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BNL 50556 BNL NORTHEAST ENERGY PERSPECTIVES STUDY

SUPPLY OF LIQUEFIED NATURAL GAS TO THE NORTHEAST

Gary R. Bray, Sara K. Julin, and John A. Simmons

April 1976

POLICY ANALYSIS DIVISION
NATIONAL CENTER FOR ANALYSIS OF ENERGY SYSTEMS
BROOKHAVEN NATIONAL LABORATORY
UPTON, NEW YORK 11973

Prepared for the
UNITED STATES ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION

DISCLAIMER

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BNL 50556
(Petroleum and Natural Gas - TID-4500)

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GARY R. BRAY, SARA K. JULIN, AND JOHN A. SIMMONS
Science Applications, Inc., McLean, Virginia

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FOREWORD

This report, submitted by Science Applications, Inc., is one of a number of issue papers prepared as part of the Brookhaven National Laboratory Northeast Energy Perspectives Study. The analyses in these papers were performed specifically to assist us in our first integrated study of the energy future of the northeastern United States.

Topics covered by the issue papers include the potential supply of energy to the Northeast from coal, oil, natural gas, liquefied natural gas (LNG), nuclear power, municipal waste, solar energy, and wind power, and the demand for energy in the Northeast from the industrial, transportation, and residential and commercial sectors. In each case a range of estimates of energy supply or demand was constructed to reflect not only a variety of possible policy and technological developments, but also the basic uncertainties of all such future projections. The integrative analysis which relates the supply and demand picture is presented in a summary report entitled "A Perspective on the Energy Future of the Northeast United States."

The issue papers prepared for the Northeast Energy Perspectives Study and the summary report will be available from:

National Technical Information Service
U.S. Department of Commerce
5285 Port Royal Road
Springfield, VA 22161

The issue papers and summary report are listed below.

H. Bronheim, "Future Oil Supply to the Northeast United States," BNL 50557 (June 1976).

R. J. Goettle, IV, "Alternative Patterns of Industrial Energy Consumption in the Northeast," BNL 50555 (March 1976).

R. N. Langlois, "Future Natural Gas Supply to the Northeast," BNL 50558 (April 1976).

J. Lee, "Future Residential and Commercial Energy Demand in the Northeast," BNL 50552 (March 1976).

P. M. Meier and T. H. McCoy, "Solid Waste as an Energy Source for the Northeast," BNL 50559 (June 1976).

P. M. Meier, T. H. McCoy, and S. Rahman, "Issues in the Future Supply of Electricity to the Northeast," BNL 50553 (June 1976).

B. S. Edelston and E. S. Rubin, "Current and Future Use of Coal in the Northeast," BNL 50560 (May 1976), Environmental Studies Institute, Carnegie-Mellon University, Pittsburgh, Penn.

V. L. Sailor and F. J. Shore, "The Future of Nuclear Power in the Northeast," BNL 50551 (March 1976).

G. R. Bray, S. K. Julin and J. A. Simmons, "Supply of Liquefied Natural Gas to the Northeast," BNL 50556 (April 1976), Science Applications, Inc., 1651 Old Meadow Road, McLean, Va.

System Design Concepts, Inc., "Transportation Energy Consumption and Conservation Policy Options in the Northeast," BNL 50554 (April 1976), System Design Concepts, Inc., 9 Rector Street, New York, N.Y. 10006.

J. Brainard et al., Editors, "A Perspective on the Energy Future of the Northeast United States," BNL 50550 (June 1976).

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SECTION I

INTRODUCTION

A. Purpose of Study

The study identifies some of the information that will be necessary to define the optimum role of liquefied natural gas (LNG) relative to other sources of energy for the Northeastern region of the United States. Included in the study is a collection, analysis and presentation of significant information dealing with the importation of LNG.

B. Scope of Study

The primary effort of this study was directed at defining the availability, projected costs, and projected schedule for obtaining imports of LNG. The projected schedule includes estimates of time required to obtain approvals from regulatory bodies, and the time required for engineering, procurement and construction of the necessary facilities. Also considered in the study were site selection criteria for an LNG receiving terminal, and the elements of an environmental impact summary.

C. Background Information

Ever since the mid-1940s, the United States has generally been consuming natural gas at a greater rate than the rate new reserves are found. Figure 1 shows just how serious the problem is. At present, the ratio of proved U.S. natural gas reserves to annual natural gas production is only about 10.

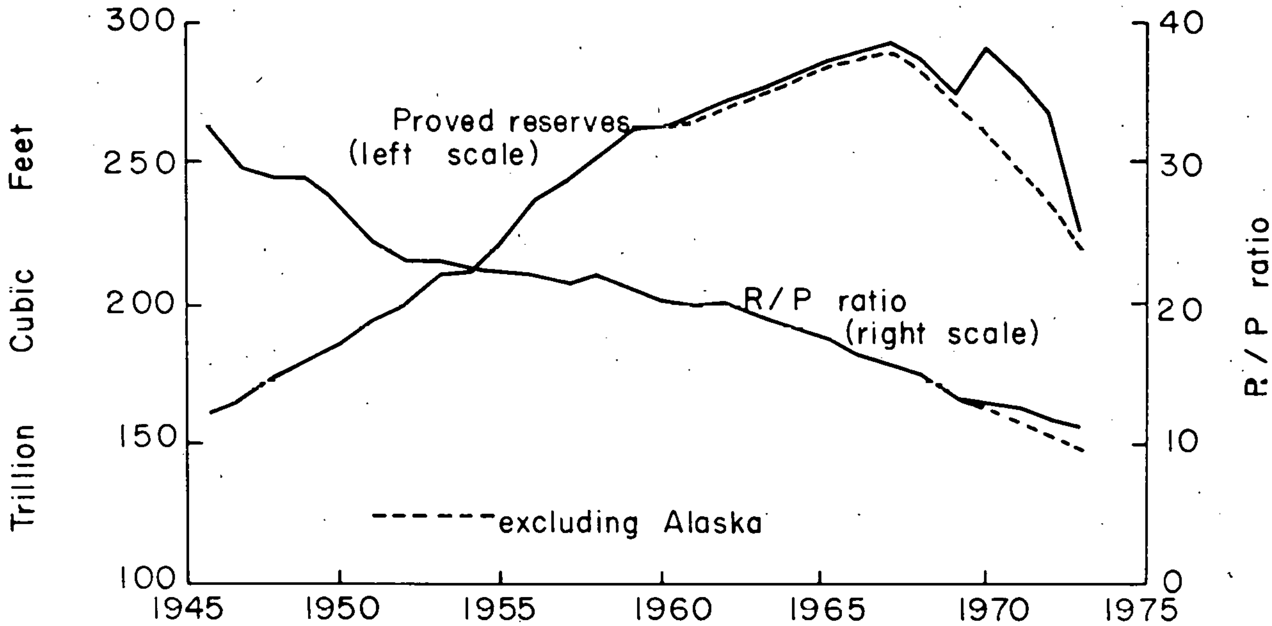

Figure 1.[6] U.S. natural gas proved reserves and reserves-to-production ratio.

Because of this and other problem areas, domestic natural gas production reached a peak of approximately 22.6 trillion cubic feet in 1973, and started a decline.

One near-term and direct result of declining production is the projected shortage of natural gas for 1975-1976. The shortage of natural gas will be even more pronounced for the Northeast region of the United States because of the effective deregulation of intrastate natural gas. This deregulation has resulted in bids for intrastate well head prices in Southern Texas of greater than $2.00 per thousand cubic feet of natural gas versus the interstate regulatory prices at the well head of $0.52 per thousand cubic feet.(13) The shortages will become worse in future years unless remedial action is taken.

There are several options available to make up the shortfall of natural gas. These options include:

- Expanded energy conservation
- Replacement of natural gas with other energy sources such as nuclear and coal
- Provide SNG (synthetic natural gas) either from other sources of petroleum or from coal gasification
- Importing LNG
- Nuclear power
- Alaskan North Slope Natural Gas
- Decontrol of interstate gas prices

Probably no one of these options will provide the entire answer. The answer will be a combination, to some degree, of many options. What is important is that some solution for the natural gas shortage be found within a reasonable time frame to prevent serious social and economic displacements within the Northeast. In particular this report examines some of the problems associated with importing LNG to provide natural gas.

Summary

The near term availability of LNG for importation into the Northeastern region of the United States is primarily dependent upon three parameters:

1. Available foreign proven resources of natural gas,
2. International competition and economic viability of agreements for exporting LNG, and
3. Distance from the exporting country to the Northeast region.

These considerations essentially limit the source countries to the following:

Abu Dhabi	Libya
Algeria	Nigeria
Iran	Saudi Arabia
Iraq	Venezuela
Kuwait	Western Russia

The present operating and planned LNG liquefaction facilities in the above countries have a combined expected capacity of approximately 3.0 billion cubic feet per day or 1.0 trillion cubic feet per year of natural gas. The present operating and planned Northeast region LNG receiving terminals have a combined expected capacity of greater than 3.2 billion cubic feet per day or 1.1 trillion cubic feet per year of natural gas. The Northeast region is competing not only with other regions of the United States but also with Europe for the limited world supply of LNG. The projected future imports of LNG to the Northeastern region ranges from zero to 1.1 trillion cubic feet per year for 1985 and up to 2.0 trillion cubic feet per year for the year 2000.

The cost of this imported natural gas (LNG), regasified from a Northeast region LNG receiving terminal, can be expected to range from $1.50 to $4.00 per MMBTU in 1975 dollars. This cost includes all capital recovery costs and operating costs related to the liquefaction, transportation, receiving, and vaporization of LNG. The flexibility of this cost reflects the inclusion of a premium charged by the exporting country, indicative of reluctance to sell an energy resource. It is estimated that an additional charge of $0.60 will be applied as distribution costs, to bring the residential customer's cost to $2.10 to $4.60 per MMBTU. Future costs of LNG can be expected to escalate at the same rate as other energy costs.

The capital cost of a fleet of LNG ships can become a significant portion of the cost of LNG. This limits the reasonable shipping distance of LNG to something under 6,000 to 9,000 miles.

The time required to scope, obtain regulatory approvals, engineer, procure, construct, and start up an LNG terminal ranges from eight to greater than ten years under today's conditions. This period of time can be divided into two basic phases. The first phase is that period of time before obtaining the regulatory approvals and the second phase includes all other activities from detailed engineering through startup. Phase I can range from two to greater than four years due to formal public hearings to decide acceptability of societal risks. Phase II can range from five to greater than six years. Changes in regulatory requirements or procedures could sharply reduce phase I requirements.

During phase I of the project the environmental effects and societal risks from the hazards of accidental fires and explosions of the specific project must be evaluated based on the site location and design of that project. Based on generic considerations it appears that the environmental impacts caused by the construction and operation of an LNG receiving terminal are minor, especially when compared with other energy plants, and the societal risks can be made to be acceptable.

There appear to be several acceptable sites for LNG receiving terminals in the Northeast region of the United States. One site - Cove Point, (Chesapeake Bay) Maryland - has already been approved by the Federal Power Commission as an acceptable site. Other sites in the Northeast which are presently the subject of approval proceedings are Staten Island, New York; Providence, R. I.; Raccoon Island, New Jersey; West Deptford, New Jersey on the Delaware River; and Everett, Massachusetts.

SECTION II

MAJOR FACILITIES AND EQUIPMENT

There are five major project areas of an LNG import system:

- Drilling for, gathering and processing of natural gas at the gas field
- Transmission of the gas to the liquefaction plant via pipelines
- Liquefaction of the natural gas (LNG)
- Transportation of LNG by ships
- LNG receiving terminal.

Each LNG import system will have a separate set of parameters; therefore, each system will have a slightly different facilities and equipment requirement. For example, the length of the LNG transport route will affect the ship round-trip time and therefore affect the necessary fleet size. The location of the liquefaction facility, with respect to the gas field, will affect the length of this transmission line, and the proximity of the receiving terminal to a deep-water harbor will dictate the cost and type of the unloading facilities. As an example, an LNG import system with the capability of delivering one billion cubic feet per day of natural gas will require the following facilities:

- Wells, gas gathering system, compressor plant and pieplines
- Liquefaction plant consisting of head-end gas cleanup equipment, multiple liquefaction cascade cycles, LNG storage tanks, and a ship loading area
- A fleet of 7 to 12 ships equipped with cryogenic tanks

- A receiving terminal including a ship unloading area, LNG storage tanks, multiple regasification trains, and connections to a major pipeline or distribution system.

Figure 2 shows an integrated LNG operation. The liquefaction, transportation, storage, and regasification require about 25 percent of the gas as collected at the well head. Liquefaction alone consumes 17 percent of the collected natural gas. Vaporization is accomplished using heat either from sea or other suitable water or from combustion of a small portion of the gas. Energywise, only the liquefaction and vaporization (if gas combustion is used) steps involve energy losses. Boil-off during storage on land or in the tankship is used as a source of power. The following table shows the LNG system's throughput and energy efficiencies.

Energy Efficiency of LNG Operations

	Gas Throughput Efficiency[6] (%)	Energy Efficiency (%)
LNG Liquefaction	83	83
LNG Tanker (boil-off used to power ship)	94.1	-
LNG Tank Storage (boil-off used to power compressors)	99.7	-
LNG Vaporization (gas fired)	97.9-100	97.9-100

Figure 3 is a schematic of an LNG receiving terminal with an estimated LNG delivery rate to supply approximately one billion cubic feet per day of regasified LNG to the pipeline. As shown a one billion cubic feet per day LNG receiving terminal would consist of a ship unloading facility, storage tanks, storage tank atmosphere pressure control system, sendout pump, vaporizers, and connections to a pipeline. The

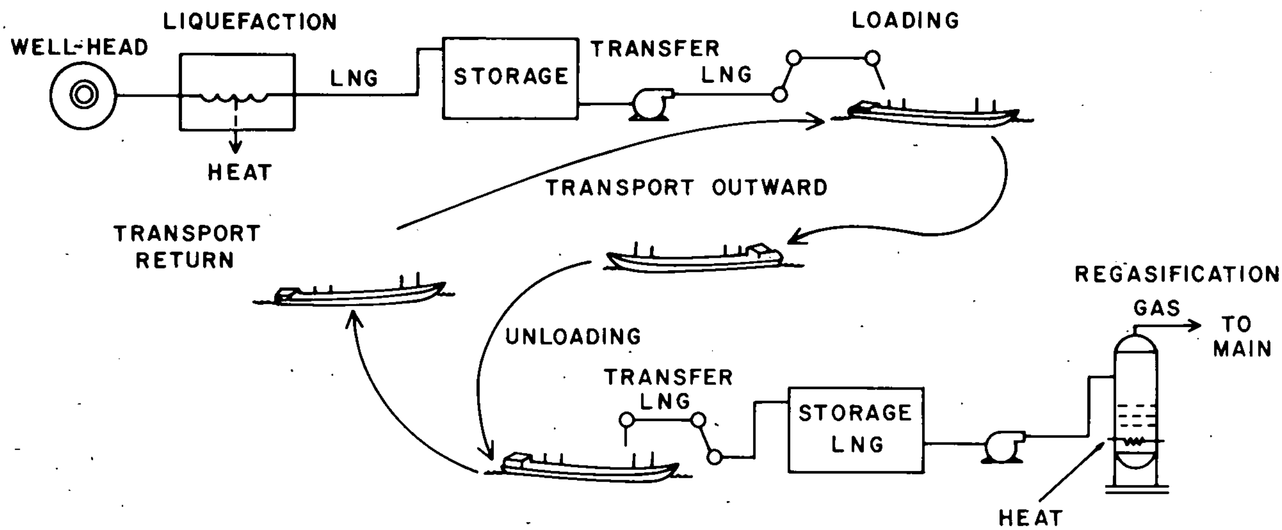

Figure 2. Integrated liquid natural gas operation(6).

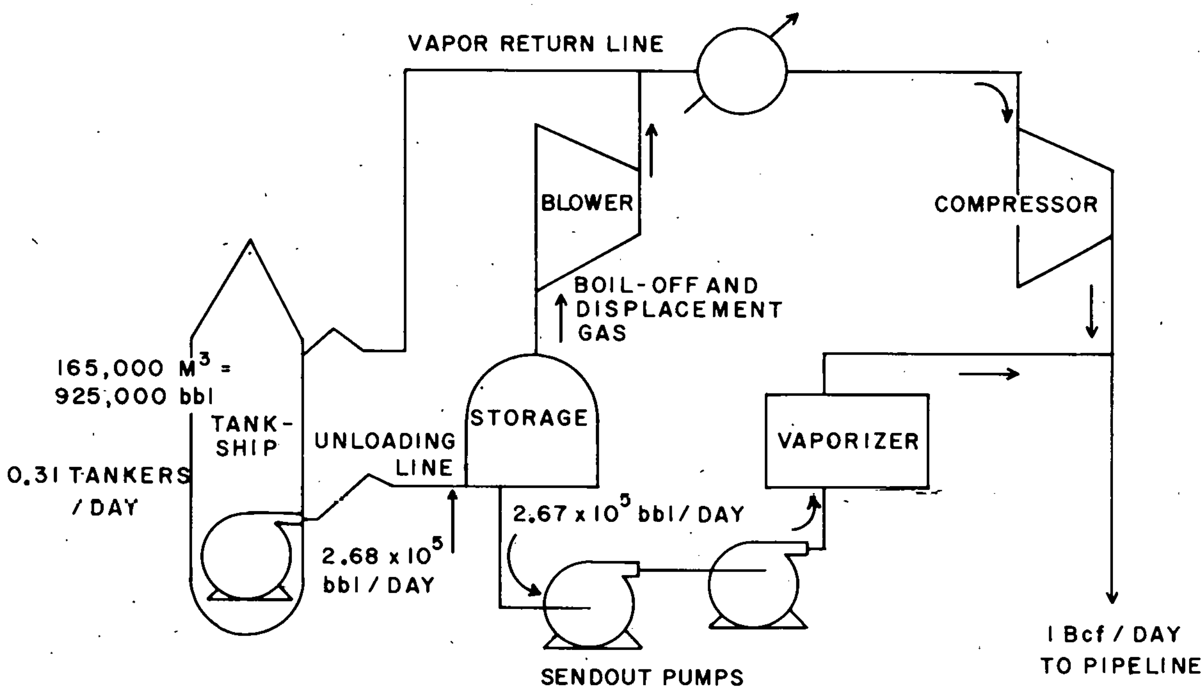

Figure 3. Typical liquified natural gas receiving terminal to supply 1 x 10^9 cubic feet of natural gas per day.

ship unloading facility might consist of two 32" to 42" diameter LNG transfer lines with an 18" vapor return line. The LNG transfer rate would be approximately 82,000 barrels per hour which would permit a 165,000 cubic meter LNG tanker to be emptied in 12 hours. The LNG storage complex might consist of four 550,000 barrel tanks. The storage tanks would be approximately 250 feet in diameter and 80 feet in height. Full height including the outer walls and insulation would be 120 feet. This volume of storage is equivalent to approximately 2.5 shiploads, and 8.25 days of storage for a delivery rate of 1 Bcf/day natural gas.

The 165,000 cubic meter LNG ships referred to above are larger than any presently in existence although 125,000 cubic meter ships are presently under construction. The following data would apply to a 165,000 cubic meter ship:

Total Length	-	1,000 feet
Beam	-	150 feet
Draft	-	40 feet
Displacement	-	125,000 long tons
LNG Capacity	-	165,000 cubic meters

The detailed engineering, procurement, and construction phase of the receiving terminal could be expected to take approximately four years.[12] Such a schedule can be seen in Figure 4. It is important to note that the regulatory approvals, negotiations for the natural gas supply, financing arrangements, and preliminary design are not included in the schedule shown in Figure 4. An expanded discussion of these factors can be found in Section V.

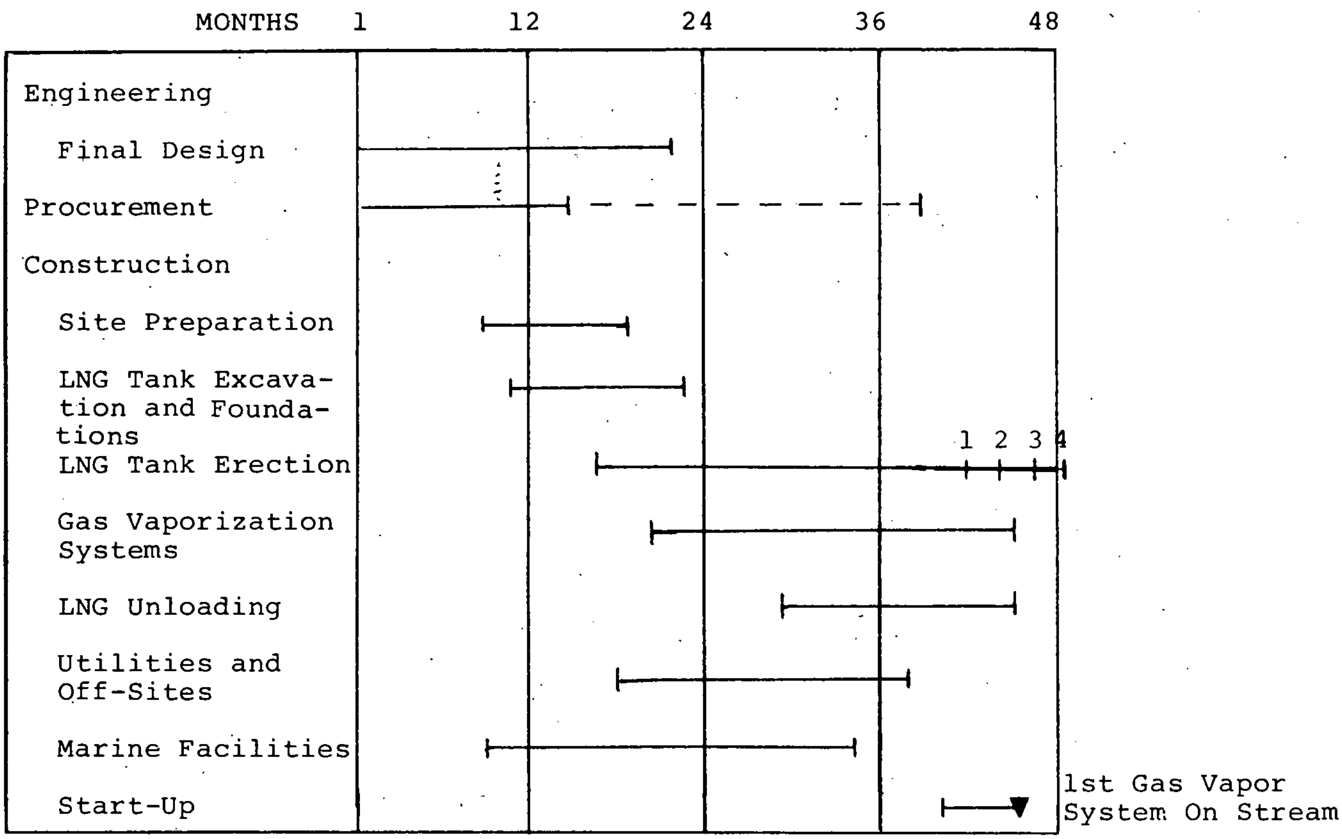

Figure 4. Project schedule.[12]

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SECTION III

INSTITUTIONAL CONSIDERATIONS AND ENVIRONMENTAL IMPACTS

A. Regulatory Agencies Reviews and Approvals

An LNG importation project proceeds after numerous authorizations have been obtained from many Federal, State and local agencies. Approvals are required for such items as the contract price of the delivered LNG, the environmental impacts of the terminal operations, compliance with specific construction and materials codes, and accident and fire contingency plans. A list of most of the agencies which are involved (generic titles for the State and local agencies) together with their jurisdiction is presented in Table 1. Of these agencies the most important, because of their rather broad authority, are the two Federal agencies: the Federal Power Commission (FPC) and the Department of Transportation (DOT).

The FPC has the lead role and is responsible for (1) preparing an Environmental Impact Statement (FPC Order No. 415-C), (2) approving the contract price for the LNG, and (3) approving the LNG terminal site and its operation. Its authority is derived from the Natural Gas Act, Sections 3 and 7. Approvals are based on appropriate information filed by the applicant, information and analysis developed by the FPC staff and information and exceptions submitted in hearings before an Administrative Law Judge. The applicant must show that the LNG to be imported is needed and will be delivered at a reasonable rate (one must have a signed contract with the exporter) and that the project is also acceptable environmentally and hazard-wise.

TABLE 1

REGULATORY BODIES AND THEIR JURISDICTION

TERMINAL - CONSTRUCTION, OPERATION, AND SAFETY
Including Docking and Unloading Area,
Storage Tanks, and Pipeline[1],[15]

Agency	Jurisdiction, Statutes, Standards, or Codes
Federal	
1) Army Corps of Engineers - U.S. Department of Conservation	- Approve construction of dock facilities and dredging beyond bulkhead or pierhead line River and Harbor Act of March 3, 1899 - Sec. 10
2) Environmental Protection Agency	- Review air, water, and noise impact on environment. NEPA 1969, Clean Air Act, Noise Control Act, Federal Water Pollution Control Act
3) Department of Interior - Bureau of Sport Fisheries and Wildlife	- Review impact on biotic communities. Fish and Wildlife Coordination Act
4) Federal Aviation Administration	- Approve structure height in accordance with aviation lanes. Federal Aviation Regulations Part 77 Sec. 77.25
5) Federal Power Commission	- Approve facilities and pipeline; authorize the importation of natural gas. Natural Gas Act
6) Department of Transportation Office of Pipeline Safety	- Establish standards for pipeline safety per the CFR Title 49, Part 192, and Natural Gas Pipeline Safety Act of 1968
7) Supervisor of Harbor	- Permission to dump dredged material at sea
8) Department of Transportation - U.S. Coast Guard	- Approve design and operation of dock facilities

TABLE 1 (Continued)

Agency	Jurisdiction, Statutes, Standards, or Codes
State	
1) Commission of Commerce	- Review construction and operation
2) Conservation Department	- Review environmental impact
3) Department of Environmental Conservation	- Approve facilities on basis of environmental impact; issue a work permit for the dredging operations and the construction of the marine facilities
4) Office of Planning Coordinator	- Review proposal for facilities
5) Public Service Commission	- Review facilities
6) Department of Labor	- Approve safety aspects of facilities
7) Environmental Control Office	- Review Corps of Engineers environmental impact of facilities and issues a permit
8) General Services Administration	- Oversee use of waterway bottoms; grants underwater land grants for underwater pipeline
9) Department of Environmental Protection	- Review environmental impact of pipeline; issue work permit for construction of pipeline; issue license for installation of pipeline; issue quitclaim deed for riparian property
10) Public Utilities Commission	- Approve safety aspects of pipeline; approve construction and operation of pipeline
Local	
1) Department of Ports and Terminals	- Review landward to pierhead line to verify compliance with Building Code; issue work permit for construction

TABLE 1 (Continued)

Local (Continued)	Jurisdiction, Statutes, Standards, or Codes
2) Fire Department	- Assess fire safety of terminal facilities; Fire Prevention Code
3) Board of Standards and Appeals	- Permit for the construction of the facilities; Zoning resolution of the city, City Building Code
4) City Planning Department	- Assess compliance with city zoning resolution
5) County Planning Countil	- Assess compliance with area zoning resolution
6) Board of Health - Bureau of Sanitary Engineers	- Approves sanitary measures "Standards for Waste Water Treatment"
7) Department of Gas, Water Supply, and Electricity	- Approves connections and use of city water, approves electrical wiring "Rules and Regulations for the Use of Water," Electrical Code of the City
8) Environmental Protection Agency (Department of Air Resources)	- Construction and operating permits
9) Department of Water Resources	- Grants approval to tie into city water mains; site drainage

TABLE 1 (Continued)

SHIPPING - TANKER OPERATION AND SAFETY

Agency	Jurisdiction, Statutes, Standards, or Codes
Federal	
1) U.S. Coast Guard (Department of Transportation)	- Regulates ship traffic, conducts inspections, and insures ship safety; CFR 43 OHA, OSHA Ports and Waterways Safety Act of 1972, Public Law 92-340; CFR 46 "General and Specific Requirements for LNG/LPG Operations"
2) U.S. Bureau of Ships	- Oversee ships and ship operations
3) Maritime Administration (Department of Commerce)	- Approve ship design and specifications "Standard Specifications for Merchant Ship Construction," December 1972
4) Environmental Protection Agency	- Assess impact on water and air quality
5) Army Corps of Engineers	- Assess environmental impact on harbor Regulations on Navigable Waterways
Local	
1) Department of Ports and Terminals	- Reviews ship movements within harbor
2) Fire Department	- Assess Fire Safety of Vessels Fire Prevention Code, NFPA 59A
3) City LNG Safety Review Board	- Assess the overall project safety considerations

Under this review process, to date only one LNG import terminal project has been approved - the Columbia LNG Corporation terminal at Cove Point, Maryland. Columbia first filed application to import LNG from Algeria in September 1970.[27] This application along with a number of subsequent applications, including a joint application by Columbia and Consolidated System LNG Corporation for the terminal facilities at Cove Point, were combined into a single application for hearings. These hearings commenced April 8, 1971 and continued through July 8, 1971. Environmental issues of the project became a major focus of the hearings. Subsequently, environmental reports were prepared by several participants, including the FPC staff, whose report was filed August 16, 1971. These reports were publicized in the Federal Register for January 21, 1972. As the result of amendments to the basic applications in November 1971, additional hearings were held from January 11 to 24, 1972. On March 24, 1974, a late petition to intervene by the Sierra Club and the Maryland Conservation Council was granted. After these parties were heard, the Presiding Examiner decided in favor of the project, subject to many conditions. The Examiner's conclusions were confirmed by order of the Commission on June 28, 1972, in which they specifically approved the environmental report of the applicants. Acceding to requests for a rehearing, oral arguments from all parties were heard on August 18 to 21, 1972. On October 5, 1972 the Commission modified certain particulars regarding some environmental issues. Subsequently, the intervenors filed a petition for review with the United States Court of Appeals. In response, the applicants filed a petition with FPC for a modification of the terminal which would remove the intervenor's objections. Subsequent to additional procedures resulting from these actions, the FPC on March 30, 1973 approved the modifications and reaffirmed their earlier orders to permit Columbia and Consolidated to construct and operate the terminal facilities and to sell natural gas as described in their petitions. However their order would not become effective until all the necessary Federal, State and local authorizations and permits (e.g. Coast Guard clearances of vessels and harbor operations and compliance with governing safety codes) had been secured. Table I is a list of the agencies that might be involved.

This formal approval process required a period of 30 months, from application to final approval. This is the first LNG terminal project that has been approved by the FPC, and it is not known if the time required is typical. The extent of intervenor action may have something to do with this. Currently the FPC still has under review two projects for which the terminal facilities are already complete, the Distrigas terminal at Everett, Massachusetts and Eascogas' terminal on Staten Island. The applications for these terminals have been complicated by some confusion concerning whether or not the imported gas would be sold intrastate instead of interstate, the FPC's reversal of their original orders declining jurisdiction over these terminals and the applicant's current lack of a long term contract for gas. In the case of Staten Island, the initial applications were made in late 1972 and final FPC resolution is not expected before the summer of 1976. Applications for other LNG projects have been pending for a shorter time.

The Department of Transportation's role consists of the regulatory authority of two of its subdivisions. The United States Coast Guard is responsible for ensuring safe practices for any tanker vessel operating under U.S. flag and any such vessel of foreign flag carrying cargo within the navigable waters of the U.S. This responsibility extends to the safety of persons and property on shore in addition to shipboard personnel, cargo and equipment. The Office of Pipeline Safety regulates the construction and operation of gas pipeline transmission systems and facilities of which an LNG terminal is a part.

The present rules and regulations established by the Coast Guard specifically for LNG ships are contained in Subchapter D ("Rules and Regulations for Tank Vessels") CG 123 dated May 1, 1969, undergoing revision. A provisional document pertaining to LNG vessels was prepared in 1972 by the USCG and the International Maritime Consultative Organization.

Current and future owners of Foreign Flag LNG vessels must submit plans and specifications for approval by the United States Coast Guard before such vessels can be used to ship LNG into U.S. ports. Construction drawings for new ships for this service must be approved by the Coast Guard, and construction is reviewed by the cognizant classification society at the shipyard.

An arrival inspection at the first U.S. port of entry is required of all such vessels built abroad to check the loaded vessel against previously submitted and approved plans and specifications. Any discrepancies noted during this inspection must be corrected before the Coast Guard will issue a "letter of compliance" for the vessel.[11]

B. Potential Environmental Impacts

A major concern of the FPC in granting approval of the construction and operation of an LNG terminal is the potential and inherent environmental impacts of such a project. Guidelines for preparing environmental reports are given in

FPC Order 485. The risk of large accidental fires that such a terminal poses to the surrounding population is the gravest of these concerns. This subsection discusses the inherent environmental concerns. It will be seen that compared with many other industries, the typical operation of an LNG terminal creates relatively minor environmental impacts. In the second subsection accidental fires are discussed.

- Air and Noise Quality

  The major source of air quality degradation arises from dust and emissions from equipment during construction. Most of the dust and emissions are temporary and cease after construction is complete. During operation of the terminal, emissions from compressors and vaporizers would be minimal since the energy source for this type of equipment is electricity or the combustion of natural gas, which characteristically is clean burning. Table 2 shows the expected levels of residuals for an LNG operation. Noise levels can be expected to rise during the construction period, and subside to normal industrial noise levels (depending on the surrounding natural vegetation) upon completion of construction. The Department of Labor, through the Occupational Safety and Health Act (1970) set a 90 dB noise level limit for eight hours of exposure per day. The EPA through the office of Noise Abatement regards 90 dB levels inadequate in protecting health and welfare. It should be noted that it has been established(19) that at 85 dB of background noise, communications by means of shouting is possible; at 65 dB of background noise, communication can take place at three feet reasonably comfortably. Satisfaction of these requirements and those of local codes may require acoustic designs for compressor housings.

TABLE 2

Residuals for Liquefied Natural Gas Operations (6)

SYSTEM	Water Pollutants (Tons/10^{12} Btu's)										Air Pollutants (Tons/10^{12} Btu's)					
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/10^{12})	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes
LIQUEFIED NATURAL GAS																
Liquefaction	NA	NA	NA	NA	NA	NA	NA	NA	NA	1.03×10^{11}	0	354.	0	0	0	0
Tanker	NA	NA	NA	NA	NA	NA	.212	0	NA	0	.0315	.437	.336	.0154	.0062	.0044
Tank	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0	NA	NA
Vaporization	NA	NA	NA	NA	NA	NA	NA	NA	NA	0	.187	1.00	.0059	.0785	.196	.108
TRANSMISSION AND DISTRIBUTION																
Pipeline	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0	103.	0	0	0.	0

NA = not applicable

- Climatic Effects

  Under normal operating conditions, only negligible effects upon the local climate would be expected. LNG is stored at atmospheric pressure at -259°F to -260°F in well insulated tanks. Thermal leakage during storage will be small, approximately 1×10^6 kcal/day per each 500,000 bbl storage tank. This heat is equivalent to the burning of 25 gal/day of gasoline and would be extracted mainly from the ambient air. Regasification of the LNG may involve the extraction of heat from a nearby, large body of water.

- Terrestrial Changes

  Natural vegetation on the LNG site would be destroyed on construction. The grade of the site might warrant major changes to accommodate the requirements of off-loading, storage and vaporization. These changes will effect the previous drainage characteristics of the site, possibly changing the existing patterns of wildlife habitation and the vegetation distribution at the site perimeter.

- Archeological, Historical and Recreational Impacts

  Recreational areas near the site will be exposed to fire hazards in the rare case of a major accident. Otherwise the principal impacts will be industrial noise, traffic disturbances where common roads are used for tank truck arrivals and departures and a potential degradation of the aesthetic quality of a nearby recreational area. Historical and archeological concerns must be carefully considered with local authorities for each possible site.

- Water Quality and Aquatic Impact
  At highly industrialized sites, the impact upon the water quality and aquatic life is expected to be minimal. At more rural sites the effect of dredging, fill and waste disposal upon the natural aquatic environment must be considered. LNG facilities present no significant polluting effects, other than the bilge pumping from docked tankers. In the instance that periodic dredging must be done to maintain the harbor, suspended residuals will temporarily decrease the light penetration of the water and hence the photosynthic processes of aquatic organisms.

- Socio-Economic Effects
  Land re-sale value in the neighborhood of the site might fluctuate (primarily downward) until the safety record of the facility has been established. Decreased aesthetic attraction of the neighborhood also may contribute to this. During the construction period the housing demand may increase, and if the local residential areas are not suitable or are unable to accommodate the construction crews, on-site temporary housing may be required. Local markets will see an increase in business during the construction period. During normal operations, the local utilities must be able to handle plant requirements.

- The Commitment of Land and Land Use
  Approximately 800 to 1200 acres of land are necessary for docks, storage and vaporization facilities, depending on the LNG terminal's daily capacity. The disturbance of this much land will probably result in the re-routing of some surface runoff and subsurface drainage. Depending upon the soil's natural

capacity to drain through percolation, an increase in surface errosion can be expected. A further consideration is the land mass compaction resulting from the construction at an LNG site. Such compaction could re-route aquifers and underground streams. In the case that such settling is not uniform, it could result in a weakening of the structural integrity of storage tanks. These problems can be mitigated by appropriate engineering and other precautions.

Expansion of existing port facilities could conflict with existing or planned land uses. Enlarging channels and harbors by dredging impose hazards on local and downstream estuarine areas.

Easements also must be obtained for pipeline and access roads to and from the terminal. Permanent right-of-way corridors for pipelines in the Northeast will be approximately 50 to 60 feet wide (6 - 7-1/2 acres/mile). For example, the proposed 26-48 inch Alaskan Pipeline will require a 100 foot wide right-of-way corridor during construction. This will be reduced to a 54-foot-wide permanent corridor, after construction, which will allow access roads within the pipeline right-of-way for maintenance operations.[10]

C. Safety and the Risk of Accidents

The hazards of importing LNG arise from possible accidents in which a large amount of LNG is spilled and subsequently ignited. There are many possible such accidents and these together with their possible consequences are summarized in Figures 5a and 5b. For example LNG might be spilled via the

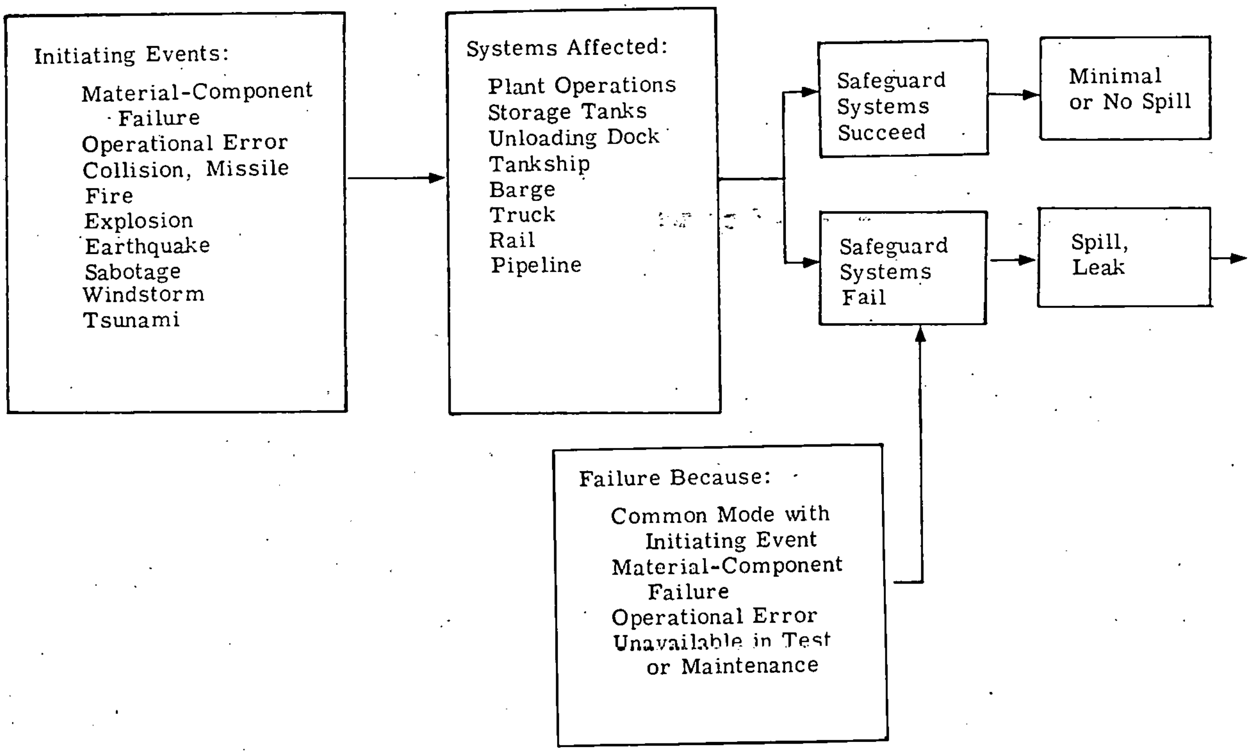

Figure 5a. Accident sequence of events determined mainly by the initiating event and terminal design.

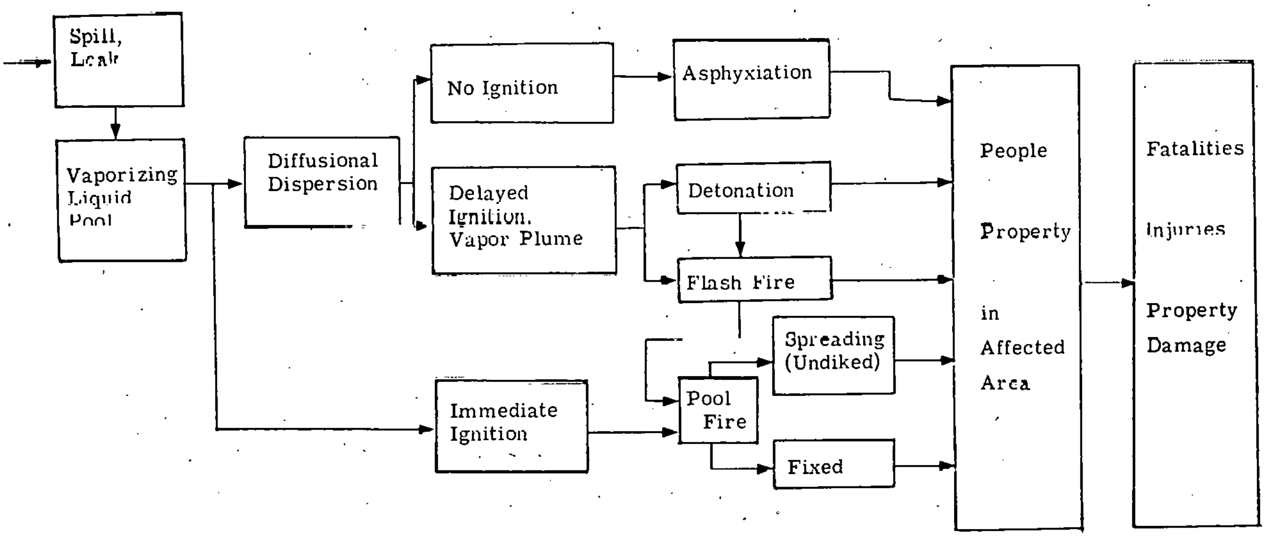

Figure 5b. Accident sequence of events determined mainly by site characteristics.

collision of another ship with an LNG tankship or the failure and collapse of a LNG storage tank. Such spills can lead to "pool" fires in which the LNG burns similarly to a "pool" of gasoline on water or land. If the spill and, consequently, the fire are large the thermal radiation has been estimated to be sufficiently intense to cause serious burns and to ignite secondary fires at distances of 1.5 to 2.5 times the radius of the pool from the center of the fire.

The most notable example of an LNG "pool" fire (and coincidently the only known major catastrophe in the U.S. involving LNG) occurred in Cleveland in October 1944. A storage tank containing 38,000 bbls (6,000 m^3) of LNG collapsed. The escaping liquid caught fire soon afterwards, and as it burned, it flowed down nearby streets, across parking lots, and into basements and storm sewers.(19) Accumulations of vapor in the latter regions caused serious explosions which demolished many homes and buildings. Fire also spread by thermal radiation from the flame of the burning liquid pool near the collapsed tank. The flame oscillated in "bursts" and reached a height of 2800 feet. Combustibles were ignited at distances of more than 1000 feet away (by radiation). In all, 135 people were killed and approximately $10,000,000 property damage was incurred.

This accident was attributed to a material failure (brittle fracture) of the tank wall at the cryogenic temperature. An important contributing factor was that the tanks were not diked to prevent the spread of the burning liquid. Modern LNG storage tanks are constructed of materials wh~~ich~~ have been demonstrated to retain their strength at cryogenic temperatures. Also, all tanks are diked.

If the spill is not ignited immediately, a large flammable plume of LNG vapor might develop and drift downwind. The flammable plume is that portion in which the vapor concentration exceeds approximately 5 percent, the lower flammability limit of methane-air mixtures. When ignition finally does occur, the burning plume could cause serious burns and ignite secondary fires at distances of 1.0 to 2.0 plume radii. No accident of this type has ever occurred with LNG. However an accident involving a spill of naptha (a highly volatile hydrocarbon fuel) is suggestive of the events and consequences of a possible LNG spill resulting from a tankship collision. In this accident the British tankship, the MV ALVA CAPE, was rammed by the tankship SS TEXACO MASSACHUSETTS in New York harbor, June 16, 1966.[20] A portion of the cargo of naphtha spilled onto the water between the two ships and survivors remembered seeing a large vapor cloud forming. Approximately two minutes after the collision, an explosion on a tug between the two ships ignited the vapor and the "pool" of naphtha on the water. Thirty-three persons, all crew members of the ships and tugs involved, died; some in the initial flash fire and explosions, some trapped in the burning "pool" fire in the water (especially the crew of one of the tugs) and others in the fires on board the ALVA CAPE and the TEXACO MASSACHUSETTS. All damage and injuries were confined to the ships and their crews.

In addition to a flash fire, the flammable plume might undergo partial detonation or otherwise create extensive overpressures. Such an occurrence would cause damage and injuries over a somewhat larger area than the plume fire. On the other hand there is no experimental evidence that unconfined LNG vapor-air plumes can detonate.

Given the above hazards of transporting and handling LNG, the question becomes how likely is the occurrence of accidental spills of LNG. This is crucial to determining the level of risk of injury, and loss of life and property damage posed by these hazards, and ultimately the acceptability of the risk. Methods to judge the acceptability of risk and to estimate the probability of accidents and adverse consequences are described briefly in the following paragraphs. LNG risks and means of their evaluation are discussed in greater detail in References 22.

For existing and established industrial activities, societal risk may be evaluated from the accident experience accrued. However, importation of large quantities of LNG is a relatively new activity for which statistically meaningful accident experience does not exist. Therefore at present, analytical methods are required to project and anticipate that experience. For this, an application of a combination of physical principles, logical arguments, and general data pertinent to LNG are used.

By the present methods, risk of accidents is quantified in terms of their likelihood (occurrences per year) and consequence (fatalities, injuries, and property damage). This quantification leads to a "risk spectrum" of likelihood versus consequence level. Examples of such spectrums are shown in Figure 6.[21] The curve labeled "All Fires and Explosions..." was obtained from statistical data whereas the lower curves for truck transport of LP-Gas and tankship transport of LNG were estimated analytically.

The LNG risk spectrum in Figure 6 does not apply to a specific site. It is a conservative (upper bound) estimate of the risk of fatalities by flash fires in LNG vapor-air plumes

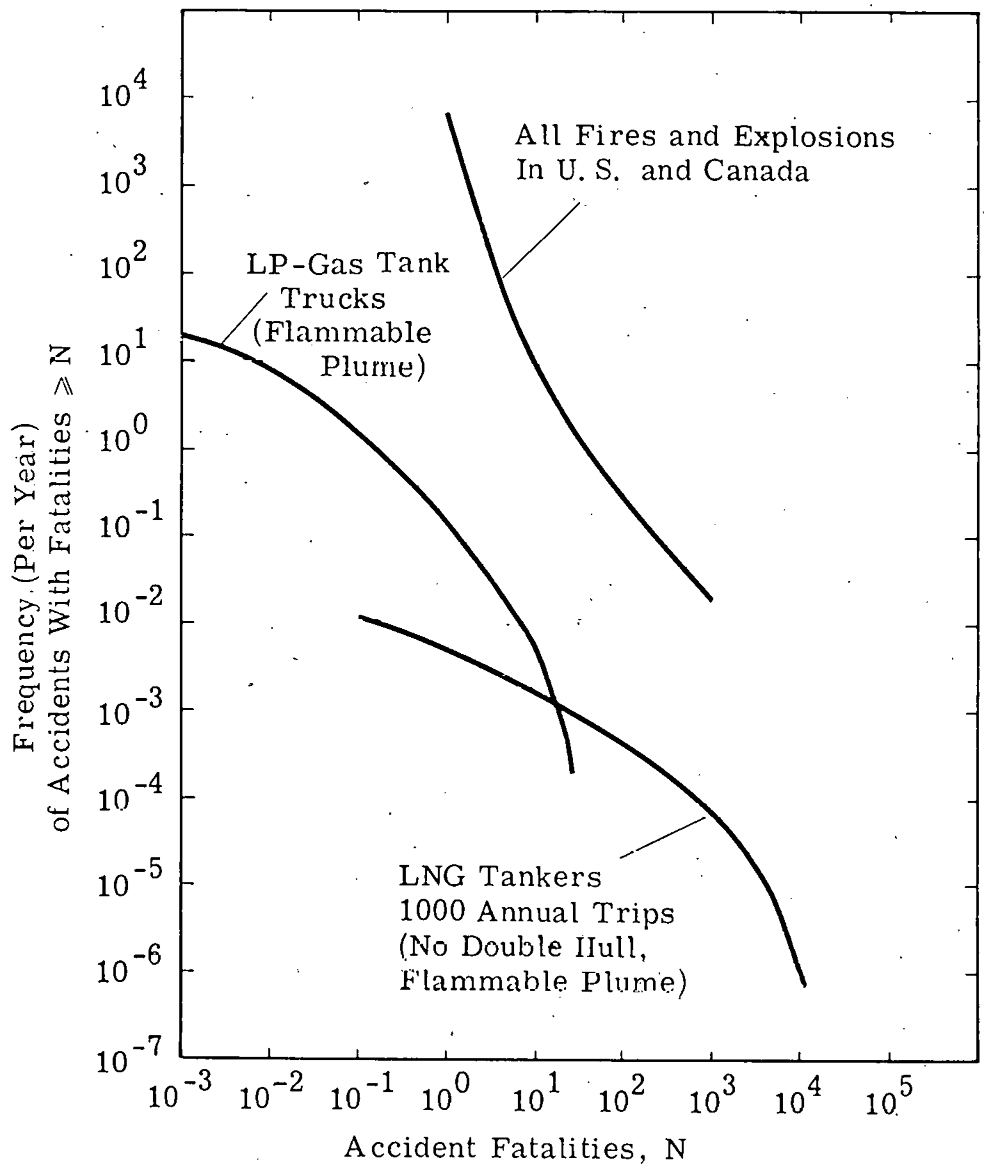

Figure 6. Comparison of some fire risks.

resulting from collisions and groundings of LNG tankships. The estimate is based on 1000 annual trips into all U.S. ports. Other accident mechanisms such as the collapse of storage tanks and injuries produced by thermal radiation from burning pools of liquid were not included in that estimate of risk. On the other hand, the flash fire hazard of tankship collisions and groundings is believed to be the major contributor to fatality risk.

The risk curves in Figure 6 exhibit a common characteristic of accidents: frequency decreases with increasing consequence. Public concern emphasizes the high consequence accidents (10's of fatalities or more) and tends to ignore the lower consequence accidents (one or two fatalities). Nevertheless, the involuntary risk to an individual is composed of both large and small accidents and the latter must not be ignored.

Summation of the products of frequency and fatalities under these curves yields the average annual expected fatalities. For fires and explosions of all kinds (in the U.S. and Canada), the sum is about 12,500 fatalities per year. For LP-Gas tank truck accidents, 1.2 fatalities per year were estimated; and for the generalized LNG tankship collisions and groundings, 0.4 fatalities per year in flash fires were estimated. The LP-Gas estimate agrees well with actual experience: an average of 1.2 fatalities per year from 1931 to 1961 and an average of 1 to 2 fatalities per year for the years 1962 to the present. This agreement may be fortuitous, but nevertheless does give confidence to the methodology used to estimate these risk values.

Another important measure of risk is the annual expectation value of accident-caused fatalities for each individual per year (units are in fatalities per individual per year). This measure of risk has a personal meaning and is convenient for comparison with the risk of other existing accident situations. Accident fatality and injury data are compiled and published annually by several institutions. Table 3 lists the numbers of accidental deaths ranging from mainly voluntary risks, such as automobile accidents, to mainly involuntary risks, such as fires in public places; and natural risks, such as being struck by lightning. For all accidents, the individual risk of death in the U.S. is about 5.6×10^{-4} per individual per year.(24)

Definitive estimations of individual risk for persons living and working near LNG import terminals on the U.S. East Coast have not been published. However the upper bound value for annual expected fatalities, mentioned above, may be used to estimate an average individual risk value. For example, Reference 1 reports that 70 annual LNG tankship trips are planned for the Eascogas terminal on Staten Island at Rossville. Further, it was stated that 168,000 persons live within a six-mile-wide corrdior centered on the tankship route through Raritan Bay and the Arthur Kill. However, because of the high probability of ignition of the vapor plume on shore, more than 90 percent of any accident fatalities are expected to be within about 1/2 mile from the shoreline. Hence the number of persons at risk is approximately $\frac{168,000}{6} = 28,000$.

TABLE 3. SOME FATAL ACCIDENTS IN THE U.S. IN 1973[24]

Accident Type	Number of Deaths	Probability of Death Per Person Per Year
Motor Vehicles	55,800	2.7×10^{-4}
Pedestrians Killed by Motor Vehicles	10,500	5×10^{-5}
Falls In Homes	9,600	4.6×10^{-5}
Falls In Public Places	5,000	2.4×10^{-5}
Fires In Homes	5,400	2.6×10^{-5}
Fires in Public Places	600	3×10^{-6}
Air Transport	1,100	5×10^{-6}
Poisoning By Gases	1,000	5×10^{-6}
Lightning	122	5×10^{-7}
Cataclysm	125	5×10^{-7}

Averaging the total expected fatalities for 70 tankship trips (the risk is directly proportional to the number of trips) over this number of people gives an average individual risk:

$$\frac{70}{1000} \times 0.4 \times \frac{1}{28,000} = 1.0 \times 10^{-6}$$

This value is within the range of the risk of death from natural cuases and some involuntary exposures as listed in Table 3. However it should be kept in mind that this risk value is believed to be conservatively high since its estimation does not account for the planned special navigational procedures and the collision resistant hull structure of LNG shipping.

It is concluded that the importation of LNG into U.S. East Coast ports may be done safely at acceptable levels of risk. However, the risks of each proposed project must be examined in detail taking into account the number of trips planned, the shipping route, population density near these routes, other shipping traffic and any planned specific navigational procedures. In general a low risk may be expected for sites which have:

1. Little other shipping traffic,
2. Predominant winds which would tend to blow an LNG vapor plume away from populated areas,
3. Low population density near the site,
4. Vigilant surveillance and control of shipping
5. A minimum number of LNG tankship trips.

Any of these features are sufficient but are not necessary for a low risk.

In order to assess the risk of a new activity, it is necessary to consider all possible accidents and evaluate probability of occurrence and consequence level of each. To facilitate this, the diagram such as that in Figures 5a and 5b is useful to identify accident sequences. As an example, the flammable plume from the collision of an LNG tanker is the following sequence. The initiating event is a collision (e.g., collision with another ship or fixed object, or a grounding) involving an LNG tanker (the terminal system affected). LNG spills onto the water and vaporizes. No safeguard systems are present to control the spill or vaporization. The vapor disperses and mixes with air, forming a plume according to the prevailing conditions, wind speed, atmospheric stability, and terrain features. As the plume grows and moves downwind, it may be ignited by any of the many ignition sources prevalent in a populated area. Ignited, the plume burns and may kill many of the unprotected (not inside houses and buildings) people within and a short distance outside it (via thermal radiation). This fire ignites the remaining pool of LNG (if any) and the resulting pool fire may cause additional damage and casualties near the collision location.

Quantitatively, each block in the figures represents an event which is discretized into one or more levels (e.g., the vaporization rate from a certain type of spill, population density ranges in area near the LNG facility, etc.). Conditional probabilities may be assigned to each of these levels based on a physical analysis or empirical relationships. Thus, there is a level and probability for each event in an accident sequence. The combination of levels defines a single consequence (people killed or property damage), and the probability of that consequence is the product of the conditional probabilities of each of the levels. This method of risk assessment is essentially the same as that used in the recent nuclear power plant safety study.[23]

A potential problem with this method of assessment is that some of the probabilities and consequences may be very uncertain. An approach for dealing with this is to make conservative assumptions in order to establish an upper bound for the risk of an accident sequence. It may turn out, and it often does, that even with such assumptions, the calculated probability and/or consequence of many accident sequences turn out to be insignificant compared to others and may be ignored. For those accident sequences which remain, the upper bound of risk is compared with the risk criteria of existing risks, and if the upper bound is less than the criteria, it may be concluded that the total risk of the activity is minimal. If not, the assumptions are re-examined to refine the estimates of event probabilities and consequence and to reduce the upper bound of risk closer to its true value.

D. Summary

There are a very large number of Federal, State and local governmental agencies which have some jurisdiction over the approval of a LNG importation application. Chief among these is the FPC which must approve both (1) the terminal site and operations, and (2) the contracted and delivered price of the imported LNG. The FPC also is responsible for preparing an environmental impact statement for the project.

The approval process could conceivably require a time as short as about one year. However, one recent application to the FPC for a terminal on the East Coast required 30 months for approval. Application for one site is still pending after 3 years and is expected to continue for still another year.

Some of the sites are located such that large populations are exposed to the hazards of large, accidental fires. Since importation of LNG is a new activity, wholly relevant accident experience for gauging the likelihood and risk of accidents does not exist. Instead, analytical methods are being applied for estimating the risks. Final results of these analyses are yet to be published but preliminary indications are that the risks posed by most of the proposed LNG import projects are acceptable.

Aside from fire hazards, the environmental impacts expected from a LNG terminal are no greater than for other industries and natural gas storage facilities. The principal impacts are the commitment of land to this use and hence the local disturbance of the terrestrial and marine environments. On the other hand, normal terminal operations may be expected to generate negligible air and water pollutants.

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SECTION IV

SITE SELECTION CRITERIA

The purpose of this section is to provide general criteria for the site selection of an LNG receiving terminal for the Northeast region of the United States. There are two viewpoints from which these criteria are derived. The first being that of the various regulatory authorities and the second, that of the firm constructing and operating the terminal. A complete set of siting criteria must meet the objectives of both parties.

The main objectives of the regulatory bodies are to protect the interests and safety of the general public and to maintain the environmental quality of the area. The main objective of the companies constructing and operating the terminal is to have an operable, efficient, and profitable operation. Insofar that it is in the public interest to have a successful LNG import project, some of the criteria are common to both parties.

The following site criteria must be met to satisfy various regulatory agencies, especially the Federal Power Commission.[26]

- The site must be on solid bedrock or other geological formations to support the proposed facilities.
- The site should not be exposed to special earthquake or climatic hazards.
- The site must be adjacent to a body of water of sufficient depth ($\sim$40 feet or more) and width ($\sim$500 feet or more) to accommodate the large LNG vessels.

- The site must allow year-round operation for base-load imports.
- Sufficient acreage must be available for lease or purchase in an area appropriate for industrial zoning. Very roughly a 1 Bcf/day receiving terminal may require 500-1200 acres of land for docks, off-loading, storage and regasification facilities.
- The site should be located such that it does not compound existing area safety problems. As an example the LNG receiving terminal should not be located at the end of an airport runway.
- The site should be so located to minimize disruption to the environment of the area during the construction phase. This includes the ability to control runoff erosion and the ability to limit damage to the area wildlife and foliage. As an example, a rocky shore-line or stable sand beach is preferable to a tidal marsh land whose ecology is more susceptible to disruptions. Deep water close to shore is desirable to minimize dredging.
- The site construction should not destroy existing archeological and historical qualities peculiar to the site area.
- Location of the site in an industrial area is desirable to minimize additional permanent damage to the natural environment and aesthetic qualities of the area.
- It is desirable that local community facilities such as housing, schools, and local transportation be able to handle the increased loads during the construction phase.

- Due to the combustible nature of natural gas, the site location must give consideration to the safety of the local population (See Section III).
- The safety precautions promulgated by the U.S. Coast Guard for LNG vessel control must be adequate to minimize the likelihood of a spill from a tankship. These precautions include Coast Guard escort, one-way traffic, movement in good weather and daylight hours only, bridge-to-bridge communications between all ships in a harbor, and adequate fendering while the LNG tankship is docked.
- The site location selection must consider the local maritime traffic.

  Minimal traffic is ideal. Short of that, the site should be located such that the local maritime traffic is interruptible without sustaining a major effect on the normal ship traffic of that port. For each delivery, it can be expected that local traffic will be temporarily interrupted to insure the safe passage of the LNG tankers. Depending on the traffic and the navigation parameters, delays should be held to less than a few hours at any particular location.[1] The frequency of LNG deliveries therefore becomes a consideration.

  Considering estimated imports of LNG into the Northeast by 1985 to be 0.8-1.1 Tcf/year (See Section VII), to satisfy this demand it would require approximately one tanker of capacity 125,000 m^3 per day. Further assuming that the four terminals in the Northeast that are presently complete or are nearly complete will be fully operable by 1985, then the frquency of deliveries can be reduced to roughly two per week per terminal.

From the viewpoint of the companies that construct and operate the terminal, the site must meet most, if not all, of the following criteria:

- The site should be in proximity to an existing major natural gas pipeline.

  The LNG must be regasified and distributed to the final customer. This distribution can be done through the existing network of natural gas pipelines. In order to minimize the cost of construction of new pipelines and additional environmental disruption, it is necessary to locate the terminal as close as possible to an existing major pipeline. The natural gas pipeline network of the Northeast Region is shown schematically in Figure 7.

- The site location should lend itself to the construction of off-loading facilities.

  A deep-water harbor that is sufficiently sheltered year round is a very desirable location for a receiving terminal. Deep-water off-loading via insulated pipelines is also possible. However, for distances greater than a few thousand feet, the cost of such a pipeline may be prohibitive. For on-shore off-loading facilities at least 40-45 feet of water (mean water level, low tide minimum of 35 feet) are required for navigation of tankers of typical dimensions: length, 750-950 feet; beam, 120-150 feet; draft, 35-40 feet. In the case that the off-loading facilities are off-shore, the greatest danger lies in structures that restrict or markedly change existing water flow. Such changes can result in bar relocation and/or creation and changes in the harbor line thus affecting all industry and traffic using the harbor.

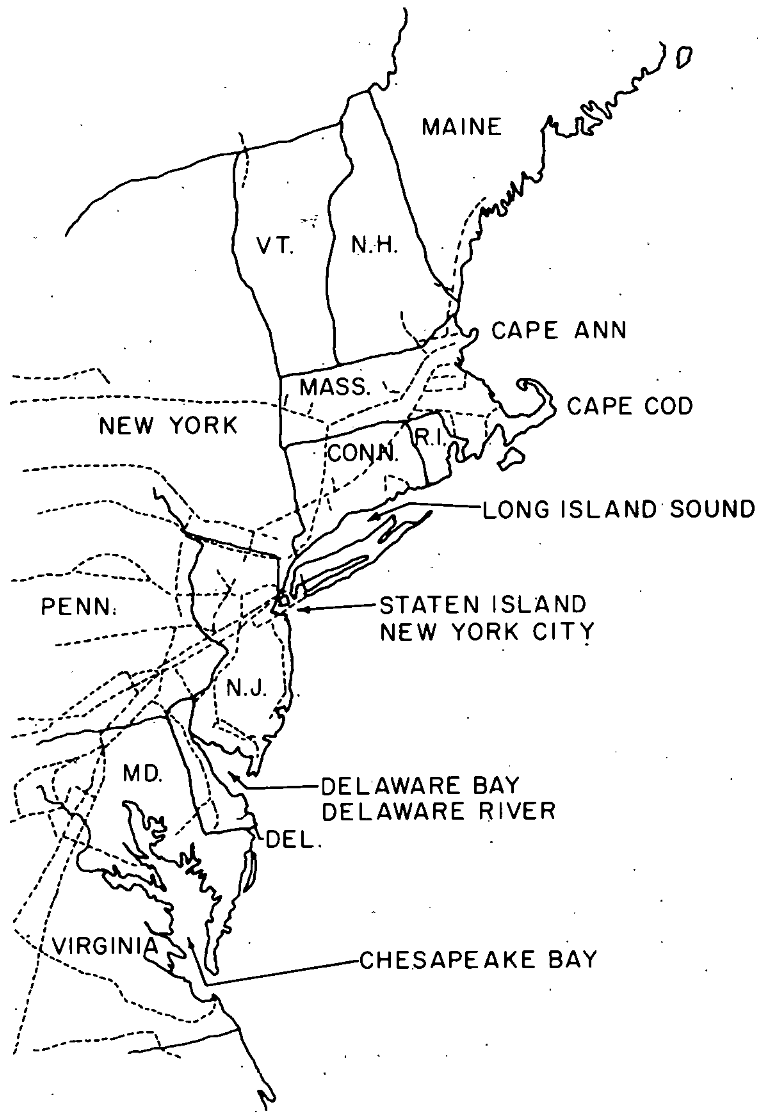

Figure 7. Major natural gas pipelines (FPC) as of 31 December 1971.

- Proximity to local utilities should lend itself to the support of construction requirements and on-going operational needs at the terminal site.

  Particularly during the three-plus years of plant construction, the local utilities must be able to provide the power and water needs. After operation is underway, much of the power demand can be satisfied by utilizing boil-off natural gas. Water demand will be minimal provided cooling water for the boil-off compressors and other needs is recycled. However, available water supply must be accessible to satisfy fire protection regulations.

In Reference 6 the following sites were suggested as possible locations for LNG receiving terminals designed to service the Northeast section of the United States:

- Penobscot Bay, Maine - The harbor is deep and the population density is low, but the site is a substantial distance from a major gas transmission line.
- Portland, Maine - The harbor also is deep and the site is located a substantial distance from a major gas transmission line. However, the population density is moderately high and the surrounding shorelines are prime residential and recreational areas.
- Boston, Massachusetts - There is an existing terminal at Everett on the Mystic River. Dorchester (Boston Gas) also has facilities for unloading ships. Although the population density is high, the proximity to pipelines and the deep water make this harbor an acceptable site.

- Providence, Rhode Island - A terminal for off-loading barges is already in existence. A terminal for ocean-going ships is under consideration and would be tied into existing major gas pipeline network in Massachusetts, approximately 5 miles away. Nearby population density is very high.
- Conanicut Island, Rhode Island - At the entrance to Narragansett Bay. A good location with an acceptable harbor and low population density. The distance to a major pipeline system is about 30 miles.
- New York, New York - The demand is high with a good distribution system, but the population density is very high and the marine traffic is heavy. A terminal already exists on Staten Island at Rossville.
- Delaware River - There are several possible sites on the Delaware River. The area natural gas demand is high and near major natural gas pipelines. The area has a medium population density. A terminal is under construction on Raccoon Island, New Jersey, across the river from Marcus Hook, PA.
- Chesapeake Bay, Maryland - There are several possible sites. The demand for natural gas is high, and the population density is medium. There may be heavy Navy traffic in some areas. A large terminal is under construction at Cove Point. This terminal will be tied into a major gas pipeline near Leesburg, VA.

The location of these sites can be seen on Figure 8.

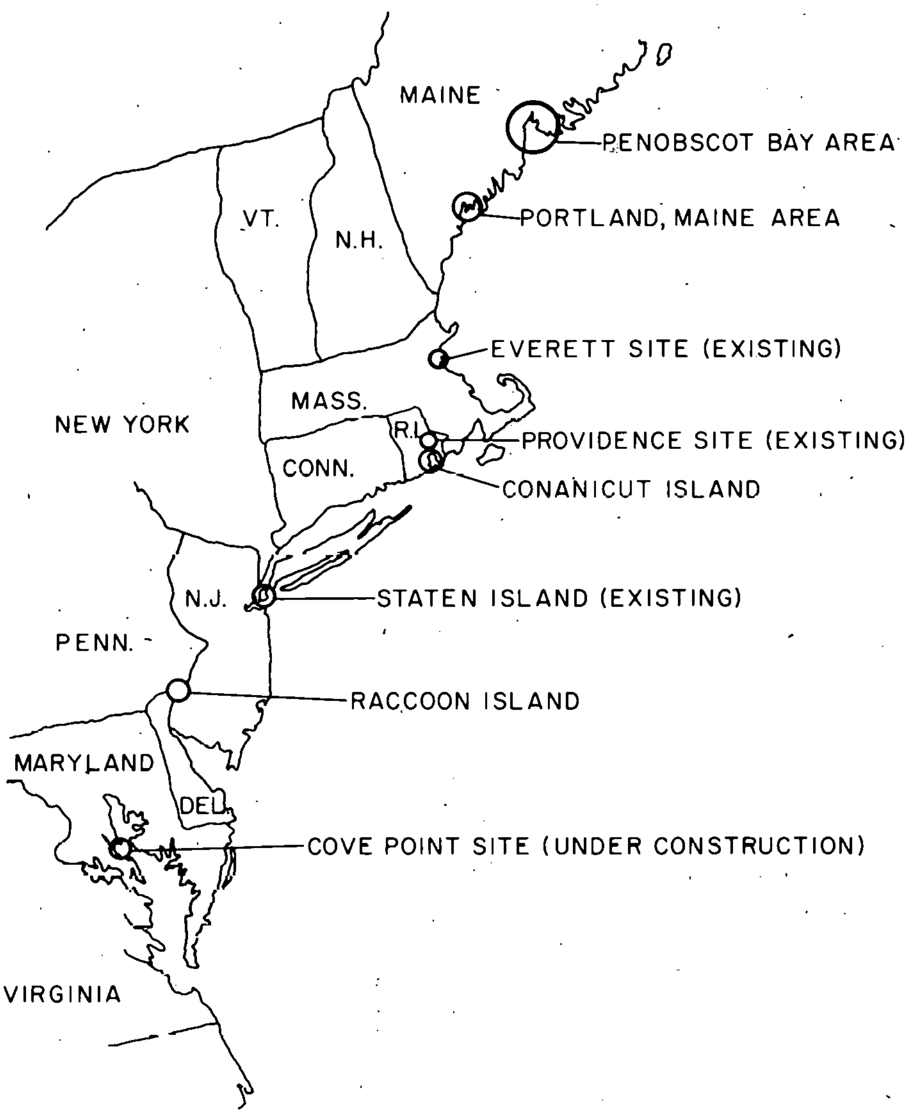

Figure 8. Possible and existing LNG receiving terminal sites.

SECTION V

TIME REQUIRED TO IMPLEMENT AN LNG PROJECT

The length of time required to bring an LNG import terminal into operation can be divided into two major sections. The first section is that period of time from the conception of the project to the granting of the project approvals by the regulatory bodies. The second section is that period of time required for detailed engineering, material and equipment procurement, construction and startup of the LNG terminal.

Section III of this study discusses the required regulatory approvals. The approval time can range from two to perhaps more than four years. During this period of time the utility or firm, wishing to construct and operate an LNG terminal, must submit an environmental impact report to the Federal Power Commission (FPC). The FPC reviews and comments on the environmental impact report and from the information it contains the FPC prepares and issues an environmental impact statement to the public. After a public comment period, a public hearing is held on the project. If the findings of the public hearing are favorable to the project and if there is no negative action by a cognizant state or local agency, FPC approval can be granted and construction can begin.

During this first section of the project, negotiations for a supply of LNG are started as well as the project financing arrangement. Preliminary engineering sufficient to support the writing of the environmental impact report and to establish the project costs is performed during the first section of the project.

Detailed engineering of the receiving terminal usually does not begin before project approval is granted. The reason for this is the uncertainty of what the final approval may require. As an example, site considerations may require special environmental protection or safety equipment to be incorporated into the basic design of the facility, thus invalidating some or all of the detailed engineering which did not include such features. Equipment procurement and construction starts soon thereafter.

Figure 9 provides an overview of an LNG receiving terminal schedule. The solid lines represent a normal schedule with the dashed lines showing the effects of various delays in schedule. In summary it requires nine to ten years to complete the full project cycle.

Not shown on the schedule in Figure 9 are those activities required to bring an LNG liquefaction facility into operation to support the receiving terminal or those activities required to provide a fleet of LNG ships to transport the LNG. Both groups of these activities must parallel the LNG terminal activities.

SECTION VI

PROJECTED AVAILABILITY AND RELIABILITY OF SUPPLY

Table 4 details the world's proved reserves of natural gas by regions. Table 5 estimates ultimate recoverable natural gas reserves. As can be seen the latter data are only estimated ranges, and as such, do not represent accurate values. Table 6 provides data on the world's 1972 natural gas production. In examining these three tables, probably the most striking feature is the United States production rate which is approximately equal to the rest of the world combined.

The purpose in presenting these three tables is to help identify possible import sources of LNG for the Northeast region of the United States. In identifying some possible sources the following criteria can be applied:

- The sea route between the Northeastern region and the source of natural gas should not be excessively long so as to minimize the necessary fleet size, the boil off losses and the transportation costs. This route should probably be less than 9,000 miles. This criteria would eliminate the Far East and the Pacific Oceania areas from consideration.
- The import source of LNG should have sufficient proven reserves of natural gas to support the major production of LNG for approximately twenty years. An example would be one billion cubic feet per day for twenty years. This would require a proven reserve of approximately seven trillion cubic feet.

Figure 9

TYPICAL LNG IMPORT TERMINAL PROJECT[18]

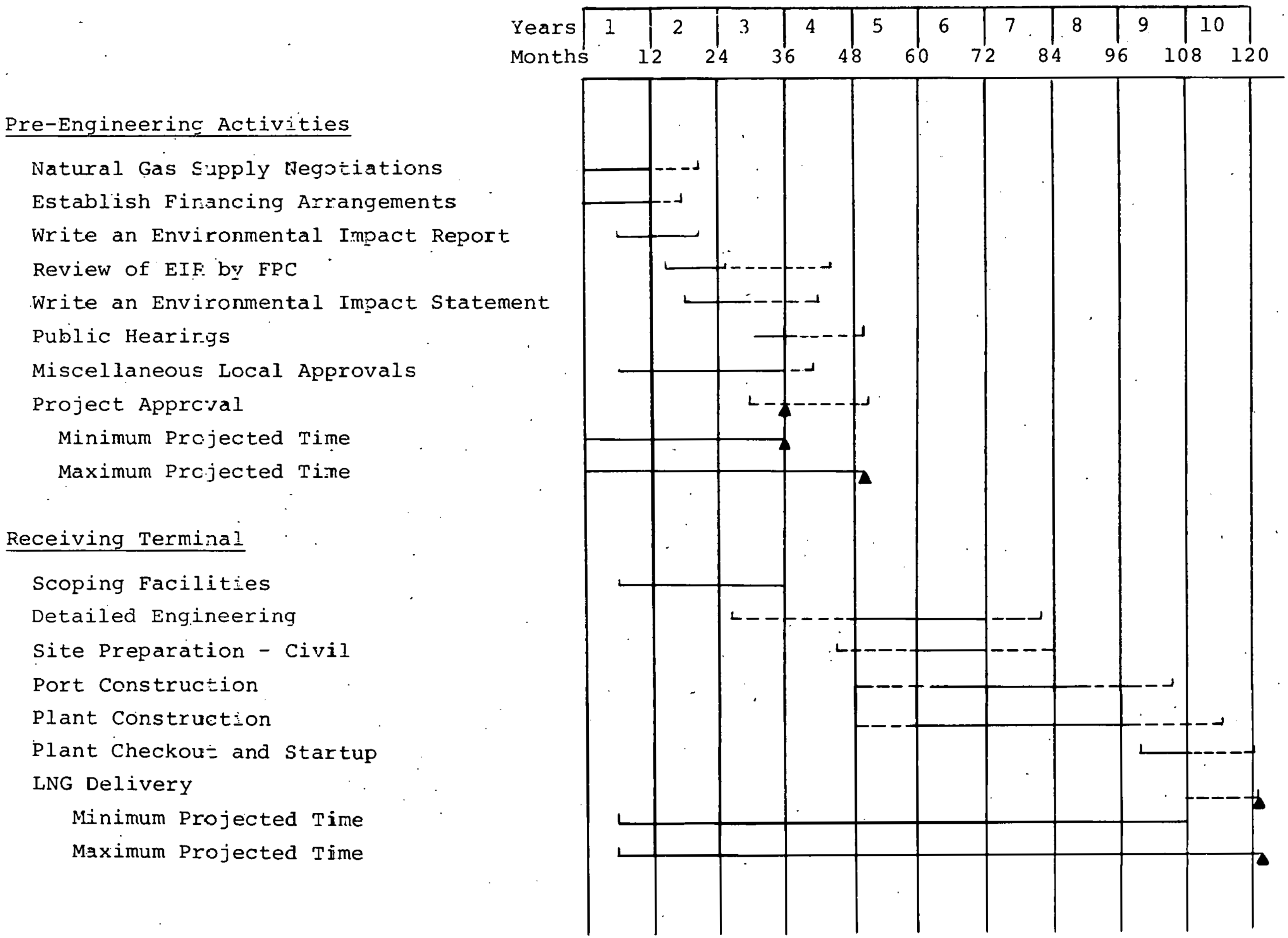

TABLE 4[2]

WORLD NATURAL GAS RESERVES (1972)
(Trillion Cubic Feet)

	Proven Reserves
North America	
Canada	55.5
Mexico	11.5
United States	237.0*
Total North America	304.0
South America	
Argentina	6.7
Bolivia	4.8
Brazil	0.9
Chile	1.8
Columbia	2.5
Ecuador	6.0
Peru	0.5
Trinidad and Tobago	4.9
Venezuela	36.0
Total South America	64.1
Africa	
Algeria	106.0
Angola	1.4
Egypt	7.5
Libyan Arab Republic	27.5
Nigeria	40.0
Tunisia	1.5
Other Africa	6.6
Total Africa	190.5
Europe	
Albania	0.3
Austria	0.6
Bulgaria	1.0
Czechoslovakia	0.5
Denmark	0.5
France	6.6
German Democratic Republic	0.5
Federal Republic of Germany	12.4
Hungary	4.2
Italy	6.0

*Proved Reserves as of December 1974[17]

TABLE 4 (Continued)

	Proven Reserves
Europe (Continued)	
Netherlands	88.0
Poland	5.0
Romania	10.0
United Kingdom	45.0
USSR	706.0
Yugoslavia	1.7
Total Europe	888.8
Asia	
Afghanistan	5.0
Bahrain	0.8
Bangledesh	9.2
Brunei	15.0
People's Republic of China	4.0
Republic of China (Taiwan)	0.5
India	1.5
Indonesia	5.5
Iran	200.0
Iraq	20.0
Japan	0.4
Kuwait	42.0
Malaysia	10.0
Oman	0.2
Pakistan	19.5
Qatar	8.0
Saudi Arabia	54.4
Syrian Arab Republic	0.7
Turkey	0.2
United Arab Emirates	11.8
Total Asia	408.2
Oceania	
Australia	37.7
New Zealand	6.0
Total Oceania	43.7
TOTAL WORLD	1,899.3

TABLE 5 (2)

ESTIMATED WORLD ULTIMATE RECOVERABLE
NATURAL GAS RESERVES (1972)
(Trillion Cubic Feet)

North America	
Canada	100 - 1,000
Mexico	100 - 1,000
United States	1,000 - 10,000*
Total North America	1,200 - 12,00
South America	
Argentina	10 - 100
Bolivia	100 - 1,000
Brazil	100 - 1,000
Chile	10 - 100
Columbia	10 - 100
Ecuador	10 - 100
Peru	10 - 100
Total South America	340 - 3,400
Africa	
Algeria	100 - 1,000
Angola	10 - 100
Botswana	10 - 100
Congo	10 - 100
Egypt	100 - 1,000
Ethiopia	10 - 100
Gabon	10 - 100
Kenya	10 - 100
Libyan Arab Republic	100 - 1,000
Mozambique	10 - 100
Nigeria	10 - 100
South Africa	10 - 100
Zaire	10 - 100
Total Africa	400 - 4,000
Europe	
France	10 - 100
German Democratic Republic	10 - 100
Federal Republic of German	10 - 100
Ireland	10 - 100

*More recent estimates of U.S. ultimate recoverable reserves indicate that 1,000 Tcf may be the upper limit.

TABLE 5 (Continued)

Europe (Continued)	
Ireland	10 - 100
Italy	100 - 1,000
Netherlands	100 - 1,000
Norway	10 - 100
Romania	10 - 100
United Kingdom	10 - 100
USSR	100 - 1,000
Total Europe	380 - 3,800
Asia	
Afghanistan	10 - 100
Bahrain	10 - 100
Bangladesh	10 - 100
Burma	10 - 100
People's Republic of China	100 - 1,000
India	10 - 100
Indonesia	100 - 1,000
Iran	100 - 1,000
Iraq	10 - 100
Republic of Korea	10 - 100
Kuwait	10 - 100
Malaysia	10 - 100
Mongolia	10 - 100
Oman	10 - 100
Pakistan	10 - 100
Phillippines	10 - 100
Qatar	10 - 100
Saudia Arabia	100 - 1,000
United Arab Emirates	10 - 100
Total Asia	500 - 5,500
Oceania	
Australia	100 - 1,000
New Zealand	10 - 100
Total Oceania	110 - 1,100
TOTAL WORLD	2,900 - 30,000

TABLE 6[2]

WORLD NATURAL GAS PRODUCTION (1972)
(Trillion Cubic Feet)

North America	
Canada	2.9
Mexico	0.7
United States[17]	21.3
Total North America	24.9
South America	
Argentina	0.3
Bolivia	0.1
Chile	0.3
Columbia	0.1
Tinidad and Tobago	0.1
Venezuela	1.7
Other South America	0.1
Total South America	2.7
Africa	
Algeria	0.1
Egypt	0.2
Libyan Arab Republic	0.5
Nigeria	0.6
Other Africa	0.1
Total Africa	1.5
Europe	
France	0.4
Federal Republic of Germany	0.6
German Democratic Republic	0.2
Hungary	0.1
Italy	0.5
Netherlands	2.0
Poland	0.2
Romania	1.2
United Kingdom	0.9
USSR	7.9
Other Europe	0.2
Total Europe	14.2
Asia	
Afghanistan	0.1
Indonesia	0.1
Iran	1.5
Kuwait	0.6
Pakistan	0.1
Saudi Arabia	1.1
Other Asia	0.4
Total Asia	3.9
Oceania	
Australia	0.1
New Zealand	0.01
Total Oceania	0.1
TOTAL WORLD	47.3

- The source country's energy wealth should be great enough to support domestic growth capabilities as well as exporting significant quantities of natural gas. This criteria would eliminate all of Europe with the possible exception of Western Russia.

The results of applying these criteria narrow the possible LNG export candidates to the following countries:

Abu Dhabi	Libya
Algeria	Nigeria
Iran	Saudi Arabia
Iraq	Venezuela
Kuwait	Western Russia

Indonesia, while farther away, has a large potential supply of natural gas and is currently exporting LNG to Japan.

The status of United States LNG import contracts is not clear. For example, on March 9, 1972, the Federal Power Commission (FPC) first authorized Distrigas of Boston to import 15.4 billion cubic feet of LNG per year for a period of twenty years. At that time the FPC held that it had no jurisdiction over the LNG receiving terminal. Later, after Distrigas had completed the terminal, the FPC reversed its position and required Distrigas to seek certification of the completed facility. During this period of time mercury corrosion problems reduced the production at the Skikda, Algeria facility, limiting LNG production to earlier commitments to Gaz de France. Because of the production problems and the FPC actions, the Algerians cancelled the contract with Distrigas. Further, Eascogas LNG Company received FPC conditional approval on December 28, 1973 to import 4.7 trillion cubic feet of LNG over a 22 year period. Again because of extended delays in FPC regulatory actions this contract was also cancelled. It is clear, however, that FPC jurisdiction does include any interstate flow of gas but does not include intrastate flow.

Japan has been receiving LNG from Alaska for several years. The main reason that the LNG was not transferred to another American port was that the Jones shipping act requires that only American-flag vessels be used for coastal traffic. During 1974 and early 1975 no LNG was imported to the United States. However, during the fall and late summer of 1975 approximately four billion cubic feet of LNG were imported in the Northeast region by Distrigas, under contract with Algeria.[14]

Table 7 lists all of the LNG baseload liquefaction facilities in the world that are either under construction or operating. Table 8 lists all of the Northeast region LNG receiving terminals that are either presently planned, under construction or ready to operate. It is important to note that the operating and planned Northeast receiving terminals' combined capacity exceeds the liquefaction capacity of the combined operating and planned North African facilities. In addition, the Northeast region of the United States is competing not only with other regions of the United States for the African source of LNG, but also with Europe.

It is important to note that the combined world LNG receiving terminal capacity, operational and planned, is more than twice the combined world LNG liquefaction facilities that are operational and planned.

Table 9 lists LNG import arrangements with various countries which have been at least considered by American firms. None of the possible arrangements listed presently represents a working relationship with routine LNG deliveries.

Table 7

Baseload LNG Liquefaction Facilities[3]

Company	Plant Site	Liquefaction Cap.-MMCFD	Storage Cap.-MMCF	Year of Operation
Phillips-Marathon	Kenai, Alaska	90	2300	1969
Camel	Arzew, Algeria	200	1840	1963
Bruneiling	Brunei, Borneo	750	4050	1973
Esso	Marra el Brega, Libya	385	2100	1970
Sonatrach	Arzew, Algeria	1100	7000	1976
Sonatrach (Phase I)	Skikda, Algeria	430	2500	1972
Sonatrach (Phase II)	Skikda, Algeria	170	1250	1975
Sonatrach (Phase III)	Skikda, Algeria	350	3500	1976
Abu Dhabi Gas Liquefaction Co.	Das Island, Abu Dhabi	350	6600	1976
Pacific Alaska	Cook Inlet, Alaska (Pending)	400	3000	1978
Pertamina	Sumatra, Indonesia	1200	8350	1977
Pertamina	Kahmantan, Indonesia	550	6250	1977
El Paso Alaska	Point Gravina, Alaska	3375	6000	1980
TOTAL		9350	54,740	

Table 8 (3)

Northeast Receiving Terminals

Company	Plant Site	Regasification Cap.-MMCFD	Storage Cap.-MMCF	Year of Operation
Distrigas Corporation	Everett, Massachusetts	135	3250	1971
PSE&G Co. N.J.	Staten Island, New York	360	6000	1973
Columbia LNG Co.	Cove Point, Maryland	1200	5000	1976
Algonquin LNG Co.	Providence, Rhode Island	675	6000	1973
Transco Terminal Co.	Raccoon Island, New Jersey	(850)	[..(In-Planning)....]	
Texas Eastern	West Deptford, New Jersey	[..........(In-Planning)..........]		

TABLE 9

LNG IMPORT CONTRACTS THAT HAVE BEEN CONSIDERED BY U.S. FIRMS

Source of LNG	Original Projected Delivery Date	Companies Involved	Projected Volumes 10^6 CF/Day
Algeria	1971	SONATRACH Alocean Ltd. Distrigas Corp.	42
Algeria	1975	SONATRACH/El Paso Gas Co. subsidiaries	
		Columbia LNG Corp.	300
		Consolidate Natural Gas Co.	350
		Southern Energy	350
Algeria	1975	SONATRACH Distrigas Corp.	123
Algeria	1976	SONATRACH/El Paso Gas Co. Transco Energy Co.	250
Trinidad	1976	Amoco Natural Gas Pipeline	200(1976) 300(1977) 400(1978)
Algeria	1976	SONATRACH/El Paso Gas Co.	250
Algeria	1976/1977	SONATRACH Public Service of NJ Philadelphia Gas Works Algonquin Gas Co. Lowell Gas Co.	500
Venezuela	1976/77	Venezuelcan Government/ Unknown	650
Nigeria	1977	Phillips Petroleum/ Unknown	1000
Nigeria	1978	Gulf Oil Co./Unknown	500
Nigeria	1978	Shell International Gas Co./Unknown	650

SECTION VII

PROJECTION OF FUTURE IMPORTS TO THE NORTHEAST REGION

A. 1985 Import Projections

The following table projects the range of foreign LNG imports to the Northeastern region of the United States for the year 1985:

	Trillion Cubic Feet
Case I	0
Case II	0.8
Case III	1.1

As indicated by Case I, the minimum LNG import for the Northeastern region could be zero. Case I could be caused by either one or both of the following items:

- The failure of regulatory bodies to grant the necessary approvals
- Foreign sources of LNG being unwilling to provide LNG at a price acceptable to the American consumer.

The action of importing an energy source and particularly a new energy source runs counter to the goals and objectives of Project Independence.

The importation of LNG in significant quantities not only represents a major out-flow of funds in the area of international balance of payments, it also increases to some degree our dependence on foreign energy supplies. While this consideration may not be an overriding factor in any actions taken by a Federal regulatory agency, the goals of Project Independence will shade any regulatory agency's actions. State and local regulatory bodies may also present roadblocks to the importation of LNG. The concerns of these agencies may center around environmental issues such as industrial utilization of coastal areas and safety issues.

The second item which may seriously limit import of LNG is price and availability of LNG. It is very desirable to have a long term contract for the supply of LNG before committing the large capital necessary for the LNG receiving, handling, and distribution facilities. These contracts are usually 15 to 20 years in duration. As developing nations reach the earlier stages of industrialization, they may become less willing to enter into long term contracts for the export of a resource as valuable as natural gas. An example of this type of attitude is Saudi Arabia. In the development of the Arabian oil fields of Abqaiq and Ghawar, the methane constituents of the associated natural gas is either reinjected in the producing zones of the oil field, consumed as fuel, or flared. More than 100 million cubic feet per day of natural gas is consumed as fuel for the pumps used in massive water-injection programs at the Ghawar oil field. Another 400 million cubic feet per day of natural gas is stored via reinjection programs. Additional quantities are pumped into a trunk pipeline system serving other industries in the Abqaiq Dhahran area. In short, Saudi Arabia is consuming natural gas in order to produce more valuable crude oil and liquefied petroleum gas.

Case II assumes that the four Northeast LNG receiving terminals which are either presently complete or nearly complete will be in full operation by 1985. The four terminals are:

Company	Plant Site	Cap. MMCFD
Distrigas Corporation	Everett, Mass.	135
PSE & G Company, N.J.	Staten Island, NY	360
Columbia LNG Company	Cove Point, MD	1200
Algonquin LNG Company	Providence, RI	675

Case II probably represents the most realistic case. The limitations of Case II are the same as Case I, regulatory approvals and LNG supplies. There either are presently, or shortly will be, sufficient LNG tankers available to import the 0.8 trillion cubic feet of LNG that Case II represents. But, Case II requires approximately 80 percent of the operating capacity of all the LNG liquefaction facilities that are either under construction or in operation, and that are so located so as to be able to supply LNG to the Northeast region.

The reason Case II is limited to the receiving terminals and liquefaction facilities presently ready to operate or under construction can be seen from Figure 9. Figure 9 projects a minimum and maximum length of time it might require to bring an LNG receiving terminal into operation. In summary the time span required for the various activities are as follows:

	Years
FPC Approval	3 to 4 years
Detail Engineering	2 to 2.5 years
Procurement and Construction	4 to 5 years
Checkout and Startup	0.5 to 1 year

Also during this period of time it is necessary to provide the liquefaction facilities required to support the LNG receiving terminal as well as the necessary fleet of LNG tankers.

With the time restraints being between nine to ten years, it would be optimistic to expect a facility to be on line by 1985 that is not now fairly well along in the scoping phase of the project.

Case III represents an optimistic case in which an additional one billion cubic feet per day, which is approximately 0.35 trillion cubic feet per year, is imported over and above that identified in Case II. Case III would require that one or more additional receiving terminals and liquefaction facilities be in operation by 1985. Two such possible sites might be Raccoon Island, New Jersey and West Deptford, New Jersey. The source of the additional LNG might be from an expanded North Africa program, the Middle East, South America, or even Indonesia.

B) Year 2000 LNG Import Projections

The "Federal Power Commission National Gas Survey" Volume I Chapter 10[9] tabulates LNG import forecasts through the end of this century. This tabulation includes seven different sources. The range of these forecasts is between 2.1 to 4.1 trillion cubic feet per year for the last decade in this century.* Assuming approximately half of the LNG imported into the United States is received by Northeast region, between one to two trillion cubic feet per year could be expected to be imported to the Northeast during the year 2000.

*In reference 8 of this tabulation, "Dupree and West, Department of Interior, 1972" 11.1 trillion cubic feet per year are listed. A review of the original reference shows that the forecast was 11.1 billion cubic feet per day which is approximately equal to 4.0 trillion cubic feet per year.

SECTION VIII

COST PROJECTIONS

Probably the most recent cost information published on the capital costs of LNG facilities can be found in the June 1975 issue of the "Pipeline and Gas Journal."[3] The Western LNG Terminal Company is presently applying for approval to operate on three LNG terminals to be located in California at Port Hueneme, Point Conception, and the Los Angeles Harbor. The total projected cost of these three terminals is $1.7 billion which includes both terminal costs and some pipeline additions and expansions. Each of the three sites are to have four 550,000 barrel storage tanks, regasification systems, and unloading facilities. The estimated cost range for such a terminal is between $375 million to $390 million. The capacity of each of these sites ranges from 3,300 to 5,000 million cubic feet per day.

The cost of the liquefaction facilities to support these terminals is less well defined. The source of LNG is expected to be liquefaction facilities in Alaska and Indonesia. Indonesia is supplying the capital for their liquefaction facilities and selling the LNG as FOB Indonesia. It is estimated that the 1,200 million cubic feet per day liquefaction facility on North Sumatra will cost approximately $650 million dollars.

It is also estimated that it will require nine 125,000 cubic meter capacity LNG ships to support the Indonesian operation. The total cost of these ships is estimated at $1.5 billion or $167 million each.

As would be expected the cost of imported natural gas has followed the rapid rise in the cost of crude oil. The Southern California Gas Company signed a LNG contract with PERTAMINA in September 1973 at a cost of $0.63/MMBTU FOB Indonesia for the delivery of 620 billion BTU per day for twenty years. At the time Indonesian crude oil was selling for $3.73 per barrel. By December 1973 crude oil sold for $6.00 per barrel and one month later it sold for $10.80 per barrel. Today the crude sells for $12.60 per barrel. The Indonesians renegotiated the September 1973 $0.63/MMBTU contract to $1.25/MMBTU with an escalation clause attached to the price of crude oil. The natural gas contract and the terminal projects await approval by the FPC.

On July 8, 1975 Distrigas Corporation of Boston, Massachusetts filed an application with the Federal Power Commission to purchase 950,000 cubic meters of LNG for import to their Everett, Massachusetts terminal. The cost of this LNG is stated as $2.30 per million BTU delivered to Everett, Massachusetts. The cost of $2.30 per million BTU included the cost of the LNG, insurance on the LNG, and the cost of transportation. The application proposes that the LNG would be received on the following schedule:

7/76 to 1/77 - 200,000 cubic meters
1/77 to 7/77 - 300,000 cubic meters
7/77 to 1/78 - 450,000 cubic meters

Presently there are no routinely scheduled imports of LNG to the United States.

As can be seen from capital costs so far outlined, an LNG import complex is capital intense. That is, it requires a very large amount of total capital investment to bring a complex into operation.

Table 10 provides a cost breakdown for a Northeast region LNG terminal. There are three major components in the cost of LNG:

a. the original natural gas,
b. capital costs, and
c. operating costs.

Capital costs are applicable to the liquefaction facilities, transportation, and receiving terminal. For the purpose of this paper a capital cost of 25 percent per year of the initial investment is assumed. The capital costs, as used, include recovery of the initial capital expenditure, plus all interest accrued from the borrowing of that capital, plus a profit or return on investment. The capital recovery factor, as expressed

$$CRF = P \frac{i(1+i)^n}{(1+i)^n-1}$$

represents the recovery of the capital plus accrued interest. An as example, if the capital is borrowed at 10 percent interest for 20 years the capital recovery factor is 0.1175 or an annual cost of 11.75 percent of capital investment. This allows a return on investment of 13.25 percent before taxes.

The price of the natural gas to be liquefied as that gas is collected at the well head has the greatest degree of uncertainty. In short, the price of the natural gas is determined by how willing the supplying country is to sell its energy resources. The natural gas price can strongly affect the operational costs of liquefaction, transportation, and regasification because each of these steps consume some portion of the natural gas collected.

TABLE 10

SUMMARY OF COSTS*

	Range of Capital Costs $\$X10^6$	Cost $\$/10^6$ BTU
A. COST AT GAS FIELD OF NATURAL GAS		0.00 - 1.58
B. CAPITAL COSTS		
1) Gas Field and Liquefaction	650 - 900	0.45 - 0.62
2) Transportation (8-LNG Ships)	800 - 1,200	0.55 - 0.83
3) Receiving and Distribution Terminal	350 - 400	0.24 - 0.27
	1,800 - 2,500	1.24 - 1.72
C. OPERATIONAL COSTS		
1) Gas Field and Liquefaction		0.12 - 0.44
2) Transportation (8-LNG Ships)		0.11 - 0.20
3) Receiving and Distribution Terminal		0.03 - 0.06
TOTAL COSTS FOB NORTHEAST UNITED STATES		1.50 - 4.00 per MMBTU

*Based on a 1,000 MMCFD complex with the gas fields and liquefaction facilities located in North Africa.

The price of the collected natural gas, as used in this Section, is a premium charged in excess of operating and capital recovery costs incurred in the collection and transportation of the natural gas to the liquefaction facility. The present world price of oil includes such a premium.

The range of the natural gas price or premium as shown in Table 10 ranges between zero to $1.58 per MMBTU. The lower limit assumes no premium is charged for the natural gas and only capital recovery and operating costs are charged. The upper limit of $1.58 per MMBTU applies the same premium charged for oil to natural gas. The upper limit price assumes that approximately eight dollars of the twelve dollars a barrel charge for world oil is a premium. Based on equivalent cost per MMBTU for oil and gas the upper limit is established as $1.58 per MMBTU.

The operating costs are the sum of the energy costs, labor, supplies, port fees, maintenance, and insurance. As indicated earlier, 17 percent of the natural gas collected is consumed in liquefaction with 6 percent, 1 percent and 2 percent consumed in transportation, storage, and regasification respectively. For the upper range of operating costs those energy costs are assumed based on the cost of the natural gas. Minor labor costs are assumed for the liquefaction facility with seven percent per year of the original capital cost being assumed as maintenance and equipment replacement costs. Operating costs of approximately five million dollars per year per LNG ship are assumed.[18] For the LNG receiving terminal a payroll of $1.8 million is assumed based on an operating staff of 90 people. Maintenance and replacement costs are assumed to be 3 percent of the original capital per year.

In summary the cost of natural gas from an LNG terminal located in the Northeast region of the United States could be expected to range from $1.50 to $4.00 per MMBTU.

The question of what the cost of imported LNG will be to the residential customer is a complex one. Table 11 shows the current relationships of the different prices of natural gas including purchases from producers and imports, and sales of natural gas to industrial users, resellers, and residential customers. As can be seen from Table 11 the purchase price of natural gas totals approximately $0.37 per thousand cubic feet with the sales price to industrial users at approximately $0.70 per thousand cubic feet and $1.50 per thousand cubic feet to residential customers.

The introduction of regasified LNG at an effective producers purchase price of $4.00 per thousand cubic feet will not cause the residential customer's costs to rise to $4.00 because the customer will be receiving a mix of regasified LNG and natural gas. But the effective price of regasified LNG to the residential customer would be $4.00 plus the markup experienced in distribution. From Table 11 the markup from the natural gas resellers at the entrance to the distribution system is approximately $0.60. Therefore it might be expected that the $0.60 distribution cost would be added to the $1.50 to $4.00 per million BTU for a residential customer cost of $2.10 to $4.60 per million BTU.

Table 12 demonstrates the effects of distance of the tankship route on the cost of LNG. This table assumes the following:

- 125,000 cubic meter tankers
- 365 days per year operation

TABLE 11 (25)

Natural Gas Prices Reported by Major Interstate Pipeline Companies

	PURCHASES			SALES		
	Domestic Producers Field Price	From Canadian and Mexican Sources	Total Purchases	To Industrial Users	To Resellers*	Total Sales
	Cents per thousand cubic feet					
1973 December	24.5	47.6	26.3	46.4	52.2	52.3
1974 January	24.3	42.7	25.7	48.1	55.0	55.1
February	25.4	43.2	26.8	49.8	56.4	56.4
March	25.7	43.2	27.0	50.8	56.9	56.9
April	25.8	46.4	27.4	49.3	57.6	57.4
May	25.7	49.3	27.5	49.9	58.6	57.9
June	26.0	47.7	27.5	50.8	59.4	58.5
July	26.3	58.7	28.6	52.5	62.0	61.1
August	26.1	57.5	28.4	55.2	64.4	63.5
September	27.3	58.8	29.5	54.7	65.2	64.3
October	27.5	58.9	29.9	56.3	64.4	64.0
November	28.5	70.9	31.7	58.7	66.8	66.6
December	32.6	74.5	35.8	60.3	67.2	67.4
1975 January	29.8	104.0	35.2	67.6	71.1	71.4
February	29.5	105.8	35.2	70.1	74.1	74.4
March	31.6	102.5	37.0	70.4	77.8	77.9

* Includes the cost of gas to the distributing utility at entrance of distribution system or point of receipt.

Average Retail Prices for Natural Gas Sold to Residential Customers

	Price in Cents Per Thousand Cubic Feet		Price in Cents Per Thousand Cubic Feet		Price in Cents Per Thousand Cubic Feet
1974 January	113	July	122	1975 January	138
February	115	August	124	February	141
March	117	September	126	March	143
April	118	October	127	April	147
May	120	November	131	May	150
June	120	December	134		

- 17 miles per hour travel rate
- two days at the loading port and two days at the receiving terminal
- 25 percent capital recovery rate.

The costs shown are only capital costs. These costs are complexed by increasing operating and energy costs caused by expanded distances. This generally reinforces the requirement that the supply of LNG be within 9,000 miles of the receiving terminal.

TABLE 12

TRANSPORTATION COSTS FROM VARIOUS SOURCES

	Approximate Distance Of Sea Route To US East Coast	Number of Ships Required	Range of Capital Investment $\$X10^6$	Capital Recovery Costs Cost $\$/10^6$ BTU
1) Venezuela	1700	5	500 - 750	0.34 - 0.51
2) Algeria	3600	8	800 - 1,200	0.55 - 0.83
3) Iran(1)	8600	18	1,800 - 2,700	1.23 - 1.85
4) Iran(2)	11,000	22	2,200 - 3,300	1.51 - 2.33
5) Indonesia	12,000	24	2,400 - 3,600	1.64 - 2.46

(1) Using the Suez Canal

(2) Not Using the Suez Canal

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SECTION IX

SECONDARY BENEFITS

Importing LNG into the Northeastern United States buys time for this region, as alternative energy sources are developing. In a sense one of the secondary benefits is the avoidance of a crippling natural gas shortage, again until alternatives are developed.

Construction of LNG receiving terminals and associated storage, vaporization and distribution facilities can provide approximately 1,000 - 2,000 jobs (peak work force) with gross wages of an estimated $40 - $50 million dollars, to the local region of such a terminal. Of these gross wages, for an anticipated 40 month construction period, approximately $28 - $35 million is disposable income. Depending on the site location, this could be a major boost to the local economy. The labor force and skills necessary for construction would be recruited primarily from the Northeast. Under normal operations, the operating staff might number 90 employees, with gross annual wages estimated to be $1.8 - $2.0 million (disposable income is then $1.37 - $1.52 million).[12]

The net effect undoubtedly will be an increase in the county tax base. During construction several events will add to local revenues. The work force required for construction will increase local retail sales. Large material expenditures to local suppliers can be expected. Property taxes on the unfinished structures and land will increase revenues to local utilities, schools, hospitals, municipalities and social services. Following completion, assessments based on a net worth of \$350 - \$400 million for the facilities would increase the local tax revenues, offsetting the increased police and fire protection services required for the typical 20 year economic lifetime of such an LNG terminal project.

An increase in LNG imports into the Northeast will require additional tank ships. As long as the cost of domestic cryogenic steel remains significantly lower than that of foreign nickle steel, foreign built LNG tankers will remain comparable in price to those built domestically, even with the more stringent U.S. Maritime regulations.

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Appendix A: The Western European Question

The effective competition between the Northeastern Region of the United States and Western Europe for North African LNG is difficult to assess. Several general considerations lead to the conclusion that it is Western Europe, rather than the U.S., that is in an excellent position to import LNG both on a preferred basis and more economically. There are four situations which tend to imply this conclusion.

First, a review of LNG carrier production indicates that Western Europe has built a significant fleet of LNG tankers, most of which remain under Western European flags. Table A-6 at the end of this appendix lists those LNG carriers built or on order in Western Europe and the U.S. since 1958. The number of those on order for the U.S. is indicative of the current LNG receiving facilities proposed or built on the East and West coasts.

A summary tally of existing and ordered LNG carriers built in Western Europe, derived from Table A-6, follows:

Existing LNG Carriers

No. of Ships	Flag	Capacity X 10^5 m^3
10	Britain	6.27
5	France	2.36
3	Italy	1.20
3	Norway	0.93
1	Spain	0.40
3	Liberia	1.46
1	Algeria	0.72

On-Order LNG Carriers

No. of Ships	Flag	Capacity X 10^5 m^3
1	Britain	0.75
1	France	1.20
6	Liberia	7.58
16	USA* (Total)	20.0
11	East Coast USA*	13.75

Assuming that LNG carriers sailing under Western European flags are or will be dedicated to that country, an indication of the potential import flow rates can be calculated. This assumption does not account for any LNG carriers under these flags which are chartered for delivery to other countries. However, the resulting over estimation is certainly balanced by not including any deliveries to Western European LNG receiving facilities from charter vessels under flags such as Norway or Liberia. This tends to make the following calculations conservative estimates. Flow rates in cubic meters of LNG per day into the four principal Western European importing countries were based upon a 344 working day year for the LNG carriers. This was then divided by the round trip time to each respective port, multiplied by the net carrier capacity per country. The final flow was then calculated by dividing the delivery capacity by 365, essentially to get a number comparable to a steady regasification capacity per country. The following table (A-1) details the results of these estimates. For direct comparison, Table A-2 shows the storage and regasification capacites of Western Europe and the U.S. East Coast

*All USA-flag carriers are built in the U.S.A.

Table A-1

WESTERN EUROPE LNG IMPORT PROJECTIONS BASED ON LNG CARRIER CAPACITY

Britain	10 days per round trip	
	Existing Carriers	0.59×10^5 m^3/day LNG
	On-Order Carriers	0.07×10^5 m^3/day LNG
	Total	0.66×10^5 m^3/day
France	9.4 days per round trip to La Havre - 12%	
	4.5 days per round trip to Fos - 88%	
	Existing Carriers	0.47×10^5 m^3/day LNG
	On-Order Carriers	0.25×10^5 m^3/day LNG
	Total	0.72×10^5 m^3/day
Spain	7.7 days per round trip	
	Existing Carriers	0.05×10^5 m^3/day LNG
Italy	7.7 days per round trip	
	Existing Carriers	0.15×10^5 m^3/day LNG
Western Europe Total		1.58×10^5 m^3/day LNG

Table A-2

IMPORT RECEIVING TERMINALS STORAGE AND REGASIFICATION CAPACITY (ACTUAL & PLANNED)

	Storage Capacity Cubic Meters LNG	Regasification Capacity m^3/day LNG
England	2.6×10^5	0.14×10^5
France	1.0×10^5	0.24×10^5
Spain	1.7×10^5	0.10×10^5
Italy	1.0×10^5	0.17×10^5
Total Western Europe	6.3×10^5	0.65×10^5
E. Coast U.S.A.	12.5×10^5	1.44×10^5
Japan	20.9×10^5	1.71×10^5

It can be seen that Western Europe's potential carrier capacity is 2.43 times its regasification capacity. Two things should be noted with regard to this ratio. First that several European LNG carrier interests are leasing their carriers to Japan, and second that expansion of regasification facilities in Europe can be anticipated with possibly less regulatory delays than met in the U.S.

The estimated import flow into the East Coast is calculated in the same manner to be a maximum of $.72 \times 10^5$ m^3/d, all of which involves on-order LNG carriers. The regasification capacity of East Coast facilities is seen to be 1.44×10^5 m^3/d, thus the import flow is only 50% of the LNG regasification capacity. These estimates indicate that the U.S. does not have the fleet capacity to maximize its LNG facilities, whereas Western Europe's LNG carrier fleet seems to point to further development in LNG imports to Western Europe.

An additional concern related to the LNG carrier fleet size is the respective transportation costs. Table A-3 tabulates some transportation costs for LNG imports into several Western European ports. This table is based on a one Bcf/d delivery of regasified LNG from a particular site, and is constructed identically to Table 12, Section VIII of this report for direct comparison. Transportation costs to the United States range from $0.55 - $0.83/$10^6$ BTU, whereas Western Europe costs are on the order of $0.20 - $0.40/$10^6$ BTU. Not only does Western Europe have a distinct advantage in this regard, but the low transportation costs put them in a very good bargaining position with LNG exporters. Considering OPEC's agreement to keep CIF* costs for oil maintained at an equal level for all importing interests, it is certainly a strong possibility they will do the same

*Cost, Insurance and Freight.

TABLE A-3

Transportation Costs for 1Bcf/d Delivery from

Several Western European Countries*

	Nautical Miles (A-6)	Round Trip Time (A-6)	# Ships Req'd Additionally	Capital Investment** $ Million	Capital Recovery $/$10^6$ BTU
LeHavre, France - Arzew, Algeria	1410	9.4d	2	$200-300	.14-.21
Fos, France - Skikda, Algeria	400	4.5	1	$100-150	.07-.10
Convey Istad, UK - Arzew, Algeria	1540	10.0	4	$400-600	.27-.41
La Spezia, Italy - Libya	990	7.7	2	$200-300	.14-.21
Barcelona, Spain - Libya	1060	7.7	3	$300-450	.21-.31

* computations exclude currently owned and operating LNG tankers.

** based on $100-150 million/120,000 - 125,000 m^3 LNG tanker.

for LNG exports. Thus, where countries desiring to purchase LNG have low transportation costs, the FOB cost of the energy resource to those countries can be higher, bringing in a greater profit to the exporting countries. This situation definately could give the Western European interests a preferred customer status with OPEC and other LNG exporters.

A second consideration is that while projected LNG imports into the U.S. represent a larger percent of the gas supply to the U.S. than do LNG imports in Western Europe as a percent of the gas supply, (see Table A-4) the intent of Project Independence will be very sensitive to the balance of imports and supplies. This possibly could result in slower regulatory approval times in the U.S. than in Europe. It is likely that Western European countries could bring LNG receiving terminals on line faster than in the U.S., since more import facilities in the U.S. represents more dependence upon foreign energy.

The third concern is the status of Japan's natural gas demand. Table A-5 represents estimates of unfulfilled natural gas demands for the U.S., Western Europe and Japan. While the U.S. and Western Europe will suffer comparable short falls, as per cent of demand, Japan will be suffering a tremendous shortfall partly due to their lack of domestic gas supplies but further compounded by the end of Alaskan LNG imports in the near future. From Table A-4 it is apparent that Japan is or will be dependent upon LNG imports for better than 80% of their natural gas demands and hense this tends to put Japan in a position to bargain harder and to invest more heavily in LNG operations to assure their energy demands can be met.

TABLE A-4

LNG & NEW GAS SUPPLY: 1975-85
(Million Cubic Feet Per Day)

U.S.	1975	1980	1985
Indigenous Production[(a)]	55,000	55,000	55,000
Supplementary Gas Supply[(b)]	3,600	5,500	11,800
Increment[(c)]	--	1,900	8,200
LNG Imports[(d)]	40	4,135	6,425
Total New Gas Supply Over '75	--	6,035	14,625
LNG as % New Supply	--	68.6	43.9

WESTERN EUROPE	1975	1980	1985
Indigenous Production	17,000	25,000	28,000
Supplementary Gas Supply[(d)]	840	1,190	5,200
Increment[(c)]	--	9,150	15,360
LNG Imports	845	2,395	4,845
Total New Gas Supply Over '75	--	11,545	20,205
LNG as % New Supply	--	20.7	24.0

JAPAN	1975	1980	1985
Indigenous Production[(e)]	250	600	900
Increment	-	350	650
LNG Imports	675	2,970	5,110
Total New Gas Supply Over '75	-	3,320	5,760
LNG as % New Supply	-	89.4	88.7

[(a)] Average of AGA alternative forecasts

[(b)] AGA (1975) includes Canadian imports, oil and coal gasification, Alaskan imports and advanced fracturing

[(c)] Additions to indigenous and supplementary after 1975

[(d)] Consists of pipeline supplies from USSR and supplies from Algeria

[(e)] OECD estimate

SOURCE: "What's Ahead for LNG?" Ocean Industry Digest of a Gastech paper by E. K. Faridany, Ocean Phoenix Transport Inc., London. Ocean Industry, November 1975

TABLE A-5

UNFULFILLED NATURAL GAS DEMAND: 1975-1985

(Million Cubic Feet per Day)

U.S.	1975	1980	1985	Annual % Growth 75/85
Potential NG Demand[a]	65,600	76,100	88,500	3.0
Total Gas Supply[b]	58,640	64,635	73,225	2.3
Unfulfilled Gas Demand	6,960	11,465	15,275	-
As % Total Demand	10.6	15.1	17.3	-

WESTERN EUROPE	1975	1980	1985	Annual % Growth 75/85
Potential NG Demand[c]	18,685	35,340	47,100	9.7
Total Gas Supply[b]	18,685	29,385	38,045	7.5
Unfulfilled Gas Demand	--	5,955	9,055	-
As % Total Demand	--	16.9	19.2	-

JAPAN	1975	1980	1985	Annual % Growth 75/85
Potential NG Demand[d]	925	4,805	9,800	26.5
Total Gas Supply[a]	925	3,570	6,010	20.6
Unfulfilled Gas Demand	--	1,235	3,790	-
As % Total Demand	--	25.7	38.7	-

[a] AGA (1975) assumes a 3% annual growth rate over 1975

[b] Summation of % indigenous production + supplementary gas supply + LNG imports

[c] OECD estimate (1975), $9 crude oil case

[d] MITI high forecast (1979)

SOURCE: "What's Ahead for LNG?" Ocean Industry Digest of a Gastech paper by E. K. Faridany, Ocean Phoenix Transport Inc., London. Ocean Industry, November 1975

The fourth observation that leads to the conclusion that Western Europe can be a very strong competitor for North African LNG concerns the proximity of the various LNG sources available to Western Europe. Of the entire fleet listed in Table A-6 (end of this Appendix) only four tankers are on order to service European LNG facilities that are too large to pass through the Suez Canal fully-loaded (LNG capacity greater than 120,000 m^3). Whereas all LNG carriers on order to supply the U.S. East Coast are of 120,000 m^3 capacity, which is too large to use the Suez Canal. The capabilities of the European fleet to economically import Persian Gulf LNG and Arabian Peninsula LNG, utilizing the Suez Canal, extends the range of European sources at still an economic advantage.

This discussion has treated Western Europe as a united consumer, rather than considering each country's respective situation. Certainly, the United States is in a strong competitive position with individual countries, provided the U.S. consumer is willing to pay more dollars for the imported natural gas than European consumers will have to pay. If cartel agreements to hold CIF prices firm do not apply to LNG exports, then the U.S. could essentially outbid Western European competitors. However, this is definitely a worst-case option. Considering the relative strength of the European economic community, Western Europe as a group or in parts could become an active force in the development of gas fields and liquefaction facilities, leading to favored contracts.

Drewry reports [A-2] that a letter of intent was signed between a Western European seven-company consortium representing West Germany, Belgium, Austria, Switzerland, France, and the Algerian LNG exporting interest Sonatrach for eventual imports of .33 Tcf/yr (gas), which is equivalent to 1.5mmcfd (LNG) or 0.43 X 10^5 m^3/d (LNG). Should support-for-development agreements be signed by consortiums of this sort, for the preferred contractor status for LNG, Europe could readily develop and consume reserves in North Africa.

TABLE A-6

Existing Worldwide LNG Carriers

Ship Name	Flag/Owner	Shipyard	Year	Capacity (m^3)
Aristotle	Paramenian	Mobile, Alabama USA	1958	5,123
Methane Princess	British	Barrow-in Furness, England	1964	27,400
Methane Progress	British	Belfast, Ireland	1964	27,400
Pythagore	French	LeHavre, France	1964	630
Jules Verne	French	LeTrait, France	1965	25,500
Artic Tokyo	Liberian	Malmo, Sweden	1968	71,000
Polar Alaska	Liberian	Malmo, Sweden	1969	71,500
Esso Brega	Italian	Genoa, Italy	1969	40,000
Esso Portoverese	Italian	Genoa, Italy	1969	40,000
Esso Liguria	Italian	Genoa, Italy	1969	40,000
Laieta	Spain	El Ferrol, Spain	1970	40,000
Hassi R'Mel	Algeria	LeSeyne, France	1971	71,500
Euclides	Liberia	LeHavre, France	1971	4,000
Descartes	France	St. Nazaire, France	1971	50,000
Gradina	Britain	St. Nazaire, France	1972	75,000

TABLE A-6 (Con't)

Ship Name	Flag Owner	Shipyard	Year	Capacity (m^3)
Gradila	Britain	St. Nazaire, France	1973	75,000
Kentown (1401)	Britain	LaSeyne, France	1973	35,000
Peder Smedvig	Norway	Moss, Norway	1973	29,000
Ben Franklin	France	LaCiotat, France	1974	120,000
Charles Tellier	France	LaCiotat, France	1974	40,080
LNG Challenger	Britain	Stavanger, Norway	1974	87,600
Gari	Britain	St. Nazaire, France	1974	75,000
Gouldia	Britain	LaCiotat, France	1974	75,000
Gastrana	Britain	St. Nazaire, France	1974	75,000
Hull 177	Norway	Moss, Norway	1974	29,000
Montana	Norway	LaSeyne, France	1975	35,000
Geomitra	Britain	LaSeyne, France	1975	75,000

On-Order Worldwide LNG Carriers

TABLE A-6 (Con't)

Ship Name	Flag Owner	Shipyard	Year	Capacity (m^3)
Genota	Britain	LaSeyne, France	1975	75,000
Hulls 198,199,200	Liberia	Stavanger, Norway	1975	125,000 ea.
Hull 608	U.S.*	Newport News, Va. USA	1975	125,000
Hull 2266	U.S.*	New Orleans, La. USA	1975	125,000
Hull 2267	U.S.	New Orleans, La. USA*	1975	125,000
2 Cryogenic Barges	U.S.	USA(?)**	1975	12,000
Hulls 609,610	U.S.(?)	Newport News, Va. USA**	1975	125,000 ea.
Hulls 283,284,287	Charter(?)	Donkerque, France	1975	125,000 ea.
Hulls 41,42,46	U.S.	Quincy, Mass. USA**	1976	125,000 ea.
Hull 2268	U.S.	New Orleans, La. USA*	1976	125,000
Hull 302	France	LaCiotat, France	1976	120,000.
Hull 1220,1221	Liberia	Kobe, Japan	1977	128,600 ea.
Hull 83	Liberia	Kiel, Germany	1977	125,800
Hull 84	(?)	Kiel, Germany	1977	125,000
Hulls A26,B26	(?)	St. Nazaire, France	1977	122,260

TABLE A-6 (Con't)

Ship Name	Flag Owner	Shipyard	Year	Capacity (m^3)
4 Hulls	U.S.(?)	Quincy, Mass. USA*	1977	125,000 ea.
3 Hulls	U.S.	New Orleans, La. USA*	1979	125,000 ea.
5 Hulls	(?)	Algerienne Cie National de Navigation (CNAN)	1977/78	125,000 ea.

* East Coast
** West Coast

APPENDIX A

REFERENCES

A-1: Pipeline and Gas Journal, June 1975.

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A-3: Ocean Industry, "Financing LNG Systems: An International Challenge," April 1974.

A-4: Ocean Industry, "1974 LNG Carrier Directory," November 1973.

A-5: FPC Natural Gas Survey, Vol. 1, Chapter 10.

A-6: Khan, A.R., "World Trade in LNG," LNG Economics and Technologies, 1972.

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Appendix B: Methanol Versus LNG

Since the processing, transportation, and storage of natural gas as LNG involves working in a cryogenic regime, the question has been asked as to whether there might be a better form in which to transport and store natural gas. One possibility suggested is the conversion of natural gas to methanol.

The methanol could be shipped and stored very much like any other light petroleum product. In order to replace or supplement natural gas supplies, the methanol would have to be regasified or reformed back to methane. Although this is possible, direct use of the methanol as a liquid fuel would probably be a more reasonable use. One such use would be as an automotive fuel as indicated by EPA-460.[1]

The following table compares methane and methanol:

	CH_4	CH_3OH
Heat of combustion Kg calories/gram moles	211	171
Heat of combustion BTU/lb	23,800	9,600
Heat of combustion (liquids) BTU/gal	82,900	63,340
Liquid densities (g/cc)	0.42	0.79

For a one-trillion BTU per day delivery system, approximately one-billion cubic feet per day of natural gas would have to be liquified, or 49,000 tons per day of methanol would have to be processed.

A flowsheet for the commercial production of methanol from natural gas can be found in a McGraw-Hill publication entitled, "107 Process Flowsheets." The process requires 750PSIG and 400°F operating temperature. Ideally, the reaction is as follows:

$$3CH_4 + 2H_2O + CO_2 \longrightarrow 4CH_3OH$$

The reaction is carried out over a copper-based catalyst and yields 99.99% pure methanol.

Reference 1 reports on two separate methanol plant studies. Both studies addressed single train units of 5,000 tons per day methanol production capacities. This is approximately twice the size of any units operating today. Based on this data, a 49,000 ton per day methanol production facility would cost between $750 to $1,000 million dollars, or approximately 15% more than an LNG liquefaction facility of the same BTU capacity.

The methanol tankers could be of the same design as the very large crude carriers (VLCC), upwards of 350,000 deadweight tons. These tankers would be approximately five times the DWT of the 125,000 cubic meter LNG ships, and approximately 2.75 times the BTU capacity. Whereas eight LNG carriers would be required to transport a trillion BTU per day of LNG from Algeria, only three methanol tankers would be needed.

If the methanol were to be used as a liquid fuel, the receiving terminal could be a normal petroleum tank farm at a cost of approximately 30% of an LNG terminal. But if the methanol were to be converted to SNG, synthetic natural gas, the receiving terminal could be expected to cost approximately the same as the methanol production facility--$750 to $1,000 million. The reason that the costs are the same is that the process is the same, only in reverse.

$$4CH_3OH \longrightarrow CO_2 + 2H_2O + 3CH_4$$

To bring the regasified methanol back to pipeline quality SNG, the carbon dioxide and water must be removed.

The following is a summary of the projected capital and operating costs of a one-trillion BTU per methanol, both as a liquid fuel and as a replacement for natural gas.

SUMMARY OF COSTS*

USING METHANOL AS A SOURCE OF SNG

	Range of Capital Costs $\$x10^6$	Cost $\$/10^6$ BTU
A. Cost at Gas Field of Natural Gas		0.00 - 1.98
B. Capital Costs		
1) Gas field and methanol production	800 - 1,100	0.55 - 0.75
2) Transportation	300 - 400	0.21 - 0.27
3) Receiving and SNG production facilities	800 - 1,100	0.55 - 0.75
C. Operating Costs		
1) Gas field and methanol production		0.20 - 0.86
2) Transportation		0.05 - 0.15
3) Receiving and SNG production facilities		0.06 - 0.08
		1.62 4.84

*Based on a 1 x 10^{12} BTU/day complex or 1 x 10^9 SCF of SNG at 1000 BTU per SCF of SNG.

SUMMARY OF COSTS*

USING METHANOL AS A LIQUID FUEL

	Range of Capital Costs $\$ x 10^6$	Cost $\$/10^6$ BTU
A. Cost at Gas Field of Natural Gas		0.00 - 1.58
B. Capital Costs		
1) Gas field and methanol production	750 - 1,000	0.51 - 0.68
2) Transportation (3 ships)	300 - 400	0.21 - 0.27
3) Receiving terminal	100 - 120	0.07 - 0.08
C. Operating Costs		
1) Gas field and methanol production		0.16 - 0.69
2) Transportation		0.05 - 0.15
3) Receiving terminal		0.01 - 0.02
		1.01 3.47

*Based on a 49,000 ton per day complex or a 1 x 10^{12} BTU/day complex with the methanol production facility in North Africa.

It is important to note that cost is not the only consideration in the comparison of an LNG energy system to a methanol system. First, methanol production facilities of 2,000 tons per day do exist, but there is a major question as to the technical feasibility of a 49,000 tons per day facility. A 49,000 tons per day facility would generate methanol at a rate of approximately 10,000 gallons per minute. Next, a large amount of fresh water is required for production of methanol - approximately 0.5 tons per ton of methanol. This amounts to approximately 25,000 tons of water per day or 2 billion gallons per year. An LNG facility requires virtually no fresh water. The cost summary for the methanol system did not include the costs of providing this water in a desert location. Finally, methanol is a very toxic chemical. A major spill of methanol may present a greater health and safety problem than an LNG spill. A detail safety analysis would have to be performed to establish the consequences of possible surface and ground water contamination resulting from a methanol spill.

In summary, the following conclusions can be made:

- The use of methanol compares favorably with LNG when the methanol is used as a liquid fuel.
- The use of methanol as a source of SNG to supplement natural gas supplies cannot economically compete with LNG.
- Major technical, safety, and environmental questions must be resolved before the widespread use of methanol fuels could begin.

REFERENCES

1. *Chemical Engineering*, June 25, 1973, p.48.
2. "Analysis of LNG Marine Transportation for the Maritime Administration," Booz-Allen Applied Research, Inc.