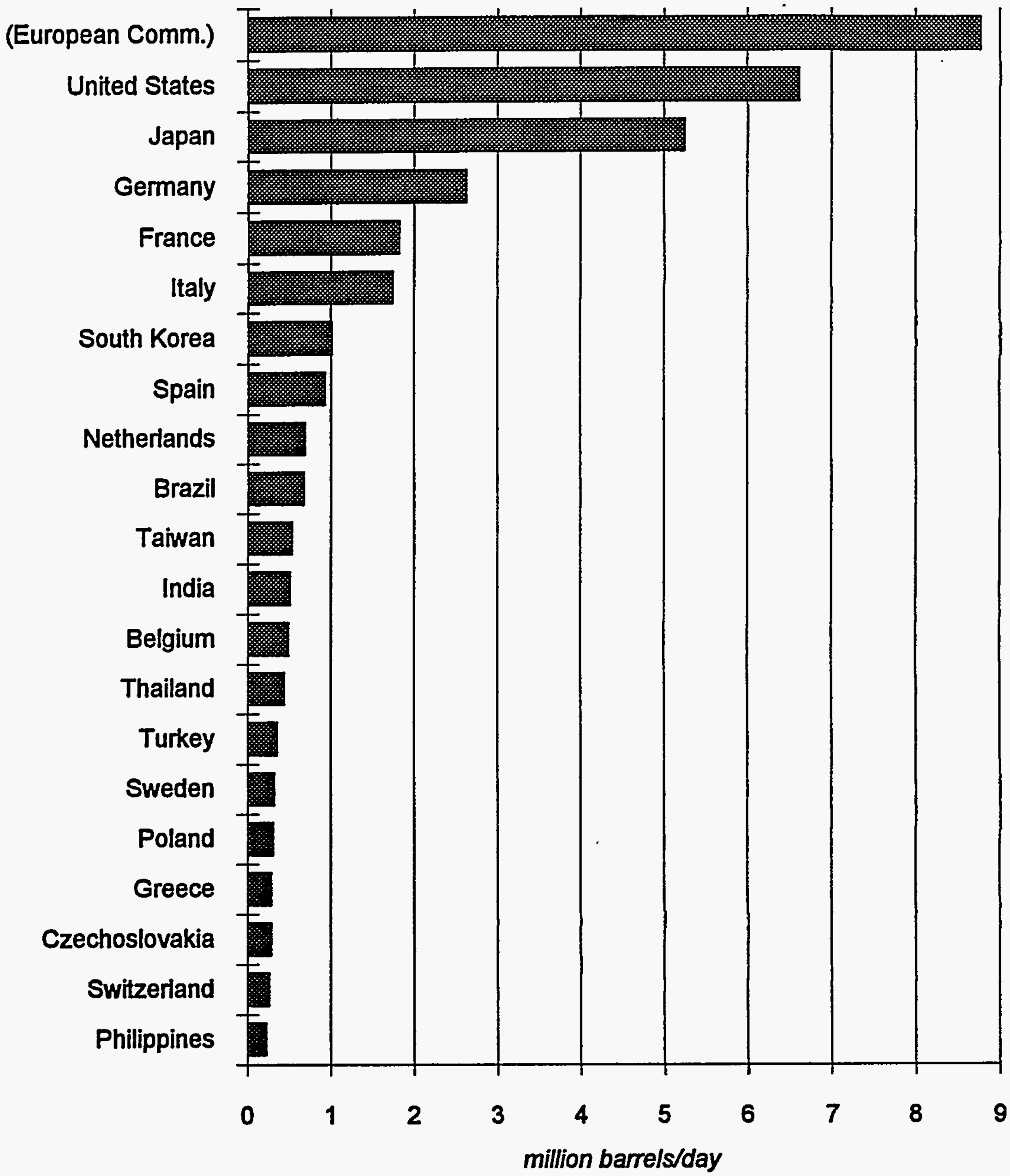
5. Oil Importers

The Top 20 net oil importers account for 78 percent of all oil imports. By definition, of course, no OPEC members appear on the list. With a few notable exceptions (such as the United Kingdom and Norway, the only highly developed economies among the oil exporters), the Top 20 importers reads like a Who's Who of the industrial and newly industrializing world (Figure 11).

The United States is number one at about 6.5 mmb/d, though imports of the European Community as a whole exceed United States import levels by a substantial margin. U.S. imports are followed by Japan at 5 mmb/d, German at about 2.5 mmb/d, and France and Italy at about 1.75 mmb/d each.

These five countries are the only ones wh imports top 1 mmb/d (although South Korea may have joined this club in 1992). Only a handful of countries import more than 500,000 b/d; the majority of nations in the world have oil imports on the order of Hawaii's. One interesting feature can be noted: Of the Top 20 importers, all but two are in Europe or the Asia-Pacific region. There are 12 European countries on the list, and 6 Asian countries; Brazil is the lone representative from South America, and the United States represents the Northern half of the hemisphere. There are no representatives from Africa.

Figure 11. Top 20 Net Oil Importers, 1991



Notes: Top 20 importers account for 78% of all worldwide imports. EC shown for comparison.

6. Oil Refining

The Top 20 oil refiners are shown in Figure 12. These account for 77 percent of the total world refining capacity. OPEC accounts for a mere 8 percent of the total.

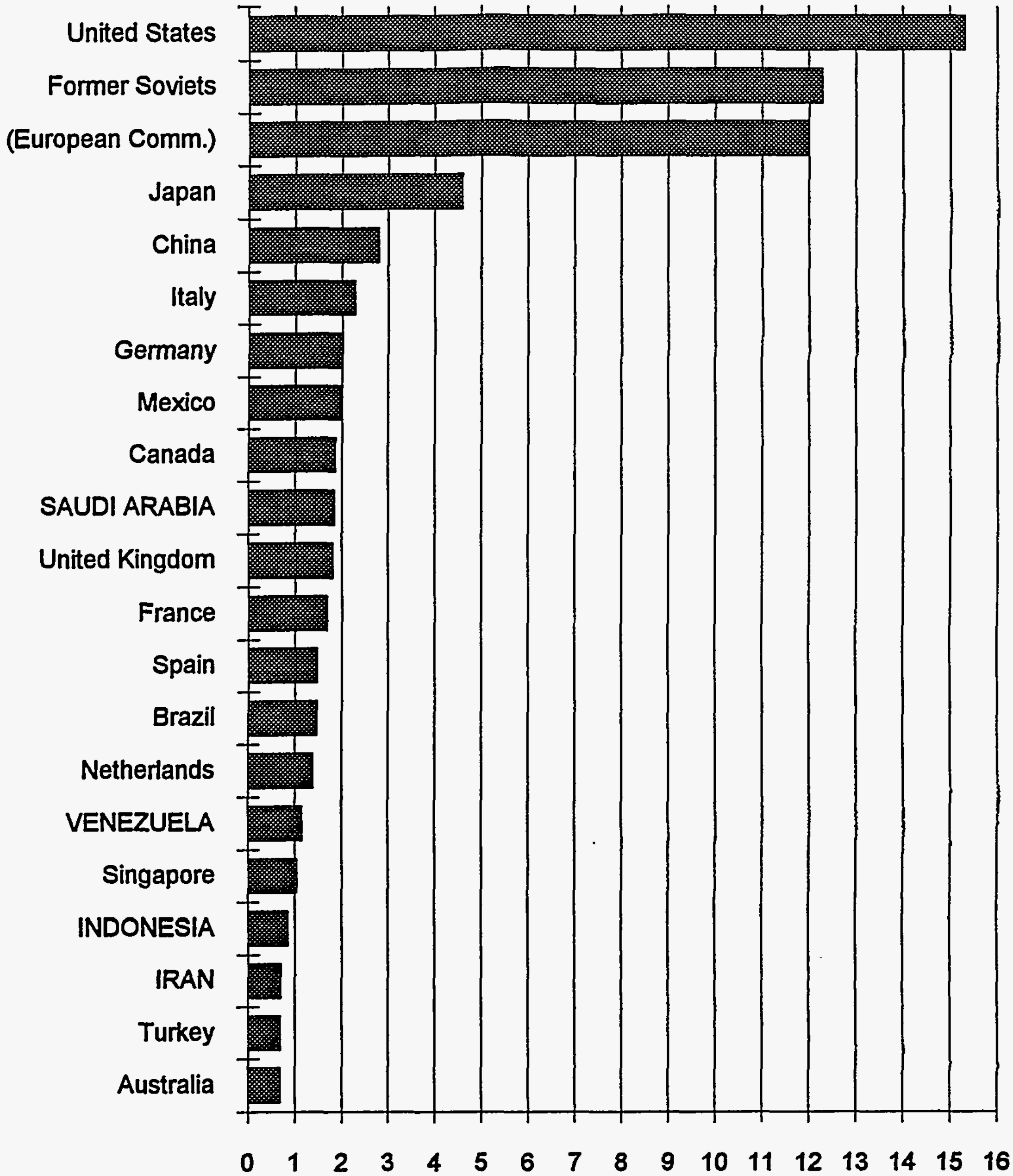
With a few exceptions, the list of the Top 20 refiners contains the same players as found in the Top 20 consumers. It might seem just common sense that the largest oil users would be the largest refiners, but this idea is not necessarily as sensible as it seems.

Prior to World War II, most refining was done near centers of oil consumption rather than oil production. In the 1950s and 1960s, the arrival of supertankers changed the economics of refining dramatically, by making it far cheaper to move crude oil in gigantic quantities than to move the same amounts of refined products in smaller shipments. As demand grew, most new refineries were located near markets, and the amount of crude oil moving on the ocean swelled.

The economics of moving the oil has favored the market-located refineries. The economics of refining the oil, however, often favors locating near the source of the oil. This is especially true at times of high energy prices, since energy for refinery fuel (as opposed to feedstock) tends to be cheaper in the producing areas. (On the other hand, construction costs are often higher in remote locations.)

Environmental considerations might change the long-term economics of shipping crude. Most oil products, such as gasoline, kerosene, or diesel, cause much less environmental damage than crude oil in the event of a spill. Fuel oil is an exception to this generalization; fuel oil is worse than crude on a barrel-for-barrel basis. But fuel oil is in surplus even in many market-located refining centers, so the environmental risk is compounded: Not only is there the risk of bringing in the crude, but the fuel oil from refining is often shipped back out as an export. Although the list of top refiners today resembles the list of top consumers, there are pressures that might make the list of top refiners grow to look more like the list of top oil producers.

Figure 12. Top 20 Refiners, 1991



Notes: Names of OPEC members are in uppercase. OPEC accounts for only 8% of world total. Top 20 account for 77% of world total. EC shown for comparison.

7. Conclusions

A handful of countries dominate various aspects of the world oil market. The demand situation in the United States, Japan, plus half-a-dozen other countries, can have dramatic effects on the market. A few exporters dominate the supply side of the international market, and from the distribution of oil reserves, this situation is bound to become more exaggerated in future years.

Prices, trade patterns, and product surpluses and deficits are determined by the large players in the market. The lesson is that smaller governments can apply policy to choices of energy types, and to matters such as local conservation; but policies designed to control prices or supplies are much less likely to meet with any success. With the Top 20 in any area of oil representing at least 75, and in some cases, more than 90 percent of the market activity, even dozens of smaller countries or governments acting together can have only a tiny effect on the behavior of the market. Ultimately, it is only domestic consumption patterns that are within local control; prices and supply patterns, like the weather, may be somewhat predictable, but need to be understood as outside forces.

B. Oil Reserves and Resources

1. The Global Resource Base

There has been so much public controversy since 1973 regarding the amount of oil "left" that many observers have concluded that the entire subject of resource estimation is simply a matter of opinion. One faction always argues that oil will soon be running out, and that there is an urgent need to move to alternatives, while another faction contends that more oil will always be forthcoming. With so many "experts" offering conflicting opinions, laypersons can be excused if they conclude that no one has the slightest idea how much oil remains in the ground.

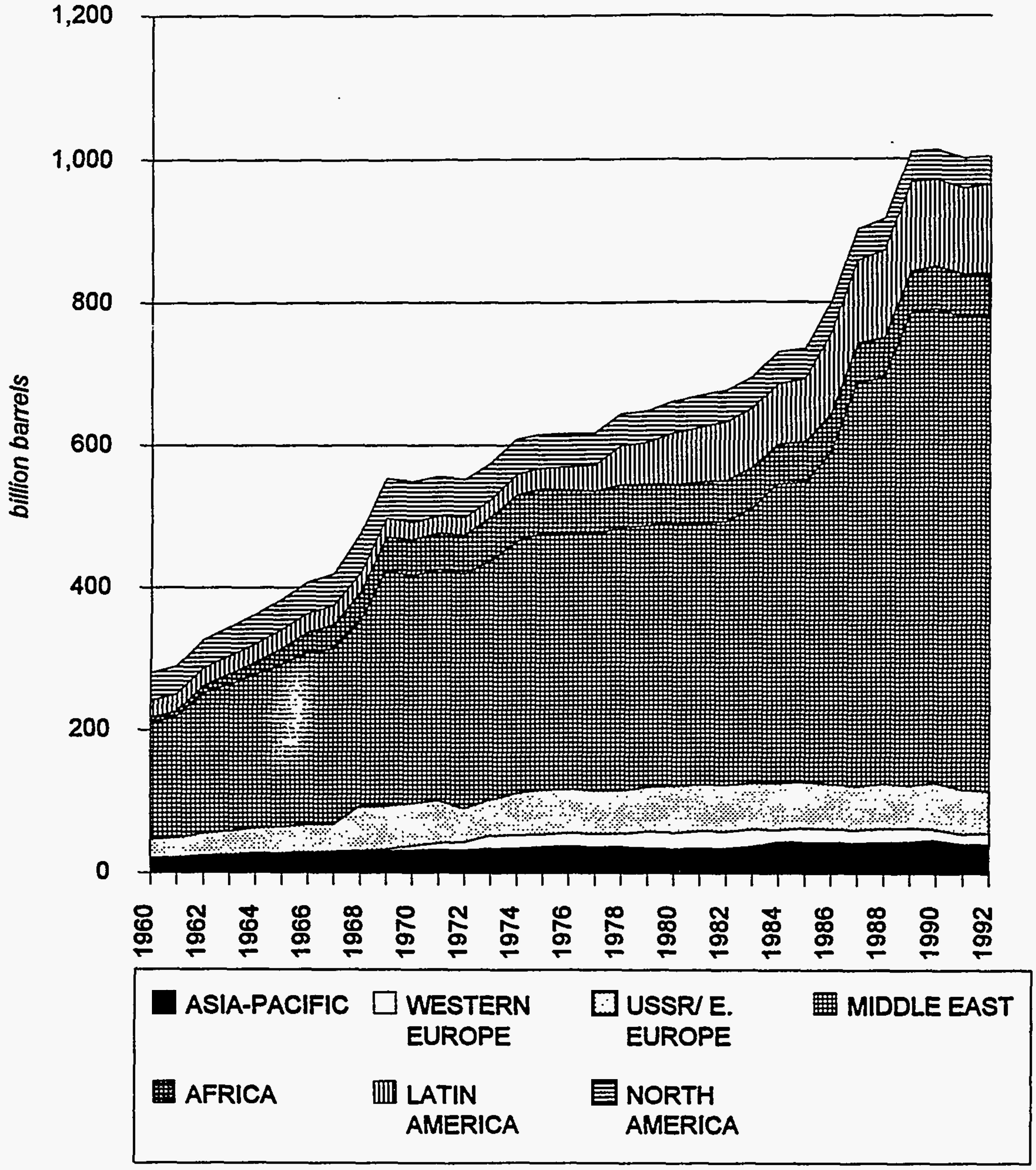
Among geologists who have carefully evaluated the world's sedimentary basins, however, there is considerable consensus about the size of the world's oil resources. Despite all the disputes that reach the pages of the daily newspapers, the four most comprehensive studies of world resources, done over a period of forty years, have agreed closely on the absolute size of the resource: About 2 trillion barrels of conventional oil resources, with perhaps 700 billion barrels of additional unconventional oil (from tar sands, asphalt lakes, and superheavy deposits). This ultimate recovery of conventional resources is about the same between studies done by Levorsen (1949), Hubbert (1962), Moody and Esser (1975), Nehring (1982), and Masters et al. (1990).

True, there is uncertainty about this number; ultimate recovery might be 10 percent higher or lower. It is extremely unlikely, however, that the world oil resource is half as large as estimated, or twice as large as estimated. The geologists have been in agreement on the issue for decades. Why then the confusion and controversy in public debates?

Confusion comes from a mixing of terms. The geological estimates are of recoverable oil *resources*, whereas the numbers bruited about in public tend to be estimates of *proven reserves*. *Resources* are the quantities of oil that are expected to be recoverable with known technologies; in the case of estimated resources, they include oil that has not yet been discovered, based on the distribution of sedimentary basins, size of structures within the basins, and various subsidiary probabilities. *Proven reserves*, on the other hand, are resources of oil that have been discovered, and are extractable at today's prices with today's conventional technologies. Resources are a number derived from scientific knowledge and probabilities; proven reserves are a matter of economics and, in the last thirty years, politics. As will be discussed in a later section, there are reasons for oil-producing countries, particularly oil-exporting countries, to overstate or understate their proven reserves.

Figure 13 shows proven reserves at year's end (as reported in *World Oil*, *Oil & Gas Journal*, and *Oil and Energy Trends*) from 1960 to 1992. Although it is true that proven reserves were relatively flat in the 1970s compared with the rapid growth in reserves of the late 1960s and late 1980s, proven reserves have fallen in only three years (1970, 1972, and 1991), and are currently nearly double the levels seen in the early 1970s. Moreover, even when there has been a decrease in proven reserves, it has been a tiny downward fluctuation.

Figure 13. Proved Oil Reserves by Region, 1960-92



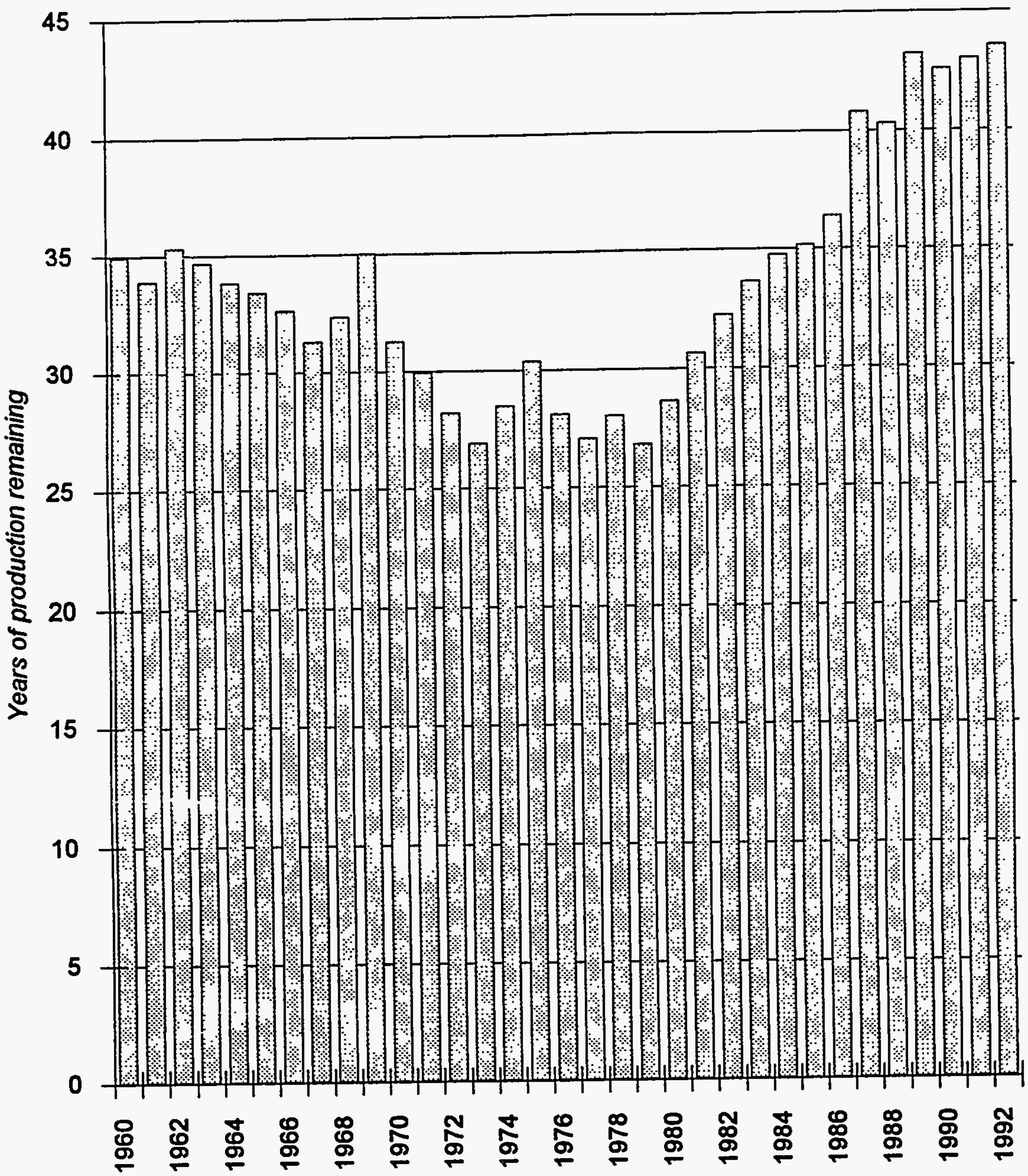
Viewed from the perspective of the 1970s, it is clear that the slow rate of increase in proven reserves at that time should be a matter for concern; it is not clear why it should have been cause for panic. To understand, it is more useful to look at the reserves-to-production ratio ("RP ratio"). This is merely the current proven reserves divided by the current rate of production; it yields the number of years of proven reserves "left" at current production rates. The RP ratios for the years 1960 through 1991 are shown in Figure 14.

The RP ratio shows a dramatic trough in the 1970s. The RP ratios for the period 1971 through 1980 are lower than any years in the 1960s or 1980s. Despite the "oil crisis" of 1973 and the huge expansion of drilling activities worldwide, the RP ratios of the 1970s stayed stubbornly low.

The RP ratio is a widely used measure of oil depletion in public debates, largely because it is easy to explain: Here's how much we have, and here's how fast we're using it. It seems to be a very common-sense measure. Unfortunately, it is a very volatile measure, since both the numerator (how much oil we have found) and the denominator (how fast we are using it) are subject to substantial changes based on price. When prices go up, the industry does not *immediately* find more oil, and consumers do not *immediately* invest in energy conservation; but within a matter of years there are moves in these directions, and the RP ratio increases sharply. Since the direction of change in the numerator (upward) and the denominator (downward) are opposite in response to higher prices, the RP ratio changes faster than either of the indicators that make it up, and the RP ratio is therefore "highly leveraged."

In the 1970s, there was not only concern about the relatively flat level of proven reserves, but also about the booming consumption. To put this in perspective, in 1973 proven world reserves were about 574 billion barrels, and annual production was 21.3 billion barrels, giving an RP ratio of 27 years. Proven reserves were essentially flat. Many concluded that even if consumption remained at its 1973 levels, the world would be "out of oil" by the year 2000.

Figure 14. RP Ratio of Proven Oil Reserves, 1960-92



More frightening than this, however, was the rate of increase in demand for oil. Production jumped 9.2 percent between 1972 and 1973. This implied a doubling of production by 1981, and a tripling of production by 1986. At this rate of increase, all of the world's proven reserves would have been pumped out of the ground by the end of 1986. As the decade progressed with relatively little change in proven reserves and only modest decreases in world oil demand, there was ample support for apocalyptic visions of our energy future.

Contrast this with the situation in 1990. World proven reserves had nearly doubled to 1.012 trillion barrels; annual production had increased only to 23.8 billion barrels, giving an RP ratio of 43 years. At current production and reserve levels, in other words, oil would not be depleted until 2033. The rate of demand increase had fallen; 1990 production was only 1.7 percent above 1989. Applying this demand growth to the existing reserves still did not deplete the reserves until 2021.

Moreover, the 1980s saw major additions to reserves worldwide. It is now generally believed that there is more oil to be found. The spurt in demand growth in the late 1980s and early 1990s is believed to be a temporary phenomenon; most economists are now talking in terms of demand growth worldwide on the order of 1 percent per annum. Thus, the "petroleum age" does not extend into the indefinite future, but petroleum is likely to remain a major fuel of modern society for many decades.

Figure 15, based on the work of Masters *et al.* shows the composition of the estimated oil resource. About one-fourth of the total resource has already been used by the beginning of the 1990s. One-third of the total resource is proven reserves of conventional oil—the number normally used in computing the RP ratio. An additional 17 percent (about one-sixth) of the resource remains to be discovered. Finally, identified reserves of unconventional oil amount to one-quarter of the total resource; in other words, the known reserves of unconventional oil are equal in volume to all of the oil the world has consumed to date.

Figure 15. Estimated Oil Resources, 1960-92

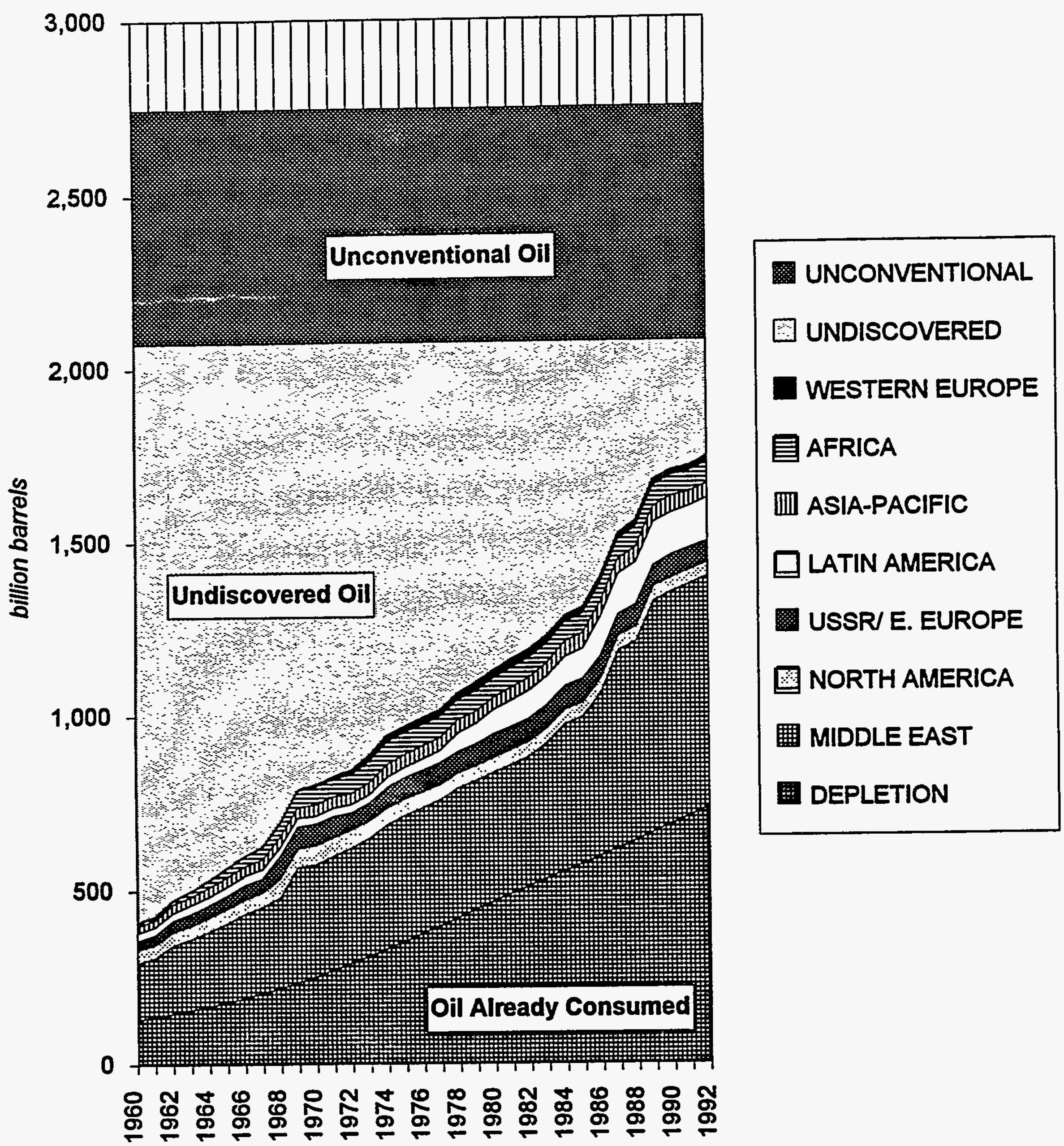


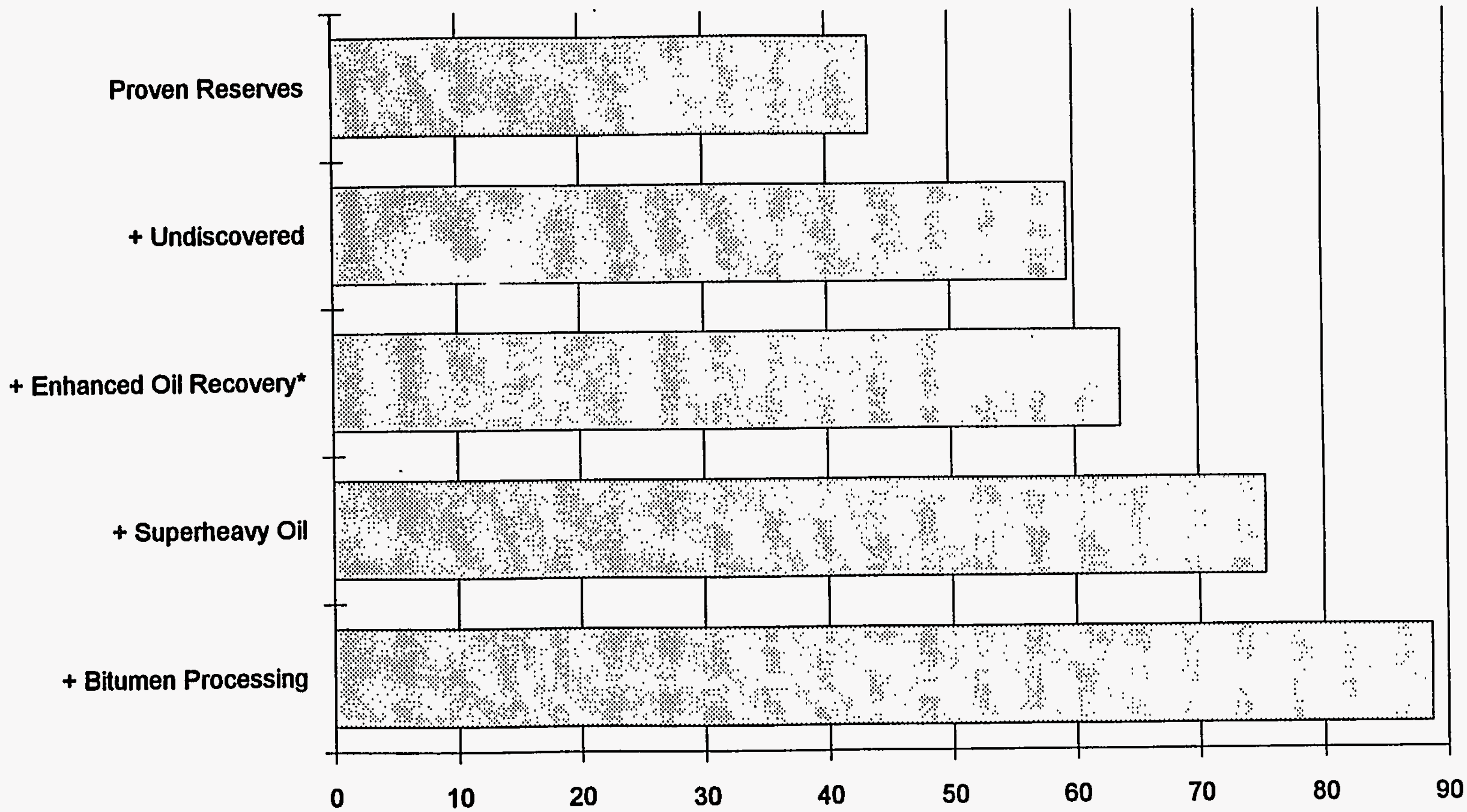
Figure 16 shows what these various increases do to the RP ratio, if the ratio is recalculated to reflect the total remaining resource rather than just proven reserves. At current consumption levels, proven reserves give about 40 years. Adding in undiscovered conventional oil resources extends this to 59 years. Enhanced oil recovery, based on East-West Center estimates, increases this to 63 years. Adding in superheavy Latin American crudes pushes the resource out to 75 years. Processing of Canadian bitumen deposits places the final RP ratio out to 88 years—the year 2079 at present consumption rates.

Thus, evaluating the whole resource gives nearly 90 years of present consumption levels. Even if a 1 percent growth rate in world demand is assumed, this resource still would not be exhausted until 2052. In reality, of course, the unconventional oils have higher production costs, and prices will tend to rise as reserves are depleted and environmental standards are tightened. This will act as a brake on consumption, slowing it in the coming decades. The world will never run out of oil, but it will gradually become scarcer and more costly. This will tend to reserve oil for higher-value uses with fewer substitutes, such as plastics manufacturing and jet fuel, and phase it out of lower-value uses such as electrical generation. This will extend the resource considerably. Barring major technological breakthroughs or fundamental restructuring of the world economy, it appears likely that oil will continue to play an important role in the world's energy economy well into the twenty-first century. At the same time, oil's *share* of total world energy demand is likely to diminish steadily. Reserved for specialized uses where liquid fuels or feedstocks are required, oil will supply less and less of the world's total energy—but in many ways it will become a more *critical* fuel, since it will be devoted to relatively unsubstitutable uses.

2. Regional Distribution of the Resource

The fact that we are not "running out" of oil in the near term does not mean that oil supply will cease to be an issue of national and local concern. Table 2 shows the current proven reserves and annual output for the oil-producing nations of the world. The Mideast contains 63 percent of the world's proven reserves. No other region even approaches the

Figure 16. Years of Oil Left at 1992 Production Rates



* EOR recovery assumed at 4.7% of ultimate conventional recovery.

Table 2. Proven Oil Reserves and Oil Output, 1991

Country/ REGION	YEAR-END RESERVES (bil b) 1991	OIL & NGL OUTPUT (kb/d) 1991
Australia	1.62	584
Bangladesh	0.00	1
Brunei	1.35	162
China	20.86	2,799
India	6.10	718
Indonesia	6.60	1,690
Japan	0.06	15
Malaysia	3.00	660
Myanmar	0.05	12
New Zealand	0.21	55
Pakistan	0.20	67
PNG	0.20	0
Philippines	0.04	6
Taiwan	0.00	2
Thailand	0.15	45
Vietnam	0.50	80
ASIA-PACIFIC	40.95	6,896
Austria	0.08	24
Denmark	0.80	148
France	0.18	65
Germany	0.40	88
Greece	0.03	17
Italy	0.69	80
Netherlands	0.10	75
Norway	7.60	1,897
Spain	0.02	28
Turkey	0.50	82
UK	4.00	1,927
W. EUROPE	14.41	4,431
Albania	0.18	30
Bulgaria	0.01	6
Czechoslov.	0.02	2
Hungary	0.16	38
Poland	0.03	2
Romania	1.17	140
Yugoslavia	0.22	43
USSR/CIS	59.91	10,406
E. EUROPE	61.69	10,667

Country/ REGION	YEAR-END RESERVES (bil b) 1991	OIL & NGL OUTPUT (kb/d) 1991
UAE	98.10	2,605
Bahrain	0.10	38
Iran	92.85	3,288
Iraq	100.00	316
Israel	0.00	0
Jordan	0.02	0
Kuwait	96.50	153
Oman	4.30	717
Qatar	3.70	433
Saudi Arabia	260.30	8,723
Syria	1.70	475
Yemen	4.00	197
MIDEAST	661.57	16,946
Algeria	9.20	1,328
Angola	1.80	503
Benin	0.10	3
Cameroon	0.40	160
Congo	0.83	156
Egypt	4.50	922
Gabon	0.73	300
Ghana	0.00	0
Ivory Coast	0.10	11
Libya	22.80	1,541
Morocco	0.00	0
Nigeria	17.90	1,918
Sudan	0.30	0
Tunisia	1.70	108
Zaire	0.06	27
AFRICA	60.42	6,977
E. HEMIS.	839.04	45,917

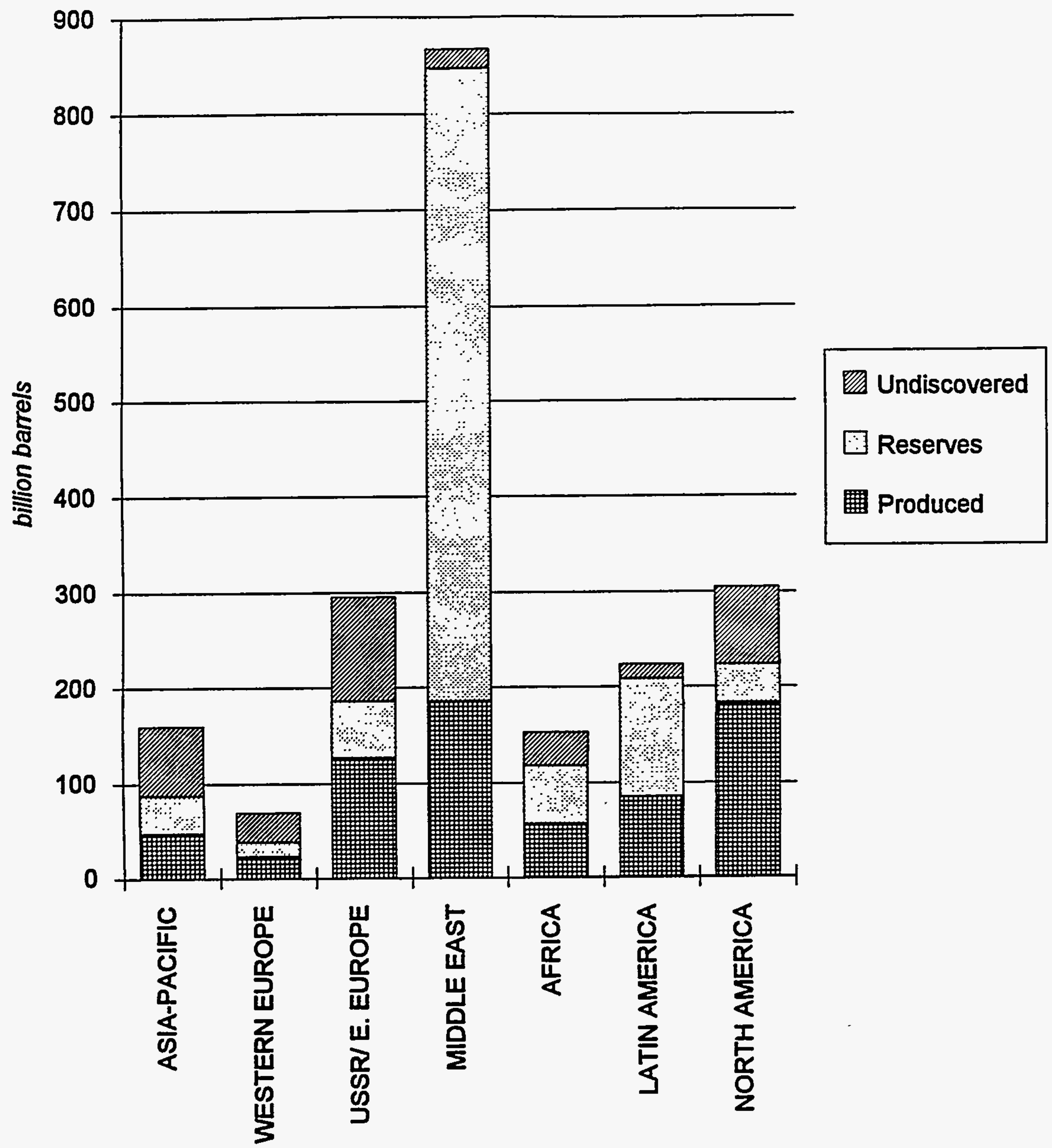
Country/ REGION	YEAR-END RESERVES (bil b) 1991	OIL & NGL OUTPUT (kb/d) 1991
Argentina	1.60	492
Barbados	0.00	1
Bolivia	0.10	22
Brazil	2.80	645
Chile	0.30	18
Colombia	1.90	434
Cuba	0.10	18
Ecuador	1.60	289
Guatemala	0.04	4
Mexico	51.30	3,125
Peru	0.40	118
Suriname	0.03	4
Trinidad	0.50	146
Venezuela	59.10	2,468
S. AMERICA	119.77	7,784
Canada	7.90	1,968
US-PADD-I	0.08	30
US-PADD-II	1.69	744
US-PADD-III	10.72	3,352
US-PADD-IV	1.59	500
US-PADD-V	12.21	2,756
US NGLs/Other	7.70	1,645
{United States}	{33.99}	{9,028}
N. AMERICA	41.89	10,996
W. HEMIS.	161.65	18,780
WORLD	1000.69	64,696

Sources: World Oil, Oil and Gas Journal, Petroleum Intelligence Weekly, 20th Century Petroleum Statisitics, US EIA, International Energy Agency size of Mideastern resource; indeed, only one region—Latin America—contains more than 10 percent of the world's proven reserves. Eastern Europe and the Commonwealth of Independent States (CIS) contain about 7 percent, Africa contains about 7 percent and North America contains a mere 4.5 percent of the world's proven reserves. This overall situation is unlikely to change, regardless of additional discoveries.

Figure 17 shows the estimated distribution of the conventional oil resource, including oil already used and oil yet undiscovered. On this basis, the Mideast's share of the resource drops somewhat, but still represents a disproportionate 42 percent of the world's original endowment. North America and the CIS/Eastern European region each show about 15 percent of the original oil resource. A number of features are particularly striking about the situation in North America, however. First, the United States and Canada are the only region of the world to have already produced more than half of its oil resource. With the exception of the huge Mideast anomaly, North America was the most-endowed oil region in the world; but most of it has already been used.

An additional point needs to be made about the North American situation. There is more oil to be discovered; in fact, estimates of undiscovered conventional oil amount to twice current proven reserves in North America. Even if all of this oil were discovered tomorrow, however, it does not substantially change the long-term situation. If the complete North American resource were "onstream," it would give North America at most 18 years of self-sufficiency—and this would still necessitate large U.S. oil imports (from Canada). Moreover, most of these undiscovered resources are likely to be in high-cost areas: Arctic regions, far off-shore, or in small, "tight" deposits. Supplying a greater percentage of U.S. oil needs from domestic sources would involve higher prices for consumers, but would only delay increased reliance on the international market by at most a handful of years. The furor over drilling in environmentally sensitive areas (such as the Alaska National Wildlife Refuge and the California Outer Continental Shelf) has given many Americans the impression that if drilling were expanded, it would significantly change the U.S. supply situation in the long term, possibly even leading to "oil independence." In fact, drilling in every national park

Figure 17. Esimates of Oil Resources Used, Identified, and Undiscovered



and wildlife refuge in the country will not alter the fact that North America has already used most of its oil.

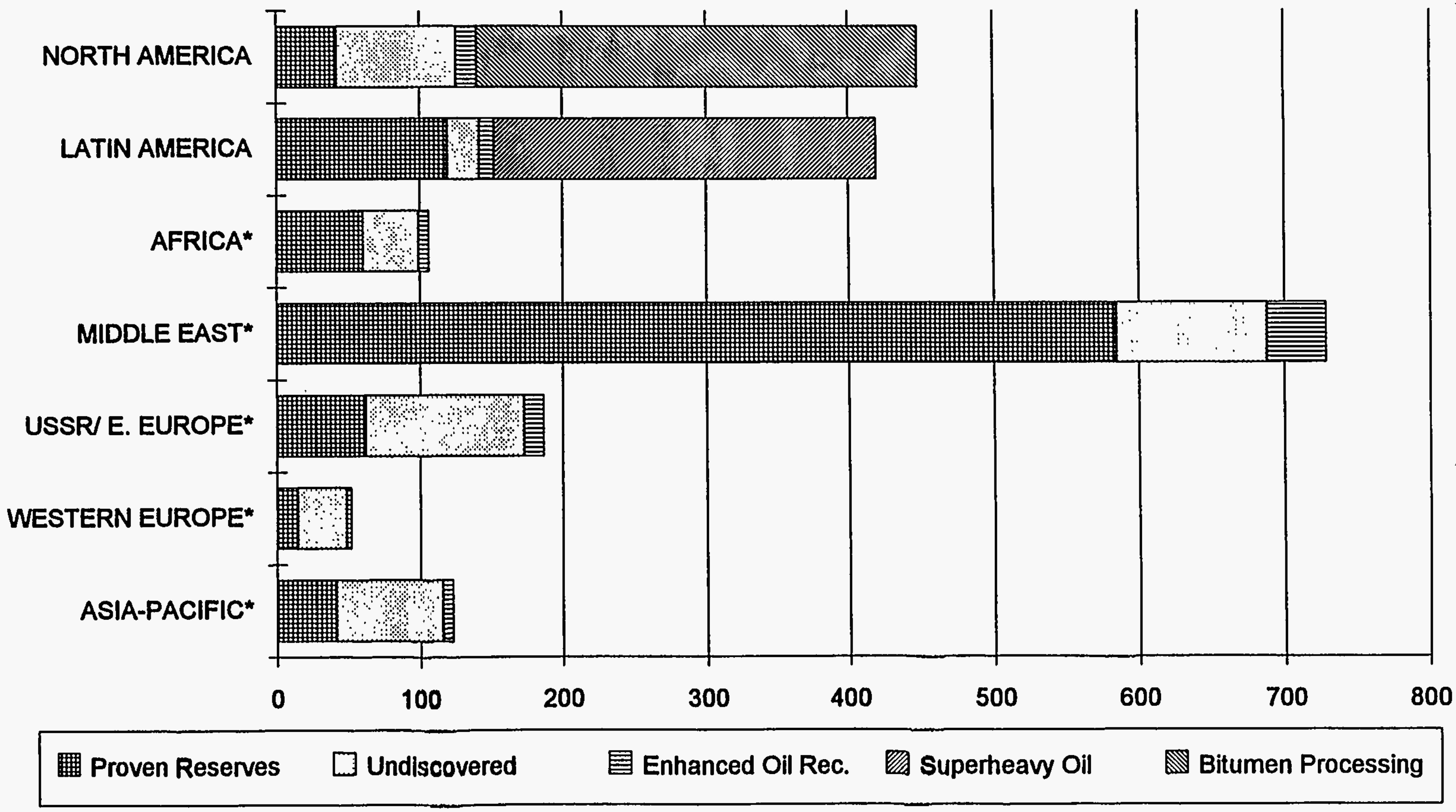
Frontier areas in the CIS and the Asia-Pacific region may increase local reserves considerably, but the potential discoveries of new conventional oil in other regions are at best comparable to the undiscovered oil in the Mideast; the next "big find" is just as likely to be in Saudi Arabia as any other prospective region. About half of the world's conventional oil is in the Mideast, and this is not likely to change.

Taking account of unconventional oil resources does change the global picture somewhat. Figure 18 shows remaining oil resources including enhanced recovery operations and unconventional oil. When these resources are summed, it *does* make a substantial change in the world picture. Western Hemisphere resources (North and South America) exceed the resources of the Middle East; South American resources nearly triple, and North American resources nearly quadruple.

What are these additional resources? They consist of two main hydrocarbon concentrations: The bitumen/tar sands deposits of Canada, and the superheavy Orinoco Belt oils of Venezuela. Both are extremely heavy, high-sulfur, viscous, environmentally unfriendly resources. To increase utilization of these resources demands huge capital investments; estimates of basic production costs range from \$14/b to \$22/b, well above the \$1.50/b production costs seen in the Mideast. Turning a Venezuelan superheavy into a light, low-sulfur crude will require an estimated initial investment of \$4 billion for a 100,000 b/d plant. Costs for Canadian bitumen upgrading are similar. Bringing on these unconventional resources at a level to supply, say, U.S. oil consumption, would require about \$650 billion—on the low side of the estimates. (On the high side, an investment of a trillion dollars might be required.)

Still, the production costs of such oil make them competitive with current oil prices, and could leave room for considerable profit. Both the Canadians and Venezuelans have

Figure 18. Estimaed Oil Remaining by Resource Type



* No substantial reserves of unconventional oil yet reported in these regions

eagerly sought foreign participation in development of these resources, even offering long-term supply guarantees and fixed-price arrangements to investors. Why, then, have these resources remained undeveloped?

The primary reason is the volatility of the market, and the low cost of Mideast oil production. If investments in Venezuela or Canada cut into the sales volumes of Mideast producers, Mideast producers would cut their prices until their oil sales increased. Quite likely, this would mean cutting prices below Venezuelan and Canadian production costs. At this point, the huge capital investments made in upgrading unconventional oil turn into large annual losses. For example, if a producer had invested in 1 million b/d of upgrading at a midpoint production cost of $18/barrel, and the world market price dropped to $10/barrel (as happened in 1986), the annual losses would amount to nearly $3 billion. No company can withstand this sort of loss; only developed-nation governments (and a few Mideast oil producers, who of course, would never invest in such a project) could afford to make such losses.

A government could afford to make such investments, however. Instead of putting money into the Strategic Petroleum Reserve, for example, the United States could invest in (or guarantee company investments in) unconventional oil upgrading, and then guarantee a minimum price for this unconventional oil imported into the United States. This could provide a stable long-term supply of oil at prices not too different from those seen in the past few years.

This would of course involve a level of government intervention that might be considered "un-American." Furthermore, even if Americans were paying a reasonable, stable price for oil, there might be considerable complaint if the world market price dropped to only half of what Americans had to pay.

Unconventional oil resources offer huge potential additions to the world's oil reserves, but at capital costs far beyond current investments in oil worldwide. At current prices, there is little incentive for investment, and even the largest oil companies cannot afford to create substantial additional productive capability. Governments (other than the owners of the resources) are unlikely to take much interest in such investments until prices show signs of sustained increases. Unless circumstances or political outlooks change dramatically, development of these resources is likely to be delayed until well into the twenty-first century.

3. Conclusions

Both the pessimists (U.S. oil is running out, world reliance on the Mideast is increasing dramatically) and the optimists (world proven reserves are at an all-time high, there is plenty of oil still to be discovered) are correct. The oil age is still far from over; there is a great deal of oil left to be produced without massive increases in price. Nonetheless, the volatile nature of prices in the last decade has not encouraged investment in productive capacity even from known deposits, and increasing oil demand in the 1990s could push production close to productive capacity. Under such circumstances, a price shock comparable to 1973 or 1979 could easily occur again. This possibility is made even more likely by the increasing importance of the Mideast in world oil trade.

At the minimum, it should be expected that oil prices will remain volatile, and that upward fluctuations will cause economic hardship and political uproar, while ensuing price collapses will endanger the development of alternative energy and energy conservation programs. At worst, the future could contain replays of the crises of the 1970s.

It may be that many of the factors that made for previous, long-duration crises have disappeared. International cooperation is no longer hamstrung by U.S.-Soviet rivalry; consumers and governments, experienced with earlier crises, are less prone to panic and take measures that endanger the physical availability of oil products; and the larger oil-exporting governments have come to believe that stable, slowly increasing prices are far more valuable to their economies than the boom-and-bust cycles of the preceding decades. In this case, future crises may look less like the Iranian Revolution of 1979, and more like the short-term disruption of the Gulf War.

In any case, oil is likely to remain a critical fuel with volatile price and supply behavior. Switching away from oil would require firm resolve on the part of policy makers and consumers: There is no alternative fuel so cheap to produce that the price of oil cannot drop enough to turn it into a lossmaker. The large Mideast reserves are not just the cheapest supplies of oil in the world; in terms of what they cost to pump out of the ground, they are the cheapest sources of energy of any kind in the world. Switching away from oil on a large scale might offer reasonable and stable prices, byt they might often be prices that would be well above the price of oil. Left to market forces, the move away from oil will take many decades and may in the short term actually see an increase in oil-reliance in many areas of the world.

C. Crude Oil Quality: API Gravity and Distillation Yields

In the popular mind—as well as in the minds of many economists who ought to know better—"oil" is thought of as a single commodity, like "water." In practical terms, "crude oil" is a term more like "motor vehicle"; it refers to a whole class of things as different as school buses and sports cars.

Oil is a complex mixture of hydrocarbons, as are natural gas and tar. The only defining characteristic of crude oils is that they are naturally occurring mixtures of hydrocarbons in the liquid range. The differences in composition between various crude oils can make dramatic differences in the yields of various oil products, in the price of the crude oils, and in the pollution consequences of using the oils.

Crude oils from different sources are as individual as fingerprints. A good petroleum chemist can tell you with a high degree of reliability the country and field of origin of a sample of crude oil.

Although crude qualities vary in thousands of ways, the oil market usually concentrates on two quality measures as key indicators: sulfur and density.

Sulfur is measured in a straightforward fashion, as the weight percentage of sulfur in the crude oil. When oil is burned, most of the sulfur in the oil is combusted to form sulfur oxides. When these combine with moisture in the atmosphere, sulfuric acid is formed, which then precipitates as "acid rain." The combination of the sulfur oxides with moisture can also take place in human sinuses and lungs, causing discomfort, difficulty breathing, and tissue damage. In addition, sulfur compounds have a strong and unpleasant odor, as anyone who has visited a volcanic vent can testify.

Virtually all crude oils contain some quantities of sulfur. Most contain considerable amounts—0.5-3.0 percent by weight—and some contain in excess of 5 percent sulfur by weight. Although these percentages might not sound large, they need to be compared with the scale on which oil is consumed. At world consumption of roughly 65 mmb/d (about the current levels), even a sulfur content of 1 percent by weight would mean the daily use of oil involves about 215 million pounds of sulfur every day; 78 billion pounds of sulfur every year.

Most of the sulfur in oil can be removed by the refiner when the oil is processed, but this involves expensive equipment, high operating costs, and greatly increased consumption of energy inside the refinery. This issue will be returned to later; for now, it is enough to note that refiners would prefer to use low-sulfur crudes and that the relative demand for low-sulfur crudes is increased whenever air pollution regulations are tightened.

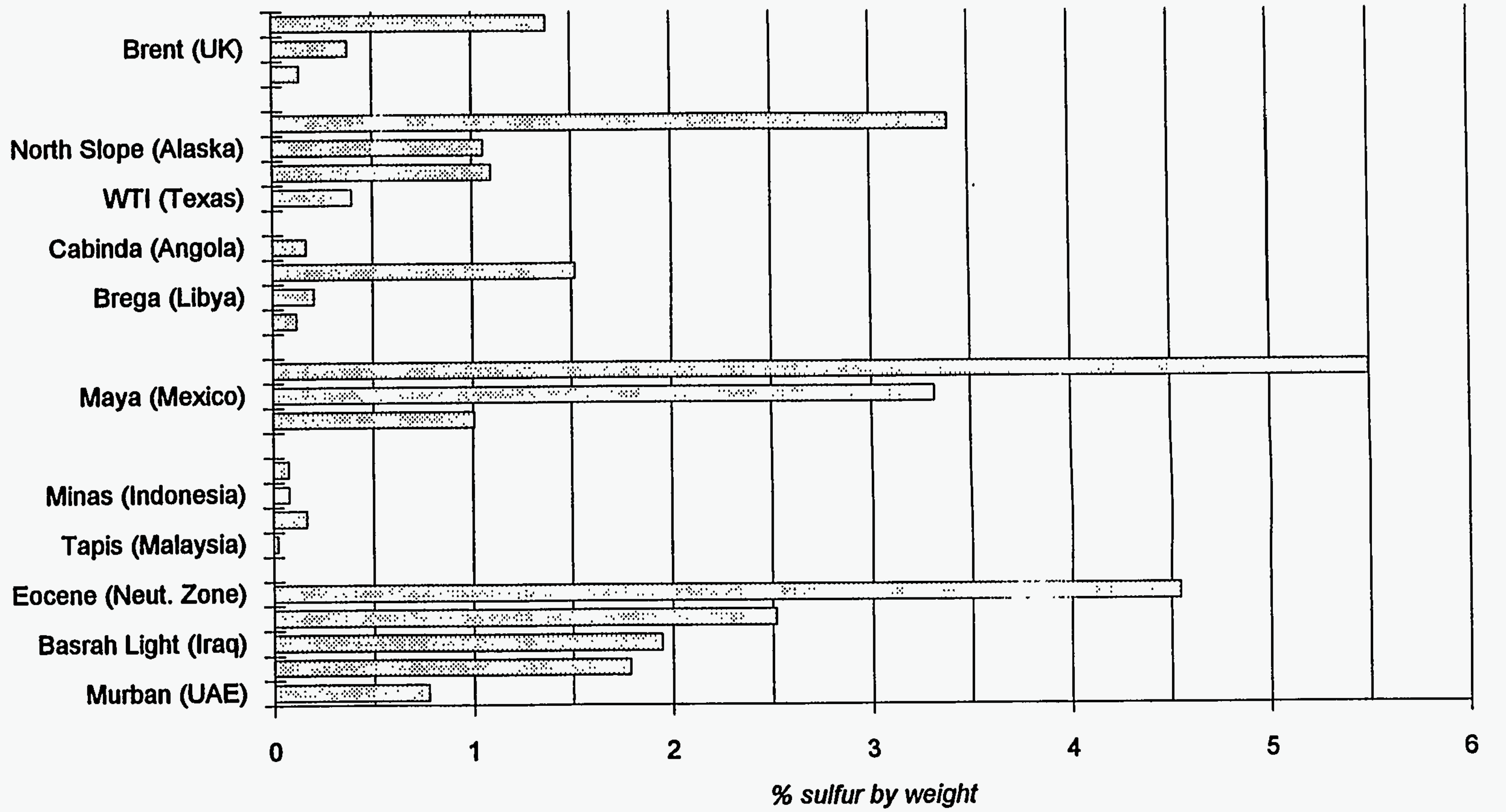
Figure 19 shows the sulfur contents in weight percent of selected crudes from around the world. Although there is variability in each area, a few generalizations usually hold good.

Virtually all of the crudes from the European North Sea, from West Africa, from the Asia-Pacific region, and from North Africa (excluding Egypt) are very low in sulfur, typically less than 0.5 percent by weight.

Most of the rest of the world's crudes range from 1-2 percent sulfur by weight, and some areas—Mexico, Venezuela, California, and the Saudi/Kuwaiti Neutral Zone— are notorious for very high sulfur contents. (The Venezuelan superheavy crudes mentioned in the previous discussion of world reserves are also very high in sulfur.)

One of the most obvious differences between various crude oils is in their density (or gravity). Most crude oils are lighter than water, but their weight varies substantially. A barrel (42 gallons) of water weighs about 358 pounds. A typical crude oil weighs about 308

Figure 19. Sulfur Content of Selected Crudes



The paraffinic crudes, which includes most of the world's low-sulfur crudes, contain considerably less gasoline and other light materials at a given level of API than the naphthenic crudes. Moreover, the precision with which the API formula predicted yields of gasoline from even naphthenic crudes turned out to be less than originally thought.

So why does the use of the cumbersome API gravity persist? Partly it is just a matter of tradition; but it also turns out to be a fair predictor of the overall distillation yield of crudes (as long as these are kept separated into naphthenic and waxy categories).

Refining will be discussed in more detail in a coming section. Here it is sufficient to know that the primary refining process is *distillation*, which boils out and captures the more volatile components of the crude oil. This process is carried out at a temperature of about 650° Fahrenheit. The most valuable components of crude oil, gasoline and naphtha ("light distillates") and kerosene, jet fuel, and diesel oil ("middle distillates"), all boil off at less than 650° F.

The less valuable material left over is residual oil, also called "resid," heavy oil, bunker fuel, long resid, atmospheric resid, bottoms, or most often just "fuel oil." Resid is mainly used for electricity generation, as well as some industrial processes, and typically sells for much less than the crude oil from which it is made. Most of the light and middle distillates, on the other hand, sell for more than the crude from which they are made. Thus, refiners typically want to minimize their output of resid and maximize their output of the various distillates.

API turns out to have a good correlation with how much material will boil off at 650° F. Figure 20 shows the percentage of material boiling off at 650 F compared with API gravity for a few naphthenic crudes. A typical 30° API crude, for example, gives about a 50/50 yield; about half of the output is resid. At 40° API, the yield of resid may drop to only 35 percent, giving 65 percent valuable distillates. A heavy, 10° API crude, may give only 16 percent distillates, leaving the refiner with 84 percent fuel oil.

pounds per barrel, but some weigh as much as 380 pounds per barrel, and some weigh as little as 275 pounds per barrel.

The density of crude oil is usually expressed as "API gravity" or "degrees of API" or, frequently, just as "API". (API is the acronym for the American Petroleum Institute, which originated the measure.) The API gravity measure requires some explanation.

Most scientists are inclined to measure density in terms of "specific gravity." Specific gravity is the density of a substance relative to the density of water. Water weighs 1 gram per cubic centimeter. Typical rocks weigh about 3 grams per cubic centimeter; thus they have a specific gravity sg=3.0. Rocks, as everyone knows, are heavier than water. Oils, typically lighter than water, tend to have specific gravities of less than 1.0. (A few, such as the Venezuelan superheavies, are heavier than water, and have specific gravities of about 1.05). Thus, the lighter the substance, the lower the specific gravity.

The API gravity is derived from the specific gravity by the formula

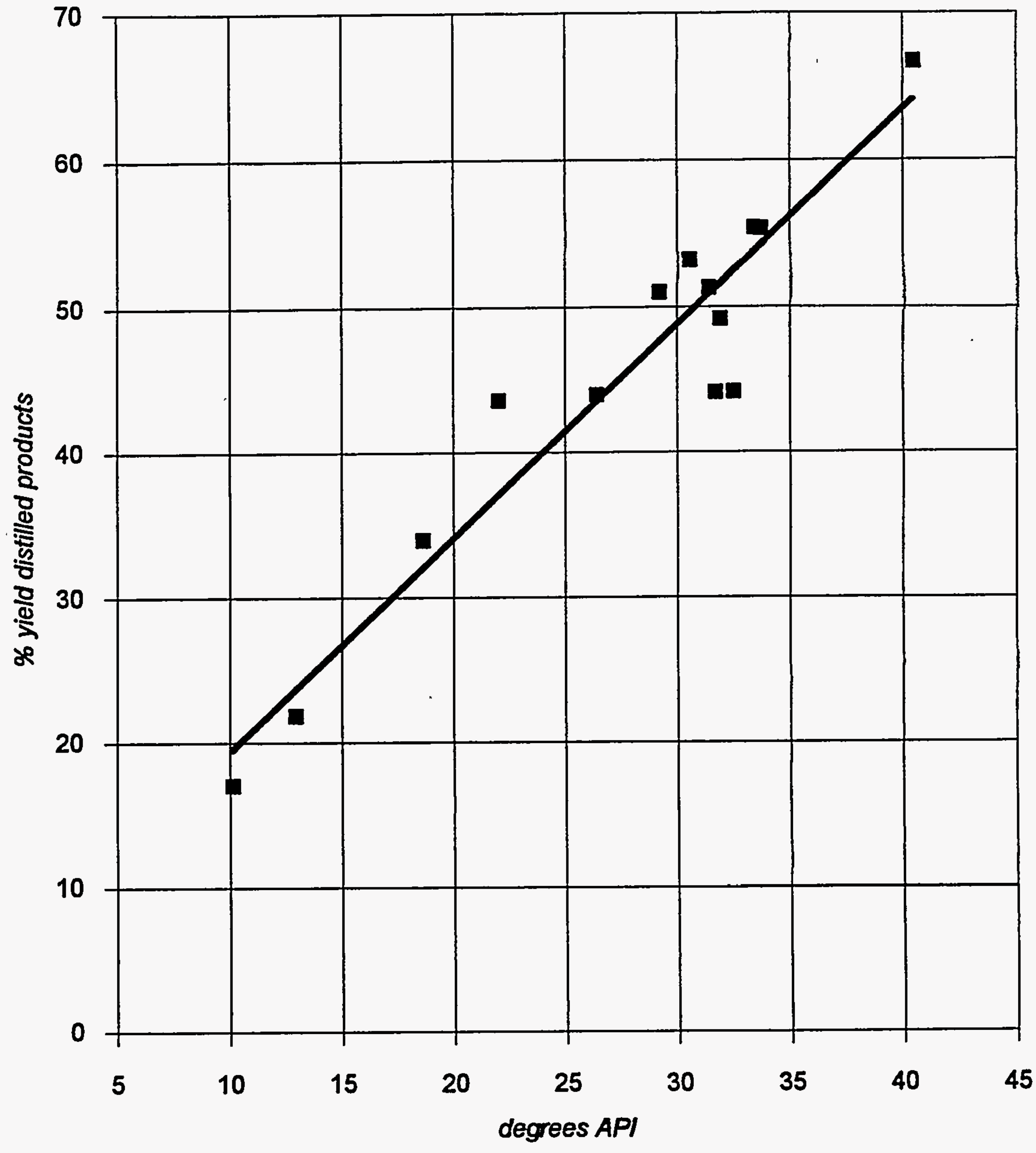
$$^{\circ}\mathrm{API} = (141.5/sg) - 131.5$$

where sg is the specific gravity. Although specific gravity increases with density, API works the other way around: the higher the API, the less dense, or "lighter" the material. On the API scale, water has a gravity of 10.0 (141.5/1.0 - 131.5). The superheavies mentioned above have an API of about 3.3. Saudi Light crude, the largest export crude on the world market, has an API of about 34°, and many of the light Australian crudes run as high as 45-55° API.

Why come up with such a complex measure of density? The answer is that in the early days of the industry, the formula for API gravity was believed to be an indicator of the amount of gasoline and naphtha that a crude would yield. A 30° API crude would give 30 percent gasoline/naphtha; a 20° API crude, only 20 percent gasoline/naphtha.

Although the formula worked fairly well for certain North American crudes, as more oils were discovered, it became apparent that there were wide deviations from the formula. In particular, it was found that there were two broad classes of crude oils — naphthenic and paraffinic (or "waxy") crudes—and that these had very different behaviors.

Figure 20. Distillation Yield versus °API for Selected Naphthenic Crudes



The low-sulfur, waxy crudes show the same sort of trend, but, as Figure 21 shows, the ratios are different. While a 30° API naphthenic crude may leave about 50 percent resid, a 30° API waxy crude will leave behind about 60 percent resid. Thus, at first glance, it might seem that waxy crudes would be worth less than naphthenic crudes of the same API—and in some periods of time this is true. At other times, the fact that waxy crudes are usually low in sulfur can push the price differential in the other direction.

The API and sulfur content do not tell the whole story, but, at any given time, a refiner can take a good guess at what a crude would be worth in terms of yields based on just those two figures. These are also important indicators for examining the trends in world reserves and production; knowing the direction that API and sulfur will be moving in future years tells us a great deal about the costs of meeting environmental regulations and the costs of different fuels made out of oil.

The variation in what crude oils can provide is seen in Figure 22, which shows the distillation yields for the same selected crudes whose sulfur contents are shown in Figure 19. This chart should make it apparent why "oil isn't just oil." For example, if supplies of Murban crude are cut off by troubles in the United Arab Emirates (UAE), perhaps a refiner can get Arab Light instead: but suddenly that refiner will have a shortage of gasoline and a surplus of fuel oil. This is one of the reasons that disruptions in oil supplies like those of 1973, 1980, and 1990, cause so much turmoil (and so many strange price movements) in the market. The world supply system is adapted to a certain "diet" of crudes, and a dynamic balance is maintained. The sudden disappearance of certain crudes from the market has far-reaching consequences.

Table 3 shows an even more practical lesson about the differences in crude oil. Based on 1989 market prices, this shows the value, in terms of straight-run product output, of four example crudes differing mainly in API gravity. There is a considerable variation in the composition and therefore the value of these crudes. Naturally, the crudes will also have different prices, since the crude producers will want any extra value in the crude to go into their pockets rather than into the pockets of the refiners.

Figure 21. Distillation Yield versus °API for Selected Paraffinic Crudes

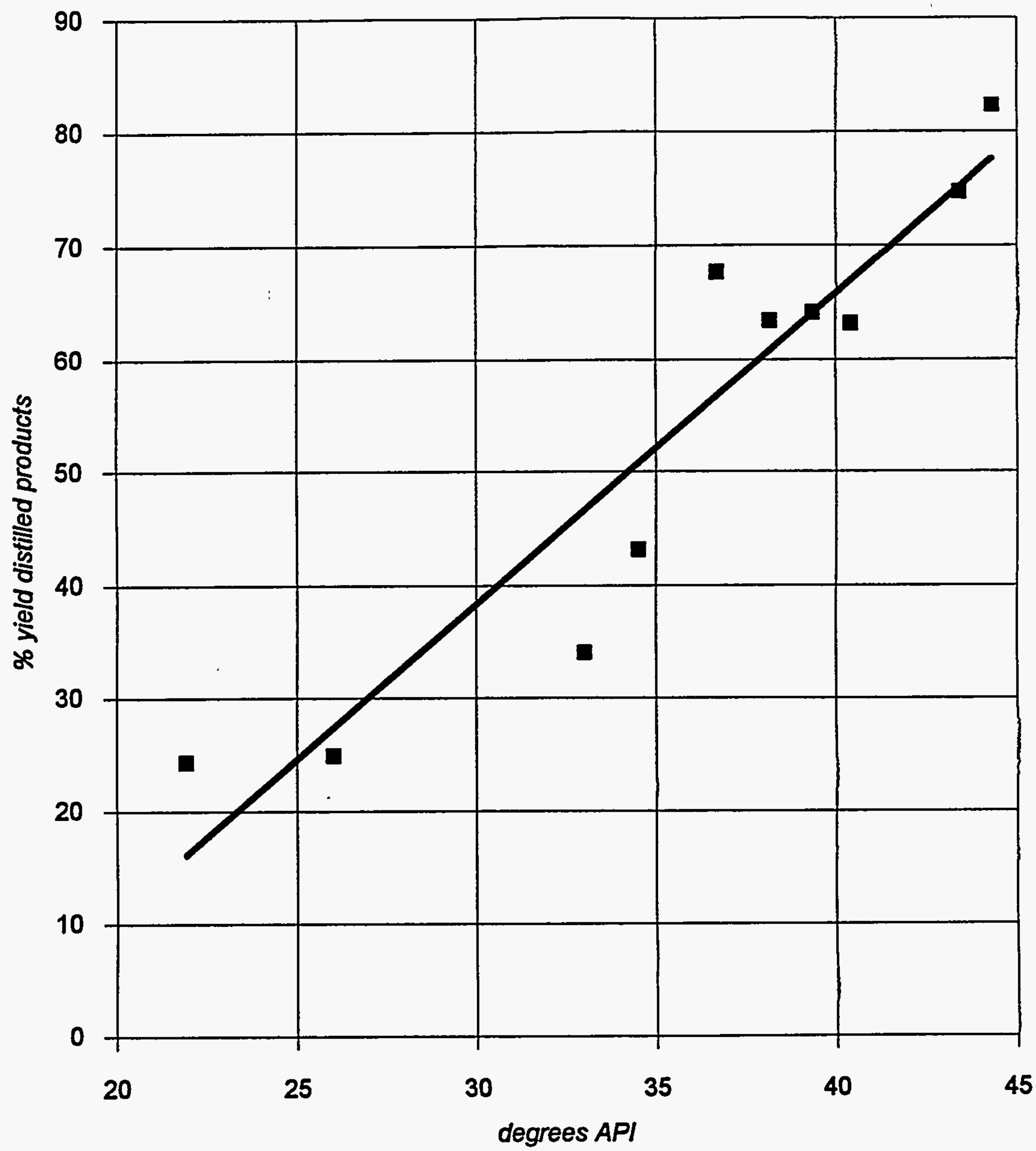


Figure 22. Distillation Yields of Selected Crudes

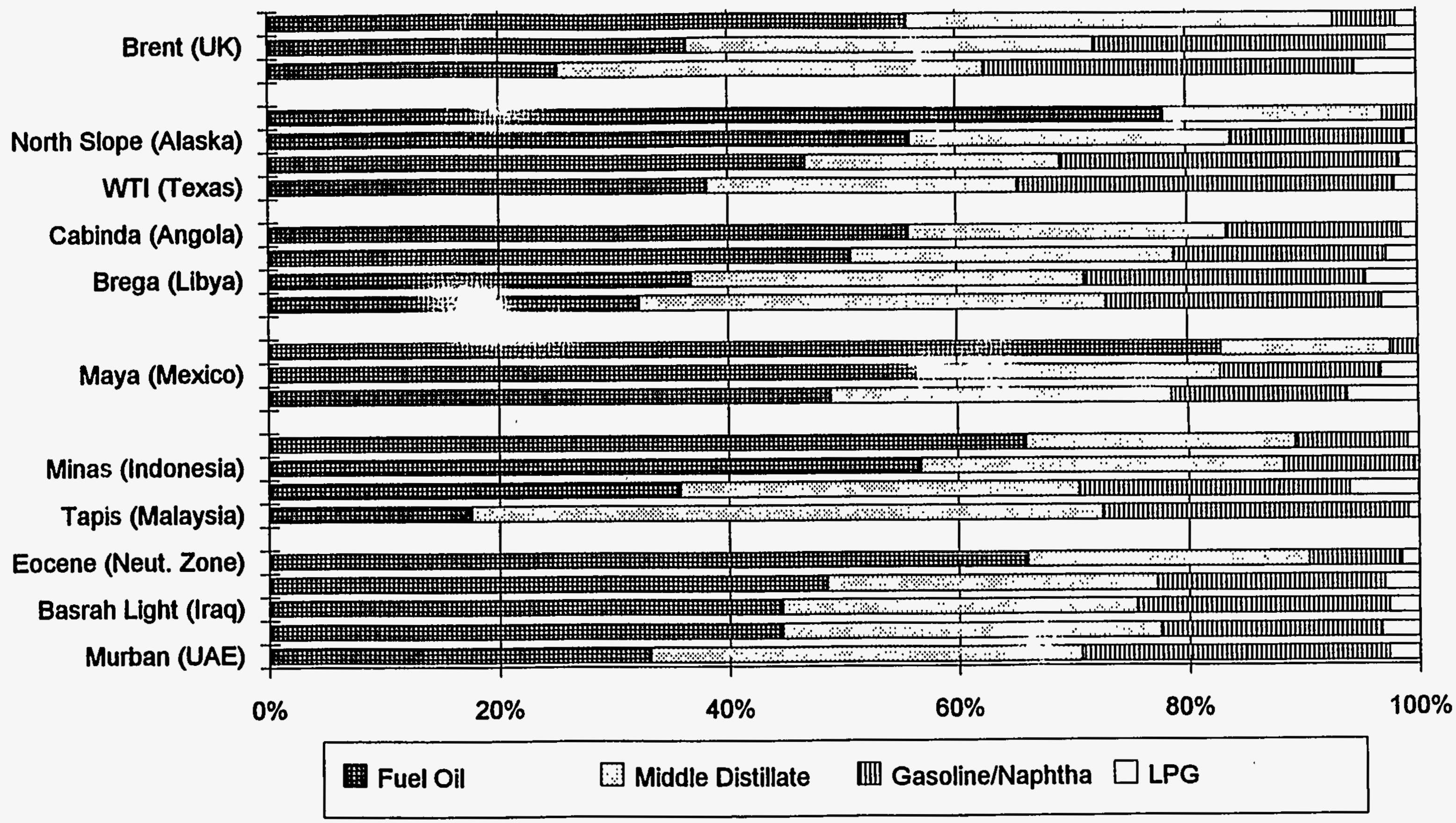


Table 3. Example of Crude Value vs. API Gravity

	Prices ($/b)	10 API (Yield)	20 API (Yield)	30 API (Yield)	40 API (Yield)
LPG	$12.00	0.5%	1.1%	2.0%	3.0%
Regular Gasoline	$21.07	0.2%	1.5%	3.5%	10.0%
Naphtha	$17.37	0.8%	2.5%	7.5%	17.0%
Jet Kerosene	$21.96	7.0%	10.0%	15.0%	20.0%
Diesel Fuel	$20.53	9.5%	15.9%	21.0%	18.0%
High-Sulf Fuel Oil	$12.54	82.0%	69.0%	51.0%	32.0%

	10 API	20 API	30 API	40 API
OUTPUT VALUES:				
LPG	$0.06	$0.13	$0.24	$0.36
Regular Gasoline	$0.04	$0.32	$0.74	$2.11
Naphtha	$0.14	$0.43	$1.30	$2.95
Jet Kerosene	$1.54	$2.20	$3.29	$4.39
Diesel Fuel	$1.95	$3.26	$4.31	$3.70
High-Sulfur Fuel Oil	$10.28	$8.65	$6.40	$4.01
Gross Product Worth, $/b	$14.01	$15.00	$16.28	$17.52
Value per API degree (relative to 10 API base)	$0.00	$0.10	$0.11	$0.12

Note: based on naphthenic crudes at mid-1989 Rotterdam spot prices.

The $3.50 per barrel spread (between 10 and 40 API) may not seem like much, but refiners normally consider themselves to be doing well if they are making 30 cents per barrel profit. Thus, a $3.50 per barrel spread is huge in oil market terms. Moreover, the spread on API and sulfur tends to get wider at times when prices increase sharply. When market disruptions cause general oil prices to jump upwards, it is the high-API, low-sulfur crudes that typically jump the highest. In the aftermath of the Iranian revolution, when Arab Light crude prices were hovering around $34/b, the light, low-sulfur Libyan crudes were fetching prices in excess of $45 per barrel.

A great deal of attention has been paid to the issue of the volume of oil reserves remaining. Much less has been given to the quality of those reserves. Most of the unexploited known reserves, notably in Venezuela, Canada, and the Middle East, are lower in API and higher in sulfur than the current market average. The light, low-sulfur crudes in Asia and the North Sea are being depleted quite rapidly; and in those OPEC countries that are not producing at full capacity, there has been a trend over the years to produce the highest-quality crudes soonest. There has been general agreement over the past three decades that the long-term trend is for crude quality to deteriorate in terms of both API and sulfur content.

This trend in crude quality, of course, runs counter to the trends in world demand. The world wants more and more gasoline, jet fuel, and diesel, and less and less fuel oil. Furthermore, concern about the environment means that the world is demanding lower-sulfur petroleum products. For reasons that will be clear in the refining discussion coming below, the more that the crude slate deviates from what is demanded, the higher petroleum prices will be pushed.

Nonetheless, a quality crisis does not appear to be upon us. Although our knowledge of future crude slates is imperfect, the most detailed recent study of the topic by Energy Security Analysis, Inc. (ESAI, 1992) suggests that in the near-term the crude slate will become higher in sulfur, but will actually increase slightly in API at the same time. The ESAI forecast is shown in Table 4. Both 1989 and 1990 are shown as base years, since the

Table 4. ESAI Crude Quality Forecast, 1992

(percentage shares of total production)

	1989	1990	1995
High-API, Low-Sulfur	33.3	34.2	30.2
High-API, Medium-Sulfur	8.9	10.3	9.6
High-API, High-Sulfur	31.0	28.9	34.3
Low-API, Low-Sulfur	0.4	0.4	0.6
Low-API, Medium-Sulfur	9.2	8.7	7.4
Low-API, High-Sulfur	17.3	17.5	17.9
Total High API	73.2	73.4	74.1
Total Low-API	26.9	26.6	25.9
Total Low-Sulfur	33.7	34.6	30.8
Total Medium-Sulfur	18.1	19.0	17.0
Total High-Sulfur	48.3	46.4	52.2

Notes: Split between High-API and Low-API at 30 degrees. Low-sulfur: <0.5%; medium-sulfur: > 0.5% & < 1.0%; high-sulfur: > 1.0%

Source: Energy Security Analysis, Inc., in Hydrocarbon Asia, July/August 1992.

1989-95 changes are more reflective of the overall trend (the loss of Kuwaiti and Iraqi production in 1990 and later years results in a few anomalous movements).

The increase in average sulfur content would tend to increase processing costs and low-sulfur crude prices even if environmental standards remained the same. These cost increases are likely to be even more rapid since they are occurring at a time when environmental standards are tightening sharply—not only in the United States, in the wake of the new Clean Air Act, but also in Europe and in most of the countries of Asia as well. On the other hand, the slight lightening in API is a welcome trend, that should to some extent counterbalance the increased costs of a high-sulfur slate.

In the longer term, of course, the crude slate will definitely resume the trend toward both higher sulfur and lower API, if only because of the vast reserves of extremely high-sulfur, low-API material in the Western Hemisphere. The decade of the 1990 may see a fairly relaxed oil market in terms of total supply (though surprising political events are always possible), but the overall trend is toward higher costs of extraction, higher cost of transportation, and, in future years, much higher costs for refining and environmental control.

D. Petroleum Products and Refining

1. Petroleum Products and Their Uses

Although we talk readily of the "demand for oil," petroleum refineries are just about the only businesses that have an actual demand for petroleum. At the point of final consumption, there is no demand for oil, but rather a demand for energy, or a demand for certain petroleum products.

There are literally thousands of grades of petroleum products, ranging from asphalt to gasoline, from propane to Vaseline. The greatest number of products are lubricating oils and greases. The greatest *volumes*, however, are in five product categories: liquefied petroleum gas (LPG); gasoline/naphtha; kerosene/jet fuel; diesel/heating oil; and heavy fuel oil. These five broad product categories account for 92 percent of total demand for oil products; the thousands of other products account for a mere 8 percent.

Table 5 gives an overview of the main oil product classes and their uses. The first thing to note is that the products are classified by their boiling range, with considerable overlap in the categories. Since the products, like the crude oil from which they are derived, are mixtures of many different hydrocarbon compounds, they do not have a single boiling point, but boil across a broad band of temperatures. LPG is the lightest material; it must be kept under pressure to be liquid at ambient temperatures. Gasoline and naphtha are light liquids which are quite volatile, and boil at temperatures beginning in the ambient range; the last drops may not boil off until well over 300° F. Kerosene and kerosene-type jet fuel (there are also some special jet fuels based on naphtha) begin boiling where gasoline and naphtha end. Diesel fuel and the "#2 Heating Fuel" used for space heating in many parts of the United States typically boil above 450° F, and are so lacking in volatility that you can put a cigarette out in them (though this practice is not recommended). Fuel oil, also called heavy fuel oil, bunker fuel, Bunker C, and "resid," is the heaviest part of the crude oil; it is material that does not even start boiling until about 650° F.

LPG has the most assorted uses of any of the main products. It is composed of propane or any of various butanes, and "LPG" may refer to either of these, or any mixtures of them. It is often used as a cooking fuel for portable stoves, as a bottled fuel for areas beyond the reach of gas pipelines and electric grids, and as lighting fuel for certain types of lanterns. It is increasingly used as a feedstock for petrochemical manufacturing, and is also used as a boiler fuel and for power generation in some areas. In addition, some jurisdictions have used LPG as an automotive fuel, especially for fleet vehicles; New Zealand and Thailand have had the most extensive programs in this area, but propane-powered cars have also been used in California because of their lowered pollution output compared to gasoline.

The distinction between gasoline and naphtha can be a source of some confusion. All gasoline is also naphtha, but not all naphtha is gasoline. Naphtha is simply the material in the specified boiling range, but to be sold as gasoline, it must meet a very strict list of

Table 5. Petroleum Products, Uses, and Alternatives

Temp. (F)	PRODUCT		USES		CURRENT SUBSTITUTES
0-50	LPG	==>	Mixed	<==	Gas, some coal
40-330	Gasoline	==>	Transport	<==	?
	Naphtha	==>	Petrochemicals	<==	?
290-520	Kerojet	==>	Transport	<==	?
		==>	Rural Cooking	<==	Wood, LPG
		==>	Home Heating (Japan)	<==	Gas
370-675	Motor Diesel	==>	Transport	<==	?
	Heating Oil	==>	Home Heating (US)	<==	Gas, solar, wood
		==>	Industrial Heat	<==	Gas, coal
650-675+	Fuel Oil	==>	Industrial Heat	<==	Gas, coal
		==>	Electric Power	<==	Gas, coal, nuclear, hydro, geothermal, wind, etc

criteria (which vary from country to country and area to area). These criteria are constantly being made more strict to control automotive pollution.

The most important specifications for a saleable gasoline are a minimum octane number and a maximum Reid vapor pressure (RVP). The octane number is a measure of how much the gasoline can be compressed before igniting; the higher the octane, the more compressible the mixture. (Premature ignition causes "knocking," which is the result of the gasoline exploding before the piston is completely depressed. This is why high-compression engines require high-octane, "premium" gasoline). The Reid vapor pressure is a measure of how easily the gasoline evaporates. A minimum RVP is needed to ensure that the gasoline comes through the fuel line to the carburetor, but the maximum RVP is even more important, since too high an RVP can cause vapor-lock. In addition, high RVPs mean more evaporation during service-station fuelling, which is a major cause of air pollution. Polluted areas such as Los Angeles tend to have much lower limits on maximum RVP. (There are also winter and summer RVPs in colder climates, with higher RVPs allowed during winter months.)

Most naphtha is used to make gasoline, but even with the greatest ingenuity, not all of the naphtha produced can "make the grade." Some of the rest of the naphtha is used to make solvents, paint thinners, and various minor products, but its biggest end-use is as feed to "ethylene crackers," the most fundamental process of the petrochemical industry, producing polyethylene, polypropylene, synthetic rubbers, and a host of other plastics. Some volumes of LPG can be substituted for naphtha in this process, but naphtha is still the critical feedstock for the manufacture of petrochemicals. In addition, there are highly volatile jet fuels based on naphtha; until recently, virtually all military jets used naphtha-type fuels. Recently, many military agencies have begun to phase out naphtha-type jet fuels for safety reasons, as its volatility makes it highly explosive.

Commercial jet fuel is all kerosene-type jet fuel, far less volatile than naphtha. Like gasoline and naphtha, all of this type of jet fuel is kerosene, but not all kerosene is jet fuel. There are many grades of kerosene for different purposes around the world, although the one that is becoming most common is dual-purpose kerosene (DPK), which meets the requirements for jet fuel as well as for most other kerosene uses.

Because jet fuel is used on such an international basis, its specifications are fairly constant. The four most important are smoke point, sulfur content, flash point, and freeze point. Smoke point is a measure of burning characteristics. An upper limit on sulfur is primarily for pollution control. The flash point specification is to ensure that the fuel does not evaporate and explode easily. The freeze point ensures that the fuel will remain liquid at low temperatures, such as are encountered at the high altitudes of modern jet travel.

Very little kerosene is used in the United States for anything other than jet fuel (and some kinds of camping equipment). In other parts of the world, however, kerosene is important for other purposes. In many rural areas of the developing world, it is the main source of cooking and lighting; there have been riots in India and Indonesia when the price of kerosene has been raised. In Japan, it remains one of the most important sources of home heating, and a cold winter in Japan can increase the international price of jet fuel dramatically.

Diesel fuel and #2 Heating Fuel are in a boiling range often referred to as "gasoil" or "light gasoil." There are a number of grades of this material, with the most important specifications being cetane number, sulfur content, and viscosity. The cetane number is best thought of as the diesel equivalent of the octane number. Sulfur must be minimized for pollution control, and there is a maximum viscosity to ensure that the material will flow easily.

In the United States, highway diesel and #2 Heating Fuel (also called HHF, Home Heating Fuel) are relatively interchangeable (though new legislation is changing this), but in most other countries, highway diesel has a high cetane specification not required of #2 Fuel. Some countries, including the United States, also have a high-cetane grade called automotive diesel for use in cars and light-duty vehicles.

Heavier, higher-viscosity, higher-sulfur grades include marine diesel (for diesel-engine and diesel turbine ships), railroad diesel, and industrial diesel. The specifications on railroad and industrial diesel vary widely around the world; some areas, such as Japan and the United States, are fairly strict on qualities, whereas in other areas industrial and railroad diesel containing up to 1.8 percent sulfur can be burned.

Fuel oils are the "bottom of the barrel." They are the material left over when distillation ceases at 650° F (which is why they are 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 any particular specification. The most important specifications on fuel oils are sulfur content and viscosity.

Sulfur and other contaminants in the crude oil (including metals and other nonhydrocarbons) tend to become concentrated in the fuel oil boiling range—an issue that will be returned to later. Therefore, fuel oils can be very high in sulfur content; a crude oil with a sulfur content of 1.8 percent by weight may yield a fuel oil with 3.5 percent sulfur. Some countries have long had strict regulations on the maximum sulfur content of fuel oil that can be burned, while others have allowed virtually any material to be used. The trend is toward tighter standards worldwide, but a large amount of fuel oil is still consumed in international shipping, where there is minimal regulation of emissions.

Low-sulfur crudes are coveted because they produce low-sulfur fuel oil, which has a higher market price, but these low-sulfur crudes, as mentioned earlier, are typically waxy. Like contaminants, most of the "wax" is also concentrated in the fuel oil range, so most of the low-sulfur crudes produce a fuel oil that is not liquid at room temperature. The viscosity of fuel oils is thus often a vital specification (although some buyers handle high viscosity materials by using heated oil tankers and heated storage tanks). Most of the fuel oils used in the world are blends of various different materials, to lower sulfur, to lower viscosity, or to provide an outlet for unwanted refinery materials.

The biggest use of fuel oil is for electric power generation, but large amounts are also used in industrial boilers, mining, smelting, and international shipping. Unlike the transport fuels (gasoline, kerojet, and diesel), where a liquid is specifically required, fuel oil is typically used simply as a source of high-temperature heat. This means that in most uses, natural gas, coal, some forms of biomass, and most other petroleum products, can all be used as alternatives to fuel oil. In the case of electrical power, all of the aforementioned alternatives are available, as well as hydropower, wind power, geothermal, and nuclear generation.

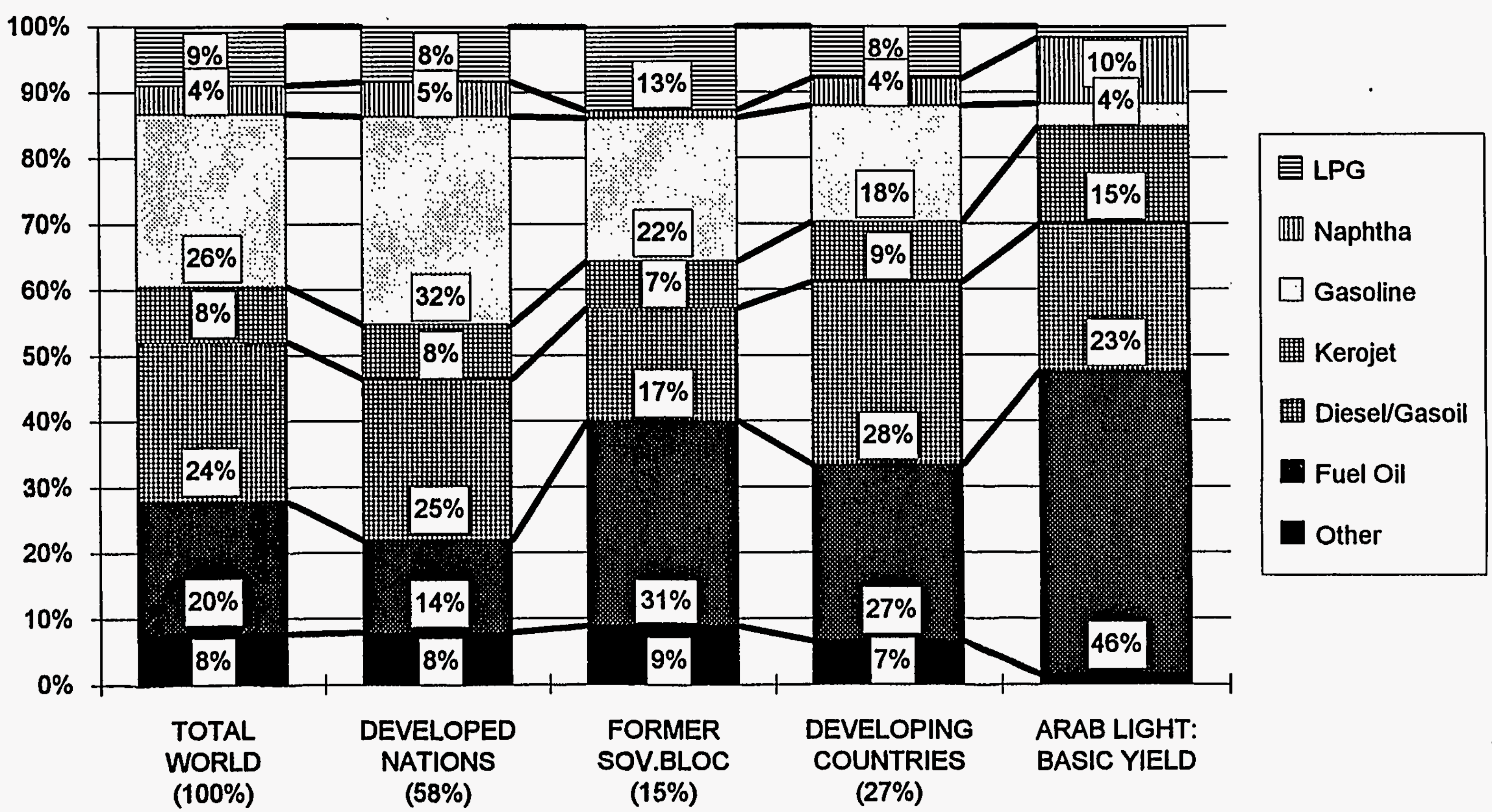
There are ready alternatives to oil products in cases where all that is needed is a heat source. Thus fuel oil is readily substituted, as is the use of #2 Heating Fuel for space heating. Some uses of kerosene and LPG have widely available substitutes, though not always convenient ones.

There are few ready alternatives to the transport fuels, or to the use of naphtha for the manufacture of petrochemicals. Most of the thousands of "other" products, such as lubricants, asphalt, and needle coke, also are relatively difficult to displace with other materials. In all of these cases—transport fuels, naphtha, and "other" oil products—it is not simply *energy* that is demanded, but an *energy form*. You can't pave a hole in the road with 1,000 cubic feet of natural gas, even if it has the same energy content as the amount of asphalt that would fill the hole; you can't lubricate a car engine with nuclear power, or fly a jet on coal. The cases where energy forms are demanded are the most critical uses of energy, and most of the cases where specific energy forms are needed are cases that require oil products.

At one time, oil was so cheap that few other fuels could compete with it even when being used only for processes like providing heat. As prices have increased, oil has been pushed out of many of its low-value uses, increasing the share of oil that is used to provide specific energy forms. Taken together, transport fuels, naphtha, and the miscellaneous "other" products account for more than 70 percent of the world's use of oil.

As Figure 23 shows, the reliance on these forms does vary between economies. For the developed world as a whole, nearly 80 percent of demand is for these relatively inflexible needs, the biggest, of course, being gasoline, at 32 percent of oil demand. The reliance on specific energy forms is not as extreme in the developing countries, or in the nations of the

Figure 23. Product Demand Shares in Different Economies



former Soviet Bloc, but the trend is for other energy sources to be substituted for oil when possible.

Most people are familiar with the drop in oil demand in the early 1980s, following the sharp rise in prices after the Iranian Revolution. Worldwide oil demand by product is shown in Figure 24 for the period 1971-90 (comprehensive figures are not yet available for 1991-92). The sudden change from rapid growth to a slump in the early 1980s is clearly visible. Closer examination, however, shows that most of the actual decline in demand is a result of the drop in consumption of fuel oil. This is even more obvious in Figure 25, which shows the annual demands for the same period excluding fuel oil. The demand valley in the early 1980s flattens out considerably. The drop in oil demand was really a drop in fuel oil demand; demand for other products remained nearly constant, even though oil prices more than doubled.

Turning back to Figure 23, one of the important features of the chart is the percentage yields of Arab Light crude oil (based on a simple hydroskimming refinery). The biggest single yield from this crude—which is often taken as an average crude oil—is about 45 percent fuel oil, compared to a world demand for fuel oil of around 20 percent. This typical crude yields more than twice as much fuel oil as the world needs. The greater elasticity of demand for fuel oil can be attributed largely to the fact that there are many alternatives to fuel oil but few to the other products.

This is quite visible in the price behaviors of fuel oil relative to other products in times of rising crude prices. Figure 26 shows the spot (Rotterdam market) prices of crude oil, regular gasoline, and high-sulfur fuel oil from 1973 to 1991. At low crude prices, all three prices are relatively close together. As crude prices rise, however, fuel oil lags behind; the gap between fuel oil price and crude price widens. This is because fuel oil is the easiest oil product to cut back on; other sources are rolled in, especially in electrical generation. (In addition, recessionary effects tend to lower industrial fuel oil demand at the same time.) A surplus of fuel oil develops, pushing fuel oil prices even lower.

Figure 24. World Oil Product Demand, 1971-91

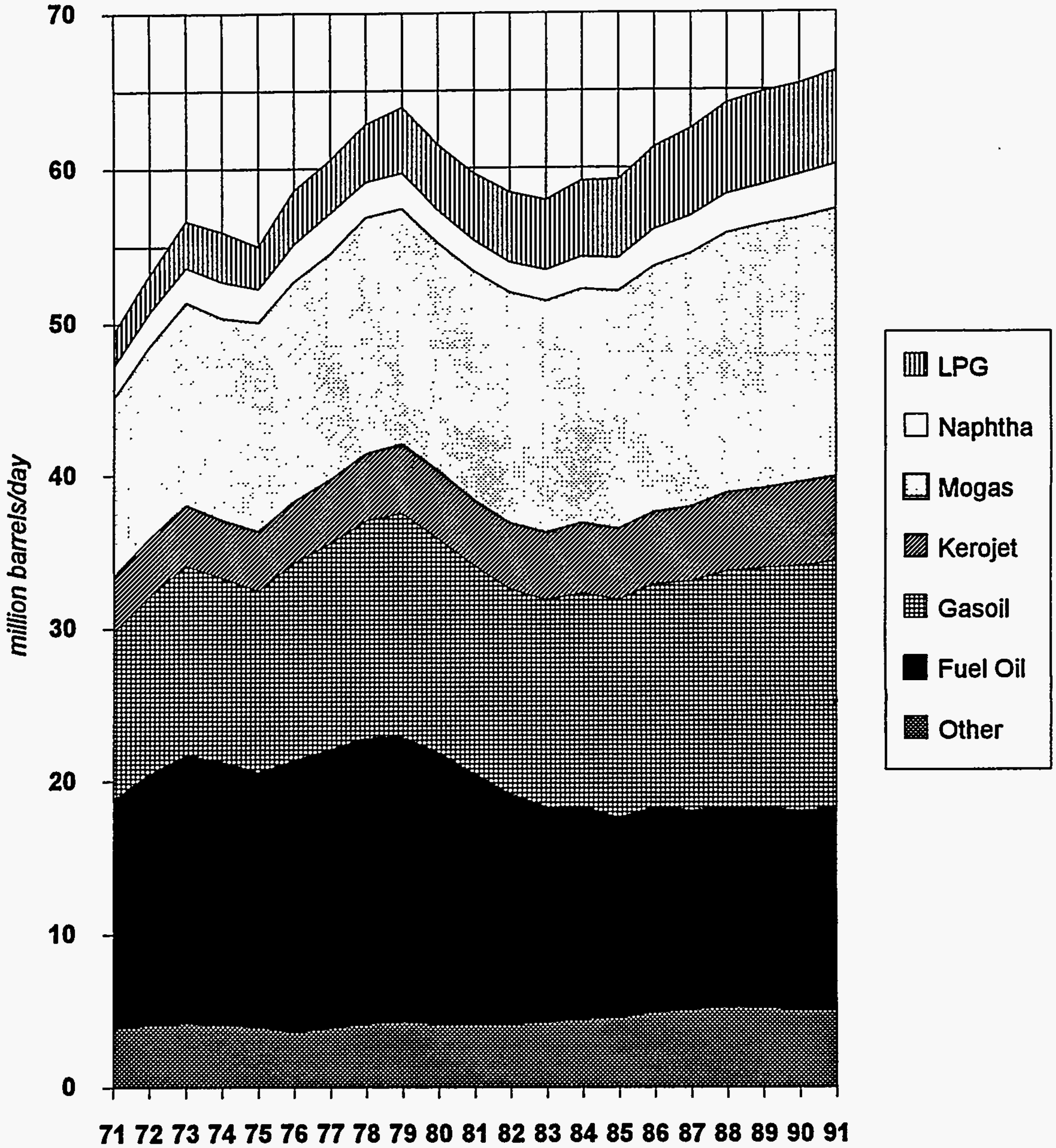


Figure 25. World Product Demand Excluding Fuel Oil, 1971-91

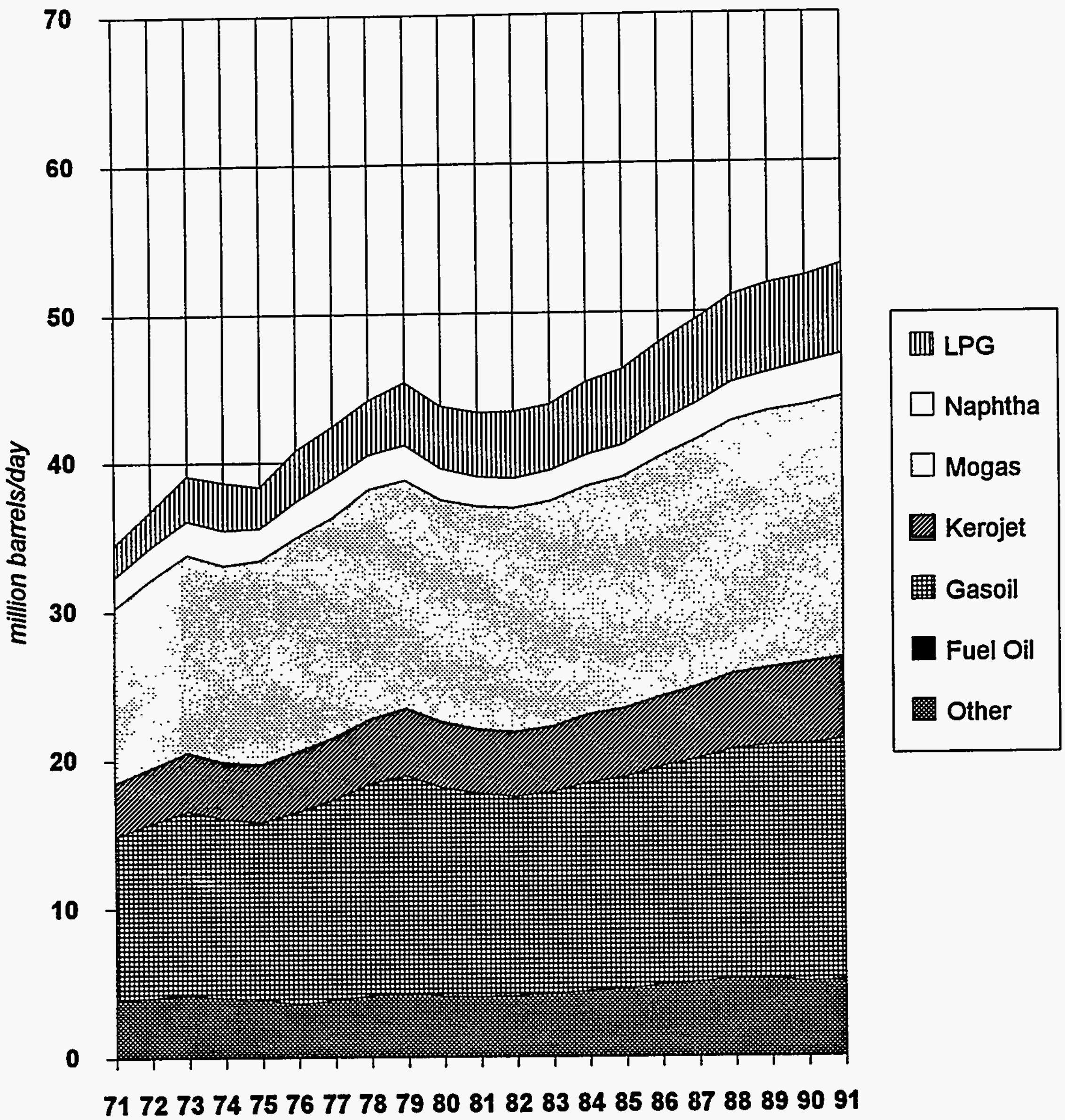
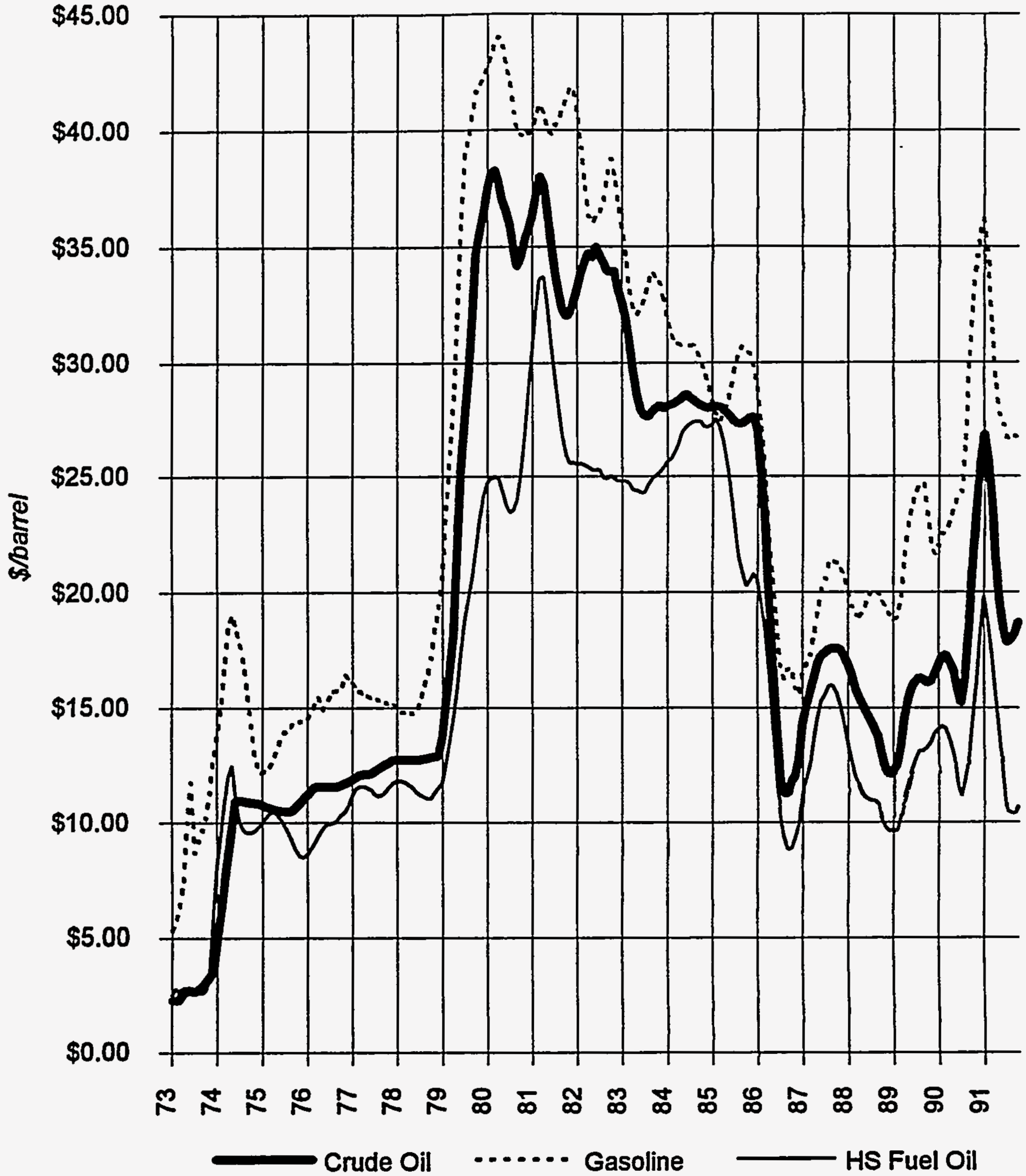


Figure 26. Spot Prices of Crude, Gasoline and Fuel Oil



Notes: Based on six-month moving average. Rotterdam spot; Arab Light 1973-85 and Dubai since 1985; regular gasoline; 3.5 % sulfur fuel oil.

Gasoline, on the other hand, shows the opposite behavior: As crude prices go up, gasoline prices go up even faster. The gap between crude price and gasoline price widens. This sometimes seems like a plot to gasoline consumers, who often suspect that crude prices and gasoline prices should go up at the same rate. The latter would be a reasonable assumption if fuel oil prices also went up at the same rate.

Consider a simplified case: We have a material X that is split into two equal parts, A and B. When X sells for $10, the price of A is $16 and the price of B is $5. Thus each unit of X produces (0.5 x $16 + 0.5 x $5) $10.50 of revenue. The *gross margin* on X is $0.50, the profit before operating costs.

Now suppose that the price of X doubles to $20. We might have a case where the prices of both A and B double, giving $21 revenue and $1 gross margin; this is what would happen if the prices all went up proportionately, as many people feel crude oil and gasoline ought to do.

But suppose the price of B goes up less than proportionately; in the extreme case, suppose that the price of B stays fixed at $5. In this case, to have the same gross margin as before ($0.50), we need revenues of $20.50. B at $5 will supply only (0.5 x $5) $2.50 of this, so the revenues from A must make up ($20.50 - $2.50) $18 of the total revenue. To get $18 of revenues from A means that the price of A must rise to $36. Thus, if the price of B remains fixed, increasing the price of X by 100 percent increases the price of A by 225 percent.

This is a vast oversimplification when applied to oil products. None of the prices remain fixed; the price of fuel oil increases, but does not increase as rapidly as crude. There are many more than two jointly produced products, and there is some flexibility in converting between them. Nonetheless, this simple example shows an important underlying principle behind oil economics that explains the wide gaps above and below the crude price in Figure 26.

Turning back to the basic yield of Arab Light on Figure 23, it is possible to apply these yield coefficients to product prices to determine the basic crude values for Arab Light across time; that is, the value of the crude is the sum of the values of its outputs. This imputed value is graphed against the actual price of crude in Figure 27.

At the scale of Figure 27, there appears to be an extremely tight correlation between crude prices and crude values. The gross margin, shown in Figure 28, tells a different story. The margin—in this case, the crude value minus the crude price—varies from $5.70 per barrel down to *minus* $4.95 per barrel. The average gross margin for the period is $0.89 per barrel.

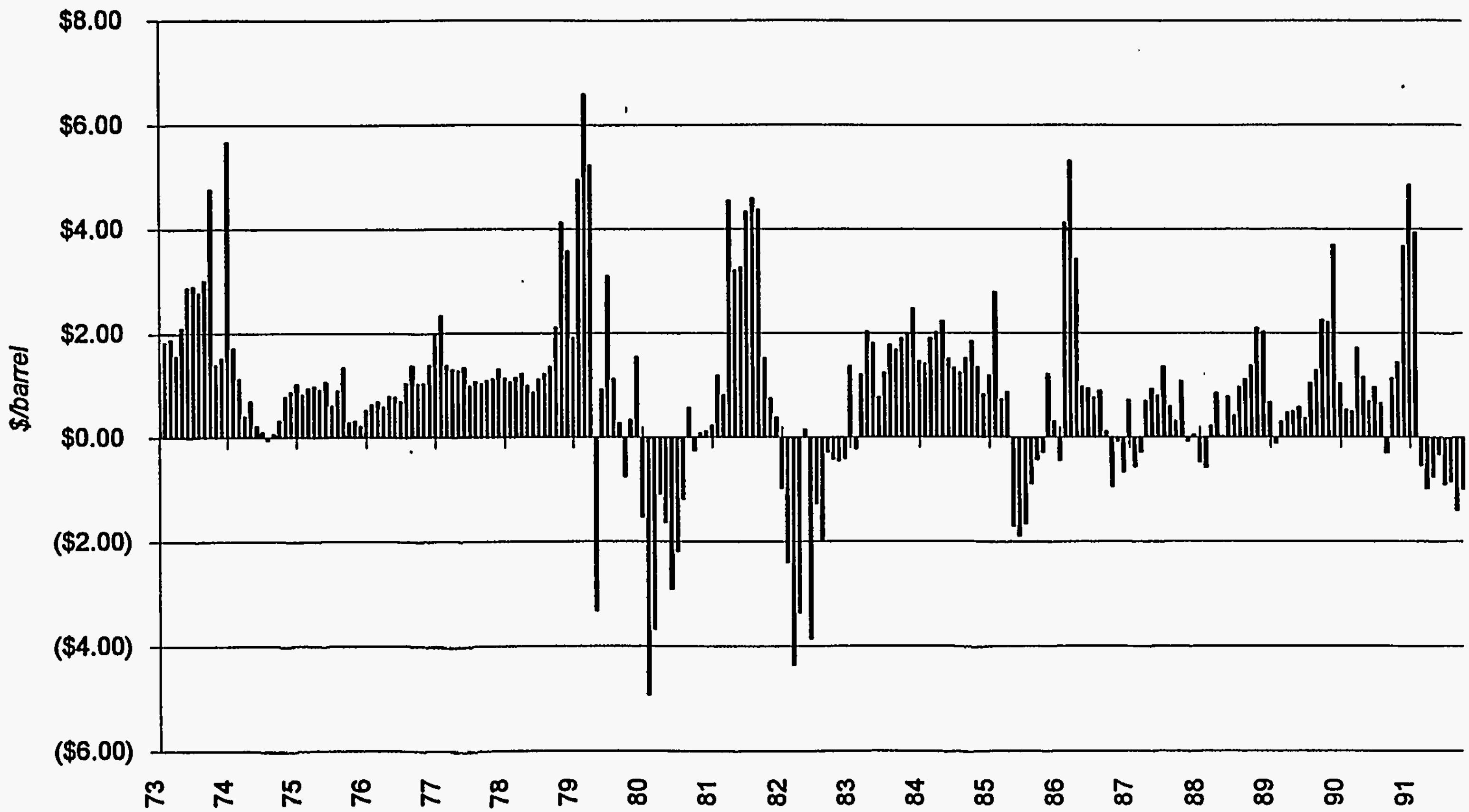
Nonetheless, the correlation still seems good; the crude values and crude prices track closely, within a few dollars per barrel up or down. What needs to be understood, however, is the scale of refinery processing. A margin of $2.00 per barrel on a 200,000 b/d refinery is an income of about $146 million per year above the cost of the crude. A negative margin means a loss of the same magnitude.

There have been periods in the past two decades when refiners made substantial profits; others where they made shockingly high losses. But the matter is not as simple as the equation of crude value and crude price might make it seem, because the output patterns are not fixed. Arab Light does not give the yields shown in Figure 23 in every refinery; indeed, every year, fewer and fewer refineries show such an output pattern. There are ways of increasing the yields of transport fuels while cutting the yield of fuel oil; there would have to be, otherwise, according to Figure 23, we would all be swimming in fuel oil by now.

On the other hand, refinery flexibility is neither infinite nor cheap. Simply cutting "demand for oil," by means such as building wind-electric farms instead of oil-fired power stations, does not automatically mean that we can use the oil saved to drive our cars. It is, however, important not to go to the other extreme and assume that saving fuel oil has no impact on the availability of gasoline. Any change in the pattern of demand affects the overall supply and price system. It unfortunately does so in a rather complex way, via the refining system.

Figure 27. Crude Prices and Crude Values, 1973-91

Figure 28. Computed Gross Margins on Spot Crude



Notes: Based on simple hydroskimming of Arab Light. Average margin for whole period is $0.89/barrel.

2. The Refining Process

There are dozens of major processes within a refinery, and dozens of different "brand names" for what are essentially identical processes. This section is not intended to be a comprehensive introduction to refining, but it does need to touch on all the major categories of technology.

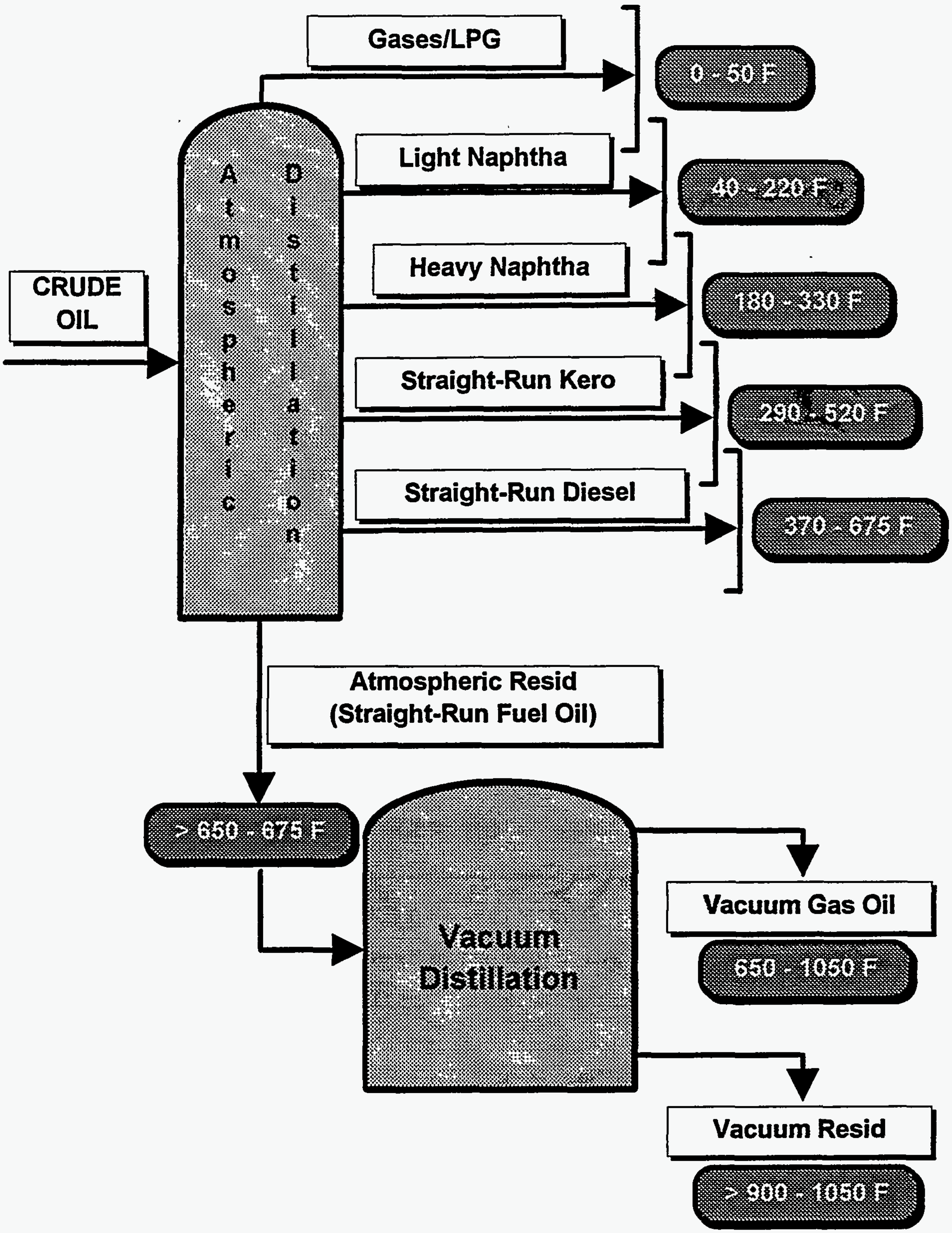
Refining technologies can be divided into four main categories according to the purpose for which they are used: distillation, cracking, reforming, and hydrotreating. Note that these are categories by *purpose* rather than by engineering principle; the actual processes within a single category often use very different chemical procedures as their basis.

Distillation

The purpose of distillation processes is to achieve a rough separation of mixtures into mixtures grouped by their boiling points. The separation in industrial processes, as opposed to laboratory benchtops, is often fairly imprecise. The famous whiskey or moonshine still is an example of industrial-process distillation; the material boiled off and captured is a much more concentrated solution of ethanol, but it still contains substantial amounts of water. Complete separation requires repeating the process again and again, using larger amounts of time and energy.

In the early days, oil was distilled exactly like whiskey: the oil was placed in a boiler, and the temperature was gradually raised. Today, continuous distillation processes, shown in Figure 29, are used everywhere in the oil industry. Instead of gradually raising the temperature, the oil is heated *before* being charged to the distillation tower. The material that is boiling when it enters the tower evaporates and travels upward where it meets a series of baffles and barriers. As it encounters these barriers, the heavier components condense, and the lighter components continue to rise. In effect, the temperature drops as the oil vapor travels up the tower column. The height at which it condenses is thus related to the boiling point of the components, so that drawing off condensed material at a given height is equivalent to drawing off material at a particular boiling range. (There are a number of

FIGURE 29. BASIC DISTILLATION PROCESS



technical flourishes added to this process in practice, in the interests of achieving better separation, but these do not alter the fundamentals described here.)

Note that the boiling ranges given in Figure 29 overlap. This not only reflects reality (separation is never perfect), but also reflects the flexibility of the distillation process itself. If the refiner wants more kerosene and less diesel, the kero cut might be taken at 290-520° F, and the diesel cut at 520-650° F. If more diesel and less kerosene is desired, the kero cut might be taken at 290-370° F, and the diesel cut at 370-650° F. An example of the effects of this kind of "cutpoint flexibility" is shown in Table 6.

The alterations in output shown in the table are striking. The output of heavy naphtha can swing between 8.5 and 13 percent; kerosene, from a mere 4.3 percent to 24.6 percent; and diesel, from 13.2 percent to 29 percent. This, of course, is just for the "typical" Mideast crude shown in the example. Each crude oil will yield a slightly—sometimes dramatically—different pattern, and a refinery may process several crudes at the same time. Thus, the output of a refinery is far from fixed, even at the level of distillation. This flexibility raises questions as to why there are ever shortages of products. When the price of, say, gasoline, starts to rise, why doesn't the refiner simply make more gasoline? To a certain extent, this happens, but there are three reasons why the extent of these kinds of shifts is limited.

First, the pressure usually isn't just on one product. Gasoline is the most politically visible product, but when the price of gasoline takes a sharp jump, the price of jet fuel and diesel have usually increased in lockstep. If there is a shortage, recutting the barrel simply shifts the shortage from one fuel to another.

Second, the fuel most likely to be in short supply is the one that "drives" the market. In most of the United States, this fuel is gasoline; in Hawaii, it is jet fuel. Typically, the refiners are already making as much of the driving fuel as possible. In the case of Hawaii, when there is a sharp price rise, the refiners could create a glut of gasoline at the expense of a shortage of jet fuel, but doing the opposite would be difficult; they are already producing as much jet fuel as possible. In the mainland United States, most refiners could produce more jet fuel, but only by cutting their gasoline output.

Finally, and most important, the cutpoint flexibility shown in Table 6 says nothing about product specifications. In a few Third World countries, fuels are still cut primarily on boiling ranges without much regard to product quality, but in most countries today it is quality specifications that are the limiting factor on cutpoint flexibility. For environmental reasons, these limitations are getting stricter every year, giving the refining system much less choice in what products are produced in what quantities. This will be discussed in more detail in the later section on product blending; for the moment it is enough to know that, while the refiner can cut the crude at whatever temperature ranges are desired, it may not be possible to make saleable products unless the crude is cut within certain specific ranges (which vary from crude to crude).

In addition to the main distillation tower (the "atmospheric crude distillation unit," or *CDU*), Figure 29 shows a second tower, the vacuum distillation unit (*VDU*).

The material that did not evaporate when charged to the main tower—material boiling at temperatures above about 650-675° F—is drawn out the base of the CDU. This material is logically called *atmospheric residuum, atmospheric bottoms, long resid, virgin resid*, or simply *straight-run fuel oil.*

This material can be further divided by boiling range. At temperatures above about 675° F, however, the constituent molecules of crude oil absorb so much thermal energy that they begin to degrade, breaking apart randomly into smaller chains of atoms. This is undesirable (unless done in a highly controlled way), so the vacuum distillation process was devised.

Just as water boils at lower temperatures in high mountains (because of reduced atmospheric pressure), oil can be made to boil at lower temperatures by reducing the pressure around it. A VDU tower splits the atmospheric bottoms into at least two more streams: lighter material, *vacuum gas oil* (VGO), and a residuum from the tower, called, as might be expected, *vacuum resid* (VR) or *vacuum bottoms* (VB).

Table 6. Example of Cutpoint Flexibility

CUT STRATEGY	Typical	Kero Max	Diesel Max	Hvy Nap. & Diesel Max	Hvy Nap. & Kero Max
Hvy Naphtha Cut Range, F	**200-290**	**200-290**	**200-290**	**200-330**	**200-330**
Kero Cut Range, F	**290-450**	**290-520**	**290-370**	**330-370**	**330-520**
Diesel Cut Range, F	**450-650**	**520-650**	**370-650**	**370-650**	**520-650**
YIELDS, % of crude input					
Gases/LPG	1.9	1.9	1.9	1.9	1.9
Light Naphtha	7.2	7.2	7.2	7.2	7.2
Heavy Naphtha	**8.5**	**8.5**	**8.5**	**13.0**	**13.0**
Kerosene/Jet Fuel	**17.5**	**24.6**	**8.8**	**4.3**	**20.1**
Diesel/#2 HF	**20.3**	**13.2**	**29.0**	**29.0**	**13.2**
Fuel Oil	44.6	44.6	44.6	44.6	44.6
TOTAL	100.0	100.0	100.0	100.0	100.0

Range of Yields, %	
Heavy Naphtha	**8.5 - 13.0**
Kerosene/Jet Fuel	**4.3 - 24.6**
Diesel/#2 HF	**13.2 - 29.0**

Output streams from the VDU have "nominal" or "effective" boiling ranges. These are the temperatures at which the material *would* boil under atmospheric pressure, not the temperature under which they were actually distilled. VGO typically is taken as a 650-1000 F nominal cut, and VB is everything that still has not boiled at a nominal temperature of 1000 F.

It may not be apparent at first why anyone would want to split fuel oil into heavier and lighter streams. In part, the purpose is to create feedstocks for certain heavy products. Lubricating oils are made from part of the VGO cut, and asphalt is made from various vacuum bottoms. These, however, account for only a small part of the use of VDU streams. The main purpose of splitting atmospheric fuel oil in a VDU is to produce feedstocks for various cracking units.

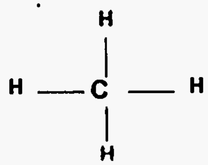
Cracking

The problem presented by Figure 23, of distillation yields from crude not matching demand patterns, is very old. In the early days of oil, the main product in demand was lighting kerosene (to replace increasingly expensive whale oil). One of the reasons Henry Ford designed his automobile to run on gasoline is that gasoline was, at the time, a virtually worthless byproduct. Crude oil has always produced far more fuel oil than refiners would like, since the price of fuel oil was always held down by coal and other heat sources.

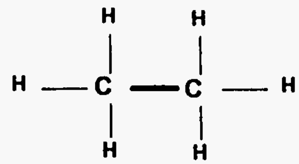
Figure 30 shows the structure of some of the lighter molecules found in petroleum. In general, as the number of carbons in the molecule goes up, so does the density, the boiling point, and the number of different compounds (called "isomers") with the same chemical formula. Ignoring the problem of carbon-carbon double bonds for the moment, there is only one kind of 1-carbon hydrocarbon (methane), only one 2-carbon (ethane), only one 3-carbon (propane). But when we reach 4-carbon compounds, there are two kinds (butane and isobutane). At 5 carbons, there are four kinds of molecules that can be designed, and the number of possibilities increases geometrically thereafter. By the time we reach even 8 carbons, the possible structures of the molecules become bewildering. The huge, branched chains that are found down in the fuel oil range are so complicated that it is

FIGURE 30. EXAMPLE CONSTITUTENTS OF PETROLEUM CUTS

1. Gases
< 0 F

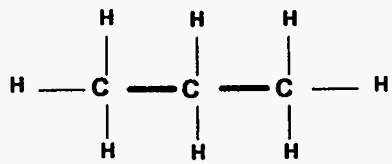


Methane - C1

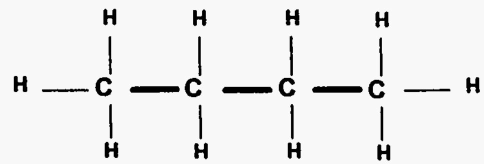


Ethane - C2

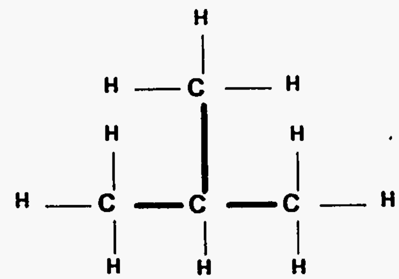
2. LPGs
-40 – 40 F



Propane - C3

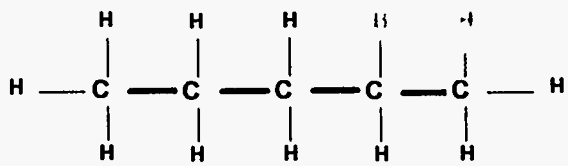


Butane - C4

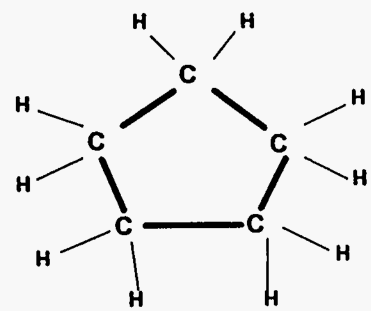


Isobutane (Methylpropane) - C4

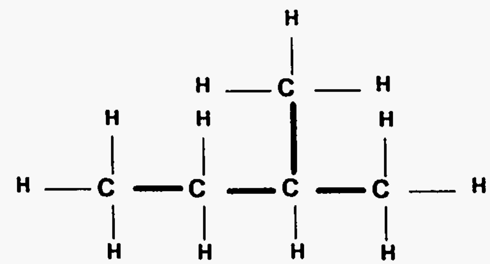
3. Naphtha
80 – 330 F



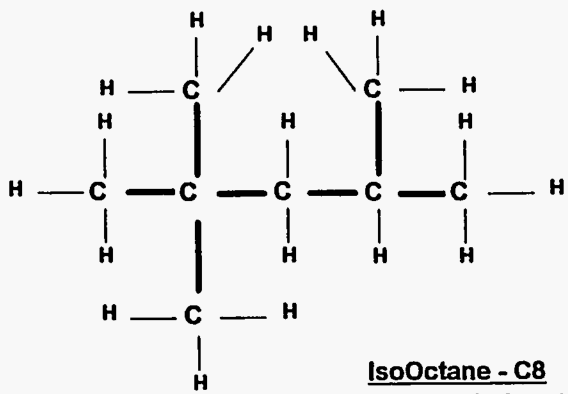
Pentane - C5



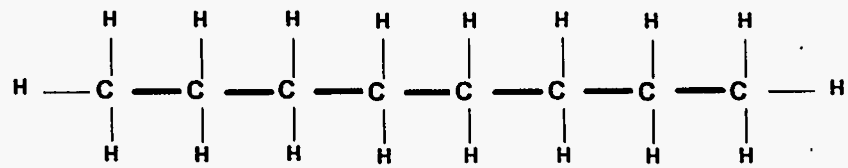
Cyclopentane - C5



Isopentane (Methylbutane) - C5



IsoOctane - C8
(2,2,4-Trimethylpentane)



Octane - C8

seldom that anyone studies their exact composition. Nonetheless, it is clear that one way to get higher yields of the light molecules we want, the ideal process would be one that breaks up the fuel oil molecules into smaller pieces.

By the early part of the twentieth century, there was already experimentation with techniques to break up fuel oil, a process that became known as "cracking." Initially, this was done simply by heating the fuel oil up beyond 650° F, at which point the thermal instabilities caused the molecules to break apart.

The problem with this kind of process, known as *thermal cracking*, is that it was difficult to control, cracked only relatively small amounts of fuel oil into lighter molecules, and produced outputs of low quality. Its one redeeming feature was that it tended to cause a great reduction in the viscosity of the fuel oil that remained after treatment; when a fairly mild form of thermal cracking is used, mainly to improve fuel oil quality, it is known as *visbreaking*.

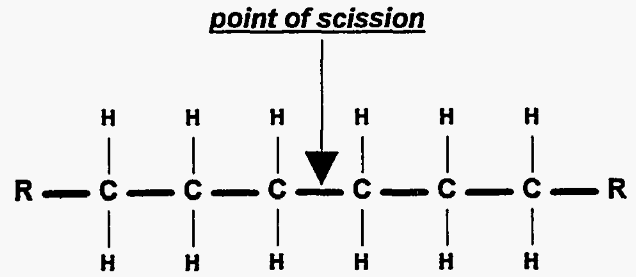
Figure 31 shows three of the main kinds of chemical reactions that go on in the processes referred to as cracking. In a thermal cracker, both reactions 1 and 2 are common. In Reaction 1, the molecule breaks apart; one half collapses into a carbon-carbon double bond, and donates its (now) spare hydrogen to the other half. In reaction 2, free carbon is deposited from the molecule in a form known as "petroleum coke." Dropping a carbon atom from the molecule leaves enough hydrogen to satisfy the bond requirements in both of the smaller molecules.

In a visbreaker, coke deposits are just a nuisance that accumulate inside the process unit, and eventually have to be cleaned out (usually by sandblasting). Coke, however, has many potential uses of its own, in steelmaking, in construction of anodes, and, if the price is low enough, as a solid fuel in its own right.

By controlling the operating parameters carefully, the deposition of coke can be maximized. The most common form of this process is *delayed coking*, a process that accumulates the coke buildup in drums that can be taken offstream and emptied. A more sophisticated form, *fluid coking*, has lower yields of coke, but better outputs of products.

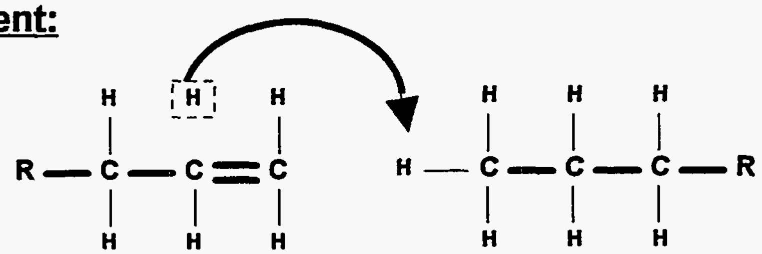
FIGURE 31. EXAMPLES OF TYPICAL CRACKING REACTIONS

Example Molecule:



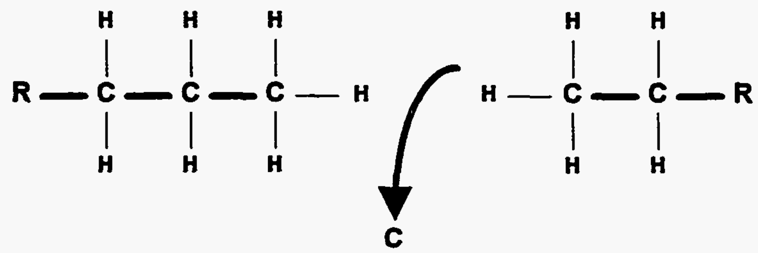
"R" is any additional hydrocarbon chain or group

1. Bond Rearrangement:



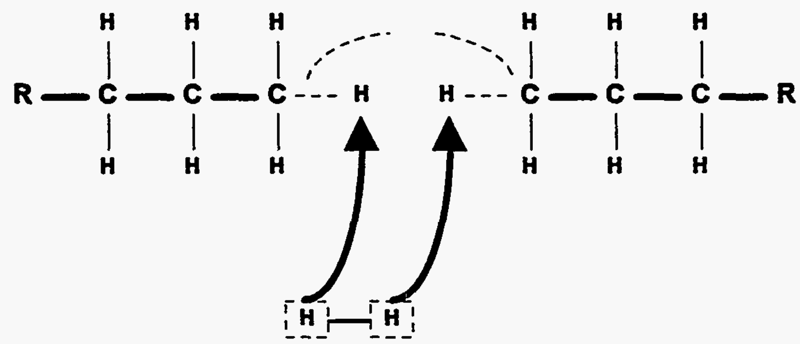
Common in both thermal and catalytic processes: FCC, Coking, Visbreaking

2. Carbon Deposition:



Common in both thermal and catalytic processes; dominant process in coking

3. Hydrocracking:



Occurs only with suitable catalyst under high pressure of hydrogen gas

The main problem with light products from both cokers and visbreakers/thermal crackers is the presence of the carbon-carbon double bond in straight-chain molecules. These molecules are *unsaturated*, and unlike cooking oils, where the more unsaturated the better, in petroleum fuels the more unsaturated the worse (with a major exception—the aromatics, which will be discussed below). These tend to have poor combustion properties, low octanes, low cetanes, and contribute more than their share to pollution from engine exhaust. Most areas have maximum specifications on *olefin* content (olefins being another name for single unsaturated bonds).

Like many other chemical processes, it was eventually discovered that certain catalysts could speed the desired cracking reactions, letting them occur more rapidly at lower temperatures, and with a greater degree of control. The greatest success story in refining technology was the development of the *fluid catalytic cracker* (FCC), which cracked fuel oil into high-value gasoline blendstocks.

The catalytic process in an FCC also relies on reactions 1 and 2 from Figure 31, but the process, as well as breaking up molecules, also has a strong tendency to turn them into cyclic compounds (like the case of cyclopentane in Figure 31), and to increase the *aromaticity* of the output as well. This results in very high-octane products, which contribute both volumetrically and qualitatively to the gasoline pool of the refinery. Unfortunately, the middle distillates (kerosene and diesel) produced from an FCC are very poor in quality, and often get blended back into the fuel oil pool.

A quick glance at Table 7 will show the obvious superiority of FCC technologies over the earlier thermal processes. Most cracking processes result in a slight volume gain on processing (since gases are less dense than fuel oil), but the important total is the total of yields in the naphtha-to-diesel range: less than 20 percent for a visbreaker, about 35 percent for coking, but around 80 percent for an FCC. Indeed, more than half of the feedstock is converted into naphtha-range gasoline blendstocks.

The catch, however, is that the catalysts in FCCs can be "poisoned" by trace metals, sulfur, and other materials; and FCCs cannot normally process the very heavy materials

Table 7. Example Yield Patterns From Cracking Units

	Output	Relative Quality	*Yield, Vol% of feedstock* Visbreaker	Delayed Coker	Fluid Coker	Fluid Cat Cracker	Hydro-cracker
	Fuel Gases	--	2.9%	7.2%	9.5%	3.0%	0.8%
	LPG/Olefinic Gases	--	1.9%	4.1%	8.4%	22.2%	11.5%
Naphtha/ Gasoline Range	Light Thermal Naphtha	poor	1.6%	1.6%	1.6%		
	Light FCC Naphtha	excellent				34.4%	
	Light HDC Naphtha	good					19.0%
	Heavy Thermal Naphtha	poor	3.4%	2.9%	3.3%		
	Heavy FCC Naphtha	excellent				28.1%	
	Heavy HDC Naphtha	good					20.3%
Kerosene Range	Thermal Kerosene	poor	5.8%	7.4%	12.2%		
	HDC Kerosene	excellent					30.1%
Diesel Range	Thermal Gasoil	poor	7.6%	24.0%	17.0%		
	Light Cycle Oil	poor				18.7%	
	HDC Gasoil	excellent					40.0%
Fuel Oil Range	Heavy Coker Gasoil	fair		34.8%	40.9%		
	Heavy Cycle Oil	fair				6.3%	
	Visbroken Resid	fair	78.2%				
	Petroleum Coke	--		21.0%	18.0%		
	TOTAL	--	**101.4%**	**103.0%**	**110.9%**	**112.7%**	**121.7%**
	TOTAL, Naphtha to Diesel	--	**18.4%**	**35.9%**	**34.1%**	**81.2%**	**109.4%**
		Main Feedstocks	Vac. Resid, Long Resid	Vac. Resid, Long Resid	Vac. Resid, Long Resid	Vacuum Gasoil*	Vacuum Gasoil**

* Newer, more resistant catalysts are making it possible to run many long resids. This is known as resid cat cracking (RCC). In times when diesel oil was in long supply, it also was common practice to run some volumes of diesel-range material to FCCs.

**There are various processes that allow hydrocracking of long resid, or even vaccum resid. This usually involves expensive feed pretreatment to avoid catalyst damage.

boiling beyond 1000° F. For this reason, FCCs were geared to run on the VGO cut from the vacuum distillation unit. Indeed, the development of the FCC was the main impetus to the spread of the VDU, which had only limited uses otherwise.

Hydrocracking (HDC), a more recent development than the FCC, also concentrates on the VGO section of the barrel. Hydrocracking uses the third reaction on Figure 31, where a catalyst aids the addition of hydrogen across a carbon-carbon bond. Since hydrogen is being added from outside, there is no formation of olefins and no deposition of coke. The addition of hydrogen actually increases the total mass of hydrocarbon produced from the process, so the volume gains from the process are considerable. Hydrocracking is also the most flexible of technologies, as the output slate can be adjusted by increasing or decreasing the hydrogen pressure. In addition, hydrocracking desulfurizes and otherwise cleans up the products while it operates.

Hydrocracking outputs are in some regards the opposite of those from an FCC. Hydrocrackers produce only mediocre gasoline blendstocks (though better than those from visbreakers and cokers), but they produce outstanding kerosene and diesel blendstocks. In general, a hydrocracker produces more overall useful output for the refiner than other cracking units, but it is at a greater expense: Hydrocrackers cost much more, and also cost more to run, because of the need for hydrogen.

Although the outputs from visbreakers and cokers may not be as useful or large as those from hydrocrackers and FCCs, visbreakers and cokers are less picky about their feedstocks. Visbreakers and cokers can take whole atmospheric resid, or even vacuum resid, as feedstock; hydrocrackers and FCCs have generally, until recently, been unable to handle much but VGO except in unusual circumstances. Thus, the thermal processes (visbreakers and cokers) and the catalytic processes (FCCs and hydrocrackers) are considered complementary in many refineries; the FCC or hydrocracker uses the VGO, while the coker or visbreaker attacks the vacuum bottoms—the latter often being unsalable even as fuel oil without further processing.

In the past five years, however, a new generation of FCC catalysts have launched a drive into what is called resid catalytic cracking (RCC). An RCC can handle atmospheric resid directly, without need to split the fuel oil into VGO and vacuum bottoms. This increases the yield of high-value products, and eliminates the need for additional processing to dispose of the vacuum bottoms. Most of the new FCCs being built are actually RCCs; indeed, many existing FCCs are being retrofitted to work with RCC catalysts. The only drawback is that the FCC/RCC technology is still poor at providing useable middle distillates—the growth product in most of the world. There is considerable current experimentation with hydrotreating (see below) of FCC light cycle oil to make decent diesel fuel from FCCs and RCCs. This is an expensive proposition, but many refiners are beginning to believe that it is more economic than hydrocracking.

Table 8 gives an indication of how important cracking can be to the total balance of a refinery. Using 100,000 barrels per day of typical crude as input, distillation yields about 52,000 barrels in the naphtha-to-diesel range, and almost as much—44,600 barrels—in the fuel oil range. After running the VGO to an FCC and the vacuum bottoms to a visbreaker, the total output in the naphtha-to-diesel range is increased to 76,800 barrels, and the total yield in the fuel oil range is pushed down to 15,900 barrels: only 15 percent of final output (23 percent if, for quality reasons, all of the light cycle oil (LCO) and thermal middle distillates have to be downblended to the fuel oil pool). It is cracking that allows the world to come close to supplying the demand for transport fuels without producing an enormous glut of fuel oil.

To put this into perspective, if it weren't for cracking processes, then to provide the world's transport fuel needs, world crude oil production and refining would have to more than double (to about 140 million barrels/day), and we would have almost 50 million barrels/day of excess fuel oil.

As befits a process so vital to the balance of the world oil system, cracking is expensive. In fact, a top-flight cracking unit, such as a worldscale hydrocracker or RCC, can cost more than the rest of the refinery it is installed in. Prices in excess of a billion

Table 8. Effects of Cracking on Refinery Yields: FCC and Visbreaker

100,000 b/d crude input

Yield, barrels/day

	Output	TOTAL After Distillation	Fluid Cat Cracker Output	TOTAL After Distillation & FCC	Visbreaker Output	TOTAL After Distillation, FCC, & Visbreaker
	Fuel Gases	1,200	792	1,992	528	2,520
	LPG/Olefinic Gases	2,100	5,861	7,961	346	8,306
Naphtha/ Gasoline Range	Straight-Run Light Naphtha	6,750		6,750		6,750
	Light Thermal Naphtha				291	291
	Light FCC Naphtha		9,075	9,075		9,075
	Straight-Run Heavy Naphtha	8,170		8,170		8,170
	Heavy Thermal Naphtha				618	618
	Heavy FCC Naphtha		7,425	7,425		7,425
Kerosene Range	Straight-Run Kerosene	16,900		16,900		16,900
	Thermal Kerosene				1,055	1,055
Diesel Range	Straight-Run Gasoil	20,200		20,200		20,200
	Thermal Gasoil				1,382	1,382
	Light Cycle Oil		4,937	4,937		4,937
Fuel Oil Range	Vacuum Gasoil	26,400				
	Heavy Cycle Oil		1,663	1,663		1,663
	Vacuum Bottoms	18,190		18,190		
	Visbroken Resid				14,225	14,225
	TOTAL	**99,910**	**29,753**	**103,263**	**18,445**	**103,517**
	TOTAL, Naphtha to Diesel	**52,020**	**21,437**	**73,457**	**3,347**	**76,804**
	TOTAL, Fuel Oil	**44,590**	**1,663**	**19,853**	**14,225**	**15,888**

dollars for a single cracking unit are now becoming commonplace, at least on the drawing boards. If a 40,000 barrels/day cracking unit costs $800 million to build (a reasonable figure on current construction), then over ten years, it will be able to process about 146 million barrels of feedstock. This means that each barrel of feed will cost *at least* $5.50 to process just in capital charges, not including interest. Basic interest can push the capital cost to about $8.50/barrel of feed, and interest plus a rate of return means that the refiner may need to get $10 or even $12 per barrel of feedstock. This means that the gap between fuel oil prices (the feedstock) and light and middle distillates (the output) needs to be wide. As seen before, this tends to happen when crude oil prices go up; the fuel oil prices sag, and instead of competing against coal and other energy sources, fuel oil becomes a feedstock within the refinery to make more transport fuels.

Ten years ago, cracking investments were made much more readily. Today, there is considerable expansion of refining worldwide, but cracking investments have not been keeping pace. The scale of investments required is now much higher than in 1980, and, more importantly, few investors have the kind of (apparently misplaced) faith in higher oil prices that was conventional wisdom a decade ago. A great amount of attention has been paid to the issue of access to crude oil; much less has been paid to whether the world is able to process the oil into the products we need. The balances inside the refining system are just as important as the availability of oil itself.

Reforming and Related Processes

Cracking breaks apart molecules. There are also a number of processes in refineries that are designed to *rearrange* molecules, either by changing their basic shape, or by bonding them together in specific ways. The most important of these is *catalytic reforming*.

Heavy naphtha is very low in octane: in the range of 40-45 RON for most crudes. (For the definition of RON, see the section on product blending below.) By rearranging the molecular structure of naphthas, however, a product called *reformate* can be produced with octane in the 90-100 RON range. The terminology varies from company to company. Shell's catalytic reformer was called a "Platformer" (because of its platinum-based catalyst) and the output was called "Platformate;" there are also Rheniformers, Powerformers, and dozens of other names for variations on what is basically a single technology.

Figure 32 shows two of the most important kinds of reactions that occur inside a "cat reformer." The first is *cyclization*, wherein a straight-chain hydrocarbon loses two hydrogen atoms and curls up to make a cyclic compound. The second reaction is *aromatization*, where a cyclic compound (possibly one produced in the reformer by the first reaction) loses pairs of hydrogens to create an aromatic ring.

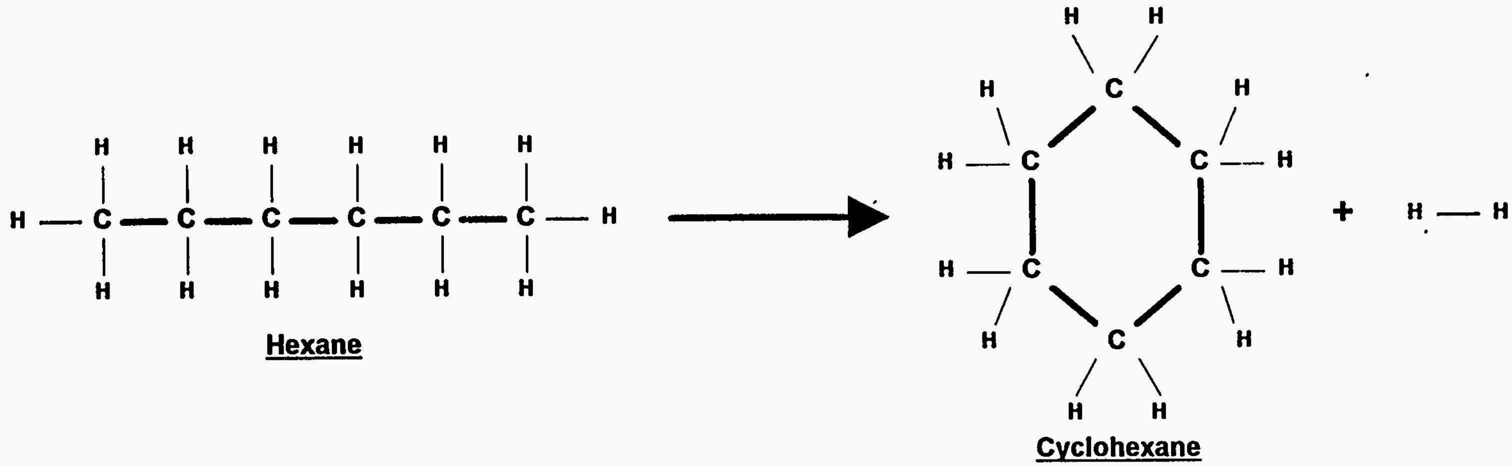
Aromatic compounds have a unique property, as the diagram of benzene shows. An aromatic ring has an even number of carbon atoms (with a minimum of six) with alternating double and single bonds between the carbons. This symmetry means that there are two equally valid ways to draw the structure of the molecule. As it turns out, however, there are not two actual *forms* of the molecule; indeed, there are not actually alternating double and single bonds. Instead, the structure of the molecule is "somewhere in-between" the two representations show in Figure 32. Some chemists talk about there being 1.5 bonds between all of the carbons. A more accurate way to view it is that all the carbons are connected by single bonds, and the electrons that would normally be involved in the double bonds circulate around the ring like an electric current.

Aromatic compounds are of more than academic interest. Their unusual structure makes them unusually stable. This means that they form important building blocks in the petrochemicals industry. It also means that they can be compressed sharply without spontaneously combusting; and this, by definition, means that they are very high-octane materials.

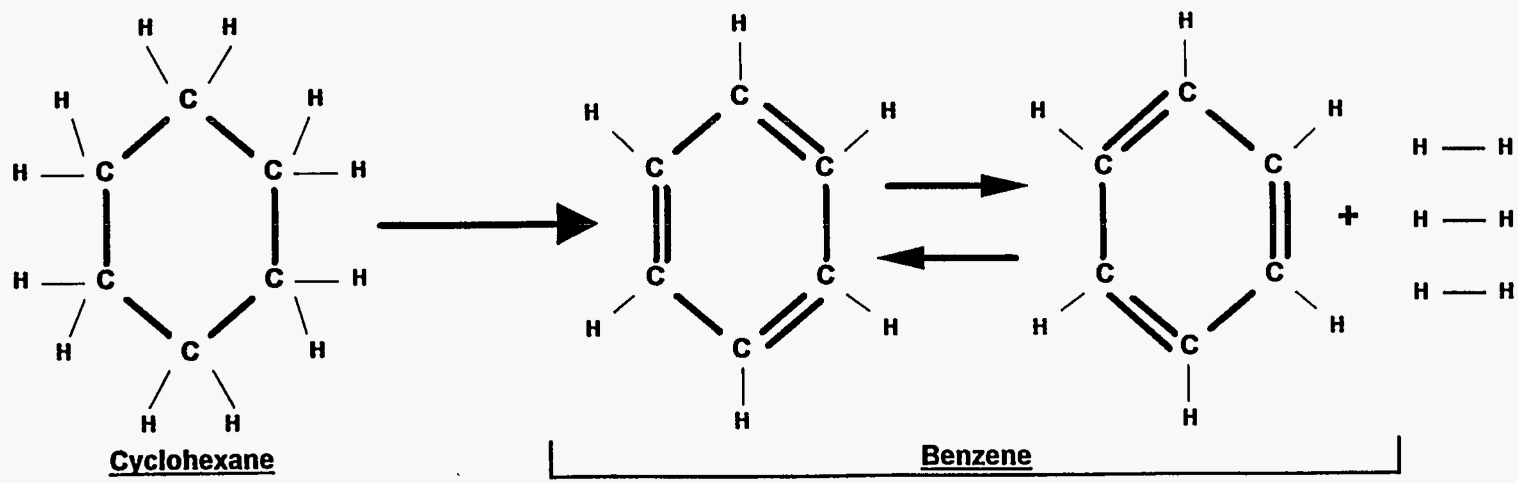
The main purpose of cat reformers is to take heavy naphtha and turn it into a material rich in aromatic molecules. Heavy naphtha itself, depending on the crude from which it is derived, is likely to have only a few percent by volume of aromatic molecules. After reforming, the output may have 50 to 70 percent aromatics. There is a cost to this improvement, of course, even beyond the capital and operating costs of the unit. The more "severe" the reforming, the higher the octane (but the lower the yields) of the reformate. In

FIGURE 32. EXAMPLES OF MAIN REFORMING REACTIONS

1. Cyclization



2. Aromatization



severe reforming, more molecules are broken apart, and, unlike the long molecules of fuel oil, when naphtha molecules break, their pieces tend to be in the LPG range of 3 and 4 carbon molecules. High severity also means more splitting out of hydrogen, which, naturally, means less hydrocarbon yield.

In addition to the processing of straight-run heavy naphthas, reformers can also be used to increase the octane of heavy naphthas from sources such as FCCs and hydrocrackers. Since these have higher octane values to begin with, the "uplift" is not nearly as dramatic. Nonetheless, reforming of cracker naphthas is widespread in nations where gasoline demand is high.

Even with fairly mild processing, the cat reformer yields substantial quantities of LPG. Since this takes place in a hydrogen-rich environment, these LPGs tend to be fully saturated (that is, have no double-bonded carbons). On the other hand, FCCs, and, to a more limited extent, cokers and visbreakers, operate in a hydrogen-deficient environment. Thus, the crackers (other than hydrocrackers) tend to produce considerable volumes of olefinic gases in the LPG range.

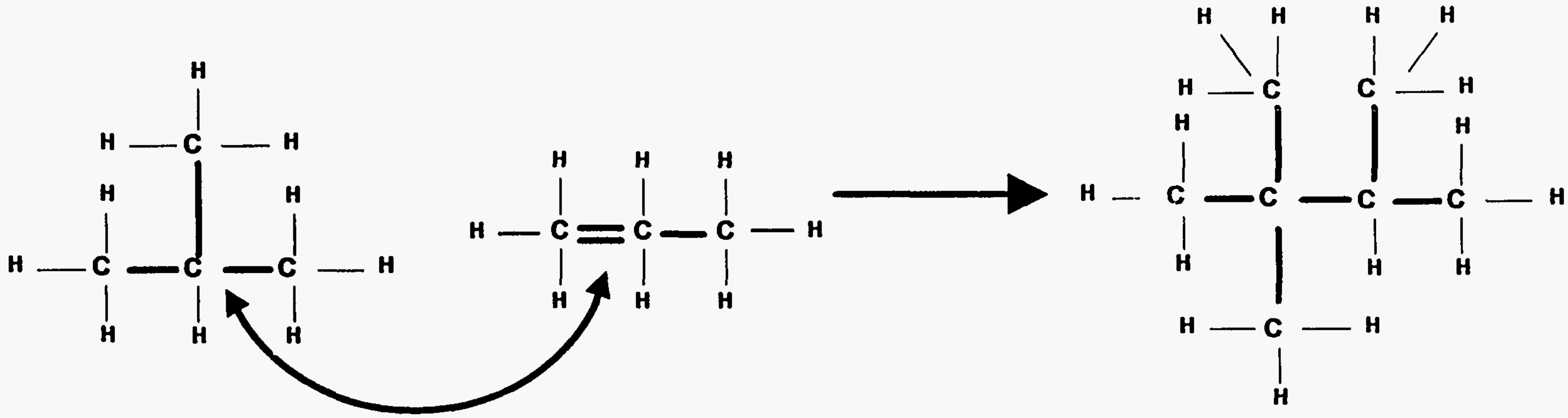
A second way of producing high-octane blendstocks takes advantage of the gas outputs of crackers and reformers by bonding LPG-type molecules together. LPG molecules have 3 or 4 carbons, therefore bonding them in pairs produces molecules with 6, 7, or 8 carbons—back in the gasoline/naphtha range.

By being selective about which kinds of molecules to react, only high-octane components can be produced. Highly branched hydrocarbons tend to be higher-octane molecules than straight-chain molecules, so the typical strategy is to react *isobutane* with the various olefinic gases. (The double bond is a natural reaction site, and is fairly easily catalyzed by strong acids.) Some of the possible pathways are shown in Figure 33.

Table 9 shows the kind of role that reformers and alkylation units play in a refinery. The (R+M)/2 octane of heavy naphthas is taken from the low 40s to the 85-95 range. The RVP increases, but still remains much lower than allowable gasoline RVPs of 8-10. The

FIGURE 33. EXAMPLES OF TYPICAL ALKYLATION REACTIONS

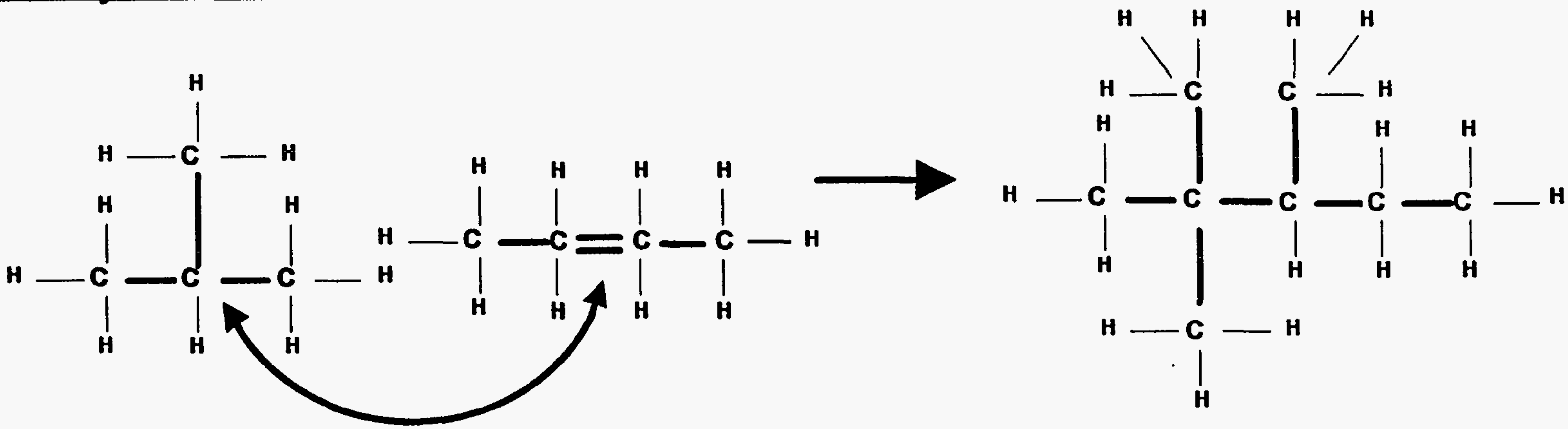
1. Propylene Feed



Isobutane | Propylene | Isoheptane (2,2,3-trimethylbutane)*

* *(and other isomers)*

2. Butylene Feed



Isobutane | Butylene | Isooctane (2,2,3-trimethylpentane)*

* *(and other isomers)*

Table 9. Examples of Catalytic Reforming and Alkylation

FEEDSTOCKS	Catalytic Reformer: Low Severity SR Feed	Medium Severity SR Feed	High Severity SR Feed	Medium Severity FCC Feed	Medium Severity HDC Feed	Alkylation: Alkylation C4 Feeds
SR Hvy Naphtha	100%	100%	100%			
Hvy FCC Naphtha				100%		
Hvy HDC Naphtha					100%	
Butylenes						58%
Isobutane						70%
Input RON	43.3	43.3	43.3	88.0	78.3	93.0 / 98.2
Input MON	42.4	42.4	42.4	79.3	73.6	92.0 / 75.7
Input (R+M)/2	42.9	42.9	42.9	83.7	76.0	92.5 / 87.0
Input RVP	1.8	1.8	1.8	0.9	1.8	72.2 / 51.0
PRODUCTION						
By-products						
Fuel Gas	4%	5%	7%	5%	7%	2%
LPG	6%	8%	11%	8%	8%	3%
Isobutane	2%	2%	3%	2%	1%	
Outputs						
Reformate	87%	83%	77%	82%	80%	
Alkylate						100%
Output RON	90.0	95.0	100.0	100.0	100.0	92.8
Output MON	81.3	84.5	89.0	88.5	86.3	90.7
Output (R+M)/2	85.7	89.8	94.5	94.3	93.2	91.7
Output RVP	2.1	2.6	3.1	3.0	3.1	4.4
Average Change in						
RON	46.7	51.7	56.7	12.0	21.7	(2.8)
MON	38.9	42.1	46.6	9.2	12.7	6.8
(R+M)/2	42.8	46.9	51.7	10.6	17.2	2.0
RVP	0.3	0.8	1.3	2.1	1.3	(57.3)

Note: All percentage figures are volume percent of feedstock.

cost, of course, is that at 86 (R+M)/2, only about 87 percent of the feedstock comes back as reformate; at 95 (R+M)/2, the yield drops to 77 percent. This decrease is compensated for by the fact that none of this naphtha would have been suitable as gasoline blendstock prior to reforming. The reformate can be pushed to a high enough octane level that it can even act to uplift other slightly sub-specification blendstocks.

Alkylation comes at the problem from the other direction. Most of the feeds to an alkylation unit have high octane values already, but, as gases (such as isobutane), they have such high RVPs that the amount that can be blended into gasoline is extremely limited. Alkylation keeps the octane at about the 92 (R+M)/2 level, but drops the RVP from the 50-70 range to the 3-6 range. Alkylate is one of the most important sources of non-aromatic octane in the oil industry.

There are other related technologies for producing gasoline blendstocks. *Polymerization* is similar to, and has been largely displaced by, alkylation. *Isomerization* units reshape molecules somewhat in the fashion of reformers, typically changing straight-chain into branched molecules. Both of these are minor, though important, processes in the overall gasoline production scheme.

<u>Hydrotreating and Hydrorefining</u>

Hydrotreating and *hydrorefining* are processes that can be applied, with the proper catalyst and equipment, to almost any feedstock. In essence, both processes use catalysts in the presence of hydrogen to remove contaminants—particularly sulfur—from various materials. In the process, they can also be used to saturate olefinic bonds and improve other characteristics.

The distinction between hydrotreating and hydrorefining is a vague one; generally, "hydrorefining" is used for more severe processes and for heavier feedstocks. Hydrorefining is done at high enough hydrogen pressures that a small amount of hydrocracking occurs. When applied to fuel-oil-range desulfurizing, enough cracking occurs to actually change the overall refinery balance, as shown in Table 10.

Table 10. Typical Hydroprocessing Operations

	Naphtha Hydrotreat	Kerosene Hydrotreat	Diesel Desulf	VGO Desulf	VGO "MHDC"*	Fuel Oil Desulf
Feedstock						
Naphtha	100%					
Kerosene		100%				
Diesel			100%			
VGO				100%	100%	
Fuel Oil						100%
Yields						
LPG				0.1%	0.9%	1.0%
Treated Naphtha	100.0%			0.1%	1.4%	5.1%
Desulf. Kerosene		99.9%		0.2%	3.4%	6.2%
Desulf. Diesel			99.8%	0.4%	28.4%	9.1%
Desulf VGO				99.3%	68.4%	
Desulf Fuel Oil						83.2%
TOTAL	100.0%	99.9%	99.8%	100.1%	102.5%	104.6%

* Operating in "Mild Hydrocracking" Mode with special catalyst

Regulations about sulfur content in gasoline and jet fuel have been in place for many decades; standards governing diesel have, until recently, been more lax, and it is only now that many countries are beginning to adopt limitations on fuel oil sulfur. For this reason, most refineries have long been equipped with hydrotreating equipment for naphtha and kerosene streams, as well as some ability to treat diesel cuts.

The expense in hydrotreating goes up sharply as the sulfur in the feed increases, and as the feedstock becomes heavier. This expense is not only a matter of capital, but also of hydrogen. The cat reformer is the only unit that produces a substantial hydrogen byproduct. This hydrogen is usually enough to treat the naphtha and most of the middle distillates in the refinery. For refiners running high sulfur crudes, the amount of hydrogen needed to desulfurize VGO or fuel oil is typically far in excess of what can be produced by the reformer. In this case, other feedstocks (or natural gas, if available) must be run to a hydrogen plant. This can lower the total yield of the refinery, and increases cost dramatically.

In the 1960s and 1970s, the most common configuration for refineries was the so-called "hydroskimming" structure. Such refineries had atmospheric distillation, cat reforming, and hydrotreating for naphtha and middle distillates. The reformer provided enough octane to enable the refiner to blend saleable gasoline, and also provided enough hydrogen to treat the middle distillates. The fuel oil was simply sold as it came from the distillation tower.

As cracking has become more widespread, and as environmental standards have tightened, hydrotreating has been extended further down the barrel. Large amounts of VGO are now treated, either to reblend into fuel oil, or as pretreatment before charging to a cracking unit. As of the present, fuel oil desulfurizers are still relatively uncommon (except in Japan and Taiwan) because of the high cost of construction and operation. Currently it is still cheaper to pay a premium for low-sulfur crude oil than to desulfurize high-sulfur resid. As discussed in later sections, this situation may change dramatically in the latter half of the 1990s.

Product Blending

Today the most complicated blending problem that faces U.S. refiners is gasoline blending. Because of the high demand for gasoline, many technologies for producing gasoline blendstocks within the refinery have become widespread; but also because of the high demand for gasoline, many pollution-control measures have been directed at gasoline formulation. Maintaining gasoline quality while meeting new standards for "gasoline reformulation" imposes a whole new set of pressures on oil product supplies.

Table 11 shows typical properties of gasoline blendstocks. The last 9 blendstocks are not strictly hydrocarbons, but *oxygenates*—ethers and alcohols which may be derived from petroleum, but also may be fully or partially from other materials.

The column headings require some explanation. First, there are two measurements of octane, RON (research octane number), and MON (motor octane number). Most countries in the world rate their gasoline in terms of RON (or have specifications for both RON and MON), but the United States rates gasoline by the compromise of averaging the two methods: RON plus MON divided by 2, usually listed at the pump as the "(R+M)/2 method." To a rough approximation, the octane of a mixture of components is the weighted average of the octanes of the individual components. (In actual practice, octane blending numbers and octane bonuses need to be applied, but this goes beyond the scope of this discussion.)

The "clear" octane number means the octane number without lead. Tetraethyl lead (TEL) is a widespread octane enhancer that was generally added to gasoline to boost octane. "Lead phase-out" was mandated in the late 1970s, and by the end of the 1980s, almost all of the gasoline sold in the United States was unleaded, or clear.

The Reid vapor pressure (RVP) is expressed in psi (pounds per square inch). The RVP of a blend *is not* the average of the RVPs of the components; RVP blends very nonlinearly. The Reid vapor pressure blending index (RVPBI) is a measure that does blend

Table 11. Typical Octane Blending Values of Streams

	RON Clear	MON Clear	(R+M)/2 Octane	RVP (psi)	RVPBI	Aromatic (Vol%)
Normal Butane	93.0	92.0	92.5	51.6	138.0	--
Isobutane	93.0	92.0	92.5	72.2	210.0	--
Mixed Butylenes	98.2	75.7	87.0	51.0	129.0	--
SR Light Naphtha	61.0	59.4	60.2	8.2	13.9	3.0
SR Heavy Naphtha	43.3	42.4	42.9	1.8	2.1	1.5
Reformate 90	90.0	81.3	85.7	2.1	2.5	45.0
Reformate 95	95.0	84.5	89.8	2.6	3.3	55.0
Reformate 100	100.0	89.0	94.5	3.1	4.1	65.0
C5+ Isomerate	86.4	81.6	84.0	10.2	18.2	--
Alkylate	92.8	90.7	91.7	4.4	6.3	--
Polymer Gasoline	94.5	82.0	88.0	3.0	3.9	--
Whole FCC Naphth	91.6	80.4	86.0	6.9	11.2	28.3
Light FCC Naphtha	94.8	81.4	88.1	12.2	22.8	31.0
Heavy FCC Naphth	88.0	79.3	83.7	0.9	0.9	25.0
Light Coker Napht	80.2	75.8	78.0	9.5	16.7	9.0
Whole Hydrocrack	82.8	79.3	81.0	8.1	13.7	3.1
Light Hydrocrackat	86.5	83.9	85.2	13.2	25.2	4.0
Heavy Hydrocrack	78.3	73.6	76.0	1.8	2.1	2.0
MTBE	118.0	[illegible]1.0	109.5	9.0	15.6	--
ETBE	120.0	102.0	111.0	4.0	5.7	--
TAME	110.0	100.0	105.0	2.5	3.1	--
Isobutyl Alcohol			102.0	5.0	7.5	--
tert-amyl Alcohol			97.0	6.0	9.4	--
tert-butyl Alcohol			100.0	9.0	15.6	--
Isopentyl Alcohol			106.0	14.0	27.1	--
Ethanol			115.0	18.0	37.1	--
Methanol			108.0	31.0	73.2	--
			Gasoline Blen	7.0	11.4	
				8.0	13.4	
				9.0	15.6	
				10.0	17.8	
				11.0	20.0	

Note: Blending behavior of oxygenates is still preliminary in many cases.

linearly; to use it, it is necessary to look up the RVPBI corresponding to each RVP, calculate the RVPBI of the mixture, and then look up the actual RVP corresponding to the RVPBI of the blend.

The aromatics column gives an estimate of the volume percentage of aromatics in the blend. It is worth noting that there is a general correlation between high aromatics and high octane, but there are some very important exceptions: Butanes, alkylate, ethers (MTBE, ETBE, TAME), and alcohols are all high in octane with no aromatics content.
Gasoline typically sells for a much higher price than naphtha, so refiners spend considerable effort to maximize the output of gasoline from the naphtha/gasoline blendstocks in the refinery. In practice, blending optimization is a field in itself; refinery models are some of the largest computer models in regular use, and the needs of refineries was one of the main drives behind the development of large-scale LP (linear programming) models in the 1960s and 1970s. Online, automated blending has also become widespread in the last decade. Analytical techniques will not only determine how the refinery streams are blended, but also determine how the refinery should be operated to maximize the value of the blendstocks available, from crude selection to cutpoint setting to cracker operation.

A detailed examination of refinery optimization would clearly be out of place in this discussion, but some understanding of the kinds of constraints faced by refiners is important to understand the new pressures on the market from environmental regulations. Table 12 gives an example of gasoline blending (done with simple averaging of the octanes rather than the full calculation needed for accuracy) to show the influence of the different process units on gasoline output. It should be kept in mind that blending optimization is far more complicated than presented here, and that there are literally dozens of other specifications (such as maximum olefins, ASTM distillation points, gum, corrosion tests, color, etc.) that must be met to produce gasoline that can be sold.

The problem assumes 100,000 barrels per day (b/d) throughput of a typical Mideast crude. Hydrotreating and auxiliary operations are taken as given. The goal is to blend a

Table 12. Example of Gasoline Blending Optimization

	Availability b/d	Octane (R+M)/2	RVPBI	Aromatics Vol%
1. After Distillation				
Butane Blended	0	92.5	138.0	0.0
Straight-Run Light Naphtha	6,750	60.2	13.9	3.0
Straight-Run Heavy Naphtha	8,170	42.9	2.1	1.5
TOTAL	**14,920**	**50.7**	**7.4**	**2.2**
Maximum Amt of 87 (R+M)/2*	**0**	**0.0**	**0.0**	**0.0**
2. After Reforming				
Butane Blended	701	92.5	138.0	0.0
Straight-Run Light Naphtha	6,750	60.2	13.9	3.0
100 RON Reformate	6,291	94.5	4.1	65.0
TOTAL	**13,742**	**77.5**	**15.7**	**31.2**
Maximum Amt of 87 (R+M)/2*	**8,912**	**87.0**	**16.7**	**46.5**
3. After FCC				
Butane Blended	1,211	92.5	138.0	0.0
Straight-Run Light Naphtha	6,750	60.2	13.9	3.0
100 RON Reformate	6,291	94.5	4.1	65.0
Light FCC Naphtha	9,075	88.1	22.8	31.0
Heavy FCC Naphtha	7,425	83.7	0.9	25.0
TOTAL	**30,752**	**82.4**	**16.3**	**29.1**
Maximum Amt of 87 (R+M)/2*	**25,500**	**87.0**	**16.7**	**34.5**
4. After Alkylation				
Butane Blended	1,468	92.5	138.0	0.0
Straight-Run Light Naphtha	6,750	60.2	13.9	3.0
100 RON Reformate	6,291	94.5	4.1	65.0
Alkylate	2,834	91.7	6.3	0.0
Light FCC Naphtha	9,075	88.1	22.8	31.0
Heavy FCC Naphtha	7,425	83.7	0.9	25.0
TOTAL	**33,843**	**83.2**	**16.4**	**26.5**
Maximum Amt of 87 (R+M)/2*	**29,148**	**87.0**	**16.7**	**30.3**
5. Reforming Hvy FCC Nap.				
Butane Blended	1,150	92.5	138.0	0.0
Straight-Run Light Naphtha	6,750	60.2	13.9	3.0
100 RON Reformate	12,008	94.5	4.1	65.0
Alkylate	2,834	91.7	6.3	0.0
Light FCC Naphtha	9,075	88.1	22.8	31.0
TOTAL	**31,817**	**85.1**	**16.5**	**34.0**
Maximum Amt of 87 (R+M)/2*	**29,576**	**87.0**	**16.7**	**36.4**

**at RVP of 9.5 (RVPBI of 16.7)*

gasoline with a minimum 87 octane (R+M)/2, and a maximum 16.7 RVPBI (corresponding to 9.5 RVP), and make as much of it as possible. It is assumed that butane is readily available in the refinery at the quantities needed.

On distillation, about 14.9 thousand barrels/day (mb/d) of material is produced in the gasoline/naphtha range. With the qualities given, however, it is impossible to blend any gasoline at all. The naphthas are both far too low in octane, and attempts to blend quantities of butane will exceed the RVPBI constraint before raising the blend octane high enough for sale. In other words, a refiner with only distillation cannot make any gasoline with a typical crude. (This was not the case before lead phase-out; in the 1960s, for example, such a refiner would simply have added a large dollop of TEL to the blend, and used butanes at a level that now violates RVP standards.)

By running the heavy naphtha to a cat reformer at high severity, we lose some volume (trading 8.2 mb/d of naphtha for 6.3 mb/d of reformate), but we are able to blend gasoline, and even blend some butane. The total naphtha/gasoline output drops to 13.7 mb/d, but of this, about 8.9 mb/d is gasoline.

Running the refinery's VGO to an FCC jumps the total naphtha/gasoline pool to 30.8 mb/d. In addition, the high octane of the FCC naphthas, and their relatively low RVPBIs, allows even more butane to be blended, bringing the gasoline production potential to 25.5 mb/d.

An FCC produces olefinic gases as well as isobutane; isobutane is also available from the cat reformer. If these are run to an alkylation unit, the gasoline/naphtha pool increases to 33.8 mb/d, of which 29.1 mb/d can be sold as gasoline.

At this point, without buying additional blendstocks from outside, the refinery production of gasoline is nearly maximized. As a last step, it is possible to run the FCC heavy naphtha to the cat reformer as well, but the increase in gasoline production is small, and the total size of the pool is cut. Whether a refiner would take this last step depends on economics, the availability of reformer capacity, and the effects on specifications other than those mentioned here.

When lead phase-out was initially proposed, it was believed that it would cause a serious octane crunch. This was averted partly by a slowdown in gasoline demand, and partly by a greater reliance on reformate and FCC naphthas as blendstocks. Notice that in Table 12, the aromatics content of the finished gasoline ranges from 30.3 to 46.5 percent. The average aromatics content in the United States is now about 32 percent by volume.

Aromatics are excellent for producing high octane fuel, but they have serious drawbacks. As all college chemistry students have long known, they are toxic and carcinogenic, and many are readily absorbed through the skin. Furthermore, their unusual stability, which makes them so attractive from an octane point of view, also makes some of the more complex varieties difficult to combust in engines. Thus, at least some of the aromatics are a major contributor to automotive pollution, and many are believed to constitute serious health risks.

For this reason, some areas and states (notably California) have moved to place restrictions on total aromatics contents of gasoline, as well as specific constraints on benzene (which regulators believe constitutes the biggest health risk). The problem, of course, is that it is difficult to make a saleable gasoline without a high aromatics content; increasing the aromatics content is the main goal of a process like cat reforming.

Alkylate is one important option for raising octane while keeping aromatics low, but the main source of the olefin feedstocks, it must be remembered, are FCCs, which tend to produce high aromatics outputs. Hydrocracker naphtha is low in aromatics but tends to have a fairly low octane. All manner of approaches to the problem of aromatics reduction are under study (including selective removal, selective saturation, catalyst changes, and cutpoint alterations), but one of the most important options is the blending of oxygenates.

Oxygenates such as MTBE and ethanol have high octane values with no aromatics content. (Ethanol, unfortunately, has a high RVP). More than this, they have been shown, because of the oxygen in their molecular structure, to increase the completeness of combustion in engines, thereby reducing emissions. The Clean Air Act has now mandated minimum oxygen contents in gasoline sold in the nation's "non-attainment" areas. In some areas, this means "gasohol" (ethanol blended into gasoline, which requires a waiver of the standard RVP restrictions); in other areas, MTBE has become the leading blendstock.

The problem is that neither of these blendstocks are cheap (nor are any of the other oxygenates); they cost considerably more than gasoline. Not only does this raise the cost of gasoline, but it also presents problems in the overall refinery balance. At present, only the non-attainment areas have mandatory blending, but it is quite likely to be adopted on a statewide basis by a number of states. This creates problems in the free flow of products from one area to another; what is gasoline in one place may not be saleable in another, and few refiners have so much tankage that they can blend several different compositions for different markets. Traditionally, price movements in major spot markets (such as Houston and Los Angeles) directly affect prices everywhere. With more specifications and more grades, market isolation (and the potential for volatile price movements) will increase. This is especially important for a small market like Hawaii, since market prices are effectively set elsewhere.

These complications may not all prove financially or economically negative for the Hawaiian consumer. It is possible, if Hawaii does not move to California-style gasoline standards, that gasoline of Hawaiian grade, no longer saleable in much of the West Coast, will become a surplus product with a lower price path than in the past. On the other hand, Hawaii has a larger percentage of octane in non-aromatic form (alkylate, dimers, and hydrocrackate) than most areas; if price differentials become wide enough, Hawaiian refiners might find themselves engaging in cross-trade, exporting low-aromatics gasoline and importing higher aromatics gasoline.

Jet kerosene is a product whose specifications are unlikely to undergo a major shift, simply because the standards for it are international in nature. Diesel oil, on the other hand, is undergoing rapid specification changes in California. As will be discussed in the later section on the regional market, the new diesel standards (low-aromatics, low-sulfur, higher cetane) may result in large exports of off-spec (by California specifications) diesel, and large imports of Asian gasoil blendstocks. This may help meet some of Hawaii's needs if curtailment of black oil shipping to outer islands is made up in the intermediate term by diesel power generation.

The precise nature of Hawaiian refining and the product supply/demand situation in the state is treated in the Task II (*Fossil Energy in Hawaii*) report of this project. At this point, the important fact to keep in mind is that it is the ability to supply or obtain on-spec products in the quantities needed that is the critical matter in petroleum security, and that the matter is far less simple than mere access to crude oil.

3. Refining and Refinery Flexibility

Figure 34 shows crude distillation capacity (often loosely referred to as "refinery capacity") for major regions of the world as of year-end 1992. Hawaii's capacity, at about 45,000 b/d, is large enough to show even at this international scale. This chart is relatively self-explanatory, and, as mentioned in Section A above, the levels of refinery capacity correlate roughly with demand for oil. As is probably clear from the previous discussion, refining is far more than crude distillation capacity, and a refinery with nothing but crude distillation may not be able to manufacture any fuels that are saleable in a developed-nation market.

Figure 35 shows the composition of oil-product demand for the same set of regions shown in Figure 34. This figure is unusually instructive regarding the structure of refining systems.

Although there are variations, around the world most countries demand is about one-third (33 percent) fuel oil/"other", one-third (33 percent) middle distillates, and one-quarter (25 percent) gasoline/naphtha. The United States/Canada and Hawaii are striking exceptions to this rule.

In the United States and Canada, fuel oil and "other" products (lubes, asphalt, greases) make up a mere 17 percent of demand. Middle distillates are somewhat lower than average, at 28 percent. Gasoline is the dominant use of petroleum at nearly half of total demand (45 percent). No other area of the world, not even the highly developed nations of

Figure 34. Crude Distillation Capacity by Region, 1992

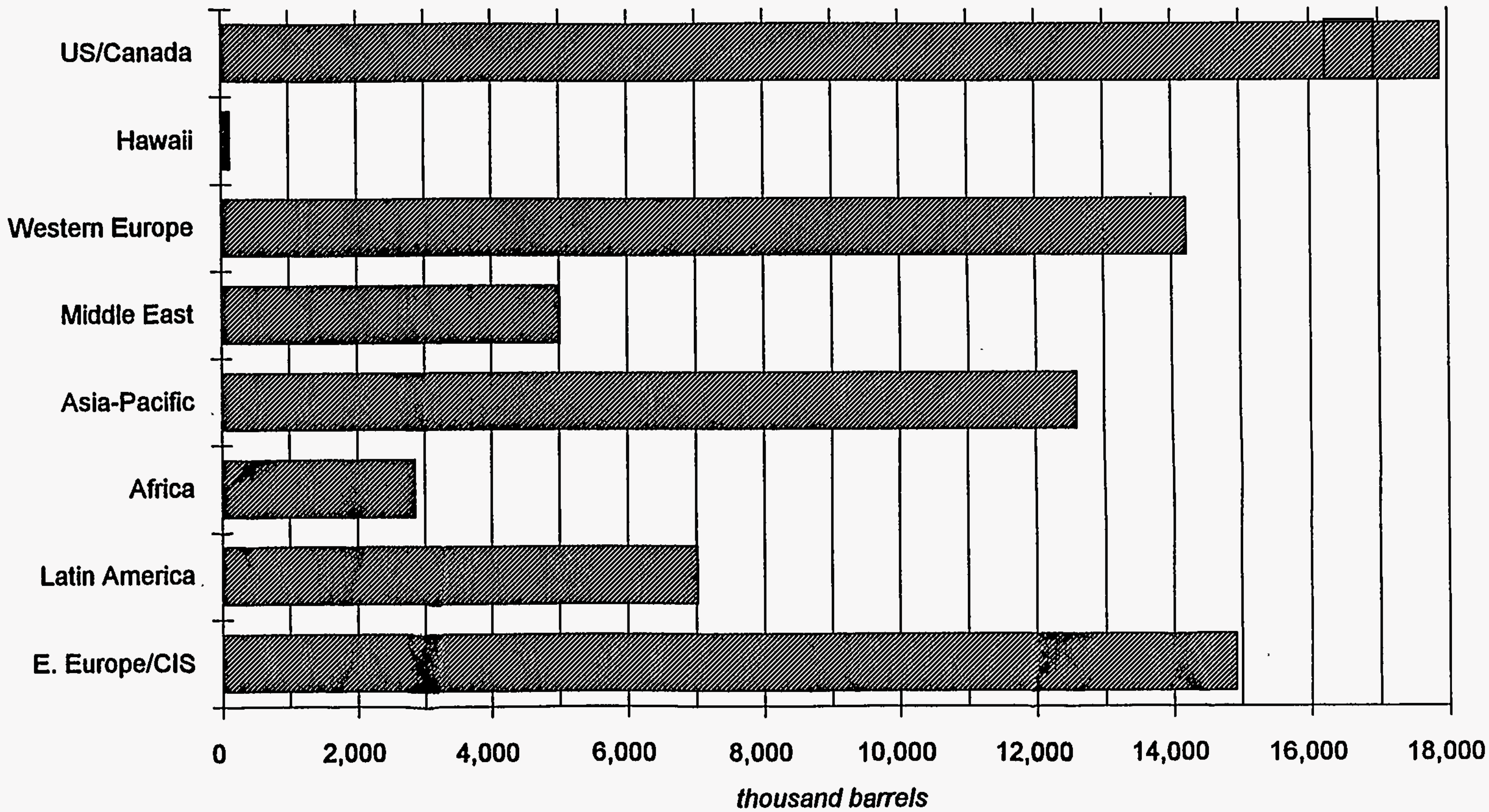
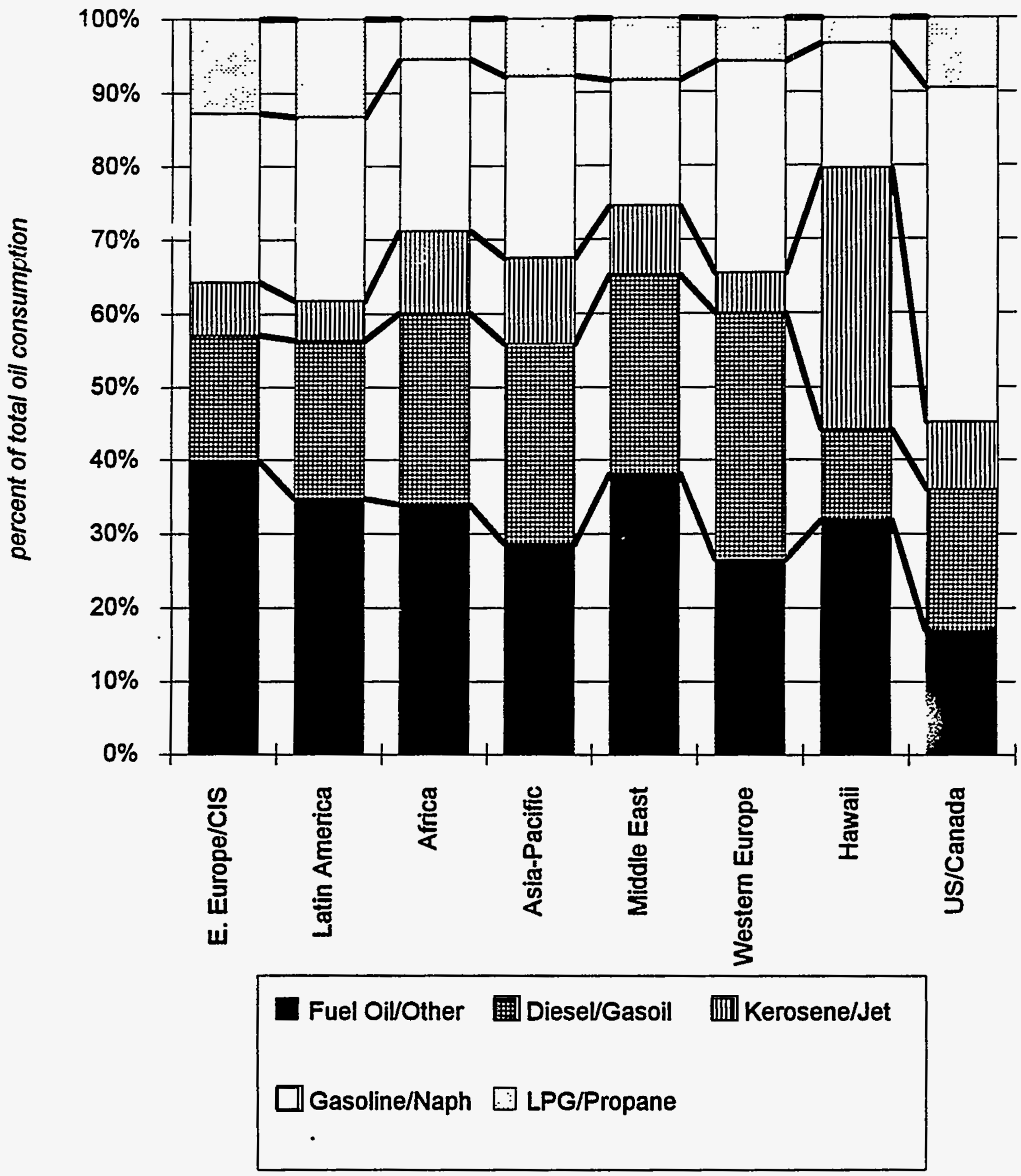


Figure 35. Regional Oil Demand Patterns, 1990-91



Europe, even approach this level of gasoline intensity.

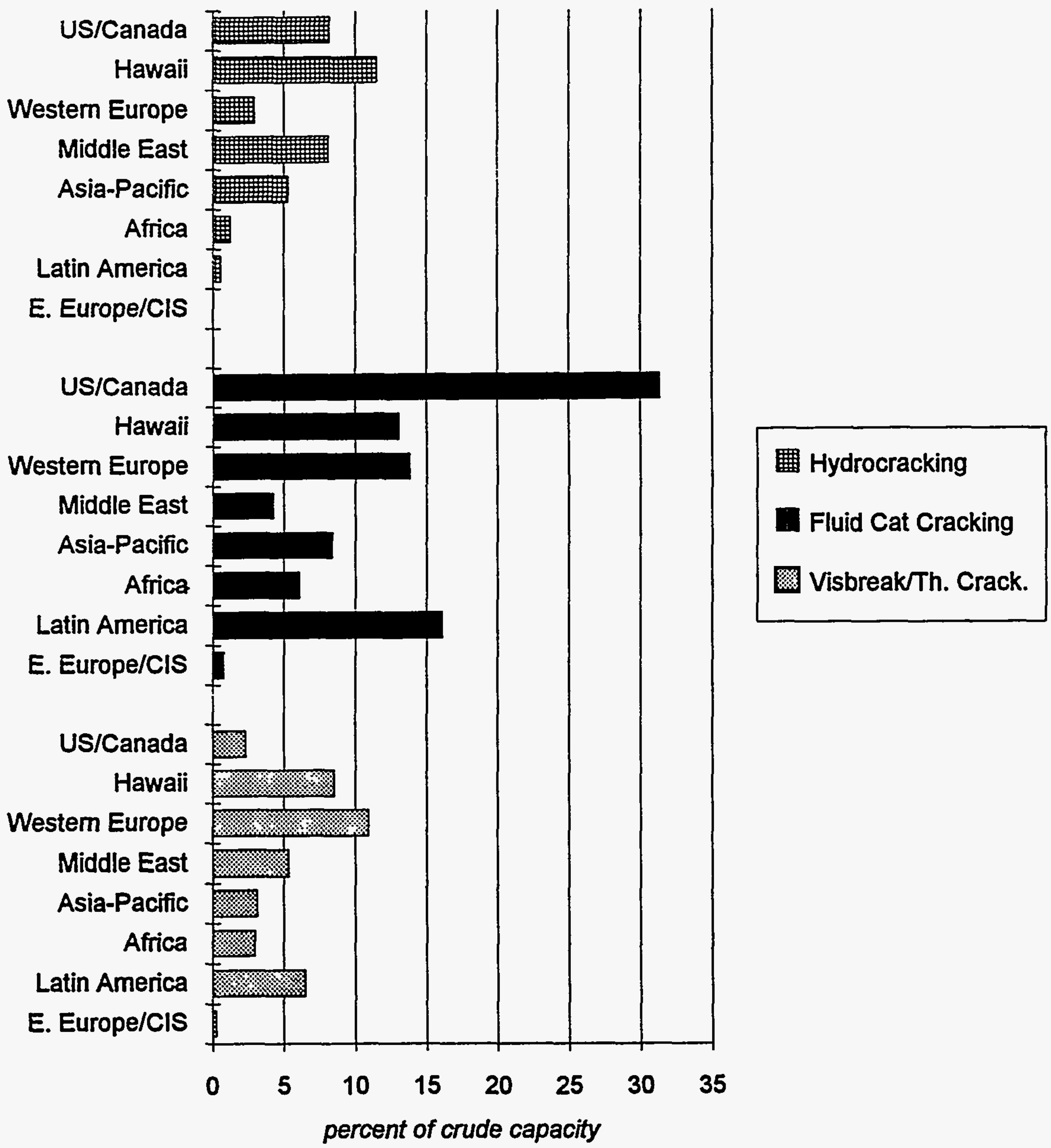
Hawaii is also unique. Fuel oil's share of demand is about typical at one-third of demand, but gasoline demand is extremely low at 17 percent—lower than most developing countries. The bulge in the barrel in Hawaii's demand is the requirement for half (48 percent) of the barrel as middle distillates. No other area even approaches this level of reliance on middle distillates. Furthermore, in areas where middle distillates are in fairly high demand, the demand is for diesel oil. In Hawaii, the demand is jet fuel; jet fuel by itself accounts for about 35 percent of the barrel. This is unparalleled; the region with the highest share of demand for jet (the Asia-Pacific region) needs only 12 percent of the barrel as jet; Hawaii's share is almost triple that.

Two immediate conclusions can be drawn from Figure 35. First, no region has a pattern of demand like the straight-run output of typical crude oil, particularly with reference to fuel oil output (which is 42-48 percent of a typical crude); therefore, there must be cracking facilities everywhere. Second, Hawaii and the United States/Canada have the patterns of demand that deviate the furthest from what a crude will yield up on a straight-run basis; therefore, their refining systems must be equally unique.

Figure 36 bears this out. This figure shows various kinds of cracking facilities relative to the size of crude distillation capacities in the various regions. Visbreaking and thermal cracking are found where there are concerns with fuel oil quality, especially in viscosity and pour-point terms. The United States, with little fuel oil demand, has little visbreaking relative to its crude capacity. The former Soviet Union, on the other hand, uses considerable quantities of fuel oil, but has never worried much about enforcing quality control. Hawaii and Western Europe, highly developed areas with a moderate need for fuel oil, have the highest installed levels of visbreaking relative to crude capacity.

As might be expected, the United States has a massive ratio of FCC capacity relative to crude distillation; this is a basic prerequisite for meeting a demand barrel that is half gasoline. Latin America has a higher ratio than might be predicted (largely because of the

Figure 36. Ratio of Cracking Capacities to Distillation, 1992



use of heavy Venezuelan crudes; extensive cracking is needed just to get yields into the range of typical Mideast crudes). Hawaii needs cracking; FCCs are not the most appropriate technology for the Hawaiian demand pattern, but it should be remembered that in past years, a great deal of Hawaiian jet fuel demand was for naphtha-type jet fuel, which a FCC could help provide. Finally, there is hydrocracking, the Rolls-Royce of cracking technologies, and here Hawaii stands out. Hawaii has a higher ratio of hydrocracking to distillation than any region of the world, rivalled only by a handful of countries. Hydrocracking is the only technology that can even begin to balance the bulge in the Hawaiian barrel shown in Figure 35.

Ratios like that in Figure 36 give some information, but it is hard to use such numbers to understand where one refining system stands relative to another: How many barrels of visbreaking equals a barrel of cat cracking? There are many ways to try to put a number on relative flexibility or sophistication of a refining system. A popular measure is the cracking-to-distillation ratio, which could be found by summing the percentages in Figure 36 (and including coking). This ratio is inherently misleading because it treats all cracking facilities as equal, and ignores cat reforming, alkylation, and other processes that certainly affect the overall output. Another measure is the Nelson Complexity Index, which accounts for all the units in a refinery, but does so on a capital-cost-weighted basis. The Nelson Index is excellent for calculating the replacement cost of a refinery, or its market value, but it tells little about what a refinery can do to balance demand.

The East-West Center has developed an index whose primary goal is to measure the relative capabilities of refineries to convert a standard crude into transport fuels. This not only accounts for the capacities of all the major processing units, but also considers the interactions between the capacities in terms of matters such as the octane pool. This Transport Fuels Index (TFI) measures the percentage of transport fuels a refinery can produce as a share of crude input. It is always possible to produce less transport fuels, simply by not cracking bottoms, not reforming naphtha, etc. Thus, this index is a good measure of relative flexibility or sophistication; it is a relative measure of how far output yields can be adjusted from the distillation yields of a crude. (Note that it is not a *prediction* of the transport fuels output, since refineries will not necessarily be running a slate that matches the standard crude. This is a measure of what different refinery configurations *could* do, all starting from a comparable basis).

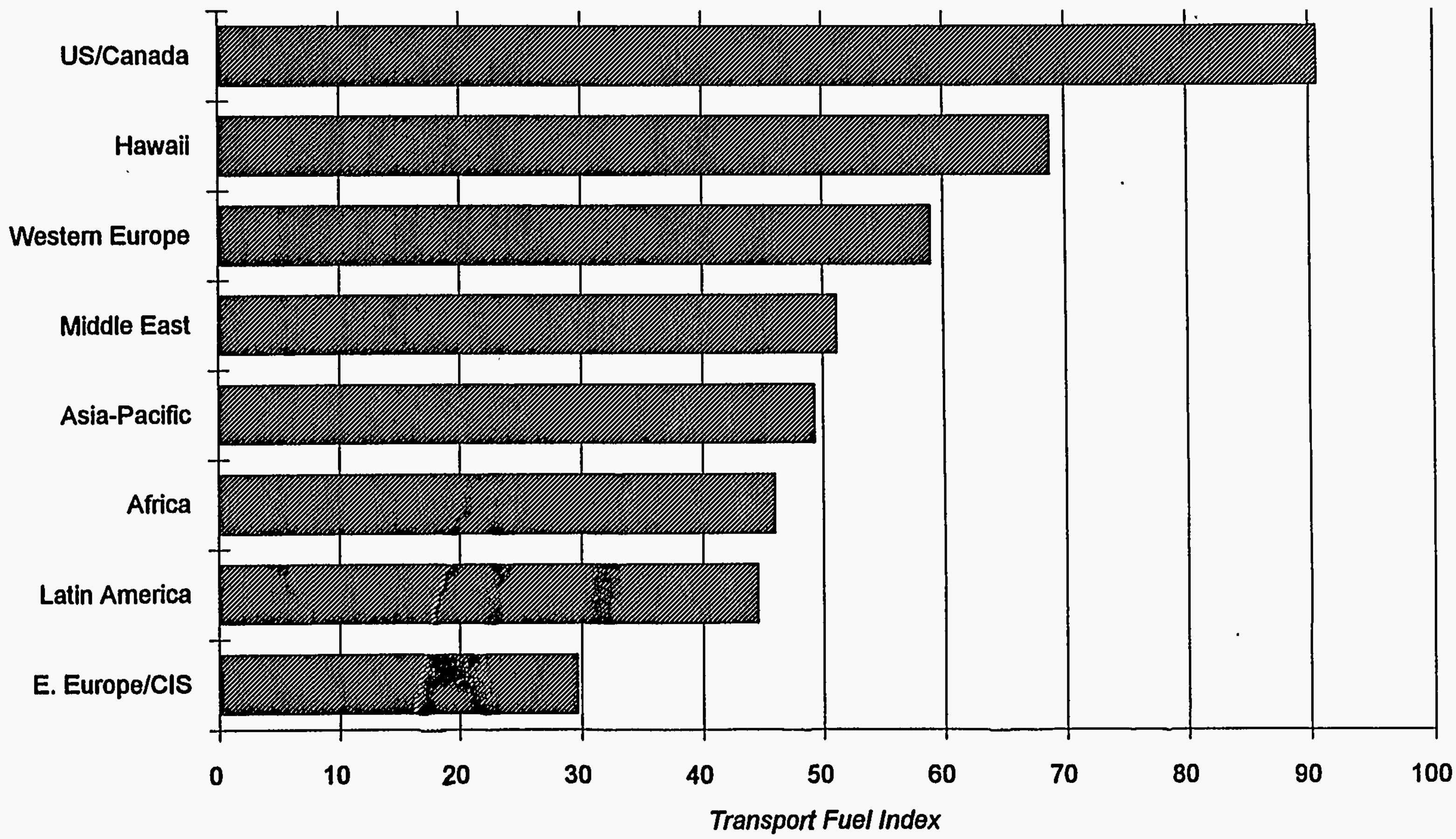
Figure 37 shows the TFIs for the regional refining systems considered above. The combination of hydrocracking, cat cracking, visbreaking, cat reforming, and alkylation, gives Hawaii one of the higher TFIs in the world. It is lower than the value for the United States and Canada as a whole, but that should be anticipated; the North American continent needs to push its fuel oil demand down to 17 percent of output, and many of the regional crudes (especially the Californian crudes) are unusually heavy.

Were it not for the sophistication of the Hawaiian refining sector, the oil situation in Hawaii would be far more complicated. Either the state would have to rely on large imports of jet fuel from elsewhere, or, if the state were to be self-sufficient, it would require a great increase in the amount of crude oil imported (and the amounts of surplus products exported). To given an indication of the magnitude: To meet jet fuel demands from a simple refinery configuration, crude imports would have to increase from about 120,000 b/d to 270,000 b/d; and there would be a surplus of about 100,000 b/d of fuel oil to be disposed of abroad, probably at a loss.

The relatively sophisticated configuration of the local refining sector allows the industry to provide much of the state's needs for jet fuel, while also covering most of the gasoline and diesel needs as a side business. But despite the sophistication of the system, demand is so slanted toward jet fuel that imports of jet are already required to balance demand. The system is already producing as much jet as it can with the current equipment.

The fact that a sophisticated system is already stretched to meet the demand for a single product needs to be taken into account in studying energy alternatives. In oil terms, the greatest reliance is on jet fuel. Unfortunately, this is the least substitutable use. If a program was introduced that could cut, say, fuel oil and gasoline use by 25 percent (for

Figure 37. TFI Refinery Sophistical Index, 1992



example, by an aggressive introduction of coal power stations and ethanol cars), the jet demand would remain unaffected. As a percentage of the barrel, it would rise from 35 to 40 percent of oil demand; middle distillates' share of oil demand would go to 55 percent. Today's demand barrel is one that cannot be satisfied by one of the world's more sophisticated refining systems; most fuel substitution measures would make this even more extreme. This does not mean that such policies are unwise or unwarranted; but it underlines the fact that oil-substitution programs may have unintended effects that should be evaluated before policies are adopted. This issue is discussed at more length in the Task II (*Fossil Energy in Hawaii*) report of this project.

E. History and Trends in the Global Oil Market

1. World Production Trends

Figure 38 shows the history of global oil production from the end of World War I to the present. The dates at which different regions became major players in the market is clear from the chart. Although the history of production in Iran goes back to the beginning of the century, the emergence of the Mideast as a major factor was a post-World War II phenomenon. Africa did not become important until the mid-1960s; the North Sea production in Western Europe was a product of the mid-1970s.

The most remarkable feature of the chart is the steep, smooth upward curve in the period 1918-73. Even major disruptions, such as the Great Depression and the Second World War, barely perturb the shape of this growth curve. The curve is remarkably exponential, like a compound interest accumulation or a population growth curve.

Figure 39 fits a regression curve to the 1919-73 data. The formula is

$$\text{Crude}_t = \text{Crude}_{t-1} \times 1.0796 - 89.625 \text{ .}$$

This, of course, is merely the formula for compound growth at a rate of about 8 percent (or more precisely 7.96 percent). Throughout most of the twentieth century, the best predictor of oil output and demand was simply 8 percent above the previous year's level. The adjusted R-squared on the regression is 0.999, an almost perfect fit between the regression curve and

Figure 38. Regional Oil Production, 1918-92

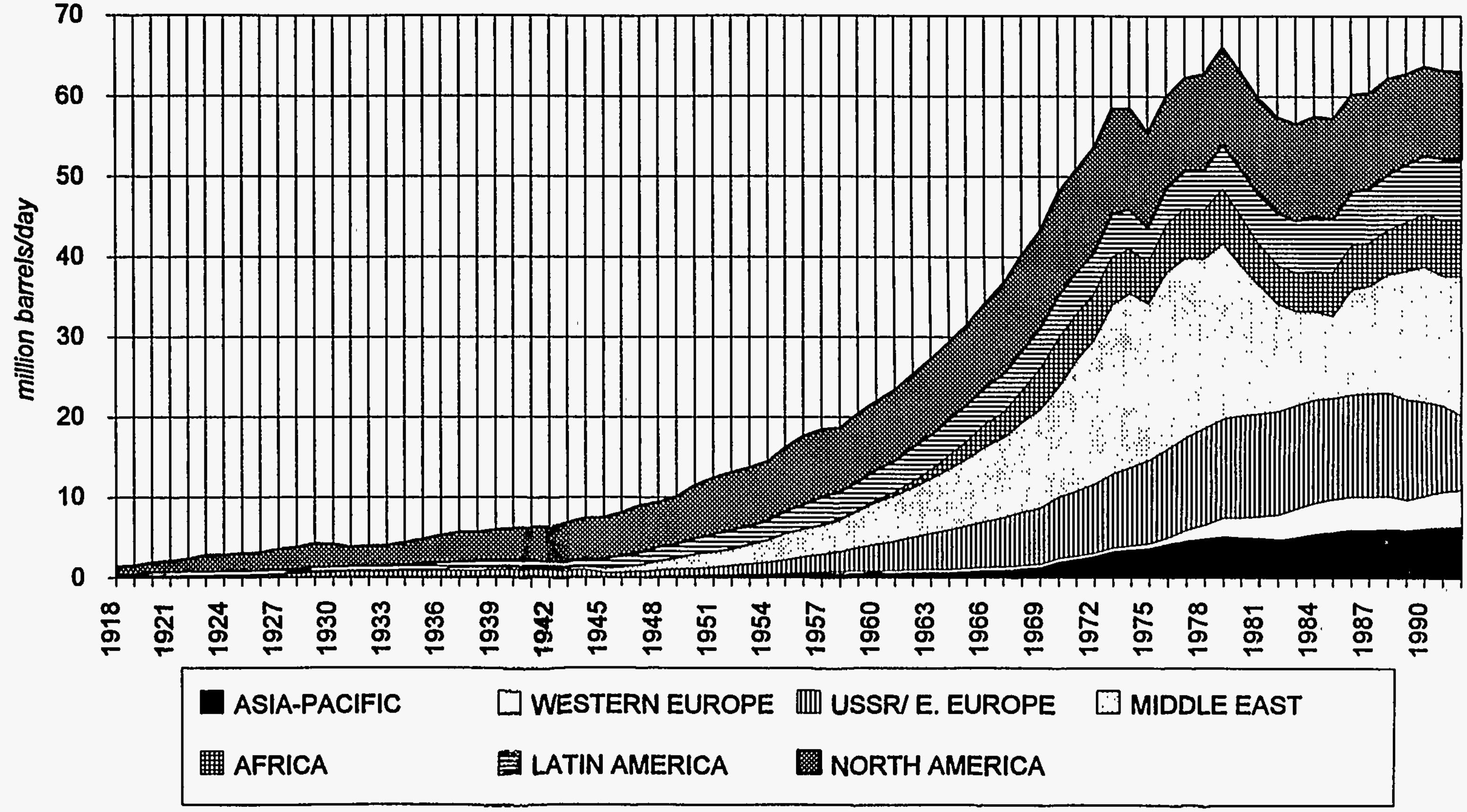
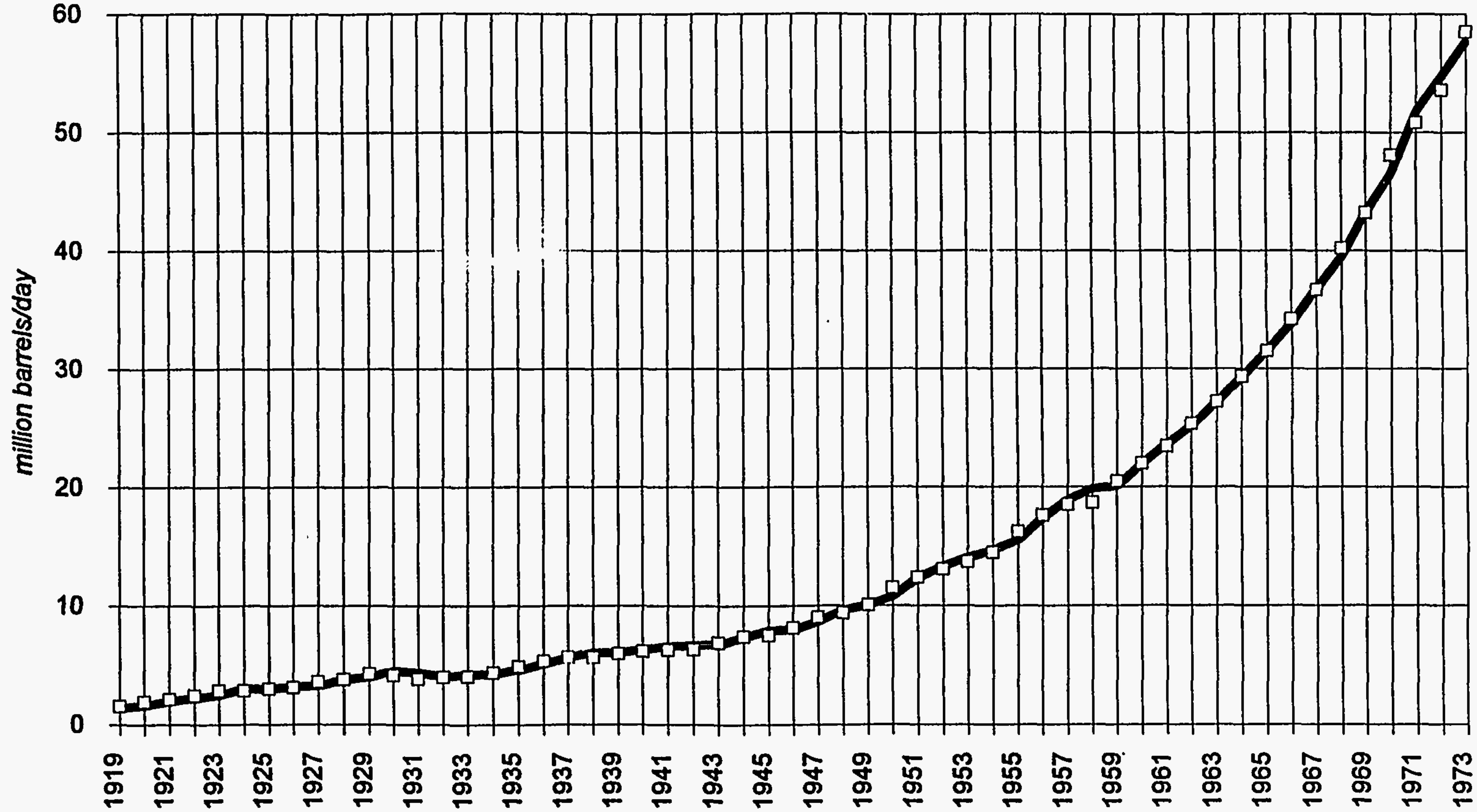


Figure 39. Compound Growth Regression on Crude Production, 1919-73



Formula: CRUDE(t) = CRUDE(t-1) x 1.0796 - 89.625 (with crude in thousand b/d) Adjusted R-squared: 0.999

the data.

This rate of expansion is of more than academic interest; it has fundamentally affected the way that society views oil, and resulted in the massive market disruptions of the 1970s.

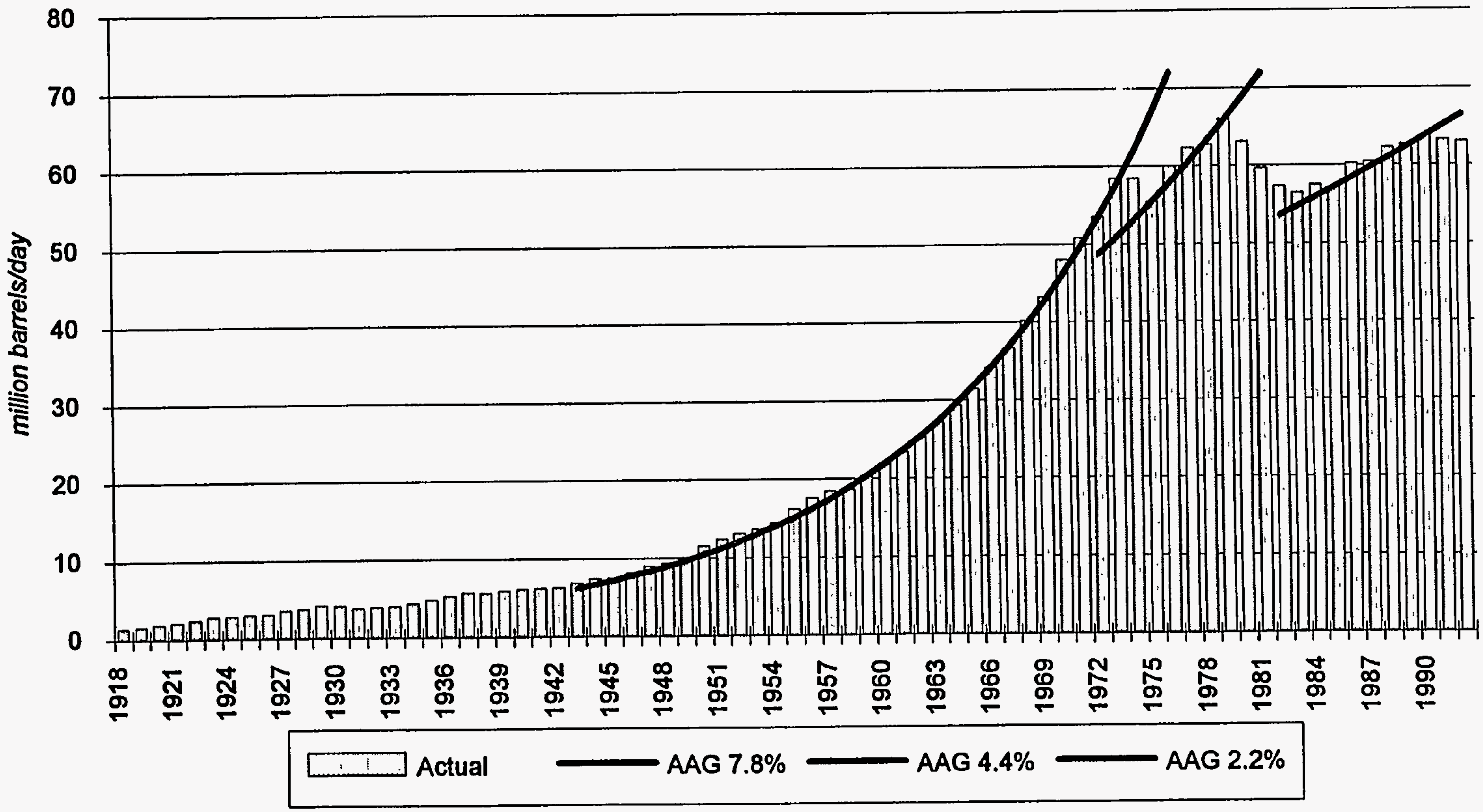
The steady and continued expansion of oil demand through 1973 led many to believe that oil demand was extremely inelastic with respect to price. The small price increase in 1971 (the Occidental Petroleum/Libya deal) was large in percentage terms; demand response was imperceptible. Even the huge increase in prices in 1973 caused only a momentary pause. Demand was basically flat in 1974, fell in the recession of 1975, but then rebounded to a level even higher than 1973 by 1976. At the time, many contended that the consumption of oil was fundamentally linked to economic growth in a fixed relationship.

In fact, although demand for oil grew rapidly in the late 1970s—indeed, oil production hit its all-time peak in 1979—demand growth had actually slowed substantially. Figure 40 shows the output of oil with tangent growth rates for the periods when uninterrupted growth resumes. The first growth period, prior to 1973, saw growth rates on the order of 7.7-7.9 percent per annum. The second growth period, 1975-79, had growth rates of about 4.4 percent per year. The most recent growth period, 1985-90, saw growth rates of only 2.2 percent.

Since both of the post-73 growth resumptions involve recovery from a demand decline and an economic recession, even the 4.4 percent and 2.2 percent rates are exaggeratedly high. Every major price spike (other than very short-term problems like the *Exxon Valdez* spill) seems to push the world economy toward lower oil demand growth rates. This may not be directly connected with the level of prices; the Gulf War, for example, did not drive prices very high, and they remained fairly low compared with 1979/80 when corrected for inflation. The effects seem to have much to do with the perception that oil can be volatile, and this alone causes high levels of caution on the part of consumers.

In the 1970s, the general belief was that oil prices could be pushed very high without major drops in consumption. In fact, some economists even proposed that OPEC countries had "backward-bending supply curves;" that is, as prices go up, beyond a certain point the

Figure 40. Growth Tangents to Crude Output, 1918-92



countries have more than enough income, and so they cut back production (which of course takes the price even higher). In 1979 and 1980, many analysts were confidently predicting $60/barrel oil by 1985 and $120/barrel oil in the 1990s.

In some ways, the analysts of the period were correct: Oil prices can be driven very, very high. In the short term, there are few substitutes, no matter what the price. What cannot happen is long-term maintenance of high prices. High prices defeat themselves in many ways. They encourage conservation, the development of alternatives, and additional oil exploration; they also tend to cause economic recession, which additionally damps the demand.

There were world crises, such as the Suez crisis of the 1950s, that affected the flow of oil for brief periods. When the major oil companies controlled the global trade, such disruptions were not allowed to have large impacts on supply or price. Only the conditions of the 1970s allowed the first oil crisis to occur.

2. OPEC, Prices, and Trade

OPEC was formed in the 1960s by a group of oil producing countries that believed that they were being taken advantage of by the international oil companies. The primary objective of the companies in the 1960s was to keep the volume of oil up and prices down; profits were seen as being in the refining and sales of oil, and there was pressure to maximize the quantity of sales.

Huge new oil fields were discovered in the Mideast and North Africa after the Second World War, and the problem faced by most producing countries was a glut of petroleum. Companies were able to play producing countries off against each other. There was so much oil and exploration acreage available that a company could bargain down the terms of exploration or production. Moreover, the countries' sales prices were a function of the "posted price" of oil, which was set by the companies. Oil was $1.80/barrel posted price through most of the 1960s, and excess cargos (the "spot market" of the day) were usually sold off at $1.30-$1.50/barrel.

Figure 41 shows the percentage shares of oil output by world regions from 1918 to 1990. North America was overwhelmingly dominant until World War II. Following the war, the Mideast began to expand; Eastern Europe fell under Soviet domination, and effectively ceased to be a full participant in the international market. (It should be kept in mind that the Rumanian oil fields, no longer regarded as major reserves, were one of the most important strategic objectives of both sides in World War II.)

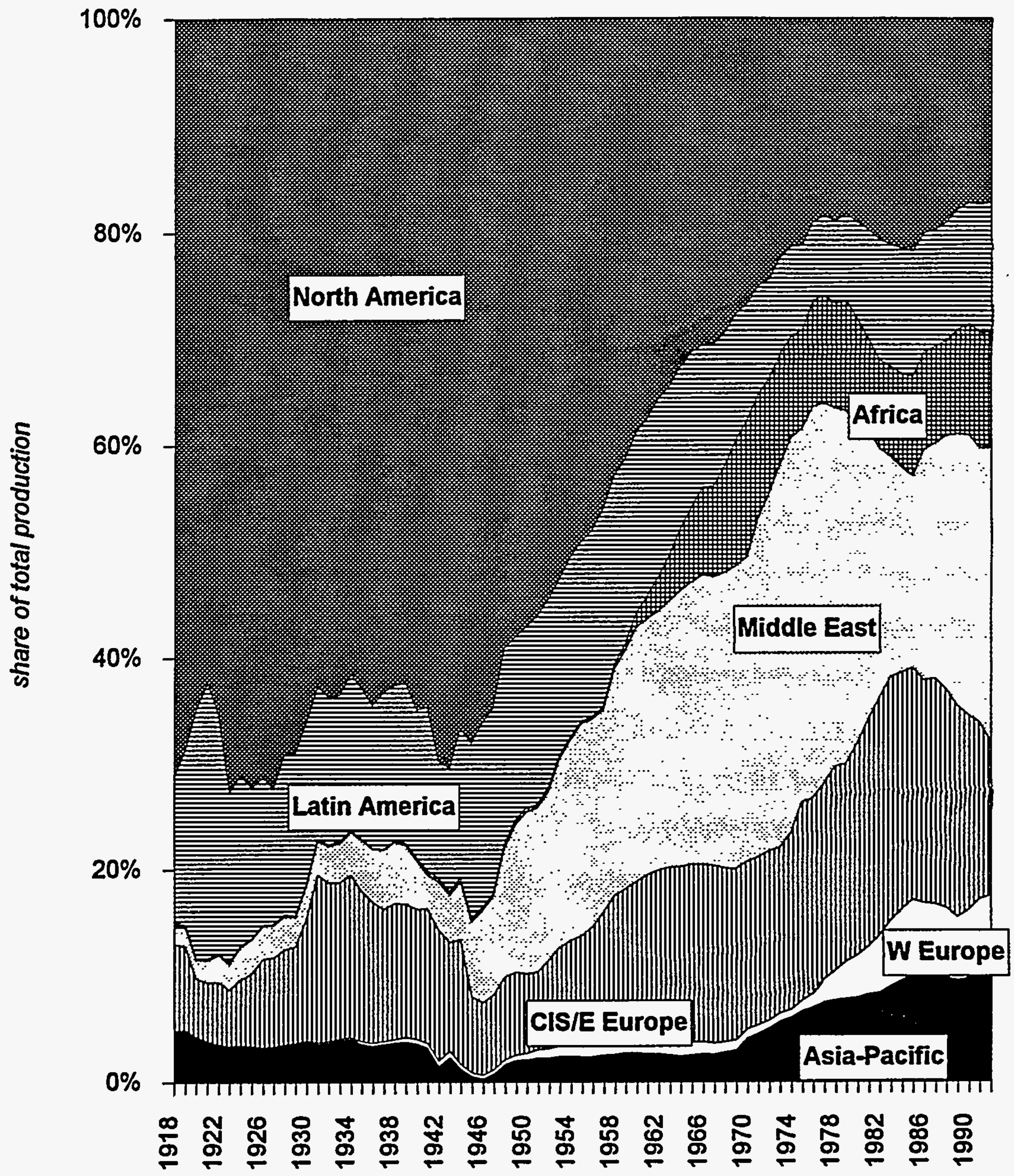
Demand for oil continued to grow at its inexorable 8 percent per annum, but output from North America could not keep pace especially since the United States was further along its depletion curve than any other area. As late as 1963, the United States had produced over half of the oil ever taken out of the ground; in 1992, this had fallen to 25 percent.

The most rapid economic growth in the post-war period was in North America, Japan, and Western Europe. North American production could not keep pace with its own demand, and Japan and Western Europe were, by some quirk of fate, among the least-generously endowed parts of the world in terms of oil resources. Thus, as demand increased, more and more of total world production began to occur in areas remote from the centers of consumption. Oil exports became one of the largest items in international trade.

As opportunities for exploration became more limited and more costly in North America, many of the smaller, independent U.S. oil companies began to seek production abroad. To compete with the majors, they offered better terms on both exploration and production. OPEC in its first decade was not an organization dedicated to raising prices; its main goal was to keep the price from falling, and to ensure that OPEC members were allowed high "production quotas" by the international majors, so that OPEC member revenues were not reduced.

The turning point involved Occidental Petroleum, a U.S. independent. Occidental (commonly referred to as "Oxy") had expanded into overseas operations, seeking oil in North Africa, and selling it in Europe. One of Oxy's most important finds was the high-quality, low-sulfur reserves in Libya; these required little processing to make saleable products and commanded premium prices.

Figure 41. Regional Shares of Oil Output, 1918-92



In 1970, Colonel Qaddafi of Libya unilaterally announced that the price set by Occidental was unsatisfactorily low, and that the prices and terms paid to Libya would have to be improved. Occidental, faced with the loss of supply to its European sales network if it were cut off from Libyan crude, complied. It was a small increase, taking the price of Libyan crude from \$2.21/b to \$2.54/b, but it was a bargaining point for Libya with the other oil companies operating in the country, and in 1972 Libya succeeded in taking the price to \$3.39/b.

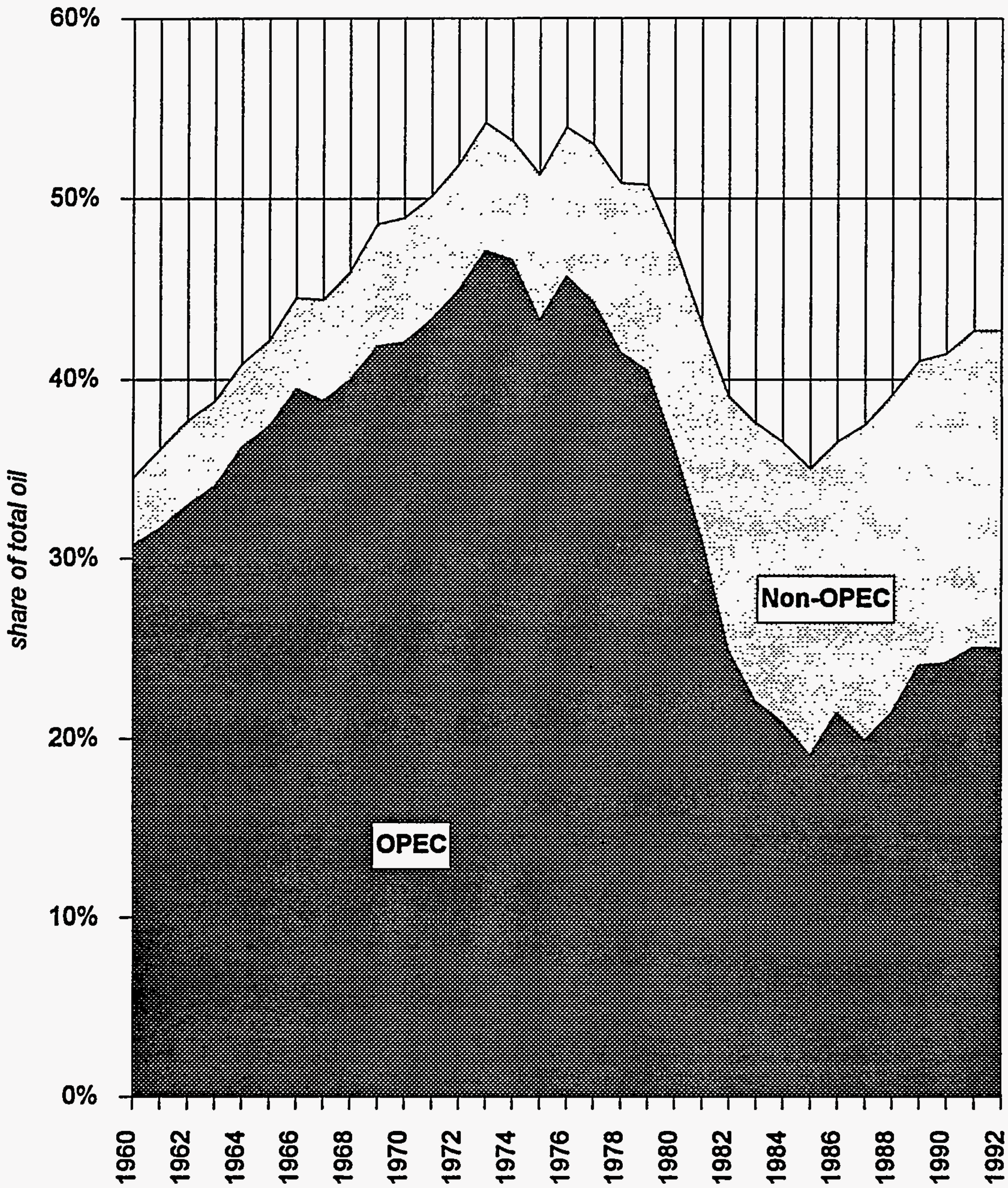
This naturally emboldened other OPEC countries, who demanded that they, also, be given a price increase. By ' 1971, the other countries had achieved their objectives, and the price increase covered m of the exporters. After this, there was continuous upward pressure on price from the O... countries, and there was a series of gradual adjustments up to the time of the Arab oil embargo in late 1973.

The embargo was a curiosity. It was not specifically intended to push up prices; it was politically rather than economically motivated. Most amusingly, some of the "hard-line" Arab nations, notably Libya and Iraq, refused to participate in the embargo on the grounds that it "didn't go far enough." Thus, two of the nations most vocally opposed to Israel were able to maintain full sales and production during the embargo.

In earlier times, the embargo might not have had such dramatic price consequences. By 1973, however, more than half of the world's oil demand was being provided by exports; more than 45 percent of all the world's needs were being provided by OPEC exports alone. The situation is shown in Figure 42.

Exports' share of demand began to fall, recovering only briefly in 1976. The boost was in non-OPEC nations' exports, however; OPEC exports as a share of demand reached their historic peak in 1973. Importing countries made efforts to cut back on imports, and tried to obtain what imports were necessary preferentially from non-OPEC nations. This trend was most pronounced in East Asia, where governments spoke in terms of security premiums they were willing to pay to avoid imports from OPEC, and most especially from Mideast OPEC members.

Figure 42. Exports Share of Total Demand, 1960-92



The situation was a boon for non-OPEC oil exporters. Exploration in non-OPEC developing countries boomed, frequently in areas that had previously been deemed too high in cost or too "unprospective." Initial success was limited, but oil exploration was pushed into many new and difficult areas.

The second oil crisis, precipitated by the Iranian revolution and the Iran-Iraq war, was poorly timed from the perspective of OPEC members, though that was clear to only a few of them at the time. Prices shot up, and some suppliers with especially desirable crudes moved to a major program of spot auctions. Libya was a particular offender in this regard. Many small refiners in the United States and Europe (whose establishment was encouraged by government policy) had little in the way of cracking or desulfurizing equipment; to make saleable product, they had to have light, low-sulfur crudes, and the spot price of these was driven into the vicinity of $45/b.

Initially prices seemed to hold, though demand began to drop. After a stormy series of meetings, OPEC agreed to settle for lower output at a higher official price of $34/b for the "marker" crude, Arab Light. The decision was by no means unanimous; the Saudi oil minister, Ahmed Zaki Yamani, agreed to go along in the name of organizational unity, but warned that the decision would be disastrous for exporters in the longer term.

Sheikh Yamani, who headed OPEC's Long-Term Strategy Committee, had long advocated the view that prices should be held at a point, around $18/b, that kept the world economy healthy, discouraged widespread exploration, and undermined the economics of alternative resources. The price would then be raised in step with world economic growth. The countries with large reserves and small populations—Saudi Arabia, Kuwait, Qatar, and United Arab Emirates—could afford to take such a long view; the more sophisticated nations, such as Venezuela, were inclined to agree. But countries with smaller reserves, or pressing economic problems, generally wished to obtain as much cash as soon as possible. Moreover, some analysts continued to argue that oil demand was fundamentally inelastic, and that demand would revive when the recession of the early 1980s disappeared.

The result was a prolonged decrease in the overall demand of oil. Most of this, as discussed previously, was the result of fuel switching in electric power. The decrease in demand fell most heavily on OPEC. Non-OPEC countries experienced a production expansion as the exploration boom of the 1970s reached fruition, and their share of exports expanded at OPEC's expense. As can be seen in Figure 42, OPEC's share of world trade and world production fell at a dizzying rate through 1985. The result was the price collapse of 1986.

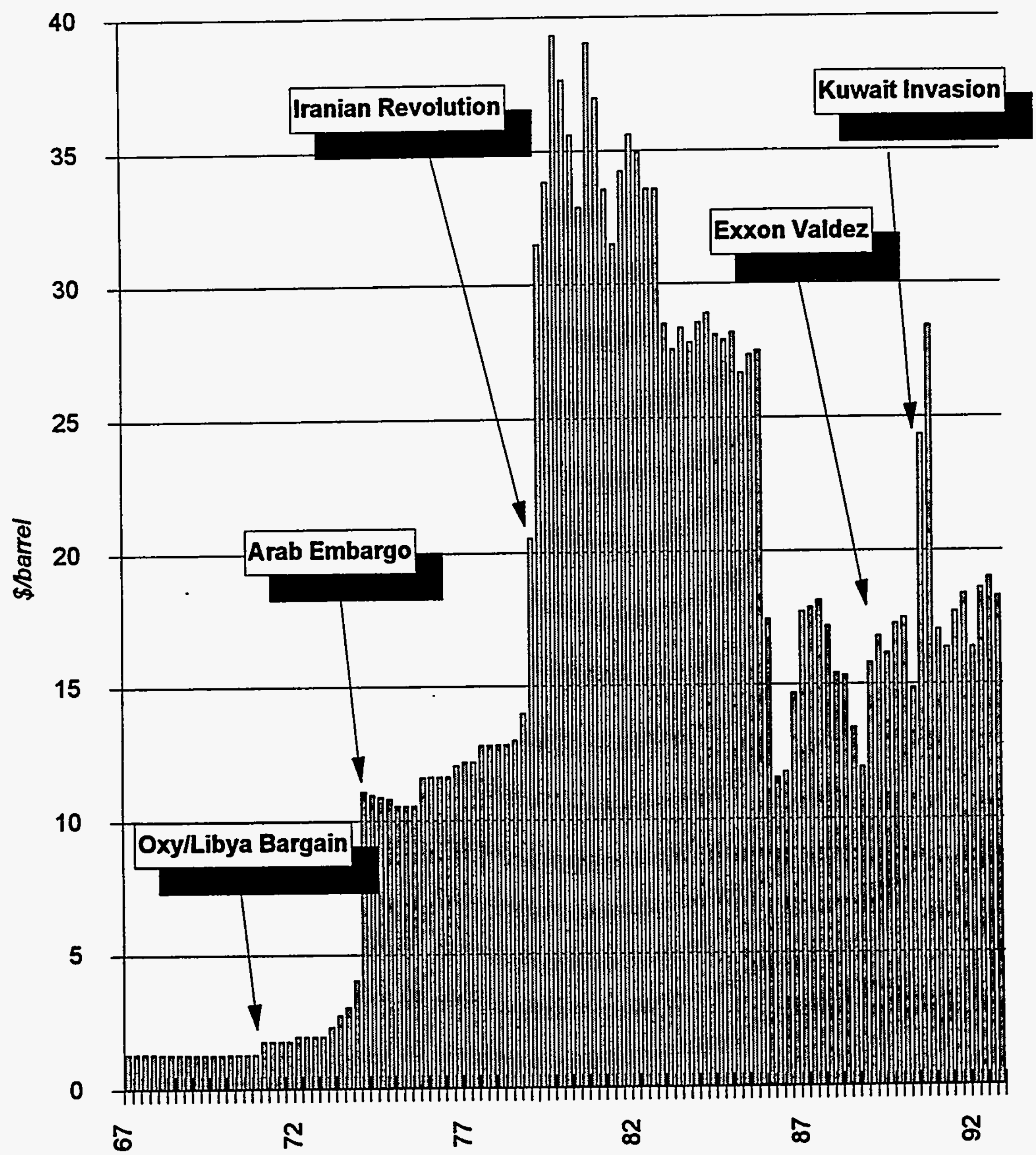
Figure 43 shows the spot market prices for Arab Light crude from 1967 to 1992, along with milestone events. The result of the Oxy/Libya price agreement can be seen as a small but portentous upward movement in a flat price path. The Arab embargo is more dramatic, but the Iranian revolution took the market to levels no one had anticipated.

There have been slight recoveries since the price collapse of 1986, as well as two price spikes: the brief rise following the *Exxon Valdez* disaster, and the recent jumps following the Gulf War. There is considerable confusion about today's market because few will now claim that they know what the price of oil "ought" to be. The public has adjusted to prices below $20/b as "normal," but the economy had done a good job of adjusting to $28/b in the early 1980s.

A clearer perspective can be gained from examining Figure 44, which shows the same events affecting the same crude, but in this case gives the prices in 1980 constant (real) dollars, with the effects of inflation removed. In real terms, the prices in the 1986-92 period are the lowest the world has seen since 1973. Even the spikes of the *Valdez* and the Gulf War are very short-lived phenomena that only touch the levels of prices seen after the first oil crisis. If oil demand is growing today, it is because oil is, relatively speaking, a bargain. Growth of 4.4 percent per annum was seen in the late 1970s, against effective prices that were much higher than today's; what is perhaps surprising is that present growth rates are so restrained.

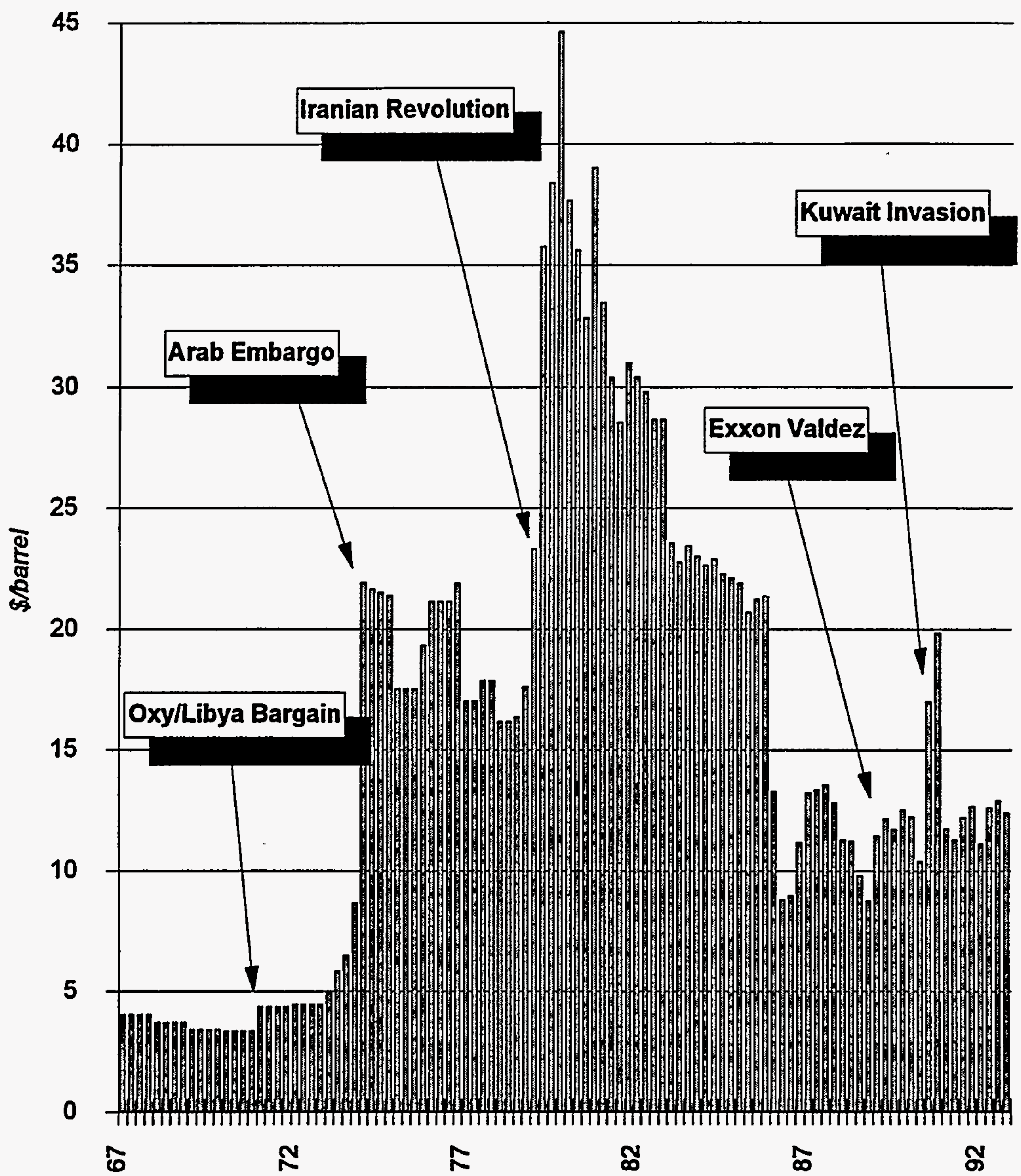
The price collapse of 1986 turned OPEC from a cartel to a club. This may be just as well for the members, since in general, OPEC has not been a very effective cartel. Although

Figure 43. Market Prices of Market Crude, 1967-92



Note: Based on Rotterdam spot Arab Light 1967-83 and on Dubai + $0.80 since 1984.

Figure 44. Real Prices of Arab Light Crude, 1967-92



Notes: Prices are in 1980 inflation-adjusted dollars. Based on Rotterdam spot Arab Light 1967-83 and on Dubai +$0.80 since 1984.

OPEC is widely blamed for price increases, the jump from $28/b to $34/b in the early 1980s was the first time that OPEC set arbitrary prices above the market (and we have seen the effects of that decision). Prior to that time, OPEC pricing decisions had merely followed the market in times of crisis, moving up to not to the highest price seen in spot trading, but to a typical or average level of spot prices. The logic for following the market up is impeccable; if they do not follow the market up, then the buyers of their crude will simply turn around and sell it at higher prices on the spot market in any case.

The public attitude, of course, is that OPEC *caused* the crises in the first place. There were OPEC members involved in four out of five of the milestones shown on Figures 43 and 44, but these events were not the result of decisions by OPEC. OPEC has thirteen members. Five are in the Mideast: Saudi Arabia, Iran, Iraq, Kuwait, and the UAE. Two (Algeria and Libya) are in North Africa, two (Nigeria and Gabon) are in West Africa, and two (Ecuador and Venezuela) are in Latin America. One final member (Indonesia) is in Asia.

Not all of the Arab oil producers are in OPEC. (And, in passing, it should be noted that not all Mideast OPEC members are Arab, Iran being the single exception.) Bahrain, Syria, Egypt, Oman, and Yemen are all important Arab oil producers that are not OPEC members. The Arab oil embargo of 1973 was just that—an embargo by Arab oil exporters. Not all Arab oil exporters participated, and not all the ones that did participate were members of OPEC. The Arab oil embargo was not an OPEC decision, and many of the OPEC members were extremely unhappy at the embargo, since they felt that they would share in the blame (as they did).

The Iranian revolution and the subsequent Iran-Iraq war involved OPEC members, but can hardly be considered an OPEC action. Indeed, two of the milestones involve OPEC members being at war with one another, Iraq being the common denominator. OPEC countries such as Gabon, Ecuador, or Indonesia may profit from the increased prices, but they can hardly be considered as architects of the crises.

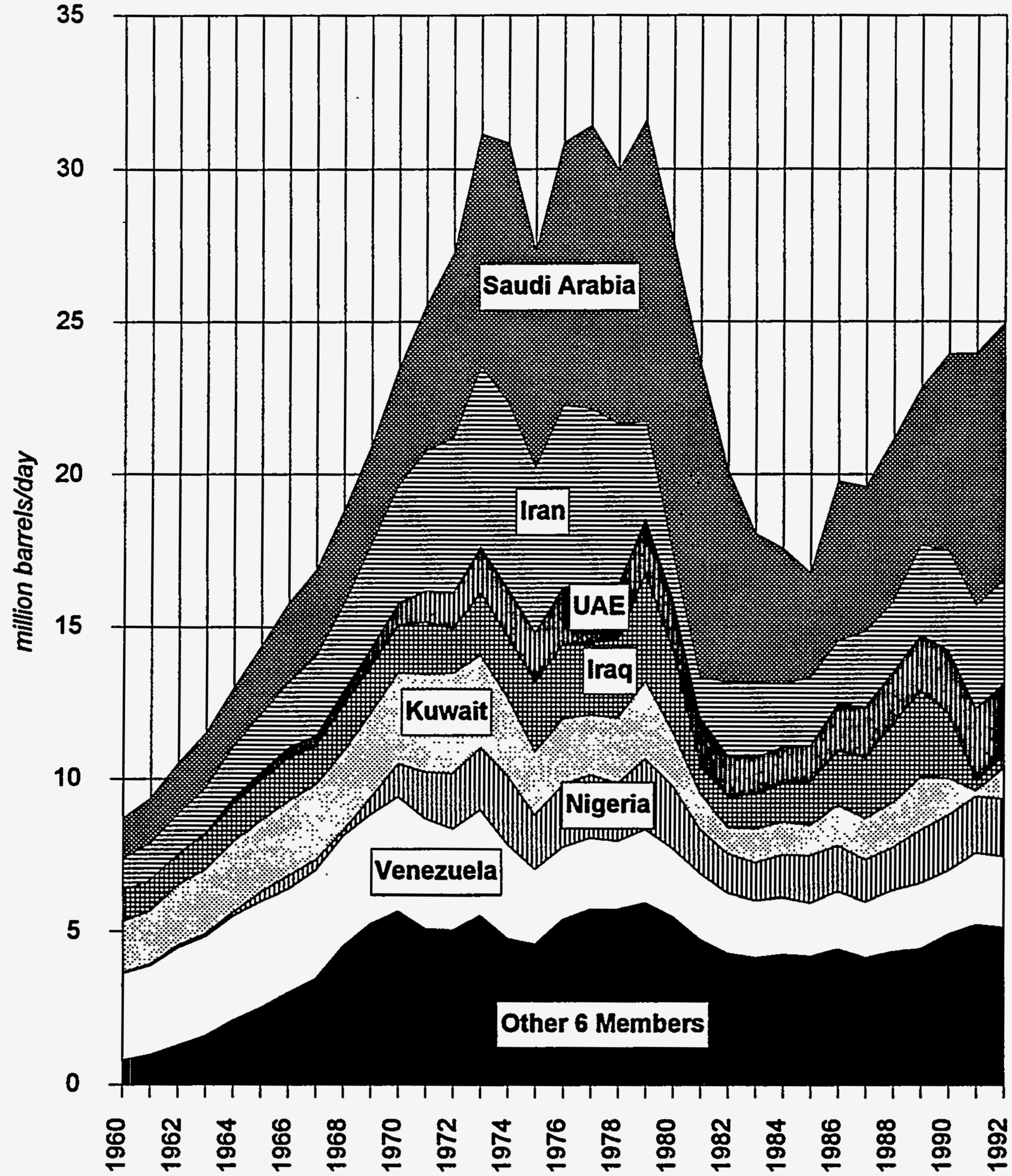
The reason OPEC is now functioning as a club rather than a cartel is that the members have fundamentally different interests at stake. Saudi Arabia, Qatar, Kuwait, Libya, and the UAE all have small populations and vast oil resources. Venezuela and Iraq have moderate-sized populations and large oil resources. Nigeria and Iran have large oil resources and large oil reserves. Algeria and Indonesia have very large populations relative to their reserves. Ecuador and Gabon both have small reserves, and have a difficult time maintaining exports.

The only requirement for joining OPEC is oil exports in excess of 100,000 barrels per day (b/d). This is less than Hawaiian oil consumption. A country need not be a major exporter to join, and, conversely, quite a few major exporters (Norway, Malaysia, China, the Commonwealth of Independent States, Mexico, Colombia, and various African countries) are not members.

Insofar as OPEC production quotas mean anything in today's market, they are applied only to the countries with massive reserves and more limited cash needs. Indonesia, Ecuador, Gabon, and Algeria generally have their quotas set somewhere near their maximum production levels. The large-reserve nations account for most of the oil, and only a few of them (Saudi Arabia, Kuwait, and Venezuela) have ever shown much restraint in production to meet the organization's goals. Figure 45 shows the production of the major OPEC nations over the last three decades. The disparities are obvious.

During the attempts to set quotas during the early 1980s, there was widespread cheating. While others were exceeding their quotas, a handful attempted to reduce the downward pressure on the market by cutting production and sticking to official prices. The Saudis bore a disproportionate burden; their production fell from over 10 million b/d in 1980 to a little over 3 million b/d in 1985. The price collapse of 1986 was a blow that shook even rich nations like Saudi Arabia; the combined effect of a production cut from 10 million b/d to 3 million b/d plus a fall in prices of about two-thirds meant that government employees arrived at work to find notice of a 30-percent pay cut.

Figure 45. OPEC Oil Production, 1960-92



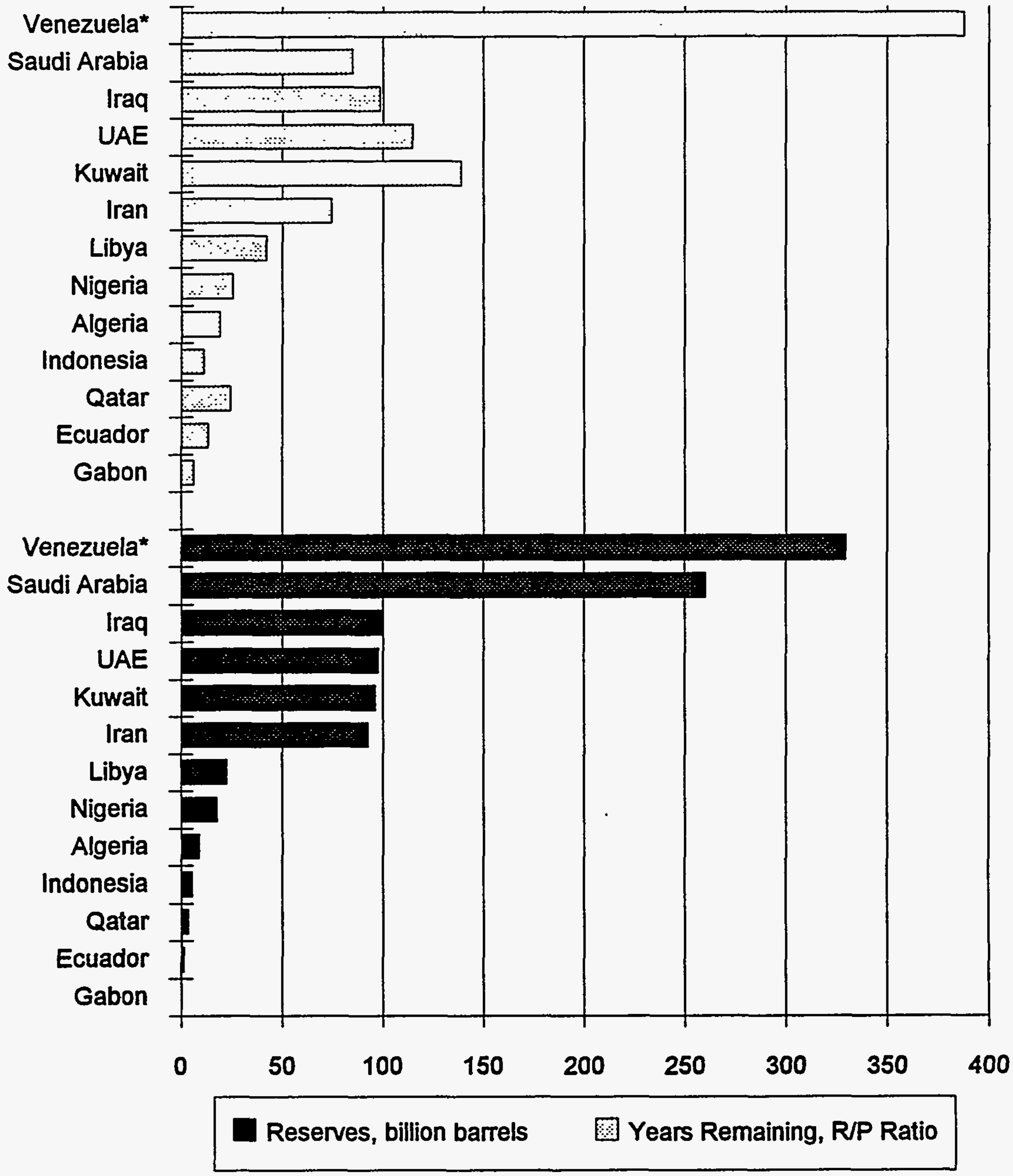
Note: Countries that do or could maintain more than 2 million b/d of capacity are shown individually.

OPEC members will have a crucial effect on the future of the market, but only a handful of the current members really matter, as can be seen in Figure 46. The future of OPEC as a force is really the future of Venezuela plus five Mideast countries: Saudi Arabia, Iraq, the UAE, Kuwait, and Iran. These six nations control 94 percent of all of OPEC's reserves. At current rates, these are the countries with more than 75 years of production remaining. For the remainder of the decade, other OPEC countries will continue to play an important role in the market, but the trend will be for production and exports to be concentrated in the hands of the leading half-dozen. Moreover, the experiences of the last decade have made most of the large producers less concerned with organizational unity and political posturing, and more concerned with long-term market management.

In some ways, the trends in the market are encouraging: As will be seen below, the supply situation during the Gulf War was closer to an actual "crisis" than in 1973 or 1974. But some of the big exporting nations have realized the advantages of stability in the market, and try to cushion supply crises; and the importers have learned to try to manage the market to prevent bidding wars, and use strategic stocks to soften prices. By any of the classic measures—spare capacity, utilization rates, level of political and military threat, or level of supply loss—the Gulf War should have been a much larger crisis than the Iranian revolution. The fact that it was not suggests that the world is now better at managing such events.

On the other hand, the increasing concentration of exportable oil in the hands of five Mideast OPEC countries (two of which, Iran and Iraq, are not noted for rational international behavior) is worrisome. Even if the world is better at managing oil crises, the degree of supply concentration that is emerging creates the potential for physical cutoffs. Early in the twenty-first century, the Persian Gulf will be more strategic than ever before, and if some semblance of political order and accord is not brought to the region, the potentials for disruptions will be enormous.

Figure 46. RP Ratios and Reserves of OPEC Members



*Venezuelan reserves include 267 billion barrels of superheavy Orinoco crudes.

3. Trends in Refining

A full discussion of developments in world refining over the preceding decades would go far beyond the scope of this report. A few of the major trends, however, need to be outlined to appreciate the changing pressures in this aspect of the market.

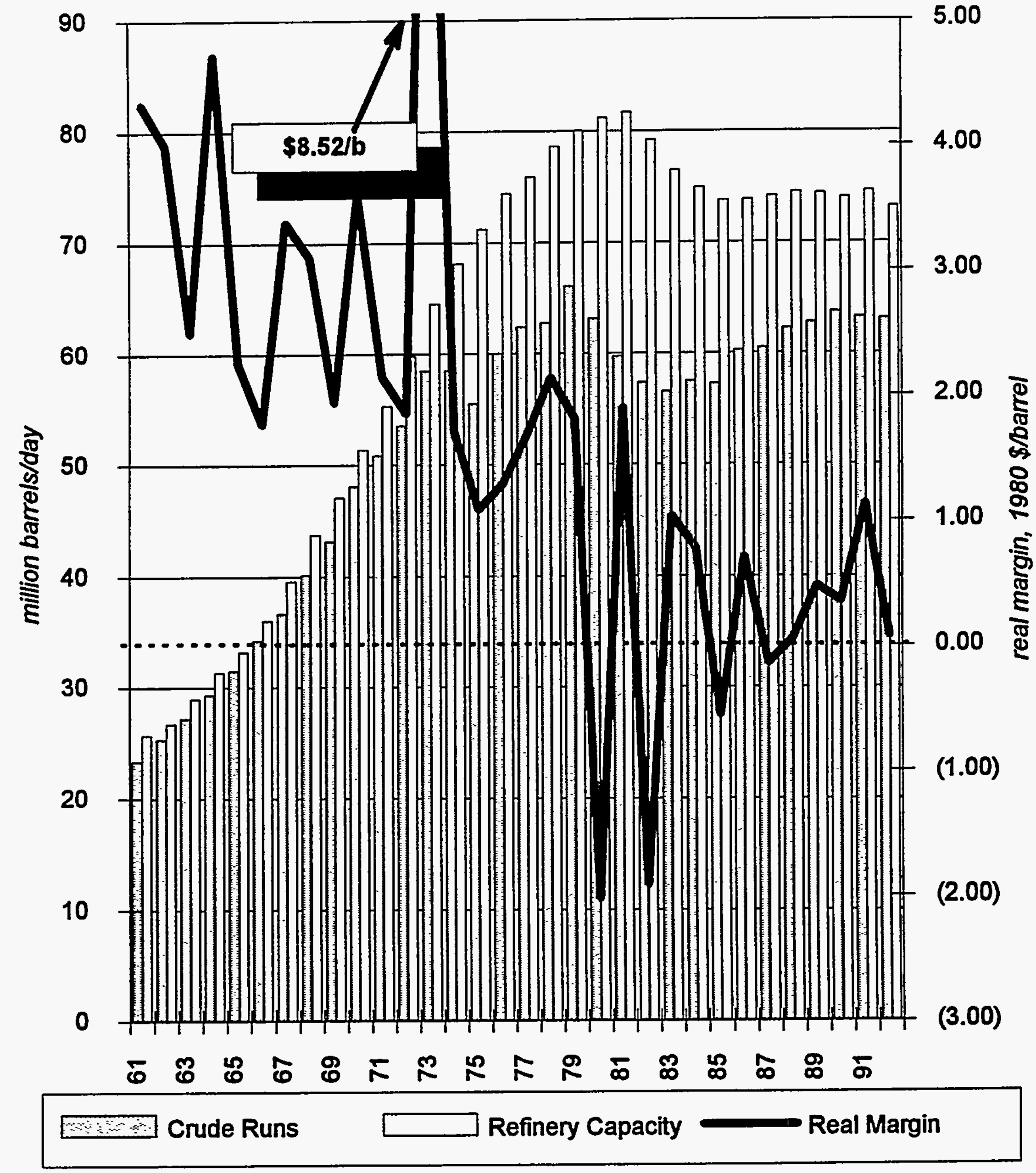
Beginning in the 1960s, there was a major push for developing countries to construct their own refining industries. The argument of most development economists at the time was that countries were foregoing the value-added of upgrading the crude into oil products. Many developing nations, both oil exporters and oil importers, began a drive into refining. (The development economist's argument today, incidentally, is that most developing countries have better things to do with their limited supplies of capital than tie them up in such capital-intensive, low-employment, low-spin-off industries.)

After the 1973 oil crisis, it was additionally argued that domestic refining enhanced a nation's energy security. This argument will be discussed at length in the report of Task II (*Fossil Energy in Hawaii*) of this project. Here, it is enough to note that the argument was widely accepted, and refinery construction was speeded after the 1973 embargo.

The results are shown in Figure 47. Refinery capacity climbed above 80 million barrels/day as refinery crude runs fell to about 55 million barrels/day. In some areas, capacity utilization fell as low as 40 percent.

The overcapacity had a dramatic effect on margins, especially when corrected for inflation. The "real margin" shown in Figure 47 is the hydroskimming margin on Arab Light-type crude at Rotterdam spot prices. When the supply/demand situation in refining was tight, margins were high, and the 1973 crunch was highly profitable for those refiners that could obtain the needed supplies of crude; indeed, spot margins have never been higher. But the margins collapsed as the refining capacity glut increased, and the 1980s was a painful period as refiners around the world went into bankruptcy and closed. Since some countries with national oil industries continued to build capacity in the 1980s, the closures were even more widespread than suggested by the total capacity decrease. In the United States, about a quarter of all refineries were scrapped.

Figure 47. Refinery Capacity, Runs, and Margins, 1961-92

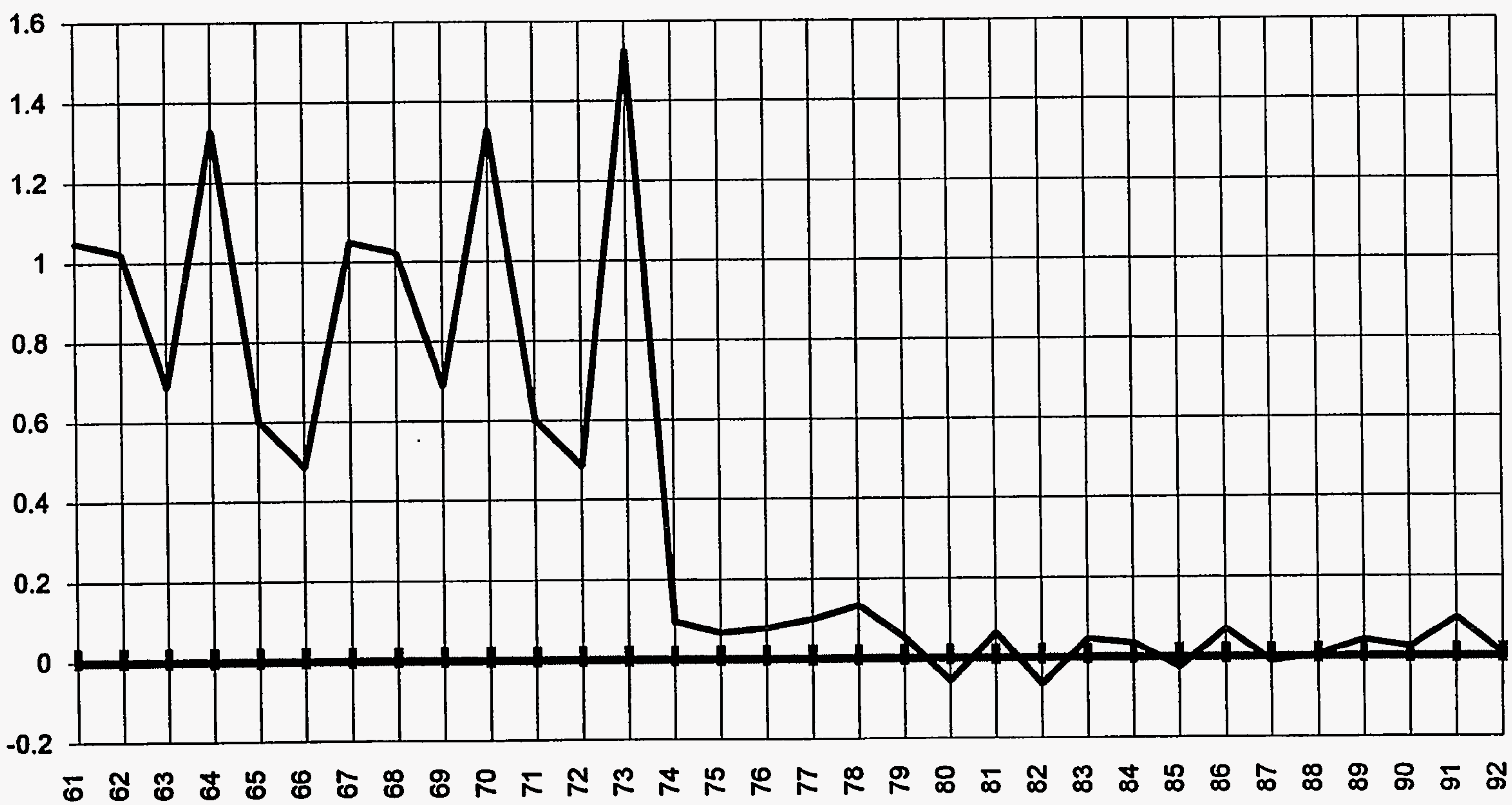


"Refinery capacity" here means crude distillation capacity. Despite the rapid declines in fuel oil demand, the capacity growth in the 1970s was so great that an excess of cracking capacity also developed. This meant that refiners were selling light products, such as gasoline and jet fuel, without recovering capital on their investments. This naturally depressed overall margins even further, since the most profitable products were underpriced. Figure 48 illustrates another way of looking at what has happened to margins over the last three decades by showing gross margins as a percentage of crude prices. In the 1960s, with low crude prices and high refinery utilization, a refiner might buy crude for $1.50 per barrel ($1.50/b) and sell the resulting products for $3.30/b. By the 1980s, a refiner might buy crude for $28/b, and sell the products for $28.50/b.

The chart exaggerates the changes, of course, since both the decrease in gross margin and the increase in crude prices play a role in determining the percentage. But in many ways this percentage expresses the crisis that has faced refiners in the 1980s: not only has the absolute profit on a barrel of oil gone down (from inflation-adjusted margins of $2-4/b), but the *risk* involved has gone up dramatically. When the gross margin is only $0.50/b or $1/b, a small percentage fluctuation in the crude price can turn the profits into losses. To give an example, the gross hydroskimming margins on Arab Light in 1961 and 1991 were virtually identical (without any inflation adjustment!). But in 1961, a jump of over 100 percent in the crude price would have been required to wipe out the margin; in 1991, a fluctuation in crude price of only 9.6 percent would wipe out the margin.

According to economists, the profitability of an endeavor must be related to the risk. To attract new capital to a risky business, the profits must be higher than in safer businesses. Because of the huge overcapacity built up in the 1970s, however, profitability in refining presently bears no relationship to the risk. Today, it is difficult to build a new refinery and break even. Most of the capital that has been invested in this sector in recent years has been to avoid losing an existing investment entirely, as in conforming to new environmental standards; much of the rest of the investment in this sector is a result of bad forecasting.

Figure 48. Gross Hydroskimming Margin As a Percentage of Crude Price, 1961-92



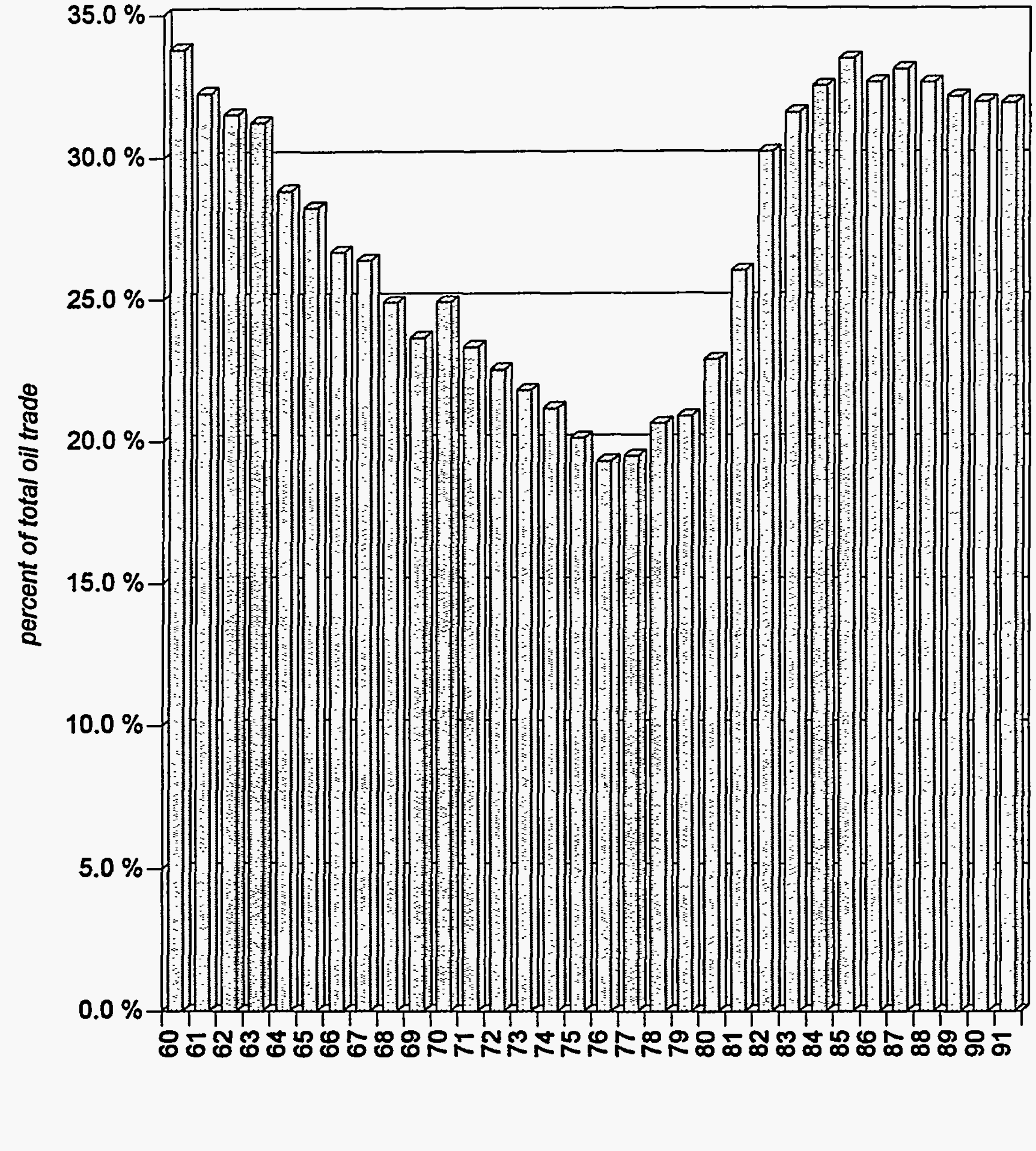
Many people find these facts preposterous, having seen the kinds of profits that oil companies often register. The companies do not, however, register these profits in refining. The money in oil is in the production. A refiner would consider a \$2.00/b hydroskimming margin a massive windfall; but even at \$18/b oil prices, the profit margin on production can easily be \$14/b. In the 1960s, companies made money on every phase of the business, from production to transport to refining to marketing. Today there are still large profits to be made in production and marketing, but the surpluses of capacity have made both refining and tanker transport among the world's least profitable businesses.

The drive to build new refining capacity in the 1960s and 1970s led to a steady decline in the fraction of oil traded as refined products. As Figure 49 shows, by the mid-1970s, 80 percent of the oil moving in international trade was crude oil; only 20 percent was refined product. The overcapacity in refining reversed this trend. By 1980, refiners facing declining local demand were beginning to look abroad for markets to keep their refineries running. The share of oil moving as refined products increased by about 50 percent, reaching a peak at the time of greatest capacity glut.

Refined products' share of trade has declined slowly since the mid-1980s. It is difficult to project the future of this aspect of the business, because there is great uncertainty about capacity construction in the coming years. There are plans for major new refineries in some regions, but present returns make it uneconomic to construct most new facilities. It is argued, with some justification, that margins will have to rise substantially as the capacity surplus disappears, and will in fact have to rise to the levels that will justify new investment. In an economically rational world, margins should indeed rise considerably in the next few years, increasing consumer prices for oil even if crude prices remain stable. But it does not take much overbuilding to compete margins away; the times of high margins that refiners remember from their youth were times when capacity was barely keeping up with demand.

As discussed in Section F below on trends in the Asia-Pacific market, the Asia-Pacific region is the most active region in refinery construction and plans for new refineries. This

Figure 49. Refined Products' Share of Oil Trade, 1960-91



has important implications for Hawaii in terms of overall energy strategy, as discussed in the report of Task II (*Fossil Energy in Hawaii*) of this project.

4. Global Crude Supply and Demand

One of the most difficult areas to forecast is oil production capacity. This is not because, as one might think, because of the difficulty of predicting new discoveries, although that adds to the uncertainty. The main uncertainty in the forecasting of crude production capacity is the plans for capacity expansion in known fields.

There are technological limitations on how rapidly oil can be produced from a reservoir. This varies with the geological structure of the field, and with other factors such as the gas/oil ratio in the deposit. Pushing production rates beyond a certain point can physically damage the field, resulting in lower ultimate recovery. This happened to many fields in the former Soviet Union, where the quota system encouraged overproduction at the expense of long-term total output.

The biggest new sources of production in the next few decades will be oil deposits that are already known and characterized; in most cases, they are already producing. Saudi Arabian capacity now stands at about 9 million b/d, but there is no physical reason that Saudi capacity cannot be taken to 15 million b/d, or even higher; in the 1960s some studies envisioned the expansion of Saudi capacity to 25 million b/d. Similarly, Kuwait, which kept production in the 1.2-1.8 million b/d range through most of the 1980s, has in the past produced 4 million b/d; Kuwait has the capability of expanding capacity to at least 7 million b/d. Iraqi, Iranian, Libyan, and Nigerian capacity are all capable of considerable expansion based on known reserves.

Venezuela has the largest expansion potential of all. Current Venezuelan capacity stands at about 3.2 million b/d. Venezuelan reserves of superheavy crudes, however, match the total oil reserves of Saudi Arabia. Production of these crudes can be expanded immensely, but currently there is no market.

In the late 1970s, many OPEC countries refused to expand capacity (or did so only clandestinely) because they believed that they would be under intense international pressure to increase production to maximum capacity to reduce prices. As it turned out, when the Iranian revolution came it was impossible for the Saudis and other price moderates to control the price increases even by bringing their spare capacity onstream.

Kuwait, Saudi Arabia, and the UAE are now all more politically inclined to increase capacity to increase their control of the market. Although most exporting countries believe that current oil prices are too low, these Gulf producers are more concerned about their ability to control prolonged price spikes in the future. In the 1960s and 1970s, these producers attempted to cooperate with other OPEC members, and watched the market spin out of control. In the future, these countries plan to *dominate* the organization rather than assist it.

Most of the information about capacity expansion plans is collected only on an anecdotal basis, by talking to oil companies that are working on the expansions, or by talking to those government officials who are willing to discuss the matter. Although journals such as *World Oil* and *Oil & Gas Journal* have articles on capacity expansions, the articles tend to come only on the heels of official announcements—a year or two before the expansion at best. The long-range plans of most countries are not publicly available.

The Program on Resources of the East-West Center has undertaken production-forecast studies for USDOE based on confidential surveys of the industry. This survey sample included contractors working in producing countries and producing-country governments. The incentive for participation was that the respondents would be presented with the aggregated results of the survey. Since the plans of other countries and companies were of critical interest to most of the participants, most were willing to provide their proprietary information on a non-disclosure basis.

These survey participants continue to provide capacity information on an informal basis when they are polled. Our current baseline capacity forecast, based on these communications, is shown in Table 13.

TABLE 13. PAST AND PROJECTED CRUDE CAPACITIES

(thousand barrels per day)

	1970	1980	1985	1988	1989	1990	1991	1992	1995	2000
China	616	2,122	2,289	2,734	2,751	2,768	2,799	2,834	2,900	3,200
INDONESIA	854	1,663	1,375	1,331	1,209	1,289	1,411	1,370	1,450	1,150
Malaysia	18	278	440	542	557	623	652	661	711	376
Others	504	962	1,408	1,525	1,504	1,598	1,597	1,631	1,835	1,843
ASIA-PACIFIC	**1,992**	**5,025**	**5,512**	**6,132**	**6,021**	**6,277**	**6,459**	**6,496**	**6,896**	**6,569**
Norway	0	525	835	1,300	1,700	1,900	1,900	2,200	2,500	2,700
U. Kingdom	4	1,662	2,689	2,329	1,743	1,850	1,927	1,926	1,700	1,400
Others	415	333	468	569	562	596	615	568	600	460
W EUROPE	**419**	**2,520**	**3,992**	**4,198**	**4,005**	**4,346**	**4,442**	**4,694**	**4,800**	**4,560**
CIS	7,142	12,215	12,150	12,477	12,150	11,390	10,296	8,899	7,900	9,600
Others	434	429	408	372	347	320	284	282	273	268
CIS/E EUR.	**7,576**	**12,644**	**12,558**	**12,849**	**12,497**	**11,710**	**10,580**	**9,181**	**8,173**	**9,868**
IRAN	5,000	5,000	3,200	3,200	3,300	3,300	3,360	3,500	4,500	4,000
IRAQ	1,800	4,000	3,500	3,500	3,500	3,500	283	417	4,000	4,500
KUWAIT	3,773	2,573	2,170	2,160	2,300	2,400	201	1,001	2,750	3,000
Oman	333	285	505	597	623	677	701	729	700	600
QATAR	500	600	600	500	450	450	440	430	700	700
SAUDI ARABIA	5,273	11,273	8,670	7,960	8,000	8,200	8,225	9,056	9,450	12,250
U. ARAB EMIR	1,078	2,160	2,260	2,295	2,320	2,350	2,605	2,805	2,300	2,500
Yemen	0	0	0	172	187	189	197	179	300	400
Others	160	213	209	300	343	430	517	567	572	598
MIDDLE EAST	**17,916**	**26,103**	**21,114**	**20,684**	**21,023**	**21,496**	**16,527**	**18,684**	**25,272**	**28,548**
ALGERIA	1,300	1,300	1,100	1,200	1,250	1,330	1,330	1,330	1,000	1,000
GABON	109	225	225	225	250	300	310	320	275	325
LIBYA	3,320	2,200	1,400	1,400	1,400	1,500	1,550	1,550	1,500	1,700
NIGERIA	1,500	2,300	1,800	1,800	1,800	1,900	1,900	1,900	2,300	2,500
Others	610	1,013	1,527	1,780	1,804	1,823	1,838	1,890	2,048	1,853
AFRICA	**6,839**	**7,038**	**6,052**	**6,405**	**6,504**	**6,853**	**6,928**	**6,990**	**7,123**	**7,378**
Colombia	226	132	181	375	406	440	429	454	600	750
ECUADOR	487	2,129	3,025	2,885	2,894	3,048	3,125	3,126	3,100	3,300
VENEZUELA	3,754	2,400	2,300	2,500	2,500	2,650	2,650	2,650	3,000	3,500
Others	839	1,376	1,801	1,737	1,775	1,813	1,786	1,852	2,150	2,499
S AMERICA	**5,306**	**6,037**	**7,307**	**7,497**	**7,575**	**7,951**	**7,990**	**8,083**	**8,850**	**10,049**
Canada*	1,496	1,830	2,000	2,000	1,990	1,980	1,970	2,080	1,900	1,700
United States*	11,313	10,235	10,622	9,852	9,232	8,994	9,028	8,780	8,200	7,800
N AMERICA	12,809	12,065	12,622	11,852	11,222	10,974	10,998	10,860	10,100	9,500
WORLD	**52,857**	**71,433**	**69,158**	**69,616**	**68,847**	**69,608**	**63,924**	**64,987**	**71,214**	**76,472**
OPEC	**28,747**	**37,822**	**31,625**	**30,956**	**31,173**	**32,217**	**27,389**	**29,455**	**36,325**	**40,425**
	54%	**53%**	**46%**	**44%**	**45%**	**46%**	**43%**	**45%**	**51%**	**53%**
Non-OPEC	**24,110**	**33,611**	**37,533**	**38,660**	**37,674**	**37,391**	**36,535**	**35,532**	**34,889**	**36,047**
	46%	**47%**	**54%**	**56%**	**55%**	**54%**	**57%**	**55%**	**49%**	**47%**

**Including NGLs. OPEC members shown in UPPERCASE.*

Figure 50 shows crude capacity and crude demand for the 1970-92 period, with forecasts to 2000. In 1973 production capacity was expanding rapidly, but was racing hard just to keep ahead of demand. The first price shock delayed and slowed demand increases, but productive capacity kept increasing. In 1979, total capacity was comfortably ahead of demand—a bad time to push oil prices to an all-time high. In the 1980s capacity slowly diminished, while demand collapsed through 1985. The huge gap between the two lines resulted in the price collapse of 1986, and the gradual recovery of demand.

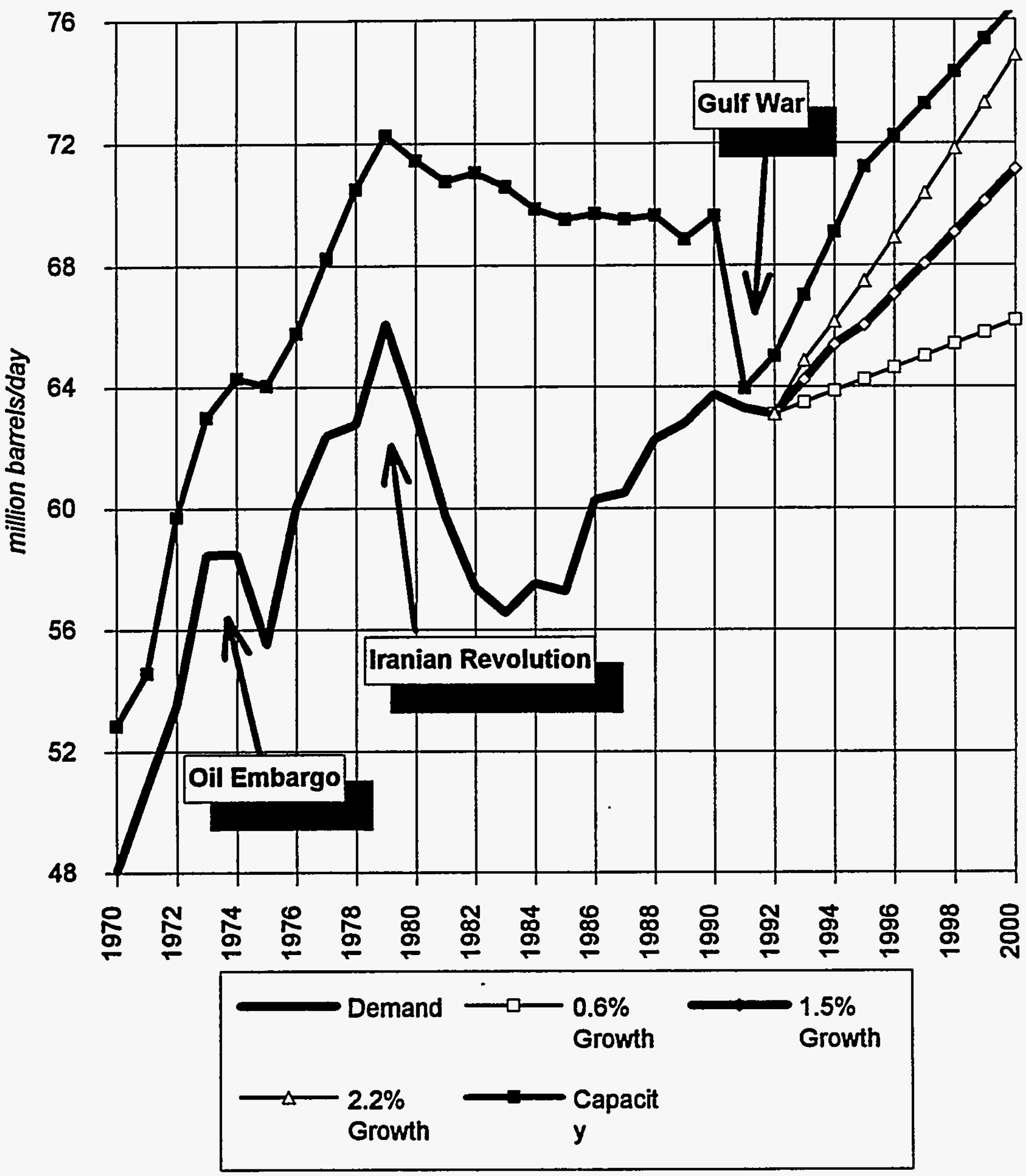
There is a fundamental difference between the dynamics of the Gulf War and the two previous Mideast crises that is apparent in the diagram. The embargo and the Iranian revolution both occurred during demand surges. The percentage gap between supply and demand was narrowing, but because of pressure from the *demand* side. The Gulf War, on the other hand, was a price crisis precipitated by a downward spike in supply potential, at a time of only moderate demand growth. Although supplies of oil were actually tighter in this period than at other times, the overall price consequences were quite moderate and short-lived compared to the aftermath of 1973 or 1979.

In part, this reflects a change in attitude on the part of some major producers, who now seek a stable, growing market, rather than a high-price market. But credit must also go to restrained demand growth in the importing countries. Rapid and apparently unstoppable demand growth—the general perception of the 1970s—gives the price hawks in the export market the whip hand. Weak or moderate demand growth favors the moderates among the exporters.

Three rates of demand growth are shown in Figure 50. The low case, 0.6 percent, is likely only if the world economy becomes sluggish throughout the 1990s. The high side, 2.2 percent, is above most analysts expectations; this would require growth at the rate seen in the second half of the 1980s, much of which was recovery of demand rather than actual net growth.

The rate of 1.5 percent per annum is a baseline forecast that assumes around a 1 percent growth rate in the industrial countries, and fairly rapid growth in the Asia-Pacific

Figure 50. Crude Capacity and Demand, 1970-91, and Projections to 2000



region and some Latin American countries. This rate is in the range currently foreseen by most governmental and oil-industry forecasters.

Figure 51 calculates the implied OPEC capacity utilization. Historic years are actual data; forecast years determine the call on OPEC oil by assuming that OPEC production will continue to act as the residual supplier; that is:

OPEC output = world demand - non-OPEC supplies

The chart is rather surprising, since it indicates that OPEC supplies were stretched tighter during the Gulf War than at any other time. The chart also shows that we are still in a situation of tight supply; the world market is more reliant on OPEC as of this writing than during either of the previous oil crises.

If capacity increases follow our baseline forecast, then OPEC utilization in the 1990s will settle at around 85 percent—a rate lower than today's. In overall supply terms, however, the OPEC utilization rate will be comparable to the level seen in the 1970s, a fact that many planners may not find comforting.

Figure 52 shows the spare crude production capacity in the world with forecasts derived from our baseline capacity projections. The chart shows quite starkly both the level of overhang in the market in the 1980s, and the narrow gap during the Gulf War.

In none of the oil crises to date has there been a physical supply shortage of crude oil. Prices have been driven up by perceptions of an *impending* shortage; in some areas, the supplies to final consumers have been disrupted by hoarding. But there has never been a time where product demands could not be met because refiners could not obtain crude. The year 1991 was the closest the world has come to such a situation, and this fact makes apparent the extent to which a supply crisis is psychological. Nineteen ninety-one should have witnessed the most severe price increase of all time, if physical supply were the driving factor; in supply terms, we are still in the danger zone.

The decade of the 1990s is likely to see less spare production capacity on average than in the 1970s. At higher levels of demand, this means that the percentage "cushion" is

Figure 51. OPEC Capacity Utilization, 1970-2000

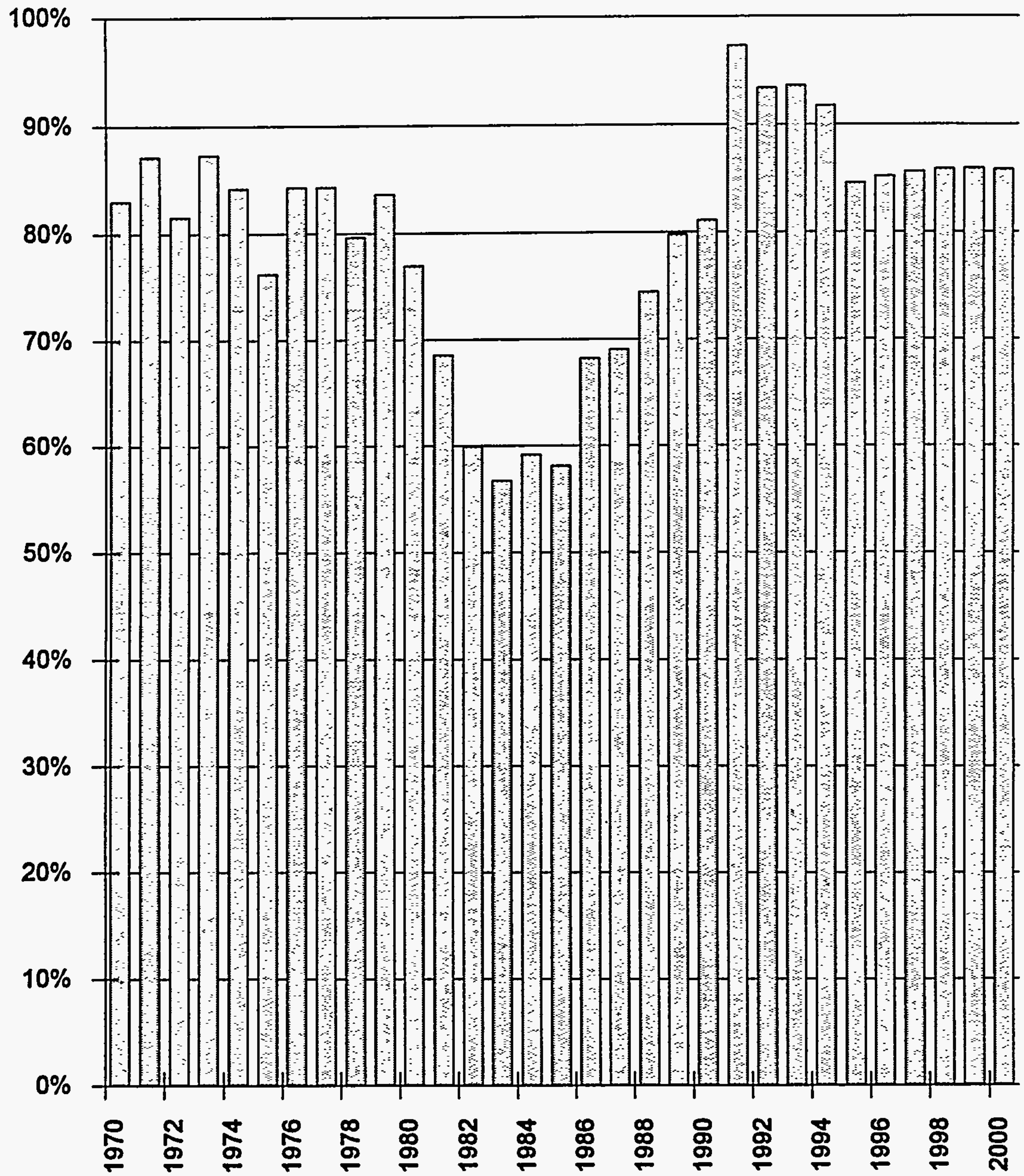
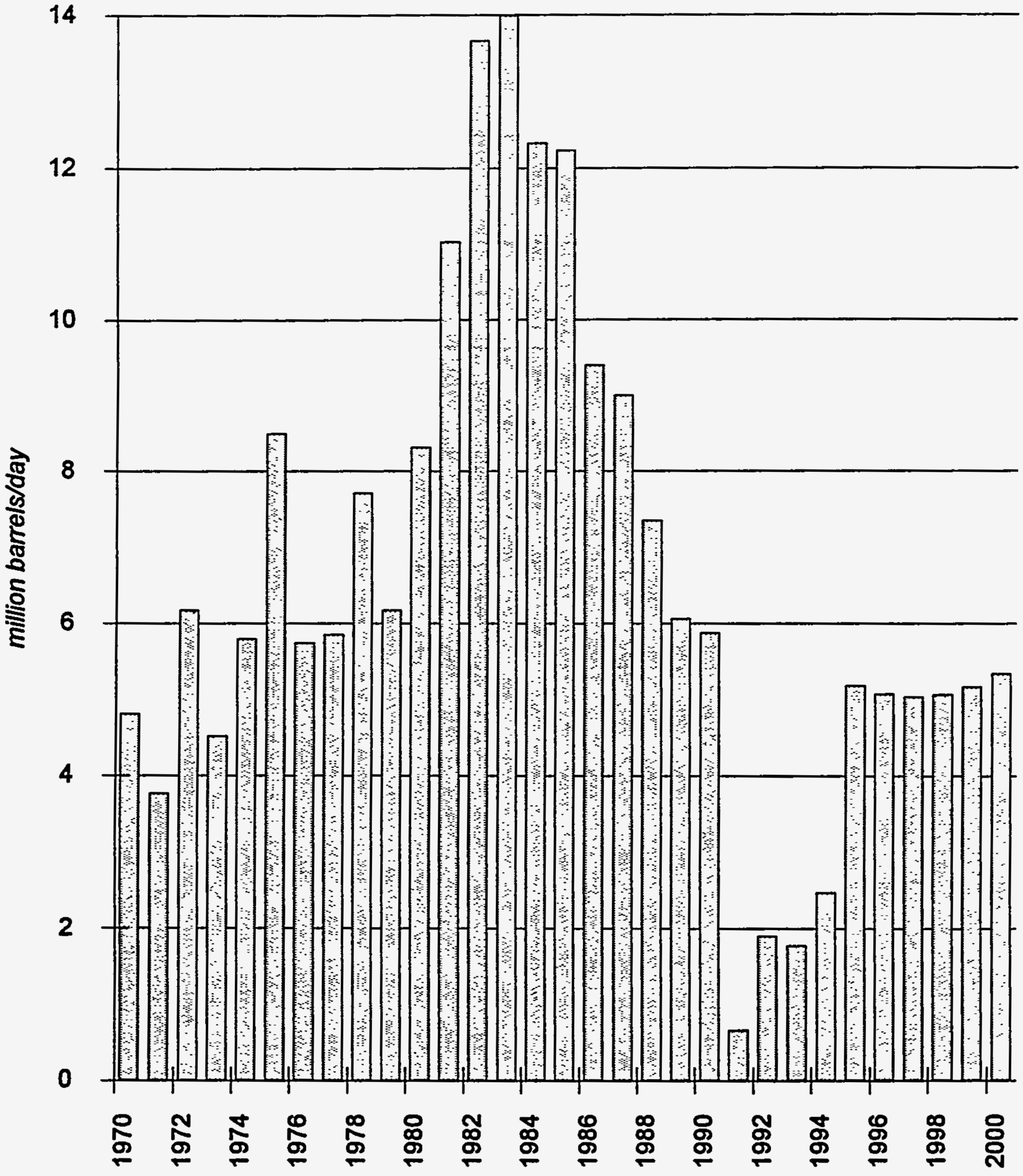


Figure 52. Spare Crude Production Capacity, 1970-2000



lower than in the past. The baseline forecast thus suggests that in terms of physical availability, the coming decade will be far more risky than the past.

During the mid-1980s, the capacity-demand gap was so wide that nothing could have tightened the market. Saudi Arabia could have cut off all supplies without making a dent in the spare capacity. Nothing short of a full cutoff of Mideast supplies (such as a blockage of the Strait of Hormuz) could have eliminated the full overhang. On the basis of the current capacity projections, the 1990s will be very different; loss of a major supplier, such as Saudi Arabia, could result in a sudden physical shortage of oil.

There is an alternative scenario. One factor that has prevented the Saudis, Kuwaitis, and Emirates from massive expansion of production capacity in the past has been fear of their neighbors, notably Iran and Iraq. Huge productive capacities not only shift the power balance in OPEC in a direction Iran and Iraq do not approve of, but it also makes these small, relatively weak countries more attractive for annexation. Iraq, of course, has long-standing claims on Kuwait; Iran has similar claims on parts of the UAE. It is easy to come up with pretexts for invasions of Saudi Arabia as well; its status as a monarchy makes it vulnerable to all manner of political agitation, and its ownership of Mecca opens it up to criticism as the exemplar of the Islamic faith.

If Kuwait, Saudi Arabia, and the UAE are now comfortable enough under an implied long-term "Desert Shield," they may expand capacity rapidly; indeed, they may do so simply to make themselves more strategically valuable to the nations outside the Gulf. There is little doubt that a full expansion of the capacity of these three countries would allow them to control any kind of rapid price increases in the market. In effect, they would become a strategic petroleum reserve in the Mideast, not under outside ownership, but under ownership of leaders whose long-term interests are linked to those of the importing nations. In this case, we could see something like a stable, managed market.

How likely is such a scenario? The "overexpansion" of Gulf capacity is quite conceivable. Whether this would lead to a millennial long-term, stable market is much less likely. The Mideast is full of unresolved conflicts and resentments—religious, political, and ethnic. The long-term stability of the Kuwaiti, Saudi, and Emirate (UAE) regimes can be questioned, even if only internal forces are considered.

Long-term stability is possible. It is not likely in the next two decades. What is more likely is a repetition of the patterns of the past, with disruptions driving the price up, and overcapacity dragging it down again. The biggest question is whether these price swings will follow the multiyear patterns established in the 1970s and 1980s, or whether the milder fluctuations of the Gulf War are the template for oil crises of the future.

5. Global Environmental Trends in Oil

Coal is typically processed very little before use. It may be washed and pulverized, but in general the metals and sulfur content of the coal are taken as given, and any environmental controls are on the emissions of the consuming process.

In oil and gas, on the other hand, the major environmental controls on contaminants such as sulfur and metals are handled *before* consumption. There may be controls on emissions as well, such as catalytic converters on cars or NO_x controls on power plants, but the main means of environmental control for the hydrocarbons is the setting of product specifications.

The process of setting specifications is far simpler for governments to implement than emission control technology, both logistically and politically. It also may be, in many ways, more economically efficient, since it doesn't specify the means by which a goal is achieved, but only the goal itself. In emission control, the government must consider which end-users should be affected, and which, if any, should be excluded; it also may become involved in long debates about technology tradeoffs. Politically, emission controls are less palatable because they raise the capital costs of the end-user; be it more expensive cars or more expensive power plants, the direct and immediate costs are quite visible, and subject to lobbying by various interest groups.

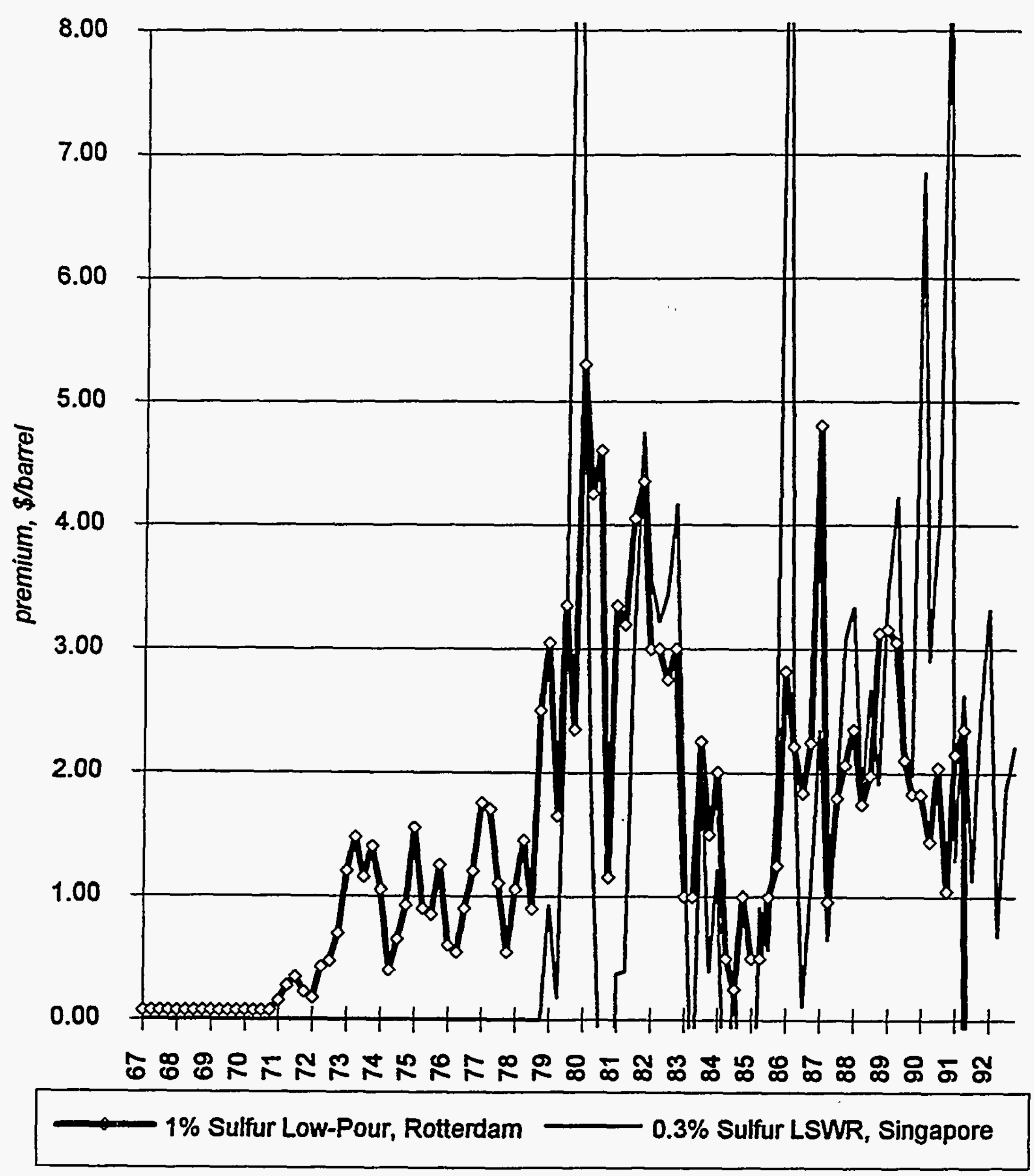
Setting specifications for petroleum products or pipeline gas places the burden on the fuel supplier. It may result in additional costs to the end-user, but these are in the form of higher fuel charges rather than up-front capital investments. Not only is removal of contaminants from liquids and gases usually easier prior to combustion, but with the diffuse use of many oil products, end-use emission control is difficult to monitor or enforce. Furthermore, from a political point of view, the additional costs of new specifications are likely to be blamed on the oil and gas companies rather than regulation.

Tighter petroleum product specifications are spreading rapidly in the developing world. Although countries such as India and China have still not taken major steps in environmental control, the adoption of unleaded gasoline has moved quickly in Asia, and Latin America may soon follow. Allowable sulfur levels in fuels are being reduced in many countries, although to very different final specifications. The one area in which most countries have been reluctant to follow the U.S. lead in new environmental controls is the reduction of aromatics in gasoline and diesel fuel.

Sulfur and other contaminants are relatively cheap to remove from light and middle distillate products, but it is expensive to remove sulfur from fuel oil, since much of it is tightly bound in the large molecules. The technology is well-developed, but not widespread. For example, for the whole of the Petroleum Administration for Defense District V (PADD-V, comprising the U.S. West Coast, Alaska, and Hawaii), there is only a single, 24,000 b/d fuel oil desulfurizer. Only Japan and Taiwan have made extensive investments in resid desulfurizing (though Korea is now expanding in this area as well).

To date, since tight sulfur specifications are found only in the industrial countries, there has generally been enough low-sulfur fuel oil available from refining of low-sulfur crudes. Figure 53 shows the price premiums paid for fuel oil that is 1 percent sulfur by weight (1%S) and 0.3%S (comparable to that burned in Hawaii), relative to the cost of standard high-sulfur fuel oil (3.5%S). The differentials are extremely volatile, especially in the Far East; Japan's stringent sulfur specifications, complex tariff system, and fluctuating hydroelectric output can result in large price spikes for low-sulfur fuel oil. Although the movements in differentials can be violent, the fluctuations since 1979 take place around a center of $2.30/b.

Figure 53. Cost Differential: Low-Sulfur Fuel Oil Minus High-Sulfur Fuel Oil, 1967-92



The operating costs of a resid desulfurizer (RDS) range from about $0.80-2.50/b, depending on the cost of hydrogen and the frequency of catalyst replacement. Most of the operating units around the world were built in the 1970s, with amortized capital costs of around $2/b. Thus, it would appear that RDS should add $2.80-4.50/b to the cost of fuel oil. Unfortunately, capital costs have increased considerably since most of the operating units were built, and installation of RDS technology is now estimated to be on the order of $4-6/b, giving total upgrading costs of $4.80-8.50/b.

As discussed in Section F below, the next few years are likely to see a short-term supply increase in low-sulfur crude output in the Asia-Pacific region. By the late 1990s, however, the supply of low-sulfur crudes in trade will probably diminish. This will happen at the same time that sulfur specifications are tightening almost everywhere, and the marginal source of low-sulfur fuel oil will have to become RDS. This could lead to a substantial jump in the price of low-sulfur fuel oil, possibly taking it above the price of crude oil. What is more likely, however, is that the price differential will be at least partly, and perhaps largely, the result of a decrease in the price of high-sulfur fuel oil. (Although the price of fuel oil is typically well below the price of crude, this has not always been the case; prior to 1973, *all* petroleum products normally cost more than the crude they were made from.) In any case, this will raise the cost of oil-based power generation even if the cost of crude remains constant.

Tanker transport will also become more expensive. The current fleet has a large amount of tonnage that will no longer be seaworthy within this decade. Furthermore, concern over oil spills is becoming a matter of global concern. The double-hulling requirements in the United States may be adopted elsewhere, as well as additional safety and operating features that will tend to raise overall costs. A cost increase was in the making in any case, as the surplus of old, underutilized tonnage moves into the scrapyards. Higher insurance premiums and greater contributions to international risk pools will also raise the cost of moving oil.

The costs of environmental control will hit disproportionately at the bottom of the barrel. Fuel oil contains most of the contaminants in the original crude in forms that are more difficult to remove; processing costs to meet new specifications will be expensive. It is the tanker transport of crude and fuel oil that is of the greatest concern in spill control; little attention is paid to the possibility of gasoline spills, since the spill would largely evaporate. Furthermore, any kind of "carbon tax" introduced *ought* to be higher for fuel oil than for the lighter products, since fuel oil contains more carbon per gallon than the lighter hydrocarbons. (In practice, most discussions of carbon taxes seem to discuss application of the tax to crude oil rather than products, in which case it is not clear how the cost of the tax would be distributed over the products.)

The costs of environmental control are likely to raise the prices of most products relative to crude oil. There is a premium to be made from crude oils that come close to meeting new specifications without costly treating and processing; most of this premium, however, is likely to be captured by the exporting country. For those monitoring price relationships for antitrust or policy purposes, these developments will introduce major complications. It is difficult to compare past trends with contemporary prices if the specifications for all of the products have changed in the interim.

6. Long-Term Prices

The 1980s are a poor period of time to use as a basis of what is "normal," but there is a strong tendency for humans to use recent past experience as a guide to the future. The 1980s saw a huge overcapacity in oil refining, tanker tonnage, and oil production capacity. There is no reason to assume that this period of time is an effective guide to normal conditions; the 1980s was more of a persistent aberration than an equilibrium.

Independent of the crude production situation, the price of oil products should be expected to rise, and the price of oil transport should be expected to rise. Both of these industries have been money losers since the 1970s, but new investment is now required, and this will occur only if there is some level of profitability (although both industries have shown themselves to be perfectly capable of competing away any profits by overinvestment). Furthermore, in both industries, new environmental legislation will raise costs as well. Price increases should be expected on petroleum products relative to crude oil, although such a development will undoubtedly launch government inquiries into pricing practices of refiners and shippers.

The big questions continue to revolve around the price of crude itself. Barring any major international accord severely penalizing the use of fossil fuels on environmental grounds, one thing is clear: *a huge, lasting price increase for crude oil is extremely unlikely in the next two decades*. This statement may strike many as overly bold, but it is grounded in the economics of the oil industry.

The cost of finding and developing oil reserves and the cost of producing oil are not logically related. To take a simple example: the cost of exploring the North Sea oil reserves, drilling, and building production platforms has been estimated at about $10/b. (It should be noted that these costs are not evenly distributed; some companies spent considerable money and found no oil, others spent little money and found huge reserves. Much of oil exploration continues to be a matter of luck.) The actual cost of producing the oil—running the platforms, maintaining the equipment, loading the oil—is at most about $4/b. Logically, then, the minimum price for this oil ought to be about $14/b.

To digress only briefly, many people conclude from this that the price of oil from these fields should not be much *above* $14/b, either—say, $16/b to give a "fair" profit. What this ignores, or course, is scarcity. No one would argue that a diamond or a gold nugget found by accident should be sold for $1, since it didn't cost the finder anything to obtain. More to the point in the Hawaiian context, no one argues that a house should be sold for its original purchase price plus, say, 10 percent to be "fair." Housing is expensive in Honolulu because land in the islands is a scarce resource. Oil is expensive because it is a scarce resource, and all of its substitutes are much more expensive.

Returning to our \$14/b North Sea oil, in practice \$14/b will not be the minimum price: \$10/b of that total is "sunk costs," money that is already spent. If the oil sells for \$16/b, then the company makes \$2/b. At \$14/b, the company breaks even.

The company has \$10/b in costs to recoup, and must spend an additional \$4/b to do so. If it never produces again, it has lost \$10/b. At prices of \$8/b, with operating costs of \$4/b, the company makes back \$4/b of its investment. This is still a loss of \$6/b. No one would have begun this project if they knew that they would lose \$6/b. But the money is already spent, and recovering \$4/b of the investment is better than recovering none of the investment. (To turn the argument around, if you are bound to lose money, losing \$6/b is better than losing \$10/b). Thus, although the "cost" of North Sea oil production may be \$14/b, the companies will keep on producing as long as they can sell for more than \$4/b.

High prices encourage exploration and capacity expansion. The results of these expansions do not go away when the price drops, except on a very gradual basis through depletion and lack of maintenance; look again at Figure 50.

For most of the countries of OPEC, oil is their economic mainstay. Few have viable economies without large oil exports. Moreover, their production costs are far below the cost levels of the North Sea or the Alaskan North Slope. Most Mideast oil has production costs of 50 cents to \$2/b, with exploration costs of only about \$1-2/b. Mideast oil is profitable at about \$4/b, and will continue to be profitable at that level for many years to come. Under the circumstances, they will continue producing no matter how low the price drops.

In Venezuela, the superheavy Orinoco Belt oils have a production cost of about \$3/b. These crudes are below 10° API, high in sulfur, and high in metals. To turn them into usable crude, the production cost leaps to \$14-22/b, most of which is capital investment for processing plants. Despite these high costs, however, this means that world crude production can be expanded enormously across a four- or five-year time horizon for a fairly reasonable level of prices. Moreover, once again, these investments are mainly sunk costs (one reason why few companies are rushing to take advantage of the Venezuelan offer); once the investments are made, production will continue at prices far below the $14-22/b levels needed as investment plus operating cost.

There are thus many sources of oil available over the next two decades, and these are likely to be brought onstream in the event of a prolonged price increase. In current circumstances, these potentials do not eliminate the possibility of price increases, but they act to limit the duration of such an increase. A leap in the price of oil lasting four or five years, like that seen in the early 1980s, will lead to the same sort of price collapse seen in the second half of the 1980s.

This has important implications for alternative energy sources. High oil prices are usually required to justify alternatives, which tend to have high basic production costs. The fundamental problem is that the production costs of oil are far below the costs of any alternative. Once it has been found and developed, oil flows out of the ground virtually for free. It takes far more money to dig up coal, liquefy gas, make ethanol from biomass, or capture solar heat in a water heating panel. At present, there is no energy technology so cheap that its economics cannot be undercut by oil. If OPEC nations begin to lose market share to alternatives, they will most assuredly cut prices until oil again is competitive.

Alternatives are often presented as a way of cutting society free of the volatile oil market. This may in fact be the case, but most consumers wish to have their cakes and eat them, too; they want alternative energy as a way of keeping their costs lower during times of high oil prices, but few appear to be willing to pay higher costs for energy in times when the oil price falls. Alternatives in the price-equivalent range of $25-50/b were eagerly sought in the early 1980s. In the mid-1980s, the price of oil itself fell to $10-12/b. Had these alternatives been widely developed and implemented, energy costs might be twice as high as they are today. This might actually be in the interests of long-term economic, environmental, and security goals, but it would be rather unpopular on a political basis.

What is desired is an alternative energy source whose cost does not rise with the price of oil, but whose price always goes down with the price of oil. There is not, to the best of our knowledge, any energy source that behaves like this (although some, like liquefied natural gas, do the opposite, with a floor price and adjustment clauses for crude price increases). This does not mean that alternative fuels and energy strategies cannot be viable, but it means that planning such systems must take into account the fact that oil-price volatility is a double-edged sword.

F. Trends in the Asia-Pacific Market

1. Introduction

The world has now become accustomed to hearing about the "economic miracles" of various Asian countries in the 1970s and 1980s. The region has several of the world's most successful economies: the reputations of Japan, South Korea, Taiwan, Hong Kong, and Singapore are now synonymous with growth. Moreover, the economic outlook continues to appear far brighter in Asia than in the rest of the world. Asia is now the focus of a multitude of books, studies and articles; hordes of businesses and investors look to the markets of Asia. The region has catapulted into the world view, and it is already difficult to recall that the world was initially astonished—perhaps insultingly so—by the Asia-Pacific economic boom of the 1980s.

The "Asia-Pacific region"—defined here as encompassing those countries stretching from Pakistan in the west to Tahiti in the east—is a region only by virtue of geographic contiguity. In contrast to Latin America, Europe, or North America, which are all regions where the countries have a common historical background, related economic problems, and a common tenor of life, the Asia-Pacific region is a bit of a catch-all; the region is vast and diverse, encompassing countries at the extremes of almost any cultural spectrum that can be chosen. The region includes microstates like tiny Kiribati; sprawling, populous countries like China; huge, sparsely populated countries like Australia and Mongolia; compact, densely populated countries like Japan, South Korea, and Taiwan. Ethnicity and languages span across as broad a horizon as the rest of the world combined. Levels of development range from super-impoverished to super-affluent. The region includes countries with rich natural resource endowments, such as Australia and Indonesia, as well as countries like Singapore, Taiwan and South Korea, which must import the bulk of their raw materials. Political systems run the gamut from liberal democracies like New Zealand to hardline communist states like Vietnam, and include many nominal democracies where the actual system of governance does not fit any convenient Western pigeonholes.

Generalizations about the Asia-Pacific region are thus a bit risky—there are exceptions to each rule. Yet in many ways it is the region's very diversity that makes it such a dynamic factor in the world market. Countries at diverse levels of development, with diverse resource endowments, see many reasons for trade. Complementarity is not difficult to find. As nations move forward along the standard paths of development, fully developed industries begin to face increased wage bills, higher production costs, heavier regulation, and more environmental sensitivity from the public—all of which are normal concomitants of higher per capita incomes—and industries subsequently move to neighboring countries further down the development ladder. Although there are fundamental differences between the countries, in many regards the South Koreas and Taiwans of today look a good deal like the Japan of a decade ago; the economy of Thailand is moving to the position formerly occupied by the East Asian countries, and Indonesia is initiating the kind of light industrialization that Thailand has already mastered. Indonesian exports seem to be everywhere; by the end of the 1980s, the government announced that the country had reached "economic takeoff phase."

Much media attention has been devoted to exports from Asia to the developed nations of North America and Western Europe, but the most rapid increases in trade have been *between* the countries of the Asia-Pacific region. Higher economic growth in one country tends to lead to higher growth in the others, and the economies of the region boomed during the 1980s. In real terms, the Japanese economy, which seems fully mature, grew at about 4 percent per annum in the 1980s. This growth was modest compared to its Asia-Pacific neighbors, however, many of whom saw sustained rates of growth in the range of 6-7 percent. The economic boom has not been limited to "the Four Tigers" (Singapore, Taiwan, South Korea, and Hong Kong, also known as "the Four Little Dragons"), but has included many of the least developed, most populous countries, such as India, China, and Indonesia.

The recessionary 1980s saw Asia emerge as the world's main engine of new economic growth, and this trend seems likely to continue beyond the 1990s and well into the next century.

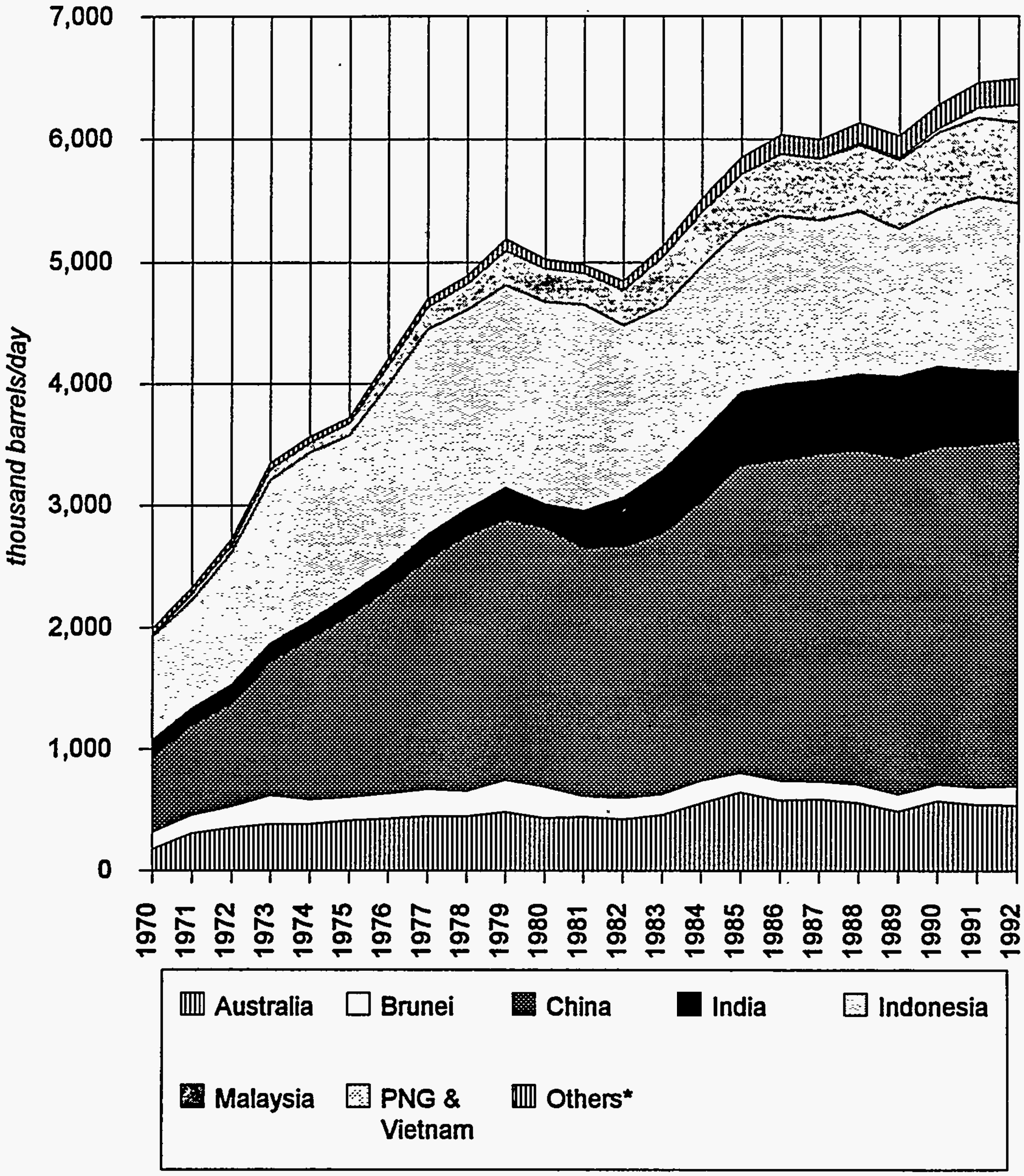
The fact that the Asia-Pacific region can "bootstrap" its way to development by trading within the region should hardly be surprising. The region contains over three billion people—nearly 60 percent of the world's population. With some notable exceptions, the countries of the region have done remarkably well at feeding their people and, despite rapid population growth, at increasing consumer incomes. The end product has been a hugely expanded market for consumer goods of all sorts, as well as a great expansion for capital investments in manufacturing facilities.

While the links between economic growth and energy consumption are not one-to-one, there is little doubt that energy and the economy are tightly wound up in one another. The economic boom of the 1980s was accompanied by rapid growth in the Asia-Pacific oil market. Three main factors—economic dynamism, lower oil prices, and reduced government regulation of the market—made possible a dramatic surge in consumption. After years in the doldrums, the oil industry made a dramatic turnaround, and its chronically capacity-surplus refining sector experienced a leap in profitability that gave birth to dozens of plans for capacity expansion and upgrading.

2. Crude Exploration, Production and Quality

Increases in Asian crude oil production over the last two decades have been dramatic. Production within the region has grown at nearly 6 percent per annum, well above the 4.4 percent growth in oil demand over the period. Output of oil approximately tripled during the two decades since 1970, growing from around 2 million barrels per day in 1970 to around 6.4 million barrels per day in 1990. Output has continued to grow; production in 1992 is estimated at 6.8 million barrels per day. As Figure 54 shows, however, the big growth was in the 1970s, when major new greenfield territories were opened to exploration. Thus,

Figure 54. Oil Output has Risen Dramatically in Asia, 1970-92



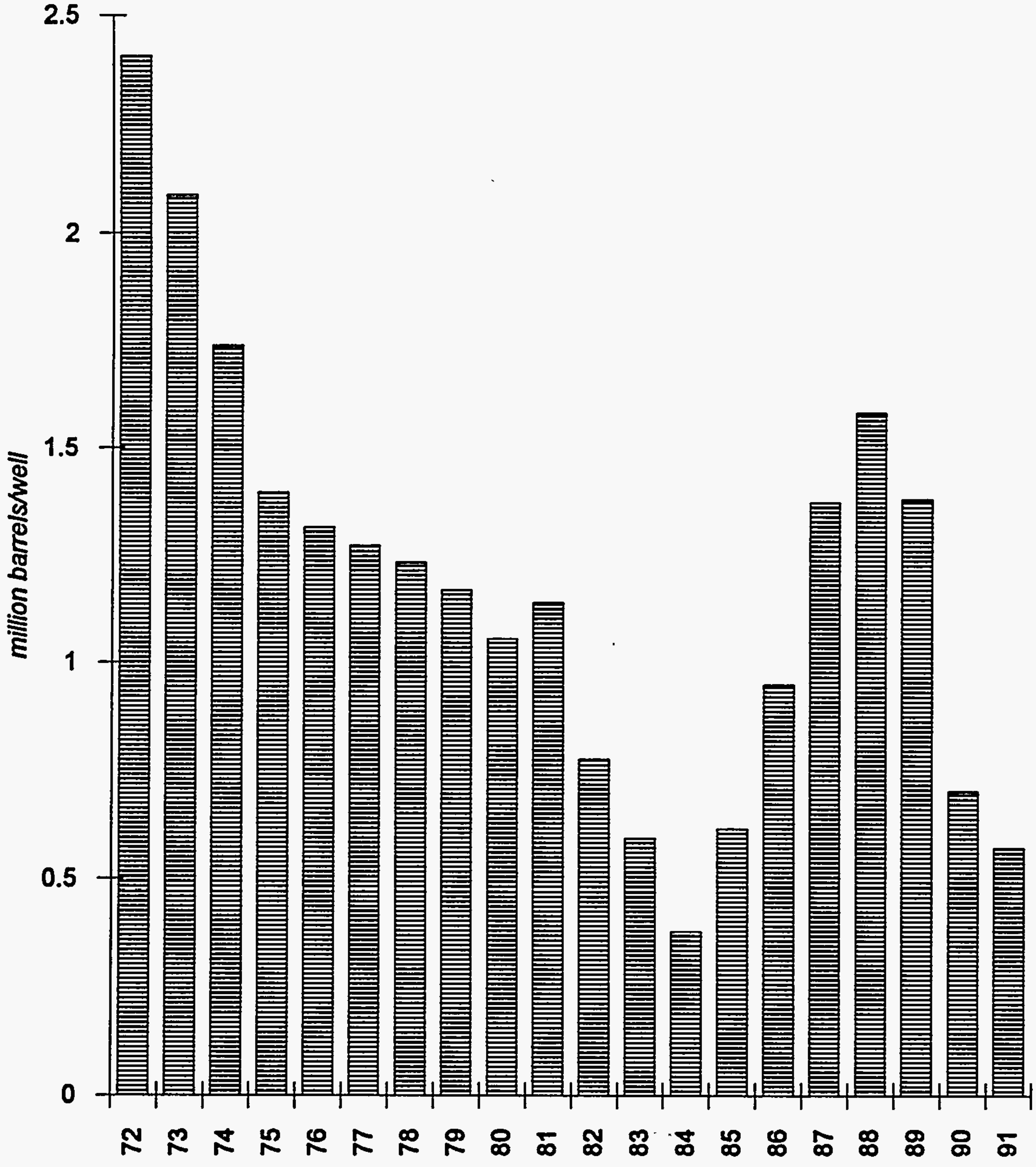
**Bangladesh, Pakistan, Japan, Taiwan, Philippines, Myanmar, Thailand, and New Zealand* although production is expected to continue to grow, the rate of increase is likely to be much lower than in the past. Furthermore, many Asian oil deposits are relatively shallow and small in extent. Unlike many of the Mideast supergiants, these deposits are very rapidly exhausted; some have sharp peaks in production only two or three years after startup, followed by quick declines. A large number of important Asian fields are already far along their depletion curves, and a continuous level of new investment in exploration is needed merely to maintain current production rates.

The oil price shocks of the 1970s motivated oil companies around the world to widen their search for crude oil. Asia was no exception—the big supply expansion in the 1970s and 1980s came from non-traditional producers. Huge increases in output were seen from China, India, and Malaysia, while output from Indonesia, the region's only OPEC member, actually declined. Much of the boom came from moving into new territory. But of course, new territory is scarcer in the 1990s, and generally less accessible; Western China and the Papua New Guinea Highlands appear to be the most promising sites in terms of reserve potential, but the transport logistics of moving oil from these locations to any market are daunting.

The exhaustion of easy greenfield sites can be seen in Figure 55, which shows, on a three-year rolling average, the amount of new oil found per well drilled in the Asia-Pacific region, in terms of million barrels per well. The period of the greatest success in finding new reserves was clearly in the early 1970s. A sharp dropoff in amount of oil found per well came in the early 1980s, when exploration was at fever pitch and wells were drilled in some rather speculative locations. This behavior tapered off as explorers grew more conservative in the latter half of the 1980s, but even ignoring the 1981-85 hump in drilling activity, there is still a steady upward trend in the number of wells that must be drilled to make additions to reserves. An increasing percentage of wells are dry holes, and those that are not are typically smaller deposits.

Indonesia offers a good case in point, since it is the Asia-Pacific region's only OPEC member and is one of the primary sources of foreign crude for Hawaii refiners. In 1991,

Figure 55. Drilling More and Finding Less: Oil Found per Well Drilled in Asia, 1972-91



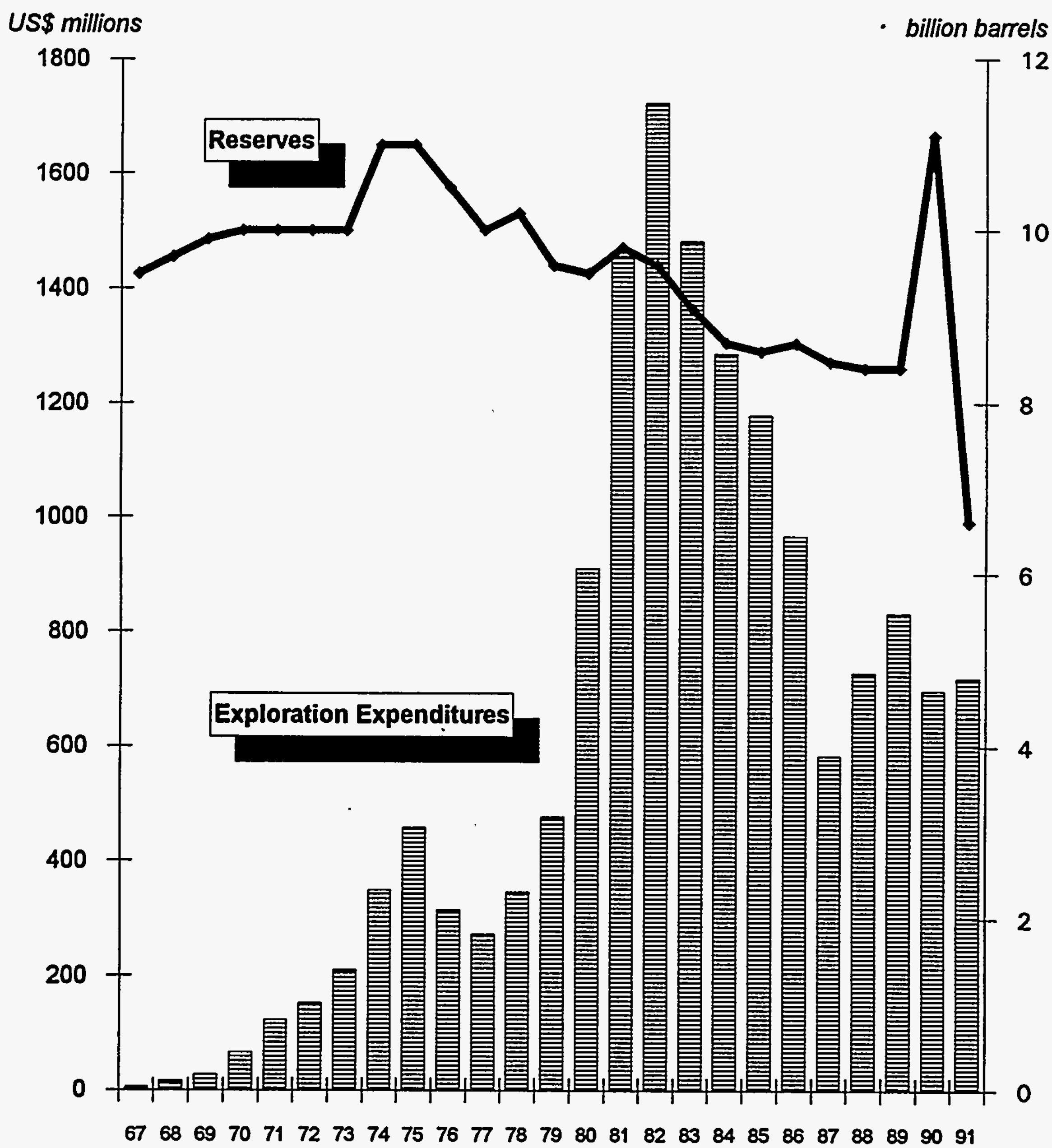
Note: 3-year running average of million barrels of oil found per well drilled.

Indonesia was the source of nearly two-thirds of Hawaii's foreign crude imports both the Chevron and the BHP refineries relied heavily on Indonesian crude inputs. Figure 56 displays the course of Indonesia's exploration expenditures versus oil reserves. The oil price shock of 1973-74 motivated companies to search for more oil, and reserves were revised from 10 billion barrels in 1974 to 11 billion barrels in 1975. The oil price shock in 1979-80 caused a major peak in oil exploration expenditures, but the additions to reserves were modest and were in fact unable to keep pace with expansions in production. The general trend in proved reserves is down, outside of an aberrant peak in 1990, the year of the Iraqi invasion of Kuwait. Reserves were subsequently revised downwards again.

To view the impact of oil price on drilling activity, Figure 57 presents the trend in wells drilled against the average selling price of crude in Indonesia. Here, the effects of the upward price shocks of the 1970s are visible, but it is also much easier to see the effects of the price crash of 1986. In 1986, the price dropped to under $14/b. The following year saw fewer wells drilled than in any year since 1969. Prices went up to around $17/b in 1987, and drilling picked up; prices slumped to about $15 in 1988, and wells drilled dropped off again in 1989. With this type of pattern, it is easy to see why the question "how much oil is there?" becomes complicated. As noted in Section B above on oil reserves and resources, there will always be some oil—at a price.

The surge in Asian production through 1985 outpaced demand growth in the producing countries, and large supplies of Chinese, Malaysian, Indonesian, Australian, and even Indian crude swamped the market in the 1980s. Expanded output, weak demand worldwide, and lack of OPEC unity fed into the collapse of oil prices in 1986, when the world saw spot prices for some crudes dropping below $10 per barrel. Asia-Pacific oil demand, which had never really slumped even under a regime of high prices, began to accelerate. The renewed demand growth of the late 1980s is continuing into the 1990s. The Iraqi invasion of Kuwait caused barely a ripple, and the perceived success of the "Desert Storm" campaign renewed consumer confidence. OPEC's efforts to control output and stabilize prices have had only

Figure 56. Spending More to Find Less: Indonesia's Oil Reserves and Exploration Expenditures, 1967-91



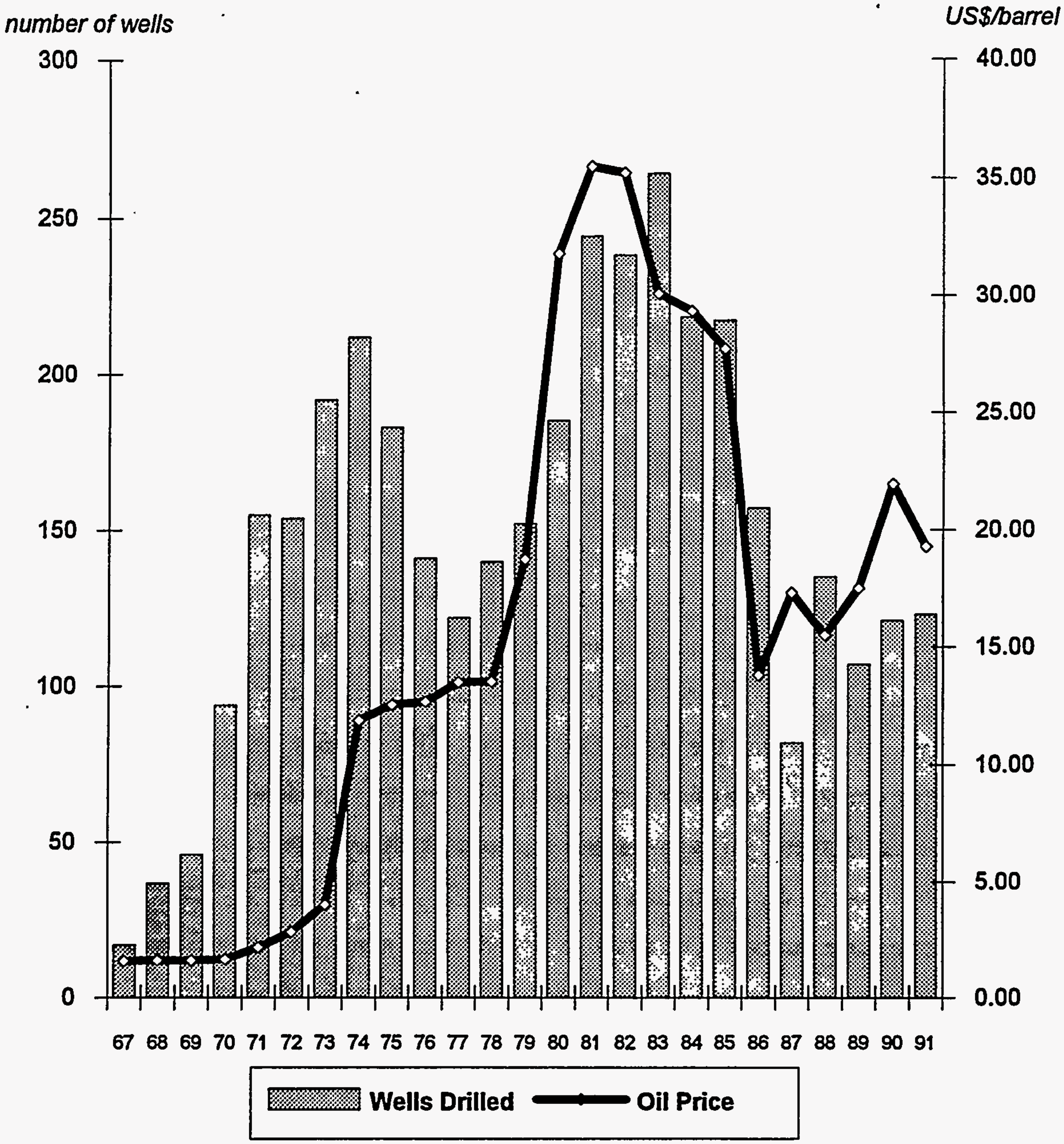
limited success. Ecuador, for example, perceived little benefit from continued membership and resigned from OPEC in the autumn of 1992.

Demand growth for oil in Asia has already begun to cut away at exportable surpluses, and the emerging trend is for a greater percentage of output to be consumed in the producing countries. The significance of this trend lies not only in the volumes lost to export markets such as Hawaii and the U.S. West Coast, but also in the quality of the resource. As discussed earlier in the section on crude quality, crude oils possess widely differing chemical properties, and the light, low-sulfur varieties are typically the most prized. In contrast to PADD-V as a whole, Hawaii is much more reliant on low-sulfur Asian crudes. Hawaii's crude slate includes typically from 40 percent to 60 percent Asian low-sulfur crudes, with the balance being Alaska North Slope crude—a medium-gravity, medium-to-high-sulfur crude.

The trend of crude quality in the region has been toward a slightly heavier, waxier slate. This trend is, and will continue to be, even more marked on the export market, where Intan, Widuri and Duri (Indonesia), Bach Ho (Vietnam), and possibly Daqing- and Shengli-type (China) crudes are on the increase. In 1989, Indonesian exports of Caltex's heavy, sweet Duri crude amounted to 76 thousand barrels per day (mb/d), but expansion of steamflooding brought exports up to 94 mb/d in 1990 and 130 mb/d in 1991. Duri crude has been a familiar input to Hawaii refineries. Another waxy, sweet crude is Maxus's Intan/Widuri, which entered the export market in December 1990. Exports were 4 mb/d in that year, but by 1991, exports reached 128 mb/d.

The current glut of waxy, sweet crudes cannot be sustained and is not the only factor affecting export markets. In fact, what may really materialize is a two-tiered market, with larger volumes of heavy, waxy crudes, but also some new supplies of condensate and ultra-light, Gippsland-type (Australia) crudes. It is the mid-grade crudes, just lighter than Minas (Indonesia), that seem to be disappearing from the export market. Heavy crudes will dominate; high-quality crudes will continue to be available in some quantities; but many of the familiar Indonesian streams will be vanishing.

Figure 57. Higher Oil Prices Stimulate Exploratory Drilling: Indonesia's Example, 1967-91



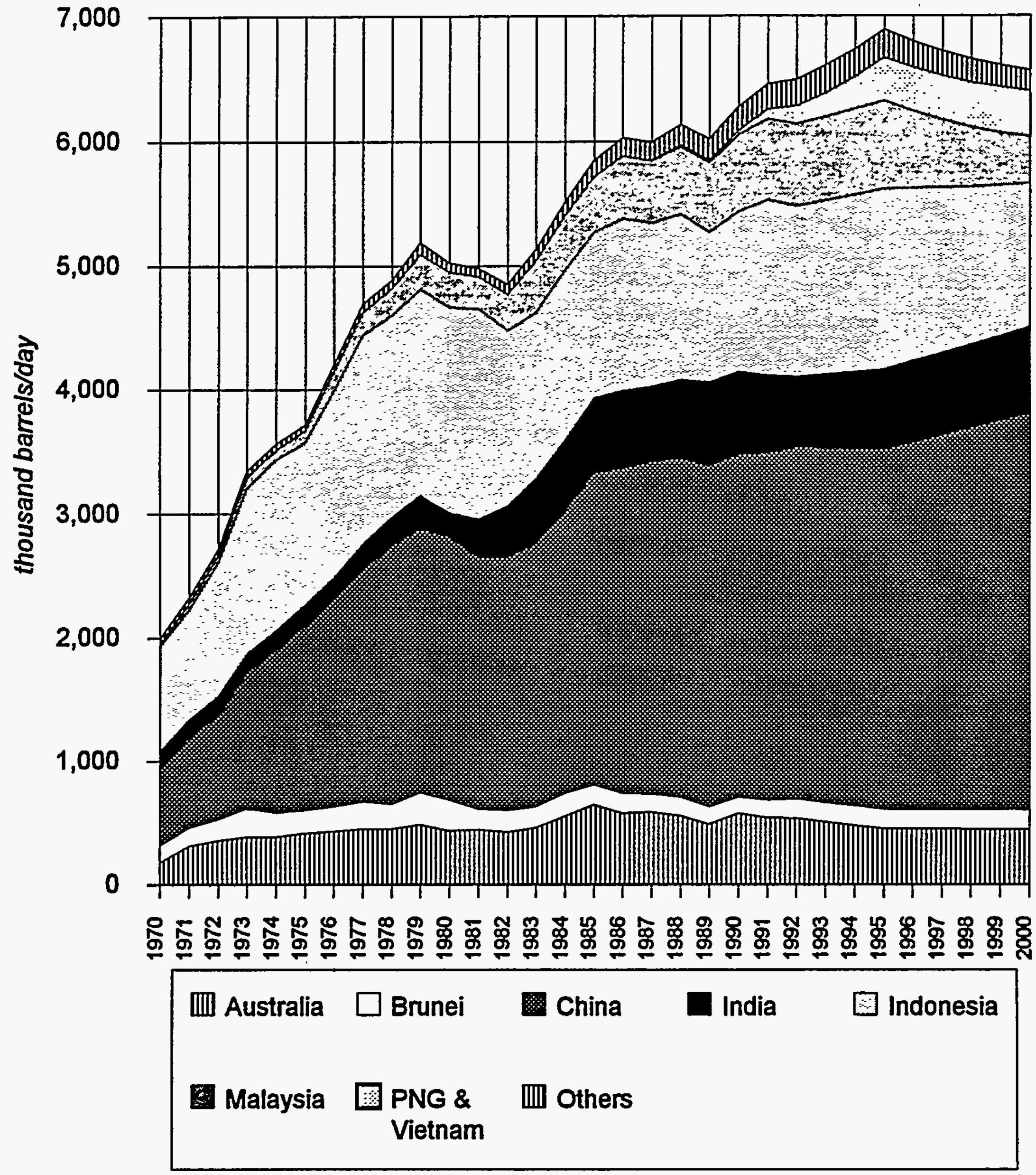
3. Crude Production and Export Availability

Historical and forecast oil production by major producing country, 1970-2000, is presented in Figure 58. The upward trend is impressive; production of around 2 million barrels per day (mmb/d) in 1970 grew to over 5 mmb/d by 1980, and is estimated at 6.5 mmb/d for 1992. Though output has risen markedly, however, the *rates* of increase vary significantly by decade: during the 1970s, output rose at an average rate of over 11 percent per year; during the 1980s, output expanded by just 2 percent per year; and in the 1990 to 1992 period, production has grown by just 1.7 percent per year. Our base case production forecast is shown in the figure; we anticipate expansions in output of around 0.9 percent per year during the 1990-95 period, followed by a slight decline of around 1 percent per year during the 1995-2000 period. After decades of expansion, output is moving toward a period of contraction.

This comes as no surprise to most market observers; in fact, most analysts had been expecting the production decline to be underway by the early 1990s. Instead, recent crude price increases, better exploration and tax terms in many countries, renewed interest in low-sulfur crudes, and increased interest in "new" producers such as Papua New Guinea, Vietnam, and Myanmàr, lead to a more optimistic outlook for Asian crude production than in recent years. Our base case projection sees an increase from 1990 levels of about 6.3 mmb/d to 6.5 mmb/d in 1992, and output is expected to reach around 6.9 mmb/d by 1995, declining only slightly during the 1995-2000 period. This forecast implies a near-term increase in Indonesian and Malaysian production, followed by a gradual decline; a strong and steady increase in Chinese, Vietnamese and Burmese production; and a much slower decline than originally foreseen for Australian output.

This base case outlook contrasts significantly with many pessimistic forecasts that were typical as recently as three to four years ago (and are still, of course, possible). Indonesian and Malaysian oil output were expected to peak briefly in 1991-92 then decline, and rapid declines were forecast for all other producers except Brunei, Myanmar, Vietnam,

Figure 58. Near-Term Growth, Long-Term Decline in Asian Oil Production, 1970-2000



Notes: "Other" comprises Bangladesh, Pakistan, Japan, Taiwan, Philippines, Myanmar, Thailand, and New Zealand. Data for 1993-2000 are projections.

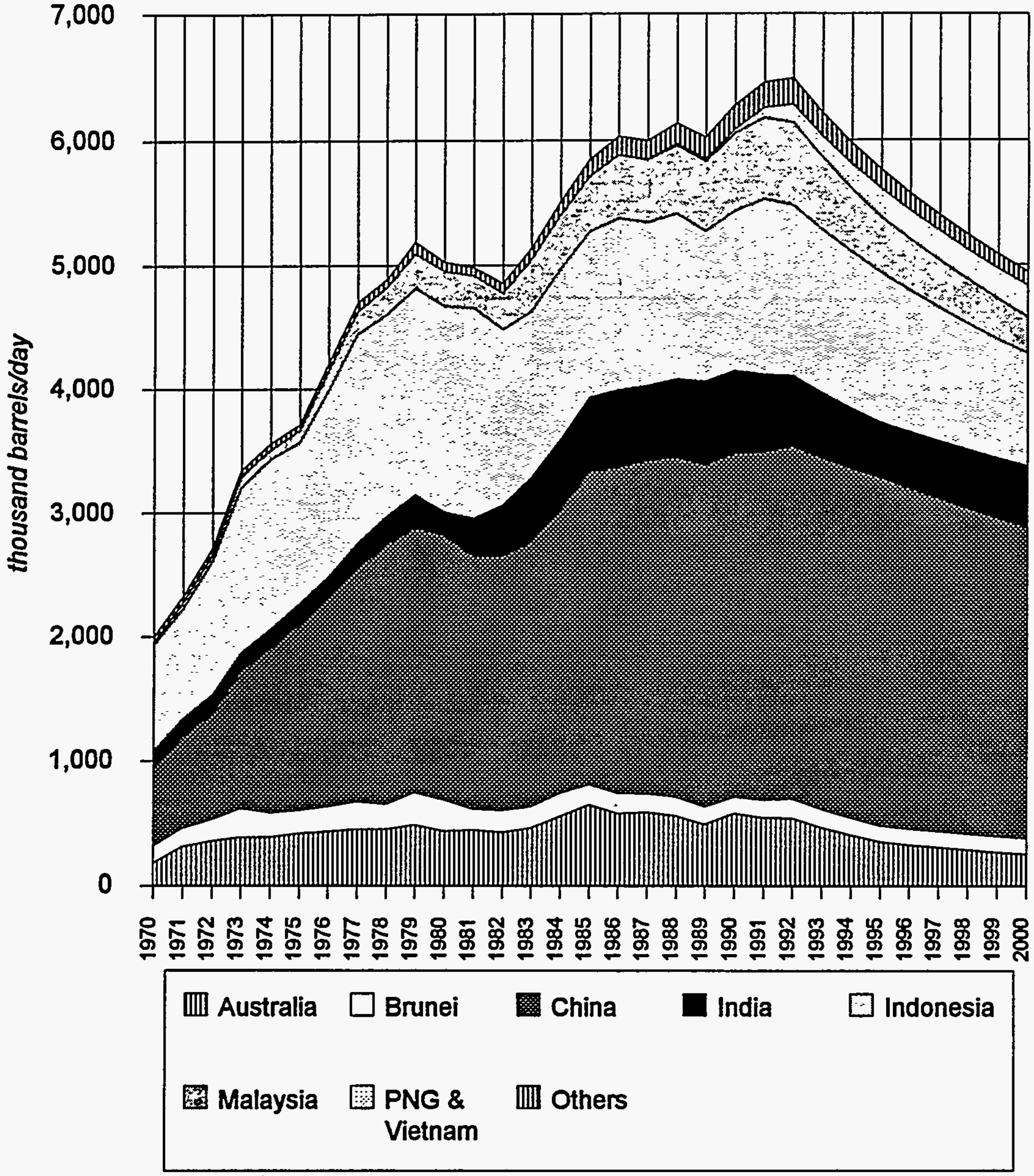
and Papua New Guinea. In total, this pessimistic outlook anticipated a 1.3 mmb/d fall in output by the end of the decade. Our low case forecast is presented in Figure 59, where 1992 marks the peak of output and the decline is thereafter steady and inexorable, bringing production down to 5.8 mmb/d in 1995 and 4.9 mmb/d by the year 2000.

Naturally, it is possible to present a forecast well above the base case forecast. Our high case forecast is depicted in Figure 60. An optimistic forecast would expect steady Australian production; large increases in Chinese and even Indian production; a substantial rise and slow decline in Indonesian and Malaysian production; and large increases in output from Brunei, Papua New Guinea, Myanmar, Vietnam, and the region's minor producers. The net result could be an increase in output of about 2.1 mmb/d between 1990 and 2000, bringing production to an all-time high of 8.4 mmb/d. Indications are that there is undiscovered oil-in-place sufficient to make this forecast a reality; whether it will be found and developed is a matter of financial incentives, transport logistics and, in some countries, a willingness to invite in foreign exploration and production (E&P) firms on favorable terms.

What are the implications of these production scenarios for the export market and Hawaii? The main factor is the volume of crude consumed domestically in Asia. Unfortunately, dozens of cases could be constructed, with varying levels of crude runs in the Asia-Pacific region. To keep matters relatively simple, we will compare the base case production forecasts against the consumption of "own crude" in domestic refining. In the case of crude-short countries such as India, additional output is delivered to the domestic industry if there is sufficient processing capacity.

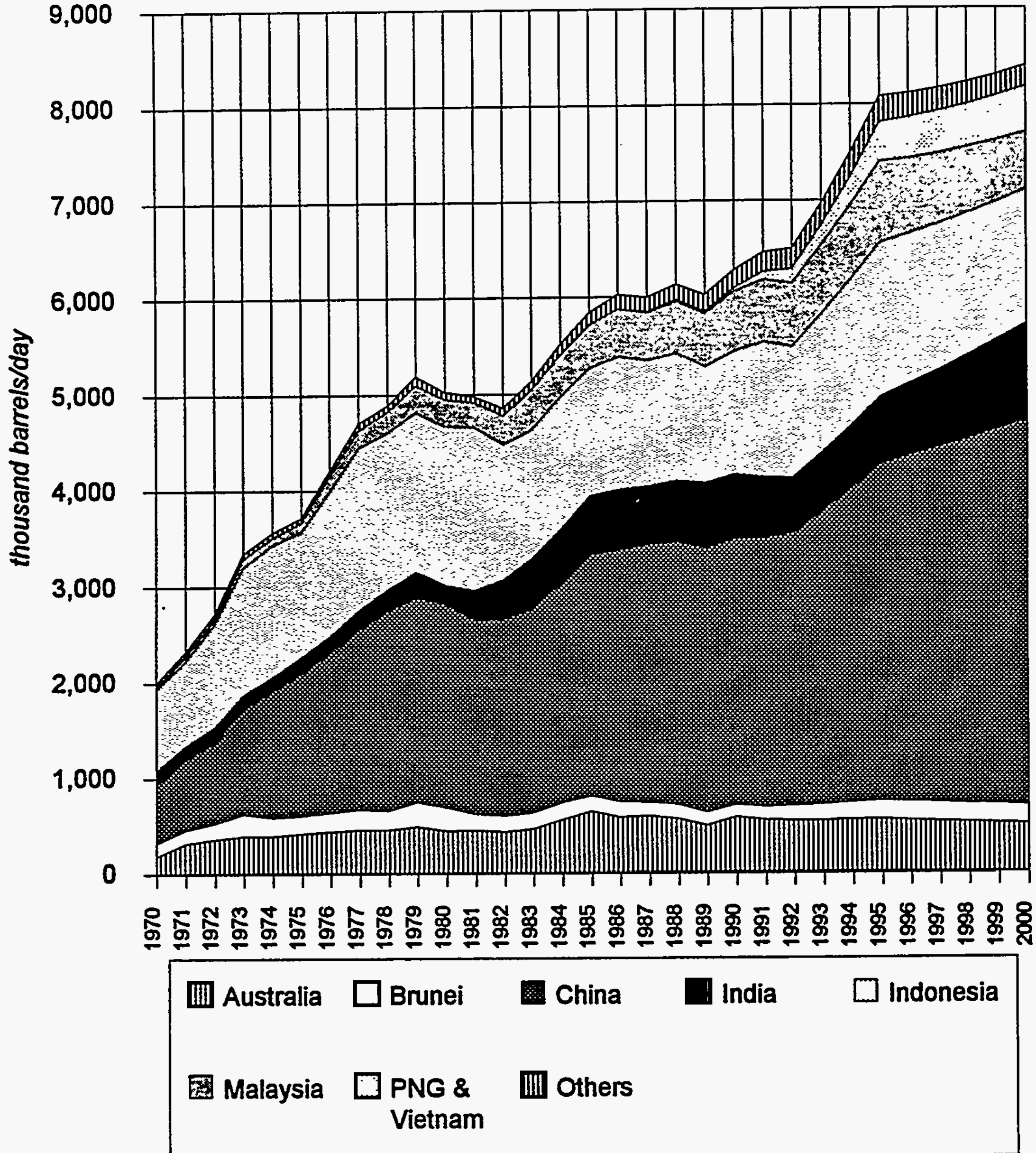
The issue of refining capacity in producing countries is a critical matter in predicting export potential. Plans for capacity additions are discussed in the section on refining; here it is sufficient to note that while Malaysia, Indonesia, India, and Vietnam all have ambitious refining plans, little of this new capacity will be onstream before 1995 (despite government claims to the contrary). Indonesia's example is worth noting; by the end of the 1980s, the government had extremely ambitious plans to move into export refining, which encompassed plans for four new export-oriented (EXOR) refineries. A variety of foreign joint venture

Figure 59. Steady Decline in Asian Oil Production: A Low-Case Forecast, 1970-2000



Notes: "Other" comprises Bangladesh, Pakistan, Japan, Taiwan, Philippines, Myanmar, Thailand, and New Zealand. Data for 1993-2000 are projections.

Figure 60. Can Oil Output Be Sustained in Asia? A High-Case Forecasts, 1970-2000



Notes: "Other" comprises Bangladesh, Pakistan, Japan, Taiwan, Philippines, Myanmar, Thailand, and New Zealand. Data for 1993-2000 are projections.

partners had expressed interest in participating. Yet the cost estimates for building these new refineries escalated to the point where investment capital was insufficient. Only the first project, EXOR 1, is now expected to be operating by 1995, followed by EXOR 3 by the end of the decade. EXORs 2 and 4 are still planned, but are not expected onstream until after the year 2000. In the meantime, after many years of restrained growth, oil demand in Indonesia has been unleashed. Demand grew from 545 mb/d in 1989 to 609 mb/d in 1990, to an estimated 705 mb/d in 1992. Our current forecast of demand is 1.126 mmb/d by the year 2000. Thus, Indonesia's EXORs seem set to become "INDORs"—Indonesian domestic refineries—which will absorb Indonesian crudes as feedstock but will contribute only a limited range of refined products for the export market.

Figure 61 plots crude export availability in the region. We expect an all-time export peak for Asian crudes in the 1992-94 period. Exports are estimated at about 2.2 mmb/d in 1992. The latter half of the decade, however, shows a sharp drop in exports as domestic refinery runs increase; exports in 2000 are only about 630 mmb/d. The biggest factors in the early-1990s peak are the new Indonesian streams (Intan, Widuri, and Duri steamflood), and increases in Chinese production which have outstripped the rate at which the Chinese can complete refinery expansions. The biggest variable is the Chinese production level; if the Chinese are unable to meet production goals, then a slow decline in Asian crude availability could begin immediately, turning into a rapid downhill slide in the second half of the decade.

Given current trends, three of today's significant exporters—China, Indonesia, and Australia—will drop out of the export market entirely. Malaysian exports are also expected to fall rapidly during the latter half of the decade. Of the major exporters, only Brunei is expected to maintain a steady level of crude exports during the 1990s.

4. Asia-Pacific Demand and Demand Patterns

Figure 62 shows product demand in the Asia-Pacific region for the period 1971-92. As elsewhere in the world, the upward trend in demand was dampened by the oil price shocks of the 1970s, with the more noticeable slump occurring in the early 1980s. In the

Figure 61. Asia-Pacific Crude Production and Export Availability, 1992-2000

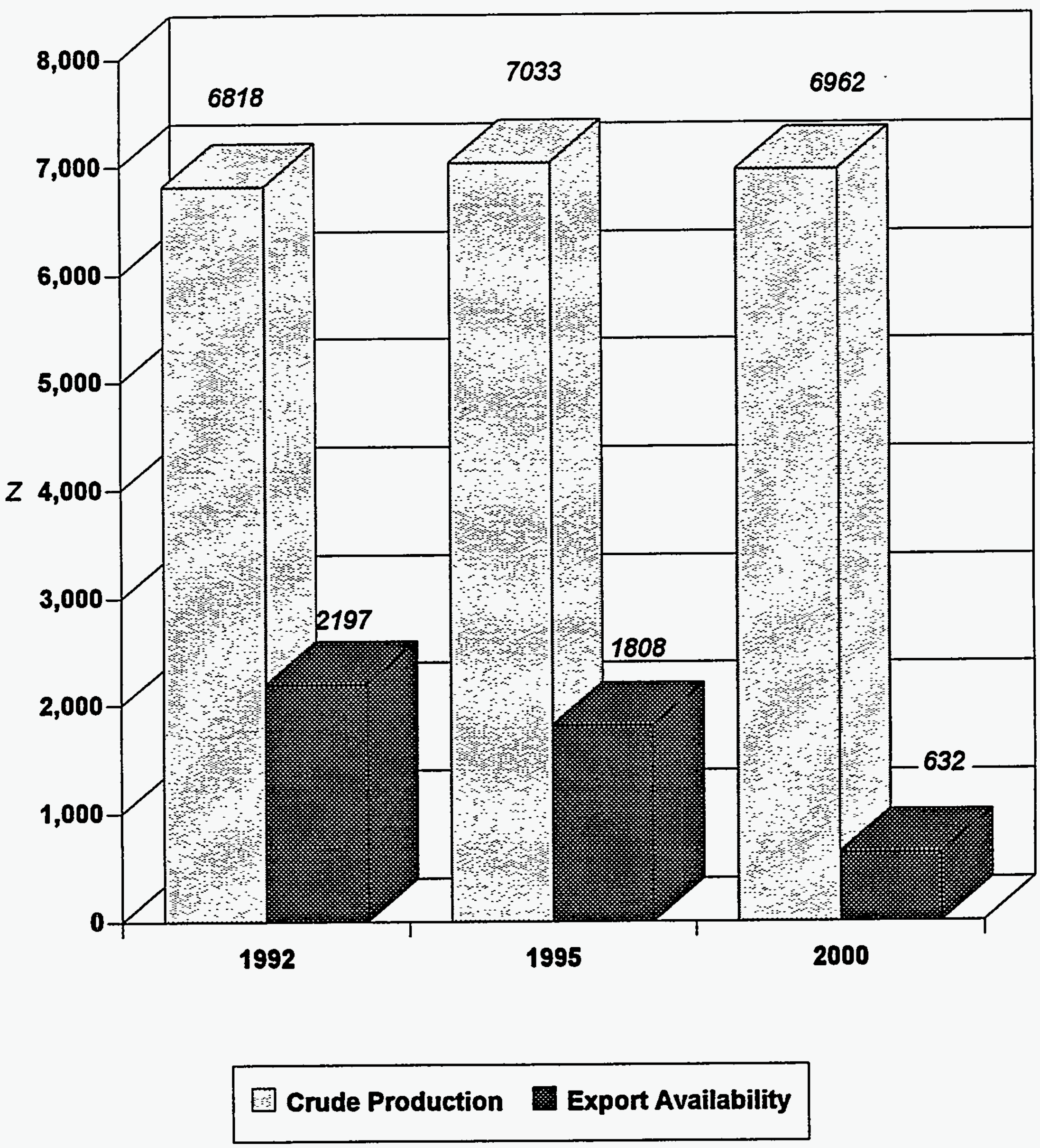
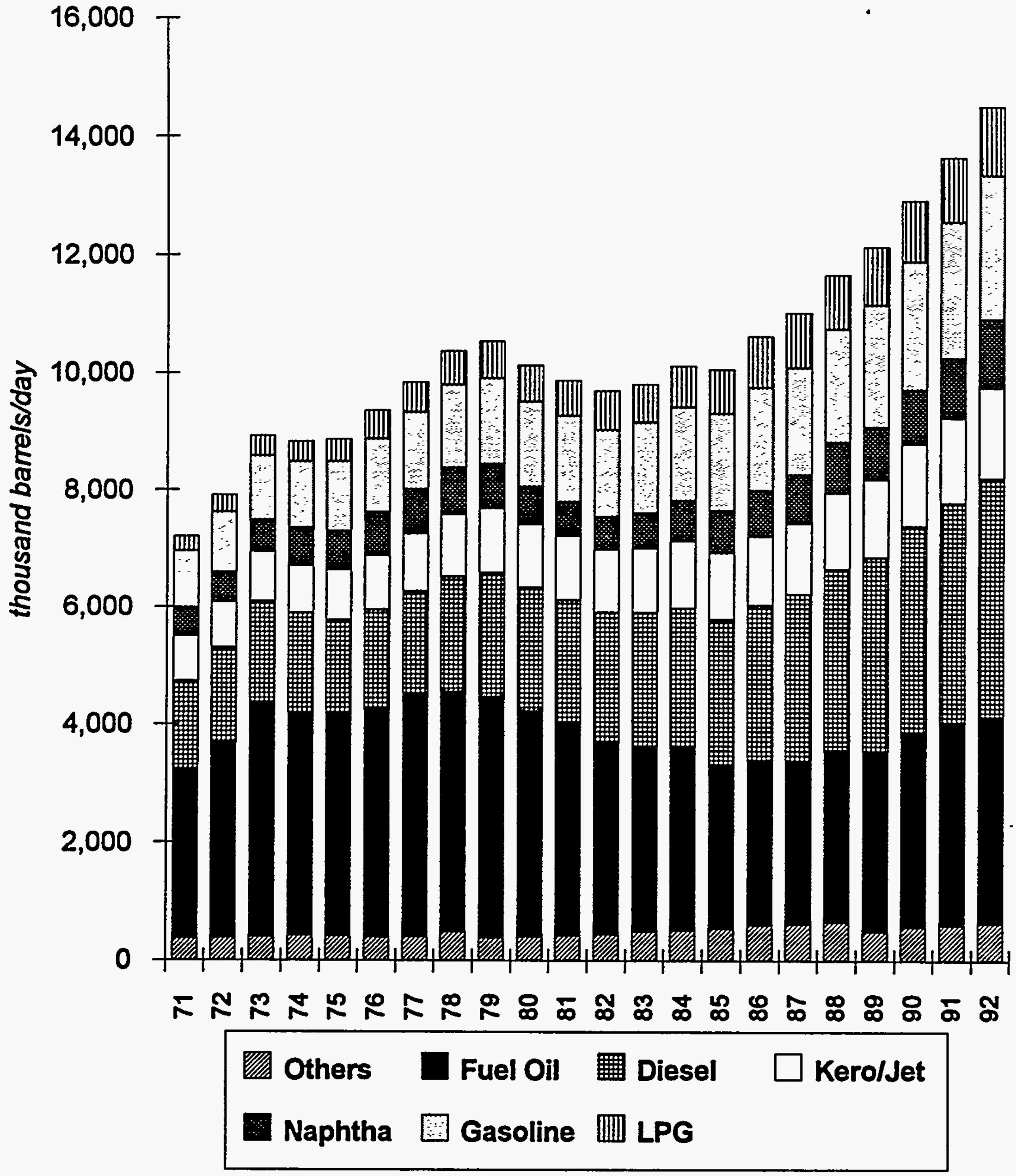


Figure 62. Asian Oil Demand by Product, 1971-92



late 1980s, there was a strong demand recovery; by 1986, demand was back at its 1979 peak levels, and by 1990, demand was well above historic highs, reaching approximately 12.9 mmb/d. Demand continued to grow in the early 1990s, reaching 13.6 mmb/d in 1991 and 14.5 mmb/d in 1992, translating into growth rates of around 6 percent per annum.

It is unlikely that this growth rate will be maintained, although if oil prices weaken again in the early 1990s, 5 percent annual growth could be the rule of the day. The absolute increases in demand are huge, but the whole of Asia still consumes less oil than the United States or Western Europe.

Following the oil price shocks of the 1970s, the demand recovery was much stronger in Asia than in other regions of the world. For products lighter than fuel oil, demand was also more resilient in the post-1979 slump. As Figure 63 shows, if fuel oil and "other" heavy products are removed from the data, oil demand merely levelled off; the decrease in demand for transport fuels, naphtha, and liquid petroleum gas (LPG) was negligible, and the takeoff in growth of these fuels in the late 1980s was astonishing. By the end of the 1980s, fuel oil demand was back at about its 1971 level, but demand for products lighter than fuel oil was more than double its 1971 level.

The result of these changes has been a substantial shift in the composition of demand. As Table 14 shows, fuel oil's share of the barrel has fallen from its level of 39-45 percent in the early 1970s to about a quarter of demand in the late 1980s and early 1990s. Kerosene and naphtha have essentially maintained their shares across the period. Gasoil has risen from 19-20 percent of the barrel in the early 1970s to about 27-28 percent in the late 1980s and early 1990s; continued growth may raise gasoil's share of the demand barrel to nearly 32 percent by the end of the decade. The largest relative growth has been in LPG, which has more than doubled its share of the barrel in the last two decades. A surprise to many might be the trend in gasoline's share of the barrel; gasoline has risen from 13 percent of the barrel to about 17 percent of the barrel, and the rise has been remarkably prolonged and steady. Asia was historically noted as a poor gasoline market, and there was much disbelief when the gasoline market came under some stress in the late 1980s, but the table allows us to see the

Figure 63. Asian Was Barely Affected by the Oil Price Shocks of the 1970s: Oil Demand (Excluding Fuel Oil and Other Heavy Products), 1971-92

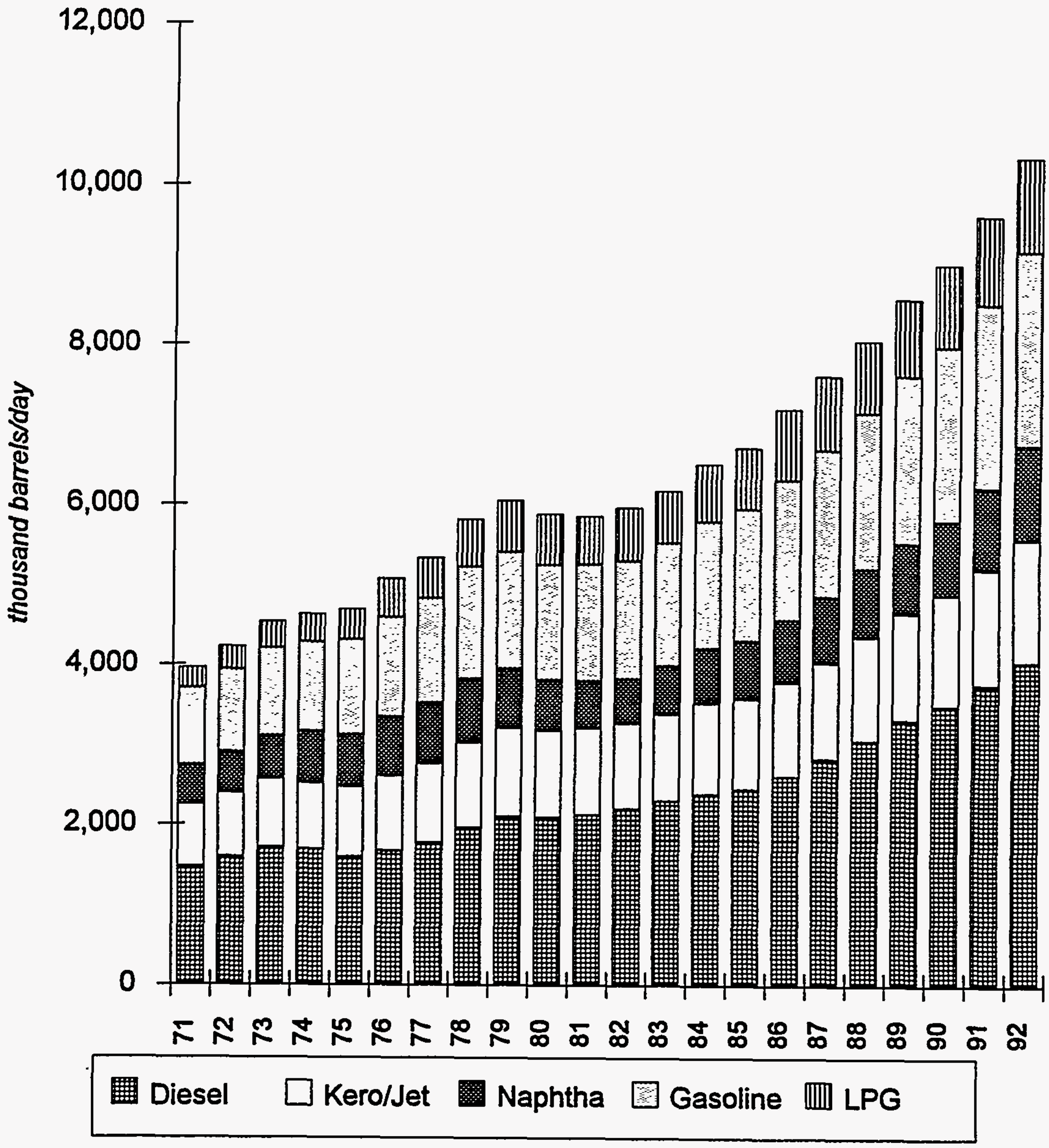


Table 14. Demand Shares by Product in the Asia-Pacific Region, 1971-2000 (%)

Year	Others	Fuel Oil	Diesel	Kero/Jet	Naphtha	Gasoline	LPG
1971	5.2	39.9	20.5	10.6	6.8	13.4	3.6
1972	4.8	0.4	20.2	10.0	6.4	13.1	3.7
1973	4.5	0.4	19.2	9.5	6.0	12.3	3.7
1974	4.8	0.4	19.2	9.3	7.3	12.7	3.9
1975	4.7	0.4	18.1	9.8	7.4	13.4	4.2
1976	4.2	0.4	17.9	10.0	7.9	13.3	5.2
1977	4.1	0.4	18.1	10.0	7.7	13.3	5.2
1978	4.6	0.4	18.9	10.3	7.6	13.5	5.7
1979	3.6	0.4	20.0	10.6	7.0	13.9	6.1
1980	4.0	0.4	20.7	10.8	6.2	14.2	6.3
1981	4.3	0.4	21.5	11.1	5.9	14.8	6.1
1982	4.6	0.3	22.8	11.2	5.7	15.2	6.8
1983	5.0	0.3	23.5	11.2	6.1	15.7	6.6
1984	5.1	0.3	23.6	11.4	6.7	15.7	6.9
1985	5.4	0.3	24.4	11.3	7.2	16.4	7.5
1986	5.7	0.3	24.6	11.2	7.3	16.5	8.3
1987	5.7	0.3	25.7	11.0	7.5	16.5	8.4
1988	5.7	0.3	26.3	11.1	7.4	16.6	7.8
1989	4.1	0.2	27.5	11.0	7.3	17.1	8.1
1990	4.5	0.3	27.1	10.8	7.1	16.8	8.0
1991	4.4	0.2	27.6	10.6	7.5	16.9	8.0
1992	4.4	0.2	27.9	10.6	8.0	16.8	8.1
1993	4.4	0.2	28.4	10.7	8.1	16.9	8.0
1994	4.3	0.2	28.9	10.7	8.2	17.1	8.0
1995	4.3	0.2	29.3	10.7	8.3	17.2	8.0
1996	4.3	0.2	29.8	10.7	8.3	17.4	8.0
1997	4.3	0.2	30.3	10.7	8.3	17.6	8.0
1998	4.3	0.2	30.8	10.6	8.3	17.8	8.0
1999	4.3	0.2	31.2	10.6	8.2	18.0	8.0
2000	4.3	0.2	31.7	10.6	8.2	18.2	8.0

gasoline boom of the late 1980s for what it really was: the continuation of a long-term trend, with gasoline claiming an increasing share of an increasing total volume of consumption.

Figure 64 and Table 15 give our base case outlook for Asian demand, based on gradually strengthening oil prices in the 1990s, a gradual slowdown in economic growth in the more advanced economies, and continued rapid growth in Asia's less developed economies. Fuel oil moves up only slightly through 1995, and then falls back modestly—the result of short-term revival of oil-fired capacity brought online because of generation shortages in many countries. Naphtha for petrochemical use shows the greatest short-term growth, but it is gasoil demand that grows most significantly over the whole of the decade.

In this scenario, Asian demand rises from about 14.5 mmb/d in 1995 to 16.4 mmb/d in 1995, a growth rate of over 4 percent per annum. The rate of increase slows after 1995 to 3.1 percent per annum, but this still adds almost 3 mmb/d to demand by 2000, when demand reaches a total of 19.1 mmb/d.

Figure 65 shows the effect of the base case demand projection on the composition of the demand barrel. Although the most dramatic whitening of the barrel took place in the 1973-85 period, the continued growth in transport fuels with stagnant demand levels for fuel oil results in a steadily declining fuel oil share. The biggest gainer is gasoil, whose share continues to expand throughout the decade; other products maintain relatively constant shares of a growing total. During the 1990-2000 period, we forecast growth in diesel demand at 5.7 percent per year.

It is hard for many analysts to imagine an Asian oil market of 17-19 mmb/d; the early and mid-1980s made observers too accustomed to a steady demand of around 10 mmb/d. What this 10 mmb/d demand masked was a steady decline in fuel oil canceled out by a steady increase in other fuels; when the fuel oil decline ended, the steady growth in the rest of the barrel became apparent.

The methodology employed here has been on a country-by-country basis; the total for Asia is simply the sum of country analyses. Most country experts will be inclined to accept

Figure 64. The Oil Demand Boom Continues in Asia: Demand by Product, 1971-92, and Projections to 2000

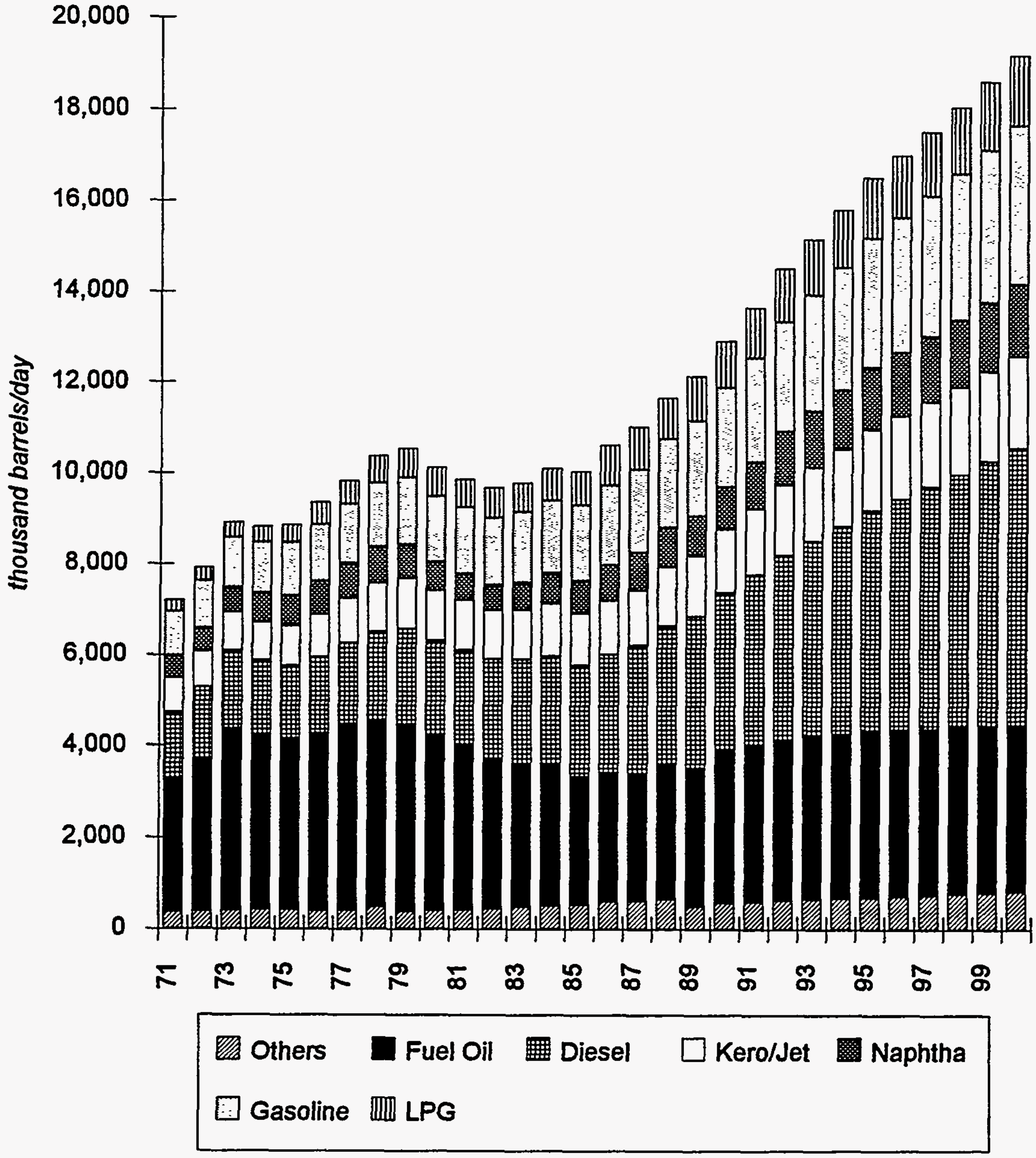


Table 15. Asia-Pacific Product Demand by Country, 1990-20/a
(thousand barrels/day)

Country	Year	Others	Fuel Oil	Diesel	Kero/Jet	Naphtha	Gasoline	LPG	Total
Australia	1990	39.7	37.9	174.4	59.3	0.3	294.4	60.8	666.8
	1991	34.0	35.9	170.5	62.7	0.5	290.5	53.5	647.6
	1992	36.1	36.3	175.2	64.9	0.7	295.0	60.7	668.9
	1995	38.4	35.8	193.4	73.9	0.7	310.0	66.0	718.0
	2000	40.6	35.3	222.8	89.2	0.8	333.0	74.9	796.6
Brunei	1990	0.2	0.0	1.4	0.6	0.0	3.7	1.5	7.4
	1991	0.2	0.0	1.2	0.6	0.0	3.8	1.6	7.4
	1992	0.2	0.0	1.0	0.5	0.0	3.8	1.8	7.4
	1995	0.3	0.0	0.7	0.4	0.0	3.9	2.3	7.6
	2000	0.3	0.0	0.5	0.6	0.0	4.5	3.0	8.9
China	1990	132.7	623.5/b	618.7/c	72.7	57.1	454.7	84.0	2,043.4
	1991	133.9	614.6/b	710.4/c	79.3	72.7	514.7	97.9	2,223.5
	1992	147.5	647.4/b	801.3/c	83.9	82.9	562.2	106.8	2,432.0
	1995	138.0	721.4/b	946.4/c	85.0	129.6	701.0	129.0	2,850.4
	2000	190.0	824.0/b	1,342.5/c	99.0	189.5	1,030.0	189.0	3,864.0
India	1990	63.0	166.0	418.0	212.0	90.0	76.0	70.0	1,095.0
	1991	102.3	166.1	431.7	215.0	85.0	85.0	77.9	1,163.0
	1992	113.2	174.6	453.7	220.6	91.8	89.6	81.3	1,224.9
	1995	147.0	191.1	555.8	254.9	126.8	107.8	110.8	1,494.2
	2000	183.8	206.2	660.1	287.8	167.2	126.0	144.3	1,775.3
Indonesia	1990	21.6	72.7	233.2	153.4	12.3	109.6	6.8	609.6
	1991	20.0	87.0	255.8	159.5	15.6	118.3	7.7	663.9
	1992	21.0	87.0	276.0	168.0	18.0	127.2	8.0	705.2
	1995	29.0	82.0	382.0	190.0	36.0	149.0	10.0	878.0
	2000	35.0	65.0	541.0	231.0	45.0	195.0	14.0	1,126.0
Japan	1990	151.0	1,275.0/d	1,102.0	517.0	536.0	766.0	587.0	4,934.0
	1991	146.0	1,225.0/d	1,155.0	532.0	561.0	789.0	607.0	5,015.0
	1992	143.0	1,228.0/d	1,173.0	550.0	603.0	807.0	618.0	5,122.0
	1995	150.0	1,162.0/d	1,323.0	615.0	590.0	870.0	650.0	5,360.0
	2000	150.0	1,029.0/d	1,512.0	663.0	582.0	949.0	710.0	5,595.0
Malaysia	1990	7.0	56.0	72.0	17.0	0.0	57.0	14.0	223.0
	1991	5.4	56.0	75.0	18.0	0.0	69.0	14.2	237.6
	1992	6.2	49.4	78.7	18.5	0.0	74.5	16.3	243.7
	1995	9.4	34.0	91.0	20.0	0.0	94.0	24.7	273.1
	2000	12.0	9.0	116.0	23.0	15.0	98.0	41.0	314.0
New Zealand	1990	3.2	7.2	22.7	15.8	0.0	45.6	4.0	98.5
	1991	6.4	6.2	23.6	13.7	0.0	44.7	4.0	98.5
	1992	3.9	8.5	24.3	15.1	0.0	45.3	3.2	100.3
	1995	4.4	5.5	26.2	17.6	0.0	48.5	3.8	106.1
	2000	4.8	5.5	28.2	22.0	0.0	53.1	3.8	117.5
Philippines	1990	0.8	85.6	71.5	20.9	0.7	35.3	12.6	227.4
	1991	0.9	82.0	81.2	20.5	0.5	30.3	13.0	228.4
	1992	0.9	98.7	100.2	25.2	0.6	36.3	14.7	276.6
	1995	1.0	103.3	89.3	27.5	0.6	38.7	18.7	279.1
	2000	1.1	123.5	111.0	34.7	0.7	47.7	25.4	344.1
Singapore	1990	3.0	233.0	46.0	36.0	22.0	12.0	11.0	363.0
	1991	2.9	259.2	41.2	38.5	20.9	11.4	10.5	384.6
	1992	3.1	257.1	44.5	40.0	22.8	12.1	11.0	390.6
	1995	3.6	251.0	56.0	44.9	29.4	14.6	12.6	412.1
	2000	4.0	265.0	66.0	53.0	37.0	17.0	14.0	456.0

Table 15. (continued)

Country	Year	Others	Fuel Oil	Diesel	Kero/Jet	Naphtha	Gasoline	LPG	Total
South Korea	1990	16.6	295.5	266.3	108.5	130.0	64.9	97.8	979.5
	1991	20.2	386.2	320.6	116.8	179.9	78.7	118.2	1,220.6
	1992	25.4	408.9	383.8	146.8	259.1	95.3	150.4	1,469.7
	1995	31.4	450.2	485.3	185.3	316.6	150.9	184.9	1,804.6
	2000	39.9	456.3	618.6	223.4	323.3	205.2	180.2	2,046.9
Taiwan	1990	100.0	222.0	80.0	18.0	60.0	94.0	40.0	614.0
	1991	88.0	233.0	86.0	20.0	65.0	102.0	39.0	633.0
	1992	95.0	233.0	85.0	25.0	65.0	107.0	42.0	652.0
	1995	103.0	245.0	94.0	23.0	100.0	120.0	49.0	734.0
	2000	110.0	222.0	95.0	26.0	151.0	135.0	54.0	793.0
Thailand	1990	9.9	88.8	169.0	39.0	0.0	64.0	31.0	401.7
	1991	10.3	104.4	169.0	43.0	3.9	63.1	37.0	430.7
	1992	12.1	121.8	182.0	50.0	4.7	70.3	37.0	477.9
	1995	14.6	196.2	271.2	65.0	28.8	95.5	42.9	714.2
	2000	18.3	216.2	385.9	91.4	44.2	133.9	62.1	952.0
Vietnam	1990	16.0/e	12.5	12.7	4.6	0.0	6.9	0.3	53.0
	1991	20.0/e	13.5	20.0	4.6	0.0	7.5	0.4	66.0
	1992	20.0/e	14.9	35.0	5.7	0.0	8.6	0.4	84.7
	1995	20.8/e	20.1	39.0	11.2	0.0	12.7	0.6	104.4
	2000	20.2/e	24.1	52.1	13.1	0.0	20.5	1.2	131.3
Other Asia /f	1990	9.7	125.0	206.0	114.0	8.8	84.0	12.0	559.5
	1991	10.0	130.0	218.0	118.0	9.5	90.0	13.0	588.5
	1992	10.6	133.3	230.0	123.9	10.0	95.0	13.6	616.3
	1995	12.4	143.5	270.1	143.4	11.8	111.5	15.7	708.4
	2000	14.0	157.7	313.1	166.3	13.3	129.3	18.8	812.4
Total	1990	574.4	3,300.7	3,493.9	1,388.8	917.2	2,168.1	1,032.8	12,875.8
	1991	600.5	3,399.1	3,759.2	1,442.2	1,014.5	2,298.0	1,094.9	13,608.3
	1992	638.1	3,498.9	4,043.7	1,538.2	1,158.6	2,429.3	1,165.2	14,472.0
	1995	703.2	3,641.2	4,823.3	1,757.1	1,370.3	2,828.1	1,321.0	16,444.2
	2000	824.0	3,638.8	6,064.8	2,023.6	1,569.0	3,477.2	1,535.6	19,133.0
AAGR	1990-91	4.5%	3.0%	7.6%	3.8%	10.6%	6.0%	6.0%	5.7%
AAGR	1991-92	6.3%	2.9%	7.6%	6.7%	14.2%	5.7%	6.4%	6.3%
AAGR	1992-95	3.3%	1.3%	6.1%	4.5%	5.8%	5.2%	4.3%	4.4%
AAGR	1990-00	3.7%	1.0%	5.7%	3.8%	5.5%	4.8%	4.0%	4.0%
AAGR	1995-00	3.2%	0.0%	4.7%	2.9%	2.7%	4.2%	3.1%	3.1%

a. 1990-1991 are actual demand.
b. Includes direct burning of crude oil for electricity generation.
c. Includes gasoil-range chemical feedstock.
d. Includes direct burning of crude and NGL for electricity generation.
e. Includes estimated Vietnamese military demand for oil products.
f. Afghanistan, Bangladesh, Bhutan, Cambodia, Hong Kong, Laos, Maldives, Mongolia, Macao, Myanmar, Nepal, North Korea, Pakistan and Sri Lanka, plus Pacific Islands.

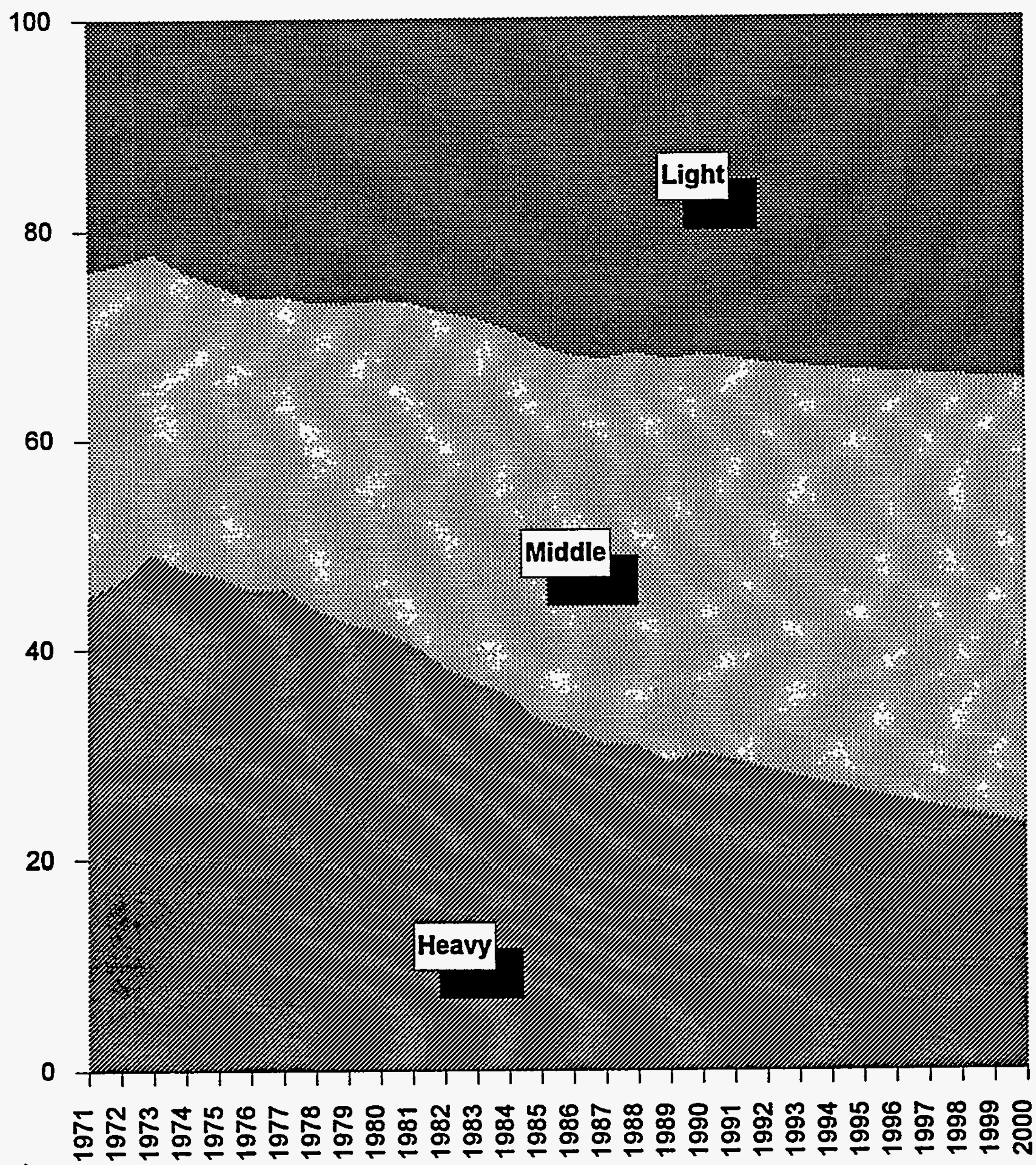
the projections for the individual country they specialize in; it is the grand total that is difficult to swallow. For the reader who has difficulty digesting demand increases of 3-6 mmb/d over the coming decade, we can only suggest a closer examination of the individual countries involved, their populations, and their plans for economic growth and industrialization.

A fact that should not be overlooked, however, is that India and China comprise a substantial fraction of the total increase in demand. It is impossible in these two countries to untangle demand from supply; much of the demand that will be allowed to emerge in these two countries is dependant on the level of success in increasing oil production. Both will be net oil importers in the 1990s (India, of course, to a much greater extent than China), but a large fraction of their demand effectively stands "outside the market," balanced against internal supplies. Both are very short of oil relative to their development needs (not to mention relative to their environmental needs in terms of limiting current levels of coal burning); higher oil supply would mean higher consumption. Much like the "net CPE exports" concept (CPE, the centrally planned economies), often employed in analyzing the former Soviet Union and Eastern Europe relative to the world market, it is the net pull on the market rather than the absolute levels of demand that are of greatest interest in India and China. It is unlikely that we would see low case demands for South Korea materialize at the same time as high case demands for Japan, since these two countries are driven by essentially similar market factors. There is no basic reason, however, that low case demand growth for China cannot coexist in a world where high case demands are seen in other Asian countries. Thus, although India and China are presented in the same tables as the other nations, trends in other nations may not be a good indicator of trends in these two countries in future years.

5. Petroleum Product Specifications and Environmental Legislation

Unlike a region such as Western Europe, there are no generalizations that can be

Figure 65. Asia-Pacific Demand Barrel Continues to Lighten: Demand Patterns, 1971-2000



Note: Data for 1993-2000 are projections.

made about environmental legislation in the Asia-Pacific region. Product specifications range from some of the most stringent in the world (Japan) to countries such as India, where even kerosene for cooking and lighting may contain up to 0.25 percent sulfur. Furthermore, there are a number of countries where specifications are lax, such as China, but the products actually in use are rather environmentally benign. Chinese crudes are naturally low in sulfur, and most gasoline is unleaded because of the high cost of tetraethyl lead (TEL).

Japan is without a doubt the leader in product specifications. All gasoline is unleaded; sulfur standards on fuels match or exceed those found in any OECD country. After Japan come Australia and New Zealand, which also have relatively strict sulfur specs, but where leaded gasoline is just entering phaseout.

In the next group are South Korea and Taiwan, which until recently had extremely limited controls on emissions and pollution in general. In both these countries, there has been an unprecedented surge in environmental concern. Not long ago, it was legal to burn 4 percent sulfur fuel oil in either country; both have phased in 1 percent-1.5 percent sulfur grades and are moving to tighten fuel oil sulfur specifications down to 0.5 percent by 1996, if possible. Both are also imposing increasingly strict controls on gasoil. South Korea is phasing out leaded gasoline by 1995; Taiwan has effectively moved to unleaded by allowing a maximum content of 0.026 gram per liter (g/l), and full phaseout should come soon.

A step below South Korea and Taiwan are the ASEAN countries, where product specs are still quite loose, but where mounting concern has made serious action on environmental issues likely in the next few years. Singapore, Thailand, and Malaysia have lowered allowable lead content from 0.4 g/l to 0.15 g/l; Indonesia's standard is 0.4 g/l; and the Philippines has moved from 0.84 g/l to 0.4 g/l in its regular grade and to 0.6 g/l in its premium grade. Indonesia has announced a program of full lead phaseout, and it is likely that Malaysia, Singapore, and Thailand will follow suit. Sulfur standards are still fairly lax (although this matters little in Indonesia because of the sweet crudes that dominate the slate), but reductions in diesel sulfur are under study, and it is likely that controls on fuel oil sulfur will be put in place in the next decade.

Finally, there are China and the poor countries of South Asia. The level of environmental concern on the part of both citizens and policy makers in these countries is often underrated; what is lacking is the economic ability to confront the problem. Surprisingly, there is discussion in India of reducing lead content in gasoline; Indian gasoline consumption is so low that the per capita lead output in the country is minuscule. In any case, improving petroleum product specifications in these countries represents the proverbial drop in the bucket. Most of the pollution comes from the enormous consumption of coal and other fuels; in China, the coal consumption is equivalent to about 15 mmb/d of oil.

The enormous volume of coal consumed in Asia poses problems on a regional basis. For example, South Korea severely tightened emission controls in the 1980s, but its pollution and acid rain problems continue to mount because of what blows in from neighboring China. Much Japanese pollution also originates on the mainland. As a recent visitor from Japan expressed it, "We breathe Chinese air." From the perspective of environmental quality, instead of tightening domestic standards further, much more could be gained from helping China clean up its pollution problems; the spillover is huge.

Planned and Proposed Sulfur Reductions

South Korea has recently adopted a 1 percent sulfur standard on urban fuel oil. There are 3.5 percent grades being burned in rural areas, but these high-sulfur fuel oils are being phased out in favor of 1 percent to 2.5 percent grades. The standard for urban fuel oil sulfur may be cut to 0.5 percent by 1996. Diesel sulfur has been cut to 0.5 percent for industrial uses and 0.2 percent for transport uses. The 0.5 percent standard will also be applied to industrial diesel oil (IDO) by 1996.

Taiwan's IDO has moved to a tighter sulfur spec, currently 0.5 percent with a longer term plan to move to 0.2 percent. The ADO sulfur spec is currently a bit high at 0.4 percent, but Taiwan hopes to move to a very strict 0.05 percent sulfur spec, possibly as early as 1996. Hong Kong has likewise been exploring the possibility of moving to the 0.05 percent standard.

In Japan, there are plans to move toward a 0.05 percent standard on gasoil similar to that proposed for parts of the United States; the change is planned by 1996, though some refiners feel that it will be difficult to meet such a target. Currently, the diesel sulfur maximum is 0.2 percent.

In Thailand, gasoil specs have recently moved to a uniform 0.5 percent sulfur level; grades had been running as high as 1.5 percent. Thailand plans to tighten the standard to 0.25 percent by 1996. Malaysia will be reducing its ADO sulfur spec from 0.5 percent currently to 0.2 percent by 1996 and its IDO sulfur spec from 1 percent currently to 0.5 percent. Throughout ASEAN, there is talk of cutting fuel oil sulfur, but thus far no specific action has been taken.

In general, the early 1990s are likely to see a flurry of environmental initiatives; South Korea and Taiwan are likely to move toward Japanese standards; ASEAN countries are likely to move toward former South Korean standards; and the poorer countries are likely to try to catch up with where ASEAN is today. The biggest hurdle will be fuel oil sulfur content; middle distillate sulfur can be reduced fairly cheaply, but fuel oil desulfurization, even via the route of desulfurizing vacuum gas oil (VGO) and reblending, is an expensive proposition, and it appears that low-sulfur crudes will be less available relative to the demand for low-sulfur products.

<u>Octane and Lead Levels in Gasoline</u>

It may come as a surprise to many, but the majority of the gasoline sold in Asia is already unleaded. This is not so much because unleaded gasoline is a widespread commodity, but mainly because the largest consumers are mostly unleaded—Japan is fully unleaded and the majority of China's gasoline is also unleaded. Beyond this, small volumes of unleaded are sold in Australia, South Korea, Taiwan, Hong Kong, Thailand, Malaysia, Singapore, and New Zealand.

The typical leading level in leaded gasoline in Asia in 1989 was 0.4 g/l. The average content of the leaded pool was 0.42 g/l. Averaged over the whole Asian pool, the estimated clear RON is about 88.4, and the average lead level (including unleaded volumes) was about 0.16 g/l.

In 1990, there was a spate of lead reductions, typically a move down from a maximum of 0.4 g/l to 0.15 g/l. The level of 0.15 g/l will be dominant in the next few years, but many countries that have made this reduction have stated their intention of moving to a lead-free pool. Malaysia, Indonesia, Singapore, South Korea, and Taiwan are all likely to be lead-free by 1996, or shortly thereafter, and Australia and Thailand should be well on their way. In addition, the Philippines, India, and a number of minor countries are likely to reduce maximum allowable leading levels by 1996. Thus, by 1996, around three-fourths of Asian gasoline demand is likely to be unleaded. Furthermore, the average leading levels of leaded grades will drop from 0.42 g/l to 0.3 g/l. Clear RON, on the other hand, will rise, from a 1989 level of 88.4 RONC to about 90.2 RONC.

By 2000, the Asian gasoline pool is likely to be perhaps as much as 85-90 percent unleaded, with leading restricted largely to South Asia. The octane of the overall pool will rise even further, to about 91.5 RONC. A grade of 92 RON unleaded will probably emerge as the dominant gasoline grade in Asia.

It may seem improbable that Asian countries will move so fast on the leading issue, especially for those who remember the bitter controversy surrounding this issue in the United States. Yet many countries—South Korea and Taiwan, most notably—have already initiated programs that will carry them into a virtually lead-free pool within the next few years, with little fanfare and little industry debate. What needs to be understood is that moving away from lead in most Asian countries will be far easier than it ever was in the United States or Europe. For most countries in the Asia-Pacific region (outside of China and Taiwan), octane supplies are not stretched; many, perhaps the majority, have unreformed heavy naphtha or other intermediate streams that can be upgraded fairly cheaply. With gasoline at such a small fraction of the barrel compared to the United States, a clear pool octane of 92 RON is not terribly difficult to achieve—especially if the Reid vapor pressure (RVP) is not tightly controlled, and if there are no plans for reductions in aromatics. Furthermore, some countries such as Malaysia and Indonesia may have significant methyl tertiary butyl ether (MTBE) capacity onstream by the time that any octane pinch is felt, and this provides yet another possible source of octane enrichment.

Indeed, a cynic might suggest that the moves to control lead in gasoline in most of these countries is a way of appearing to be concerned about the environment while avoiding more important and less tractable pollution problems. The volume of gasoline consumed is small; the volume of high-sulfur gasoil and fuel oil burned in the region is very large, and much of the burning takes place in high-density urban settings. If phasing out of lead in gasoline is merely a first step in a broader program of environmental control, then it may be seen as a reasonable starting place; but if it is meant to substitute for the specification changes that are needed regarding the sulfur contents of products, or the emissions from coal burning, then the effect on the state of the environment in most countries will be negligible.

Policies Affecting Fuel Choice: Nuclear Power, CO2, and Acid Rain

Most of Asia is still confined to using whatever sources of fuel for power generation are cheapest and most available. In East Asia, however, rising affluence and environmental concern are making fuel choices in power generation a major political issue. This is nothing new to those experienced with the situation in the United States or Europe, but in East Asia the choices are more pressing because of the growth in electricity demand. Major commitments must be made in the 1990s.

Major concerns in Japan, Taiwan, and South Korea are security of supply, safety, and pollution. The main emphasis in pollution is on emissions of sulfur compounds, but awareness of the problems of greenhouse gases is gaining more widespread attention.

Nuclear power tends to be favored by planners on energy security grounds, although they are typically quick to point out the absence of greenhouse gases and sulfur emissions from nuclear plants. Particularly in Japan, however, there has always been widespread public concern about the safety of nuclear plants. The Chernobyl accident sent a wave of alarm through many Japanese who previously had a tolerant view of nuclear power. A fire in a Taiwanese plant galvanized public opinion there. To date, the opposition to nuclear power in South Korea has been relatively muted, but there is a growing undercurrent of discontent with the country's pro-nuclear stance.

Coal is disliked by environmentalists and the public in general. Emissions tend to be expensive to control, ash disposal is a major problem in countries where land is at a premium, the greenhouse gas emissions per unit energy are high, and coal is generally perceived as "dirty." Few people want a coal plant sited in their community. There is considerable opposition to construction of new coal-fired plants in Taiwan and Japan, although many environmentalists claim to prefer them to nuclear facilities.

The oft-cited solution to the problem is expansion of gas-fired power plants. While gas does generate some volume of greenhouse gas, its carbon-hydrogen ratio is lower than any other fossil fuel. Gas is cleaner burning than other alternatives, and presents no disposal or emission problems. The difficulty, of course, is that gas supplies in East Asia are minimal, and the needed volumes must be imported as liquefied natural gas (LNG). Planners object to this on energy security grounds, as well as the grounds of high fuel costs. Nonetheless, there is less public opposition to the use of LNG than to either coal or nuclear, and LNG use in East Asia may expand quite rapidly in the 1990s. The ultimate difficulty other than cost is that LNG supplies are not large, and the lead time for new plants is very long.

Many consumers object to reliance on oil because of security issues—at least in principle. What many planners and politicians in Asia are discovering, however, is that oil-fired power generation is easily expanded without raising a public uproar, especially if existing mothballed capacity is employed. Oil storage and transport facilities are ubiquitous enough, moreover, that no one tends to notice their operation, whereas new coal terminals or liquefied natural gas (LNG) ports always provoke public debate. Therefore, although planners are increasingly looking toward LNG as a major element in their future generation mix (as the least unpalatable, rather than the most desirable fuel strategy), oil is forming an important stopgap measure in providing electric power.

East Asian planners are resisting the inclusion of an expanded role for oil in generation as a permanent element in their plans; no current strategy recommends more use of oil in the longer term. Despite this reluctance, oil is creeping back into the power mix, and may not be backed out as quickly as some planners would like—most particularly since many official plans still call for substantial nuclear and coal expansions. Oil does have substantial advantages; although not as environmentally benign as gas, its sulfur emissions can be controlled fairly readily. Furthermore, despite accidents like the *Exxon Valdez* spill, oil is not perceived as a major threat in transport or storage. At present, LNG is viewed as something of a panacea by many members of the public in East Asia. One major LNG accident could readily change this view.

6. Asia-Pacific Refining, Upgrading Trends, and Product Balances

Prior to the second oil shock, a lively product trade was emerging within Asia. Countries such as South Korea, with spare capacity and difficulty in balancing demand, were becoming important factors in the market. The second oil shock sharply curtailed the growth of this kind of trade, largely because governments in Asia (with the notable exception, of course, of Singapore) took measures to discourage refining for other than the domestic market. The main movements within Asia in the early 1980s were sales of surplus products resulting from attempts to balance demand—naphtha from India, naphtha and fuel oil from Indonesia, and miscellaneous movements from a variety of countries.

The role of product trade in the Asian market expanded substantially in the 1980s, however. With a reluctance to allow expansion of refinery facilities—even, in many cases, upgrading facilities—product imports began to look more desirable as a means of balancing demand. The export refineries of the Persian Gulf, which began to come onstream in the early and mid-1980s, found fairly ready markets for their output in the Far East; and the ready supply of products on the market in turn encouraged the view that the refinery overcapacity was a permanent feature of the industry. Only in the closing years of the 1980s did it become apparent that refinery runs were gradually expanding to the point where capacity additions might be needed in the Far East. It took the Iraqi invasion of Kuwait, and the consequent cutoff of naphtha and middle distillate supplies, to convince many Asian policy makers that the market situation had changed from one of surplus to an impending shortage.

As of 1990, Asia-Pacific crude refining capacity stood at 12.5 mmb/d, facing a demand of about 13 mmb/d of products (12 mmb/d excluding LPG). By 1992, more than 2 mmb/d had been added to crude capacity, bringing regional capacity to 14.6 mmb/d. Refinery construction in China accounted for a large share of the increase. To provide a detailed look at the Asia-Pacific refining industry, Table 16 shows country-by-country configurations at the end of 1992.

The region as a whole has relatively little cracking capacity compared to Europe or the United States, and the capacity is concentrated in a few key countries. One of the curious features of the region is that so much of the cracking capacity is based on fluid catalytic crackers (FCCs)—a gasoline-oriented technology in a part of the world where gasoline is a small part of the barrel. The historical reasons for this are too diverse to discuss in depth; much of it is simply a matter of cost. China has long had the technology for building its own FCCs, and so has expanded them despite their poor fit to Chinese demand patterns; India has been unable to afford more sophisticated cracking, although the need for hydrocracking is now becoming clear. It is impossible to make sense out of the overall Asian refinery balance unless it is realized that a substantial amount of the region's cat cracking capacity is run to maximize light cycle oil (LCO) for diesel blending rather than FCC naphtha for gasoline blending, though LCO makes poor quality diesel.

The increase in demand of nearly 3 mmb/d between 1985 and 1990 took the region from a substantial refining surplus, where products were imported from outside the region because of price competition, to a region of refining deficit, where product imports from outside the region were a matter of necessity. The pressure on capacity, and the upward pressure on margins has led to proposals for dozens of new refining projects, ranging from the pragmatic to the absurd. Based on firmly planned projects only, regional capacity is set

Table 16. Asia-Pacific Refinery Configurations, 1992

(thousand barrels/calendar day)

COUNTRY	CDU	FCC/ RCC	CAT REF	HDC	VISB./ COKING
Australia	677	204	160		
Bangladesh	31		2		
Brunei	10				
Myanmar	32				5
China	3,160	876	135	143	348
India	1,037	137	28		115
Indonesia	829	13	72	85	126
Japan	4,649	670	687	113	119
Malaysia	210		30		
New Zealand	84		21	24	
Pakistan	126		5		
Philippines	300	27	34		
Singapore	1,033	25	61	60	189
South Korea	1,530		79	44	17
Sri Lanka	50		4		13
Taiwan	578	45	117	18	17
Thailand	311	9	50	15	17
Total	14,648	2,006	1,485	502	966
Excl. Japan:	9,999	1,336	798	389	847
Excl. Japan and China:	6,839	460	663	246	499

CDU: crude distillate unit

FCC/RCC: fluid catalytic cracker/resid catalytic cracker

CAT REF: catalytic reformer

HDC: hydrocracker

VISB: visbreaker

to increase by almost 50 percent during the 1990s, growing from 12.5 mmb/d in 1990 to 18.5 mmb/d by 2000. About 2 mmb/d of new crude distillation (CDU) capacity was added between 1990 and 1992; another 1.9 mmb/d is likely to be completed by 1995, followed by another 2 mmb/d by the year 2000. Less likely, but still proposed and possible, are an additional 2.6 mmb/d of CDU capacity by 2000. Upon close examination, a substantial number of these projects turn out to be poorly planned "export" facilities proposed by companies with little or no experience in oil. Many such projects can be rejected out of hand as extremely unlikely to be approved, financed, or built.

This, however, still leaves about 3.9 mmb/d of new capacity grounded in some degree of reality for the 1992-2000 period. Part of this is proposed reopening of mothballed capacity, meaning that not all of the additional 3.8 mmb/d requires actual new construction. For example, we have assumed that 300,000 b/d of capacity will be demothballed in Japan in 1993 and 1994. Most of the new construction is planned for completion in the 1995-2000 period; greenfield projects typically have rather long lead times, so there may be several years between the commencement of a new refinery project and its completion.

The expansions we believe to be firm by a 1995 onstream date are summarized in Table 17; the resulting total capacities for the region are shown in Table 18.

The largest expansions are in China, Japan (based on demothballing), South Korea, Thailand, and India. Indonesia and Malaysia have ambitious plans oriented toward export refining, but the bulk of their plans will not be achieved before 1995, and a number of greenfield projects are not likely before 2000.

The new facilities planned are not, in general, hydroskimming refineries. Nearly 140,000 b/d of hydrocracking is planned by 1995, as well as over 500,000 b/d of new catalytic cracking capacity. The new cat cracking capacity around the region is expected to be resid cat cracking (RCC), as opposed to those running VGO feeds.

Table 19 shows planned capacity additions that we believe are firm for a 2000 onstream date. These include additions that are highly probable, such as the ventures planned in Indonesia and Malaysia, as well as some that are less firm, such as the Indian

Table 17. Asia-Pacific Refinery Construction Firm Projects: Capacity Additions by 1995

(thousand barrels/day)

COUNTRY	CDU	FCC/ RCC	CAT REF	HDC	VISB./ COKING
Australia	12	11			
Bangladesh					
Brunei			5		
Myanmar					
China	511	103	41	64	29
India	144	18	17	24	3
Indonesia	113	87			
Japan	300	129	22		26
Malaysia	90				
New Zealand					
Pakistan	38		4	19	11
Philippines	92		19		24
Singapore	202	30	50	4	
South Korea	198	99		28	
Sri Lanka					
Taiwan	63		50		
Thailand	99	37	49		
Total	1,861	514	257	138	93
Excl. Japan:	1,561	385	235	138	67
Excl. Japan and China:	1,050	282	194	74	38

CDU: crude distillate unit

FCC/RCC: fluid catalytic cracker/resid catalytic cracker

CAT REF: catalytic reformer

HDC: hydrocracker

VISB: visbreaker

Table 18. Asia-Pacific Refinery Capacity in 1995

('thousand barrels/calendar day)

COUNTRY	CDU	FCC/ RCC	CAT REF	HDC	VISB./ COKING
Australia	689	215	160		
Bangladesh	31		2		
Brunei	10		5		
Myanmar	32				5
China	3,671	979	176	207	376
India	1,181	155	46	24	118
Indonesia	942	100	72	85	126
Japan	4,949	799	709	113	145
Malaysia	300		30		
New Zealand	84		21	24	
Pakistan	164		9	32	11
Philippines	392	27	53		24
Singapore	1,235	55	111	63	189
South Korea	1,728	99	79	71	17
Sri Lanka	50		4		13
Taiwan	641	45	167	18	18
Thailand	410	46	99	15	17
Total	16,508	2,520	1,742	652	1,059
Excl. Japan:	11,559	1,721	1,033	539	914
Excl. Japan and China:	7,888	742	857	332	537

Note: Totals include current capacity and new capacity to be built by 1995.

Table 19. Asia-Pacific Refinery Construction Likely Projects: Capacity Additions by 2000

(thousand barrels/day)

COUNTRY	CDU	FCC/ RCC	CAT REF	HDC	VISB./ COKING
Australia					
Bangladesh					
Brunei					
Myanmar					
China	670	20	8	76	
India	230				
Indonesia	114	96	31		14
Japan	195				19
Malaysia	140	50			
New Zealand			6	2	
Pakistan	108				
Philippines					
Singapore					
South Korea	90				
Sri Lanka					
Taiwan	150				
Thailand	284	33	36	41	18
Total	1,980	199	80	119	51
Excl. Japan:	1,785	199	80	119	32
Excl. Japan and China:	1,115	179	72	43	32

CDU: crude distillate unit

FCC/RCC: fluid catalytic cracker/resid catalytic cracker

CAT REF: catalytic reformer

HDC: hydrocracker

VISB: visbreaker

expansions and some of the possible capacity in Thailand.

The effects on regional capacity of the expansion plans in Tables 17 and 18 are summarized in Table 20, which shows regional capacity if all soundly planned projects proposed are actually built by the year 2000. Some of these projects may be shelved; others not yet proposed may actually be built. Nonetheless, Table 20 offers a good planning basis for assumptions about regional capacity in the late 1990s. There are also a number of other refinery projects planned, but for a variety of reasons we do not yet consider them firm plans. It is still, of course, possible that they may go forward by the year 2000; for reference, these proposed/possible projects are listed in Table 21. The total additions are summarized graphically in Figure 66.

In gross terms, the balance between supply and demand is likely to continue to be relatively tight. Base case demands (excluding LPG) of 15.1 mmb/d of products in 1995 face a refinery capacity of about 16.5 mmb/d—a situation close to that seen in 1992, with demand excluding LPG at around 13.3 mmb/d and CDU capacity at around 14.7 mmb/d. By 2000, however, if no additional expansions beyond those presently planned for 1995 are built, 18.6 mmb/d of non-LPG demand will face a regional capacity of 16.5 mmb/d. If only firm plans move ahead by the year 2000, just 18.5 mmb/d of CDU capacity will be running to meet 18.6 mmb/d of non-LPG demand.

Does this mean that there is an urgent need for more capacity to be built? The answer is not at all clear, particularly if refinery capital investments are so high that their only hope for profitability is continued high margins. The Mideast countries will continue to have exportable surpluses of products to move to Far East markets, and high margins will make construction of additional refining capacity in the Mideast more likely; already there are a number of projects proposed in the United Arab Emirates (UAE), some to be based on imported crude. Furthermore, if Asia-Pacific demand grows more slowly than in the base case, the current planned additions to capacity may be about the right size to keep the situation relatively stable in the late 1990s. If demand is strong and margins are favorable, another 2.6 mmb/d of capacity is possible by the year 2000. Additional projects beyond

Table 20. Asia-Pacific Likely Refinery Capacity in 2000

(thousand barrels/calendar day)

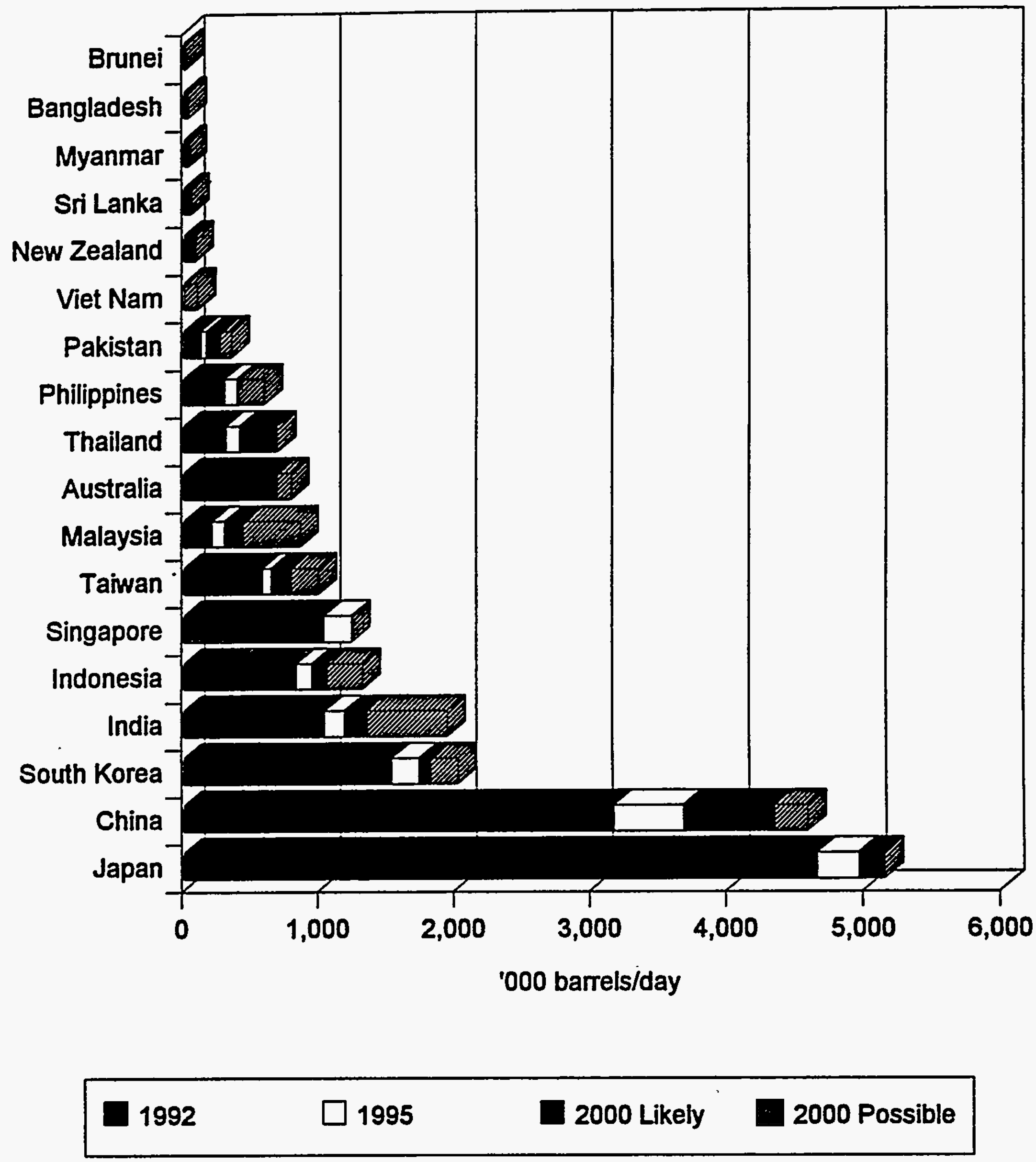
COUNTRY	CDU	FCC/ RCC	CAT REF	HDC	VISB/ COKING
Australia	689	215	160		
Bangladesh	31		2		
Brunei	10		5		
Myanmar	32				5
China	4,341	999	184	283	376
India	1,411	155	46	24	118
Indonesia	1,056	196	102	85	140
Japan	5,144	799	709	113	164
Malaysia	439	50	30		
New Zealand	84		27	26	
Pakistan	272		9	19	11
Philippines	392	27	53		24
Singapore	1,235	55	111	63	189
South Korea	1,818	99	79	71	17
Sri Lanka	50		4		13
Taiwan	791	45	167	18	18
Thailand	693	80	135	56	35
Total	18,488	2,719	1,822	758	1,110
Excl. Japan:	13,344	1,920	1,113	645	946
Excl. Japan and China:	9,003	921	929	362	569

Note: Totals include current capacity, plus firm additions by 1995, plus likely additions post-1995.

Table 21. Asia-Pacific Refinery Construction
Proposed/Possible Projects: Possible Additional Capacity by 2000
(thousand barrels/calendar day)

COUNTRY	CDU	FCC/ RCC	CAT REF	HDC	VISB./ COKING
Australia	100				
Bangladesh					
Brunei					
Myanmar					
China	240				
India	777				
Indonesia	259	98	41		
Japan					
Malaysia	418				
New Zealand					
Pakistan	80				
Philippines	200				
Singapore					
South Korea	198				
Sri Lanka					
Taiwan	200				
Thailand					
Viet Nam	100				
Total	2,572	98	41		
Excl. Japan:	2,572	98	41		
Excl. Japan and China:	2,332	98	41		

Figure 66. Asia-Pacific Refining Capacity: 1992, 1995 and 2000



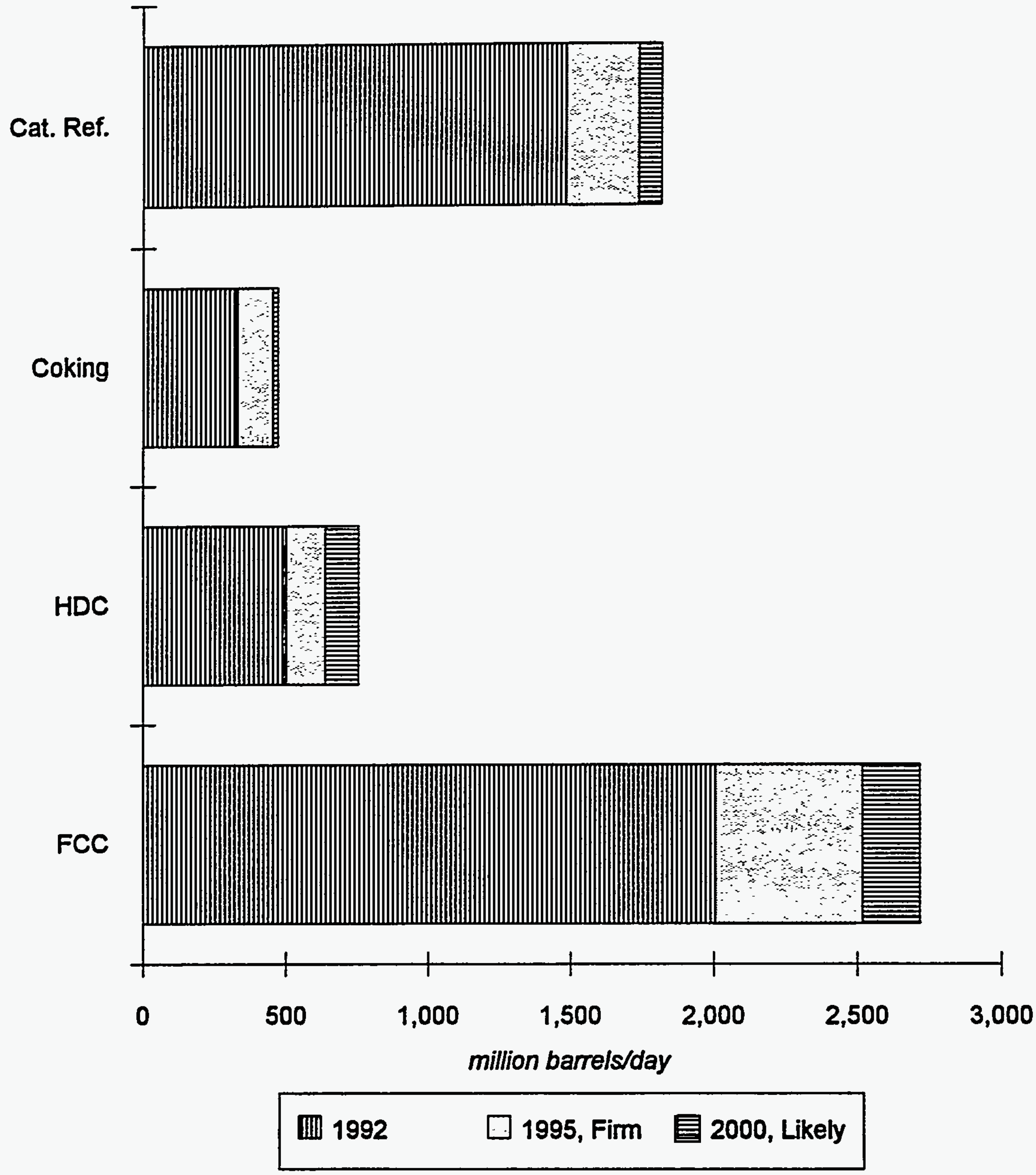
those presently on the books can probably be accommodated without throwing the market into overcapacity; the present situation, however, suggests that capacity will continue to be relatively tight. A tight market, of course, is something that refiners would like to maintain, since it means that their assets are highly valued. There seems to be a heady attitude in some Asian countries that an overcapacity situation in the 1990s is impossible. This assumption is incorrect. If capital investments are the only hurdle, the world oil industry is capable of turning any situation into overcapacity within a five-year time horizon. At present, the outlook is for solid profitability, but this profitability is not by any means invulnerable.

Figure 67 shows the planned expansions in regional upgrading capacity from the earlier tables. The largest firm expansion is in catalytic cracking, with significant additions in catalytic reforming, and some additions in hydrocracking and coking as well.

Among the cracking technologies, cat cracking is the most strongly favored. There are a number of reasons for this expansion in cat cracking, virtually all of which is RCC rather than FCC. First, much of the capacity is slated for export refineries, which are aiming at the gasoline market as a primary target. Second, the RCC technology solves to some extent the problem of disposal of vacuum bottoms that arises when too much VGO feed is pulled out of the resid pool. Hydrocracker (HDC) and FCC additions can only be carried so far before they require concomitant additions of coking or visbreaking. Finally, RCCs, though more expensive than conventional FCCs, are a cheaper form of cracking, both in terms of capital investment and operating costs, than HDCs, even though the strength of the diesel demand in Asia seems to warrant more investment in hydrocracking.

The need for additional HDC capacity has been recognized, though plans lag behind what might be desirable in terms of balancing the demand barrel. Additions to HDC capacity are planned in China, India, Pakistan, Singapore, and South Korea. Tentative plans for HDC units in Indonesia, Malaysia, Taiwan, and Thailand, however, have been shelved. In percentage terms, the relative expansion of regional HDC capacity is significant, but in

Figure 67. Refinery Upgrading Capacity Trends in Asia, 1992-2000



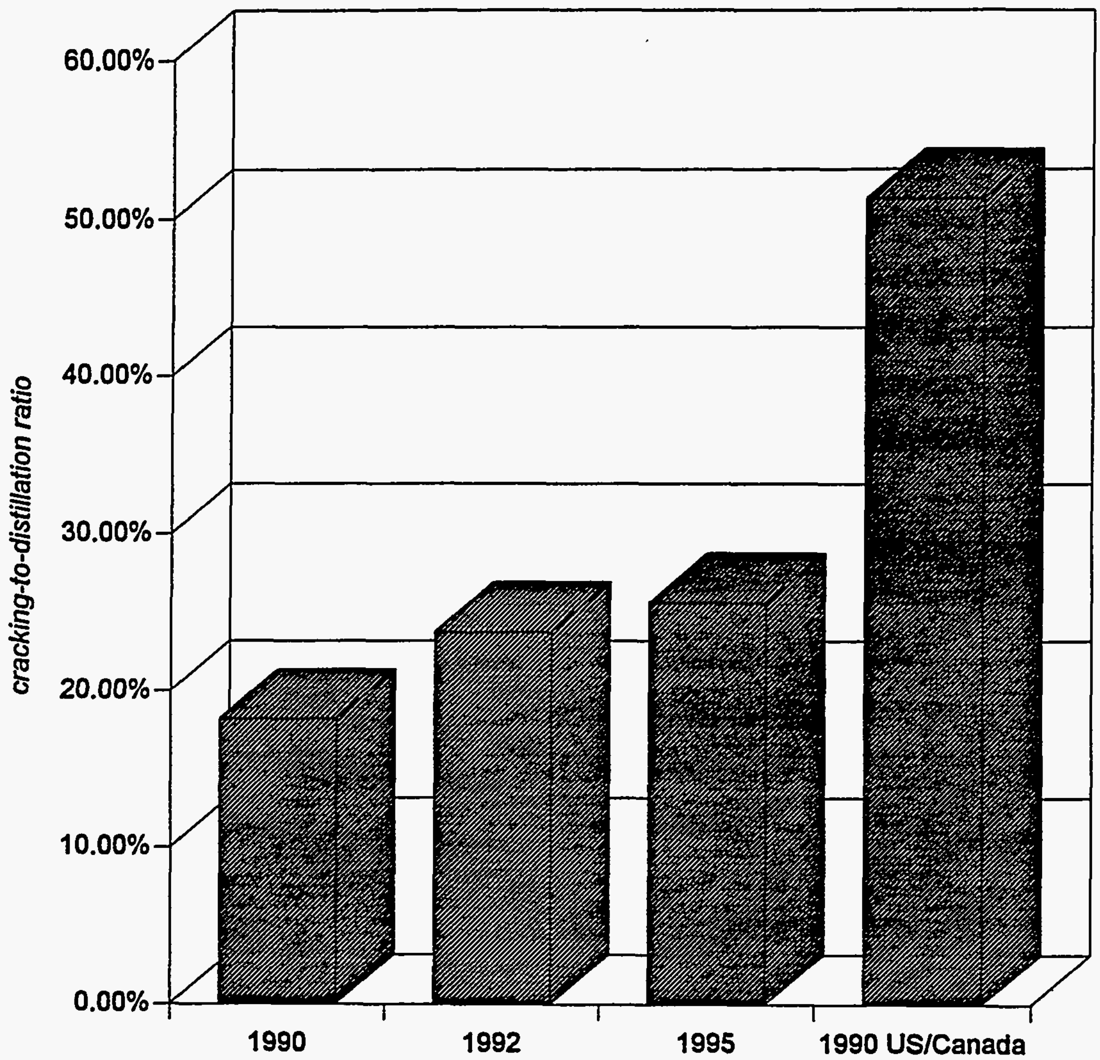
absolute terms the total amount of hydrocracking will still lag considerably behind cat cracking—758,000 b/d of HDC capacity in 2000 as compared to 2.7 mmb/d of cat cracking.

Despite the large amount of new CDU capacity planned, and the substantial amount of demothballing likely to occur, the additions of new upgrading units will result in an increase in the average sophistication of regional refining. Figure 68 shows the cracking-to-distillation ratio for the region in 1990, 1992, and 1995. "Cracking" includes FCC/RCC, HDC, and thermal cracking/coking. (Refer to Figure 36 for detailed regional comparisons by cracking type.) While the Asia-Pacific ratio remains low compared to the United States or many Mideastern countries—it is and will continue to be less than half the ratio seen in the United States/Canada in 1990—it does show that average Asian refinery flexibility will be on the upswing in the coming decade.

A better index of refinery complexity has been developed by the East-West Center's Program on Resources. This index, the transport fuels index (TFI), is discussed more fully in Section D above on petroleum products and refining. Figure 37 compares the TFIs for Hawaii, the Asia-Pacific region, and other major world regions. The Asia-Pacific region's TFI of around 50 places it roughly on par with the refinery industries of the Middle East, Africa, and Latin America, but it lags behind the United States/Canada, Hawaii, and Western Europe. Figure 69 provides a more detailed look at the individual countries of the Asia-Pacific, along with the United States, the world, and the Asia-Pacific regional average for comparison. In the Asia-Pacific region, only three countries—Australia, New Zealand, and Taiwan—have TFIs higher than the world average. Figure 70 compares the region's TFI with the actual percentage of transport fuels in the demand barrel. In contrast to the refinery industry of North America, the Asian refining industry cannot hope to satisfy transport fuels demand with its current configuration.

The end result is that the region must meet marginal demand for transport fuels via imports. The regional trade balance for 1991 is shown in Table 22, which also shows our forecast balances for 1995 and 2000. In 1991, refined product imports amounted to almost 3 mmb/d, 1.1 mmb/d of which was transport fuels, while product exports of 1.9 mmb/d

Figure 68. Asia-Pacific Refinery Sophistication Is Increasing, Though Gradually: Cracking-to-Distillation Ratio, 1990-95



Note: cracking-to-distillation ratio is defined as (thermal cracking+FCC+HDC)/CDU capacity.

Figure 69. Transport Fuel Index: Asia-Pacific Comparative Refinery Complexity, 1992

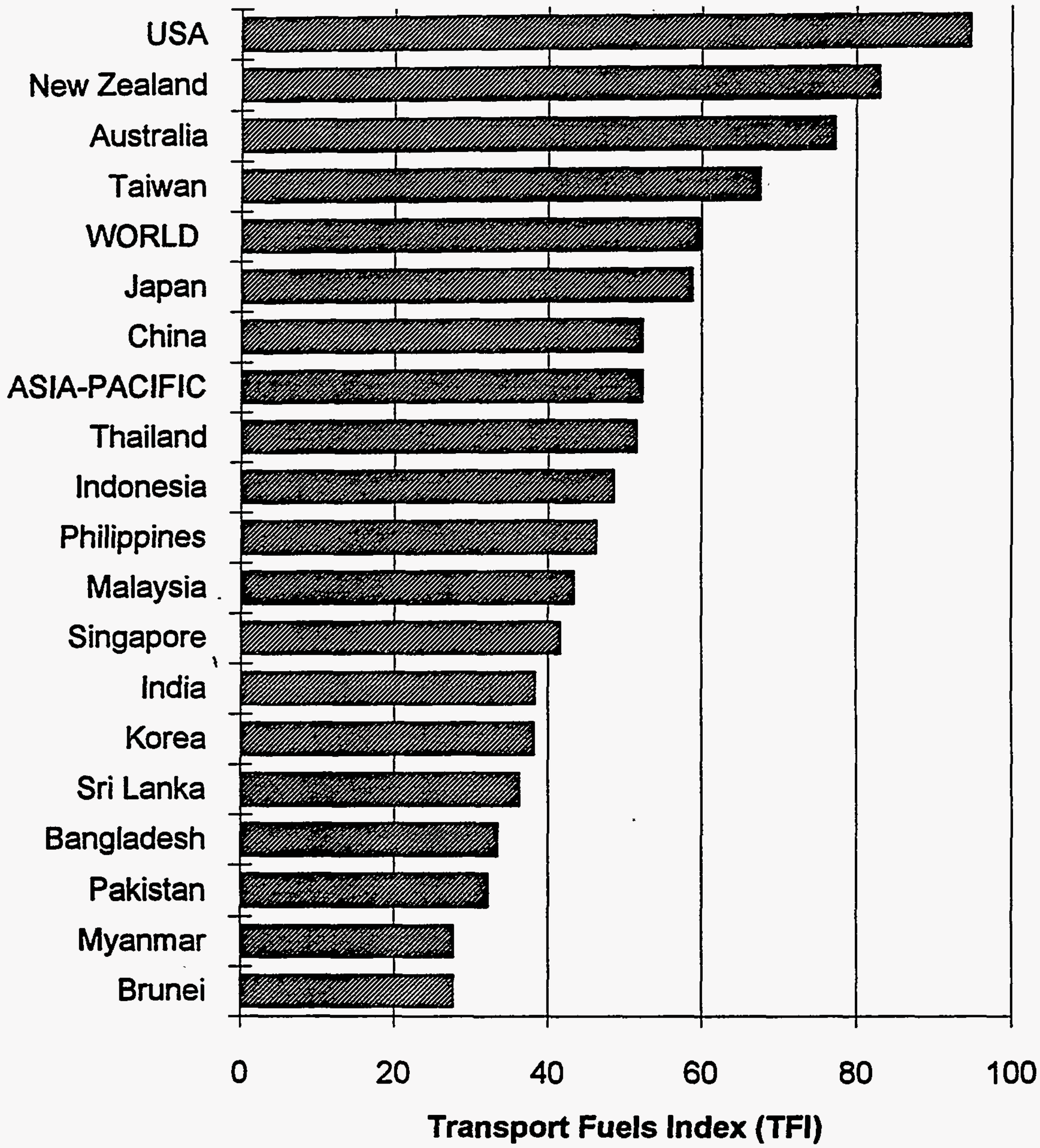


Figure 70. The Asia-Pacific Region's Ability to Produce Transport Fuels Lags Demand, 1992

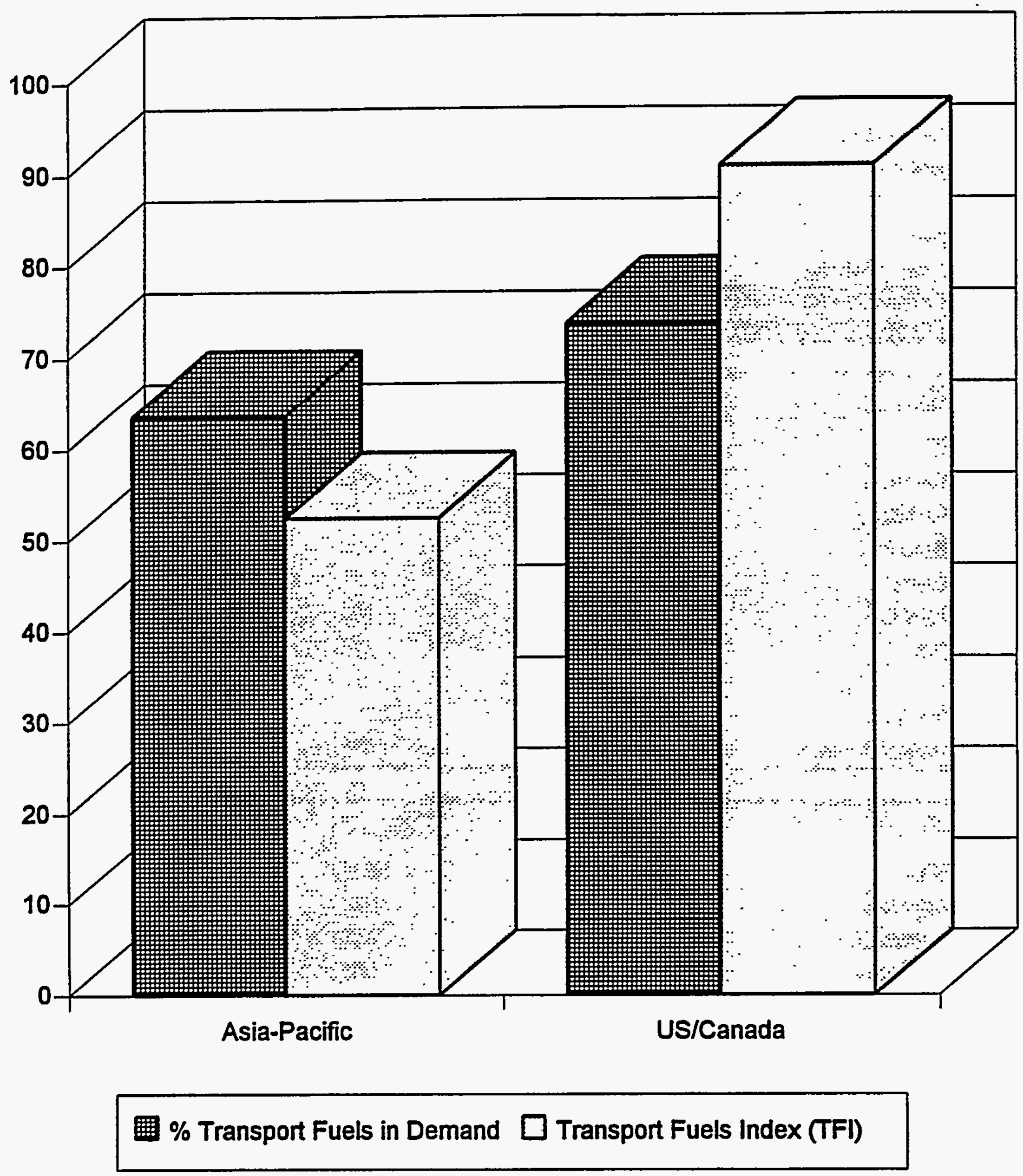


Table 22. Asia-Pacific Petroleum Product Balances, 1991, 1995 and 2000
(thousand barrels/day)

1991	Production	Imports /a	Exports /a	Demand
LPG	514	615	52	1,095
Gasoline	2,233	249	184	2,298
Naphtha	808	432	190	1,014
Kero /Jet	1,438	279	310	1,442
Diesel	3,592	616	457	3,759
Fuel Oil /b	2,795	691	611	2,891
Others	598	82	75	600
Total	**11,979**	**2,964**	**1,880**	**13,100**
Transp. Fuels	7,263	1,144	952	7,499

a. Intra-region trade is included.
b. Excludes direct burning of crude oil in China and Japan

1995	Production	Imports	Exports	Demand
LPG	1,219	491	389	1,321
Naphtha	1,068	493	110	1,451
Gasoline	2,873	146	191	2,828
Kero /Jet	1,775	185	203	1,757
Diesel	3,944	1,103	224	4,823
Fuel Oil	3,377	320	423	3,274
Other	499	277	47	648
TOTAL	**14,753**	**3,016**	**1,586**	**16,102**
Transp. Fuels	6,786	1,781	536	8,031

2000	Production	Imports	Exports	Demand
LPG	1,358	540	363	1,536
Naphtha	1,032	724	78	1,678
Gasoline	3,560	153	235	3,477
Kero /Jet	2,048	158	182	2,024
Diesel	4,819	1,509	263	6,065
Fuel Oil	3,636	232	513	3,355
Other	580	188	53	715
TOTAL	**17,033**	**3,504**	**1,687**	**18,850**
Transp. Fuels	7,899	2,391	523	9,767

included 950 mb/d of transport fuels. This gap is expected to widen in the coming years; in our forecast balance for 1995, imports of transport fuels amount to around 1,780 mb/d while exports total 540 mb/d; and in our forecast balance for 2000, transport fuel imports reach nearly 2,400 mb/d versus exports of just 520 mb/d.

A number of conclusions can be drawn from the table. First, in gross terms, firmly planned expansions do a reasonable job of meeting overall demand for gasoline, jet fuel, and fuel oil (which is in surplus), but demand for diesel far outstrips the capabilities of the refining system, and huge quantities of naphtha feedstock will also be required from outside the region. Net imports from outside the region are expected to total 1,430 mb/d in 1995, and 1,817 mb/d in 2000. Moreover, significant imports of LPG will be required from outside the region unless gas processing within Asia expands significantly beyond present plans.

The overall pattern shows a small but steady surplus of fuel oil, on the order of 100-300 mb/d. Higher demand could easily consume this amount, but the surplus suggests that, despite major expansions of upgrading capacity in the 1990s, additional cracking expansions may be economic.

The most interesting features of the balance sheet are the naphtha/gasoline split and the kero/gasoil split. There are significant deficits of both naphtha and gasoil projected that worsen as the decade progresses. On the other hand, there are exportable surpluses of both gasoline and kerosene. If there are export markets for these at favorable prices outside the region, then these will represent significant profit opportunities, but there is always the option of downblending these streams to their counterparts to decrease the region's deficits.

What this suggests is a narrowing of the gasoline/naphtha and kero/gasoil differentials in the region—most likely by a strengthening of the naphtha and gasoil prices. In the case of naphtha prices in particular, a major strengthening is probable in the near future. Historically, the Asia-Pacific naphtha market has been out of step with the rest of the world, showing far wider gasoline/naphtha differentials than in other major markets. This situation has been supported by significant naphtha surpluses within the region, featuring exports from

Indonesia, India, Singapore, Malaysia, and a number of other refining centers. As gasoline demand and production increase, these exports will dry up in the 1990s. Only Singapore will remain as a major exporter of naphtha by 1995; exports will be available from India, Indonesia, Malaysia, and a number of minor refiners, but at reduced volumes. Total naphtha exports within the region in 1995 will amount to only about 110 mb/d, while import requirements will total 493 mb/d. This gap widens further by the end of the decade; by 2000, naphtha exports will amount to 78 mb/d, with imports required at 724 mb/d.

Some major refiners, most notably Japan and South Korea, have seen the option for gasoline exports based on their ability to generate surplus octane. Although these countries have a volumetric deficit in the light distillates, both would be capable, in the 1990s, of producing exportable volumes of high-grade gasoline; Japan's export potential of 92 RONC in 1995 has been estimated at 60-70 mb/d. Such a possibility rests, however, on cheap naphtha imports. If the gasoline/naphtha differential narrows, the attractiveness of gasoline exports from naphtha-importing countries diminishes sharply. There will be significant gasoline export potential in Asia in the 1990s, but it is not likely to come from the countries that are major naphtha importers.

In the 1990s, the major product exporters in the region will all be within ASEAN: Singapore, Indonesia, and Malaysia. Japan's importance as an importer will diminish in the 1990s as domestic runs increase, an important point to be noted by regional exporters, who have long counted on Japan as a major outlet. The emergence of other importers, however, should more than make up for lost market opportunities in Japan.

Unless refining capacity can be added at greater rates than current Chinese capabilities suggest, China will emerge as a significant importer of products in the 1990s. If field development proceeds as expected, China will have (as it did in the mid-1980s) sufficient oil to meet its needs but insufficient processing capabilities. Thus, much of China's "import" requirements are likely to be met by processing deals and crude/product swaps. Overall, this is probably a healthy matter for the region, since it will put more low-sulfur crude onto the market; the low-sulfur characteristics of Chinese crude will be more valued elsewhere than in

China. Nonetheless, China's projected product import slate is not something that will readily be obtained through processing; it is a highly upgraded slate, with essentially zero fuel oil requirement. Like most of its neighbors, China will find itself purchasing larger quantities of diesel and naphtha feedstock than it has historically required.

The gasoil deficit emerging in Asia is the most worrisome feature of the market. Additional upgrading will not contribute toward solving the problem unless the upgrading is hydrocracking-based. To date, gasoil prices have not justified HDC expansions in most markets. This argues for higher gasoil prices, lower kero/gasoil differentials to support downblending, and a curtailment of gasoil demand in many countries via price mechanisms or other policy measures.

There will undoubtedly be continued supplies of products available from the Mideast in the 1990s, but the Mideast suppliers are unlikely to be content to supply low-value products like naphtha and gasoil to support excess Asian production of high-value gasoline and kerojet. Some basic realignments in price seem likely by the middle of the decade if not sooner, and these in turn may cause some gradual adjustments in Asian patterns of demand.

7. Asia-Pacific/PADD-V Linkages

The U.S. West Coast, defined here as the seven states in PADD-V (Alaska, Arizona, California, Hawaii, Nevada, Oregon and Washington), is one of the largest oil markets in the world. The region is the site of two of the top four oil-producing states in the United States, oil product demand is over 2.5 million barrels per day, and the refining industry is one of the most flexible in the world. Indigenous energy resources are fairly impressive, with petroleum retaining the dominant share at almost half of the primary energy mix.

The size of the U.S. West Coast market and its strong trade links with other Pacific Rim nations have focussed an increasing amount of attention on the region, its policies, and its needs. Many companies planning to move into export refining, for example, look hopefully to markets in Southern California, which are widely considered lucrative but may prove costly to penetrate. California tends to dominate discussions of the U.S. West Coast, and when the term "U.S. West Coast" is mentioned, California is often the only state that springs to mind. This is understandable, given the size of the California economy which, if taken as a nation, would rank among the ten largest economic powers in the world. The mistake many analysts make, however, is defining the U.S. West Coast too narrowly and viewing West Coast issues as simply California issues. Within PADD-V, there is much diversity and a great deal of interdependence: Alaska is a major source of crude for the other states; Washington provides refined products to Oregon; California provides products to Nevada and Arizona; both the Washington area refiners and the California refiners trade products with Hawaii; natural gas pipelines run throughout the coastal states; and electric power grid connections allow power wheeling among the contiguous mainland states. California's energy market is closely linked with other West Coast states, and we therefore define the U.S. West Coast as containing all seven PADD-V states.

Another feature shared by the PADD-V states is isolation from other U.S. areas. Hawaii and Alaska are noncontiguous states, and even the five that are contiguous are separated from other U.S. regions by mountain ranges. Only three crude oil pipelines link the U.S. West Coast with external markets: the Transmountain Pipeline from Canada to Washington state, the Four Corners Pipeline from Southern California to the U.S. Gulf region, and the Celeron/All-American Pipeline from Central California to the U.S. Gulf.

The U.S. West Coast takes pride in the fact that it is considered a pioneer in environmental protection. Still, the Los Angeles basin has the nation's worst air pollution problem, and it is clear that additional measures must be taken to improve air quality. California's regulatory environment is growing increasingly strict.

Currently, Alaskan and Californian crude production averages around 1.8 mmb/d and 1.0 mmb/d, respectively. The high levels of local production have fostered a major oil industry, and the region is currently a net-exporter of oil. This status will change during the 1990s, and the region as a whole will become a net-importer of oil.

The production declines on the U.S. West Coast will occur in tandem with production declines in many key Asia-Pacific producers, such as Indonesia, China, and Australia.

Indonesia has for a number of years been the chief foreign source of crude for the U.S. West Coast, with imports ranging from 75 to 150 mb/d—typically representing around two-thirds of total U.S. West Coast foreign imports. As mentioned above, however, the export availability of Indonesian crudes will fall off sharply from current levels and may disappear entirely by the year 2000, since production will begin to decline and domestic refining activity will rise. The West Coast and Hawaii, like many others, will find the market for light, sweet, Asian crudes to be much tighter during the coming decade.

Approximately 10 percent of the U.S. West Coast crude slate is imported from foreign sources. Hawaii is unusual in that its crude slate is typically 40 to 60 percent foreign. In Hawaii and in the U.S. West Coast as a whole, foreign crude imports are overwhelmingly dominated by Asia-Pacific crudes. Figure 71 shows the trend in foreign crude imports by source, 1981-91, while Figure 72 provides a look at refined product imports by source for the same period. There is considerably more diversity in sources of refined product imports, though the Asia-Pacific region still plays an important role. Table 23 provides a detailed look at crude and product imports in 1991. In 1991, Asia-Pacific crudes accounted for 69 percent of the foreign crude slate, but just 26 percent of product imports. The importance of Asian crudes in the PADD-V import mix has been considerably higher in past years—from 1985 to 1987, Southeast Asia provided around three-quarters of imports, with Indonesia alone the source of around two-thirds. Indonesia's share fell to around 60 percent in 1988 and averaged around 44 percent in 1991. Imports in 1989 were far more diverse than in the past. In 1985, seven countries (including Liberia) provided crude into the U.S. West Coast. By 1989, the number had grown to 11, and in 1990, crude was imported from 19 different countries. Chevron in particular diversified its sources of supply. The 1989 import figures also show a significant increase in imports of Ecuadorian crude, the chief reason being that the *Exxon Valdez* oil spill temporarily suspended shipments of Alaska North Slope (ANS) crude. The percentage yields from primary distillation of Ecuador's Oriente crude is remarkably similar to yields from ANS crude. Even ARCO,

Figure 71. Asia-Pacific Crudes Dominate PADD-V Imports, 1981-91

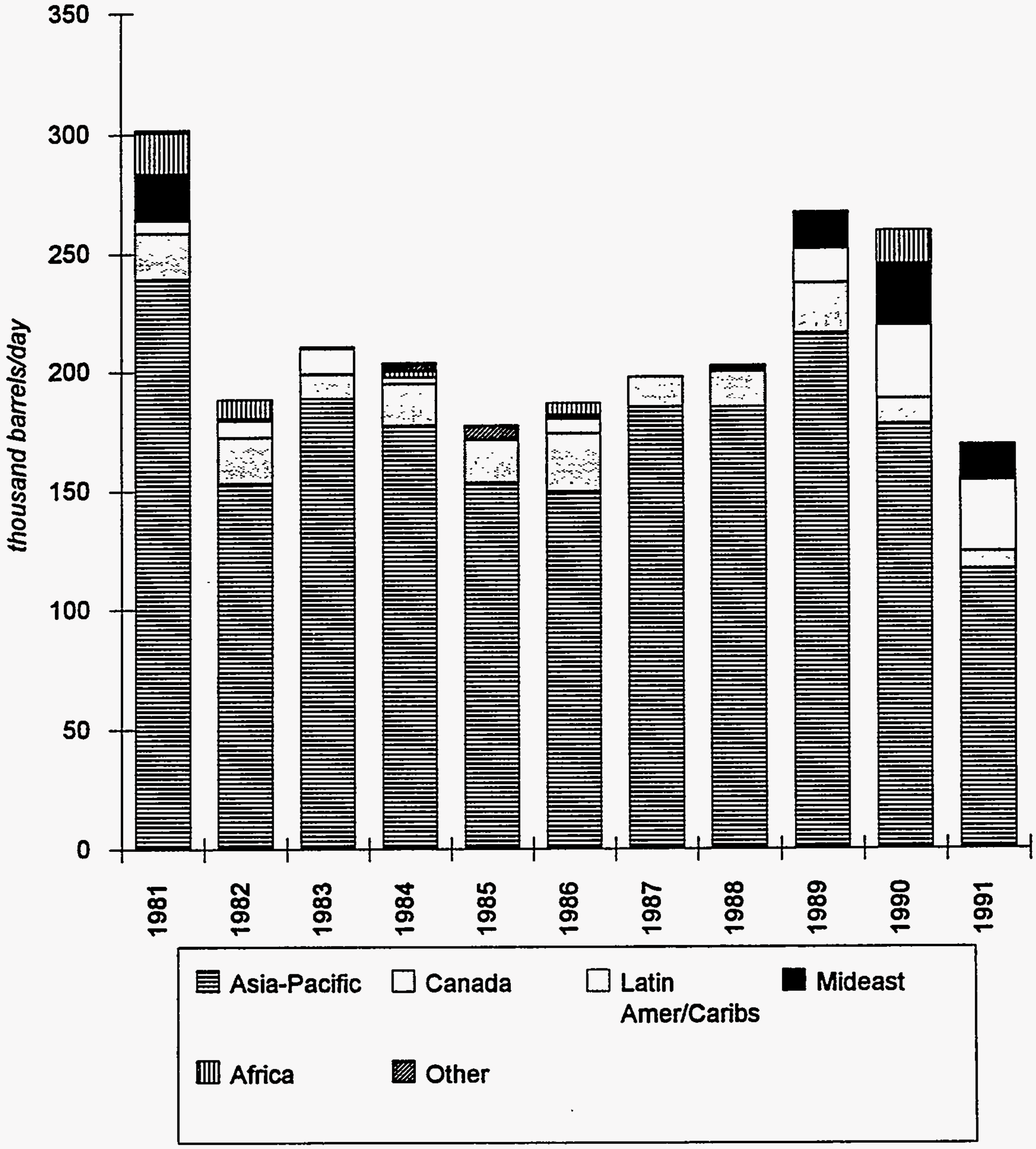


Figure 72. PADD-V Product Imports, 1981-91

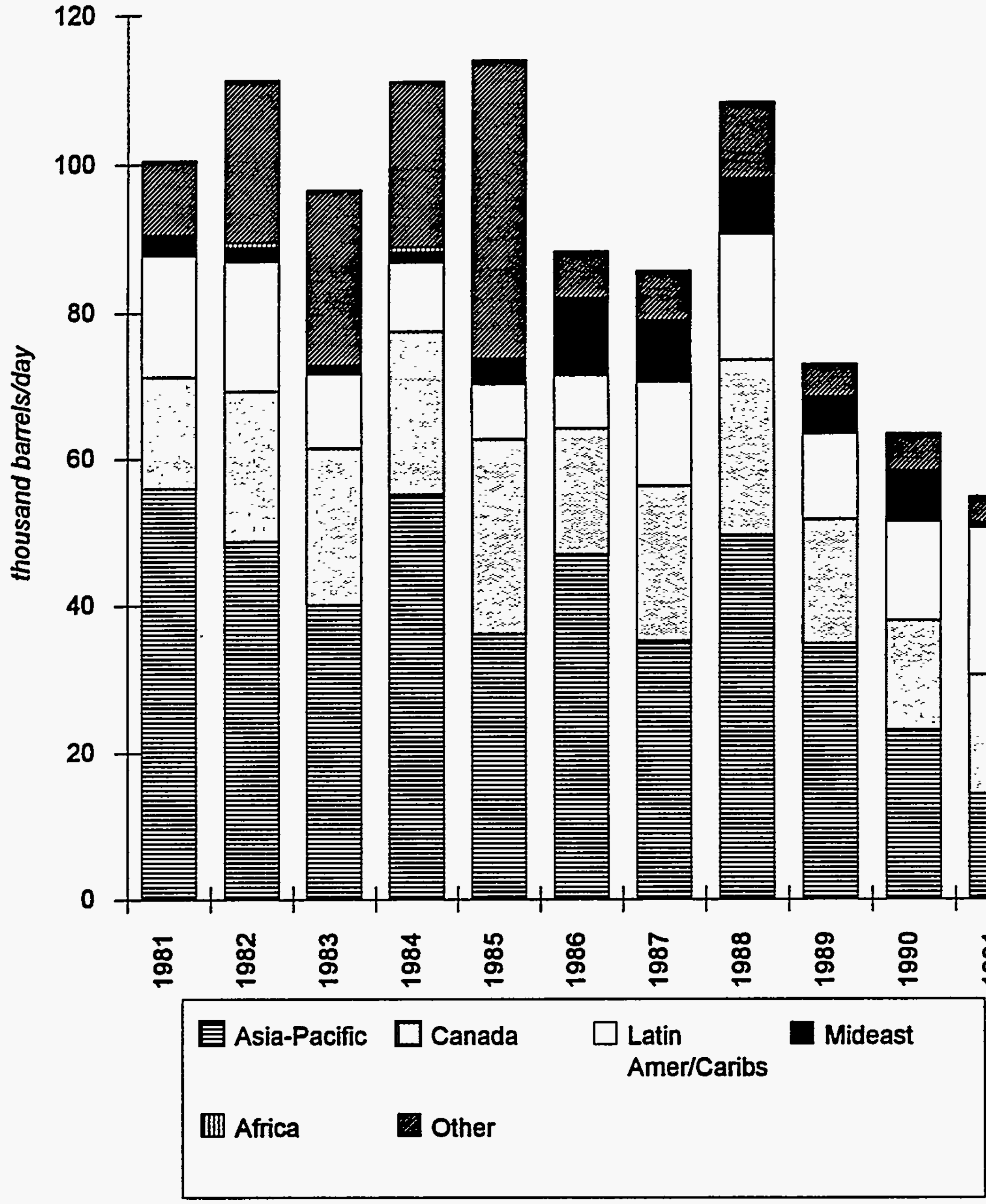


Table 23. PADD-V Imports of Crude Oil and Petroleum Products by Country and Region of Origin, 1991

(thousand barrels)

Country of Origin	Crude Oil	LPG	Unfinished Oils	GBC	Mogas	Jet Fuel	Diesel	Fuel Oil	Naptha & Feedstock	Road Oil	Other	Total	Total Products	% of Crude	% of Products
Asia-Pacific	**42,404**	**0**	**614**	**0**	**1,262**	**0**	**85**	**2,963**	**270**	**0**	**0**	**47,598**	**5,194**	**69.1%**	**26.1%**
Australia	6,436	0	0	0	0	0	0	53	0	0	0	6,489	53	10.5%	0.3%
Brunei	671	0	0	0	0	0	0	0	0	0	0	671	0	1.1%	0.0%
China	2,079	0	0	0	1,262	0	0	0	0	0	0	3,341	1,262	3.4%	6.3%
Indonesia	27,262	0	0	0	0	0	0	1,393	0	0	0	28,655	1,393	44.4%	7.0%
Japan	0	0	0	0	0	0	0	0	96	0	0	96	96	0.0%	0.5%
Korea	0	0	0	0	0	0	0	0	174	0	0	174	174	0.0%	0.9%
Malaysia	5,281	0	0	0	0	0	0	0	0	0	0	5,281	0	8.6%	0.0%
Singapore	0	0	614	0	0	0	85	1,517	0	0	0	2,216	2,216	0.0%	11.1%
Thailand	675	0	0	0	0	0	0	0	0	0	0	675	0	1.1%	0.0%
Canada	**2,679**	**817**	**86**	**60**	**3,069**	**90**	**1,039**	**59**	**70**	**85**	**552**	**8,606**	**5,927**	**4.4%**	**29.8%**
Latin Amer./Caribs	**10,781**	**0**	**1,362**	**0**	**0**	**1,032**	**221**	**3,888**	**0**	**308**	**462**	**18,054**	**7,273**	**17.6%**	**36.5%**
Argentina	0	0	0	0	0	0	0	208	0	0	0	208	208	0.0%	1.0%
Ecuador	7,201	0	164	0	0	0	0	1,111	0	0	0	8,476	1,275	11.7%	6.4%
Mexico	614	0	0	0	0	620	0	80	0	233	23	1,570	956	1.0%	4.8%
Neth. Antilles	0	0	641	0	0	0	0	348	0	0	0	989	989	0.0%	5.0%
Trinidad & Tobago	0	0	0	0	0	0	0	1,192	0	0	0	1,192	1,192	0.0%	6.0%
Venezuela	2,966	0	253	0	0	230	221	949	0	75	439	5,133	2,167	4.8%	10.9%
Virgin Islands	0	0	304	0	0	182	0	0	0	0	0	486	486	0.0%	2.4%
Middle East	**5,158**	**0**	**0**	**51**	**0**	**75**	**0**	**0**	**0**	**0**	**110**	**5,394**	**236**	**8.4%**	**1.2%**
Saudi Arabia	5,001	0	0	51	0	75	0	0	0	0	110	5,237	236	8.1%	1.2%
Oman	157	0	0	0	0	0	0	0	0	0	0	157	0	0.3%	0.0%
Other	**379**	**0**	**646**	**0**	**0**	**0**	**0**	**644**	**0**	**0**	**0**	**1,669**	**1,290**	**0.6%**	**6.5%**
TOTAL	**61,401**	**817**	**2,708**	**111**	**4,331**	**1,197**	**1,345**	**7,554**	**340**	**393**	**1,124**	**81,321**	**19,920**	**100%**	**100%**
Daily Average	168.2	2.2	7.4	0.3	11.9	3.3	3.7	20.7	0.9	1.1	3.1	222.8	54.6		

Source: USDOE Petroleum Supply Monthly whose Washington refinery is geared specifically for ANS crude, imported Ecuadorian crude after the *Valdez* oil spill.

With refineries in Northern California, Southern California, Hawaii, and Alaska (though the Alaska refineries in general process local crudes only), Chevron is the West Coast's main importer of foreign crudes. Other importers of note include Unocal, Shell, and BHP/PRI. Among the PADD-V states, only Hawaii relies on foreign crudes for the majority of its crude requirements, importing around 77 mb/d of foreign crude 1991. In contrast, California's foreign crude imports totalled only around 71 mb/d in 1991. It should be noted, however, that foreign crudes play a more important role in California than the absolute volumes indicate, because they serve to lighten the heavy, sour California crude slate. Small refiners in particular benefit from access to light, sweet Asian crudes. Independent refiners with significant quantities of Asian crudes in their refining slate included Pacific Refining in Northern California and Golden West Refining in Southern California.

The question of when PADD-V will become a net importer is subject to assumptions about crude production and refinery runs. Figure 73 charts historical crude production and refinery crude runs for the period 1981-91. The surplus is clearly dwindling; given current trends, we estimate that crude production and crude runs will intersect during the latter half of the 1990s.

The implication is that, during the coming decade, foreign crude imports will increase. The West Coast is still a crude-surplus region, but the crude surplus buffer is beginning to dwindle. Figure 74 shows the trend of inter-PADD transfers of crude—that is, transfers of PADD-V crude to other PADDs. From 1982 to 1988, transfers were around 600-700 mb/d. This situation is now turning around; in 1989, crude transfers to other PADDs averaged about 400 mb/d, and in 1990 and 1991 transfers averaged less than 300 mb/d.

As noted, there will be increasing competition in the market for high-quality Asian crudes. The Asia-Pacific region may not be able to serve as a major supplier of crude oil, but the rapid expansions in Asia-Pacific refinery capacity may allow certain levels of refined

Figure 73. U.S. West Coast Crude Runs Are Catching up with Local Crude Production: Refinery Runs and Field Production, 1981-91

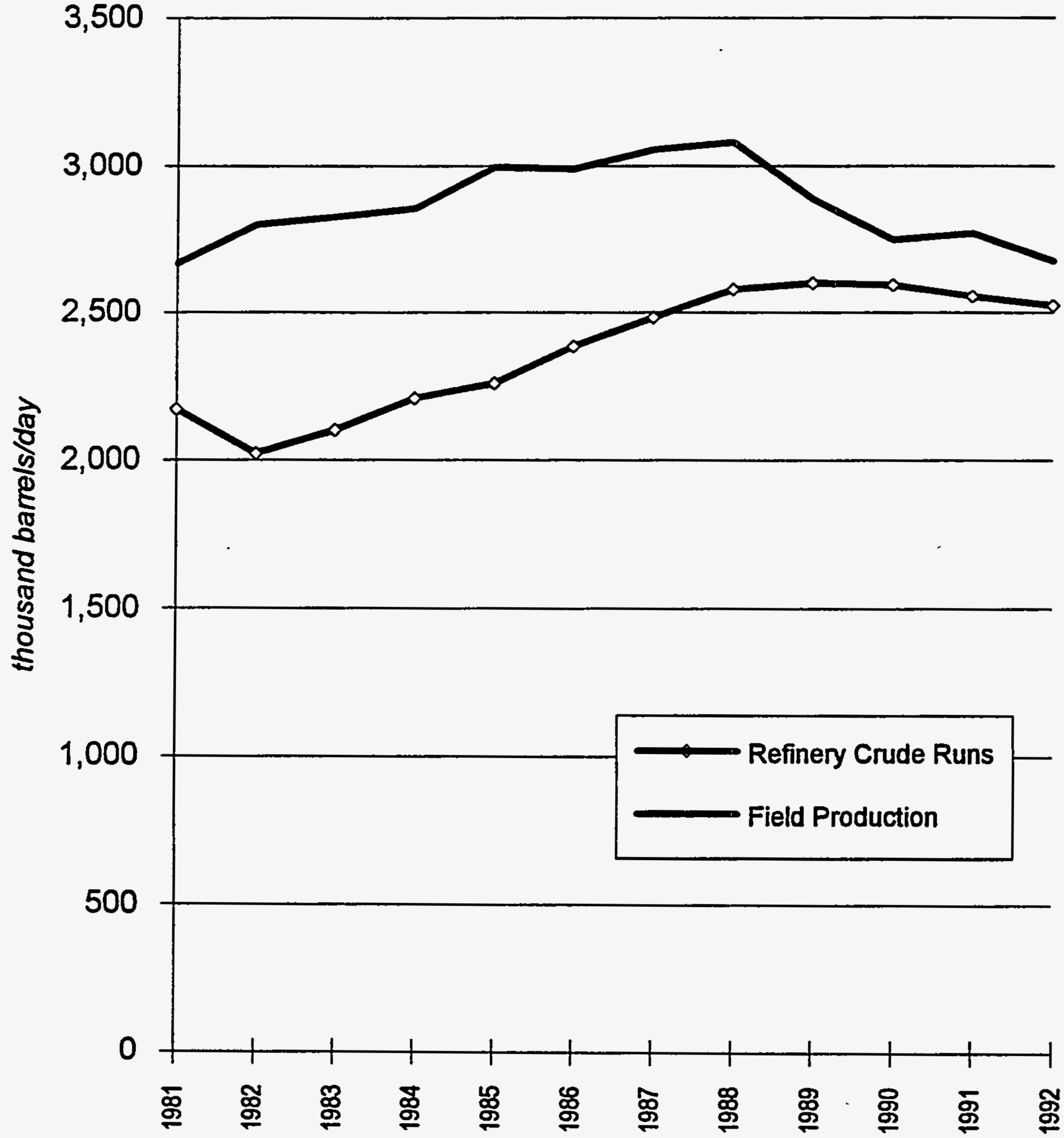
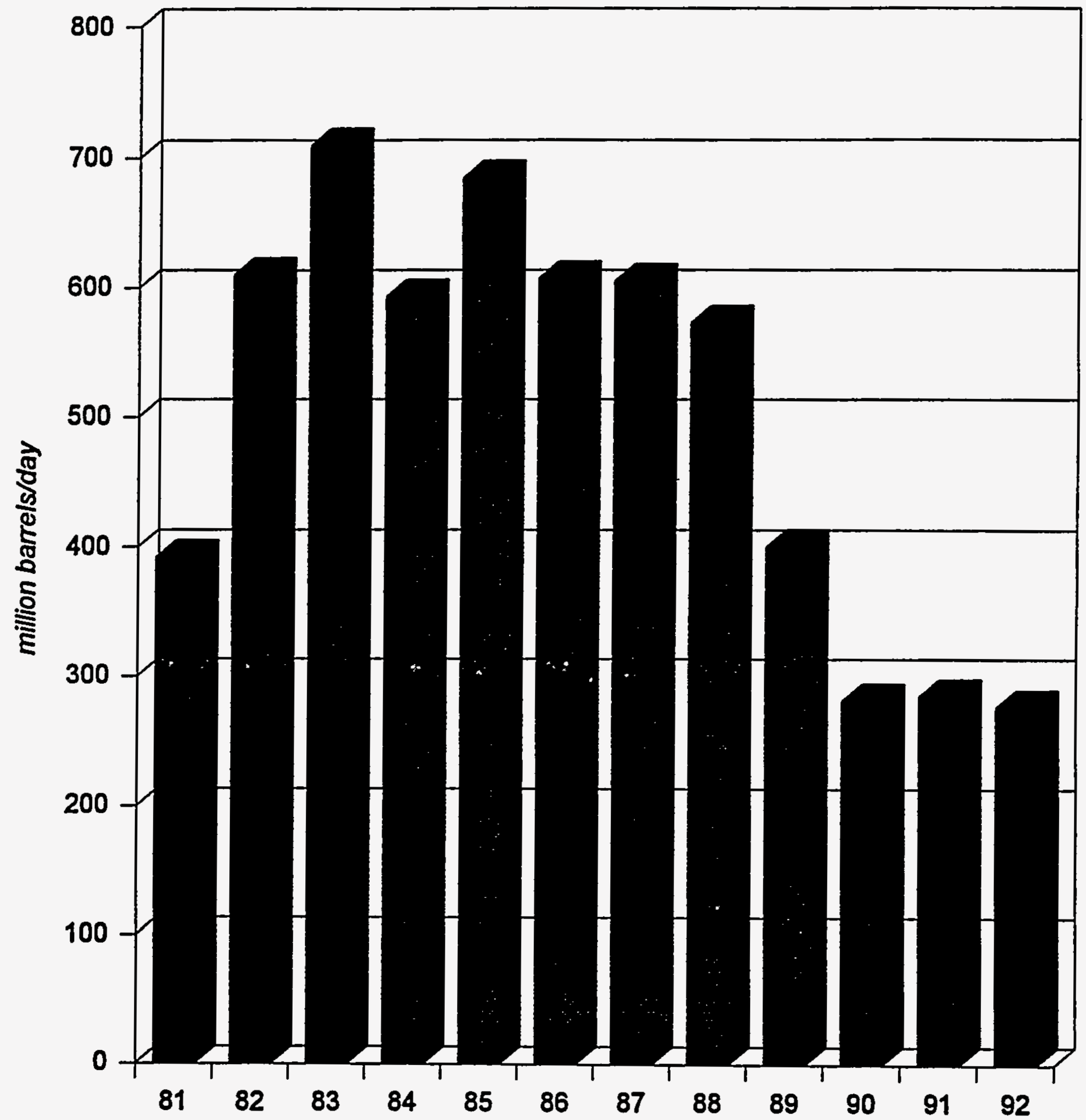


Figure 74. The PADD-V Crude Surplus is Dwindling: Surpluses, 1981-91



product exports. Depending on petroleum product specifications, the complementarity between Asia and the U.S. West Coast could increase in the 1990s. Although U.S. West Coast gasoil exports are of low overall quality, they could represent an important contribution to the Asian blending pool; and Asian gasoline blendstocks, if they are able to meet the moving target of U.S. West Coast specifications, could help ease some of the pressure in the California gasoline market as it attempts to reformulate its fuels. It may even be possible that Asian low-sulfur, low-aromatics, high-cetane diesel will find its way into the California market; certain naturally occurring straight-run diesels in Asia are far closer than domestic ones to the stringent specifications for reformulated automotive diesel set to take effect in October 1993. These specifications call for ADO with a maximum of 0.05 percent sulfur and a cap on aromatics of 10 percent (with exceptions up to 20 percent for alternative formulations still meeting emissions standards). None of the U.S. West Coast crudes yield straight-run diesel material that comes close to meeting the new standard, but several straight-run Asian gasoils come quite close. A two-way trade in diesel is a possibility for the 1990s, with relatively poor quality diesel moving out of PADD-V and smaller quantities of higher-quality diesel and gasoline blendstocks coming back on the return voyage.

8. Changing Government Policies and the Oil Industry

The energy scene in the 1970s and early 1980s worldwide was dominated by government policies. In Asia, where government traditionally holds tight reins on the economy, government involvement in the energy industries of most countries became the driving feature of the market.

In general, there were two patterns of behavior with respect to governing energy demand. The first, which might be called the Japanese model, was to respond to the first oil crisis by curtailing demand by whatever measures possible. The second, which might be called the Thai model, was to respond to the first oil crisis by attempting to shield the economy from the price increases, and, reluctantly, after the second crisis, to allow prices to increase, but to attempt to shield certain energy products from the market by systems of cross-subsidies. Most countries eventually ended up with one or more products that were priced at an excessively low level compared with other energy prices: diesel in Thailand; kerosene in India, Indonesia, and Japan; and fuel oil in South Korea. The effect, unsurprisingly, was to distort demand patterns.

Demand patterns for oil were further perturbed by non-price measures taken by governments. The biggest effect was felt in the electric power sector, where mandated switches away from oil were the order of the day. In both South Korea and Japan, to mention two cases, mandated changes in fuel for power generation cut away at fuel oil's share of the barrel, while high gasoline prices kept gasoline demand low. Coupled with depression in the petrochemical market, which pushed down demand for naphtha, the result was dampened demand at both ends of the barrel, and most of the incremental demand growth was for the middle distillates.

Having adjusted to regulated high prices, most governments resisted the collapse of the crude market in 1986. Few let the price decreases in the market pass on to consumers. It was only after one or two years of persistently low prices that Asian governments gradually allowed their domestic markets to respond to changes in the international oil scene. Even before the prices were passed on, however, the strengthening of domestic currencies against the dollar was encouraging substantial demand growth. Looking at Figure 63, it is obvious that, for the products lighter than fuel oil, an Asian demand boom was well underway by 1983. The continued downward pressure on fuel oil, however, via government fiat, disguised the trend, leading most observers to believe that they were studying a stagnant market.

The lessons of Figure 63 are important. Today, many industry analysts are wondering if the demand growth in Asia is a temporary phenomenon, a quirk of the last few years. In actuality, the demand boom has existed through most of the 1980s, despite the best efforts of governments to curtail it. Despite high prices and policies specifically designed to curb consumption, Asian demand for LPG and the transport fuels has been healthy since 1970, with a brief weakness in 1980-82. It is the three years following the Iranian revolution that are the aberration, not the recent trend. Asia contains a disproportionately large fraction of the world's population and consumes only a small fraction of the world's oil. Continued economic growth will mean continued increases in demand. Much of the late 1980s demand boom is simply the bottoming-out of government-sponsored fuel-oil-substitution programs, which allow the real demand trends to be seen.

Privatization and reduction of government regulation have been the watchwords of the 1980s in the United States and Western Europe. Given that the highly interventionist economies of Asia have in general outperformed the rest of the world in the last two decades, it might seem surprising that Asian countries have paid any attention to this Western fashion; but in the late 1980s, deregulation and greater openness to the world market have become major policy goals in most Asian nations. The oil industry, which has been tightly regulated in most countries where it is not actually a government monopoly, has been targeted for major liberalizations in most of Asia.

Australia has already deregulated its industry, making it one of the freest oil markets in the world. New Zealand has spun off most of its government holdings in oil and chemicals. Japan has officially announced a phased deregulation plan for refining, though it falls short of full deregulation, and South Korea has a controversial proposal for freeing its market.

Malaysia, where the state enterprise Petronas has long had to compete head-on in the domestic market with international majors, has become something of a model for countries with national oil companies. Thailand is moving toward liberalization of its market and has agreed to a number of new refining expansions and grassroots facilities involving foreign companies. Indonesia does not allow foreign competition in its domestic market, but, in a move that surprised many, it has approved the construction of joint-venture export refineries. Even Taiwan's CPC, which was long restricted to a strictly domestic role, has been allowed to seek overseas ventures and to find joint venture partners in chemicals and refining—as well as upstream ventures.

The two major holdouts in Asia's progressive liberalization are India and China. Both have allowed only minor and highly constrained foreign participation in their down-stream industries and have restricted foreign participation in upstream ventures to certain areas on terms that no longer seemed attractive after the early 1980s. There is a growing recognition in both countries, however, that price reforms and a wider scope for foreign investment are needed in the coming decade. Strong vested interests, nationalist sentiments, and economies that find it hard to allow repatriation of profits will make the opening of these markets difficult; however, it may be impossible for them to meet their capital needs for investment in the oil industry over the next decade, if some fundamental realignments in thinking do not take place.

With the exception of a few countries—Australia, Singapore, New Zealand, and, just conceivably, South Korea—truly free markets in oil are unlikely to emerge in Asia in the next decade. What has changed fundamentally, however, is that governments now recognize that it is impossible to isolate their economies from the world market and that it is extremely expensive even to try. Many of the Asian countries are exemplary managers of their economies, but few of them are adept at running specific businesses; as elsewhere in the world, most government enterprises have been money-losers. There is a general trend to back away from direct involvement in decision making in oil, and to hold even national oil companies more at arms-length. There will be less transfer of government money to the energy sector in the coming decade, and even state enterprises will be under pressure to either achieve self-financing or seek joint-venture partners for new investment needs.

The Asian oil market will continue to be strongly affected by government policies that are not strictly regulatory (such as environmental specifications) in nature, but most countries will be far more open than in the past. The fact that the current trend toward liberalization was not reversed by the Kuwaiti crisis shows that governments in the region are now resigned to the fact that national policies cannot swim against the flow of international market developments. Most Asian nations are now interested in shaping their energy industries rather than controlling them directly.

9. Conclusions: The Areas of Uncertainty

A planner in Hawaii facing the rapidly changing situation in Asia should in principle monitor every aspect of the market on an ongoing basis. Too many of the important factors in the Asian market are based on demands that have not yet materialized, oil fields that have not yet been discovered, and refineries that are not yet under construction. "Fluid" is a mild word to describe a situation that still exists mainly on paper.

Nonetheless, to plan intelligent strategies requires making some assumptions about the situation in Asia five or ten years hence. Monitoring everything is simply not possible, but there are a few key factors that should be watched closely on an ongoing basis because of the magnitude of the impact that they could have on the market.

First and foremost—and most likely to be neglected—are the emerging situations in China and India. These countries have the greatest uncertainties about future demand levels, the largest questions about future levels of oil output, and face the biggest financial and logistical difficulties in building enough sophisticated refining capacity to meet their demand. Both countries may be pushed onto the market as major product importers in the 1990s, but both have refinery self-sufficiency as key national goals within their respective oil industries. Their demands on the market could mount rapidly, but an ambitious capacity-expansion program could then reverse the trend quickly. China and India are the major wild cards in the Asian oil market of the 1990s.

Second, Japanese policies should be followed closely. MITI's intent to allow Japanese refining to expand once again has already promised to cut away at Japan's traditional high levels of product imports. Japanese refining will remain highly responsive to government policy despite the current liberalization program. Policies on crude burning in the Japanese electric-power sector can have a major impact on the regional crude slate. Japan will continue to be the largest player in the Asian market, and it is well worth the planner's time to track the Byzantine process within MITI's governance of the Japanese energy system.

Third, and perhaps obviously, the Indonesian program of expansion into export refining needs to be monitored closely, since, despite the government's commitments to the current plans, there is still ample time and latitude for change. The Indonesian expansion plan in the 1980s was notorious for delays, cost overruns, and, once completed, for poor utilization rates. This situation is unlikely to repeat itself in the 1990s, not only because of the presence of joint-venture partners, but also because Pertamina's refining group and the energy ministry are now in better control of the situation. Despite more effective management, however, there is considerable room for changes in current plans before the series of export-oriented refineries come onstream. Less refinery construction may mean less disruption in availability of Indonesian crudes for Hawaii refineries; more refinery construction may, however, make it economical to increase product imports.

Finally, the oil production prospects in some of the more minor countries should be followed closely. There has been a tendency in the past for analysts to focus primarily on changes in Indonesia, China, and Malaysia, neglecting developments in other countries. Such an approach has worked in a relatively slack oil market. In the 1990s, with higher demands for low-sulfur crudes and probably a lower availability of such crudes on the export market, the incremental supplies from other exporters can have an important impact on the market. This effect is most likely to be felt around 1995, following an expansion of availability in the early 1990s that may lead some to adopt a complacent attitude. Later in the decade, however, the supply situation in Australia, Papua New Guinea, Vietnam, and Burma will become of increasing importance; and, since the renewed exploration in these countries is focussed mainly on greenfield plays, there may be important surprises in store. Hawaii's crude slate may evolve away from the traditional Indonesian crudes and move toward Papua New Guinea or Vietnamese crudes.

III. The World Gas Industry

The gas market offers a striking contrast to the globally integrated, interconnected oil market. There is nothing even approaching a "world market price" for gas, because so little is traded. Difficulties in transportation dominate the industry and result in a situation where gas can be sold in different areas of the world at prices that differ by as much as 1,400 percent, all without major economic distortions. Until recently, in fact, a large percentage of the gas produced in association with oil was simply flared to dispose of it.

Although the consumption of all fossil fuels attained a steep growth curve after the Second World War, oil and coal have a long history in many areas of the world. Gas, on the other hand, was developed only in a few areas prior to the 1970s. As late as 1970, North America still accounted for more than 63 percent of all gas consumption; the United States and Soviet Union together made up nearly 85 percent of all demand.

Because of its geography, the physical characteristics of gas, and technical constraints, gas plays only a limited role in the world energy picture. In no nation is it the dominant fuel. There are strong indications that gas use will continue to rise both in absolute and percentage terms, especially because of its perceived environmental advantages. Given present prices and technologies, however, the amount of oil displaced by gas is likely to remain limited without concerted government efforts.

This section provides a global and regional look at the evolving gas market as background to overall Hawaiian energy policy. The specific roles that gas might play in the Hawaiian energy system are treated in the report of Task II (*Fossil Energy in Hawaii*) of this project, and the background economics and a technology review of LNG are provided in the report of Task III (*Greenfield Options*).

A. Prologue: "The Rule Of 20"

Today's gas industry is more concentrated than the global petroleum industry. The "Rule of 20" applies to gas even more than to oil. Indeed, a Rule of 10 would nearly suffice for gas.

Unlike oil, which is used by all of the world's countries, only 76 countries consume gas. Although about 88 countries have gas reserves, only 69 are currently producers, and the reserves in the remaining countries are untapped. The cost and difficulties of getting gas to markets, either domestic or international, mean that many countries continue to leave their resources in the ground.

1. Gas Reserves

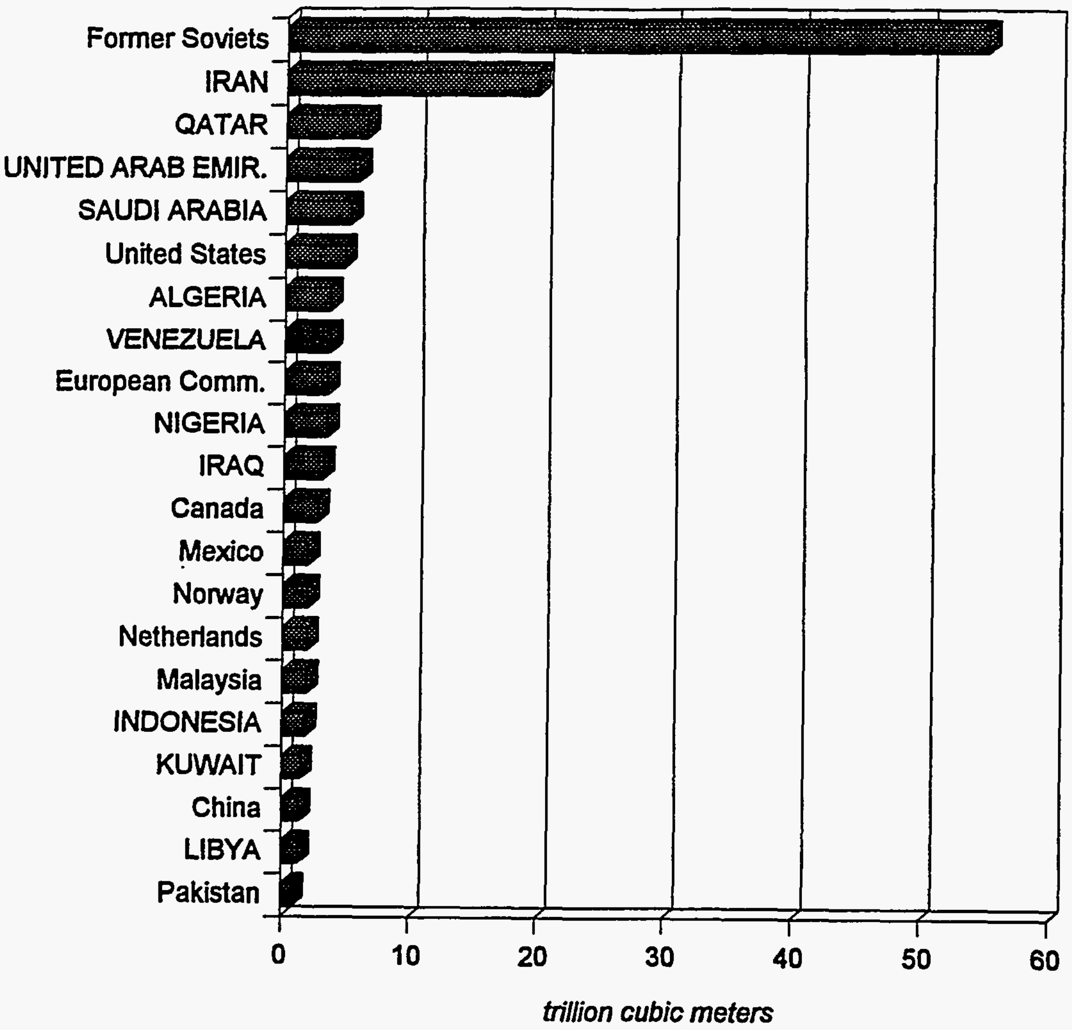
Figure 75 shows the proven gas reserves of the top 20 countries in 1991. These 20 countries account for 93 percent of the world's known reserves of gas.

The Commonwealth of Independent States (CIS, the former Soviet Union) dominates the world reserve picture. The CIS alone has about 40 percent of all the world's conventional gas reserves. In addition, the CIS also has identified (though not assessed) huge deposits of "methane hydrates" (gas locked up in ice) in Siberia.

The next four largest reserves are in OPEC countries around the Persian Gulf. More than half the countries shown on the figure are OPEC members, and of the 13 members of OPEC, only two—Gabon and Ecuador—are not in the top 20. Despite the number of OPEC countries listed, OPEC accounts for only 40 percent of total reserves.

Although the collapse of the Soviet Union means that fewer strategic issues are now raised about reliance on "Eastern Bloc" resources, OPEC and the CIS have between them about 80 percent of all world gas reserves. In terms of stability of supply sources, it can be argued that gas offers security risks at least as large as those seen in the oil industry. (The relative security of gas and oil imports is discussed in the report of Task II, entitled *Fossil Energy in Hawaii*, of this project.)

Figure 75. Top 20 Gas Reserves, 1992



Note: Names of OPEC members are in uppercase. OPEC accounts for 40% of world reserves. The top 20 countries account for 93% of world reserves.

The United States has the sixth largest reserves in the world, but these amount to only about 3.5 percent of the world's known reserves.

The majority of the top 20 in gas reserves are major oil-producing countries, but two—the Netherlands and Pakistan—have little or no oil. Although not shown on the graph, a number of other countries (mainly in Africa and South America) have proven gas reserves but inconsequential reserves of oil.

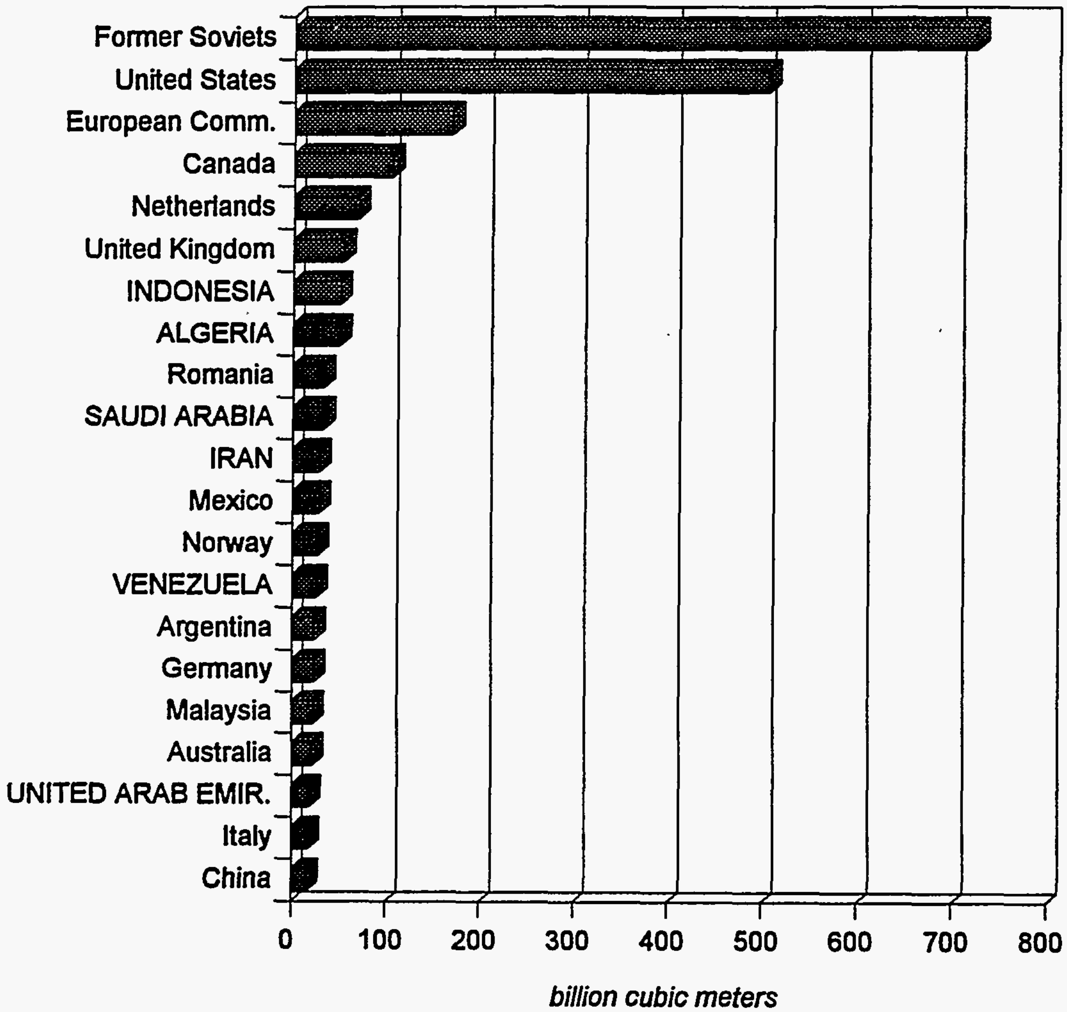
2. Gas Production

Figure 76 shows the top 20 gas producers. As in the case of oil, many of the countries on the list are the same as on the list of reserves, but the order is rather different. In the case of gas, however, some countries with large reserves—Qatar, Nigeria, Iraq, Kuwait, Libya, and Pakistan—are displaced from the list of major producers by others—the United Kingdom, Romania, Argentina, Germany, Australia, and Italy—with relatively small reserves.

The former Soviet Union maintains the lead, followed fairly closely by the United States. The European Community (shown only for comparison) is in third place as a grouping; the third place in countries is taken by Canada, followed by the Netherlands and the United Kingdom.

It is noteworthy that the top producers, after the former Soviet Union, are industrial (OECD) countries. Eight OECD members are among the top 20, compared to four OECD members in the equivalent ranking of oil production. The chart includes countries, such as Germany and Italy, that are not often thought of as hydrocarbon producers. This is an important point: the development of gas resources is more dependent on access to markets than on the cost of extraction or the size of the resource. The United States, United Kingdom, Germany, and Italy are major producers because they have markets and distribution infrastructure; Canada, Norway, and the Netherlands are major producers because they border on major markets.

Figure 76. Top 20 Gas Producers, 1992



Note: Name of OPEC members are in uppercase. OPEC accounts for 11% of world production.
Top 20 account for 95% of total world output.

The top 20 countries shown in Figure 76 account for 95 percent of all gas production. OPEC has 40 percent of reserves but a mere 11 percent of production. while 11 members of OPEC are listed among the top 20 in terms of gas reserves, only six are listed among the top 20 producers.

If reserves-to-production (RP) ratios are somewhat questionable as measures of reserve depletion for petroleum, they are doubly so for gas. In many cases, the RP ratio for gas is infinite, since some countries with reserves have zero production. Figure 77 shows the RP ratio for the top 20 producers. Iran and the United Arab Emirates (UAE) have huge RP ratios (686 years and 301 years, respectively), but this is more a reflection of their limited market opportunities than any measure of the extent of their reserves.

Nonetheless, the overall pattern is clear, and the conclusions are similar to those seen in the oil market. Most of the industrial countries, which have smaller reserves on average, are also depleting their reserves much more rapidly than the OPEC countries. One of the big differences in the markets, of course, is the former Soviet Union, which has at least 75 years of additional production even at its current high output levels.

3. Gas Consumption

As Figure 78 indicates, gas consumption is effectively a three-level market, with the top seven consumers accounting for about 85 percent of global demand, and the remaining 15 percent being distributed among the other 69 consumers. At the top are the CIS and the United States, which together account for 60 percent of demand (roughly 30 percent each). The second tier represents a tenfold decrease in consumption. This tier comprises Canada, Germany, the United Kingdom, Japan, and Italy, each of which accounts for about 3 percent of world demand.

The next tier represents a decrease by half again and comprises countries that each account for 1.5 percent of world demand or less. All of the OPEC countries shown fall into this third level. Their consumption of gas, like their consumption of oil, is a small part of the overall picture, at only 8 percent of world output.

Figure 77. RP Ratios of Top 20 Gas Producers, 1992

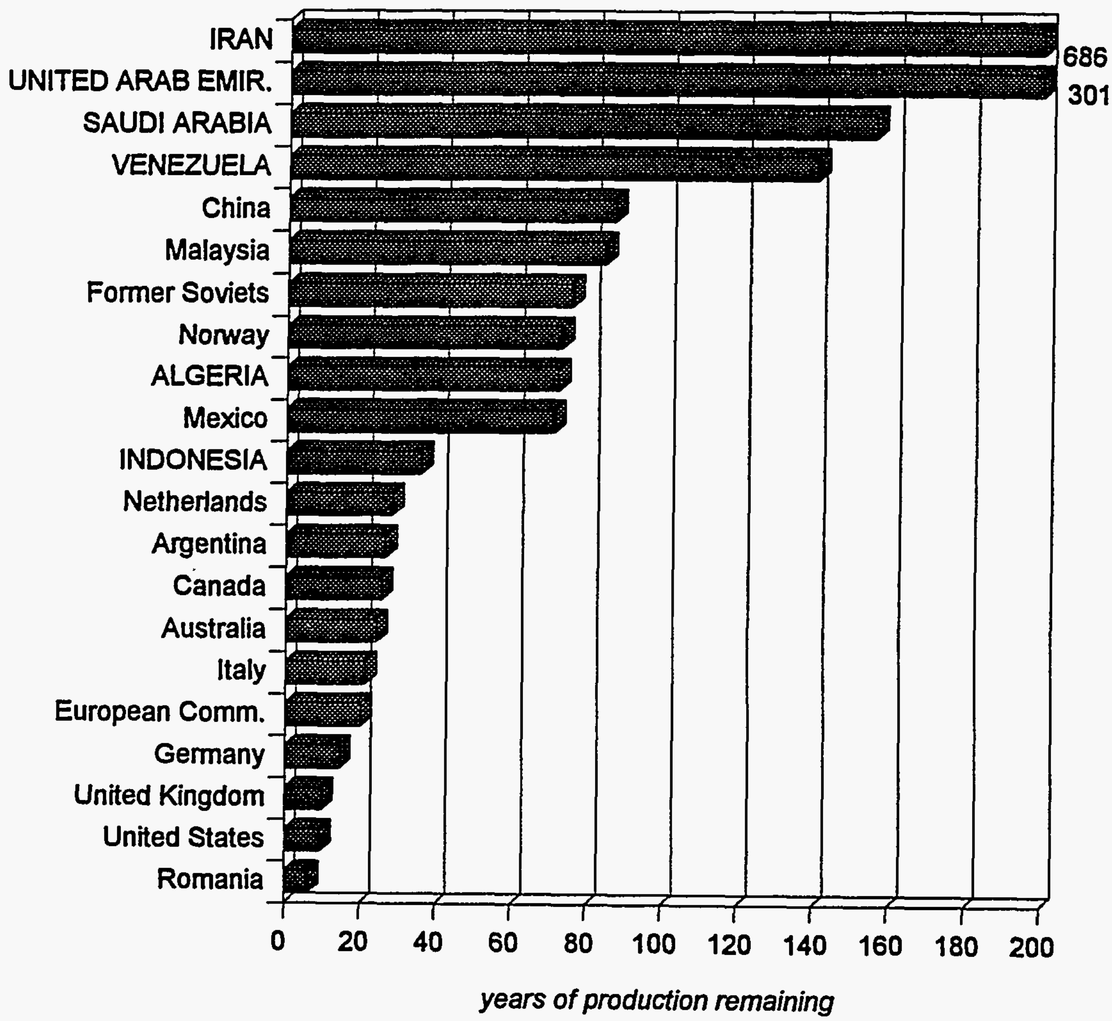
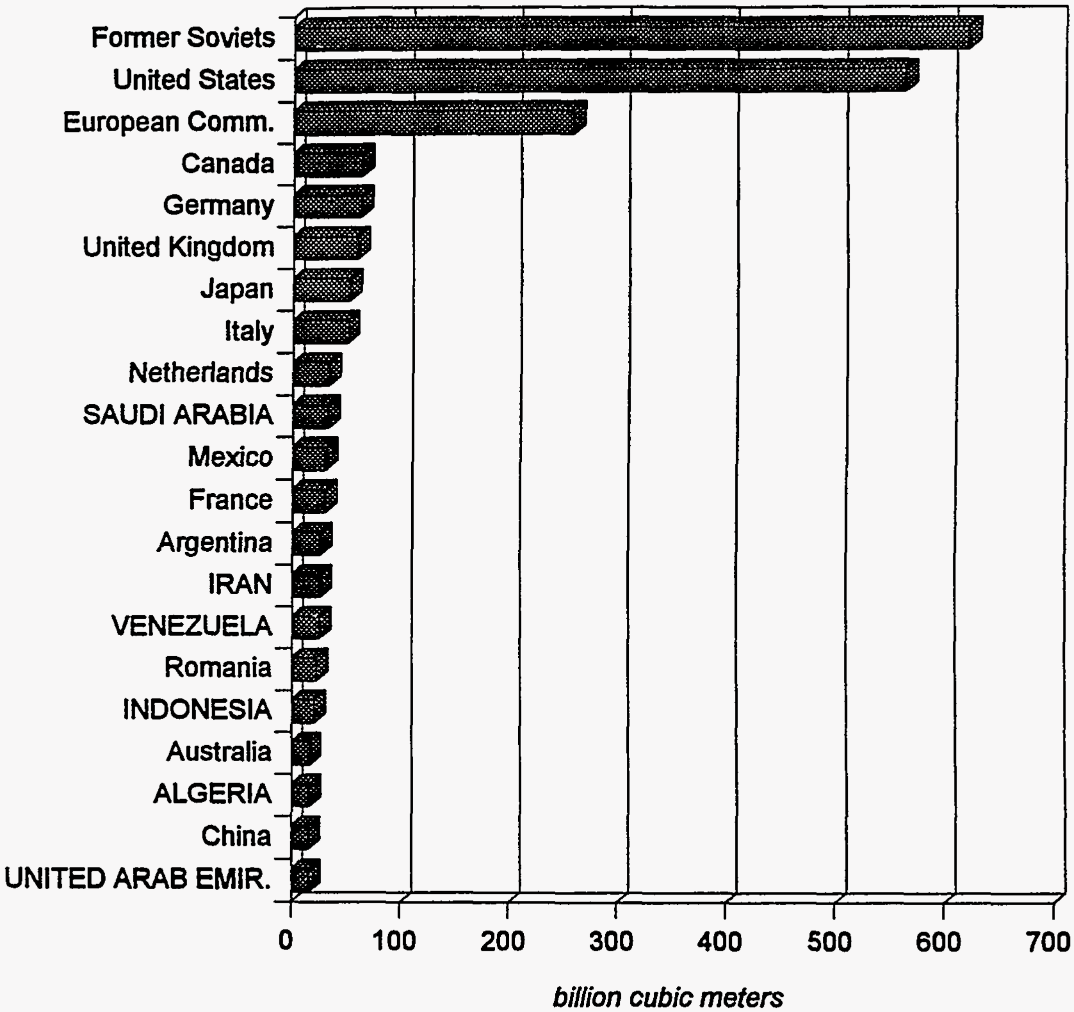


Figure 78. Top 20 Gas Consumers, 1991



Note: Names of OPEC members are in uppercase. OPEC accounts for 8% of consumption and the top 20 account for 90%.

4. Gas Exporters

The top 20 gas exporters account for more than 99 percent of all exports. Indeed, the top six exporters alone—the CIS, Canada, Netherlands, Algeria, Indonesia, and Norway—provide 77 percent of all exports.

Of the total exports, OPEC countries account for 22 percent, although this is very unevenly distributed. The two top gas exporters in OPEC are among the smaller OPEC oil producers: Algeria, and Indonesia. These two countries were also among the earliest participants in the LNG market. (The first LNG export facility was built in Algeria in the early 1960s, although Algeria also has a subsea pipeline across the Mediterranean to Italy.) The UAE and Libya are also LNG exporters, and, like Indonesia, LNG is their only gas export mode.

Iran and Iraq are both restricted to pipeline exports, and their pipelines run to only single destinations, both of which might seem peculiar. The Iranian pipeline runs to what was once the Soviet Union. This line was constructed in the 1970s, because the Soviet government found it profitable to import Iranian gas into the south, thereby making some of its own gas available for exports to the West. This trade was disrupted by the Iranian revolution, although exports resumed at moderate levels in the mid-1980s.

The Iraqi pipeline, ironically, runs only to Kuwait. Kuwait's ambitious refinery upgrading campaign in the early 1980s resulted in the cracking of virtually all Kuwaiti fuel oil into lighter products. This change left Kuwait short of fuel for its electric power plants and resulted in short-term imports of fuel oil. The Iraqi pipeline was completed in 1986 and provided gas up to the date of the Iraqi invasion of Kuwait. The exports have not yet resumed.

Another international pipeline runs from Afghanistan into the central CIS. The Afghan exports date back to the late 1960s, and were fairly constant until the later stages of the Afghanistan conflict. Gas was cut off briefly after the Soviet withdrawal but seems to have resumed subsequently.

These examples highlight a major problem in the international gas trade: the fundamental lack of flexibility. Oil can be loaded and discharged at literally thousands of terminals around the world; although there are limitations on the size of vessel that can use certain moorings, with only a few exceptions oil can be delivered from virtually any country to any other. Pipelines, on the other hand are subject to all manner of political risk. The Middle East is littered with unused or only intermittently operated pipelines for both gas and oil: Saudi Arabia-Israel, Iraq-Turkey, Iraq-Kuwait, Iraq-Israel, Iraq-Syria, Iraq-Saudi Arabia, Syria-Israel, Syria-Lebanon, and Saudi Arabia-Lebanon, some dating back to the 1950s. The United States lobbied hard against the Russia-Western Europe pipeline system because of perceived political risk.

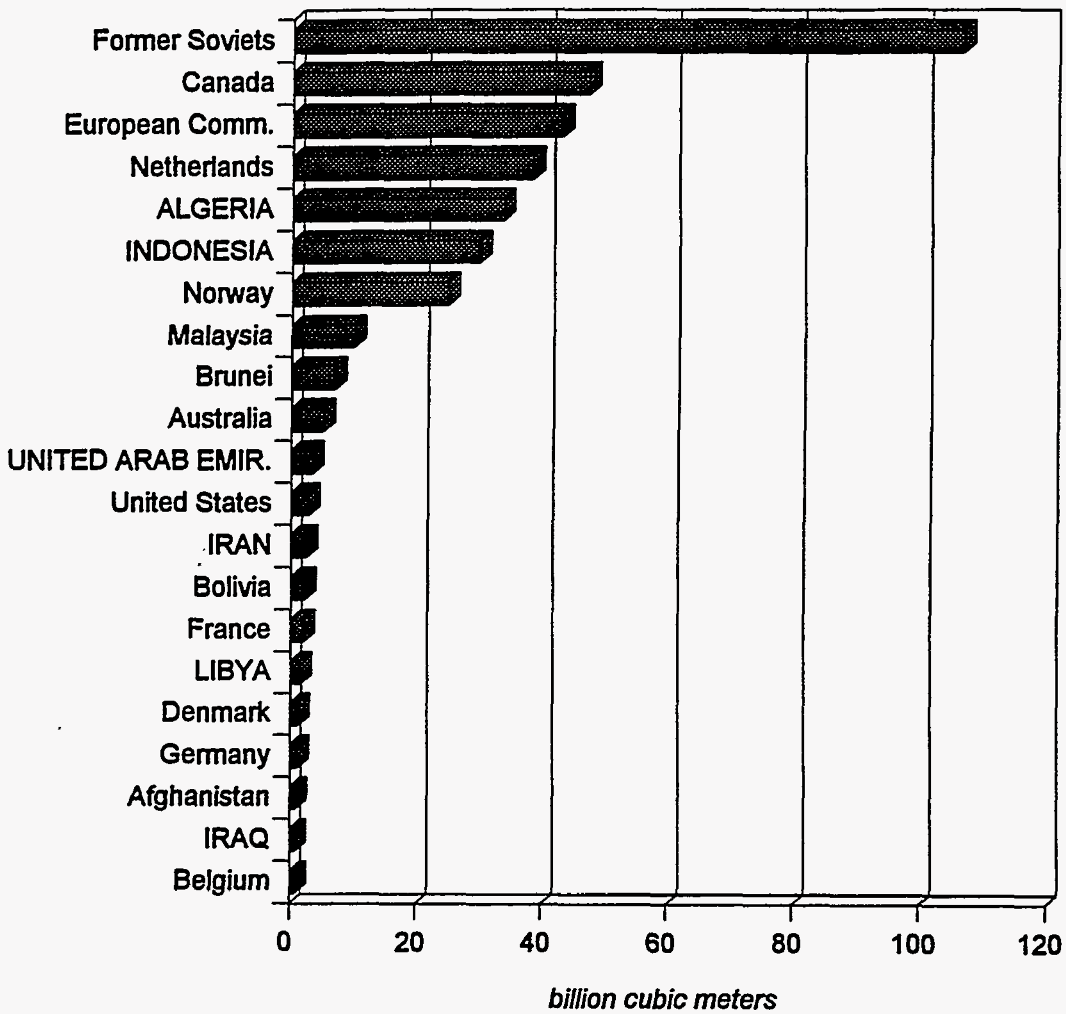
In terms of potential supply and demand, there are dozens of pipeline connections that would make good economic sense, in Asia, Latin America, the Mideast, and Africa. In terms of politics, the days of such gas grids still seem remote.

The majority of developing countries listed in Figure 79 have opted for LNG as their main gas export option. There has never been a cutoff of LNG supplies. LNG is more flexible than pipelines in terms of sources and destinations, but at present it also is limited in ability to switch between sources and destinations. This will be dealt with in more detail in later sections.

5. Gas Importers

Historically, gas imports have been governed largely by a combination of potential demand and proximity. Thus, the majority of the big importers have had access to secure pipeline connections. The United States is connected to Canada and Mexico; continental Europe is connected to the former Soviet Union, Norway, and Algeria; Argentina is connected to Bolivia. In these countries, the outside supplies are used to augment or replace domestic production. A number of countries (the United States, France, Belgium, Germany, the CIS, and Canada) both import and export gas, either because of geographic market spread, or by acting as a gateway to other markets.

Figure 79. Top 20 Gas Exporters, 1991



Note: Names of OPEC members are in uppercase. OPEC accounts for 22% of exports and the top 20 account for 99.9%.

A recent emergence, however, has been the increasing importance of importers that have no proximity to their suppliers. Japan has only a tiny output of domestic natural gas but has become the world's largest single importer of gas based solely on LNG. Korea, which began to take LNG only in late 1986, has already joined the top 20 importers, and Taiwan should be among the top 20 importers in the next two years. These developments are unique not just because they are based on LNG, but also because they involve the planned creation of markets where none existed before.

As shown in Figure 80, the top 20 importers account for 97 percent of all imports. OPEC is inconsequential at 0.3 percent of imports, but the CIS imports are by no means negligible (though they are dwarfed by CIS exports).

6. LNG Trade

LNG technology is complex, and LNG contracts can be arcane, but the structure of the international LNG market is simplicity itself, because there are so few players.

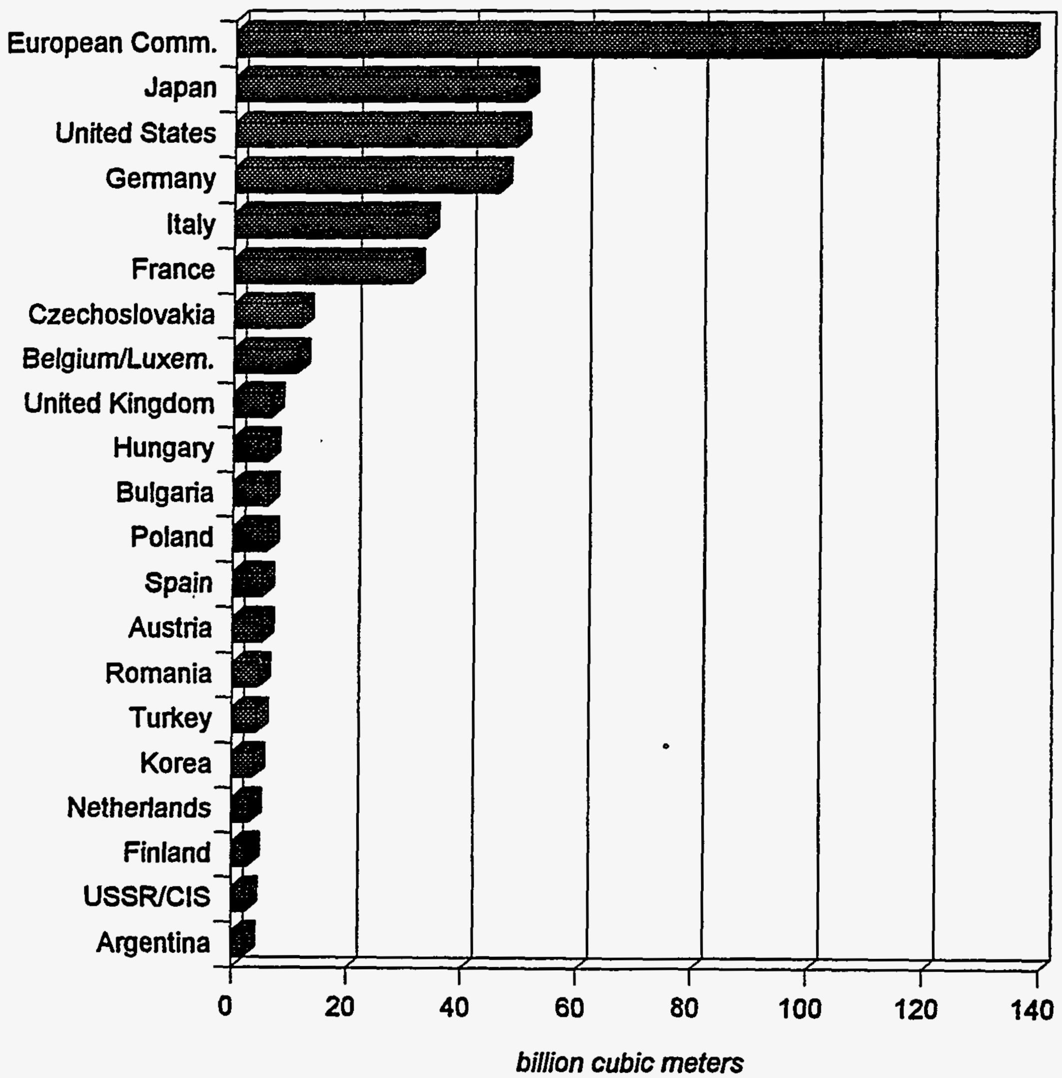
Figure 81 shows all eight LNG exporters and the eight importers. Indonesia is the largest exporter at 30 billion cubic meters (bcm), followed by Algeria at 19 bcm. By comparison, exports from the United States (1.3 bcm) or Libya (1.6 bcm) amount to only about 5 percent of Indonesia's volume.

The United States imports onto the Atlantic coast and exports from Alaska. Only Algeria and Indonesia are diversified exporters. All of Libya's exports currently go to Spain. All LNG exports from the United States, UAE, Brunei, Malaysia, and Australia go to Japan.

Algerian exports go to the United States, Belgium, France, Italy, and Spain, and in the past have gone to the United Kingdom. Indonesian exports are restricted to East Asia, primarily Japan (24.2 bcm), with smaller cargos to Korea and Taiwan.

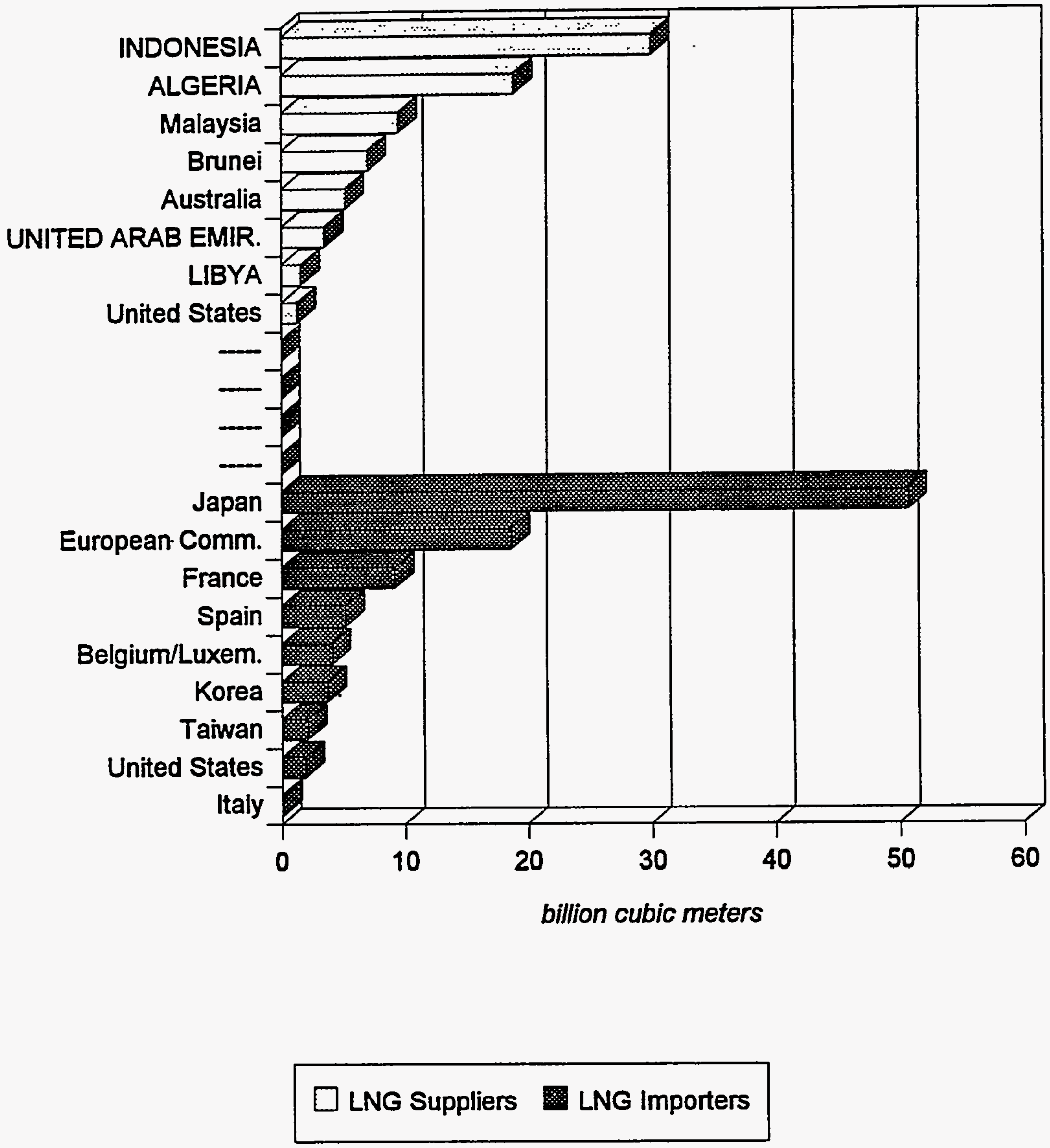
There have been discussions about LNG development in a number of potential exporting countries, with studies going on for years (and, in a few cases, decades). Among the major prospects have been Qatar, Nigeria, Siberia, Oman, Venezuela, Iran,

Figure 80. Top 20 Gas Importers, 1991



Note: OPEC accounts for only 0.3% of imports whereas the top 20 account for 97%.

Figure 81. LNG Traders, 1991



Note: A total for the European Community is added for comparative purposes.

and China. Of these, only the Qataris are firmly set to join the market in the near future, though projects in Nigeria and Siberia (Sakhalin Island) are also reckoned as having good chances of being implemented.

OPEC countries currently account for 70 percent of LNG exports. Completion of plants in Qatar and Nigeria would push the OPEC share even higher. It should be noted, however, that OPEC does not govern the gas supply or pricing issues (even in principle) of its members; the OPEC mandate is strictly limited to crude oil. An LNG cartel would be far easier to manage than a cartel in oil, but none of the producers are anxious to create one. It is difficult enough to get the investment financing and long-term contract commitments for an LNG project without adding additional political risks to the process.

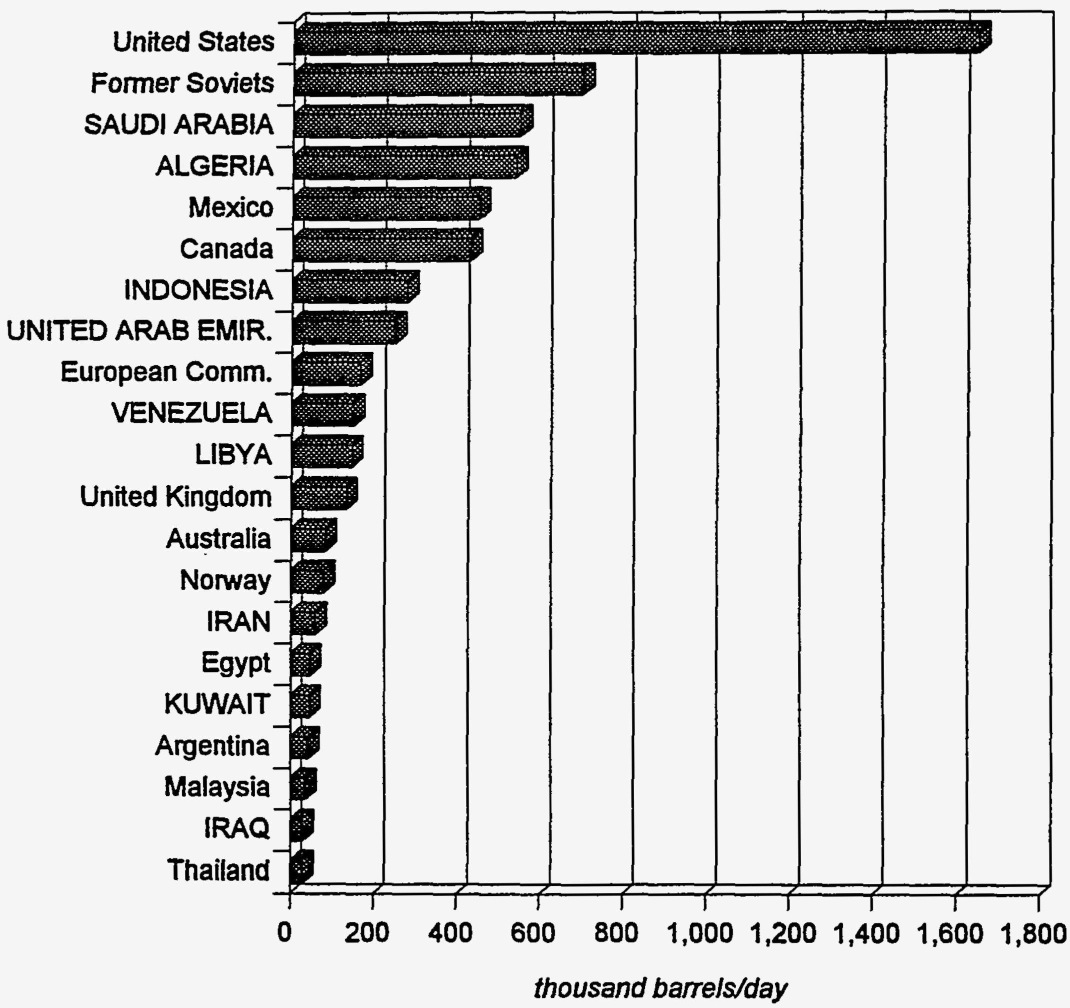
7. Natural Gas Processing

As will be discussed below, the processing of raw natural gas into pipeline-quality gas or LNG yields a number of by-products collectively referred to as natural gas liquids (NGL). These volumes are typically reported as part of oil production, since they are used like oil products. But their contribution to liquefied petroleum gas (LPG) and to petroleum product supply are not at all negligible. About 5 million of the 65 million barrels/day of world "oil" output actually comes from the processing of natural gas.

Figure 82 shows the top 20 producers of NGLs. The top 20 account for 98 percent of all NGL production. The United States is by far the largest gas processor at 1.65 million barrels/day of output, more than twice the volume of the nearest competitor. Although CIS gas production is higher than U.S. production, the NGL output from Soviet gas is only 0.7 million barrels/day—partly because of gas composition, partly because the CIS has not installed sufficient gas processing facilities.

OPEC is an important player in the NGL market. Although OPEC gas production is only 11 percent of the world total, OPEC NGL output is 36 percent of the world total, largely because of the high percentage of OPEC gas output that is "associated gas" (discussed in detail below).

Figure 82. Top 20 NGL Producers, 1991



Note: Name of OPEC members are in uppercase. OPEC accounts for 36% of output and the top 20 account for 98%.

8. Conclusions

The gas market is dominated, to an even greater degree than the oil market, by a few players. Moreover, the individual policies of the producers and consumers have far more impact than in the oil market, because the market for gas is split into segments that are regional at best. One country may pay very different prices to various suppliers for its gas imports, and the prices may be set on contracts that have different expiration dates and different escalation clauses. Prices for imported gas are very different in the United States, Europe, and Japan, and more important, the markets are *discrete*. A new contract price established between Indonesia and Japan will not affect the price between Algeria and the United States.

There are sometimes options of "striking a good deal" in the gas trade that are absent from the oil market. Contracts are long-term and are usually honored. In general, however, most gas suppliers are now expecting premium prices because of perceived environmental benefits and energy diversification.

Whether gas is more or less "secure" as an import item is examined in Chapter IV of the Task II (*Fossil Energy in Hawaii*) report of this project. In the context of the above statistics, however, it is clear that a few countries are crucial to international trade. A disruption in Indonesian supplies, for example, would cut supplies of gas to Japan by 50 percent and to Korea and Taiwan by 100 percent. Furthermore, it is unlikely that any of this lost volume could be obtained from elsewhere in the short term; there is no real spot market in LNG.

On the other hand, the curious aspect of the international gas market is that the total loss of Indonesian supplies would not necessarily affect the supply or price to any countries other than those receiving LNG from Indonesia. There is no such thing as an "isolated disruption" in the oil market; in the international gas market, this is the only kind of disruption possible at present.

B. Gas and Gas Components

Few energy sources are as complex as the diverse collection of materials referred to as natural gas. Gas varies widely in composition and quality. It may be produced as a primary energy product or as a by-product of oil production. It has highly specialized storage and transport requirements. In addition, the components of natural gas may be used as feedstock to a broad array of chemical industries that have widely varying capital requirements.

Most energy economists are accustomed to dealing with natural gas as a homogeneous fuel that competes with coal and fuel oil on a Btu basis. While this approach is satisfactory for many energy forecasting purposes, the material in reference is typically "pipeline gas," which is only a single component of the gas resource. The availability of gas on the international market is affected by the value of all of its components as well as the comparative costs of other fuels. Furthermore, gas can act as a substitute for only a limited array of oil uses; gas, in general, is more versatile than coal but less versatile than petroleum. Because of the nature of the resource, however, the line between gas and oil is fundamentally blurred.

1. Natural Gas: A Complicated Fuel

When most energy analysts use the term "natural gas," they are referring to pipeline-quality gas: a mixture of methane, containing small amounts of ethane and variable amounts of inert ingredients (including molecular nitrogen and water). This mixture, which generally has a heating value in the order of 1,000 Btu per cubic foot (Btu/cf), or 35,300 Btu/cubic meter, is used almost exclusively as a fuel. On the other hand, when a petroleum specialist refers to "gas," he may be referring to pipeline-quality gas, to liquefied natural gas (LNG, composed of almost pure methane), or, more often, to gaseous hydrocarbons and inert gases that come out of some type of hydrocarbon reservoir. The characteristics of the gas at the wellhead go far in determining both the uses and value of the resource, as well as many of the investment requirements and constraints on its exploitation.

Natural gas occurs in three major categories, depending on the mixture of materials in the source reservoir. The first, and until recently, most common source category is associated gas: gas that is present as a "gas cap" above the crude oil in the reservoir. Some analysts refer to only the dissolved gas as "associated," and call the other material "gas-cap gas." Associated gas is a by-product of crude oil production; thus, its rate of production is typically determined by the production plan for the oil field. Since the gas is in intimate contact with the crude oil, hydrocarbons are carried along with the gas stream when it emerges from the well.

The second category is nonassociated gas. This refers to gas produced from reservoirs containing no crude oil. Such gas is often referred to as "discretionary gas," since the rate of production is, within technical limits, produced at arbitrary and often varying rates. Nonassociated gas is normally high in methane content (the lightest hydrocarbon) and contains few of the heavier hydrocarbons. The exact composition can vary widely, and since the heavier hydrocarbons are generally higher in value than methane, the economics of the resource are strongly affected by the gas composition.

The third source of gas is from condensate fields. Condensate fields are midway between oil fields and nonassociated gas reservoirs. Such fields are rich in hydrocarbons heavier than methane, but generally lack the high-boiling range components that constitute the fuel oil fraction of crude oil. Generally speaking, the lighter the liquids in the field, the richer the field will be in methane gas.

Condensate fields are so named because much of the material escapes from the well as a gas stream but then condenses to a liquid on expansion and cooling. There is no sharp dividing line between crude oil fields, condensate fields, and nonassociated gas fields; some nonassociated gas fields rich in heavy hydrocarbons could be called condensate fields, and some of the heavier condensate deposits could be classified as very light crude oil. Condensates are of growing importance in the Asia-Pacific region, as they seem to be of relatively common occurrence in the island arcs that make up Indonesia, New Guinea, and the North Australian Coast. Condensate fields are often discovered during exploration for crude, and many of the new ultralight Australian crudes could as easily have been classed as condensates.

These three sources of gas present quite different opportunities and problems to the producer (and, in some cases, to importers as well). The most difficult source to manage under present conditions is associated gas. The gas must be produced along with the crude oil whether it is needed or not; thus, it is often thought of as having no intrinsic cost and is seen as a virtually free source of energy or raw material. As the nations of the Mideast have discovered, however, basing new industries on this gas can be a risky proposition; if crude oil production is curtailed, for policy reasons or otherwise, the industries built to exploit the cheap gas resource can find themselves without the expected supplies of fuel and feedstock. Depending on the industry, the difficulty of replacing these gas supplies can range from inconvenient and expensive to technologically impossible. Many countries are now finding it prudent to base gas-requiring industries, especially chemical plants, on the amount of gas available at the minimum crude oil production level; increments of gas above that level can be fed as fuel to industries that can readily adopt dual-fuel firing so that a substitute fuel can be used during times of low oil production.

At present, most gas-export projects are based on nonassociated gas. As the international gas trade grows, however, and as economies of scale become more important in LNG projects, many proposed gas-export schemes are coming to rely on gas from both nonassociated and associated fields. This means that gas exports, and not simply gas production, may be increasingly subject to fluctuations in crude output. (It might be argued that this trend may even act to place a floor on crude production in some countries, since LNG contract commitments might force certain levels of crude output.)

Use of associated gas is further complicated by the fact that it is often needed for reinjection into the oil field to maintain pressure and enhance the long-term recovery of crude oil. Only a certain fraction of this gas is ultimately recoverable, although the fraction is high in certain oil fields. Not all oil fields respond well to gas injection; for some, water pressurization is more effective. If reinjection is required, this delays the availability of the gas for other uses, and sometimes results in a peculiar production profile for the gas resource.

Nonassociated gas poses far fewer problems in planning, since the production rate can be controlled without reference to its economic effects on the oil industry. Nonassociated gas projects must therefore stand on their own merits; there is no crude oil to "pay for" the development of the gas resource. Unless the gas is intended for export industries, the market situation is easier to anticipate and control, and there is little danger of new industries finding themselves adrift with no source of fuel or feedstock.

Just as condensate deposits are midway between crude oil fields and nonassociated gas fields in composition, so also are they in-between with respect to resource planning. Depending on the composition of the deposit and market conditions, either the fuelgas or the condensate liquids may be the most valuable fraction; the situation may change as prices shift. No country is likely to program its oil production profile to optimize the exploitation of associated gas, but programming the production of condensate fields can vary widely as to whether the liquids production or the fuelgas production dominate the economics.

In addition to the production-planning problems posed by natural gas, gas also has some transport features that distinguish it from other fossil fuels. Unlike coal, it can be moved in pipelines, with economics only slightly worse than for oil or oil products. Unlike oil, however, the light components of natural gas are difficult to store or move by tanker. The only practical storage mechanism for methane under most circumstances is injection into a natural geologic reservoir, a technique fairly common in the United States. These underground storage techniques are expensive, not least because they normally entail some losses. In general, natural gas, like electricity, is an energy source whose production rate must tightly follow demand.

2. Components and General Classifications

The most abundant hydrocarbon in gas is typically methane, the simplest of the hydrocarbons. Composed of a single carbon atom and four hydrogen atoms, methane is so light and nonpolar that it liquefies only at a temperature of about -260° F.

As one progresses up the hydrocarbon series from methane to two-, three-, and four-carbon compounds, the general trend is for the boiling point to increase and for the compound to become less common in the gas stream. Thus, methane (CH_4) is normally the most common natural gas hydrocarbon, followed by ethane (C_2H_6), propane (C_3H_8), and the butanes (C_4H_{10}). The compounds heavier than butane are liquids at normal temperatures; if these form a high proportion of the mixture, the deposit is likely to be referred to as a condensate field.

Table 24 shows selected physical properties for the first five straight-chain alkanes (hydrocarbons with no multiple bonds) commonly found in natural gas. As the table indicates, many of the gross properties begin to converge as the molecular weight increases and the compounds begin to behave more like oil products in common trade. Methane and ethane are outliers; both are gaseous except at extremely low temperatures or high pressures. Propane and butane liquefy readily at temperatures and pressures not radically different from environmental conditions; they may be thought of as easily liquefied gases or easily evaporated liquids. When the pentanes are reached, the realm of true (if volatile) liquids is entered; from pentane and beyond, the properties of the components resemble the properties of oil products.

There is considerable confusion regarding terms such as "condensate," "LPG," "natural gas liquids," and other gas-processing terminology, largely because these terms are imprecise and used in an overlapping fashion. Figure 83 shows a classification of major groupings of hydrocarbons; it should be borne in mind, however, that such terms are used inconsistently, often by the same author. The most confusing term is "natural gas liquids" (NGLs—not to be confused with *LNG*, which is *liquefied* natural gas). In the most general case, NGLs refer to the materials heavier than methane. In a shorthand fashion, however,

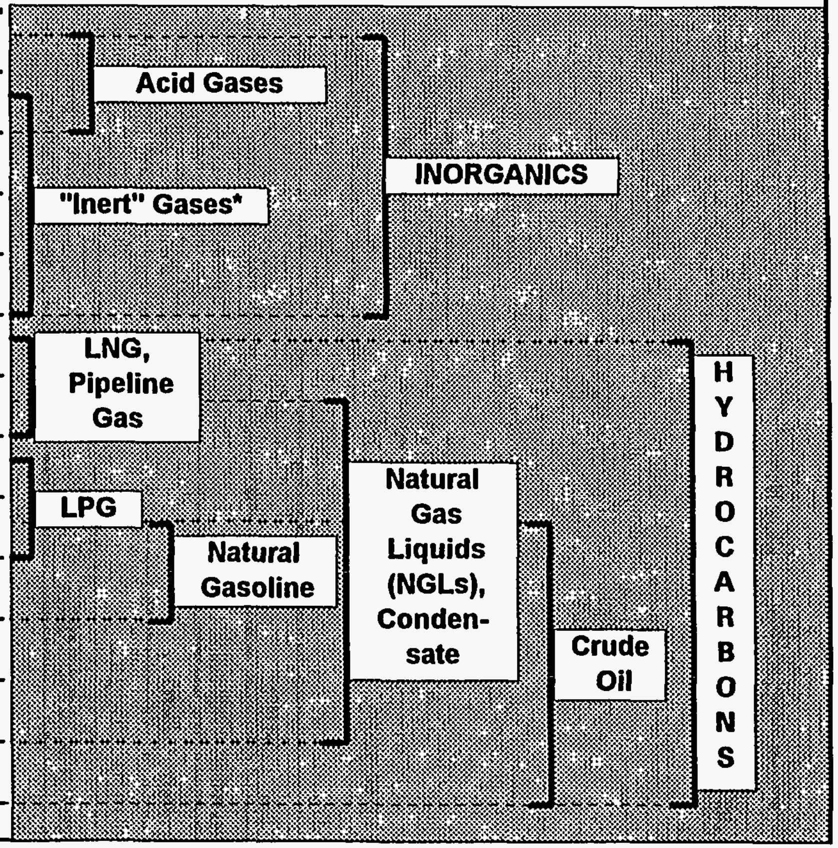
Table 24. Properties of Natural Gas Components

	Methane	Ethane	Propane	Butane	Pentane
Molecular weight	16.04	30.07	44.09	58.12	72.15
Gas density, lb/cf	0.042	0.079	0.116	0.153	0.190
Gas density, kg/cm	0.678	1.270	1.860	2.453	3.046
Liquid specific Gravity	0.415*	0.360	0.510	0.580	0.630
Liquid density, lb/cf	26.50*	22.36	31.78	36.45	39.59
Liquid density, kg/cm	1.65*	1.40	1.98	2.28	2.47
Vapor pressure, psi, 70 F	---	---	124.3	31.3	9.4
Barrels/ton	14.3*	17.6	12.6	11.0	9.9
cf liquid/ton	83.2*	98.6	70.7	61.7	55.7
cm liquid/ton	2.36*	2.79	2.00	1.75	1.58
Heating value, Btu/cf gas	1,012	1,800	2,563	3,390	4,009
Heating value, Btu/cm gas	35,734	63,558	90,500	119,701	141,558
Boiling point, F	-258.7	-127.5	-43.7	31.1	96.9
Boiling point, C	-161.5	-88.6	-42.1	-0.5	36.1
cf gas/barrel liquid	3,644*	1,579	1,507	1,309	1,171
cm gas/barrel liquid	103*	45	43	37	33
cf gas/ton	52,104*	27,793	18,984	14,396	11,593
cm gas/ton	1,476*	787	538	408	328

**As LNG: theoretical values for methane under these conditions differ considerably from these measurements.*

Figure 83. Terminology of Gas Components

Boiling Range, F	Typical Vol% Assoc.	Typical Vol% Nonass.	"High" Vol%	Component
< ambient	2.1	1.1	5.5	Hydrogen Sulfide
< ambient	7.2	0.9	70.0	Carbon Dioxide
< ambient	2.5	1.5	13.0	Nitrogen
< ambient	0.0	0.0	15.0	Helium
< ambient	0.6	0.4	10.0	Other Inorganic
< ambient	51.1	92.3	99.0	Methane
< ambient	18.5	1.9	25.0	Ethane
< ambient	11.5	0.6	20.0	Propane
31 - 40	4.4	0.3	10.0	Butanes
50 - 220	2.1	1.1	5.0	Light Naphtha
180 - 330	0.0	0.0	3.0	Heavy Naphtha
290 - 675	0.0	0.0	3.0	Middle Distillates
650 +	0.0	0.0	0.0	Fuel Oil



*An industry term. Only Helium is an inert gas in terms of the periodic table.

many analysts use "NGLs" to mean pentane-and-heavier materials; the classification used under such a system is "methane/ethane/LPG/NGLs" or "fuelgas/LPG/NGLs." The latter classification is particularly convenient, since it groups the hydrocarbons into those that are gaseous except at extreme temperature or pressure ("fuelgas," consisting of the ethane and methane), those that are typically liquids under normal conditions ("NGLs," consisting of the pentanes and heavier components), and those that move readily between the two states (liquefied petroleum gases or LPGs).

Table 25 gives some examples of average gas compositions from key gas-producing countries. A general pattern is for methane to constitute a lower fraction of the gas in associated gas and a higher fraction in nonassociated gas. There are significant exceptions to this generalization, however. For instance, Thailand's gas is much richer in the more complex hydrocarbons than most nonassociated gas fields.

Despite the clear danger of generalizing about such a variable resource, experts have reviewed worldwide resources and estimated the compositions of typical associated and nonassociated gas streams. Two of these estimates are shown in Table 26.

Alongside these estimates, Table 26 also shows the weight percent of the components, and gives the tonnages of the various hydrocarbons recoverable from the two "typical" streams. This underlines the importance of gas composition in planning: 10 billion cubic meters/day of this typical associated gas contains about 1.42 million tons/year of LPG and natural gasoline, whereas the nonassociated gas contains only about 183,000 tons/year—a ratio of 8 to 1.

Thus, some gas streams may be developed to obtain their liquids content. In such cases, the methane content may essentially be a by-product. This may lead to very different pricing behavior than when a stand-alone field of "dry" gas is developed on its own merit.

Table 25. Composition of Representative Natural Gases

(percent by weight)

	Methane	Ethane	Propane	Butane	Pentane+	Carbon Dioxide	Hydrogen Sulfide	Nitrogen	Other
Algeria									
Hassi R'Mel	83.5	7.0	2.1	1.0	0.4	0.2		5.8	
*Hassi Messoud**	56.6	22.2	12.2	1.8	4.3	1.5			1.5
Bahrain	80.2	1.5	0.3	0.7	0.1	6.1	0.1	11.1	0.1
Brunei	88.0	5.1	4.8	1.8	0.2			0.1	
Indonesia*	71.9	5.7	2.6	1.4	3.6	14.4	0.0	0.4	
Iran	74.9	13.0	7.2	3.1	1.5	0.3			
Libya*	64.5	21.0	8.4	4.2	1.9				
Nigeria	88.1	6.1	2.1	0.3	1.1	2.1			0.2
Qatar*	55.5	13.3	9.7	4.6	4.8	7.0	2.9	1.1	1.1
Saudi Arabia*	51.0	18.5	11.5	4.4	2.2	9.1	2.8	0.5	
Syria*	54.5	11.7	8.9	6.1	4.3	3.5	3.4	7.2	0.4
UAE*	55.7	16.6	11.6	5.4	3.8	5.5	0.8	0.5	0.1

** Associated gases.*

Table 26. Hydrocarbon Tonnage Available from Typical Gas Streams

(at 10 million cubic meters/day output)

	Typical Associated Gas				Typical Nonassociated Gas			
	Gas vol %	Hydrocarbon Wt %	Tons/year	Barrels/ day	Gas vol %	Hydrocarbon Wt %	Tons/year	Barrels/ day
Methane	51.06	35.7	1,263,039	---	92.3	89.4	2,283,145	---
Ethane	18.52	24.3	858,739	---	1.92	3.5	88,981	---
Propanes	11.53	22.2	782,823	27,023	0.58	1.4	39,547	1,365
Butanes	4.37	11.1	391,235	11,791	0.3	1.1	26,836	809
Pentanes+	2.14	6.7	237,989	6,455	1.05	4.6	116,523	3,160
Non-hydrocarbon	12.38	---	---	---	3.85	---	---	---

C. Resources, Reserves, and Production

1. Global Resources and Reserves

Less attention has been paid over the years to the estimation of the recoverable gas resources of the planet than to oil, largely because gas is considered a far less desirable "find." Oil is readily exportable and readily exploited at relatively low cost; the main cost is finding it. Gas, on the other hand, requires major investments to develop it after discovery, whether it is to be used domestically or exported. The total amount of exploration specifically devoted to finding gas reserves has been very limited; most gas discoveries have been made as a side-effect of oil exploration, whether the gas is associated or nonassociated. Only in a few countries—for example, Saudi Arabia, in an attempt to break the linkage between its gas and oil production levels—have explored for nonassociated gas *per se*.

The most careful overall survey of likely gas resources is, once again, Masters *et al.* In terms of total energy available, they estimate that the energy originally available in the form of conventional gas reserves is roughly comparable to that of oil. Figure 84 shows the regional distribution of proven reserves of gas for the period 1967-92. As the chart shows, huge leaps have taken place in the reserves of the Commonwealth of Independent States (CIS) and Mideast, with gentler but substantial increases in Asia-Pacific and Latin American reserves. The reserves of other regions have been surprisingly constant, with a gradual declining trend in North America.

The increases in reserves have been dramatic. Since 1967, proven gas reserves have increased four-and-a-half times (as compared to two-and-a-half times for oil). This amounts to a compound growth rate of 6.3 percent annually. This rate of discovery well outpaced the rate of increase in production until 1982. As Figure 85 shows, after 1983 there was a slight slump in the world reserves-to-production (RP) ratio, with a gradual recovery in the early 1990s.

Based on the most recent estimates by the U.S. Geological Survey (USGS), the ultimate recoverable gas resource is about 300 trillion cubic meters (tcm). Of this, about 15

Figure 84. Proven Gas Reserves, 1967-92

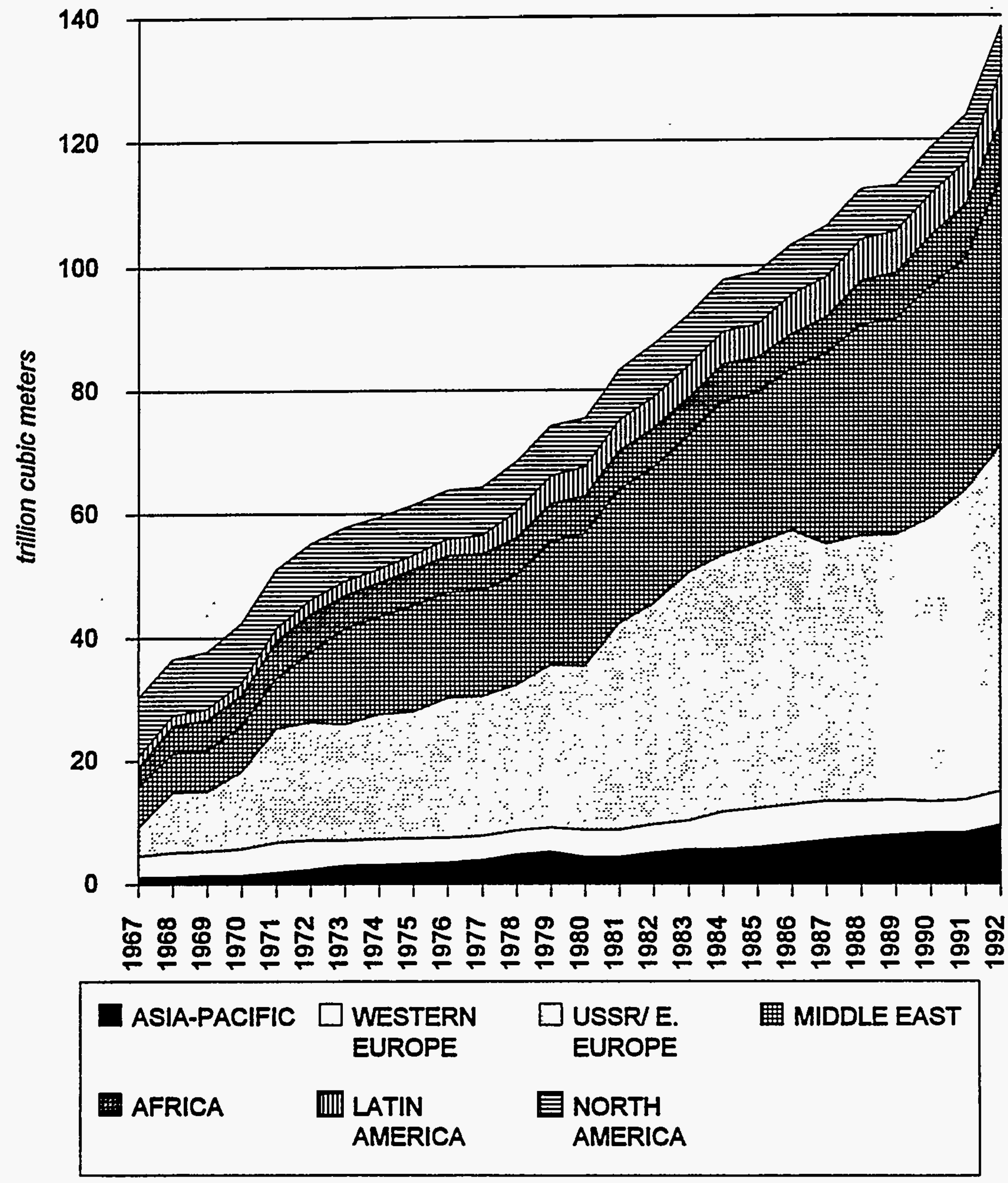
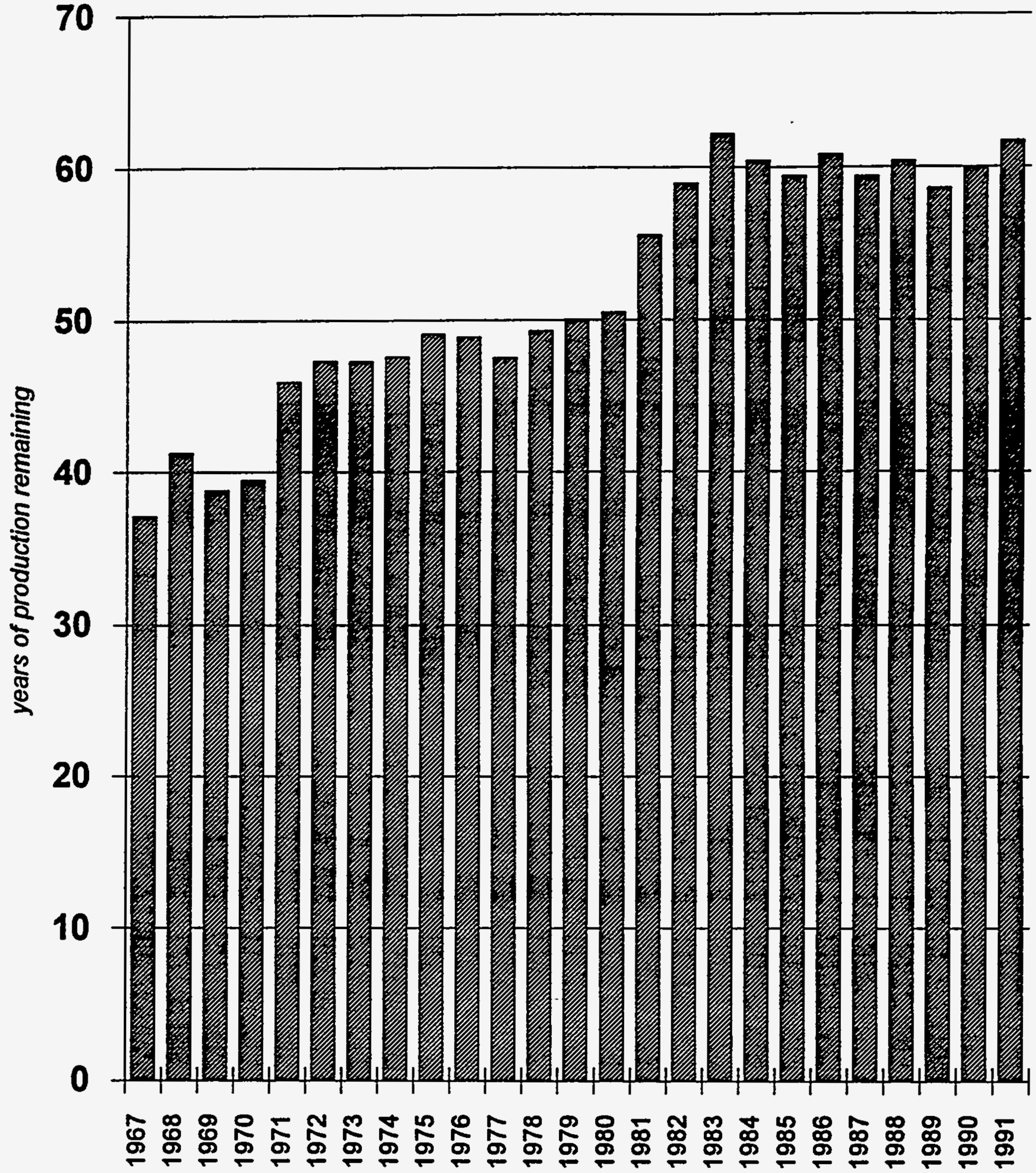


Figure 85. RP Ratio of Proven Gas Reserves



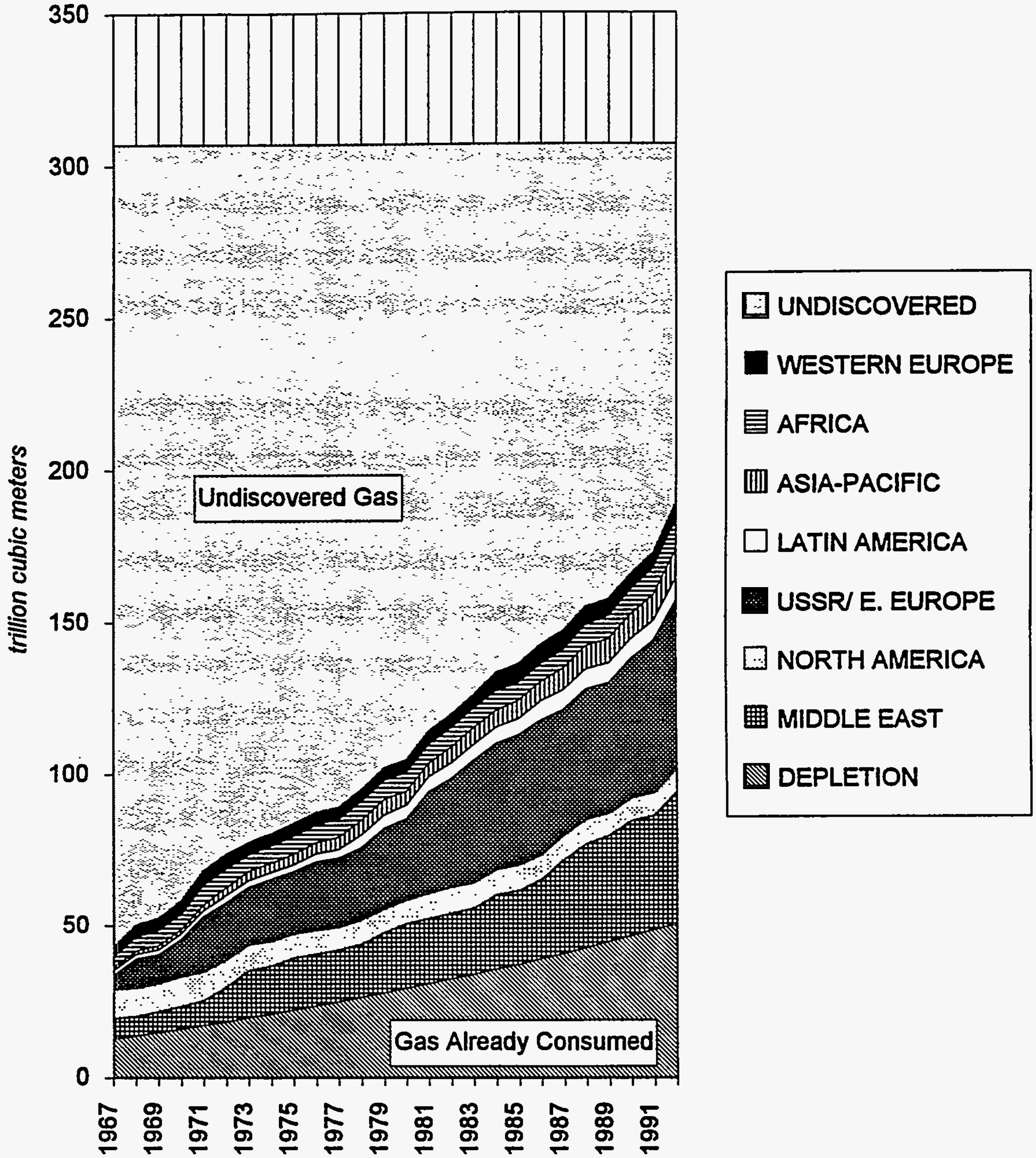
percent has already been used, 45 percent is in proven reserves, and another 40 percent still awaits discovery (possibly as more oil is discovered).

Estimated gas resources and consumption are shown in Figure 86 for the years 1967-92. The figure differs in one important regard from the similar chart shown in an earlier chapter for oil resources. While the estimate of "undiscovered" gas is added to the chart, there is no estimate for "unconventional" gas. There are a number of known sources of unconventional gas, including difficult geologic deposits (such as "tight sands"), coal-bed methane, methane hydrates in polar regions, and renewable sources such as waste treatment gases. There is no doubt that the potential volume of such sources is very large indeed, but the uncertainties about costs and prices have discouraged comprehensive evaluations of these resources. One thing is certain: the resource shown in Figure 86 is an underestimate and possibly a dramatic underestimate.

At least some volumes of unconventional gas are likely to be recovered in the near future for environmental reasons. Methane is a worse greenhouse gas than carbon dioxide, and concern about methane emissions is mounting. Although there is uncertainty about the contribution of various sources to global methane emissions (most is undoubtedly from agriculture), one of the more concentrated sources is coal mining. A number of evaluations of coal-bed methane recovery are under way in Australia, and the World Bank is sponsoring similar projects in China. Even if the economics of coal-bed methane as an energy source are relatively poor, it may become a substantial source of energy as a side-effect of pollution abatement—and some analysts believe that it may be economic in its own right.

In addition, there is a school of thought among cosmologists and geologists that there may be additional large sources of "abiogenic" methane deep in the earth's crust. Although deep drilling projects to date have not produced much evidence in support of this theory, it is possible that large amounts of methane may have been formed early in the planet's history by inorganic processes. (Note that, even if methane was formed, there is nothing to ensure it was trapped. A gas field requires not only a source rock but a reservoir rock as well).

Figure 86. Estimated Gas Resources, 1967-92



In any case, undiscovered gas is almost certainly twice present reserves, and possibly much more than that. The direct biological sources of methane, it should be noted, are renewable; this represents the only major source of hydrocarbons that is renewable on less than a geological scale.

2. Regional Resources and Reserves

Figure 87 shows estimates (based on ultimate resources from Master's plus current reserve and historical production data) of the regional distribution of natural gas resources. The most striking feature of the graph is the amount of gas already produced in North America, compared with other regions. As of 1992, North America had produced more than half of the gas ever produced in the world. Thus, it should come as no surprise that many analysts believe that North America may be on the verge of a long production decline.

The production future of North American gas is vitally dependent on gas prices. The undiscovered resource is three times larger than the proven reserves. Indeed, the amount of gas remaining to be discovered in North America is not much less than the undiscovered resources in the CIS, the Mideast, or Asia. Most of this gas, however, is likely to be found in remote locations (such as Alaska and Northern Canada) or in small deposits where the costs of pipelining it to market are high on a per-unit basis.

The total gas resources, known or otherwise, of Western Europe, Latin America, and Africa are relatively small. A substantial increase in Latin American and African gas utilization should be expected in the 1990s, but domestic utilization of gas on these continents is limited in scope unless massive imports are undertaken.

Figure 88 shows the RP ratios for these regions, calculated both against 1992 proven reserves and against proven reserves plus undiscovered resources. The outlook in both Western Europe and North America is similar; present reserves would last for 10-20 years at current production rates, and additional discoveries could push this to 50-60 years.

In North America, Western Europe, and the CIS/Eastern Europe, the RP ratios are fairly meaningful—that is, these regions are already heavy users of gas, whose production

Figure 87. Estimates Of Gas Resources Used, Identified, And Undiscovered

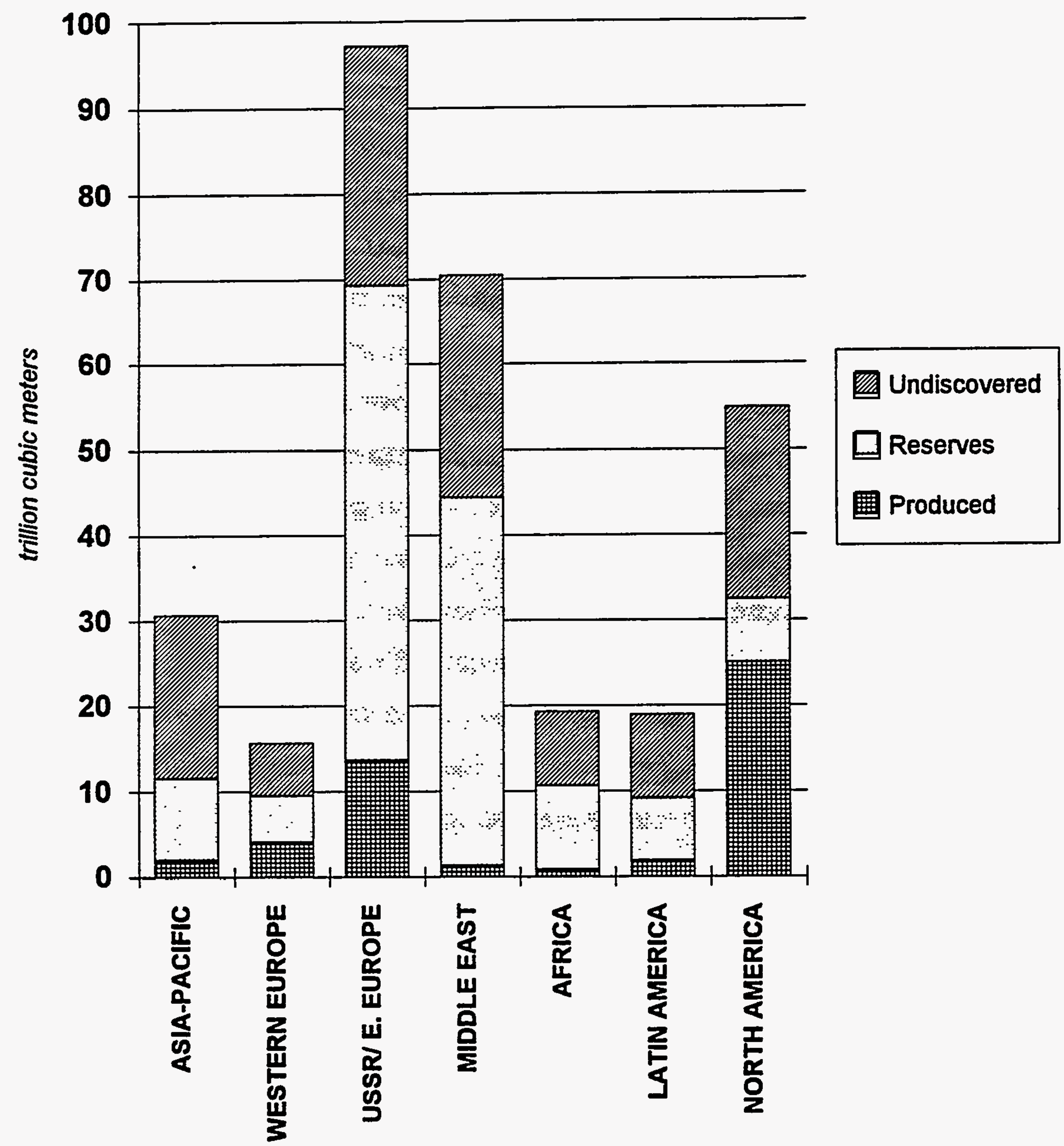
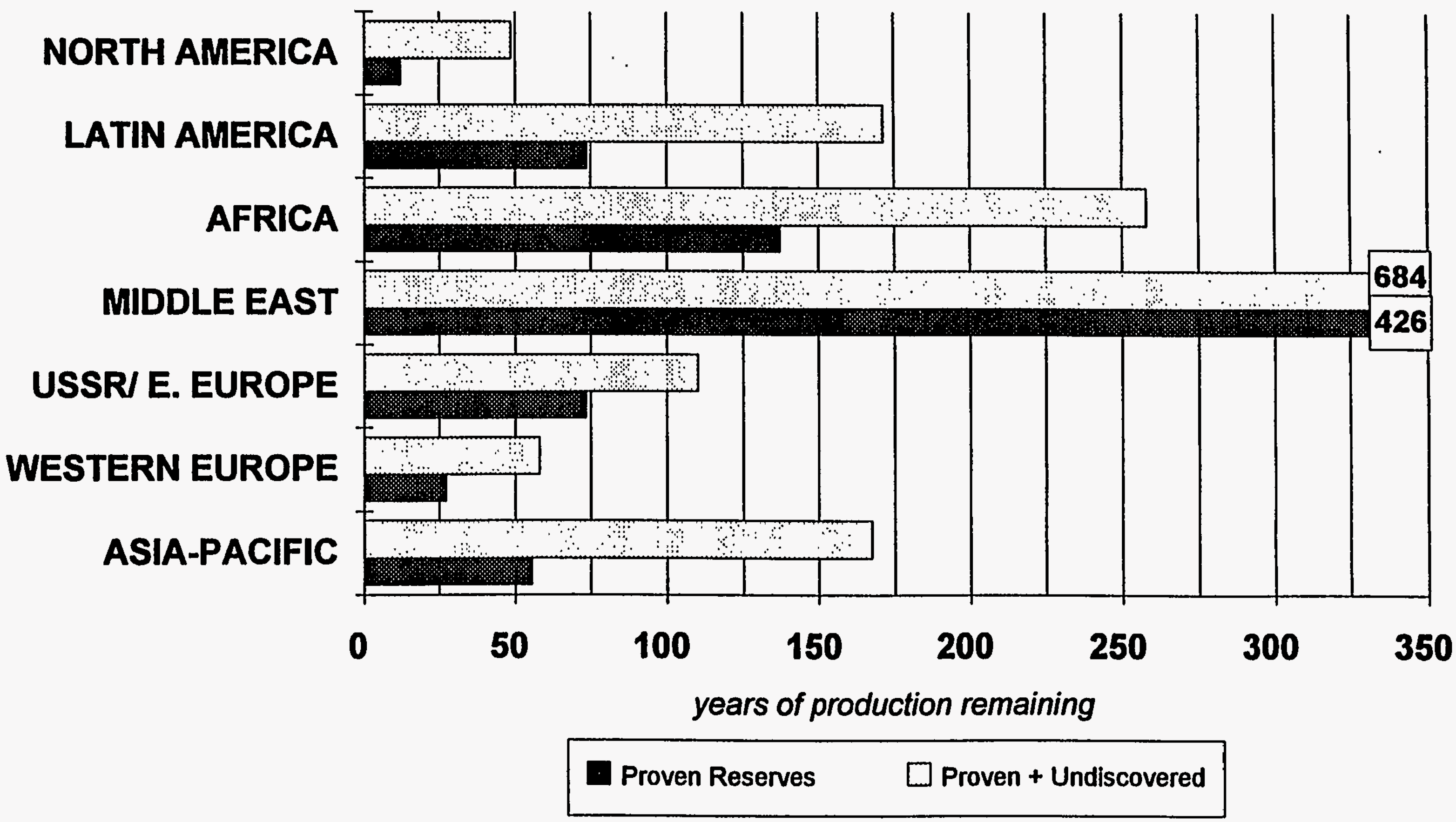


Figure 88. RP Ratios of Gas by Region



has more or less stabilized. There may be slow growth or decline in the rate of production as more reserves are found, but the RP ratios give some sensible indication of the availability of the resource in future years.

The same cannot be said for the RP ratios of the other regions. In Africa and Latin America, the relatively high RPs reflect low utilization of a small resource. At higher utilization rates, this resource will be quickly exhausted. The Middle East, by contrast, reflects low utilization of a very large resource. Much higher production rates are both possible and likely, but high production could be sustained for a considerable period. To put this in perspective, the proven plus undiscovered resources of the Mideast could support North American production rates for 110 years or current world production rates for 35 years.

The CIS RPs reflect a large resource with very high production rates. These rates are likely to be maintained, as gas is one of the reliable foreign currency earners of the CIS nations. Exploration, especially in Siberia (quite likely financed by Japan and Korea) should uncover additional gas deposits throughout the next decade.

The Asia-Pacific region has a fragmented geography and geology. The resource is of moderate size, but very unevenly distributed and exploited. The most promising areas for major additions to reserves, unfortunately, are those areas where reserves are already high: Australia, China, Indonesia, Malaysia, and Thailand. The existing pattern of gas-surplus and gas-short nations is likely to persist, and in Australia, Indonesia, and Malaysia, the pace of additional gas developments is likely to parallel the growth of economic export opportunities.

Table 27 shows the current proven reserves by country, along with rather speculative country-by-country estimates of undiscovered resources derived from Masters *et al.* It should be noted that these numbers may deviate somewhat from the USGS estimates because of changes in output and proven reserves since the publication of the estimates. Moreover, a few of the smaller producers were included by USGS as "other" in each region. In these cases, their shares of the "other" ultimate resources have been determined by ratioing the

Table 27. World Gas Reserves and Resources, 1992

(billion cubic meters)

	PRODUCED	RESERVES	UNKNOWN
UAE	183.5	5,794.4	1,215.6
Bahrain	72.4	164.5	0.8
Iran	414.9	19,801.8	13,173.3
Iraq	45.4	3,101.1	1,328.2
Israel	2.1	0.4	0.6
Jordan		6.1	1.9
Kuwait	122.5	1,498.2	3.0
Oman	35.7	478.6	52.1
Qatar	82.5	6,428.8	5.0
Saudi Arab.	363.7	5,185.5	10,140.4
Syria	6.9	198.2	59.6
Yemen		393.7	123.3
MIDEAST	1,329.5	43,051.3	26,103.9
Algeria	580.9	3,625.0	3.2
Angola	2.7	51.0	144.6
Cameroon		110.5	795.8
Congo	2.4	76.5	91.0
Egypt	71.9	436.1	653.1
Eq. Guinea		36.8	153.6
Ethiopia		22.7	94.5
Gabon	5.0	11.3	40.3
Ghana			
Ivory Coast		99.1	413.5
Libya	102.9	1,308.4	231.3
Madagas.		2.0	8.3
Morocco	1.9	1.0	11.0
Mozamb.		65.1	271.7
Namibia		147.3	614.3
Nigeria	40.1	3,398.5	3,216.8
Rwanda	0.0	56.6	236.4
Somalia		5.7	23.6
S Africa		53.8	224.5
Sudan		85.0	354.4
Tanzania		116.1	484.4
Tunisia	7.1	85.0	502.7
Zaire		30.0	125.0
AFRICA	815.0	9,823.4	8,693.9
Argentina	327.5	642.9	1,125.3
Barbados	0.4	0.2	0.8
Bolivia	49.3	116.3	230.9
Brazil	47.2	124.6	1,499.1
Chile	97.7	110.5	188.3
Colombia	84.5	203.9	362.9
Cuba	0.4	2.8	2.5
Ecuador	1.6	110.4	227.8
Guatemala		0.3	0.6
Mexico	682.7	2,007.9	4,446.1
Panama			
Peru	22.7	199.8	315.6
Trinidad	82.7	246.4	96.3
Venezuela	461.0	3,582.3	1,223.7
S.AMERICA	1,857.7	7,348.4	9,720.0

	PRODUCED	RESERVES	UNKNOWN
Afghanistan	64.8	99.1	92.8
Australia	242.0	517.0	2,824.4
Bangladesh	43.5	719.3	
Brunei	170.6	396.5	126.0
China	278.9	1,399.0	7,016.5
India	121.4	735.0	559.6
Indonesia	553.6	1,823.5	3,117.1
Japan	74.3	27.4	56.6
Korea	0.0	0.0	
Malaysia	149.4	1,920.1	1,287.1
Myanmar	12.6	277.5	134.7
New Zealand	49.4	95.9	519.4
Pakistan	209.6	877.9	668.3
PNG		402.2	239.4
Philippines		45.3	27.0
Taiwan	30.8	68.0	46.9
Thailand	50.4	239.7	1,834.0
Vietnam	0.6	14.2	749.9
ASIA-PACIFIC	2,051.9	9,657.7	19,299.7
Austria	63.5	16.1	0.4
Belgium/Lux	1.9		
Denmark	20.5	112.9	1.0
Finland			
France	194.9	35.1	10.0
Germany	499.3	343.0	52.7
Greece	1.3	8.5	0.0
Ireland	25.6	19.8	0.0
Italy	458.9	368.1	0.0
Netherlands	1,554.2	1,950.2	5.0
Norway	395.5	2,000.3	4,967.6
Spain	7.6	19.8	0.5
Sweden			
Switzerland			
Turkey	1.8	17.2	0.5
UK	855.5	540.1	983.3
W EUROPE	4,080.5	5,431.0	6,021.0
Albania	5.6	19.8	8.8
Bulgaria	10.9	7.1	5.0
Czech.	35.7	13.3	15.6
Hungary	141.5	106.4	78.8
Poland	141.8	158.5	96.5
Romania	1,015.5	207.7	12.5
Yugoslavia	47.4	82.0	44.8
USSR/CIS	12,269.6	55,007.1	27,993.8
USSR/ EE	13,667.9	55,602.0	28,255.8
Canada	2,279.5	2,711.2	10,160.8
USA	22,723.9	4,731.3	12,278.6
N AMERICA	25,003.3	7,442.5	22,439.4
WORLD	48,805.8	138,356.3	120,633.7

"other" total by their share of proven reserves plus cumulative production (that is, their share of known reserves).

3. Gas Production

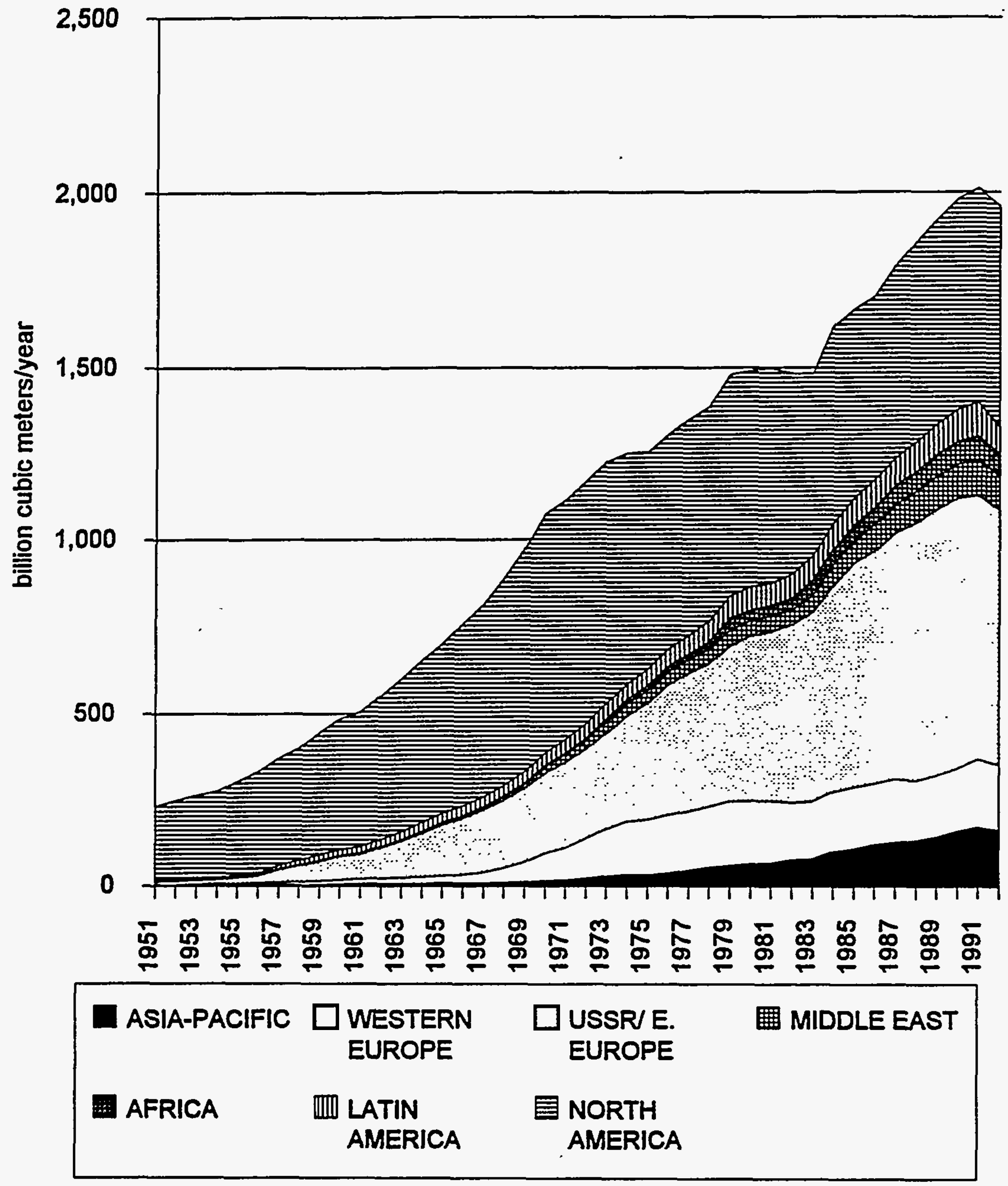
Figure 89 shows world gas production by region for the period 1951-92. The overwhelming dominance of North America, the CIS, and Western Europe is clear. The basis for the high level of depletion in North America is unmistakable. North American gas production was already at high levels before production even commenced in most other countries.

The rapid growth in production is readily apparent from the very steep curve in the figure. From 1951 to 1992 the average annual growth rates were about 5.5 percent for world gas output and in the range of 11-13 percent for the Asia-Pacific region, Western Europe, and CIS/Eastern Europe. North American production growth, which was far more modest at 2.6 percent per annum, still compares favorably with the annual North American oil production growth of only 1.1 percent over the same period.

The development of the industry is even more obvious in Figure 90, which shows the shares of each region in world gas production. In the early 1950s, North America was the only important gas-producing region. The Soviet Union pursued an aggressive program of gas exploitation in the late 1950s and early 1960s. Another major expansion occurred in Western Europe following the first oil price shock in 1973, and Soviet production continued to expand in importance throughout the 1980s as new markets became available through the east-west pipeline system.

The enormous expansion of the gas market needs to be viewed in the context of the entire hydrocarbons industry. Figure 91 shows oil, gas, and NGL output for the world during 1951-92, with the gas and NGL figures converted to energy equivalents of millions of barrels per day of crude oil. Gas production indeed expanded enormously across the period, and in percentage terms NGL production expanded even more rapidly. As gas processing became more widespread, more NGLS were extracted from every unit of gas production.

Figure 89. World Gas Production, 1951-92



Note: Figures for 1992 are preliminary estimates.

Figure 90. Regional Shares of Gas Production, 1951-91

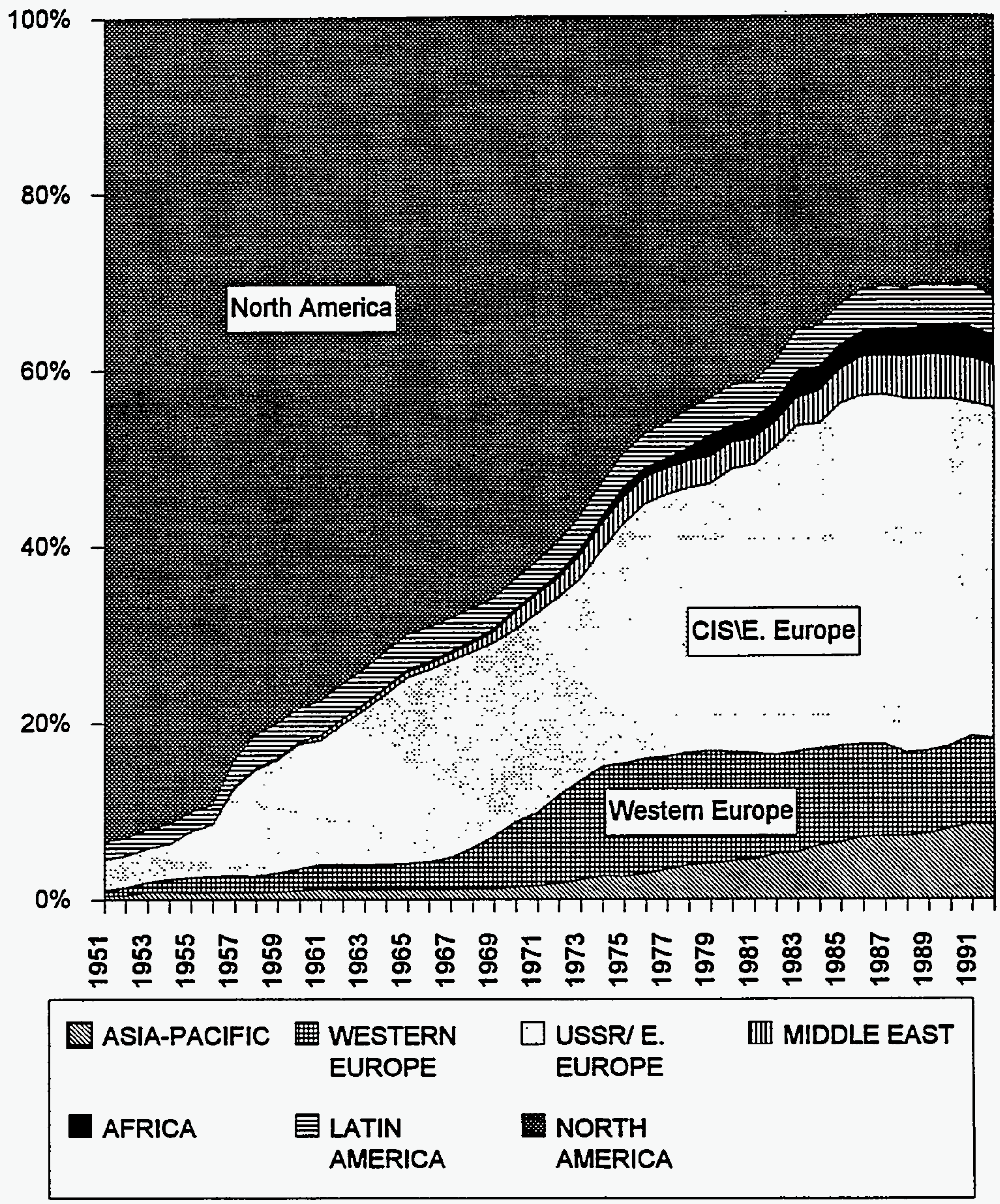
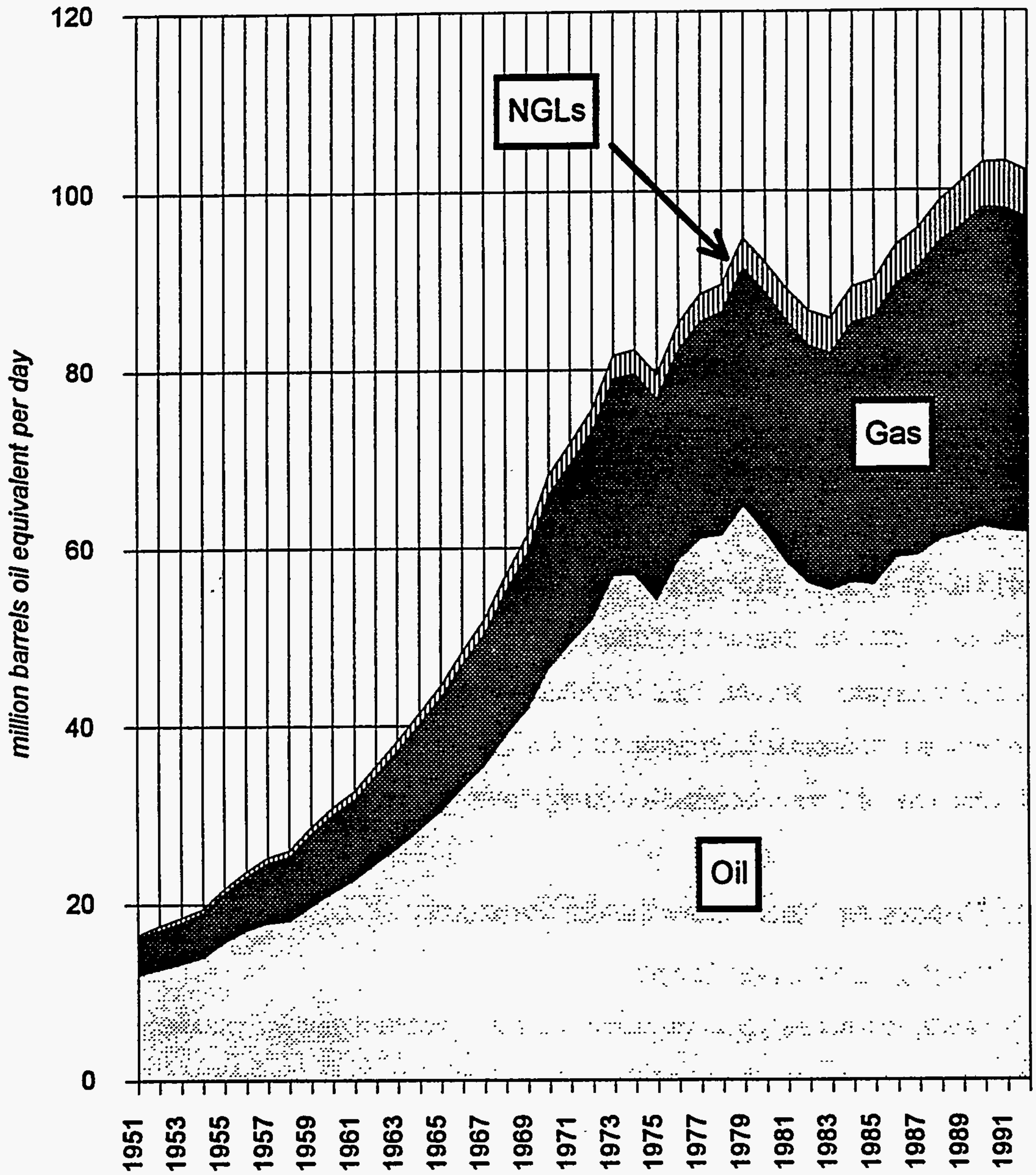


Figure 91. Shares of Oil, Gas, and NGL in World Hydrocarbon Production, 1951-92



The combined effect of higher gas production plus more intensive extraction resulted in a world growth in NGL output of nearly 7 percent per year on average for the entire period.

Despite the huge expansion in gas output, the importance of gas has expanded only modestly over the period. In 1951 natural gas plus NGLs provided about 27 percent of all hydrocarbon energy in the world. By 1992 natural gas plus NGLs expanded to about 40 percent of world hydrocarbon energy. This changeover has been viewed by some as a basic transition in the uses of energy, with gas moving into roles previously occupied by oil as a result of higher prices. Realistically, however, it is more sensible to view the transition as the gradual worldwide spread of North American consumption patterns: gas and NGLs already provided about 40 percent of U.S. hydrocarbon requirements in 1951, and the ensuing forty years merely saw the rest of the world converge to a similar pattern.

The biggest transition in coming years may not be an increase in gas use at the expense of oil, but rather an increase in the amount of gas traded internationally. There is no reason to believe that this trend will outpace the similar trend in oil, since the world is also looking at increased reliance on international trade for oil supplies in the coming decades. What may change is that gas may become more readily available to importers who previously had no source of supplies. The cheapest way to achieve this, of course, will be the extension of the international pipeline system in areas where the political conditions warrant and geography permits. In the Mideast, Africa, and Asia, however, we are also likely to witness a continued expansion of the LNG trade, since the options for pipeline exports from most of the countries with large reserves in these regions are quite limited.

D. Gas Processing and Gas-Based Products

1. Basic Processing and Purification

Virtually no natural gas streams are utilized without some processing. At the minimum, any moisture in the system must be reduced to a very low level. Even without any higher hydrocarbons other than methane, considerable treatment may be required before the gas can be charged to a fuelgas pipeline system. Hydrogen sulfide, carbon dioxide, and particulate must all be reduced to very low concentrations. The removal of the acid gases, hydrogen sulfide, and carbon dioxide is vital, since these substances can cause serious corrosion damage to pipelines and equipment. In addition, in some cases the concentration of inert gases must be reduced to raise the Btu value of the gas to an acceptable level. Most natural gas burners are designed to function across only a restricted range of energy contents per cubic foot of gas. Pipeline systems are designed to operate at certain pressures, based on the heat content per unit volume of gas anticipated. If the Btu content of the gas falls outside the required range, steps must be taken to raise the Btu content, either by extracting inert components such as nitrogen, or by blending in higher-Btu streams (for example, adding ethane from another field, or blending in another fuelgas). These two stages in gas processing—removing contaminants and adjusting the Btu content—are often referred to as "clean-up and concentration." Concentration is not always required, but clean-up processes are an integral part of natural gas production.

Clean-up is the most idiosyncratic part of gas processing, with a bewildering array of competing and complementary processes. Moisture control is achieved by passing the gas over a desiccant for adsorption/absorption, by injecting dew point depressants to cause precipitation of the water, or by expansion refrigeration to chill the water vapor to a temperature below its condensation point. Removal of hydrogen sulfide and carbon dioxide is achieved by adsorption processes or by a host of proprietary reagents, which react with the acid gases to form liquid or solid intermediate compounds. The exact choice of clean-up technology depends on the concentration of the contaminants in the gas stream, the concentration of the contaminants with respect to one another, the volume of gas to be treated, and the wellhead pressure of the gas. Only a detailed engineering study can determine the best combination of clean-up technologies for a particular gas stream.

Fortunately, gas clean-up is not solely an expense item. Clean-up residues can yield saleable chemical products that offset some of the costs. If the hydrogen sulfide concentration is high, subsequent processing can recover more than 95 percent of the sulfur in the original gas as elemental sulfur—an easily transportable, marketable raw material.

Carbon dioxide is valuable for reinjection into oil fields for enhanced oil recovery. If recovered near an urban center, it also has a number of important uses in the food processing industry and in the manufacture of "dry ice" for low-temperature, low-moisture storage and transport of spoilable foodstuffs. Finally, natural gas is the only major source of helium and, if substantial amounts of this scarce element are present in the gas stream, extraction may well be worthwhile.

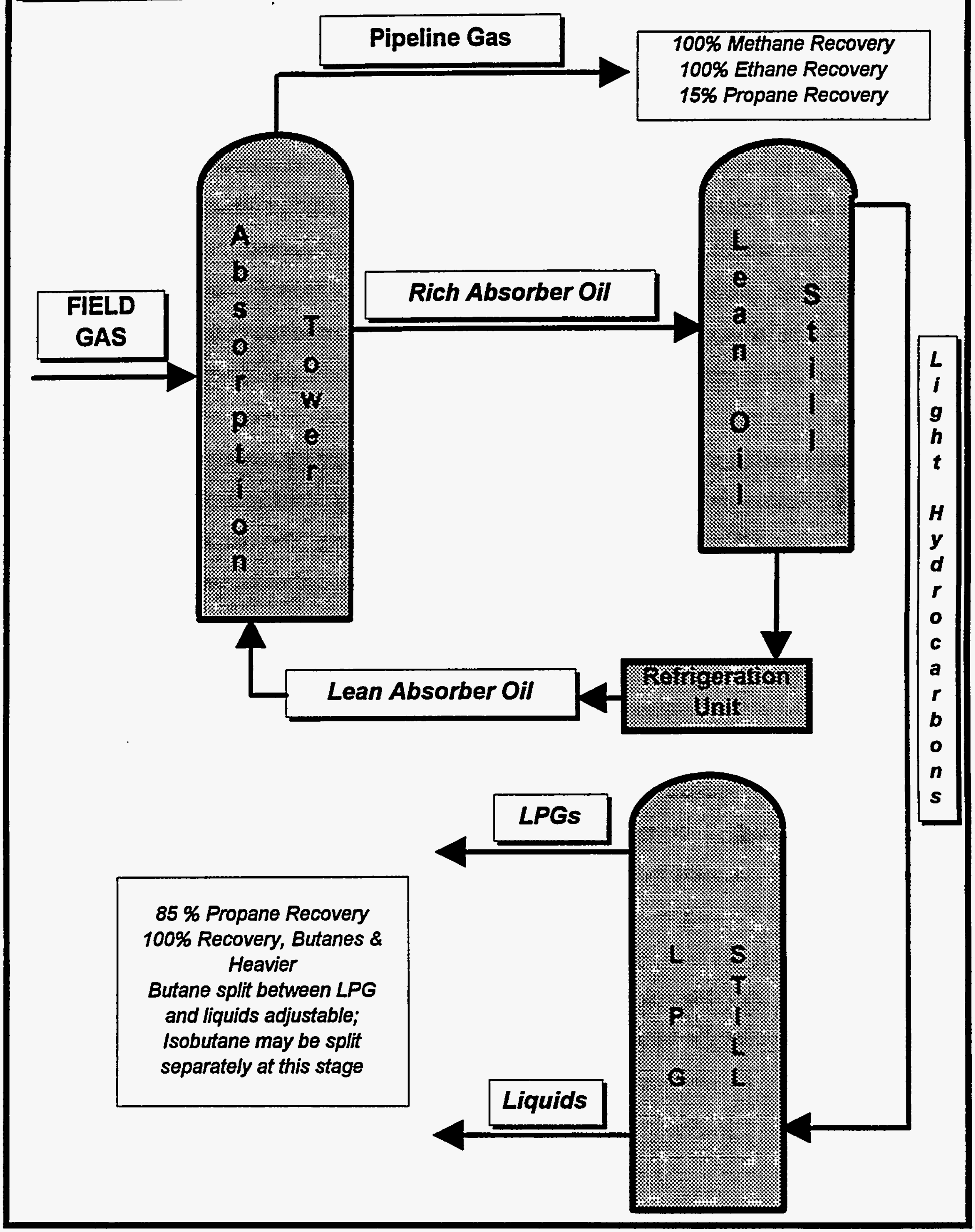
2. LPG and NGL Extraction

Separation of the hydrocarbon streams into marketable products also depends on the composition and volume of gas produced. If the gas is relatively "dry" or "lean" (that is, lacking in the heavier hydrocarbons), it may be charged to a fuelgas system after only clean-up and concentration. If, on the other hand, the gas is "wet" or "rich" (having significant amounts of material in the propane-and-heavier range), the LPG and NGLs can be extracted. In fact, these liquid and easily liquefiable components must be extracted before the gas stream can be charged to a fuelgas network. If the heavier hydrocarbons were left in the fuelgas stream, two-phase flow would develop, with pools of liquid hydrocarbon crawling along the pipeline beneath a stream of rapidly moving gases. Were one of these liquid pools, or "slugs," to arrive at a burner nozzle, the Btu content per cubic foot at the nozzle would leap by almost 9,000 percent, with potentially catastrophic results.

There are two basic processes for extraction. The first, the absorption process, can be used in situations where ethane recovery is not desired, but the bulk of the LPG-and-heavier components are to be extracted.

Figure 92 illustrates the absorption process. Raw natural gas enters the absorption tower, where the heavier hydrocarbons are absorbed into a heavy oil. The unabsorbed material—including most of the methane and ethane, about 15 percent of the propane, and most of the inert gases—passes out of the tower and enters the fuelgas system. The rich absorber oil, containing the NGLs from the gas, is heated and charged to a distillation unit, where the NGLs are boiled out of the absorber oil. The absorber oil is then chilled and

Figure 92. Absorption Fractionation of Gas

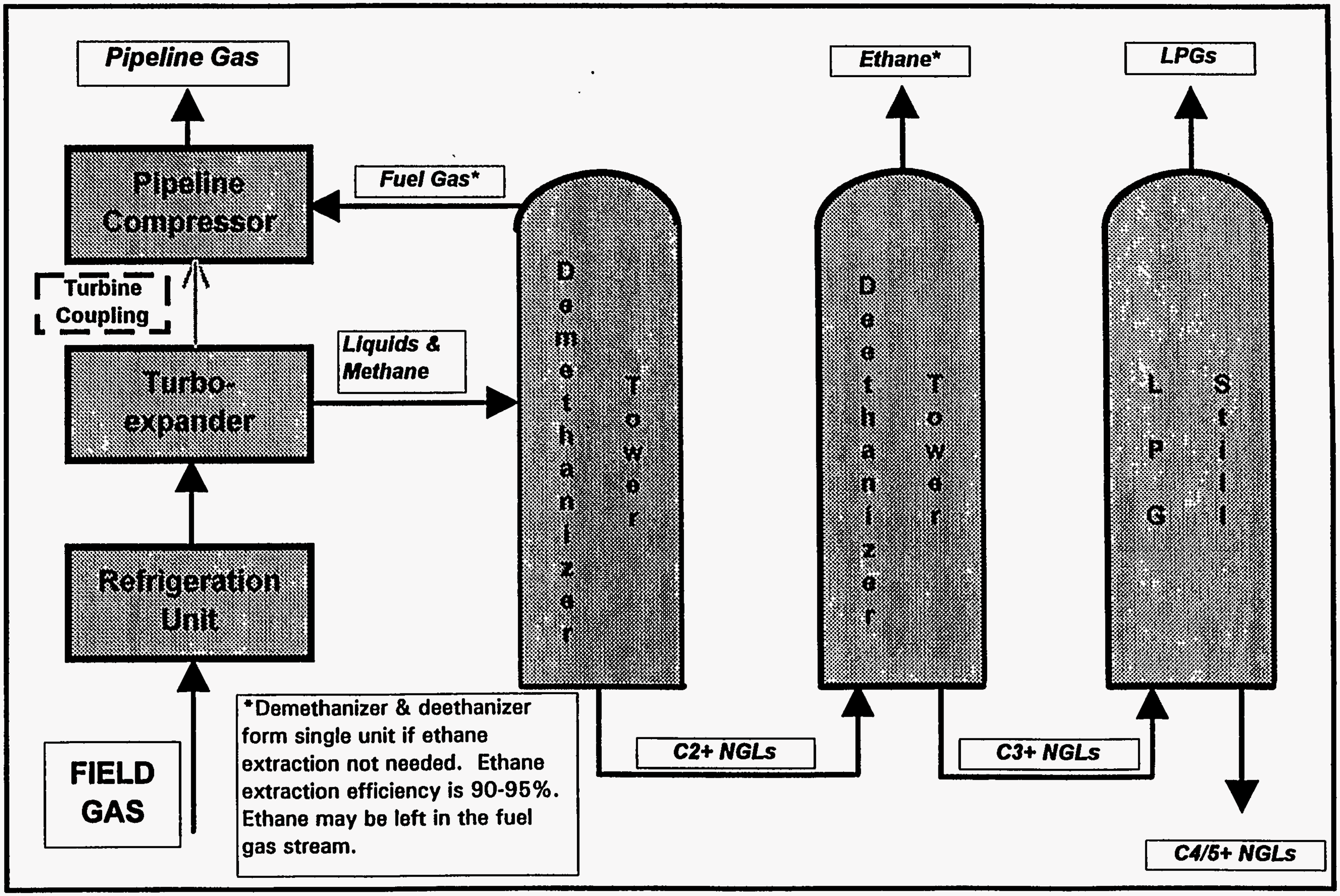


returned to the absorption tower to pick up more NGLs. The NGL stream from the distillation tower is charged to a series of fractionators, which remove successively heavier fractions of the NGLs into separate streams. The fractionation may consist of nothing more than splitting out LPG from the NGL stream, or may go as far as fractionating the mixture into propane, butane, isobutane, light naphtha, heavy naphtha, etc.

In situations where separate ethane recovery is desired, the turboexpansion process must be used. Turboexpansion may also compete with absorption even when ethane recovery is not needed. The turboexpansion process is shown schematically in Figure 93. Incoming natural gas is chilled and then run through a turboexpander, doing work, giving up heat, and dropping in pressure. This results in a drop in temperature to as low as -150°F, sufficient to liquefy ethane. This extremely cold mixture is run to a tower where gas and liquids are separated. The gases (which may include the ethane if the process is conducted at higher temperatures) are then run to a compressor, which receives some of its power from the work of expansion of the gas in the turboexpander. The compressor raises the pressure of the fuelgas to the pressure required by the pipeline system. The cold liquids are charged to a series of fractionators that recover progressively heavier hydrocarbons at successively higher temperatures. The fractionation process is similar to that in the absorption process, except that ethane can be recovered as well. Fractionation of the liquid NGLs into individual product streams is no different from standard refinery operations

As in the case of gas clean-up, the optimum process for natural gas fractionation is determined by the characteristics of the gas reserve and can be established precisely only by detailed engineering. In some cases, with relatively dry gas, satisfactory levels of LPG extraction can be achieved with a simple turboexpander in or near the field. In other cases, particularly with condensates, a more elaborate and expensive set of processes may be required, including a gross "gas/oil" separation unit ahead of the absorption or turboexpansion unit. Regardless of the exact circumstances, basic natural gas processing is usually a requirement for tapping the gas resource. In many cases, it may help to pay for development of otherwise uneconomic resources. In natural gas, the "by-products" may

Figure 93. Turboexpansion Fractionation of Gas



often be as important as the "resource," and ignoring the capital requirements and possible revenues from the gas-processing sector can result in incorrect analyses of the economics of natural gas production.

3. Liquefied Natural Gas (LNG)

LNG is, at present, the only form in which natural gas can be transported, economically and in any quantity, outside a pipeline system. LNG production requires chilling to very low temperatures (-260° F) and removal of impurities such as water and carbon dioxide to avoid the formation of solids in the system. The technology will be discussed in other reports in this series, but at this point it is sufficient to note that the basic processes are similar to those of NGL extraction, carried down to the point where methane is liquefied as well.

A complete LNG delivery system requires large capital investment for each of its components. The liquefaction plant (an elaborate system of compressors, fractionation facilities, and refrigeration units) must be built, and an export terminal with specialized storage, berthing, and loading facilities must be provided. For the marine transport, cryogenic LNG tankers must be employed. And at the import terminal, in addition to the berthing, unloading, and storage facilities, a regasification plant must be constructed.

Excluding the cost of gathering and cleaning the natural gas, the exporter can expect to face minimum investments on the order of $1-3 billion for a "small" project to produce 10 million cubic meters per day (mmcm/d), and costs of several billion more for large projects. Projects for production of less than 10 mmcm/d are now generally considered uneconomic, although there is much discussion (but little action) about "mini-LNG" plants that would enable small, remote gas deposits to be utilized for export.

Very large gas reserves are necessary to benefit from the significant economies of scale. The minimum recoverable reserves required are in the order of 85 billion cubic meters (bcm). Reserves on the order of 150 bcm are generally considered necessary to produce a really economic project. Glancing at Table 27, it might seem that there are a considerable number of candidates for LNG exporters, based on the number of countries whose reserves exceed the minimum requirement. Unless the reserves are located in a single basin or along a corridor, however, the transport facilities for gathering gas from a multitude of fields can increase the cost of required pipelines at a dramatic rate and increase the size of reserves necessary for an economically attractive project. Not only are large reserves needed, but they must be centrally located or easily gathered.

There is a tendency for the scope of LNG projects to be expanded during the study period, as more gas sources are added, in an attempt to increase the plant throughput and obtain higher profits. Such increases may indeed result in greater profitability, but they may also steeply increase the capital cost. By the time the Bonny LNG project in Nigeria was shelved in the early 1980s, capital cost estimates were on the order of $12-$14 billion. (The Bonny LNG project has recently resurfaced in a new incarnation and is once again under serious study). When it is recognized that most of these costs must be paid for in foreign exchange, it is not surprising that so many LNG projects have been studied for years and then abandoned. Even if projected profitability is excellent, the scale and risks in such projects can cause cancellation or postponement.

Often the gas resources are left untapped while the LNG project is studied, the complex financing and marketing arrangements are negotiated, and the project is restudied on a new scale. If the project is then abandoned, the nation's gas development program may have been delayed by years; in the interim, other domestic industries could have been using the gas or other projects could have been completed.

LNG projects also face highly constrained market opportunities. There are only a handful of buyers; because of the limited number of specialized import terminals, there is only a limited opportunity for any sort of spot market to emerge. In its practical operation, an LNG chain (comprising gas production, treatment, liquefaction, storage, loading, ocean transport, unloading, storage, regasification, and transportation to consumer) is very similar to a pipeline, and both suppliers and importers need very long-term contracts.

The fact that suppliers and importers are virtually "married" has an effect on the exact processing requirements at the LNG facility as well. Different importers may require different specifications of LNG, thus further limiting trade opportunities. For example, in the early 1980s, negotiations between Algeria and the U.S. for certain LNG supplies collapsed, because the available Algerian cargos had too high an ethane content to match U.S. pipeline-gas specifications. In Japan, on the other hand, most contract prices have an escalator based on the Btu content of the delivered gas, and the regasification facilities are equipped to recover whatever LPG or other materials are shipped with the cargo.

Although many countries have pursued LNG as part and parcel of an energy diversification strategy, LNG remains a small portion of the total energy supply system even in the large importers of East Asia. (In Japan, by far the world's largest importer, LNG is no more than 9.6 percent of total energy demand. In Korea it is 2.9 percent and in Taiwan a mere 1.5 percent.) The "marriage" forming a long-term supply partnership is interesting from an energy-security point of view. The exporting country will typically be as anxious as the importer to maintain the contract volumes, since it is a vital source of revenues. Unlike oil, it is very difficult to find another buyer in the event of a political disagreement. It is, indeed, difficult even to find anything to do with the specialized ships owned by the project, since they are really useful only for the movement of LNG and ethylene gas. The LNG supplier has a huge foreign debt to pay off by sales of the product and probably has little infrastructure to use the project gas domestically. Thus, a politically motivated cutoff of supply is less likely—though by no means beyond imagining—and a bid-up of prices by competition among buyers is also not a probable occurrence. Both parties to an LNG agreement have strong incentives to keep the gas flowing.

On the other hand, in case of a cutoff, the consequences could be far more severe for the importer than for the exporter, since it would be difficult to find replacements for the volumes. Countries do not maintain spare LNG capacity; there is no Organization of LNG Exporting Countries with large surge capacities held back from the market. On occasion there are spare volumes available from a supplier, but in the event of a crisis, finding make-up volumes is very unlikely. A cutoff would not have to be a political move by the supplier; it could as easily be an industrial mishap, a natural disaster, or an act of war by another nation. There is little doubt that, had Iran and Iraq had LNG facilities, these would have become major bombing targets during the Iran-Iraq War. Moreover, even the closure of a strategic strait could shut down LNG supplies from some countries. While the *risk* of a supply cutoff is probably far lower for LNG than for any other energy import, the *consequences* for any importer heavily reliant on LNG could be far more severe. A secure import plan with LNG playing a major role in energy supplies would require a kind of strategic planning that no country has yet undertaken.

4. Uses of Gas and Gas By-products

Fuelgas

After the clean-up and gas processing has occurred, it would seem that the direct burning of fuelgas as an energy source would be a simple matter. While this is generally true, the analysis of the fuelgas in terms of fuel substitution and new fuel uses is not always straightforward. Since fuelgas is normally the largest volume output of a gas-development program, its economics and pricing are issues of foremost concern.

To be used, gas must first be transported to a market. Long-distance pipelines are expensive, often constituting the major element in the cost of delivered gas. After the gas has reached the market center, it must enter a distribution network to be delivered to consumers. Such a distribution network may be modest, as in the case of distribution to a few large industrial customers; or it may be elaborate and extensive, with a multitude of meters, as in the case of an urban/residential network. Finally, investment may be required on the consumer's side as well. In industrial plants, burners must be converted. In residential or commercial networks, consumers must buy new equipment such as stoves or water-heaters. Spread over a large number of customers, the total investment required by consumers is not negligible.

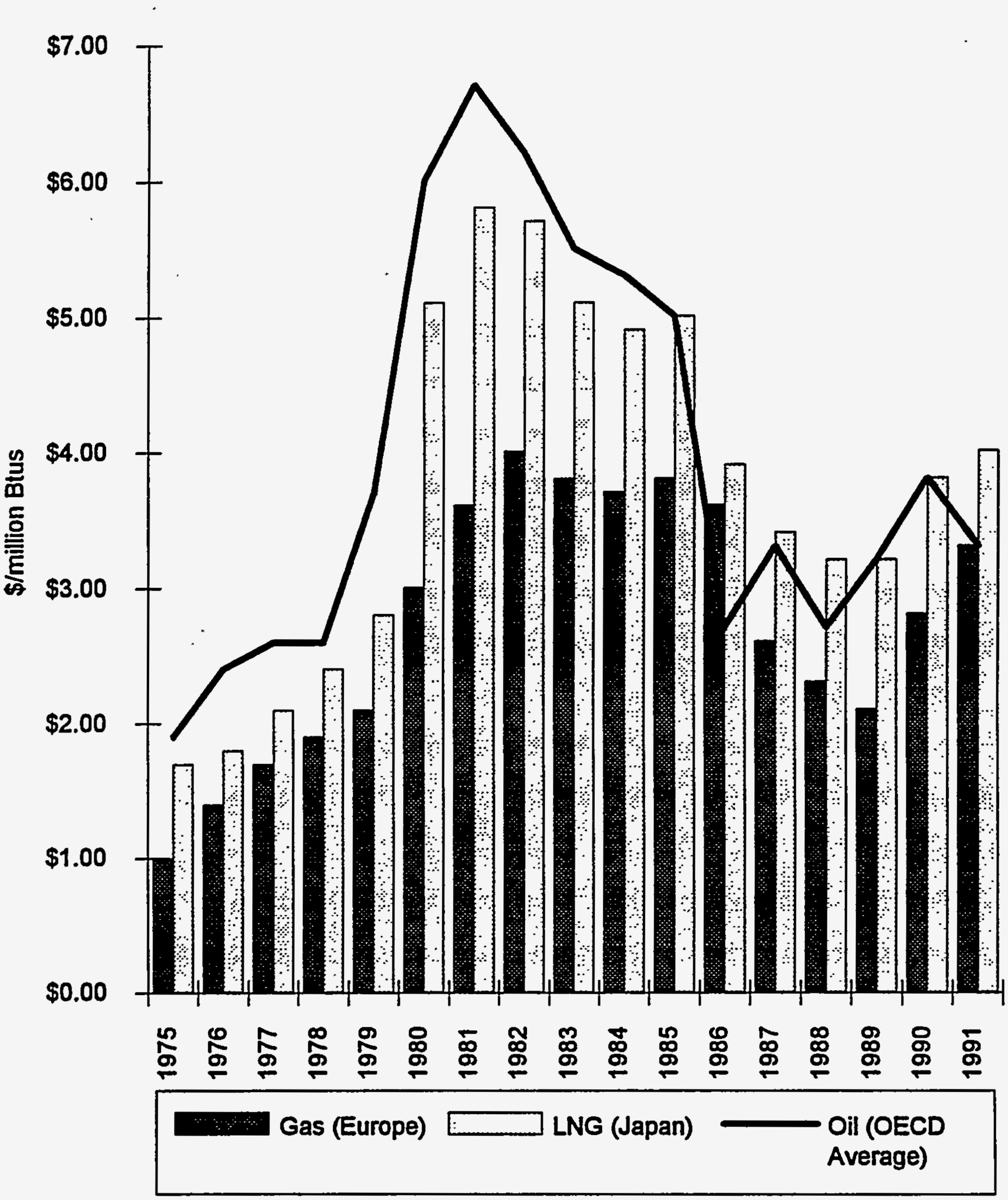
Given such a large cost for transport and distribution, it is sometimes easier to move the consumer to the gas rather than vice-versa. This approach has been taken in the United States with coal, which suffers similar transport difficulties; mine-mouth electrical plants are becoming increasingly common. In general, if the final product is more cheaply transported than the gas, locating the facilities near the gas field will be favored.

Such siting decisions are generally possible only if the gas is destined to meet new demands rather than replacing existing energy uses. It is seldom economic to shut down an existing plant and rebuild the facility in another location merely to save on transportation. It is obviously impractical to relocate residences to take advantage of cheaper cooking fuel and usually uneconomic to relocate existing power plants (although this has been done in the case of old generating facilities that were once on the edge of urban centers and gradually found themselves well within the city limits).

Gas cannot meet all energy needs, but with sufficient investment it can be fairly versatile. It readily substitutes for oil or coal in power generation and boiler-fuel uses and generally offers higher efficiency and much lower pollution. It can displace commercial and residential electricity in cooking and water heating and even in large-scale air conditioning. With a considerable restructuring of the capital stock of automobiles and existing service stations, compressed natural gas (CNG) can displace gasoline. With even more elaborate adaptations, it can also provide heavy transport, such as buses and diesel trucks, although these technologies are less proven. What gas cannot do to date is provide air transport, efficient lighting, or power to electronic appliances.

The possible roles and costs of large-scale gas use in the Hawaiian context will be fully explored in a later report. What needs to be noted here is that gas is not typically cheaper than oil if it is imported as LNG. Indeed, in the future, it may command a significant premium over oil prices because of its environmental benefits and its high hydrogen/carbon ratio (which minimizes CO_2 production per unit of energy). Figure 94 shows the prices of imported pipeline gas in Europe, imported LNG in Japan, and imported oil for the industrial nations as a group. Imported pipeline gas offers significant price

Figure 94. Gas and Oil Import Prices, 1975-91



advantages relative to oil; the savings from LNG relative to oil were smaller in the mid-1970s, and by 1985 LNG was receiving a premium over the average oil price. LNG may have significant advantages for the importer in many aspects, but massive cost savings to the consumer is not one of them.

Liquefied Petroleum Gases (LPG)

LPG is primarily composed of propane and butanes in varying proportions, with small volumes of propylene and butylene, as well as trace amounts of ethane and pentanes. Propane and butane are sold as separate liquids for various uses, but most LPG is consumed as a mixture. The properties of commercial LPGs vary according to the proportions of propane and butane; most countries set standards that allow several marketable mixtures.

In domestic applications, LPG is usually provided in refillable gas cylinders that can be connected to domestic appliances. This use of LPG has become widespread in rural areas of the developed nations, as well as many urban areas of the developing world.

In addition to its production from natural gas processing, LPG is also produced by refinery processes, sometimes in fairly large quantities. For this reason, most nations already have some experience in the local transport and marketing of LPG.

Use of LPG as an industrial fuel is quite limited except in Japan, where stringent environmental controls encourage the use of LPG in power generation and as a boiler fuel. Elsewhere, LPG is usually considered too valuable to burn under boilers, but it is a clean and versatile fuel.

LPG is an important feedstock for the manufacture of olefinic petrochemicals. Propane can produce ethylene and propylene (base chemicals for a wide array of derivatives), while butane can be used to manufacture butylenes and butadiene (important inputs for synthetic rubber manufacture).

The direct use of LPG as an automotive fuel is well established in parts of Italy, Japan, the United States, Thailand, New Zealand, and elsewhere. Conversion of standard engines to run on propane, butane, or LPG mixtures is straightforward and relatively cheap.

Because supplies are limited and not many service stations provide LPG filling, the use of LPG in combustion engines has mainly been limited to fleet vehicles: corporate automobiles, buses, taxis, delivery vans, and small trucks. The clean combustion properties of LPG are a major advantage in polluted urban areas; Tokyo and Bangkok have long encouraged the switching of taxis and other vehicles to LPG because of the emissions reductions possible.

LPG is relatively easy to transport and store. In liquid form it is readily moved by pipeline and can be stored in tanks at moderate pressures. It is as safe under proper conditions as any oil product; thus, it is acceptable to locate LPG tank farms in or near urban centers.

LPG is also relatively easy to transport in bulk LPG carriers in a specialized type of tanker, at present mainly cooled in liquid form. Trade in LPG has expanded rapidly over the last twenty years. Large volumes are now moved by sea, particularly from the Middle East to Japan and Korea. The market for LPG, unlike that of LNG, is well-developed; there are a multitude of import terminals and even a substantial spot market centering around the United States Gulf Coast.

Because LPG is often produced from associated gas, LPG prices can be subject to volatile short-term price behavior as oil production levels fluctuate. Despite this, the overall market for LPG appears to be relatively stable from year to year. LPG has many of the advantages of oil: relative ease of transportation and use, widespread import and export markets, and relatively easy storage. In price and supply volatility terms, unfortunately, it also has the potential to resemble oil in the longer term.

Condensates: Natural Gas Liquids (NGLs)

As discussed earlier, NGLs may be produced from three different sources. First, these "condensates" may be produced in conjunction with oil from existing oil fields. Second, condensate may be a by-product of gas processing, either in the preparation of pipeline-quality gas for local distribution, or in the manufacture of LNG. Third, condensate may be produced directly from gas/condensate fields. With the growth of the LNG market, the need for gas processing has increased significantly, and the condensate by-product has made major additions to the traditional supplies of condensate. While condensates from gas processing are mostly light, condensates emerging directly from fields are generally heavier and produced in much higher volume.

There are three different outlets for condensate. The first is direct burning under the boiler for power generation. Currently about 5 percent of Asia-Pacific condensate production is consumed in the power sector. Direct burning is not the most economical use of condensate, and such use is expected to decline as a proportion of total condensate consumption. Almost all direct burning of condensates takes place in Japan, where it complements direct burning of LPG.

Second, because of their high naphtha content, condensates are used as petrochemical feedstock for production of plastics, organic chemicals, and fertilizers. The preferred condensates for petrochemical use are the lighter type of liquids, largely because most petrochemical facilities have been designed to use refinery naphtha as feed. Substituting light condensate fractions requires no changes to existing equipment. Although precise figures are not available, it is estimated that up to 20 percent of condensate output is consumed as petrochemical feedstock, but the numbers fluctuate rapidly depending on market conditions.

Condensate as refinery feedstock is the third and largest outlet. Currently, over 70 percent of light and heavy condensates are mixed with crude oil. However, the amount of condensate that can be accepted in the crude oil charged to the distillation tower in a typical refinery is limited. Condensates are so much lighter than crude oil that adding condensate soon saturates the light products offtake on the tower. This situation can be improved somewhat by "debottlenecking" the distillation offtake. A number of producers of condensate, particularly Australia, Indonesia, and Malaysia, have at times found it difficult to market their condensate directly. Since their crude prices are higher, they have chosen to mix their condensate into their crude streams and sell the mixture as crude. These "enriched" crudes are high-quality, high-API crudes for any buyers whose facilities can handle the high naphtha output.

The problems of bottlenecks are much less common in the United States and Western Europe, because the natural gas industry in these areas fractionates most raw condensate into light naphtha, heavy naphtha, raw kerosene, and sometimes gasoil and light fuel oil. These operations are carried out at a few central locations that receive raw condensate via pipeline from other gas processing facilities. Fractionation of raw condensate is carried out in distillation towers which are similar in design and cost to refinery distillation towers. The fractions produced may be sold directly to end-users (such as petrochemical plants) or sold to refiners as blending stocks or feeds to units such as catalytic reformers. Because these products may be processed or blended downstream of the primary distillation towers, they do not disrupt refinery flows in the way that crude mixed with condensate does. Since they do not disrupt the flows, and since distillation costs are not carried by the refiner, these products command prices above the price refiners are willing to pay for raw condensate.

E. The International Gas Market

1. Market Structure

Paul Frankel, the foremost energy economist of his day, once stated that the most important item to remember about oil is that it is a liquid. While this seems like a pointless truism at first glance, there is much wisdom in it. Oil, unlike coal, can be moved easily with simple pumps and piping; it conforms to the shape of any container it is placed in, moving easily from pipeline to ship to storage tank; it need not be kept under pressure.

By analogy, the important thing to remember about natural gas is that it is a gas. It is easy to move with pumps and piping, but its energy density is low. A gas pipeline can move only about one-quarter as much energy as an oil pipeline of equal size and requires stronger compressors and construction materials. To be stored or shipped in containers of manageable size, gas must be kept under pressure or chilled to temperatures below which air liquefies. It is very expensive to store gas or to move it by means other than pipelines. Storage requires specialized facilities (such as LNG tanks) or very propitious local geology (such as an empty gas reservoir). Shipping requires specialized transport and specialized terminals at both ends. As a result of these infrastructural barriers to trade, and the expense of providing this infrastructure, most natural gas is consumed near the source of production. In 1991, of the total 1,965 bcm of natural gas consumed in the world, only 310 bcm, or 16 percent, was consumed outside the country of production. Of the traded amount, the former Soviet Union alone accounted for fully one-third of the total.

Natural gas trade receives more than its share of attention, partly because gas-rich countries (and the companies that found the gas reserves) hope to find a way to earn export income, and partly because oil-importing areas are always dreaming of a way of freeing themselves from the oil market. Nonetheless, as Figure 95 makes clear, gas trade is a small share of the total gas picture, and the oft-discussed LNG market is actually tiny.

The small role of international trade in the total gas market is best understood by contrast with oil. Figure 96 shows the shares that the import/export market plays in natural gas consumption, crude oil demand, and total oil demand. (Since oil can be imported as crude and then reexported as products—measured here as the trade share of total oil demand—in principle it is possible that in some future year the amount of oil exports will actually exceed the amount of oil consumed.) Even on the mildest measure of trade's share in oil demand (the crude market), oil exports always account for at least 35 percent of demand, and historically more than half of demand is typically met by the export market.

Pipelines are expensive, but pipeline gas transport is typically cheaper than LNG shipping. At distances of less than 2,000 miles, pipelines are cheaper per mile than LNG carriers, and when the cost of the liquefaction plant is taken into account, pipelines are almost always the preferred mode. Under the circumstances, the market shares displayed in Figure 97 are unsurprising.

Table 27 shows large reserves in many countries that are small consumers. Table 28 shows the world gas balance for 1991. (Note that exports are always higher than imports because of pipeline losses and consumption, and LNG boil-off during shipping.) Consulting this table along with a map, it is hard to find many new possibilities for pipeline linkages that are not infeasible because of geography or political risk. The events in Eastern Europe

Figure 95. World Gas Supply by Source, 1951-91

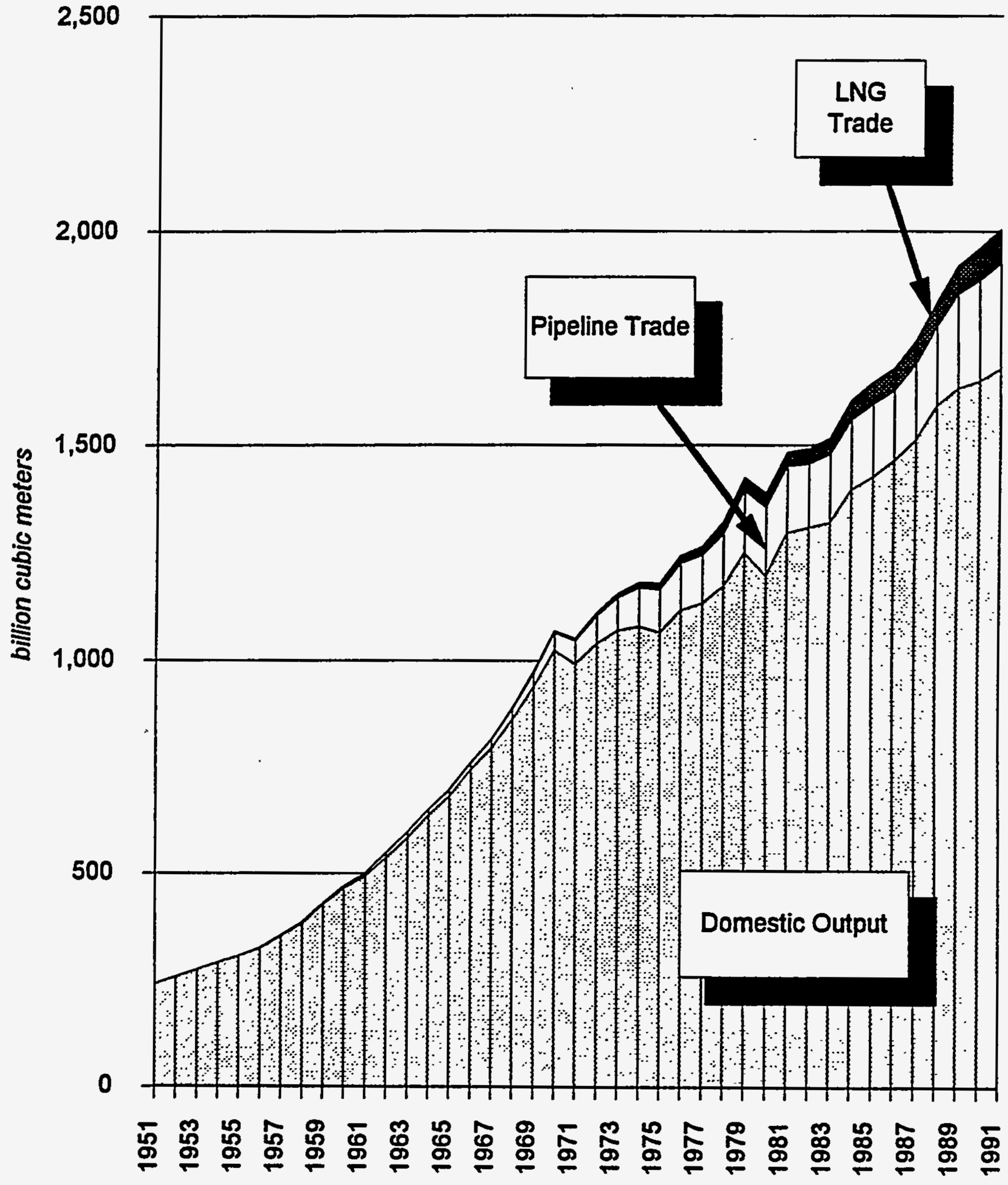
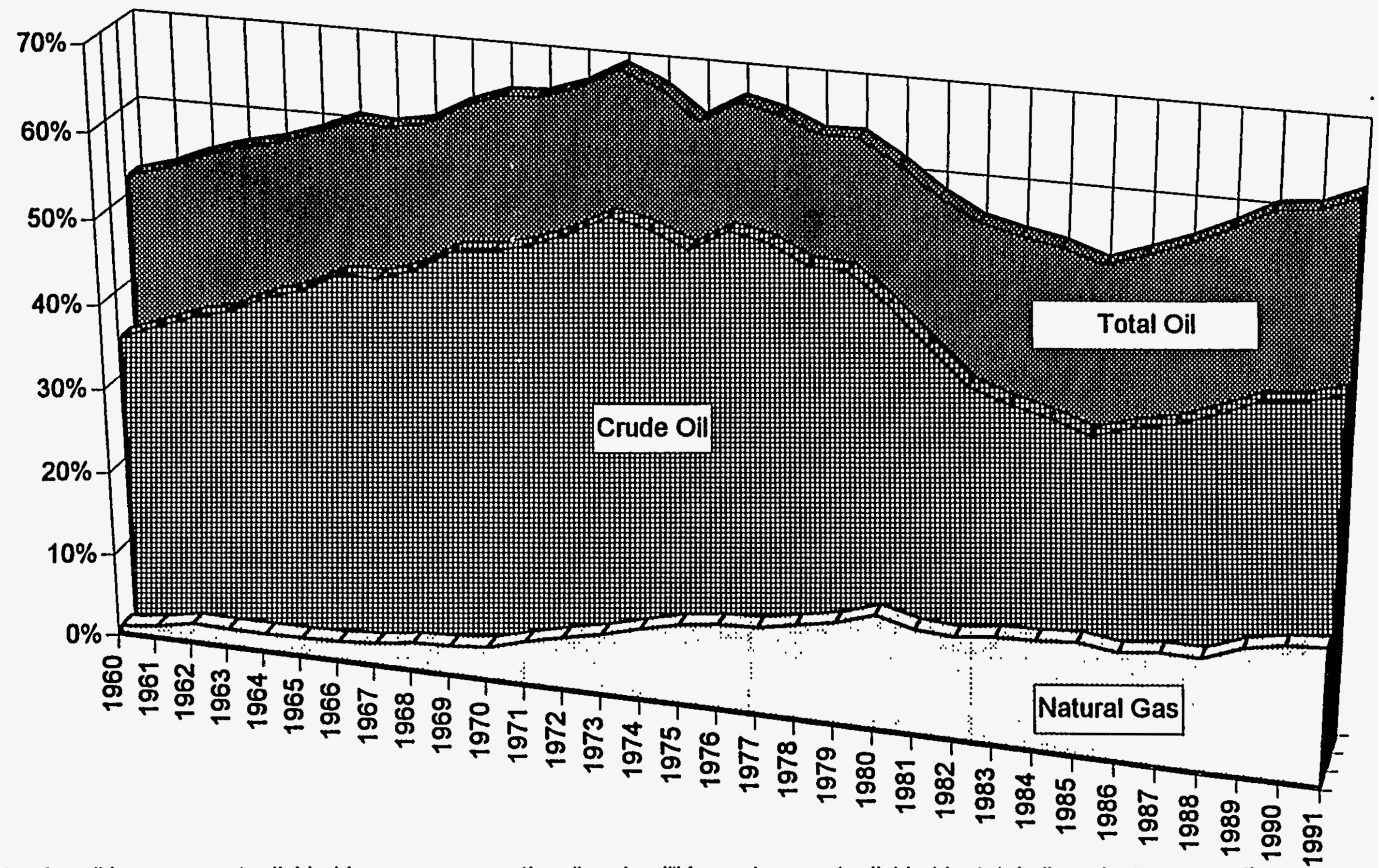


Figure 96. World Hydrocarbons: Shares Supplied by Imports, 1960-91



Notes: "Natural gas" is gas exports divided by gas consumption; "crude oil" is crude exports divided by total oil product consumption; and a "total oil" is all oil traded (both crude and refined product) divided by total oil product consumption.

Figure 97. International Gas Trade: Pipeline versus LNG, 1951-91

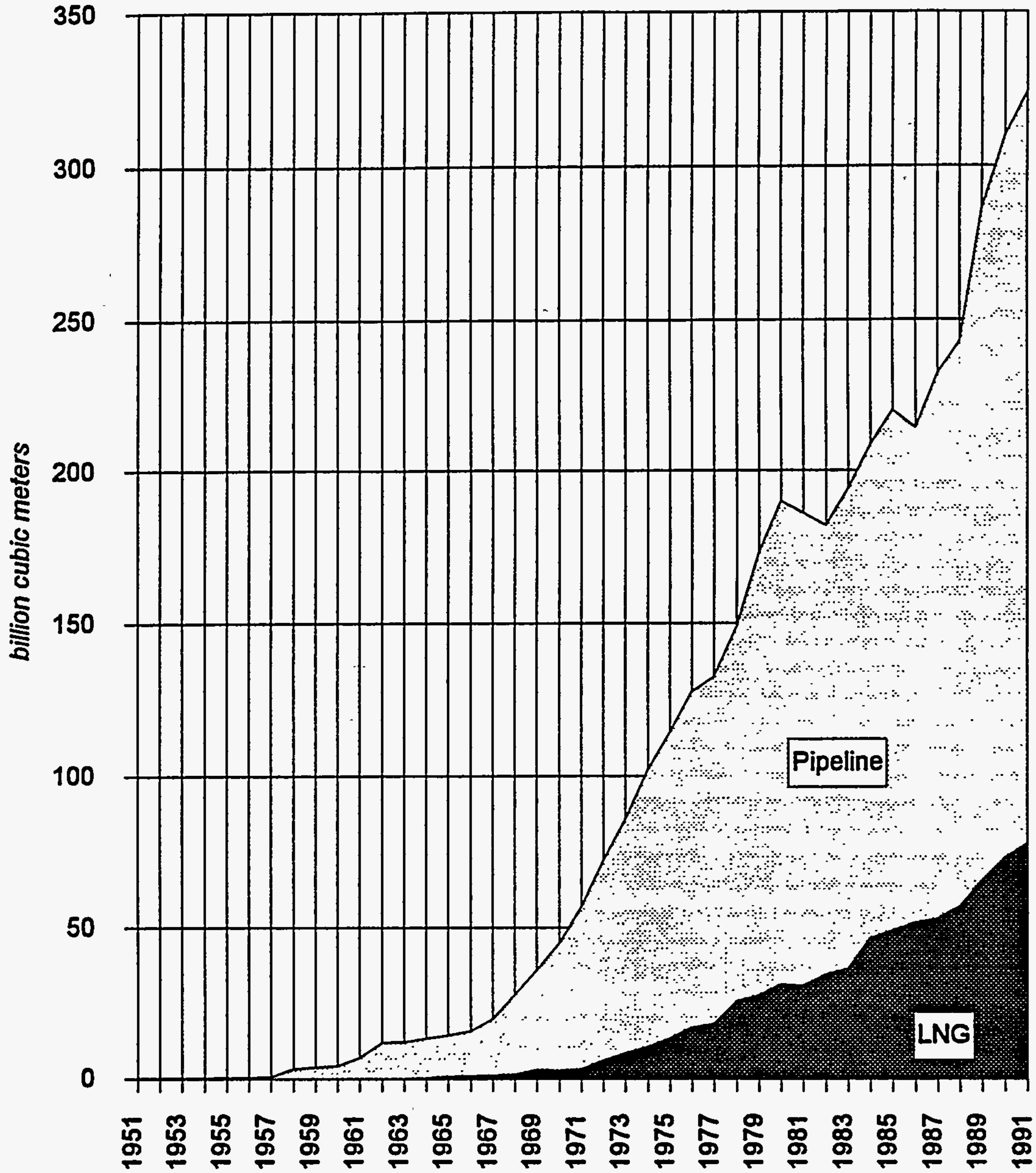


Table 28. World Gas Balance, 1991

(billion cubic meters)

	OUTPUT	IMPORTS	EXPORTS	DEMAND	Diff.
UAE	19.2		3.5	15.7	
Bahrain	4.9			4.9	
Iran	28.9		2.5	26.4	
Iraq	2.2		0.8	1.4	0.0
Israel	0.0			0.0	
Jordan					
Kuwait	4.4	0.8		5.2	
Oman	2.5			2.5	
Qatar	5.5			5.5	
Saudi Arab.	33.2			33.2	
Syria	0.2			0.2	
Yemen					
MIDEAST	101.1	0.8	6.8	95.1	

	OUTPUT	IMPORTS	EXPORTS	DEMAND	Diff.
Algeria	50.1		33.7	16.4	
Angola	0.2			0.2	
Cameroon					
Congo	0.0			0.0	
Egypt	9.1			9.1	
Eq. Guinea					
Ethiopia					
Gabon	0.3			0.3	
Ghana					
Ivory Coast					
Libya	6.8		1.6	5.2	
Madagas.					
Morocco	0.1			0.1	
Mozamb.					
Namibia					
Nigeria	4.7			4.7	
Rwanda	0.0			0.0	
Somalia					
S Africa					
Sudan					
Tanzania					
Tunisia	0.4	0.7		1.1	
Zaire					
AFRICA	71.6	0.7	35.3	37.0	0.0

	OUTPUT	IMPORTS	EXPORTS	DEMAND	Diff.
Argentina	24.2	2.2		26.4	0.0
Barbados	0.0			0.0	0.0
Bolivia	3.0		2.2	0.8	
Brazil	4.1			4.1	
Chile	4.2			4.2	
Colombia	5.3			5.3	
Cuba	0.0			0.0	
Ecuador	0.1			0.1	
Guatemala					
Mexico	28.2	1.2		31.1	(1.7)
Panama					
Peru	0.5			0.5	
Trinidad	4.2			4.2	
Venezuela	25.4			25.4	
S AMERICA	99.4	3.4	2.2	102.3	(1.7)

	OUTPUT	IMPORTS	EXPORTS	DEMAND	Diff.
Afghanistan	3.0		0.9	2.1	
Australia	22.1		5.2	16.9	0.
Bangladesh	4.5			4.5	
Brunei	9.7		7.0	2.7	
China	16.1			16.1	
India	15.0			15.0	
Indonesia	50.8		30.0	20.8	
Japan	2.1	50.7		52.8	0.
Korea		3.7		3.9	(0.
Malaysia	22.7		10.0	12.7	
Myanmar	1.1			1.1	
New Zealand	5.1			5.1	
Pakistan	15.0			15.0	
PNG					
Philippines					
Taiwan	0.0	2.1		2.1	
Thailand	7.6			7.6	
Vietnam					
ASIA-PACIFIC	174.6	56.5	53.1	178.2	(0.

	OUTPUT	IMPORTS	EXPORTS	DEMAND	Diff.
Austria	1.3	5.2		6.3	0.
Belgium/Lux	0.0	11.2	1.3	9.6	0.
Denmark	3.5		1.3	2.2	
Finland		2.8		2.7	0.
France	3.6	31.2	2.1	30.7	2.
Germany	18.1	46.2	1.2	63.1	0.
Greece	0.1			0.1	0.
Ireland	2.4			2.4	
Italy	17.3	33.6		50.9	0.
Netherlands	69.1	3.2	38.5	33.8	0.
Norway	27.3		25.0	2.3	
Spain	1.3	5.2		6.1	0.
Sweden		0.6		0.8	(0.
Switzerland		2.1		2.1	
Turkey	0.2	4.3		4.2	0.
UK	54.2	6.7		60.2	0.
W EUROPE	198.6	152.3	69.4	277.5	4.

	OUTPUT	IMPORTS	EXPORTS	DEMAND	Diff.
Albania	0.5			0.5	
Bulgaria	0.9	6.0		6.4	0.
Czech.	1.0	11.8		12.8	
Hungary	4.5	6.1		10.2	0.
Poland	4.3	5.9		10.2	
Romania	18.0	4.6		23.0	(0.
Yugoslavia	2.7			2.7	
USSR/CIS	724.7	3.4	106.7	622.2	(0.
USSR/ EE	756.6	37.8	106.7	688.0	(0.

	OUTPUT	IMPORTS	EXPORTS	DEMAND	Diff.
Canada	105.7	0.3	47.4	63.5	(5.
USA	506.2	49.3	2.8	564.1	(11.
N AMERICA	611.8	49.6	50.2	627.6	(16.

	OUTPUT	IMPORTS	EXPORTS	DEMAND	Diff.
WORLD	2,013.7	301.1	323.7	2,005.6	(14.

show that the political map of the world can change rapidly, but today a great many possible pipeline connections that would be economically sensible, such as the Persian Gulf either to Europe or to South Asia, seem as remote as ever.

The infrastructural barriers involved in gas exports ensure that an integrated market in gas will never arise. Transport costs simply form too large a percentage of the delivered cost of the good for arbitrage to take place across the Atlantic or Pacific. What is emerging, however, are some distinct regional markets, some based primarily on pipelines and some based primarily on LNG.

2. Pipeline Trade

As noted above, most natural gas traded internationally moves by pipeline and is for the most part concentrated into only three major international trade flows (see Table 29). The first encompasses natural gas trade between Canada and the United States. Western Canada has become a major gas supplier to the western United States, particularly California, which does not enjoy the abundance of hydropower resources found in Washington and Oregon. It also supplies natural gas to the upper Midwest, and more recently pipelines have begun bringing Canadian gas to the Northeast United States as well. A small but growing trade has emerged of U.S. gas—mainly Texan gas—piped south to Mexican border areas, where the explosive growth of the *maquiladora* industries has increased demand for energy beyond what Mexico can provide from its gas fields, which are located mainly along the Yucatan coast of the Gulf of Mexico.

The second major flow is intra-European Community trade in gas from the Netherlands and from Norway. The Netherlands is Western Europe's largest producer of natural gas and one of its earliest producers. The foundations of the modern Dutch welfare state were built on surplus income from natural gas sales, and the accompanying industrial decline stemming from the Netherlands's subsequent loss of international competitiveness was

Table 29. International Pipeline Trade of Natural Gas, 1991

(billion cubic meters)

Importers	Exporters											% of
	US	Canada	Bolivia	Denmar	Germany	Netherlands	Norway	CIS	Iran	Algeria	Total	Total Imp.
US		47.4									47.4	*19.7*
Canada	0.3										0.3	*0.1*
North America	**0.3**	**47.4**									**47.7**	*19.8*
Argentina			2.2								2.2	*0.9*
Mexico	1.2										1.2	*0.5*
Latin America	**1.2**		**2.2**								**3.4**	*1.4*
Austria					0.1			5.1			5.2	*2.2*
Belgium						4.3	2.3				6.6	*2.7*
Finland								2.8			2.8	*1.2*
France						5.6	5.7	10.7			22.0	*9.1*
Germany				0.7		22.1	8.0	29.6			60.4	*25.1*
Italy						5.3		14.1		14.1	33.5	*13.9*
Luxembourg						0.5					0.5	*0.2*
Netherlands							2.3				2.3	*1.0*
Sweden				0.6							0.6	*0.2*
Switzerland					1.1	0.7		0.3			2.1	*0.9*
Turkey								4.3			4.3	*1.8*
UK							6.7				6.7	*2.8*
Western Europe				**1.3**	**1.2**	**38.5**	**25.0**	**66.9**		**14.1**	**147.0**	*61.0*
CIS									2.5		2.5	*1.0*
Bulgaria								6.0			6.0	*2.5*
Czechoslovakia								12.8			12.8	*5.3*
Hungary								6.1			6.1	*2.5*
Poland								5.9			5.9	*2.4*
Romania								4.6			4.6	*1.9*
Ex-Yugoslavia								4.4			4.4	*1.8*
CIS/Eastern Europe								**39.8**	**2.5**		**42.3**	*17.5*
Tunisia										0.7	0.7	*0.3*
Africa										**0.7**	**0.7**	*0.3*
Total Exports	**1.5**	**47.4**	**2.2**	**1.3**	**1.2**	**38.5**	**25.0**	**106.7**	**2.5**	**14.8**	**241.1**	*100.0*
% Total Exports	*0.6*	*19.7*	*0.9*	*0.5*	*0.5*	*16.0*	*10.4*	*44.3*	*1.0*	*6.1*	*100.0*	

Source: Cedigaz, as cited by BP Statistical Review of World Energy, June 1992.

a phenomenon that has come to be called the "Dutch disease." Demand for natural gas rose sharply in Western Europe after the first oil price shock of 1973 and soon outstripped supply from the Netherlands and Norway. This led Western Europe to look east to the Soviet Union for additional supplies.

The third major flow—and by far the world's largest—is that between the former Soviet Union and its Eastern European trading bloc and Western Europe. As with the case of oil, the Soviet Union provided large volumes of energy (39.3 bcm in 1991) to the generally energy-poor Eastern European countries—Poland, Czechoslovakia, Bulgaria, Romania, and Hungary—in return for the import of their manufactured goods. In the 1970s this trade expanded to include Western Europe, which, over objections by the United States to the sale of compressors for the Soviet gas pipeline system, began to import large quantities of Soviet gas. In 1991 the 67.2 bcm of natural gas imported to Western Europe from the Soviet Union marginally exceeded the volume provided by the Netherlands and Norway. Italy, alone among the Western European countries, imports gas from the Netherlands, the former Soviet Union, and from Algeria, to which it is connected by submarine pipeline under the Mediterranean Sea.

With the dissolution of the Soviet Union, the fall of communist governments and economic decline throughout Eastern Europe, the collapse of the Comecon trading bloc, and the initiation of "hard currency" trade payments, the export of gas to Eastern Europe from Russia has declined as Russia has reoriented it sales to Western Europe. Western Europe now relies on gas for 17 percent of its primary energy demand, up from only 5 percent in 1970, and fully 25 percent of Europe's natural gas demand is now imported from the former Soviet Union.

The prospects for increased exports of gas from the CIS (Russia in particular) are clouded by the economic turmoil that has engulfed the countries of the region since their formal independence at the end of 1991. Huge investments will be needed to exploit the massive reserves remaining in Russia and to construct the thousands of miles of pipeline needed to bring it to market. Nevertheless, since growth in Russian domestic demand for natural gas is expected to slow in the 1990s owing to economic dislocation, a shift away from gas-intensive heavy industry, and fewer prospects for substitution to gas (which currently provides an amazing 42 percent of total Russian energy consumption), increases in natural gas production can translate almost directly into exports. According to projections by the U.S. Energy Information Agency, potential exports of natural gas from Russia to Europe could reach as high as 228 bcm, which is more than double the 1991 volume, by the year 2010.

At the same time, the European market for natural gas is expected to continue to grow as gas-fired power generation replaces phased-out coal or nuclear plants or provides new generation capacity. A number of projects currently underway will expand the geographical scope of the market, the largest of which is the construction of the natural gas distribution system throughout Portugal. Other proposals are already under consideration as well: according to the International Energy Agency of the OECD, studies are under way to add a third pipeline from Norway to mainland Europe, to construct pipelines linking Spain to the French gas grid to allow imports from Norway, to build an additional pipeline from Russia to Germany and other Western European countries, and to link Greece to supplies of Russian gas. Italy is considering the addition of a fourth line to the trans-Mediterranean pipeline to expand imports from Algeria, and Spain may import gas from Algeria through a proposed pipeline ("Transmed 2") running through Morocco. The United Kingdom, which currently is not a gas exporter, may link its domestic grid to Ireland through a submarine pipeline. This projected growth in natural gas demand in Europe is expected to increase the share of natural gas in Europe's primary energy mix to over 25 percent by 2010. Imports from Russia at that time may account for up to 40 percent of total supply.

3. LNG Trade

Since the start-up of the world's first liquefaction plant in Algeria in 1964, international trade in LNG has risen at a phenomenal rate, averaging 20 percent per year over the ensuing 27 years. The LNG trade, like the pipeline gas trade, has a highly concentrated market structure with only a few major suppliers. Unlike the pipeline gas trade, there are only a few major consumers. The nature of the LNG trade—highly capital intensive supply trains, specialized transport carriers, and fixed receiving and degasification terminals—links buyer and seller in a more closely bound relationship than the pipeline gas trade does.

Currently, the world has eight LNG exporters: the United States, Abu Dhabi, Algeria, Libya, Brunei, Indonesia, Malaysia, and Australia. It also has the same number of importers: the United States, Belgium, France, Italy, Spain, Japan, South Korea, and Taiwan. In 1991 these countries traded a total of 76.5 bcm (57 million tons) of LNG, or a little over 30 percent of the volume traded by pipeline (Table 30). As Figure 98 demonstrates, this trade was split almost 75/25 between Asia and Western Europe, with Japan alone accounting for 66 percent of world imports of LNG. Similarly, Indonesia is the "Russia" of international LNG trade; its exports in 1991 accounted for 39 percent of the world total.

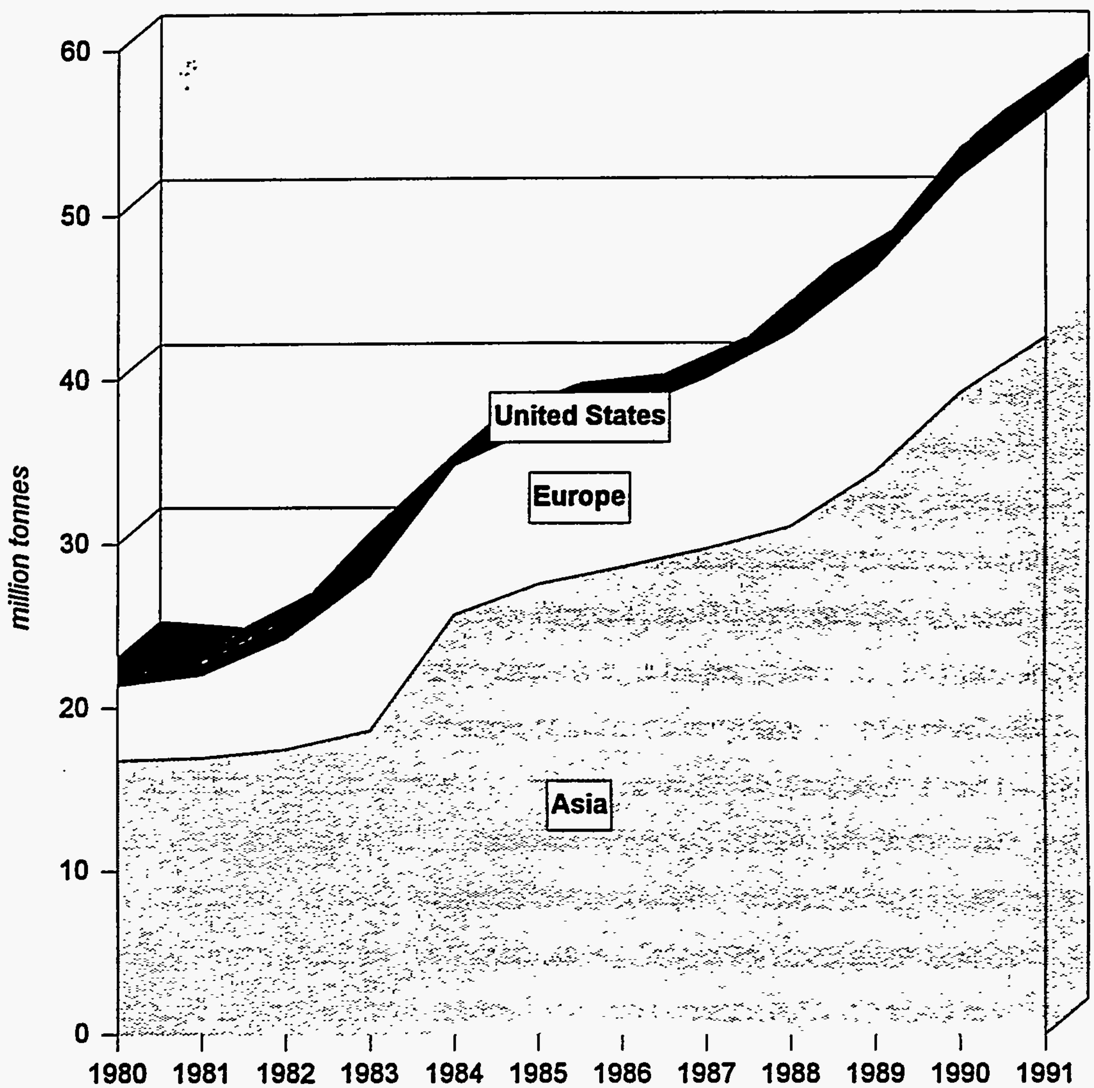
Pricing of LNG has been a key factor in the determination of capital investment for these mega-projects. Since LNG is delivered under long-term contracts, prices are indexed to crude oil prices in one way or the other, and in addition contracts have specified take-or-pay obligations as a fixed percentage of annual contract volumes. During the past few years, in response to customers' request for increased flexibility of LNG contracts, several new agreements have been reached. The agreement between Taiwan's Chinese Petroleum Corporation (CPC) and Indonesia's Pertamina, for instance, calls for take-or-pay obligations of only 65 percent. Furthermore, this is the first contract in the Asia-Pacific region that includes annual "allowances," actually increasing contract flexibility. Algeria agreed to deliver 220,000 tons of LNG to Tokyo Gas and Osaka Gas during 1989. Chubu Electric and Osaka Gas have reached agreements with Pertamina, calling for LNG deliveries over contract periods of three and five years, respectively. Other schemes have included partial price indexation to coal prices. One point all of these developments have in common, is that they signal changing contractual practices. With an increasing number of LNG plans being fully amortized, long-term contracts, declared as vital in LNG trades in the past, seem to lose

Table 30. International Trade of LNG, 1991
(billion cubic meters)

Importers	Exporters									% of
	US	Abu Dhabi	Algeria	Libya	Brunei	Indonesia	Malaysia	Australia	Total	Total Imp.
US			1.9						1.9	*2.5*
North America			**1.9**						**1.9**	***2.5***
Belgium			4.1						4.1	*5.3*
France			9.2						9.2	*11.9*
Italy			0.1						0.1	*0.1*
Spain			3.6	1.6					5.2	*6.8*
Western Europe			**17.0**	**1.6**					**18.6**	***24.2***
Japan	1.3	3.5			7.0	24.2	9.5	5.2	50.7	*65.8*
S. Korea						3.7			3.7	*4.8*
Taiwan						2.1			2.1	*2.7*
Asia	**1.3**	**3.5**			**7.0**	**30.0**	**9.5**	**5.2**	**56.5**	***73.4***
Total Exports	**1.3**	**3.5**	**18.9**	**1.6**	**7.0**	**30.0**	**9.5**	**5.2**	**77.0**	*100.0*
% Total Exports	*1.7*	*4.5*	*24.5*	*2.1*	*9.1*	*39.0*	*12.3*	*6.8*	*100.0*	

Source: Cedigaz, cited in BP Statistical Review of World Energy, June 1992

Figure 98. Regional Shares of LNG imports, 1980-91



Source: Oil & Gas Journal, July 27, 1992, citing Drewry Shipping Consultants.

some of their significance. For exporters who have operated plants for nearly two decades, guaranteed long-term sales in terms of volumes seem to become less important. This however, does not mean that future deliveries will be agreed on only on a, comparatively, short-term basis, for long-term sales guarantees remain crucial to viability of new projects. On the other hand, consuming countries, especially Japan, are requesting increased flexibility, both in terms of annual volumes, as well as pricing and related aspects. Still, since the long-term LNG prospects in consuming countries largely depend on LNG's competitiveness in comparison to competing energy sources, changes in contracting practices seem to be inevitable. Taking into account, on the other hand, concerns about supply security in importing countries, it does not appear to be very likely that a majority of contracts will be put on short-term basis. As a result, a two-tiered practice could evolve, with long-term contracts being signed for volumes delivered from new plants, while some renewals of older contracts may be agreed on for shorter periods. Also, short-term deliveries from excess capacities may be agreed on as unexpected and/or seasonal demand arises. However, increased flexibility in LNG contracts is crucial to further market penetration of natural gas and, indirectly, to decreasing environmental pollution. Increased flexibility can, in addition, contribute to supply security in importing countries, which to a large extent depend on energy imports, particularly on oil imports from OPEC.

This discussion is directly related to the possibility of an emerging LNG spot market. Although it has been concluded that the number of short-term contracts in the regional LNG trade may increase in the future, particular features of LNG markets have to be borne in mind when dealing with probable future developments. Unless fundamental changes in technical and economic parameters take place, spot trade of LNG similar to those of crude oil and/or petroleum products cannot develop, because loading, unloading, and storage facilities are few in number, limited in capacities, and available in only a few countries. Furthermore, the predominance of LNG utilization for power generation (intermediary and baseload) is likely to limit possible peak demand. Therefore, with substantial demand fluctuations in excess of contract volumes being highly unlikely, and required hardware, in particular on the demand side, existing in only a few countries, spot trade in LNG similar to oil spot trades cannot be expected in the foreseeable future. This, however, as stated above, does not mean that comparatively short-term trades will not materialize. In the contrary, an increasing number of such trades is likely to be agreed on simply because more flexibility in contract duration is required in order to further increase regional LNG trade.

LNG prices continue to be dependent on a basket of crude oils. In early 1993 the c.i.f. price of LNG to Japan was hovering around \$3.60 per thousand cubic feet—more than twice U.S. gas prices. The debate continues on whether LNG can be priced against something besides crude and whether the spot market activity will pick up. In the United States, gas is in competition with gas. In Asia, gas remains dependent on oil prices well into the latter half of this decade. Ironically, for new grassroots LNG projects to become viable, a 50 percent increase in the price of gas would be necessary, because of the high costs of such projects. Either the price of oil must rise, or the current formula needs to be reevaluated with a view to giving LNG a premium over the current crude-price based formula.

F. The Emerging Asia-Pacific Gas Market

In the Asia-Pacific region, large and developed natural gas industries are found in China, Malaysia, Indonesia, Brunei, Australia, and Thailand, whereas Japan (the largest consuming nation), Korea, and Taiwan are the region's major importers. Detailed demand figures are given in Table 31, and a chart of the trend in overall regional consumption is provided in Figure 99.

In China, owing to insufficient investment and policies that priced natural gas below the cost of production, natural gas output has stagnated for the last decade. The majority of commercial production, however, is used as feedstock to the chemical industry in the production of nitrogenous fertilizers. China spends over US\$1.2 billion per year to import nitrogenous fertilizers, and it has recently started a program to improve the efficiency of its domestic gas-based fertilizer plants to reduce unit consumption of natural gas and increase

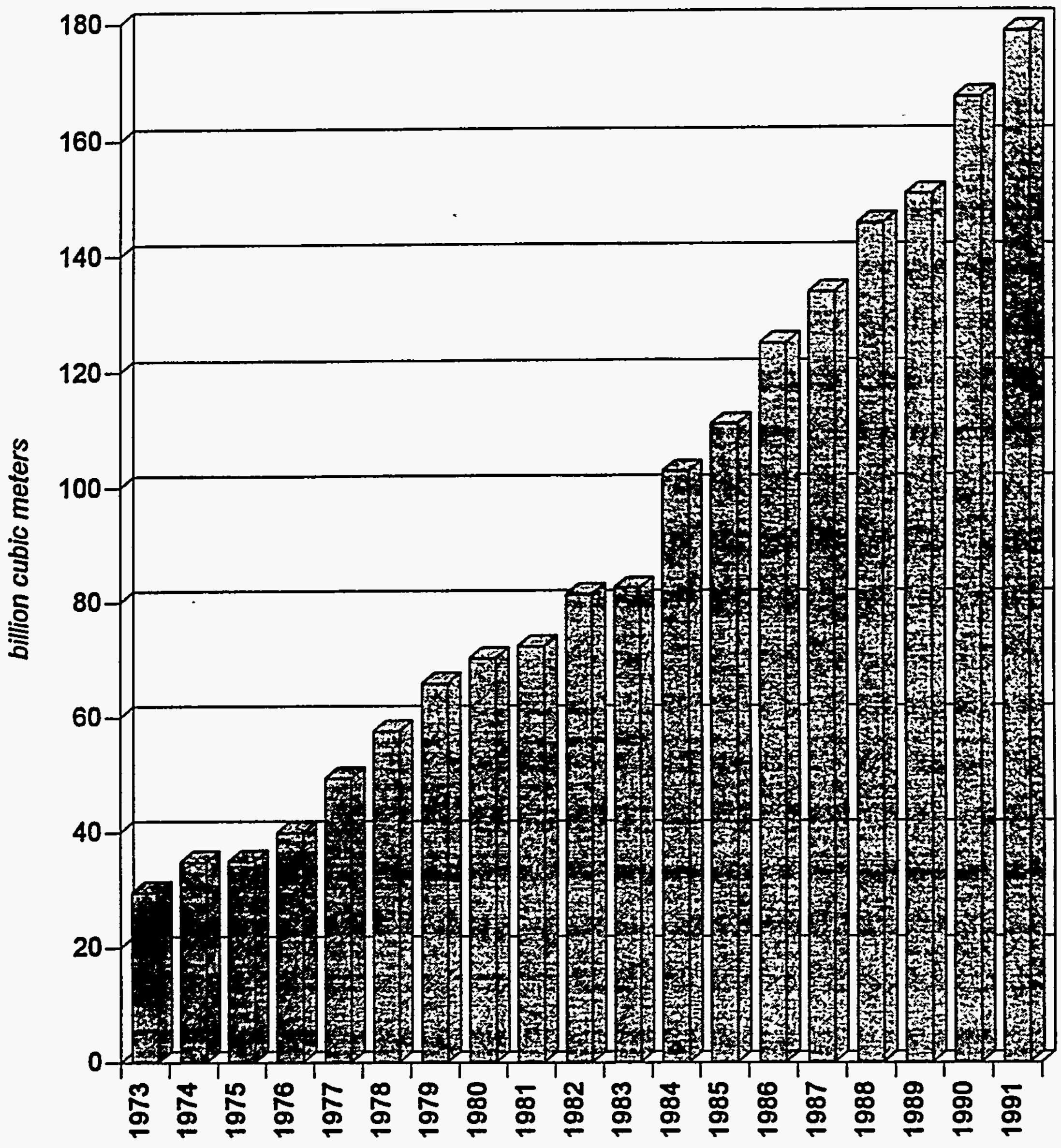
Table 31. Natural Gas Demand in the Asia-Pacific Region, 1973-91

(billion cubic meters)

	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	73-91 A.A.I. %
Afghanistan	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.1	0.1	0.1	0.2	0.5	0.6	0.6	0.6	2.0	1.9	2.0	2.1	14.9
Australia	3.9	4.3	4.8	5.6	6.7	6.9	7.1	9.2	10.6	11.7	11.8	12.5	11.6	14.6	15.0	15.8	14.9	17.3	16.9	8.5
Bangladesh	0.6	0.6	0.6	0.8	0.8	0.8	0.9	1.1	1.3	1.8	1.8	2.3	2.7	3.0	3.1	3.6	3.9	4.3	4.5	11.7
Brunei	0.4	0.7	0.8	0.5	0.9	1.3	1.4	2.7	2.9	1.9	1.2	1.5	1.3	0.5	1.1	2.1	2.1	2.2	2.7	10.4
China	6.0	7.5	8.9	10.1	12.1	13.7	14.5	14.3	12.7	11.9	12.2	12.4	12.9	13.8	13.9	14.3	15.0	15.3	16.1	5.6
India	0.6	0.7	0.9	1.1	1.2	1.3	1.4	1.3	2.4	3.2	4.1	6.8	7.9	8.2	9.4	11.1	12.4	14.4	15.0	19.4
Indonesia	5.1	5.4	2.3	2.3	5.0	5.8	9.6	7.1	7.5	7.4	8.3	9.8	10.1	14.7	15.5	16.2	14.9	19.8	20.8	8.1
Japan	5.5	7.4	8.8	10.5	12.9	18.0	21.4	24.9	24.9	25.8	27.7	37.2	39.9	42.1	42.8	44.6	48.1	50.4	52.8	13.4
Korea	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	2.2	2.9	2.8	3.2	3.9	
Malaysia	0.3	0.4	0.4	0.6	0.6	0.6	0.7	0.3	0.2	2.5	0.2	2.5	4.2	6.8	7.3	7.9	9.5	10.1	12.7	22.1
Myanmar	0.1	0.1	0.2	0.3	0.2	0.3	0.3	0.3	0.4	0.4	0.5	0.8	1.0	1.1	1.1	1.1	1.1	1.1	1.1	14.1
New Zealand	0.3	0.3	0.3	0.9	1.4	1.4	1.4	1.0	1.0	3.1	2.0	2.7	3.3	3.8	3.7	4.0	4.3	4.7	5.1	17.9
Pakistan	4.4	5.0	4.7	5.2	5.9	5.9	5.7	6.9	6.8	8.8	9.6	10.1	10.3	11.0	11.9	12.6	12.4	14.3	15.0	7.0
Taiwan	2.1	2.2	2.1	1.7	1.3	1.1	1.1	1.0	1.0	1.2	1.2	1.2	1.1	1.0	1.0	1.1	1.1	1.4	2.1	0.0
Thailand	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	1.3	1.6	2.4	3.7	3.6	4.9	5.9	5.8	6.3	7.6	
Total Region	29.6	34.9	35.0	39.9	49.4	57.5	65.8	70.1	72.2	81.2	82.4	102.6	110.7	124.7	133.5	145.3	150.3	167.1	178.2	10.5

Sources: ADB, IEA, OECD.

Figure 99. Natural Gas Consumption in the Asia-Pacific Region, 1973-91



output of fertilizers. China is also placing greater emphasis on the supply of natural gas as an alternative to coal for urban residents as a way to combat severe urban air pollution. Although residential use accounts for less than 10 percent of total natural gas consumption, this figure is expected to grow over the next decade when large newly discovered fields in northern China are developed.

In Malaysia the natural gas sector has long been primarily oriented toward LNG exports, and domestic use remained low. In the late 1980s the government formulated a comprehensive plan (the Peninsular Gas Utilization Project) to bring offshore gas to the mainland of West Malaysia for use primarily in the electric power sector, as a substitute for large volumes of fuel oil that were still being burned. The pipeline plan was extended south to include Singapore, and with the completion of the project in 1992, Malaysia and Singapore together reduced fuel oil consumption in the power sector by 32,000 b/d, or nearly one-fourth of their total consumption in that sector.

Indonesia is the largest producer of natural gas in the Asia-Pacific region, and it is the largest exporter as well. Since the first Indonesian LNG plant began operation in 1977, the export sector of the industry has flourished while domestic use of natural gas resources has grown little. In 1990 fully 75 percent of Indonesia's net available natural gas (*i.e.* after discounting flaring and losses) was exported. Consumption in the residential and commercial sectors accounted for only a little over 1 percent of the available supply, and the power sector consumed only half as much as the residential and commercial sectors.

Australia joined the ranks of LNG exporters in 1990. The choice to export natural gas rather than supply it to the domestic market was based primarily on the geographical location of the natural gas reserves rather than a lack of domestic marketing infrastructure. Although natural gas is produced in numerous locations around the country, the export sector of the industry is located near the producing fields of the northwest continental shelf, far from the population and industrial centers of south and southeastern Australia. In the rest of the country, natural gas is delivered to nearly all sectors of the economy and is an important fuel for Australia's mining and minerals industries.

Production of natural gas in Thailand did not begin until 1981. The main producing fields are located in the Gulf of Thailand and are connected to the mainland by the world's longest submarine pipeline. Planned from the beginning as a substitute for fuel oil use in power generation, nearly all Thai natural gas production has been dedicated to the state-run power sector. Before 1986, when oil prices were still high, the government began promoting the use of natural gas in other industries such as cement production, but the fall in oil price made the relatively high-priced Thai gas uncompetitive with fuel oil for private industry. Thai gas produced in the Gulf is relatively "wet"—that is, is contains high levels of propane and butane—and is coproduced with about 22,000 b/d of condensate. The propane and butane are stripped from the gas at a major LPG plant located at the shore-fall of the submarine pipeline, which has allowed Thailand to reduce LPG imports dramatically and promote LPG use in the residential, commercial, and transport sectors.

Japan is the region's largest natural gas consumer. Less than 4 percent of Japan's consumption is produced domestically, and the balance is imported entirely in the form of LNG. Japan began imports of LNG in 1969, and consumption has risen since then to account for nearly 10 percent of Japan's total energy consumption. Despite its importance in Japan's overall energy balance, the use of LNG is restricted geographically. Consumers—mostly power utilities—are nearly all located in the proximate areas of the ports of Tokyo, Osaka, and Nagoya where major LNG import terminals are located.

Korea and Taiwan are the latest countries to begin the use of LNG. Korea's first imports arrived in late 1986, while Taiwan received its first shipment in mid-1989. In both countries, LNG is seen as an important fuel source for new power plants and as a substitute for oil in some existing generation facilities.

1. Impetus for Growth

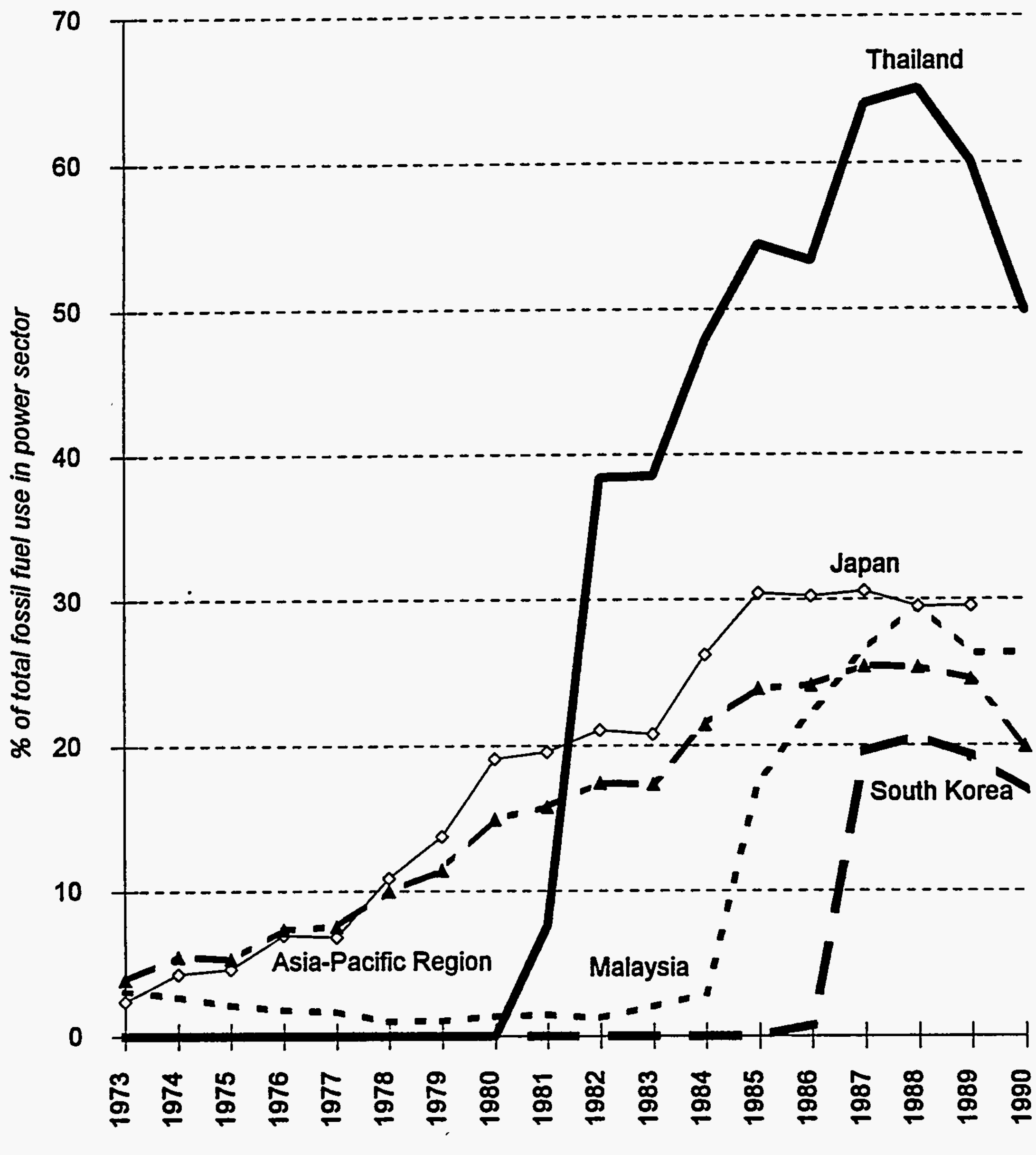
The primary force stimulating increased use of natural gas in the Asia-Pacific region is the explosive growth of electricity demand combined with high rates of economic growth and growing concern over the environment. In this region, natural gas is relatively abundant, but its exploitation has been a fairly recent phenomenon compared to oil or coal. Indeed, in 1973 natural gas consumption was only 30 bcm, or a mere 15 percent of the level that was recorded in 1991.

The demand for natural gas received a large boost from the jump in international oil prices in 1973. As one of the most oil-dependent regions in the world, the Asia-Pacific region was hit hard by the effects of higher oil prices, which not only created great pressures on the foreign trade balances of the region, but also led to across-the-board inflation, as oil was a major input to many industrial operations, including the electric power sector. As shown in Figure 100, natural gas accounted for less than 5 percent of total fossil fuel consumption in the power sector in 1973, at which time oil was the dominant fuel for power generation. Japan was among the first countries in the region to expand the use of natural gas in the power sector, and its rising imports of LNG were delivered almost exclusively to power plants.

It was not until the second oil shock that greater emphasis was placed on the use of natural gas in the power sector. Nearly all the countries in the region began widespread programs of substitution, of which one of the most impressive was that of Thailand, which went from zero gas use in 1980 to displacing over 65 percent of its oil and coal use in power generation with gas by 1986. Excluding India and China, natural gas accounted for one-fourth of all fossil fuel use in power generation in the region by 1988.

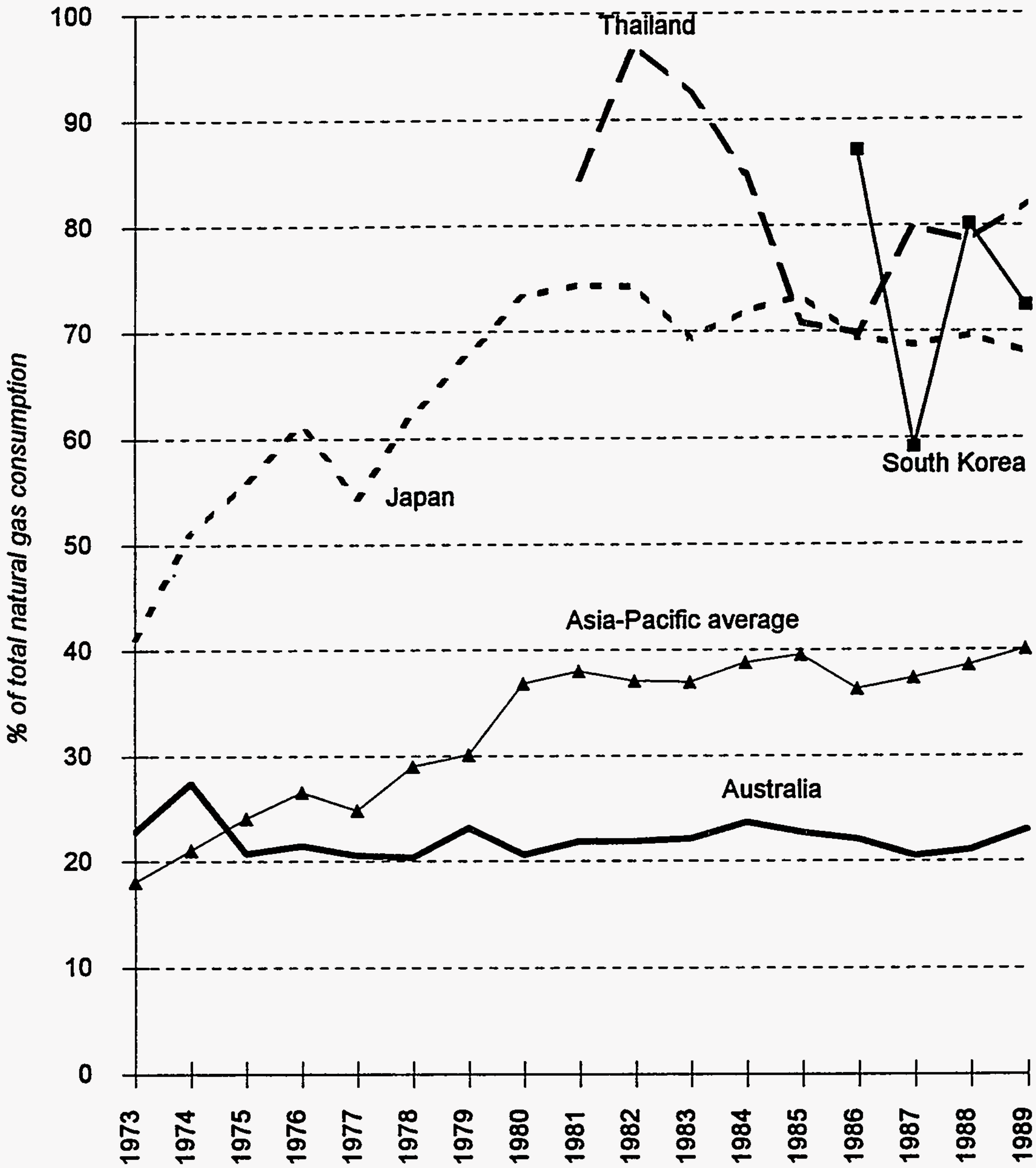
The decline in the share of gas after 1988 (to around 20 percent in 1990) is not indicative of decreased emphasis on gas use in the power sector. Instead, it reflects the inability of new gas sources to keep up with an accelerating growth in demand for electricity. The unparalleled growth in the economies of the region after 1987 have sent power demand soaring, and, as shown in Figure 101, the countries in the region have actually devoted more of their gas resources to the power sector since 1986. In 1990 alone, gas use in the Japanese power sector jumped from less than 70 percent to 80 percent of total natural gas consumption. The expected high rates of economic growth in the region and the concomitant need for even higher levels of generation capacity—combined with stricter standards for

Figure 100. Share of Natural Gas in Electric Power Generation, 1973-90



Note: Regional average excludes China and India.

Figure 101. Natural Gas Consumption in the Power Sector, 1973-91



combustion emissions—will continue to provide substantial impetus to growth in demand for natural gas.

2. Economic and Security Considerations

The oil price shock of 1973, and in particular that of 1979, sharply highlighted the dependency of many countries in the region on imported oil and the vulnerability of their economies to disruptions in supply and volatility in prices. The economic pressures wrought by the oil price shocks motivated many national planners to adopt energy policy programs centered on substitution away from oil and diversification of supply. As a core feature of the drive to reduce dependency on oil, many countries accelerated exploration and development of indigenous energy resources, including oil, coal, natural gas, and hydropower, and many enacted policies requiring the switch away from fuel oil to coal, nuclear, or natural gas in the power sector.

As countries in the region accelerated programs of exploration for domestic oil, many of them found natural gas instead, or a combination of both. This allowed national planners to achieve two objectives at once: to reduce dependence on Middle East oil imports and to diversify the mix of national energy supply.

The fall in oil prices after 1986 shifted the focus of energy planners away from questions of security of supply—which naturally favored exploitation of domestic natural gas resources—to concern about achieving a stable supply of energy at least cost. In the era of cheap oil, this led to a renewed surge in growth of oil demand, but, unlike in earlier periods, most of the growth in oil demand came from the transport sectors, where demand for gasoline, diesel and jet fuel were rising rapidly. This structural shift away from fuel oil use in power generation to the use of natural gas has preserved, and even expanded, the demand for natural gas. Moreover, since many of the countries in the region have adopted tighter pollution standards, clean-burning natural gas has become a strategic resource for simultaneously satisfying security, economic, and environmental goals.

As discussed earlier, there is a question about the security of LNG supplies in terms of opportunities for replacement in the event of a supply cutoff. None of the importers in the region have made LNG the centerpiece of their energy security strategies. LNG is simply one more alternative, with its own particular role to play in the general energy economy.

It is important to distinguish the political rhetoric of the importing countries from their actual motivations. For Japan, LNG in power generation is only partly an alternative to oil; it is also a remedy for a nuclear program that is stalling in the wake of widespread grassroots opposition. At one time, LNG imports were pursued in the name of oil displacement, but increasingly the justification of environmental quality is used. In fact, the development of LNG as an energy source in the Far East is part of a long-term strategy of diversification, and the goal is to achieve a broad-spectrum, flexible energy-import system, not to achieve specific fuel displacements or achieve environmental goals.

3. Issues of Scale

Unlike oil, natural gas development requires a commitment to infrastructure investment linking producer and consumer that is not paralleled in the oil industry. Whether through a system of gathering stations, processing plants, compressors, and pipelines or further through cryogenic liquefaction and delivery by LNG carrier, natural gas is supplied to consumers on a long-term basis, since this is the only way to economically justify the scale of investment required to explore, develop, and produce natural gas fields. As a result of this requirement to integrate production and consumption planning, a number of issues of scale arise in the natural gas industry that delimit the economic viability of projects.

One issue is the size of the reserve base and the life of deposits at any particular level of production. Constructing a multi-million dollar pipeline, for example, to deliver natural gas to a factory requires that the production be maintained at a certain level for a long enough time to allow a full pay-back of the investment in transport infrastructure, as well as cover the costs of exploration and development of the reserves. This becomes an even more restrictive constraint when the decision is made to reticulate an urban area for gas supply, since the expense of extending pipelines into tens or hundreds of thousands of households and commercial establishments is enormous, and the network must be supplied with gas for decades to justify the expense involved. As a result, many large gas deposits located far from consuming centers remain undeveloped; if these same gas fields were located in greater proximity to markets, or in proximity to an established transport infrastructure, they would most likely be considered commercially viable and developed. Similarly, small gas deposits near consuming centers may go undeveloped since they may unable to sustain a supply of gas long enough to make the returns on investment attractive.

Another issue of scale is that of the size of the market itself. Remote, small, or dispersed markets are unlikely candidates for natural gas supply since the costs of supplying these markets often cannot justify the expense of developing and transporting the natural gas. The unit costs of pipeline delivery, for example, generally increases exponentially as the diameter of the line decreases linearly; thus, a pipeline half the size may cost four times as much to build per unit of natural gas delivered. Similarly, in the case of LNG, the huge investments required to build liquefaction plants, LNG carriers, and receiving terminals—in addition to any infrastructure investment need on the consuming end—cannot be justified except in cases where a large long-term dedicated market for the LNG is found. (Further consideration of LNG, specifically in the context of Hawaii's energy market, is provided in the Task III report of this project, entitled *Greenfield Options*.)

4. Emerging Gas Conversion Technologies

Further growth in the scope of natural gas utilization is presently limited by the financial and geographical constraints of building new pipeline systems and LNG facilities. In the case of "remote" natural gas, even these options are generally uneconomical, and thus countries with major reserves of remote natural gas have been attempting to develop alternate uses for their resources. As a major gas producer in Malaysia, Shell has taken the lead in developing new alternative markets for natural gas; their approach, based on a new technology now being implemented in Bintulu, Malaysia, is to convert natural gas into high-value transport fuels such as diesel.

The Shell middle distillate synthesis (SMDS) process was developed to convert natural gas into middle distillate fuels (primarily diesel). It is based on the Fischer-Tropsch process, first developed in Germany in the 1920s and applied there (and later in South Africa and China) for liquid-fuel synthesis from coal. With the advent of cheap petroleum supplies, especially after World War II, this process was largely abandoned as uneconomical, except in the special case of South Africa, which was subject to an oil import embargo and thus required alternative supplies of motor fuels.

In Malaysia, Shell is using the process to convert remote natural gas located in offshore Central Luconia and adjacent areas of Sarawak into liquid fuels. The pilot plant, estimated to cost US$800 million, is located next to the Malaysian LNG plant and will use 2.8 mmcm/d of offshore natural gas (at the same price as that sold to the LNG plant) to produce 470,000 tons/year of synthetic oil products, including diesel, kerosene, naphtha, and paraffins (wax). The plant, which was scheduled to go onstream in March 1993, was designed to maximize the production of any of these fuels depending on the market conditions, but it is expected that the plant will be primarily oriented towards diesel production. One by-product—waxy raffinate—is a premier tribological feedstock for the production of very high-viscosity motor lubricants and will be exported to plants in Australia or France. Although no details about costs of production have been released, the profit margins are reported to be even lower than those from standard refinery operations. As a pilot plant, however, it will provide technical and economic experience valuable for further development of this new conversion technology.

A similar gas-to-liquid conversion technology is in place in New Zealand, where domestic gas resources have been used to produce motor gasoline. The experience of this country, where state intervention in the energy markets has been replaced by a deregulated private energy industry, provides instructive examples of the role of natural gas in an isolated, island location.

5. Unconventional Uses of Gas: The New Zealand Experience

New Zealand's experience with natural gas is instructive for Hawaii, even though its "unconventional uses of gas" apply to domestically produced gas, which Hawaii lacks. The use of gas in New Zealand was a costly proposition, but it was undertaken in order to reduce the country's dependence on oil. Although there are large and obvious differences between the economies of New Zealand and Hawaii, there are important similarities. New Zealand is a modern island state with a relatively small population, geographically isolated from major markets. New Zealand has hydrocarbon resources that Hawaii lacks, but the large reserves are in gas. New Zealand has attempted to carry gas-substitution further than any other country, attempting to move it into power generation, residential use, and transport.

Domestic Supply and Synfuels

The exploration of New Zealand's sedimentary basins have revealed that the country is, in general, more gas-prone than oil-prone. Proven gas reserves of around 127 bcm equate to nearly 640 million barrels of oil equivalent (mmboe), an amount roughly four times the size of the proven oil reserve. This proven reserve figure may be somewhat conservative, since estimates for several recently discovered fields have yet to be published. Still, gas reserves are not extensive when viewed from an international perspective: Indonesia's gas reserves are more than 25 times as large as New Zealand's. In New Zealand gas has not become an internationally traded commodity, and this situation is unlikely to change.

During the 1970s and 1980s, the domestic natural gas pipeline network was expanded to reach virtually all major centers on the North Island. Large users such as the power sector and the petrochemical industries in Taranaki now account for around three-quarters of national gas consumption. In contrast to the oil market, New Zealand's natural gas market remains regulated both at the wholesale and retail level, chiefly because of the premier position in the market held by Petrocorp—New Zealand's leading oil and gas company—as a major natural gas producer, processor, and pipeline distributor.

The major players in New Zealand's natural gas industry are Petrocorp—both as a producer and as a marketer operating through its subsidiary the Natural Gas Corporation (NGC)—Shell BP Todd, and Maui Development, Ltd. Each of these organizations is intricately linked to the others through consortia or agreements. Prior to deregulation, the government was also a major player in the market through the Gas and Geothermal Trading Group (GGT), a division of the former Ministry of Energy. GGT has been disbanded, and its residual functions have been transferred to the Department of the Treasury.

In the early 1980s the government strongly encouraged gas utilization in the residential sector as part of its overall goal to reduce dependence on imported oil, and established the world's first commercial gas-to-gasoline synthetic fuel ("synfuel") plant. The government also promoted development of the petrochemical industry, though in this case the government was not displacing oil, but rather launching an entirely new energy-intensive industry.

The collapse of oil prices in 1986 made many alternative fuel development projects uneconomical, including New Zealand's synfuels. The government found itself subsidizing the synfuels plant and in December 1988 sought to sell its 75 percent interest to Petrocorp. The Commerce Commission at the time disallowed the sale, however, citing Petrocorp's already-dominant position in the gas market. A sale was eventually concluded in 1990, and Fletcher Challenge is now the majority owner of the synfuels plant. The sale, which relieved the government of commercial involvement, was in essence equivalent to paying a lump-sum subsidy rather than annual subsidies. The conditions of sale, however, included a number of constraints. Mobil retains offtake rights for up to 60 percent of the output of gasoline and receives a discount of US$1.45 per barrel below the international price. Fletcher Challenge is also required to pay a clawback to the Crown on gasoline or methanol-equivalent production up to 580,000 tons per year.

Gas Production and Distribution

Table 32 details gross natural gas production, liquefied petroleum gas (LPG) extraction, flaring/loss/conversion, manufactured gas production, and total production for the period 1974-90. Total production has increased enormously over the past two decades, growing at average annual rates of 15 percent during the 1974-80 period and nearly 32 percent during the 1980-85 period. During the latter half of the 1980s, production rose to 4.2 bcm annually and has maintained this level.

The Maui field accounts for around 84 percent of domestic gas production as well as a large portion of domestic condensate production. In all, it is the single largest energy resource in the country. Maintaining high levels of gas output is largely a function of maintaining output from the Maui field. Toward that end, the second stage of Maui development is now underway. As of late 1991, over 60 percent of the work had been completed on the new Maui B platform, a 15-km pipeline between the existing and new platforms, and modifications to the Maui A platform and the onshore Oanui production station. The project is expected to be completed by April 1993. Initially, the Maui B project had been envisioned as a stand-alone system, with an estimated cost of US$1.6 billion. Scaling the project down to a satellite of the existing platform, which is located 33 km offshore, cut the expected cost in half. The Maui B platform is expected to be capable of producing 11.3 mmcm/d), initially from six wells. For a period of around five years, it will also produce up to 1,000 b/d of crude and condensate from two wells.

After the Maui field, the second-largest gas producer is the Kapuni field, which accounts for around 10-11 percent of total production. The McKee and Kaimiro fields account for 3-4 percent, while the remaining 2-3 percent comes from the Waihapa field. The only new production expected onstream during the 1990s will come from the Tariki/Ahuroa fields, which are expected to come on stream in 1995. This new production, however, will serve mainly to offset production declines in the McKee, Kaimiro, and Waihapa fields, so overall gas production will expand very little during the remainder of the decade. The Kupe field is not expected to enter commercial production until after the turn of the century.

Table 32. Natural Gas Production in New Zealand, 1974-1990

(million cubic meters)

Year	Gross Production	LPG Extracted	Flare,Loss, Conversion	Net Production	Manufactured Gas Production	Total Production
1974	297	1	84	232	105	337
1975	325	1	86	259	128	387
1976	851	3	126	787	0	787
1977	1,361	5	136	1,333	128	1,461
1978	1,258	6	81	1,277	115	1,392
1979	997	10	255	787	110	898
1980	899	19	113	689	95	784
1981	1,197	12	102	914	95	1,009
1982	2,068	14	118	1,707	85	1,792
1983	2,245	16	120	1,855	72	1,927
1984	2,804	23	139	2,402	62	2,463
1985	3,555	42	165	3,073	45	3,119
1986	4,114	48	91	3,834	32	3,866
1987	3,989	48	73	3,718	10	3,727
1988	4,424	36	110	4,049	7	4,056
1989	4,618	36	84	4,193	6	4,200
1990	4,574	38	93	4,172	5	4,177
Period			Average annual growth rate (%)			
1974-80	20.3	63.7	5.0	19.9	-1.7	15.1
1980-85	31.6	17.1	7.9	34.9	-13.7	31.8
1985-90	5.2	-1.7	-10.8	6.3	-36.9	6.0

Source: New Zealand Ministry of Commerce, "Energy Data File." Original units are in Petajoules.

Notes: "flared, lost, & converted" gas includes gas used in manufactured gas production.

Gas Processing

The gas processing industry is centered in the Taranaki area near the producing fields. There are six gas processing facilities. Table 33 lists processing capacities and recent production by plant. Maui gas comes ashore at Oanui, the site of New Zealand's largest gas processing facility, which has a capacity of 18.1 mmcm/d. The facility uses a refrigerated absorption process to strip the gas of propane, butane, LPG, and condensate. Condensate is the main product, with output averaging 12,500 b/d. Treated Maui gas then enters the pipeline network serving a variety of North Island users. The other five gas processing facilities are located at Kapuni. Shell BP Todd's facility at Kapuni produces around 5,000 b/d of condensate, and the remaining natural gas is generally sold to NGC. The other facilities are operated by NGC and the Petrochemical Corporation of New Zealand (Petrochem), both of which are fully owned subsidiaries of Petrocorp. NGC's facilities use a combination of refrigeration, absorption, and refrigerated absorption processes to strip out liquid fractions such as propane and debutanized natural gasoline, before delivering the gas into the pipeline.

Petrochem's facilities at Kapuni are used to prepare gas feedstock for the ammonia/urea plant. These facilities use a combination of refrigeration, absorption, refrigerated absorption, and compression to remove LPG, butane, and debutanized natural gasoline before sending the remaining natural gas fraction and carbon dioxide to the ammonia/urea plant.

Gas Consumption

Table 34 and Figure 102 display natural gas consumption by end use. In 1990 around 64 percent of total production was consumed by electricity generation and the synfuels plant (with roughly equal shares), around 12 percent was used by enterprises including the manufacture of compressed natural gas (CNG), and the remaining 24 percent was accounted for by private sales. Major industrial and commercial users include the building industry, dairy factories, pulp and paper mills, and freezing works.

Figure 102. Natural Gas Consumption by End Use in New Zealand, 1974-90

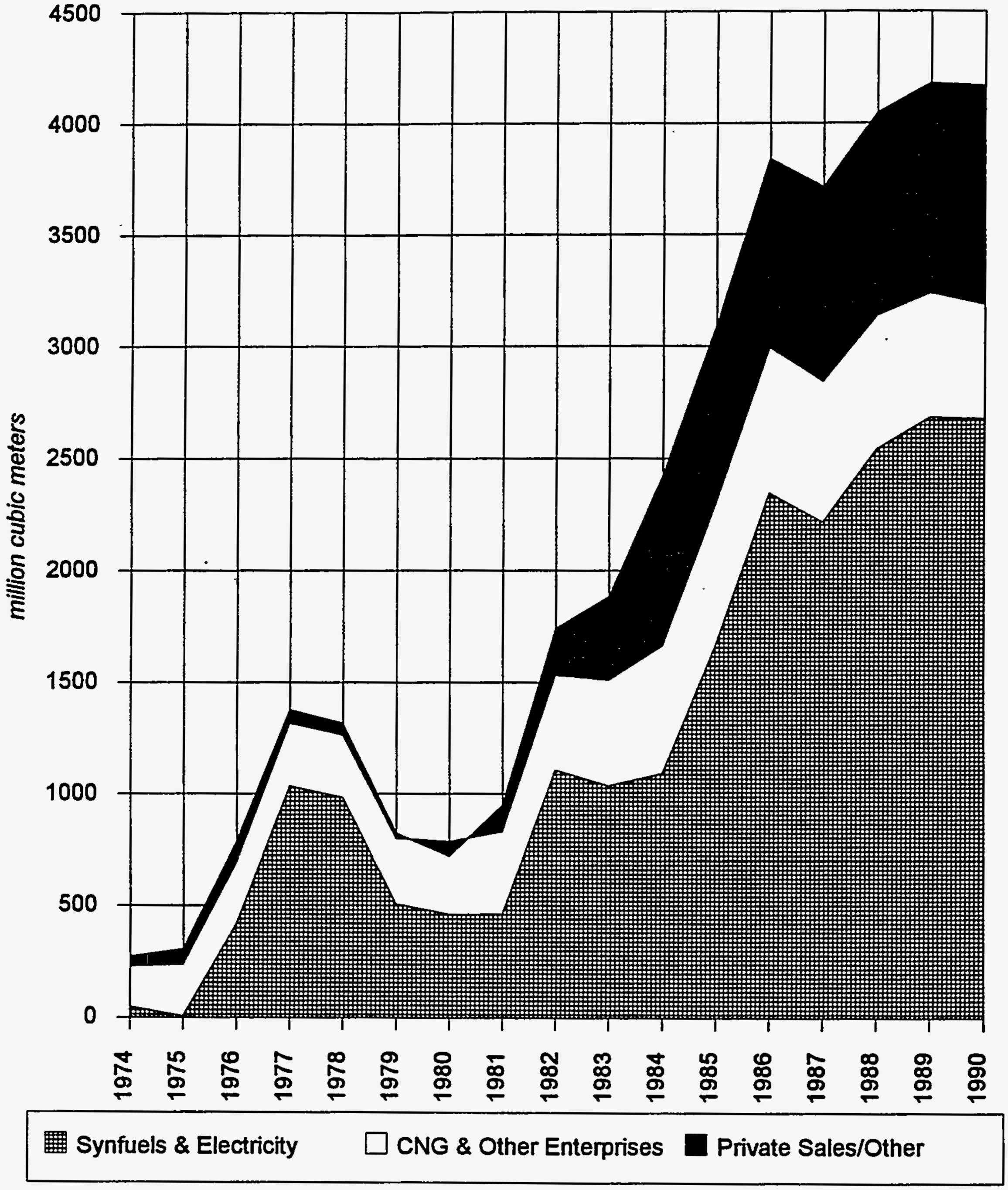


Table 33. Gas Processing Facilities in New Zealand, 1992

					Production (thousand barrels/day, 1991):				
Company	Plant/Location	Gas Capacity *(million cm/d)*	Throughput *(million cm/d)*	Process/ Method*	Propane	Butane	LPG	Debutanized Nat. Gasoline	Condensate
Natural Gas Corp.	Kapuni	2.8	1.6	1,2,3	39.0			9.0	
	Kapuni	4.3	1.0	3					
Petrochem NZ	Kapuni, Waimate West	2.8	1.4	1,2,3,4		0.7	37.7	9.6	
	Kapuni, Waimate West	4.3	1.2	1,2,3,4					
Shell BP Todd	Kapuni	6.4	5.4	4			55.0	13.0	230.0
	Maui, Oanui	20.2	12.2	2		15.0	160.0		630.0
Totals		40.8	22.9		39.0	15.7	252.7	31.6	860.0

*Gas processing/conditioning methods:
1=absorption, 2=refrigerated absorption, 3=refrigeration, 4=compression.
Source: Oil and Gas Journal, "Worldwide Gas Processing Survey," July 20, 1992.

Table 34. Natural Gas Consumption in New Zealand, 1974-90

(million cubic meters)

million cubic feet

Year	Total Production	Synfuels & Electricity Gen.	CNG & Other Undertakings	Private Sales
1974	11,882	1,712	6,358	1,491
1975	13,642	197	8,136	2,401
1976	27,760	14,773	9,726	3,253
1977	51,538	36,454	10,045	2,139
1978	49,113	34,725	9,873	1,901
1979	31,681	17,854	10,447	762
1980	27,648	16,314	11,397	-2,352
1981	35,588	16,314	13,012	4,138
1982	63,234	39,067	15,003	7,268
1983	67,978	36,544	16,797	13,003
1984	86,916	38,584	20,124	26,703
1985	110,039	58,732	22,377	27,899
1986	136,409	82,682	22,959	29,817
1987	131,516	78,135	22,197	30,702
1988	143,125	89,606	21,033	32,062
1989	148,190	94,694	19,501	33,242
1990	147,376	94,416	18,026	34,610
1991	33,258	20,378	3,851	8,931
Period	Average annual growht rate (%)			
1974-80	15.1	45.6	10.2	0.0
1980-85	31.8	29.2	14.4	0.0
1985-90	6.0	10.0	-4.2	4.4

Source: New Zealand Ministry of Commerce, "Energy Data File."

Notes: Original units are in Petajoules.

"Private sales" a calculated amount being the remainder of production

The commissioning of the methanol plant in 1983 resulted in a visible increase in gas use, as did the commissioning of the synfuels plant in 1985. Throughout the 1980s, natural gas use in the power sector also rose considerably, so that natural gas grew to dominate thermal electricity generation. Natural gas accounts for around 89 percent of thermal public electricity generation, with the remainder accounted for by coal and a very small amount of oil.

The drop seen in gas use for CNG and by other enterprises during the latter half of the 1980s largely can be explained by the drop in CNG use as an automotive fuel. Table 35 and Figure 103 show the rapid increase in CNG sales during the early 1980s, when the government was actively promoting CNG as an automotive fuel, followed by a steady decline from 1985 to 1990. There are several reasons for the decline. First, the price of oil dropped in 1986, so that in relative terms CNG became more expensive. The Liquid Fuels Trust Board based analyses of CNG's cost-competitiveness on the assumption that the retail price of CNG would be held at 50 percent of the price of premium gasoline on an energy equivalent basis. But after 1986, the CNG:gasoline price ratio rose to 60 percent. Used car dealers began to remove CNG kits before reselling the cars. Second, the rate of conversion slowed considerably after the government discontinued conversion loans in December 1987. Conversion kits cost in the range of NZ$1,500-2,000 (US$950-1,250). Third, there was some natural aging and attrition in the existing CNG fleet, and fourth, there was very little by way of a concerted marketing scheme by the CNG industry.

Both CNG and LPG were promoted by the government as a means of diversifying sources of automotive fuel, but as the government began to withdraw from direct involvement in the energy market, the vehicle conversion loan scheme was handed over to the private sector, and financial and administrative assistance for marketing and promotional activities was withdrawn. In contrast to the CNG industry, which was slow to promote the use of CNG, the LPG industry was active in advertising and marketing, and as a result, the LPG industry suffered far less after the fall in oil prices.

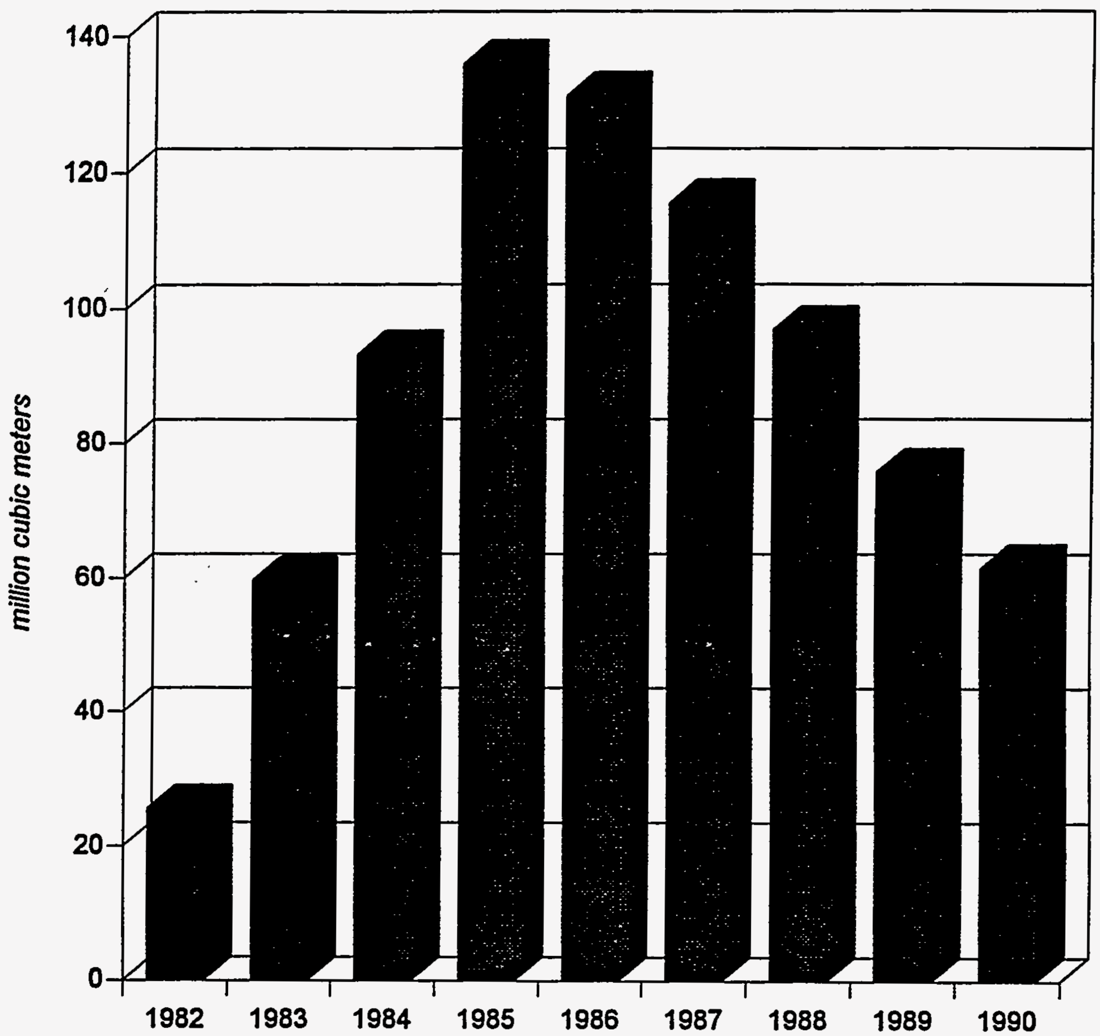
Table 35. CNG Sales in New Zealand 1982-90

Year	(million cm)	(thousand cm/d)
1982	26	70.2
1983	60	163.4
1984	93	255.1
1985	136	372.2
1986	131	359.5
1987	115	316.4
1988	97	265.1
1989	76	207.2
1990	61	168.3
Period	Average annual growth rate (%)	
1982-86	50.4	
1986-90	-17.3	

Source: New Zealand Ministry of Commerce, "Energy Data File,".

Note: original units are in Petajoules.

Figure 103. CNG Sales in New Zealand, 1982-90



LPG typically consists of propane and butane in roughly a 60:40 ratio. Since propane (C_3) and butane (C_4) have higher boiling points than methane (C_1) and ethane (C_2), LPG is easier to transport. It also has a higher heat content. LPG can substitute for gasoline, particularly in large fleet operations, and can also substitute for diesel and kerosene in certain industrial and commercial applications, especially those where a clean-burning fuel is required and sources of reticulated natural gas are not readily available. Consumption of LPG and natural gas liquids (NGL) increased during the 1970s and 1980s, growing from less than 200 b/d in 1974 to nearly 3,000 b/d in 1985 and 3,900 b/d in 1990. In total transportation fuel use, the volumes of LPG are small, representing in 1990 only 2.3 percent of transportation fuel use. Still, in the context of the LPG and NGL used in 1990, around 52 percent was devoted to transportation use, indicating the relative importance of the transport sector to LPG marketers. Other LPG end users are the industrial sector (36 percent of LPG use in 1990) and the domestic sector (12 percent of LPG use).

Petrochemical Facilities

The major bulk users of natural gas are the three petrochemical facilities: the Petrochem ammonia/urea plant at Kapuni, the Petralgas methanol plant at Waitara, and the New Zealand Synthetic Fuels Corporation synthetic gasoline facility (owned 75 percent by Petrocorp and 25 percent by Mobil), located at Motonui. Based on standard industry references, the feedstock requirements are about 0.2 mmcm/d of gas for the ammonia/urea plant, 1.1 mmcm/d for the methanol plant, and 3.6 mmcm/d for the synfuels plant. Total gas feedstocks needed by these three establishments are about 4.9 mmcm/d—equal to 41-45 percent of total gas production in 1990. Actual feed inputs depend on utilization rates at the facilities. The Synfuels plant, for example, has a rated capacity of 570,000 tons/year, but actual output is capable of exceeding 650,000 tons/year. In the 1987-88 financial year, an explosion at the plant's methanol reformer resulted in an annual production total of only 476,455 tons (around 11,100 b/d), but by the following year production reached 657,900 tons (15,300 b/d).

Since the intermediate product in the synfuels process is methanol, Petrocorp is able to take its share of the output as either methanol or syngas, depending on the market value of the commodities. Petrocorp either sells the syngas to the refiners for blending or exports the product, since Petrocorp is not involved at the wholesale level. Mobil takes the majority of its output as syngas, which it sells directly into the unleaded regular gasoline market or ships to the refinery for blending into leaded premium gasoline.

The ammonia/urea plant is also producing at levels greater than its original rated capacity of 87,000 tons/year (t/y) of ammonia, which in turn produces 150,000 t/y of urea. Recent production levels are estimated at 95,700 t/y of ammonia, producing 165,000 t/y of urea. The urea is a premium-grade granulated form, which makes storage, transport, and application convenient. Around one-third of the urea is used by domestic agriculture (as a fertilizer) and industry (in resin manufacturing), and the remainder is exported, primarily to Australia, Japan, East Asia, and the United States. Any ammonia not required for urea production typically is sold in New Zealand for refrigeration purposes.

The Petralgas methanol plant, which was commissioned in 1983 with a design capacity of around 400,000 t/y, has been producing at levels at least 20 percent higher than nameplate capacity. The facility is noted as one of the most efficient methanol plants in the world.

Summary

New Zealand's sedimentary basins have proved more gas-prone than oil-prone, with proven gas reserves amounting to roughly four times the proven oil reserve. As a domestic, non-oil energy source, natural gas is highly valued. The gas industry was given an early boost by the government's involvement, and the government continues to be a major player in the market. Gas production expanded rapidly during the 1970s and early 1980s, but slowed considerably toward the late 1980s. In general, new developments in gas production are viewed more as a means of slowing production declines than expanding the industry. Already, a considerable commitment has been made to gas-intensive industries, and the North Island has been extensively reticulated. The gas resource is not large by international standards and most likely will continue to be absorbed domestically. Additional gas finds are possible, but since some of the more promising structures are located in remote areas, such as the Great South Basin, the fields would have to be very large to justify development. This should hold true even if gas prices in the region rise, as they are likely to do because of booming demand for liquefied natural gas in countries such as Japan, Taiwan, and South Korea.

New Zealand's experience in natural gas development has shown that domestic natural gas resources can form the basis of a varied and dynamic economic sector. Used in power plants, petrochemicals, residential and commercial sectors, industry, and as feedstock to the production of methanol and gasoline, natural gas enjoys a wider range of uses in New Zealand than in most smaller producing nations. The synfuels program pioneered alternative uses of natural gas, but it became apparent after 1986 that this success was gained at the expense of substantial government subsidies, thereby distorting the allocation of natural gas resources to their highest value uses. The subsequent deregulation of the economy and the withdrawal of the government from involvement in the commercial applications of natural gas left the sector open to competition from other fuels. Although the result has been a decline in the use of natural gas for transport uses, deregulation has increased the value to the economy as a whole in those sectors where natural gas still retains a competitive advantage.

Gasoline prices in New Zealand are relatively high by U.S. standards, but CNG has been unable to hold its own against oil without government subsidies. Of course, much of this interfuel competition occurred during the oil-price slump of the late 1980s; at higher oil prices, CNG might be more favored. As noted in the chapter on the world oil market, however, oil prices are likely to continue their volatile behavior in future years. This means that, in free-market competition between fuels, there are likely to be prolonged periods in which oil will undercut its competition. New Zealand has the advantage of its own gas production, which should be fairly stable in price at times when oil prices are increasing. For gas-importing countries, however, the widespread linkage of LNG prices to the price of crude suggests that the perceived price benefits from CNG relative to gasoline are likely to be minimized by increases in the cost of gas imports.

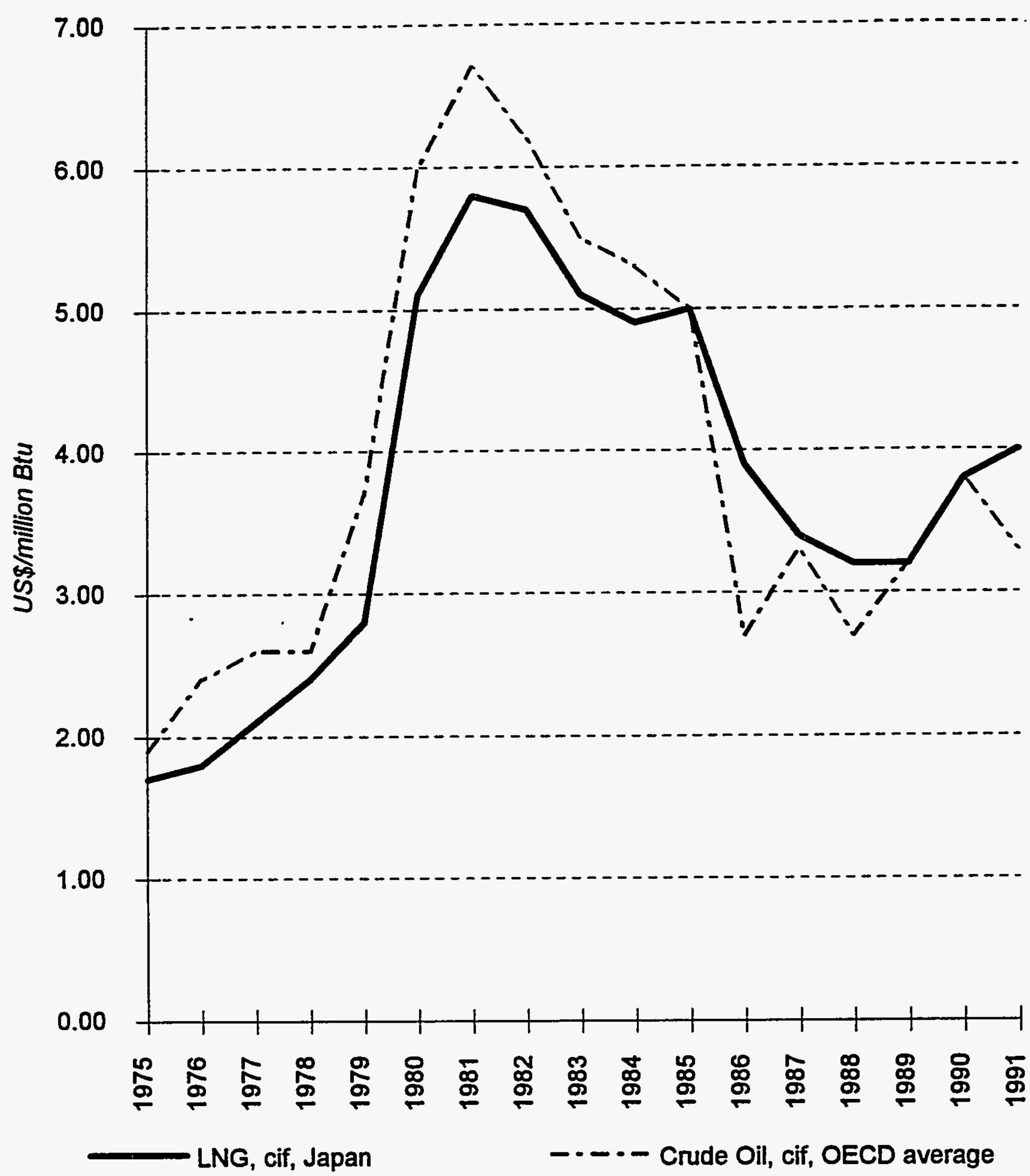
6. Trends and Outlook for the Regional LNG Market

The forecasted high rate of LNG demand growth in the Asia-Pacific region may please environmentalists eager to see this "clean" fuel substitute for coal, oil, or nuclear power, but there remain substantial obstacles to the expansion of LNG use over the next decade. The primary problems are those of rising costs and LNG pricing.

During the growth phase of the LNG market, LNG was priced to be competitive with crude oil, and, by extension, fuel oil, which was a major fuel for power generation. When oil prices were high in the early 1980s, this pricing provided substantial benefits to LNG producers, who profited from the higher margins that high oil prices brought. In the late 1980s, however, two trends brought difficulties to LNG producers and now serve as major obstacles to the implementation of new LNG projects in the region, which are of critical necessity in fulfilling expected LNG demand early in the next century. The first of these trends was a return to a period of low oil prices, which in turned wiped out the high margins enjoyed in the early part of the decade (see Figure 104). Although the profitability of LNG projects is generally not known in detail, many producers reported periods after 1986 during which their revenues barely covered their operating costs. Currently, nominal LNG prices are one-third lower than their peak in 1980; in real terms, prices now are hardly higher than they were in 1975.

The second trend has been that of rising costs. Costs of construction and operation of LNG plants have risen at least 100 percent during the 1980s, according to Shell, one of the world's major LNG producers, and the cost of LNG tankers has more than doubled. These higher costs do not have a major impact on established suppliers who have paid off most of the capital costs of their plants, but in combination with low

Figure 104. LNG and Crude Oil Prices, 1975-91



LNG prices, they are a significant financial disincentive to the construction of new grassroots plants. These cost factors will be discussed in more detail in the report of Task III (*Greenfield Options*) of this project.

Demand Outlook

Although numerous projects designed to meet the expected LNG demand after 2000 have been proposed in the last few years, the economic viability of all of them have been called into question under the current LNG pricing formula, which cannot provide a sufficient return in a regime of relatively low oil prices to recover both operating and capital costs of new plants. Moreover, projected LNG demand in the Far East has been continually revised upward, because of electricity growth that has been faster than expected, strong popular resistance to additional nuclear power construction, and difficulties in siting coal-fired power plants. Currently, Japan officially forecasts the addition of 40 new nuclear power plants by 2010, but it is unlikely that more than 25 can be built. This leaves a gap of at least 15,000 megawatts of capacity to be fired by other fuels, most of which will likely be natural gas. In Taiwan construction of the fourth nuclear power plant has been postponed since the mid-1980s and may well be delayed indefinitely, despite the government's inclusion of the fourth plant in its electric power forecasts. Once again, the resulting gap will likely be filled by natural gas.

In addition, Japan's direct burning of crude for power generation will face supply constraints, since it may not be possible to gain access to some 350,000 b/d of low-sulfur crudes for under-the-boiler use by the late 1990s. This fuel may also be replaced by LNG, adding 10-15 million metric tons of new LNG demand.[1]

Overall, Japan, which will remain the single most important LNG consumer in the world, is expected to witness a rise in LNG demand to 48-50 million metric tons by 2000, and as much as 65-70 million metric tons by 2010. Although much of this increase is slated for the power sector, but the Japanese government hopes to increase the use of natural gas in

[1]Rounded figures for projections are given in the metric standard of international trade. For conversion purposes, 1 metric ton = 1.102 short tons; 1 short ton = 0.9072 metric ton.

industry and residential sectors as well. Japan's Ministry of International Trade and Industry (MITI) has put forth a number of proposals for extending the natural gas pipeline system throughout the country. Comparing Japan's overall 10 percent share of natural gas in total energy consumption to the 20-25 percent share that gas holds in the United States and in Europe, MITI proposes to extend a trunk pipeline outside of the port areas of Tokyo, Nagoya, and Osaka, where most of LNG use is currently concentrated, to connect the three cities and to bring natural gas to other areas of the country, where consumers currently rely on supplies of propane gas and LPG. MITI estimates that such a trunk line would cost US$9.5 billion and could be completed in 2010, but a major obstacle to the plan is financing. The high costs of land and of reticulating urban areas may raise the final price tag far above the estimated US$9.5 billion.

In Korea LNG demand will likely reach 8-10 million metric tons by 2000, and demand in Taiwan may rise to 7-8 million metric tons as gas-based power generation capacity jumps from 751 MW in 1991 to 8,590 MW in 2001. By 2010 demand in each of these two countries may reach 12-15 million metric tons. Consequently, by 2010 LNG demand in the region may exceed 100 million metric tons, which is more than double present levels.

Supply Outlook

The Asia-Pacific region is currently facing a serious challenge to satisfy the expected levels of LNG demand after 2000. The region's existing suppliers—Malaysia, Indonesia, Brunei, and Australia—plus Abu Dhabi in the Middle East, all have supply contracts extending to the year 2000 and beyond; all as well are planning capacity expansions, but the additional volumes will be insufficient to meet demand after the turn of the century.

The largest expansion to existing capacity will come from Malaysia, where 7.5 million metric tons of new capacity will be available by 1996—4 million metric tons of which has already been committed 50/50 to Taiwan and Korea, and 3.5 million metric tons to Japan.

Indonesia is undertaking the expansion of the Bontang LNG plant on Kalimantan to supply an additional 4.6 million metric tons during the 1990s. The facility at Arun will also be expanded by 2 million metric tons, but the gas supply available to the plant is sufficient only to maintain this higher level of output for 25 years.

Australia is planning to expand capacity by 2.6 million metric tons, of which 1 million metric tons has already been committed. Abu Dhabi, the only non-Asian supplier to the region is set to expand production by 2.6 million metric tons. Brunei as well is increasing production capacity by 500,000 metric tons through debottlenecking of the supply terminal, and the delivery of new LNG carriers to Alaska will allow it to expand exports by a further 100,000 metric tons.

Taken together, the expansion of capacity by existing suppliers will boost available supplies by nearly 20 million metric tons by the end of the decade, but given the higher estimates of demand growth in Japan, Taiwan, and Korea, new projects will become a necessity by that time if projected demand is to be met (see Table 36).

Currently, the only grassroots project likely to be on line by the end of the decade is the proposed Qatar LNG plant, which will initially produce 4 million metric tons of LNG (for Japan), and later raise total output to 6 million metric tons. This additional 4 million metric tons will allow the region to maintain a basic balance in LNG supply and demand by 2000. But in the ensuing decade, a serious supply gap looms, since demand is expected to grow by a further 60 percent, whereas no additional grassroots projects have yet been committed. With a demand for LNG in the range of 100 million metric tons in 2010, more than 37 million metric tons of new production capacity will be needed.

Aside from the Qatar project, a half-dozen or more other grassroots projects have been proposed to supply the region. All of them have been delayed owing to rising costs of construction and low oil prices, which make the projects either financially inviable or economically marginal. The project backers have been unable to secure the needed investment by consumers, who balk at the higher LNG prices necessary to justify the massive capital costs of these projects in the face of continued, and forecasted, low oil prices. No

Table 36. LNG Capacity Expansion to 2010
(million metric tonnes)

	1992	2000	2010
Existing Supply			
Australia	5.0	7.6	7.6
Brunei	5.1	5.6	5.6
Indonesia	22.4	29.0	29.0
Malaysia	7.5	15.0	15.0
Alaska	1.0	1.1	1.1
Abu Dhabi	2.3	4.9	4.9
Total/Supply	43.3	63.2	63.2
LNG Demand			
Japan	37.5	50.0	70.0
Korea	2.7	10.0	16.0
Taiwan	1.6	7.0	15.0
Total Demand	41.8	67.0	101.0
Surplus/(Deficit)	1.5	(3.8)	(37.8)

Proposed Projects	2000	2010	Cost* (US$ billion)
Qatar	4.0	6.0	5
Oman		5.0	6
Yemen		5.0	6
Australia/Gorgon		6.0	10
Indonesia/Natuna		12.0	13
Alaska		14.0	15
Sakhalin		4.0	10
Total Proposed	4.0	52.0	65
Surplus/(Deficit)	0.2	14.2	

Source: Cedigaz, Oil & Gas Journal, BP, EWC.

*Averages of estimates.

less than US$50 billion of new investment will be required to provide the additional capacity needed to satisfy incremental demand after 2000. To be profitable, LNG prices would need to rise from their current $3.50-4.00 per million Btu (mmBtu) range to $5.00-5.50/mmBtu or higher, which would be substantially above the relative cost of crude oil.

The maturation of the LNG market, combined with the closer linkages between the overall oil market and the markets for the transport fuels (gasoline, diesel, and jet fuel), lessens the need to link LNG prices to a shrinking portion of the oil market (fuel oil), that is largely reserved for boiler and power generation uses. As the major consumers of LNG, power generation utilities place a premium on security of supply and minimal price volatility, while preferring cleaner-burning fuels to reduce both the environmental load and the cost of achieving stricter emissions standards. Gas has thus become a preferred fuel of choice throughout the region for power generation purposes. And yet, without a fundamental shift in the way that LNG is priced, to incorporate the premium attached to the fuel, it is unlikely that the needed investment will be forthcoming to ensure the higher levels of demand foreseen into the next century.

IV. The World Coal Industry

Coal is the most widely available source of fuel in the world. Although the majority of coal reserves are located in only about ten countries, many other countries have commercial coal deposits. Because of coal's abundance and the location of sizable reserves in stable economies, there is little chance of the formation a cartel like the one in the oil market. Coal is considered the most stable and low risk internationally traded energy commodity. Coal prices have decreased substantially over the past decade, and no substantial price increases in constant dollars are predicted. However, short-term higher prices and shortages should be anticipated, and the possibility exists that very low-sulfur coal may command a substantial premium in the late 1990s. In particular, limits of 0.5 percent or lower on the sulfur content of imported coal significantly increase the risk of paying higher prices and experiencing difficulty in receiving supplies of high quality coals.

The main drawback to using coal is the level of emissions associated with coal burning without some sort of pollution control technology. Consumers are faced with the choice of using less coal, burning coal more efficiently and cleanly, or switching to other fuels. A combination of these options is expected to occur. Newly commercial clean coal technologies and technologies under development for coal-fired power plants make coal burning competitive with other fuel choices. Clean coal technologies can reduce emissions of SO_2 to levels comparable to oil-fired power plants now in use. The capital costs of coal-fired plants with pollution control equipment are higher than those for oil- or gas-fired plants, but operating costs for the coal-fired plants are lower.

A. Coal Reserves

Total world reserves of coal are about one trillion tons.[1] At 1992 levels of production, these coal reserves will last more than 300 years. This compares to only 42 years of oil reserves at present production levels. Because of coal's relative accessibility, lower price, and security, the industrialized, and in particular, the developing areas of the world such as the Asia-Pacific region (which accounts for 29 percent of the world's reserves of coal) will continue to rely heavily on coal to satisfy rapidly growing energy needs.

Figure 105 shows the proven reserves of the ten countries with the largest coal reserves in the world. These ten countries represent 93 percent of the world's coal reserves. The CIS (the former Soviet Union) and the United States dominate, accounting for a combined 46 percent of total world coal reserves.

Reserve figures, however, should be relied upon only as broad indicators. Reserve estimation methods differ among countries and a large margin of error should be assumed. Countries have different definitions or classifications as to what constitutes a reserve or a resource. For example, the fact that CIS reserve estimates are so high may be due to the counting of high-cost coals that are not economic to extract at present market prices.

A generally accepted definition of reserves is "those quantities of coal which geological and engineering information indicate with reasonable certainty can be recovered in the future from known deposits under existing economic and operating conditions." The level of accuracy of estimates is generally divided into three categories. The term "proven" reserves indicates coal that is accurately known to exist and is economic to mine.

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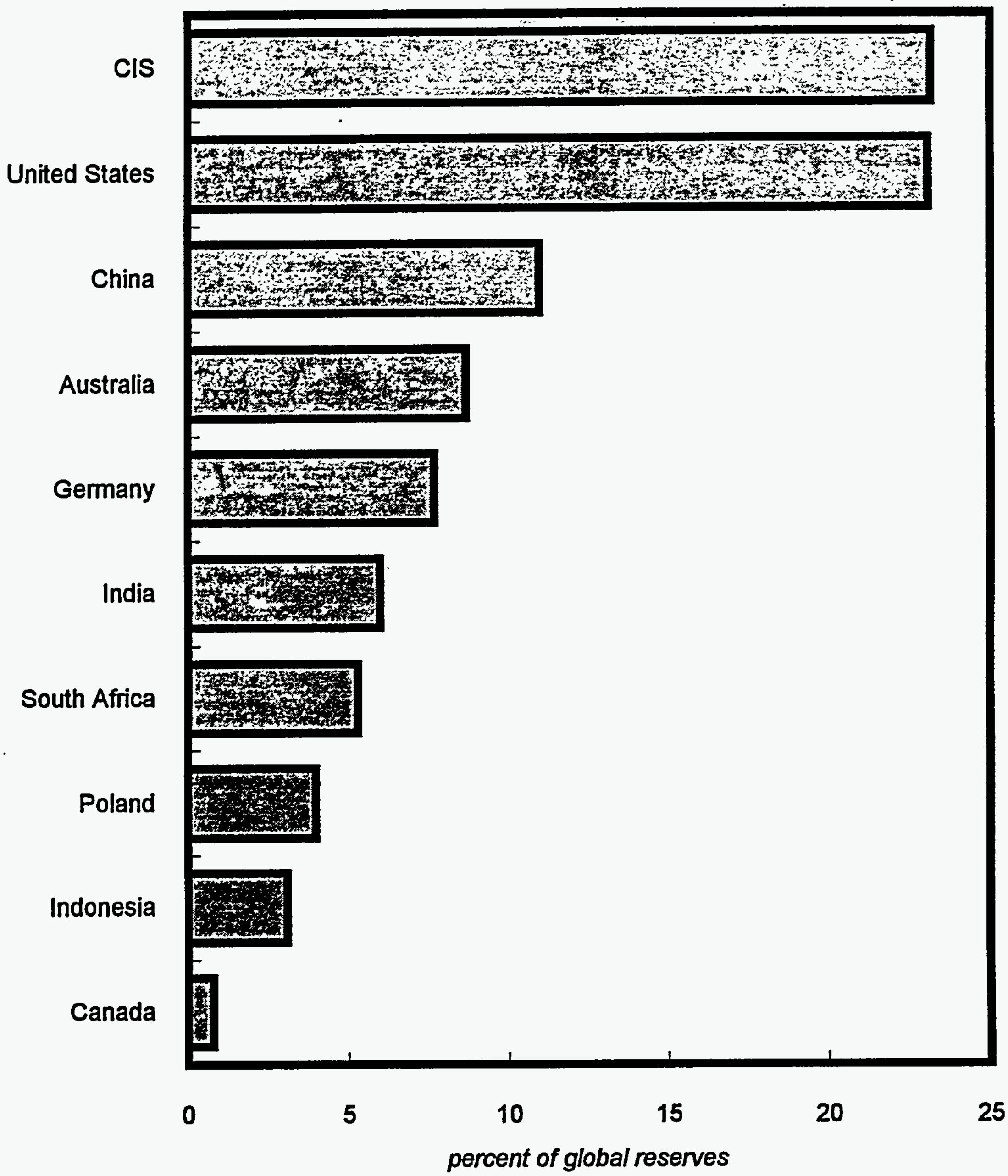
[1]Since the world's trade in coal is standardized on the metric system, all data in this section (Chapter IV, The World Coal Industry) of Task I (*World and Regional Fossil Energy Dynamics*) is presented in metric tons. For reference when dealing specifically with the Hawaiian market, the data in the Task II report (*Fossil Energy in Hawaii*) have been converted to short tons. The following conversion factors may be useful: 1 short ton = 2,000 pounds = 0.907 metric tons. 1 metric ton = 1.1 short tons. 1 mile = 1.61 kilometers. 1 kilometer = 0.62 miles. 1 kilocalorie = 3.97 Btu.

Figure 105. Top Ten Coal Reserves, 1991



reserves indicates coal that is accurately known to exist and is economic to mine. "Probable" reserves refer to coal that is less accurately defined (through drilling) than proven reserves. "Possible" reserves indicate coal that is estimated to exist, often through extensions of adjacent probable reserves. Such estimates are subject to a higher degree of uncertainty than those associated with probable reserves.

Although a majority of coal reserves are located in ten countries, coal is widely distributed throughout the world. Many countries have commercial coal reserves, and presently the largest coal exporters are relatively stable countries. There have been no attempts to control world coal supplies and regulate prices, in contrast to what has occurred in oil through OPEC. Coal is considered to be a more secure source of energy than oil or natural gas.

B. Coal Classification and Quality

Coal classification and sampling is a complex process that differs among countries and individual users. A simplified classification system is explained here. Electric utilities usually consider seven basic criteria in selecting steam coals for electric power plants. Although coal-fired power plants can be designed to burn almost any quality of coal, most importing electric utilities design their coal-fired power plants to burn the dominant traded coal to ensure flexibility in purchasing. The following are general guidelines for internationally traded steam coals in the Asia-Pacific region.

(1) **Heat content or calorific value** is the amount of heat produced in burning a unit of coal. Electric utilities commonly purchase coal with a calorific value of 11,160-12,150 Btu/lb (approx. 6,200 - 6,750 kilocalories/kg). A few utilities blend lower heat value coals with high heat value coals.

(2) **Volatile matter** includes those substances, other than moisture (water), that are given off as gas during combustion. Typically, the volatile matter in coal is in the range of 25-36 percent. High volatile matter content coals may have a greater tendency for spontaneous combustion.

(3) **Total moisture** is the moisture retained in coal after air drying. Maximum moisture contents range from 10 percent to 15 percent. Increased moisture content reduces heat content, increases shipping costs, and creates difficulties in handling.

(4) **Ash content** is the amount of incombustible material in a coal. Maximum ash contents are in the range of 12-16 percent. High ash coals reduce heat contents, increase shipping costs, and, of particular importance, increase waste disposal costs.

(5) **Sulfur content** is the amount of sulfur in coal as a percent or in parts per million. Most coal traded internationally contains about 0.6-1.0 percent sulfur. When coal is burned, sulfur gases (sulfates and sulfides) are emitted. These gases are serious pollutants in some areas.

(6) **Hardness** is the relative grindability of coal and is measured by the Hardgrove grindability index (HGI). The higher numbers in this index represent the softer coals that are preferred by utilities. The typical minimum HGI is 45-50.

(7) **Ash fusion** is the temperature at which coal melts. Typical minimum ash fusion temperatures are 1,200-1,300°C. Lower fusion temperature coals result in slagging and fouling of equipment.

Coals are commonly ranked according to three broad categories: anthracite, bituminous, and the subbituminous coals and lignites. Anthracite is the highest rank coal and has low volatile matter and a high carbon content. Anthracite usually has the highest heat content but is rarely used for electricity generation because it burns too slowly.

Bituminous coal can be divided further into steam (thermal) coals and coking (metallurgical) coals. These coals usually have a heat content of 11,000 Btu/lb or greater, volatile matter in the 16-36 percent range, and moisture content in the 10-15 percent range. Most internationally traded steam coal has a medium to high heat content (11,000 -12,150 Btu/lb) and a mid-range (25-36 percent) volatile matter percentage. The term "steam" coal encompasses any bituminous coal that is utilized as a heating source. This category includes bituminous coal used in power plants, cement making, brick making and in residential heating. Bituminous coals dominate the international trade for coals used in the electric utility sector.

Figure 106 represents a majority of the world's traded steam coal capacity. Fifty-six percent of mine capacity falls into the 0.6-0.9 percent sulfur content range, and 44 percent of export mine capacity has a maximum sulfur content of 0.5 percent. As pollution control regulations tighten and steam coal demand increases, lower sulfur coal will likely command premium prices. As shown in Figure 107, Australia and Indonesia have a combined 77 percent of the export capacity of the coals with a sulfur content of 0.5 percent or less. Australia currently exports most of its low-sulfur coal to Japan, while Indonesia is currently in the process of expanding production to approach capacity levels. It should be noted that most of the coal with a sulfur content of 0.5 percent or less in Indonesia or the western United States also has lower relative heat content. This coal is more expensive to ship per unit of energy, and may cause some problems in blending with other coals. Hawaii will have little difficulty in obtaining coals with a maximum sulfur content of 0.5 percent over the long term. However, this coal may command a premium in the future.

Coals with physical and chemical properties that would allow the production of coke suitable for use in a blast furnace are defined as coking coal. (One ton of coking coal, with medium volatile content, produces approximately 0.7 tons of coke.) Coking coal usually has a heat content in the 11,000-13,000 Btu/lb range. The moisture content of coking coal must be lower than 10 percent due to problems in handling and the lower heat contents that accompany high moisture content coals. Volatile matter must be in the 16-36 percent range with the best quality coking coals are in the 20-35 percent range. High volatile matter results in lower coke yields. A maximum 0.8 percent sulfur content is required for coking coal due to the unsatisfactory quality of steel which results from using coke containing high levels of sulfur.

Subbituminous coals and lignites are consumed mainly within the countries where they are produced. They are used mainly for home heating, industrial boiler fuels, or mine-mouth electricity production. Modest amounts of higher quality subbituminous coals (above 9,900 Btu/lb) are traded internationally. Lignite, which has a heat content below 7,500 Btu/lb, is not traded.

Figure 106. Sulfur Content Based on a Survey of More than 60 Percent of World Steam Coal Export Capacity

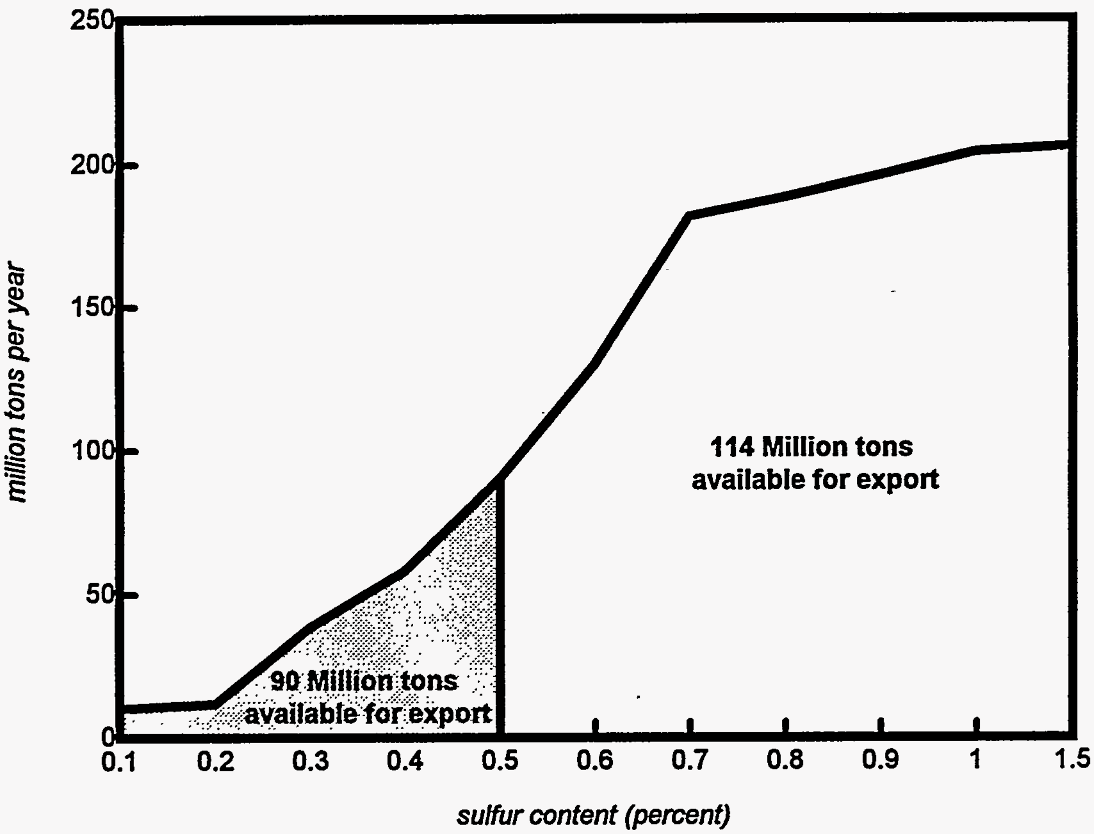
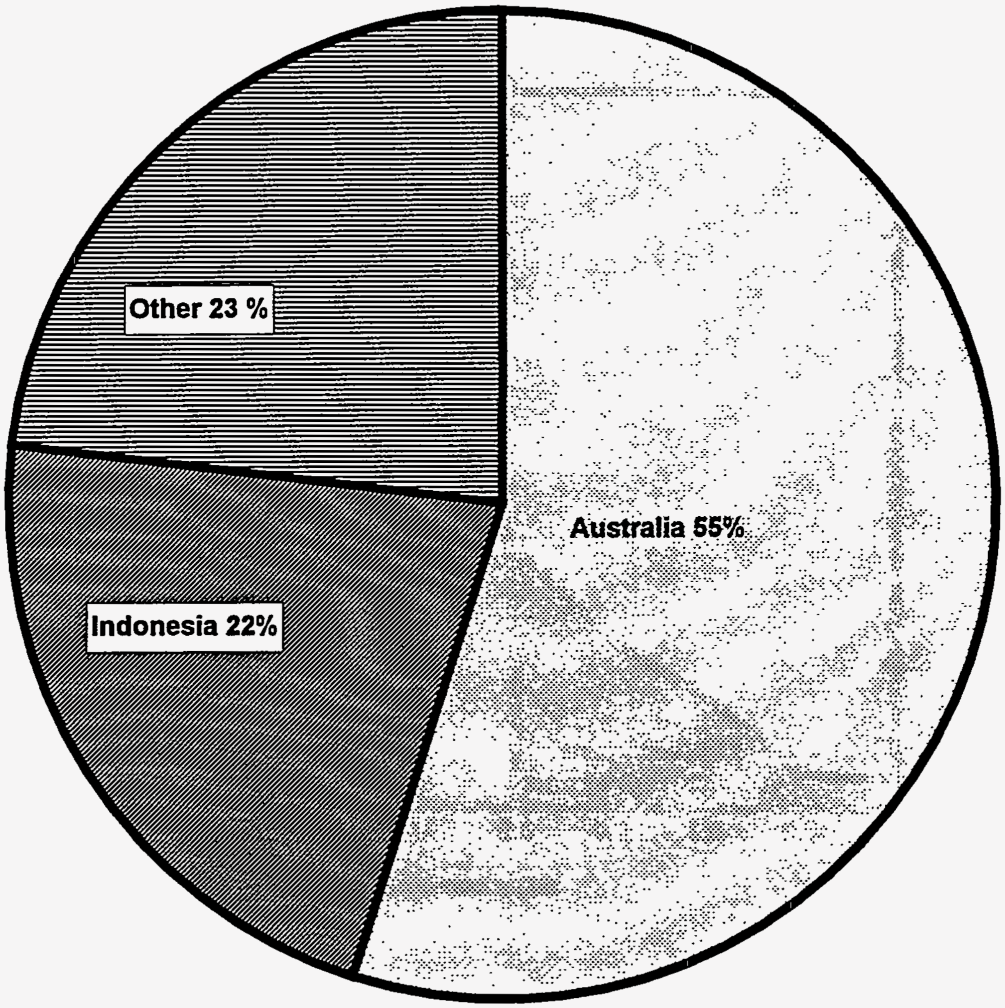


Figure 107. Country Shares of Traded Steam Coal (0.5 Percent Sulfur or Less)



Source: Data compiled from statistics on over 60 percent of traded thermal coal capacity.

The practice of using lignite in mine-mouth power plants may decline in the future due to increased environmental and human health concerns. A large number of lignite deposits have high sulfur contents. Large, low-sulfur lignite deposits exist in Australia, Indonesia, and the United States.

C. Coal Utilization

The first knowledge and use of coal occurred several thousands of years ago. The mining and use of coal as a heating fuel became more common beginning about 2,000 years ago, but levels of coal consumption did not begin to grow rapidly until the industrial revolution. The industrial revolution was basically fuelled on coal, both through the spread of the steam engine and by the development of iron making using coal instead of charcoal. Today, coal is used for a variety of purposes, but its main uses include thermal heating (electric power plants and industrial boilers), cement production, and steel making. Also, in a few developing countries such as China, home heating accounts for a substantial share of coal consumption. Coal accounts for over 50 percent of the electricity generated in the United States.

1. Power Generation

Coal-fired power plants, like all power plants fired by fossil fuels, generate electricity from steam. High-pressure steam drives a turbine which then generates electricity. Modern pulverized coal-fired (PCF) power plants achieve efficiencies in the range of 35-38 percent, with older plants achieving much lower efficiencies. For baseload electricity generation, each megawatt of electricity requires about 2,500 tons of coal per year.

2. Cement Production

Pulverized coal is the most common type of fuel used in the cement making process. Portions of calcium carbonate, silica, alumina, iron oxide, and other minor components are ground, blended, and fed into a kiln fueled, in most cases, by coal. Also, ash from the coal is increasingly used in cement manufacturing. Specifications for coal used in the cement industry are less stringent than for the electric power sector. Cement production is a very energy intensive process involving both heating and electricity consumption for grinding, blending and other operations. Typically about 1-2 tons of coal are consumed in the production of 10 tons of cement.

3. Steel Making

Coal is most commonly consumed in steel making processes as coke. Coke is produced by heating coking coal in a coke oven in the absence of air. Coke, iron ore, and other components are then fed into the top of a furnace into which hot air is injected. After reduction, the molten metal is drawn out of the bottom of the furnace, and the waste coke oven gases are recovered from the top.

Pulverized coal injection (PCI), which is used widely in Japan and Korea and is becoming more widely used in other countries, replaces a portion of coke during blast furnace operation. One ton of PCI coal replaces about 1.6 tons of coking coal. Quality requirements for PCI coal are much broader than those for coking coal used in common blast furnaces. The result is that cheaper coals can be used for PCI. PCI rates of 75-100 kg per ton of hot metal are reported in a number of countries.

Coal is used in smaller quantities for a variety of other purposes including gasification (town gas production and fuel for gas turbines in electric power plants), ammonia and fertilizer production, and liquefaction.

D. Coal Transportation

For internationally traded coal, transport costs often account for one half or more of the total delivered cost of a ton of coal. In some cases, such as in the western United States, Canada, and the CIS, long rail distances limit penetration into international markets. For example, the rail and shipping costs involved in the transport of coal from the western United States to Japan is currently $26-30/ton. These high transport costs make western U.S. coal less competitive than exports from Australia and Indonesia. The latter have much lower total transport costs and are thus able to bid prices down to levels that U.S. producers cannot match. A few countries, particularly Japan, continue to purchase a modest share of higher cost coals, in part to diversify supplies and give added assurance against supply disruptions. After the oil crises of the 1970s, attention was placed on diversifying energy supplies, and thus cost was not the only consideration when buying coals. Recent trends indicate a move back to placing increased emphasis on economic considerations and giving less attention to strategic issues. A brief overview of the transport situations in some of the world's major exporting and importing countries is provided below.

1. Australia

Most of the major coal deposits in Australia are located within 250 km of deep-water ports. The advantage of having deposits near the coast is reduced, however, because Australian producers pay higher rail rates per ton-mile than other major competitors. Australian coal rail networks are owned and operated by the New South Wales (NSW) and Queensland state governments. Port facilities are generally privately owned, but some have state involvement. In the event of significant price reductions or large losses in profits by producers, the state governments have the flexibility to reduce rail rates and other levies to assist producers.

2. Canada

Most western Canadian producers must transport their coal over 1,000 km to deep-water ports. High transport costs place Canadian coal at a cost disadvantage in the Asia-Pacific region, which is its main export market. Additionally, coal transported over rail to eastern Canada and the United States must travel more than 2,000 km.

3. China

Currently, coal accounts for one-third of the total railway shipments in China, and the present rail system for most main routes is operating at capacity. China's demand for coal is projected to grow to 1.5 billion tons by 2000 from 1.1 billion tons in 1991. As a result of insufficient investments in the transportation sector, the shortage of transport capacity is very serious. Although rail lines for exports are receiving priority, periodic shortages in meeting export commitments may occur. The main coal producing areas are in north-central China, long distances from the industry and population centers where coal must be transported.

4. Colombia

The rail and port facilities, located at Puerto Bolivar, Colombia, are integrated with the mine operation at the large Cerrejon Norte mine, Colombia's main source of coal production. Rail and port costs each account for a low US$1.50/ton. Cerrejon Norte is jointly owned by the state-run Carbocol and an Exxon subsidiary. The mine is about 150 km by rail from Puerto Bolivar.

5. Japan

Most of Japan's coking coal imports are unloaded directly into industry facilities, and more than half of the imported steam coal is unloaded at coal "centers" near the ports. These centers are responsible for unloading, stocking, and shipping coal to end users. Users pay one general fee for all services.

6. South Africa

The Richards Bay Coal Terminal, South Africa's main coal export port, has been expanded recently to handle about 53 million tons/year of coal. Freight rates in South Africa are slightly higher per ton-mile than those of the western U.S. coal producers, but coal must be transported only about one-fourth the distance. Rail transport is currently provided by a state-run corporation. To compete in Europe and Asia, South Africa must price its coal at low f.o.b.t. rates. (The term f.o.b.t. stands for "free on board and trimmed," or simply the price of coal on board the ship at the export port.) Recent prices have been about US$25/ton.

7. United States

Producers and railroads in the United States are free to negotiate freight rates according to their situations, and coal freight rates vary considerably across the country. Although rail rates tend to be low (in the range of 0.9 cents to 2 cents per ton-mile), the mines are mostly located more than 200 km from ports involved in shipping coal to the Asia-Pacific region. As a result, U.S. rail transport costs are the highest among the major coal exporting countries to the region.

8. Seaborne Transport

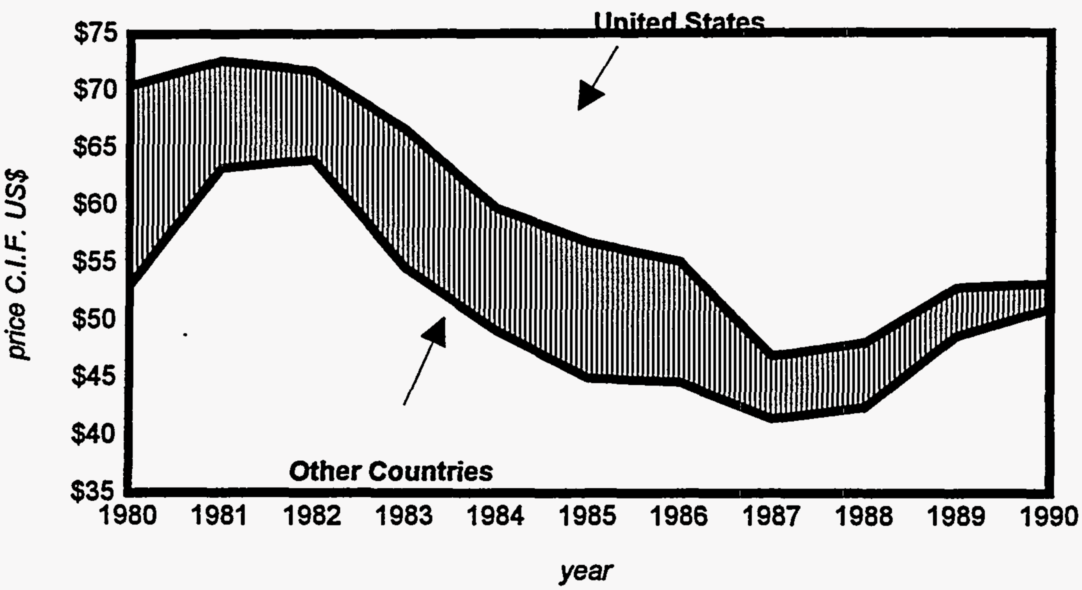
Seaborne coal trade has risen at a rate of about 5 percent per year over the past decade due to more countries relying on imported coal to supply fuel for electric power plants. Since 1990 the annual seaborne trade of steam coal has matched or exceeded the seaborne trade of coking coal. This large increase in seaborne coal movement has generated extra shipping demand, particularly for the large Panamax and Capesize ships. Panamax vessels carry 60,000-80,000 ton cargos, and Capesize vessels carry 110,000-130,000 ton cargos. Presently, 80 percent of seaborne coal is carried by vessels with capacities above 50,000 tons.

The price of shipping coal to any deep-water port in the world in larger ships is less than US$15.00 per ton. Smaller Panamax vessels, which will most likely be used by consumers in Hawaii, carry coal at near Capesize rates when there is excess capacity, but more typically they are 20-40 percent more expensive.

E. Pricing

In the Asia-Pacific region, the vigorous competition between Indonesian and Australian suppliers has resulted in prices as low as US$25 f.o.b.t. There has been speculation for over a decade that coal prices would increase due to large projected increases

Figure 108. Average C.I.F. Prices of U.S. and Non-U.S. Steam Coal Exports to Japan, 1980-90



Note: Prices are expressed in term of cost, insurance, and freight (c.i.f.), reflecting the total cost to consumer.

in demand. However, coal producers have consistently expanded supplies, and continued vigorous competition has caused coal prices to fall in recent years. As shown in Figure 108, average real coal prices in Japan (the largest importer of coal in the world) have decreased steadily over the past decade. As stated above, this decrease in price has accelerated over the past two years. In 1993 price reductions of US$1-2/ton were reported in long-term contracts for steam and coking coals.[2]

In constant dollar terms, coal prices are unlikely to be higher than the average price of the past five years. There will be short-term fluctuations, as experienced in the case of other energy commodities, but the large reserve base and highly competitive nature of the coal industry strongly support the view that coal prices will increase no more rapidly than inflation over the next two decades.

F. The World Coal Market

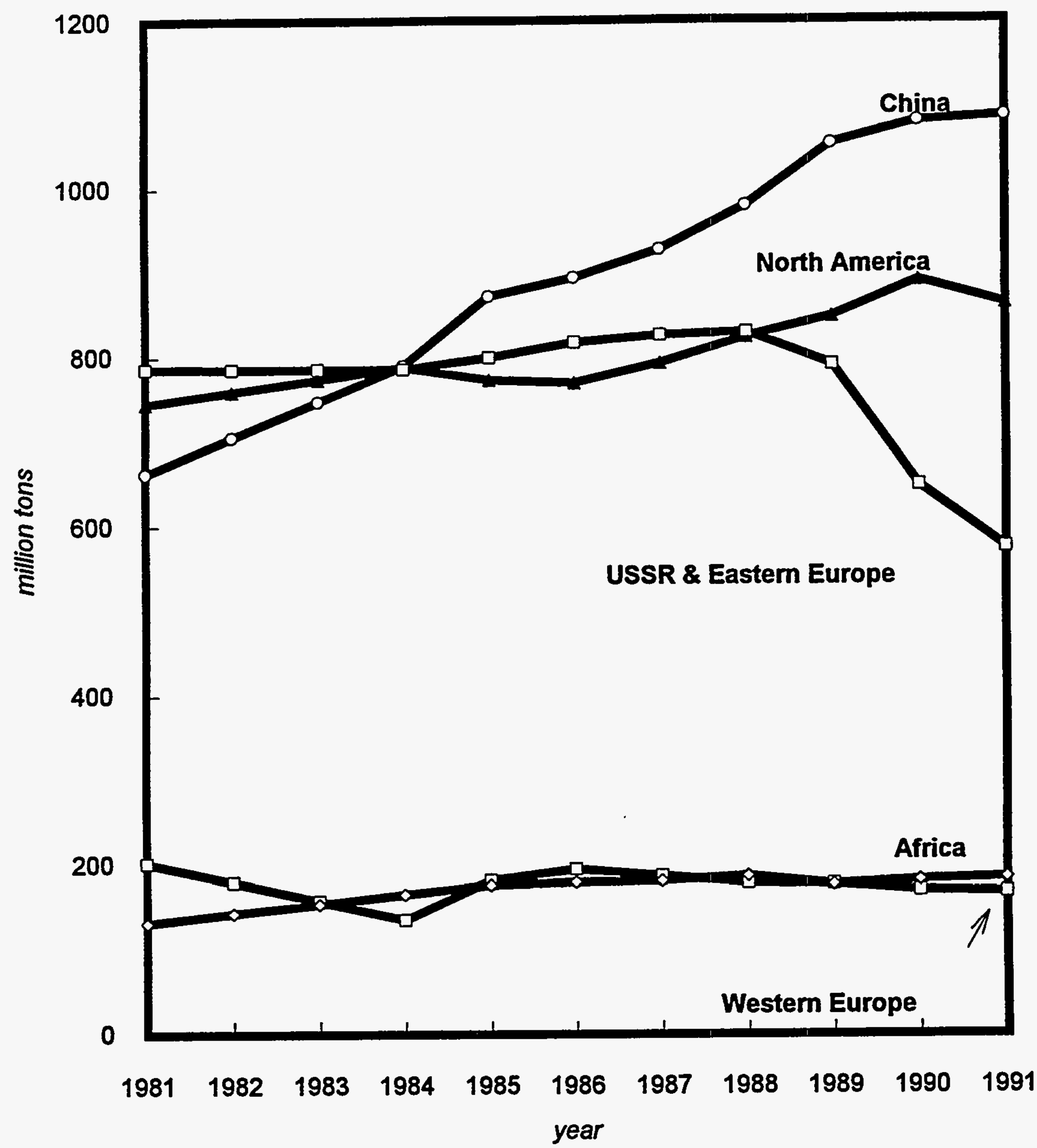
The world coal situation has been changing rapidly over the past few years, and uncertainties exist as to what coal's role will be in global markets in the next decades. Since coal is the most abundant, widely available fuel source and reserve depletion is not a concern, coal is expected to continue to compete effectively with alternative energy sources in many countries.

Coal production in the major coal producing regions and China from 1981-91 is shown in Figure 109. Over the past decade, China has become the world's largest producer of coal (1.09 billion tons in 1991). Over the last five years, the former Soviet Union and Eastern Europe have experienced a substantial decline in production due to political upheaval and change.

Uncertainties arise concerning coal use primarily because of increased environmental pressures, particularly in the industrialized countries but increasingly in the developing countries. The environmental viewpoints of industrial and developing countries are gradually

[2]*King's International Coal Trade*, 4 March 1993.

Figure 109. Coal Production of Major Bituminous Producers, 1981-91



pressures, particularly in the industrialized countries but increasingly in the developing countries. The environmental viewpoints of industrial and developing countries are gradually moving together over time. At present most developing countries place more importance on economic growth than environmental issues.

Countries are faced with three key options in dealing with environmental problems associated with coal. The first is to substitute cleaner fuels (natural gas) for coal. The second is to burn coal more cleanly. Environmental standards for coal-fired plants are increasing rapidly and a range of clean coal technologies have been developed. More advanced clean coal technologies are being developed to address the stricter standards. As these newer technologies become commercially proven, they are likely to be adopted more widely. Some of theses technologies not only decrease emissions but also increase the efficiency of coal use. The final option is to burn cleaner, low-sulfur coals.

There is a growing trend to allow market forces to determine the levels of coal that will be produced and consumed around the world. Central and even Western Europe are in the process of relaxing state control over the development and movement of coal. Elsewhere in the world, less emphasis is being placed on strategic issues such as diversification of fuel sources, and more emphasis is being placed on economics and achieving improved environmental standards. The largest increase in coal consumption and trade in the world over the next two decades is expected to be in the Asia-Pacific region.

1. The Asia-Pacific Region

The Asia-Pacific region (defined here as Asia, Australia, and the west and south Pacific economies) leads the world in dependence on coal. Almost half of the region's energy requirements (48 percent) are supplied by coal, compared to less than a quarter (22 percent) for the rest of the world. The outlook for Asia over the next two decades is for annual coal consumption to increase by more than 1 billion tons, with coal imports reaching about 350 million tons by 2010. Steam coal's share of total coal imports will increase from 50 percent today to more than 75 percent in 2010. Australia is projected to remain the dominant coal exporter to Asia over the 1990-2010 period, although it is projected to lose a modest share of the export market to Indonesia and possibly China.

The following sections examine the factors influencing coal use, the role that coal plays in Asia, and projections of coal production, consumption, and trade to 2010.

2. Factors Influencing Coal Use

Efficiency of Coal Use

The efficiency of coal use varies widely. The following is an indication of the reported range, plus an indication of the amount typically used in modern plants. For electricity generation, national thermal plant efficiencies vary from about 29 percent to 39 percent, with 35-37 percent typical of modern facilities. Maximum efficiencies above 37 percent with modern technologies are rare. (Japanese estimates of 39 percent efficiencies are believed to be due to a difference in methods of calculation.) Increases in efficiency of about one-third could be achieved in some major coal-consuming economies by replacing old power plants with modern facilities.

For crude steel production using blast furnace technology, coke consumption varies widely according to how modern the plant is and the availability of alternative energy inputs. Typical modern facilities use 450-500 kg of coke per ton of crude steel production. Older facilities use more than 550 kg of coke per ton of crude steel.

The use of pulverized coal injection (PCI) as a partial substitute for hard coking coal is increasing in the region. Rates of PCI use are mostly in the 75-125 kg per ton of crude steel range, but some new facilities can use up to 150 kg per ton. Some facilities are expected to be using 150-200 kg PCI per ton of crude steel by 2000.

Coal Quality and Coal Preparation

Quality requirements vary according to end-use, economic considerations, the technology in which the coal is used, and environmental factors. Coking coal specifications are the most stringent, followed by steam coal, with coal used in cement production having the most flexibility. Due to blending of both steam and coking coals, it is becoming increasingly difficult to generalize about the qualities of coal that can be sold to these sectors.

Both electric utilities and steel producers in Asia will use lower quality coals if the price is significantly lower. A number of governments limit sulfur to a maximum of 1.0 percent in steam coal imports.

Coal preparation (washing), particularly to reduce ash and pyritic sulfur contents, is practiced on a wide scale for coal entering export markets but on a more limited scale for steaming coal used at the local level. This is particularly true in China and India where most coal undergoes little beneficiation before use. Increased coal beneficiation in these economies appears to be one of the most cost-effective options to achieve higher efficiencies in coal burning and in reducing environmental pollution. However, the low prices received in these countries provide little incentive to wash coal.

3. Determinants of Coal in Asia's Future

Important factors determining changes in coal production, consumption, and trade in Asia are: (1) government policies, (2) economic and electricity growth rates, (3) energy alternatives, (4) strategic factors, (5) competition and prices, and (6) environmental factors. These factors are briefly discussed below.

Government Policies

Governments have considerable influence on energy choices through policies, tax incentives, legislation, and directives. This is particularly true in electricity generation, because the majority of electric utilities in Asia are state corporations and closely follow government policies and directives. Most governments in Asia consider coal a very important part of their energy mix. Although there is encouragement of domestic coal production, the trend is away from providing high subsidies to maintain domestic production.

Economic and Electricity Growth Rates in Asia

The growth rate in electricity consumption is higher than gross domestic product (GDP) rates in most Asian economies. Table 37 shows the average annual growth rates of GDP and electricity consumption in the major Asian economies and in Australia, Canada, New Zealand, the United States, and the world as a whole during the past decade. Both the average GDP and electricity growth rates are typically two to three times as high in the Asian economies as they are on average in the world or in most industrialized economies. Projections of GDP growth rates are made to 1995 that indicate slightly lower overall GDP growth rates. The overall GDP growth rate in Asia (excluding Australia) for the decade of the 1990s is projected to be in the 6.5-7.5 percent range. As shown in Table 37, during the 1980s electricity consumption grew at averages of 7-11 percent per year in most Asian economies. In some economies—most notably China, India, and Indonesia—the growth rate in demand for electricity exceeded the growth rate in electricity supplies.

Energy Options

Most Asian economies have limited amounts of oil and gas and have policies to promote the use of thermal coal for electricity generation. Coal is abundant in Asia and is the largest energy resource in Australia, China, India, North Korea, Russia, and Vietnam.

After the second oil crisis in 1979, there was a shift toward increased steam coal use for electricity generation in Hong Kong, Indonesia, Japan, South Korea, Philippines, Taiwan, and Thailand. The trend toward greater coal use in electricity generation is projected to continue over the 1990-2010 period. However, where sufficient natural gas is available, it is expected to be the fuel of choice in preference to coal. Natural gas dominates the power sector of Malaysia which has abundant low cost natural gas reserves. In addition, natural gas is expected to compete with coal in Hong Kong, Indonesia, Thailand, and selected areas of southern China. In Japan stringent environmental regulations allow relatively high-cost liquefied natural gas (LNG) to compete with coal.

Competition and Prices

The rapid growth in demand for internationally traded steam coal has been more than matched by increased supplies from both traditional coal producing economies and new suppliers. A decade ago many forecasts indicated increasing prices for steam coal. However, Figure 108 shows that the trend in c.i.f. ("cost, insurance, freight" or the total cost of coal to the consumer) steam coal prices in constant 1990 dollars for the world's largest coal importer, Japan, was strongly downward over the past decade. This downward

Table 37. GDP and Electricity Growth Rates of Asian Economies, Australia, the United States, and the World, 1980-95
(average percent per year)

	GDP Growth Rates 1980-1990	GDP Growth Rates 1990-1995	Electricity Growth Rates 1980-1989
ASIA:			
Indonesia	5.5	7.1	14.2
Pakistan	6.3	5.1	11.9
Korea	9.7	8.5	11.1
Thailand	7.6	8.3	10.8
India	5.3	4.7	9.1
Malaysia	5.2	7.6	8.6
Hong Kong	7.1	5.1	8.5
Singapore	6.4	6.8	8.3
Taiwan	7.7	7.1	8.3
China	9.5	8.0	7.7
Philippines	0.9	3.6	4.3
Japan	4.1	4.6	3.7
OTHER:			
Australia	3.4	1.8	4.9
New Zealand	1.9	2.9*	2.9
Canada	3.4	2.4*	3.3
United States	3.4	2.2	2.6
WORLD:	3.2	2.5-2.7	3.7

Sources: International Financial Statistics, UN Energy Statistics Yearbooks, 1983-1989; Coal Information, 1991; "Social Indicators in the Taiwan Area, 1990"; and East-West Center estimates.

* 1990-95 New Zealand and Canada growth rates are estimates for the 1989-2000 period, Coal Information, 1991.

trend was continuing in mid 1992, with both f.o.b.t. and c.i.f. coal prices well below the 1990 level.

Figure 108 also shows that the trend in the price of U.S. steam coal exports has been moving closer to the weighted average price of steam coal from other countries. The decrease in the spread of steam coal prices appears to result from two basic factors: increased competition among sellers and less premium being paid to diversify sources of supplies. With respect to coal from the western United States, substantial reductions in rail transport rates have been a key factor in improving the competitive position of western U.S. coal exports. However, at present low international steam coal prices, most U.S. coal producers are not actively considering opportunities for expanding exports to Asia.

Coal price swings can last from two to five years. However, the combination of strong competitive pressures and the extensive reserve base is expected to keep the trend in long-term export steam coal prices in the range of US$32-42/ton f.o.b.t. in constant 1992 dollars over the next two decades. In 1993 numerous spot f.o.b.t. sales of steaming coal were reported from exporting economies in the US$25-30 per ton range.

During the past decade China, Colombia, and Indonesia entered the steam coal export market with very competitive export prices. These three economies are projected to account for 80-90 million tons of seaborne steam coal trade by 2000. Colombia and Indonesia have large reserves within 150 kilometers of the coast and are highly competitive on the basis of f.o.b.t. cash operating costs. China has massive reserves located 700-1,000 kilometers from ports and is expanding mine and rail capacity.

Table 38 shows representative long-term coal costs (in constant 1992 US$/ton) from the major exporting countries. The two destinations in the table for c.i.f. coal are Japan and Europe. Both operating and total costs, which include a medium return on the amount of capital invested, are shown in the table. Costs for individual mines may vary considerably from the costs appearing in the table. In the short term, coal prices can drop as low as operating costs, but in the long term, companies must receive an adequate return on the capital invested in their projects. Because supplies from each country reflect a range of mines from new to old (and thus there are different capital charges per ton of coal), prices

Table 38. Representative Long-Term Coal Costs
(1992 US$/ton)[1]

	Australia		Canada		China		Colombia	
	Op. cost [2]	Total cost [3]	Op. cost	Total cost	Op. cost	Total cost	Op. cost	Total cost
Mine operating cost	15.0	24.0	21.0	28.0	14.0	21.0	19.0	34.0
Rail/ Barge & port cost	10.0	10.0	16.5	16.5	15.0	15.0	7.0	7.0
f.o.b.t. cost	25.0	34.0	37.5	44.5	29.0	36.0	26.0	41.0
Shipping cost (to Japan)	7.0	7.0	8.0	8.0	5.0	5.0	11.5	11.5
CIF total cost (to Japan)	**32.0**	**41.0**	**45.5**	**52.5**	**34.0**	**41.0**	**37.5**	**52.5**
Shipping cost (to Europe)	11.5	11.5	14.0	14.0	12.5	12.5	8.0	8.0
CIF total cost (to Europe)	**36.5**	**45.5**	**51.5**	**58.5**	**41.5**	**48.5**	**34.0**	**49.0**

	Indonesia		South Africa		United States (West)		United States (East)	
	Op. cost	Total cost	Op. cost	Total cost	Op. cost	Total cost	Op. cost	Total cost
Mine operating cost	14.0	23.0	12.0	20.0	20.0	28.0	20.0	29.0
Rail/ Barge & port cost	8.0	8.0	12.0	12.0	20.0	20.0	14.0	14.0
f.o.b.t. cost	22.0	31.0	24.0	32.0	40.0	48.0	34.0	43.0
Shipping cost (to Japan)	7.0	7.0	10.0	10.0	8.0	8.0	13.0	13.0
CIF total cost (to Japan)	**29.0**	**38.0**	**34.0**	**42.0**	**48.0**	**56.0**	**47.0**	**56.0**
Shipping cost (to Europe)	10.7	10.7	9.3	9.3	14.0	14.0	6.5	6.5
CIF total cost (to Europe)	**32.7**	**41.7**	**33.3**	**41.3**	**54.0**	**62.0**	**40.5**	**49.5**

[1]Note: Actual prices may vary according to market forces but, on average, are not expected to fall below the operating costs represented here.

[2]Op. cost = Operating costs. [3]Total cost = operating cost + capital cost.

can remain below total costs for many years. The East-West Center's Program on Resources views c.i.f. prices greater than US$45 per ton of coal as uncompetitive in the Asia-Pacific region.

Coal prices in the Hawaii market will most likely be $2-4 per ton higher than deliveries to Japan because of the smaller volumes and smaller ships that are required. western U.S. coal supplies to Hawaii appear to be only marginally competitive with imports from Australia and Indonesia. The federal statutory (Jones Act) requirement that only U.S. ships move coal between U.S. ports adds significantly to the cost of U.S. coal delivered to Hawaii. There is some potential for competitive coals from Alaska by the turn of the century if substantial deposits near Alaskan ports are developed. However, these deposits have a very low energy content, and modifications in power plant specifications would probably be necessary for the coal to be used efficiently. The conclusion is that coal from Australia and Indonesia (and perhaps a small percentage from China and Colombia) is likely to continue to be the primary source of imports to Hawaii over the long term. Table 38 also indicates that the eastern United States, South Africa, and Colombia are presently the most competitive suppliers to Europe, while Australia, Indonesia, and China are the most competitive suppliers to Asia.

Strategic Factors

Strategic factors are particularly important to Asian economies. Specifically, most major coal importing economies in Asia have a goal of diversifying sources of supply of coal. Most governments claim that there is no set limit to the share of coal that they will import from any one exporter, but imports above 40-50 percent from any one exporter are likely to cause considerable concern among importing governments. During the 1990s, governments have become more reluctant to subsidize coal developments for strategic reasons and are relying more heavily on market forces. In recent years, political barriers to coal trade between some economies have been reduced.

Environmental Trends

The impact of environmental trends on coal use should be divided into two categories. The first category includes traditional pollutants (ash, SO_2, and NOx) that can be controlled with existing technologies. All Asian economies are projected to substantially reduce these pollutants as they expand and modernize their power plants. The second category of pollutants are greenhouse gases, dominated by CO_2, that cannot be readily controlled with existing technologies. The present strategy of most Asian economies, with respect to the control of greenhouse gas emissions, is to promote greater efficiency in power generation and energy use.

In spite of concerns about coal's contribution to greenhouse gases, the developing economies of Asia have not made major changes in their plans for future coal use. In most cases, the alternatives would slow economic growth rates. Economic growth remains a high priority among the heavily populated Asian economies, even at the expense of some deterioration of the environment. Japan is the most likely major coal consumer in the region to follow a strategy to substantially reduce coal consumption in order to control greenhouse gas emissions. In some Asian countries, the role of natural gas is expected to increase.

G. Asia-Pacific Coal Outlook: 1990-2010

Coal production in Asia has grown at an average annual rate of about 5 percent over the past two decades and is projected to moderate to 2.5-3.5 percent per year over the 1990-2010 period. The East-West Center's projections are based on an average growth rate of 2.9 percent per year. This growth rate in coal production, shown in Table 39, parallels the projected growth of 2.9 percent in consumption shown in Table 40. For both production and consumption, China and India are projected to heavily dominate growth over the 1990-2010 period, with Australia maintaining its third place position.

As shown in Table 40, Asian coal consumption is projected to increase from 1.6 billion tons in 1990 to 2.2 billion tons in 2000 and 2.8 billion tons in 2010, an increase of 1.2 billion tons over the two-decade period or 60 million tons per year. Table 41 shows net trade of coal over the 1990-2010 period. Net coal imports to the Asian region are projected to gradually increase from 34 million tons in 1990 to 55 million tons in 2010. As a percentage of total Asian imports, the share of imports from non-Asian producers is

Table 39. Coal Production in Asia,[1] 1990-2010
(million metric tons)

Economy	1990	2000	2010	Change 1990-2010
China	1,080	1,400	1,700	620
India	201	345	555	354
Australia	163	216	285	122
Korea (North)	49	60	70	21
Korea (South)	21	13	7	-14
Indonesia	11	50	75	64
Japan	8	1	1	-7
Vietnam	5	10	15	10
Others 11	4	10	15	
Philippines	1	4	5	4
Total	1,543	2,009	2,728	+1,185

Source: EWC Coal Project projections, 1992.

1. Asia includes the SW Pacific but excludes Russia; excludes lignite.

Table 40. Coal Consumption in Asia,[1] 1990-2010 (million metric tons)

Economy	1990	2000	2010	Increase 1990-2010
China	1,063	1,365	1,655	592
India	205	360	575	370
Japan	113	142	151	38
Australia	57	66	85	28
Korea (North)	52	65	75	23
Korea (South)	43	56	60	17
Taiwan	19	35	57	38
Hong Kong	10	13	16	6
Indonesia	7	25	45	38
Vietnam	4	8	17	13
Philippines	3	13	22	19
Thailand	1	6	25	24
Others	10	16	22	12
Total	1,587	2,170	2,805	1,218

Source: East-West Center Coal Project projections, 1992.

1. Asia includes the SW Pacific but excludes Russia; 1990 figures do not include stock adjustments; excludes lignite.

Table 41. Coal Trade in Asia,[1] 1990-2010
(million metric tons)

	1990	2000	2010	Change 1990-2010
Net Exporters				
Australia	106	150	200	94
China	17	35	45	28
Russia (Eastern)	10	11	13	3
Indonesia	4	25	30	26
Vietnam	1	4	7	6
Net Exports	138	225	295	157
Net Importers				
Japan	105	141	150	45
Korea (South)	22	43	53	31
Taiwan	19	35	57	38
Hong Kong	10	13	16	6
India	4	15	20	16
Korea (North)	3	5	5	2
Philippines	2	9	17	15
Thailand	1	6	25	24
Others	6	6	7	1
Net Imports	172	273	350	178
Net Trade	-34	-48	-55	-21

Source: East-West Center Coal Project projections, 1992.

1. Asia includes the SW Pacific; excludes lignite. Includes exports from eastern Russia into the Pacific, but Russia is not included in the production and consumption tables.

projected to decrease from 20 percent in 1990 to 16 percent in 2010. This relative decline in share of imports from outside the Asia region is because the demand for imports is mostly for lower priced steaming coal, which can be supplied more competitively from producers within the region.

In Table 42 net steam coal imports are projected to grow at 6.1 percent per year from 81 million tons in 1990 to 265 million tons in 2010. Net trade of steam coal into Asia is projected to increase from 11 million tons in 1990 to 54 million tons in 2010. Japan, South Korea and Taiwan are projected to account for two-thirds of the growth in imports of steam coal over the 1990-2010 period. The primary consumers of traded steaming coal are the electric power and cement industries, with an increasing amount going to the steel industries for pulverized coal injection use.

Figure 110 shows the trends in steam and coking coal imports of Asian economies from 1980 to 1990, with projections to 2010. Steam coal is now approximately equal to coking coal imports, but as shown in Figure 110, steam coal is expected to account for all net increases in coal imports to 2010.

The traditional blast furnace technologies will continue to dominate steel making over the 1990-2010 period. The stagnation in coking coal imports, shown in Figure 110, is due to the following four trends: (1) a slowing in the growth rate in steel-making capacity of coking coal importing economies in Asia; (2) reduced coke use per ton of crude steel production, (3) a higher percentage of lower quality coking coal in the mix, and (4) greater use of PCI coal.

It should be noted that China, with over 50 million tons of steel making capacity, is expected to double its capacity by 2010. China is expected to become the world's largest steel producer by 2010. China has large reserves of high quality coking coal and is expected to continue to meet most of its coking coal requirements from domestic supplies.

1. Coal Trends in Asia

The following section provides a brief summary of key coal and environmental issues in coal consuming economies of the Asian region.

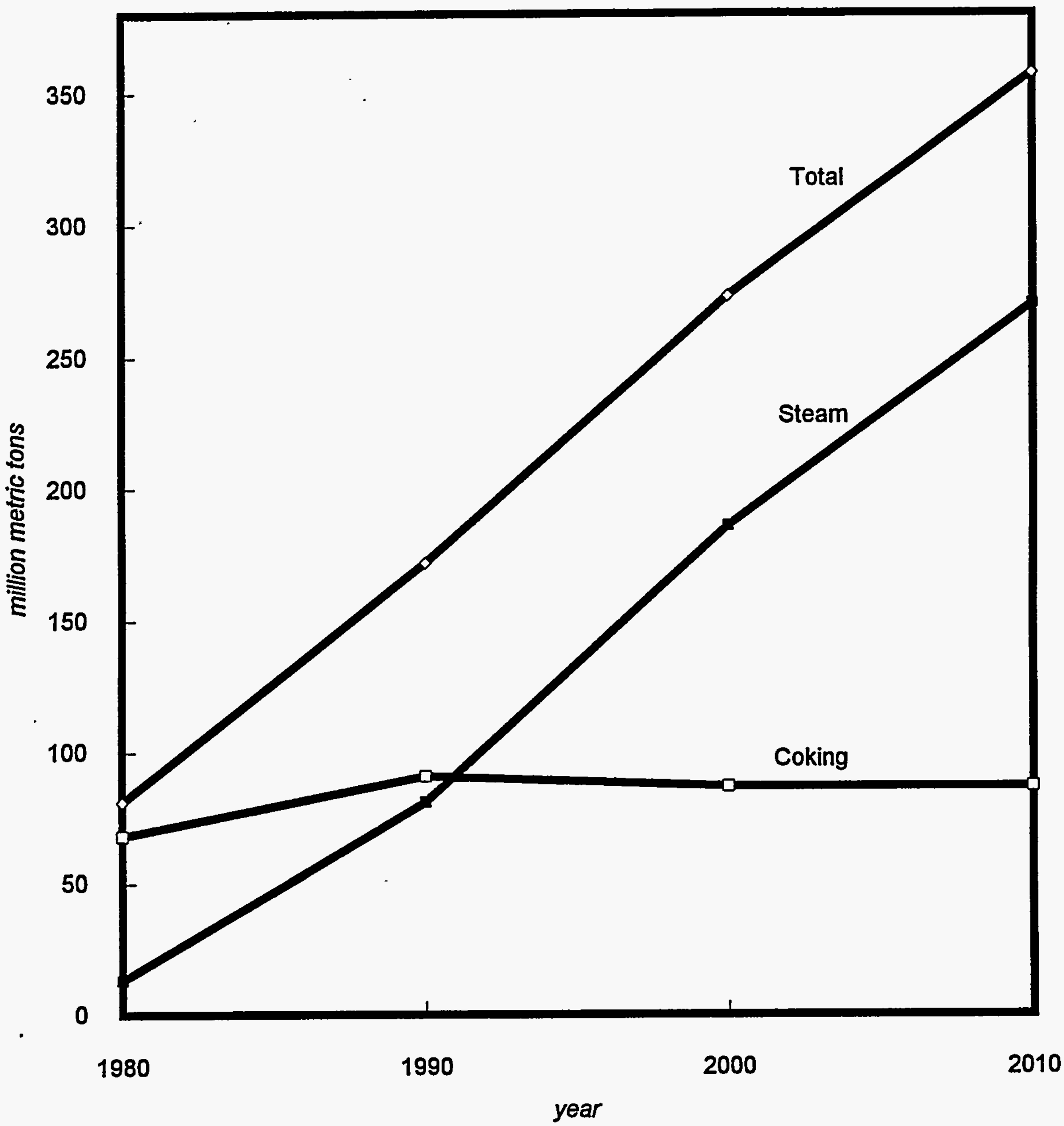
Table 42. Steam Coal Trade in Asia,[1] 1990-2010
(million metric tons)

	1990	2000	2010	Change 1990-2010
Net Exporters				
Australia	49	80	130	81
China 13	28	36	23	
Indonesia	4	25	30	26
Russia (Eastern)	3	6	8	5
Vietnam	1	4	7	6
Net Exports	70	143	211	141
Net Importers				
Japan	37	81	93	56
Taiwan	15	29	50	35
Korea (South)	10	30	40	30
Hong Kong	10	13	16	6
Philippines	2	9	17	15
Thailand	1	6	25	24
India	0	10	14	14
Korea (North)	0	2	3	3
Other	6	6	7	1
Net Imports	81	186	265	184
Net Trade	-11	-43	-54	-43

Source: EWC Coal Project projections, 1992.

1. Steam coal includes anthracite.

Figure 110. Asian Steam and Coking Coal Imports, 1980-2010



Australia. Australia produces about 175 million tons of hard coal and 50 million tons of lignite per year. It is expected to retain its position as both the largest exporter of coal to the world and to the Asia-Pacific region over the next two decades. Recoverable reserves of bituminous coal are in the range of 35-45 billion tons, and depletion is not a significant issue.

Australian coal exports have historically been the basis for both quality standards and prices in Asian coal trade, and most coal importing utilities have designed their coal-fired power plants to burn Australian coal. However, with the recent entry of competitive, lower-heat-content Indonesian coal into Asian coal markets, Asian utilities are becoming more flexible in the qualities of coal they will use for electricity generation.

Over the 1982-92 period, Australian coal exports grew at an average rate of over 9.0 percent per year, reaching 127 million tons in 1992. Exports are conservatively projected to increase to at least 150 million and 200 million tons in 2000 and 2010, respectively. Australian coal industry executives say that the f.o.b.t. price of coal in constant 1991 dollars must be significantly above US$40 per ton before major investments in new production will be made. Substantial expansion of some existing mines could occur, however, with a price range of US$35-40 per ton.

Australia's strong competitive position in coal exports to Asia results from four key factors: the size and quality of the deposits, their location within 250 kilometers of established deep-water ports, the high quality of most of the rail and port infrastructure, and Australia's stable investment climate. Although most of the producing coal mines in Australia are within 250 kilometers of the coast, rail rates are higher per kilometer than those of other coal exporting countries. State government taxes in the major coal exporting state of Queensland are the primary reason for these higher per-kilometer rail rates.

Coal is Australia's largest export commodity in terms of value, and government policies continue to encourage expansion in this sector. Although Australia is projected to continue to dominate coal trade in Asia over the 1990-2010 period, expansions in Indonesian exports are expected to cut into Australia's share of the Asian market during the next few years.

The Australian government and industry have a keen interest in protecting export markets for coal. The primary goal has been to maintain Australia's competitive position in international coal trade by improving the economics and quality of Australian coal supplies. The primary focus of Australian research is on improving the quality of its coal products through improved beneficiation.

To date, Australian electricity generating plants have not needed to install sulfur recovery equipment or clean coal technologies. This is partly because the majority of Australian coals contain less than 1 percent sulfur and partly because most plants are located away from population centers.

China. China is the world's largest producer and consumer of coal, and it has set a goal to produce 1.4 billion tons of coal in 2000. It has huge coal resources (nearly 1 trillion tons), of which proven recoverable reserves are in the range of 200-300 billion tons.

Coal demand is expected to grow at least as fast as government projections, and possibly much faster because of (1) the potential for rapid economic growth resulting from an accelerated migration from the rural to the urban areas over the next two decades (resulting in higher labor growth in the more productive urban sector, higher incomes, and higher electricity consumption); (2) improvements in the incentive wage system in the state sector (workers will then become more productive); (3) improvements in the financial system (more capital for investments); and (4) less potential for energy conservation than in the 1980s.

Coal accounts for a very high 75 percent of total primary energy consumption. China faces formidable problems in controlling emissions from coal burning, because about two-thirds of coal consumption is among millions of residential, commercial, and other medium and small users, where the introduction of coal technologies is far more difficult than for large users, such as electric utilities and steel mills.

China's coal exports have increased from 5 million tons in 1980 to 20 million tons in 1991, and are projected to increase to about 35 million tons in 2000 and 45 million tons in 2010. Long-term projections of exports for China are subject to considerable uncertainty because domestic demand for coal continues to exceed production. Exports occur because of the government's drive to earn foreign exchange and to repay foreign loans that finance coal and related infrastructure projects. There are signs, however, that the growth in exports may slow in the future, because of high domestic demand and higher domestic prices.

China has very large tonnages of high quality thermal and coking coal within 700-900 km of the coast. The distance disadvantage is partially offset by the combination of the low charges applied to coal transport and proximity to other Asian markets. The inadequate rail transport system to the coast is being upgraded.

The Chinese economy has continued to grow at impressive rates in recent years. Even with the general slowdown in world economic growth, China experienced an economic growth rate of more than 10 percent in the first half of 1992.

The government's domestic energy strategy places heavy emphasis on increasing efficiency in coal use in three broad areas: promoting cogeneration in urban areas, increasing the share of heating by central heating systems, and increasing the share of electricity generation in the total energy mix.

Hong Kong. Hong Kong switched from total dependence on oil for electricity generation in 1981 to almost total dependence on coal in 1990. This pattern is changing again in the 1990s as nuclear and natural gas power plants come onstream. One 900-MW nuclear power unit at the Daya Bay plant began operation across the border in China in 1993, and another 900-MW unit is expected to come on line in 1994. Plans for a new 6,000-MW coal-fired unit (Black Point Power Plant) have recently been modified so that natural gas can be burned. The new plan is to bring natural gas over an 800-km pipeline from Hainan Island to fire the first 2,400-3,000 MW of capacity at the Black Point Plant. This will reduce the future increases in demand for coal from the original 14-16 million tons per year to 7.5-9.0 million tons per year.

The demand for electricity is projected to grow at 5-6 percent during the 1990s compared to about 9 percent in the 1980s. Total consumption of steam coal for electricity consumption is projected to increase from approximately 10 million tons in 1990 to 13 and 16 million tons in 2000 and 2010, respectively.

Hong Kong has become an important catalyst for rapid economic growth in adjacent Chinese provinces, and this is accelerating the growth in electricity demand in this region. Hong Kong based companies (such as Hopewell Holdings) are playing an important role in build-operate-transfer (BOT) power plant expansions in China.

Australia and South Africa each supply about one-third of Hong Kong's coal requirements. Competition from China and Indonesia could reduce these shares in the future. Hong Kong aggressively follows strategies to purchase coal at the lowest cost.

India. Coal accounts for about 60 percent of total commercial energy consumption in India. India's Tata Energy Research Institute (TERI) has made projections of India's future coal requirements under a "business as usual" scenario. TERI's projections assume that both electricity and coal consumption will increase at an average of 7 percent per year between 1989 and 2010.[3] By comparison, during 1976-90 coal production grew at an average 5.5 percent per year, and electricity-generation demand for coal grew by an annual average of 11.7 percent. TERI projects that total coal consumption will grow from about 200 million tons in 1989 to about 450 million tons in 2000 and 775 million tons in 2010.

Demand for electricity has historically exceeded supplies and domestic targets for coal production are usually not achieved. Therefore, the East-West Center's projections in Tables 39 and 40 for India assume that coal supplies and consumption will continue to grow at the historical average of 5.5 percent to 2000 and will then decrease slightly to 5.0 percent during the subsequent ten years. These lower growth rates result in the production of 345 million tons in 2000 and 555 million tons in 2010, which would be more than 100 million and 200 million tons, respectively, below the TERI estimates. These lower estimates follow the trend in the Indian government's revised Eighth Five-Year Plan (1992-97).

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[3]K. K. Misra (1991), "Coal's Future Role in Meeting Energy Demand in Asia," paper presented at the IAE/OECD Conference on Coal, the Environment and Development: Technologies to Reduce Greenhouse Gas Emissions, Sydney, Australia.

India's domestic coal resources are large but are mostly below the quality standards of internationally traded coals. Major improvements are required in mining, beneficiation, and transport of India's coal to meet domestic requirements. There is no practical energy alternative to coal as the most important source of energy in India over the 1990-2010 period. Domestic coking coal requirements are exceedingly difficult to meet from domestic supplies, and a few million tons must be imported each year. Imports are presently restricted to about 5 million tons of coking coal, and both coking and steaming coal imports would probably rapidly increase if restrictions were removed.

There is discussion about allowing active foreign private sector participation in power plants and in mining. If this were to occur in the 1990s, there would be a rapid increase in imports of coal that could range in the tens of millions of tons during the 2000-2010 period. Such changes are expected to occur slowly and will be reflected in a gradual increase in foreign investment in India's coal sector.

Although environmental problems associated with coal burning in this heavily populated country are serious, major investments in emission control equipment are unlikely in the foreseeable future. The priority of the 1990s appears to be the control of ash emissions and the increase of generation efficiencies, rather than the installation of flue gas desulfurization (FGD) systems.

Recent trends toward greater political and economic instability increase the uncertainty of any long-term energy projections for India.

Indonesia. Indonesia's large steam coal export potential was not recognized until the 1980s. Rapid expansion in production from extensive deposits in Kalimantan are underway, and Indonesia appears to be the lowest cost, potentially large coal exporter in the Asian market. Although Indonesia has some premium steam coal (such as Kaltim Prima), most of the coal has one or more quality deficiencies that may constrain its market potential. In general, Kalimantan coals contain low sulfur, low to medium energy, and medium to high moisture. Some coals have exceptionally low sulfur contents of 0.1 percent that could meet sulfur emission standards in most countries without FGD.

Indonesia's coal production can be expanded by a few tens of millions of tons at lower costs per ton than expansions in most other coal exporting countries. The main constraints on the low-cost expansion of coal production for at least the next decade are the share of coal that consumers will accept (strategic and quality constraints) and the rate of growth in domestic demand in Indonesia.

Accurate projections of coal production, consumption, and trade for 2000 and beyond are subject to considerable uncertainty at this early stage of coal expansion in Indonesia. Given this caveat, production is projected to jump from 20 million tons in 1992 to 50 million and 75 million tons in 2000 and 2010, respectively. Exports are projected to increase from an estimated 12-13 million tons in 1992 to 25 million tons in 2000 and then gradually increase to 30 million tons by 2010.

Indonesia's population is the fourth largest in the world (more than 180 million people in 1990) and is projected to reach a quarter billion people within two decades. Electricity consumption has been growing at roughly 15 percent per year for the past two decades, with oil and gas accounting for the majority of total generation. Indonesian oil and gas reserves are substantial but insufficient to meet longer-term export plans and the growth in the domestic energy market. The government's state utility plans to shift to coal-fired generation over the next two decades. However, delays in financing and high construction costs for coal-fired plants may result in greater than expected expansions in oil and gas capacity during the 1990s.

The growth rate in exports is expected to slow in the early part of the twenty-first century, as a consequence of the rapid growth in domestic demand and of the share of the Asian market that can be filled by Indonesian quality coal.

Japan. As stated earlier, Japan is the largest importer of coal in the world. Its imports of 110 million tons in 1991 represented an increase of 3.9 percent over 1990. Most of this growth was in imports of steaming coal for electricity generation, which increased 28 percent to 20 million tons in 1991. Steam coal imports are expected to exceed coking coal imports within five years.

The Japanese government's goal is for coal consumption to increase from the present 113 million tons to a plateau of 142 million tons in the period 2000-2010. This goal of stabilizing coal consumption at 142 million tons per year will help Japan achieve its environmental objective of limiting greenhouse gas emissions. For the purposes of this study, an estimate of 142 million tons is assumed for 2000, rising gradually to 151 million tons in 2010. This estimate is slightly higher than government goals and substantially lower than some industry estimates.

She share of steam coal in Japan's total coal consumption is expected to increase from 40 percent in 1990 to more than 60 percent in 2010. The demand for coking coal in the steel industry is projected to decline by at least 15 percent over the 1990-2010 period, because of contractions in the size of the steel industry and substitution by PCI. Production from Japan's domestic coal mining industry is projected to continue declining from 8 million tons today to an insignificant amount by 2010. The actual rate of decline is determined by government policies that are aimed at moderating the negative impact of mine closures.

Philippines. The Philippines has modest amounts of oil, geothermal energy, and low quality coals that are being developed to meet a portion of the country's energy requirements. At present coal accounts for 7 percent (405 MW) of total electricity generating capacity, and by 2000 coal-fired capacity is projected to jump to about 30 percent of the total. Although accelerating the development of low quality domestic coal has been a goal since the late 1970s, the production potential appears limited to a few million tons per year.

The current domestic coal production of about 1.5 million tons per year is projected to increase to about 4 million tons in 2000 and then gradually increase to perhaps 5 million tons in 2010. Because of its poor quality, the domestic coal is blended with imported coal to meet power-plant specifications. Imported coal is projected to increase rapidly after the mid-1990s reaching about 9 million tons in 2000 and 17 million tons in 2010. Serious electricity shortages exist in the Philippines, and accelerated efforts to expand capacity are planned.

Private-sector investment in large power plants is under way. Hopewell Holdings of Hong Kong recently completed construction of a gas turbine plant near Manila under a build-operate-transfer (BOT) agreement and plans to build a 700 MW coal-fired power plant under another BOT agreement.

South Korea. The second oil shock in 1979 was the stimulus that caused the South Korean government to actively encourage substitution away from dependence on oil. The use of nuclear power and coal grew rapidly during the 1980s, and a small amount of LNG entered the energy mix at the end of the 1980s. In 1990 Korea's installed power generating capacity was 36 percent nuclear, 23 percent oil, 18 percent coal, 12 percent LNG, and 11 percent hydropower.

Imported coal consumption in 1991 was about 30 million tons, of which thermal coal accounted for 13 million tons. Imports increased rapidly over the past decade, from 7 million tons in 1980 to 22 million tons in 1990, and are projected to increase to 43 million and 53 million tons in 2000 and 2010, respectively. Korea's long-term strategy for thermal coal imports is to obtain 60 percent through long-term contracts, 30 percent through joint ventures, and 10 percent on the spot market.

Taiwan. Taiwan has very limited energy resources and is heavily dependent on imported energy. Since the second energy crisis in 1979, coal consumption for power generation has soared. Coal's share of total energy supplies is projected to increase from 24 percent in 1990 to 31 percent in 2000. Steam coal imports to Taipower are estimated at 12 million tons in 1992. Total coal consumption is projected to triple by 2010, increasing from 19 million tons in 1990 to 57 million tons in 2010. The share of power generation in total coal consumption is expected to increase from 47 percent in 1990 to 59 percent in 2000. There is limited potential for expansion of the steel industry in Taiwan, however, for economic and environmental reasons.

Taiwan follows a strategy to diversify sources of supply of coal. A significant shift has occurred in the mix of imported coal, with Indonesian suppliers cutting into Australia's market share, and recently approval has been given to Taipower to purchase up to 20 percent of its coal requirements from China. Taipower's long-term strategy is to obtain about 20 percent of its coal requirements from the spot market.

Thailand. Since the 1970s Thailand has had an active program to diversify energy sources and promote development of domestic energy resources of lignite, natural gas, and oil. Oil's share of total primary energy is projected to decrease from 66 percent in 1990 to 55 percent in 2010. The share of domestic lignite is expected to increase marginally from 11 percent in 1990 to 12 percent in 2010. Domestic reserves of lignite, oil and gas will be largely committed by the turn of the century. However, it is important to note that lignite production is expanding rapidly in Thailand. In 1991 Thailand produced about 15 million tons of lignite and subbituminous coal, and the government projects production of 37 million tons in 2000. Production increases after about 2000 are expected to be much more gradual than in the 1990s, because the largest known deposit at Mae Moh will be fully developed by that time.

The major change expected in total primary energy is the share of imported coal, which is projected to jump from 1 percent in 1990 to 18 percent in 2010, reflecting an increase from less than 1 million tons in 1990 to about 25 million tons in 2010. The first major development supplied by imported coal is the planned 2,800-MW coal-fired plant at Aio Phai, 120 km south of Bangkok. The first 700-MW unit at this plant is expected to begin operation in 1996 or 1997, and the plant will include flue gas desulfurization equipment.

In the north at Mae Moh, where the country's largest mine-mouth lignite power station is located, SO_2 levels recently exceeded maximum allowable limits. All future power plant expansions at the large Mae Moh mine are expected to be accompanied by flue gas desufurization equipment. In addition, coal imports for electricity generation are expected to be restricted to low-sulfur coal.

Thailand has plans to accelerate efforts to import natural gas from neighboring Myanmar (Burma) and Malaysia and also (if sufficient gas is discovered) Cambodia and Vietnam. In addition, Laos and Cambodia have substantial hydroelectric potential that they would like to develop for electricity exports to Thailand. The role of coal in Thailand's generation mix could therefore be lower than projected, if natural gas and electricity imports can be secured at competitive prices and in large amounts.

New Zealand. A minor player in the overall Asian coal market is New Zealand. The country produces about 2.5 million tons of coal per year. It has modest amounts of hard coal reserves and substantial amounts of lignite resources. A small amount of coking coal is exported. Exports are projected to increase to 1.0-1.5 millions tons per year by 2010.

North Korea. North Korea is an important coal producer and user. It produces mostly anthracite, which is consumed mainly in the domestic market. There is considerable uncertainty about the true level of coal production, and estimates range from 35 million to 60 million tons. per year. North Korea is believed to have limited investments in modern pollution control technologies, and it is therefore probably a major polluter in the region.

The outlook for future coal production, consumption, and trade is heavily dependent on progress to open up the economy, the eventual reunification with South Korea, and the size and quality of coal reserves. If reunification occurs (perhaps by 2000 or 2005), it would probably have a substantial impact on coal trade and on investments in emissions control equipment in North Korea. Two basic yet quite different scenarios are plausible. Under the first scenario, much of the coal industry is high-cost, and there is a contraction in production as the high-cost mines are closed and coal imports increase. In the second scenario, the deposits are large and high in quality, and a rapid increase in foreign investment results in substantial increases in both production and exports. Uncertainties about North Korea's future role in coal cannot be easily resolved, but they still must be considered in long-term projections for the region.

Malaysia Malaysia uses about two million tons annually of mostly imported coal. It is not expected to become an important user of coal over the next two decades, during which time large reserves of oil and natural gas are expected to meet most of Malaysia's energy requirements. Natural gas alone is expected to meet more than two-thirds of Malaysia's generation mix in the medium term.

East Malaysia has significant potential for development of coal and could eventually export a few million tons per year. About a billion tons of coal are located at inland sites—75 percent in Sarawak and 24 percent in Sabah—but the development of this resource would require major investments in infrastructure. Moreover, some of the best reserves are in environmentally sensitive areas.

Pakistan. Pakistan has a few billion tons of mostly subeconomic, low-quality coal and a limited amount of coal that can be classified as reserves. Pakistan produces 2-3 million tons of coal and consumes about 4 million tons per year. Large expansions in domestic production are unlikely to be economic, and imported coal appears to be a more viable longer-term option. Plans are under way to build a major 4,000-MW power plant burning imported coal. This would push consumption to 7-10 million tons by about 2000 and 12-16 million tons by 2010. However, problems in raising capital appear likely to result in delays in achieving the goal of 4,000 MW of coal-fired capacity.

Eastern Russia. The eastern part of Russia has very large coal resources, mostly more than 2,500 km from the Pacific ports of the Russian Far East. The economics of present exports are marginal and large expansions are unlikely over the next two decades. However, there may be substantial thermal coal deposits within a few hundred kilometers of Pacific ports. These deposits, if they exist in commercial quantities, would not play a significant role in the 1990s but might become a significant factor in Asian coal trade after 2000.

Vietnam. Vietnam has large energy resources of anthracite coal and hydropower, substantial reserves of oil, and potential for major discoveries of both oil and natural gas. Present production of anthracite is about 5 million tons per year, and about 1.5 million tons were exported in 1992. Recent agreements between Vietnam and China may result in an increase of about 1.0 million tons per year or more in exports to China. Current world trade in anthracite is estimated at about 15 million tons, and Asia accounts for about one-third of the total. The Vietnamese government projects that production will be in the range of 6.8-8.4 million tons in 2000 and will rise modestly thereafter to 6.8-8.9 million tons by 2005. The government expects to export about 3 million tons of anthracite exports in 2000.

The East-West Center's projections, which assume that production will expand to 10 million tons in 2000 and 15 million tons in 2010, are more optimistic than those of the Vietnamese government. These projections assume substantial foreign assistance in expanding coal capacity, however, and are subject to considerable uncertainty. A discover of large natural gas deposits in Vietnam, for example, could decrease the growth in domestic demand for coal.

The basis of the more optimistic projections for anthracite production and exports are as follows: First, the anthracite seams in Vietnam are among the thickest in the world. Second, large deposits exist close to the coast (within 10-25 kilometers). Third, changes under way to allow active private-sector participation will probably bring in the necessary investments in modern technologies for mining, processing, transportation, and port handling of anthracite. The three key uncertainties are the mining conditions (stripping ratios and the continuity of coal beds), the ability of foreign private companies to establish and maintain efficient operations, and the problems in finding a suitable site for a deep-water port.

Australian, Indonesian, French, and British companies have shown interest in developing anthracite mines near Halong Bay in northern Vietnam. The most extensive feasibility program for a mine development has been carried out by BHP of Australia. In addition, Indonesian, British, and French firms are evaluating projects.

A potentially important factor in future supplies of internationally traded anthracite is that both North Korea and Vietnam may have large deposits that could be mined at relatively low cost with modern mining equipment. Vietnam is already opening up to active foreign investment, and North Korea could open within a decade. Therefore, it is possible that substantial supplies of anthracite at relatively low prices could become a factor in international trade during the 2000-2010 period.

Summary of Asian Trends. Asia's lower-income economies have high levels of growth in electricity demand, and most depend heavily on coal in their energy mix. China and India dominate this group. Asia is projected to increase its coal consumption by about 1.2 billion tons over the 1990-2010 period. Environmental concerns are being gradually addressed with respect to the traditional pollutants (particulates, SO_2, and NOx). However, with the possible exception of Japan, all Asian economies are likely to give priority to meeting the growth in demand for energy necessary to maintain economic growth, and they are unlikely to place major constraints on energy consumption to reduce their greenhouse gas (CO_2) emissions.

Expansions of coal capacity for exports over the past decade have been characterized by development of deposits within 250 kilometers of ports and a movement toward lower heat content coals. The cash operating costs of new supplies tend to be lower than those of existing suppliers. In Asia, Indonesia is the primary new supplier and is cutting into the market shares held by traditional exporters, particularly Australia. Australia is projected to remain the largest exporter of coal to Asia over the 1990-2010 period.

2. Coal Trends in Europe and the Americas

• Coal trade in Europe is expected to expand by 150-200 million tons to 370-420 million tons in the next two decades. This rapid increase in coal trade is due to a number of factors including the elimination of coal mining subsidies within the unified European Community (EC) and the opening of the economies of eastern Europe. The closing of formerly subsidized, uneconomic mines will result in increased imports of lower-cost coal. Also many of the coal mines in eastern Europe will not be able to compete with internationally traded coal and will therefore be closed. European buyers will increasingly be forced to seek a greater share of their coal from outside national and even European boundaries. A brief overview of the major coal using countries in Europe is provided below.

United Kingdom. The United Kingdom is expected to account for much of the projected increase in coal imports to Europe. In 1991, the United Kingdom produced about 93 million tons of coal (*BP Statistical Review 1992*). There has been a trend toward the elimination of widespread subsides in British coal mines. Privatization of the electric power industry in the United Kingdom will be one of the main factors in the continued decline of coal production. In the past, the utilities were required to purchase almost all of their supplies from British Coal. As this situation is gradually phased out, utilities will be able to use external suppliers. Utilities have already made purchases from U.S., Australian, and Canadian suppliers, and this trend is expected to continue.

Italy. Because of its limited supplies of indigenous energy resources, Italy is forced to rely on imports to meet energy needs. Italy is western Europe's largest importer of coal (with about 20 million tons of coal imports in 1990 according to *Coal Information 1991*) and is expected to remain one of the top three importers in Western Europe over the next two decades.

Germany. As subsidies and regulations on coal purchasing, production, and transportation are eliminated, German imports of coal are expected to increase at a steady pace over the next twenty years. Steam coal will enjoy the most growth, with much slower growth in coking coal imports. West Germany's coal imports are expected to reach 20 million tons by 2000 and then jump to 80 million tons by 2010, where East Germany is expected to import 4-10 million tons of mostly steam coal for new coal-fired power plants over that period (*Annual Prospects*, 1991). Coal provides about 30 percent of West Germany's energy needs and 70 percent of East Germany's.

Eastern Europe. The major coal producing and importing countries of Eastern Europe include the European CIS countries, Albania, Bulgaria, Czechoslovakia, Hungary, Romania, and Poland. In the past, these countries were limited to trading among themselves. The movement toward more open market economies is expected to result in increased coal trade. Coal prices, which are significantly lower than international market prices due to the heavy subsidizing of state run coal mines, are expected to increase steadily over the next few years. Many mines, however, will be uneconomic to operate at the higher prices and will eventually be closed. Coal production has already declined in Czechoslovakia, Poland, and the eastern CIS.

Canada. Coal accounts for only 20 percent of total energy use in Canada, and a large portion of the coal used for power generation and in steel mills is imported from the United States. The use of U.S. coals rather than Canadian coal is due to the distance that western Canadian coal must be transported to Canada's eastern coal users. Canada produced 40 million tons of bituminous coal and 26 million tons of subbituminous coal and lignite in 1991. A majority of the hard coal produced was exported to the Asia-Pacific region. Canadian coals are able to compete in the Asia-Pacific region mostly due to the strategic policies of Asian countries rather than from economic considerations. In the Asia-Pacific market, long transport distances and high mining costs make most Canadian coals uneconomic compared to Australian and Indonesian coals. Canada's coal exports are expected to decrease at least over the next decade.

United States. The United States is the world's second largest producer of coal and has such extensive reserves that depletion is not a significant factor for at least the next 100 years. However, changes in legislation relating to sulfur emissions from coal burning are likely to cause shortages of low-sulfur coal in some central and eastern areas in the later 1990s. The United States produces about 900 million tons of coal each year, with 60 percent coming from the east and 40 percent from the west. Coal production is projected to increase by about 50 percent over the next two decades to about 1.3 billion tons.

Electric utilities account for over 85 percent of total domestic coal consumption, and this share is increasing. In the export market, coking coal accounts for 60 percent of the approximately 110 million tons of total coal exports.

Coal is exported primarily from eastern and Gulf states, with only modest exports from western states. The fundamental problem with west coast exports, which are mostly steaming coals destined for Asia, is the distance of 1,500 to 2,000 km or more that the coal must be carried by rail to the port. Even though the mining costs of some western deposits are among the lowest in the world ($6 per ton), and the rail rates per ton kilometer (under $0.01) are among the lowest in the world, the distance disadvantage has prevented western coals from capturing a significant share of the Asian steaming coal market. West coast exports in the 5-10 million tons per year range are projected for the late 1990s, perhaps increasing to 10-15 million tons in the 2000-2010 period.

Production of western coals is increasing at a faster rate than eastern coals for two reasons. Although most western coals have a much lower energy content than central and eastern coals, they can be mined for one-half to one-quarter of the cost and typically contain much lower sulfur contents. The combination of these factors, and the availability of efficient rail and barge transportation networks, have allowed western coal to take thermal coal markets away from central and eastern U.S. coal producers, in areas where utilities are switching to low-sulfur coal. Environmental legislation and controls taking effect in 1995 and 2000 are expected to result in greater demand for western coal exports by central and eastern electric utilities. Only modest growth in the export of high quality steam coal from western U.S. ports is expected over the next decade.

Mexico. Mexico currently imports about 5 million tons of coal. A majority of current coal consumption is supplied by indigenous mines, but a rapid increase in demand for coal and imports is likely over the next two decades. This will allow Mexico to export a larger portion of its oil production. Coal producers in the United States (Powder River Basin) and Colombia appear well positioned to benefit from substantial increases in Mexican imports.

Brazil. Brazil's was one of the fastest growing steel producers in the world in the 1980s and its steel making industry is expected to grow at moderate rates over the next two decades.

Imports of coking coal for use in Brazil's steel mills are projected to grow from about 10 million tons currently to 15 million tons in 2010.

Colombia. The Cerrejon Norte mine located in the northeastern part of the country currently dominates production, but the Colombian government has plans to expand coal operations from six other coal producing areas. Mine capacity at Cerrejon is expected to be expanded from 15 million tons in 1991 to about 25 million tons in the late 1990s. Total Colombian coal exports of low-sulfur coal could reach 30 million tons by the year 2000. Only a small percentage of Colombian coal is sold in the Asia-Pacific region.

H. Coal Technologies

A more in-depth assessment of energy technologies will be given later in this study, so discussion here will be limited only to the major technologies associated with coal burning and coal emission control. Clean coal technologies are defined by the Asia Pacific Economic Cooperation (APEC) forum as "technology designed to improve the efficiency of coal use and/or enhance environmental performance." Clean coal technologies allow electric utilities to burn coal for power generation and meet stringent environmental regulations. The view of coal as a "dirty" fuel is misleading in the case of clean coal technology plants. For example, Hawaii's coal-fired fluidized bed combustion (FBC) power plant at Barbers Point has much lower pollution emission levels than most oil- and coal-fired power plants currently in operation throughout the world.

A major $5-6 billion research and development program on clean coal technologies is under way in the United States, and advances in these technologies are reducing both capital and operating costs over time. Clean coal technologies can be divided into four broad categories: (1) pre-combustion, (2) combustion, (3) post-combustion, and (4) conversion. In Hawaii, only fluidized bed combustion (FBC) and flue gas desulfurization (FGD) options are likely during the 1990's. However, after 2000, integrated gasification combined cycle (IGCC) could become a competitive alternative and would result in pollution levels approximately as low as any alternative, including natural gas.

1. Flue Gas Desulfurization (FGD)

FGD is the technology used most frequently by utilities today to meet tightening regulations on SO_2 emissions on both coal- and oil-fired plants. FGD equipment or scrubbers can remove over 90 percent of the sulfur from flue gases and can be designed to reduce NOx emissions at the same time. The technology makes use of the reaction of lime or limestone with SO_2 in the flue gas to form gypsum and calcium sulfites. The gypsum can then be used as a building material.

2. Fluidized Bed Combustors (FBC)

FBC is the furnace technology used in Hawaii at the AES Barbers Point coal-fired plant. In place of the conventional furnace, coal and limestone are fluidized by rising air currents. "Fluidized bed" is a general name for the process in which finely divided solids float in a gas (air), thereby behaving like a fluid. The combustion products from this fluidized bed include unburned coal and ash, which are separated from the flue gas and returned to the furnace. As in the FGD system, the SO_2 in the flue gas reacts with the injected limestone causing the same solid or liquid products, and the lower combustion temperatures inherent in the process lead to reduced NOx emissions. SO_2 removal is over 90 percent. Two types of FBC technologies exist: one operates under atmospheric conditions (normal pressure), and the other (called pressurized FBC) is still in the demonstration stage but appears promising after the turn of the century.

3. Integrated Gasification Combined Cycle (IGCC)

In this process, coal is gasified by partial combustion in a high-pressure furnace. The gas is cooled, cleaned, and then used to fire a gas turbine. Waste heat from the gasification and gas turbine exhaust are then used to create steam to power a conventional steam turbine. Coal usage and the emission of pollutants associated with this technology are lower than those of the two technologies discussed above. This technology is not yet commercially viable, however, and is currently only in the demonstration plant phase. With continual improvements and experience with the technology, commercial viability may be reached after the turn of the century.

I. Summary and Conclusions

The key considerations with respect to the long-term supply of coal to a power plant are that the cost of generation is below the next best alternative and that environmental emissions are below the limits imposed by government.

The long-term price of coal traded internationally is not expected to increase significantly in constant U.S. dollar terms, and coal is projected to remain the lowest-cost energy option for large power plants. However, the capital costs of coal-fired plants with pollution control equipment are higher than those of oil- or gas-fired plants, and site-specific feasibility studies are required to determine the best economic option. If power plant economics in Hawaii are similar to other coastal plants in Asia, coal will likely remain a highly competitive energy option over at least the next two decades.

V. Environmental Trends Affecting Fossil Fuels

This section on environmental trends affecting fossil fuel use covers four main areas: global warming and fuel choice; the U.S. Clean Air Act and the recently announced British thermal unit (Btu) tax; environmental trends in Asia; and environmental trends in Hawaii. The discussion is limited to trends and possibilities. No attempt is made to quantify the effects of environmental legislation and attitudes on fuel use: such an analysis is not only far beyond the scope of this contract, it is well nigh impossible to do with any degree of accuracy. It is possible, however, to summarize the major thrusts of the environmental movement in the Asia-Pacific region, the United States, and Hawaii and to assess how they affect the outlook for fossil fuel use. It is in fact essential to do so, since many of our most pressing environmental problems are directly related to patterns of energy use.

A. Global Warming and Fuel Choice

1. The Nature of the Effect

The greenhouse effect is a well-known phenomenon in the physical sciences. Even in the early 1970s, many scientists were raising questions about the growing load of carbon dioxide in the atmosphere; there were "teach-ins" on the subject at the very first Earth Day. Despite this, the problem only became popular in the public mind in the late 1980s. There have been rather silly discussions where it has been questioned "whether the greenhouse effect is real." There is no question that the *physical* mechanisms are real; there are significant questions as to how it will operate at a global level given all the other factors affecting climate. And, significantly, the scientific evidence is not clear on the actual extent of global warming that is occurring and will occur.[4]

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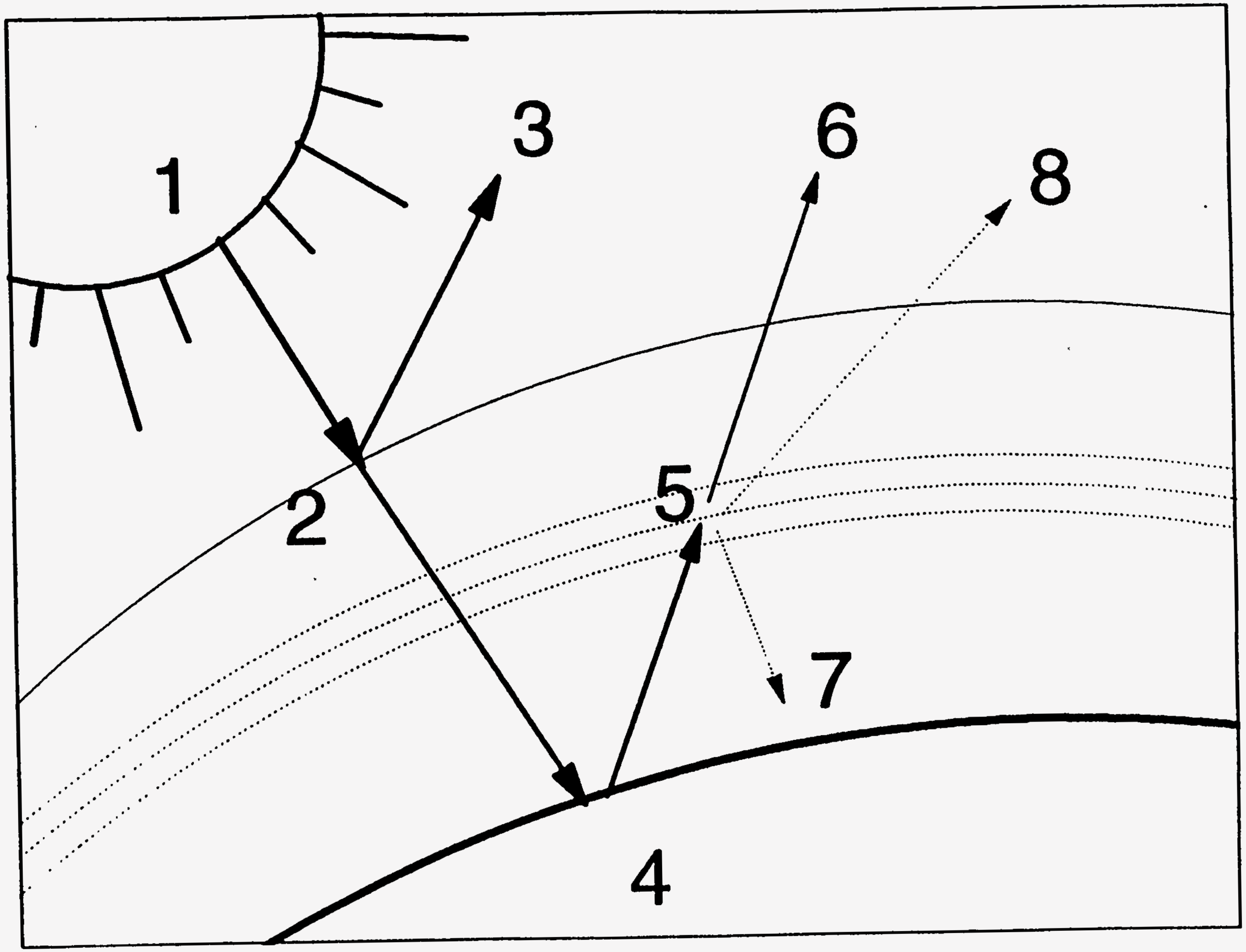
[4]See, for example, The George C. Marshall Institute, *Global Warming Update: Recent Scientific Findings*. Washington, D.C., 1992.

Atmospheric radiative transfer—the movement of light and heat through the atmosphere—is one of the most complex areas in modern science, and there are still big questions as to what is actually in the atmosphere and how the components interact. A very oversimplified diagram of how the greenhouse effect works is shown in Figure 111.

Solar radiation leaves the sun (1) and reaches the Earth's atmosphere (2). Some of it is scattered or reflected back into space (3). Some of it travels through the atmosphere and is absorbed on the Earth's surface (4). The high-energy light (ultraviolet and visible) is degraded into low-energy heat waves (infrared), which are radiated away from the Earth. This radiation then encounters certain kinds of gas molecules called "greenhouse gases" that absorb and reemit radiation in the infrared range (5). Some of the infrared continues on into space (6). Some is absorbed. When an infrared light photon is absorbed, it may be reemitted in any direction. The net effect is that some is radiated back toward Earth (7), while some is radiated out into space (8). For the temperature on Earth to stay constant, then ignoring the small amount of energy actually stored at (4), (1) = (3) + (6) + (8). In other words, the amount of energy going out of the system has to equal the amount coming in.

All things held equal, if the concentration of greenhouse gases increases, then the amount of radiation locked up in the atmosphere increases, and the temperature increases. Similarly, if the concentration falls, the temperature falls. The greenhouse effect is so-named because this is precisely the principle behind greenhouses: Visible light enters through the glass of the greenhouse, heats the interior, but then cannot escape as infrared radiation because glass is opaque in the infrared region of the spectrum. The greenhouse effect is necessary for the survival of life on the planet: the greenhouse gases are like a blanket that keeps the earth warm. The problem is one of balance. Too little greenhouse gas, and the planet gets too cold; too much, and it gets too hot. The problem today is that the emissions of greenhouse gases from human activities have greatly increased, without any countervailing increase in the absorption of the gases from the atmosphere.

Figure 111. Simplified Diagram of Greenhouse Effect



The entire issue is made more complicated by feedback effects, many of which have probably not even been identified. For example, higher temperatures mean more water evaporating, which means more clouds. Water itself is a greenhouse gas, so the feedback suggests that the warming effect may accelerate. The infamous chlorofluorocarbons (CFCs), which attack the ozone layer, are the most powerful of greenhouse gases; but ozone is a greenhouse gas itself, so removing CFCs, while unquestionably an urgent matter, does not decrease the greenhouse warming quite as much as predicted. (The newest complication—the surprising "sulfate effect" recently announced by two U.S. research teams—is discussed below.)

2. Carbon Dioxide Emissions

The most important greenhouse gas (other than water, which must be taken for granted as a feature of our planet) is carbon dioxide (CO_2). The discussions of CO_2 levels in the media have led many people to conclude that CO_2 is a "pollutant" like sulfur or nitrogen oxides. In public discussions of power plants, it is common to find that many members of the audience believe that CO_2 is some kind of contaminant in the fuel that should somehow be removed or "scrubbed" from the fuel or exhaust gases. The whole purpose of burning something is to produce CO_2; it is the combination of oxygen with carbon that is the main source of energy release in every common fuel, renewable or nonrenewable. The best way to avoid creating CO_2 is to avoid burning things.

There is one important exception to the above rules, and that is hydrogen. When hydrogen gas is burned, the only combustion product is water. As many people have realized over the years, hydrogen could be the fuel at the center of an elegant, nonpolluting energy cycle. Water can be split apart into hydrogen and oxygen molecules by the application of electricity ($2\ H_2O \rightarrow 2\ H_2 + O_2$). The source of electricity could be clean and renewable, from wind generators or solar photovoltaics. The hydrogen could be stored and then burned (in cars, jets, stoves, etc.) as needed, converting it back to water. No wastes, no CO_2, no contaminants like sulfur.

There are a number of problems with such a concept at present. First is the cost of producing hydrogen from electrolysis of water. At present, the main sources of hydrogen are catalytic reforming of naphtha in refineries and steam reforming of methane and other light hydrocarbons. By far the cheapest hydrogen comes from stripping hydrogen from oil or natural gas. Second is the issue of storage. Hydrogen is a very light gas that is difficult to compress, and its energy density is very low. Compressing hydrogen for use in automobiles adds to the energy use of the system considerably. Finally, the electricity to generate the hydrogen is far too expensive from renewable sources with today's technologies; and if the hydrogen is generated from conventional power plants based on coal, oil, or natural gas, the amount of CO_2 generated in producing the electricity far outweighs the environmental benefits of using hydrogen fuels in the first place.

The technologies relating to renewable electric power and hydrogen storage are constantly advancing. (There has recently been an important breakthrough in storage using reduced iron as the hydrogen storage mechanism rather than compressing it as a gas, for example.) But in the near term it is clear that the bulk of human energy uses will involve the emission of CO_2 on a large scale. The most important hope for CO_2 emission abatement is the use of renewable fuels, such as biomass, ethanol, and methanol. Biofuels have the potential, if farmed renewably, of absorbing as much CO_2 each year as they emit.

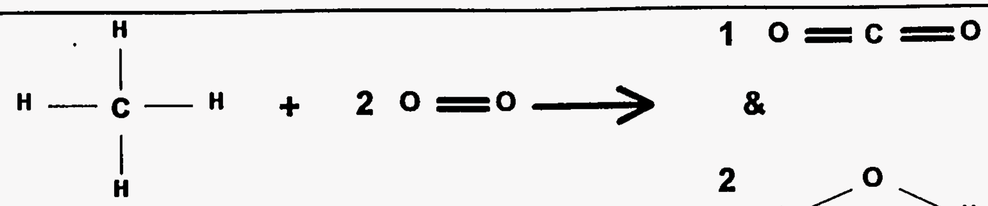
Combustion may necessarily involve the emission of CO_2 in most cases, but the differences in the chemical composition of fuels means that the amount of CO_2 emitted per unit of energy output varies across a considerable range. To see why this is the case, it is useful to look a little more closely at the chemical processes of combustion.

Figure 112 shows combustion processes for representative hydrocarbons. The simplest example is the combustion of methane, CH_4.

Combustion of hydrocarbons generates heat from two sources. The oxidation of carbon to CO_2, and the oxidation of hydrogen to H_2O. Two oxygen atoms (one O_2 molecule) are required for every carbon, and one oxygen atom is required for every two hydrogens. Thus, as Figure 112(*1*) shows, methane requires one oxygen molecule for the single carbon

Figure 112. CO2 Generation by Hydrocarbons

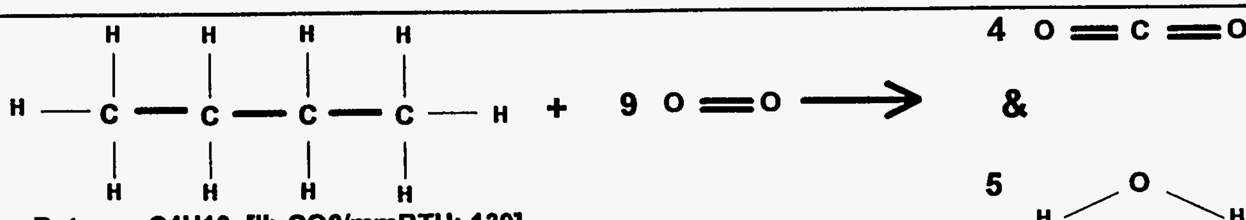
1
H/C: 4:1
wt% C: 75%
wt% H: 25%
NATURAL GAS



Methane - C1H4 [lb CO2/mmBTU: 115]

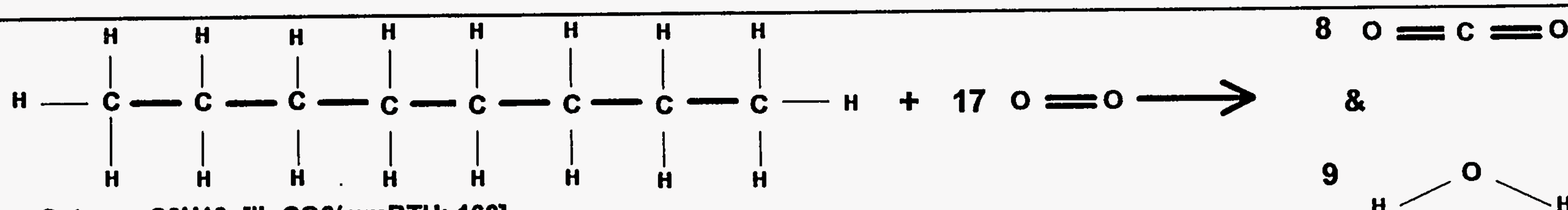
26,000.00

2
H/C: 2.5:1
wt% C: 83%
wt% H: 17%
LPG



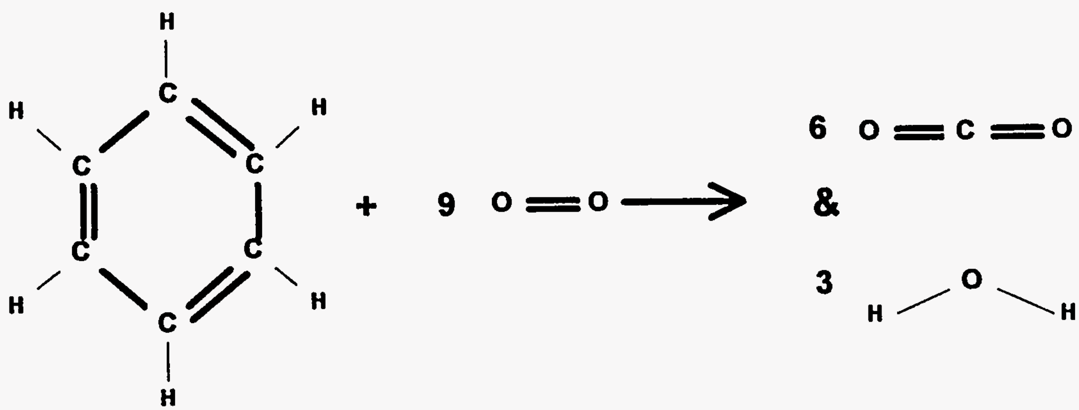
Butane - C4H10 [lb CO2/mmBTU: 139]

3
H/C: 2.25:1
wt% C: 84%
wt% H: 16%
GASOLINE



Octane - C8H18 [lb CO2/mmBTU: 162]

4
H/C: 1:1
wt% C: 92%
wt% H: 8%
GASOLINE



Benzene - C6H6 [lb CO2/mmBTU: 188]

5
lb CO2 per million BTU: 165
H/C: 1.17:1
wt% C: 91%
wt% H: 9%
"TYPICAL" FUEL OIL

Fuel Oils vary widely in chemical composition. Some have as little as 86% C by weight; some run as high as 95%. In general, uncracked fuel oils have higher H/C ratios, and waxy crudes give higher H/C ratios as well.

atom, and one oxygen molecule for the four hydrogen atoms. The yield of the process is 1 CO_2 molecule and two water molecules.

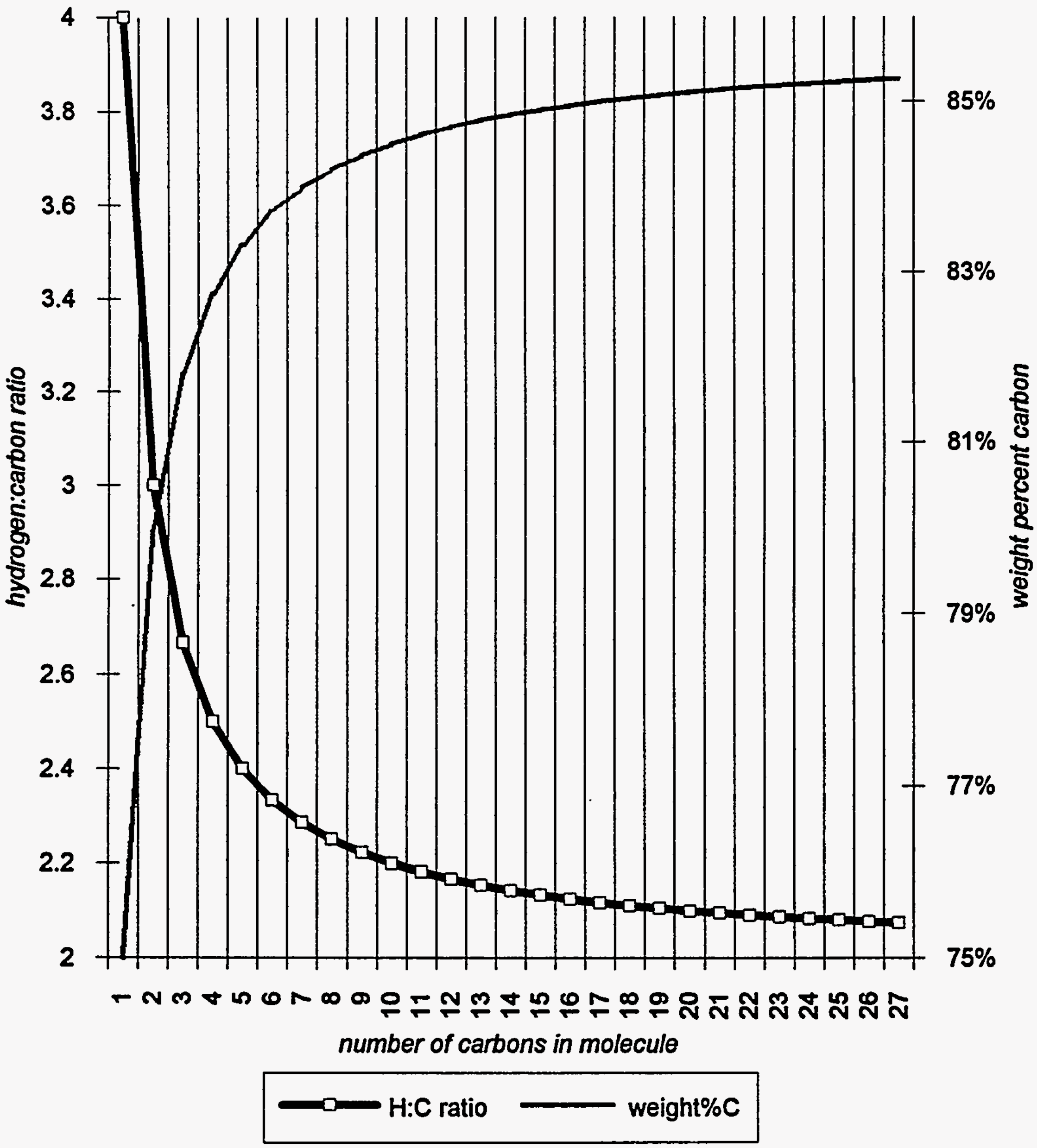
Methane has the highest ratio of hydrogen to carbon of the conventional fuel sources, a ratio of 4:1. Since carbon (atomic weight 12) is so much more massive than hydrogen (atomic weight 1), however, even for methane the carbon weight percentage is 75 percent. The next highest ratio of hydrogen to carbon (H:C ratio or H/C ratio) is for ethane, C_2H_6, at an H:C ratio of 3:1; for this molecule, the weight percentage of carbon increases to 80 percent.

Figure 113 shows the H:C ratio and weight percentage carbon for noncyclic alkanes (C_nH_{2n+2}) as a function of the number of carbons in the molecule. The H:C ratio drops sharply from its high of 4:1, approaching a value of 2:1 at high carbon numbers; the weight percentage of carbon rises sharply from 75 percent for methane to a limiting value of about 86 percent for high carbon numbers. There is a big difference in CO_2 emissions per unit between methane, ethane, liquefied petroleum gas (LPG), and noncyclic higher alkanes, but there is much less difference between the emissions of CO_2 per unit between, say, an 8-carbon alkane and a 50-carbon alkane.

Turning back to Figure 112, when butane is reached, the H:C ratio is 2.5:1; by the time octane is reached, it has declined to 2.25:1, well on its way to the limit of 2:1. Note that as the H:C ratio changes, the ratio of water to CO_2 output changes in synchrony. The ratio of water to CO_2 for methane is 2:1; for butane, 1.25:1; for octane, 1.125:1. In other words, while methane produces twice as much water as CO_2, as the carbon chains get longer, the trend is to produce water and CO_2 on a one-to-one basis.

Of course, noncyclic alkanes are not the only kinds of hydrocarbons. In fact, they are the hydrocarbons richest in hydrogen; they are said to be "saturated" with hydrogen. ("Unsaturated," as in "polyunsaturated fats," implies carbon-carbon double bonds. Each carbon-carbon double bond means two less hydrogen atoms in the molecule.) At the extreme

Figure 113. H:C Ratio and Carbon Weight for n-Hydrocarbons



are the aromatic molecules like benzene (Figure 112(*4*)), which have an H:C ratio of 1:1. Whereas methane produces two water molecules for every CO_2 output, benzene produces two CO_2 molecules for every water molecule. A substance like gasoline is a mixture of materials like n-octane (Figure 112(*3*)) and benzene, with the result that the net emissions of gasoline are somewhere in between these two examples.

Fuel oil is a complicated mixture of materials, and the H:C ratio and carbon weight percent are variable depending on the crude source and the blending elements. Typically most fuel oils contain some cracked material, which tends to raise the concentration of unsaturated bonds and aromatic ring structures.

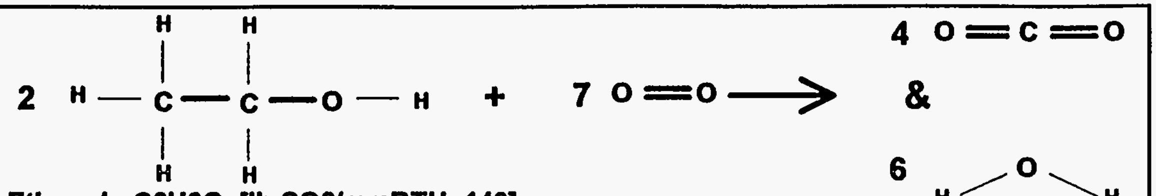
Methane has the lowest CO_2 emissions per unit energy of any hydrocarbon, at 115 pounds of CO_2 per million British thermal units (mmBtu). Butane emissions are higher, at 139 lb CO_2/mmBtu, while octane increases further to 162 lb CO_2/mmBtu. Because of the low H:C ratio, a compound like benzene has emissions of 188 lb CO_2/mmBtu, a very high number for a hydrocarbon.

The same principles may be applied to nonhydrocarbon fuels, including other fossil fuels such as coal, and renewable resources such as ethanol and wood. The difference, of course, is that these other fuels contain more than just hydrogen and carbon; many already have oxygen included in the molecule. Oxygen bound in a molecule means, chemically speaking, that the molecule is already "partially burned;" it will have less energy to release per unit weight than a hydrocarbon counterpart.

The chemical reactions for some nonhydrocarbons are shown in Figure 114. The simplest reaction is that of ethanol. The weight percentages of carbon are now less indicative than for the hydrocarbons, since the heavy (atomic weight 16) oxygen atom contributes to the molecule's mass. Ethanol emits 149 lb CO_2/mmBtu, a lower figure than gasoline (about 162 lb/mmBtu), but higher than LPG (about 138 lb CO_2/mmBtu), and much higher than methane (115 lb CO_2/mmBtu). Ethanol not only emits less CO_2 per unit energy than oil, but also has the potential of being carbon balanced, since the crops from which ethanol is produced would draw the CO_2 out of the atmosphere, resulting in no net CO_2 change.

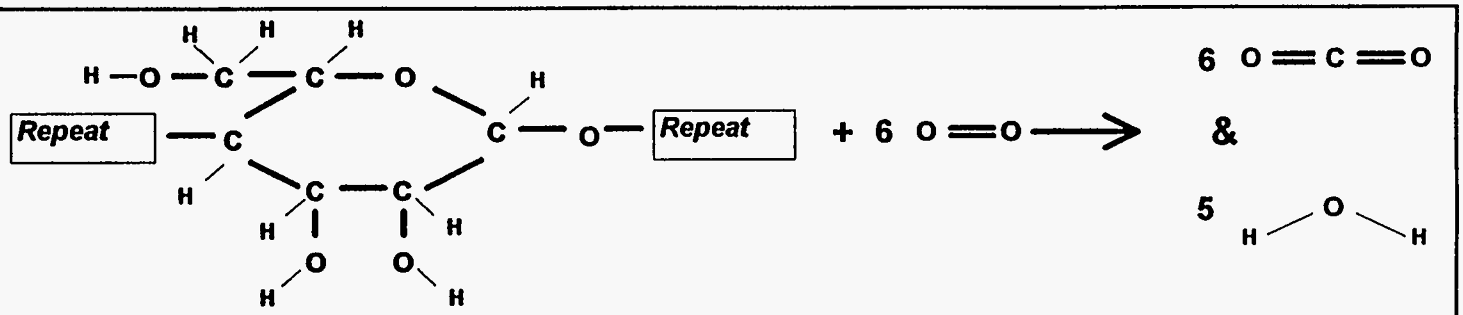
Figure 114. CO2 Generation by Nonhydrocarbons

1
H/C: 2:1
wt% C: 52%
wt% H: 13%
wt% O: 35%
ETHANOL



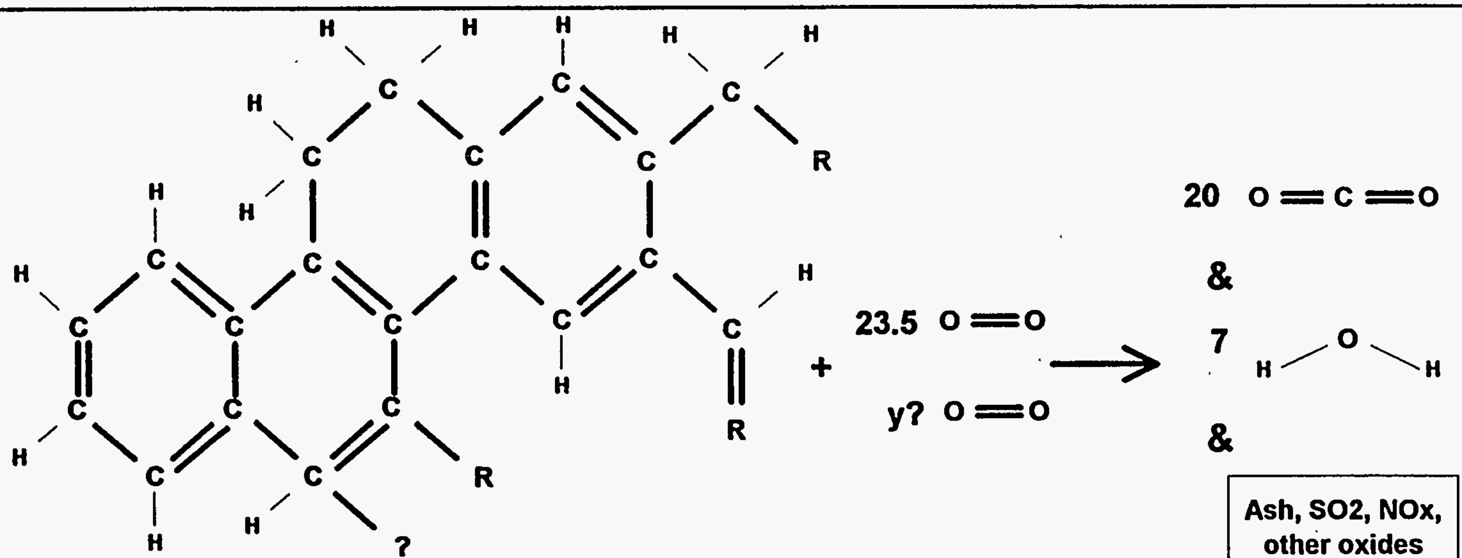
Ethanol - C2H6O [lb CO2/mmBTU: 149]

2
H/C: 1.7:1
wt% C: 44%
wt% H: 6%
wt% O: 50%
WOOD



Cellulose - C6H10O5 [lb CO2/mmBTU: 211]

3
H/C: 0.7:1
wt% C: 81%
wt% H: 5%
wt% ?: 14%
COAL



Bituminous Coal - Cn H .7n ?x [lb CO2/mmBTU: 206]

Figure 114(*2*) shows the structure of cellulose, the main component of wood, straw, and dry plant matter. Cellulose is composed of long chains of repeating *Beta*-D-glucose sugar molecules with an overall formula of $(C_6H_{10}O_5)_n$. Its H:C ratio is lower than most hydrocarbons, and the high concentration of oxygen in the molecule gives woody materials a fairly low heating value; about half the weight of dry wood is typically oxygen. Although there is a wide variance in emissions from wood burning (depending on wood type, moisture content, and combustion technology), it typically has one of the highest ratios of CO_2 per unit energy, at about 211 lb CO_2/mmBtu. Once again, of course, with a sustainable-yield harvesting system, wood fuels could be grown so as to make no net CO_2 contribution to the atmosphere.

Finally, one of the infinite possible structures of a segment of coal is shown in Figure 114(*3*). The burnable fraction of coal is mostly carbon, with a low H:C ratio that is about 0.7:1 for a fairly good bituminous coal and much lower for some others. The carbon weight percent can also be fairly low, since some coals are loaded with inert materials (ash and clay), oxygen, sulfur, and other contaminants. The emissions of CO_2 from coal are the highest of any fossil fuel (other than minor fuels like peat), at about 206 lb CO_2/mmBtu. Low-grade coals can have even higher CO_2 output per unit energy.

Table 43 summarizes typical carbon contents and CO_2 output from the main combustible fuels considered in this study. There are many ways of looking at the concentration of carbon or CO_2, including emissions per unit volume, per unit weight, and per unit energy. To put matters into terms that may be more immediately tangible, the table also gives output in terms of emissions per barrel of oil equivalent and per gallon of gasoline equivalent. To put matters into perspective, someone who fills up their car with 12 gallons of gasoline per week is putting out about 242 pounds of carbon dioxide every week or 12,600 pounds (5.7 tons) of CO_2 every year. If CO_2 were a solid instead of a gas, this quantity of material would be quite noticeable indeed.

In fact, the weight of CO_2 emitted strikes many as impossible at first glance. There is a large increase in weight being provided from oxygen in the atmosphere; a pound of carbon when burned will produce 3.67 pounds of CO_2.

Obviously the best approach to restraining CO_2 emissions (other than conservation and increased efficiency of course!) is to use renewable sources (or nuclear power). As long as fossil fuels continue to be burned, however, the ranking of sources would seem to be self-evident: natural gas is preferable to LPG is preferable to oil is preferable to coal. In terms of direct CO_2 emissions, this is clear. CO_2, however, is not the only greenhouse gas, and the direct emissions of CO_2 from combustion are not necessarily a measure of the greenhouse impact of using a given fuel.

3. Sources of Greenhouse Gases

On a Btu basis the burning of natural gas releases the least carbon dioxide into the atmosphere. As well as being a clean-burning fuel, with contaminants easier-removed than from oil or coal, there is now a widespread belief that natural gas can make a major contribution to cutting down the emissions of greenhouse gases. The problems with this belief are that methane itself is a greenhouse gas; that much of the carbon dioxide "scrubbed" from natural gas during processing is simply emitted to the atmosphere; and that in the case of liquefied natural gas (LNG), the liquefaction energy use is itself a substantial emitter of carbon dioxide.

There are a number of ways to measure the "danger" of a greenhouse gas. One of the most widely used is the global warming potential (GWP) of the International Panel on Climate Change (IPCC), which measures the warming effect relative to an equal amount of carbon dioxide. Table 44 shows a selection of GWPs for various gases. As the table shows, the short-term effects of methane emissions into the atmosphere are far higher than those of carbon dioxide—about 63 times more potent, in fact (although still well below the startling effectiveness of CFCs). In the longer term, methane in the atmosphere is oxidized to carbon dioxide; in the short run it is worse, in the long run, just as bad.

Table 43. Carbon Content and Carbon Dioxide Output From Fuels

Carbon Contents

	Pounds Carbon	Native Measure	lb C per cubic foot	lb C per mmBTU	lb C per pound	lb C per barrel oil equivalent	lb C per gal gasoline equivalent
Natural Gas	3.3	per therm	0.03291	31.44	0.750	182.3	3.93
LNG	1,680	per tonne	19.88	31.44	0.750	182.3	3.93
Propane	3.5	per gallon	25.87	37.68	0.817	218.5	4.71
Butane	4.0	per gallon	29.98	37.94	0.825	220.1	4.74
Methanol	2.5	per gallon	18.70	38.37	0.380	222.6	4.80
Ethanol	3.5	per gallon	26.18	40.69	0.531	236.0	5.09
Gasoline	5.5	per gallon	41.14	44.05	0.877	255.5	5.51
Diesel	6.0	per gallon	44.88	44.71	0.844	259.3	5.59
Crude Oil	255.0	per barrel	0.00	44.93	0.853	260.6	5.62
Fuel Oil	6.4	per gallon	48.17	45.15	0.809	261.9	5.64
Coal (Bitum.)	1,300	per short ton	0.00	56.41	0.650	327.1	7.05
Wood	1,032	per dry cord	8.06	57.56	0.468	333.9	7.20

Carbon Dioxide Output

	Pounds CO2	Native Measure	lb CO2 per cubic foot	lb CO2 per mmBTU	lb CO2 per pound	lb CO2 per barrel oil equivalent	lb CO2 per gal gasoline equivalent
Natural Gas	12.2	per therm	0.12066	115.29	2.750	668.7	14.41
LNG	6,160.6	per tonne	72.88	115.29	2.750	668.7	14.41
Propane	12.7	per gallon	94.86	138.17	2.996	801.4	17.27
Butane	14.7	per gallon	109.95	139.13	3.025	806.9	17.39
Methanol	9.2	per gallon	68.57	140.72	1.395	816.2	17.59
Ethanol	12.8	per gallon	96.00	149.19	1.948	865.3	18.65
Gasoline	20.2	per gallon	150.86	161.54	3.214	936.9	20.19
Diesel	22.0	per gallon	164.57	163.96	3.094	951.0	20.50
Crude Oil	935.1	per barrel	166.53	164.77	3.128	955.7	20.60
Fuel Oil	23.6	per gallon	176.64	165.58	2.965	960.4	20.70
Coal (Bitum.)	4,767.1	per short ton	204.85	206.84	2.384	1,199.7	25.85
Wood	3,784.3	per dry cord	29.57	211.08	1.717	1,224.2	26.38

Table 44. Relative Global Warming Effects

	Time Horizon, Years		
	20	100	500
Carbon Dioxide	1	1	1
Methane	63	21	9
Nitrous Oxide	270	290	190
Halocarbons	350-7100	85-7300	29-7400
Non-methane hydrocarbons	28	8	3

Source: Intergovernmental Panel on Climate Change, 1990

As shown in Table 45, the main "anthropogenic" emissions of methane are not from fossil fuels but from agriculture. The biggest culprits are animal raising (particularly ruminants such as cows and oxen, which emit large quantities of methane gas) and rice paddies. Between these emissions and the rapid rate of deforestation in many areas, the Third World countries are contributing to global warming more than is commonly believed. Such problems go far beyond the bounds of energy policy and raise a whole host of abatement issues with no clear solutions.

Within the confines of fossil fuels, however, the precise tradeoffs between gas, oil, and coal in terms of global warming are far from clear. Using typical factors for pounds of carbon dioxide emissions per mmBtu (gas = 115, oil = 165, coal = 206) the advantages of natural gas seem obvious. Generation from pipeline gas seems to offer substantial benefits over the other fuels, but, when the fuel source is LNG, the combined effects of methane leakage, carbon dioxide emissions from processing, fuel use in liquefaction, and fuel use in transport can make the greenhouse load from natural gas power generation higher than oil—and sometimes even higher than coal.

To confuse matters further, unfortunately, there are methane emissions associated with oil production and refining, and a surprising quantity of methane ("mine gas") is released by coal mining. Depending on the precise assumptions made and ratios used, it is possible to "prove" that any of the fossil fuels is more environmentally sound than the others. Most of the research in this area has been devoted to ascribing the current emissions of methane and carbon dioxide to existing practices; little has been done to assist the policy maker in determining the entire supply-chain consequences of choosing one fuel over another. Environmentally, the use of gas has one level of impact when the fuel source is previously flared associated oil-field gas and another when it is imported LNG from a high-CO_2, high-sulfur nonassociated gas field. (Furthermore, some countries—notably China—release or flare off tremendous quantities of coal-mine gas; utilization of this gas would have a highly favorable environmental effect by cutting down methane emissions and replacing consumption of other fuels.)

Table 45. Anthropogenic Sources of Greenhouse Gases

Gas	Energy Activity[1]	Other Activity	Output Shares	Share of Global Warming	of which: Energy	of which: Other
CO2				61%	47%	14%
	Fossil Fuels		77%			
		Land Use[2]	23%			
CH4				15%	3%	12%
	Oil & Gas		13%			
	Coal Mining		10%			
		Rice	32%			
		Livestock	23%			
		Land Use*	12%			
		Landfills	10%			
Halocarbons (CFCs)				12%	12%	0%
	Chemicals		100%			
NyOx				10%	9%	1%
	Chemicals		78%			
	Fossil Fuels		14%			
		Land Use*	8%			
CO/NMHCs/Other				2%	1.8%	0.2%
	Fossil Fuels		88%			
		Land Use*	12%			
				TOTAL	73%	27%

[1] Including non-energy uses of hydrocarbons and releases of petrochemicals
[2]primarily deforestation & biomass clearing; some of this clearing is energy use
SOURCE: Calculated from data in "Climate Change: The IPCC Scientific Assessment"

In addition, there is considerable controversy over the lifecycle impacts of even renewable sources of liquid fuels such as ethanol and methanol, although these calculations often assume that considerable fossil-fuel inputs are "required" for fertilizing, harvesting, gathering, or preprocessing the biomass inputs. (This may be the case for a given project, but it is by no means a requirement of biomass projects in general.)

On top of these uncertainties, new research has made the greenhouse effect seem even more complicated than before.

4. The Sulfate Effect

Thomas Karl, a researcher at the U.S. Meteorological Service, made himself very unpopular at a number of conferences by his analysis of U.S. weather-station data, which showed that the climate did not appear to be warming as predicted by everyone's models. Simply by presenting his observed facts, he became widely quoted by those who wished to claim there was no greenhouse problem, and widely attacked by those to whom global warming had become basic dogma. His detractors suggested that the U.S. stations were too close to urban areas, or that the United States had a weather pattern that deviated from the global average.

Karl responded by gathering one of the most comprehensive temperature datasets ever gathered including North America, the Soviet Union records, and the records of Chinese stations. His findings, published in *Tellus*, were a shock to almost everyone. In essence, Karl's analysis showed that nighttime temperatures were getting warmer, but daytime temperatures were essentially constant.

A few of the people who were *not* shocked at Karl's results were Charlson and his research team at the University of Washington, who had been modelling the role of sulfate particles in the atmosphere. Their work, completed near the time that Karl announced his results, predicted an effect exactly like that Karl had discovered. The paper published by Charlson's team in *Science* showed that sulfate particles released from combustion of fossil fuels had powerful scattering effects on incoming light radiation. Referring back to Figure

111, during the day, the sulfates in the atmosphere increase the reflection of sunlight into space (3), decreasing the amount of light reaching the Earth (4). This means that, during daylight hours, the sulfates actually have a cooling effect. At night, however, the operation of the greenhouse effect can be seen in the form of steady warming. Even more startling than this mechanism was the team's estimate of the magnitude of the cooling—just about enough that it cancels the greenhouse effect in the Northern Hemisphere. (Of course, in the Southern Hemisphere, with less sulfur being released, the greenhouse warming is taking place...and that is where the Antarctic ice sheet is.)

Charlson's team stresses that much further research is needed. Sulfur emissions are in many ways more complex to model than carbon dioxide. While carbon dioxide spreads out rapidly over the globe, sulfate particles are charged and tend clump together. Thus, the effect they have on incoming radiation can vary dramatically between relatively close sites. Furthermore, they tend to act as condensation nuclei for water in the atmosphere, forming clouds (which is why they come down as acid rain).

The lifetime of carbon dioxide molecules in the atmosphere is measured in centuries; the lifetime of sulfate molecules is measured in days. In effect, this means that if by some miracle sulfate emissions were eliminated tomorrow, man-made sulfate in the atmosphere would drop precipitously in a matter of months. **There is no conceivable program of carbon dioxide emission abatement that could be implemented to counter a sudden removal of the sulfates from the atmosphere.** In short, if sulfur emissions are sharply curtailed, the most widely validated models suggest that the carbon dioxide already in the atmosphere is more than sufficient to sharply increase global temperatures.

This is a new area of inquiry, and more study is clearly needed, but at the moment the equation seems to be: cut acid rain, increase global warming. This may be an urgent matter, since the U.S. Clean Air Act will crack down hard on sulfur emissions, and is already being looked at as a model by many other countries. (Though it must be noted that many major coal-burning countries still have very little by way of sulfur emission controls.)

Continuing to emit sulfur dioxide, however, only delays the day of reckoning. The sulfur stays in the atmosphere for a matter of only weeks; the CO_2 burned along with it stays there for centuries. The sulfates are "masking" an accumulating burden of greenhouse gases that grows ever larger. Keeping sulfur emissions high is no sort of solution to the problem. The real danger, however, is that if sulfur emissions are suddenly abated, a leap in the observable consequences of global warming could lead to a belief that the process of warming is accelerating, and this in turn could lead to panic-engendered policies.

5. Conclusions

There is a new and laudable sense of urgency in international policy discussions about the global environment. The international agreement on CFCs is a landmark in cooperative management of the planet (although it is still too little, too late; given their lifetime in the atmosphere, their global warming effects that are hundreds of times greater than CO_2, and their role in ozone depletion, any further emission of CFCs is too much).

There is also a danger that an upsurge in concern for the environment in response to apparent acceleration of global warming will cause the adoption of policies that will make things worse or will cost large sums of money and then be abandoned in favor of other approaches. This may be particularly true since research on the topic is ongoing. A prudent approach might be to undertake relatively low-cost options to reduce greenhouse gas emissions in the near term, but to hold off on committing to the more costly options unless their benefits become clearer. Natural gas is not a planet saver if the pipelines leak or if massive amounts of fossil fuels are used to liquify and transport the gas. In fact, even under the best of circumstances, switching from oil to gas will cut CO_2 emissions by only 30 percent. This is a large reduction, but it doesn't mean that a world running entirely on gas (which is impossible given world reserves) would have eliminated the problem of global warming. Natural gas combustion emits a great deal of CO_2, even if it is less than the competition.

There are certain steps that can be taken that fall into the category of "no regrets." Conservation and improved energy efficiency is the most obvious area that is of benefit under any scenario. Burning a mmBtu of gas instead of a mmBtu of oil reduces CO_2 emissions by about 50 pounds; *saving* a mmBtu of oil reduces CO_2 emissions by 166 pounds and usually saves money at the same time.

Planting trees to compensate for new energy projects (as practiced by Applied Energy Systems, AES, operators of Hawaii's coal-fired power plant)—and possibly even expanding planting to counterbalance existing emissions—is certainly a "no regrets" approach. It is hard to imagine being sorry that trees were planted; it seems like a fairly risk-free undertaking with benefits that can reach far beyond CO_2 abatement alone.

When renewables appear to be in a competitive range with fossil fuels on a reliable basis, expanded use should be encouraged. Solar, windpower, and OTEC cause no greenhouse gas emissions. Ethanol and methanol offer alternatives to oil that have the potential to be carbon-balanced, but they must be developed with some degree of caution if their full environmental benefits are to be achieved.

Outside of the above points, however, making decisions regarding fuel choice on a CO_2-emissions basis would require substantial careful research, especially to narrow the range of uncertainty with regard to the actual amount of global warming and its possible consequences. Unlike typical pollutant problems, CO_2 is a global problem, not a local one, and the emissions of CO_2 in an energy-exporting country have just as much impact on Hawaii as emissions of CO_2 in Honolulu. Selection of the most benign fuel involves looking far back beyond emissions at the burner tip.

Some sort of international or OECD "carbon tax" is likely in the 1990s, especially if global warming seems to be having a perceptible effect. Such a tax would of course hit coal the hardest, followed by oil, LPG, and finally natural gas. Whether such a tax as imposed (probably at the point of consumption) would really make sense in terms of saving the environment is questionable (for example, Japan's gas is all LNG and therefore involves more CO_2 emissions than its gas consumption suggests) and somewhat beside the point; there is a probability that such a tax will be imposed even if it doesn't make a great deal of sense. In this case, economics may drive fuel choice in new directions; hopefully the economic tradeoffs will have a sensible relationship with the environmental tradeoffs that they are designed to reflect.

B. U.S. Measures: Clean Air Act and Btu Taxes

1. The Clean Air Act

The Clean Air Act (CAA) as it currently stands (after the 1990 amendments) has little direct effect on Hawaii. Hawaii and Alaska are specifically excluded from the Title IV amendments, which are designed primarily to control acid rain and secondarily to lower nitrogen oxides. Even if Title IV were extended to Hawaii, it is unlikely that it would cause major changes in the current energy technologies, since Hawaiian standards are already fairly strict. Revisions of the standards for coal-fired utility plants would be unlikely to exceed the existing requirements of the state; plants like the AES facility with advanced combustion technologies and low-sulfur coal feed are already well in advance of most coal facilities in the world.

Controls on nitrogen oxide emission from power plants in ozone nonattainment areas, or on fuel reformulation in general air-quality nonattainment areas, will not affect Hawaii, since Hawaii is far from being a nonattainment area. Guidelines of the Environmental Protection Agency (EPA), still in the formulation stage under Title III, however, could have some effect on the Hawaiian utility situation. EPA is currently examining and defining "hazardous air pollutants" from utility sources. If new levels of control are required, or if new pollutants are identified for abatement, then new controls might be required on power plants in Hawaii as well. Nonetheless, the impact is likely to be far less in Hawaii than in most areas. Similarly, new visibility standards for areas near national parks and wilderness areas might constrain Hawaii's ability to build coal-fired power plants next to Volcanoes National Park or on the slopes of Haleakala, but the state would be unlikely to encourage such siting in the first place.

The biggest direct uncertainty for Hawaii will be EPA determinations under the CAA of the designation of wastes as hazardous, toxic, or nontoxic. If ash or scrubber residue from coal plants is classified as hazardous or toxic, this could dramatically affect the economics of coal in Hawaii without a corresponding effect on oil or gas.

Although the direct impacts of the CAA on Hawaii will be minimal (because Hawaii already has clean air and relatively strict controls), the main uncertainties regarding the CAA for Hawaii are the *indirect* effects. Requirements for fuel reformulation in nonattainment areas on the mainland will change the nature of the market; and state measures, such as those adopted in California, may go well beyond the federal requirements.

The main nonattainment areas are, naturally enough, where most of the people live. Consider the State of Washington, where Seattle/Tacoma and Spokane are CO nonattainment areas, or Alaska, where Anchorage and Fairbanks are CO nonattainment areas. This means that the main markets will require fuel reformulation. At this point, oil companies must ask themselves if they wish to maintain several separate sets of delivery infrastructure (premium reformulated, regular reformulated, midgrade reformulated, premium unreformulated, midgrade unreformulated...) just to provide unreformulated fuels to minor markets in the countryside. Although it is likely to raise the costs of fuel, in most circumstances the pressure will be for reformulation to become the *de facto* standard even in areas where it is not required. Moreover, many states are likely to extend the requirements of their nonattainment areas to the entire state.

Hawaiian prices are linked to U.S. West Coast prices and to Asian prices. More stringent product specifications could have any number of impacts on Hawaii—not all of them necessarily negative. For example, the stringent new diesel standards being applied in California may mean that refiners have substantial surpluses of diesel that no longer meet California specifications; much of this is liable to make its way to Asia as exports, but it could provide a source of lower-cost diesel in Hawaii. Similarly, there may be some room for Hawaiian refiners to produce some volume of California-grade gasoline for export, and import Hawaiian-grade gasoline from California.

It is too early to predict what the indirect effects of fuel reformulation on the Hawaiian situation may be, but the proliferation of different standards on both sides of the Pacific (with Hawaii in between them) may mean that the actual specifications of fuels used in Hawaii are no longer common anywhere else. This could have advantages for the state or disadvantages; in all likelihood, it will produce some of both. This situation requires monitoring, but no action in the immediate near future.

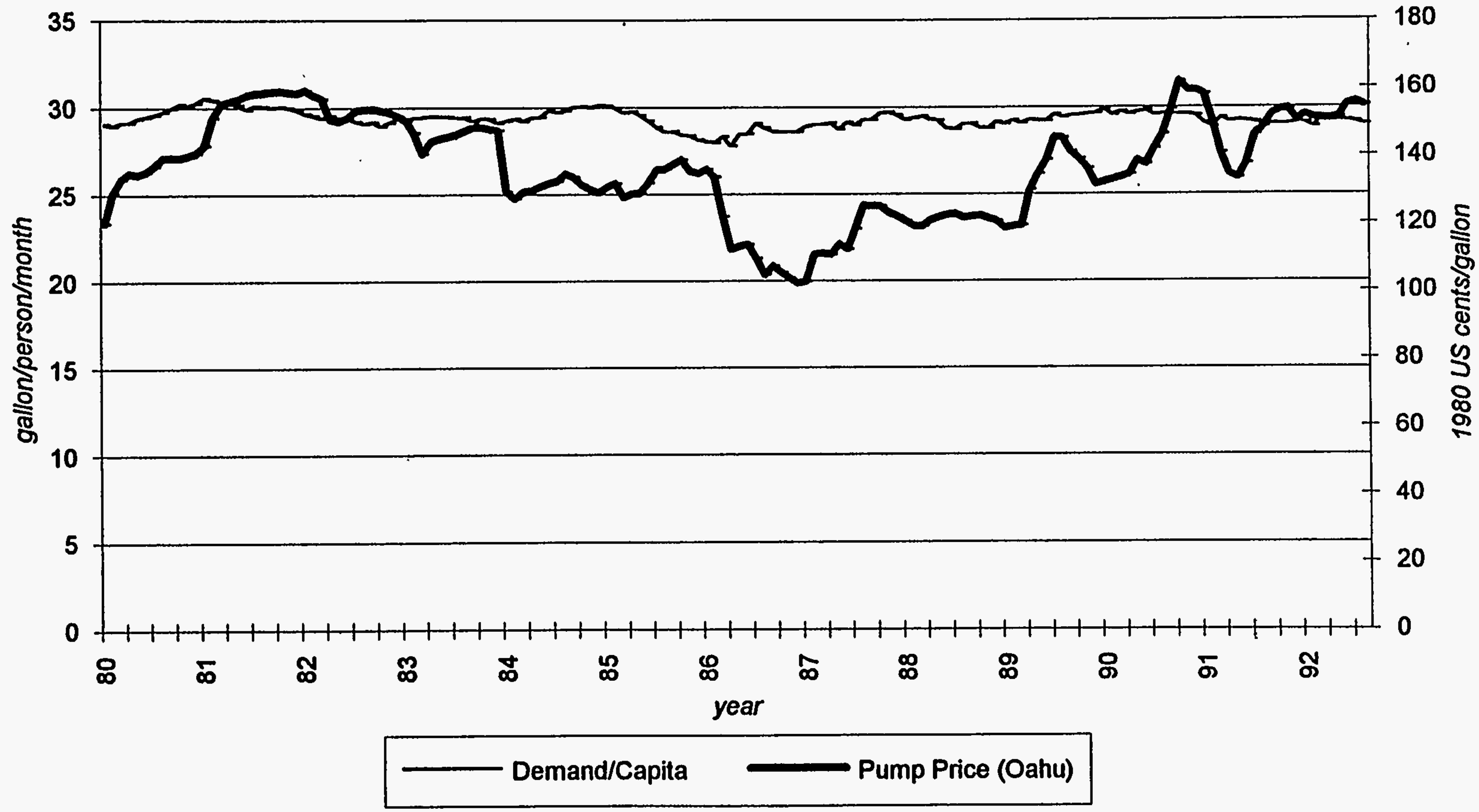
2. The Btu Tax

The impacts of fuel reformulation on Hawaii may be difficult to assess; but the impacts of the Btu tax as presently proposed are fairly clear. This study concurs with DBEDT's preliminary analysis that the direct per-capita tax cost to Hawaii will be twice the national average; the outflow from Hawaii to the federal coffers will be on the order of $180 million annually. This is largely because Hawaii is so massively oil dependant; the proposed tax rates are twice as high for oil as for other fuels.

The increase in fuel costs may have the effect of encouraging the deployment of alternative fuels to some extent, but it can be argued that, in the aftermath of the 1970s and 1980s experiences with alternatives, the main roadblock to further deployment is more the volatility of prices than their absolute level.

One of the justifications for the tax, other than the basic need for revenue, is that it will encourage conservation, and, in the case of the punitive premium on oil, will encourage fuel-switching as well. Hawaii may not be a paragon of energy conservation, but per-capita use is one of the lowest in the nation. Moreover, for many fuels consumption is already so constrained by high relative prices and geographical factors that additional price responsiveness is not to be expected in the range of increases seen through a Btu tax. Gasoline demand is a case in point. Figure 115 shows Hawaiian per-capita gasoline demand and corresponding gasoline prices. Hawaiian gasoline demand is almost flat through the 1980s—a period of large price swings—at about 29 gallons per person per month. Indeed, many of the movements in demand are the *opposite* of what would be expected from the

Figure 115. Hawaii Gasoline: Consumption and Prices, 1980-93



Note: Consumption data are based on a 12-month moving average to eliminate seasonality.

movement in price. Regression analysis of the data, utilizing generalized least squares to correct for serial autocorrelation, and including income effects, still shows a price elasticity of zero for Hawaiian gasoline consumption. There is very little discretionary driving in the state except for tourism, and tourism mileages are not determined by gasoline prices to any noticeable extent.

In other words, for many fuels the Btu tax in Hawaii will have little effect on demand, but a major effect on withdrawing cash from the economy. In most parts of the United States, there are conventional alternatives to oil available from nearby geographical sources, and the scale of operations (such as power generation) can provide for large investments. Hawaii faces problems in both its remoteness and in factors of scale, especially on the outlying islands. It is hard to see any benefit to the Hawaiian economy of the Btu tax, but Hawaii will pay a disproportionate share. The only possible benefits would be if the increased prices accelerated the deployment of renewable energy sources, but it is hard to see that the Btu tax will encourage this: it is too small to give a clear advantage to alternatives. If the state were imposing such a tax, and diverting the revenues to expansion of local renewable energy supplies, then there might be advantages in terms of lowering imports and local job creation. With the revenues flowing out of the state into general financing of the federal government, it is hard to identify any advantages to the state economy, the Hawaiian consumer, or the Hawaiian environment.

There are also some conceptual difficulties with the Btu tax on oil that need to be ironed out—and could make a substantial difference to Hawaii. Table 46 shows the consequences of the Btu tax from two possible implementations and three possible viewpoints.

First is the "naive" analysis of the situation, which applies the Btu tax to all oil based on Btu content. At this level, the most remarkable feature is the increases in price seen for some fuels. Fuel oil is hit the hardest, with a 42 percent jump in current prices. This is partly a result of fuel oil having the lowest prices, and partly a result of fuel oil having the

Table 46. Effects of BTU Tax on Relative Prices

"Naive Analysis"	mmBTU/ barrel	Imposed Tax, $/b	Charged Tax, $/b	Current Prices, $/b	Price With Tax, $/b	Increase From Tax
Crude Oil	5.80	$3.48	$3.48	$15.61	$19.09	22%
Gasoline	5.25	$3.15	$3.15	$27.81	$30.96	11%
Jet Fuel	5.60	$3.36	$3.36	$22.39	$25.75	15%
Diesel	5.75	$3.45	$3.45	$20.92	$24.37	16%
Fuel Oil	6.29	$3.77	$3.77	$8.95	$12.72	42%

Case 1: Low Fuel Oil	Assumed Yield	Estimated Tax, $/b	Revenues $/b	Extra Pass-On, $/b	Price With Tax, $/b	Increase From Tax
Crude Oil		$3.48				
Gasoline	44%	$3.15	$1.39	$0.28	$31.24	12%
Jet Fuel	15%	$3.36	$0.50	$0.28	$26.03	16%
Diesel	25%	$3.45	$0.86	$0.28	$24.65	18%
Fuel Oil	12%	$1.89	$0.23		$10.84	21%
Other	7%	$3.48	$0.24	$0.28		
Total sales	103%		$3.22			
Non-Fuel Oil	91%					
Shortfall, $/b			$0.26			

Case 2: High Fuel Oil	Assumed Yield	Estimated Tax, $/b	Revenues $/b	Extra Pass-On, $/b	Price With Tax, $/b	Increase From Tax
Crude Oil		$3.48				
Gasoline	18%	$3.15	$0.57	$1.63	$32.59	17%
Jet Fuel	10%	$3.36	$0.34	$1.63	$27.38	22%
Diesel	22%	$3.45	$0.76	$1.63	$26.00	24%
Fuel Oil	45%	$1.89	$0.85		$10.84	21%
Other	3%	$3.48	$0.10	$1.63		
Total sales	98%		$2.62			
Non-Fuel Oil	53%					
Shortfall, $/b			$0.86			

Product prices based on March 1993 PIW West Coast Spot. ANS Feb. 1993 California crude prices.

highest Btus per barrel. Crude increases 22 percent; gasoline prices increase a mere 11 percent.

The big question is: at what point will the fuel be taxed? If it is taxed at the refinery gate, after refining, then the crude tax shown in the naive analysis is irrelevant; the prices will be the product prices shown. In such a case, fuel oil prices will increase substantially.

A second option is to tax the crude oil and allow the refiner to pass the increase on to the consumer. In this case, of course, how much of the tax is recaptured will depend on the relative strength of demand for products rather than the Btu content of the fuels. To remain competitive, refiners will have to price fuel oil in line with other energy sources. Thus, the maximum amount of tax that can be passed on to fuel oil users is half of the actual tax imposed (making the tax on fuel oil equivalent per mmBtu to coal and natural gas). This is shown in Case 1. The problem is that the taxes required on the crude inputs by the government total \$3.48, leaving a shortfall collected from the sales of products of \$0.26. This tax must be recaptured by spreading it to other products (gasoline, jet fuel, and others) that do not face so much competition with other energy sources. By so doing, the prices of other products are raised (here it is assumed that the shortfall is prorationed among the other products according to output volumes), and the percentage increase in the price of fuel oil is pulled down close to the increase in the price of crude.

Different refiners will be differently affected by such a measure, however, since their output patterns vary widely. Case 1 was computed for the output pattern of a typical U.S. refiner. Case 2 shows the same analysis for a refiner with a high fuel oil output. In this case, the amount of tax that has to be passed on to other products is three times higher. This extra tax that must be passed on must also be spread over a much smaller volume of non-fuel-oil products. This puts such a refiner at a competitive disadvantage of \$1.35 per barrel in the gasoline, jet, and diesel markets, which will certainly spell bankruptcy for America's remaining hydroskimming refineries.

A tax directly on the crude rather than on the refinery gate products is certainly better for Hawaii, since it would not result in such a sharp leap in fuel oil prices. But in addition to the problems that it presents of being inequitable between refiners, it also raise other peculiar questions. What about imports of products? Obviously the U.S. government cannot tax the crude oil used in some other country. In this case, the only logical thing to do is tax the product imports at the levels shown in the "naive" case. This results, however, in a massive disparity between fuel oil import prices and refinery gate fuel oil prices, and it would most likely shut out any fuel oil imports. On the other hand, it would offer foreign refiners a price advantage over U.S. refiners on gasoline, jet fuel, diesel, and other non-fuel-oil products. This situation would discourage fuel oil imports, but encourage the imports of other products—exactly the kind of industrial policy that should be avoided.

None of the problems would occur, of course, if the Btu tax were uniform between energy sources. It is the tax premium placed on oil that creates these distortions. However, the current administration seems set upon a punitive tax on oil, and this is approved of by a great many voters. In this case, once the implementers of the policy realize the complications that arise from allowing pass-through of prices by taxing crude, the likely response will be to settle on refinery gate prices, like those shown in the "naive" analysis, and let crude go untaxed. This is the simplest and least-distorting policy, but it is also the policy that will place the greatest burden on Hawaii consumers.

C. Environmental Trends In Asia

1. How Significant is the Environmental Ethic in Asia?

The *Honolulu Star-Bulletin* recently published an article titled "EWC study assails Asia-Pacific region's huge appetite for oil," noting that the East-West Center's forecasts indicate oil demand growing from around 14.5 million barrels per day (mmb/d) in 1992 to 16.4 mmb/d in 1995 and 19.1 mmb/d in the year 2000, translating into growth rates of 4.4 percent per year in the 1992-95 period and 3.1 percent per year in the 1995-2000 period. The Asia-Pacific region is the fastest-growing oil market in the world. But to say the East-West Center "assails" this type of growth is not entirely accurate. It is true that overwhelming dependency on imported oil can cause a variety of problems, and the EWC is naturally concerned with the economic, political, and environmental health of the region. Bit the EWC does not criticize growth *per se* and cannot legitimately request that the Asia-Pacific countries cut back on oil consumption. In per-capita terms, the United States uses oil on a scale orders of magnitude greater than the Asia-Pacific region. In 1990 the average Asia-Pacific resident used 1.4 barrels of oil per year; in contrast, the average person in the United States and Canada used 24.6 barrels. Similarly, while it is appropriate for all countries to be concerned with protecting the global environment, it is hypocrisy for governments to demand strong environmental protection programs in other countries when their own programs are weak.

This is not intended as a condemnation of the developed world, nor is it an excuse for poorer countries to pollute the environment simply because they are poor—though it is of course true that rich countries can better afford to pay for environmental clean-up than poor countries. The point is that environmental trends in Asia must be placed in the proper context. Environmental hazards and policies run the gamut in Asia. Many areas are seriously polluted, while others remain quite unspoiled. In populous, developing areas, however, the rapid pace of development combined with sheer population pressure inevitably creates some level of environmental hazard. When matters boil down to a choice between feeding its people or cleaning up the environment, it is easy to understand how some governments must make the short-term choices that promote economic growth accompanied by some level of environmental degradation. Yet an environmental ethic nonetheless is sweeping much of the Asia-Pacific region. The regulations and programs designed to protect the environment are not as strict or comprehensive as those seen in the United States, but when viewed in the proper context it is clear that they are very significant.

The Asia-Pacific region is already the world's largest oil importer. In the aftermath of the price shocks of the 1970s, many governments tried to discourage reliance on oil by keeping prices artificially high. In spite of the continually high prices, however, demand continued to grow. On the positive side, high prices did encourage efficient use of oil. While it is still possible to increase energy efficiency in many countries, the Asia-Pacific countries already tend to use their oil more effectively than most other countries. There is little room to "cut back" on oil use without actually cutting into economic activity. As long as economic activity continues to expand in the Asia-Pacific region, it appears almost inevitable that oil demand will also continue to expand during the 1990s. The link between energy input and economic output is not necessarily one-to-one, but the links are nonetheless so strong that it would take a very dire economic downturn to halt the ongoing boom in demand for oil. The demand outlook is therefore much more robust than in most other world regions.

The concern over increasing oil demand is really not so much environmental as economic and political. In principle, it is easy to object to reliance on oil because of security issues. But compared to, say, coal, oil has certain environmental benefits. Additionally, since the infrastructure for importing, processing, storing, and using oil is largely in place, expanding the use of oil in the power sector is usually a far easier task than building new LNG terminals, even if LNG is a cleaner-burning fuel. When it comes down to a question of public perception and public assessment of environmental risk, the results may turn out differently than when national, regional, or global environmental risks are weighed. In that respect, it is easy to see how governments and companies may find themselves using more oil as a stopgap measure to cope with booming energy demand growth. Oil-fired power generation is easily expanded without raising a public uproar, especially if existing mothballed capacity is employed. Oil storage and transport facilities are ubiquitous enough that no one tends to notice their operation; new coal terminals or LNG ports are always a matter of public debate.

2. Policies Affecting Fuel Choice: Nuclear Power, CO_2, and Acid Rain

Most of Asia is still confined to using whatever sources of fuel for power generation are cheapest and most available. In East Asia, however, rising affluence and environmental concern are making fuel choices in power generation a major political issue. This is nothing new to those experienced with the situation in the United States or Europe, but in East Asia the choices are more pressing because of the growth in electricity demand. Major commitments must be made in the 1990s.

Major concerns in Japan, Taiwan, and South Korea are security of supply, safety, and pollution. The main emphasis in pollution regards emissions of sulfur compounds, but awareness of the problems of greenhouse gases are gaining more widespread attention.

Nuclear power tends to be favored by planners on energy security grounds, although they are typically quick to point out the lack of greenhouse gases and sulfur emissions. The expansion of nuclear power in Japan has been rapid: in 1973 nuclear power amounted to 0.8 percent of the Japanese energy mix; by 1979 nuclear's share had increased to 5.2 percent, and by 1990 nuclear power contributed 12.3 percent of Japanese energy. Japan's official plans call for a steadily increasing share of nuclear energy in the fuel mix and anticipate a percentage share of 14.5 percent in 1995, 16.6 percent in 2000, and 18.9 percent in 2005.

Particularly in Japan, however, there has always been widespread public concern about the safety of nuclear plants. The Chernobyl accident in April 1986 sent a wave of alarm through many of the Japanese who had taken a tolerant view toward nuclear power. A fire at the Ma'anshan nuclear station in Taiwan in December 1985 acted to galvanize public opinion there. To date, the opposition to nuclear power in South Korea is relatively muted, but there is a growing undercurrent of discontent with the country's pro-nuclear stance. Environmentalists in Asia are divided on the topic of nuclear power; as "clean" as nuclear power is in terms of greenhouse gas and sulfur emissions, the issue of radioactive waste remains alarming. Waste storage, transport, and reprocessing are all somewhat risky; some countries such as New Zealand and various Pacific island nations refuse to allow ships carrying radioactive waste within their territorial boundaries.

Coal is disliked by environmentalists and the public in general. Emissions tend to be expensive to control, ash disposal is a major problem in countries where land is at a premium, the greenhouse gas emissions per unit energy are high, and coal is generally perceived as "dirty." Few people want a coal plant sited in their community. There is considerable opposition to construction of new coal-fired plants in Taiwan and Japan, although many environmentalists claim to prefer them to nuclear facilities. Japan is the world's largest importer of coal and imported 70 million tons of oil equivalent (mmtoe) in 1990. Like nuclear, coal is also being promoted as an alternative to oil in the power sector. Imports are forecast to grow to around 76 mmtoe in 1995 and 86 mmtoe in the year 2000, thereafter remaining steady. Coal's share of the Japanese energy mix will remain at around 17 percent during the coming decade.

Much of coal's bad reputation stems from how it has been used; clean coal technologies are relatively new and are not widespread in Asia. When coal is mentioned, it usually conjures up images of old-fashioned, smoke-spewing power plants. Much of the air quality problems in East Asia are in fact blamed on China, where roughly 1.2 million tons of coal per year are burned with little regard for emission controls or coal washing. South Korea severely tightened emission controls in the 1980s, but its pollution and acid rain problems continue to mount because of what blows in from neighboring China. Much Japanese pollution also originates on the mainland. As a recent visitor from Japan expressed it, "We breathe Chinese air." Tightening domestic standards further in an already strictly regulated environment like Japan may pay off in steadily diminishing returns. From the perspective of regional environmental quality, much more could be gained from helping China clean up its pollution problems; the spillover is huge.

The oft-cited solution to the problem is expansion of gas-fired power plants. While gas does generate some volume of greenhouse gas, its carbon-hydrogen ratio is lower than any other fossil fuel. Gas is cleaner burning than other alternatives, and presents no disposal or emission problems. The difficulty, of course, is that gas supplies in East Asia are minimal, and the needed volumes must be imported as LNG. Planners object to this on energy security grounds, as well as the grounds of high fuel costs. Nonetheless, there is less public opposition to the use of LNG than to either coal or nuclear, and it is expected that LNG use in East Asia will continue to expand quite rapidly in the 1990s. The ultimate difficulty other than cost is that LNG supplies are not large, and the lead time for new plants is very long.

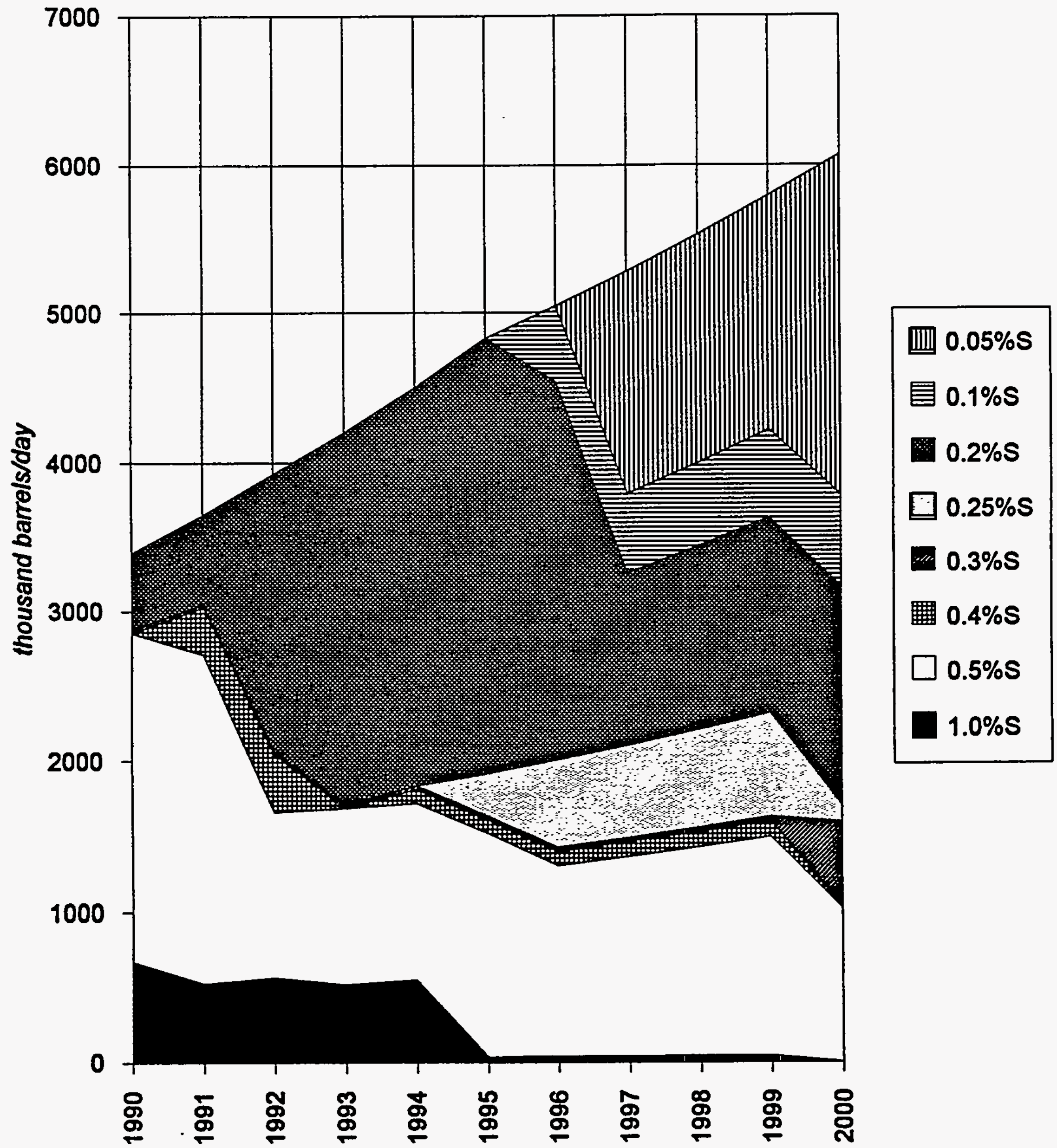
East Asian planners are resisting the inclusion of an expanded role for oil in generation as a permanent element in their plans; no current strategy recommends more use of oil in the longer term. Despite this reluctance, oil is creeping back into the power mix, and may not be backed out as quickly as some planners would like—most particularly since many official plans still call for substantial nuclear and coal expansions. Oil does have substantial advantages; although not as environmentally benign as gas, its sulfur emissions can be controlled fairly readily. Furthermore, despite accidents like the *Exxon Valdez* spill, oil is not perceived as a major threat in transport or storage. At present, LNG is viewed as something of a panacea by many members of the public in East Asia. One major LNG accident could readily change this view.

3. Planned and Proposed Sulfur Reductions

With respect to most oil products, much of the Asia-Pacific region has been fortunate enough to have a low-sulfur crude slate and a correspondingly low-sulfur product slate. But as noted, many of the high-quality crudes of Asia are playing out, and by the latter half of the decade, higher-sulfur Middle East crudes will capture an increasing share of the crude slate. Many countries are moving to tighten sulfur specifications—almost all will tighten diesel sulfur standards, and some are also working to reduce fuel oil sulfur. Figure 116 displays a forecast of diesel consumption by sulfur grade from 1990 to 2000. The highest-sulfur grades—those with up to 1% sulfur by weight (1%S)—are shown to be almost completely phased out by 1995. A major move is under way to 0.2%S diesel, but by the latter half of the decade ultra-low sulfur grades of 0.1%S and 0.05%S are phased in also. Much of the region, however, remains in the 0.25%S to 0.5%S range.

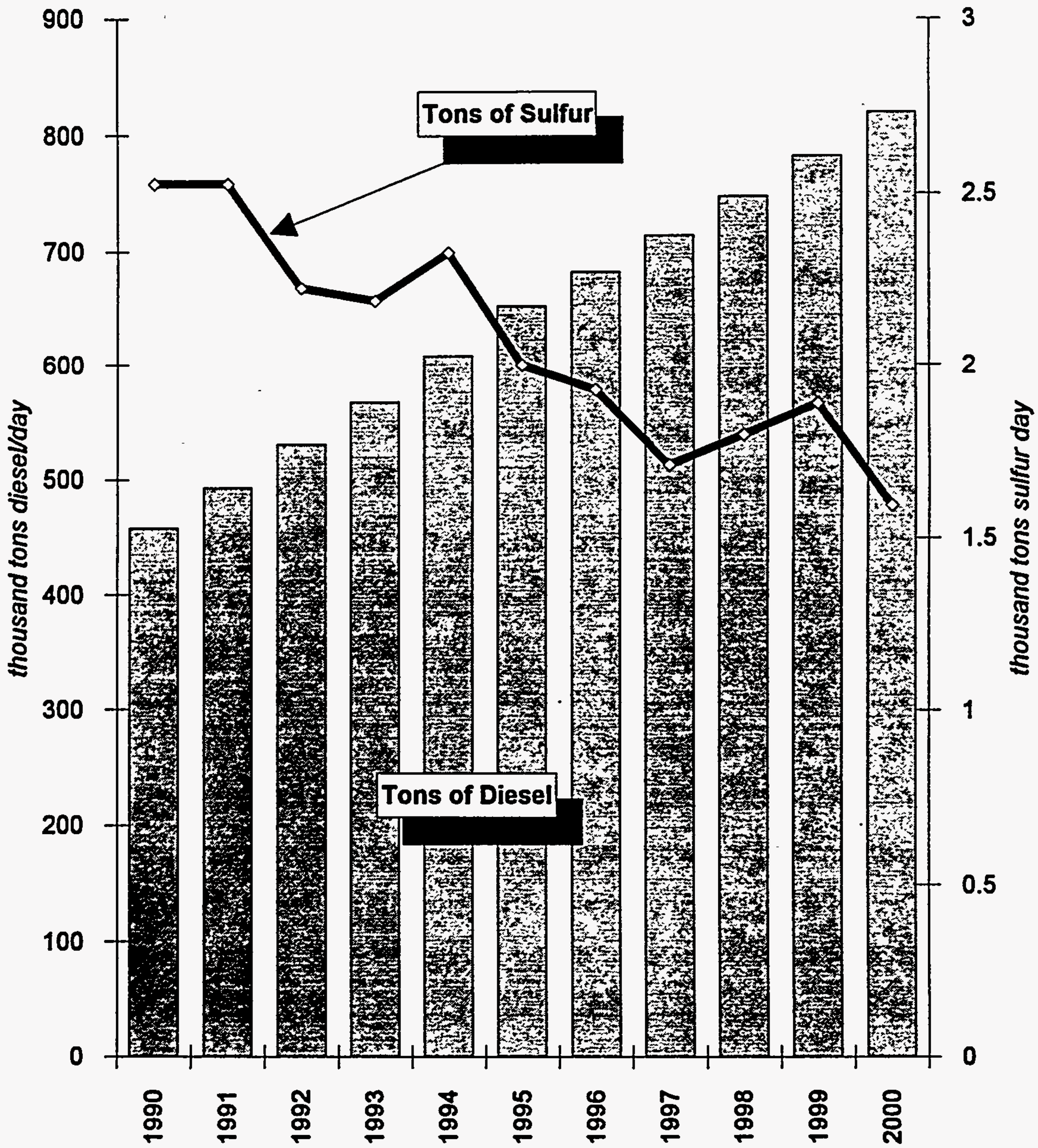
With the rapid growth in diesel demand, however, one question naturally springs to mind: how do the proposed changes in diesel sulfur content affect the *total* amount of sulfur that might enter the atmosphere because of diesel use? Figure 117 examines this issue by calculating the absolute tonnage of sulfur in the diesel pool. Even though the total tonnage of diesel consumed in the Asia-Pacific market expands enormously, the projected changes in

Figure 116. Diesel Sulfur Specifications Are Being Tightened in the Asia-Pacific Region, 1990-2000



Source: East-West Center

Figure 117. Despite Rapid Growth in Asia-Pacific Diesel Use, Total Sulfur Content is Decreasing, 1990-2000



diesel sulfur content are more than sufficient to counteract the upward trend. According to this study's calculations, in 1990 the diesel pool of around 458 thousand tons per day (mt/d) contained around 2.5 mt/d of sulfur. By 1995 diesel demand will grow to 652 mt/d, but the tonnage of sulfur will fall to 2.0 mt/d. By the year 2000 diesel demand will reach nearly 820 mt/d, but this will include only 1.6 mt/d of sulfur. In 1990 average diesel sulfur content was 0.55%S; by 1995 it is estimated to be be 0.38%S; and this average should fall to 0.19%S by the end of the decade.

The current fuel oil sulfur specification in South Korea and Taiwan is around 1.0%S. By U.S. standards, this may sound high, but it represents a rapid reduction from prior levels of 3.5%S. Both countries reduced fuel oil sulfur from the previous level of 1.5% to 1.0%S in July 1993. South Korea cut its diesel standard from 0.5%S in 1990 to 0.4%S in 1991 and to 0.2%S in 1993. A level of 0.1%S is the longer-term goal for 1996. Like South Korea, Taiwan's 0.5%S diesel grade reportedly will be reduced to 0.2%S in 1993, and Taiwan plans to phase in ultra-low-sulfur (0.05%S) diesel by 1997.

In Japan diesel sulfur was cut from 0.5%S in 1990 to 0.2%S in 1991, and the plan is to move to a 0.05%S standard on gasoil similar to that mandated for parts of the United States by 1997. At 0.25%S in urban areas, Japan's fuel oil sulfur specs are already on a par with U.S. standards.

In Thailand diesel grades often ran as high as 1.5%S, but the standard was reduced to 0.5%S in 1991, and the plan is to cut sulfur by half to 0.25%S by 1996. Fuel oil sulfur levels are a maximum 3%S currently, with a plan to move to 2%S in 1995.

Throughout ASEAN there is talk of cutting fuel oil sulfur, but to date there has been little specific action taken. Fuel oil with a maximum 3.5%S can be used in the Philippines, and no change has been announced. Singapore's standard for domestic use is 2%S, but very little fuel oil is used in Singapore proper; most of Singapore's fuel oil is sold as ship's bunker fuel, and this is typically 3.5%S material. Brunei has no fuel oil demand at all. Malaysia and Indonesia are in the situation of having such sweet crude slates that sulfur limits, which are currently 1.6%S and 1.5%S respectively, are not constraining.

Australia's plans with regards to diesel sulfur are similar to Taiwan's and Thailand's; 0.5%S grades should give way to 0.25%S grades by 1996, with 0.05%S the goal for 2000. Australia's fuel oil sulfur standard stands at 1.5%, and no changes are firmly planned. In general, the Green movement in Australia has focused more on coal use than on oil. Coal remains Australia's largest export earner. Australia is the world's leading coal exporter, with 1992 exports reaching a record-high of 127 million tons.

The early 1990s witnessed a flurry of environmental initiatives, and the rest of the decade is sure to bring more changes. South Korea and Taiwan are likely to move toward Japanese standards; ASEAN countries are likely to move toward former South Korean and Taiwanese standards; and the poorer countries are likely to try to catch up with where ASEAN is today. The biggest hurdle will be fuel oil sulfur content; middle distillate sulfur can be reduced fairly cheaply, but fuel oil desulfurization, even via the route of desulfurizing vacuum gasoil (VGO) and reblending, is an expensive proposition, and it appears that low-sulfur crudes will be less available relative to the demand for low-sulfur products.

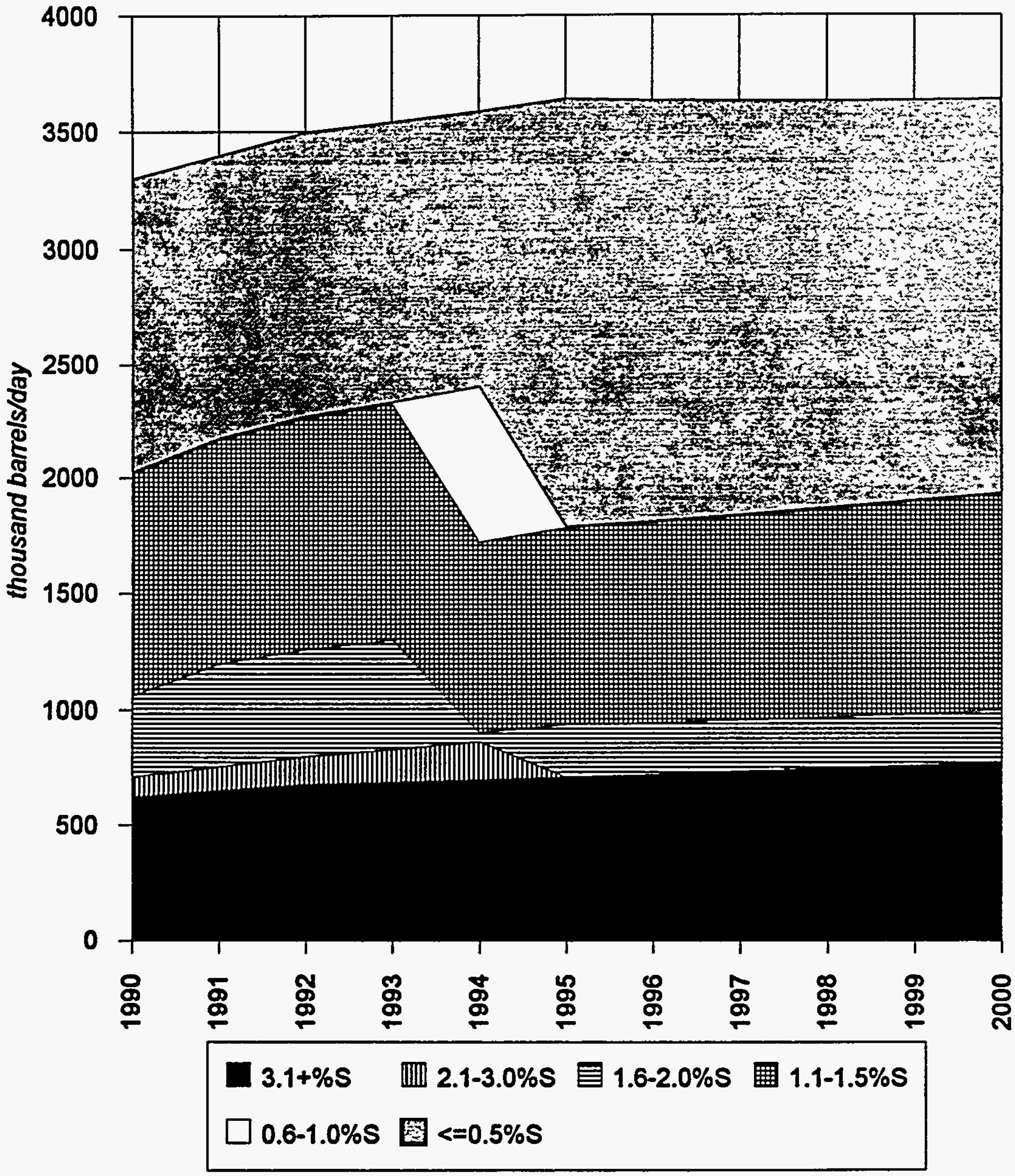
Few countries currently operate direct residual fuel oil desulfurizers, or RDS units. Japan is the leader with 401 thousand barrels per day (mb/d) of RDS capacity, followed by Taiwan with 95 mb/d. New Zealand has a small (7 mb/d) RDS unit also, but these three countries are thus far the only ones directly desulfurizing fuel oil. In early 1993 total Asia-Pacific RDS capacity was 503 mb/d. South Korea will be the fourth Asia-Pacific country to add RDS capacity, with 77 mb/d coming onstream by 1995. Taiwan and Japan will both be expanding their RDS capacity by 1995 as well, bringing the regional total RDS figure to 671 mb/d. By the year 2000, RDS capacity will reach around 813 mb/d, given likely expansion plans. This is not large, given the size of the regional fuel oil market, but the additions made in Japan, Taiwan, and South Korea will generally allow these countries to desulfurize more fuel oil than in the past. When the ratio between RDS capacity and fuel oil demand is taken as a comparative measure, Japan in 1992 could desulfurize around 33 percent of its fuel oil, Taiwan could desulfurize 41 percent, and South Korea could desulfurize none. By 1995 the RDS/fuel oil demand ratios for Japan, Taiwan, and South Korea will reach, respectively, 40 percent, 51 percent, and 17 percent, and by 2000 the ratios will be 57 percent, 56 percent, and 17 percent, respectively.

The price differential between low-sulfur fuel oil (LSFO) and high-sulfur fuel oil (HSFO) will inevitably widen as low-sulfur crude availability declines and countries adopt stricter fuel oil sulfur standards. The question remains as to how large the differential must be—and how long a wide differential is sustained—before countries build RDS units. The cost of directly desulfurizing fuel oil has gone up and is now in the range of \$6-\$9/barrel. This may serve as a good rule of thumb in approximating a future LSFO-HSFO price differential.

For some U.S. West Coast refiners, the move to LSFO in South Korea and Taiwan poses problems. Fuel oil is in continuous surplus on the West Coast (exports range from 100-150 mb/d), and East Asia has been a major market outlet. Historically, 1%S fuel oil that was considered HSFO—and hence was of little use—in the U.S. West Coast market found ready markets in Asia. This 1%S material could be blended with even sourer fuel oil from Middle Eastern crudes to meet standards of 1.5%S. As Asian fuel oil sulfur standards tighten to 0.5%S, the value of West Coast fuel oil will drop even further. Historically, these West Coast fuel oils have commanded a premium over bunker C fuel oil, which typically contains up to 3.5%S, and refiners very much want the premium to persist.

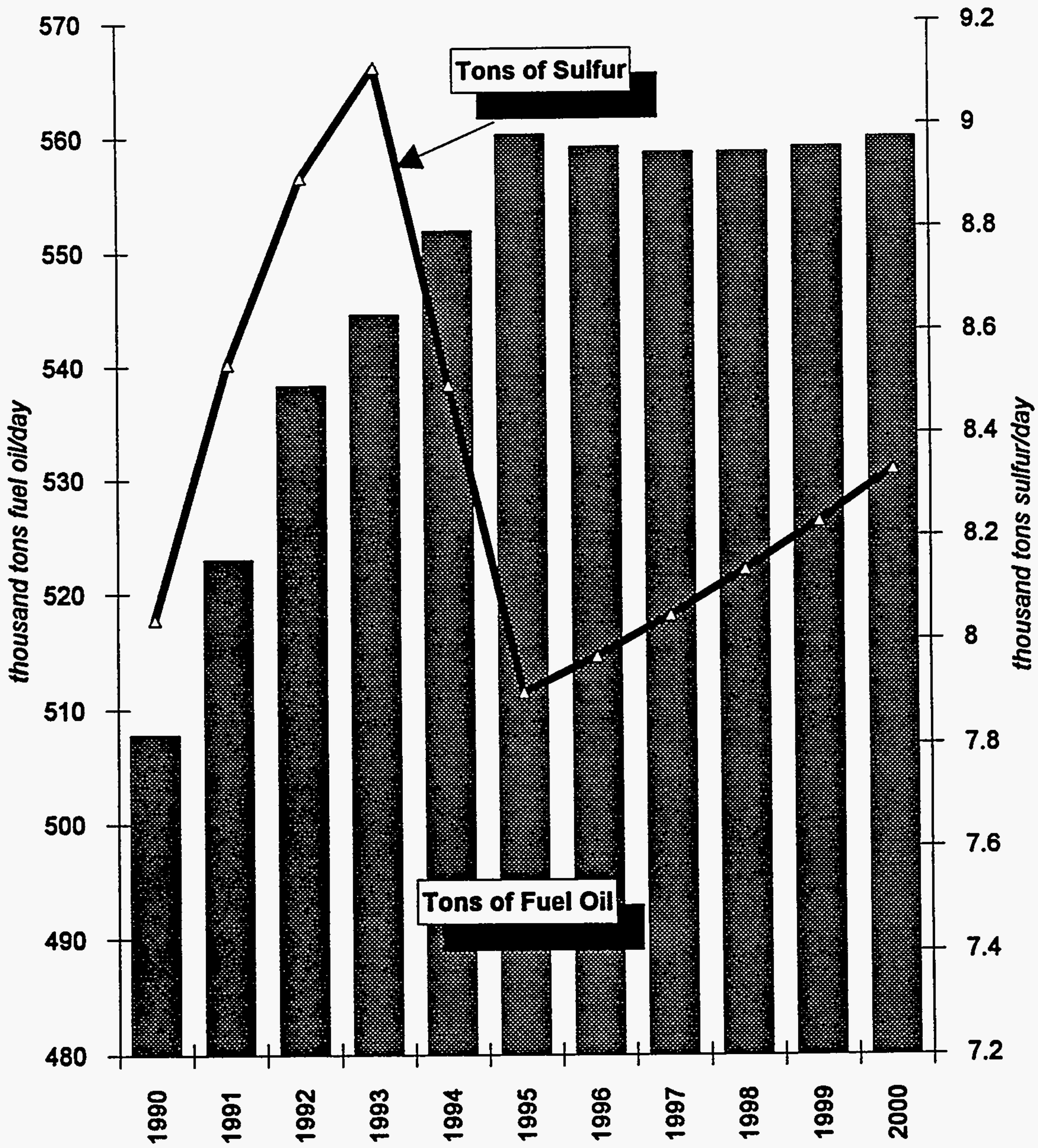
On a regional basis, there is much less concrete action being taken to reduce fuel oil sulfur. Figure 118 displays an assessment of Asia-Pacific fuel oil demand by sulfur grade, 1990-2000. The move toward 0.5%S LSFO in 1995 is clearly visible, but it is entirely a function of the actions of two countries: South Korea and Taiwan. Their actions cause a precipitous drop in total tonnage of fuel oil sulfur, as Figure 119 illustrates, but without further action in Asia, sulfur tonnage begins to creep back up in the 1995-2000 period. Part of the explanation for this is that the countries without firm plans to restrict fuel oil sulfur are also often the countries without firm plans to back HSFO out of electric power generation or heavy industry. Also, a significant amount of the highest-sulfur material is devoted to

Figure 118. Asia-Pacific Fuel Oil by Sulfur Content, 1990-2000



Source: East-West Center.

Figure 119. Fuel Oil Sulfur Specifications Could be Tightened Further in Asia, 1990-2000



ship bunkering, and the demand for shipping is robust in areas where rapid economic development is under way and trade is expanding.

4. The Move Toward Higher-Quality Gasoline

As the United States, and particularly California, move toward more strictly reformulated gasoline and diesel, the Asia-Pacific region has been increasingly perceived as a potential source of clean fuels. In part, this perception is the result of a fairly aggressive campaign in certain Asia-Pacific areas to build export-oriented refineries. Such proposals have called mostly for gasoline-producing technologies, and the U.S. West Coast has been mentioned as a possible market. The more closely one examines the Asia-Pacific market, however, the less clear it is that the region will emerge as much of a "clean-fuel supplier." This is not to say that the region is not moving toward cleaner transport fuels; it is doing this with a rapidity that has surprised many observers. The specification changes, however, are mild compared to the standards emerging in the United States and the U.S. West Coast region, indicating that few of the Asia-Pacific countries will be producing fuels that meet stringent U.S. requirements. In addition, the rapid growth in Asia-Pacific oil demand dictates that most Asian transport fuels and fuel blending components will remain in the region, with a few possible exceptions where increased trans-Pacific trade may become increasingly beneficial.

In this section, possible refinery output in 1995 and 2000 is compared to this study's current forecast of demand. The methodology employed involved computer modeling of refinery capabilities and behavior for the Asia-Pacific refining countries and the U.S. West Coast, defined here as the seven states of the Petroleum Administration for Defense District V (PADD-V): Alaska, Arizona, California, Hawaii, Nevada, Oregon, and Washington. The refinery models incorporate all firm and likely expansions in capacity by country for 1995 and 2000. Fuel specifications by country, current and planned, were surveyed to determine where fuel quality will be heading. When countries are unable to satisfy domestic demand for transport fuels, trade is necessary. Gasoline, naphtha, and diesel balances are projected to 1995 and 2000 to identify the volumes of net trade anticipated in the Pacific-rim region. In this analysis, Asian gasoline exports to the U.S. West Coast will be limited both by volume and quality considerations.

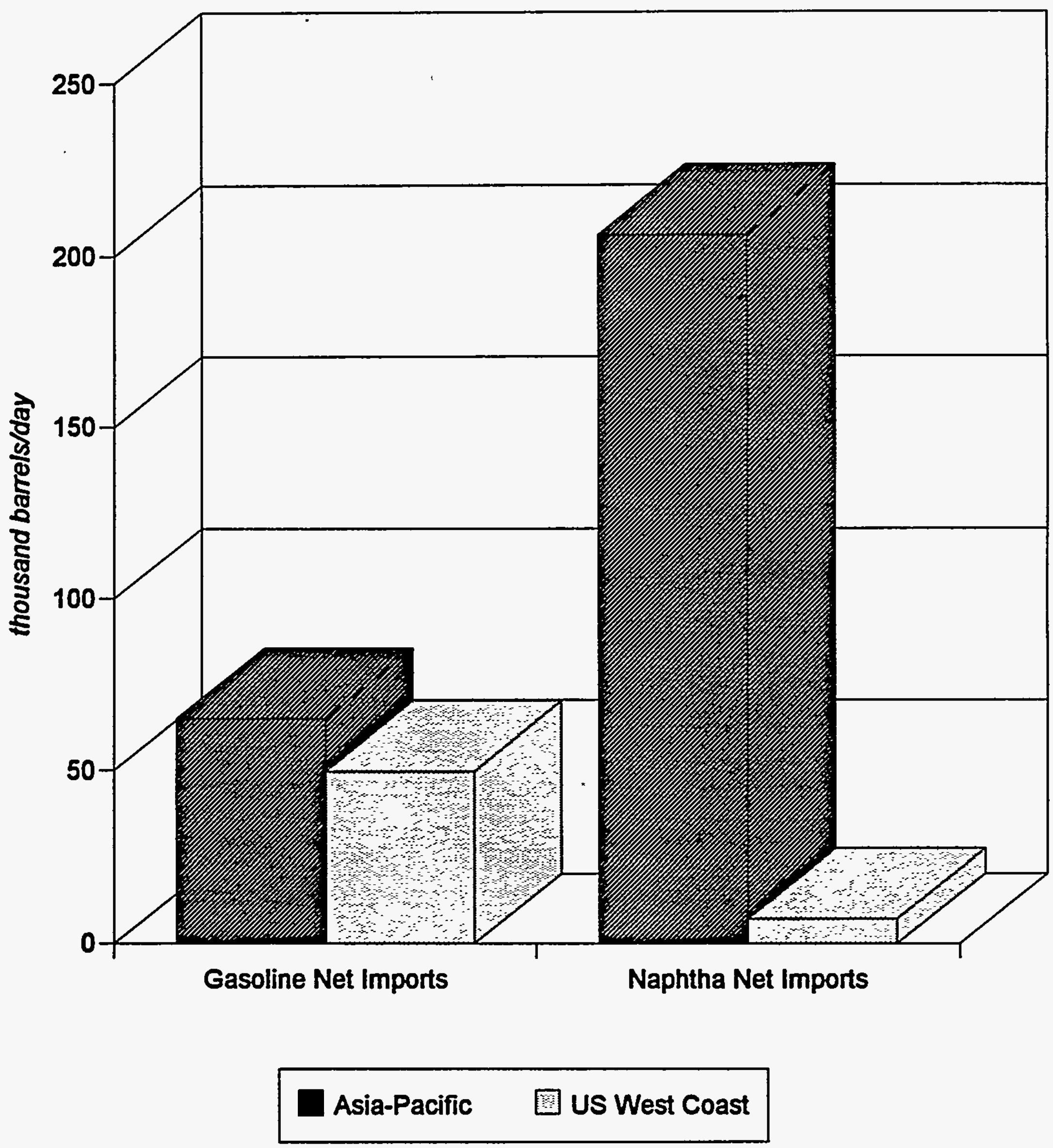
Light distillate volume considerations. As noted, the demand barrel in Asia is dominated by middle distillates, with light distillates also capturing a larger share of the barrel. Simple topping and hydroskimming configurations are unable to match the incremental demand barrel. Yet for the most part, refinery upgrading capacity has not been added at levels commensurate with the rapid expansion of crude distillation capacity. At first glance, it is puzzling to see the extensive reliance on catalytic cracking as the chief cracking technology and the large amount of catalytic reforming; in a diesel-dominated market, why has the refining industry invested so heavily in such a mix of gasoline-producing technologies?

Part of the answer is that a significant amount of the region's FCC capacity—particularly in India and China—is run in a mode that maximizes light cycle oil output. Light cycle oils, hydrotreated or otherwise, are not the most outstanding diesel blendstock, but they play an important role in meeting Asian demand. The incremental pattern of demand in Asia can only be met by a hydrocracking configuration, but refiners in general have rejected this in favor of the less costly FCC/RCC plus hydrotreating approach.

The end result, however, is that the region's refineries are less sophisticated than the world average, and generally less well able to cope with growing demand for higher-quality fuels.

The Asia-Pacific region is not known as a gasoline exporter. Recently, the region has been a net importer of both gasoline and, more notably, naphtha, as Figure 120 displays. In 1991 the Asia-Pacific region required gasoline imports of around 65 mb/d plus naphtha imports of over 240 mb/d. The prospect of Asia as a source of gasoline exports has only recently become a topic of discussion, largely because of a number of ambitious plans to build export-oriented refineries. The U.S. West Coast was often mentioned as a potentially lucrative market for Asian gasoline.

Figure 120. Light Distillate Supplies Have Been Tight in the Pacific Rim Market: Net Imports of Gasoline and Naphtha, 1991



Two factors will work against the feasibility of Asian gasoline exports to the U.S. West Coast: the first deals with fuel quantity, and the second deals with fuel quality. On the volume side, rapid demand growth in Asia has already cut into the volumes originally destined for export markets. Additionally, although the expansions now under way will enable the Asia-Pacific refining industry to produce a certain amount of gasoline for export, the regional industry will not be able to fully satisfy demand for gasoline *plus* naphtha. Figure 121 displays the projected 1995 trade balance for naphtha and gasoline in the Asia-Pacific and U.S. West Coast markets. Gasoline exports from the Asia-Pacific region could amount to around 50 mb/d in 1995, but the region will remain hugely dependent on outside sources of naphtha—import requirements are forecast at around 380 mb/d. The U.S. West Coast, on the other hand, should be able to satisfy local demand for gasoline and may have a small surplus of naphtha.

As additional refinery capacity comes onstream in the latter half of the decade, gasoline exports from Asia could reach over 80 mb/d, but, as Figure 122 indicates, the import requirement for naphtha may exceed 645 mb/d. Depending on the price differential between gasoline and naphtha, certain naphtha streams may not be upgraded into finished motor gasoline at all, and gasoline exports may drop accordingly. In addition, the U.S. West Coast is expected to remain self-sufficient in gasoline supply and to have a continuing small surplus of naphtha.

<u>Gasoline Quality Considerations.</u> The second factor that will militate against Asian gasoline achieving significant market penetration in the U.S. West Coast market is gasoline quality. The gasolines of the Asia-Pacific region run the gamut in quality terms. In some countries, gasolines are underpowered, heavily leaded, and quite high in poor-quality blendstocks such as thermal naphtha, coker naphtha, and BTX raffinate (the material remaining after aromatics extraction). On the other hand, in many other countries the lead phaseout is complete or

Figure 121. Asia-Pacific Refiners Can Export Gasoline in 1995, But Naphtha Remains in Short Supply

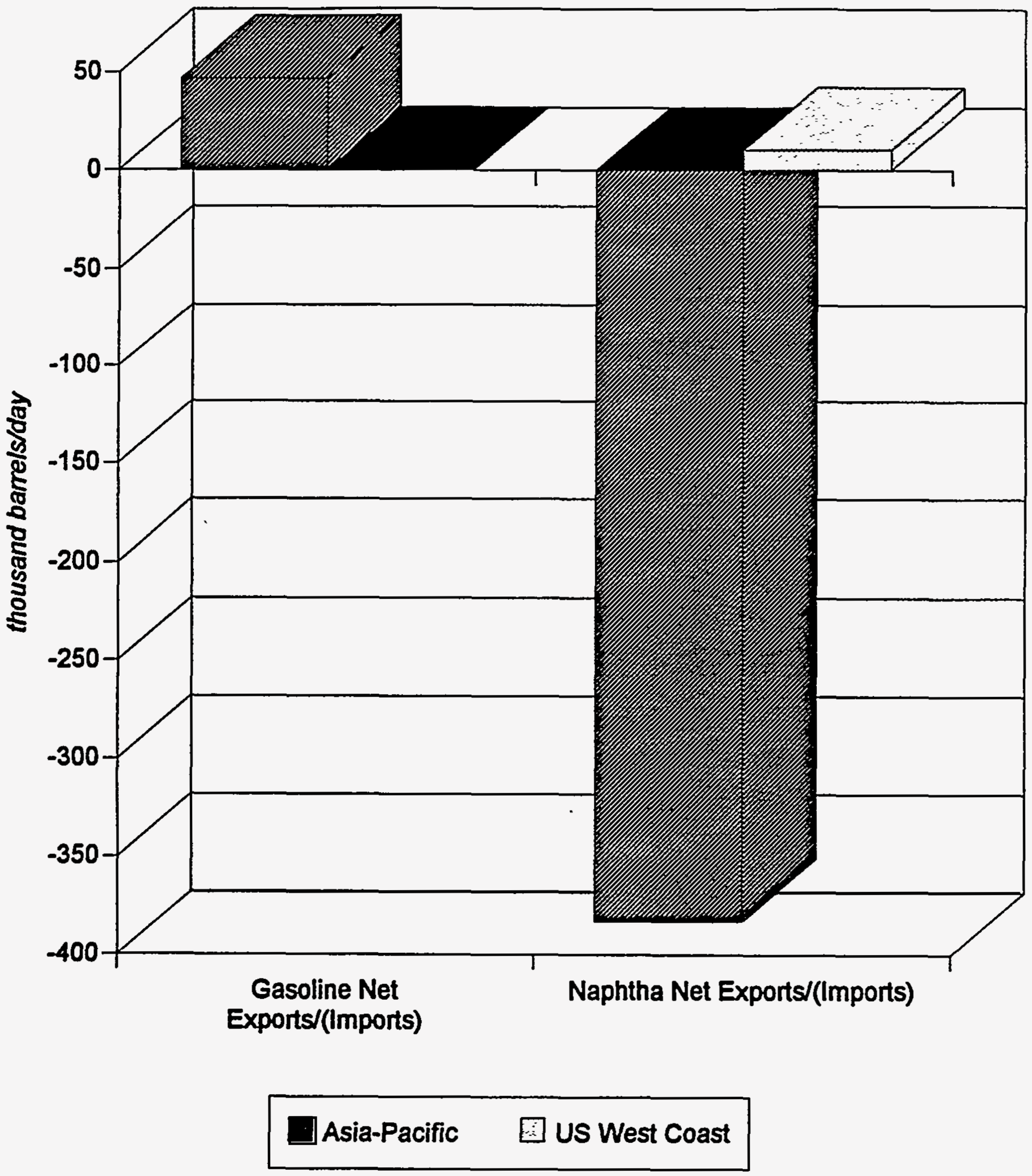
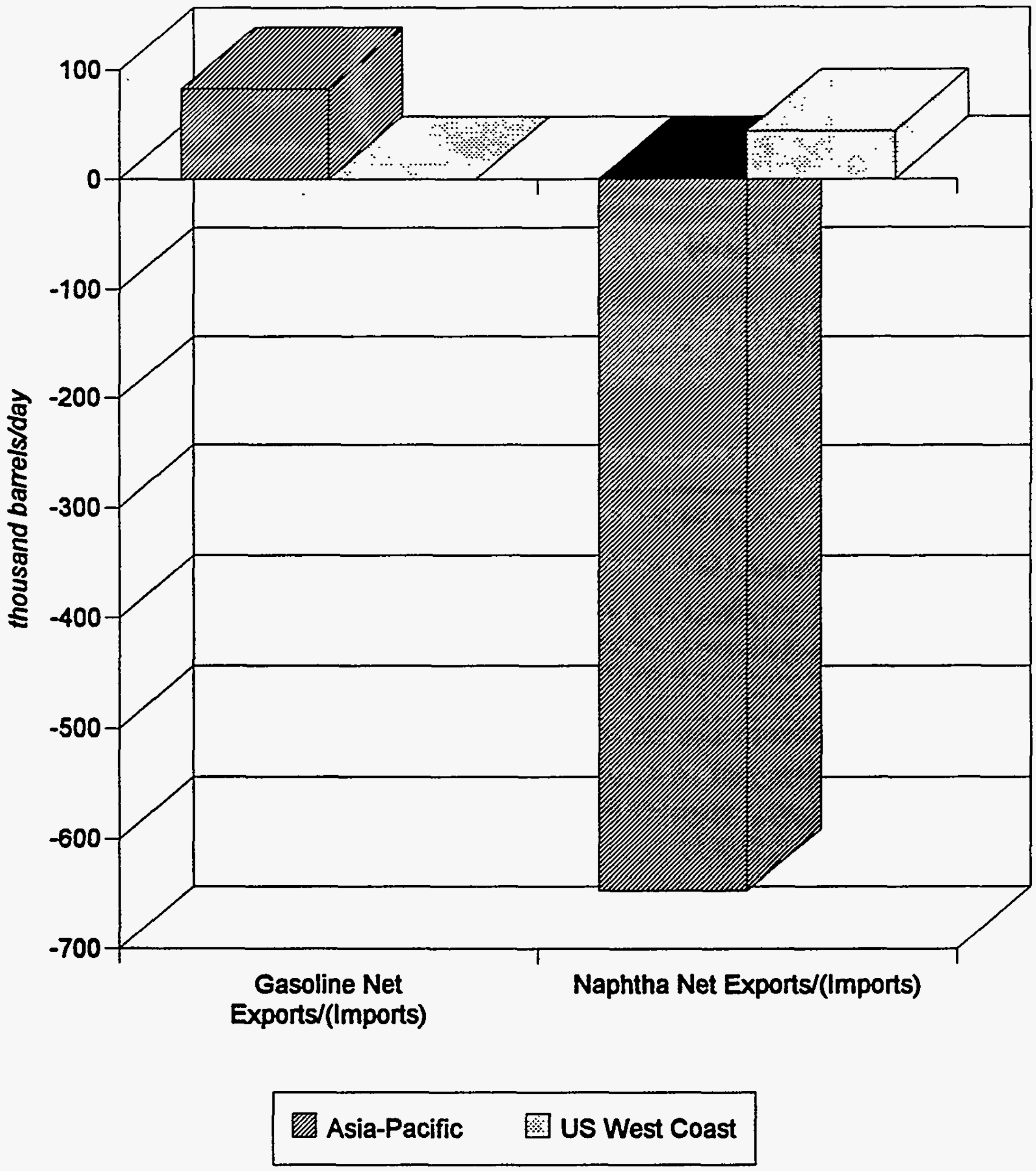


Figure 122. Heavy Reliance on Naphtha Imports May Reduce the Likelihood of Asian Gasoline Exports in 2000



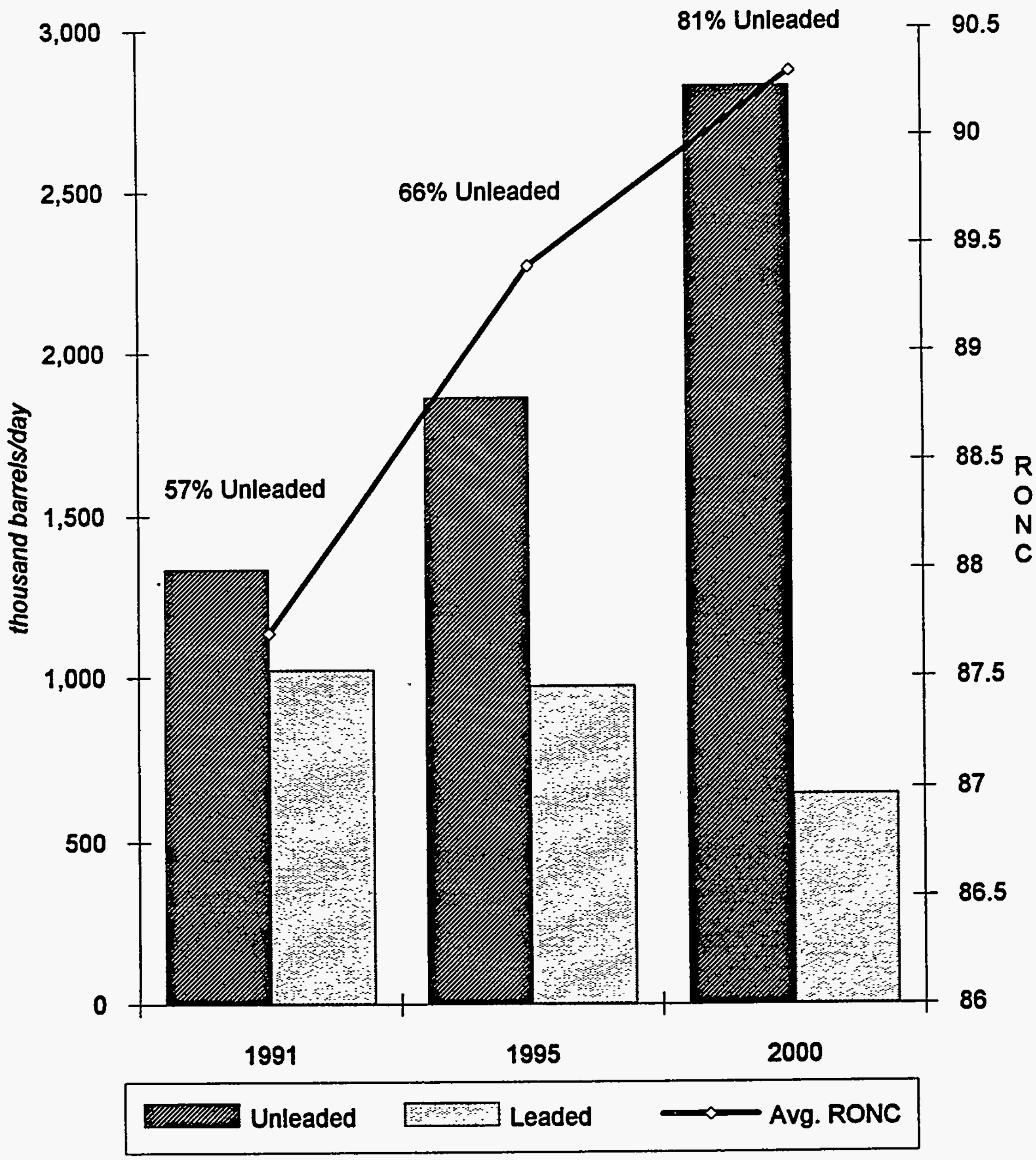
nearly complete, octane ratings are high, and some gasolines are already oxygenated with moderate quantities of MTBE. New Zealand even produces a synthetic gasoline from natural gas, which is free of many of the "bad actors" now being targeted for reduction in California and other U.S. gasolines.

The majority of Asian gasoline is in fact already unleaded, and the lead phaseout is proceeding rapidly. Figure 123 portrays the changing gasoline pool in Asia from 1991 to 2000. In 1991, 57 percent of the pool was unleaded, and average octane, defined here as the effective RON clear for the entire pool, was 87.7 RONC. By 1995 around two-thirds of the pool should be unleaded, and pool octane should increase to 89.4 RONC. By the year 2000, East-West Center calculations indicate that 81 percent of the pool will be unleaded, and pool octane will reach 90.3 RONC. These calculations assume that South Korea and Taiwan will be completely lead-free by 1995 and that Indonesia, Malaysia, New Zealand, and Thailand will follow suit by 2000. Japan, of course, is already a completely unleaded market.

In addition to the countries moving toward full lead phaseout, most countries are reducing maximum allowable leading levels. Figure 124 displays average leading levels for the leaded pool and the total pool for 1991, 1995, and 2000. For the leaded grades, average leading levels are set to decline from 0.3 grams of lead per liter (gPb/l) in 1991 to 0.25 gPb/l in 1995 and 0.21 gPb/l in the year 2000. For the pool as a whole, lead levels will drop from 0.13 gPb/l in 1991 to 0.09 gPb/l in 1995 and 0.04 gPb/l by the end of the decade. Average octane levels will still increase.

As noted in the section on refining, the Asia-Pacific refining industry relies quite heavily on FCC and catalytic reforming technologies. For most of the countries, octane is not in short supply, and this makes the lead phaseout an easier task. But much of the octane comes from aromatics-rich FCC naphthas and reformate, which raises the question of whether Asian gasolines would be suitable for U.S. markets where gasoline aromatics content will be capped at 25 percent. Figure 125 presents a detailed look at the aromatics content in various Asia-Pacific gasolines for 1991, 1995, and 2000, and how they compare to the 25

Figure 123. Asia Moves Toward Unleaded Gasoline, 1991-2000



Note: Avg. RON is effective RON clear for total gasoline pool.

Figure 124. Asia-Pacific Octane Levels are Increasing Despite Reductions in Leading, 1991-2000

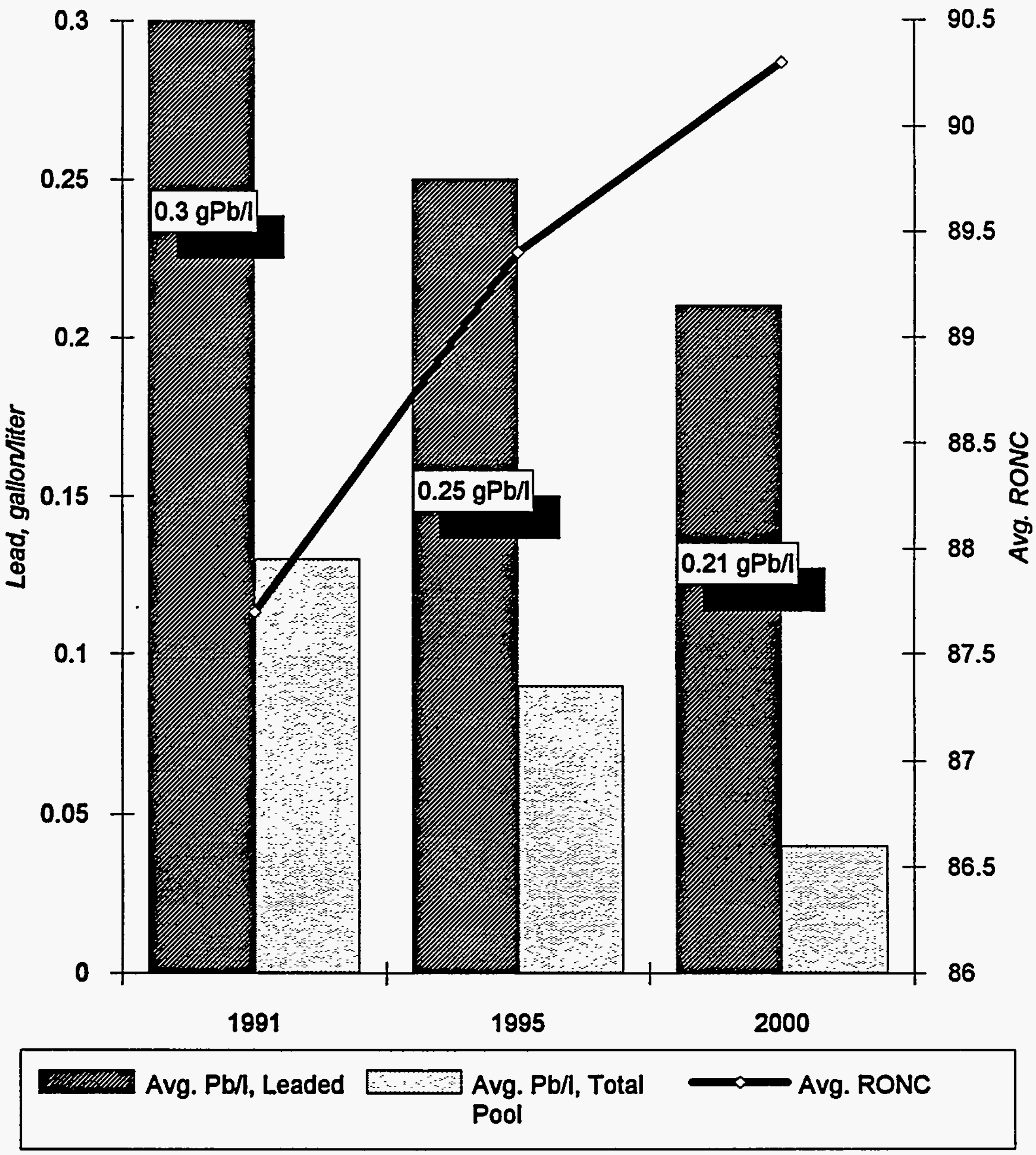
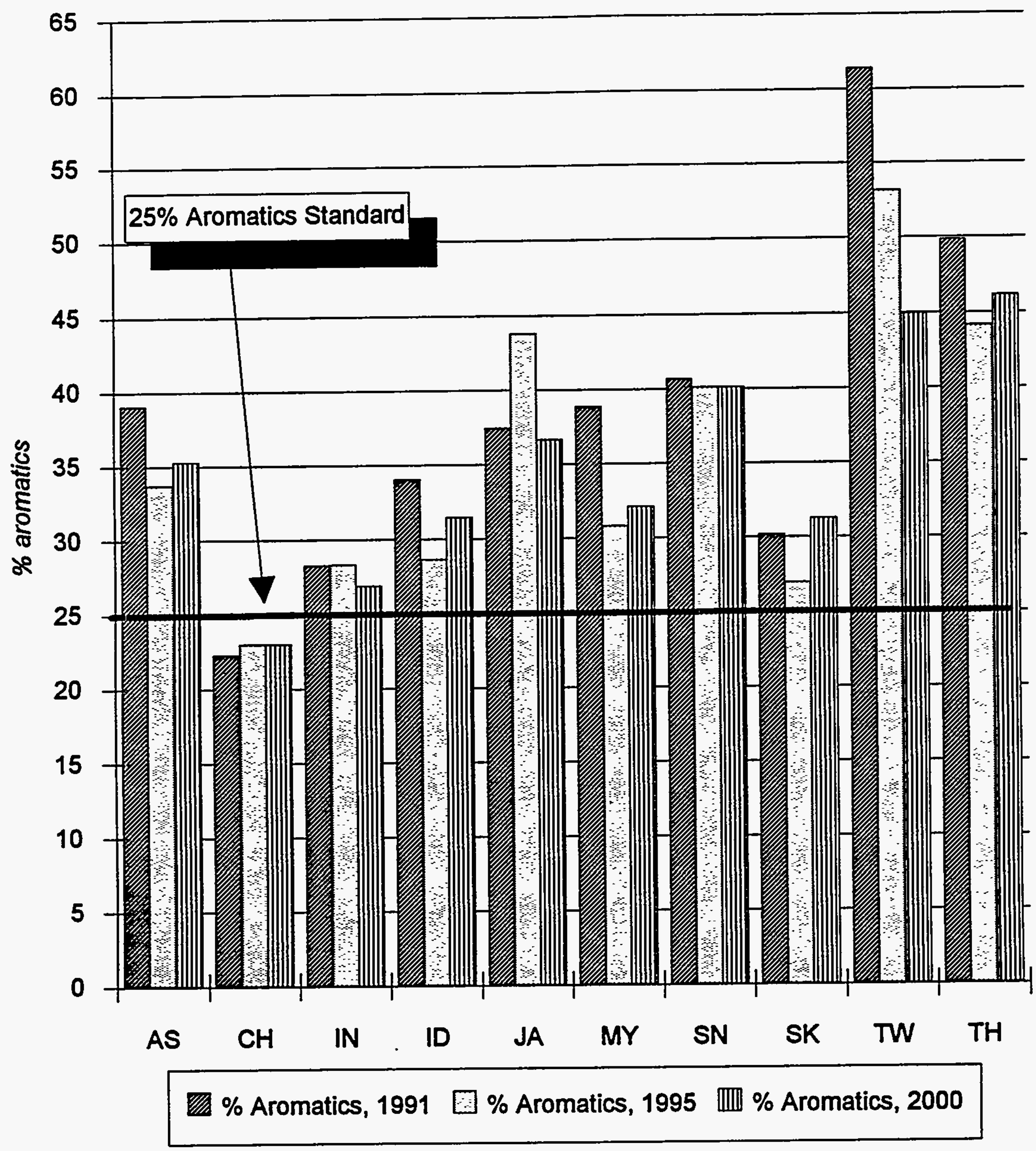


Figure 125. How Do Asia-Pacific Gasolines Compare to the 25% Aromatics Standard?



percent limit. With the exception of China, all Asia-Pacific gasolines exceed the 25 percent limit—some by a significant amount. In large part, the Chinese gasoline in question is low in aromatics because the majority of Chinese reformers are linked to BTX (benzene, toluene, xylene) extraction units; octane levels are therefore understandably low.

Even though Asia-Pacific governments are not restricting gasoline aromatics, it appears that aromatics levels will be declining somewhat in a variety of countries, particularly those that have relied almost solely on reformate as an octane source. FCC/RCC naphthas will play a larger role in the gasoline pool, and although at around 24 to 32 percent aromatics they are aromatics-rich, they are far less so than reformates, which typically have aromatics contents in the range of 50 percent to 74 percent.

The reliance on FCC/RCC technology also offers opportunities to expand both alkylation and MTBE capacity based on FCC/RCC olefins. Figure 126 displays current and planned alkylation capacity. Currently, Japan, Australia, China, Taiwan, the Philippines, Indonesia, and South Korea operate alkylation units. Japan, Indonesia and South Korea will be adding to their alkylation capacities. New alkylation capacity is also planned in Malaysia, Singapore, and Thailand. Alkylation capacity is set to grow from 128 mb/d in 1992 to 194 mb/d in 1995 and 230 mb/d by the end of the decade.

Major expansions are also possible in Asia-Pacific MTBE capacity, as shown in Figure 127. In 1992 MTBE capacity stood at around 23 mb/d, with units operating in Japan, South Korea, Taiwan, China, and Singapore. Planned additions should bring capacity to 41 mb/d by 1995 and to perhaps 87 mb/d by the year 2000. If all planned expansions move forward, Indonesia, Malaysia, Thailand, and Australia will also enter the ranks of Asia-Pacific MTBE producers.

Although gasoline quality is improving in the Asia-Pacific region, no Asian country is adopting fuel reformulation standards as strict as those of California or the rest of the United States. It will be possible for some Asia-Pacific refiners to produce an export-grade gasoline that meets California specifications, particularly with regional increases in alkylation and MTBE capacity, but doing so might prove thankless, since the West Coast industry appears

Figure 126. Current and Planned Asia-Pacific Alkylation Capacity, 1992-2000

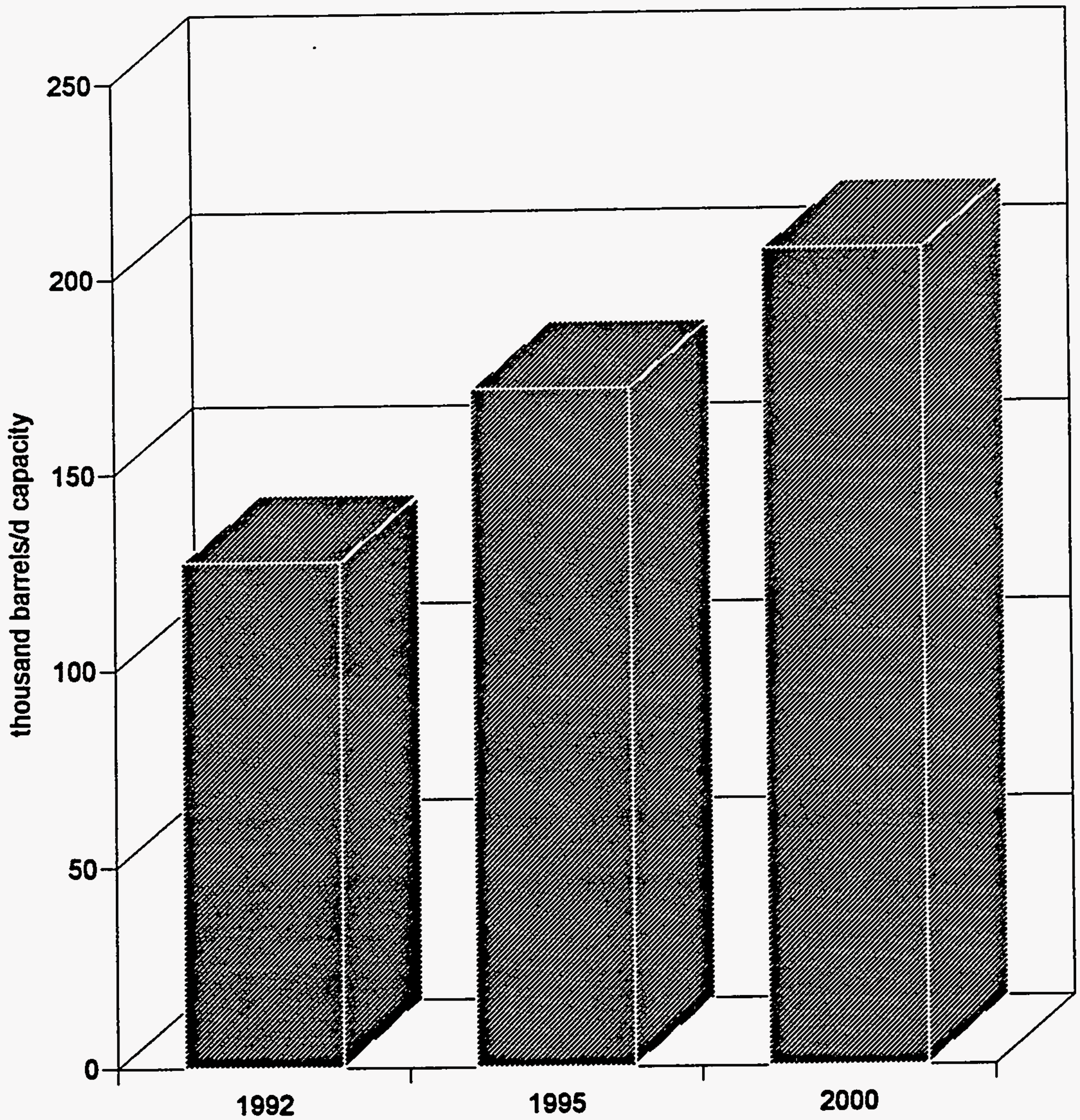
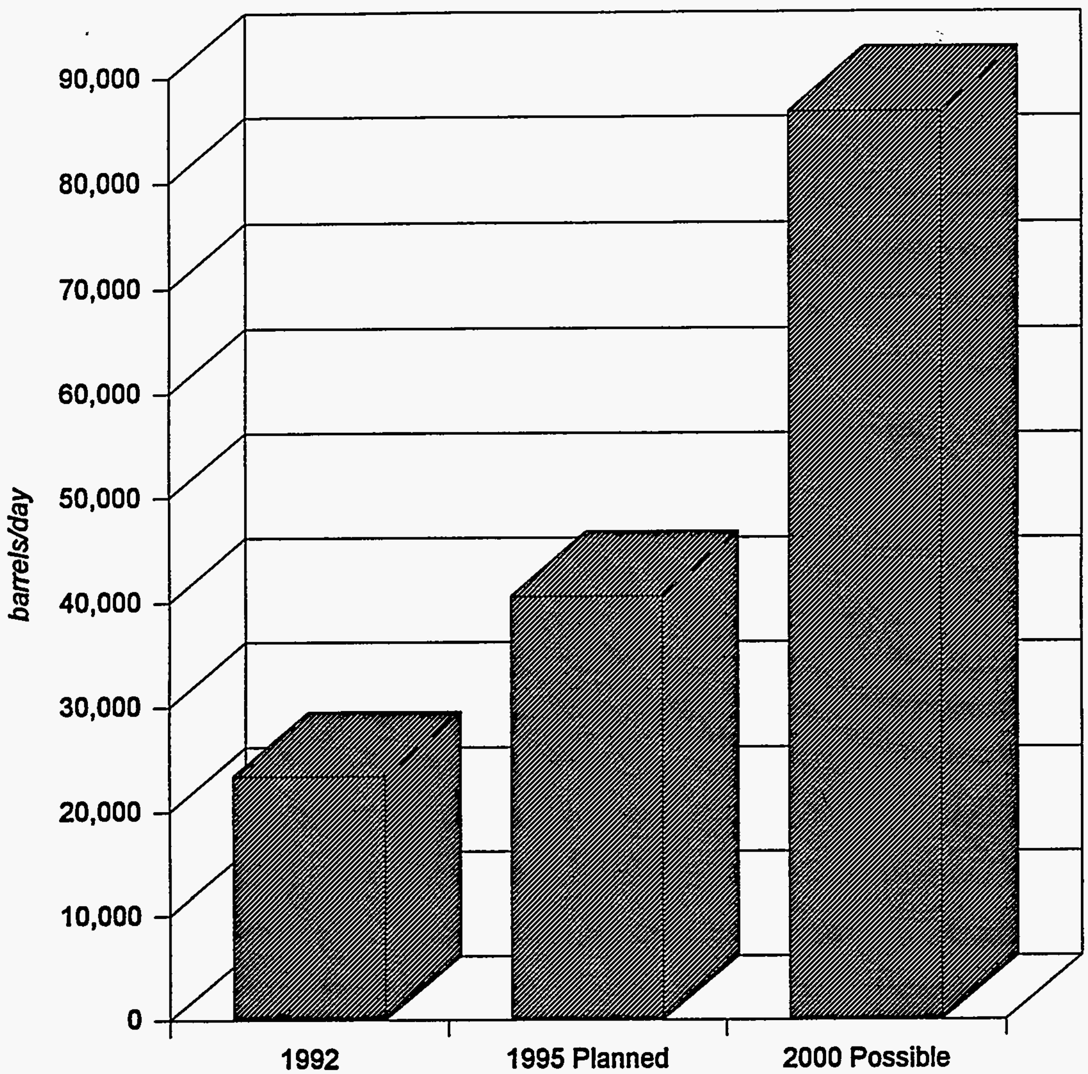


Figure 127. Major Expansions are Possible in Asia-Pacific MTBE Capacity During the 1990s



fully capable of meeting market requirements. For reasons of both quantity and quality, it appears far less likely that the Asia-Pacific region will serve as a source of clean gasoline to the United States. At most, we may see U.S. imports of gasoline blendstocks such as MTBE and alkylate, if they can be spared.

5. The Diesel Supply Gap Widens: Impetus for Trade

While trans-Pacific trade in gasoline may be limited, there may be interesting opportunities for increased diesel trade. The Asia-Pacific region is chronically short of diesel, whereas the U.S. West Coast has typically been a net exporter of diesel. Figure 128 displays net trade in diesel for the Asia-Pacific countries and the U.S. West Coast in 1991. The largest diesel exporter was, predictably, Singapore, distantly followed by the U.S. West Coast, South Korea, Australia, and New Zealand. In all, the net exporters provided 358 mb/d of diesel. The net importers, however, required 476 mb/d.

By 1995 Asia-Pacific diesel import requirements are forecast to surge, with regional importers requiring over 1,100 mb/d. Regional exporters will be able to provide just 369 mb/d. This picture is presented in Figure 129. The regional exporters are once again led by Singapore, but exports from the U.S. West Coast are expected to expand significantly from their 1991 level. Miniscule exports are expected from Taiwan and New Zealand, but all other Asia-Pacific countries are forecast to be net importers of diesel by 1995.

By the year 2000, the diesel supply gap widens even more dramatically. As shown in Figure 130, Asia-Pacific diesel importers will require imports of around 1,500 mb/d, while regional exporters will be able to provide less than 450 mb/d. Singapore and the U.S. West Coast remain the exporters of note, but the completion of refineries in Malaysia and Taiwan will also allow a certain level of exports. On the importer side, India, Indonesia, South Korea, and Thailand may find it increasingly burdensome to meet diesel demand via imports; each will be seeking volumes on the order of 200-350 mb/d.

The looming supply gap in Asia may offer valuable opportunities to U.S. West Coast refiners, perhaps especially those who will not be producing the reformulated automotive

Figure 128. Asia-Pacific and U.S. West Coast Diesel Net Exports/Imports, 1991

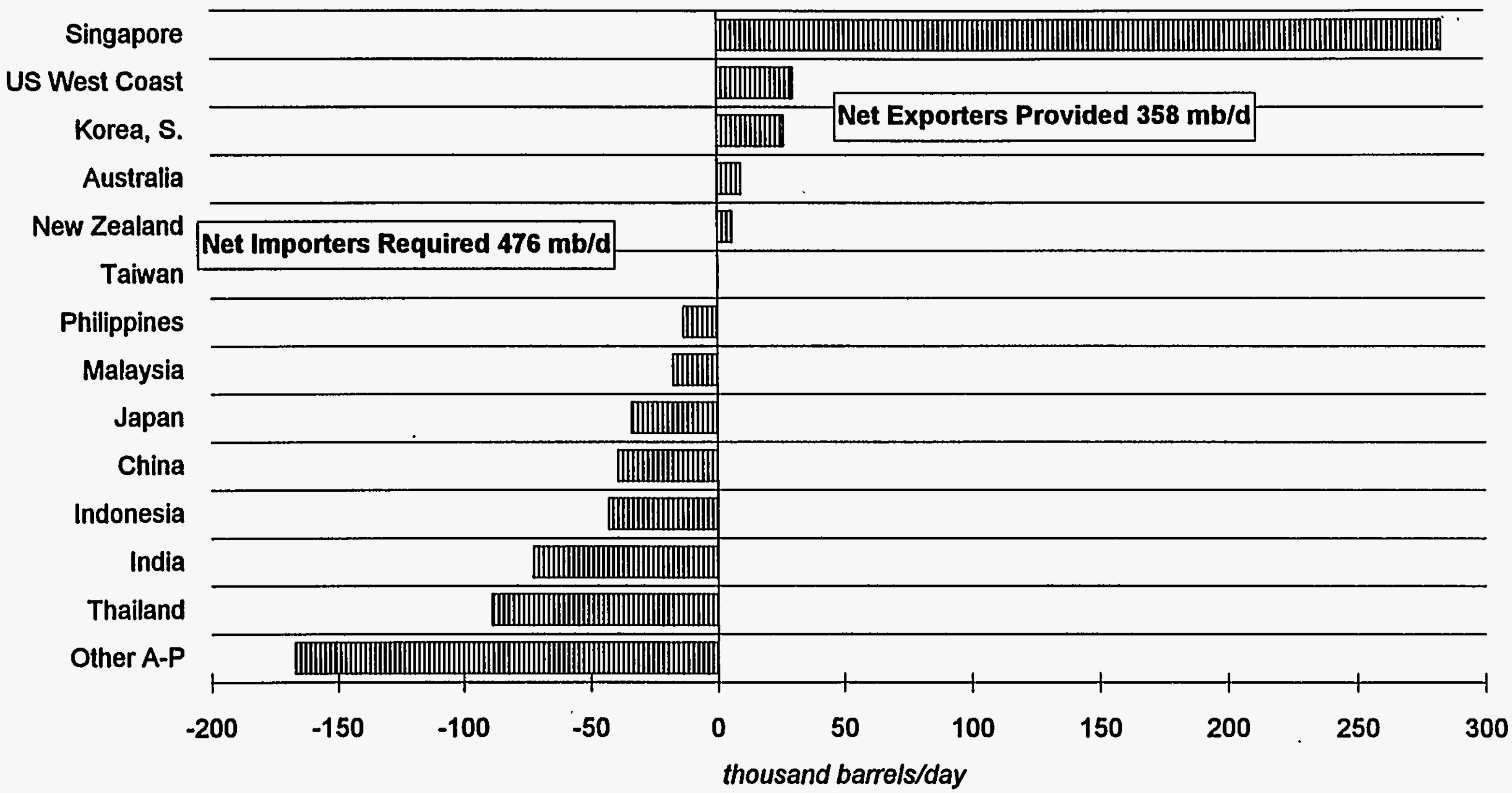


Figure 129. Diesel Import Requirements Surge in the Asia-Pacific Region: Projected Net Exports/Imports, 1995

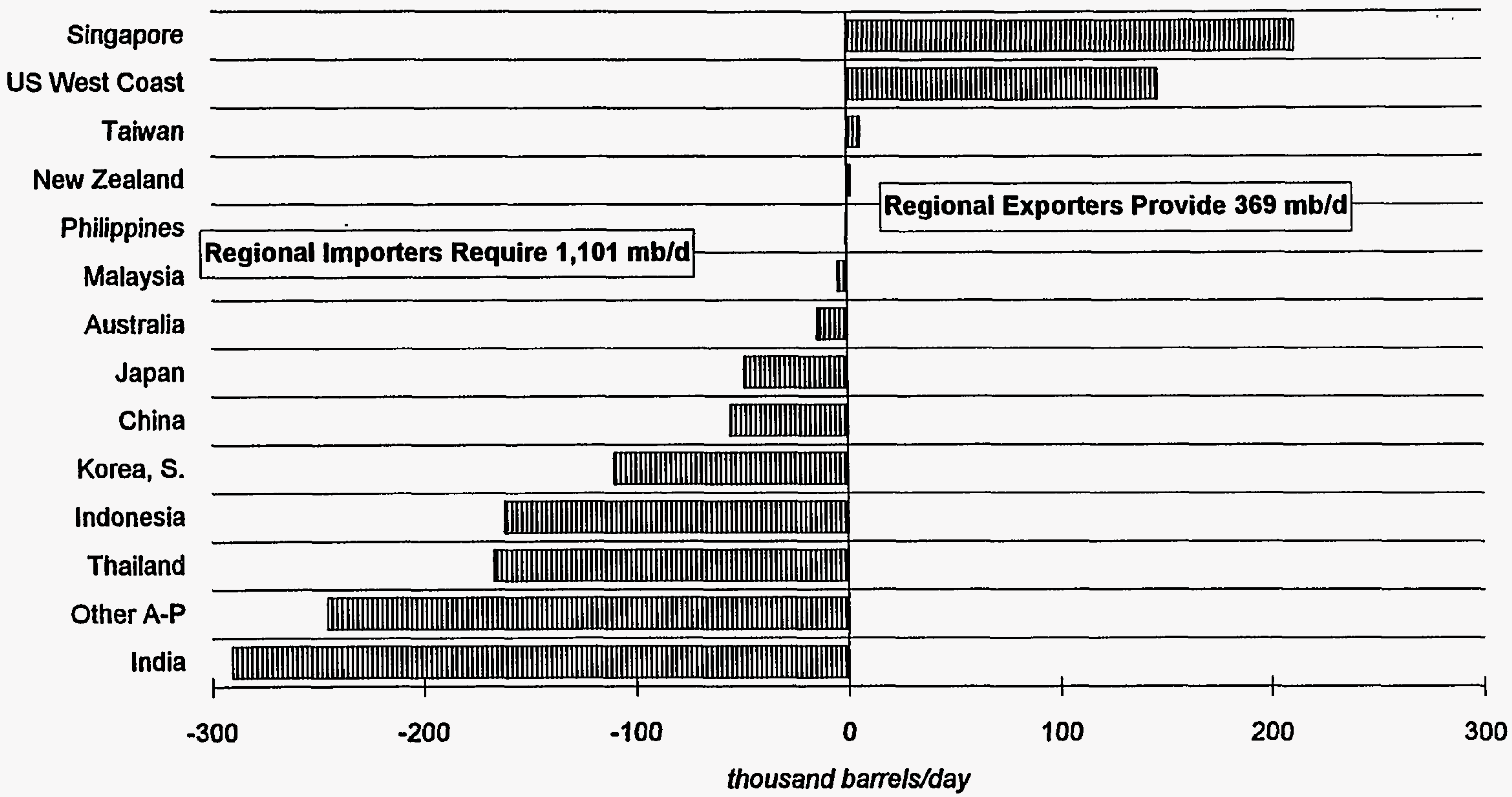
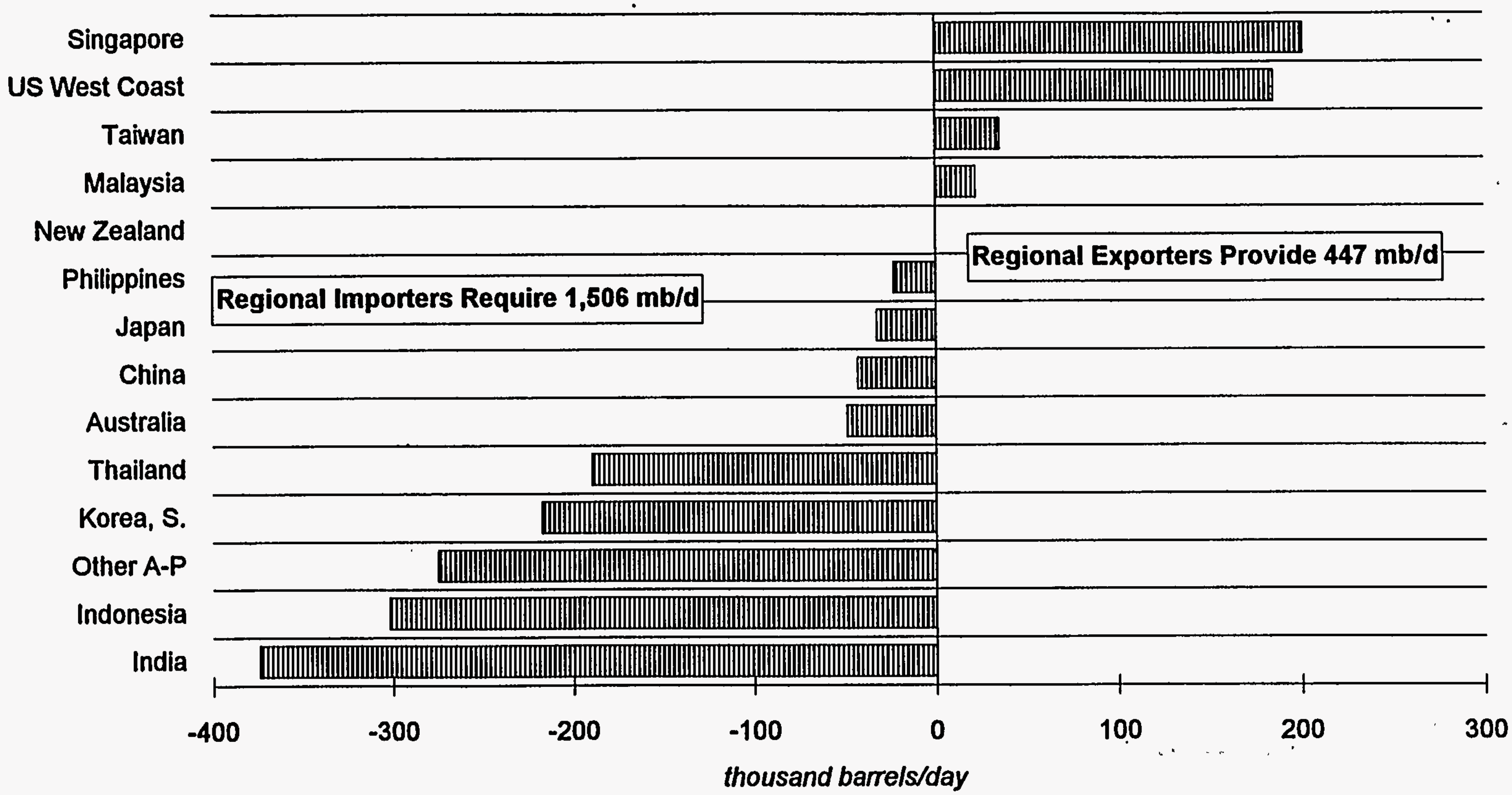


Figure 130. The Diesel Supply Gap Widens: Asia-Pacific and US West Coast Net Exports/Imports, 2000

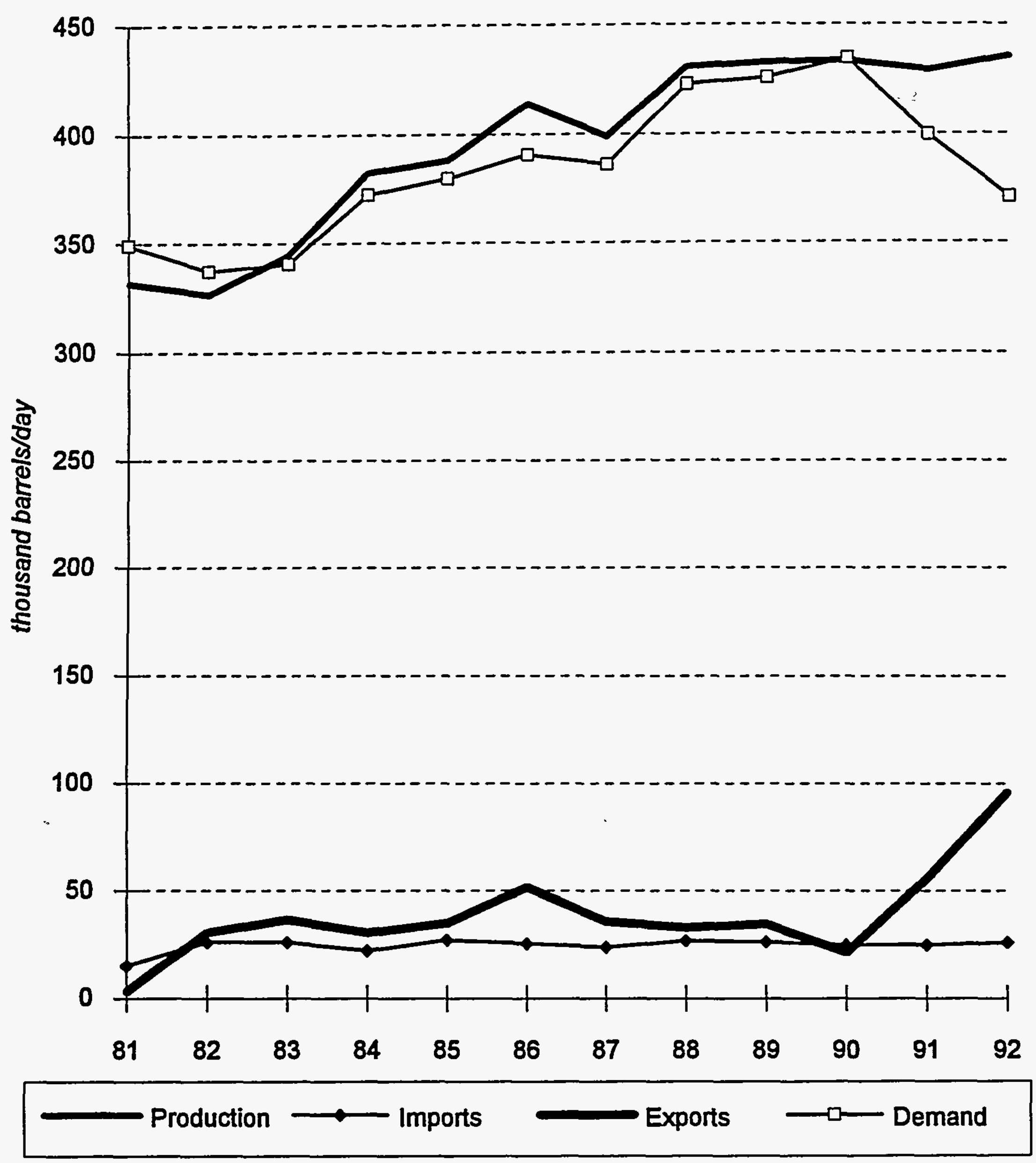


diesel soon to be required by the California Air Resources Board. Diesel prices are expected to show strength in Asia, and sulfur limitations are far less severe, although many countries are now reducing diesel sulfur levels. To date, there are no restrictions on aromatics content, and none are planned.

Figure 131 presents PADD-V's diesel balance for 1981-92. Small surpluses of diesel have been commonplace in the PADD-V region, and Asia has served as a ready market for this diesel—though most of what is exported is not considered automotive grade. In 1991 and 1992, the diesel surplus grew significantly larger; output remained roughly constant, but diesel demand dropped off significantly. The drop in demand is largely attributed to poor economic performance in the U.S. West Coast, but it is not clear that improved economic conditions in the 1992-2000 period will result in a strong recovery in West Coast diesel demand, particularly since diesel reformulation regulations took effect in the fall of 1993. The forecast balances presented above assume that PADD-V diesel demand will recover to 400 mb/d by 1995 and grow only modestly afterward. It is possible that demand will remain at 370 mb/d or fall even lower; conversely, it is also possible that demand will rise. On the supply side, the West Coast industry is easily capable of producing diesel in the 450-550 mb/d range, provided that West Coast refinery capacity does not contract much further. Production of "clean diesel" may be limited in any case, since even major refiners are reluctant to make the investments needed to produce ultra-low sulfur, low-aromatics diesel. Given the range of possible output and consumption, diesel exports from the U.S. West Coast can be expected to fall in the range of 50-250 mb/d, with exports in the 100-150 mb/d range appearing most likely.

As with gasoline, trans-Pacific trade in diesel will be affected by both quantity and quality. In the case of diesel, however, both factors seem to encourage increased trade. Diesel volumes will be in short supply in the Asia-Pacific region and in surplus on the U.S. West Coast. Straight-run diesels in Asia tend to be of better quality than straight-run diesel on the U.S. West Coast: they are often higher in cetane, lower in sulfur, and lower in aromatics—in short, they are quite a bit closer to the clean diesel specified by environmental

Figure 131. The US West Coast as a Major Diesel Exporter? PADD-V Diesel Balance, 1981-92



*Note: 1992 data are January-Nov. only

regulatory agencies in the United States. Straight-run diesel from Alaska North Slope (ANS) crude has cetane index of around 47, contains around 35 percent aromatics by volume, and has a sulfur content of around 0.6 percent by weight. Many California crudes are even more sulfurous; for example, straight-run diesel from California's offshore Hondo field contains around 3.6 percent sulfur by weight.

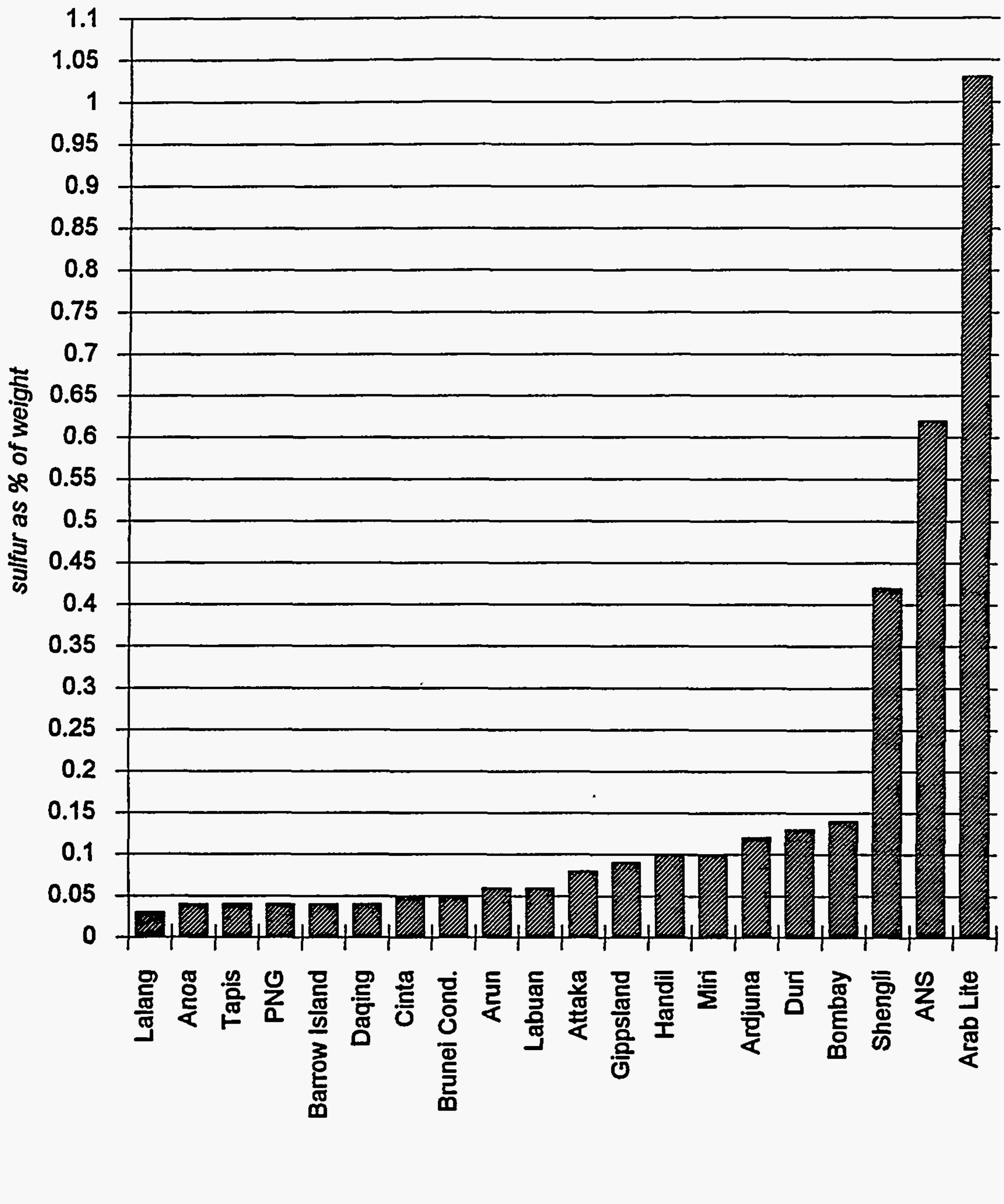
In marked contrast, there are a host of Asia-Pacific crudes that yield straight-run diesels with sulfur contents in the 0.05-0.15%S range—some of these diesels already meet the 0.05%S specification soon to be required, and others would require only light hydrotreating. Figure 132 displays sulfur contents for selected straight-run diesels, including ANS and Arab Light for purposes of comparison.

Additionally, many straight-run Asia-Pacific diesels have cetane indices in the 50-60 range and relatively low (10-30 percent) aromatics contents. Unlike the case with gasoline, where aromatics contribute to high octane ratings, diesel aromaticity is inversely proportional to the cetane index. These diesels would require less cetane enhancement and far less aromatics saturation.

6. Conclusion

The Asia-Pacific region is noted as one of, if not the, main engines of growth in the world economy. The population is large—approximately 60 percent of the world total—and there is an enormous amount of pent-up demand for goods and services. The region is also extraordinarily diverse, making generalizations difficult. Yet it can be said that an environmental movement has taken hold in many countries, particularly in East and Southeast Asia. Environmental regulations are not as strict as those in the United States, but many are significant because they are emerging in some countries that are considered low-income economies. Much of the conventional wisdom has held that poor countries could not afford to care for the environment and that, when a choice had to be made between economic

Figure 132. Sulfur Content in Selected Straight-Run Diesels



advancement and environmental protection, the environment would always take the hind seat. Instead, many developing countries are viewing environmental protection quite seriously, and many are seeking to avoid some of the pitfalls experienced, for example, by the United States when it was in its early stages of economic development.

Energy demand growth is rapid and is likely to continue at a rapid pace during the 1990s. There is little doubt that the Pacific Rim has emerged as a major growth market for petroleum fuels, with light and middle distillates capturing increasingly large shares of the demand barrel. It is also clear that many key Asia-Pacific countries are moving toward better-quality fuels: unleaded or low-lead gasoline with higher octane averages and often with some amount of oxygenation; lower-sulfur diesel, both industrial grades and high-speed automotive grades; and lower-sulfur fuel oil in certain markets (chiefly in East-Asia). Yet the specification changes are mild in comparison to those being adopted in California and the rest of the United States. Many U.S. West Coast refiners will find it difficult to meet the new standards with the traditional West Coast crude slate and may look to Asia for high-quality gasoline, diesel, LSFO, or gasoline and diesel blending components. There was initially much talk of gasoline exports from Asian export-oriented refineries; the quantity and quality issues discussed in this section lead to the conclusion that little, if any, Asian gasoline will find its way into the West Coast market.

Blendstocks such as MTBE and alkylate might prove welcome additions to the U.S. West Coast pool, but they are also important constituents of the Asian gasoline pool, particularly since the use of tetraethyl lead is being phased out in many countries and efforts to improve octane ratings are underway simultaneously. The price of these blendstocks most likely would have to be quite high before any significant quantity could be tempted out of the Asian pool. It now appears that there may be more opportunities for diesel trade than gasoline trade, with larger quantities of U.S. West Coast diesel that cannot meet the exacting new standards being shipped to Asia and small quantities of high-quality diesel or diesel blendstock coming into the West Coast on the return voyage. The cost and ease of shipping naturally will affect the overall economics, but in any event it seems likely that there will be expansions of diesel trade on traditional avenues. What remains to be seen is whether new niche opportunities may arise for more innovative trade in fuel blendstocks, where trade occurs not only to balance volumetric supply and demand but also because of fuel quality differentials.

D. Environmental Trends in Hawaii

1. The State of the State Environment

Hawaii's environment is diverse: tropical rain forests, deserts, arid rainshadow areas, mangroves and estuaries, swampland, coral reef ecosystems, highland plains, and snow-capped mountains. The island geography provided a habitat where unique flora and fauna were able to evolve. Despite all-too-rapid extinctions, Hawaii remains the home of the highest percentage of endemic plant and animal species in the world. The first Polynesians to settle in Hawaii changed the natural landscape and environment, bringing a variety of plants and animals, but they also brought a rich and fascinating culture and forever changed the cultural landscape. It stands to reason that Hawaii's environmental hazards, blessings, and overall outlook are markedly different from other states. Because of Hawaii's geography, many of the types of environmental hazards that plague Mainland cities of comparable size are virtually nonexistent here, while other problems are compounded. Air pollution, as a notable example, generally is not seen as a serious problem outside of a few localized sites—such as enclosed parking structures. The absence of many heavy industries reduces risk of toxic waste contamination. Even the oft-publicized problems with sewage treatment and release are less of an environmental hazard here than they might be elsewhere, since most of the bacteria that thrive in sewage die rapidly in saltwater and sunlight.

On the energy-environment side, the small size of the energy market has certain environmental benefits. As one example, the smallness of the market allowed the state to avoid both the construction of nuclear power plants and the resultant headaches associated with radioactive waste storage and disposal. Importing our energy resources is expensive and poses certain hazards during transport, but the lack of a fossil fuel resource base has an upside as well as a downside: no coal mining, no coal marshalling yards or extensive railroad networks, no oil and gas exploration or drilling—either onshore or offshore—and very little need for oil and gas pipelines, processing, and export terminals.

Hawaii is beautiful, and there is little risk of pollution-induced mortality and morbidity. Yet the state is far from pristine, and many of the environmental benefits that are the most highly prized are also under the greatest pressure. A large part of the urgency that underlies Hawaii's environmental movement stems from the fact that environmental degradation came so rapidly that the impacts were clearly visible; today's citizen in Hawaii has seen changes firsthand. It does not take a series of tales from a parent or grandparent to convince a young adult that Hawaii is growing more crowded, more developed, more dirty. And in a state where tourism is the number-one industry, it is clearly imperative that the natural environment be protected.

2. Energy and the Environment in Hawaii: Conflict and Consensus

The relationship between environmental protection and fossil fuel use is a complicated one in Hawaii. It is easy to assert that using fossil fuels is bad for the environment, but it cannot be said that all alternative sources of energy are environmentally benign. There is widespread agreement that *something* must be done to reduce Hawaii's dependence on imported oil, and there is widespread agreement that Hawaii's environment should be protected. It would be difficult to find anyone in the state who favors *more* oil-import dependence and *more* environmental degradation. But there is not always consensus as to which energy options we should pursue, which environmental regulations we should adopt, and how much we should spend. The issues are complex, and the allied camps are sometimes an eclectic mix. In many cases, the debates pit one group of environmentalists against another.

The Geothermal Controversy. The geothermal controversy has offered perhaps the most spectacular local example of this phenomenon in recent years. On the U.S. Mainland, most would agree that geothermal energy offers an attractive alternative to fossil fuels, but many people in Hawaii feel that the risks of extensive geothermal development outweigh the benefits. Modest development of the Big Island's geothermal resource (the immediate plan is to produce 25 MW) could alleviate brownouts and rolling blackouts, and it could potentially eliminate the need for oil shipments from Oahu, reducing both oil consumption and possible risks of oil spills. Intensive development of the resource, combined with the construction of three 200-mile long submarine transmission cables, was envisioned by many as a way to export perhaps 500 MW of electricity to the main center of demand, Honolulu, as well as perhaps Maui, Lanai, and Molokai en route. This could reduce or eliminate oil shipments to the latter islands and could back some oil out of the power sector on Oahu as well. At the time of this writing (November 1993), there are no plans to build a subsea cable for exports of geothermal-based electricity. The geothermal developments are for use exclusively on the Big Island.

The geothermal opposition has been vocal. Some of the opponents cite public health and safety considerations; Puna Geothermal Venture's KS-7 and KS-8 wells experienced widely publicized blowouts, and hydrogen sulfide gas emissions reached unacceptable levels. Additionally, the development is located in Wao Kele O Puna, the last major lowland rain forest in the United States. Opponents of the Puna geothermal development assign paramount importance to preservation of this habitat. Native Hawaiian opponents attach great cultural and religious significance to the region, particularly devotees of the Goddess Pele. Some believe that Pele creates new land, that the land belongs to the people *after* the lava is cool, but that whatever is still hot belongs to Pele alone. The debate is far from over. At this time, the environmental and safety impacts of the development are being thoroughly reassessed, and it appears that the developers will have much work to do to convince the public that geothermal energy can be developed safely.

The Biomass Question. Biomass use offers another example of potentially conflicting environmental/energy goals. Biomass, chiefly in the form of sugarcane bagasse, is Hawaii's premier renewable energy source and currently provides a significant amount of Hawaii's primary energy supply. Biomass could also help supplant fossil fuel use in the transport sector, where it is the most difficult to find substitutes, by serving as a base for alcohol fuels, notably ethanol. Ethanol makes a high-quality automotive fuel, and the availability of alcohol-fueled vehicles is improving as other states phase in alternative-fuel and variable-fuel vehicle programs. Strictly speaking, there is enough land in Hawaii that could be cultivated to provide sufficient biomass for a commercial-size ethanol plant. Realistically speaking, however, the land is not presently available, and the economics are not proven, particularly since Hawaii land prices are extremely high. On grounds of social justice, many contend that affordable housing is a higher priority for use of the land. Some oppose expansion of cultivation for biomass on other environmental grounds, such as increased water use, pesticide and fertilizer use, and energy use.

<u>The Rail Transit Proposal.</u> The proposed construction of a mass transit system in Honolulu touched off yet another controversy where energy and environmental goals seemed to mesh and collide at the same time. Advocates contended that a mass transit system was perhaps the only solution to traffic congestion and one of the few ways to conserve gasoline. Opponents were unmoved by these arguments and offered counterarguments that questioned projections of ridership, overall cost, and energy consumption. The draft environmental impact statement did not, however, make any grand claims about the energy benefits of rail transit. It noted that electrical energy consumption would rise, and that gasoline consumption would decline only modestly. Depending on the plan adopted, bus fuel consumption could rise significantly. It would also take a substantial amount of energy to build a rail transit system, and there would be possible increases in gasoline consumption and automotive emissions during the construction phase, when motorists would be faced with greater traffic congestion. Whether the opponents of rail transit were right or wrong, they were effective in turning public sentiment against rail transit, and the project was shelved once again.

H-power and Recycling. A final example of competing environmental goals focuses on the H-power plant. H-power helps the state meet dual goals: non-oil power generation and solid waste management, both of which are very high priority items and appear to have widespread public support. Environmental concerns arose nonetheless. First, like any combustion facility, the H-power plant emits airborne pollutants such as sulfur dioxide, nitrogen oxides, carbon dioxide, and particulate matter. Heavy metals including lead and arsenic also have shown up in H-power emissions. Emissions are monitored and regulated by the Department of Health, but the controls have not had a perfect track record. Second, some environmental factions think the H-power plant competes for solid waste that otherwise would be recycled, and they argue that the state has favored H-power at the expense of curbside recycling programs. The state report noted the relationship between recycling and H-power, but has stated that there is more than enough waste generated on Oahu to satisfy contractual obligations to the H-power plant and provide recyclers with all the material they can handle.

3. Oil Shipping and Oil Spill Hazards

Few events have had such galvanizing effect on public perception as the *Exxon Valdez* oil spill in Alaska's Prince William Sound in March 1989. Although oil spill legislation at the federal level had been in the works for many years, it is widely thought that the *Exxon Valdez* disaster was a deciding factor in the passage of the Oil Pollution Act of 1990 (OPA 90). While it was clear that some sort of oil pollution legislation was inevitable, OPA 90 allows unlimited liability to be assessed upon the shipper (and possibly upon all parties to the shipment). This has resulted in the relocation of at least one U.S. West Coast shipping company to Canada and has also caused the withdrawal of Chevron and PRI from shipping of fuel oil to Hawaii's neighbor islands. The cost of a single accident, especially in a place like Hawaii, could literally wipe out any oil company currently operating. It is impossible to insure against unlimited liability. The University of Hawaii's Sea Grant College Program estimates that a 30,000 barrel black oil spill in Hawaii would cost $30 million to clean up and could have worst-case economic damages on the order of $3-5 billion.[5]

OPA 90 does not provide for unlimited liability in all cases; there are limitations specified in the legislation. The feature that has proven worrisome to shippers is that the limitations are voided under certain circumstances. Some of these circumstances are perfectly logical and justifiable, such as when a spill occurs because of "gross negligence or wilful misconduct." While this seems reasonable enough, the limitation of liability as stated in OPA is may be voided if the company involved was at the time in violation of federal safety, construction, or operation regulations. Judging by past experience in liability litigation, many legal experts feel that there will be few cases where there is not some violation of some sort of federal safety, construction, or operation regulation; and there will similarly be few cases where these violations will not be shown by plaintiffs' lawyers to be causative to at least some extent. As court case after court case has shown, even a small contributory causation is usually enough to ensure that the "deep pocket" will bear the entire financial liability of an accident. The door to unlimited liability is still open as far as most analysts are concerned.

Proponents of OPA 90, however, are convinced that this is the only way to ensure timely and thorough clean-up, provide full compensation for damages, and force improvements in the fleet. The specter of unlimited liability has already prompted oil companies to expand safety training programs.

Although OPA 90 gives the president what appear to be sweeping powers in intervening in the aftermath of a spill to take over the containment and cleanup process, some legal scholars have raised doubts as to the extent to which the wording of the law actually empowers the president. In any case, despite the intent of the law, it is doubtful that the president would decide on such intervention in the critical early hours of a spill; politically, it seems much more likely that the president would decide on federal intervention

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[5]Jack R. Davidson, "Estimated Clean-up Costs Associated with a 30,000 Barrel Oil Spill in the Kaiwi Channel," Sea Grant College Program, University of Hawaii, 9 April 1992.

only after the spill had clearly reached disaster proportions or had been severely mishandled by the initial response crew.

Congress considered a unified national-response approach to spill containment and cleanup, but, in the punitive mood that ran high after the *Exxon Valdez* disaster, many members felt that the company involved in the spill needed to be vitally involved in the containment effort. The legislation as it stands is a compromise between those who felt that the responsible party needed to direct the clean-up (largely, one must presume, as a punishment) and those who favored a unified response. The difficulty is that there are dozens of small oil companies with limited resources and even more limited experience in handling spills; making such firms the spearhead of operational efforts to contain a major spill is clearly not in the interests of the environment.

Indeed, Thomas Wagner, a well-known pollution lawyer, argues that OPA 90 actually makes containment and clean-up a more complicated and less effective matter:

> Whether the responsible party or the federal government undertakes the clean-up, the new removal provisions add to an already complicated chain of uncoordinated command...Rather than simplify and streamline the removal process by placing responsibility in a single agency, the Act exacerbates the already convoluted removal process. The kibitzing and finger-pointing which so drastically impeded the Alaskan clean-up effort will almost necessarily be compounded under any oil-spill removal program in the future.[6]

In current liability law, "responsibility" for a mishap is usually assessed by a jury against the parties. For example, the main cause of a disaster could be natural forces, but a person or company could be held "10 percent responsible" for not taking proper precautions or not making the proper responses. The problem is that recovery of damages is not related to responsibility: any party found to be negligent in any way can be assessed the full value of

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[6]Thomas J. Wagner, "The Oil Pollution Act of 1990: An Analysis," *Journal of Maritime Law and Commerce*, Vol. 21, No. 4, October 1990, pp. 584-585.

the awarded damages. Clearly, *any* involved party can be viewed as being at least somewhat responsible for any kind of accident. Hence, companies are rightly concerned about the current unlimited liability policy.

Companies have the sole responsibility for providing containment and clean-up teams for spill emergencies. The performance of Exxon, the world's largest oil company, during the Alaska spill, makes it apparent that even the largest companies are ill-prepared to manage a disaster; imagine the level of preparedness of small companies.

Oil spills are infrequent events. Therefore, no disaster-response team in any company is likely to have much experience in dealing with spills. Furthermore, any such team stands a good likelihood of being located at a site far from the incident, resulting in the loss of precious time in the critical early stages of a spill.

Companies are extremely reluctant to send their employees into a hazardous situation. Rough seas or poor flying conditions can delay response. Insufficient innovative research on spill containment and clean-up has been undertaken because of the fragmented nature of the response system.

New legislation requiring double hulls on tankers will lessen the probability of spills, but will not eliminate them. Nothing substantive has been done to respond to a spill disaster when it occurs. The damage will still be done, and someone will be liable. This is good for the lawyers, but not a step forward for the environment.

OPA 90 caused a local controversy when, in early 1992, Pacific Resources Inc. (PRI) announced that it would discontinue shipments of heavy fuel oil to the neighbor islands. Under state law, liability is capped at $750 million, but this has been called a "false cap" because federal unlimited liability provisions override state law. Hawaiian Electric Industries, Inc.'s Hawaiian Tug and Barge Corporation is now the only shipper moving the needed volumes, but it remains to be seen whether in the longer term, fuel oil shipping in the islands is worth the potential risk to both the shipper and to the environment. At present, fuel oil offers the most economical source of fuel for power generation on most islands other than Oahu, but it could easily be argued that this is because the full environmental risk premium associated with fuel oil is not being paid.

Most Hawaii residents seem to applaud taking a get-tough attitude with respect to the consequences of oil pollution, while simultaneously expecting oil to be delivered throughout the islands at fairly low costs. Any hardships imposed by raising the costs of black oil shipping on an interisland basis will be borne by islands with small populations, not necessarily by Oahu.

4. Assessing Public Perceptions

Surveys of Hawaii residents conducted by the Hawaii Energy Strategy (HES) Program,[7] by Hawaiian Electric, and by others show some rather surprising results. Although the need to keep costs low is always stressed, roughly 70 percent of respondents to the HES survey (which is, presumably, a more energy-aware group than the state average) would be willing to pay higher energy prices to decrease dependence on oil.

On the other hand, when asked to state their highest priority in the Hawaiian Electric survey (using a more representative sample), 31 percent of Oahu residents selected keeping electric bills as low as possible; 25 percent rated environmental protection as the top priority; 19 percent chose lessening oil dependence; and 9 percent identified programs to increase energy efficiency as their top concern. This would appear to suggest that those seeking lower rates are the largest group, but it can be argued that those who identified environment, energy efficiency, or oil reduction as their top priorities would all share a great number of the same goals; and all of these respondents *did not* find the lowest costs to be an overriding concern. This indicates that the results of the HES questionnaire may not be as unrepresentative as might be suspected; about 30 percent of the respondents in that survey were unwilling to pay higher energy prices to reduce oil dependance, and this is quite likely a similar group to those who identify lower bills as their number one priority.

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[7]See State of Hawaii, Department of Business, Economic Development, and Tourism, *Proceedings of the Hawaii Energy Strategy Workshop*, 23 October 1992.

Although the structure of the existing surveys is not adequate to make trade-offs, the results strongly suggest that the levels of environmental awareness in the state are fairly high, and that measures to increase energy self-sufficiency should enjoy fairly widespread support except in cases where there seems to be a conflict with environmental preservation. Most of the alternatives to oil are likely to be perceived as environmentally preferable as well, with the exceptions of geothermal and, possibly, coal. The HES survey asks for rankings of oil alternatives on a 1-5 scale of disapprove-approve, and coal ranks lower than the other alternatives (but, with a score of 2.93, can be viewed as more or less neutral, as opposed to the other sources which gained high approval ratings). The spread of responses on coal may reflect genuine differences of opinion, but it also may reflect how the question was posed: "Coal" stirs up very different mental images, ranging from ideals of twenty-first-century clean coal technologies to industrial-revolution images of smokestacks belching black fumes. The question that needs to be posed in the future is whether coal or oil would be preferable at the expected levels of emissions from the technology, and given planned offset and abatement schemes (such as AES's tree-planting program).

5. Conclusions

Although oil supplies will not be running out in the near future, they will be subject to continued price fluctuations, and environmental-protection measures enacted on both sides of the Pacific will tend to increase the cost of using oil products, even if the price of crude is somewhat restrained. Particularly important from the Hawaiian perspective is the future of the fuel oil market.

There is likely to be a glut of fuel oil in the Pacific for at least a decade. Refinery runs will be increasing, but without a concomitant increase in cracking—or at least without enough new cracking to balance supply and demand for light products. Thus, it would seem to be a good time to be a fuel oil user.

There are, however, many factors that are likely to make fuel oil far less attractive in the Hawaiian context in coming years. The fuel oil that will be in surplus around the region will be high-sulfur fuel oil, not the low-sulfur material that is required for Hawaiian power stations. This might not seem to pose a problem, since the premium of low-sulfur fuel oil over high-sulfur fuel oil has only been about $2.00/b ($0.30/mmBtu). Today, the marginal source of low-sulfur fuel oil is crude distillation; in the next ten years, it is likely that increasing sulfur standards and decreasing exports of low-sulfur crudes in Asia will make resid desulfurization the marginal source of low-sulfur fuel oil. Current construction and operating costs in Asia suggest that this could result in a spread of $6.00/b or more between the low-sulfur and high-sulfur fuel oil prices.

On top of this, the Btu tax as likely to be implemented hits fuel oil hardest of all in both percentage terms and in terms of the tax per barrel. Any "carbon tax" accepted within the International Energy Agency (IEA) will also hit fuel oil fairly hard (though not as hard as coal). Above all, the increasing transport costs of fuel oil (because of high insurance premiums) may also put upward pressure on prices in some areas. It is too early to draw firm conclusions about the future of the fuel oil price in the region, but it seems quite likely that the historic differentials between low-sulfur fuel oil and light oil products will narrow, at least from the consumer's point of view.

Given these trends, and the general support for displacement of oil, it may be time to confront the public with some more explicit choices. Is the preference for energy prices that are lower on average, but more volatile, or prices somewhat higher on average, but more stable? Would it be worth the cost to have more domestic, stable-price energy sources in the mix even if this meant that one or two fuels became much more expensive? There is a clear dislike for Hawaii's dependence on oil: is this attitude engendered mainly by price volatility, fear of physical shortages, an environmental ethic, or a combination of these?

What everyone would of course like best is a nonpolluting, locally produced, renewable energy source whose price remains constant when oil prices go up, but whose prices decrease if oil prices go down. Until this panacea is found, however, more mundane choices must be made. One of the basic questions that has not been answered is, among those who wish to switch away from oil, whether the primary reason for their preference is a dislike of dependence on oil per se or whether it is the price behavior of oil that is the critical problem. This is a vital policy question, because so many schemes for rolling in alternatives are deliberately linked to oil prices—the most obvious case being "avoided cost" power pricing, where independent power producers sell their power to the utility at some measure of the utility's marginal cost of production. There are many ways to calculate an avoided cost, and many different contract formats have been used in Hawaii. Some provide a fixed price for the power based on expected average prices of oil, but across the nation the most common form has probably been direct linkage to oil prices. Any format is fine if the goal is simply to substitute other sources for oil; but if the main goal is to weaken or break the linkage between local energy prices and the fluctuations of the oil market, then avoided costs based on direct indexing to oil achieve nothing at all. The unanswered question remains: when the public votes in a poll to reduce dependence on oil, are they voting against oil consumption or against oil prices? The Integrated Resource Planning (IRP) process offers the most favorable forum for assessing many of these issues, since the IRP is able to consider energy issues on the broadest possible scale. Charging the Public Utilities Commission (PUC), for example, with pursuing a particular goal in approving avoided-cost contracts, could be done more readily through the IRP mechanism than through a formal directive from the legislature; legislation is neither a good tool for specifying goals that cannot be put into precise language, nor a good way to set direction in a situation where there are a great number of trade-offs.

One of the dangers for Hawaii is that the environmental ethic so clearly reflected in public opinion will result in legislative decisions that are gestural rather than useful. Reformulated fuels offer one of the most likely areas for such a problem to emerge. As California, and nonattainment urban centers all along the Pacific Coast, move to reformulated gasoline and diesel, there will be political pressures—possibly from the public, possibly from members of the legislature—to voluntarily adopt reformulation in Hawaii so as to show that Hawaii is at least as environmentally progressive as California. The problem is that fuel reformulation in California (which goes beyond the minimum requirements of the Clean Air

Act amendments) signifies not so much a glowing environmental ethic as a severe case of environmental degradation. Many of the problems that reformulation is designed to correct (high emissions of carbon monoxide, NO_x, and ozone generation) are problems only in densely populated air basins; in a more open environment like that of Hawaii, these materials quickly degrade to harmless normal components of air. Simple measures—such as requiring better nozzle confinement on gasoline pumps to control evaporative losses—could make greater improvements to the Hawaiian air quality than moving to reformulated gasoline.

The one area of reformulation that might be examined for Hawaii is the reduction of aromatics in gasoline. Aromatics reduction has been a major goal in California; many of the aromatics, particularly benzene, have long been known to be carcinogenic. Whether this poses a genuine health risk other than to those who siphon gasoline has been a matter of heated debate. The aromatics are designed to be burned within the automobile, not to come in direct contact with humans. There is a certain risk in handling motor fuels, but whether this risk is high enough to warrant aromatics controls in Hawaii is open to question. Even in California, aromatics have not been eliminated, but merely reduced, at a relatively high price; it is difficult to assess whether a fractional reduction in these dangerous components is worth the cost. In Los Angeles, where the inhabitants are in effect cooped up with their pollutants at a very high density, there is a powerful incentive to err on the side of caution.

The scientific research on the environment on the U.S. Mainland is of course important to Hawaii, but it is not at all clear that the environmental priorities of the Mainland should be allowed to set the priorities of Hawaii. Some of the most pressing issues on the mainland, such as pollution of air and river systems, are not nearly as pressing in Hawaii, where the air basin is the vast central Pacific and the river systems are short and receive minimal intentional discharge. Hawaii has its own set of problems: contamination of the land is a far more critical issue, as are any pollution of the water table or pollution that affects coral reefs. The danger is that, with growing green attitudes everywhere, the focus of energy strategy will be constrained by an environmental agenda that is appropriate to the Mainland while not addressing the unique issues of the Hawaiian ecosystem.