4

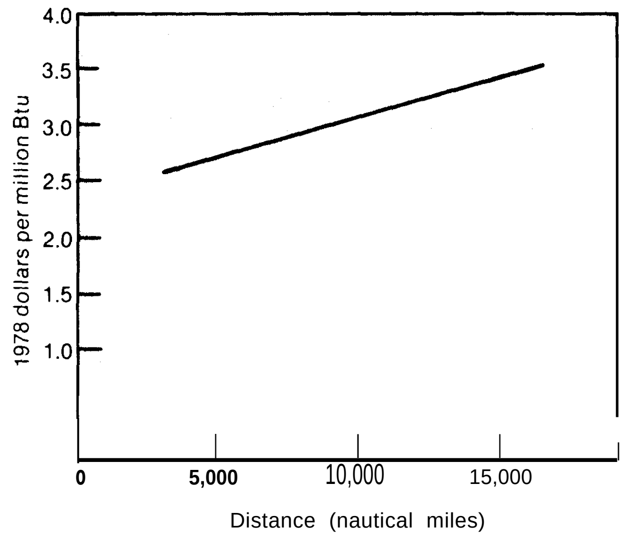
Project Structure, Cost, and Financing

Project Structure, Cost, and Financing

The only present way to transport natural gas across ocean distances is to ship it as a liquid at — 260o F in specially insulated tankers. Methane, the principal constituent, is 600" times denser in liquid form than as a gas at room temperature, and this reduction in volume permits economical use of ships notwithstanding the cost of specialized liquefaction, revaporization, storage, and other terminal facilities.

Liquefied natural gas (LNG) projects are expensive. The total capital required for a world-scale venture involving 1 billion cubic feet per day (Bcf/d) beginning in the early to mid-1980s is nearly $.5 billion (1978 dollars). Approximately 40 percent of this cost is applied to the gas production and liquefaction facilities in the exporting nation, about 40 percent is needed for ships, and the balance of about 20 percent is for the import terminal and revaporization facilities in the United States. The cost of service, including operating~ expenses and amortization of the initial investment, for a typically structured project appears as a function of distance in figure 12.

Figure 12.— Cost of Service as a Function of Distance for a Typical LNG Import Project in the Fifth Year of Operation (1990)



SOURCE OTA, based on Jensen Associates data

An LNG importer must pay in addition to transportation costs a return to the producing country for the wellhead value of the gas, and supply contracts generally contain f.o.b. price provisions calculated to make imported gas competitive with distillate fuels in the U.S. market. However, escalation formulas in present contracts are such that delivered LNG prices should rise more sIowly than those of products from foreign crude oil.

Financial risk represents another element of cost, and the public guarantees in part the commercial success of' an LNG project through regulated retail prices designed to allow investors to recover portions of their cost notwithstanding some kinds of failure or loss. on the other hand the risk of' unilateral interruption of shipments by the supplier country is reduced by high capital costs and a project structure that ties buyer and seller into a tight economic partnership.

LNG projects

Commercial I.NG trading began in 1964 with the Algeria- United Kingdom project, involving ().()4 trillion cubic feet (Tcf) of gas per year. Over the past 15 years, the international trade has grown to 12 currently operating projects totaling 1.75 Tcf/yr from six producer countries (table 24). Japan has the largest portion of present imports (45 percent), f'ollowed by Western Europe (29 percent) and the United States (26 percent). However, the rate of future expansion in international LNG trade is uncertain. Should all the projects listed in table 24 materialize, worldwide trade in LNG would increase to 6.44 Tcf/yr by the mid-1980's, of which U.S. imports

59-406 0 - 80 - 6

Table 24.–Operational LNG Projects, as of July 1,1979

Origin	Destination: Country	Destination: Terminal	Purchasing companies	Startup date	Contract Volumes[a] Tcf/year	Remarks
OPERATING						
Algeria						
Arzew	United Kingdom	Canvey Is.	British Gas Corp.	1964	0.04	Contract has been extended
Arzew	France	Le Havre	Gaz de France	1965	0.02	
Skikda	France	Fos	Gaz de France	1972-73 1971-77	0.14	
Skikda	United States	Everett, Mass.	Distrigas	1978	0.05	
Skikda	Spain	Barcelona	Enagas	1976	0.55	
Arzew	United States	Cove Pt., Md. Savannah, Ga.	Columbia Gas, Consolidated Gas, Southern Energy	1978	0.40	
Alaska						
Kenai	Japan	Negishi	Tokyo Electric Tokyo Gas	1969	0.05[b]	
Brunei						
Lumut	Japan	Negishi Sodegaura Semboku	Tokyo Electric Tokyo Gas Osaka Gas	1972	0.26[b]	
Libya						
Marsa el Brega	Spain	Barcelona	Catalana de Gas	1971	0.04	
Marsa el Brega	Italy	La Spezia	Snare	1970	0.09	
Abu Dhabi						
Das Island	Japan	Sodegaura	Tokyo Electric	1977	0.10[b]	
Indonesia						
Badak (Bontag)	Japan	Himeji Chita	Kansai Electric Chubu Electric	1977	0.16[b]	
Arun (Lhakseumawe)	Japan	Tobata Semboku	Kyushu Electric Osaka Gas Nippon Steel	1978	0.22[b]	
APPROVED						
Algeria						
Hassi R'mel (gas pipeline)	Italy	Sicily	ENI	1981	0.44	Pipeline replaced an LNG project
Arzew	Belgium	Zeebrugge	Distrigaz	1982	0.20	Terminal site uncertain
Arzew	France	Montoir	Gaz de France	1980	0.20	
Arzew/Skikda	United States	Lake Charles, La.	Trunk line	1980	0.18	
Arzew/Skikda	West Germany Netherlands	Wilhelmshaven Emshaven	Ruhrgas, Salzgitter, Gasunie	1984	0.41	
Arzew/Skikda	West Germany	Wilhelmshaven	Brigitta-Thyssen	1985	0.16	
Indonesia						
Arun	United States	Pt. Conception	Pacific Gas & Electric So. California Gas	1983	0.20	Approved Sept. 26, 1979.
Alaska						
Cook Inlet	United States	Pt. Conception	Pacific Gas & Electric So. California Gas	?	0.15	Approved Oct. 12, 1979. Added reserves needed
PROBABLE						
Australia						
Dampier	Japan	Tokyo	Tokyo Electric Tokyo Gas, etc.	1984-85	0.33	

Table 24.—Operational LNG Projects, as of July 1, 1979—continued

Origin	Destination: Country	Destination: Terminal	Purchasing companies	Startup date	Contract volumes[a] Tcf/year	Remarks
Malaysia						
Bintulu	Japan	Sodegaura	Tokyo Electric Tokyo Gas, etc.	1983	0.31[b]	
Indonesia						
Badak (exp.)	Japan	Various	Chubu Electric Osaka Gas Kansai Toho Gas	1983	0.16[b]	
			POSSIBLE (active)			
Nigeria						
Bonny	United States/ Europe		Columbia, Consolidated, Southern, Mich-Wis, Trunkline and others	Mid 1980s	0.6	
Trinidad						
Pt. Lisas	United States	Gulf coast	Tenneco Peoples	1984-85	0.18	
Canada						
Melville Is. (Arctic Is.)	Canada/ United States	St. Lawrence	Southern Natural Gas	1982-83	0.09	
Australia						
Dampier	United States	Pt. Conception	So. California Gas Pacific Gas & Electric	late 1980's	0-0.15	
Cabo Negro	United States	Pt. Conception	So. California Gas Pacific Gas & Electric	1983-85	0.08	
Indonesia						
A run (exp.)	Japan	Various		1985	0.12	
			POSSIBLE			
Algeria						
not announced	Sweden	Wilhelmshaven	Swedegas AB	1984-85	0.07	Trends in Swedish energy policy cast doubt on this project
not announced	France		Gaz de France		0.18	
not announced	Switzerland				0.000018	
not announced	Austria	Ferngas; OMV			0.07	
not announced	Yugoslavia				0.07-0.11	
Arzew	United States	La Salle	United, El Paso El Paso	mid 1980's	**0.40**	
Qatar						
not announced	Japan	Tokyo	Tokyo Electric Tokyo Gas Mitsubishi Shell	mid 1980's	**0.31**[b]	
Abu Dhabi						
Rubais	Japan		C. Itoh & Co.	mid 1980's	0.25[b]	
Colombia	United States				**0.05**	
U.S.S.R.						
Yakutsk	United States Japan		Tokyo Gas Tokyo Electric El Paso Occidental		0.75	

Table 24.—Operational LNG Projects, as of July 1, 1979—continued

Origin	Destination: Country	Destination: Terminal	Purchasing companies	Startup date	Contract volumes[a] Tcf/year	Remarks
Murmansk	United States Europe				0.75	
United Kingdom						
North Sea	United Kingdom				0.75	Floating barge liquefaction plant.
Iran	Japan				0.13	
Thailand	Japan					
China	Japan					
New ***Zealand***	Japan					Maui gas, Mobil has proposed an automotive fuel project

[a]At 1,020 Btu/cf Normally contract volumes are given f o b the liquefaction plant
[b]Indicates c. i. f. volumes, i e , delivered.

SOURCE Jensen Associates, Inc.

would account for about 36 percent. Not all of these projects will come to fruition, however, and most past projections regarding the future of LNG trade have overestimated the rate of growth. The possible level of LNG imports is particularly uncertain in the U.S. market, where Government policy regarding LNG imports has been difficult to predict. The Department of Energy (DOE), the Federal Energy Regulatory Commission (FERC), and State Public Utilities Commissions decide on all aspects of individual projects case-by-case in regulatory proceedings that take years, Given the present uncertainties, a more reasonable expectation would be that worldwide trade in LNG will reach 4.19 Tcf/yr by 1985, of which 46 percent will move to Western Europe, 34 percent to Japan, and 20 percent to the United States.

A baseload LNG project is a complex and highly capital-intensive venture, consisting of' three primary segments (figure 13):

1. liquefaction, storage, and loading facilities in the producing country;
2. transportation facilities (cryogenic tankers); and
3. terminal and revaporization facilities in the receiving country.

Total capital investment of a 1 Bcf/d project can exceed $5 billion (1978 dollars). The cost varies with such factors as the gas-gathering system, shipping distance, and new delivery pipelines required. The cost of liquefaction and related facilities in the producing country can account for as much as 50 percent of overall project costs. [1]

What follows is a more detailed description of the physical and cost structure in LNG import projects, including the price policies of the exporting countries. Two LNG projects are used for the purpose of illustration: Pac Indonesia and Algeria 11. Although only one of them has received final U.S. Government approval as of this writing, * the projects are good examples, because their costs and pricing provisions are recent and represent current LNG trade.

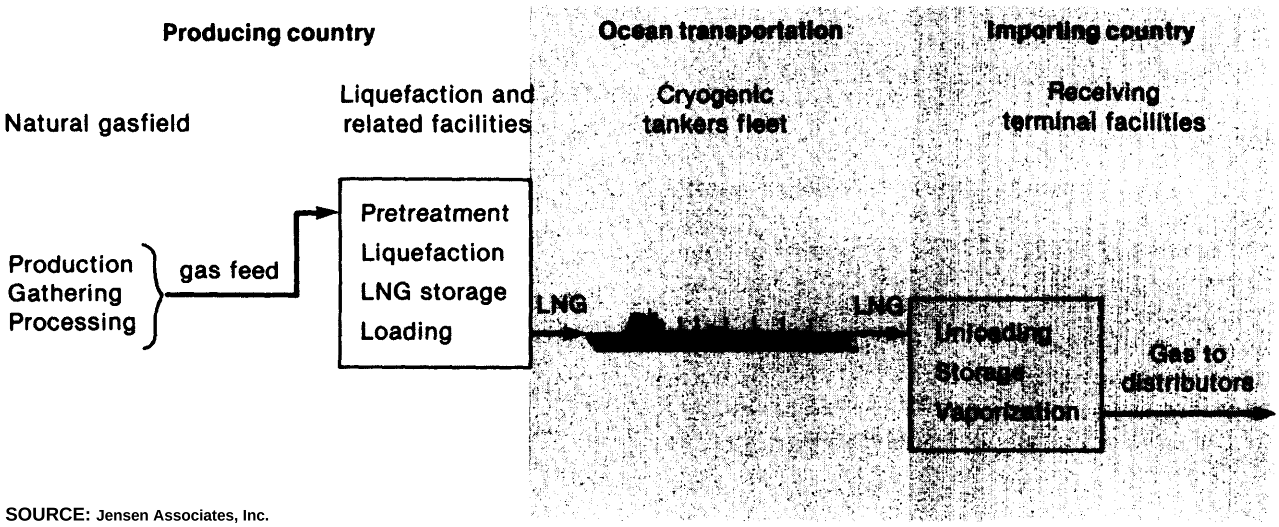
Algeria II

The proposed project was based on an October 28, 1975, contract, as amended, between Sonatrach (Societe Nationale pour la recherche,

[1]For development of typical LNG cost estimates, see K. N. Di Napoli, "Estimating Costs for Base-load LNG Plants," *Oil and Gas Journal*, Nov. 17, 1975.

*The Algeria II project was conditionally approved by the FPC/FERC administrative law judge on Oct. 25, 1977. However, under the Department of Energy Organization Act effective Oct. 1, 1977, import jurisdiction was transferred to DOE's Energy Regulatory Administration (ERA). DOE ERA reversed the initial decision in its Opinion No. 4 of Dec. 21, 1978. Permission for rehearing has been recently granted.

Figure 13.— Major Segments of an LNG Import Project



SOURCE: Jensen Associates, Inc.

la production, le transport, la transformation et la commercialization des hydrocarbons) and El Paso Atlantic Company (a subsidiary of El Paso).[2] It provided for the sale of LNG containing 410,625 billion Btu annually, for a term of 20 years. This amount is equivalent to approximately 1 Bcf/d of natural gas at 1,125 Btu/cf.

The gas was to be produced by Sonatrach, the Algerian State oil and gas company, in the Sahara, pipelined 315 miles to the Mediterranean coast, and there liquefied, stored, and loaded aboard LNG tankers. El Paso Atlantic, which would acquire the title to the LNG at the tanker's receiving flange, would arrange for the transportation by a fleet of 12 cryogenic tankers to an import terminal and regasification plant (the La Salle terminal) located near Port O'Connor, Tex. Six of the ships would be provided by Sonatrach and six by Atlantic. As each vessel entered the international waters off the coast of A]geria, the title to the LNG would pass to El Paso Eastern, the legal importer. The La Salle terminal facilities would be built and operated by the El Paso LNG Terminal Company which receives, stores, and revaporizes the LNG. At the outlet of the terminal, the gas would be sold by El Paso Eastern: 65 percent to the El Paso Natural Gas and 35 percent to the United LNG Company. The entire quantity would be pipelined to the United Gas Pipeline Company's existing mainline facilities near Victoria, Tex. There, United LNG's 35 percent of the gas would be sold to its parent, United Gas Pipeline, which serves other major pipelines that deliver gas throughout the area east of the Mississippi. The remaining 65 percent of the gas would be transported via a new 432-mile-long pipeline to be built by El Paso Natural to its Waha treating plant located in Reeves County, Tex., where it would enter the present El Paso system serving the Southwest and California.

In 1977, at the time of the participants' initial application to the Federal Power Commission (FPC) for import authorization, the total capital costs of the project were estimated as follows:*

- $2,300 million for gas wells, pipeline, and liquefaction facilities in Algeria (including $391 million for interest on funds used during construction);

'The El Paso Companies involved in the project, and their genealogy, are as follows:

The El Paso Company
El Paso LNG Company — El Paso Natural Gas Company [El Paso Natural]
El Paso Eastern Company ("Eastern")
El Paso LNG Terminal Company ("Terminal")
El Paso Atlantic Company ["Atlantic")

SOURCE Initial Decision, Upon Applications to Import LNG from Algeria, FERC 01. I 2.5, 1979, Docket Nos CP 77.330, et al p 4

* In 1975-76 dollars.

- $1,752 million for 12 vessels and shoreside facilities required for ocean freight; and
- $719 million for receiving terminal, regasification plant, and new pipelines in Texas.

Pac Indonesia

Two gas utilities in California—Pacific Lighting Corporation (PLC) and Pacific Gas and Electric Company (PG&E)—have formed a partnership to import LNG from Indonesia through two subsidiaries. The first subsidiary, Pac Indonesia, has entered into a contract with Pertamina, the Indonesian Government-owned oil and gas company, for the purchase of 226,194 billion Btu annually (approximately 550 MMcf/d) for a period of 20 years. *

The gas for the project would be produced in the Arun field of Northwest Sumatra by Mobil Oil Indonesia, Inc., under a production-sharing contract with Pertamina. From the field, the gas will be transported via a 20-mile pipeline to the liquefaction plant, which will be owned and financed by Pertamina.

Pac Indonesa has entered into contracts for the hire of nine cryogenic tankers to transport the purchased LNG from North Sumatra to California. Three of the vessels have already been completed in foreign shipyards and plans call for the remaining six to be constructed in the United States.

The LNG would be delivered to a proposed receiving terminal to be constructed by Western LNG Terminal Associates, the second subsidiary, near Point Conception, Calif. After storage and revaporization, the gas will be transported via a new 112-mile pipeline to the transmission systems of PLC and PG&E, which will jointly own the pipeline. Pac Indonesia will sell half of the gas to Southern California Gas (So Cal), a wholly owned subsidiary of PLC, and the other half to PG&E. The two utilities combined comprise the transportation and marketing mechanism that handles virtually all natural gas consumption in California.

Based on 1976-77 cost estimates, the capital expenditures for the project are as follows:

- $869 million for the pipeline, liquefaction plant, and related facilities in Indonesia, (including an estimated $164 million for interest during construction but not the cost of developing the Arum gasfield);
- $1,230 million required for nine chartered tankers, including $930 million for six vessels to be built in the United States (at $155 million per ship);
- $436 million allocated for the receiving terminal and pipelines in California. These facilities, estimated to cost a total of $749 million, are to be shared by Pac Indonesia and Pac Alaska. On the basis of the contracted throughputs, the cost allocated to Pac Indonesia would be just over 58 percent of the total.

Pricing policies of exporting countries

As a consequence of large crude oil price increases in 1973-74, the LNG projects negotiated or renegotiated after 1974 contain fuel-related escalation clauses applicable to their base f.o.b. ship's rail prices, the purpose of which are to establish parity between LNG and alternative fuels. Minimum (floor) price levels designed to remove the producing country's investment, or to assure the timely repayment of project-related debt, have also become standard contractual provisions. In addition, the pricing formulas usually contain safeguards against currency fluctuations. Sonatrach has adopted a fairly uniform f.o.b. pricing policy for all of its recent contracts—U. S. and European alike. A review of the major price provisions in the Algeria II and Pac Indonesia contracts provides a good indication of a LNG pricing mechanism that typifies all recent LNG trades.[3]

*The original contract between Perusahaan Pertambangan Minyak Dan Gas Bumi Negara (Pertamina) and Pac Indonesia's predecessor—Pacific Lighting International, S, A.—was signed in September 1973. Since then, it has been amended three times in regard to its pricing provisions. The last amendment was introduced in July 1978.

[3]For a more detailed discussion of LNG pricing mechanisms, see "Economic Considerations and Operating History of Base-Load LNG Projects, " Philip J. Anderson and Edward J. Daniels, Institute of Gas "technology, December 1977.

The procedural history of pricing clauses negotiated and approved in the Pertamina-Pac Indonesia contract illustrates the evolution of policy involved in f.o.b. pricing. Under the original September 6, 1973, Pertamina contract, the price to be paid by Pac Indonesia's predecessor would be $0.63/million Btu (MMBtu) plus 2-percent annual escalations, adjusted by a currency reevaluation factor and subject to certain floor and ceiling levels. The Indonesian Government did not, however, approve the contract on the ground that the price formula which contained a fixed escalator would not reflect the development of world energy prices in general and, in particular, was not linked to the price of Indonesian crude oil. Consequently, the first amendment issued January 9, 1975, established a new f.o.b. base price of $l.25/MMBtu—approximately double the prior price—and deleted the fixed 2-percent-per-year price escalator. A new escalation formula reflected equally changes in Indonesian crude oil export prices and U.S. energy prices as measured by the Bureau of Labor Statistics wholesale index for fuels. The renegotiated formula no longer contained a floor or a ceiling, so it offered no protection to either party against potentially wide fluctuations in LNG price through the operation of the escalation clause. The possibility of a fall in crude oil prices presumably led to the minimum bill provision, which assured Pertamina's lenders that the price of LNG would be at least sufficient to service Pertamina's debt and to meet operating and maintenance expenses (second amendment, issued October 28, 1975).

Although the FPC administrative law judge conditionally approved the proposed project and its pricing provisions, one of FPC'S successor agencies, DOE's Economic Regulatory Administration (ERA), did not allow the automatic flow through of cost increases under the price escalator clause, charging that the provision was tied too directly to future movements in OPEC-administered prices, and that the U.S. fuels index would be influenced by future domestic energy pricing policy and by the price of the import itself; thus creating a significant self-compounding effect.[4] This rejection of the escalator later led to yet another price amendment, issued July 28, 1978, and approved by DOE/ERA shortly thereafter.

Under the renegotiated escalation clause, the Indonesian half of the escalator will still be tied to Indonesian crude oil export price, but with the added constraint of a 15-percent absolute limit on annual fluctuations in that price. Any adjustment above the 15-percent absolute limit or below the floor can be carried forward until it can be applied. The U.S. half of the escalator was changed to substitute the broader based Bureau of Labor Statistics "all commodities" index for the former fuels-related index.

The pricing formula, as finally approved, is shown in figure 14. The calculated contract sales price is $1.25/MMBtu multiplied by the equally weighted changes in the Indonesian crude price (subject to a limit on annual fluctuations) and in the U.S. wholesale index for all commodities. A contract sales price is then multiplied by a currency reevaluation factor to arrive at the billing prices. *

If at any time during the debt amortization period, the calculated contract sales price should be lower than the minimum price calculated by Pertamina, the latter will be the billing prices

The Pertamina-Pac Indonesia contract includes a "most favored nation clause" under which Pac Indonesia would be entitled to a contract sales price for LNG no higher, on an f.o.b. equivalent basis, than that paid by any other importer under any other contract with Pertamina in existence as of January 9, 1975. Otherwise, the contract does not provide for future price reviews.

The Algerian pricing system has a twofold purpose: 1) to ensure that imported *gas is* com-

[4]DOE/ERA, Opinion No. 1, Dec. 30, 1977.

* However, operation of the currency factor cannot reduce the billing price below what it was on the date of first deliveries, nor increase it more than 25 percent above the otherwise applicable price in any given calendar quarter.

[5]The FPC administrative law judge who conditionally approved the Pac Indonesia project interpreted the minimum bill subject to all the provisions of the sales contract. Thus, Pac Indonesia would not be required to pay for quantities *not delivered* "whether by reason of Pertamina's fault or force majeure or assimilated circumstances occuring in any part of the facilities, including the ships or terminals" (Initial Decision, p 62)

Figure 14.—Pricing Provisions of Pac Indonesia and Algeria II Import Projects (U.S. dollars per million Btu, gross heating value, loaded f.o.b.)

Pac Indonesia

Contract sales price

Calculated quarterly.

$$P = P_o x (0.5 \frac{A}{\$11.00} + 0.5 \frac{W}{135.0})$$

P = calculated contract sales price.

P_o = $1.25.

A = applicable Indonesian crude oil price.

W = applicable value of the index of wholesale prices—all commodities

Currency revaluation factor

Applies to the contract sales price.

$$B = 1 + \frac{\Sigma \frac{c2}{c1} - 1}{11}$$

cl = the commercial rate of exchange in effect on the date of initial deliveries for each of the currencies.

C2 = the arithmetic average of the commercial rates of exchange on the applicable dates in each quarter for each of the currencies.

B = 1 until its absolute value changes at least by 0.1 o/o. Thereafter new value for B used only if it differs from old by 0.1 % or more.

Maximum B = 1.25.

Minimum contract sales price

During its debt amortization period Pertamina will calculate a price sufficient to meet:

1) 'epayment of principal amount (including nterest during construction),

2) ɔayment of interest when due, and

3) ɔayment of projected costs of operation and naintenance.

Algeria II

Contract ("invoice") price

Calculated semiannually.

$$P = P_o (0.5 \frac{F}{F_o} + 0.5 \frac{F^1}{F^1_o})$$

P = invoice price.

P_o = base price equal to $1.30 as of July 1, 1975.

F = price of No. 2 fuel oil for New York harbor.

F_o = $12.642.

F^1 = price for No. 6 fuel oil, low pour, max. sulfur of 0.30%, delivered New York harbor.

F^1_o = **$13.505.**

Minimum price

Calculated monthly.

MP = MP_o (E + 1).

MP = minimum price.

MP_o = base minimum price equal to $1.30/MMBtu as of July 1, 1975.

E = arithmetic average of the results obtained by applying the formula:
R
~– 1 to each of **6** currencies.

A = average commercial exchange rate for each currency during July 1975.

B = average commercial exchange rate for each currency as measured by average purchase and sales rates for telegraphic transfer for each business day of preceding month.

E = O until its value increases by at least 0.1% as compared to O. Thereafter new value for E used only if it differs from old value by 0.1 % or more.

Floor MP = U.S. $1.30.

Recalculations of the minimum price will be made *once* according to the following formula:

$$MP^1 = \$.80 \frac{X}{2,300} + \$.15 \frac{Y}{60} + \$.35$$

MP1 = recalculated minimum price.

x = actual capital costs incurred by Sonatrach (in millions of dollars),

Y = actual operating costs of Sonatrach during the first year of operations (in millions of dollars).

adjust the minimum price only upwards, and with no upper limit.

Since oil prices are likely to continue rising, the contract ("invoice") price rather than the minimum price will probably determine Sonatrach's billing price. Recently, Sonatrach and El Paso's subsidiary have renegotiated the invoice price formula in a 1969 contract which underlies the Algeria I project. * Under the 1969 contract, the current price for LNG f.,o.b. Algeria would amount to some $0.363 /MMBtu. In rationalizing the price renegotiation, Sonatrach has observed that "in the decade since signing of the contract, the capital cost and operating costs of the project have increased substantially, and that, as a result, Sonatrach is suffering a huge financial burden while providing the cheapest incremental source of natural gas to the United States,"[7] The renegotiated base price will be $1.75/MMBtu, effective as of July 1, 1979. A series of discounts will be applied to this price ranging from $0.60/MMBtu for the remainder of 1979 and then decreasing by $0. 10/MMBtu increments until mid-1983. The price escalator is tied to No. 2 and No. 6 fuel oils as described for the Algeria 11 project.

Unlike the Pertamina contract, the Sonatrach agreement provides for the regular review of the contract sales price. The parties are expected to meet during the first year after regular delivery begins, and every 4 years thereafter, to ascertain whether the prevailing price of the gas resulting from this project is still competitive in the U.S. energy markets. Furthermore, either party may request a meeting at any time if the particular indices selected to reflect fuel oil prices in the U.S. market fail to do so adequately.

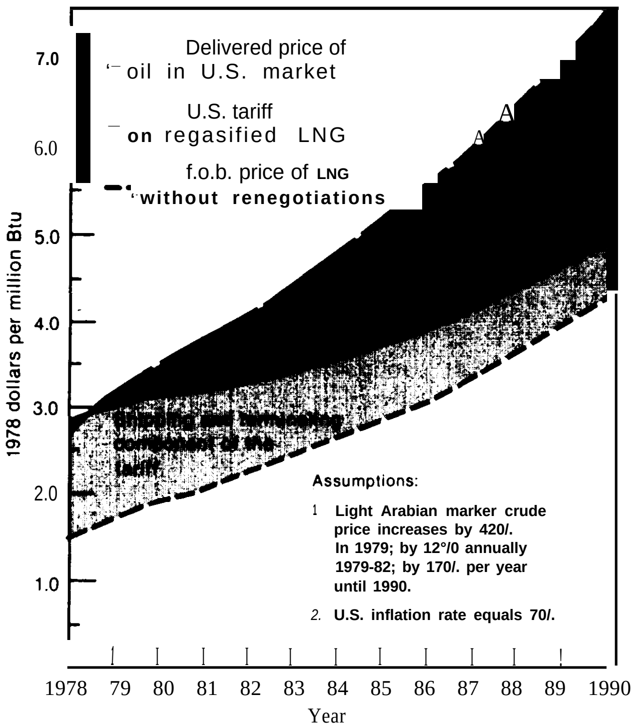
This important price provision may result in significantly higher f.o.b. prices to Sonatrach than would otherwise prevail without renegotiations. The reason is the disparity, which is

*In the Algeria I project El Paso Algeria purchases 1 Bcf/day equivalent of LNG from Sonatrach and delivers it to three importing pipeline companies—to subsidiaries of Consolidated Natural Gas Company and Columbia Gas System, Inc., at *Cove Point, Md.*, and to a subsidiary of Southern Natural Gas Company at Elba Island, Ga. Deliveries of LNG under the Algeria I project commenced on Mar. 1, 1978.

[7] *The Wall Street Journal,* May 14, 1979.

likely to develop over time, between the U.S. tariff imposed on the regasified LNG and the price of oil in U.S. markets (figure 15). In light of

Figure 15.—Comparison of the Forecast U.S. Tariff on Regasified LNG in the Algeria II Project With the Delivered Price of Fuel Oil*



. Every 4 years a portion of the difference between the delivered price of oil and the U.S. tariff on regasified LNG is liable to Sonatrach's claims through the operation of the price renegotiation clause.

SOURCE: Jensen Associates, Inc.

the price review provision, Sonatrach may claim this potential price differential for its own benefit. The price disparity–represented on the graph by the darker tone–will occur for the following reasons:

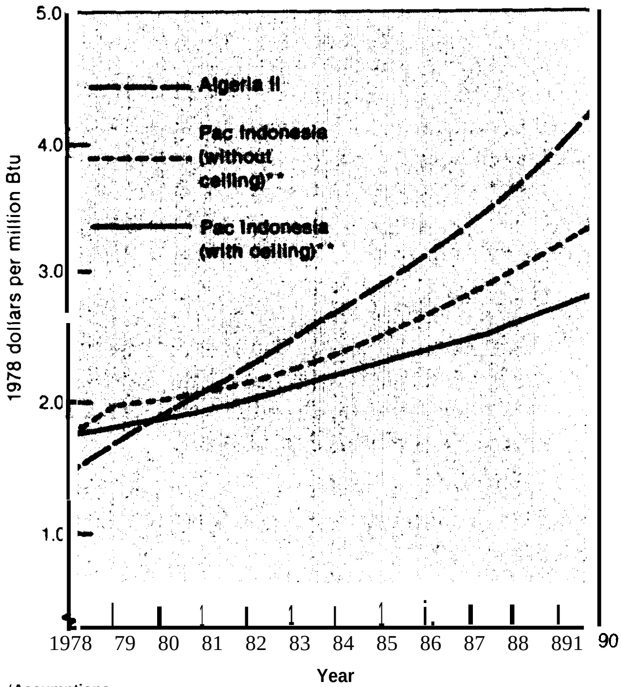
- The LNG (f.o.b.) price component of the tariff grows in the same proportion as the oil price, but since this rate of growth applies to a smaller base, the dollar difference between the oil price and the f.o.b. price for LNG increases in time.
- The shipping and terminating components of the tariff consist largely of capital charges, which are either fixed or declining in time–depending on how the tariff is designed. Operating costs are subject to inflation, but they constitute a small portion of the tariff. For simplicity, the graph reflects the assumption that the shipping and terminating components of the tariff will remain fixed.
- Because the f.o.b. price of LNG grows more slowly in terms of-absolute dollars than the oil price, while the shipping and terminating costs are fixed, a gap develops and grows between the price of oil and the tariff for the regasified LNG.

Revisions of f.o.b. price may well serve as a vehicle for liquidating such disparity by adding the price differential to Sonatrach's f.o.b. price for LNG. It should also be noted that by keeping the price of the gas competitive with that of oil, the price revision clause assures the marketability of Algerian gas in the United States. For instance, should the regasified LNG become more expensive than reference New York harbor fuel oils, the price renegotiation clause may be invoked to bring the price of Algerian gas down to the competitive level.

Conditional approval of the Algeria 11 project by the FPC/FERC administrative law judge on October 25, 1977, was subsequently reversed by DOE/ERA. Much of the ERA criticism of Sonatrach's price provisions echoed its earlier objection to the Pac Indonesia pricing mechanism prior to the issuance of the last amendment. ERA objected mostly to the fact that the Sonatrach price escalator is entirely linked to future changes in OPEC-determined prices of premium petroleum products. The formula was found lacking safeguards against extreme oil price increases, since it imposed no limits on the annual price fluctuations. ERA also criticized the use of No. 2 and No. 6 posted prices rather than the weighted average of the actual transaction prices (the latter practice is proposed for the Pac Indonesia project). DOE/ERA, however, indicated that its approval of the Pac Indonesia project did not create a precedent for subsequent decisions. In other words, should Sonatrach adopt exactly the same price provisions as Pertamina, the project would not necessarily be approved on those grounds alone.

Figure 16 depicts the forecast f.o.b. prices derived from Sonatrach's and Pertamina's formulas assuming no price renegotiations. Under the

Figure 16.—Forecast f.o.b. Prices Paid for LNG in Pac Indonesia and Algeria II Projects*



'Assumptions:

1. Light Arabian marker crude price increases by 420/. in 1979; by 12°/0 annually 1979-82; by 17°A per year until 1990.
2 U.S. inflation rate equals 70/. annually.
3. Sonatrach's formula IS not periodically revised.

•"The two curves for Pac Indonesia show f.o.b. price calculated with and without the 15 percent ceiling on the annual fluctuations In the value of the Indonesia half of the price escalator.

SOURCE: Jensen Associates, Inc.

listed assumptions, Algeria 11 prices would increase considerably faster than Pac Indonesia's. This difference is due to two factors:

1. the expected rate of growth in the price of imported fuel oil is well above the presumed U.S. inflation rate; and
2. the annual ceiling on the Indonesian crude price increases limits the impact of the project price hikes.

Producing country facilities and related costs

PAC INDONESIA

The Pac Indonesia project entails the following operations in Indonesia:[8]

1. Production and gathering by Mobil Oil Indonesia of natural gas from the Arun field in North Sumatra and transportation of the gas via pipeline to Pertamina's liquefaction plant and marine terminal on the north coast of Sumatra.
2. Liquefaction, storage, and delivery of the LNG by Pertamina to the LNG vessels chartered by the Pac Indonesia LNG company at Pertamina's marine terminal.

The source of the gas is specified in the Pertamina contract as Contract Area "B" in the Aceh Province, * which contains the inland Arun gas condensate field discovered by Mobil Oil Indonesia in late 1971. Arun's proven reserves consist of an estimated 13 Tcf of nonassociated gas. For an LNG import project, nonassociated gas is preferable because the availability and stability of its supply is not adversely affected by potential interruptions and other problems in crude oil production.** Pertamina has contracted to sell LNG produced from Arun not only to Pac Indonesia by also to a group of five Japanese purchasers, who are scheduled to receive a slightly greater average daily volume.

The field is being developed by Mobil Indonesia, a wholly owned subsidiary of Mobil Oil Corporation, under a production-sharing contract with Pertamina. Eventually, 64 wells (with an average depth of 11,483 ft) will be needed to maintain an adequate gas supply for both Pac

'For description, see *Initial Derision on Importation of Liquefied Natural Gas From Indonesia,* FPC, July .22, 1977, *Docket NO.. CP 74-10* et al.

● Other producer countries, for instance Algeria, do not dedicate specific gas reserves to the fulfillment of individual contracts All Algerian gas reserves stand twhind all of its contracts.

* *For instance, Libyan gas is normally f'ound associated with crude oil and therefore gas availability depends to a great extent on crude oil production. Conservation policies in I.ihyan crude oil production will limit the quantities of gas available for liquefaction.

Indonesia and Japanese contracts. Due to unusually high reservoir pressure and temperature, each wellhead has to be equipped with specially designed piping and valves to control the gas stream.

From the field, the gas is transported to the Arun liquefaction plant at the north coast of Sumatra via a 42-inch-diameter, 20-mile-long pipeline with a design capacity of 1,777 MMcf/d–sufficient to transport the quantities of gas to service both the Japanese and the Pac Indonesia contracts. * As shown in table 25, the capital cost of the pipeline attributable to Pac Indonesia (half of the total) is $13 million.

Table 25.—Estimated Capital Costs of Indonesian-Based LNG Facilities for Pacific Indonesia Project' (millions of dollars)b

	Amount	Total
Pipeline		$ 13
Plant facilities		
Gas treating and liquefaction (3 trains)	202	
LNG storage and loading	81	
Plant utilities	59	
Site development, buildings, miscellaneous	88	
Contractor's home office costs	72	502
Supporting facilities		
Housing	49	
Communications facilities	6	
Other	7	62
Intangibles		
Project management	25	
Pre-startup and training costs	18	
Other (land, insurance, taxes, royalties, misc.)	35	78
Contingencies		50
Subtotal		**705**
Interest on funds used during construction:		**164**
Total		**$869**

aThese cost estimates include.
-The construction of liquefaction trains 4,5, and 6, assuming that procurement will take place in the world market and that mechanical completion of the 4th, 5th, and 6th trains will fake place in May, August, and November 1981 respectively.
-One-hlalf of the cost associated with the "common" facilities required to service all six liquefaction trains. Interest during construction is not included.
bresumably 1976 dollars.
cEstlmated by Jensen Associates, Inc.

SOURCE: Testimony of President.Director of Pertamlna, Piet Harjono, before the Federal Power Commlsslon, Feb. 25, 1977. Exhibit No. 175, FPC Docket No CP-74-160.

*Mobil Indonesia estimates that its total expenditures in the Arun field will amount to approximately $1 billion of capital and operating costs over the life of the Japanese and Pac Indonesia contracts.

The liquefaction plant converts the natural gas received from the pipeline into a liquid suitable for storage. A liquefaction facility consists of three main sections.

1. *Gas preparation* section-Any constituents, such as water vapor, which freeze at liquefaction temperatures and thereby plug the cryogenic equipment, must be removed. Removal of hydrogen sulfide is also required to meet LNG product specifications.
2. *Liquefaction* section—Mechanical equipment refrigerates the gas in order to liquefy it. At atmospheric pressure, the gas becomes a liquid at – 260° F and its volume diminishes by a factor of 600.
3. *Storage and loading* section—Insulated tankers retain the natural gas as a liquid at atmospheric pressure, and the loading system transfers the product from land-based storage to oceangoing tankers.

Approximately 3 years are required for the complete design and construction of a large liquefaction plant.

The liquefaction facilities proposed for the Pac Indonesia project (the Arun plant) represent equipment, processes, and costs that are typical for contemporary large-scale LNG plants. The overall Arun plant will include six liquefaction trains (three for the Japanese project and three for Pac Indonesia) together with feed gas pretreatment, refrigerant preparation and storage, LNG loading, and required offsite and utility facilities.9 The first three liquefaction trains have already been completed and, since August 1978, are serving Pertamina's obligations to the Japanese clients. The design and construction of the first three trains anticipated the projected six-train operation in terms of sizing, location, and utilities layout. This sharing of facilities

[9]Testimony of Mr. William H. Thompson, an employee of Bechtel Overseas Corporation, before the FPC on Jan. 7, 1976 (FPC Docket No. CP 74-160, et al. Exhibits 48-53). Bechtel performed detailed design studies and procurement services for the Indonesian facilities. It also has responsibility for the construction.

[10]When completed, the LNG plant will contain 355 km (220 miles) of carbon steel pipe; 28 km (17 miles) of stainless steel pipe; 70,000 cubic meters (91,600 cubic yards) of concrete; 305,000 cubic meters (400,000 cubic yards) of rock and aggregate; 6.7 million cubic meters (12.7 million cubic yards) of dredging; and 900 km (560 miles) of electrical cable. *Oil and Gas Journal,* Mar. 13, 1978.

Photo credit El Paso Co

Frost forms at the flange and on the articulating arm as cold LNG flows onto an LNG tanker at the loading terminal

provides for convenience in operation and savings in capital costs.

Each train is designed to produce LNG equivalent to 200 MMcf'/d* in 341 days Of annual operation. Three trains would therefore produce 102 percent of the annual quantity contracted for by Pac Indonesia. Indeed, the Indonesian plants that serve Japanese contracts (Arun as well as the somewhat older Badak plant) have consistently produced well in excess of their design capacity. Reliability of production is enhanced by the fact that both gas-processing and liquefaction trains are arranged in parallel so that the failure of any one component will not result in a plant shutdown. Table 25 indicates that liquefaction equipment represents the greatest portion of direct costs-about w percent. Pertamina estimateci the cost of one liquefaction train to be constructed for Pac Indonesia at $67 million, assuming that procurement would take place in the world market and that all three trains would be completed by the end of 1981. *

LNG will be stored in four double-walled insulated tanks of 125,000 m^3 each. The combined capacity of the four tanks equals 8.5 days ful] production of' the six-train plant. The loading system utilizes four pumps (with a fifth as a spare), which drain LNG from the tanks through two insulated pipes. The pipes terminate in loading arms that accommodate the relative movement of the ship **and** the pier. The system is capable of loading a 125,000 m^3 ship in 12 hours at either of two berths. The total cost of LNG storage and loading facilities is $162 mil-Iion, half of which constitutes Pac Indonesia's share.

ALGERIA II

The Algeria 11 project1[11] provides for daily delivery of approximately 1 Bcf/d, a volume close to the combined Pac Indonesia and Japanese contractual amounts. Liquefaction, storage, and loading facilities proposed for the Algeria 11 project are very similar to the ones described for the Arun plant. The six-train liquefaction facility at Arzew will use the same air products and chemicals (APCI) liquefaction process* * as in the Indonesia project. Plants are similarly arranged m parallel independent equipment trains. However, the facilities are designed to produce 105 percent of requireded yearly quantities in 330 days, thus, in theory, providing a greater allowance for downtime than the Arun plant (102 percent in 341 days). On the other hand, the Arzew plant will have relatively less storage space than the one at A run. Arzew will

*About 16 percent of the gross feed gas entering the plant is used as process fuel or lost in storage.

*The Pertamina-Pac Indonesia contract provides for delivery of LNG for maritime shipment commencing 38 months after receipt of all government approvals. Since the final U.S. approval of the terminal site has just recently been received, Pertamina will have to revise its proposed construction schedule.

[11]For more detailed discussion of the project, see *Initial Decision,* FERC, op.cit: and *Algeria II Project Summary,* El Paso, March 1977.

**This process utilizes a combined propane/mixed refrigerant cycle.

have three storage tanks, each with capacity of 100,000 m^3, to accommodate its 1,000 MMcf/d production, compared to Arun's four 125,000 m^3 tanks for the combined Pac Indonesia-Japanese production of 1,131 MMcf/d. Loading facilities are similar in both countries. Another common feature is sharing of equipment among projects. The six proposed trains for Algeria 11 will share certain supporting facilities—such as the cooling water system, steam system, and administration—with those already serving the Algeria I project, and the marine terminal will also serve other future projects.

As can be seen from table 26, the estimated capital cost of liquefaction and supporting facili-

Table 26.—Capital Costs per Million Btu of Daily Contractual Quantity (1976 dollars/million Btu/day)

	Pac Indonesia	Algeria II
Pipeline from gasfield to liquefaction plant	$ 21	$ 360
Liquefaction, storage, and loading	1,117	1,134
Subtotal.	1,138	1,494
Estimated interest on funds used during construction	265	348
Total.	$1,403	$1,842

SOURCE: Jensen Associates, Inc.

ties per million Btu of contracted daily production is comparable in both projects, reflecting similar processes and equipment. Sonatrach estimates the total capital cost of its Arzew plant at $1,276 million.

The most significant difference in the costs of the two projects lies in the respective field and pipeline systems. The Hassi R'Mel field, which will Supply gas for the Algeria 11 project, * requires only 22 wells with an average depth of 7,054 ft to supply the contract quantity. In comparison the Indonesian Arun field requires 64 wells with an average depth of 11,483 ft, plus special stream control equipment, to produce a similar amount of gas. These factors influence production costs, since, for example, drilling costs rise almost exponentially with well depth. Sonatrach has estimated that its field facilities for Algeria 11 would cost $228 million.

While the Pac Indonesia project requires only a 20-mile, 42-inch pipeline between the field and the liquefaction plant, the cost of which would be shared with the Japanese purchasers, Sonatrach plans to construct a 315-mile-long, 40-inch-diameter pipeline exclusively for the Algeria II project between Hassi R'Mel and the liquefaction plant at Arzew. Gas turbines at five compressor stations will maintain the pressure and flow. The estimated cost of the pipeline is $405 million, and as shown in table 26 the capital cost it represents per million Btu of daily contracted quantity is 17 times higher in the Algeria II project than in Pac Indonesia, reelecting the difference in the mileage. * Sonatrach estimates the total construction funds to be $2,300 million, and the annual operating cost at $60 million (1976 prices).

Transportation facilities—cryogenic tankers

Although they resemble conventional tankers in many ways, LNG carriers are highly specialized, with designs strongly influenced by the unique characteristics of LNG—especially its low density, cryogenic temperature, and flammability. [12] The principal feature is extensive insulation of the tanks to minimize vaporization en route and to protect parts of the ship's structure that would be damaged by extreme cold.

For the actual arrangements of LNG shipping, several alternatives are available. An importer, or exporter, may own the vessels or operate them through bare-boat charters, contracts of affreightment, time charters, or leverage lease arrangements. The proposed shipping arrangements for Algeria 11 and Pac Indonesia illustrate two of these alternatives.

The Algeria 11 fleet would consist of 12 tankers, each with cargo capacity of 125,000 m^3. Six of the vessels would be furnished by Sonatrach,

*Hassi R'Mel is one of the largest fields of nonassociated gas in the world, and it serves a number of Sonatrach contracts.

*In terms of pipeline capital costs per million Btu-mile of daily contracted quantity, Sonatrach's costs are similar to Pertamina's.

[12] For a comparison of the principal characteristics of an LNG carrier with those of an oil tanker of equivalent size see "Algeria II LNG Project Plants Detailed," Dr. Luino Dell'Osso, the *Oil and Gas Journal*, May 29, 1978.

Photo credjt Marty Saccone

Modern LNG tankers typically carry 125,000 m^3 of liquefied gas

the other six by El Paso Atlantic, presumably through indivual shipowners. I[s]

Each carrier will have an average service speed of 18.5 knots and will be capable of completing the round trip voyage of about 10, I50 nautical miles between Arzew and the La Salle terminal in an average of 28.4 days. With each ship operating from 332 to 333 days per year, the fleet will transport 143 loads of LNG annually, and a ship will arrive at the La Salle terminal approximately every 2.5 days. The energy delivered by the LNG carrier fleet for use in the United States will represent about 95 percent of the quantity loaded at the Arzew terminal. The small amount of vapor that boils off during the trip is consumed as fuel in the ship's boilers.

In addition to the double hull, other safety features of the carriers include a computerized collision avoidance system, bow thruster, lead-detection systems, dry-chemical and water fire-fighting systems, two complete navigational ra-

[13] It has not been finally decided whether Atlantic would build the six ships or charter them in some fashion. Most probably, each ship will be owned by a separate subsidiary of the El Paso LNG Company: three foreign and three domestic corporations are assumed. (*Summary of the Evidence*, El Paso Eastern Compay, et al., July 15, 1977, Docket Nos. CP 77-330, et al.)

dar systems, and five separate communication systems. 14

The estimated yard cost per vessel, constructed in a foreign shipyard—or in a U.S. shipyard, after construction differential subsidy*—would be about $106.5 million at 1976 prices. Other direct and indirect capital costs relating to the vessels (see table 27) would bring the estimated capital investment per ship to $142.6 million. Shore-based facilities for all] 12 vessels would be supplied by Atlantic at an estimated cost of $40 million. Thus, assuming that the same capital cost is required for Atlantic's and Sonatrach's vessels ($142.6 million per tanker), the aggregate investment by Atlantic would be $896 million, and $856 million by Sonatrach. The total estimated capital cost for the Algeria II tanker fleet would therefore amount to **$1,752** million, or $1)639 / MMBtu / d.

Operating costs of LNG vessels are a function of trip distance. For Algeria 11, the total fleet operating expenses per year have been estimated at $72.5 million (1976 prices). Atlantic's operating cost—for three foreign and three domestic vessels--would amount to. about $38 million annually (see table 28). The corresponding expenses for Sonatrach's vessels are expected to be the same as those estimated for Atlantic's foreign vessels, 15 and therefore would tot al about $34.5 million. The total operating costs amount to $(). 19 / MIMBtu delivered in the Algeria 11 project.

The Pac Indonesia project involves a different shipping arrangement. To transport the purchased LNG from North Sumatra to the United States (8,300" nautical miles each way), Pac Indonesia has entered into contracts for the hire of nine vessels. Three of the vessels have already been constructed in foreign shipyards, and plans call for the remaining six to be built in U.S. yards. All of the ships would be available to Pac Indonesia under time charter agreements, which provide for monthly billing beginning on specified dates. The FPC'S administrative law judge described these arrangements as follows:

> An important feature of the time charters and transportation agreements for all nine ships is the offhire provisions which, generally, absolve Pac Indonesia from payment during the period when the vessel is prevented from working through no fault of Pac Indonesia (for example, through collision, stranding, fire, or other

Table 27.—Estimated Capital Requirements for El Paso Atlantic—Six Vessels
(thousands of 1976 dollars)

Description	Amount	Total
Capital costs for six vessels		
Direct vessel capital costs		
Yard cost, six-125,000 m³ LNG carriers	$640,200	
Construction supervision, inspection, design, and plan approval	9,600	
Owner's outfitting equipment and expenses	10,884	
Preoperating and organizing expenses	5,829	
Sea and gas trials	1,842	$668,335
Other vessel capital costs		
Replacement cost insurance	4,104	
Financing fees	10,530	
Working capital associated with vessels	13,746	28,380
Capitalized financing charges		
Allowance for funds used during construction consisting of:		
Interest on debt funds @ 8.8%/annum	77,172	
Allowance on equity funds @ 18.41%/annum	64,867	142,039
Fleet contingency		16,776
Total capital costs for six vessels		855,550
Shore-based facilities and project capital costs		
Shore-based structures and equipment	6,953	
Precertification intangible plant	4,897	
Capitalized administrative and general expenses, consulting fees, and other	9,585	
Provision for working capital	567	
Allowance on equity funds @ 18.41%/annum	17,186	
Shore-based contingency	838	40,026
Estimated total capital requirements		$895,576

SOURCE: El Paso Atlantic Company, *Economics of Shipping Algerian LNG to Texas Gulf Coast*, Oct. 11,1976.

[14] "Algeria II LNG Project Plans Detailed," *loc. cit.*, p. 67. Safety analyses for LNG projects repeatedly identify a ship accident as the most likely event that could trigger the most serious type of LNG accident (*Transportation of Liquefied Natural Gas,* OTA, September 1977, p. 18).

*Governments offer various subsidy programs to the shipbuilding industry in individual countries to keep their shipyards competitive in the LNG tanker market. In the United States, most tankers are financed with several forms of aid from MarAd, one of which is a construction differential subsidy (CDS). For Algeria II vessels to be constructed in the United States, a 25-percent CDS has been applied to the estimated $142 million yard cost per vessel (1976, 4th quarter prices).

[15] *Summary of the Evidence,* op. cit., p. 23.

Table 28.—Estimated Annual Operating Expenses for El Paso Atlantic—Six Vessels

Operating expenses for six vessels	Thousands of 1976 dollars
Crew (3 foreign, 3 U.S.)	$ 8,172
Maintenance and repair	5,856
Stores and supplies @ $103,000/ship	618
Bunker “C” fuel @ $1,371,000/ship	8,226
Nitrogen	354
Annual insurance premiums	8,484
Post charges	2,484
Shoreside expenses	3,527
Manning agent (3 foreign ships only)	42
Miscellaneous expenses @ $29,000/ship	174
Estimated total annual operating expenses	$37,937

SOURCE. El Paso Atlantlc Company, Economics of Shipping *A/ger/an LNG to Texas Gulf Coast,* Oct 11, 1976

accident or damage to the vessel, breakdown of the vessel’s machinery, deficiency of men or stores). These risks are thus borne by the shipowners, not Pac Indonesia. 16

The capacity of each vessel will be about 125,000 m^3, the industry’s current standard. Each carrier will be scheduled to operate 345 days out of the year (as opposed to 332 to 333 in the Algeria II project) leaving the balance of the year for shipyard repairs and miscellaneous delays. At an average speed of 18.5 knots, each ship will require 18.7 days for the 8,300 nautical-mile voyage from Indonesia to the United States and will be able to complete 8.5 round trips per year. The energy delivered to the United States will be approximately 92 percent of the quantity loaded at the A run terminal, reflecting fuel use of boil-off vapors during the voyage.

To illustrate how the shipping distance affects costs, the capital and operating costs per vessel on Pac Indonesia’s project are assumed to equal the corresponding costs for Algeria II. Under such an assumption, the shipping costs per million Btu of LNG delivered daily in the Pac Indonesia project would exceed by 42 percent the equivalent costs in the Algeria 11 case, as a result of the greater distance involved in the Inck)-nesian project.

The capital costs of the three foreign ships constructed in French shipyards* and chartered by Pac Indonesia are not publicly disclosed, but can be reasonably estimated at approximately $100 million per vessel. Pac Indonesia’s transportation contracts with U.S. shippers, concluded in late 1975, provide for charter rates based, in part, on the estimated capital costs of $140 million per American-mack tinsel plus escalations. The FPC judge used $155 million estimated average capital cost per U.S. vessel in establishing the shipping component of Pac Indonesia’s initial certificate rate. This figure represents the judge’s estimate (in mid-1977) of the average cost for the six U.S. tankers assuming a specified delivery schedule between January 1980 and May 1981. The actual inflation in LNG tanker construction costs in the United States turned out to be higher, judging by the current (mid-1979) total price estimate of about $195 million (after subsidy) per 125,000 m^3 vessel to be delivered in 1982-83.

Receiving country terminal and regasification facilities

A terminal for the receipt of LNG consists of three major segments-unloading, storage, and vaporization. The principal components of the unloading portion of the terminal are berthing facilities, unloading arms and lines, return vapor lines and blowers, and prov’isions for handling excess vaporization due to boil off. The storage facilities at the receiving terminal are similar in type to those at the liquefaction plant. “The regasification (vaporizing) equipment consists of liquid pumps and vaporizers. Regasification facilities represent much less sophisticated technology than do the liquefaction plants in the producing country. In terms of the total costs involved, the importing country’s facilities usually account for the smallest portion of a three-part LNG project. The design and construction of the receiving terminal facilities require 2 to 3 years.

Pac Indonesia proposes the construction of an LNG terminal on the southern California coast approximately 3.5 miles east of Point [conception. * The plant will have an ultimate baseload capability of 1,300 M Mcf/d, with peak \’aporiza-

[16] *Initial Decision on Importation on Liquefied Natural Gas from Indonesia,* FPC, op. cit., p. 17.

*One was completed in 1975, the other two in 1977.

*The Public Utilities Commission of California, which considered several sites for the Pac Indonesia terminal, chose Point Conception because a 1977 State law required an unpopulated location for the site.

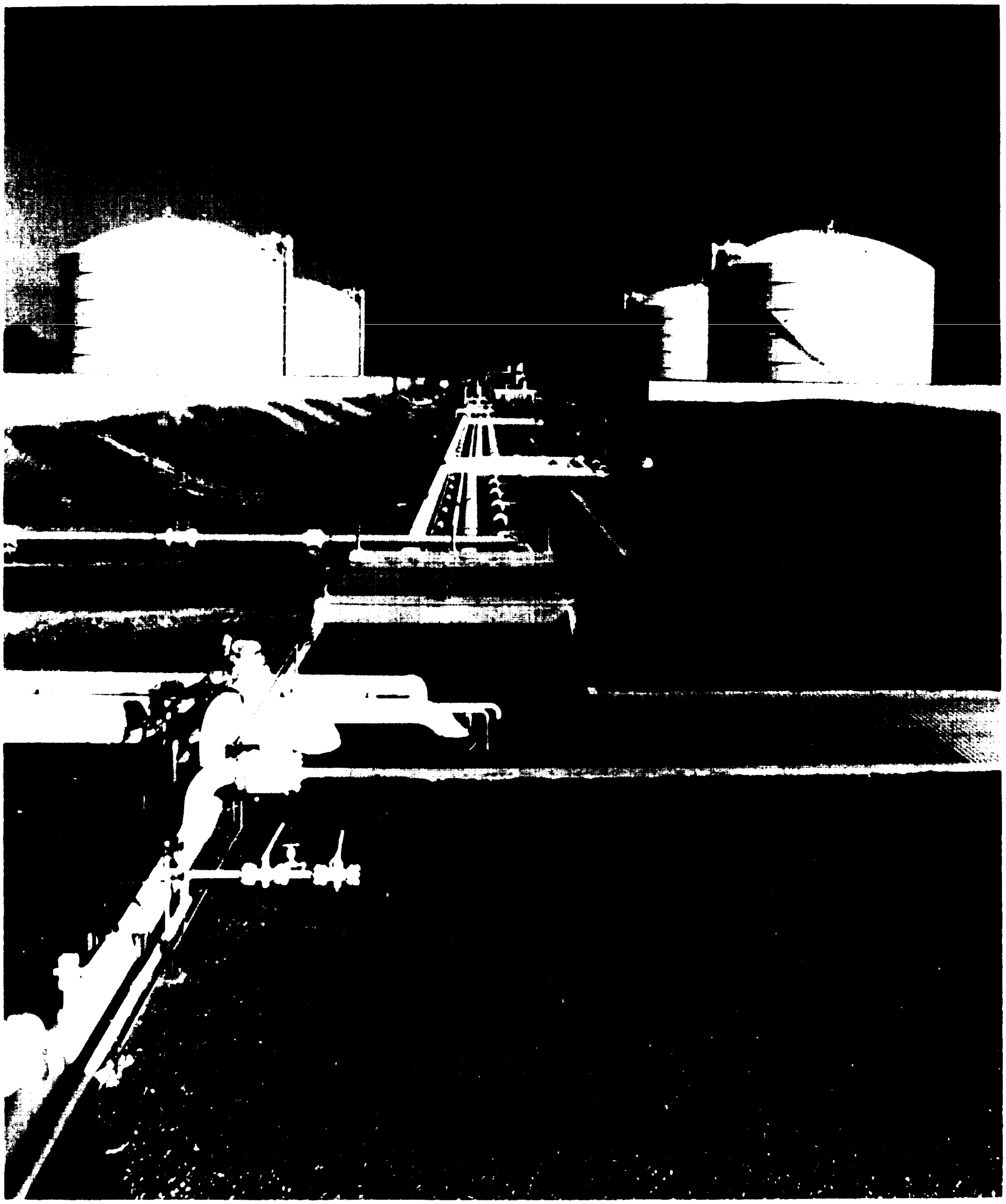


Photo credit' Courtesy of Colomb/a Gas System, Inc.., Consolidated Natural **Gas Co,** *and American Petroleum Institute*

LNG receiving terminal at Cove Point, Md. At the terminal LNG will be converted back into ordinary natural gas for use by customers of the Columbia Gas System, Inc., and the Consolidated Natural Gas Company tion capacity of an additional 300 MMcf/d. The Indonesian volume to be received at the terminal is estimated to be about 500 MMcf/d. The total baseload capacity will be shared by Pac Indonesia and Pacific Alaska LNG Associates (the latter proposes to import LNG from the Cook Inlet area of Alaska).

The marine facilities will consist of one berth located about 4,600 ft offshore. LNG from the ship will be unloaded into the land-based LNG storage tanks by onboard ship pumps. Three 550,000 barrel double-wall, insulated storage tanks are planned for the terminal.

Thirteen seawater-heated LNG vaporizers will be installed to accommodate the total baseload, and peaking capacity of 300 Mcf/d will be provided by additional gas-fired LNG vaporizers. The vaporization plant is designed to deliver natural gas continuously 365 days per year. The gas will then go through a trim heater, odorizers, and metering station, before entering the gas transmission system.

A 112-mile, 34-inch pipeline looped with another 45-mile, 34-inch pipeline will extend from the metering station at the terminal site to a point of interconnection with PG&E's existing pipeline near Gosford, Calif., with an intervening interconnection with Southern California Gas Company's present facilities at North Coles Levee. The present pipeline design requires no compressor stations. 17

The total estimated capital cost of the Point Conception terminal amounts to $632 million (in mid-1977 dollars), and the annual operating costs to $20 million—see tables 29 and 30 respectively. The estimated capital cost of the new pipeline requires another $117 million (see table 31). On a strictly volumetric basis, the Pac Indonesia share will be over 58 percent, or $368 million for the terminal facilities and $68 million for the pipeline. Pac Indonesia's costs would be higher if the facilities were built for the use of this project alone. For instance, all storage tanks would still be needed, due to the industry's practice of requiring that storage space be suffi-

[17]The proposed Point Conception terminal is described in the Western LNG Terminal Associates' Application No. 57626 before PUC of California, Oct. 14, 1977.

Table 29.—Point Conception Terminal Estimate of Capital Costs
(1.3 Bcf/d baseload capacity plus 0.3 Bfc/d peaking capacity)

	Thousands of 1977 dollars	
Construction costs		
LNG unloading	$24,828	
LNG storage	76,382	
Vaporization	48,772	
Seawater system	61,173	
Utilities and offsites	76,403	
Dock and trestle	78,027	$365,585
Engineering fees and sales tax		13,264
Contingencies and in-house costs		59,497
General terminal costs		33,955
Allowance for funds used during construction		150,623
Spare parts, working capital and financing fees		9,076
Capital costs total		$632,000

SOURCE: Western LNG Terminal Associates, Application No. 57626 before the Public Utilities Commission of the State of California, 10114177, vol. 1, Dec. 14, 1977.

Table 30.—Point Conception Terminal Estimate of Annual Operating Costs
(1.3 Bcf/d baseload capacity plus 0.3 Bcf/d peaking capacity)

	Thousands of 1977 dollars
Total manpower	$ 1,102
Utilities:	
Fuel	2,650
Electricity	10,400
Nitrogen	100
Chemicals:	
Water treatment, thiophane, chlorine	500
Maintenance @ 1% of $379 million (construction cost)	3,790
Insurance @ 0.5% of $379 million	1,895
Total annual operating costs	$20,437

SOURCE: Western LNG Terminal Associates, Application No. 57626 before the Public Utilities Commission of the State of California, 10114177, vol. 1, dated Dec. 14, 1977.

Table 31.—Point Conception to Gosford Pipeline Estimate of Investment Requirements

	Thousands of 1977 dollars
Construction costs	$ 91,867
Engineering fees and sales tax	4,743
Contingencies and in-house costs	11,163
Allowance for funds used during construction	7,978
Spare parts and working capital	1,090
Investment requirements total	$116,841

SOURCE: Western LNG Terminal Associates, Application No. 57626 before the Public Utilities Commission of the State of California, 10114177, vol. 1, dated Dec. 14, 1977.

cient to accommodate at least two LNG shiploads. Pipeline costs also exhibit economies of scale.

The Algeria 11 project involves the construction of the La Salle terminal in Matagorda Bay, designed for a maximum sendout rate of 1.64 Bcf/d. Thus, unlike Pac Indonesia's terminal, La Salle would be serving only the Algeria 11 project. 1[8] The marine terminal consists of independent berths to accommodate two LNG carriers simultaneously. More storage will be available than in Pac Indonesia's terminal; three 629)000 barrel tanks. The estimated cost of the La Salle terminal is $456 million (4th quarter, 1976), which as table 32 indicates, amounts to a higher cost per million Btu delivered than in Pac Indonesia's project. This discrepancy is due primarily to the volumetric cost allocation for the Pac Indonesia project, and only secondarily to the physical differences between the two terminals.

[18]The terminal may be used for receiving LPG or LNG from outside this project during periods of interruption. This use would mitigate the cost of El Paso (and to consumers) in the event of supply interruption (*Summary of the Evidence*, El Paso Eastern, et al., FPC Docket CP 77-330, et al., p. 40).

Algeria II requires more extensive pipeline facilities on the receiving end than does Pac Indonesia. El Paso Natural proposes to build a pipeline capable of accepting 115 percent of the average daily output of La Salle terminal, or 1,065 MMcf. The first 31 miles of the new pipeline (36-inch diameter) will transport the gas from the La Salle terminal to United LNG's present facilities near Victoria, Tex., where 35 percent of the total quantity will be sold. The remaining 65 percent will be transported via a 432-mile (30-inch diameter) pipeline to El Paso Natural's system at Waya, Tex. Together with the required five compressor stations, the new pipeline facilities are estimated to cost $263 million. As shown in table 32, the pipeline cost per million Btu per day is 37 percent of the total capital investment in Algeria II import facilities, whereas similar costs for the Pac Indonesia project are only 16 percent.

Table 32.–Capital Costs for Import Facilities per Million Btu of Daily Delivered Quantity of LNG

	Total capital cost (1977 $ million)		Assumed throughput (billion Btu/day)	1977 $/MMBtu/day		
	Terminal and regasification	Pipeline		Terminal and regasification	Pipeline	Total
Pac Indonesia. . . .	$632	$117	$ 570[a]	$1,109	205	1,314
			978[b]	646	120	766
Algeria II	456	263	1,069	427	246	673

[a]Assuming only Pac Indonesia's volume.
[b]Assuming both Pac Indonesia's and Pac Alaska's volumes.
SOURCE: Jensen Associates, Inc.

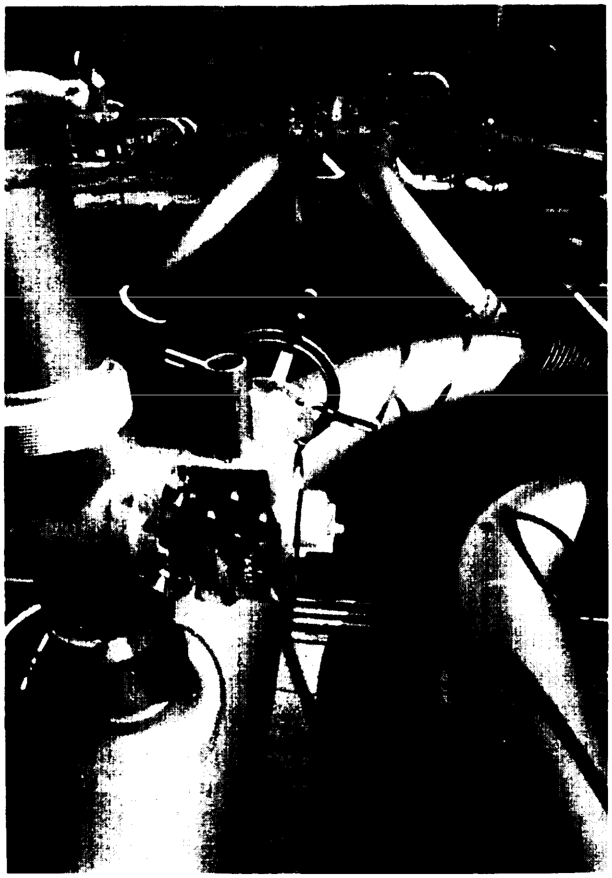
LNG financing

Because much of the cost of an LNG project is incurred at the beginning of the project, and because an LNG project has a long economic lifetime, financing terms strongly influence the unit cost (cost-of-service) of moving the gas from the field to the market. This section examines some of the major financing options open to LNG project sponsors and then, incorporating this information, derives an idealized cost-of-service.

Overview

The fundamental determinants of financibility for any capital project are risk and return. The important characteristics of an LNG project affecting perceptions regarding risk and return are:

- The total capital costs of an LNG project are large, and the return is not certain.



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- Ownership of LNG projects is often spread among parties in different countries.
- Integrated LNG projects are comprised of several stages (e.g., liquefaction, shipping), each one possessing an individual identity.

To see how the scale of capital requirements for an LNG project impacts financibility, it is useful to put the capital requirements in perspective. The estimated costs of the proposed Algeria 11 project total over $5 billion from wellhead to final consumer. By comparison, total U.S. net private fixed investment in 1978 was only $128.7 billion, * and this for the largest economy in the world.

*Figure net of capital consumption allowance

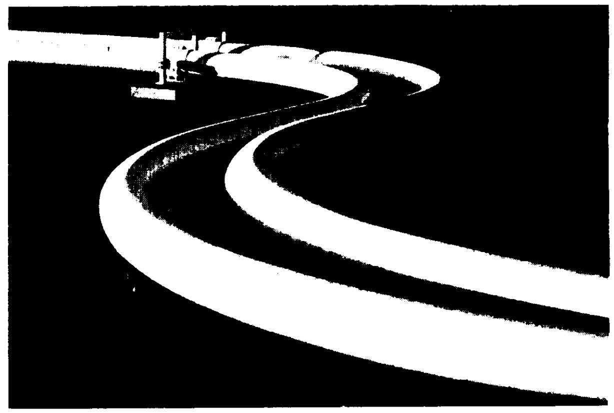

Photo credit. El Paso Co

Natural gas transmission lines may be seen above--ground in remote areas, but most of the Nation's pipeline system is underground

Because capital requirements are so large, project sponsors may have to look to several capital markets for funding, simply because the total exposure would be too large for one market to absorb. By using several capital markets and many lenders, project sponsors can diffuse the large financial risk of the project and thereby reduce borrowing costs. However, the use of several capital markets (or, for that matter, large financing in one capital market) may entail substantial transactions costs, offsetting the gains achieved through this strategy and, in fact, ultimately limiting the degree of diversification that is economically feasible.

Transaction costs incurred through diversification may take several forms. The requirement for documentation alone can be significant. In the U.S. institutional market, for example, each of several separate bond issues underwritten and offered publicly could require a separate prospectus and indenture, demanding significant outlays for legal, accounting, and possibly technical services. Transactions costs may also take the form of decreased flexibility. Restrictive covenants required in one capital market on, say, an issue of unsecured bonds may limit the project sponsors' freedom in obtaining financing in other markets.

In addition to the high transaction costs of reliance on many sources for financing, the size of the project ultimately limits the capacity of capital markets to absorb the risk. Whereas a modestly sized capital investment can be divided among many investors so as to represent only a small portion of any single portfolio, an LNG project is sufficiently large that enough lenders may not be available to distribute the risk adequately.

A second major factor influencing financibility is the international character of LNG projects, since financiers look to the contracts among the parties for security. Since the contract signatories are typically domiciled in different countries and, perhaps more fundamentally, since their physical facilities are located in different countries, no one legal jurisdiction can enforce the claims of one party against another.

A third factor is the multistage nature of the LNG project, and separate stages of the LNG project may have access to different capital markets for several reasons. First, for facilities to be owned, for example, by the producing country, officially supported credits may be available from countries desiring to promote exports from their own construction and capital goods industries. A second reason is that potential lenders may have different attitudes toward risk depending on the stage. An LNG import terminal, for example, can be used efficiently for one purpose only: the receipt, storage, and regasification of liquid gases at the location where the terminal is built. If the project fails because of, say, market conditions in the importing country, the terminal just sits there generating capital charges. The LNG carriers, on the other hand, if prohibited from offloading at the inoperative terminal can still be used in an LNG trade somewhere else. Thus, the potential investors might perceive less risk attendant on LNG carriers than on an import terminal.

The following sections examine, in light of these general considerations, some of the financing options open to the sponsors of LNG projects, with a particular view toward their effects on project cost. The discussion is organized by production stage: first, exporting country facilities, then ships, and finally, U.S. import terminals. For each stage, the discussion of financing focuses on the debt requirements, and the section on the financing of exporting country facilities includes overall project equity.

Exporting country facilities

Total capital requirements for exporting facilities may vary considerably with differences in gasfield characteristics, distance of field from the plantsite, cost of local labor, and other variables, but for a project of 1 Bcf/d the total cost of all exporting country facilities is likely to be well over $1 billion, and may exceed $2 billion.

The total cost of the facilities may be financed with the credit backing of the exporting country itself, as in the case of the Algeria 11 project, by outside participants, such as multinational oil companies, or a combination of both. While "project" financing, for which the security is the value of the specific facilities or contractual obligations associated with the project itself, may be possible in concept, financing is not likely to be obtained in this way without independent credit support.

Major sources of capital for producing country facilities include the eurocurrency market, private and public equity, and in the case of exporting country ownership, officially supported export credits. Each of these sources are discussed below.

OFFICIALLY SUPPORTED EXPORT CREDITS

Several Organization for Economic Cooperation and Development (OECD) countries have officially supported export credit programs, which supply direct loans and credit guarantees to promote their industries. This tied financing offers some important advantages to the LNG exporting country. While some export credit programs, such as those of the United States and Germany have tended to be on basically commercial terms, other countries, such as France, Japan, and the United Kingdom offer preferential–if not concessionary–credit supports. The lower cost of the financing available from some countries improves the economic viability of the project from the point of view of the producing country and also lowers the cost-of-service. A second advantage of officially supported export credits is that other potential lenders to the project may feel more secure in their investments with the participation of official government agencies, and in any event, will perceive that the lower cost of funds available through export credit financing provides additional capacity to service private debt.

France, through its foreign trade bank BFCE (Banque Francaise du Commerce **Exterieur),** provides financing for long-term maturities through either direct credits at subsidized rates or through discount and refinancing arrangements. The rate on the BFCE direct credit, or discount on the subsidized portion of the bank loan, is set by BFCE so that the blended rate, * exclusive of fees and premiums, is at the minimum allowed under the OECD arrangement. * * In addition, Coface (Compagnis Francaise d'Assurance pour le Commerce Exterieur) guarantees the total amount of the credit (BFCE plus private portion) for a rate premium of approximately 0.85 percent.

In some cases, however, the French "mix" credits by tying aid and loans together in one package. Such tied-aid credits may include loans at rates as low as 3.5 percent with repayment terms up to 20 years. The average cost of such a package is therefore considerably less than it would be in a strict export finance deal.

Japan, through the Ministry of International Trade and Industry and its Export-Import Bank, also provides long-term finance packages on preferential terms. As France's BFCE, Japan's Export-Import Bank will extend direct credits, up to 60 percent of the total export financing, so that the blended rate is at or near the minimum allowed by the OECD arrangement. As with Coface, their Export-Import Bank provides insurance for its own and the private loan portions of the total credit for a premium.

Japan has officially denied that it offers tied-aid credits to an extent that would derogate the OECD arrangement. However, some claim that tied-aid credits on essentially concessionary terms are widely available for export financing from Japan.

The United Kingdom through ECGD (Export Credits Guarantee Department) sets rates for commercial bank loans to buyers and pays a direct interest subsidy to banks to make up for the actual cost of funds. To relieve the overall credit burden this creates, ECGD also provides limited refinancing for sterling denominated loans used for export financing. ECGD guarantees 100 percent of the bank loans, and the rates set by ECGD are, as in the case of France and Japan, at or near the minimum allowed under the OECD arrangement. British tied-aid credit financing is also available.

The United States and Germany are more conservative in their approach to export financing. Historically neither country has typically offered tied-aid financing of exports. In addition, both countries operate their respective export programs without recourse to subsidy–in the case of Germany only a modicum of direct credits are even provided at long-term and preferential rates, the bulk of long-term credit support taking the form of insurance.

The United States through the Export-Import Bank (Eximbank) and related organizations such as the Private Export Funding Corporation, provides support for long-term export credits. Historically, Eximbank has provided direct credit at rates linked to the agency's cost of funds and has guaranteed the private bank portions of the total credit, which are usually extended at floating rates. Eximbank typically charges a guarantee fee on the private bank portion.

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*The effective average rate for the total subsidized and unsubsidized portions.

**The OECD Arrangement of Guidelines for Officially Supported Export Credits represents an attempt by participating OECD nations to forestall wasteful and commercially unsound competition among participants for export contracts. This agreement, which replaced the old Consensus Agreement, limits competition in interest rates and repayment terms. For buyers classed as "relatively poor countries" repayment terms are allowed up to 10 years. Interest rates are not permitted to be below 7.5 percent on longer maturities and 7.25 percent for maturities of 2 to 5 years. For "relatively rich countries" repayment terms are limited to a maximum of 8.5 years at a minimum interest rate of 8 percent for the longer maturities and 7.5 percent for maturities of 2 to 5 years. All export finance packages require a cash downpayment of 15 percent of the total contract value of goods and services by the purchasing country.

In addition to the 85 percent of contract value permitted to be supported by export credits, certain local cost coverage is allowed by the arrangement. Local cost coverage is limited, however, so that the total amount does not exceed 100 percent of the contract value of goods and services to be exported.

Recently, however, U.S. Eximbank policy has begun to favor improving competitiveness with foreign export agencies. This policy shift is reflected in the tendency toward increased direct coverage at reduced rates. In so-called exceptional cases, Eximbank may offer a direct credit for the total amount of the export credit (85 percent of the contract cost of the goods and services) at rates below the agency's marginal cost of funds.

An example of the use of export credit is the U.S. Eximbank's $240 million credit to Algeria to help finance $320 million U.S. goods and services component of the Arzew 11 liquefaction plant. The credit was extended to Sonatrach at 8.5 percent. Repayment is in 20 semiannual payments beginning 6 months after the last of six liquefaction trains is completed. The remainder of the U.S. goods and services component is to be financed by a Sonatrach payment of $48 million (15 percent) and private-source loans of $32 million. Payments on the total of the Eximbank credit and the private source loans will be arranged in such a way that the private-source loans are paid off first.

THE EUROCURRENCY MARKET

Another important source for financing of LNG exporting country facilities (whether owned by the country in question or by outside parties) is the eurocurrency market, in which loans are negotiated in currencies not native to the country in which the bank offering the loan is located (eurocurrency bank credits) and bonds are issued outside the country of the borrower (international bonds). The size of this market is substantial. In 1978 alone, over $70 billion in eurocurrency bank credits were negotiated, and new international bond issues totaled $35 billion. In 1978, Algeria, a major LNG producing nation, borrowed over $3 billion on the eurocurrency market, while Indonesia, another important LNG center, borrowed over $1 billion.

An important feature of the eurocurrency bank credit market is that its funding tends to be for periods of no more than 5 to 10 years. Also, loans on this market typically have floating interest rates. So, for example, a loan on this market with a repayment term of 8 years might carry an interest rate of 1.75 percent over LIBOR (the London interbank offering rate, a measure of the bank's cost of funds), reflecting maturities of 6 months. At the end of each 6-month period, the loan is effectively renewed for the amount of principal still outstanding at an interest rate corresponding to the then- current LIBOR.

One of the main advantages of the eurocurrency bank credit market is that with sufficient credit backing, such as the guarantee of the Central Bank or Development Bank of the potential LNG exporting country, considerable funds are available on this market. A second advantage is that credit obtained on this market, and private-source capital in general, tends to have fewer strings attached than, for example, the tied loans available through officially supported export-financing agencies.

Two important disadvantages of this market are the shortness of the repayment periods and the variability of the interest rates. The economics of large projects with long lifetimes sometimes are not certain until late in the project, and if the loan must be amortized over too short a period at the beginning, debt service may exceed the available cash flow after deduction of other expenses. In such an instance, borrowing from equity is required, and to the extent that this is expensive or simply not feasible, other financing arrangements are necessary,

The variability of interest rates on eurocurrency bank credit also adds a dimension of uncertainty to the management of cash flow and to the overall economics of the project. owners of long-term projects may be willing to pay a considerable premium to remove this element of uncertainty.

An example of eurocurrency bank credit is the $250 million 7-year loan raised by Sonatrach, guaranteed by the Banque Nationale de'Algerie, and jointly led by Citicorp, Bank of America, Apicorp, Bankers Trust, Bank of Montreal, and Continental Illinois. This loan carries an interest rate of 1-3/8 percent over LIBOR and will help to finance the Arzew II liquefaction plant facilities.

Fixed interest rate financing is also possible on the euromarket through the issue of bonds or notes. These international bonds, which are comparable in terms of maturity with eurocurrency bank credits (5 to 10 years), can provide added cash flow predictability at a minimum cost.

Examples of eurobonds are two recent Sonatrach issues, one 12 million dinars (DA) guaranteed by the Banque Exterieure d'Algerie, maturing in 10 years, bearing a yield of 8.5 percent; and one DA 8 million 5-year maturity bearing 8.5 percent.

PUBLIC AND PRIVATE EQUITY

A third important element of financing for LNG exporting country facilities is public and private equity. Equity capital can be generated by reinvestment of earnings, such as profits from a country's other hydrocarbon ventures or the net revenues from unrelated operations of a multinational oil company; or alternatively, through the issue of ownership shares, as exemplified by the Islamic Development Bank's equity participation in Jordan's petroleum refinery project. Equity can be public, resulting from taxation or earnings on public enterprises; or private, supplied by ownership of shares by private entities.

Generally, lenders require some equity as a buffer in the event of difficulties, but it can dilute ownership and is typically more expensive than debt. The U.S. Eximbank, for exampIe requires a 15-percent cash payment by the buyer of U.S. export goods. This 15-percent may be funded by equity or debt or both, however, and this 15-percent should therefore not be viewed as necessarily bearing "true" equity costs.

CONCLUS1ON

Whether the project owners are to be the exporting country itself, an outside entity, or a combination, many financing options are available as described above. Nevertheless, certain constraints should be recognized. The availability of officially supported export credit financing at preferential or concessionary rates may depend on who owns the producing country facilities. In addition, while project financing is possible in principle, it is rare in practice, and consequently, the total cost of the financing may exceed the prima facie cost of the borrowings because of the impact on the debt capacity of the guarantor.

Shipping

Many of the private capital markets for the financing of exporting country facilities are open also for LNG ships. In addition, as in the case of the exporting country facilities, officially supported financing is available for LNG shipping and may be provided by export credit agencies such as Germany's Hermes (Hermes Kreditversicherung) or by other government agencies such as the U.S. Maritime Administration (MarAd).

MarAd offers a loan guarantee program applicable to LNG ships if they are built in U.S. shipyards, registered under the U.S. flag, owned by U.S. entities, and crewed by U.S. citizens. Under these conditions, as much as 87.5 percent of the total cost of a ship can be financed by an issue of U.S. Government guaranteed serial or sinking fund bonds, either with maturities up to 25 years. The cost to the borrower is the yield on the bonds plus the MarAd guarantee fee (0.5 to 1.0 percent of the outstanding balance), amounting to a total in the range of a Baa industrial.

The MarAd program is not subsidized, though default claims are paid from a pool funded by MarAd's overall operations. Consequently, the public does not contribute directly to defraying the cost of funds to borrowers using MarAd credit guarantees. However, the MarAd guarantee is valuable to potential borrowers in the sense that MarAd may be better able to spread the risk in ship financing than private capital markets. In addition, the ability to issue U.S. Treasury-backed bonds affords shipowners access to other capital markets that, because of institutional or legal barriers, would otherwise be closed. Another advantage of the MarAd program is long repayment terms of up to 25 years, although the maximum term might be unusual in the case of a LNG ship.

If the owners of the ships are to be foreign to the country where the ships are built, officially supported export credits may be available. Important LNG ship-exporting countries in the OECD include France, the United States, Italy, and Norway. Financing terms are determined by the individual countries in accordance with the OECD Arrangement on Ships, which supersedes the Arrangement on Guidelines for Officially Supported Export Credits in the case of shipping and sets a minimum interest rate of 7.5 percent, a maximum repayment period of 8 years, and a maximum coverage of 80 percent of ship cost.

While the interest rate allowed on officially supported export credits for ships is preferential, the shortness of the repayment period constitutes a disadvantage of this type of financing. The heavy debt requirements during the early years of the project can, depending on the pricing or tariff provisions governing cash flow, effectively postpone repayment of expensive equity capital.

U.S. facilities

The cost of U.S. facilities, including the marine terminal, LNG storage tanks, vaporization units, and transmission lines to deliver the gas, can vary widely depending on location and design. The proposed La Salle terminal facilities and delivery lines to E] Paso United's system were estimated to cost approximately $700 million, while the proposed Tapco project, sponsored by Tenneco to bring LNG from Algeria into New Brunswick, Canada and then to the United States through a longer pipeline, would have cost nearly $1.5 billion.

In the past, construction of U.S. facilities has been accomplished through the credit of financially strong corporations. Examples include Southern Natural Gas Company's Savannah, Ga., terminal and the planned Trunkline terminal at Lake Charles, La. Each of these facilities is owned and operated by a subsidiary of a major U.S. interstate pipeline company, and debt issues to finance LNG terminals are carried in both cases on the balance sheets of the parents, which provide substantial credit support.

Southern's Savannah terminal illustrates another feature of U.S. financing, the tax-exempt bond market. Section 103(B)(4)(D) of the U.S. Internal Revenue Code, which relates to docks, wharfs, and storage facilities, may allow the issue of debt securities that are exempt from Federal, State, and local income taxes. For this type of issue, the market yield cost to the borrower is less. Southern's Savannah terminal, for example, was financed partly through the issue of tax-exempt revenue bonds by the Savannah Port Authority. These bonds were marketed at a price of 99.75 percent of par and with a coupon rate between 5.7 and 6.75 percent, depending on the maturity (serial and sinking fund bonds were in combination to permit full amortization by equal payments over the lifetime of the financing). At the time of the prospectus, Aaa bonds were yielding around 9.5 percent, considerably more than the Savannah Port Authority bonds.

Conclusion

The financing options open to LNG import sponsors are strongly influenced by the magnitude of total capital requirements, as well as the international character and multistage nature of the projects. Generally, private capital markets are open to sponsors with strong credit support, but financing costs may be high because of sheer scale.

In addition, low-cost subsidized financing is available for particular stages of the project, depending on such factors as ownership, location, the country supplying construction and materials, and taxes. Also financing costs may be high due to regulatory incentives, for example, to finance U.S. facilities independently. The next section examines the effects of alternative financing arrangements on the unit cost (cost-of-service) of moving gas from a remote source to U.S. markets.

Cost-of-service

The cost-of-service calculated by project stage for a hypothetical world-scale LNG project (approximately 1 Bcf/d), idealized in economic and financial structure, is described below. This cost was defined as the sum, for a particular year, of operating costs, capital costs (debt and equity), and taxes divided by the Btu's delivered into the U.S. pipeline system. The procedure allowed direct comparison by project-stage in terms of units ultimately delivered, and at the same time, allowed determination of the wellhead value of the gas given the price in the U.S. market, since fuel and loss is included in the cost-of-service.

The capital charge (service on debt and equity) was assumed to be level in constant dollars over the lifetime of the project and was calculated so that the net present value of the shareholders' cash flow would equal zero at the assumed discount rate.

Also, the cost-of-service estimate here differs from what would be typical in a regulatory proceeding in that the cost of gas expended as fuel and loss was determined at the ultimate netback wellhead value, while a "regulatory" calculation usually assumes the value of fuel and loss to reflect a fixed price, for example, the contract sale price f.o.b. the point of export. An advantage of valuing the fuel and loss at the ultimate wellhead netback, is that it allows direct comparison of the cost-of-service of LNG projects with the cost-of-service of alternative technologies to move gas from the wellhead to the market. A peculiarity of this approach is that since capital and nonfuel operating costs affect the ultimate wellhead netback, the value of fuel and loss depends, in part, on these other components.

Base case

Parameter values for the base case cost-of-service calculation were derived largely from the testimony in recent LNG proceedings. This calculation was performed for a project starting in 1985, and costs were escalated to reflect the difference in timing between the idealized base case and recent proposals. The assumed 3,736 nautical miles approximates the shipping distance from Algeria to the United States. For complete enumeration of all parameters, see volume II (working papers).

For U.S. facilities, the financing was assumed to reflect current market rates and terms for large projects in U.S. capital markets on the balance sheets of gas utility companies. For shipping, MarAd financing was assumed with an interest rate in the vicinity of *Baa* industrial bonds and a repayment term of 15 years. Exporting country facilities were assumed to hav'e access to export credit financing programs for the bulk of their financing, and rates and terms represented here are those for the recent U.S. Eximbank credit to Algeria to help finance the Arzew II liquefaction plant. The assumed rate of return on equity is 17 percent.

Tables 33 and 34 show the results of a representative base case cost-of-service calculation, expressed in constant 1978 dollars. As can be seen, the bulk of the costs are in shipping and liquefaction. Also fuel and loss represent a significant portion of the total and, for liquefaction, actually exceed the capital and operating cost component. Overall, taxes constitute less than 10 percent of the fifth year cost-of-service for this idealized project. However, much of the debt service is loaded toward the front end of the project and since interest payments are deductible, taxes as a fraction of the total cost-of-service increase over the lifetime of the project, as shown in figures 17 and 18.

Sensitivity

The sensitivity of the cost-of-service to changes in the debt ratio on U.S. facilities and the repayment period for ship financing, and to

Table 33.—Cost of Service of an LNG Project Beginning in 1985 in the Fifth Year of Operation"
(1978 dollars/million Btu delivered into U.S. pipeline system)

	Field facilities and pipeline to liquefaction plant	Liquefaction plant, terminal and loading	Shipping	U.S. facilities	Total
Capital and operating	$0.226	$0.656	$0.564	$0.273	$1.719
Fuel and loss	0.084	0.659	0.091	0.101	0.935
Income taxes	0.053	0.106	0.038	0.017	0.214
Total cost-of-service.	$0.363	$1.421	$0.693	$0.391	$2.868

[a]Costs for a world-scale LNG project with a round trip shipping distance of 7,472 nautical miles and a distance from gasfield to liquefaction plant of approximately 300 statute miles

SOURCE Jensen Associates, Inc.

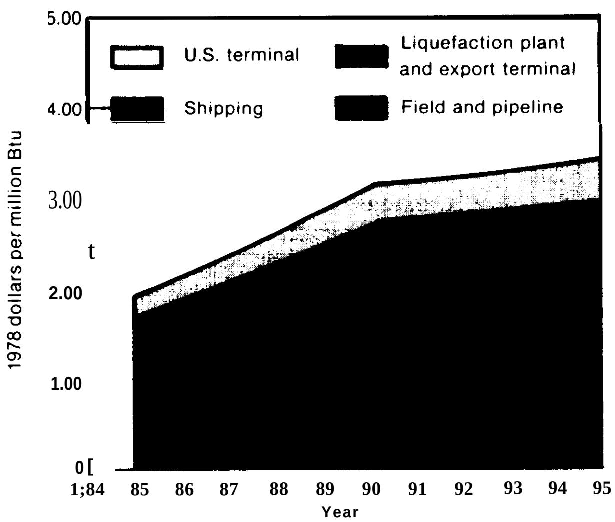
Table 34.—Sample Calculation of Wellhead Netback Price in 1989 for a Project Beginning in 1985
(1978 dollars/million Btu at wellhead)

Gas price into U.S. pipeline system[a].	$6.138
Cost of service[b].	2.868
Wellhead netback.	$3.270

[a]Based on postulated price of No. 2 fuel oil in Philadelphia, netted back to Cove Point, Md.
[b]Includes fuel and loss valued at wellhead netback; 7,472 nautical miles round trip distance.

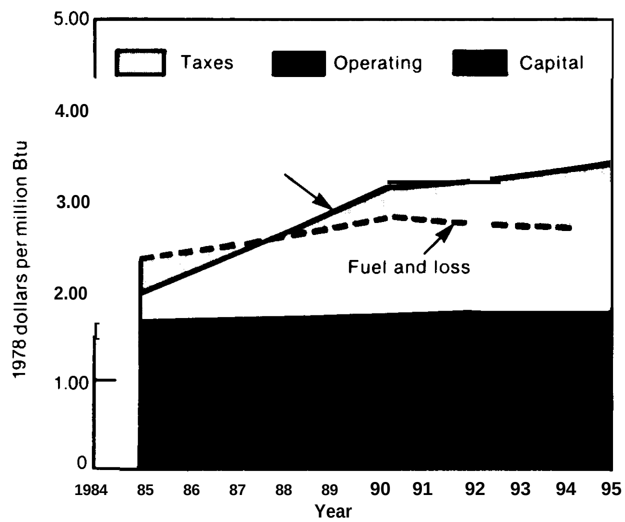
SOURCE: Jensen Associates, Inc.

Figure 17.— LNG Cost of Service by Project Section



SOURCE Jensen Associates, Inc

Figure 18.—LNG Cost of Service by Type of Cost



SOURCE. Jensen Associates, Inc.

setting the interest rate on all debt at 12 percent is relatively insignificant. These changes produced a net cost increase of $0.05 /MMBtu. However, the cost-of-service is more sensitive to changes in the return on equity in all portions of the project and to changes in the U.S. debt interest rate, Tables **35** and **36 show the effect of in**creming and reducing the return on equity and the interest on U.S. debt by 2 percent. The effects are symmetrical, changing the total charges, excluciing fuel and loss, by about $0.21 /MMBtu (1978 dollars) or approximately 10 percent. However, when the fuel effects, which offset the gross changes in capital and operating cost portions of the project, are included, the net effect is a change of about $0.16/MMBtu (1978 dollars) or approximately 6 percent in the total cost-of-service in the fifth year of operation of an LNG project. Cost-of-service calculations for shipping were based on an average distance of **7,472 nautical** miles. Tables 37 and 38 show that when the distance is reduced by one-half or doubled, the effect on the cost of shipping is in the same proportion. However, the netback val-

Table 35.—impact of Fifth Year Cost of Service of Reducing Return on Equity to 15 Percent and Interest on U.S. Debt to 10 Percent"
(1978 dollarsl million Btu ultimately delivered)

	U.S. facilities	Shipping	Liquefaction plant	Field and pipeline facilities	Total
Reduced return capital costs, operating costs, and income taxes.	$0.246	$0.546	$0.691	$0.244	$1.727
Base case capital costs, operating costs, and income taxes.	0.290	0.602	0.763	0.279	1.934
Gross change in cost of service	**(0.044)**	**(0.056)**	**(0.072)**	**(0.035)**	**(0.207)**
Reduced return fuel and loss. .	0.106	0.095	0.692	0.088	0.981
Base case fuel and loss	0.101	0.091	0.659	0.084	0.935
Change in fuel and loss component.	0.005	0.004	0.033	0.004	0.046
Net change in cost of service. .	(0.039)	(0.052)	(0.039)	(0.031)	(0.161)

[a]From 17 and 12 percent respectively

SOURCE: Jensen Associates, Inc.

Table 36.—impact of Fifth Year Cost of Service of Increasing Return on Equity to 19 Percent and Interest on U.S. Debt to 14 Percent"
(1978 dollarsl million Btu ultimately delivered)

	U.S. facilities	Shipping	Liquefaction plant	Field and pipeline facilities	Total
Raised return case capital charges, operating costs, and income taxes	$0.337	**$0.662**	**$0.833**	**$0.314**	**$2.146**
Base case **capital charges, operating costs, and income taxes. . . . .**	**0.290**	**0.602**	**0.763**	**0.279**	**1.934**
Gross change in cost of service	**0.047**	**0.060**	**0.070**	**0.035**	**0.212**
Raised return case fuel and loss	0.096	0.086	0.626	0.080	0.888
Base case fuel and loss	0.101	0.091	0.659	0.084	0.935
Change in fuel and loss component.	(0.005)	(0.005)	(0.033)	(0.004)	(0.047)
Net change in cost of service. .	0.042	0.055	0.037	0.031	0.165

aFrom 17 and 12 percent respectively.

SOURCE. Jensen Associates, Inc

ue of the gas and thus the cost of fuel are reduced, which tends to offset the changes in capital and operating costs. Another effect of shortening shipping distance is a reduction in the amount of LNG boiled-off and used as transportation fuel. Consequently, less LNG needs to be loaded at the liquefaction plant to maintain the same deliveries to ultimate destinations. For this reason, liquefaction plants and field and pipeline facilities can be reduced somewhat in scale, as shown in table 37. on the other hand, increasing shipping distances will produce the opposite effects.

Ironically, the total fuel and loss portion of the cost-of-service for the short voyage case is higher than for the base case and similarly, total fuel and loss for the long voyage case is lower than for the base case. This result is contrary to what one would expect but comes about because of the convention adopted in this analysis, that the cost of fuel and loss is calculated at the netback

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Table 37.—impact on Fifth Year Cost of Service of Reducing the Round Trip Voyage Distance to 3,274 Nautical Miles'
(1978 dollars/million Btu ultimately delivered)

	U.S. facilities	Shipping	Liquefaction plant	Field and pipeline facilities	Total
Short-voyage capital charges, operating costs, and income taxes.	$0.290	$0.300	$0.754	$0.276	$1.620
Base case capital charges, operating costs, and income taxes.	0.290	0.602	0.763	0.279	1.934
Gross change in cost of service	. —	(0.302)	(0.009)	(0.003)	(0.314)
Short-voyage fuel and loss. . . .	0.110	0.053	0.709	0.090	0.962
Base case fuel and loss	0.101	0.091	0.659	0.084	0.935
Change in fuel and loss component.	0.009	(0.038)	0.050	0.006	0.027
Net change in cost of service. .	0.009	(0.340)	0.041	0.003	(0.287)

aBase case distance IS 7,472 nautical miles.

SOURCE: Jensen Associates, Inc

Table 38.—impact on Fifth Year Cost of Service of Increasing the Round Trip Voyage Distance to 16,694 Nautical Miles'
(1978 dollars/million Btu ultimately delivered)

	U.S. facilities	Shipping	Liquefaction plant	Field and pipeline facilities	Total
Long-voyage capital charges, operating costs, and income taxes.	$0.290	$1.294	$0.784	$0.287	$2.655
Base case capital charges, operating costs, and income taxes.	0.290	0.602	0.763	0.279	1.934
Gross **change** in cost of service	—	**0.692**	0.021	0.008	0.721
Long-voyage fuel and loss	0.082	0.149	0.546	0.070	0.847
Base case fuel and loss	0.101	0.091	0.659	0.084	0.935
Change in fuel and loss component.	(0.019)	0.058	(0.1 13)	(0.014)	(0.088)
Net change in cost of service. .	(0.019)	0.750	(0.092)	(0.006)	0.633

aBase case is 7,472 nautical miles.

SOURCE: Jensen Associates, Inc.

value at the wellhead. Since most of the fuel is used in the liquefaction plant, the short voyage raises the netback value of the fuel and loss which in turn increases the fuel and loss prices at the liquefaction facility. The opposite is true when LNG is shipped over long distances. Higher capital costs of boil-off reduce the netback value at the wellhead and thus the cost of fuel and losses. When the shipping distance is reduced by half the total cost-of-service for the project is reduced by 10 percent, and when the distance is doubled, the cost-of-service is increased by 22 percent.

Financial risk

Because of the size and complexity of LNG investments as well as the unpredictability of future events during a project's life, the nature and distribution of financial risk and uncertainty are important to consider. From a government policy standpoint, public exposure deserves particular attention.

Individual investments in single liquefaction facilities, import terminals, or ships separate from integrated projects are not yet possible, except perhaps in Japanese trades. In the future, if more trade develops and facilities become more widespread, such investments will occur. But now only a complete project with long-term contractual commitments and simultaneous construction of liquefaction facilities, ships, and the receiving/regasification terminal is economically feasible.

The money invested in LNG projects is at risk from a variety of perils, including technical feasibility, project failure, project interruption or delay, cost overruns, and market uncertainties. These problems are described below and illustrated in a discussion of the proposed Pac-Indonesia project.

Technical feasibility

The financiers of an LNG project are first interested in its technical feasibility, which they assess in historical terms. In January 1959, the first shipload of LNG left Lake Charles, La., on the *Methane Pioneer* and arrived at Canvey Island, England—near London. This shipment was part of a project sponsored by the British Gas Council, Continental Oil Company, and Union Stockyards to test equipment and to examine the feasibility of international LNG trade. In 1964, the first baseload, long-term commercial project started with shipments from Arzew, Algeria, to Canvey Island and Le Havre, France. Today 12 LNG projects are in operation, and the technical and economic feasibility of the technology has been demonstrated. Several shipyards and engineering/construction firms have shown their ability to build reliable LNG ships and facilities. Technical and construction risks are perceived as no greater than those for other large sophisticated international engineering and construction projects.

Project failure

Of greatest concern to the owners and financiers of an LNG project is the possibility for project failure after significant amounts of money have been spent. For example, the Eascogas Project, which was to bring LNG from Skikda, Algeria, to the east coast of the United States, was originally expected to begin some years ago. A receiving terminal at Staten Island was completed at a cost of over $100 million (1974 dollars), and two ships intended for the project were built at the General Dynamics shipyard at Quincy, Mass. Government authorities in the United States have refused to allow operation of the Staten Island terminal, which is now a complete financial loss unless the facilities are used to store LNG for peak shaving. One of the ships has subsequently been incorporated into an LNG trade from Indonesia to Japan while the other is unemployed, and thus far a loss to its owners.

As mentioned earlier, some supply contracts contain explicit provisions for periodic review of prices, while others may have to be renegotiated under changed circumstances because the parties are in separate countries not governed by a common legal jurisdiction. In either case, although producers and purchasers both face substantial incentives to come to terms, negotiations could conceivably break down after the facilities have been built and put into operation.

Project failure can also occur if facilities are destroyed by natural causes, civil strife, or war, or if a major change in attitude within one country causes project termination. For example, the Khomeini government in Iran is reported to have canceled the IGAT 11 project scheduled to sell gas to the U. S. S. R., which would in turn sell gas to Czechoslovakia and gas companies in Germany, France, and Austria, beginning in 1981. Unfortunately, Iran canceled the project after considerable investment in pipelines.

Project interruption or delay

Technical problems can delay or interrupt LNG projects. Normally, when any complex plant starts up, problems arise. In LNG liquefaction plants, typical problems include clogging of cooling water intakes by sand, seaweed, jellyfish, or debris; failures in the blading in turbines, compressors, or pumps; fouling of heat exchangers on the water side due to buildup of algae; clogging, possibly by ice, of spray rings, for cooling the storage tanks; or bearing failures in pumps. 19

However, other technical problems can cause longer delays or force cessation of LNG projects, causing severe financial impacts. For example, when the Libyan LNG plant was first started in 1969, several problems arose in the pipeline bringing gas to the liquefaction plant, resulting in additional delay of over a year. Libya also interrupted the LNG project by government edict when negotiations over prices broke down.

In another case, the main heat exchangers in the liquefaction train of the Skikda, Algeria, plant were shut down for extended periods due to a combination of mechanical wear caused by vibration, which ruptured heat exchanger tubes, and corrosion caused by mercury in the heat exchangers.

Delays have also occurred in ship construction, and at least two yards have been unable to fabricate the LNG containment systems on schedule. However, a surplus of LNG ships, some in layup and awaiting employment, could compensate for delays in the construction of new ones.

Cost overrun

The cost of any project, especially during an inflationary period, can be greater than anticipated. If construction costs rise too fast and financing for the overrun cannot be found, the project will not be completed and all investments are lost. More likely, the project will be completed with added financing, but the cost overrun must ulimately be borne by someone. Operating costs can also exceed expectations and cause either the sales price to rise or the earnings of project sponsors to fall.

Market uncertainties

Since the projects involve long-term contracts and investments, losses will result if the LNG should not be marketable up to 20 years in the future at prices that cover the sponsors’ costs. Factors that contribute to uncertainty in this area are the possibility of increased domestic fuel production and conservation, the unpredictability of long-term economic growth rates, the unknown future course of world oil prices, possible changes in regulatory policy, and the outcome of any supply contract renegotiations.

Who bears the financial risk?

The costs of project failure, operating or capital cost overruns, supply interruption or reduction, damage to facilities, or adverse governmental decisions, are borne by the various parties in an LNG project. These parties are the owners of the liquefaction plant, the ships, and the receiving/regasification terminals; the lenders to the project; the guarantors of financing; the various governments who tax or otherwise receive revenues from the project; the insurers of the facilities; and the consumers of the regasified LNG. The distribution of risk is determined by contracts among the parties; the financing agreements binding owners, lenders, and those who guarantee financing; the tariffs established by regulatory agencies; tax codes; and insurance agreements. The precise way in which these contractual instruments and tariffs divide the risk will vary according to negotiations and regulatory decisions which take place when the project is financed.

In order to reduce the capital costs of the project and thus increase profits and reduce the final price of LNG to the consumer, a substantial portion of the investments need to be financed by lenders who provide long-term loans at modest rates of interest. Lenders include banks, insurance companies, and governmental finance organizations such as MarAd and Eximbank, and their need to minimize exposure strongly shapes the risk distribution of an LNG project. Banks and insurance companies lend other peoples' money, that of their depositors, other creditors, or policyholders, and they are obliged to repay in full. Therefore, lenders, especially private banks and insurance companies, want their money back no matter what happens to the LNG project. They insist on guarantees of loan repayment from creditworthy parties, who can be governments, natural gas consumers through "all events" tariffs, * or large corporations with ongoing businesses out side of the LNG project.

The owners of the project, who provide the equity capital, money which is their own, will typically absorb more risk in an LNG project than lenders, provided the potential return is greater by virtue of their so doing. If the return to the owners is limited, as it is in the United States for regulated utilities, the owner will also seek limitations of risk. The balance of risk and return that the project owners will accept is influenced by their own special circumstances and by other investment opportunities which are competing for the equity capital needed by an LNG project. Finally, as a genera] rule, those parties who control the LNG facilities usually assume risk on it.

The Pac Indonesia project— An example of risk distribution

The Pac Indonesia case illustrates how risk is distributed among the parties in an LNG project. While this project is somewhat different from early U.S. LNG import projects, it represents an appropriate example, since it is the only project to be approved under the new organization of DOE. The estimates are current and typical of recent LNG proposals, and the contractual relationships reflect more than a decade of experience. However, the reader should remember that the distribution of risk in any project is in part determined by the environment at the time of negotiations,

Although generally representative, the Pac Indonesia project is unique in sevreral ways. First, Indonesia currently is completely dependent on Japan as its primary LNG customer. Also, the California gas utilities would like to use the same west coast terminal for an additional project to bring LNG from the Cook Inlet in Alaska, and the proposed American shiponmer's have expressed reservations and have not yet committed their resources. Finally, the revolution in Iran and the subsequent rapid increase in world crude oil prices during the first half of 1979 have sharply altered perceptions about world oil availability and price from the time the project was first negotiated and approved by DOE/ ERA.

LIQUEFACTION AND LOADING FACILITIES

Indonesian liquefaction and loading facilities are estimated to cost about $869 million representing the largest single capital portion of the project. Pertamina, the national oil company of Indonesia, is the owner. Mobil Oil Indonesia Inc., owns the producing facilities and bears the financial risk associated with them.

The instruments that distribute the risk are the contract for the sale and purchase of LNG between Pertamina and Pac Indonesia, and the security agreement for financing the liquefaction and loading terminal facilities. Two parts of the sales contract are important: the take-or-pay and the force majeure clauses. The take-or-pay clause requires Pac Indonesia to pay for the LNG tendered at the annual contract amount, whether or not the LNG is taken. The burden of marketing the LNG is thereby placed on Pac Indonesia, which is in a position to control its risk in this area. However, the force majeure clause is broad and provides for cessation of contract obligations for acts of God, industrial strife, or governmental decisions interrupting the operation of Indonesian facilities, ships, or U.S. facilities. This clause places most of the risk for the investment in Indonesia on Indonesian interests. Lenders to Pertamina for the liquefaction

*The "all events" cost-of-service tariff effectively insulates equity-holders from debt service risk by ensuring that payments by consumers will be sufficient to service debt in all events. Thus insulated from debt service risk, the shareholder does not increase his exposure as much with added financial leverage. Required rates of return on equity are lower than they would be otherwise, and since bond rates are lower than equity rates, the unit costs can be reduced in this way.

trains and base terminal are protected from financial loss by a guarantee of repayment from the Indonesian Central Bank.

Table 39 summarizes the risks and their distribution for the liquefaction trains and loading terminal. The perils that can occur, the mechanisms by which risk is transferred, the criteria governing the transfer, the amount transferred, who pays, and a reference to the source of the information are included in the table.

Force majeure events are borne solely by Pertamina and other Indonesian interests. If cost overruns occur in the construction of Indonesian facilities, they are borne by Indonesian interests, since the LNG price is not based on cost. An academic exception is that if the price of crude oil falls, and if the United States reverses its inflation and enters a deflationary period, the f.o.b. price for LNG may fall below a minimum established to ensure repayment of the lenders to the Indonesian facilities. In such a case, U.S. consumers are guaranteeing repayment of lenders, a risk most observers of oil markets and price behavior in industrial nations view as insignificant.

However, LNG contracts do transfer some risk to the buyer, and through the tariff, ultimately to the U.S. gas consumer. If the U.S. dollar falls on foreign exchange markets, the LNG price is adjusted to ensure that Indonesia recovers real value for LNG relative to a market basket of currencies. Also, Pertamina will not accept the risk that the buyer will desire for whatever reason not to take future LNG. Thus, if the LNG becomes unmarketable, the risk of failure in marketing the LNG is transferred to the buyer and will be passed on through the tariff to the gas consumers.

SHIPPING

The six ships for the Pac Indonesia project, to be constructed in U.S. shipyards for delivery in 1983-84, are estimated to cost approximately $155 million (1978 dollars) each, excluding the construction differential subsidy by MarAd. A total of approximately $93o million to be paid by their owners and lenders will thus be at risk. Three other foreign ships have already been constructed at costs that are unknown but estimated at an average of $100 million (1976 dollars) each. In this project, the ships will be owned by independent shipowners, Ogden Marine and Zapata, who provide the equity financing, and chartered to Pac Indonesia.

MarAd will guarantee loans of up to 75 percent of the yard cost of a U.S. ship if a construction differential subsidy is provided, or up to 87.5 percent of the yard cost if no construction differential subsidy is involved. These loan guarantees are available only to ships built in American yards, for American owners, to haul goods in a trade that includes America. However, MarAd may negotiate with the shipowner for additional money beyond the 25-percent equity interest to help protect the Government

Table 39.—Distribution of Financial Risk for Liquefaction and Loading Facilities of the Pac Indonesia Project

Event	Risk transfer mechanism	Criteria	Amount	Paid by	References
1. Supply reduction or interruption	Sales contract	Force majeure	All	Indonesian interests	LNG sales contract
2. Project failure before or after startup, liquefaction, or terminal problems		Force majeure	All	Indonesian interests	LNG sales contract
3. Cost overrun on Indonesian facilities	None. Price not cost-based	If price drops, minimum bill	All	Indonesian interests	LNG sales contract
4. Ship unavailable—no fault of Pac Indonesia, e.g., delay in ship construction	Sales contract, take-or-pay, charter hire, minimum bill	Not force majeure	Difference in LNG price when quantities made	Shipowner limited to 10% of capital cost remaining customers	LNG sales contract, charter hire
5. Dollar depreciation in foreign exchange markets	Tariff	Automatic	Ft~l	U.S. consumers	ERA 2, P.15

aERA refers to an Opinion of the U.S. Department of Energy/Economic Regulatory Administration guarantee. For example, MarAd required U.S. shipowners (Lochmar) in the Trunkline LNG project to finance the 25-percent equity portion of the ships and to put up initial working capital equivalent to 1 M years' operation to provide added protection in case the ships are not employed immediately after they have been delivered. Marine insurance covers losses from sinkings, collisions, acts of God, and hull and machinery failures.

Pending a resolution of who bears the financial risk, the proposed American shipowners for Pac Indonesia have not yet committed themselves to providing the ships. If the proposed owners decide not to provide the shipping, Japanese firms are expected to do so. However, in this discussion it is assumed that the American firms will build the ships in American shipyards, using a construction differential subsidy.

The risk of failure of other parts of the project, which would leave ships unemployed, are controlled by the charter arrangements between the shipowners and Pac Indonesia, and by the U.S. tariff which governs how Pac Indonesia passes on its costs to consumers of natural gas. Pac Indonesia has signed time charters for 20 years with the various owners, under which the shipowner guarantees to deliver a ship of specified speed, fuel consumption, and boil-off rates. Pac Indonesia pays for the capital, maintenance, and the operating costs of the ship. These payments are reduced if the ship does not meet technical requirements or is not available, and the shipowner also assumes all costs when the ship is not available for service and the fault is not Pac Indonesia's.

Through the time charter mechanism, many of the risks are transferred to Pac Indonesia. However, the arrangements also specify that Pac Indonesia need not assume the risks if they are passed on to the LNG consumer via an approved tariff for foreign ships, or in the case of a fall in the foreign exchange rate, offset by a currency adjustment clause.

ERA and the administrative law judge in their opinion and initial decision recommended a "minimum bill" provision of the tariff by which Pac Indonesia would charge Southern California Gas and Pacific Gas & Electric for the LNG. This provision specifies the costs that can be passed on even if the full amount of gas is not flowing, and includes the time charters or other arrangements for ocean transportation. In this way, the cost of shipping automatically passes to the gas consumer after the project has begun,

Table 40 shows the sources of risk, the contractual instruments for distributing them, the amounts, and who pays. As the table shows, as long as the project is operating and the ships are available, the charter-hire agreement and the tariff pass all costs of supply interruption or reduction, increases in operating costs, or reduction in the value of the dollar relative to a market basket of currencies, on to the gas consumer via minimum bill provisions. However, for events that occur before the gas begins to flow, such as cost overruns on U.S. ships during construction, or project failure before or after startup, passthrough of costs to the consumer is not automatic. In the latter case, FERC will decide if and to what extent gas consumers pay after an appeal under section 4 of the Natural Gas Act. Thus, what costs the consumer and the shipowner assume will be determined by an administrative ruling following an evidentiary hearing to determine, for example, whether cost overruns were "prudent. "

The proposed U.S. shipowners in the Pac Indonesia project have complained that they bear undue risk if they must depend on the outcome of an administrative appeal in the event of cost overruns or project failure. The shipowners (ERA Decision No. 6, p. 9) have argued that unless the customers are required through the tariff to pay for the charter obligations in the event of project failure, MarAd title XI financing will not be available. However, ERA and the administrative law judge did not find sufficient evidence to support this claim. This finding is supported by the fact that ship financing and construction for the Trunkline LNG project is proceeding with MarAd loan guarantees. However, the interests, objectives, and perceptions of the proposed Pac Indonesia shipowners, which are otherwise independent of the project, may be different from those of their Trunkline counterparts; Panhandle Eastern Pipeline Company, the

Table 40.—Distribution of Financial Risk for Ships of the Pac Indonesia Project

Event	Risk transfer mechanism	Criteria	Amount	Paid bv	References
1. Supply reduction or interruption	Minimum bill	Automatic	[illegible]	[illegible]	ERA 1, p. 30 ERA 6, pp. 11-14
2. Project failure before or after startup, liquefaction, or terminal problems	Sec. 4 type filling	Facts surrounding project failure			ERA 1, p. 32 ERA 6, p. 33 ERA 6, p. 10
3. Cost overrun	Sec. 4 hearing	Prudent	Prudent portion Imprudent portion	Customers Shipowners	ID, ERA 1 ERA 6, p.5
4. Ships unavailable, no fault of Pac Indonesia, LNG available	Charter contract			Shipowners	
5. Dollar fall in foreign exchange	Tariff	Automatic	Foreign ships	Customers	ID p. 80 ERA 1, p. 27
6. Increases in operating costs and maintenance	Tariff	Automatic subject to review	Actual costs of contract escalation	Customers, shipowners	ERA 6, p. 11
7. Delay in startup after charters begin (foreign ships)	DOE review, tariff	Proper accounting and calculation	All minus interim hire	Customers	ERA 6, p. 8
8. Ships unavailable (force majeure)	Charter contract, minimum bill	Automatic	Charter fee, minus other recovery	Customers	ERA 1, p. 30 ERA 6, pp.11-14

[a]ERA refers to an opinion of the U.S. Department of Energy/Economic Regulatory Administration.
ID refers to the initial decision of an administrative law judge of the Federal Energy Regulatory Commission.

parent of Trunkline LNG; General Dynamics Corporation, builder of the ships; and Moore McCormack Bulk Transport, Inc., the operator of the ships.

RECEIVING/REGASIFICATION TERMINAL

The import terminal and regasification facilities, with an associated pipeline to move the revaporized natural gas to existing pipelines, represent the smallest of the investments in an LNG project but are the ones on U.S. soil. In the case of the Point Conception plan, these facilities would cost approximately $700 million (1978 dollars) and could be used as an import terminal for about 560 to 600 MMcf/d of Indonesian LNG with remaining capacity for an Alaskan LNG project of approximately 350 MMcf/d. In addition, the Point Conception site is intended to store LNG for peak shaving.

Approximately 75 percent of the costs of the terminal are expected to be financed by debt, primarily from banks or insurance companies, and the rest by equity capital. The distribution of risk is determined by the tariff and the security arrangements between the lenders and owners of the terminal as shown in table 41.

In its decisions, DOE/ERA very clearly distinguishes between risk before startup and risk that might occur after the gas is flowing.

Before project startup, ERA requires a section 4 filing with FERC in order to determine what costs would be passed on to consumers. In the case of a cost overrun, ERA suggests that only prudent costs be passed on to customers, and that shareholders bear imprudent costs. For project failure before startup, no explicit criteria for passing on costs have been established. The ERA decision clearly states that the credit before completion should be provided by private creditworthy parties, who guarantee loans. Elsewhere, the FERC staff and others argue that if the project fails, in no case should the equity costs be passed on to consumers.

ERA recommends a minimum bill portion of the tariff providing that after gas first flows, the debt portion of the terminals and other cost be passed on automatically to gas consumers even if the project fails. In the event of failure, supply reduction, or interruption after project completion, the ERA opinion (in contrast to the Trunkline LNG decision) will also consider possible re-

Table 41 .—Distribution of Financial Risk at the Receiving/Regasification Terminal of the Pac Indonesia Project

Event	Risk transfer mechanism	Criteria	Amount	Paid by	References
1. Supply reduction or interruption	a. Minimum bill	Automatic	a. When less than 900/. delivered, no return of or on equity on undelivered volumes. Recovery of other allowed costs.	Customer	ID p. 81 ERA 6, p. 13 ERA 1, p. 30
	b. Sec. 4 type proceedings	Extraordinary circumstances	b. Pro rata return of and on equtiy	Shareholders and perhaps customers	ERA 1, p. 32
2. Project failure before startup	Sec. 4 filing	Circumstances	As determined	Customers	ERA 1, PP.32-33 ERA 6, p. 11
3. Cost overrun	Sec. 4 filing	Prudent	Allowed Disallowed	Customers, Shareholders	ERA 6, p. 16-17
4. Ships unavailable—no fault of Pac Indonesia or Terminal Associates	Minimum bill is 90% deliveries	Automatic	Costs and equity on deliveries. Pro rata equity	Customers, Shareholders	ERA 1, p. 30 ERA 6, pp. 11-14
5. Project failure after startup	Minimum bill Sec. 4 filing	Automatic Circumstances	Non-equity, Equity	Customers Shareholders and customers	ERA 1, P.33 ERA 6, p. 13

[a]ERA refers to an Opinion of the U.S. Department of Energy/Economic Regulatory Administration.
ID refers to an Initial Decision of an Administrative Law Judge of the Federal Energy Regulatory Commission

turn of equity costs in the terminal regasification facilities in a section 4 proceeding if extraordinary circumstances can be shown.

SUMMARY OF RISK DISTRIBUTION

The distribution of risk in an LNG project, as exemplified by Pac Indonesia is as follows:

Financial risk of the producing country facilities: ($869 million, 1976 dollars)

- Most risks are borne by the owner of the liquefaction facility, Pertamina, the gas producer, Mobil, or the Indonesian Government through loan guarantees.
- Risk of the marketability of the LNG is born b-y the U.S. gas companies and gas consumers.

Financial risks of shipping: ($1,230 million, 1978 dollars)

- Insurance companies take normal shipping risks such as damage to the ship, grounding, storm, etc. Gas consumers ultimately pay the insurance premium.
- While the project is in operation, gas consumers bear costs if LNG flow is interrupted or reduced.
- If the project fails, the shipowner may bear the risk, at least on his equity in the ship, although FERC, after evidentiary hearings, may pass on some costs to the gas consumer.
- Cost overruns may be borne by the shipowner, unless after evidentiary hearings FERC decides to pass on prudent costs to the gas consumer.
- If all else fails, the lenders for U.S. ships with financing guaranteed by MarAd receive payment from the MarAd Federal Ship Financing Fund, and if that is exhausted, from the U.S. Treasury.

Receiving/regasification terminal: ($437 million, 1977 dollars)

- Loss due to project failure before gas flows may be fully borne by shareholders, unless FERC, after an evidentiary hearing, decides to pass some or all costs on to gas consumers.
- After gas flows, the non-equity costs of the terminal are borne by gas consumers. Shareholders bear risk of loss of equity and return on it in proportion to the reduction of LNG flows except that FERC may pass on

equity costs to consumers in extraordinary circumstances.

- Cost overruns may be borne by shareholders unless FERC, in an evidentiary hearing, passes on prudent costs to gas consumers.

Risk of LNG embargo by the producing country

Four of the six largest actual or potential exporters of natural gas from the Eastern Hemisphere—Algeria, Iran, Indonesia, and Nigeria—are members of OPEC. The U.S.S.R. is an adversary superpower. Only the last, Australia, is a member of OECD. As oil exporters, OPEC members have demonstrated their readiness to impose increases in price at short notice on existing contract terms. Some of them, also, have embargoed crude exports for political reasons.

On the other hand, the supplier as well as the purchaser experiences dependence on LNG trade and faces incentives not to interrupt shipments. LNG exports characteristically involve substantially greater capital investment than exports of oil of comparable energy content. Contracts for 15 to 25 years of deliveries after at least 5 years of negotiation and plant construction, are necessary in order to amortize huge initial financial outlays. A large proportion of this investment, in gathering and trunk pipelines, liquefaction, plants, and terminals, is in the exporting country, and in all cases so far, host governments have participated in the financing. If performance under a long-term contract were interrupted, alternative exports that would maintain revenues to pay capital charges would be very hard to arrange. The projects are technically integrated, and the only mobile capital involved, the cryogenic tankers, will often be under the effective control of foreign joint-venture partners or import customers, and until now, no "merchant trade" in LNG has developed. (Some LNG tankers have been built speculatively, and as the international trade expands, a fringe of uncommitted tonnage will no doubt become available for the occasional balancing transaction between customers with terminals.) Furthermore, selling the gas in the exporter's domestic market would be disadvantageous, because local customers do not use LNG and may not be located close to the pipelines leading to liquefaction terminals, and export volumes are generally surplus over domestic consumption anyway,

These characteristics of present international gas trade seem to lock all parties to an LNG supply contract into a closed economic loop. The costs of interruption, and of insurance against it (technical as well as financial), will be heavy. The resource is not lost (in the case of nonassociated gas), but all parties will share all the cost of downtime on a large accumulation of costly, dedicated capital.

This generalization in no sense precludes arguments over price while a contract is in force. It simply increases the pressure on all parties to settle short of interrupting the gas flow. Also, 20-year contracts in an environment of rapid inflation and rising real prices for alternative fuels require effective escalation and review clauses.

In extreme circumstances, the high cost of interruption will not necessarily prevent gas being cut off for political purposes. one of the few cases on record of an LNG contract's actually being interrupted was Libya's action against the EXXON trade to Italy and Spain, which indeed involved associated gas and was thus more costly for both sides. * That arbitrary action may have been at once commercially and politically motivated. Although interrupting a gas operation for political purposes is demonstrably more costly than interrupting oil exports, it is nonetheless possible.

The risk of supply curtailment can be reduced through policies that require the "exchange of economic hostages, " as suggested by Resources for the Future. Under such a policy, "the producing country would own liquefaction facilities and tankers, and would finance them with borrowings other than from U.S. parties or government entities such as the Export-Import Bank. "[20]

*The gas might have been, but was not, flared. Instead, the Libyan Government closed down EXXON's crude oil production from the Zelten field as well.

[20]Sam H. Schurr, et al. *Energy in America's Future—The Choices Before Us* (Baltimore, Md.: Johns Hopkins University Press, 1979), p. 437.