4. LNG AND GTL PRODUCT MARKETS

This section contains a review of the Asian LNG market and the U.S. refined product markets, and a review of future supply/demand volumes and prices in these markets. The two options for utilizing North Slope gas described in **Section 3** would produce different types of products that would be sold in different end user markets and different market locations. The LNG option would produce LNG that would be marketed in Japan, South Korea, and Taiwan. The GTL option would produce a refinery feedstock having a large concentration of material that would be refined to gasoline and distillate products (e.g., jet fuel, home heating oil, No. 2 fuel, or diesel fuel) and would be marketed to U.S. West Coast refineries or exported.

4.1 U.S. West Coast Oil Product Markets

The U.S. West Coast is a major market for oil products with most of the consumed products being produced by refineries located in the region. In 1994, the refineries in the region (PAD District V)[a] produced about 2.8 MMB/D of refined products to meet a demand of 2.7 MMB/D in the region. Gasoline was 49.5% and distillate was 29.0% of the total refined products demand (EIA, 1995b).

In assessing the value of a GTL product as a feedstock to a refinery, the primary variable is the average crude price. The value of a feedstock, such as GTL products, can be estimated from the average crude price and is based on the relative processing costs and value of the refined products.

The refined products of highest value are gasoline and distillates, which sell at higher prices than crude oil because of the processing cost to convert crude oil to these products. In **Figure 4.1**, prices of gasoline and No. 2 fuel oil (one of the distillate products) are plotted along with the average price of crude oil imported into the U.S. (EIA, 1995c). As can be seen, the prices of these products track the pattern of movements of crude oil prices. The wholesale gasoline price averages \$8/BBL higher than crude oil and No. 2 fuel oil price averages \$6/BBL higher than crude oil. In addition, the products that are made in the Shell SMDS plant in Malaysia and the Exxon AGC-21 pilot project are higher value fuel products than those made from crude oil because of the zero sulfur, nitrogen, and aromatic content, which makes them ideal for meeting the new low-emission regulations for diesel, etc. (Eilers, 1990; Eisenberg, 1994). These products

a. Petroleum Administration for Defense District V (PAD District V) includes Alaska, Arizona, California, Hawaii, Nevada, Oregon, and Washington (EIA, 1995b).

are expected to make excellent high value blending products for meeting the new California low-emission fuel regulations and thus could have a higher value than normal diesel and gasoline products. Shell reports that the high-quality distillates made in its Malaysia plant have been commanding premiums of \$8 to \$10/BBL over crude oil-derived distillate in the California market (Oil Daily, 1994d).

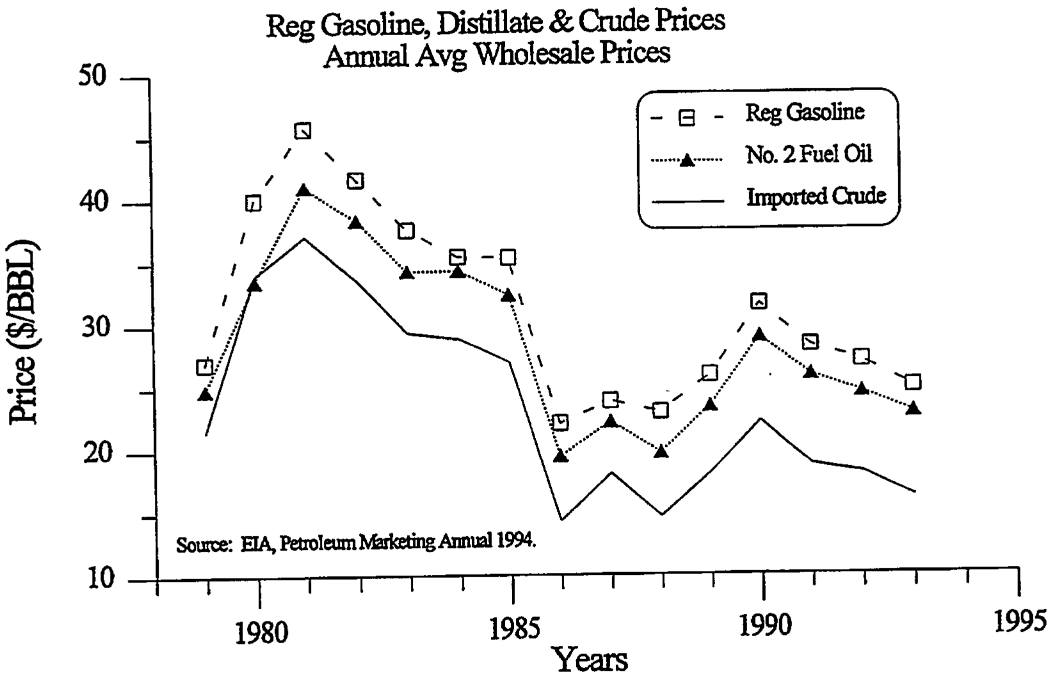

Figure 4.1. U.S. average annual wholesale prices for gasoline, No. 2 fuel oil, and imported crude oil in dollars of the day (EIA, 1995c).

GTL products envisioned in this study, would be expected to fit reasonably well into the West Coast refinery situation. The GTL product would arrive at the West Coast refineries mixed with Alaska crude oil. (However, if it is feasible to transport GTL products in TAPS as alternating slugs with the crude oil, the products would remain separate from the crude oil and be transported as hydrocarbon fuels that would not have to be separated from the crude oil in the refining process. The feasibility of this option was not evaluated in this study.) West Coast refineries were specifically designed for the Alaska crude and many of them are highly complex with a higher level of hydrocracking facilities than in most refining areas. The GTL product envisioned for this application contains high concentrations of straight chain paraffins. In the distillate boiling range, this feedstock makes attractive diesel fuel material, but the higher boiling paraffins are best converted to valuable products by hydrocracking. Thus, while any change in refinery feedstock requires some adaptation in refinery operation, the West Coast refinery market appears to be a reasonably good target market for GTL products from the processing and refinery product standpoint.

At today's crude market prices and state of development, GTL projects look attractive only for a few producing locations, primarily remote locations where gas has a low market value as discussed by Hackworth (DOE, 1995). Even for low-value remote gas, the analyses by Hackworth indicate that increasing crude prices are needed to provide a reasonable return on GTL conversion facilities and provide a reasonably attractive wellhead price to producers. The EIA's 1995 forecast of oil prices is shown in **Figure 4.2** (EIA, 1995). The EIA 1995 forecasts span the range of other published forecasts (see **Table 4.1**). To provide an additional comparison, a flat oil price of $18/BBL is also used in this study. As shown in **Figure 4.1**, when shown in dollars of the day, crude oil prices have fluctuated for the last 10 years but have shown neither an upward or downward trend.

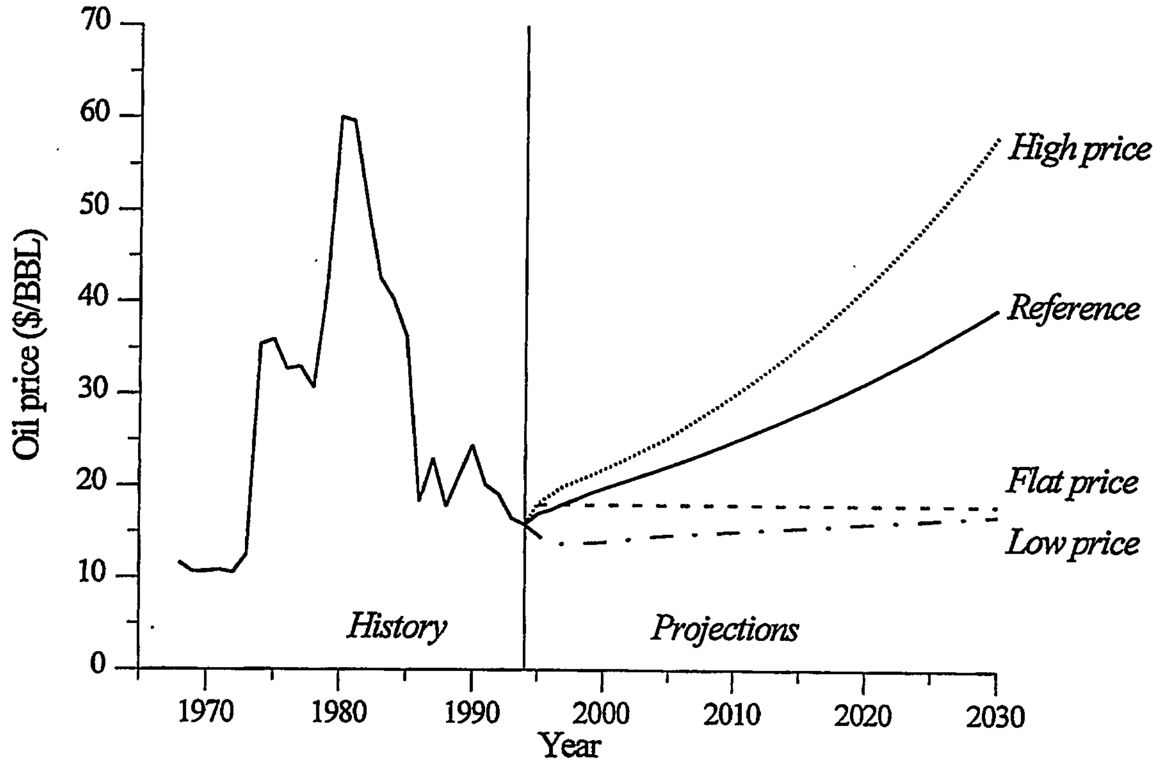

Figure 4.2. Historical world oil prices and world oil price forecasts in 1/1/95$ (EIA, 1995).

4.2 LNG Markets

Natural gas that has been discovered in locations where there is little local demand has experienced great difficulty in building markets in distant major energy market areas. Over the last half-century, oil production in the Middle East has gained a major market share in the oil markets of Asia, Europe, and the U.S. In contrast, there has been little development and export of natural gas from the Middle East despite its large volume of discovered natural gas reserves (**Table 4.2**).

Table 4.1. Comparative forecasts of world oil prices (EIA, 1995).

	1995 dollars per barrel		
Forecast	2000	2005	2010
AEO95 *reference*	19.76	22.21	24.92
AEO95 *low price*	13.97	14.72	15.13
AEO95 *high price*	21.85	25.36	29.95
DRI	20.86	25.76	29.31
WEFA	19.58	21.26	22.30
IEA	23.94	29.14	29.14
GRI	19.40	—	21.44
PEL	16.65	25.62	15.62
NRC	25.25	26.35	26.35
CEC	21.99	24.23	26.68

Table 4.2. World Gas Statistics (BP, 1995; OGJ, 1995i).

	Reserves (TCF)	Production (TCF)	R/P Ratio
North America	311	24.8	12.5
Latin America	189	2.5	76.1
Western Europe	216	8.4	25.8
Former Soviet Union	1976	23.7	83.4
Middle East	1594	4.5	354.5
Africa	341	2.6	131.0
Asia and Australia	350	7.0	49.7
TOTAL	4978	73.5	67.7

The natural gas reserves and/or resources, which are located far from major markets (usually referred to as remote gas), face a significant transportation disadvantage. To get to markets, remote gas must usually be liquefied either by conversion to LNG or by one of the chemical conversion processes (GTL) discussed in **Section 3**. To date, LNG has been the primary means used to move natural gas to distant markets. The LNG business has been built primarily around two geographical pairings; the North Africa to Europe trade and the Asia/Australia supply of Japanese markets. As **Figure 4.3a** and **Figure 4.3b** show, these two trades account for most of the current world LNG traffic. The Asia/Australia trade has experienced the most robust growth, growing at an average 7% per year between 1984 and 1995. North African export has grown at 4% per year during the same period.

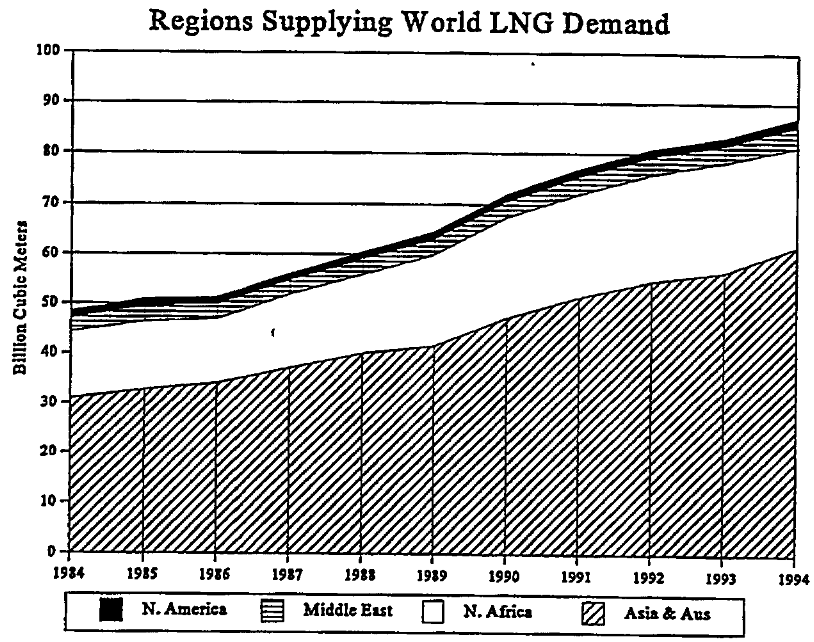

Figure 4.3a. LNG world supply volumes and regions (BP, 1995).

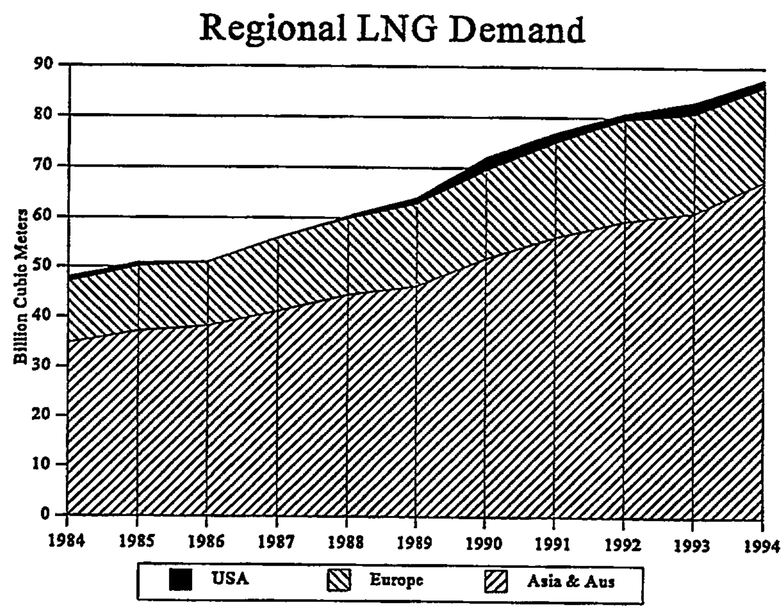

Figure 4.3b. LNG world regional demand (BP, 1995).

There has also been a small export volume (1.7% of world supply) from the production facility in southern Alaska, and from Abu Dhabi in the Middle East (4.9% of world supply) (ADNR, 1995c). The Alaska and Abu Dhabi exports are marketed in Japan (BP, 1995).

Japan is the largest LNG market representing 65% of world demand in 1994. LNG demand in Japan has grown at a rather steady 5% per year over the past decade. Worldwide LNG consumption has increased 6.2% per year between 1984 and 1994 (BP, 1995).

At the Eleventh International Conference & Exhibition on Liquefied Natural Gas held July 3-6, 1995, a number of industry forecasters exchanged views on the future growth of LNG demand. Generally, the forecasts are for healthy LNG growth to continue, but at a slightly diminished growth rate. Forecasts by CEDIGAZ (Cornot-Gandolphe, 1995) and by consultant Malcolm Peebles (Peebles, 1995), see demand growing to 130 million metric tonnes per year (MMTPA) by the year 2010 as shown below in **Table 4.3**. Asian markets are seen as continuing to be the major LNG market representing two-thirds of the 2010 demand. Japan's share is forecasted to decline as demands in other Asian countries grow at a faster rate.

Table 4.3 World LNG demand forecast (after Cornot-Gandolphe, 1995).

	1994	2000	2010
LNG Demand (MMTPA)	65	90	130

Historically, the delivered price of LNG has been strongly influenced by the price of crude oil, as shown in **Figure 4.4** (BP, 1995). LNG prices rose almost in proportion to crude in 1978 and 1979. When world oil prices fell precipitously in 1986, LNG followed the downward path at a somewhat slower pace. In recent years, LNG has been selling at a price premium over crude delivered to the Japanese market. This may or may not continue in the future but the potential for development of power generation plants based on LNG as announced in 1994 by Tokyo Electric, suggests that an LNG market could develop that would not be as strongly tied to crude oil prices (Alaska Conservation Foundation, 1994).

Although there has historically been a significant correlation between crude oil and LNG prices, there are some important differences in the cost structures of crude versus LNG that have major impacts on who supplies which market and how supply contracts are written. When $20/barrel crude oil is delivered to Japan, only about $0.70 to $1.50 of that $20 goes for transportation with the producers at the plant gate receiving about 90% of the market price. By contrast, if LNG is delivered to Japan at $3.40/MMBTU (equivalent to $20/BBL on a BTU basis), the producer at the wellhead may only receive a small fraction of

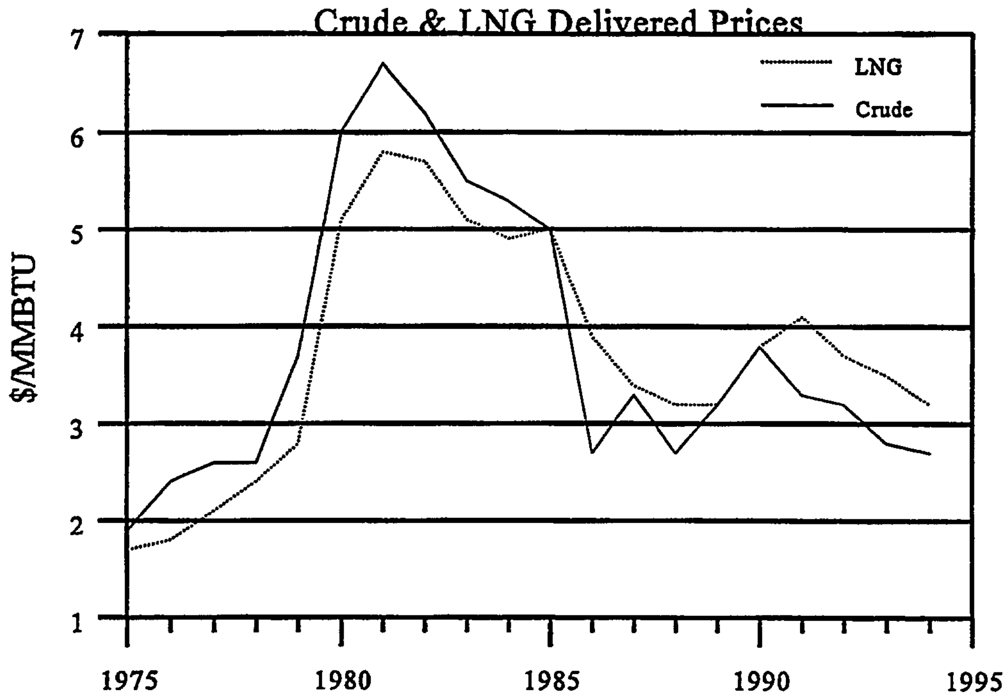

Figure 4.4. Historical prices for LNG and crude oil (BP, 1995)

the sale price (e.g., 5% to 25%) with the balance being consumed by liquefaction and transportation costs. Cost breakdowns for liquefaction and transportation costs are discussed in detail in the papers presented at the Eleventh International Conference & Exhibition on Liquefied Natural Gas (Cornot-Gandolphe, 1995; Hawkshaw, 1995).

Sellers and buyers of LNG are both well aware that the price of crude oil could drop to $10/barrel or, in tight market situations, could jump quickly to $40/barrel and remain at that level for several years. Long-term LNG contracts take this into account by retarding the rise or decline in LNG prices during crude oil price spikes and collapses (Hawkshaw, 1995). **Figure 4.5** is an illustration of a possible long-term LNG contract that is typical of historical contracts that allow the buyer and developer to share the risk of price fluctuations. Between a crude price of $14 and $25/BBL, the LNG price is adjusted proportionally for changes in the price of crude oil based on BTU content. However, if the crude oil price drops below $14/BBL, the LNG price declines only a fraction of the crude oil price decline. Conversely, if the crude oil price rises above $25/BBL, the LNG price increases only a fraction of the crude oil price increase.

Hawkshaw and Flower (1995) addressed the question of the supply sources for future demand. They presented a view that the supply sources for the future Asian market will be based on relative cost

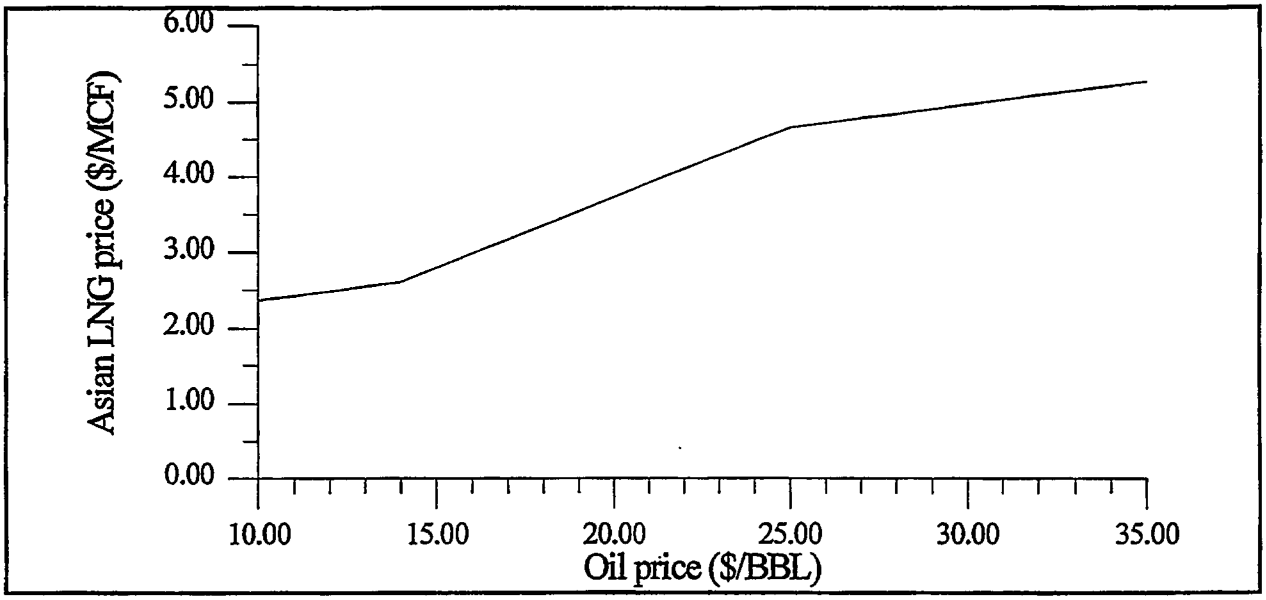

Figure 4.5. Example of relationship for a long-range LNG contract showing dependence on crude oil prices.

competitiveness. **Figure 4.6** represents this assessment of cost of delivery from various supply sources. According to Hawkshaw and Flower, new supply would first come from expansion in Australia and Indonesia and from the grass roots projects in South East Asia. As shown, North Slope Alaska falls in the least cost competitive grouping. Viewed from a cost competitiveness basis, an LNG project for North Slope gas faces a major cost disadvantage because it must support a $6.6 billion gas pipeline in addition to the liquefaction and LNG transportation cost. In contrast, YPC believes TAGS has better economics than any of the proposed LNG project according to the North Slope Natural Gas Pipeline Status Report published in 1994 by the Alaska Conservation Foundation; i.e., "Yukon Pacific modeling based on what they claim to be very conservative assumptions shows that TAGS has the best overall economics of any of the proposed projects (Qatar, Oman, New Guinea, Natuna Island, Sakhalin) vying to serve the post-2000 Asian LNG market." (Alaska Conservation Foundation, 1994, p. 5).

4.3 Summary

The prospects for utilization of North Slope natural gas are strongly tied to world crude prices. There has been steady growth in the Asian LNG market but the supply sources have been Asian and Australian gas located at comparatively short distances from the markets in Japan, Korea and Taiwan. Because crude prices have shown no sign of increasing in recent years and because GTL technology is only emerging to commercialization, there have been only a few GTL projects. The possible future price path for crude oil would not impact LNG and GTL options equally. A high crude price path would more favorably impact GTL than the LNG option. These market price impacts are described in detail in **Section 5.**

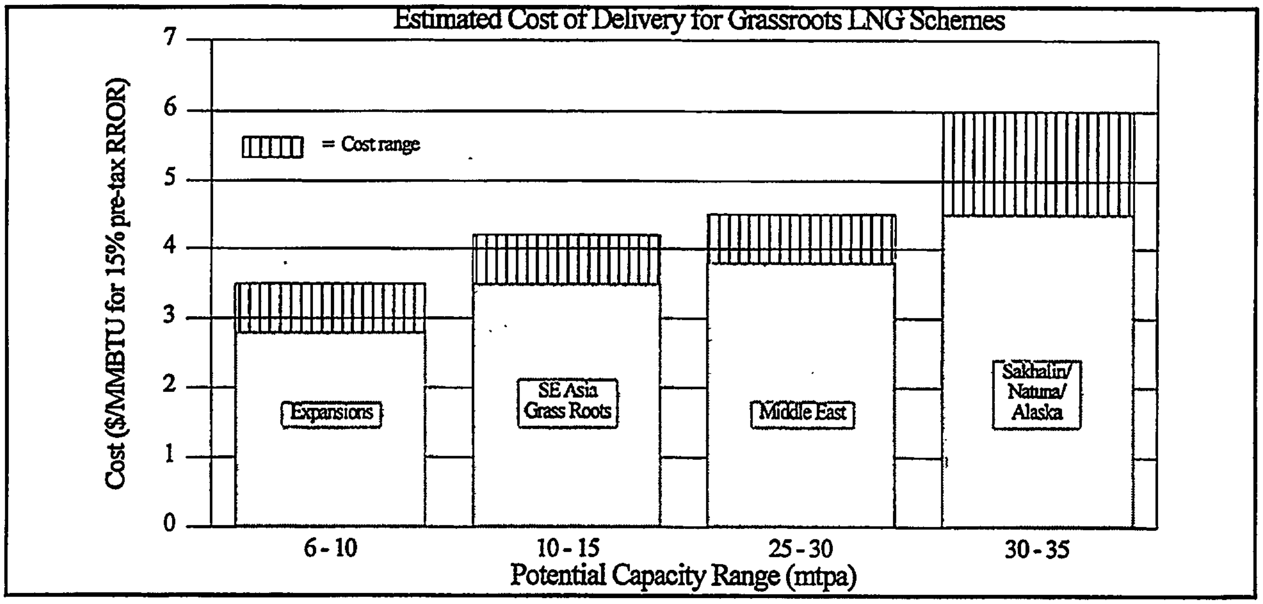

Figure 4.6. Estimated Pacific Rim delivery costs for LNG from various sources (Hawkshaw and Flower, 1995).