EAST ASIA/PACIFIC NATURAL GAS TRADE

FINAL REPORT

International Natural Gas Trade Project
Center for Energy Policy Research
Energy Laboratory
Massachusetts Institute of Technology
March 1986
MIT EL 86-005

Acknowledgment

This policy analysis of East Asia/Pacific natural gas trade has been generously supported by the participating organizations listed below. They have been helpful in sharing information and perspectives, and we have benefitted greatly from their assistance. However, the views and contents of this report are the authors' sole responsibility, and do not necessarily reflect the views of the participating organizations nor the Massachusetts Institute of Technology.

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Chevron Corporation, San Francisco, U.S.A.

Den norske Creditbank, Oslo, Norway

Department of Energy, Mines and Resources, Ottawa, Canada

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Kawasaki Heavy Industries, Ltd., Tokyo, Japan

Ministry of Energy, Ontario, Toronto, Canada

Nippon Oil Company, Ltd., Tokyo, Japan

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Royal Dutch/Shell Group

Royal Ministry of Petroleum and Energy, Oslo, Norway

Tokyo Gas Company, Ltd., Tokyo, Japan

United States Department of Energy, Washington, D.C.

Yukon Pacific Corporation, Anchorage, U.S.A.

INTRODUCTION

This report on Natural Gas Trade in the Pacific Basin is the second of three units being produced by the Center for Energy Policy Research. The first unit on Canadian-U.S. trade has already been published, and the third, on Western Europe, will be completed by August 1986.

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This paper will examine how a set of past policies and practices has produced a pattern of LNG use in Japan which has likely reached the maximum possible volume under those conditions. It appears as though this effect was unintended, and now even may be seen as unfortunate. However, changing these conditions is difficult, and the likelihood of success uncertain.

The policies and practices described are those of Japan because it is the giant of liquefied natural gas (LNG) utilization. Japanese experience has created much of the world's perception about LNG, and both producing and consuming countries' expectations have been shaped by that experience. In this paper, we describe key elements of the Japanese experience, and show that it was perhaps more random or accidental than deliberate, with consequences that may be self-limiting to greatly increased natural gas use in that country.

LNG IN JAPAN

Because the Asia-Pacific region's perception of LNG trade has been so influenced by the Japanese experience, Japan was selected to examine policy issues for both consuming and producing countries in the region.

In this paper, a major focus is given to town gas companies, even though they import only 20 percent of current contract volumes. As will be discussed later, the dominance by electric utility use of LNG imports will likely continue. However, the potential growth of natural gas use in Japan is probably higher outside the electric utility sector, which thus highlights the role of--and policy toward--town gas companies as a major determinant of future LNG imports into Japan.

To understand current Japanese policy on gas utilization, examination of its historic development is necessary. This examination shows that three important factors have not yet been successfully integrated in current Japanese policy making. These are: 1) regulation of gas distribution companies (referred to in this paper as town gas companies); 2) environmental regulation; and 3) electric utility fuel diversification strategies following the two oil price shocks.

Town Gas Companies--Background

The development of town gas companies using manufactured gas followed patterns similar to that in other countries. Commercial enterprises were begun in the late 19th century to gasify coal, primarily for lighting. Development of electric lighting early in the 20th century affected this principal market of the town gas companies, and gas sales began to be directed toward other purposes, primarily for cooking.

Because Japan has virtually no natural gas resources, town gas companies were especially dependent on coal for manufacturing of gas. Domestic coal reserves are also limited and were subject to price increases. Thus, as the price of coal increased, town gas companies--whose sale prices to municipalities were largely fixed--were caught in savage margin squeezes. In some cases, bankruptcies resulted, causing failures of service. To ameliorate such problems, National Gas Act legislation was enacted by the Imperial Diet in 1923, 1925, and 1930. These provisions included:

1. The establishment of new gas manufacturing plants and modifications to existing plants to be on a permission basis;
2. Regulations governing the use of public property such as rivers, roads, etc., for distributing gas;
3. The regulation of gas prices and related terms and conditions;
4. Safety aspects for gas manufacturing plant;
5. Limitations relating to calorified value, pressure, and quantity[1]; and
6. In 1930, amendments giving national authority for permitting increases in capital structure and resolving disputes between companies and municipalities.

By the late 1940s and early 1950s, town gas companies had begun to recover from the war years and resume full service to customers. A series of legislative changes in the 1950s led to a regulatory pattern that gave considerable authority to gas companies in their service areas, but which also imposed service obligations. Because there were no interprefectural or intercity movements of gas by pipeline, each gas company was responsible for its own supplies and marketing. As a result, the gas industry remained fragmented, largely local in its orientation, and serving mostly a residential market, which could support the rather high-cost gas supply.

[1] Malcolm W.H. Peebles, Evolution of the Gas Industry, New York University Press, New York, New York, p. 96.

In the mid-1950s, feedstock for gas manufacturing began to shift away from sole dependence on coal and toward crude oil, naptha, and (liquefied petroleum gases (LPGs). The acceleration in the Japanese economy increased gas demand in all sectors, and especially the residential. Gas use for water heaters became more widespread, though space heating still lagged. Some sales began to the industrial sector (primarily feedstock for the chemicals business) and for new commercial buildings in the major metropolitan areas.

Thus, by the mid-1960s, town gas companies were enjoying major growth in their markets, especially the residential sector. The limited use of gas for cooking and water heating permitted high unit prices despite considerable load fluctuation. New hookups increased revenue, and everyone was reasonably happy. As indicated previously, the structure of the town gas industry and its regulation were locally oriented and served a high-value residential market. By the mid-1960s world oil prices were low, and oil-based feedstocks were increasing in use without significant controversy.

Town Gas Policy

The Japanese Ministry of International Trade and Industry (MITI) has exerted considerable influence over major portions of industrial policy in Japan. It appears as though the town gas sector is one to which MITI has given virtually no attention historically. There is no literature speculating on why this sector has received so little emphasis, so some speculation is in order.

First, one might ask why the town gas sector is sufficiently important to warrant attention. In terms of the history described above, there was little reason to invite major policy attention. The gas supplied was oriented to an entirely local market, was small in volume, and produced by companies that were of diverse ownership (about 180 private and 70 municipal).[2] Of course, not all parts of the industry are small, as measured by number of customers, with Tokyo Gas Company the world's largest gas utility with over 6 million customers and Osaka Gas Company with over 4 million.[3]

During the post-World War II period, other sectors of Japanese energy industry received significant attention by MITI, especially oil and electric utility companies (with nuclear power development receiving particular attention and resources). The lack of attention to town gas companies was therefore likely simply due to lack of interest. Because town gas was serving the residential sector for cooking, hot water, and some space heating, premium prices could be claimed, and even gas manufacturing from coal or naptha could be profitable in that market. Thus, no "problem" was seen to be solved in this sector, so apparently no MITI attention (or resources) seemed warranted--at least until the late 1960s and beyond.

Unfortunately, this past orientation has not evolved into policy more appropriate from the 1980s to the end of this century. As will be

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[2] Peebles, ibid., p. 108.

[3] Peebles, ibid.

discussed below, town gas companies' capacity for growth now depends on their ability to expand markets beyond the residential into other sectors, especially the industrial. Constrained by structural change in the Japanese economy and environmental rules, only LNG appears to offer the prospect of major expansion, especially to industrial customers. To successfully compete in the industrial sector, LNG feedstock price must compete with other fuels now used on the industrial sector.

The key to a stronger competitive position may be an expanded and integrated transportation system that would allow load balancing shifts of gas supply, increase flexibility, decrease dependence on storage and LNG tanker schedules, and reduce technical supply/delivery problems. However, the Japanese policy of benign neglect of the gas industry has not resulted in such an interconnected system. This circumstance now makes it more difficult for town gas companies to take a lead--or even prominent--role in negotiations for LNG projects. Instead, in past projects they have been linked with electric power companies who have approached LNG with a quite different economic outlook.

Thus, the lack of interconnection among major gas-using areas puts a very different perspective on LNG usage by town gas companies than would have occurred if these companies had been rationalized into something like the nine electric power company service areas. A decision to rationalize may well be critical in setting out a strategy for expanded LNG utilization. If the decision is taken to continue to allow nearly 250 town gas companies to operate in historical fashion, then LNG importation will continue to depend on electric utility company strategies and decisions.

If the decision is made to rationalize organization of the service areas, then town gas company import of LNG could be significantly separated from electric utility decisions.

The implications of this policy decision will be touched upon later when we take up the issue of pricing and take-or-pay terms. Historically, electric utility circumstances have differed from town gas interests, remain so today, and will likely diverge further in the future.

Impact of Environmental Policy

For now, however, we will return to the 1960s when environmental constraints were becoming increasingly binding on both town gas and electric utility companies. Coal-based gas was still utilized, with coke being sold to the steel industry, then thriving. To maintain the supply of coke to industry requirements, the gas had to flow in fairly constant volumes. This led to an increase in industrial base-load gas contracts.

At the same time, electric utility companies were expanding to meet rapidly increasing demand. Capacity additions were fired by all traditional fuels, with nuclear reactors beginning to emerge as serious competition. However, coal-fired plants continued to be constructed for base-load and there was a major expansion of capacity fired by high-sulfur crude oil. Demand was growing strongly and electric utilities were scrambling to install capacity. Contributions to pollution by these facilities combined with continued gas/coke processing by the town gas industry began to produce serious air quality problems.

The exceptional performance of the Japanese economy in the 1950s and

1960s needs no elaboration. Also well-documented are the series of environmental problems in both water and air quality in this period. Toxic discharges into streams resulted in a series of environmental issues that received spectacular publicity. Population reconcentration and economic growth in Tokyo, Osaka, and Nagoya brought increasing demand for both electricity and gas. Use of all fuels increased, but especially high-sulfur crude oil and coal.

The resulting increase in sulfur and other air contaminants fed growing public concern about the need for tougher air quality rules. In the 1960s, the first air quality laws were passed, and gave substantial approval power to local governments. By the mid-1960s some of that authority was being utilized. In 1964, Yokohama City made a land sale to Tokyo Electric Power Company conditional on the use of low-sulfur oil and high stacks.[4]

It was in the context of these increasingly stringent air quality standards that LNG first emerged as a desirable and feasible fuel for both town gas and electric utility companies. Phillips and Marathon had substantial reserves of natural gas in the Cook Inlet area of Alaska, and lacked an obvious local market of equivalent magnitude. They had begun examining LNG sales to Japan in the early 1960s, and the discussions continued for some years. The central issue appeared to be pricing, with the cost of LNG facilities suggesting a c.i.f. price somewhat higher than that for crude oil.

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[4] Julian Gresser, Koichiro Fujikura, and Okio Morishima, Japanese Environmental Policy: A Comparative Assessment, The M.I.T. Press, Cambridge, Massachusetts, 1981, p. 265.

When finally concluded, the contract called for a 15-year term for delivery of 960,000 tons per year at U.S. 1969 \$.52 per Btu c.i.f. At this time the Btu equivalent price for oil was approximately \$0.30.[5] Thus, the difference paid by the importers, Tokyo Gas Company and Tokyo Electric Power Company, was motivated by the need to increase capacity, which was becoming increasingly difficult to do using heavier oils or coal (as noted above). Thus, clean, but higher-priced LNG made sense to both companies in the mid-1960s.

The next Japanese project was from Brunei, with delivery commencing in 1972 at over 7 billion cubic meters per year. This was five times the size of the Alaska project and also was fostered by the 1960s' environmental restrictions previously mentioned. By commencement of delivery, oil prices increased by more than those for LNG, with the latter being less than 30 percent higher. Again, this was a premium worth paying in order to continue to expand capacity in an environmentally acceptable way. The lead participants in the Brunei project again were Tokyo Electric Power and Tokyo Gas. Osaka Gas also made its first appearance in LNG trade, with an interest of about 10 percent in this project.

Recalling that the c.i.f. price in 1969 was \$.52 per Btu for Alaska-Japan, and not greatly higher for Brunei-Japan in 1972, two points should be noted. First, there is some basis to consider that today's LNG prices need not be at the levels of 1985 oil prices--even considering that cost inflation has been higher in LNG-type equipment than the pattern of

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[5] Tadahiko Ohashi, An Analysis of the Future of Natural Gas in Japan, Tokyo Gas Company, Tokyo, Japan, 1985, p. 17.

general cost inflation. We will return to this question later in this study (see Supply paper). The second point is that pre-1973 contracts were based on the need for a fuel that allowed capacity for both town gas and electricity to be expanded. Without the Alaska and Brunei arrangements, both Tokyo Electric and Tokyo Gas would have been pressed to meet demand for service then occurring. Thus, they were willing to pay a premium for fuels that would allow them to expand their revenue base and meet their customers' growing demand. Seen in this light, LNG contracts that allowed expansion of service in a tightening environmental climate likely were appropriate.

Policy Toward Supply Diversification: Oil Imports and Electric Utility Companies

By the mid-1970s, concern for environmental matters was swamped by the oil price jump of 1973-74. Japan had increased its oil imports more than ten-fold between 1960 and 1973,[6] and was deeply concerned about its heavy reliance on Middle East suppliers. In this context, stability of supply was of special concern, since disruption was the least tolerable outcome for an import-dependent nation.

MITI initiated a series of policy actions that were designed both to diversify supply sources, and even more importantly, to reduce reliance on oil imports. For the electric utility sector, an already ambitious nuclear program was accelerated, coal use expanded (from suppliers as diverse as the United States, Canada, Australia, and South Africa), and LNG imports

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[6] Joseph A. Yager with Shelley Matsuba, The Energy Balance in Northeast Asia, The Brookings Institution, Washington, D.C., 1984, pp. 10-11.

were encouraged. All of these steps had significant impact on electric utility companies, but of special note was the LNG question.

A striking characteristic of Japan is that crude oil was (and is) burned directly in electric utility boilers. Therefore, any substitution of crude oil imports by LNG for that purpose would be considered desirable, especially if the price were the same and diversification of supply sources was attained. The supply diversification has been achieved with contracts in place with Alaska (Cook Inlet), Brunei, Abu Dhabi, Malaysia, and Australia, and active discussions with Canada, Alaska (North Slope), Thailand, U.S.S.R. (Sakhalin), and Qatar will further proliferate supply points.

Because a significant policy goal was to reduce oil imports, cost minimization took a back seat to other factors. Thus, if LNG could be imported at a price no higher than high-sulfur (or even low-sulfur) crudes, then the electric power company was largely indifferent from a cost perspective. The rigidities of take-or-pay contracts and other problems were in part off-set by the environmental advantage LNG substitution gave to the companies.

However, while the unique circumstances of the electric utility sector made them indifferent to this LNG contracting and price structure, we shall see later that the town gas companies were not to remain indifferent. But for the present, all seemed well.

During the year following initial deliveries of gas from Brunei (1972), the first oil price shock occurred. After 1973, two new gas projects were initiated bringing LNG from Abu Dhabi, and more importantly, from

Indonesia. Including all Japanese imports of LNG through the Northwest Shelf Project (Australia), electric power companies have taken 78 percent of the total. This preponderant influence of the electric power companies has led to an LNG import policy with significant implications for future LNG use.

The first effect of electric utility dominance arises from the willingness to pay a c.i.f. price for LNG at crude parity. The apparent reasons for this are several. As mentioned previously, Japanese electric utility companies historically have burned crude oil directly under their boilers, so they are indifferent to a fuel whose delivered cost is nearly the same. Since the company is following a policy to reduce oil imports, LNG use is seen as desirable. In addition, the long-term contracts for LNG fit the long lead time style of this sector, and gives companies some sense of supply security. By substituting LNG for oil, the utilities also respond to air pollution concerns and thus are seen as good citizens.

But perhaps the most important reason for utilities' relative indifference to price is that LNG buys them time. Under the high take-or-pay requirements, electric utilities use LNG for base-to-intermediate load generation. While installed nuclear capacity is built, a national interconnecting electrical grid is established, and technology for clean utilization of coal is developed, LNG provides an excellent interim solution for electric utility companies. Additionally, the national policy of minimizing oil imports and diversifying the number of nations supplying both oil and LNG is being advanced.

Current LNG Contracts: A Major Problem for Town Gas Companies

Unfortunately, what works for the electric utility company is a serious barrier to the major Japanese town gas companies, and eventually to those gas-producing nations that hope to export LNG to Japan. Recalling our earlier discussion about manufactured gas by town gas companies, it was evident that the only market available was that which could pay the highest prices: the residential customer and the chemical industry, which needed gas for feedstock. Now, the market expansion available to the town gas companies is primarily in the industrial and commercial sectors, though some modest residential growth may be expected. Prices of competing fuels are set by government policy and as can be seen in the following two tables, LNG delivered by gas companies faces very rugged competition.

Whether fuels competing with town gas/LNG are subsidized (either explicitly, or implicitly as kerosene has been in the past) will not be dealt with in this paper. However, it may be surmised that Japanese policy has been to discourage town gas expansion into markets traditionally held by suppliers of oil products (including LPGs). This interpretation of circumstances may be given weight by the decision in 1984 to place the same import tax on LNG as had been previously levied on crude oil and product imports.[7] The combination of these factors has had a considerable negative impact on the growing competitiveness of town gas companies. It is an open question whether MITI policy intended this effect, but its consequences may be most serious--as will be discussed below.

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[7]International Energy Agency, Energy Policies and Programmes of IEA Countries: 1984 Review, Paris, France, 1985, p. 322.

Table 1

Unit Price Trends of Energy in the Residential and Commercial Sector

fiscal year	Yen Per Thousand Kcal				Relative Indices			
	Kerosene	LPG	Electricity	City Gas	Kerosene	LPG	Electricity	City Gas
1970	2.17	6.47	14.64	5.40	1.0	3.0	6.7	2.5
1974	3.47	11.40	17.44	8.15	1.0	3.3	5.0	2.3
1978	4.48	13.91	21.56	11.18	1.0	3.1	4.8	2.5
1979	5.39	14.61	21.43	10.65	1.0	2.7	4.0	2.0
1980	9.34	19.24	28.06	14.60	1.0	2.1	3.0	1.6
1981	9.87	21.32	28.10	14.60	1.0	2.2	2.8	1.5
1982	10.86	21.83	28.10	14.60	1.0	2.0	2.6	1.3
1983	10.10	22.00	28.10	19.60	1.0	2.2	2.8	1.4

Source: Kazuo Furuto, "Kerosene Demand as Part of Total Energy Demand in the Residential and Commercial Sector," Energy in Japan, July 1983, p. 18, Table 4. 1983 figures are estimates from the Institute of Energy Economics.

Table 2

Comparison of Industrial Fuel Prices and Burner Tip Costs
(Yen Per Thousand Kcal)

	Average			High Sulfur C = 100		
Fuel Prices	1981	1982	1983	1981	1982	1983
Kerosene	8.55	9.81	9.34	146	162	175
High fuel oil A	7.86	9.04	8.59	135	149	161
Fuel oil C	6.51	6.73	6.02	111	111	113
High-sulfur heavy fuel oil C	5.84	6.05	5.34	100	100	100
Industrial LNG	7.51	8.08	7.07	129	134	132
Butane	6.54	6.61	7.11	112	109	133
Coal	3.06	2.78	2.42	52	46	45
Burner-tip Costs						
Kerosene	8.72	9.98	9.51	131*	152	162
Heavy oil A*	8.12	9.30	8.85	122	141	151
Low-sulfur C*	6.84	7.06	6.35	102	108	109
High-sulfur C*	6.36	6.57	5.86	100	100	100
Industrial LNG*	7.70	8.26	7.26	115	126	124
Butane	7.22	7.29	7.79	108*	111	133
Coal*	6.37	6.09	5.73	95	93	98

*Mid-points of ranges.

Source: Naoto Sagawa, "Inter-energy Competition in Japan, the United States and Western Europe," Energy in Japan, November 1983, Table 3, p. 20. 1982 and 1983 figures are estimates from the Institute of Energy Economics.

Of course, the collapse of oil prices in early 1986 has had a variety of impacts on LNG importation into Japan. First, because current LNG contracts are based on official selling prices, LNG prices are remaining higher longer than oil or oil product prices. This is a problem for all Japanese LNG users, but especially acute for town gas companies. Because there has been a relaxation of oil product imports to Japan (together with lower product prices from spot crudes imported by Japanese refiners), price competition for industrial and commercial users is becoming even more difficult for town gas companies--and the problem will increase in severity.

Another effect of falling crude prices is to highlight the problem of rigid take-or-pay requirements in LNG contracts. Any pause in demand cannot be met by reduced takes of LNG supplies. The obvious alternative for a Japanese importer would be to re-sell some portion of contracted supply, perhaps to a new user, or to a user who had a peak demand counter to the original importer. However, this alternative cannot be pursued because of a second problem: Current LNG contracts expressly prohibit the re-sale or transfer of LNG shipments. These two rigidities in current contracts increasingly cause difficulties for both electric utilities and town gas companies, and increase the likelihood of LNG being perceived as a fuel of significant risks and problems. Electric utility companies have alternative fuels to rely upon, but town gas companies may be more gravely affected.

Thus, if LNG is available to town gas companies at a crude oil price (whether official selling price or other basis) equivalent, the companies' markets will be limited. Therefore, the amount of LNG the gas companies can absorb at that price will be severely constrained. Indeed, for the reasons described above, currently participating gas companies probably are nearing their peak absorption of LNG. Since it is unlikely that electric utility companies will have interest in new LNG projects for the reasons cited above, we thus now may be witnessing peak LNG utilization in Japan.

Of course, there are circumstances under which electric utility companies could increase their utilization of LNG. An internal study by ARCO Alaska pointed out that at a 3 percent growth in electricity demand, incremental supply between 1995 and 2000 would be 100 billion kWhs. Of this, half the supply is projected to be nuclear, and the other half from coal, LNG, oil, or other sources. If the demand growth forecast is correct, any slippage in nuclear schedules or coal plant construction would create potential increased demand for LNG. The study does not analyze the fuel mix if oil prices continue to be weak.

While the possibility of increased electric utility use must be reckoned with, falling oil prices (and the contract problems mentioned previously) make it more likely that we are in fact seeing the peak of LNG utilization in Japan. If so, a potentially grave issue must be considered. If the following factors continue to exist, we may see the prospect of serious problems for the three major town gas companies:

1. Low oil prices and continued use of official prices for LNG pricing;
2. Rigid take-or-pay and no-resale terms in LNG contracts;
3. Explicit or implicit Japanese policy which works against expanded town gas utilization of LNG by industrial, commercial, and residential sectors; and

4. LNG contracts pegged at c.i.f. oil parity.

Put simply, all town gas company growth since 1970 is directly correlated to their increased utilization of LNG. While town gas is less than 20 percent of all LNG imports, it now represents over 60 percent of the total feedstock of the town gas companies--and is still growing.[8] If LNG imports are constrained because of the four factors mentioned above, the gas companies could face quite serious feedstock problems. The dominant position of electric utility companies in LNG imports means the future flow of gas is dependent upon their needs. If electricity generation grows with other fuels, town gas companies may face a no-growth situation or even declining sales.

While it may be extreme to suggest that company viability is threatened, major problems are certainly possible. Until some method is worked out to free town gas LNG supplies from the rigidities of current contracting practices, potentially serious problems loom. The current sharp drop in oil prices may bring these concerns into prominence much more quickly.

Summary

This discussion has shown how policy regulation of town gas companies has led to a fragmented industry that lacks the connections necessary to balance loads and make the most efficient national use of expensive feedstock resources. Instead, high manufacturing costs, high storage costs

[8]Japan Gas Assocation data, reported in Ohashi, op.cit.

for LNG, and dependence on electric utilities for LNG projects have rendered further expansion most difficult. We also have seen how environmental regulations have affected the perspective of appropriate pricing for LNG resources. While the environmental issue remains important, demand is seriously constrained at LNG prices equivalent to oil prices. Finally, we have examined how electric utility interests and contracting prices have established LNG price levels and contracting practices that limit the amount of LNG that will be used in Japan.

A NOTE ON KOREA

The Republic of Korea (Korea) situation offers an interesting potential contrast to Japan. Korea contracted with Indonesia for 2 million tons of LNG to commence deliveries in 1986, with a potential additional 1 mm tons per year by 1989-90. Original Korean plans were to follow the Japanese pattern of LNG use in electric power generation, thus backing out oil imports.

However, Korea now is reported to be considering an alternative policy for LNG utilization. Instead of use in electric power generation, the Koreans are evaluating conversion of oil-burning plants to coal to take advantage of very low-cost coal imports. As the following calculation indicates (Table 3), the economics are attractive, and would be even more so if coal prices were lower.

Because the Koreans have already committed to the LNG deliveries, they are considering a strategy of town gas utilization of the LNG. This would involve a trunk gas pipeline of some 500 kilometers to reach potential

Table 3

Increased Costs of Conversion and Use of Fuel
A 350 MW Generating Plant Using LNG and Coal as Two Possible Alternatives to Oil
(6,000 Full Load Factor Equivalents p.a.)
(U.S. $ thousands)

	Steam Coal[a]	LNG ($5.5/MMBtu)	LNG ($4.5/MMBtu)
Cost of Conversion:			
Oil to alternative p.a.[b]	5,812	258	258
Annualized cost of UHDE "scrubber:"			
Capital Cost p.a.[c]	2,640	---	---
Operating costs	5,471	---	---
Operating costs in excess of oil-firing alternative	2,506	)[d]	)[d]
Costs of fuel	55,965.8	102,358.4	83,748
Totals	72,394.8	102,616.4	84,005
Cost per kWh (U.S. cents)	3.44	4.88	4.0
LNG "premium"	---	1.44	0.56

SOURCES: ELSAM, 1982. Interviews: Vestkraft, Esbjerg; Jysk-fynske elsamarbejde (ELSAM), Fredericia, Denmark. Gas efficiency factor from Medici (1974). The use of Danish data in this table is due to an inability to acquire the relevant material from Japan. The Danish electrical industry has achieved a wide reputation for its efficiency and for ease of information access, which makes it an "ideal" shadow price case for the Japanese electrical industry. It is likely that these Danish estimates are low in comparison to estimates elsewhere and in Japan.

NOTES: [a]Average c.i.f. September 1982: $64.02/metric ton; 6,500 kcal/kg 3% less efficiency than fuel oil.

[b]Cost of conversion estimated at $52.9 million for coal, $2.36 million for natural gas. Annualized even payments over 15 years principle and interest. 7% interest.

[c]Capital costs of UHDE "scrubber:" $24.1 million. Amortized as with cost of conversion.

[d]There are operating cost savings not entered here. See text for explanation. It is assumed as well that LNG has 10% more boiler efficiency than oil.

From: J.D. Davis, Blue Gold: The Political Economy of Natural Gas, 1984, p. 225.

industrial base-load customers in the southern peninsula (Ulsan, Pusan, etc.) and a distribution system for tying in residential and commercial customers en route in Seoul, ChunChon, Taegu, Pusan, etc. This would encompass a majority both of the population and of the commercial stock in the country.

While no published estimates of cost currently are available, such a policy and utilization pattern would appear attractive. It would allow LNG to be treated as natural gas, including a full range of sector pricing from premium residential to base-load industrial. If LNG exporters understand that LNG would be treated as natural gas in Korea (which they appear not to with respect to Japan), then Korean demand could be substantial.

PRODUCING COUNTRY POLICY

The preceeding sections have reviewed the circumstances affecting natural gas use in Japan (and Korea). Market conditions have changed rather drastically over the last 15 years, and the oil price falls over the last 3 months suggest that the changes are still occurring.

One conclusion that seems inescapable is that c.i.f. oil parity priced LNG projects will not find a future market in Japan. The only circumstance in which this would occur is a substantial shortfall in planned nuclear or coal electricity generation capacity expansion. Such a situation could then create an additional call on LNG for such base-loading plants--at least for some interim period.

As indicated in this review, and in the Demand paper by Arthur Wright, the likely real opportunity for expansion of LNG trade is outside of the electric utility sector. The town gas companies offer the potential for major expansion, but not under the pricing and take-or-pay conditions of previous contracts. Additions to gas distribution infrastructure are costly, and the interfuel competition severe--especially with falling or unstable oil prices. Several implications are clear from this situation, and are ones which must be faced by current and/or potential exporters of LNG.

In view of the future potential markets in East Asia, some serious rethinking of LNG pricing is in order. With contract price references being turned upside down by the oil market, previous fears about existing contract structures being threatened by new contract arrangements are now moot. Any profitable export scheme should be considered on its own merit, unless there is a more profitable domestic utilization project available.

Because the future of LNG prices is so uncertain, two other producer policies should be carefully examined. National policies toward royalties and taxes were shaped during an era of increasing prices, and are clearly no longer appropriate for lower and unstable price movements. The kind of flexibility demonstrated by recent Canadian gas policy suggests a more appropriate policy for the next several years of LNG trade. Otherwise, new investment planning by producing companies will be adversely affected.

The second matter is the question of discount rates. With the value of gas in the ground so uncertain, then higher discount rates should be utilized than those thought appropriate in the 1970s and early 1980s. Such a change will not make an uneconomic project worthy, but may change perspectives on the tactics of project timing.

Finally, as will be recalled from the discussion of the Alaska and Brunei projects, c.i.f. prices were less than $1.00 U.S. in current dollars. Either there has been no technological progress at any stage of the LNG "chain," including liquefaction facilities, ocean transport, storage and regasification, or some other set of events have gravely affected cost reductions in this process. One suspects that some of the events affecting cost have been rent-taking by engineering/construction firms and suppliers, labor, government (through taxation), and producing companies--all of whom perhaps have a rate-of-return expectation no longer appropriate to future LNG projects.

Other papers in this project examine the issues of supply costs and demand under alternative prices. Regardless, it is clear that either the era of LNG has ended, or a second LNG era with a new perspective is about to emerge. Policy makers in producing countries and Japan must be prepared to examine and, when necessary, discard old perceptions and practices.

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INTRODUCTION

Strategic Issues in Pacific-Basin Demand for Natural Gas

Compared with North America, the U.S.S.R., and Western Europe, the Pacific Basin is still a young market for natural gas. Production and use of natural gas date only from the late 1960s, and in earnest only from the mid-1970s. The region has, of course, been undergoing rapid economic growth and structural change. If the recent pace of economic progress continues through the end of this century, we might expect to find the Pacific-Basin gas market considerably more mature by the year 2000.

Economic progress will not, however, be the only determinant of the course of this market over the next fifteen years. Institutional factors will also play a central role.[1] Two in particular--how the overall market is organized, and the way the individual participants in the market choose to make decisions--will be very important. Other chapters in this report discuss institutional factors (e.g., those on supply, contracts, and government policies). But these factors are especially important for understanding gas demand in the Pacific Basin.

The future of gas demand depends on complex strategic decisions made under considerable uncertainty. Much new gas demand can occur only if energy consumers install expensive, durable gas-using equipment. Decisions to do so are contingent on reliable access, on predictable terms, to gas supplies, which themselves entail large investments not easily converted to other uses if proven unsound. Both demand and supply decisions hinge on what people expect gas prices to be, or (perhaps more important) how they expect them to be formed (for instance, in relation to oil prices). These decisions also are contingent upon governmental permissions to proceed with projects. Governmental decision making is often an important source of uncertainty in its own right.

This complex of decisions is not unique to the Pacific-Basin gas market. What sets this market apart from the other major international markets is that its trade flows consist exclusively of liquefied natural gas (LNG). Technologically, this characteristic of the Pacific-Basin market is the mere product of geography and geology. Economically, however, the "LNG factor" has made a real difference in the evolution of the market to this point. A critical role has been played by the institutions that have grown up for trading LNG.

These institutions were born of the world oil price shocks of the 1970s. True, it was the higher real energy prices, plus expectations that they would go yet higher, that made many LNG projects economically viable. But the atmosphere of scarcity that prevailed at the time meant that LNG was viewed as one of the "premium" fuels that could close the "gap" as precious oil supplies ran out. Government price and import policies toward oil made it acceptable to pay the premium for LNG. Not surprisingly, it was thought only right and natural that LNG prices should be tied firmly to oil prices. Moreover, many governments (not trusting world energy markets and worried about security of supply) involved themselves directly in negotiating and even undertaking LNG ventures. As a result, LNG contracts were treated as matters of high national policy.

Times, and attitudes, have changed in world energy markets. Several LNG contracts have gone sour in North America, but the ramifications have been limited--contract litigation for one interstate pipeline, Chapter 11 bankruptcy for one LNG importing firm. No existing deals in the Pacific Basin have yet been broken, but the actual impact of the changes in world energy markets has been greater there because of the dominance of LNG in gas trade. This is especially true of prospects for future growth of natural gas demand in the region. The magnitude and geographic pattern of demand growth will depend crucially on the answers to questions like, "How will LNG be priced?," "Will different contract forms emerge?", and "Can people form the stable expectations that will be required if Pacific-Basin trade in LNG is to expand?"

If nothing much changes in the institutions for trading LNG, we should not expect much growth in demand for natural gas in the Pacific Basin. If, however, LNG comes to be priced more independently--not uncorrelated with oil but not tightly indexed, either, and not on an exact thermal-equivalent basis--and if the market's actors (including especially governments) are willing to consider more flexible contract forms, international trade in natural gas in this region will grow more in accordance with the bright prospects for overall economic progress.

Actors in the Pacific Basin Market for Natural Gas

The demand side of the Pacific Basin gas market consists of Japan and The Rest--a group of much smaller users, singly and collectively, actually and potentially, than Japan. Japan is by far the dominant factor on this side of the market, to the point of possessing considerable potential monopsony power.[2] The Rest, which include Korea, Taiwan, Hong Kong, Australia, and Thailand, are not without interest or significance. The group counts among its numbers several rapidly growing economies, and two of them are potential producer-exporters as well as consumers of natural gas. Nevertheless, Japan now represents the bulk of Pacific-Basin gas demand and (under any plausible set of assumptions) will continue to do so at least through the end of this century. Even unusually rapid demand growth among The Rest will only cut into, not end, Japan's dominance.

Thus, it is no exaggeration to argue that, as Japan goes, so goes Pacific Basin trade in natural gas. (The same would be true for coal and oil, though to a lesser extent in the latter case because of the better organized world market). For this reason, we shall focus in this chapter primarily on the demand for natural gas in Japan. Before taking up the Japanese case, however, it is well to examine briefly The Rest of the actors in the Pacific Basin market for natural gas.

The Rest of the Market in Brief

Korea and Taiwan have recently been among the economic (and industrial) growth leaders of the world. Of the two, Korea is the more likely to play a visible role in Pacific Basin gas trade over the next fifteen years, merely by virtue of having already signed a contract to import LNG. The imported LNG is to be used in electric power generation. Outside analysts have suggested that Korea could make more effective use of this gas in industry, and instead generate power with coal. This strategy would, however, require large investments in gas distribution and combustion equipment--investments of the kind that the Korean government is currently reluctant to sanction because of the pressure it would place on its net foreign borrowing situation. A careful analysis of this set of issues is beyond the scope of this chapter. Here, we simply note the interesting possibility that Korea could become quite a bit more of a factor than it is at present in Pacific Basin gas trade, but that for this to happen would require changes in domestic economic and financial policies that are not now in prospect.

Thailand and Australia both have domestic natural gas resources. Australia will shortly become an active seller in Pacific Basin gas trade and is counted among the modern industrialized nations of the world. However, Australia's exportable gas is on the Northwest Shelf, too far from the populous and developed southeast to compete with central Australian gas reserves; and the southwest Australian market will not put a very big dent in LNG exports. Thailand is aggressively pursuing economic growth; however, even with rapid economic growth and intensive domestic use of natural gas, Thailand will not make much of a difference in total Pacific Basin gas demand for some years.

Finally, Hong Kong has long been a vibrant economic force in eastern Asia, far out of proportion to its tiny size. That very size, however, restricts the potential significance of any gas demand growth for the broader regional market. In addition, the uncertainties growing out of the transfer to the Peoples Republic of China at the end of this century are likely to put a damper on the growth of the Hong Kong economy, and on growth in the demand for natural gas, over the period covered by this study.

Outline of the Remainder of the Chapter

The first step in understanding Japanese gas demand prospects for the period 1985-2000 is to define some terms and develop certain concepts that will be used throughout the remaining discussion. This we do in the section immediately following.

Directly following that, we briefly consider several special features of the Japanese case. These special features derive from those of LNG, discussed earlier. Most of Japanese gas use, and all of any future increments, (1) consist of LNG that (2) is imported. A third special feature is the way LNG is priced. Prospects for significant growth in demand over the next fifteen years hinge on whether this third special feature changes and (if so) how.

The ensuing material gets down to cases. These are presented in alternative-scenario format, reflecting the two quite different world views that lie behind them. We term the first scenario the "consensus view," referring to the broad agreement among government officials and many business representatives that the fate of Japanese purchases and uses of LNG from now until the year 2000 has been largely settled. In contrast, the second scenario--labelled the "dissenting view"--considers the conditions necessary for Pacific Basin gas trade to expand significantly over the next fifteen years. Obviously, for this to happen Japanese gas demand must grow faster than is foreseen in the consensus view. Two prerequisites, though, are (1) that the relative price of LNG decline enough to permit greater penetration of industrial markets; and (2) that Japanese decision makers (public and private) respond appropriately to the decline. Of course, decision makers (public and private) in the LNG-supplying countries must also reconcile themselves to the lower returns that would go with a lower relative LNG price.

The chapter concludes with a summary and a recap of the main conclusions.

THE NATURE OF DEMAND FOR NATURAL GAS

Economic Demand Functions for Gas

Throughout this chapter, the "demand" for gas will refer to a function relating different quantities demanded by purchasers to different prices charged by sellers. Typically, one or more "shift parameters" will (if varied) increase or decrease the entire function. The central shift parameter in gas demand functions is the price of the competing oil product (e.g., residual fuel oil). Other shift parameters are household income, user equipment stocks and prices, technologies, and people's preferences (or "tastes").

By postulating that individuals or firms behave rationally, we can deduce that demand curves "slope downward": At low prices, greater amounts of a given good will be demanded than at higher prices--holding constant the various shift parameters. As a rule, quantity demanded will respond more to a given price change in the long run than in the short run. The shift parameters tend to be fixed in the short run but variable in the long run. If a price changes suddenly, purchasers' short-run quantity responses will be restricted in scope. With time, however, that scope will broaden as long-run changes--in people's tastes, end-use equipment, technologies, purchases of complementary goods, and so on--occur.

No discussion of economic demand functions for natural gas in the mid-1980s would be complete without paying some attention to changes in world oil prices. We noted above that the price of the competing oil product is typically the "central" shift parameter in gas demand functions: An increase in oil prices will increase gas demand, and vice versa. The magnitude of the effect of a given change in oil prices will differ, depending on people's expectations about the permanence of the change. If they expect it to last, the effect on gas demand will be greater than if the change is viewed as transitory.

With the benefit of hindsight, it appears that many people thought the oil price increases of the 1970s were permanent. Otherwise they would not have locked themselves into gas contracts with price and other terms set at "premium" levels and tied to oil at or near thermal parity. We now (March 1986) know that oil-price expectations should be based on volatility, not continual increases. Therefore, energy users will tend to add a risk premium to oil prices that will at least partly cushion the decline in gas demand owing to falling oil prices. Further, expectations based on oil-price volatility should lead to different contract forms for trading natural gas. In particular, we should expect greater reliance on flexible-price contracts, with price referents much more loosely tied to oil.

Note that the reduced demand for natural gas caused by falling oil prices will be offset somewhat by supply-side macroeconomic expansion throughout the world induced by lower energy prices. This expansion will be the obverse of the <u>negative</u> supply-side shocks to aggregate world output caused by the oil-price increases of the 1970s.

"Final" and "Derived" Demands

There are various categories, or customer classes, of gas demand, depending on the customer's specific end use. Only residential demand for gas is final as opposed to "intermediate" on the scale of human consumption. Commercial, industrial, and electric-utility demands are, in economic argot, derived from the ultimate demands for goods produced with the gas. Both kinds of demand still depend, short- and long-run, on the price of gas. But the price often differs by customer class, and the other arguments in the demand functions differ as well.

For residential gas demand, the prices of near substitutes--mainly distillate fuel oil ("No. 2") and increasingly electric power--are important shift parameters. Household income is also an argument, as is user equipment: in the short run, the stock itself, and in the long run, the prices of equipment. Government policies may affect residential demand for gas, too. In Japan, for instance, government subsidies to kerosene may have retarded the growth of residential gas demand.

The derived demands of commercial, industrial, and electric-utility customers do not depend on income, except indirectly in the aggregate through its effect on final-goods demands. Stocks of equipment and technology are important arguments of these demands. The long-run decision to install "dual-fuel" (gas and oil) capability (or more rarely, in the case of coal, to maintain spare combustion capacity) makes fuel switching a short-run possibility. For most commercial demands, relevant substitutes include distillate fuel oil or electric power. Industrial users can substitute either distillate or residual fuel oil, depending on the application; substitution in most feedstock uses is limited in the short run, because of design complexities in chemical processes. Electric utilities view residual fuel oil as the effective short-run substitute fuel for natural gas. Coal (base load) and distillate fuel oil (peaking) are long-run substitutes, as of course are nuclear, hydro, pumped storage and other non-fossil-fuel forms of generation. Finally, public policies may also affect derived demands for gas--viz., regulation of the siting of nuclear plants and restrictions on sulphur emissions.

The different categories of gas demand tend to have different marginal values in use, given a particular market equilibrium. The differences trace to the supply prices (costs of provision) of acceptable alternatives, whether it be rival fuel/energy systems or substitute processes or final goods. Homeowners, for example, can heat with distillate fuel oil, gas, or electricity (coal is no longer widely acceptable); or they can wear extra layers of clothing, learn to enjoy ambient temperatures of 60 degrees F. (15 degrees C.), or move to a warmer climate. Electric utilities, in contrast, may find coal a quite acceptable alternative to natural gas for raising steam, even if expensive scrubbing is required for environmental reasons,.

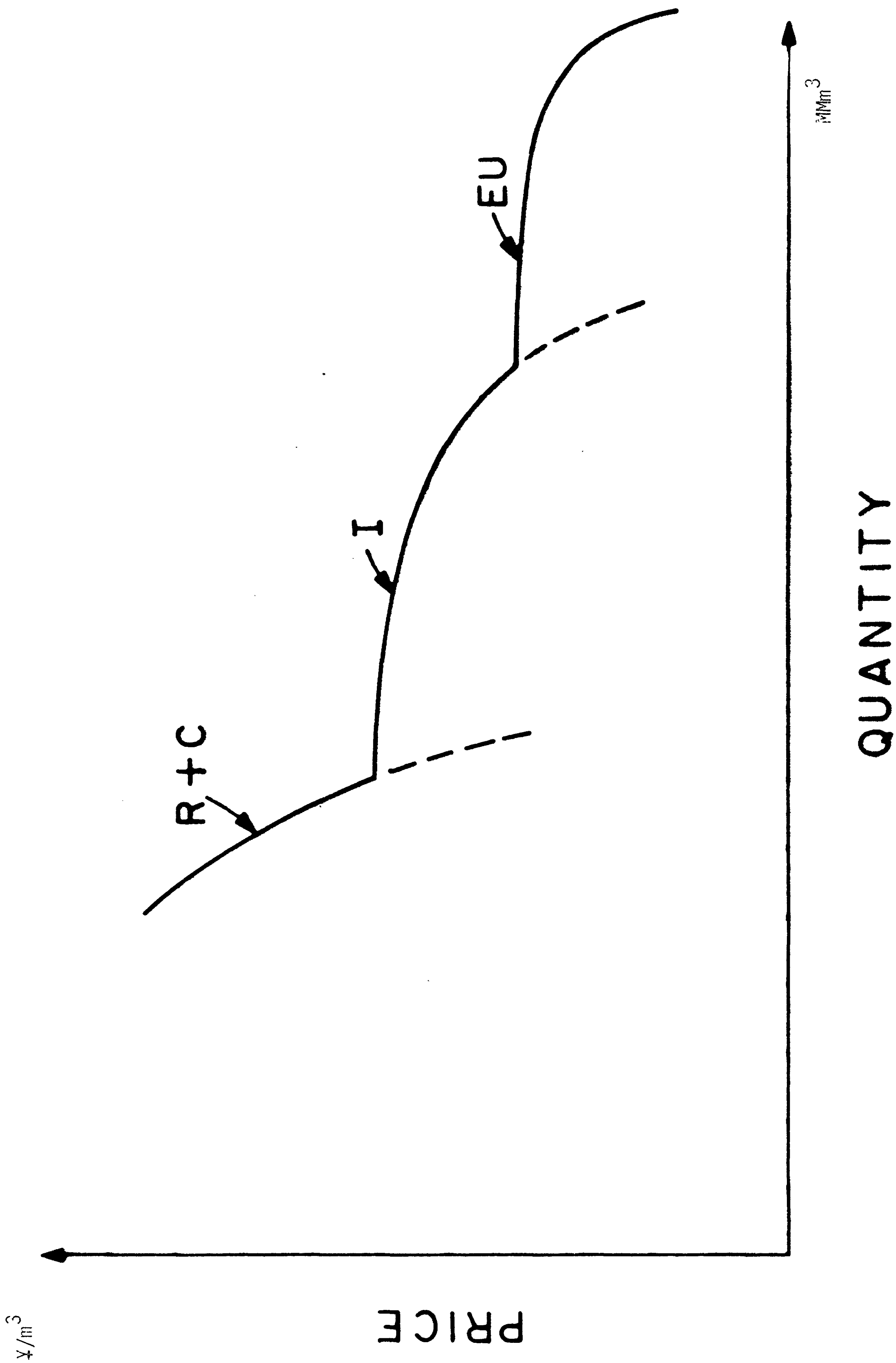
Broadly speaking, residential (R) and commercial (C) gas demands are less responsive to variations in price than are industrial (I) and electric-utility (EU) demands. We say that R and C are less "price-elastic" than I and EU demands: For a given percentage change in price, the percentage changes in quantities demanded for R and C use are relatively smaller than are true of I and EU uses. R and C demands are sometimes labelled "captive," suggesting that homeowners and shopkeepers are prisoners of capital outlays that represent a large fraction of their total costs of gas use. There are, of course, exceptions. Some very large commercial gas customers (e.g., apartment houses) find it worthwhile to invest in fuel-switching capability. And certain industrial customers--e.g., petrochemical producers and some firms using process heat--employ techniques designed expressly for natural gas. Thus, they have less elastic demands than the "penny-switchers" who swing from gas to residual fuel oil and back in response to relative-price movements of as little as a penny per million Btu (MMBtu).

These seeming arcana of natural gas economics are important to understanding how gas markets operate under various conditions. Differences in marginal use-value and price elasticity across market segments imply the existence of distinct ranges in the total demand curve in a given gas market. Figure 1 depicts a stylized market for natural gas at end-use. The highest demand prices and steepest slopes occur in the region labelled "R+C" (for residential and commercial). Next comes the region of industrial demand (labelled "I"), followed by that for electric utilities' demands (labelled "EU"). The range of the R+C region of the demand curve below where the I region begins is not relevant: No seller will sell gas for R+C use if I-use will fetch a better price. This is similarly true for the range of the I region below where the EU region begins.

Exactly where on the demand curve a given market will "clear"--where, in other words, the supply to that market intersects the demand--is of considerable importance to gas marketing decisions. A price-taking (or price-regulated) seller of gas will realize greater revenues, other factors constant, if the market clears in the R+C range than in the I or EU range of the demand curve. (Absent government regulation, price discrimination may be feasible in natural gas sales because of the high cost to most customers of reselling purchased gas. Where scale economies exist [e.g., in large-diameter pipelines], price discrimination--in inverse proportion to the customers' price elasticities of demands--is even desirable from the standpoint of economic efficiency.)

Not long ago, natural gas was regarded as a "premium" fuel in many parts of the world--North America (except on the Gulf Coast), Western Europe, Japan (but not in the U.S.S.R.)--because incremental units of gas

FIGURE 1



delivered to many markets fetched R+C prices. Today, people have begun to view it more as a "blue-collar" fuel that will clear in the I range (against residual fuel oil) or even (in the long run) in the EU range (against coal)--in the process opening up new markets to natural gas. This view is now common in North America, and to a lesser extent in Western Europe. In the Pacific Basin and especially in Japan, however, gas (derived from LNG) is still a premium fuel. Whether this will change depends (as we have noted) on institutional as well as economic factors.

NATURAL GAS DEMAND IN THE JAPANESE POLICY SETTING

The LNG Factor at Work

Natural gas decision making in Japan illustrates well our earlier assertion that Pacific Basin gas trade differs from other international gas markets because it is conducted exclusively in LNG. Flows of the good in Japan are organized in the familiar discrete, vertically integrated projects consisting of liquefaction, special transportation, and storage/regasification. More important, however, the purchase and use of LNG are bound up with government import policies, because Japan imports virtually all of its primary energy other than hydroelectric power. Environmental concerns lay behind the initial introduction of LNG into Japan in the late 1960s. By the mid-1970s, however, the policy focus had shifted, following the Arab oil embargo and the oil price shock, to the displacement of oil and the diversification of both types and sources of energy.

The political concern for security means that the Japanese government intervenes actively to influence with whom LNG deals are negotiated. Further, once the deals are struck, their political value means that the

Japanese government has a stake in protecting their financial viability, if necessary by intervening in pricing and even allocation decisions. Combined with the inherent clumsiness of LNG technology, the result is a rigidly structured set of arrangements for making decisions about buying and selling LNG.

These arrangements do not operate through the competitive market forces of conventional economic analysis. Market forces are of course one constraint, because most of the operatives in LNG (as well as other forms of energy) are private entities that do not willingly incur losses. But to understand the Japanese demand for natural gas--its past evolution and future prospects--one must keep in mind that government policies also constrain the decisions made.

Two Competing Views of the Future of Natural Gas in Japan

Natural gas has in a short space of time become a major factor in the Japanese energy picture. This has happened under the aegis of the combined economic and political system just outlined. Among the majority of the participants in this system--the government agencies who have overseen the rapid rise of natural gas, and the business firms (virtually all of them electric and gas utilities) who have carried it out--there seems to be a consensus about the future prospects for natural gas in Japan. The major published forecasts all seem quite similar, as we shall see. Subject to minor differences of emphasis, the consensus is that natural gas will continue to grow in the future but at a noticeably slower pace than over the past decade or so. Implicitly, holders of the consensus view assume that the existing institutions, which succeeded in managing rapid growth, will prove equally successful at managing the more modest future pace.

A dissenting view is that it would be possible, and economically advantageous, to have considerably faster future growth of natural gas in Japan than the consensus scenario entails. Proponents of this more optimistic scenario range from academic gadflies to representatives of Japanese construction firms (and foreign owners of rights to gas supplies) who chafe under the constraints that (in their view) the existing system places on gas growth. Central to the dissenting view is the notion that change is abroad in world gas markets. Since about 1980, these markets (along with those for other energy goods) have gone from being supply-constrained to being demand-constrained. To take advantage of this change, the dissenters argue, Japan will have to alter its approach to LNG deals, perhaps even its attitude toward the core issue of energy import security. Failure to adopt new tactics to take advantage of the change will be costly and may even place Japan at a disadvantage in world LNG trade. Not altering present institutions and policies will certainly stifle the investments (e.g., in infrastructure for moving gas around once it is landed) required if natural gas is to realize its full potential in the Japanese economy.

These two competing views of the future of natural gas in Japan are the vehicle for the remaining discussion in this paper.

SCENARIO I: THE CONSENSUS VIEW

Development of Gas Use in Japan

As in Europe and North America, the original gas business in Japan consisted of "town" or "city" gas, which was manufactured from coal or LPG and used for lighting and cooking. The town gas industry tapped into what few indigenous resources of natural gas Japan possesses, but they are small enough to be negligible by present standards, which include the large-scale importation of LNG.

The LNG era began in the late 1960s, prompted (as already noted) by concerns for air quality. As Table 1 illustrates, however, the second and larger wave of LNG contracts followed the disruptions in the world oil market in 1973-74. These new contracts diversified Japan's sources of LNG, adding three new suppliers. The latest round of new contracts added another (Australia), and prospective contracts (with Thailand and the U.S.S.R.) would continue the pattern. The goal of diversification is openly stated,[3] and one source refers to a "MITI ban on extra LNG dependency on Indonesia"[4] (currently the largest single supplier) as a reason for turning to Australia and (at the time) Canada.

The existing and planned LNG projects all exhibit the familiar discrete, lumpy form--vertically integrated from field to burner tip, with continuous-flow "take-or-pay" provisions and seller restrictions on end-use written into the contracts. With two minor exceptions (involving 3.4 percent of total contract volumes), all of the contracts have been signed by large electric utilities and the "big three" town gas companies (Osaka Gas, Toho Gas and Tokyo Gas). Table 2 shows how heavily these two groups of producers have dominated the importation of LNG into Japan. Table 3 shows the rapid increase in the use of LNG in electric power generation, and Table 4 illustrates how the importation of LNG has penetrated the city gas industry. Note that the increase between 1970 and 1983 in the use of LNG to produce city gas roughly equals the increase in total city gas sales over the same period.

All of this activity has been set up in "supply-mode" rather than "network" form. Once landed in Japan, LNG can be shifted among customers

Table 1

LNG Projects (Japan)

10^3t

	SOURCE	STARTING YEAR	CONTRACT PERIOD (YEARS)	ANNUAL AMOUNT	IMPORTERS
OPERATED	U.S.A. (ALASKA)	1969	20	960	Tokyo Gas 240 Tokyo E.P. 720
	BRUNEI	1972	20	5140	Tokyo Gas 1060 Tokyo E.P. 3450 Osaka Gas 630
	U.A.E. (ABU DHABI)	1977	20	2060	Tokyo E.P. 2060
	INDONESIA (I)	1977	23	7500	Kansai E.P. 2400 Chubu E.P. 1500 Kyushu E.P. 1500 Osaka Gas 1300 Nippon Steel 600
	MALAYSIA	1983	20	600	Tokyo Gas 2000 Tokyo E.P. 4000
	INDONESIA (II)	1983	20	3200	Chubu E.P. 1500 Kansai E.P. 800 Toho Gas 500 Osaka Gas 400
	INDONESIA (III)	1984	20	3300	Tohoku E.P. 2550 Tokyo E.P. 400 Others 350
	SUBTOTAL			28160	Electricity 21430 Gas 5780 Others 950
PLANNED	AUSTRALIA	1989	19	5840	Tokyo E.P. 900 Kansai E.P. 900 Chubu E.P. 900 Chugoku E.P. 900 Kyushu E.P. 900 Tokyo Gas 580 Osaka Gas 580 Toho Gas 180
	CANADA (cancelled January 1986)	1989	20	2350	Chubu E.P. 1600 Chugoku E.P. 300 Kyushu E.P. 300 Toho Gas 150
	SUBTOTAL			8190	Electricity 6700 GAS 1490
TOTAL		-----		36350	Electricity 28130 Gas 7620 Others 950

Table 2

LNG Use by Sector

10^3t

Fiscal Year	Electricity	City Gas	Others	Total
1969	92	75	-	167
1970	717	241	-	958
71	714	251	-	965
72	677	278	-	955
73	1,379	959	-	2,338
74	2,475	1,300	-	3,775
75	3,326	1,621	-	4,947
76	3,920	1,972	17	5,909
77	5,703	2,429	92	8,224
78	8,603	2,703	213	11,519
79	11,708	3,070	191	14,969
1980	12,987	3,444	216	16,647
81	13,227	3,801	298	17,326
82	13,358	3,992	338	17,688
83	16,332	4,692	369	20,393
84	20,616	5,051	383	26,050
1990	29,000	7,200	300	36,500
1995	30,000	9,600	400	40,000
2000	30,000	11,100	400	41,500

Sources: Synthetic Energy Statistics of Japan (MITI) [11/83]
Japan Gas Association

Table 3

SOURCES OF ELECTRIC POWER: INSTALLED CAPACITY AND USE

		Historical								Forecast	
		1960	1965	1970	1975	1980	1981	1982	1983	1990	1995
Hydro-Electric	I	11,770	15,270	18,920	23,790	28,670	30,480	32,190	32,400	38,500	42,000
		53	70	74	79	85	84	77	81	92	101
Thermal (Total)	I	8,880	21,123	38,710	69,350	85,180	88,940	90,470	93,580	104,600	115,000
	P	49	98	229	310	347	352	343	361	403	419
Oil	I	430	9,050	23,630	58,990	59,480	62,010	61,730	60,090	50,000	49,000
	P	17	53	178	259	226	224	240	202	140	115
Coal	I	8,450	11,680	13,870	5,640	5,260	5,990	6,650	8,230	1,400	2,100
	P	32	44	40	16	23	29	36	44	65	95
LNG	I	0	500	1,200	4,700	19,710	19,710	20,210	23,380	40,000	43,500
	P	0	1	5	20	77	79	79	91	165	170
LPG	I	0	0	0	0	600	1,100	1,700	1,700	--	--
	P	0	0	0	0	4	4	6	4	10	10
Other Gas (& Geothermal)	I	0	0	10	20	130	130	180	180	600	1,500
	P	0	1	7	15	17	18	19	21	23	29
Nuclear	I	0	0	1,320	6,600	15,510	16,080	17,180	18,280	34,000	48,000
	P	0	0	5	25	82	87	102	113	190	285
TOTAL	I	20,650	36,500	58,960	99,740	29,360	135,500	139,840	144,260	177,100	20,500
	P	102	168	308	414	514	523	523	556	685	805

I = Installed Capacity, MW　　P - Production, 10^9 kWh

Source: IEE, August, 1985.

Table 4

Raw Material Balance of City Gas in Japan

10^9 Kcal, (%)

raw material \ year	1970	1975	1980	1983	1990	1995	2000	
							Low	High
COAL	(37.2) 19,294	(22.3) 17,500	(13.3) 13,383	(10.0) 11,701	(7.1) 10,440	(6.8) 10,440	(4.9) 10,440	(4.7) 10,440
LNG (NATURAL GAS)	(15.2) 7,891	(34.3) 26,929	(42.3) 42,550	(61.0) 71,323	(71.3) 104,830	(76.5) 138,010	(74.0) 157,790	(80.4) 178,540
OIL	(47.6) 24,703	(43.4) 34,170	(44.4) 44,713	(29.0) 33,884	(21.6) 31,820	(17.7) 31,960	(21.1) 44,880	(14.9) 33,150
TOTAL	(100) 51,888	(100) 78,599	(100) 100,646	(100) 116,908	(100) 147,090	(100) 180,410	(100) 213,110	(100) 222,130

Source: Japan Gas Association

only within the immediate environs of the importing entity (electric or gas utility). Limited movements by tank-truck occur, but there is nothing resembling an interrelated national pipeline grid of the kind now common throughout North America and Europe. This lack is of some significance for the kinds of problems that the growing Japanese gas industry has faced, as we shall discuss presently.

Since the mid-1970s, the price terms in the LNG contracts have been closely pegged to crude oil prices. A rough calculation of the ratio of average LNG prices paid (per unit of heat value) to average crude oil prices paid shows a drop from 1.72 in 1969 to 0.75 in 1974, then a gradual rise to parity by 1978, where it has remained (except for the period of the second oil-price spike, 1979-80).[5] Pegging LNG contract prices to crude was demanded by sellers, who were able to play on the perception of gas as a "premium" fuel that could close the oil "gap." The practice is not generally found in pipeline-gas markets, where the ratio ranges from about two-thirds to nine-tenths.[6] Recently, the practice has been called into question in LNG trade, as world energy market conditions and perceptions have changed. Japanese actors in LNG trading have begun to try to reduce the ratio, but the extent of the reduction to aim for remains controversial and in fact figures in the differences between the "consensus" and the "dissenting" scenarios.

Problems and Solutions

Deals arranged under the system just outlined supported rapid growth of LNG use in Japan during the 1970s and into the 1980s. As can be seen in Table 2, the use of LNG rose more than 25-fold between 1972 and 1984, and more than 3-fold between 1977 and 1984. However, this growth was not without its problems. In part, the problems trace to the tendency (common to all the advanced industrial countries) to overestimate total energy use--or (equivalently) to underestimate the price elasticities of energy demands--following the oil price shock of the 1970s. But the problems also trace in part to the rigidities of the Japanese system for arranging LNG deals.

Rapid as it has been, actual growth in LNG use has not fully lived up to earlier expectations. This is reflected in several ways, including continual postponements of initial deliveries under new contracts, and repeated reductions in forecasts of future consumption (hence also in the implied growth rates inbetween).[7] Because of the rigid take-or-pay requirements in the existing LNG contracts, Japanese gas and electric utilities have found themselves with an excess supply of LNG.[8] In response, in 1985 MITI established an "LNG Introduction Promotion Center" to encourage some 248 small local town gas companies to begin using LNG as a feedstock in making town gas. The Center will provide information and technical assistance, and also undertake a study to investigate establishing a special joint company to tackle the thorny problem of transporting LNG from the present delivery points to the small town gas companies.[9]

Another response to the excess supply of LNG has been to try to induce industrial firms to use LNG. Subsidies are available to defray part of the cost of hook-ups [10] Also, in 1980 MITI established a special rate for gas used by industrial-end users meeting certain conditions. This rate was about half that applicable to gas for household use, and it "compares favorably with the current fuel oil A price."[11] A noteworthy feature of these measures is that they are aimed not at short-term, temporary--

"interruptible"--use but rather at long-term, "firm" use. To qualify for the special industrial rate, firms have to guarantee takes of 90-100 percent of contract volumes for a minimum of three years. Offering lower prices to industrial gas users makes good sense, given their relatively high price elasticities of demand. However, we would not normally expect "firm" as opposed to "interruptible" service to be provided (indeed, required) at the low prices. Presumably, this arrangement is an ad hoc response to an unforeseen excess supply and not a long-term policy.

Importers of LNG into Japan have also encountered phase problems. Their LNG contracts call for quite rigid delivery schedules and fixed amounts per delivery, in large part because of economies in the seagoing shipping of LNG. Their own calls for LNG, however, vary over time, with the seasons and with business activity. In North American and European gas markets, this kind of imbalance is handled by arranging short-term sales and purchases (e.g., on an "interruptible" basis, at somewhat lower prices) to occasional customers. This is not possible in Japan, however, because it lacks the necessary gas transportation network. Also, many LNG contracts contain clauses that restrict resale--the product in our view of the prevailing oil-market conditions at the time the contracts were signed.

Consensus Forecasts

Whatever the current problems with LNG, both the policies to deal with them and the underlying system appear to have broad support. The main groups represented in the consensus are the Japanese government, the large electric utilities active in LNG contracting, the "Big Three" gas utilities (Osaka, Toho, and Tokyo), and apparently some industrial companies (including oil firms).

The consensus extends to forecasts about the future of LNG to the year 2000. Table 5 gives a number of forecasts by three different groups, prepared at various points over the past two or three years. MITIs foresee the greatest growth in LNG use, but they are not all that different from the IEEs (but the IEE has to our knowledge not yet made a forecast for 2000). The PAJ forecasts are notably lower than both MITIs and the IEEs (perhaps reflecting some wishful thinking). Comparing the 8/85 PAJ forecast with the 11/83 (revised) MITI forecast, PAJ's figures are lower by 11.5 % in 1990, 13.5 % in 1995, and 15.4 % in 2000. The other notable feature of the forecasts in Table 5 is the progressive scaling back that has occurred over time. The later MITI and PAJ forecasts call for very little growth in Japanese LNG use between 1995 and 2000. The totals for both years are in fact very close to the total contract volumes. If they prove accurate, these consensus forecasts leave little room for additional gas trade in the Pacific Basin originating from Japanese demand.

SCENARIO II: THE DISSENTING VIEW

The consensus view of the future of natural gas in Japan is not a unanimous one. A few observers argue that the use of natural gas--from LNG--could expand substantially faster than the modest pace assumed by the government and many private actors. For the dissenters' view to be viable, of course, would require some basic changes, both in the LNG market and in Japanese policies toward gas and other forms of energy. Neither set of changes is inevitable or certain, but they are not impossible either. Of the two, the market changes are perhaps the more likely.

We first examine the feasibility of the dissenting view. Then we sketch the conditions necessary for this view to come to pass and consider the chances for these conditions actually to obtain.

TABLE 5. "CONSENSUS" FORECASTS OF JAPANESE L.N.G. USE

(million metric tons)

Forecasting Agency and Date:	1984 (actual)	1990	1995	2000
MITI (4/82)	26.7	43.0	n.a.	51.9
MITI (11/83)	26.7	36.5	40.0	43.0
(later revision:	26.7	36.5	40.0	41.5)
IEE (6/84)	26.7	34.0	40.0	--
PAJ (6/84)	26.7	33.2	37.0	40.9
PAJ (8/85)	26.7	32.3	34.6	35.1

LEGEND: MITI = Ministry of International Trade and Industry
IEE = Institute of Energy Economics
PAJ = Petroleum Association of Japan

NOTE: IEE's forecast for 1995 is the same for all three scenarios considered: "most likely," "low-growth," and "high-growth." Presumably, then, the variation in total gas use is expected to be accounted for by variations in non-LNG sources of gas.

SOURCES: Tokyo Gas Co., The Role of LNG (Past, Present, and Future), Tokyo, June 1985.

IEE, "Japan's Long-Term Energy Supply/Demand Forecast," manuscript, June 7, 1984.

PAJ, documents given to Professor Richard Samuels, autumn 1985.

Feasbility of the Dissenting View on LNG Demand in Japan

The core issue of feasibility is how much room there is in the Japanese economy to expand the use of natural gas. Two rough calculations are available.

One calculation, by Tadahiko Ohashi,[12] focuses narrowly on the "Big Three" city gas companies, Osaka, Toho, and Tokyo, inclusive of the smaller gas companies that are proximate enough to them to take more LNG if it were offered. He first estimates the "ultimate supply capacity" of the Big Three, based on "existing pipeline networks and re-gasification sites." Of the total of 15-16 million tons annually of LNG-equivalent, only some 80 percent, or 12-13 million tons of LNG, could actually be supplied by LNG, he says, "because of the rigidity of LNG supply and the policy of diversification of raw materials." Subtracting the gas utilities' existing contracts for LNG (some 7.62 million tons, total) gives "additional capability" for new LNG supplies of 4.4-4.5 million tons. This capability is some 16.9 to 20.7 percent of the 1984 figure for total Japanese LNG consumption (see Table 2). [Note: The "optimistic" variant of the model assumes that LNG use in 1990, 1995, and 2000 is 20 percent greater than the MITI forecast.] Thus, substantial demand growth just in the "Big Three" service areas could be accommodated without much additional investment in distribution capacity.

The Ohashi calculation is a decidedly conservative one. Not only does it not envision major investment in new gas-supply infrastructure, it also assumes no changes in LNG supply arrangements, and it ignores expansion of demand from the electric utility sector. A number of observers think that the consensus view of electric-utility demand for LNG is too low, given environmental concerns about coal-fired and nuclear capacity, and an apparent trend toward relatively greater peak (as opposed to base-load) demand for electricity.[13]

In the other calculation, much rougher than that just described, we attempt to establish an absolute outer bound for Japanese LNG use in the mid-1980s. Using the detailed "Green Book" of energy balances,[14] we calculate that in 1984 the Japanese economy could--emphasize could--have absorbed an additional 194.7 million metric tons of LNG by displacing coal, crude oil and refined products, and synthetic gas. The logic of the calculation is as follows:

1. Replace all non-LNG sources of city gas with LNG.
2. Replace all petroleum products, crude oil, coal, and coke used in generating electricity with LNG. (But do not displace any nuclear, hydro, or existing LNG generation.)
3. Replace all petroleum products and coal used in industry with LNG.
4. Replace all petroleum products used in the residential and commercial sectors with LNG.
5. In the industrial, residential and commercial sectors, we did not displace the city gas or the electric power used, because they are already taken into account in items 1-4.

The data in the source are reported in 10^6 kCal; we converted them to 10^6 MMt by multiplying by 1.23. The numerical totals for each category above are as follows:

1. 5.7 MMt
2. 70.1 MMt
3. 82.4 MMt
4. 36.5 MMt

Total: 194.7 MMt

Total 1984 consumption of LNG in Japan comes to only 13.4 percent of this absolute outer bound. Thus, even minor penetration by LNG into the existing non-LNG fuel uses would support rather large increases in LNG trade in the Pacific Basin.

Obviously, the greatest room for extra LNG use in Japan is in industry, but the potential is also great in electric-power production. Even in the residential sector, which is widely regarded as nearly saturated so far as LNG is concerned, a penetration of only 25 percent of the 1984 outer-bound potential would mean increased use of more than 9 million tons of LNG per year. Of course, such a penetration would be the most expensive of the lot, in terms of required investment in additional distribution infrastructure.

Conditions for a Non-Consensus Approach to LNG in Japan

Four conditions must obtain before the dissenting view would be practicable.

LNG Pricing

The first and most important condition has to do with LNG pricing. In the words of one prominent analyst:[15] "Even though this [MITI, Nov. 1983] forecast is widely supported among Japanese energy experts, no one can deny that LNG pricing is the key to the actual future demand for LNG."

The relative price of LNG must be lower than it currently is (roughly at parity with crude oil), and the process of redetermining LNG prices over time must be released from its bondage to crude oil. (The ideal referent would be a liquid spot price for LNG--see the next subsection.) This condition would permit LNG to compete in "non-premium" fuel markets. These two changes will require flexibility mainly on the part of the sellers in the Pacific Basin Market, although buyers renegotiating for additional LNG supplies would be in a position to "encourage" them.

Spot LNG Trading

The second condition is much greater flexibility in worldwide trading of LNG> Ideally, this would take the form of a liquid spot market--that is, one active enough that no one deal would significantly affect the price.[16] A "liquid spot" market would be far boarder (i.e., more liquid) than a distress-sale "spot" market that acts merely as a safety valve for occasional surpluses or shortfalls. (Spot transactions in the latter sense seem already to have appeared in the Pacific Basin.)[17]

Regional (If Not National) Gas Networks in Japan

The third condition is designed to permit greater flexibility in trading LNG inside Japan. The principal component of this condition would be substantial investment in regional, if not national, gas networks. In addition, it would obviously require relaxation of diversification requirements by fuel type (though not necessarily by geographic source).

Price Discrimination in INVERSE Proportion to the Elasticity of Demand

The fourth condition is to adopt LNG pricing that discriminates in inverse proportion to the price elasticity of user demand. This would be in contrast to the present policy of offering "firm" service--designed for customers will low price elasticities of demand--at preferentially low rates. So-called Ramsey-price gas rates would provide added flexibility in the market by additing users who are willing to switch on or off gas as market conditions ease or tighten.

How likely is it that the above four conditions can be met? On pricing, the essential development is that suppliers acknowledge that world energy markets, including those for gas, are now demand-constrained, not supply-constrained as they were in the 1970s and early 1980s. Realism here should reduce their reservation prices for gas, wean them from the insistence on tying gas prices tightly to crude oil or refined products, and (one would hope) persuade them that restricting the resale of LNG will only hamper the long-term growth of the market. Realism of this kind has broken out in North America and Western Europe, and shows distinct signs of doing so in the Pacific Basin. Admittedly, the rapid slide of oil prices in late 1985 and early 1986 has made realism more painful to bear.

The conventional wisdom is that LNG cannot be traded on a liquid spot basis, because the projects are lumpy and require careful coordination of the inputs and outputs. But lumpiness is a relative, not an absolute measure; in an expanded LNG market, an LNG train that was "lumpy" in 1980 would be but a part of a larger flow in (say) the 1990s. And vertical coordination between inputs and outputs within projects was a necessity born of the limited extent of trading, and therefore of facilities for producing, shipping, and handling LNG. No intrinsic characteristic of LNG makes such coordination necessary--_if_ participants in the market could get reliable access to facilities when they wanted to trade. Where excess LNG capacity has made suppliers willing to trade, a few spot transactions have already occurred (in Europe as well as the Pacific Basin). The argument that LNG cannot be traded spot is reminiscent of the parallel--spurious--argument about common carriage in North American pipeline networks in the 1930s. Ironically, a key argument in the latter debate was that natural gas could not be economically stored--scarcely a constraint in the case of LNG!

Regional gas distribution networks could take the form of pipeline grids (such as now exist in North America and Europe) or of "nodes" of LNG delivery and regasification facilities interconnected by tankers. Japanese actors and observers, whether in the "consensus" or the "dissenting" camp, seem strongly to prefer interconnected nodes to pipeline systems. For a nmumber of reasons--e.g., the island layout of the country, the danger of earthquakes, and population densities--pipeline construction is viewed as very, indeed, prohibitively expensive.[18] A nodal system, however, meets with a rather favorable reception--provided, of course, that the demand is there--precisely the point of contention between the consensus and dissenting views.

Regional (if not national) gas distribution networks would be an expensive proposition, without a doubt. However, they could be cheap at the price in the long run, compared with (1) continued subsidies to "firm" industrial customers necessitated by market rigidity owing to the lack of networks; and (2) foregoing the greater use of LNG. The latter point could be especially telling if Japan, by refusing to build such networks, were to cut itself off from falling LNG prices in the Pacific Basin. Note that Japan may get at least the beginnings of regional networks out of its "LNG Introduction Promotion Center," established in 1985.

The fourth and final condition, adopting Ramsey-pricing in place of the existing pattern of subsidizing LNG use by price-insensitive industrial users, would not be controversial, once the other three conditions had been met. As argued earlier, the necessity to subsidize "firm" instead of "interruptible" use stemmed in part from the rigid nature of the existing system of LNG purchase and use in Japan. Absent that system, Ramsey prices would virtually suggest themselves as the appropriate way to price gas.

This has begun to happen in the North American market, despite a time-honored tradition of cross-subsidizing homeowners' and small businesses' uses of gas out of pipeline revenues from industrial customers. The force behind the change is that gas markets are now seen as demand, not supply constrained.

SUMMARY AND CONCLUSIONS

The Pacific Basin market for natural gas resembles other major gas markets around the world in many respects. Future economic growth will obviously be a key determinant of gas demand, as will oil prices and people's expectations about when and how they will change. Both demand and supply decisions involve large capital outlays that depend on complex decisions under uncertainty. Government policies figure centrally in decisions on the production and use of natural gas.

What sets the Pacific Basin market apart from the other major international markets for gas is that its trade flows consist exclusively of LNG. In the setting of the 1970s--particularly, the two oil-price shocks and the expectations that oil prices would remain high or even increase--a peculiar set of institutions and policies grew up for trading LNG. Important characteristics of these trading arrangements include the use of oil prices as contract referents for setting LNG prices, high take-or-pays, and restrictions on resale. The Japanese government also participated actively in setting the terms used in trading LNG. This trading system was the basis for the rapid introduction and growth of LNG use in the Japanese economy.

The future prospects for Japanese demand for LNG divide into two broad competing scenarios. One, which we have called the "consensus view,"

FOOTNOTES

[1] The Pacific Basin is very much like North America and Western Europe in at least this respect.

[2] The extent of this monopsony power and Japan's ability to exercise it depends on, among other things, the way LNG trade is organized, the level of world oil prices, and the extent of The Rest's gas demands. Japan will be freer to exercise monopsony power, other things equal, the more that sellers of LNG are effectively limited to the Pacific Basin. Within that area, the greater the gas demands of The Rest, the less will Japan be able to exert market buying power.

[3] For instance, "to ensure a stable supply of LNG, Japan has been endeavoring to diversify its import sources and is planning to start importing from Australia and Canada" -- Ministry of International Trade and Industry (MITI), Energy in Japan: Facts and Figures, Tokyo, August 1985, p. 24.

[4] International Gas Report, November 8, 1985, p. 10.

[5] Ministry of Finance, Japan Exports and Imports, cited in Tokyo Gas Co., The Role of LNG (Past, Present and Future), Tokyo, June 1985, Table 8. The ratio reported is the joint outcome of many forces, including changes in exchange rates, the lags in the link between crude oil and LNG prices, and changes in the composition of crudes purchased in Japan. However, the broad range of the movement in the ratio seems indicative of the general trend of this relationship.

[6] An exception to the rule cropped up in the North American gas market during the 1970s, in the form of "indefinite" price escalators pegged to various indices of oil prices.

[7] For instance, between April 1982 and November 1983, MITI reduced its forecast of LNG use in 1990 and 2000 as follows:

	April 1982 Forecast	November 1983 Forecast	%Reduction
1990	43.0	36.5 MMt	15.1%
2000	51.9	43.0 MMt	17.1%

The forecast for 2000 has subsequently been reduced by a further 1.5 MMt to 41.5 MMt (see Tables 2 and 5).

[8] One estimate puts this excess supply at 1.6 MMt of LNG by fiscal year 1988 (Japan Petroleum and Energy Weekly, September 2, 1985.

[9] We have not yet found any discussion of the broader implications of solving this thorny problem -- namely, that a grid of some sort to link the small town gas companies to LNG supplies could also be used to bring direct gas service to industrial and large commercial customers. That is, we could have here the beginnings of a national Japanese gas grid. We return to this question in section 5.

[10] See, for example, Institute of Energy Economics, --[Journal]--, p. 51.

[11] Japan Petroleum and Energy Weekly, October 8, 1984, pp. 4-5; also, Institute of Energy Economics, op.cit., p. 46.

[12] op.cit., pp. 13-14.

[13] For example, private communication from a Canadian gas-producing firm, commenting on the first draft of the Pacific Basin report.

[14] Institute of Energy Economics, Energy Balances in Japan (1984), Energy Data and Modelling Center, 1985.

[15] Tadahiko Ohashi, "An Analysis of the Future of Natural Gas in Japan," typescript, June 1985, p. 1.

[16] Barring huge growth in gas demand from the rest of the region, this condition would also require that Japanese participants in the market act as individuals, not in concert (e.g., through a government agency).

[17] International Gas Report, December 2, 1985.

[18] Osaka Gas Co. undertook an economic feasibility study of a pipeline running westward from the Himeji LNG terminal (just west of Osaka), through Okayama and Hiroshima, across the Kanmon Straits to Nagasaki (summarized in a company communication kindly supplied at the January 1986 project meeting at M.I.T.). The implied costs per MMBtu would make gas delivered through the pipeline system prohibitively expensive. We are not clear to what extent this study explored the possible increase in gas use along the pipeline, with concomitant savings per MMBtu from laying a larger diameter pipe.

NATURAL GAS SUPPLY IN THE ASIA-PACIFIC REGION

by

M.A. Adelman and Michael C. Lynch

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with the assistance of Jeffrey A. Stewart

"[L]ed by Algeria, the OPEC countries have taken the position that 'oil-gas [price] equivalency...[is]...a necessary incentive to develop (natural gas) reserves economically.'"[1]

"Today's gloomy LNG market, with shipments to the U.S. halted while European and Japanese buyers clamor for better terms, has not discouraged half a dozen countries from planning new export capacity."[2]

SUMMARY

The natural gas market in the Asia-Pacific region is currently in a state of supply surplus, demonstrated by the low level of exploitation of reserves and the disparity between the number of eager sellers and the paucity of buyers. Regulatory delays affecting several projects have mitigated the surplus, but not removed it. The resources in the region are underexploited, growing rapidly, and still immature. Thus, no physical contraint on supply can be foreseen.

The high level of profits available from an LNG project in the region is the main reason for the number of eager sellers, and exists because of the cartelized price for petroleum in world markets. However, some of the projects are less profitable than others, and could suffer should competition induce price cutting or in response to continued low oil prices.

LNG costs should remain stable in the worst event, for two reasons.

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[1] World Natural Gas Outlook: What Role For OPEC?, Bijan Mossavar-Rahmani and Sharmin Mossavar-Rahmani, Economist Intelligence Unit, Special Report No. 157, 1984, p. 4.

[2] "Poor LNG Outlook Not Dispelling Plans to Expand Capacity," Petroleum Intelligence Weekly, 12/2/85, p. 4.

Since the resource base is still immature, production costs are quite small and unikely to increase rapidly. Second, the major costs of LNG projects are the actual processes of liquefying, transporting, and regasifying the natural gas, which is not a resource cost, but a manufacturing cost. Since manufacturing costs typically fall over time, scarcity not being a factor, so should LNG costs. In addition, it appears that a variety of factors led to excessive cost escalation in the construction of liquefaction plants. Most or all of these factors are now gone or diminishing, so near-time costs for new projects could show serious declines.

INTRODUCTION

Like the North American natural gas market, the Asia-Pacific market finds itself with a supply surplus in the face of weak demand. Unlike North America, supply to the major consuming centers requires tanker transport. As a result, long lead times and heavy capital investment are necessary. Thus, the market changes only slowly, and participants often have more at risk.

Given this situation, our aim is to analyze the options available to producers. These options are defined on the one side by the cost of producing and transporting the gas and on the other by the value of the gas in its various uses. This chapter will seek to indicate the costs involved, as well as providing direction for these costs.

The second section will provide a brief history of natural gas supply in the Asia-Pacific region, followed by a section on the current situation regarding resources and production. Following that is a discussion of LNG costs, including the different estimates and the reasons they differ, as well as the factors that have led to changes in costs over time and our expectations for future costs. The final section will offer conclusions, and appendices will cover field development costs and details of the large projects now proposed or underway.

BACKGROUND

The history of natural gas utilization in the Asia-Pacific area is much shorter than in North America for the simple reason that most supply lies not only far from consumers, but across vast expanses of ocean. High distribution costs require an industrialized economy to utilize gas efficiently, and of the developed countries in the region only Australia has historically had any significant reserves. Of course, coal gas has been used for decades, especially in Japan, although its market penetration has always been limited.[3]

Thus, establishment of a market required the development of the technology to liquefy and ship natural gas, which occurred in the 1960s,[4] but in light of the expense of shipment and the highly competitive crude oil prices prevailing, the economic impetus for the development of LNG projects was less than compelling.

Although the availabiity of cheap crude oil did not encourage development of new energy resources, when Japanese policy-makers moved to discourage the emisssion of sulfur from power plants, the electric utility industry began to seek supplies of fuels containing less

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3 Tokyo Gas was founded in 1985, for instance.

4 The first commercial shipments of LNG began between Algeria and Britain in 1964.

pollutants.[5] This, combined with the availability of abundant gas reserves lacking local markets, first in Alaska's Cook Inlet, then in Brunei, led to the initiation of LNG trade in the Pacific.

Actually, at the time regional gas reserves were not large. In 1969, the year the first LNG project in the Pacific began operation, natual gas reserves in the region totalled 50 trillion cubic feet (Tcf), equal to about 3 years of total Japanese energy consumption.[6] However, most of this supply was located in Pakistan, whose reserves were subsequently downgraded. In fact, Indonesia, Brunei, and Malaysia, the three largest exporters at present, only held 3 Tcf of reserves.

This reflected, in large part, the definition of reserves as resources available given current prices. Not only was there little incentive to explore for gas with oil at $3 a barrel, but any gas strike would be labelled sub-marginal or uneconomic, if not listed as a dry hole, unless it was in close proximity to a consumer. As Figure 1 shows, gas reserves soared upward with the development of a market. By January 1974, reserves in the "non-consuming" countries[7] had soared ten-fold, to 35 Tcf, although production was still only 129 billion cubic feet (Bcf), or less than half a percent of reserves.[8] These three countries now boast early 100 Tcf of reserves.[9]

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[5] This is discussed in more detail in the chapter on policy.

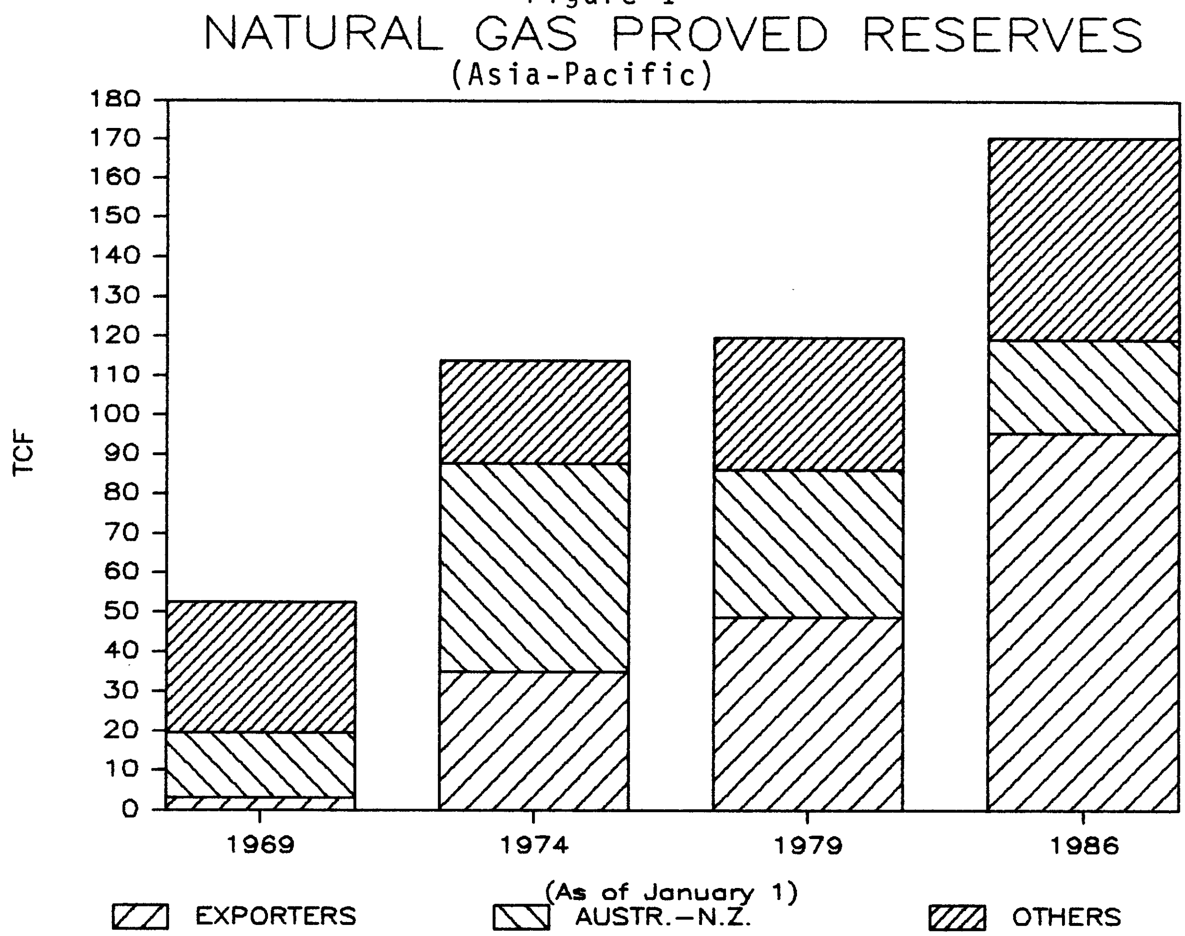
[6] Oil and Gas Journal, 12/30/68, p. 102.

[7] Brunei, Indonesia and Malaysia. Bangladesh and Pakistan had 8 and 10 Tcf in reserves in 1974 respectively, but have to date used their gas for domestic consumption. Afghanistan will be considered a part of the European gas market, since its exports have been exclusively directed at the U.S.S.R.

[8] Oil and Gas Journal, 12/31/73, p. 86-87.

[9] Ibid., 12/30/85, pp. 66-67.

Figure 1



Source: Oil and Gas Journal, Worldwide issues.

The two oil crises that occurred during the 1970s played a significant role in the development of both natural gas reserves and the LNG trade in the Pacific.[10] By raising the price of the major competitive fuel, the value of LNG was increased substantially, and the profits to be had from a project increased concomitantly, despite large cost increases. Since LNG imports were being priced at crude oil parity (cif), their prices increased with every oil price increase, as can be seen in Figure 2. Using constant costs for an export project, Figure 3 shows how the typical wellhead value of natural gas dedicated to an LNG project has risen over the years. (As will be demonstrated below, costs have not, in fact, been constant, and are thus overstated in the earlier years.)

The wellhead value, though, understates the perceived value of the gas during the 1970s, especially after the Iranian Oil Crisis. The idea that the world was suffering from resource scarcity became widely held, with prediction of soaring energy prices dominating discussion. (This was furthered by the natural gas shortage in the United States.) In reality, the apparent resource scarcity was due to short-term, non-geologic phenomena including regulation effects and supply disruption. The United States in particular experienced a supply "short" as a result of regulation, although policy-makers had long argued that the regulations were in response to the shortage rather than the other way around.

Table 1 lists all of the existing LNG projects and those still being actively considered in the Asia-Pacific region. Many of those proposed

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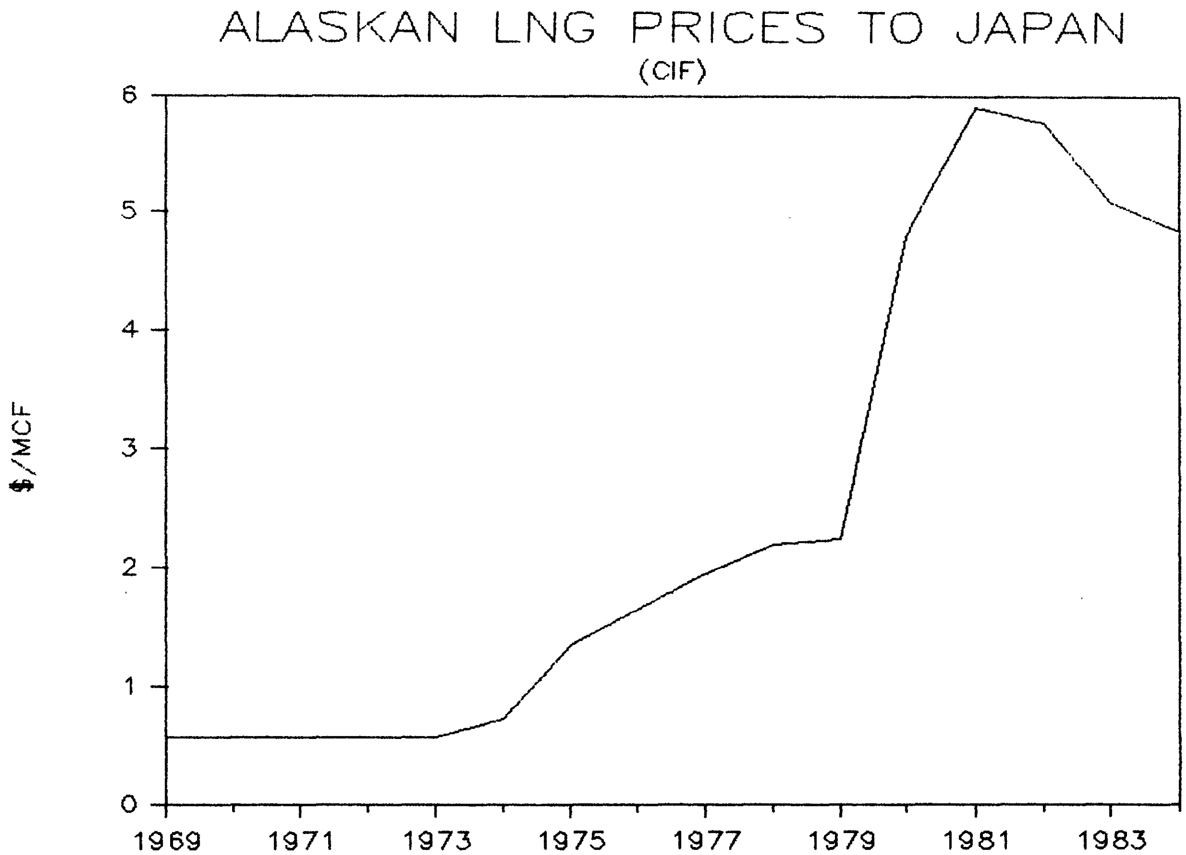
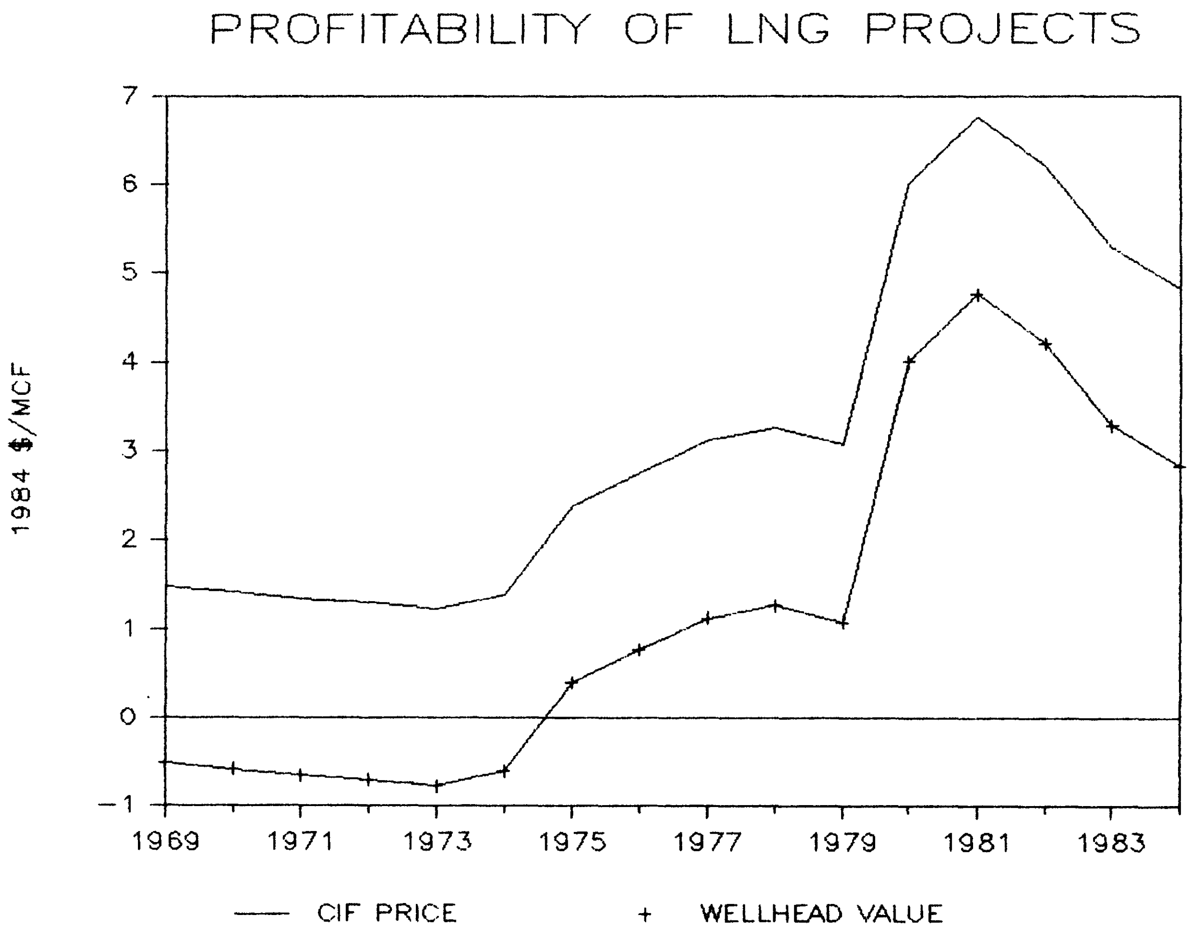
[10] The oil crises also provided a strong desire for diversification away from petroleum consumption for security reasons, which played a role in encouraging the importation of LNG, especially in Japan.

Figure 2



Source: International Crude Oil and Product Prices, July 1985.

Figure 3



Sources: Prices from Figure 2, costs assumed at $2/Mcf.

Table 1
LNG Projects in the Asia-Pacific Region

A. Currently Operational

Exporter	Starting Date	Ending Date	Quantity (million tonnes)
Alaska	1969	1989	.96
Brunei	1973	1993	5.14
Abu Dhabi	1977	1997	2.06
Indonesia (Badak 1)	1977	1997	3.0
Indonesia (Arun 1)	1978	1998	4.5
Malaysia	1983	2003	6.0
Indonesia (Badak 2)	1983	2003	3.2
Indonesia (Arún 2)	1984	2004	3.3
Total			28.16 (1408 Bcf)

B. Planned or Proposed

Exporter	Starting Date*	Quantity (mt)	Status
Indonesia (Arun 3, to Korea)	1986	2	Under construction
Indonesia (to Taiwan)	1988?	1.5	In negotiations
Australia	1989?	6	Contracts signed
Canada	1989?	2.9	Not finalized
Alaska (TAGS)			
Phase I	1990	4.8	Proposed
Phase II	1992	4.1	"
Phase III	1994	5.6	"
Qatar	1990	6	Proposed
USSR (Sakhalin)	1990+	3	In Negotiations
Australia (Elf to ?)	mid-1990s	2	Proposed

*Estimated

Sources: BP Review of World Gas for existing, published reports for all others.

Note: Japan is buyer except where otherwise noted.

were initiated in resonse to express interest on the part of Japanses buyers, who, like many other consumers, seriously overestimated their needs for natural gas during the late 1970s and early 1980s. Because of this overestimation, among other reasons, a number of projects that were considered firm wound up postponed for a number of years, and several eager suppliers are finding it difficult to arouse much interest on the part of prospective buyers.[11]

The market is, in effect, in disequilibium: too many Btus chasing too little demand. Since the cost of providing the Btus is well under the current price, moving in the direction of equilibrium means lower prices to increase demand and reduce supply. The constrainst on the movement of prices and supply will be addressed in the next two sections.

THE SUPPLY OF NATURAL GAS IN THE ASIA-PACIFIC REGION

Unlike North America, where the United States and Canada collect and distribute extensive amounts of data on production, reserves, and expenditures, few countries in the Asia-Pacific region provide data that can be used in a meaningful way,[12] particularly regarding expenditures. As a result, this analysis involves estimating costs from the physical evidence available, rather than transfomring the data into the appropriate forms.

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[11] Some producers have complained that the Japanese deliberately encouraged the development of a glut to improve their own bargaining position, but, in reality, most buyers (and producers) were reacting to the same perceived market environment with identical expectations. In addition, domestic regulatory difficulties in the producing countries have been responsible for many of the delays that have occurred.

[12] Australia collects and publishes substantial data on production and reserves, but not expenditures, nor does it break down reserves into discoveries versus revisions and extensions, etc.

Fortunately, because resource development is still quite immature in the region, much of the gas comes from a few large fields, rather than a mutitude of smaller ones as in North America, and so relying on physical data (e.g., water depth, field depth, and flow rates) is a much esaier task.

Resources

Table 2 shows production and reserves in the countries of the Pacific Basin, including (for reference) the United States and Canada. The United States is taken as an indication of a possible or attainable depletion rate, given the economic incentives and the lack of a government ceiling on depletion. A frequent rule of thumb in the oil industry is to have a 15:1 reserves:production ratio, i.e., 6.67 percent depletion, but the United States has long produced at higher rates. The higher the depletion rate, the larger the needed investment, but the quicker the payout. There is always a tradeoff between the two.[13]

It is apparent that the Pacific Basin reserves are being under-depleted and the case is even stronger than Table 2 would indicate. The gas fields known to date were found as an accidental result of the search for oil. Deliberate search for gas would thus result in more discovery. Moreover, experience shows that reserves keep expanding even without new-field discovery, because of the extensions of old fields, and increasing knowledge of how to extract more

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[13] For a more complete explanation, see M.A. Adelman, "OPEC as a Cartel," in James M. Griffin and David J. Teece, eds., OPEC Behavior and World Oil Prices, (George Allen & Unwin), 1982, especially pp. 57-59.

TABLE 2
PRODUCTION THROUGH YEAR/
RESERVES AT YEAR END

	1985			1984			1982		
	Product. (Bcf)	Reserves (tcf)	Productio / Reserves	Product. (Bcf)	Reserves (tcf)	Production/ Reserves	Product. (Bcf)	Reserves (tcf)	Production/ Reserves
Australia	480	18.22	0.026	444	17.85	0.025	416	17.77	0.023
Brunei	299	7.4	0.04	312	7.3	0.043	342	6.8	0.05
Indonesia	1089	35.6	0.031	732	40	0.018	569	29.6	0.019
Japan	80	1.1	0.073	74	0.72	0.103	80	0.72	0.111
Malaysia	277	52.7	0.005	120	50	0.002	37	34	0.001
New Zeala	141	5.52	0.026	135	5.44	0.025	101	5.55	0.018
Pakistan	366	15.4	0.024	355	15.76	0.023	315	18.54	0.017
Taiwan	48	0.81	0.059	60	0.54	0.111	60	0.56	0.107
Thailand	128	5.4	0.024	78	5.9	0.013	n.a.	11	n.a.
Total	2908	142.15	0.02	2310	143.51	0.016	1920	124.54	0.015
U.S.	17261	197	0.088	18068	198	0.091	18731	204	0.092
Canada	3245	99.7	0.033	2652	92.3	0.029	2546	97	0.026

Note: 1985 production estimated using prod thru 9/85 multiplied
by the average 1981-84 (yearly prod/cuma 9/85 prod) factor for each country.
Thailand factor based on 83 and 84 factors only.

sources: Oil & Gas Journal 1982-1985
reserves: "Worldwide Oil & Gas at a Glance"
production: "Worldwide Oil & Gas Production"

hydrocarbon more cheaply.[14] But both finding and development require investment, which does not make sense if reserves already available are not being used. The low depletion rate indicates that production can be greatly increased at little increase in cost, or possibly even some decrease because of learning effects, economies of scale, and utilization of existing infrastructure.

Figure 1 showed that reserves have been increasing rapidly in the Asia-Pacific area in the last 15 years, from 53 Tcf at the beginning of 1969 to 96 Tcf in 1986. That this should occur despite the lack of markets for additional gas is suggestive of the extent of the underlying resource. In fact, drilling in the area is much less than in North America, as can be seen in Table 3, which shows rigs active and wells drilled in 1984. Of course, the United States has considerably more land area suitable for exploration, but even when corrected for this, the drilling level in the United States is still roughly ten times that of Southeast Asia.[15] Historically, of course, the ratio is even more

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[14] For a fuller discussion, see "Supply Aspects of North American Gas Trade," by M.A. Adelman and Michael C. Lynch, with the assistance of Kenichi Ohashi, in Final Report on Canadian-U.S. Natural Gas Trade, MIT Energy Laboratory Report 85-013. Hereafter referred to as the North American paper.

[15] The United States has roughly 3.8 million square miles of sedimentary basins, while Southeast Asia (Brunei, Malaysia, Indonesia, and Thailand) have 153 thousand. (See Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States, U.S. Geological Survey Circular 860, 1981, p. 13, and "Assessment of Undiscovered Conventionally Recoverable Petroleum Resources in Tertiary Sedimentary Basins of Malaysia and Brunei," by Keith Robinson, U.S. Geological Survey Open-File Report 84-328, 1984, p. 4.) Thus, using the data from Table 3, there are 20.7 well completions in the United States per 1000 square miles of sedimentary basins, and only 2.2 in Southeast Asia. For rigs active, the U.S. figure is actually slightly below that for Southeast Asia, reflecting the fact that many U.S. wells are drilled onshore and require much less rig-time. Unfortunately, the figures cannot be broken down into exploratory versus development wells, or onshore versus offshore. Data for seismic crews operating in

TABLE 3
EXPLORATORY ACTIVITY IN THE ASIA-PACIFIC REGION

	Seismic Crews Operating (Onshore)	(Offshore)	Rigs Active (Onshore)	(Offshore)	Well Completions
U.S.	440	46	2216	213	78542
Canada	89	3			7095
Australia			24	10	182
New Zealand			0	0	15
Far East	93	16	179	69	404
of which:					
Brunei			2	7	6
Indonesia			56	26	267
Malaysia			0	9	20
Thailand			5	6	38
Other			116	21	73

Notes: Seismic activity is first half of 1984;
rigs active are for 1984, and well completions for 1983.
All data is reported in International Petroleum Encyclopedia, 1985, Pennwell Publishing, pp. 241, 283-285.

strongly biased in favor of the United States than is reflected by the most recent data. Thus, the level of exploratory activity could be considered relatively light, especially in regard to the potential, although current levels are certainly more encouraging that those in the past.

The reasons for the low level of activity are related to a variety of factors, including the rate at which governments grant exploration permits, production ceiling, especially in Indonesia, and other government disincentives, but also the lack of markets for natural gas, where that has been discovered. The rapid, if unintentional, rise in natural gas reserves that occurred in the last fifteen years indicates that lack of resource has not been a constraint.

Given the much lower level of exploration in these areas, estimates of the ultimate potential are bound to be much less accurate. Of course, they are not necessarily accurate in heavily explored areas such as the United States, but there the problem is more one of data interpretation rather than of data availability.[16] Various observers have made estimates of the resources in the region, and these are presented in Table 4. As can be seen, most believe that the amount of undiscovered "conventional" natural gas is still several times the current level of reserves.

These estimates indicate the current potential economically exploitable resources. As noted in our previous report, they underestimate future resource development because of definitional problems. Specifically, they rely on current technology, prices,

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Southeast Asia are unavaiable.

16 See the North American report for a full discussion.

Table 4
Estimates of Ultimately Recoverable Reserves of Natural Gas in the Asia-Pacific Region
(Tcf)

Source	Region	Estimated Total URR	Estimated Undiscovered Resources
Hendricks	Oceania	350	
	Asia	200	
Mobil	Oceania	555	450
IGT	Australia+ NewZealand	500	462.7
	Other Asia	520	358.4
DOE	Indonesia	115	42
	Malaysia + Brunei	133	80
	Thailand	37	21
Masters/ USGS	Asia+ Oceania	750	500

Notes: IGT Other Asia includes USSR, and 2650 TCF was subtracted from URR to derive number shown, based on Hendricks, see page 68.

Sources: Hendricks and Mobil from IGT, pp. 51, 67.
IGT is Joseph D. Parent, A Survey of United States and Total World Production, Proved Reserves, and Remaining Recoverable Resources of Fossil Fuels and Uranium, Institute of Gas Technology, 1980.
Masters is from Charles D. Masters, "World Petroleum Resources - a Perspective," USGS Open-File Report 85-248, 1985.
DOE is from USGS estimates, cited in The Petroleum Resources of Indonesia, Malaysia, Brunei, and Thailand, 7/84, p. 102.

and costs. Thus, they may include a minimum size as a cutoff for economically exploitable fields in a given area, which relates to the current state of development of that area. Over the years and decades, as infrastructure is built up through the development of currently exploitable fields, the incremental cost of adding a new field drops, since it can exploit existing pipelines, handling and processing facilities, service industries, and so forth.

Looked at another way, the minimum economic field size in Indonesia at present is much larger than in, for example, Oklahoma. Yet, in Oklahoma, the minimum economic field size has dropped over time due to the expansion of the natural gas pipeline system, as more fields are added. The same will occur in Indonesia, so by the time the currently known fields are declining, the potential resource base will have grown as the minimum economic field size drops.

Production Costs

Cost data for Pacific Basin oil and gas are very scarce. However, the Basin is similar to offshore Louisiana, although drilling is somewhat easier, as indicated by the following:

> "Southeast Asia platforms are generally less expensive because the wave design criteria allows [sic] for a lighter structure, except where typhoons are most prevalent. Contributing to the lighter costs are smaller labor expenses. [New Zealand is an exception.] Platform costs everywhere else are virtually the same as the Gulf of Mexico."[17]

Thus, it is possible to use the data for the U.S. offshore region to estimate costs in the Pacific basin. In Table 5, the estimation proceeds

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[17] Leonard Leblanc, "Platform Price Tag Climbs," Offshore, September 1978, p. 86.

TABLE 5
DEVELOPMENT COSTS

1	Drilling and equiping wells per well	2.9 ($MM)
2	Allowance for dry holes and non drilling costs per well	2.9 ($MM)
3	Allowance for pipeline to shore and possible higher cost of overseas operations per well	2.9 ($MM)
4	Total development cost per well	8.7 ($MM)
5	Annual development-operating cost per well	1.91 ($MM)
6	Development-operating costs per day per well	5200 ($)
7	Development-operating cost as sold	0.260 ($/Mcf)
8	development cost in ground	0.060 ($/Mcf)

sources:
1. 1984 JAS 10,000' Off LA
2. Adelman and Ward
3. assumed 50% of 1 + 2
4. line 1 + line 2 + line 3
5. line 4 * (.12 + .05 +.05), allowing 12% disc. rate, 5% depletion, 5% operating costs
6. line 5 /365
7. line 6 / assumed flowrate of 20 MMcfd
8. dev cost at wellhead = line 4 * 0.17 / 7.3 bcf/year = $0.203/Mcf (.17=depletion + disc. rate, 7.3 bcf = yearly production
   dev cost in ground = dev cost at wellhead divided by (1+(i/a))=(1+(.12/.05))

as follows. Producing depths in the Pacific Basin rarely reach 10,000 feet. In 1984, it cost about $3 million for an offshore Louisiana well to that depth (including its share of platform). An allowance for development dry holes, and for non-drilling expenditures (chiefly lease equipment), doubles this.

In addition, 50 percent has been arbitrarily added to allow for pipelining to shore and for possibly higher costs of working overseas. Thus, the base case well costs $8.7 million.

A depletion/decline rate of 5 percent for the base case is then assumed, and a cost of capital (minimum rate of return) of 12 percent. In the United States, it would be 10 percent, but some allowance for greater risk must be made outside North America.

More uncertain is the 5 percent for operating costs. In estimating costs for Canada, operating costs for the Venture project were set to zero on the assumption that liquids extracted from the gas and sold would about balance off operating costs. This is not done here because the liquids are not so easily accumulated and sold in the relatively remote locations in the Pacific Basin.

Thus, the $8.7 million investment is equivalent to an annual cost of $1.9 million per year, or $5200 per well per day.[18]

Appendix A lists 102 nonassociated gas or gas-condensate fields. The average flow rate was 20 million cubic feet (MMcf) per well per day, with of course much variation. (This equates to 3,000 barrels of oil per day, which is a good but not great rate.) The development-operating cost is then $5200/20 MMcf, or 26 cents per Mcf. If the needed rate of return

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[18] The methodology by which total costs are converted into annual costs is discussed in the North American paper, pp. 33-36.

were, say, not 12 but 20 percent, then the needed revenue would be 36 cents.

Reported costs, whether from a private or a public company, may differ from this esimates for a variety of reasons. Accounting techniques may vary, some companies may have higher or lower costs than others, due to better or worse efficiency levels, or differences in timing of investment,[19] the fear of expropriation may encourage a company to report higher costs to deter such a move, or lower costs to demonstrate competence, and so forth. These things cannot be estimated given available data; all we can estimate is a norm for the region.

Appendix B provides several estimates of mostly offshore developments in the Pacific Basin. They vary over and under the base case, due to differences in field depth, pipeline length, etc. Where there is sufficient information to vary the base case, i.e., total investment, initial flow rate, and depletion/decline rate, we derive an estimated cost figure for comparison. Announcements by companies will normally overstate costs, of course, since governments are watching.[20] However, there is no means of correction. It is evident that the base case is within the range of what has been announced, and the scale of the error is not significant.

In Appendix C, discussion of actual projects will show the cost variation that occurs. The reference case of \$0.26-\$0.36/Mcf represents fields in Indonesia, Malaysia, and Brunei; other areas like Australia,

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[19] Companies that paid land bonuses or bought equipment in the early 1980s would show higher costs than those who waited until later and bought (or paid) in a more competitive environment.

[20] Under the most prevalent type of production-sharing contract, in developing an oil field, the company's share of production is partly determined by the level of costs.

Table 6
Delivered Costs of LNG
Recent Estimates ($/MMBtu)

	WA-WE	NA-WE	PG-WE	PG-Japan
Siegal & Niering (1980)	$3.35-390		3.95-4.50	3.95-4 50
Vrancken (1982)*	4.30-4.70	3.00-3.40		4.60-4.80
IEA (1982)	4.15	3.40	4.90	4.90
BMR (1984)	4.41		5.25	4.41
DiNapoli (1984)	3.30			4.30

WA = West Africa
NA = North Africa
WE = West Europe
PG = Persian Gulf

NOTE: Regasification assumed at $0.40 and production and gathering at $0.30 unless otherwise shown.

*Liquefaction plant taxed at 50%.

Sources: OPEC = The OPEC Natural Gas Dilemma, by Bijan Mossavar-Rahmani, and Sharmin Mossavar-Rahmani, Westview Press, 1986, (using calcuations originally made by the OPEC Gas Pricing Committee).

DiNapoli = "Economics of LNG Projects," Oil and Gas Journal, 2/20/84.

IEA = Natural Gas: Prospects to 2000, OECD/IEA, Paris, 1982.

Mueller = "LNG: A Prince or a Pauper?" by Donald L. Mueller, Vice President, International Gas Development Corporation, presented 9/26/83, Calgary, Alberta, Canada.

Vrancken = "The Exportation of Natural Gas," by Peter Vrancken, advisor to Peeten LNG, Ltd. in The Economics of Natural Gas Development, Conference Speakers' Papers, venice, Italy, 6/21 - 22, 1982, sponsored by Financial Times and Jensen Associates, Inc.

Siegal & Niering = "Special Report on World Natural Gas Pricing," by Jeffrey Siegal and Frank E. Niering, Jr , Petroleum Economist, 9/80.

LNG-6 = LNG Handbook: A Commemorative Publiscation of LNG-6, 1981. We are indebted to JGC Corporation for this information.

Bonfiglioli and Cima = Cited in IEA, p. 125

Canada, and Qatar will shown noticeable deviations from this estimate.

OCEAN-BORNE SHIPMENT OF NATURAL GAS

In analyzing costs of producing natural gas in the Asia-Pacific region, the previous section demonstrated that they were below those in North America, especially in the United States. The much lower utilization of resources in the Pacific Basin is partly a function of the high cost of transportation, which is by necessity accomplished through the tanker shipment of LNG. Since there is substantial difference of opinion as to the actual costs of delivering LNG, and a large degree of uncertainty regarding the direction of future costs, a more detailed examination is necessary.

Current Estimates[21]

The most concise estimates of current LNG costs are shown in Table 6. In section A, the estimates are shown in dollars as given, and in section B they are converted to common dollars using the U.S. implicit price deflator, although this index may not be the appropriate one for inflating LNG costs.[22] For a long-distance project, such as one from the Persian Gulf to Japan, the analyses seem to be in rough agreement, at least in given dollars, although the highest estimate is more than a third higher than the lowest. A more detailed examination of the analyses and of specific aspects of costs is provided below.

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[21] Examples of specific project costs will be discussed in more detail in the section on cost escalation and in the appendix on proposed projects.

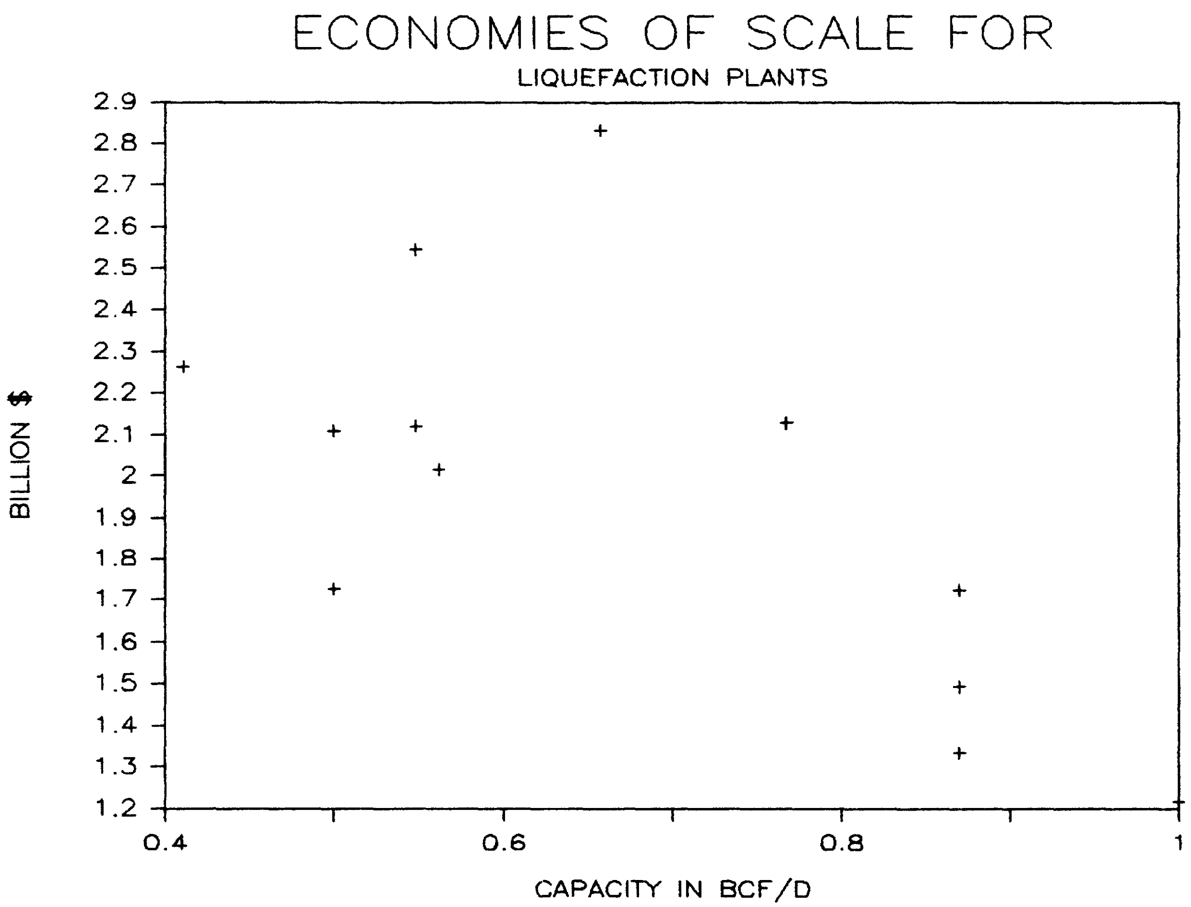
[22] In point of fact, the dollars being used are not always made explicit; in some cases, we have assumed them based on the time of publication.

Table 7
Liquefaction Plant Costs Estimates

Source:	Capacity (mcf/d)	Capital Cost (Million 1982$)	Capital Cost (per bcf/d)
IEA	870	1160	1333
	2600	2899	1115
Vrancken	870	1300	1494
	870	1500	1724
Mueller	500	863	1726
	500	1055	2110
DiNapoli	1000	1217	1217
Brown & Root:			
Phase I:	658	1863	2833
Phase II:	562	1132	2016
Phase III:	767	1633	2129
LNG-6			
Base case	411	930	2263
Middle Eas	548	1395	2545
Southeast	548	1162	2121

Sources:
IEA = Natural Gas: Prospects to 2000, International Energy Agency, (Paris, 1982).
Brown & Root = "Trans Alaska Gas System: Economics of an Alternative for North Slope Natural Gas" (Anchorage, 1983).
DiNapoli = "Economics of LNG Projects," Oil and Gas Journal, 2/20/84.
Vrancken = "The Exportation of Natural Gas", in The Economics of Natural Gas Development (Venice, 1982).
Mueller = "LNG: A Prince or a Pauper" presented in Calgary 9/83.
LNG-6 = LNG Handbook, a Commemorative Publication of LNG-6, 1981. We are indebted to JGC Corporation for this information.

Figure 4



Sources: See Table 7.

Table 8
Liquefaction Cost Estimates
($/Mcf)

LNG-6	1.20
DiNapoli	
3 mt plant	1.75
6 mt plant	1.20
IEA	1.10
Bonfiglioli and Cima	1.10-1.40
OPEC	2.10

Sources: See Table 6.

Liquefaction Costs

Estimates of the capital cost for a liquefaction plant are provided in Table 7. (See the section on cost escalation for a list of reported plant costs.) The variance is quite large, but can be partly explained. Costs for construction depend in part on the region where the plant is built and the size of the plant, both of which are discussed below, and, as in the case with Phase I of the TAGS system, the extent to which the system is being overbuilt to handle subsequent additions to capacity. In addition, the assumptions about future inflation and interest rates can substantially affect the estimated costs.[23] The main reason for the divergence seems to be the different size used, given the importance of economies of scale. When these estimates are plotted for size and cost/unit of capacity (see Figure 4), economies of scale can be seen.

Table 8 shows the costs per Mcf as derived by these and other analysts.[24] There does seem to be a certain convergence around $1.00/Mcf plus fuel costs (discussed below), which are roughly $0.15-$0.30/Mcf, depending on the assumption about prices to the liquefaction plant. In fact, this agrees fairly well with the results of a survey performed for this project of a number of Japanese gas distribution companies, trading

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[23] Exchange rate fluctuations play an important, but complex role, and have not been considered here.

[24] Unfortunately, the Mossavar-Rahmanis published a long paper (the EIU report referred to on page 1) and a shorter excerpt ("OPEC Natural Gas Projects Face a Bleak Outlook," Petroleum Intelligence Weekly, 3/19/84, pp. 7-8), which showed startingly different costs. The recent publication of the book, The OPEC Natural Gas Dilemma, Westview Press, 1986, does not exactly resolve the estimate dilemma, since it repeats both sets of costs. The lower costs are attributed to a 1980 OPEC study, and the higher are said to be Iranian estimates (see pages 84-85). Based on these estimates, the book provides a base case example for an LNG project (p. 98), and these are the ones reported here.

companies, construction companies, and large consumers (shown in Figure 5).[25]

Shipping and Tanker Costs

Table 9 shows a strong convergence on the question of shipping costs, although the size of the ships employed does have some effect. In fact, it indicates that capital cost estimates fall within a narrow range, agree relatively closely with reported actual costs, and have not changed much over time. Our survey indicated that costs have been slightly less than the estimates shown in Table 9 (see Figure 6).

Regasification Costs

Regasification again produces close agreement, as seen in Table 10. The only real difference is derived from a question of economies of scale, with DiNapoli suggesting that a small import facility will be much more expensive per unit of capacity. In this instance, however, our survey respondents suggested costs were slightly lower (see Figure 7), which may be due to cheaper construction costs in Japan than elsewhere.[26]

Conclusion: Costs per Mcf

Thus, it appears that current LNG costs are on the order of

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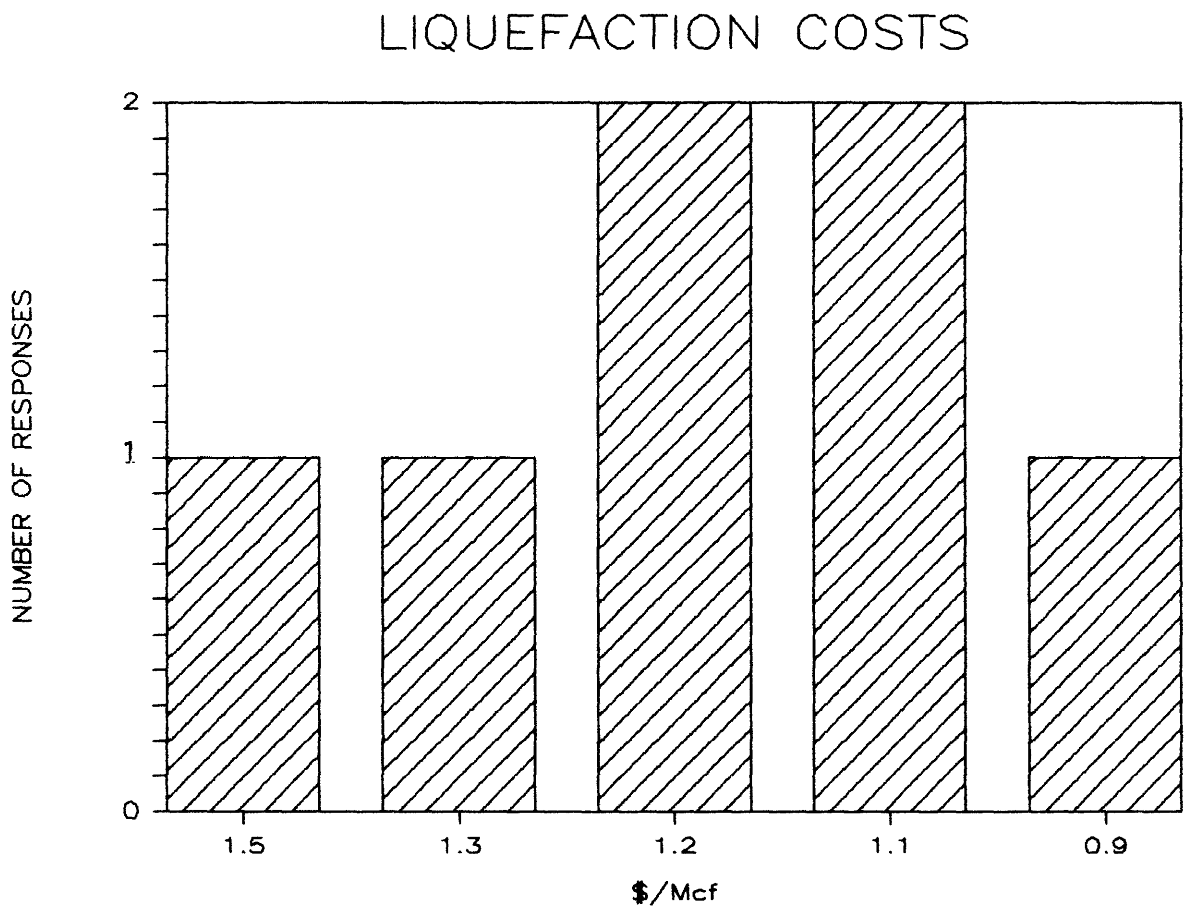
[25] Although the results indicate the cost level estimated by respondents, the survey was carried out by indicating our estimates of the different costs associated with LNG and asking respondents to differ with them. This technique does produce a certain bias toward the original estimate, which should be kept in mind when observing these results.

[26] Contrary to the tendency to agree with a provided estimate, as mentioned in the previous footnote, our respondents largely disagreed with our original estimate, which was $0.35/Mcf.

Figure 5



Source: CEPR survey of Japanese companies, 1985.

Table 9A
Shipping Cost Estimates
($/Mcf/1000 miles)

DiNapoli	0.25
Mueller	0.25
Vrancken	0.25
OPEC	0.16

Table 9B
Tanker Costs

Year	Country	Current $ (Million)	Tanker Size (tcm)	1984 $/100 tcm
1965	U.K.-Algeria	13.2	12	332
		13.3	16	248
1966	U.S.-Japan	[50 total]*	?? same ??	302
1970	Algeria-W.E.	50	120	100
	Brunei-Japan	27-30	75	92
	General	28	87.6	76
1974	Algeria	95.7	125	149
1978	Malaysia	120	125	142
1982	IEA	150	130	144
	Jensen	160		
1983	DiNapoli	150	100	161

*Project 60% larger than U.K./Algeria. Assume three ships.

Sources: See Table 6, and published reports.

Table 10A
Regasification Cost Estimates
($/Mcf)

OPEC	0.44
DiNapoli	
3 mt	0.60
6 mt	0.40
IEA	0.40
Bonfiglioli	0.30-0.40

Sources: See Table 6.

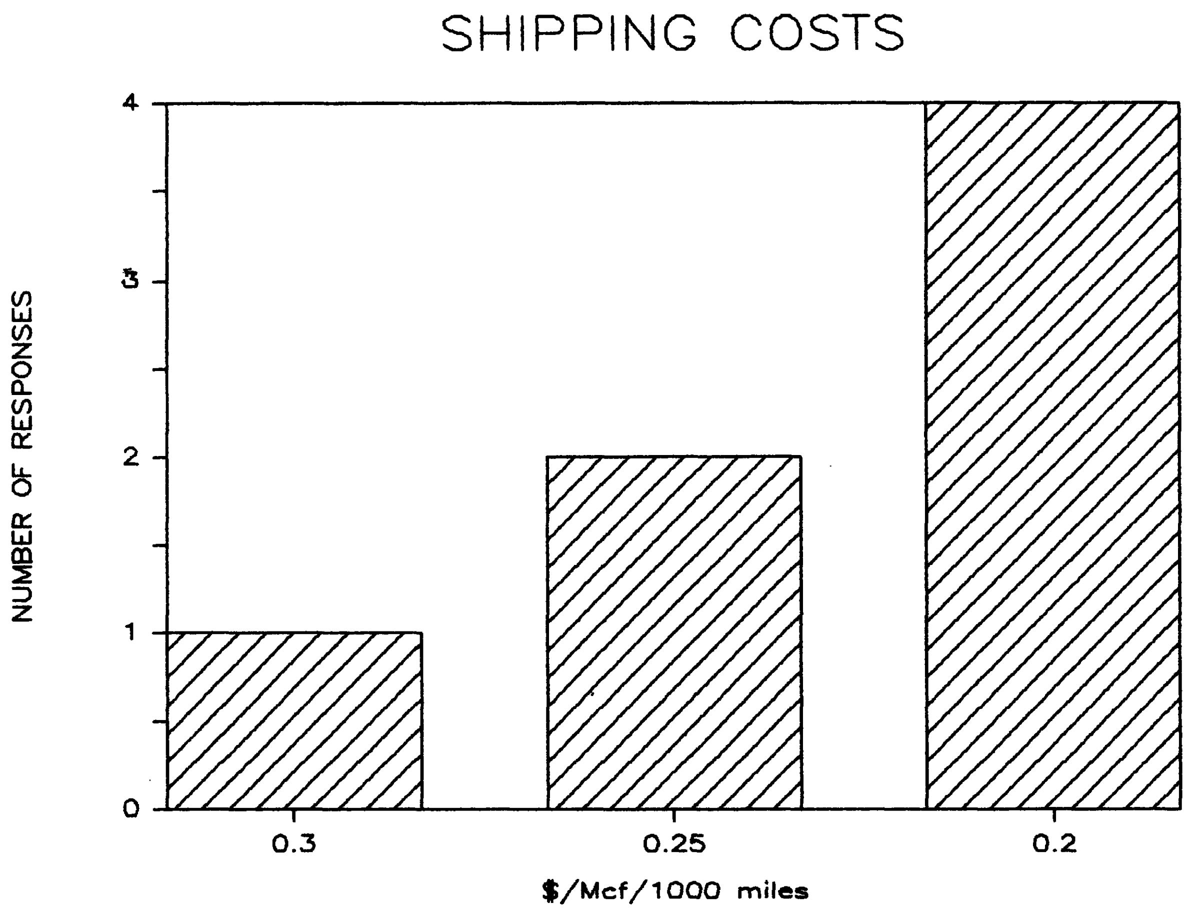
Table 10B

LNG Regasification Plant Cost Estimates

Year	Importer	Million $ (Current)	Size (mcf/d)	10^6 $/bcf/d
1965	Spain	16-20	48	1,167
1970	U.S.	50-90	484	352
1982	IEA	450	484	1,162
		650	968	839
1983	DiNapoli	543.4	1000	585

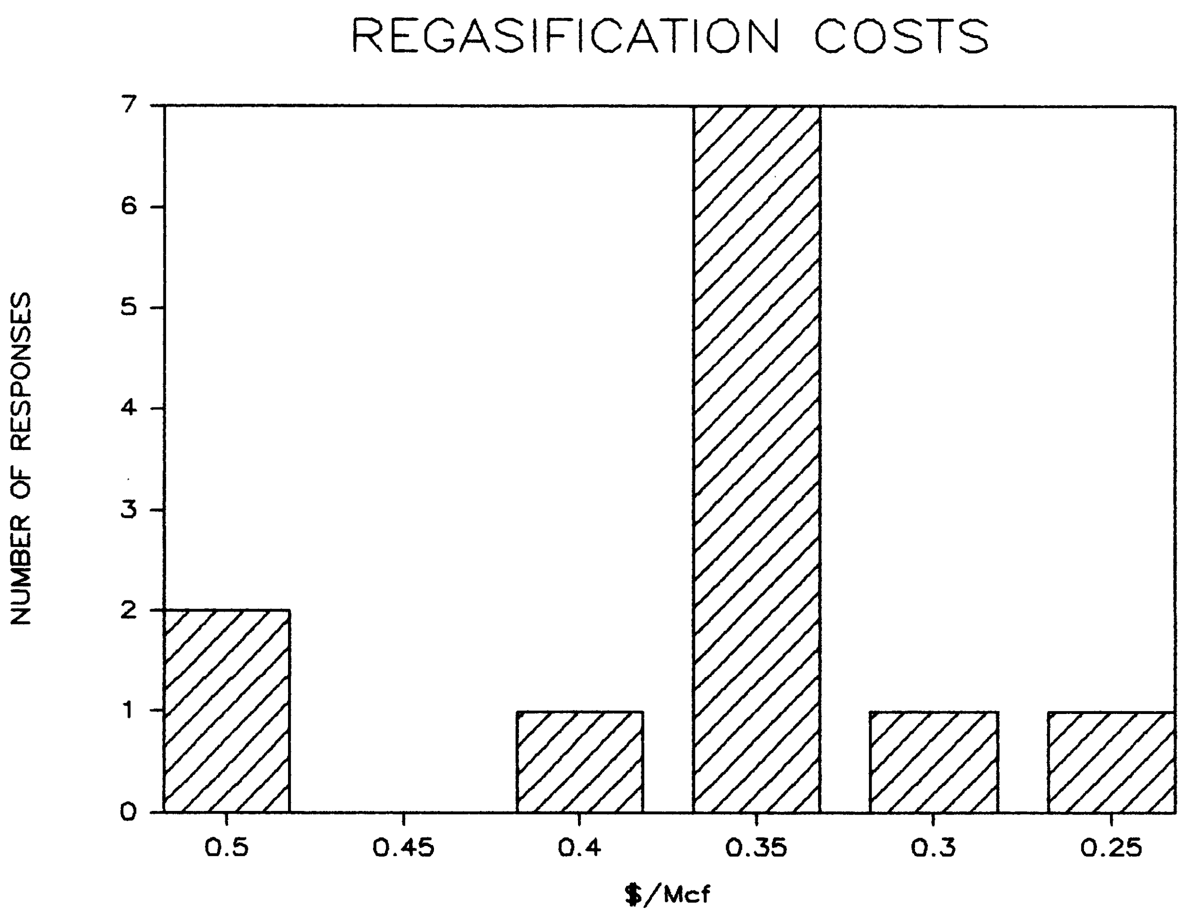
Sources: Published reports, and see Table 6.

Figure 6



Source: CEPR survey of Japanese companies, 1985.

Figure 7



Source: CEPR survey of Japanese companies.

$1.00/Mcf for liquefaction, plus fuel, $0.20/Mcf per 1000 miles of shipping distance, and $0.35/Mcf for regasification (at least in Japan).[27] However, this does not address the difference in capital costs by locale, economies of scale, fuel costs, and the future trend for LNG costs, all of which are discussed below.

Cost Variance by Locale

Unfortunately, the costs of constructing a liquefaction plant cannot be easily fixed, in part because of differences in construction costs by geographical area. These are partly a function of differences in construction costs in general, such as labor costs, land values, etc., and partly due to special circumstances relating to LNG, such as the nature of the soil at a site and its suitability for use as insulation, local safety regulations, etc. Since there have only been six liquefaction plants constructed serving the Pacific market to date,[28] and since these plants were constructed at different times and under different circumsances, it is not possible to provide a definitive statement of the variance in liquefaction plant construction costs by geographical location.

On the other hand, there are clearly differences, and it would be useful to address them. In our survey, we asked the respondants to estimate the difference between average liquefaction costs and those for particular producing countries. The responses are shown in Figure 8,

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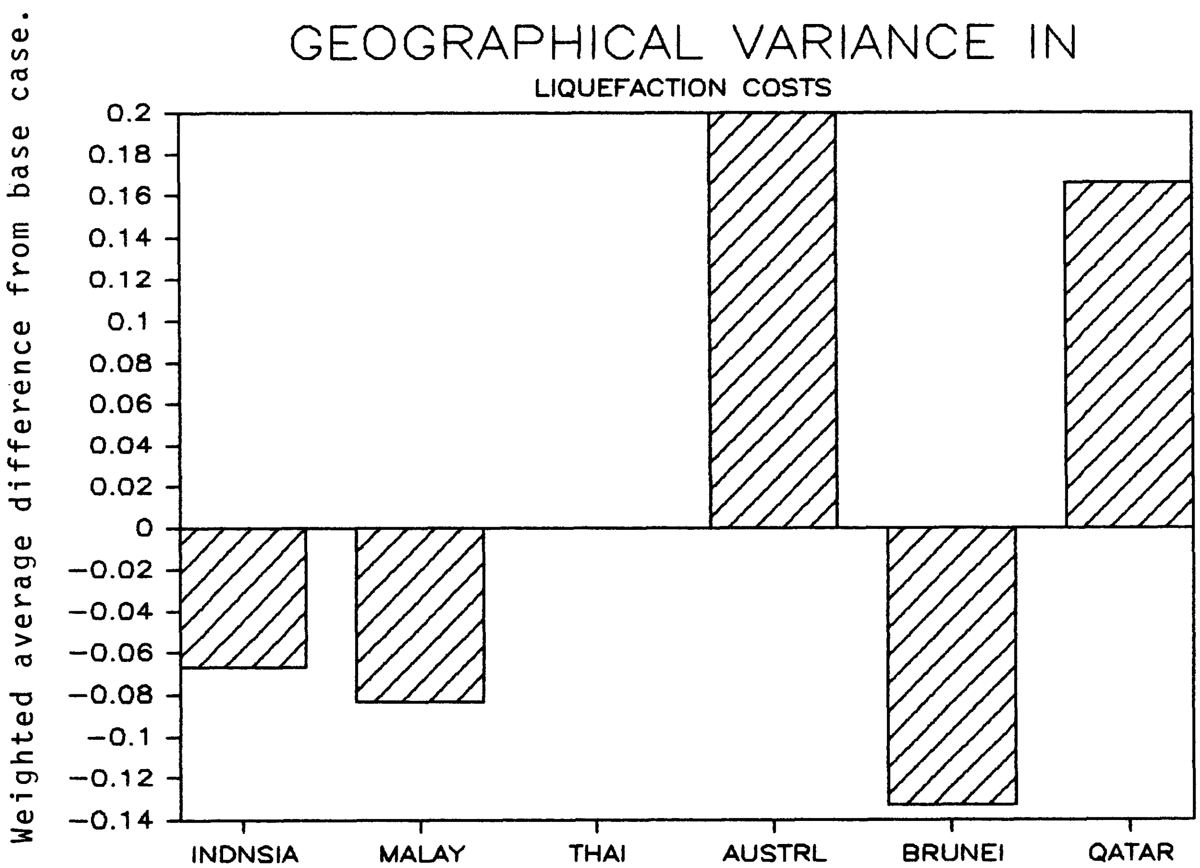
[27] Unlike the case for liquefaction, fuel, and other natural gas losses (e.g., boiloff) are included in the shipping and regasification costs because they are much smaller in those instances. A fuller discussion of fuel costs follows.

[28] Counting Arun and Badak in Indonesia as separate plants, but not any subsequent additions to capacity.

Figure 8



Source: CEPR survey of Japanese companies, 1985.

which indicates that Australia and Qatar have higher than average costs, presumably due to high labor costs, while the costs in the other producing countries are fairly close to the base case.

Economies of Scale

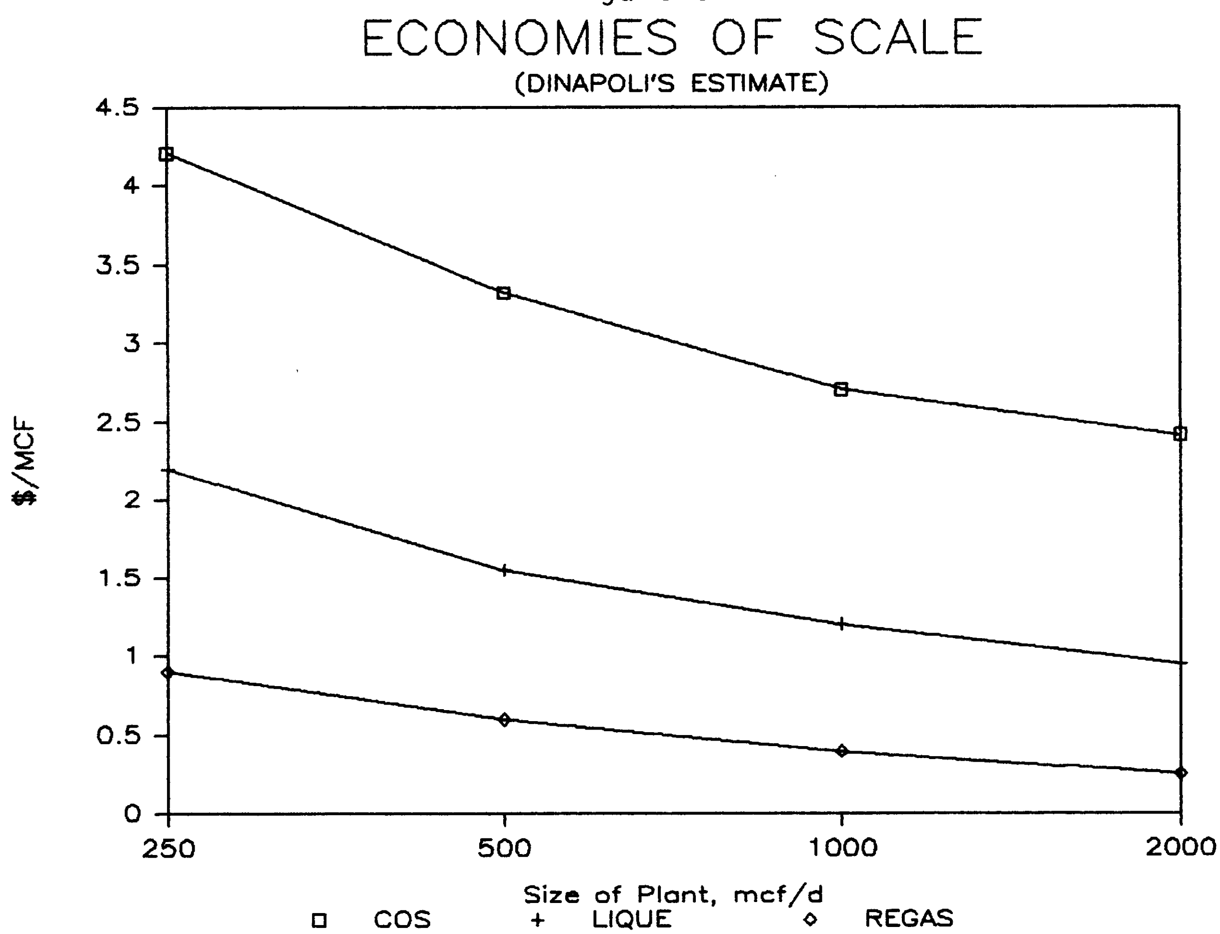
It has long been argued that economies of scale in LNG projects are substantial, thus reducing the motivation for countries with small surplus natural gas reserves to exploit them. Again, the small number of active LNG projects, and the fact that they all tend to be large,[29] limits our ability to provide much empirical work on this subject. However, a quick glance back at Figure 4 shows the obvious correlation between size and estimated cost per unit.

The best work to date on this subject is that of DiNapoli, who shows sharply declining costs until a fairly large size is reached. Figure 9 shows his estimates for liquefaction, regasification, and total costs for different size projects. Overall, he estimates that for a 3,900 mile distance, the cost of service falls from $4.21/Mcf for a 250 MMcf/d (90 Bcf/yr) project, to $2.41/Mcf for one eight times as large, or 2 Bcf/d (730 Bcf/yr). (Most of the savings occur in the early stages of scale-up.)

This is important for the development of natural gas reserves for export in the Pacific Basin. Where large reserves are available, such as Indonesia, projects are much more profitable than in countries with exportable surpluses that are relatively small, such as Thailand. Since the size of reserves can also be indicative of production costs, the

[29] Most existing liquefaction plants are on the order of 4 to 6 million tonnes of LNG per year (200 to 300 Bcf).

Figure 9



COS = Cost of Service

Source: Robert N. DiNapoli, "Economics of LNG Projects," in Oil and Gas Journal, 2/20/84.

effect can be even stronger than that shown in Figure 9. Thus, the small producers must accept lower netbacks and are more vulnerable to falling prices.

Fuel Costs

One of the most overlooked variables in the estimation of liquefaction costs, as well as in overall LNG costs, is the price that the project is charged for the natural gas it uses. Since LNG projects use roughly 20 percent of the inputted natural gas for fuel and other losses, the price charged for this fuel can make a substantial difference.

For existing liquefaction plants, the fuel use appears to be approximately 15 percent.[30] (DiNapoli later argued that for new projects it should be in the range of 8 to 10 percent, and the cost effects of this will be shown below.[31]) For shipping, the best estimate is 0.125

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[30] The LNG-6 Handbook gives a figure of 13-15 percent, the OPEC Gas Pricing Committee estimates 15 percent (MossavarRahmani, *op. cit.*, p. 99), and DiNapoli's estimate puts it at 13.5-16 percent, in "Estimating Costs for Base-load LNG Plants," *Oil and Gas Journal*, 11/17/75, p. 58. In *Trans Alaska Gas System: Economics of an Alternative for North Slope Gas, 1983* (hereafter referred to as the Brown & Root report), the total system fuel use was put at 12.2 percent. (See Economics section, p. 38.) According to Walter J. Mead, El Paso put liquefaction plant fuel use at 5.34 percent of input volume. (Walter J. Mead, with George W. Rogers and Rufus Z. Smith, *Transporting Natural Gas from the Arctic: The Alternative Systems*, American Enterprise Institute, 1977, p. 18.) This may reflect a semantic definition, since approximately two-thirds of total natural gas use is for fuel, and the rest is loss during storage and ship loading. See DiNapoli, *ibid*.

[31] Robert N. DiNapoli, "Economics of LNG Projects," *Oil and Gas Journal*, 2/20/84, p. 50. Industry sources have suggested that electric drivers would reduce fuel use to 6-7 percent, with an electricity cost of $0.15/Mcf. In areas where plant-gate natural gas costs were high and electricity relatively cheap, electric-driven compressors might be competitive. Alaska and Canada come to mind as two possible examples.

percent per day of shipping time,[32] which at 18.5 knots would be approximately 1 percent from Indonesia to Japan and 2 percent for Abu Dhabi. Estimates of fuel use in regasification include DiNapoli's 1.5 percent, OPEC's 2.2 percent, and El Paso's 8 percent.[33] We will use 2 percent as a compromise between DiNapoli and OPEC.

Using the values of 15 percent for liquefaction, 0.125 percent/day shipping loss, and 2 percent for regasification, Table 11 shows the cost of fuel for an LNG project exporting to Japan from various points under three different pricing assumptions. Naturally, since most of the use is not distance related, there is little difference between them. However, the price charged is very important, and can raise the price of delivered natural gas from \$0.20/Mcf to \$0.90/Mcf.

Various analysts use different estimates for the cost of fuel. Bonfiglioli and Cima performed sensitivity analyses from \$2 to \$4/Mcf, while DiNapoli uses \$1/Mcf as a base case for liquefaction feed (as does LNG-6), but also performs sensitivity analyses with prices up to \$3/Mcf. For boiloff and ship fuel, he assumes prices equivalent to \$34/barrel for

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[32] This is from DiNapoli (1984, p. 49). OPEC's estimate is 8 percent total, but this includes fuel use and does not indicate the variation according to distance. (EIU, ibid.) El Paso estimated losses at 1.59 percent for a 2000 mile (or 4 day) journey, which would be 0.4 percent per day. The most authoritative estimate is from a brochure describing the characteristics of new LNG tankers, entitled "Mitsui-Moss Type High Performance LNG Carrier", from Mitsui Engineering & Shipbuilding Co., Ltd., which describes boil-off rates at 0.25 percent per day for existing ships and 0.12 percent per day for new, high performance ships.

[33] Mead puts the El Paso regasification fuel use at 0.08 percent, but we assume that to be a typographical error. See Robert N. DiNapoli, "Design Needs for Base-load LNG Storage, Regasification," Oil and Gas Journal, 10/22/73, p. 70.

Table 11
Cost of Natural Gas Used as Fuel
($/Mcf delivered)

A. $5/Mcf fuel price

Country	Liquefaction requirements	Regasification	Boiloff	Total
Persian Gulf	0.65	0.15	0.09	0.894
Indonesia	0.65	0.15	0.04	0.844
Australia	0.65	0.15	0.04	0.844
Alaska	0.65	0.15	0.04	0.844
Canada	0.65	0.15	0.04	0.844
Malaysia	0.65	0.15	0.04	0.844
Thailand	0.65	0.15	0.04	0.844
Brunei	0.65	0.15	0.04	0.838

B. $3/Mcf fuel price

Country	Liquefaction requirements	Regasification	Boiloff	Total
Persian Gulf	0.39	0.09	0.07	0.551
Indonesia	0.39	0.09	0.03	0.513
Australia	0.39	0.09	0.03	0.514
Alaska	0.39	0.09	0.03	0.514
Canada	0.39	0.09	0.03	0.514
Malaysia	0.39	0.09	0.03	0.511
Thailand	0.39	0.09	0.03	0.511
Brunei	0.39	0.09	0.03	0.506

C. $1/Mcf fuel price

Country	Liquefaction requirements	Regasification	Boiloff	Total
Persian Gulf	0.13	0.03	0.02	0.184
Indonesia	0.13	0.03	0.01	0.171
Australia	0.13	0.03	0.01	0.171
Alaska	0.13	0.03	0.01	0.171
Canada	0.13	0.03	0.01	0.171
Malaysia	0.13	0.03	0.01	0.170
Thailand	0.13	0.03	0.01	0.170
Brunei	0.13	0.03	0.01	0.169

oil.[34] Although the evidence from the OPEC Gas Pricing Committee is not clear, it suggests that they consider $5/Mcf an appropriate value, since it is the value they would otherwise receive for the gas when delivered to the customer.[35] However, since they are delivering most of the gas to the liquefaction plant gate at a fraction of the cost of delivery to the regasification plant, the revenues on the gas used for liquefaction are substantially higher than for gas delivered to the LNG importer. Although there is no logical justification for this, it does not make a difference when the exporting country owns the liquefaction plant: It is merely a question of where the profits are counted. It has, however, served to raise the costs described for LNG projects by OPEC members to justify the need for high prices.

If, instead, a project were to be charged for the fuel used according to the cost of having delivered the fuel to the point of use, including an appropriate return on capital, etc., then fuel costs would change substantially. This is especially true since three-quarters of the gas use is at the liquefaction plant, and production and delivery costs have already been seen to be low. Table 12 shows the results of such a strategy, suggesting that any price over $0.25/Mcf of delivered gas would be rent, not costs for the project, depending on the field production costs and vintage and type of equipment. Naturally, if a producer had a use for the gas that would yield a higher value than selling it for a 15-20 percent rate of return, the gas would not be available. At present, though, this does not appear to be the case in

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[34] DiNapoli (1984) pp. 49-50. Bonfiglioli and Cima are cited in International Energy Agency, Natural Gas: Prospects to 2000, (1982) p. 125.

[35] Mossavar-Rahmani, op. cit., p. 97.

Table 12
Cost of Natural Gas Used as Fuel
if Priced at Cost at Points of Use
($/Mcf)

	Reference Case	High Production Costs	Efficient Liquefaction Drivers	Low Boiloff Rate
Production/gathering costs: (and price to liquefaction plant)	$0.500	$1.000	$0.500	$0.500
Cost of fuel used in liquefaction:	$0.075	$0.150	$0.045	$0.075
Cost of liquefaction:	$1.000	$1.000	$1.000	$1.000
Price on board ship:	$1.575	$2.150	$1.545	$1.575
Cost of boiloff losses (Indonesia to Japan)	$0.032	$0.043	$0.031	$0.016
Cost of shipment: (Indonesia to Japan)	$0.700	$0.700	$0.700	$0.700
Price at regasification point:	$2.307	$2.893	$2.276	$2.291
Cost of fuel used in regasification	$0.035	$0.043	$0.034	$0.034
Total cost of fuel used if priced at cost: (cents per Mcf of delivered gas)	14.1	23.6	11.0	12.5

Fuel use and shrinkage assumptions

	Reference	Efficient
Liquefaction	15%	9%
Boiloff	.25%/day	.125%/day
Regasification	1.5%	1.5%

any of the LNG exporters.

Inflation of Capital Costs for LNG

One phenomenon that has troubled the LNG trade industry has been the rapid increase in costs for capital equipment associated with the shipment of LNG. Cost inflation has been particularly evident in the case of liquefaction plants, but also regasification facilities. Tankers have not been affected to the same degree, and the reasons are both important and revealing.

It can be seen from Table 13 that the capital cost for capacity, when normalized for size, has increased dramatically since the early days of the industry. Of course, the costs for plants of different sizes in different locations are not strictly comparable, but the inflation can be seen also by comparing plants built (or proposed) in the same country at different times. As Table 14 shows, even here costs have risen far faster than inflation.[36] For Alaska, the real inflation rate between 1966 and 1982 was 5.0 percent,[37] while Algeria experienced 7.4 percent between 1974 and 1978. In Indonesia, the other country where plants have been constructed over a period of time, the rate of inflation has been tempered by economies resulting from existing infrastructure.

Of course, it will be argued that this does not take into account economies of scale. The liquefaction plants proposed first by El Paso and now for TAGS are twice as large as that built to export natural gas

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[36] References to the inflation rate always refer to the rate as measured by the implicit price deflator of the U.S. Gross Domestic Product, reported annually in the Economic Report of the President.

[37] Based on 1966 estimates for actual costs, and 1982 estimates for the proposed TAGS liquefaction plant. See Petroleum Press Service, 8/66, p. 307, and Brown & Root, p. 33.

Table 13
LNG: Plant Costs

Year	Country	Cost in Current Million $	Size (mcf/d)	10^6 1984 $/1 bcf/day
1965	Nigeria	50	100-200	1,123
	Algeria	87	150	1,738
1966	United States	50	140	1,037
1970	Venezuela	215	500	1.047
	Venezuela	159	450	861
1974	Abu Dhabi	300	435	1,336
	Algeria	850	1500	1,098
1975	Norway	304	435	1,238
1978	Iran	500	630	1,176
	Malaysia	1000	870	1,703
	Iran	762	400	2,822
	Algeria	1500	2300	966
1982	Malaysia	2000	870	2,476
1983	Canada	2000	435	4,751

Sources: Published reports; many were estimates for proposed plants.

Table 14
Area-Specific Project Inflation

Area	First Estimate (1984$/1 bcf/d capacity)	Second Estimate (1984$/1 bcf/d capacity)	Inflation per year (percent)
Alaska	$1062 (1966)	$2330 (1982)	5.0
Algeria	$1098 (1974)	$1462 (1978)	7.4

Sources Published reports.

from Cook Inlet. Using DiNapoli's estimates for economies of scale, they should be 2.5 times cheaper per unit than the small one, instead of twice as expensive.

Beyond the question of economies of scale lies the question of technological maturation. The Kenai plant was the second LNG plant built anywhere in the world, yet instead of the technology becoming better understood and more refined, lowering costs, they have continued to rise.[38] This suggests that inflation has been even more severe than indicated in Tables 13 and 14. Even without the question of technological maturation, real costs for an Alaskan liquefaction plant have risen by a factor of 5, 10.6 percent per annum, versus (and on top of) a general inflation rate in the United States of 6.4 percent over the same period.

This is supported by several other observations. Mueller estimates that costs for a typical 500 Mcf/d liquefaction plant increased 8 percent per year from 1970 to 1982, and over 10 percent per year from 1975 to 1982.[39] Inflation in the latter period was twice the U.S. inflation rate.

For regasification plants, similar trends can be observed. Table 10 included a handful of estimates gathered over time, and real inflation is definitely present. Another indicator would be two estimates by DiNapoli, seen in Table 15, in which the cost of a regasification plant increased by 20 percent per year over the course of the late 1970s.

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[38] Of course, given the small number of plants that have been built, large generational advances in technology have not had time to occur.

[39] Donald L. Mueller, "LNG: A Prince or a Pauper?" presented to Canadian Energy Research Institute, 9/26/83, p. 4. The dollars are presumably nominal.

Table 15
Regasification Cost Inflation

Item	3/13/78	4/4/83	Inflation (% p.a.)
Site development		20.8	n.a.
Marine and unloading	35.0	41.7	3.5
Storage	40.0	80.0	14.9
Vaoprization			
Seawater	27.6	85.0	25.2
Gas-fired	2.4	12.5	39.1
Auxiliaries	20.0	75.0	30.3
Total Direct Cost	125.0	315.0	20.3
Indirect, 25%	31.3	78.8	20.3
Bare plant Cost	156.3	393.8	20.3
Contingency, 10% in 1978, 15% in 1983	15.6	59.1	30.5
Total erected plant cost	171.9	452.8	19.7

Sources: Raw data from "Costs are Estimated for LNG Terminals," Robert N. DiNapoli, Oil and Gas Journal, 3/13/78, pp. 83-84, and; "LNG Costs Reflect Changes in Economy and Technology," DiNapoli, Oil & Gas Journal, 4/4/83, pp. 138-143.
In calculating inflation on the total erected plant cost, site preparation is excluded from 1983 estimate. Plant used in 1983 adjusted for size.

This extraordinary cost inflation creates problems for analysts and project planners alike. The prospect that future costs will continue to accelerate affects the time when a project should be developed, or whether it should be developed at all. Or, if a deceleration is possible, will it enable marginal projects to become viable? For buyers, especially with other sources of energy becoming more competitive, future cost trends are very important. How does one predict costs for projects with long planning and lead-times with any certainty?

Unfortunately, there has been little analysis of factor cost inflation in the LNG industry, mainly due to the small number of projects involved and the difficulty in comparing them. However, there are other industries and large-scale capital projects with which they can be compared, and a body of evidence to explain what has happened in the past decade. We feel that some indication of future trends can be provided from these examples.

LARGE-SCALE CAPITAL PROJECT INFLATION

History

In the first place, it must be admitted that inflation rates were very high during the 1970s. As can be seen in Figure 10, most of the developed countries experienced a substantial increase in domestic inflation rates during this period, although both the absolute and relative rates differed markedly depending on the nature of the domestic economy, the policies followed by the governments, etc.[40]

The extremely high inflation rates of the 1970s were, if anything,

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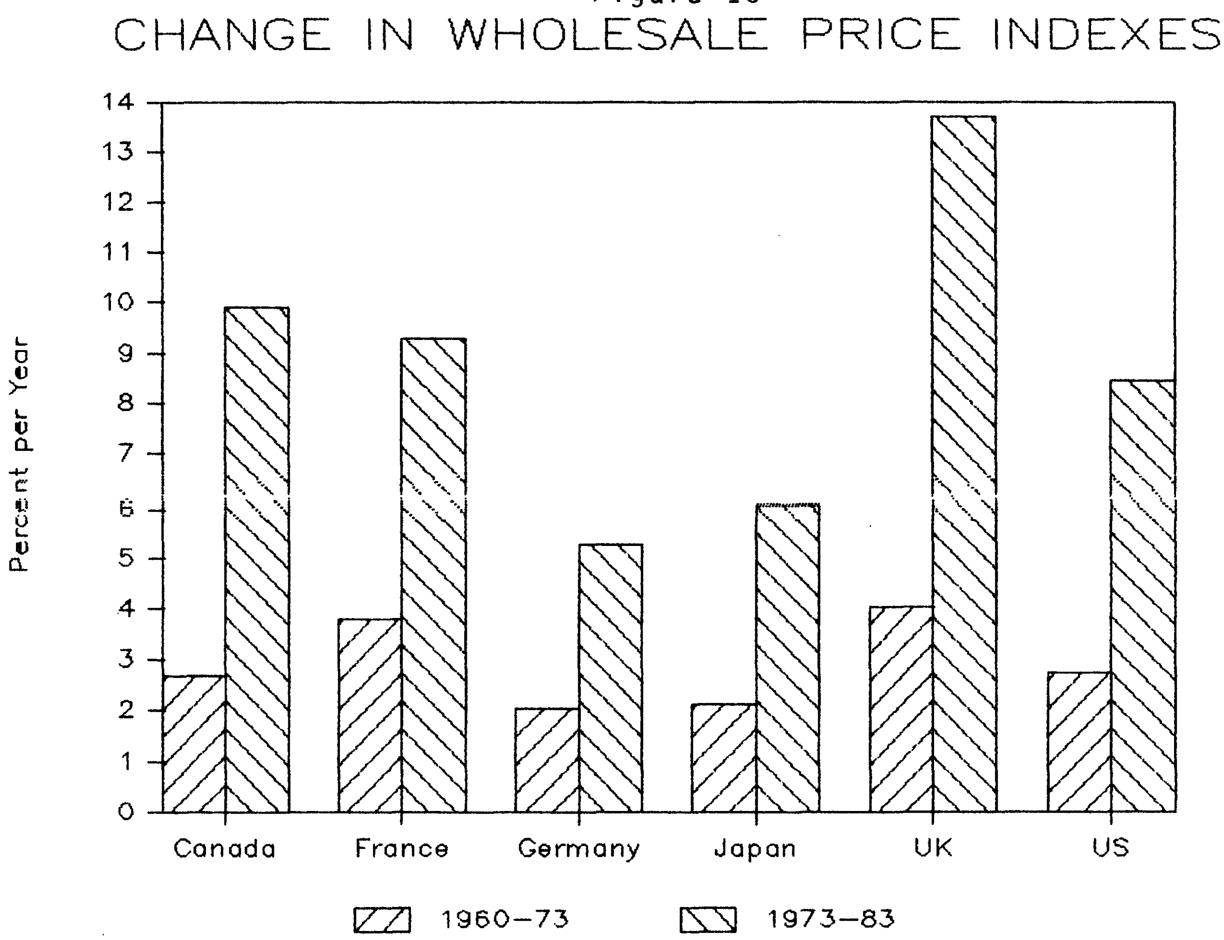
[40] See Knut Anton Mork, ed., Energy Prices, Inflation, and Economic Activity (Ballinger, 1981) for an explanation of the impact on inflation of oil price shocks.

Figure 10



Source: International Financial Statistics.

magnified in the construction industry. Examples abound: The construction of nuclear power plants, industry construction, oil development--all soared in costs. One study, commissioned to discover the reason for the high cost escalation in North Sea development projects, examined petrochemical and steel plants, among others, and found that high inflation had occurred generally in projects with a high development component, not just in the North Sea.[41]

Many reasons were given, some of which are most appropriate to the North Sea. These include:

> (1) Inaccuracies in cost input estimates for projects with known scope but high development content;
> (2) Technical changes in project scope; and
> (3) Changes in project method arising from additional regulations.[42]

Fortunately, there are a number of inflators that can provide some indication of the extent of cost escalation in large-scale capital projects generally, as well as the nature of the trends. The U.S. government collects data on inflation in non-residential structures and equipment, the category that presumably includes liquefaction plants. In addition, private groups provide inflation indexes for pipeline and refinery construction, the latter in particular resembling an LNG plant in size and nature, though with important differences. However, examining them can give us some direction for the impulses

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[41] See North Sea Costs Escalation Study, Part II, Peat Marwick Mitchell & Co. and Atkins Planning, Energy Paper Number 7, Department of Energy, London, Her Majesty's Stationery Office, 12/31/75, especially page 35. Such problems are not limited to the OECD countries. Prime Minister Ryzhkov of the Soviet Union recently complained that costs of current construction projects were running 24 percent over estimates. See "Soviet Premier, in Congress Talk, Criticizes Economy," New York Times, 3/4/86, p. A6.

[42] North Sea Costs Escalation Study, Part I, Department of Energy Study Group, pp. 3-4.

behind LNG capital cost inflation.

Figure 11A shows the indices for non-residential structure, oil pipeline construction, and refinery construction (materials only).[43] Obviously, substantial inflation has occurred, but mainly resulting from general inflation, as can be seen in Figure 11B, which shows the indices corrected for inflation.[44] Although the cost escalation of the 1970s is readily observable, the fact remains that over long periods of time, real inflation in capital costs has not been the norm. Periods of inflation, although sometimes intense, have alternated with periods of deflation. As Figure 11C shows, these periods have frequently coincided for the different indices, with stretches when all three indices have moved largely in the same direction. Table 16 lists these periods, their duration, and the extent of the accompanying in(de)flation.

Certainly, the aforementioned factors which created the high cost inflation for development in the North Sea had some impact on inflation in other spheres, such as refinery construction, but there are obviously other causes as well. These include:

(1) Lower productivity growth rates, resulting from:
(a) entry into the work force of larger numbers of new workers, who were less well trained; and
(b) excessive rates of growth in a particular sector, outstripping its ability to smoothly absorb and train new workers;
(2) Learning curve effects, as unanticipated problems became apparent and had to be resolved;
(3) Labor inflation, feeding back from economy-wide inflation;

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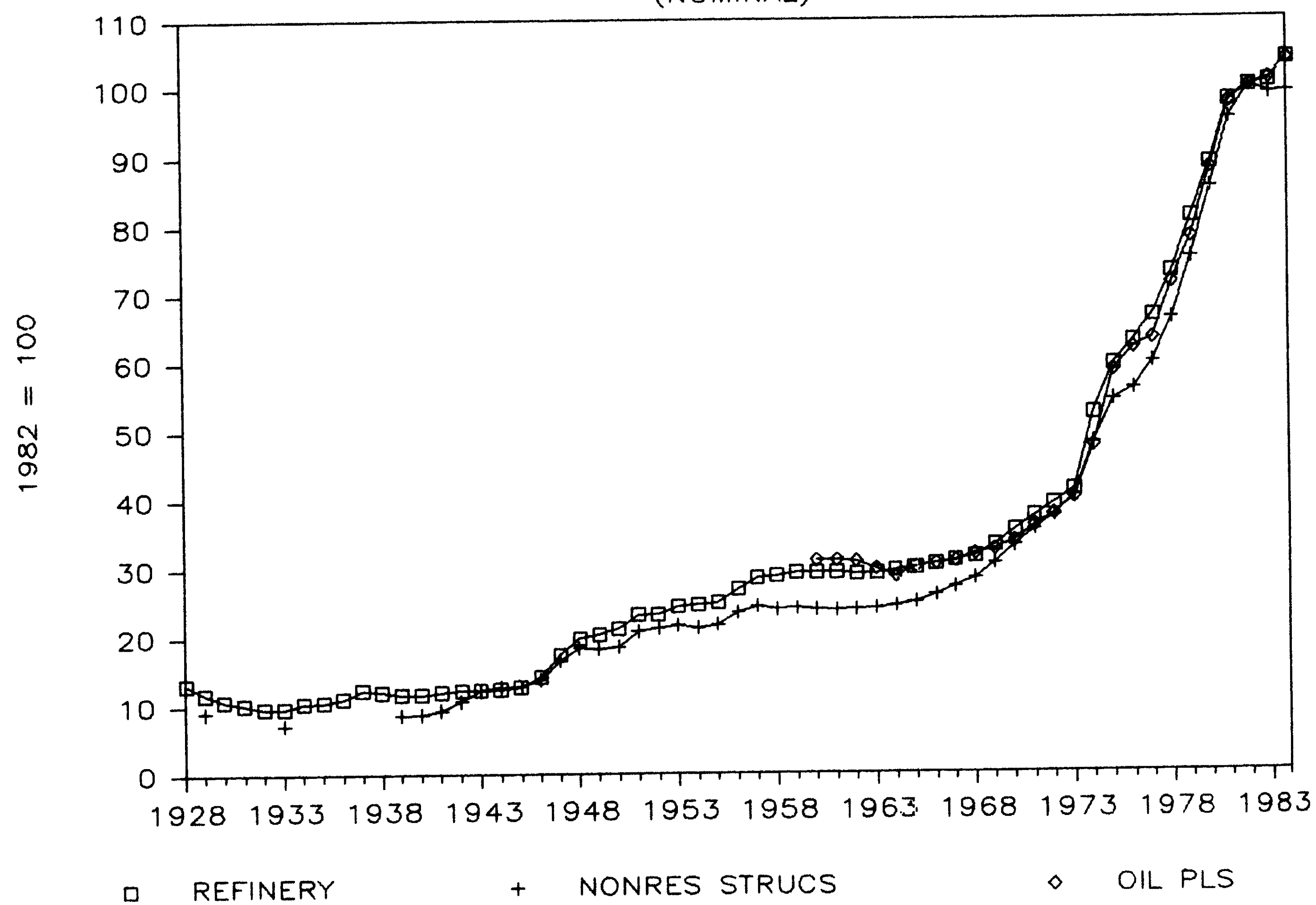
[43] The refinery construction index includes a labor component, which we have disregarded due to the fact that labor costs behave differently from capital costs, and the foreign location of liquefaction plants means that U.S. wage and productivity trends are not particularly meaningful in this instance.

[44] That is, divided by the U.S. implicit price deflator, yielding the rate of change relative to the inflation rate.

Figure 11A

INFLATORS FOR LARGE-SCALE PROJECTS

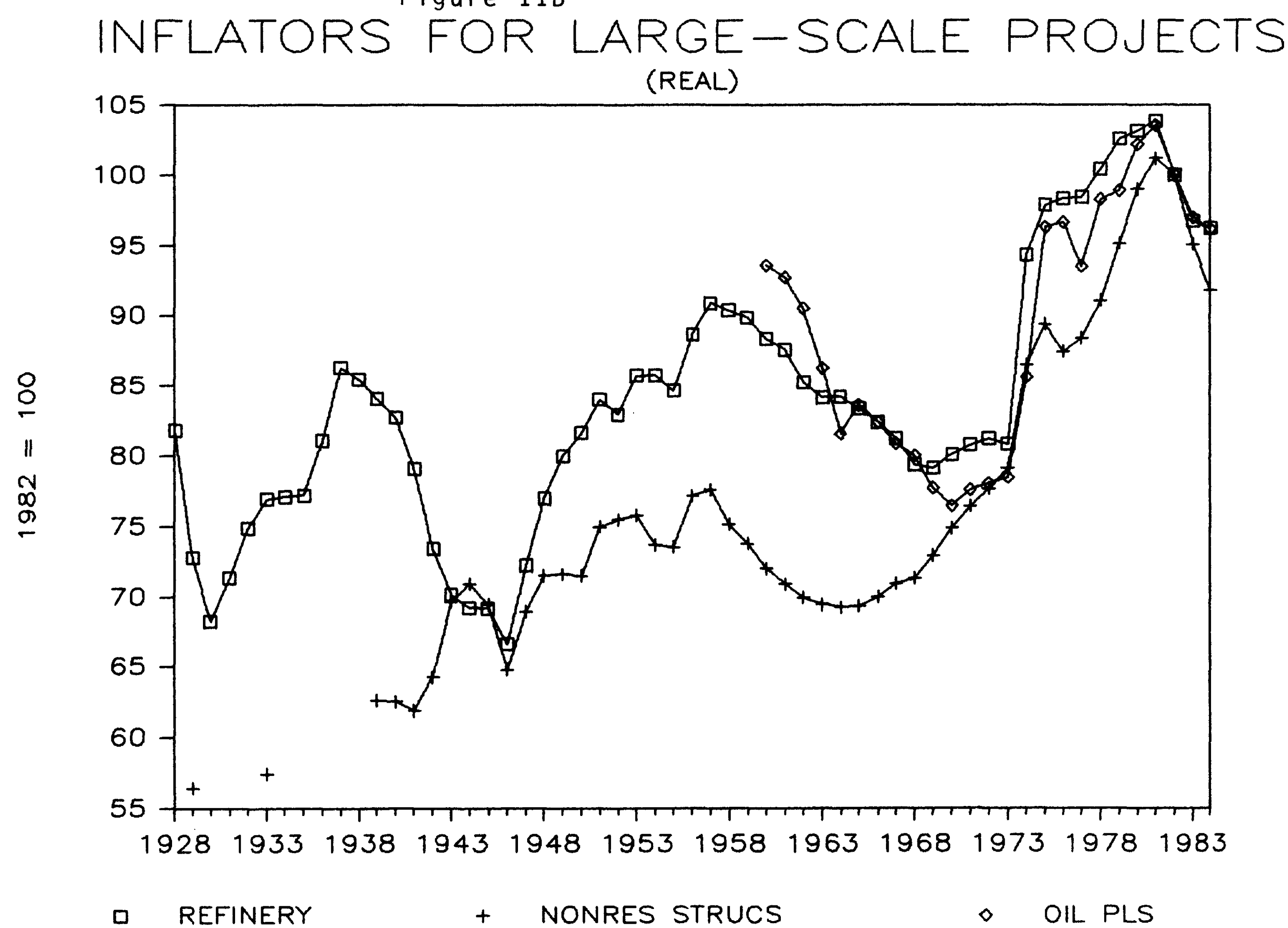
(NOMINAL)



Sources: Oil and Gas Journal, Economic Report of the President.

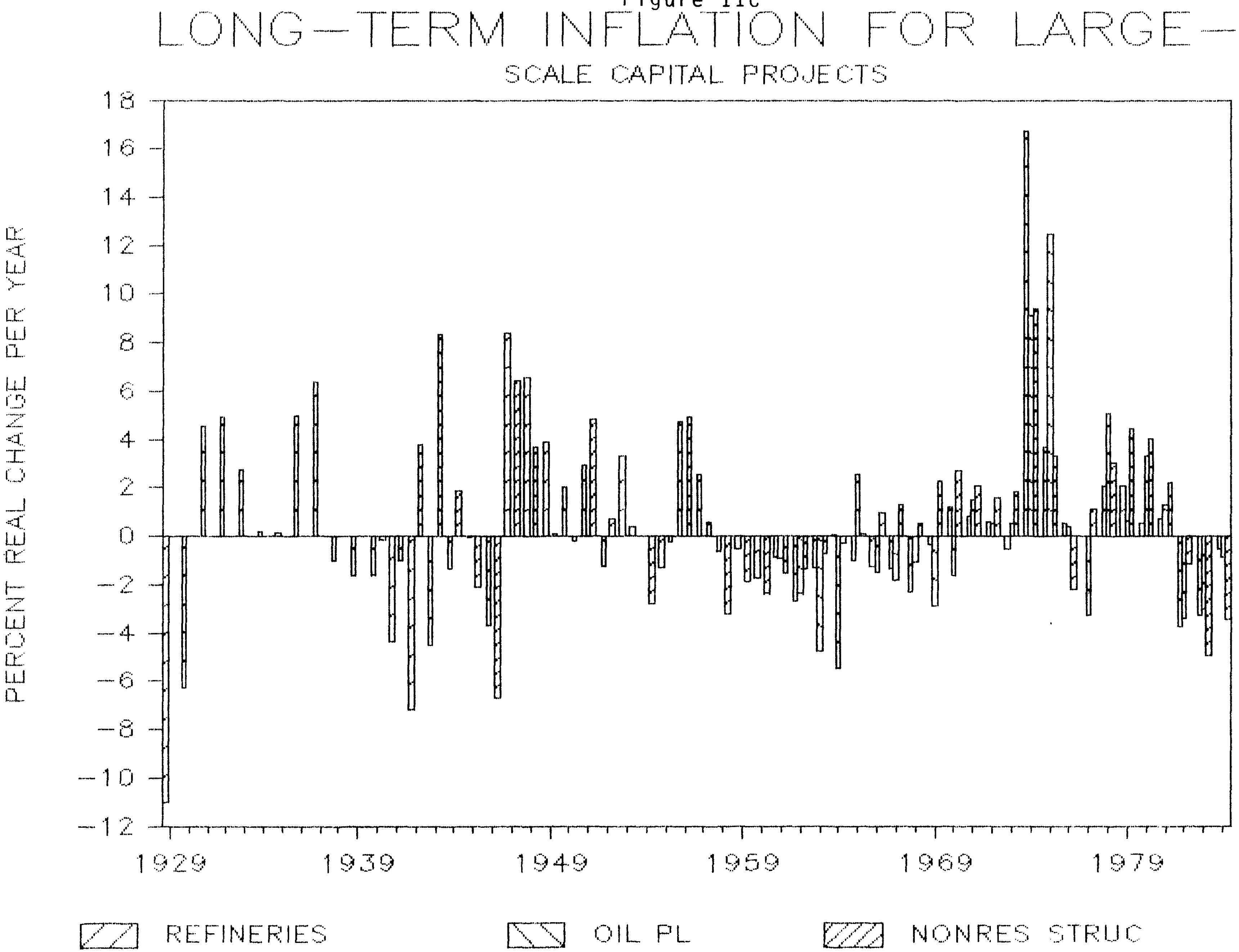
Oil PLS = Oil pipelines

Figure 11B



Sources: Oil and Gas Journal, Economic Report of the President.

Figure 11C



Sources: See Table 11B.

Table 16

	Period	Duration (Years)	% p.r.	IPD
Nelson Refinery Index (Materials)	1930-37	8	+3.4	-1.5
	1937-46	9	-2.9	+4.5
	1946-57	11	+2.9	+3.6
	1957-69	12	-1.2	+2.4
	1969-81	12	+2.3	+7.0
	1981-84	3	-2.6	+4.6
Non-Residential Structures	1939*-57	18	+1.2	+4.7
	1957-65	8	-1.4	+1.7
	1965-81	16	+2.4	+6.2
	1981-84	3	-3.3	+4.6
Morgan Oil Pipeline Index	1960*-70	10	-2.0	+2.9
	1970-81	11	+2.8	+7.1
	1981-84	3	-2.5	+4.6

*First year of consistent data.

Sources: Oil and Gas Journal, and Economic Report of the President.

(4) Higher interest expense, as a result of:
(a) Higher interest rates; and
(b) Longer delays, due to public opposition and legal challenges, and more regulatory interference, as agencies responded to public interests changing from economic growth and progress to more emphasis on safety and environmental protection; and
(5) Demand-driven inflation, as the number of liquefaction plants that were planned, ordered, and under construction soared beyond the ability of the industry to meet them, resulting in less efficiency, as well as higher prices simply reflecting market pressures, and rent-capturing by groups at all levels.

The first three effects are fairly general, and need not be addressed here. However, the last two require more detailed attention.

Interest Expense

Throughout this analysis, real costs and interest rates have been used, with the assumption that real interest rates, at least, do not change. In fact, this has not proved to be the case in recent years, as demonstrated in Figure 12. Real interest rates, defined here as the corporate bond rate for Aaa rated issues minus the inflation rate as represnted by the implicit price deflator for the U.S. gross domestic product, were approximately 2 percent when the early LNG projects began, but have recently risen to levels roughly four times higher as inflation has fallen faster than interest rates.[45] Nominal interest rates, those charged to a given project, have also risen sharply, from 4.49 percent in 1965 to 12.71 percent in 1984.

Capital-intensive projects like LNG have been affected by this. As it happens, the construction period for liquefaction plants is only about

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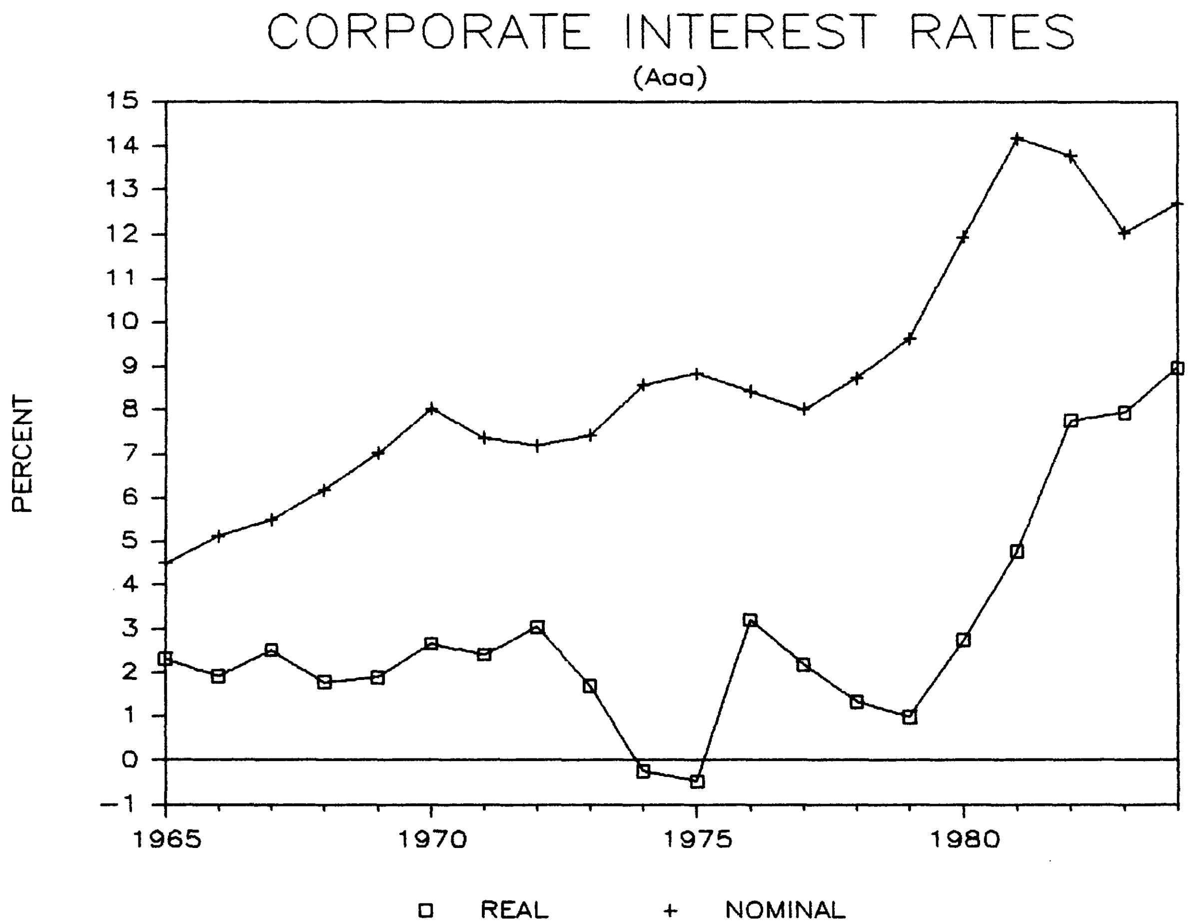
[45] Foreign interest rates do not correlate perfectly with those in the United States for a variety of reasons, but have generally risen also as a result of higher U.S. rates.

Figure 12



Source: Economic Report of the President, 1985.

two years,[46] so the effect is less than for other projects, e.g., nuclear power plants.[47] Still, interest expense has grown to over 10 percent in some cases, especially during the early 1980s, when nominal rates were at a peak. When the TAGS report was published, an interest rate of 14 percent was assumed, which was roughly the prevailing Aaa corporate rate. Since that time, however, nominal rates have dropped approximately 4.5 percent,[48] meaning that interest expense for a liquefaction plant would drop by about one-third, such that the final costs of building the liquefaction plant would be $41 million cheaper (about 2 percent), all else being equal. Since the price of LNG is not a function of the prevailing interest rates, the cost of capital over the life of the project would also be lowered under current interest rates than those prevailing in the early 1980s. Since interest rates and discount rates are closely related, net present value should be independent of changes in the prevailing interest rate.

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[46] Brown & Root report, Exhibit A2. The total lead-time is longer, but the pre-construction phase involves relatively small expenditures.

[47] As an example, the Brown & Root report estimated interest and financing costs on the Phase I liquefaction plant at 12.2 percent of the total nominal cost of the project. For nuclear power plants, a recent OECD report put interest costs at up to 32 percent in the United States, but only about 15 percent for most European countries. See Nculear Energy Agency, Organization of Economic Cooperation and Development, The Costs of Generating Electricity in Nuclear and Coal Fired Power Stations, p. 27.

[48] As of March 14, 1986, rates had reached 9.53 percent, according to the Wall Street Journal, but the short-term future remains unpredictable.

Demand-Driven Inflation

In the report on North American natural gas trade prospects,[49] substantial attention was paid to the role of demand pressures on drilling costs (rigs, services, etc.). Figure 13, showing the level of liquefaction construction activity worldwide for the last two decades, indicates a strong peak in the early 1980s. Whether or not this level continues depends on the fate of a number of proposed projects.[50]

Demand-driven inflation is aggravated by the fact that relatively few companies are involved in the building of liquefaction plants, compared to other industrial ventures, and the plants are not transferrable. That is, once a company has begun construction, everyone is locked in. The plant cannot be taken out or moved, resold or traded.

The best indicator of this effect is the difference in cost inflation for nonresidential structures versus durable equipment, as shown in Figure 14. Since equipment can be imported, traded, etc., much more readily than buildings and plants, the market is more competitive and inflation is more moderate.[51] The same phenomenon appears in the LNG industry, where fixed assets (i.e., liquefaction and regasification plants) have inflated in cost much more than non-fixed assets (i.e., tankers). The costs for tankers appear to have held steady for a

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[49] See especially pages 36-40.

[50] The figure includes the North West Shelf project. Possible expansion includes Thailand, Qatar, and the TAGS project in Alaska. A two-year lead-time is assumed in the figure, as shown in the Brown & Root report, although confidential materials on another project suggests a three-year lead-time. This would not change the nature of the graph, only the absolute level of the peak.

[51] Of course, the construction industry is becoming more competitive in the United States, with increasing examples of foreign competition. See Fred Moavenzadeh, "Construction's High-Technology Revolution," Technology Review, 10/85, p. 34.

Figure 13

LNG CAPACITY UNDER CONSTRUCTION

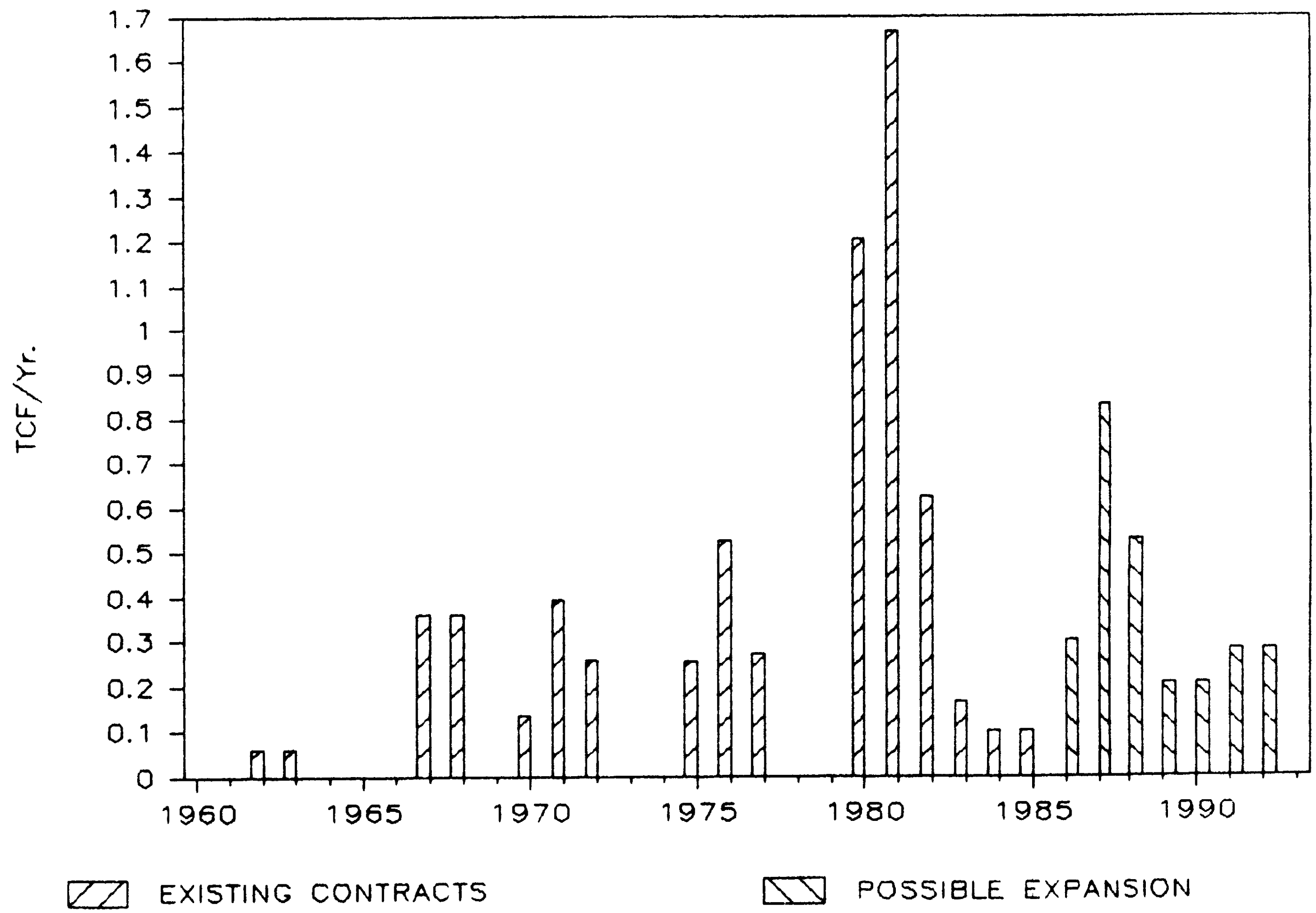
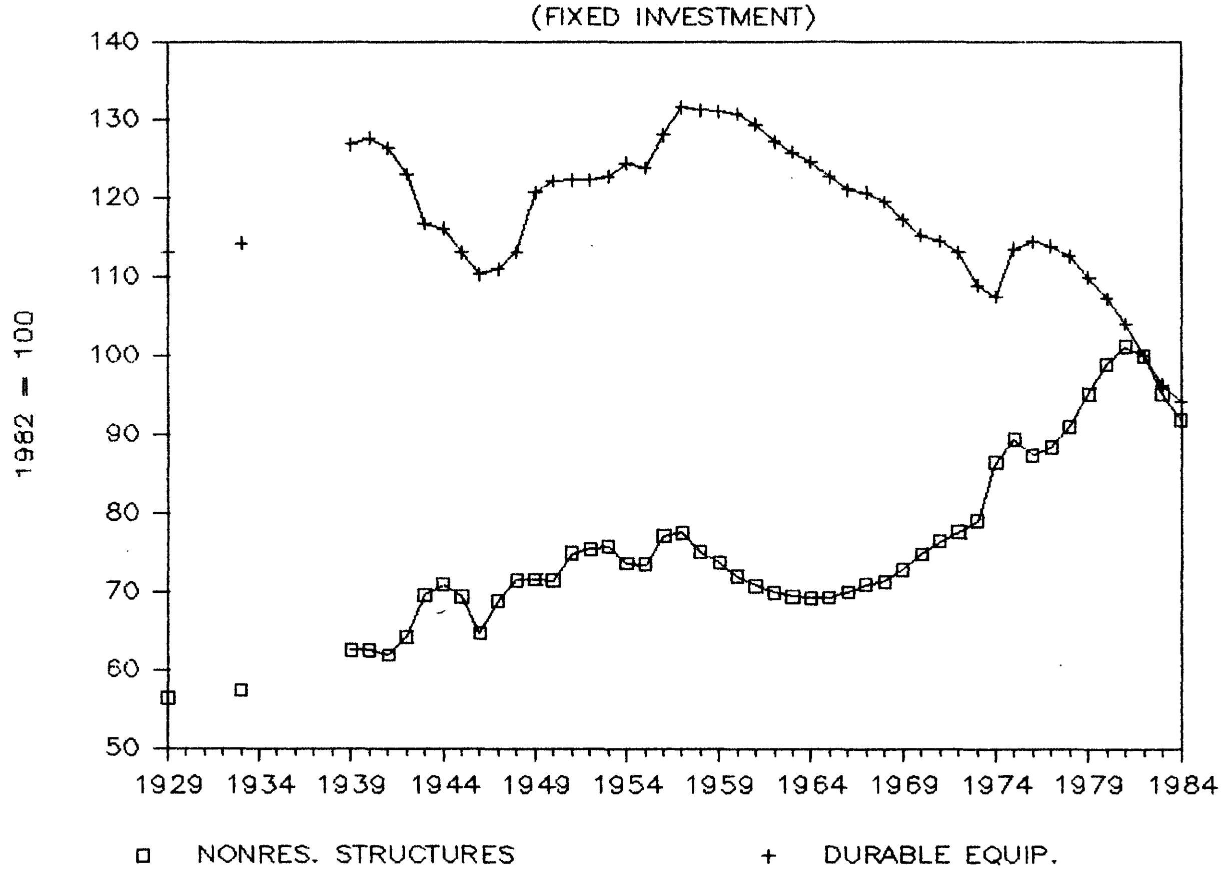


Figure 14

REAL INFLATION INDICES

(FIXED INVESTMENT)



Source: <u>Economic Report of the President</u>.

number of years, as was shown in Table 9.[52]

If demand-driven inflation simply meant that prices for plants went up while costs stayed constant and profits increased, then prices would easily fall back when demand was reduced. In fact, however, the rents represented by those profits are likely to be captured at various points and by different actors, from producer to builder, from worker to manager to government official.

First, it must be pointed out that "rent-capturing" is not a simple concept. There is no line item that represents rent-capturing by contractors, regulators, suppliers, etc., in a project's budget. The term rent-capturing includes such things as:

- Padding expenses, including transferring expenses from other projects to a lucrative one, or having that project bear costs that are not directly attributable to it.
- Corruption, including payoffs to local officials, as well as skimming of funds within the project by officials of the operator.
- Less efficiency in terms of allowing payrolls to grow.
- Less resistance to wage demands from labor.
- Higher payments for royalties and land acquisition.

Before describing specific examples of rent-capturing, it must be acknowledged that it is not necessarily illegal or even unethical. If an LNG supplier provides LNG to a buyer at a fixed price, it is immaterial to the buyer if the supplier uses the profits to offset other expenses. In such instances, the parties injured are the poor analysts who see inflated project cost estimates.

Another form of rent-capturing is, of course, corruption. Naturally, there is little or no data on this aside from occasional cases that have been prosecuted in the United States, or scandals where a specific payment made for preferential treatment may come to light. It

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[52] Based on a variety of published reports.

has been said publicly that kickbacks in the U.S. oil-field supply industry have inflated drilling costs 30 to 40 percent in some cases.[53] While it would be chauvinistic to assume that corruption is worse in Third World countries, it would be foolhardy to assume that it is less than in the United States. One benchmark is a recent comment by a Pemex official, who ascribed 15 percent of Pemex's costs to union malpractices, which are institutionalized in the Mexican system.[54] Since "malpractices" are hardly confined to the union, then management corruption could easily double this. While it is difficult to compare Mexican corruption in a quantitative manner to the countries under study, it suggests that, at the least, a fraction of the reported costs of a liquefaction plant is probably due to payoffs and kickbacks, the share being larger during boom times than during the current lean times.

Inattention to inefficiencies is another problem. As one official put it recently, "During the boom, everybody had a lot of money and really didn't pay much attention to drug and alcohol abuse. Now, everybody has to tighten up and it's starting to attract a lot of attention. Everyone is looking at the bottom line."[55]

At the same time, costs might be unintentionally increased by cutting back on things like safety and maintenance. One recent story reported that, in order to cut down on drilling time, at least one

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[53] See "Oil-Field Investigators Say Fraud Flourishes, from Wells to Offices," Wall Street Journal, 1/15/85, p. 1. The citation is from a U.S. attorney in Oklahoma City. It was also suggested by an industry official that efforts to end corruption were just beginning.

[54] See "Mexico Suffers Greatly as Oil Prices Decline but Debts Linger on," Wall Street Journal, 10/9/85, p. 26. The official was actually arguing that 15 percent was too small to clean up, given the political costs.

[55] From "Drugs Offshore," Offshore, 1/86, p. 31.

operator had illegally conducted certain operations at night, resulting in an accident that took the life of a driller.[56]

When analyzing costs for a project, this type of cost must be considered a transfer payment, much like land bonuses. They will always exist, and will expand and contract with the level of rents to be had.

EXPECTATIONS OF FUTURE COST INFLATION

Trends

A number of the factors driving costs up in the 1970s were temporary. For example, with lower interest rates, the interest costs for a lengthy construction project will be diminished. Also, the work force is growing older and should show better productivity in the future, at least in the United States. For the present, regulatory impact seems to have levelled off in most countries, either because of a political backlash against regulatory agencies or because the particular technologies have reached an "acceptable" level of control or understanding.[57] All of the indexes for the large-scale capital projects shown earlier (Figures 11A-C) have turned downward since their 1981 peak. This suggests that a period of deflation is ahead, which could last a decade and see real costs fall by a total of 20 percent.

More important for near-term behavior is the lack of demand-driven inflation and the return of what can only be described as severe

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[56] See "Safety Last: Job Deaths and Injuries Seem to be Increasing After Years of Decline," Wall Street Journal, 3/18/86, p. 1.

[57] Of course, since political attitudes affect this very strongly, regulatory pressures could once again become a major force.

competition in the construction industry.[58] While the pipeline cost index has flattened out in the last few years, reported project costs have fallen substantially, as Table 17 shows. Although the number of companies that can build a liquefaction plant is smaller than those that can build, say, a bridge, the deflation that has occurred in other large-scale capital projects should also become visible for liquefaction plants.[59] This could result in sharp, near-term decreases in costs for new projects. Certainly, the world surplus of LNG tankers should hold those prices down. At worst, cost trends will be moderate, and at best they will move downward sharply.

In our survey of Japanese companies involved with LNG, the expectations were for the opposite. Although a few foresaw short-term decreases in costs, most expected real long-term costs, at all phases of LNG projects, to be 5 to 15 percent higher than at present.

Impact of Technology

In our previous paper, the role of advancing knowledge and technology in preventing the rise of mineral costs due to resource depletion was mentioned extensively. LNG projects, viewed as

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[58] Note that little effort is made to address the impact of exchange rate fluctuation on costs for overseas construction projects. Given a liquefacation plant built in Malaysia by a team of American/Italian/Japanese contractors, for example, the effect is difficult to measure. However, with prices for the output in U.S. dollars, and plants built (potentially or actually) by foreign contractors, costs should be moderated by a strong U.S. dollar, as was observed in the past several years. The weaker U.S. dollar should reduce the expected moderating cost trend, but the extent is difficult to gauge.

[59] Examples include a Thai petrochemical plant, for which the final bid for a series of contracts was less than half the projected amount (Oil and Gas Journal, 10/14/85, p. 64) and the Bosporus bridge project, which came in 15 percent below the expected level. Wall Street Journal, 5/29/85, p. 18.

Table 17
Trends in Pipeline Construction Costs

Length	Diameter	Cost	
(miles)	(inches)	(million $)	($/inch/mile)
A. 1983			
48.6	48	135.0	57,870
74.1	42	131.2	42,157
158.0	42	313.0	47,167
38.6	42	68.2	42,068
60.6	42	129.0	50,684
10.5	36	7.9	20,999
360.0	36	536.0	41,358
23.0	36	20.0	24,155
B. 1984			
(miles)	(inches)	(million $)	($/inch/mile)
22.5	42	21.4	22,686
217.6	42	291.2	31,863
155.3	36	157.1	28,100
29.6	36	30.8	28,953
86.5	30	79.2	30,510
112.0	30	73.8	21,964
23.8	30	15.1	21,184
C. 1985			
(miles)	(inches)	(million $)	($/inch/mile)
5.4	42	6.6	28,887
4.1	36	10.1	67,931
81.0	36	51.0	17,476
11.1	36	8.5	21,154
322.5	36	251.7	21,680

Source: Oil and Gas Journal, Pipeline Economics issue, various years.

manufacturing processes rather than as resource exploitation, should see the down pressure of technical advance and increasing productivity without the upward pressure due to depletion.[60] Certainly, moves such as increased efficiency of fuel use in liquefaction plants should bring noticeable cost savings, but it is difficult to point to specific design changes and technical advances that will become important in the next decade or two.[61]

To date, most of the research seems to focus on making small or inaccessible fields viable. With oil fields, ships are now available that can dock at a mooring point and allow the undersea facility to produce directly into their tanks. Some efforts have been made to do the same for natural gas fields, in one instance suggesting floating methanol plants.[62] There has also been the suggestion that the offloaded LNG could be used to create liquid nitrogen, which could be loaded into the tanker and used to liquefy gas at the field without requiring a separate liquefaction plant.[63]

However, these innovations are not useful in the Pacific Basin, where the fields tend to be large and cheap to produce. Advances applicable to them, i.e., more efficient liquefaction technology, and

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[60] The cost pressure from depletion comes at the natural gas production stage and was discussed in the section on production costs.

[61] It might be easier for an engineering/construction firm to point these out, however.

[62] See Magne Ostby and Arild N. Nystad, "Floating Plant Could Convert Gas to Methanol Economically," World Oil, April 1980, pp. 49-53. The plant was intended to float off an oil production platform and use associated gas that would otherwise be flared.

[63] Obviously, there would be thermal losses, which would be an added cost. Most Japanese LNG importers currently utilize the cold energy derived from regasification.

cheaper construction or insulation, are not currently known.

Since a number of companies which received our survey are involved with the development of equipment used in the LNG industry, it seemed only natural to survey them regarding technological advances whose introduction they anticipated. Naturally, no company is likely to release trade secrets, but given the lead time on developing this type of equipment, even such items as were publicly known would have an impact only over the next decade.

In fact, there was little to suggest major cost breakthroughs. The main item mentioned was a plan to recapture boiloff gas from tankers and either reliquefy it or burn it as fuel. However, the cost savings for the delivered LNG do not promise to be great.

Appendix A

REPORTED GAS FLOWRATES BY COUNTRY
(MMcfd)

A. Indonesia

nonassociated gas	condensate gas	nonassociated and condensate gas	associated gas
29.4	39.5	39.5	22.5
24.0	28.7	29.4	21.2
23.9	27.8	28.7	10.0
20.8	22.7	27.8	9.6
19.0	19.3	24.0	7.1
12.5	15.5	23.9	3.1
10.4	10.0	22.7	2.5
7.1	9.7	20.8	1.6
6.1	7.0	19.3	1.5
4.0	6.0	19.0	1.5
3.28		15.5	1.5
2.2		12.5	
		10.4	
		10.0	
		9.7	
		7.1	
		7.0	
		6.1	
		6.0	
		4.0	
		3.28	
		2.2	

B. Thailand

nonassociated gas	condensate gas	nonassociated and condensate gas	associated gas
76.0	68.8	76.0	2.0
34.6	37.0	68.8	
27.6	30.1	37.0	
27.6	30.0	34.6	
18.0	28.6	30.1	
15.7	28.0	30.0	
14.0	26.0	28.6	
9.3	18.7	28.0	
	12.0	27.6	
	10.8	27.6	
	9.4	26.0	
	3.5	18.7	
		18.0	
		15.7	
		14.0	
		12.0	
		10.8	
		9.4	
		9.3	
		3.5	

C. Australia

nonassociated gas	condensate gas	nonassociated and condensate gas	associated gas
65.2	39.2	65.2	7.9
57.0	27.0	57.0	3.9
34.4	15.4	39.2	2.9
32.3	8.22	34.4	2.2
22.7	7.4	32.3	2.0
18.7	4.7	27.0	1.2
16.3	1.06	22.7	1.0
11.3	0.9	18.7	
11.0		16.3	
11.0		15.4	
11.0		11.3	
9.5		11.0	
9.5		11.0	
9.3		11.0	
8.5		9.5	
8.5		9.5	
8.0		9.3	
7.7		8.5	
7.6		8.5	
7.5		8.22	
7.2		8.0	
6.9		7.7	
6.6		7.6	
6.33		7.5	
6.1		7.4	
6.0		7.2	
6.0		6.9	
6.0		6.6	
6.0		6.33	
5.5		6.1	
5.4		6.0	
5.4		6.0	
5.0		6.0	
4.1		6.0	
2.0		5.5	
1.7		5.4	
0.8		5.4	
		5.0	
		4.7	
		4.1	
		2.0	
		1.7	
		1.06	
		0.9	
		0.8	

D. Aggregate Flowrates

	INDONESIA	AUSTRALIA	THAILAND	CONSOLIDATED
Mean Flowrate	21.3	13.7	29.6	19.6
Standard Deviation	25.6	19.1	37.1	26.8

Source: Calculated from Tables A-C. Original data from World Oil and Petroleum Economist, 1980-85.

Appendix B

DEVELOPMENT COSTS

Malaysia

Central Luconia Field
announced development cost

Development Cost

1.	development cost	1.5	($B)
2.	reserves	13	(Tcf)
3.	production rate	650	(Bcf/year)
4.	equivalent annual operating cost	330	($MM)
5.	development cost in ground	0.115	($/Mcf)
6.	developing-operating cost as sold	0.508	($/Mcf)

Sources:

1. total cost (development and LNG plant): International Petroleum Encyclopedia, 1984; cost of LNG plant: Petroleum Economist, 4/1982; development cost escalated from $82 to $84 using IAAP drilling index; LNG plant cost not escalated.

2. Petroleum Economist, 2/1982.

3. Q = aR assume a = .05

4. 22 percent of development cost (i = .12 + a = .05 + op = .05).

5. c = development cost/reserves.

6. operating cost/production rate (line 4/line 3).

NOTE: Data n.a. to calculating theoretical development cost.

<u>China</u>

Yacheng Field

announced development cost

1.	expected development cost	400	($MM)
2.	reserves	3000	(Bcf)
3.	production rate	127.75	(Bcf/year)
4.	depletion	0.016	
5.	annual development-operating cost	74	($MM)
6.	development cost in ground	0.133	($/Mcf)
7.	development-operating cost as sold	0.579	($/Mcf)

Sources:

1,2,3 from <u>Wall Street Journal</u>, September 30, 1985, p. 25.
4. a = 0.016 to satisfy equation Q * (1-exp (-aT)) = aR and Q = 127.75, T = 30 T = 30 from <u>Wall Street Journal</u>
5. 18.6 percent development cost (1 = .12 + a = .016 + op = .05)
6. c = development cost/reserves
7. operating cost/production rate (line 5/line 3) * developing-operating cost as sold = 0.587 $/Mcf a = .05 Q = ar

calculated development cost

1.	well depth	13000	
2.	average cost/well 13000 off La.	4.2	($MM)
3.	number of wells	12	
4.	total well cost	50	($MM)
5.	dryhole and nondrill cost	50	($MM)
6.	pipeline cost 30" 65 miles	77	($MM)
7.	total development cost	177	($MM)
8.	depletion rate	0.016	
9.	annual development-operating cost	33	($MM)
10.	development cost in ground	0.059	($/Mcf)
11.	developing-operating cost as sold	0.258	($/Mcf)

Sources:

1,3. <u>Wall Street Journal</u>, <u>op.cit.</u>
2. <u>Joint Association Survey</u>, 1984.
5. Adelman and Ward.
6. Adelman and Ward, pipeline costs. Adjusted to $84 using Morgan pipeline costs indices dimensions in <u>Wall Street Journal</u>, <u>op.cit.</u>
8. a = 0.016 to satisfy equation Q * (1-exp(-aT)) = aR and Q = 127.75. T = 30 T = 30 from <u>Wall Street Journal</u>.
9. 18.6% development cost (1 = .12 + a = .016 + op = .05)
10. c = development cost/reserves
11. operating cost (line 9)/Q Q = 127.75 Bcf/year * development-operating cost as sold = 0.260 $/Mcf with a = .05 Q = aR.

Thailand
"B" STructure
announced development costs

1.	development cost	536	($MM)
2.	reserves	5.8	(Tcf)
3.	production rate	290	(Bcf/year)
4.	annual development-operating cost	118	($MM)
5.	development cost in ground	0.092	($/Mcf)
6.	developing-operating cost as sold	0.407	($/Mcf)

SOURCES:

1. International Petroleum Encyclopedia, 1980, adjusted to 1984 $ with IAPP index.
2. International Petroleum Encyclopedia, 1980.
3. Q = aR, assume a = .05.
4. 22 percent of development cost (i = .12 + a = .05 + 0- = .05).
5. c = development cost/reserves
6. operating cost/production rate (line 4/line 3).

calculated development cost

1.	well depth	8000	
2.	average cost/well 8000 off La. JAS	2.5	($MM)
3.	total # of wells	40	
4.	total well cost	100	($MM)
5.	pipeline cost at 32", 115 miles	144	($MM)
6.	dryhole and nondrilling costs	100	($MM)
7.	total development cost	344	($MM)
8.	annual developing-operating cost	76	($MM)
9.	development cost in ground	0.059	($/Mcf)
10.	development-operating cost as sold	0.262	($/Mcf)

Sources:

1,3. International Petroleum Encyclopedia, 1980, maximum well depth.
2. Joint Annual Survey, 1979, adjusted to 1984 $ by IAAP index.
5. Adelman and Ward pipeline costs adjusted to 1984 $ by Morgan pipeline cost index dimensions in International Petroleum Encyclopedia, 1980.
6. Adelman and Ward.
8. 22 percent total development cost (1 = .12 + a = .05 + op = .05) assume a = .05
9. c = total development cost/reserves
10. c = operating cost (line 8)/Q Q = aR = 0.05 * 5800 = 290 Bc/year.

Appendix C

PRODUCER COUNTRY OVERVIEWS

This appendix provides a brief description of the situation in the different producer countries, in order to allow for a more complete analysis of the potential for future gas exports. In the instances where information on specific proposed projects is available, some analysis of the viability will be performed.

Potential future consumption in producing countries is difficult to analyze, because much of it depends on the level of investment undertaken to displace oil consumptioon. Converting a power plant, refinery, or cement plant can result in a large, sudden increment to consumption, so that past demand trends are not particularly useful in analyzing future trends. However, given the desire to find some means of using the gas without incurring the large transportation costs of an LNG project, most countries are examining various forms of domestic utilization. For the nations with small reserves, this will affect their ability to export LNG in the future.

Even so, small nations like Qatar are limited in their ability to absorb gas domestically, poor nations like Thailand are unable to make massive investments in energy-intensive export industries, and diverse nations like Indonesia will find it uneconomic to develop a residential distribution network, given the low level of consumption per household and the high capital costs. This sort of information is useful in describing the potential for natural gas exports.

In discussing the various projects, costs must, of course, play a prominent role. Unfortunately, as mentioned in the main body of this report, so few liquefaction plants have been built, at widely different times and places, that definitive estimates are not possible. The uncertainty is enhanced by the current highly competitive market for the construction of such projects, which could lead to lower costs in the short run.

Thus, the capital and unit costs for delivered natural gas should be considered indicative, rather than definitive. This project has relied heavily on reports in the trade press, as well as confidential feedback from those in the industry, but these have varied widely. In addition, given the effect of differences in the amount of development time needed, interest rates paid by participants, liquids production,[1] savings from existing infrastructure, and similar factors, a large degree of uncertainty is present. Since the margin for error on capital costs are so uncertain, this appendix does not employ rigorous project analysis techniques. Instead, cost per Mcf in a given project are determined using the shorthand method described in the North American report, which yields a good approximations.[2]

Alaska

In our previous report on the subject, it was estimated that

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[1] In a few cases, the projected level of liquids to be produced are known, but in most instances they are not.

[2] This method is translated as:

Cost per Mcf = C(d) * (i+a+C(o))

where C(d) is total capital costs, i is the interest rate, a is the depletion rate, and C(o) is the operating cost factor. Throughout, we have assumed i at 12%, a at 5%, and C(o) at 5%. Thus, the cost per Mcf is 22% of the capital cost.

the cost of delivering natural gas from the wellhead at Prudhoe Bay to the citygate in Japan, i.e., including regasification, was between \$2.55/Mcf and \$4.60/Mcf, with a bias toward the low end. Since that time, there has unfortunately been no new information concerning project costs,[3] although feedback from the report has tended to be positive. The question now becomes: Will the price of oil be high enough to make this project viable, especially if price discounts are necessary to increase market penetration in Japan? Given the quantities of LNG involved, optimism about the level of demand in the Asia-Pacific region is necessary. These questions are addressed in further detail in the section on demand.

Australia

For this report, the domestic gas industry will be essentially ignored and the focus instead centered on the North West Shelf project, especially its plans to export LNG to Japan beginning in 1989. The domestic gas industry involves a large number of relatively small deposits in the south and east, which supply the population centers there. The local surplus appears to be small relative to other producing areas in Asia, although depressed prices have acted to reduce drilling. However, the main consuming centers of the country are in the southeastern corner of the continent; the distance to them and the lack of any developed areas in between has meant that this gas could not be commercially exploited until the oil price increases of the 1970s, and particularly the development of the LNG market. In order to access a

[3] A number of studies are underway at the present time, but nothing has, as of yet, been reported.

domestic market large enough to use even a fraction of the gas to be produced,[4] a 1500 kilometer pipeline had to be built. The relatively small volumes being shipped result in higher per-unit costs than for a similar transportation distance in, for example, North America.

With approximately 10 Tcf of reserves available and a small domestic market, it seems only natural that an LNG project would be developed. As of late 1985, a contract was signed calling for 5.8 million tonnes per year (290 Bcf) of LNG to be shipped to Japan beginning in late 1989, and plateauing in 1995. The cost of the project has been put at as much as A$8.5 billion (about US$6 billion), including production, liquefaction, and shipping.[5] Other sources suggest that the cost will be somewhat higher, but include capital expenditures on fields that will occur in the latter half of the 1990s.[6] These sources put the cost of building the liquefaction plant at $2.7 billion, substantially higher than our "base case," and attribute the difference to the addition of supporting infrastructure for the local area.

Although these costs are rather high, especially relative to projects established in the 1970s, the project has the potential to be quite profitable. Partly this is due to the associated production of 1.5 million tonnes of condensate, which consists of one-quarter the volume of the LNG, but a higher fraction of the revenues of the project, due to the

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4 The contract called for 400 MMcf/d to be delivered, but the demand estimates turned out to be optimistic, partly due to the subsequent failure to attract energy-intensive industry to the area. At present, the amount consumed is only about 250 MMcf/d (according to <u>Financial Times Energy Economist</u>, June 1985, p. 2.

5 <u>Oil and Gas Journal</u>, 12/19/83, p. 67.

6 Industry sources.

lower transportation costs for condensate.[7] Naturally, the price of oil will determine the profitability, but even at \$3/Mcf for landed LNG, (\$18/barrel for crude oil) the project appears profitable.[8]

In fact, profitability may be enhanced by a recent discovery off the North West Shelf, which indicates a high level of condensate. The well tested at 38 MMcf/d of gas and 4,670 b/d of condensate, four times that of any other discovery in Woodside's concession area.[9] If this field is brought on line as part of the LNG export project, then condensate production would be on the order of 5 million tonnes per year, rather than 1.5. Although the relative costs are not available at this point, from a standpoint of relative profits, the project could become a condensate field with LNG exports as a byproduct. Figure C-1 shows the relative level of revenues for LNG and condensate depending on the two possible levels of liquids production.

Brunei

Possessed of small reserves (7.4 Tcf) and little opportunity for domestic consumption, Brunei turned to LNG exports very early. With low production costs and a presumably cheap liquefaction plant, delivered cost to Japan is probably on the order of \$2/Mcf or less. Expansion is unlikely without major new reserve additions, and since current

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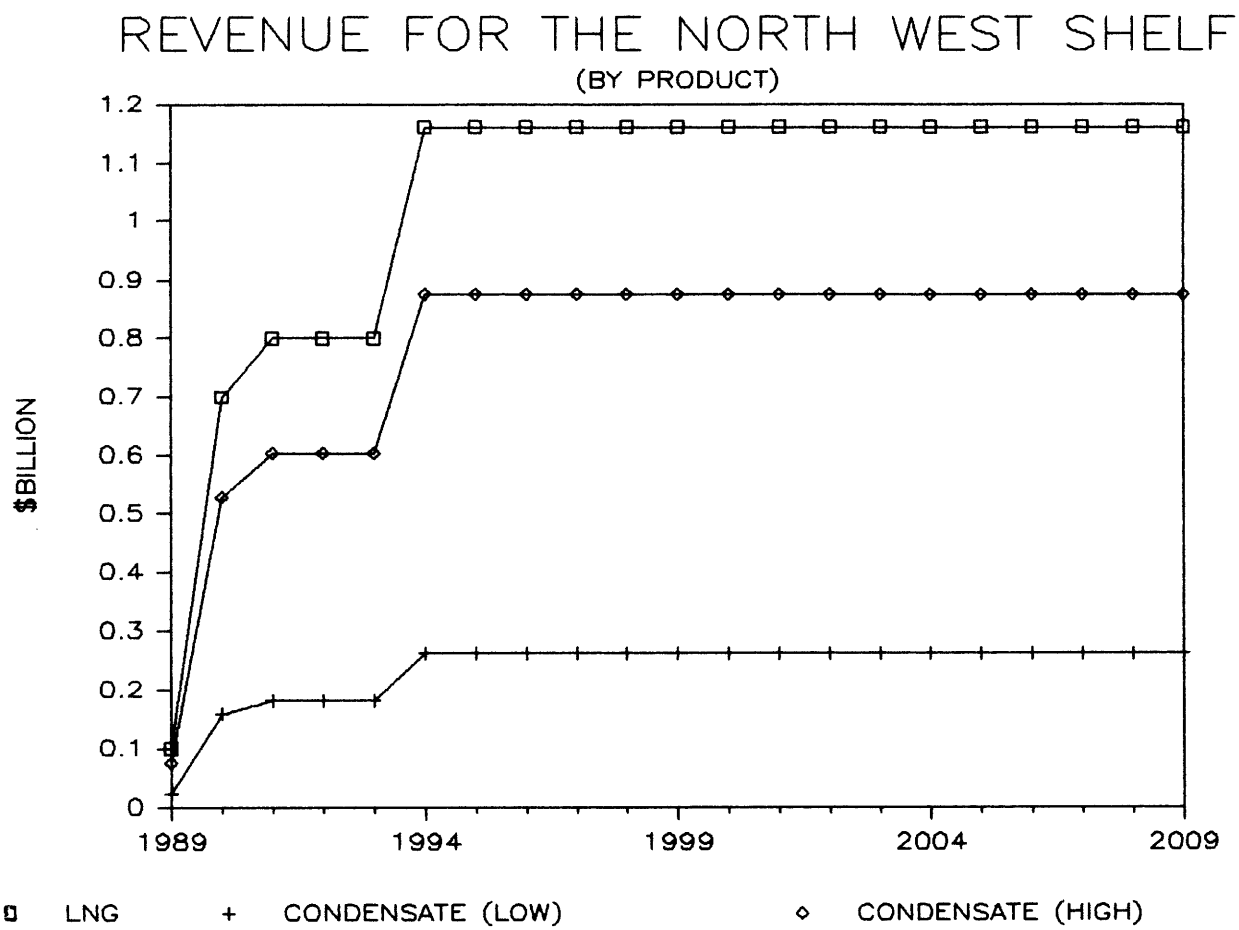
[7] In fact, in most markets condensate is worth about the same as oil, since it can be used as refinery or chemical feedstock, but in the Asian market, delivered natural gas is also worth as much as oil (roughly). If the project were aimed at the U.S. or European markets, the liquids would become much more important. Information on the cost of extracting the liquids is not available, however.

[8] Ignoring taxes, royalties, and other transfer payments, and pricing the condensate accordingly.

[9] International Gas Report, 11/8/85, p. 10.

Figure C-1


REVENUE FOR THE NORTH WEST SHELF
(BY PRODUCT)
$BILLION
1.2
1.1
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
1989
1994
1999
2004
2009
LNG
CONDENSATE (LOW)
CONDENSATE (HIGH)

exploration is limited, this is unlikely in the near future.

Canada

The Canadian natural gas supply situation was discussed at some length in the previous report, along with the Western Canada LNG export project. Since then, the LNG export project has been cancelled, due to pricing uncertainties resulting from the recent plunge in oil prices. Inasmuch as our last estimate of costs showed the project to be marginal at $28/barrel for oil prices, lower prices certainly would be damaging to its prospects, even with lower, reestimated costs.[10]

Indonesia

With its exports currently running at 700 Bcf/yr. (with an additional 100 Bcf/yr. to Korea coming onstream later this year), Indonesia is by far the largest LNG exporter in Asia. Highly productive gas fields, (Arun wells produce at 170 mcf/d,[11] n times our reference cost case shown in Table 5), and existing infrastructure (production capacity exists to add 300 Bcf/yr. of production without significant expenditures[12] mean that capacity additions will be among the cheapest sources of LNG in the world. Mlotok estimates that the original Arun plant delivers LNG to Japan for a cost of $1.40/Mcf[13], and the recent

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[10] An industry source recently suggested that the pipeline and liquefaction costs would be on the order of $2.50/Mcf. Production and shipping would add about another $2/Mcf.

[11] Paul Mlotok, "The Oil Industry in the Far East: Indonesian Oil and Gas," Salomon Brothers, Inc., October 1984, p. 7.

[12] Industry sources.

[13] Ibid., p. 6. Excluding regasification.

expansion, while undoubtedly more expensive for reasons discussed in the main body of this report, will remain relatively cheap, on the order of $2/Mcf. New capacity might cost as much as $3/Mcf, including shipping and regasification and depending on construction costs.

With 40 Tcf in natural gas reserves, little potential for domestic utilization, and talk of another 150 Tcf in the Natuna field,[14] Indonesia is still actively seeking to increase its production and exports of LNG.

Malaysia

With approximately 10 Tcf of associated gas reserves and 43 Tcf of nonassociated gas reserves,[15] Malaysia has limited options beyond LNG exports. Although Malaysia has been attempting to encourage exploration and development of its oil resources, it has been hindered by an apparent desire to cooperate with OPEC in holding down production to help stabilize prices. This could have an impact on foreign oil companies' future drilling, reducing the unintentional discovery of natural gas.[16]

Even so, current reserves would support a substantial increase in consumption. Production costs appear low, and the liquefaction plant, at about $2 billion,[17] was not cheap, although well within reason. The result is an estimated cost of delivered natural gas to Japan of about

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[14] See International Petroleum Encyclopedia 1985, p. 96.

[15] See "Gas Opens a New Era," Petroleum Economist, 2/83, p. 47. In addition, 25 Tcf of probable gas reserves are listed, with a 50 percent probability basis. Reserves have changed little since.

[16] Discovery of gas in the search for oil has been quite common in Malaysia, with Esso Production Malaysia Inc. hitting gas in 65 percent of the structures it has drilled. See International Petroleum Encyclopedia 1985, Pennwell Publishing, p. 102.

[17] Oil and Gas Journal, 2/14/83, p. 82.

$2.75. With existing infrastructure in place, future expansion should be cheaper, making new projects quite competitive.

Current government plans include the intent to increase gas consumption significantly, in three phases, to replace as much as 190,000 barrels per day of oil consumption.[18] The Trengganu Gas Project involves the production of 150 Bcf/year of mostly associated gas for domestic consumption, peaking in 1989, and another 50 Bcf/yr. is to be sent via pipeline to power stations in Singapore.[19] While this will increase marketed production by two-thirds over the LNG project, it will still leave the depletion rate at about 1 percent. Plans to increase the amount of energy-intensive industry such as petrochemicals or even establish a gas-fired synthetic fuel plant, even if brought to fruition, would increase consumption, but only slowly and at a small rate relative to gas reserves.

Thailand

Given the current reserves level of 5.4 Tcf[20] and domestic consumption level of 350 mcf/d, it might seem odd that a consortium has been formed to analyze the feasibility for LNG exports to Japan. In reality, Thailand's reserves are understated by pricing and development disputes with the operators. For example, Exxon has an undeveloped onshore field with 1.6 Tcf of estimated reserves, with no market, and Texas Pacific's holdings include only 1.9 Tcf of proved reserves, but

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[18] Petroleum Intelligence Weekly, 5/28/84, p. 7.

[19] See "Gas Opens a New Era," Petroleum Economist, 2/83, p. 47, and Petroleum Intelligence Weekly, 1/13/86, p. 8.

[20] Oil and Gas Journal, 12/30/85, p.66.

5.4 Tcf of probable reserves.[21] The government's indecision over whether to keep its natural gas reserves for domestic consumption or export them as LNG, and its perceived uncooperative attitude toward the foreign oil companies, has resulted in long delays in field development and reduced commitments from oil companies. Texas Pacific, in fact, is now seeking to sell its acreage and deposits to the government.[22]

The existing surplus of natural gas,[23] combined with the existence of a number of gas fields that could be exploited, has led to the formation of a consortium to consider a small-scale LNG export project. The members are Mitsui, Mitsubishi, Sumitomo, and Marubenu on the importing side, and Thai LNG Co., a government promoted Thai firm, on the domestic side.[24] The project is still in the exploratory stages, and although $9 billion has been mentioned as the possible cost, the amount and source of the gas to be committed has not yet been mentioned. Inasmuch as previous projects were on the order of two to three million tonnes of LNG per year, with cost estimates of $3 billion, give or take $500 million, the new consortium apparently has something more grandiose in mind.

The costs of natural gas production for offshore Thailand, based on initial reports of the Erawan field, are shown in Appendix B. Subsequent problems with the field, reflected in the downward revision of reserves

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[21] Oil and Gas Journal, 9/2/85, p. 36.

[22] Wall Street Journal, 9/5/85, p. 36.

[23] Union's fields are operating at 78 percent of capacity, due to constraints on processing plant capacity.

[24] Oil and Gas Journal, 11/25/85, p. 51.

by two-thirds, resulted in the need for additional drilling and raised costs, although reports on the exact amount vary from "more than $1 billion" to $2.1 billion.[25] At those levels, the delivered costs of the gas to shore would be on the order of $1 to $2/Mcf. Since the gas separation plant cost $320 million and delivers 770,000 tonnes of liquids a year, it is obviously quite profitable.[26]

On the other hand, the suggested LNG project capital costs are quite high. Assuming $3 billion for a 3 million tonne project leaves the cost of delivery at $4-5/Mcf.[27] Also, given a perception in the oil industry that the government of Thailand has been less than accommodating, the risk factor on this project may be viewed as higher than in other areas. With weak oil prices, and high costs and risks, this project does not appear strong.

Qatar

The North Dome natural gas field is the largest field known outside of the Soviet Union, with an estimated 150 Tcf of reserves. In fact, the field is so large it dwarfs any potential use for it, even ignoring the fact that the region is awash with unused natural gas. As a result, exports offer the only hope for realizing the major portion of the value

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[25] See Oil and Gas Journal, 8/26/85, p. 37, and Petroleum Intelligence Weekly, 12/10/84, p. 11. The discrepancy could include differences in whether or not exploration expenditures and the gas separation plant are included. The reports are not specific enough to be enlightening about this.

[26] Assuming that annual capital and operating costs are 25 percent of total capital costs, the cost per tonne is roughly $100, less than half of 1985 prices for LPGs.

[27] If field development costs are not included in the capital cost figure, then $1/Mcf must be added.

of the field.

Unfortunately, Qatar is as far from the major natural gas consuming markets as possible.[28] On top of that, construction costs in the Middle East are among the highest in the world.[29] As a result, the project costs are put at $6 billion by most observers, although this includes a large quantity of liquids production.[30] No publicly available breakdown of costs is available at present, partly because the project is still in early planning phases, but at least a portion of the project costs are for the initial phase of the project, which involves production for the domestic market.

The cost of producing 300 Bcf of natural gas has been put variously at $500 million to $1.5 billion.[31] Production costs appear to be on the order of $0.50/Mcf, and liquefaction about $1.75/Mcf (including fuel). At the same time, the 1.75 million tonnes per year of condensate and .7 million tonnes per year of LPG should yield revenues equating to about $0.20-$0.40/Mcf, depending on the level of oil prices. However, given a

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[28] The potential for exports to Europe will be dealt with in the next phase of this project.

[29] For example, the cost of building some of the petrochemical plants in Saudi Arabia has been described as twice as high as in Western Europe or Japan. See John Cranfield, "Downstream Ventures Face the Test," in Petroleum Economist, 12/85, p. 445. In our survey of Japanese companies, respondents suggested that costs in Qatar would be 20 percent higher than average.

[30] It should also be noted that, to the extent that OPEC members are faced with production quotas, LNG provides an outlet for hydrocarbon production, even if with much lower profit margins, and the associated liquids are not covered by quotas.

[31] Unfortunately, neither source can be cited, but the latter source appears to be more credible, while the former number seems to be. Given the size of the field and the shallow waters involved, production costs should be very low. The two estimates suggest roughly $0.40/Mcf to $1.20/Mcf.

shipping distance of about 7,800 miles, shipping costs will be about $1.60/Mcf. Thus, delivered costs will be between $3.50/Mcf and $4.50/Mcf, depending on the offset from sale of liquids, etc.

While it might be possible to reduce some capital costs in the prevailing competitive construction environment, Qatar cannot be moved any closer to markets. Thus, it will remain at a cost disadvantage to the other low-cost producers for some time to come. Strong oil prices would render this unimportant, but such a scenario is difficult to predict at present.

U.S.S.R. (Sakhalin)

In 1977, a Japanese consortium found oil and gas off Sakhalin Island, and plans to export the natural gas to Japan have been under consideration since then. (The U.S.S.R. has little domestic need for the gas. For the purposes of this report, potential gas exports to Asia from new deposits or from inland areas will not be considered.) The project would involve the export of 3 million tonnes of LNG (150 Bcf) per year, and the overall costs have been put at about $4 billion.[32]

The resulting costs are higher than the Thai project, and the harsher environment and lower level of operations suggests a potential for more uncertainty about costs, as well as higher operating costs. Whether or not the Soviet government is considered more benign to

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[32] At present, a definitive project plan does not exist, but various estimates range from $3 billion (Jonathan P. Stern, Natural Gas Trade in North America and Asia, Gower Press, 1985, p. 201), to more than $3.3 billion, from Tadahiko Ohashi, "An Analysis of the Future of Natural Gas in Japan," to $3.8 billion (confidential academic sources) and $4.5 billion in a confidential industry memo, which was drawn from open press sources. It is interesting that the Japanese estimate is one of the lowest, given the reported reluctance of Japanese gas companies to participate in this project.

resource development is a question for the importers to answer.

A LIQUEFIED NATURAL GAS TRADE MODEL OF THE PACIFIC BASIN

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INTRODUCTION

This is a brief description and overview of the Pacific Basin liquefied natural gas (LNG) trade model which has been developed as part of the M.I.T. Center for Energy Policy Research (CEPR) project on international gas trade. The primary purpose of the model is to provide a consistent framework for determining the least-cost program of meeting alternative projections of LNG demand in the Pacific basin. Here, a program refers to the time pattern of production, exports, and investment in extraction and liquefaction capacity in each of the producing countries. Another objective of the model is to help determine the financial flows to and from buyers and sellers associated with particular programs and price projections. In the future, it may be possible to extend the model to examine the question of what would be the optimal level of LNG demand for Japan or other regional purchasers. But the feasibility of this extension will depend on data availability, from which explicit price-sensitive demand functions could be estimated.[1]

As presently formulated, the model does not determine the time path of LNG demand itself. Rther, these are taken as projections derived as part of the demand study of this project. Of course, the model can be solved repeatedly to investigate what would happen if demand grew more or

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[1] This was the procedure used for the North American model, which attempted to simulate market behavior using functions representing U.S. demand for Canadian exports as a function of price, and various parameters about Canadian costs, reserves, and tax policy.

less rapidly. The model then examines all possible means for meeting these LNG demands, and then selects the one which has the lowest present value cost.

Collectively, the set of possible programs is referred to as the feasible set. The constraints given to the model determine which programs are and are not feasible. Some constraints are technical, such as those related to reserve size or technical limits to production in different areas. Other constraints might represent policy interventions on the part of one or another government in the regions. These would include possible upper or lower bounds on production or exports. There also may be contractual constraints representing commitments to deliver or buy from a certain country, even though that may not be the least-cost source. While it may be assumed that the technical constraints are fully predetermined, the others are subject to public and private policy and might vary from run to run of the model.

The costs associated with each program are calculated on the basis of cost estimates developed as part of the project. These include investment in extraction capacity, extraction operating costs, liquefaction operating costs, investment in new liquefaction plants, LNG transportation costs, and operating and capital costs of regasification. These are discounted and summed to derive the present value cost of each program for meeting demand. A linear programming algorithm is used to find the least-cost program.[2]

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[2] There is no presumption that the least cost solution is the most likely to emerge in the future. Rather the purpose is to ascertain the cost of deviations which may be due to government interventions, diversification objectives, pre-existing contractual relationships, taxation policy, etc.

In addition, the model includes various accounting identities used to determine the net financial flows of each program as a function of the price for LNG which the purchasers pay, as well LNG project financing arrangements. The purchase price can be different for exports from different countries to different destinations. These differences would result from contractual arrangements that utilize different pricing formulas.

LNG production and exports and required new investment levels are calculated at periodic intervals beginning in 1985 and continuing until 2015. In the earlier years, the time intervals are shorter (three years in length), while five-year intervals are used for the later years.[3] This long time horizon is required to account fully for the long investment lags and long operating lives of major capacity expansion projects. Dynamic relations are also important because production in earlier periods affects marginal production costs in the future. Because of well-known and inevitable problems with terminal conditions, we report results only through 2006.

The remainder of the paper is divided into three sections. In the next section, the algebraic formulation of the model is presented and discussed. The internal pricing structure of the model is reviewed in the following section. The final section reviews illustrative results.

MODEL FORMULATION

In technical terms, the model is formulated as a mathematical programming problem in which a computer algorithm is used to find the

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[3] This is a convenience adopted to save on computer time.

optimal time path of the values of the endogenous variables (e.g., exports from each country, investment in new liquefaction plants, etc.). We report on the present formulation of the model. It should be understood that this modelling framework is considerably more flexible in the sense that additional constraints, projects, producing regions, policy interventions, etc. could be added. Indeed, as the model is used, it will be important to make modifications based on initial results and enhanced perceptions of the issues that need further investigation.

The model includes eight supplying countries that could supply the Pacific market with LNG. These are Australia, Brunei, Canada, Indonesia, Malaysia, the Gulf countries, Thailand, and Alaska. When required, the model can differentiate between more than one supply region in a particular country. Thus, on the supply side it is important to keep track of what is occurring at both the country and regional levels; the latter is a finer breakdown. Table 1 presents a full list of supply regions, existing capacity for gas production, and relevant costs data which are used in the simulations. LNG demand arises from two possible sources: Japan and an aggregation of other countries such as South Korea and Taiwan. The model also keeps track of other (non-LNG) demands for gas.

The model is described in more detail in the following sub-sections. The format in each section will be to provide the underlying motivation of the constraint and describe it specifically in words and algebraic equations. In general, endogenous variables are represented by capital letters and parameters by lower-case letters. Bars over letters indicate exogenous variables. The subscripts "i","j", "m", and "t" refer to the producing regions, producing countries, export markets, and the time period, respectively. All quantities are in Bcf units, except where noted.

Supply-Demand Balances

We begin with the identity that total gas production in each producing region is used either for export in the form of LNG or for deliveries to the local market of that country. These supply-demand balances are expressed in the following relationship:

$$\begin{bmatrix} \text{Total} \\ \text{Production,} \\ \text{Region } i \end{bmatrix} = \begin{bmatrix} \text{Domestic} \\ \text{Deliveries,} \\ \text{from Region } i \end{bmatrix} + \begin{bmatrix} \text{Total} \\ \text{Exports,} \\ \text{from Region } i \end{bmatrix}$$

Let $X_{i,t}$ represent annual production in region i in year t; $DS_{i,j,t}$ represent deliveries to the domestic market in country j; and $EX_{i,t}$ stand for total gas exports from region i in period t.[4] Algebraically, we have:

(1) $$X_{i,t} = DS_{i,j,t} + EX_{i,t}$$

For each country, j, we require that total deliveries of gas from each of the producing regions equal total domestic demand for gas. That is:

$$\begin{bmatrix} \text{Domestic} \\ \text{Demand,} \\ \text{Country, } j \end{bmatrix} = \begin{bmatrix} \text{Sum of} \\ \text{Deliveries, from} \\ \text{All Regions } i\text{, in country } j \end{bmatrix}$$

Note that these domestic demands for gas are projected exogenously, and could in many cases be zero. Defining total domestic demand as $D_{j,t}$, the following equation is used, where the summation includes only those producing regions i which are in country j:[5]

[4] Gas is exported as LNG after going through a liquefaction process.

[5] We also allow the possibility that some regions, perhaps for location reasons, cannot supply the domestic market at all. In those cases, all output is dedicated to LNG exports. In all cases, production and delivery variables are constrained to be non-negative.

(2) $$D_{j,t} = \sum_i DS_{i,t}$$

Supply-Demand Balance of Export Markets

In addition to satisfying domestic gas demand, the model has the following constraints that insure there are sufficient LNG exports, from all the supplying regions together, to meet projected demands in Japan and the "Other" Asian markets. That is:

$$\begin{bmatrix}\text{Total LNG Deliveries}\\ \text{to Market m}\\ \text{year t}\end{bmatrix} = \begin{bmatrix}\text{Total LNG}\\ \text{Demand at Market m,}\\ \text{year t}\end{bmatrix}$$

Now we define a new export variable $E_{i,m,t}$ to be the LNG exports originating from all regions i and being delivered to market m in year t. The total demand for natural gas in market m is given by $D_{m,t}$. Algebraically:

(3) $$\sum_i E_{i,m,t} = D_{m,t}$$

To insure that everything balances, we specify that that the sum of deliveries to all markets from region i equals total total LNG exports from that regions. That is:

(4) $$\sum_m E_{i,m,t} = EX_{i,t}$$

For each country, the following two equations determine total LNG exports to each market m, $E_{j,m,t}$, and total LNG exports, $EX_{j,t}$.

(5) $$E_{j,m,t} = \sum_i E_{i,m,t}$$

(6) $$EX_{j,t} = \sum_{i} EX_{i,t}$$

Note that in equations (5)-(6), the summation includes only those regions i which are in country j.

Production-Reserve Relationships

There is a recursive relation between production in any one period and remaining reserves in the next period. That is:

$$\begin{bmatrix} \text{Reserves in} \\ \text{Region i at} \\ \text{Start Period t} \end{bmatrix} = \begin{bmatrix} \text{Reserves in} \\ \text{Region i at} \\ \text{Start Period t-1} \end{bmatrix} - \begin{bmatrix} \text{Number} \\ \text{of Years} \\ \text{per Period} \end{bmatrix} \bullet \begin{bmatrix} \text{Annual} \\ \text{Production in} \\ \text{Region i in} \\ \text{Period t-1} \end{bmatrix}$$

Defining $R_{i,t}$ as reserves in region i at the start of period t and remembering that periods are n years in length, the equation form is[6]:

(7) $$R_{i,t} = R_{i,t-1} - n_t X_{i,t-1}$$

The following constraints represent a simple approximation to the limitations on annual production imposed by the level of remaining reserves. That is, production in each region can be no greater than an exogenously specified fraction of reserves left in that region.[7]

$$\begin{bmatrix} \text{Annual} \\ \text{Production} \\ \text{in Region i,} \\ \text{Period t-1} \end{bmatrix} \leq \begin{bmatrix} \text{Maximal Rate} \\ \text{of Reserve} \\ \text{Depletion} \end{bmatrix} \bullet \begin{bmatrix} \text{Reserves in Region} \\ \text{i, at Start of} \\ \text{Period t} \end{bmatrix}$$

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[6] The number of years in a period can vary. Balances are computed more frequently in the early years.

[7] We recognize that the technical relationship between production and reserves is more complicated, but have adopted this formulation for its simplicity. If data were available, it would not be difficult to substitute more complex equations.

These maximal rates, $a_{p,t}$, can represent technical/engineering limits or more restrictive policy interventions. Initially, technically imposed bounds are assumed.

(8) $$X_{i,t} \leq a_i R_{i,t}$$

Production-Investment Relationships

Annual production in each region is also constrained by available productive capacity, which in turn depends on previously undertaken investment projects. 1985 extraction capacity is predetermined, but endogenous investment activities allow that to be augmented at constant capital costs per unit production in each region. That is:

$$\begin{bmatrix}\text{Annual}\\ \text{Production}\\ \text{in Region i,}\\ \text{Period t}\end{bmatrix} \leq \begin{bmatrix}\text{Production}\\ \text{Capacity}\\ \text{in Region i,}\\ \text{Period t-1}\end{bmatrix} + \begin{bmatrix}\text{Capacity}\\ \text{Created}\\ \text{in Region i,}\\ \text{Period t}\end{bmatrix}$$

Let $K_{i,t}$ stand for capacity to produce in region i in year t, and $\Delta K_{i,t}$ stand for new capacity introduced in period t. We then have the following relationships:

(9) $$X_{i,t} \leq K_{i,t}$$

(10) $$K_{i,t} = K_{i,t-1} + \Delta K_{i,t}$$

Liquefaction Capacity Constraints

LNG exports from each region must go through a liquefaction process, which implies that existing capacity in any period puts an upper bound on total exports from that LNG region. In addition to what exists in the base year, new capacity can be created through investment activities. That is:

$$\begin{bmatrix}\text{Annual LNG} \\ \text{Exports} \\ \text{from Region i,} \\ \text{Period t}\end{bmatrix} \leq \begin{bmatrix}\text{Liquefaction} \\ \text{Capacity} \\ \text{in Region i,} \\ \text{Period t-1}\end{bmatrix} + \begin{bmatrix}\text{Capacity} \\ \text{Created} \\ \text{in Region i,} \\ \text{Period t}\end{bmatrix}$$

Defining $KL_{i,t}$ and $\Delta KL_{i,t}$ as liquefaction capacity and additions in region i in period t, we have the following relationships which are akin to (9) and (10):

(11) $$EX_{i,t} \leq KL_{i,t}$$

(12) $$KL_{i,t} = KL_{i,t-1} + \Delta KL_{i,t}$$

However, in contrast with expansion of extractive capacity, liquefaction plants are subject to economies of scale. That is, larger plants have lower unit capital costs. But, taking advantage of these may imply excess capacity in some periods, which also has a cost. Here, we assume that each region can invest in plants that come in only two sizes, a "large" plant capable of producing 6 million tons (300 BCF) per year and a "small" plant half that size. Capacity expansion is expressed in the following relationship:

$$\begin{bmatrix}\text{Capacity} \\ \text{Created} \\ \text{in Region i,} \\ \text{Period t}\end{bmatrix} = \begin{bmatrix}\text{Number} \\ \text{of Small} \\ \text{Plants} \\ \text{Installed,} \\ \text{Period t}\end{bmatrix} \bullet \begin{bmatrix}\text{Size of} \\ \text{Small} \\ \text{Plants}\end{bmatrix} + \begin{bmatrix}\text{Number} \\ \text{of Large} \\ \text{Plants} \\ \text{Installed} \\ \text{Period t}\end{bmatrix} \bullet \begin{bmatrix}\text{Size of} \\ \text{Large} \\ \text{Plants}\end{bmatrix}$$

Defining $NS_{i,t}$ and $NL_{i,t}$ as the number of small and large plants installed in region i in year t, and ss and sl as their respective sizes, we have the following algebraic relationship:

(13) $$KL_{i,t} = ss\ NS_{i,t} + sl\ NL_{i,t}$$

Regasification Capacity Constraints

Finally, the model also has constraints that insure there are sufficient regasification facilities available in each market to meet the total LNG imports in each period. These constraints are fully symmetric with those for gas production. New investment activities are chosen to insure that these constraints are met. That is:

$$\begin{bmatrix}\text{Annual} \\ \text{LNG Imports} \\ \text{in Market m,} \\ \text{Period t}\end{bmatrix} \leq \begin{bmatrix}\text{Regasification} \\ \text{Capacity} \\ \text{in Market m,} \\ \text{Period t-1}\end{bmatrix} + \begin{bmatrix}\text{Capacity} \\ \text{Created} \\ \text{in Market m,} \\ \text{Period t}\end{bmatrix}$$

Let $KG_{m,t}$ stand for regasification capacity in market m in year t, and $\Delta KG_{m,t}$ stand for new capacity introduced in period t. We then have the following relationships:

$$D_{m,t} \leq KG_{m,t} \tag{14}$$

$$KG_{m,t} = KG_{m,t-1} + \Delta KG_{m,t} \tag{15}$$

Cost Calculations

The model considers three types of out-of-pocket costs. These are: (1) the operating (or current) costs of gas production, liquefaction, and regasification; (2) the capital costs associated with investment and capacity expansion in extraction, liquefaction, and regasification; and (3) shipping costs of taking LNG from a producing region to market. The unit costs of each of these are projected exogenously. First consider operating costs.

$$\begin{bmatrix}\text{Extraction} \\ \text{Operating} \\ \text{Costs,} \\ \text{Region i} \\ \text{Period t}\end{bmatrix} = \begin{bmatrix}\text{Unit} \\ \text{Extraction} \\ \text{Operating} \\ \text{Costs,} \\ \text{Region i}\end{bmatrix} \bullet \begin{bmatrix}\text{Total} \\ \text{Annual} \\ \text{Production} \\ \text{Region i,} \\ \text{Period t}\end{bmatrix}$$

$$\begin{bmatrix}\text{Liquefaction}\\ \text{Operating}\\ \text{Costs,}\\ \text{Region } i\\ \text{Period } t\end{bmatrix} = \begin{bmatrix}\text{Unit}\\ \text{Liquefaction}\\ \text{Operating}\\ \text{Costs,}\\ \text{Region } i\end{bmatrix} \bullet \begin{bmatrix}\text{Total}\\ \text{Annual LNG}\\ \text{Exports}\\ \text{Region } i,\\ \text{Period } t\end{bmatrix}$$

$$\begin{bmatrix}\text{Regasification}\\ \text{Operating}\\ \text{Costs,}\\ \text{Market } m\\ \text{Period } t\end{bmatrix} = \begin{bmatrix}\text{Unit}\\ \text{Regasification}\\ \text{Operating}\\ \text{Costs,}\\ \text{Region } i\end{bmatrix} \bullet \begin{bmatrix}\text{Total}\\ \text{Annual LNG}\\ \text{Imports}\\ \text{Market } m,\\ \text{Period } t\end{bmatrix}$$

Define OC_t as total operating costs in year t, $oc_{p,i}$ as unit operating costs of gas production in region i, $oc_{f,i}$ as unit operating costs of liquefaction plants in region i,[8] and $oc_{r,m}$ as unit operating costs of regasification plants in market m. The following equation defines total operating costs:

$$OC_t = \sum_i oc_{p,i}X_{i,t} + \sum_i oc_{f,i}EX_{i,t} + \sum_m oc_{r,m}D_{m,t} \qquad (16)$$

Similarly, shipping costs are determined as linear functions of exports from source i to market j. That is:

$$\begin{bmatrix}\text{Shipping}\\ \text{Costs,}\\ \text{from Region } i\\ \text{to Market } m,\\ \text{in Period } t\end{bmatrix} = \begin{bmatrix}\text{Unit}\\ \text{Shipping}\\ \text{Costs,}\\ \text{from Region } i\\ \text{to Market } m\end{bmatrix} \bullet \begin{bmatrix}\text{LNG Exports}\\ \text{from Region } i\\ \text{to Market } m,\\ \text{Period } t\\ \end{bmatrix}$$

Total shipping costs are the sum of the costs from each producing to each consuming area. SC_t is defined as total shipping cost in period t and $sc_{i,m}$ is the unit shipping cost to market m from region i. That is:

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8 We assume here that large and small plants have identical unit operating costs. The model can be run with different assumptions.

(17) $$SC_t = \sum_m \sum_i sc_{i,m} E_{i,m,t}$$

Annual capital costs are a function of the three types of investment that occur: extraction, liquefaction, and regasification. The unit costs are projected exogenously, and the investment levels are endogenous.

$$\begin{bmatrix}\text{Extraction}\\ \text{Capital}\\ \text{Costs,}\\ \text{Region } i\\ \text{Period } t\end{bmatrix} = \begin{bmatrix}\text{Unit}\\ \text{Extraction}\\ \text{Capital}\\ \text{Costs,}\\ \text{Region } i\end{bmatrix} \bullet \begin{bmatrix}\text{Increased}\\ \text{Production}\\ \text{Capacity}\\ \text{Region } i,\\ \text{Period } t\end{bmatrix}$$

$$\begin{bmatrix}\text{Liquefaction}\\ \text{Capital}\\ \text{Costs,}\\ \text{Region } i\\ \text{Period } t\end{bmatrix} = \begin{bmatrix}\text{Small Unit}\\ \text{Liquefaction}\\ \text{Capital}\\ \text{Costs,}\\ \text{Region } i\end{bmatrix} \bullet \begin{bmatrix}\text{Number of Small}\\ \text{Liquefaction}\\ \text{Plants added}\\ \text{Region } i,\\ \text{Period } t\end{bmatrix}$$

$$+ \begin{bmatrix}\text{Large Unit}\\ \text{Liquefaction}\\ \text{Capital}\\ \text{Costs,}\\ \text{Region } i\end{bmatrix} \bullet \begin{bmatrix}\text{Number of Large}\\ \text{Liquefaction}\\ \text{Plants added}\\ \text{Region } i,\\ \text{Period } t\end{bmatrix}$$

$$\begin{bmatrix}\text{Regasification}\\ \text{Capital}\\ \text{Costs,}\\ \text{Market } m\\ \text{Period } t\end{bmatrix} = \begin{bmatrix}\text{Unit}\\ \text{Regasification}\\ \text{Capital}\\ \text{Costs,}\\ \text{Region } i\end{bmatrix} \bullet \begin{bmatrix}\text{Increased}\\ \text{Regasification}\\ \text{Capacity}\\ \text{Market } m,\\ \text{Period } t\end{bmatrix}$$

Define IN_t as total investment costs in year t, $cc_{p,i}$ as unit capital costs of gas production in region i, $cl_{f,i}$ as the cost of a large liquefaction plant in region i, $cs_{f,i}$ as the cost of a small liquefaction plant in region i, and $cc_{r,m}$ as unit capital costs of regasification plants in market m.[9] The following equation defines total investment costs:

[9] To account for terminal conditions and the long life of investments, the capital costs near the end of the planning horizon are truncated.

(18) $IN_t = \sum_i cc_{p,i}\Delta K_{i,t} + \sum_i cl_{f,i}NL_{i,t} + \sum_i cs_{f,i}NS_{i,t} + \sum_m cc_{r,m}\Delta KG_{m,t}$

Objective Function

The objective function represents what the model is attempting to achieve, or how it selects among alternative programs that are feasible in the sense that all constraints are satisfied. Here, the model is asked to find the feasible program with the lowest discounted present value cost.

Define TDC as the total discounted costs of any solution, and k_t as the discount factor applicable to period t.[10] This total is calculated using the following equation:

$$(19) \qquad TDC = \sum_t k_t[OC_t + SC_t + IN_t]$$

PRICE STRUCTURE OF THE MODEL

In technical terms, the model is formulated as a mathematical programming problem in which a computer algorithm is used to find the optimal time path of the values of the endogenous variables (e.g., exports from each country, investment in new liquefaction plants, etc.). We report on the present formulation of the model. It should be understood that this modelling framework is considerably more flexible in the sense that additional constraints, projects, producing regions, policy interventions, etc. could be added. Indeed, as the model is used, it will be important to make modifications based on initial results and enhanced perceptions of the issues that need further investigation.

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10 In principle the discount rate need not be constant over time. Also, different discount factors could be applied to different flows if these differed substantially in their risk characteristics.

In addition to solving for the endogenous variables described above (technically called primal variables), the programming algorithm also calculates a set of implicit or "shadow" prices (dual variables). Each constraint or equation has a shadow price associated with it that represents the marginal cost, in terms of whatever objective function is being used, of that constraint. These are calculated based on the model's internal cost structure and are used in determining the optimality of any intermediate solution. In effect, the model knows that an optimal solution is found when: (a) all variables that are positive in the solution have the property that the marginal benefits (MB) from increasing that variable by a little bit exactly equal the marginal costs (MC) of doing so, and (b) there are no variables for which marginal benefits exceed marginal costs.[11] These costs and benefits are calculated using the shadow price structure. The shadow prices also have the useful property that they can be used in evaluating specific projects outside the model itself, so long as those projects are not too large.

By way of illustrating how the shadow price structure works, here we examine the interrelations among a few key prices and variables. Consider first the costs and benefits of exporting a small additional amount from region i to market m, that is, variable $E_{i,m,t}$. This variable appears in equations (3), (4), and (17).[12] The shadow prices associated with each of these equations or constraints can be used to perform a cost-benefit test on whether this variable should be increased or decreased. The cost of the

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[11] These are known as the complementary slackness conditions and hold for all constrained optimizing problems.

[12] Equation (5) is merely an accounting identity and does not have a shadow price here so it is ignored.

LNG is the shadow price of equation (4). To this must be added transportation costs, which are $sc_{i,m}$ times the shadow price of the shipping cost equation (17). This must be compared with the implicit value of gas exports to market m, which is the shadow price of equation (3). If the total cost of increasing $E_{i,m,t}$, calculated this way, is less than the marginal cost elsewhere, then the model will choose to increase these exports and reduce them elsewhere.

The next step is to see what determines the marginal cost of LNG in region i. Here we examine the equations where $EX_{i,t}$ appears. Natural gas is purchased implicitly at the shadow price of equation (1). To this are added the operating costs and capital rental charges of liquefaction, from equations (16) and (11) respectively.[13]

The cost of gas delivered to the liquefaction plant ($X_{i,t}$) can also be derived. Here equations (1), (7), (8), (9), and (16) are used. Marginal operating costs of extractions are $oc_{p,i}$ times the shadow price of equation (16). Annual capital rental charges for equipment are the shadow prices associated with equation (9). Together these form total out-of-pocket marginal production costs. In addition to these, there are "user" costs related to resource depletion. These appear as the shadow prices of constraints (7) and (8). The shadow price of (8) is the value of being able to produce one more unit from a low-cost reserve in which production is constrained by an upper limit related to remaining reserves. The shadow price of (7) represents the cost of limiting future production from the

---

[13] Because we allow for economies of scale in liquefaction investment, there may be excess capacity in some periods, implying no capital rental charge. This is consistent with the "sunk cost" rule. As with any economies of scale model, frequently not all capital charges can be explicitly allocated. Technically, there are shadow prices associated with the constraints that liquefaction plants are added only in integer units.

reserve because depletion now decreases the upper bounds on possible production in later years.[14]

If any of these constraints are not binding, the shadow prices of those constraints of course are zero. In general, low-cost reserves will have relatively high user costs to the extent that production and exports from them are limited. At the other extreme, truly marginal producing regions will have zero user cost.[15]

In a similar way, the full price structure of the model can be readily analyzed. Using the shadow price structure, it is possible to evaluate the economics of alternative investments, cost structures, or export possibilities not included in the model itself, by using the model's shadow prices as inputs in a discounted cost-benefit calculation.

RESULTS

In this section, we illustrate how the model can be used to analyze the factors determining least-cost supply patterns and marginal costs of delivering LNG. In particular, we review six cases designed to highlight the effects of changes in demand growth, pre-existing contracts, and diversification strategies.

The simulations utilize data developed as part of the supply and demand parts of this study. Table 1 summarizes the cost data for each of the potential producing regions. Operating and shipping costs are annual charges per Mcf, while the capital costs for gas extraction and

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[14] In the marginal cost-benefit test, this shadow price is multiplied by the number of years in a period.

[15] The output of the model also includes implicit costs of production for regions which are not producing because their marginal costs exceed those of other regions. This allows the user to examine questions of competitiveness.

liquefaction represent to total cost of the equipment required to produce at the rate of one Mcf per year. These data do not always correlate exactly with the analysis in the supply chapter for several reasons, including differences in format. For instance, pipeline costs are included as part of extraction costs rather than as a separate item. Where liquids are produced as a byproduct of an LNG project, the expected profits are subtracted from liquefaction or extraction costs, and are not included in the numbers shown in Table 1.

Where actual data exist on projects under consideration or in operation in particular regions, they have been used. But much of this data is confidential and cannot be cited extensively. In other cases, published data have been used, although sometimes in modified form. Where neither published nor unpublished data for a specific region were available, costs were estimated subjectively on the basis of similarities with similar projects elsewhere.[16]

A final word of caution on the data: There is great uncertainty about costs for projects in newer areas that have not been developed. Not only can capital costs diverge from predicted values, but the data available on the amount of liquids in some fields or the development costs for fields that are not fully delineated (Thailand being a perfect example) are very poor.

Tables 2-5 illustrate how the model can be used to investigate the sensitivity of supply patterns and the marginal cost of LNG to faster or slower rates of demand growth. Case A, which we use as a reference case, corresponds to the demand projections made by MITI in 1983. Here, LNG

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[16] For details, refer to discussions in the supply chapter.

demand rises from 1482 Bcf in 1986 to 2000 Bcf in 1995 and 2483 Bcf in 2010.[17] The total discounted value of the investment, operating, and transportation costs associated with meeting these levels of demand most efficiently comes to $13.7 billion.

In this case, increased LNG demand is met first by shipments from Malaysia, which is the lowest cost marginal supplier.[18] After 1995, Indonesian production and exports begin to expand as Malaysian output reaches limits imposed by availability of reserves. It is only in 2010 that additional LNG from outside the region (from the Gulf and Canada) become economic to exploit. The last box in Table 2 presents the time path of the shadow price of LNG delivered to Japan and regasified. This price includes shipping costs, operating costs of extractions and liquefaction, annualized capital charges, and user costs.[19] These latter represent the costs of having to move from lower- to higher-cost reserves. We see that for Case A the marginal cost of gas to Japan starts in 1986 at $2.35 per Mcf and increases quite slowly until the late 1990s. Between 2000 and 2010, the marginal cost would increase by 50 percent as LNG from more expensive locations such as Canada come on stream.

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[17] In addition, all cases specify LNG demand in Korea and Taiwan increasing to 250 Bcf by 1989 and then remaining at that level.

[18] Extraction and liquefaction costs are assumed identical in Brunei, Indonesia, and Malaysia. However, Brunei does not have the reserves to expand current production, and Malaysia has a slight shipping cost advantage over Indonesia.

[19] This cost is not necessarily the same as the price that Japanese consumers actually pay since it does not include any taxes, subsidies, or pure profits. Instead, it represents a measure of the true opportunity cost of the gas delivered to Japan.

Cases B, C, and D represent higher and lower levels of LNG demand growth in Japan. The effects of slower demand growth, as forecast by the Petroleum Association of Japan in 1985, are shown in Table 3. In this case, demand grows so slowly that all increments through 2010 can be met from the lowest-cost marginal source, Malaysia. However, from 1995 on, the shadow price of gas begins to rise because the model sees beyond 2010 when additional increments can no longer come from Malaysia.

If demand were to grow more rapidly, higher-cost sources would be needed sooner, and marginal costs would rise correspondingly. Demand levels for Case C are assumed to be 20 percent higher than in Case B. Although Malaysia remains the marginal supplier initially, additional Indonesian production is required in 1992. After 1995, the Gulf region is the marginal supplier, with Canada beginning to export in 2010. Case D represents a "super-optimistic" scenario, with LNG demand increasing by 7 percent annually until 2000 and afterward by 3 percent a year. This has the effects of moving up in time the increased production from Indonesia, the Gulf, and Canada. Australian production is required by 2010.

In Cases A-D, the model is allowed to find the least-cost pattern for meeting the required demand without any constraints on how much or how little should be delivered from any one region. Cases E and F are meant to illustrate how the model can be used to estimate the costs of any deviations from the unconstrained outcome. Using the same levels of LNG demand as in Case A, Case E simulates the impact of forcing the model to honor all existing contracts, which includes delivery of 300 Bcf per year from Australia beginning in 1989. We know this has to be more costly, since these deliveries were not chosen in Case A. As shown in Table 6, this results in a $1000 million increase in total discounted costs because higher-cost Australian LNG is used at the expense of exports from first Malaysia and later Indonesia. Note, however, that the rate of increase in the marginal cost of gas is slower than in Case A because lower-cost reserves are available for use at a later date.

The potential costs of a supplier diversification strategy are summarized in Table 7. In this case, we specify that no country can expand LNG deliveries to account for more than 25 percent of the Japanese market. This has the effect of slowing the rate of increase of exports from Malaysia in the near term and from Indonesia later on. The exports lost by these countries is made up for by deliveries from first the Gulf and later Canada. The additional costs of this strategy are quite modest, in the range of $700 million, because the cost differences between the lowest-cost areas (Malaysia) and others is not very large.

In closing, we again caution that these results are meant to be illustrative of the model's workings. They are highly sensitive to the specific cost data for each region and to the exogenous demand projections. These data indicate that marginal costs do not rise very sharply unless demand grows extremely rapidly. Different results would result if the data contained in Table 1 were revised substantially with wider differences across regions.

Table 1

Pacific Region LNG Trade Model: Cost Data

	Initial		Gas Extraction		Liquefaction			Shipping
	Reserves (TCF)	Capacity (BCF)	Capital ($/MCF)	Operating ($/MCF)	Operating ($/Ton)	Capital ($/Ton)		to Japan ($/MCF)
INDONESIA	40.0	700	1.75	.08	17.5	400	300	0.80
BRUNEI	7.3	260	1.75	.08	17.5	400	300	0.63
MALAYSIA	50.0	300	1.75	.08	17.5	400	300	0.75
THAILAND	6.0		4.75	.20	25.0	500	375	0.75
ALASKA	2.0	50	6.00	.30	17.5	800	350	0.83
CANADA	3.6		4.75	.20	27.5	600	400	0.83
AUSTRALIA	15.0		3.25	.15	22.5	600	450	0.83
GULF	150.0	103	1.76	.10	20.0	465	350	1.65

NOTE1: Capital cost refers to upfront investment charges per unit of annual productive capacity installed.

NOTE2: Operational and shipping costs refer to annual charges incurred per unit of output.

NOTE3: For Liquefaction Costs, the first amount is for plants with 3MT capacity; the second term is for plants with 6MT capacity.

Table 2

Pacific Region LNG Trade Model: Case A

****
*** SCENARIO ASSUMPTION ***
*** MITI83 DEMAND ***
****

Discounted Costs of Scenario = $13.7
(Billions of $)

Total LNG Exports
(BCF per Year)

	1986	1989	1992	1995	2000	2005	2010
INDONESIA	700	700	700	700	822	1029	1047
BRUNEI	260	260	260	248	186	140	105
MALAYSIA	469	869	1030	1149	1238	1238	1238
ALASKA	50	50	50	50	50	50	40
CANADA							110
GULF	103	103	103	103	103	103	193
Total Shipments	1582	1982	2143	2250	2399	2560	2733
- JAPAN	1482	1732	1893	2000	2149	2310	2483
- KOREA & TAIWAN	100	250	250	250	250	250	250

Shadow Price of Regassified LNG Delivered in Japan
($ per MCF)

1986	1989	1992	1995	2000	2005	2010
2.35	2.38	2.42	2.92	3.01	3.13	4.18

Table 3

Pacific Region LNG Trade Model: Case B

```
*********************************************
***        SCENARIO ASSUMPTION            ***
***           PAJ85 DEMAND                ***
*********************************************
```

Discounted Costs of Scenario = $10.8
(Billions of $)

Total LNG Exports
(BCF per Year)

	1986	1989	1992	1995	2000	2005	2010
INDONESIA	700	700	700	700	700	700	700
BRUNEI	260	260	260	248	186	140	105
MALAYSIA	409	702	797	879	968	1041	1114
ALASKA	50	50	50	50	50	50	40
GULF	103	103	103	103	103	103	103
Total Shipments	1522	1815	1910	1980	2007	2034	2062
- JAPAN	1422	1565	1660	1730	1757	1784	1812
- KOREA & TAIWAN	100	250	250	250	250	250	250

Shadow Price of Regassified LNG Delivered in Japan
($ per MCF)

	1986	1989	1992	1995	2000	2005	2010
	2.33	2.35	2.37	2.83	2.85	2.87	3.23

Table 4

Pacific Region LNG Trade Model: Case C

```
***********************************************
***          SCENARIO ASSUMPTION            ***
***      OPTIMISTIC DEMAND: 1.2 * PAJ       ***
***********************************************
```

Discounted Costs of Scenario = $17.6
(Billions of $)

Total LNG Exports
(BCF per Year)

	1986	1989	1992	1995	2000	2005	2010
INDONESIA	700	700	813	953	953	953	953
BRUNEI	260	260	260	248	186	140	105
MALAYSIA	561	1154	1296	1296	1296	1296	1077
ALASKA	50	50	50	50	50	50	40
CANADA							131
GULF	103	103	103	103	344	583	924
Total Shipments	1674	2267	2522	2650	2829	3022	3230
- JAPAN	1574	2017	2272	2400	2579	2772	2980
- KOREA & TAIWAN	100	250	250	250	250	250	250

Shadow Price of Regassified LNG Delivered in Japan
($ per MCF)

1986	1989	1992	1995	2000	2005	2010
2.40	2.43	2.50	3.09	3.56	3.70	5.04

Table 5

Pacific Region LNG Trade Model: Case D

```
*************************************************
***          SCENARIO ASSUMPTION              ***
***        SUPER OPTIMISTIC DEMAND:           ***
***          1986-1999: 7% A YEAR             ***
***          2000-2010: 3% A YEAR             ***
*************************************************
```

Discounted Costs of Scenario = $23.7
(Billions of $)

Total LNG Exports
(BCF per Year)

	1986	1989	1992	1995	2000	2005	2010
INDONESIA	700	700	754	943	1153	1153	865
BRUNEI	260	260	260	248	186	140	105
MALAYSIA	515	1009	1377	1377	1377	1377	1032
ALASKA	50	50	50	50	50	50	40
CANADA					83	83	111
AUSTRALIA							477
GULF	103	103	103	443	1343	2017	2917
Total Shipments	1628	2122	2544	3061	4192	4820	5547
- JAPAN	1520	1872	2294	2811	3942	4570	5297
- KOREA & TAIWAN	100	250	250	250	250	250	250

Shadow Price of Regassified LNG Delivered in Japan
($ PER MCF)

1986	1989	1992	1995	2000	2005	2010
2.43	2.47	2.55	3.18	4.05	3.29	5.33

Table 6

Pacific Region LNG Trade Model: Case E

```
**************************************************
***           SCENARIO ASSUMPTION              ***
***              MITI83 DEMAND                 ***
***            EXISTING CONTRACTS              ***
**************************************************
```

Discounted Costs of Scenario = $14.7
(Billions of $)

Total LNG Exports
(BCF per Year)

	1986	1989	1992	1995	2000	2005	2010
INDONESIA	700	700	700	700	700	709	926
BRUNEI	260	260	260	248	186	140	105
MALAYSIA	469	569	730	849	1060	1259	1259
ALASKA	50	50	50	50	50	50	40
AUSTRALIA		300	300	300	300	300	300
GULF	103	103	103	103	103	103	103
Total Shipments	1582	1982	2143	2250	2399	2561	2733
- JAPAN	1482	1732	1893	2000	2149	2311	2483
- KOREA & TAIWAN	100	250	250	250	250	250	250

Shadow Price of Regassified LNG Delivered in Japan
($ per MCF)

1986	1989	1992	1995	2000	2005	2010
2.34	2.20	2.12	2.69	2.40	2.81	3.44

Table 7

Pacific Region LNG Trade Model: Case F

```
*************************************************
***          SCENARIO ASSUMPTION              ***
***             MITI83 DEMAND                 ***
***        SUPPLIER DIVERSIFICATION           ***
*************************************************
```

Discounted Costs of Scenario = $14.4
(Billions of $)

Total LNG Exports
(BCF per Year)

	1986	1989	1992	1995	2000	2005	2010
INDONESIA	700	850	850	850	850	850	895
BRUNEI	260	260	260	248	186	140	105
MALAYSIA	469	604	668	700	745	793	845
ALASKA	50	50	50	50	50	50	40
CANADA						34	155
GULF	103	218	315	402	569	693	693
Total Shipments	1582	1982	2143	2250	2400	2560	2733
- JAPAN	1482	1732	1893	2000	2150	2310	2483
- KOREA & TAIWAN	100	250	250	250	250	250	250

Shadow Price of Regassified LNG Delivered in Japan
($ per MCF)

1986	1989	1992	1995	2000	2005	2010
2.36	3.13	3.18	3.78	3.84	3.85	4.23

LONG-TERM LNG CONTRACTING UNDER ALTERNATIVE PRICE SCENARIOS

by

Guy M. Barudin and John E. Parsons

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John E. Parsons

INTRODUCTION

Our objective in this paper is to determine how important typical take-or-pay contracts are likely to be to various producers in the East Asian market under the current and impending market conditions. Are there producers who can prudently look to relaxing the size of take or the degree of stringency in take requirements as a means for expanding their position in the Japanese market? What are the likely costs to a producer in a high-cost project if it seeks to relax the standard portion of the capacity committed in take-or-pay contracts before the project is finally approved? Our results indicate that the opportunities available are strikingly different for low-and-high cost producers in the East Asian markets. High-cost producers face the usual pressure for strong take-or-pay contracts. There are, however, several producers whose costs are low enough that they face the opportunity to enjoy security without the high degree of take-or-pay requirements that have been typical in LNG contracts.

The next section provides a brief overview in terms of cash flow of three stylized LNG projects in the East Asian market. We will use this overview and the present-value calculations as a benchmark against which compare the importance of take-or-pay contracting for different projects under different price scenarios.[1] The third section discusses the primary motivation for long-term take-or-pay contracts and illustrates the importance of take-or-pay contracts to securing the producer's profits. In related work we have developed a model for estimating the value of these contracts. In this paper this model is applied to the sample LNG export project and show that under current conditions these contracts may not be as valuable as they have been in the past, or alternatively that greater flexibility is warranted.

LNG PROJECTS: A DISCOUNTED CASH FLOW ANALYSIS

This section compares the present value and cash flow structure of three stylized LNG projects--a low capital cost project, a high capital cost project, and a project involving a marginal addition to existing capacity. The low capital cost project would be representative, for example, of some of the fields in Indonesia; the high capital cost project would be representative of the Australian or Canadian operations; and the marginal capacity additions would be more general, although again an addition to current Indonesian capacity might be the most immediate example.

The low-cost project involves the development of a 6 million ton per year gas field and LNG facility in Indonesia intended to supply the Japanese market. Table 1 sets out the specific quantities associated with an LNG facility in that region under some general assumptions. Capital expenditures constitute construction of 300 Bcf/year gas production capacity, 6 million ton/year liquefaction and regasification plants, and

[1] In this paper we sometimes refer to take-or-pay contracts as forward contracts. The prices agreed to in the contracts we label forward prices.

shipping capacity necessary to transport LNG to the Japanese market. Total capital expenditures are $2.5 billion and are incurred over a 5-year period in the pattern indicated in Table 1. The field has a 20-year projected life. Operations begin in 1989 and rise to full capacity in 1993. Operating costs are assumed constant at $0.55 per Mcf. If we assume that the prevailing market price of gas will be $3.85/Mcf, Table 1 shows that the project has a Net Present Value of $2.59 billion. The present value of the capital expenditures is $1.86 billion; the net present value of total expenditures, $2.6 billion. The per unit allocated capital cost is $1.38/Mcf. The per unit total cost is therefore $1.93/Mcf.

Table 1

NPV FOR A LOW-COST PRODUCER

Capital Expenditure: $2.5 Billion
Peak Output: 300 Bcf/year
Operating cost: $0.55/Mcf
Market Price: $3.85/Mcf

Year	Capital Expenditure ($ mil)	Quant. Sold (mil Mcf)	Revs. ($ mil)	Oper. Cost ($ mil)	Net Operating Cash Flow ($ mil)
1985	75				- 75
1986	450				-450
1987	880				-880
1988	800				-800
1989	300	180	690	99	290
1990	0	210	810	120	690
1991	0	240	920	132	790
1992	0	270	1000	149	890
1993	0	300	1200	165	990
.	.	.	.	.	.
.	.	.	.	.	.
.	.	.	.	.	.
2005	0	300	1200	165	990

NPV @ 12% = $2.59 Billion

Table 2 presents comparable information for a field with the characteristics of high capital cost development in Australia. This field has production capacity of 7 million tons of LNG per year. Total fixed cost expenditures of $5.82 billion over 10 years result in output that starts in 1989 and rises slowly to capacity by 1993. Mean operating costs are $.87/Mcf.

Table 2

NPV FOR A HIGH-COST PRODUCER

Capital Expenditure: $5.82 Billion
Peak Output: 365 Bcf/year
Operating Costs: $0.87/Mcf
Market Price: $3.85/Mcf

Year	Capital Expenditure ($ mil)	Quant. Sold (mil Mcf)	Revs. ($ mil)	Oper. Cost ($ mil)	Net Operating Cash Flow ($ mil)
pre 1985	430				-430
1986	580				-580
1987	990				-990
1988	840				-840
1989	580	150	560	127	-150
1990	760	180	700	159	-210
1991	910	220	840	191	-260
1992	290	330	1300	286	690
1993	290	370	1400	318	800
1994	160	370	1400	318	930
1995	0	370	1400	318	1100
.	.	.	.	.	.
.	.	.	.	.	.
.	.	.	.	.	.
2005	0	370	1400	318	1100

NPV @ 12% $1.05 Billion

At a market price of $3.85, Australia's NPV, although positive at $1.05 billion, is 60 percent lower than Indonesia's $2.59 billion. The present value of the capital expenditures is $3.47 billion; the present value of total expenditures is $4.79 billion. The per unit allocated capital cost is $2.29/Mcf. Total per unit costs are therefore $3.16/Mcf.

Finally we present the data for a marginal addition of capacity to an already existing facility. Reasonable estimates for a typical low-cost addition project call for capital expenditures of $1.39 billion for 4 million tons per year, or 200 Bcf/year, added capacity. The market price is again assumed to be $3.85/Mcf. Operating costs are the same as existing

Table 3

NPV FOR A MARGINAL CAPACITY ADDDITION

Capital Expenditure: $1.4 Billion
Peak Output: 200 Bcf/year
Operating cost: $0.55/Mcf
Market Price: $3.85/Mcf

Year	Capital Expenditure ($ mil)	Quant. Sold (mil Mcf)	Revs. ($ mil)	Oper. Cost ($ mil)	Net Operating Cash Flow ($ mil)
1985	42				- 42
1986	250				-250
1987	487				-487
1988	445				-445
1989	167	120	460	66	229
1990	0	140	540	77	462
1991	0	160	620	88	528
1992	0	180	690	99	594
1993	0	200	770	110	660
.	.	.	.	.	.
.	.	.	.	.	.
.	.	.	.	.	.
2005	0	300	770	110	660

NPV @ 12% = $ 1.93 Billion

fields, \$0.55/Mcf. This project has a NPV of \$1.34 billion. The per unit allocated capital costs are \$1.15/Mcf and the total costs per unit are \$1.70/Mcf.

We have also calculated the Net Present Values for these three fields under alternative assumptions about price, and we have summarized the relevant comparative information in Table 4 below.

Table 4

SUMMARY OF COST/NPV DATA

	Low Capital Cost	High Capital Cost	Marginal Project
Capital Costs:			
\$ per Mcf	1.38	2.29	1.15
Present Value (\$ Bill)	1.86	3.47	1.03
Operating Costs:			
\$ per Mcf	0.55	0.87	0.55
Present Value (\$ Bill)	0.74	1.32	0.50
Net Present Value (\$ Bill)			
Price = \$3.85/Mcf	2.59	1.05	1.93
Price = \$3.35/Mcf	1.92	0.29	1.48
Price = \$4.35/Mcf	3.27	1.81	2.38

OPPORTUNISM: THE ROLE OF LONG-TERM CONTRACTS

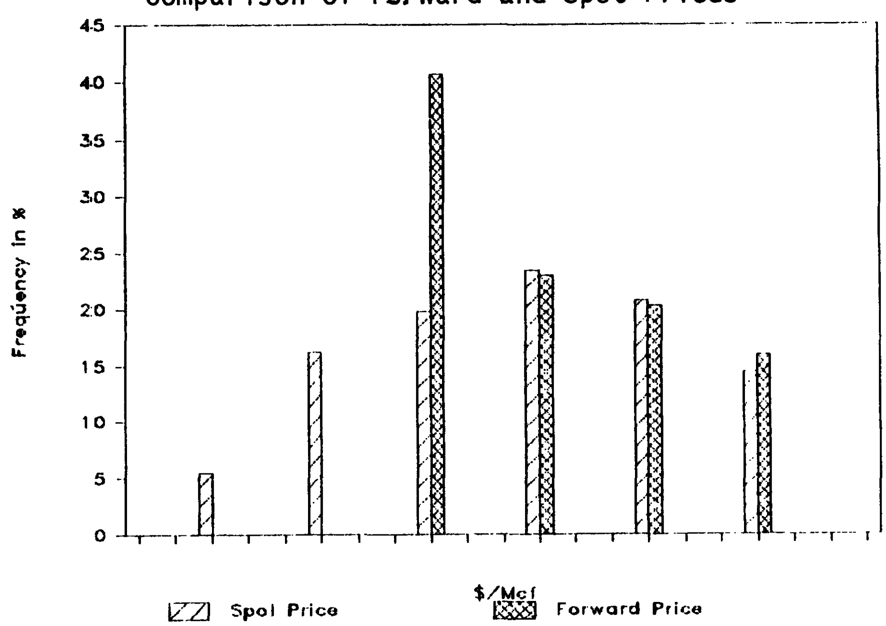
Long-term and strict take-or-pay contracts are a typical if bothersome feature of LNG markets. These long-term contracts permit the producer to lock in a rate of return or to avoid some of the risk associated with marketing the natural gas on the spot markets over the years after installation of capacity. This section will discuss our method of analyzing the value of take-or-pay contracts to the producers in each of the three fields that we are considering and under various scenarios about market conditions. We begin with a short review of the motivation behind these contracts.

A potential producer of natural gas who is planning to install capacity for export of LNG must accept an unusually large capital expenditure for facilities that will be largely dedicated to a particular buyer or at best to a market of very few buyers. This feature of the market for LNG makes the marketing of LNG significantly different from that of many other commodities. In many markets the producer invests in facilities and subsequently sells its output at the best prices it can then negotiate. In the LNG market the producer finds the buyers before it installs the facilities. This is because the producer's capacity installation decision will affect the prices at which it can sell its product in future years, and in general it will lower the prices that the producer will receive. The actual prices eventually received by the producer without the take-or-pay contracts may sometimes be above and sometimes below those agreed to by the producer in the take-or-pay contracts. On average, however, they are below.

The reason for this is that the producer with installed and unused capacity is in a significantly worse position for negotiating with potential customers than is the producer bargaining a price prior to its installation of capacity. For example, imagine a potential producer considering the installation of large-scale capacity for liquefaction and currently bargaining with a potential customer over the delivery price. If the current offer made by the customer is \$3.00/Mcf, then the producer can walk away from the table and give up the \$3.00/Mcf, but also give up the \$2.64/Mcf capital and operating cost: a net loss of only \$0.36/Mcf. Of course, whether or not to reject this offer and what counter offer to make depends critically upon the alternative uses for the gas, the other offers which the producer imagines it can negotiate, etc. However, clearly the per Mcf margin also factors into this decision. A producer that has already installed capacity and that faces the same offer of \$3.00/Mcf from the customer faces a much more difficult decision. The \$2.14/Mcf capital charge has already been incurred, and cannot be avoided if the producer rejects the customer's price offer. Instead what this producer sacrifices if he rejects the offer is the price, \$3.00/Mcf minus the operating cost, \$0.50/Mcf, or \$2.50. This producer is going to be more reluctant to reject the offer, that is, his bargaining position is weaker. The customer is aware of this, and is more likely to make and stick to lower offers than he would if he were negotiating against the producer seeking a take-or-pay purchase contract.

Figure 1

Comparison of Forward and Spot Prices



The role of take-or-pay contracts for securing better pricing terms to the producer can be illustrated in the figure below. The figure depicts the probable distribution of contract prices that a typical producer in the EastAsian Market could expect to receive as a result of negotiations for take-or-pay contracts, and it contrasts this distribution with the distribution that the producer could expect to receive if he built his capacity and then sought to arrange sales on a more short-term basis.

Obviously the lower anticipated prices will impact significantly upon the present value of the project or on the company's ability to cover the costs of construction and operation of the production and liquifaction facilities. The primary objective of this paper is to present our analysis of how significant this factor is for different LNG projects in the East Asian market.

The importance of this bargaining power depends upon many factors. We have constructed a computer model that simulates the bargaining process that would arise in negotiating contracts prior to the installation of capacity and of the likely price that the seller would receive in the event that he first installed capacity and then attempted to market his gas. The theoretical basis for this model is analyzed and explained in Parsons (1986) and is included as an Appendix to this paper. A simple explanation of the model and its use is given in Barudin and Parsons (1986). The following section discusses the results of our use of this model to analyze the value of take-or-pay contracts for the three East Asian projects mentioned above.

CONTRACTS AND PROJECTS

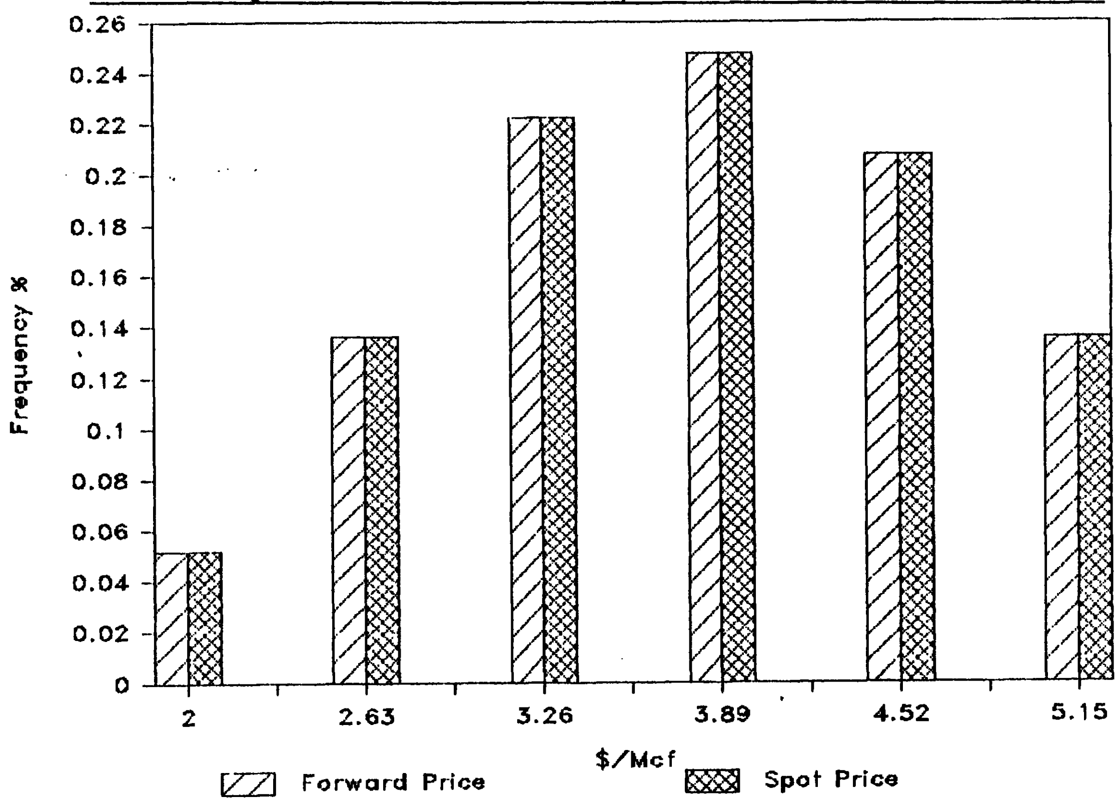
One particular factor that determines the value of the take-or-pay contracts appears to be of particular importance for the Japanese LNG market and differentiates it from other gas markets: the size of the expected profit margin. When the profit margin inclusive of capital charges is very small, then the producer who has not installed capacity will be relatively willing to walk away from the table while the producer with already installed capacity may not be willing to walk away. If the margin is large, then neither producer may need to walk away from the table: the additional bargaining power obtained by the producer without previously installed capacity is not of much significance relative to the bargaining power that the producer of both types already holds. Again, it should be recalled that fiscal regimes are not included as cost elements in this analysis. To the extent that taxes and royalties raise the per unit costs closer to the expected price, the cost bargaining power will be larger.

Table 4 above therefore summarizes some of the critical information necessary for determining the importance of take-or-pay contracts for the different projects. As one can readily see from Table 4, the profit margin on the LNG export project for Indonesia, the low capital cost producer, is large relative to the size of capital cost. The total operating costs are $0.55/Mcf. The capital costs are $1.38/Mcf. The expected price is $3.85, implying a total margin of $1.92/Mcf. The average price will have to drop by 50 percent before the producer without take-or-pay contracts will feel any sacrifice relative to the producer using take-or-pay contracts. We have done some simulation of the take-or-pay contracting process and of sales without take-or-pay contracts for the project presented in Table 1. The expected distribution of prices with and without take-or-pay contracts is exhibited in Figure 2.

The distributions of prices with and without take-or-pay contracts are almost identical. The results for this field are only slightly sensitive to the specifications of the model: for some very extreme scenarios in which the price might drop as low as \$1.75 and \$1.50/Mcf is the price distribution for the producer without take-or-pay contracts slightly less

Figure 2

Take-or-Pay Contract Prices vs. Spot Prices: Low-Cost Projects



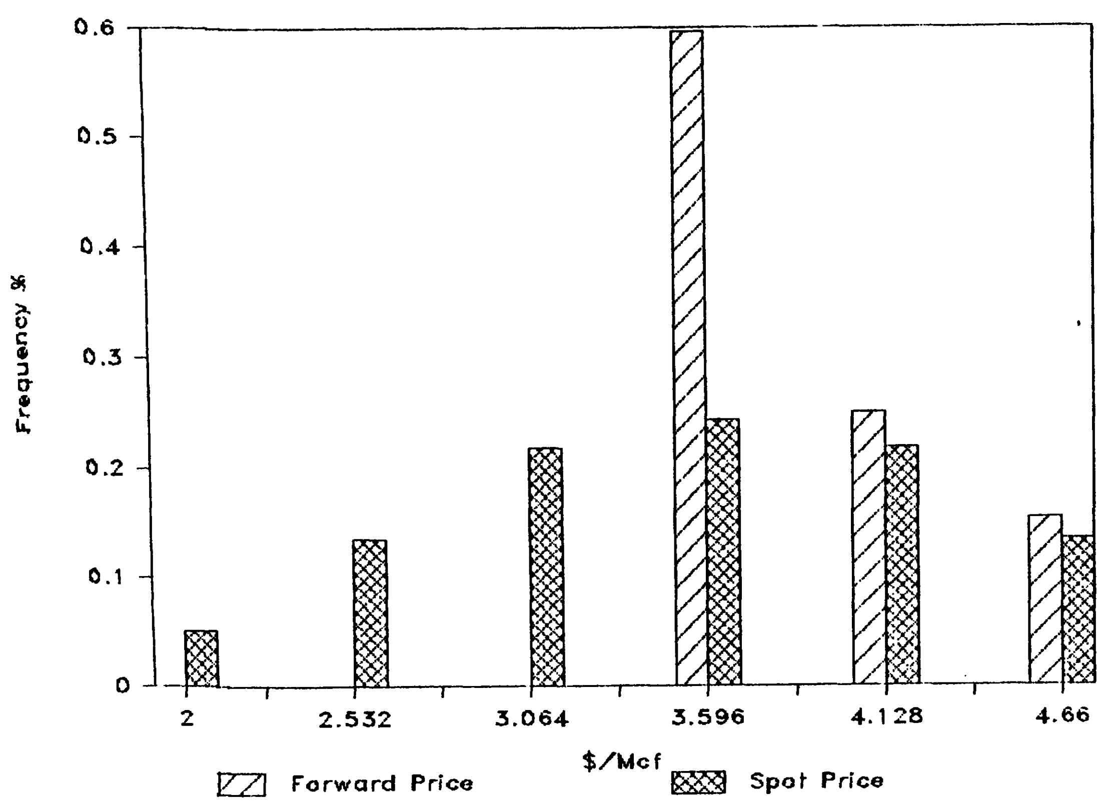
than the distribution for the producer with take-or-pay contracts. For our base-case analysis the abandonment of strong take-or-pay provisions leaves the expected price and the net present value of the project unchanged: In the extreme case the expected price without take-or-pay contracts drops to \$3.83/Mcf, and the net present value of the Indonesian project falls by less than 1 percent or \$25 million.

This is an extremely small figure with which to justify the decision to require large and rigid take-or-pay contracts, and this is evidence that traditional reluctance to develop projects using more flexible forms or even less secure forms is causing potentially valuable projects to be sacrificed. However, this result is directly contingent upon the current values used for costs and for expected prices. If these values are significantly revised, then this conclusion will be similarly reevaluated.

These results should be contrasted with those for our high capital cost project, the Australian project. In this case the total per unit costs without taxes or royalties of $3.16 approaches the expected price of $3.85. One can see from Figure 3 below that the pattern of prices from

Figure 3

Take-or-Pay Contract Prices vs. Spot Prices: High-Cost Projects



spot sales is going to be significantly different from that for forward contracts. On average the price will be 6.5 percent less. The results for net present value are tremendous: an approximately 36 percent decline, or a loss of $378 million, if stringent take-or-pay contracts are not completed as a pre-condition to the installation of capacity.

For our marginal addition to capacity the results are comparable to the results for the Indonesia project, as one would expect. The full set of results for all three projects is summarized in Table 5 below.

Table 5

SCENARIO 1, p=3.85/Mcf

	Low Capital Cost	High Capital Cost	Marginal Project
Expected Contract Price $/Mcf			
Forward Sales	3.85	3.85	3.85
Spot Sales (3.83)	3.85	3.60	3.85
Net Present Value ($ Bill)			
Forward Sales	2.59	1.05	1.93
Spot Sales (2.57)	2.59	0.67	1.93
Difference (0.02)	0	0.38	0
% Loss (1)	0	36	0

Note: We have included in parentheses results for the low-cost project under more extreme assumptions regarding the lower bound for price.

These results are very sensitive to the anticipated price for natural gas: The importance of take-or-pay contracts is determined by the relationship between the marginal costs of a project and the expected price. If the expected price is much lower, then conceivably the contracts are more important for even the low-cost projects than our information in Table 5 would indicate. In Tables 6 and 7 we present similar results for the cases which the expected price for LNG is $3.35/Mcf and $4.35. It is important to note that even at an expected price of $3.35/Mcf, the take-or-pay contracts are relatively unimportant for the low-cost producer, and certainly for the marginal capacity addition. At prices further below $3.35 we would expect this to change. For the high-cost producer, a drop in the expected price from $3.85 to $3.35 has dramatic influence upon the importance of take-or-pay contracts: They make or break the project and secure to the producer the full net present value. Without strong take-or-pay contracts, a high-cost producer cannot contemplate construction of significant capacity at prices below the $3.85 range. Table 7 shows the results for a higher expected price. In this case the low-cost and the marginal producer's can assuredly relax the take requirements they impose before agreeing to install capacity. The high-cost producer is more secure, but take requirements are still much more important to the high-cost producer than they were to the low-cost producer at yet lower expected prices.

Table 6

SCENARIO 2, p=$3.35/Mcf

	Low Capital Cost	High Capital Cost	Marginal Project
Expected Contract Price $/Mcf			
Forward Sales	3.35	3.35	3.35
Spot Sales	3.35	3.16	3.35
Net Present Value ($ Bill)			
Forward Sales	2.59	1.05	1.93
Spot Sales	1.92	0.29	1.48
Difference	3.27	1.81	2.38
% Loss	0	100	0

Table 7

SCENARIO 3, p=$4.35/Mcf

	Low Capital Cost	High Capital Cost	Marginal Project
Expected Contract Price $/Mcf			
Forward Sales	4.35	4.35	4.35
Spot Sales			
Net Present Value ($ Bill)			
Forward Sales	2.59	1.05	1.93
Spot Sales	1.92	0.29	1.48
Difference	3.27	1.81	2.38
% Loss	0	12	0

Bibliography

Barudin, Guy, and John Parsons, "A Simulation Model of Forward Contracting and Spot Sales for Large Investment Projects," M.I.T. Energy Lab Working Paper, January 1986.

Parsons, John E., "Valuing Forward Purchase Contracts Using Auction Models with an Application to Natural Gas Take-or-Pay Contracts," M.I.T. Energy Laboratory Working Paper, January 1986.

Appendix A

A SIMULATION MODEL OF FORWARD CONTRACTING AND SPOT SALES FOR LARGE INVESTMENT PROJECTS

by

Guy Barudin

and

John E. Parsons

INTRODUCTION

Capital investment decisions involve complex forecasts of market conditions far into the future and often include difficult negotiations on contracts to purchase or supply large quantities of goods or services over long time horizons. A typical decision maker must balance the benefits of locking in a profit by negotiating a fixed supply contract against the price discounts required in a long-term contract and the possibility that future prices may be better than those which can be negotiated in a long-term contract. The buyer worries about the cost of taking on a long-term rigid obligation and compares it with the possible benefits in terms of price and in terms of a guaranteed source of supply.

CONTRACT is an easy-to-use personal computer program for decision makers and researchers trying to assess the value or cost of locking in a price through a long-term contract. It creates a framework for analysis of capital investment and financing decisions by allowing the simulation of the process of negotiation and its outcomes. Specifically, **CONTRACT**

measures the annualized profit advantage of successfully contracting with customers prior to investing in capacity, an arrangement known as forward contracting.

For example, consider the decision whether or not to develop a natural gas field. Suppose that the developer has identified three or four prospective buyers for the gas. The potential producer is not certain of the price that it could successfully negotiate, but must make some estimate of that price. The producer can determine that each of the potential buyers values the gas at somewhere between $2.90 and $4.00 per thousand cubic feet (Mcf). Productive capacity and life of the field have been estimated. Development costs are also known. **CONTRACT** will show the expected profitablity of developing the field under forward contracting and will compare that with the profits which the producer should anticipate making if he were to develop the field without first signing supply contracts. **CONTRACT** also allows repeated simulation of the inherently nonrepetitive capital investment decision under various market conditions, such as the number of buyers, buyer valuations, cost levels, et cetera.

TERMINOLOGY AND STRUCTURE

CONTRACT is most appropriate for modelling investment projects that involve a relatively large initial investment in capital equipment that will be irrevocably dedicated to a particular use or dedicated to a small set of users. For projects fitting this description, the price that the producer can negotiate through long-term forward contracts may be significantly higher than the price that the producer should anticipate negotiating if it proceeds to install its capacity in the absence of signing such contracts. **CONTRACT** allows the decision maker to estimate this difference.[1]

Projects modelled with **CONTRACT** are analyzed in terms of the following elements:

- **THE CHARGE-UNIT:** Prices and marginal operating costs associated with producing the output are measured in some specific, consistent, and familiar unit such as million cubic feet, board feet, acres, or gallons. This unit is called the charge-unit;

- **PRODUCTION CAPACITY:** A fixed amount of annual production capacity is installed as the result of a given fixed investment. The capacity is given in terms of charge units;

- **UNIT CAPITAL COST:** The user determines the appropriate allocation of this fixed investment cost to a charge unit: For example, it is typical for many projects to assume an even level of production annually for a given number of years--in this case, the appropriate allocation would be the "equivalent annual cost" per charge unit. For other patterns of usage an alternative unit capital charge would have to be derived. This per charge-unit capital or investment cost remains constant over the ranges of possible installed capacities analyzed;

- **MARGINAL OPERATING COST:** Given a certain level of production capacity, the producer can manufacture any number of charge units up to that capacity at a constant unit cost, the marginal operating cost. The combination of the unit capital charge and the marginal operating cost will yield two concepts of marginal cost: i) "marginal cost before," the sum of the unit capital cost and marginal operating cost, i.e., the cost incurred

[1] For a more detailed analysis of the theory behind the value secured through long-term contracts and the use of a model such as CONTRACT to estimate this value, see John E. Parsons, "Valuing Forward Purchase Contracts Using Auction Models," M.I.T. Energy Laboratory Working Paper, Cambridge, Massachusetts, January 1986.

to produce an additional unit when the contracting and planned production decisions are made prior to the installation of capacity, and ii) "marginal cost after," simply the marginal operating cost, i.e., the cost incurred to produce an additional unit when contracts and production decisions are made after the capacity has been installed;

SALE-UNIT: Capacity output can be subdivided and sold in subsets. For example, if a natural gas field produces 100 million cubic feet (Mcf) of gas per day, it can be sold as

-1 unit of 100 Mcf/day
-2 units of 50 Mcf/day
-3 units of 33.33 Mcf/day

and so on. These subsets of capacity offered for sale are called <u>sale-units</u> since they are units of capacity for sale;

- **NUMBER OF BUYERS:** The market for the commodity produced consists of a small number of buyers. In our natural gas example, the particular field might be situated such that it may serve three distinct major buyers, pipelines, or markets. The total number of end-users would not be appropriate as the number of buyers since they do not each independently contract with the producer. <u>Each of the buyers has a potential demand for ONE SALE-UNIT</u>: therefore, the appropriate size of a sale-unit is determined by the amount of production that is likely to be purchased by an average buyer;

- **RESERVATION PRICES:** The producer assesses a range of prices over which it anticipates the various potential buyers might value the product available. For example, the producer may expect that it can obtain a price of $3.50/Mcf, or per charge unit, for the gas. However, it is aware that potentially there are several buyers out there willing to pay more, or alternatively that its buyers may actually only be willing to pay much less. In extreme cases the price might be as high as $5/Mcf or as low as $1/Mcf. This inherent uncertainty is represented as a range of prices that each customer might be willing to pay--for example, $1, $2, $3, $4, or $5 per charge unit. For computational reasons we restrict the possible set of values to a few points evenly spaced within a range. These values are called reservation prices. **CONTRACT** models various scenarios in which different numbers of buyers are willing to buy the product at each reservation price: In a given scenario the reservation price that actually describes how much a particular buyer is willing to pay is called that buyer's reservation value.

MODELLING NEGOTIATIONS

With these pieces of information, **CONTRACT** automatically calculates the price that the producer can anticipate negotiating under various scenarios for buyer demands and under the two alternatives, forward contracting and ex post contracting, and then **CONTRACT** calculates the average profit earned by the producer under forward contracting versus ex post contracting.

CONTRACT models the available set of scenarios using the following algorithm: i) assume that each buyer is equally likely to have a reservation value at any of the chosen set of reservation prices, ii) calculate all of the possible combinations of the total number of buyers at each reservation price and the probability of each combination.

CONTRACT models the negotiations over price for a given scenario using the following algorithm: i) start at the highest reservation price--if there are enough buyers willing to pay this price so they more than exhaust total capacity, then the price will be bid up to this reservation price and the full capacity will be sold; ii) if not, drop to the next reservation price and check to see if there are a total number of buyers willing to pay this price and more than exhaust capacity--if so, then all units of capacity are sold at this price; iii) if there are exactly enough buyers willing to pay this price and exhaust capacity, then **CONTRACT** sets the price above the reservation price at which the number of buyers more than exhausts capacity; iv) if not enough buyers are found at this reservation price, then continue through steps i-iii at successively lower reservation prices; v) if, at the lowest reservation price just above marginal cost, there are not enough buyers willing to pay that reservation price and exhaust capacity, then the price is set at this reservation price, but only enough units are produced to exactly supply those buyers with reservation prices above the marginal cost.

This model of the outcome of contract negotiations can be justified in two ways. First, it is directly analogous to the outcome that would occur if the producer sold its available capacity by means of a sealed bid system in which all buyers paid the clearing price, and in which the minimum bid required for participation is the marginal cost. Second, the expected revenue from this model is the highest that the producer can obtain using any method of sale or bargaining given its uncertainty about each buyer's actual reservation value and given its inability to credibly commit itself to a minimum bid above its marginal cost.[2]

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[2]For a derivation of these results, see Milton Harris and Arthur Raviv, "A Theory of Monopoly Pricing Schemes with Demand Uncertainty," American Economic Review, Vol. 71, pp. 347-365, 1981. For a discussion of alternative algorithms, see John Parsons, "Valuing Forward Purchase Contracts Using Auction Models," op.cit.

USING CONTRACT-AN EXAMPLE

Before actually running the **CONTRACT** program, the user should have on hand values for:

-annual production capacity in charge-units
-number of prospective buyers
-number of allowable reservation prices
-the number of sale-units
-marginal operating cost per charge-unit
-buyers' minimum and maximum reservation prices

For example, consider our natural gas field. A familiar unit of measurement is thousand cubic feet (Mcf), so that will be the charge-unit. If we develop the field it will have a production capacity of 150 million cubic feet/day, or 54.75 Bcf/year for 20 years. In terms of our charge unit it will have capacity of 54.75 E6 Mcf/year. If the total fixed costs necessary for developing this level of capacity amount to $1 billion, and if our discount rate is 10 percent, then the equivalent annual cost is $1 billion/8.514 = $117.454 million/year. Since we produce 54.75 E6 Mcf/year, the per charge unit capital cost is $2.145/Mcf. We know that there are 3 potential buyers and that all three have reservation values somewhere between $2.90/Mcf and $4.00/Mcf for our gas. We decide to set the number of reservation prices at 4, and so the reservation prices are $2.90, $3.27, $3.63, and $4/Mcf. Our typical buyer is likely to purchase the full capacity, 54.75 Bcf/year, so there is 1 sale-unit of size 54.75 Bcf or, to be consistent, 54.75 E6 Mcf. After development costs, we need only pay $0.50/Mcf to extract the gas, so marginal operating cost is $0.50/Mcf.

CONTRACT prompts the user for all information in the terminology described earlier. The program requires an IBM Personal Computer or compatible. Users have the option to see results 1) in summary form on the screen, or 2) printed in summary form, or 3) printed results in a detailed table displaying the outcome of negotiations for each scenario and which shows precisely how **CONTRACT** summed to get final profit figures.

To run the program start with the DOS **A>** prompt. Insert the program diskette into Drive A and type **CONTRACT**. Follow all responses by hitting the Return key. To stop the program at any time, hit **<CONTROL><BREAK>**. Type **RUN** to restart.

Follow this sample session as it demonstrates how the example outlined above would look in a **CONTRACT** run. All items typed by the user are underlined.

INTERPRETING CONTRACT PRINTOUT

The printed output begins with a statement of the items that the user inputed to the program. These include the "PRODUCTION OUTPUT," or capacity, the "NO. OF BUYERS," the number of "DISCRETE PRICES," the "MIN. RESERVATION PRICE," and the "MAX. RESERVATION PRICE". From the information given by the user on the marginal operating cost and the per unit capital charge, **CONTRACT** calculates the marginal total cost--listed here as "MARG COST-before." This is the marginal cost figure that is used in the algorithm that calculates the price for each scenario of forward contracting. However, once production capacity has been installed the capital charge is not variable, and therefore "MARG COST-after" is just the figure inputted by the user for marginal cost: This is the marginal cost figure that is used in the algorithm which calculates price for each scenario of <u>ex-post</u> contracting. Given the maximum and minimum reservation prices and the number of reservation prices, the program claculates the interval between each reservation price--the number which is listed "RES. PRICE INCREMENT." The program also lists the number of sale units as

```
ANNUAL PRODUCTIVE OUTPUT (in charge-units)? 54.75

FIXED COST PER CHARGE-UNIT ? 2.145

NUMBER OF BUYERS ? 3

NUMBER OF DISCRETE BUYER VALUE LEVELS ? 4

NUMBER OF SALE-UNITS ? 1

MARGINAL COST ( $ per charge-unit) ? .5

MIN. RESERVATION PRICE ? 2.1

MAX. RESERVATION PRICE ? 3.5

OUTPUT TO (P)RINTER  or (S)CREEN ? p

DO YOU WISH TO SEE A FULL TABLEAU? ( (Y)ES or (N)O )? y
```

PRODUCTION OUTPUT = 54750000

NO. OF BUYERS = 3

DISCRETE PRICES = 4

MIN. RESERVATION PRICE = 2.10

MAX. RESERVATION PRICE = 3.50

MARG COST-before = 2.65

MARG COST-after = 0.50

RES. PRICE INCREMENT = 0.47

SALE-UNITS AVAILABLE = 1

SALE-UNIT SIZE = 5.475E+07

					CONTRACTING BEFORE DEVEL				CONTRACTING AFTER DEVEL					
				FREQ.	PRICE	PRICE - M.C.	QTY.	EXP OPR PROF	PRICE	PRICE - M.C.	QTY.	EXP OPR REVS.	EXP REVS-FIXED COST	NET PROFIT (PRE-POST)
3	0	0	0	0.01563	3.03	0.39	0	0	2.10	1.60	1	1368750	-466231	466231
2	1	0	0	0.04688	3.03	0.39	0	0	2.41	1.91	1	4904688	-600254	600254
2	0	1	0	0.04688	3.03	0.39	1	996621	2.41	1.91	1	4904688	-600254	1596875
2	0	0	1	0.04688	3.03	0.39	1	996621	2.41	1.91	1	4904688	-600254	1596875
1	2	0	0	0.04688	3.03	0.39	0	0	2.57	2.07	1	5303906	-201036	201036
1	1	1	0	0.09375	3.03	0.39	1	1993242	2.83	2.33	1	11938540	928658	1064584
1	1	0	1	0.09375	3.03	0.39	1	1993242	2.83	2.33	1	11938540	928658	1064584
1	0	2	0	0.04688	3.03	0.39	1	996621	3.03	2.53	1	6501563	996621	0
1	0	1	1	0.09375	3.28	0.64	1	3270743	3.28	2.78	1	14280630	3270742	1
1	0	0	2	0.04688	3.50	0.86	1	2194278	3.50	3.00	1	7699219	2194278	0
0	3	0	0	0.01563	3.03	0.39	0	0	2.57	2.07	1	1767969	-67012	67012
0	2	1	0	0.04688	3.03	0.39	1	996621	2.83	2.33	1	5969271	464329	532292
0	2	0	1	0.04688	3.03	0.39	1	996621	2.83	2.33	1	5969271	464329	532292
0	1	2	0	0.04688	3.03	0.39	1	996621	3.03	2.53	1	6501563	996621	0
0	1	1	1	0.09375	3.28	0.64	1	3270743	3.28	2.78	1	14280630	3270742	1
0	1	0	2	0.04688	3.50	0.86	1	2194278	3.50	3.00	1	7699219	2194278	0
0	0	3	0	0.01563	3.03	0.39	1	332207	3.03	2.53	1	2167188	332207	0
0	0	2	1	0.04688	3.28	0.64	1	1635371	3.28	2.78	1	7140313	1635371	0
0	0	1	2	0.04688	3.50	0.86	1	2194278	3.50	3.00	1	7699219	2194278	0
0	0	0	3	0.01563	3.50	0.86	1	731426	3.50	3.00	1	2566406	731426	0

T BEFORE = 3
TOT PROFIT - contracting before devel = 2.578954E+07

T AFTER = 1
TOT.PROFIT - contracting after devel = 1.80675E+07

**** PERCENT ADVANTAGE OF PRIOR CONTRACT: ****
[PROFIT(bef)-PROFIT(aft)]/PROFIT(bef) = 29.94

inputted by the user gave, and **CONTRACT** calculates the implied size of one sale-unit: This unit size is the quantity of the product that the average buyer is willing to buy at its reservation value.

Below this summary information is a table listing vertically the various possible scenarios for demand, and horizontally the results of the forward and ex-post negotiations. The first set of columns including the column labelled "FREQ." represent the number of buyers at each reservation price for a given scenario, and the associated probability of this scenario. For example, row 1 represents the scenario that all three buyers have reservation values equal to the minimum reservation price of $2.10, and the probability 0.01563 for this scenario; row 2 represents the case that two of the three buyers have reservation values equal to the minimum and that one buyer has a reservation value one increment above the minimum at $2.57, and the probability 0.04688 of this event.

The next set of columns list the results of the forward contracting negotiating process for each scenario. For the scenario described in row 1 all three buyers have reservation values of $2.10, all below the marginal cost of $3.50. The price is therefore set equal to the reservation price just above the marginal cost, or $3.03, but no buyer is willing to purchase, and therefore the quantity sold is zero. For the scenario described in row 8 there is one buyer with a reservation value of $2.10 and two buyers with reservation values of $3.03. Since there is only enough capacity for one buyer, the two buyers at $3.03 will compete the price up to their reservation value, p=$3.03/Mcf, and q=1. If we subtract the marginal cost, then the seller receives a per charge unit profit of $0.39/Mcf which is listed in the column directly following price. The final column lists the expected profit obtained in this scenario. It is the product of the per charge-unit profit margin, the number of charge units sold, and the probability of the scenario. For row 8, it is equal to (\$0.39/Mcf).(54750 mcf).(0.04688) = \$.997 million.

The next set of columns list analogous information for the case of ex-post contracting; that is, contracting after development or installation of capacity. The price is determined by the same algorithm using the marginal operating cost instead of the marginal total cost. The profit margin displayed in the following column is the difference between the price and the marginal operating cost; it is the operating profit. The expected operating revenue for this scenario is the product of the per charge-unit operating profit margin, the number of charge units sold, and the probability of the scenario. The final column incorporates the sunk costs into the calculations. It is the expected revenue minus the expected expenditure on capital for this scenario.

The difference between forward and ex-post contracting can be seen in the scenario described in row 2. In this scenario there is one buyer with a reservation value of \$2.57/Mcf, and two buyers with reservation values at \$2.10/Mcf. These are all below the marginal total cost of \$2.65/Mcf, and therefore if the producer attempted to negotiate a contract before installing capacity it would find no buyers willing to pay the costs of production. It would sign no contracts and make no sales, but it would also not incur the costs of capacity installation. In the case of ex-post contracting the producer has already expended the capital costs. The marginal operating cost is \$0.50/Mcf. The producer will therefore sell the one unit of capacity to the buyer with the highest reservation value at a price of \$2.41/Mcf, slightly below that buyer's reservation value. This price covers marginal cost, and the per unit operating profit is listed on the table as $1.91/Mcf; the expected operating profit is listed as $4.905 million. However, this per unit profit does not cover the per unit capital expenses, and therefore the expected profit inclusive of capital charges is negative, -$.600 million.

In a scenario such as that described in row 8 there is no difference between forward and ex-post contracting. The price that the producer receives has been bid above the level of marginal cost inclusive of capital charges; the price is, in this case, exclusively determined by the competition between the buyers, and not by the negotiating power of the producer with one of the buyers. The producer incurs the capital costs in both forward and ex-post contracting. In all scenarios of this sort the last column, the difference between the profits from forward and ex-post contracting, will contain a zero.

Below these columns appears the summary of the expected profits earned from forward and ex-post contracting. "TOT PROFIT - contracting before devel" is the sum of the expected profits for each scenario listed under the column labelled "Gross Exp Profit" under the "Contracting Before Devel" heading. The entry "TOT PROFIT - contracting after devel" is the sum of expected profits net of capital charges listed under the column labelled "Exp Profit-Fixed Cost" under the "Contracting After Devel" heading. The associated number, "T BEFORE," is the lowest reservation price at which the producer will accept bids in the case of forward contracting: In this case it is 3, or $3.03. For ex-post contracting the lowest reservation price at which the producer will accept bids, "T AFTER," is 1, or $2.10. If, for a particular run of **CONTRACT**, these two numbers are identical then, the profit from forward and ex-post contracting will be the same.

The user may wish to see only the summary information, including the inputted figures and the total expected profits from forward and <u>ex-post</u> contracting. This can be done using either the screen or the printer. If the user has selected printed output, then by responding with a "N" to the query whether or not a full tableau is requested they receive the summary information only. Alternatively the user may request screen output by responding with an "S" to the query whether screen or printed information is desired. Screen output is always in the summary form. The summary information received from either the screen or the printer is:

```
        PRODUCTION OUTPUT =  54750000
            NO. OF BUYERS =      3
          DISCRETE PRICES =      4
  MIN. RESERVATION PRICE =      2.10
  MAX. RESERVATION PRICE =      3.50
        MARG COST-before  =      2.65
         MARG COST-after  =      0.50
    RES. PRICE INCREMENT =      0.47
    SALE-UNITS AVAILABLE =      1
           SALE-UNIT SIZE =  5.475E+07


       T BEFORE    =       3
 TOT PROFIT - contracting before devel =   2.578954E+07

       T  AFTER    =       1
 TOT.PROFIT - contracting after devel  =  1.80675E+07

 ****  PERCENT  ADVANTAGE  OF  PRIOR CONTRACT:  ****
 [PROFIT(bef)-PROFIT(aft)]/PROFIT(bef)  =    29.94
```

THE POWER OF CONTRACT

What if more customers for the natural gas can be found? How will changing development costs affect the relative profitability of forward and <u>ex-post</u> contracting? **CONTRACT** allows the user to try alternate problem formulations and to watch how changing market conditions change the benefits of a project.

In our natural gas example, suppose that instead of three buyers, each potentially willing to purchase a quantity of gas equal to the full output, we faced three buyers each potentially willing to purchase only one-half of the full output. Then we are essentially facing a lower demand schedule, and we expect that profits would be correspondingly less. **CONTRACT** will easily confirm this intuituion, but in addition it will draw attention to the increased importance of forward contracting. To represent this case we raise the number of sale units to 2, reducing thereby the size of each to 18,250 Mcf. The output for this case is displayed below.

Profit under forward contracting has indeed declined--by 38 percent, from $25.7 million/year to $15.8 million/year. Profit for <u>ex-post</u> contracting has, however, declined by more than 132 percent. Profit for <u>ex-post</u> contracting is, in fact, negative. This means that the average price earned from negotiations after capacity is installed will not cover the operating and capital charges. Without forward contracts the capacity should not be installed at all. The most important result to note is that under these different market conditions the forward contract becomes more critical, and **CONTRACT** gives one a measure of by how much.

```
     PRODUCTION OUTPUT =  54750000

          NO. OF BUYERS =      3

        DISCRETE PRICES =      4

MIN. RESERVATION PRICE =      2.10

MAX. RESERVATION PRICE =      3.50

    MARG COST-before    =      2.65

     MARG COST-after    =      0.50

  RES. PRICE INCREMENT =      0.47

  SALE-UNITS AVAILABLE =      2

        SALE-UNIT SIZE =  2.7375E+07


       T BEFORE    =      3
TOT PROFIT - contracting before devel =  1.581477E+07

       T  AFTER    =      1
TOT.PROFIT - contracting after devel  = -5885636

 ****  PERCENT  ADVANTAGE  OF  PRIOR CONTRACT:  ****
[PROFIT(bef)-PROFIT(aft)]/PROFIT(bef) =  137.22
```

Consider now the scenario that the number of buyers increases from 3 to 5. Profits increase accordingly. Note, however, that in this case the relative importance of forward contracting declines.

```
     PRODUCTION OUTPUT =  54750000
         NO. OF BUYERS =     5
       DISCRETE PRICES =     4
MIN. RESERVATION PRICE =     2.10
MAX. RESERVATION PRICE =     3.50
    MARG COST-before   =     2.65
     MARG COST-after   =     0.50
  RES. PRICE INCREMENT =     0.47
  SALE-UNITS AVAILABLE =     1
        SALE-UNIT SIZE =  5.475E+07


       T BEFORE    =      3
TOT PROFIT - contracting before devel =  3.482849E+07

       T  AFTER    =      1
TOT.PROFIT - contracting after devel  =  3.304605E+07

 ****  PERCENT  ADVANTAGE  OF  PRIOR CONTRACT:  ****
[PROFIT(bef)-PROFIT(aft)]/PROFIT(bef) =    5.12
```

BACKGROUND INFORMATION ABOUT THE PROGRAM

CONTRACT is capable of analyzing many combinations of buyer numbers and reservation price levels. The following table shows the combinations that the program and data diskette already have been written to accept:

	PRICE INCREMENTS					
BUYERS	2	3	4	5	6	7
2	•	•	•	•	•	
3	•	•	•	•	•	
4	•	•	•	•	•	
5	•	•	•	•	•	
8		•	•	•		
12		•	•	•		
16			•			

The program is equipped with a BASIC program entitled **WRITER** which will create data files to permit **CONTRACT** to work on other combinations. Simply get into BASIC, load, and run **WRITER**. It is an interactive program which prompts the user for the required information. The important constraint on the use of **WRITER** is the size of the matrix of combinations being generated and the user's available memory.

The original source code for **CONTRACT** is included for users familiar with BASIC and interested in the details of the program and desiring to modify it to fit their particular purposes. Users could, for example, adapt the program to accept alternative probability distributions for the various scenarios. Other variations on the fundamental program are also possible.

```
10      CLS:FULL$=" "
20      COLOR 14.0
30      LOCATE 1,20
40      PRINT
50     INPUT "ANNUAL PRODUCTIVE OUTPUT (in charge-units)";CAPACITY
60     PRINT
70     INPUT "FIXED COST PER CHARGE-UNIT ":FIXEDPERUNIT
80     PRINT
90     ADVANTAGE=0
100     INPUT "NUMBER OF BUYERS ";N$
110        N = VAL(N$)
120        IF N<1 THEN 3120
130     PRINT
140     INPUT "NUMBER OF DISCRETE BUYER VALUE LEVELS ";K$
150        K = VAL(K$)
160        IF K<1 THEN 3120
170     PRINT
180    FILE$ = "DATA" + N$ + K$
190    INPUT "NUMBER OF SALE-UNITS ";Q
200       IF Q<1 THEN 3120
210    PRINT
220    INPUT "MARGINAL COST ( $ per charge-unit) ";CAFTER
230       IF CAFTER <0 THEN 3120
240       CBEFORE=CAFTER + FIXEDPERUNIT
250    PRINT
260    INPUT "MIN. RESERVATION PRICE ";L
270       IF L<0 THEN 3120
280    PRINT
290    INPUT "MAX. RESERVATION PRICE ";H
300       IF H<1 THEN 3120
310       IF H<=L THEN 3120
320    PRINT
330    INPUT "OUTPUT TO (P)RINTER  or (S)CREEN ";OUTPUT$
340       IF OUTPUT$="s" OR OUTPUT$="S" THEN GOTO 390
350    IF OUTPUT$ <> "P" AND OUTPUT$ <> "p" THEN PRINT "AGAIN, PLEASE":GOTO
330
360    PRINT
370    INPUT "DO YOU WISH TO SEE A FULL TABLEAU? ( (Y)ES or (N)O )";FULL$
380    PRINT
390   DIM G(3)
400   FIXEDCOST=FIXEDPERUNIT*CAPACITY  'total annual fixed cost
410   D=(H-L)/(K-1)                    'calculate interval size
420   UNITSIZE = CAPACITY/Q
430 '
440                                    'given the above information,
450                                    'an optimal quantity of sales and
460                                    'can be calculated, based on
470                                    'a value referred to as "T" by
480                                    '  Harris and Raviv
490 '************************** calculate prior contract T Value ******
500   FOR Y=1 TO K
510   IF L+( (Y-1) *D) >= CBEFORE THEN 550
520   NEXT Y
530   PRINT "MARGINAL COST FOR CONTRACTING BEFORE IS TOO HIGH"
540   PRINT "TRY AGAIN BY TYPING `RUN' ":GOTO 3110
550   TVALBEFORE=Y
560 '**************************** Calculate ex post T Value  **********
```

```
570   FOR I = 1 TO K
580   IF L+( (I-1) *D) >= CAFTER THEN 630
590   NEXT I
600   PRINT "MARGINAL COST FOR CONTRACTING AFTER IS TO HIGH"
610   PRINT " TRY AGAIN BY TYPING `RUN' ":GOTO 3110
620   '
630   TVALAFTER = I
640 '**********************************************************
650   K1=(1/K)^(N-1)
660   K2=(1/K)
670 '
680 '****************** calculate A-Values **********************
690   DIM M(K)
700   DIM O(K)
710   DIM T(K)
720   DIM A(K)
730   C1 =1
740   I=1
750   IF I>K THEN 1440
760   A1=Q:A2=0
770   IF A1>(N-1) THEN 1120
780    '
790   IF C1=2 THEN 820
800   IF A2>(Q-2) THEN 1070
810   GOTO 830
820   IF A2>(Q-1) THEN 1070
830   G(1)=(N-1):G(2)=A1:G(3)=(N-1-A1)
840   GOSUB 3140
850   R=R1
860   G(1)=A1:G(2)=A2:G(3)=A1-A2
870   GOSUB 3140
880   R=R*R1
890   Z=(K-I)
900   Y=A2
910   IF Z<>Y THEN 930
920   IF Z=0 THEN 950
930   X=Z^Y
940   R=R*X
950   Z=(I-1)
960   Y=(N-A1-1)
970   IF Y<>Z THEN 990
980   IF Z=0 THEN 1010
990   X=Z^Y
1000   R=R*X
1010   IF C1=1 THEN 1040
1020   X=(Q-A2)/(A1-A2+1)
1030   R=R*X
1040   S1=S1+R
1050   R=1
1060   A2=A2+1: GOTO 790
1070   S=S+S1
1080   S1=0
1090   A1=A1+1
1100   A2=0
1110   GOTO 770
1120   IF C1=2 THEN 1160
1130   M(I)=K1*S
```

```
1140  S=0
1150  C1=2:GOTO 760
1160  O(I)=K1*S:S=0
1170 C1=1
1180 R=1
1190 G(1)=(N-1):G(2)=(N-Q):G(3)=(Q-1)
1200 GOSUB 3140
1210 R=R*R1
1220 Z=(K-I)
1230 Y=(Q-1)
1240 IF Y<>Z THEN 1250:IF Z=0 THEN 1270
1250 X=Z^Y
1260 R=R*X
1270 Z=I
1280 Y=(N-Q)
1290 R1=Z^Y
1300 Z=(I-1)
1310 R2=1
1320 IF Z<>Y THEN 1340
1330 IF Z=0 THEN 1350
1340 R2=Z^Y
1350 R=(R1-R2)*R
1360 R=R*K1
1370 IF R<>0 THEN 1390
1380 R=1
1390 T(I)=R
1400 X=O(I)-M(I)
1410 A(I)=1-(X/T(I))
1420 I=I+1
1430     GOTO 750
1440 '******************************** end of A-calc section *********
1450 '
1460 '**************** calc t profit and quant in before & after state *****
1470 '
1480                                     ' Go read in prob-distn from disk
1490         GOSUB 3500                  :'Create distn matrix from the data
1500                                     'Calc price & consump using array J
1510 PRINT "*********** RUNNING....please wait **************"
1520 W=ROWS
1530 DIM THOLDPRICE(W):DIM THOLDQUANT(W):DIM THOLDARRAY(W)
1540 DIM TBEFOREQUANT(W):DIM TBEFOREPRICE(W):DIM TBEFOREARRAY(W)
1550 DIM TAFTERQUANT(W):DIM TAFTERPRICE(W):DIM TAFTERARRAY(W)
1560 '************************ loop through 'before' & 'after' state *****
1570                                     'calculate profits,quantities for
1580                                     'forward or ex-post contracts
1590 FOR PREFIX=1 TO 2
1600     IF PREFIX = 1 THEN THOLD=TVALBEFORE:GOTO 1620
1610     THOLD=TVALAFTER
1620     PRICEHOLD1 = L + (THOLD-1)*D
1630     FOR C2= 1 TO W
1640        S=0                                         'S is the sum of demand
1650        FOR I = K TO 1 STEP -1
1660          S = S + J(C2,I)
1670          IF S < Q THEN 1750
1680          IF S > Q THEN PRICEHOLD2 = L + (I-1)*D:GOTO 1780
1690          FOR I1 = I-1 TO 1 STEP -1 : 'here if demand sum = quant supplied
1700             S = S + J(C2,I1)
```

```
1710            IF S > Q THEN PRICEHOLD2 = L + (I1-1)*D + A(I1)*D: GOTO 1780
1720          NEXT I1
1730          IF S = Q THEN GOTO 1790
1740          PRINT "PROBLEM WITH DATA:T* SECTION. PLEASE TRY AGAIN":GOTO 3110
1750 '                 here if S<Q
1760        IF I=THOLD THEN THOLDQUANT(C2)=S :THOLDPRICE(C2)=PRICEHOLD1:GOTO
1810
1770       NEXT I
1780         IF PRICEHOLD1<=PRICEHOLD2 THEN THOLDPRICE(C2)=PRICEHOLD2:GOTO 1800
1790         THOLDPRICE(C2) = PRICEHOLD1
1800         THOLDQUANT(C2) = Q : GOTO 1810
1810      NEXT C2
1820      THOLDPROFIT=0                          'create T* profit array
1830      IF PREFIX = 2 THEN 1920
1840      TBEFOREPROFIT = 0
1850      FOR X1=1 TO W
1860         X=FREQ(X1)*THOLDQUANT(X1)*UNITSIZE*(THOLDPRICE(X1)-CBEFORE)
1870         TBEFOREARRAY(X1)=X
1880         TBEFOREPROFIT=TBEFOREPROFIT + X
1890         TBEFOREQUANT(X1)=THOLDQUANT(X1):TBEFOREPRICE(X1)=THOLDPRICE(X1)
1900      NEXT X1
1910      GOTO 2000
1920      TAFTERPROFIT = 0
1930      FOR X2=1 TO W
1940         X=FREQ(X2)*THOLDQUANT(X2)*UNITSIZE*(THOLDPRICE(X2)-CAFTER)
1950         X=X-(FIXEDCOST*FREQ(X2))           'profit=revenues-(fixed cost)
1960         TAFTERARRAY(X2)=X
1970         TAFTERPROFIT=TAFTERPROFIT + X
1980         TAFTERQUANT(X2)=THOLDQUANT(X2):TAFTERPRICE(X2)=THOLDPRICE(X2)
1990      NEXT X2
2000 NEXT PREFIX
2010  '*************************  display section ***********************
2020  IF OUTPUT$ = "S" OR OUTPUT$ ="s" THEN GOTO 2770
2030      WIDTH "LPT1:",132
2040      X$=SPACE$(2*K+7)
2050  LPRINT:LPRINT
2060      LPRINT USING "     PRODUCTION OUTPUT = #########";CAPACITY
2070      LPRINT
2080      LPRINT USING "         NO. OF BUYERS =    ###";N
2090      LPRINT
2100      LPRINT USING "       DISCRETE PRICES =    ###";K
2110      LPRINT
2120      LPRINT USING "MIN. RESERVATION PRICE = #####.##";L
2130      LPRINT
2140      LPRINT USING "MAX. RESERVATION PRICE = #####.##";H
2150      LPRINT
2160      LPRINT USING "    MARG COST-before   = #####.##";CBEFORE
2170      LPRINT
2180      LPRINT USING "     MARG COST-after   = #####.##";CAFTER
2190      LPRINT
2200      LPRINT USING "  RES. PRICE INCREMENT = #####.##";D
2210      LPRINT
2220      LPRINT USING "  SALE-UNITS AVAILABLE = #####";Q
2230      LPRINT
2240      LPRINT  "        SALE-UNIT SIZE = ";UNITSIZE
2250  LPRINT
2260            IF FULL$ = "N" OR FULL$ = "n" THEN 2590
```

```
2270    LPRINT
2280  LPRINT CHR$(15)
2290  LPRINT X$;"  ";"    ";"
";"________";"_________";"_______";"_________";"          ";
2300  LPRINT "_________";"_________";"______";"_______";"______";"_______
";"   ___________"
2310  LPRINT X$;"  ";"    ";"  ";"|  CONTRACTING BEFORE DEVEL       |";"
";"|    CONTRACTING AFTER DEVEL                |    |"
2320  LPRINT X$;" FREQ.";" ";"  ";"  PRICE  ";" PRICE - ";"  QTY. ";"  EXP
OPR";"      ";
2330  LPRINT " PRICE    ";" PRICE -  ";"  QTY. ";" EXP OPR  ";"  ";"EXP REVS-
";"  NET PROFIT"
2340  LPRINT X$;"  ";"    ";"  ";"         ";"  M.C.   ";"       ";"
PROF";"       ";
2350  LPRINT "         ";" M.C.     ";"       ";"  REVS. ";"   ";"FIXED COST
";"   (PRE-POST) "
2360  LPRINT
2370 '
2380    FOR C9=1 TO W                             'enter the distribution
2390         FOR S9= 1 TO K
2400         LPRINT USING "## ";J(C9,S9);
2410         NEXT S9
2420      LPRINT "    ";
2430      LPRINT USING "#.#####";FREQ(C9);
2440      LPRINT " ";
2450      LPRINT USING "  ##.##  ";TBEFOREPRICE(C9);
2460      LPRINT USING "  ##.##  ";TBEFOREPRICE(C9)-CBEFORE;
2470      LPRINT USING "  ## ";TBEFOREQUANT(C9);
2480      LPRINT USING "  #######";TBEFOREARRAY(C9);
2490      LPRINT "        ";
2500      LPRINT USING "  ##.##  ";TAFTERPRICE(C9);
2510      LPRINT USING "  ##.##  ";TAFTERPRICE(C9)-CAFTER;
2520      LPRINT USING "   ## ";TAFTERQUANT(C9);
2530      LPRINT USING " ######## ";TAFTERARRAY(C9)+(FIXEDCOST*FREQ(C9));
2540      LPRINT USING "   ######## ";TAFTERARRAY(C9);
2550      LPRINT USING "     ########";TBEFOREARRAY(C9) - TAFTERARRAY(C9)
2560    NEXT C9
2570 LPRINT CHR$(18)
2580 '
2590 '
2600 LPRINT
2610 LPRINT
2620 LPRINT USING "       T BEFORE   =     ##   ";TVALBEFORE
2630 LPRINT "TOT PROFIT - contracting before devel = ";TBEFOREPROFIT
2640 LPRINT
2650 LPRINT USING "       T  AFTER    =     ##   ";TVALAFTER
2660 LPRINT "TOT.PROFIT - contracting after devel  = ";TAFTERPROFIT
2670 LPRINT
2680 LPRINT " ****  PERCENT  ADVANTAGE  OF  PRIOR CONTRACT:  ****"
2690 LPRINT USING "[PROFIT(bef)-PROFIT(aft)]/PROFIT(bef) =
####.##";100*(TBEFOREPROFIT-TAFTERPROFIT)/TBEFOREPROFIT
2700 LPRINT
2710 GOTO 3060
2720 '
2730 '
2740 '
2750 '
```

```
2760 '
2770 '                                    screen output section
2780      CLS
2790      FOR ZZ=1 TO 4:SOUND 440,2:SOUND 660,2:NEXT ZZ
2800      X$=SPACE$(2*K+7)
2810      PRINT
2820      PRINT
2830      PRINT "          PRODUCTION OUTPUT = ";CAPACITY
2840      PRINT
2850      PRINT  "     BUYERS =    ";N;"           DISCRETE PRICES =   ";K
2860      PRINT
2870      PRINT  "MIN. RESERVATION PRICE = ";L;"   MAX. RESERVATION PRICE = ";H
2880      PRINT
2890   PRINT  "MARG COST-before  = ";CBEFORE;"      MARG COST-after   = ";CAFTER
2900      PRINT
2910      PRINT  "  SALE-UNITS AVAILABLE = ";Q;"   SALE-UNIT SIZE = ";UNITSIZE
2920      PRINT
2950 PRINT "-----------------------------------------------------"
2960 PRINT "             T BEFORE    = ";TVALBEFORE
2970 PRINT  " PROFIT - contracting before devel = ";TBEFOREPROFIT
2980 PRINT
2990 PRINT USING "        T  AFTER   =      ##   ";TVALAFTER
3000 PRINT  " PROFIT - contracting after devel  = ";TAFTERPROFIT
3010 PRINT "-----------------------------------------------------"
3020 PRINT
3030 PRINT " ****  PERCENT  ADVANTAGE  OF  PRIOR CONTRACT:  ****"
3040 PRINT USING "[PROFIT(bef)-PROFIT(aft)]/PROFIT(bef) =
#####.##";100*(TBEFOREPROFIT-TAFTERPROFIT)/TBEFOREPROFIT
3050 '
3060        ERASE FREQ,J
3070        ERASE THOLDPRICE,THOLDARRAY,THOLDQUANT
3080        ERASE TAFTERPRICE,TAFTERARRAY,TAFTERQUANT
3090        ERASE TBEFOREPRICE,TBEFOREARRAY,TBEFOREQUANT
3100 '
3110 END
3120 PRINT "OOPS - THERE IS A DATA PROBLEM. PLEASE REENTER.":GOTO 40
3130 '
3140   FOR Z=1 TO 3                        '*** COMBINATORICS SECTION
3150     X=1
3160       IF G(Z)=0 THEN 3210
3170       IF G(Z)=1 THEN 3210
3180        FOR Y=1 TO G(Z)
3190        X=X*Y
3200        NEXT Y
3210       G(Z)=X
3220   NEXT Z
3230   R1=G(1)/(G(2)*G(3))
3240   RETURN
3250 '
3260 '
3270 R1=1:C3=1
3280 G1=J(C2,C3)
3290 X=1
3300 Y=1
3310 FOR Y=1 TO G1
3320 X=X*Y
3330 NEXT Y
```

```
3340 R1=R1*X
3350 IF C3=K THEN 3370
3360 C3=C3+1:GOTO 3280
3370 RETURN
3380 U2=U2*100:U2=CINT(US):U2=U2/100
3390 RETURN
3400 '
3410 '
3420 '********************************* A Value Printout *****************
3430 LPRINT "  COL.       A-VALUE"
3440  FOR O1=1 TO K-1
3450 LPRINT USING "  ##";O1;
3460 LPRINT USING "           ###.###";A(O1)
3470  NEXT O1
3480 RETURN
3490 '
3500 '*********************** PROGRAM TO READ DATA INTO ARRAY **************
3510 PRINT
3520 G(1)=(K+N-1):G(2)=(K-1):G(3)=N
3530 FOR Z=1 TO 3
3540 X=1
3550 IF G(Z)=0 THEN 3600
3560 IF G(Z)=1 THEN 3600
3570 FOR Y=1 TO G(Z)
3580 X=X*Y
3590 NEXT Y
3600 G(Z)=X
3610 NEXT Z
3620 R1=G(1)/(G(2)*G(3))
3630 DIM J(R1,K)
3640 DIM FREQ(R1)
3650                                  'READY ARRAY FOR INPUT OF PROB. DATA
3660                                  ' AND FREQUENCY DATA FROM DISK
3670 OPEN "I",#1,FILE$
3680   FOR R=1 TO R1
3690      FOR COL=1 TO K
3700      INPUT #1,J(R,COL)
3710      NEXT COL
3720   INPUT #1,FREQ(R)
3730   NEXT R
3740 CLOSE
3750 ROWS=R1
3760 RETURN
```

TECHNOLOGIES FOR NATURAL GAS UTILIZATION

by

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INTRODUCTION

Natural gas is an ideal fuel for residential, commercial, industrial, or electric generation applications where high-quality, controllable thermal energy is required. Because the fuel can be delivered essentially pollution-free (no sulfur, inorganic solids, or heavy hydrocarbons), it is possible to build the simplest of combustion systems to produce high-temperature heat with emissions of only CO_2, H_2O, and some NOx, depending upon the application and design of combustion system.

Natural gas systems have the lowest capital costs of any system using a hydrocarbon as its primary energy source. The problem with natural gas as a primary thermal energy source is that it is difficult to transport and store. Conventional crude oil and its many liquid derivitives are much easier to store and transport and have much higher energy density per unit volume under normal temperatures and pressures.[1]

Both pressurization and liquefaction are used to transport natural gas, but the former requires the cost of constructing and maintaining pipelines from source to end use, and the latter involves cost in liquefying,

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[1]One cubic foot of middle distillate has, under standard conditions, a heat at combustion of 10^6 Btu/ft^3, while natural gas (or methane) is only 10 Btu/ft^3. By going to higher pressure (140 bars), the energy density increases to 180,000 Btu/ft^3 or by liquefying at approximately -160°C the energy density becomes 675,000 Btu/ft^3.

transporting in special temperature-controlled vessels, and regasification for final use.

For contiguous land masses and a large natural gas demand, a system of pipelines has proven to be an efficient and economic system. The network of natural gas pipelines in North America has functioned well for over 50 years and collects, transports, and distributes 25 percent of U.S. total energy demand. Any contiguous land mass that has a significant natural gas supply potential and future demand potential must carefully consider pipeline networks in its energy planning. Figure 1 shows the relative costs of delivery of hydrocarbon fuels by pipelines or ocean transport, including liquefaction of natural gas.

Liquefaction of natural gas is a well-developed, mature technology whose major disadvantage is cost for liquefaction, transport, and regasification, except for long distances (over 3,000 miles) where it competes with pipeline transmission. For large-size facilities, say 1 Bcf/d, Adelman and Lynch (see Supply paper) give typical costs for liquefaction and regasification of \$1.50/Mcf plus transportation charges of \$0.20/1000 mile. Thus, processing and transport charges for 3000 to 4000 mile transport are typically \$2.00 to \$2.50 per Mcf. To this must be added the resource cost plus any profits, taxes, etc. Adelman and Lynch give typical discovery and development costs of \$0.30/Mcf, so delivered LNG from supplier to large consumer at prices of \$3.00 to \$4.00/Mcf should be feasible and allow for reasonable profit margins at all parts in the system. At these prices, LNG is competitive with other clean liquid fuels such as middle distillates with world crude oil around \$20/bbl. Because

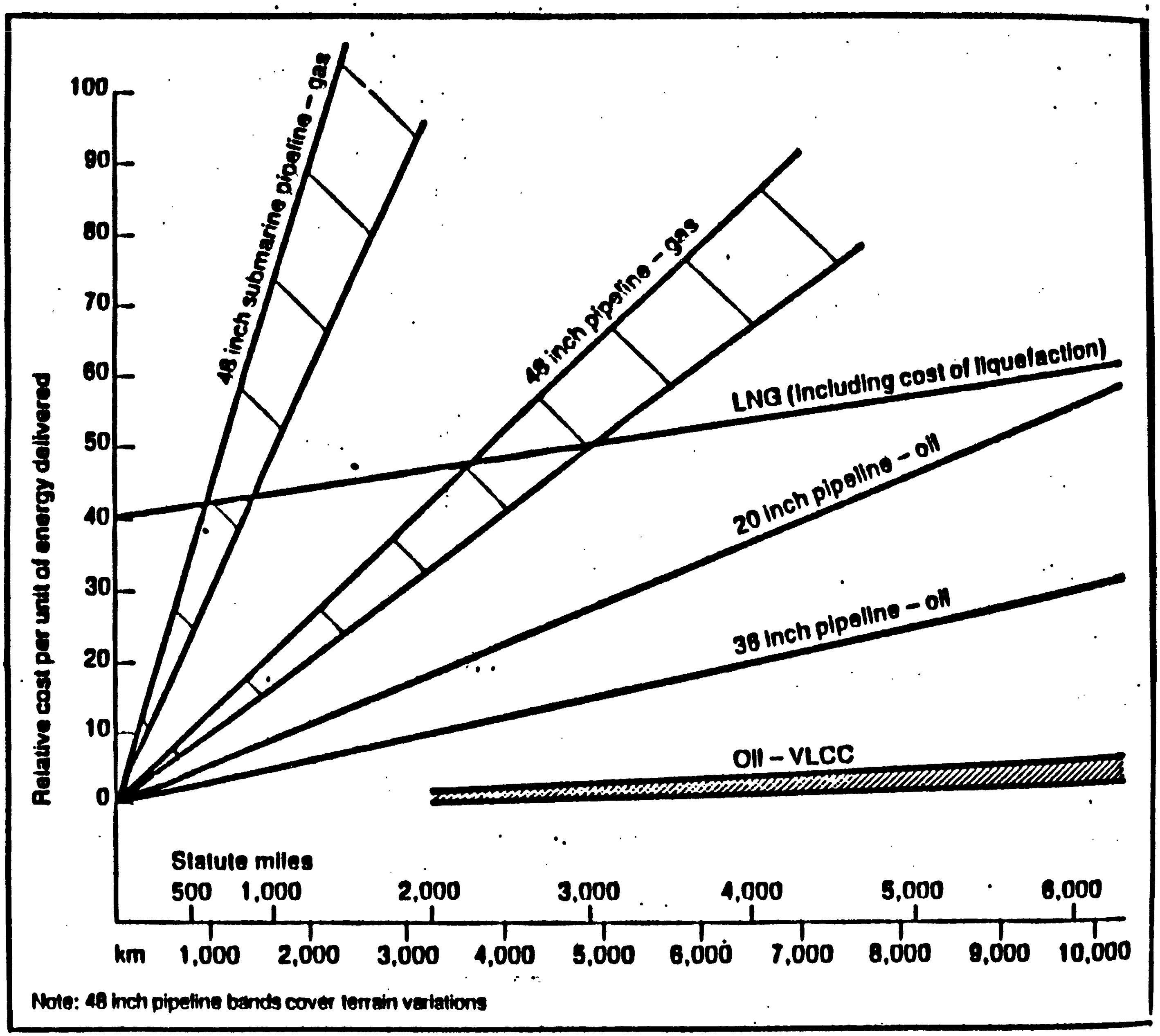


Figure 1. Comparison of Oil and Gas Transportation Costs.

Source: The Petroleum Handbook (Sixth Edition), Elsevier Publishing Company, New York, New York, 1983, p. 532 (Figure 8.7).

natural gas is difficult and expensive to store and transport via pipelines or LNG, the potential for large rents to be obtained by resource owners and developers, under normal supply/demand conditions, is substantially less for natural gas than for crude oil.

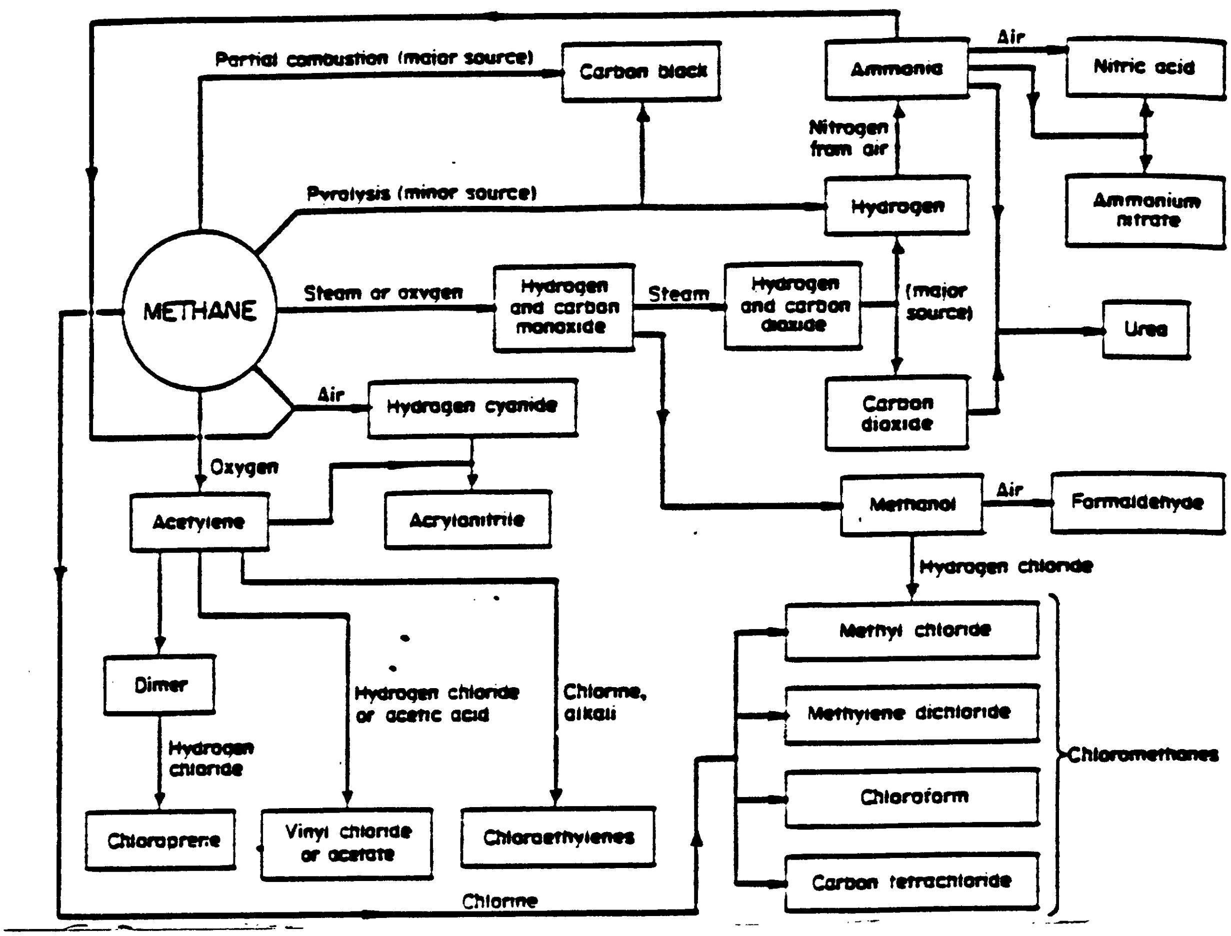
Today delivery of natural gas to the end user can be by pipeline, conversion to LNG and transport, or conversion to a liquid such as methanol, gasoline, or middle distillate. If a transportation fuel is desired, chemical conversion to methanol, gasoline, and middle distillate is technically feasible but expensive in processing costs and primary energy lost in conversion relative to petroleum-derived liquid fuels.

There are significant worldwide R&D programs in the laboratories of the major oil and chemical companies on ways to transform the methane molecule to a more useful hydrocarbon. The high chemical stability of the CH_4 molecule makes this a difficult and expensive task in terms of process economics and energy lost. New chemical conversion technology may come, but making projections based on inventions not yet made is even more risky than predicting world crude oil prices. History has not been kind to such forecasts.

The following sections discuss specific potential technologies based on methane and methane-derived chemical or transportation fuels.

METHANE TO CHEMICALS

Figure 2 shows the typical petrochemicals derived from methane. In addition to carbon black, the major primary products, often used as



Basic Derivative	Produced Annually, 10^6 kg (last year reported)*	Uses, percent
Ammonia	17,545	Fertilizer 80, plastics and fibers 10, explosives 5
Carbon black	1,227	Tires 65, other rubber 25, colorant and filler 10
Methanol	3,830	Polymers 50, solvents 10, derivatives (HCHO, CH_3COOH)
Chloromethanes		
CH_3Cl, methyl chloride	177	Silicones 57, tetramethyl lead 19
CH_2Cl_2, methylene chloride	236	Paint remover 30, aerosol propellant 20, degreaser 10
$CHCl_3$, chloroform	183	Fluorocarbons 90
CCl_4, carbon tetrachloride	322	Fluorocarbons 95, degreasing, fumigant, etc. 5
Acetylene	131	VCM 37, 1,4-butanediol 25, V acetate 14, V fluoride, and acetylene black 5
Hydrogen cyanide	227	MMA 58, cyanuric chloride 17, chelating agents 13, NaCN 9

Figure 2. Petrochemicals from Methane.

Source: George T. Austin, Shreve's Chemical Process Industries (Fifth Edition), McGraw-Hill Book Company, New York, New York, 1984, p. 750.

feedstocks for other products, are ammonia, methanol, and acetylene. The methanol and ammonia streams follow after producing synthesis gas (CO, H_2) from methane by steam reforming or partial oxidation. These products can be derived from synthesis gas produced from any feedstock (coal, heavy petroleum, etc.), but for products with a hydrogen/carbon ratio of two or greater, methane is the preferred feedstock to produce the hydrogen at minimum energy and processing costs.

The extraction of methane as associated gas from petroleum production by petroleum-exporting nations, plus the general surplus of methane in remote locations or in nations with modest population or industrialization, has resulted in a worldwide excess of petrochemical production from methane. Since chemicals derived from methane are a logical way to obtain markets, there is every reason to believe this excess of methane-produced chemicals will continue and be exported to the developed Western world. In North America and Europe, where pipeline networks allow methane delivery for fuel use to a wide range of consumers, use of methane for chemical feedstocks faces stiff competition and has been declining.

METHANOL FOR LIQUID TRANSPORTATION OF FUELS

Methanol can also be used as a transportation fuel. For such use it has both advantages and disadvantages, but it is clearly one way that methane can be converted for use in a huge worldwide market.

The first disadvantage of methanol over petroleum-derived gasoline or middle distillate is its lower energy per unit volume (or weight).

Methanol (CH_3OH) has 52 percent of the energy/gallon of isooctane (C_8H_{18}), a representative hydrocarbon with which to compare commercial unleaded gasoline. Other disadvantages of methanol often cited are its tendency to dissolve some gasket materials (elastomers and rubbers) and the coatings on the interior of gasoline tanks used in today's commercial gasoline-powered vehicles. Other factors affecting its use in present internal combustion engines are a vapor pressure 2 1/2 times, and a heat of vaporization 4 times, that of gasoline. Thus, methanol cannot be used as a direct substitute for gasoline in cars designed and optimized for gasoline.

It is, however, possible to design internal combustion engines specifically for methanol and offset some of the energy per unit volume penalties and gain other advantages, i.e., lower levels of emitted pollutants. Reference 1 gives data on internal combustion engines using methanol and concludes that properly designed engines can give about 20 percent higher output for the same size, consume about 15 percent less energy at part load, and at high load operate more economically than comparable diesel engines.

Reference 2 has comparable results using a research engine, and further shows that 10 to 20 percent H_2O added to methanol gas yields greater energy efficiency and lower emissions. Here a single cylinder test engine using methanol and also isooctane was operated under conditions that met standard U.S. EPA emissions requirements. It was shown that a properly designed methanol engine could have greater efficiency than a gasoline engine when both met stringent emission conditions. As much as 40 percent greater output per unit of energy consumed was obtained by increasing the compression ratio from 8 to 12 and also adding 10 to 20 percent H_2O to reduce NOx emissions. The higher octane rating of methanol plus its cleaner burning characteristics, if exploited in a dedicated engine designed for methanol, partially offsets the lower energy per unit volume or weight of methanol over gasoline.

In today's world, with transportation vehicles optimized for gasoline or diesel fuel, it is very difficult to postulate a methanol fuel strategy. The problems of developing markets for methanol-fueled vehicles (in addition to the comparative cost of methanol and gasoline) are substantial and probably insurmountable. If methane is to become a significant resource for transportation vehicles, the methane-to-methanol-to-gasoline process developed by Mobil or the middle distillate Shell process may be the only feasible way to use methane as a primary source for transportation vehicles when considering the total economics of auto production, fuel distribution, and primary energy resource.

Gasoline from Methanol

The Mobil process using the shape-selective zeolites ZSM-5 yield approximately 95 percent of the energy in the methanol in the hydrocarbon yield. With additional processing, 88 wt percent of the hydrocarbon can be in the gasoline range. Thus, the gasoline yield and energy yield are reasonable for the overall process. However, even at these yields, it takes approximately 2 1/2 gallons of methanol to yield one gallon of gasoline. The Mobil-M route takes methanol to a product compatible with existing transportation equipment and is the only commercially operating process for going from methane to gasoline. Methane to synthesis gas to methanol to gasoline carries with it significant processing costs plus energy loss from the primary feedstock. Methane is not a promising economic route considering that today's crude oil prices are around \$20/bbl.

Middle Distillate from Methane

The production of middle distillate from synthesis gas has been developed by Shell and also Gulf-Badger. These processes are essentially Fischer-Tropsch reactions optimized to produce aliphatic straight chain hydrocarbons in the middle to upper part of the C_1 to C_{50} range. The Shell process first produces a product that is 40 to 70 percent wax, depending upon process conditions, and then hydrocracks the wax to the desired end products. Typical final product yields are 60 percent gas oil, 25 percent kerosene, and 15 percent tops/naptha for a process maximizing gas oil. For a maximum of kerosene, the yields are typically 50 percent kerosene, 25 percent gas oil, and 25 percent tops/naptha (see Reference 4).

Overall thermal efficiency of methane to hydrocarbons is about 60 percent. The Shell process for middle distillates or gasoline is an alternative to the production of methanol as a way to obtain liquid fuels. Well-optimized methanol processes will usually yield better thermal efficiency--say, 65 to 70 percent, as compared with about 50 percent for the higher hydrocarbon fuels preferred for transportation.

Compressed Natural Gas-Fueled Vehicles

Natural gas is an excellent fuel for use in internal combustion engines. Gasoline and diesel fuels have specific combustion characteristics requiring that engines be designed to match the fuel to give optimum performance: spark ignition (gasoline), and high-compression auto ignition (diesel). Natural gas, which has an octane of approximately 130 (compared to 87 to 92 for no-lead gasoline) needs higher compression ratios (15/1) plus spark ignition because it does not auto-ignite as does diesel fuel. While dual-fueled engines, both gasoline and diesel plus methane, can and have been built, the efficient use of natural gas vehicles requires dedicated vehicles.

All general-purpose vehicles need, in addition to their design and manufacturing infrastructure, an operational fuel supply system. Developed nations have an existing transportation system based on gasoline and diesel fuel. So long as reasonably priced petroleum-derived fuels exist, it is hard to imagine a set of conditions that would bring forth both the manufacturing infrastructure and a compressed natural gas fuel supply system in competition with the existing complex and highly competitive auto/truck manufacturing and fuel supply system. However, in nations where the indigenous resource base is predominantly natural gas--Canada, New Zealand, Australia, and Indonesia (i.e., many nations in the Asia/Pacific region)--an alternate mobile vehicle infrastructure could, and may, be a logical development.

For most countries the most probable natural gas-fueled vehicles market is for fleet vehicles--short-range intercity vehicles, such as taxis, delivery trucks, postal service, police vehicles, school buses, and government fleet vehicles. Special engines and fuel delivery systems could be developed to serve such a market. In the United States there are 4 x 10^6 fleet automobiles in fleets of 10 or more and 3 x 10^6 fleet trucks in fleets of 6 or more. Manufacturing to supply the special engines for this fleet is technically feasible and the national network of natural gas pipelines could distribute the fuel.[2]

METHANE FOR ELECTRICITY GENERATION

Via Gas Turbine and Steam Turbine Cycles

Gas-fired boilers for steam turbine (rankine cycle) drives for electricity generation have a long history of use in the United States. Before 1970, natural gas was the dominant industrial and utility boiler fuel in the southwestern United States. In 1985, because of excess natural gas capacity and hence favorable prices, there was 3 Tcf of natural gas burned by electric utility companies. For 1986 the drop in world crude oil prices may affect the natural gas consumed. Nevertheless, the lower capital costs of natural gas boilers, considering combustor design and emission control, make such systems competitive against heavy residual fuel oil and even coal if long-term modestly priced natural gas is available.

While uncertainties in both government regulations and the future price

[2]A typical conversion factor (clearly engine-specific) for natural gas to gasoline is 125 cu. ft. natural gas = 1 gallon of gasoline. Thus, if the average gasoline consumption per vehicle is 1000 gallons per year, it would require 8 x 10^6 vehicles to create 1 trillion cu. ft. of natural gas demand.

of natural gas makes conventional boiler steam turbine systems unlikely in the United States, there is growing interest in gas turbine combined cycle systems (GTCC) for electric utility applications. In the United States, several utility companies are currently planning GTCC installations based on using middle distillate (7) or using natural gas by obtaining a Federal Energy Regulatory Commission (FERC) waiver of the Fuel Use Act for a specified period (usually 10 years).

For natural gas-fired electricity generation in applications where natural gas can be planned for the useful life of the installation (30 to 50 years), the favorable capital costs and heat rates now available for GTCC systems make them highly competitive for future installations of new generating capacity. Data taken from the EPRI study are shown in Table 1.

Table 1

PLANT COSTS AND HEAT RATES

System	($ 1984/kW) (overnight cost)	(Btu/kWhr)
Advanced Gas Turbine Combined Cycle	500	8,000
Advanced Combustion Turbines	250	11,000

SOURCE: Electric Power Research Institute, "Planning Data Book for Gasification-Combined-Cycle Plants: Phased Capacity Additions," EPRI Report No. EPRI AP-4345, Electric Power Research Institute, Palo Alto, California, January 1986.

Lower capital costs by a factor of 2 plus a 20 percent improvement in heat rate make the GTCC system very competitive over conventional coal-fired boilers. The ability to add capacity in modest sizes, 100 to 250 MW per unit, is an advantage for small systems or where load growth is modest. In the Asia/Pacific region where there is significant present and future natural gas available, the GTCC system is a promising and very competitive technology.

The largest commitment to gas turbine combined cycle systems comes from the Japanese utility industry (see Reference 10). The plan is for 7,200 MW to be built by 1994. Tohoku Electric brought on stream two 548 MW GTCC systems in 1985 that were supplied by Mitsubishi. The measured efficiency was 49.1 percent (low heating value [LHV] for methane). Using the high heating value (HHV) typically used in U.S. efficiency calculations would yield 44 percent efficiency. The NOx level was 10 ppm obtained using a low NOx combustor followed by selective catalytic reduction using ammonia hydroxide in the exhaust streams. The combination of high efficiency and very low emitted pollution is a major accomplishment. The approximate 10 point gain in efficiency over conventional scrubbed coal or heavy fuel oil fired steam plants is a significant fuel savings for these natural gas fired GTCC systems. While less than one year of operation has been logged on these plants, the current and projected availability of these plants is high, making them attractive competitors for base-load as well as intermediate-load applications.

The first of the GTCC systems at Tohoku Electric was built in approximately 30 months and placed into commercial use just 34 months from the start of construction. Modular design and factory construction of the heat recovery boiler (4 units: economiser, evaporator, SCR module, super heater) plus three gas turbines (118 MW) and one steam turbine (191 MW) helped to reduce the plant construction time.

The initial low capital overnight cost of GTCC--$500/kW in the United States, and $400 to $500/kW in Japan--is further aided in holding final plant costs down by the short construction period. For a 3 percent escalation rate and 12 percent interest the following is the percentage increase in overnight costs during time of construction, assuming a linear construction expenditure rate.

Construction	Increase in Overnight Cost by Escalation and Allowance for Funds Used During Construction
3 years	+25%
5 years	+46%
10 years	+116%

The lower capital cost of GTCC plants allows them to use more expensive fuels and still be cost competitive. Typically, coal-fired power plants will cost at least two times that of GTCC plants. At $500/kW for GTCC systems and with a 14 percent rate of return on capital, this results in at least a $1.50/MMBtu fuel price premium that can be paid for a natural gas fueled system. The lower operating and maintenance costs of GTCC over coal-fueled plants yield at least another $1.00/MMBtu cost advantage for the clean-burning fuel. Thus, lower capital and operating costs of natural gas-fired plants allow fuel premiums of $2.50/MMBtu or larger on a comparative cost of producing one kWhr of electricity. The higher thermal efficiency of the GTCC systems (approximately 20 percent) further help to offset the premium paid for a clean-buring fuel.

The advanced GTCC systems with heat rates of 8,000 Btu/kWhr (η = 42 + percent) are believed to have even further potential for improvement.

Higher gas turbine temperatures through material improvements and interblade cooling are currently under development and expected soon in commercially available equipment with projected heat rates around 7,500 Btu/kWhr. Further potential efficiency gains may be possible using the isothermal turbine concepts employing interstage reheat. Gas turbines for stationary base-load electric power generation have the potential to add 5 to 10 percentage points to their overall thermal efficiency during the next 20 years through continual design optimization.

Methane for Electricity Generation: Via Fuel Cells

Fuel cell systems using phosphoric acid electrolytes and hydrogen as the fuel are under commercial development by United Technologies. Funding from the Gas Research Institute (GRI) and the Department of Energy (DOE) have produced a 40 kW system and units are being field-tested in the United States and Japan. Concurrently, EPRI and DOE are funding a parallel development at United Technologies of an 11 MW phosphoric acid fuel cell. Recently, United Technologies and Toshiba of Japan entered into a joint agreement for development of the phosphoric acid fuel cell. These two companies are currently seeking purchase commitments for 23 systems from utilities worldwide to begin initial production of these 11 MW systems. The price on these systems has met with resistance from electric utilities and at this time the marketing success of the first production units is unknown. The maximum system efficiency is approximately 41 percent and the cost exceeds $2,000/kW (current price is $2,000/kW + site costs). The high capital cost and low efficiencies, coupled with no appreciable gains in cost as unit sizes increase, make fuel cells a poor bet for large-scale electric power generation. The GTCC system is much more promising for intermediate and base-load power.

Specialty applications in commercial or large residential complexes may be an application. Alternately, modest power generation in a city's central core where load exceeds existing transmission facilities is a potential application. Fuel cell systems are unlikely to be major sources of methane demand in the next decade, if at all, unless new technology not now foreseen becomes available.

INDUSTRIAL COGENERATION: A SOURCE OF NATURAL GAS DEMAND

The installation of cogeneration facilities becomes economic when the electric power generated produces revenue (or savings) that justifies the additional capital required for a cogeneration facility over a simple steam-raising facility. For plants in the range of 125 x 10^6 Btu/hr to 1,000 x 10^6 Btu/hr, the additional capital for the cogeneration part of the system is approximately 130 percent for the smaller and 85 percent for the larger systems. Thus a cogeneration plant will involve a capital investment approximately two times that of a boiler producing process steam. The ability to generate enough revenue from electricity production to justify the larger capital makes cogeneration systems very sensitive to the plant steam-load factor. In general, load factors at least 50 percent or larger are required for cogeneration to be feasible (usually found in petrochemical plants, steel plants, etc.).

For the United States, the opportunities for cogeneration are in six major industrial sectors (SIC 20 - Food; SIC 22 - Textile Mill Products; SIC 26 - Pulp and Paper; SIC 28 - Chemicals; SIC 29 - Petroleum and Coal Products; SIC 33 - Primary Metals). Natural gas has to compete in price with middle distillate and residual fuel oil to obtain the cogeneration market. Dual fuel capability is usually standard practice in package boilers and cogeneration facilities. It is thus easy to shift from gaseous to liquid fuels and prices will determine which fuel is used.

CONCLUSIONS

The prospect for new technology to be a major driving force for methane to develop new markets is very poor except for GTCC systems used for electric power generation. In the United States and probably most other consuming countries, this requires the delivery of methane to the burner tip below $4.00/Mcf. For base-load plants with a 70 percent load factor using an advanced GTCC system with 8,000 Btu/kWhr, every $1.00 per Mcf represents a $0.008 per kWhr fuel cost. For capital charges of 18 percent, every $500/kW plus a 70 percent load factor also represents a $0.015/kWhr capital cost. Considering all factors (clean emissions, modest sized units of capacity, low capital costs, well-established technology), the gas turbine or GTCC system gives methane a reasonably competitive position against any other electric power generation system--heavy fuel oil, coal, or nuclear. A 1,000 MW GTCC system at 8,000 Btu/kWhr and a 70 percent load factor represents a potential natural gas demand of 50 billion cu. ft./yr. For Japan, the 7,200 MW of GTCC systems that are planned to be completed by 1994 represent an additional 350 billion cu. ft./yr of natural gas demand.

Electric power generation thus represents one of the major sources of new natural gas demand.

Natural gas as an energy source for residential, commercial, and industrial thermal loads is dependent upon the delivery system, not new end-use technology. While considerable improvements have been made in furnaces for all applications and gas-driven thermal machines for air conditioning, process drying, compression, etc., there is no outstanding technology development that appears to offer unique opportunities for new natural gas applications in conventional markets. Natural gas has always been and still is a very desirable primary energy source for these markets when it can be delivered at competitive prices.

The potential for natural gas in the transportation market exists but, as discussed earlier, has the disadvantage of requiring special engines and a dedicated delivery system. The transformation of methane to gasoline and middle distillate has significant process and energy costs. While the technology has improved, no outstanding breakthroughs have been made, nor can any be forecast with any degree of assurance. The stable CH_4 molecule is a difficult one to transform into the higher energy density and more transportable higher-order liquid hydrocarbons.

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