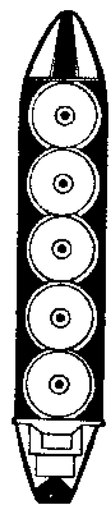
LEGAL ASPECTS
of the ocean carriage and receipt of liquefied
NATURAL GAS

Peter N. Swan



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related publication

THE FUTURE MANAGEMENT OF THE OREGON COAST: PROCEEDINGS OF A SYMPOSIUM HELD AT THE LAW CENTER, UNIVERSITY OF OREGON, OCTOBER 27, 1972. Publication No. W-74-001. (Price: $3.00) 167 pp.

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contents

CHAPTER III

CHAPTER IV

introduction and background

PROJECTED UTILIZATION AND SHORTFALL OF SUPPLY

In October of 1975 the vice-chairman of the Federal Power Commission characterized the nation's natural gas supply as being in the "crisis" phase. He stated that the shortage was "manifested by shrinking proved inventories, declining productions, and increasing curtailment of deliveries of firm . . . [commitments to deliver] natural gas . . . by interstate pipeline companies." (Statement of Don S. Smith in *Hearings before the House Subcommittee on Public Lands of the Committee on Interior and Insular Affairs*, 94 Cong., 1st Sess., October 19, 1975, written statement p.1 [hereinafter referred to as "Smith statement"].) As of 1974, additions to proven reserves had been less than natural gas production for seven straight years and had been close to equality for eight years preceding that (American Gas Association data reproduced in Table I, *Id.* at 3). When Alaskan reserves and production are included with those of the lower 48 states, the discovery of the Prudhoe Bay reserves in 1970 makes that year exceptional. But despite the fact that 1970 saw the largest addition to reserves ever, production was at 22 trillion cubic feet (TCF) and the additions-to-reserve-over-production ratio was just a modest 1.7 (*Id.* at 5). Statistics gathered by the Federal Power Commission from interstate pipeline companies on Form 15 reveal a similar pattern in the ratio. (*Id.* at 7). In 1974 production actually started to decline and the portion of the production which reached interstate pipelines declined substantially (by 9%) in the two years from 1972 to 1974. (*Id.* at 2). The economic realities underlying the disproportionate decrease in supply to interstate pipelines will be explored more fully in Chapter VIII, *Deregulation of Domestic Natural Gas, infra.*

FPC staff estimated in an early 1975 study that if present rates of reserve addition continued through 1985 there would be a shortfall, in terms of maintaining reserves against projected production, of 151 TCF (*Id.* at 11). The FPC's Staff Report No. 2 "Natural Gas Supply and Demand 1971-1990" predicted a demand of 34.5 TCF in 1980 and 39.8 TCF by 1985. (Conference on LNG Importation and

Terminal Safety 279 (N.A.S. 1972)). Curtailments of firm commitments through interstate pipelines had risen to 1.7 TCF in 1974 and it is probable that most of the users denied natural gas switched to high price imported oil. (*Id.* at 12).

Measuring "probable" reserves is more speculative and estimates about Alaska range from 15 to 54 TCF. These estimates suggest that the total national reserves might be enhanced by anywhere from 7% to 20% through confirmation of gas deposits in Alaska alone. Proven reserves in Alaska are distributed between the Sadleroschit Formation in Prudhoe Bay (20.5 TCF) and the Sag River Formation (2 TCF), the Naval Petroleum Reserve No. 4, both also on the North Slope (370 BCF), and Cook Inlet Basin (5.9 TCF). (Statement of Richard L. Dunham, Chairman FPC before Senate Committees on Commerce and the Interior and Insular Affairs, February 17, 1976, attachment IV, 1-4).

The Canadian Petroleum Association as of 1974 estimated the proven reserves in the Beaufort Sea-Mackenzie Basin at 4 TCF and the reserves in the Arctic Islands to range between 8.5 and 12.5 TCF (*Id.* at 5-6). There is also speculation that 10 TCF may be discovered in the Alaskan outer continental shelf in the next decade (*Id.* at 7 quoting the report of Gordon Zareski, Chief, Planning and Development Division, Bureau of Natural Gas, FPC). Speculative estimates of future discoveries in Canadian fields range from 124 TCF to 350 TCF (*Id.* at 14).

Production estimates for Alaska and Canadian natural gas production during the period 1980 through 1985 would indicate a maximum of around 16 TCF. Some of the North Slope gas is associated gas (associated with crude oil deposits) and thus may be reinjected to maintain reservoir pressure in the early years of development. This would tend to decrease the previously mentioned production estimate (*Id.* at 17-22).

Since natural gas sources include those on other continents which cannot be imported to the United States in a gaseous state via pipeline, this discussion of supply shortfall will be limited to U.S.-Canadian reserves and production. The FPC staff attempted to project shortfall in future years. Assuming continued regulation of well-head price, the possibility of LNG imports, but excluding gas produced in Alaska, FPC staff estimated a 19.5 TCF shortfall in the year 1985. To the extent shortfall projections are based on projections of demand at current regulated prices, they may be unrealistic, but production is also expected to drop. One measure of the increasing difficulty in discovering and producing natural gas is the finding rate of gas per foot of well drilled. This has been declining from a rate of 831 thousand cubic feet per foot in 1967 to 104 MCF per foot in 1973. (*Id.* at 36-37) (Comptroller General's Report to Congress, Natural Gas Shortage: The Role of Imported Liquified Natural Gas, 22 (1975)) An FPC curtailment study of the 1974-75 heating season revealed that the 16 interstate pipelines suffering the greatest curtailments ranged from a low of 13.9% of requirements to a high of 42% of requirements. Some of the pipeline companies involved were Cities Service (24.8%), Northwest Pipeline (15.8%), El Paso (17%), Panhandle Eastern (16.4%), Columbia (21.4%) and Transcontinental Gas (25.7%) (*Id.*at 38-39). Curtailment statistics indicate that net curtailments rose from the 0.018 TCF in 1970 to 1.1679 TCF in 1974 (Comptroller General's Report to Congress, *supra* at 16).

SOURCES OF NATURAL GAS

Gas, like petroleum, is a hydrocarbon product which is formed from the chemical processes operating on dead plant and animal matter over the millenia of geologic time. Gas may be found in the same reservoir as crude oil and may even be entrained with it in the production process. Such gas is referred to as "associated gas" or "solution gas". Other deposits of natural gas are entirely separate from crude oil strata or reservoirs and are usually older with respect to time of origin. Such reserves are referred to as "non-associated reserves." Most of the foreign gas deposits, especially those in Russia, Iran and Algeria are non-associated. The third possibility is present over parts of the Prudhoe Bay oil field where the natural gases are present in a pocket or "cap" vertically over the petroleum reservoir. Such gas, although not technically "associated", can be, and sometimes is, produced more or less contemporaneously with the extraction of oil.

Natural gas is itself a mixture of several different gases with methane being the principal constituent. Other gases found in natural gas are ethane, propane, isobutane, N'butane and nitrogen. (Trident Engineering Associates, Inc., Maritime LNG Manual 214 (July 1974)). At minimum quality, methane represents 89% of the mixture, ethane slightly over 7% and propane slightly over 2% (*Id.*). Natural gas is purchased from the producer according to its heating quality, *i.e.*, its BTU content. Inputs which must be measured to compute heating value are temperature, volume and precise composition. The composition can be determined by a gas-liquid spectrometer. Samples to be sent through the spectrometer are taken from at least ten different locations within each tank on an LNG carrier. The units of the heating value are BTU's per standard cubic foot (*Id.* at 213). The composition of natural gas from different gas fields causes variation as to heating value and moisture content. Stored liquefied gas from the same gas field can vary in density with the coldest and densest liquids settling to the bottom of the tank if not agitated or replaced over time. Since "heating value" is referenced to *standard* cubic feet, allowances can be made for the density variable. Prior to liquefaction, natural gas is dehumidified so differences in this inherent property do not enter into the heating value computations.

In addition to gas fields in Alaska and Canada, natural gas is produced for export in Algeria, Libya, Brunei and Indonesia. North Sea gas deposits will soon produce gas for the domestic markets of the United Kingdom and Norway. In all probability this gas will be piped in undersea pipelines in gaseous form. Technical and engineering problems are being solved rapidly and it is reasonable to expect work on such a pipeline to be underway by 1980. If this technology proves practicable it may be that it can be adapted for a trans-Mediterranean pipeline from North Africa to Europe. Other countries where natural gas deposits are known to exist are the USSR, Nigeria, Iran and Saudi Arabia. For want of transportation systems to deliver the gas to markets, such gas is now either being flared at the wellhead or is being reinjected (in cases of associated gas), or is being left in the ground. See also 111-112 *infra*.

THE ECONOMICS OF LIQUEFIED NATURAL GAS

Even before the current energy shortage, the technology existed for the liquefying and storing of natural gas. This was done in various locations in the United States on a relatively small scale for gas fired electric utilities or natural gas utilities. In these applications it is economic to liquefy gas delivered during times of reduced demand and store in liquid form for revaporization in periods of peak load when pipeline deliveries would either fall short of demand or would involve premium pricing.

The phases of the LNG cycle are essentially production of the natural gas, liquefaction, storage or transport, revaporization, distribution and consumption. Details of this cycle will be discussed in the succeeding section. If the gas is from associated gas field production it may be viewed as a by-product (with little or no cost) once the petroleum is extracted, or it may be viewed as a product sharing joint costs with the production of crude oil. For intra-state consumer sales of natural gas the controlling price element is usually the wellhead price. The costs for dehumidification, odorization and distribution are not overwhelming. When long pipe runs are involved, distribution costs start to mount. If sales are directly or indirectly through interstate pipelines the wellhead price is regulated (*see*, Chapter VII, § 7 Certification and § 4 Approval of Rates, *Jurisdictional Issues, infra*). The implications of regulated prices for domestic natural gas are discussed in Chapter VIII *infra*. When LNG is introduced because of transportation across oceans or through mountains (by cryogenic tanker truck) where pipelines cannot be built, large additional costs are incurred. The liquefaction process is capital intensive and requires sophisticated equipment and technicians. Liquefaction facilities are located in seaports for obvious reasons. The gathering and transportation lines that lead from the gas fields to the liquefaction facilities may be of varying length. For Alaskan production these behind-the-plant pipelines may present legal problems with regard to FPC regulatory jurisdiction (*see*, Chapter VII, § 7 Certification and § 4 Approval of Rates, *Jurisdictional Issues, infra*). Since tanker loading is a discrete rather than a continuous phenomena, some holding capacity in the form of storage tanks is required at liquefaction facilities. These, too, are costly. This is because of the insulation required for thermal efficiency and because of instrumentation and structural integrity required for safety.

Liquefied natural gas is maintained at temperatures in the vicinity of minus 260 degrees Farenheit. Such cryogenic temperatures would embrittle the steel in an ordinary tankship and thus special purpose vessels must be designed to carry the LNG. In the second generation ships now being built, the optimal economic size appears to be between 120,000 and 165,000 cubic meter capacity. A study underway at the Massachusetts Institute of Technology indicates that the use of 300,000 cubic meter ships could save nearly $22 million for each million cubic foot of gas carried in a typical year over the second generation ship capacities. This comparison uses a 15% discount rate for present worth and only addresses capital and operating costs for the vessels. However, such ships would have drafts of forty-eight feet which would require dredging at most berths or might require deepwater (offshore) terminals. These facilities might well be more costly than those required for ships presently under construction. *See* Marcus and Larson, "U.S. Offshore Terminals: If and When", p. 8 and Exh. 5 (draft of paper to be presented to S.N.A.M.E. in 1977). As in the cargo tanks, there are the twin problems of thermal efficiency and structural integrity. The latter problem is complicated by the dynamics of vibration while under way and the usual ship motions of pitch, yaw and roll. Nickel steel or aluminum tanks and valving designed to withstand cryogenic temperatures add to the costs of LNG carriers. Operational performance requirements are so unique for cryogenic cargoes that each class of vessel will incur substantial developmental and design costs. Similarly, hardware equipment, pumps, etc. used with cryogenic cargoes are not invariably "shelf items" and a certain amount of custom manufacturing by sub-contractors is involved. A reliable source has estimated the cost of a 125,000 cubic meter carrier to be 140 million dollars delivered in 1980. Additionally, because of the hazardous nature of their cargo, these ships are equipped with many fail-safe devices having elaborate instrumentation and with complex electronic navigational equipment. Economical aspects of LNG carriers include their short turn-around time and their relatively shallow draft (36') which give them wide versatility of destinations.

In 1972 estimates of the cost of transportation were 8 cents per thousand cubic feet per 1,000 miles. (Gaseous volume measurement used even though transportation would be in liquefied form which occupies only 1/630 of gaseous volume.) At the time of these estimates the capital cost of the carriers was approximately half of what it is estimated it will be in 1980. Thus, if anything, this figure is unrealistically low for future deliveries.

To illustrate the sizeable portion of the ultimate price which is attributable to ocean transportation of LNG, two recent projections are informative. El Paso-Alaska estimates that the unit transportation costs of gas delivered from Prudhoe Bay fields to the main El Paso pipeline at Topcoc, Arizona would be approximately $1.56 per thousand cubic feet. (Statement of Richard L. Dunham, Chairman, FPC, *supra* at 58.) Of course, some portion of this represents costs of getting the gas from Oxnard, California to Topcoc, Arizona and across the width of Alaska to Gravina's liquefaction plant. In any event, it shows that transportation from remote producing fields, especially when that transportation includes an LNG carrier, can be costly. The second estimate is from Pacific-Alaska LNG Company and it is an estimate of the delivered costs of vaporized natural gas from the Cook Inlet area transported by LNG carriers to Southern California. The estimate is $2.43 per thousand cubic feet, or $2.40 per million BTU's. While this is not seriously out of line with certain other energy costs, it is far greater than the FOB price Alaska and indicates that transportation is a costly element of the pricing of natural gas derived from LNG. (Statement of Don S. Smith, Vice-Chairman FPC, in *Hearings before the House Subcommittee on Public Lands of the Committee on Interior and Insular Affairs*, October 9, 1975 at 36.)

At the receiving end, there must again be cryogenic storage tanks, vented and monitored with instruments to prevent such phenomena as "roll over" or undue vapor pressures. Additionally, there must be elaborate insulated ship-to-shore piping and Chiksan arms, or their equivalent, for unloading. Revaporization and compression equipment is a necessary item for the terminal operator in order to convert LNG to a marketable (distributable) commodity. Finally, adequate berthage and transfer pipelines must be constructed. Whenever heat or shaft horsepower is required in any of these processes natural gas can be utilized. This does not mean that the work is done "for free" but simply that using gas is usually the most efficient way to do it and that the cost (*i.e.*, gas consumed) is taken into account in determining the price of the gas remaining to be sold. Some large industrial customers have their own cryogenic storage facilities and as to these customers the importer may deliver by cryogenic barge or tank truck without introducing the product into a gaseous pipeline.

The projected El Paso-Alaska project involves a 500 acre liquefaction plant at Gravina Point in Alaska composed of a gas treating facility, a dehydration unit, a refrigeration and compression plant and the storage tanks in addition to a 1200' pier. Carriage would be accomplished by eleven 165,000 meter LNG ships. At the receiving end in Southern California a 227 acre facility would involve a 4600' offshore pier, insulated storage tanks capable of accomodating two simultaneous unloadings, vaporization equipment and associated cryogenic pipelines (Final Environmental Impact Statement [FEIS], Alaska Natural Gas Transportation Systems, I-B 29 (FPC Staff)). The cost of the overall system as described above is estimated to be 7.6 billion dollars standardized at 1975 cost levels (Statement of Richard L. Dunham, *supra* at 57). By an interesting contrast, an estimate submitted only a few months earlier in late 1975 for this project was estimated to be only 5.5 billion dollars and this estimate included a gaseous transportation pipeline from Prudhoe Bay to Gravina Point, but excluded the cost of the reception terminal in Southern California. (Statement of Donald S. Smith, Vice Chairman FPC, *Hearings before the Subcommittee on Public Lands of the House Committee on Interior and Insular Affairs*, October 9, 1975, 94th Cong., 1st Sess. at 31-32.)

Booz-Allen Applied Research undertook a study of the Liquefied Natural Gas Technology and Transports System (MARAD Contract No. 3-36201) commissioned by the Maritime Administration. The study was completed in 1973 and is discussed *infra* in connection with the estimated size of American flag fleet of LNG carriers. As a part of this study, Booz-Allen and its sub-contractor, Manalytics, Inc. prepared a computer program and various data arrays for computer memory designed to be used by MARAD in evaluating proposals for designs of LNG carriers, LNG trade routes, and the desirability of construction and operating subsidies. The principal output of the computer program was a required freight rate in dollars per delivered cubic meter of LNG or in dollars per million BTU's (Booz-Allen Applied Research, Inc., Analysis of LNG Marine Transportation, Appendix D (13) (Nov. 1973)).

Other useful information revealed by the Booz-Allen computer program would be the total number of ships required in the fleet and capital costs and operating costs for ships and shoreside facilities (*Id.*). J.J. Henry and Co. was a consultant for purposes of describing the specifications and operating characteristics of certain "generic" ships which represent the standardized designs for 75,000 and 125,000 cubic meter carriers using spherical, freestanding, or membrane tanks constrained to a thirty-six foot draft. A bidder can then test various trade routes against generic ship performance and costs, or it can offer changes for numerous variables in the generic ship design. A semi-permanent data file not only stores data applicable to generic ships, but also allows the user to input parameters for a specific proposal such as LNG density, changed steel costs, reduced crew costs, etc. *See* Appendix Exh. 31. Parameters and coefficients for various regression equations on rate of interest, port costs and depreciation can be entered into these arrays. Frequently empirical data has been studied and an equation has been developed of the form $a + b(V)^c$, where "a" is a constant (intercept), "b" is a coefficient and "c" is the exponent with V being a variable which can be input for any particular proposal. Capital recovery factor computations assume straight-line depreciation, equity financing, and a specified tax rate. (*Id.* at D(22)). The Institute of Gas Technology provided data on shoreside facility costs as a function of storage capacity in cubic meters (*Id.* at D(23)). Using a two port approximation of a multiple port cyclic cueing theory model and reasoning that extra berths are only useful to the extent that there is sufficient storage to unload a berthed vessel, economic indifference points can be computed. At such points the cost of delaying a vessel equals the cost of adding an additional berth and creating additional shoreside storage (*Id.* at D(62)). Since random occurrences during voyages will make ships that initially depart at regular intervals tend to space out and bunch, standard deviations about the mean in a normal distribution and the concept of a "safety factor" are added to the analysis to permit servicing of the majority of the random "bunching" of vessel arrivals (*Id.* at D(63)). Using a sophisticated design of dependent arrays of data, inputs for labor and materials for all the components and systems of the vessel can be specified. These are converted eventually to tons or man hours and a higher level array converts these to dollars. At a higher level still, the computer factors by an overhead coefficient which varies whether it applies to labor, management, insurance, conventional hull construction, or cryogenic systems. (*Id.* at D(26-27)). The construction data arrays for generic ships are already on file in the semi-permanent data and the bidder's vessel data can be input either in its entirety or as changes to the generic data.

Another file known as the technical specifications file, includes forty different items including volume of cryogenic insulation, fuel capacity, shaft horsepower utilized, speed loaded, boil-off rate in loaded and ballast conditions, fuel use rate at sea, annual layup time, loading and discharge rates, lightship weight, and firstship costs, (if known) (*Id.* at D(32) and *see* Appendix Exh. 32). Formulas were derived from empirical studies to compute crew costs, hull maintainance and repair costs, and stores and supplies costs (*Id.* at D(35)). Since LNG ships are such a recent innovation there is no reliable empirical data on maintainance and repair for the cryogenic systems and these were simply estimated to be $100,000 for 130,000 cubic meter ship each year (*Id.* at D(36)). Using algorithms developed and stored in the computers memory, the computer can, for any given LNG cargo in any given ship on any given voyage, compute firstship capital costs, total voyage times (broken down by sea time, preparation time, cargo handling time, and annual layup time). It can also accurately compute the cargo available for sale upon delivery, the cargo consumed as boil-off fuel and the cargo left in heel and other necessary factors to obtain all of the components of operating costs. In addition to cost projections for specific ship designs, the program is able to output useful projections of delivered cost or required freight rate as functions of ship size or trade route length or tank configuration or insulation design.

DEVELOPMENT OF LNG TECHNOLOGY

The history of LNG, at least to the general public, is marked by two notorious incidents. The first incident was the collapse of the LNG storage tank belonging to the East Ohio Gas Company in Cleveland Ohio on October 20, 1944. Immediately following the tank rupture there was a tremendous fire which killed 133 people and destroyed adjacent buildings and dwellings. (Weinberg, *Cargo of Fire: A Call for Stricter Regulation of Liquified Natural Gas Shipment and Storage,* 4 Fordham Urban L.J. 495 (1976)). The Cleveland tanks ruptured due to a metallurgical (brittle) failure which could be attributed to the lack of knowledge on the part of the designers of the effect of the very low temperatures on the strength of certain steels under stress. (*See generally,* Report on the Investigation of the Fire at the Liquefaction, Storage and Regasification Plant of the East Ohio Gas Company (Bureau of Mines #RI3867, February, 1946)).

The second tragic incident involved a fire in an LNG storage tank belonging to the Texas Eastern Transmission Company (TETCO) at Staten Island, New York on February 10, 1973. Forty of the forty-two workmen in the then empty tank were unable to escape and died of suffocation from the smoke of the fire. The tank had been empty for thirteen months but prior to that had been in service for nearly twenty-one months. The tank was of pre-stressed concrete in the shape of a cylindrical shell with a domed roof. Inside the concrete shell, insulation consisting of two four-inch layers of polyurethane was held in place by an aluminum lattice and covered by a 4 mil layer of aluminized mylar and organic bonding material. The floor of the tank was additionally covered with polyurethane sheeting. The domed ceiling was approximately sixty-three feet above the floor of the tank. The exterior of the tank was surrounded by an earthen wall. A leak in the mylar liner was detected in October of 1970, but its exact location was ambiguous because of confusing readouts from the instrumentation. Fourteen months later the tank was emptied and purged. Workmen then entered for the purpose of cleaning and repairing the tank. This work had been going on for nearly a year with the approval of the New York Fire Department when the fire occurred. (Zabatakis and Burgess, *Investigation of Explosion of Staten Island Natural Gas Storage Tank* (Bureau of Mines Publication) incorporated in *Subcommittee on Investigations of the House Committee on Interstate and Foreign Commerce, Legislative Issues Relating to the Safety of LNG Storage,* 93d Cong., 2d Sess. 605 (Committee Print 1974)). Although the fire did involve combustible hydrocarbons and was in fact traceable to the storage of LNG in the tank, it was not a threat to surrounding property or persons and it occurred during the maintenance phase rather than the operational phase of handling LNG. Two significant findings emerge from the investigation following that fire. The first was that the insulation material was not fire proof. This was obviously a shortcoming of design. The second finding was that the liner had rips and tears in it and permitted liquid to seep into the insulation. (The New York Fire Department investigation revealed a ten foot three inch rip in the bottom of the tank.) This investigation was made after the fire which caused the roof to fall in, however, and it cannot be said with certainty that the crashing roof did not cause the rip (*Id.* at 755). It appeared that the fire itself was ignited by the workmen, either through using non-spark-proof equipment such as vacuum cleaners, or by violating the smoking rules and introducing cigarette lighters into the interior of the tank. This appears to have been a personnel training problem. FPC staff felt that the primary design deficiency was use of the laminated mylar-aluminum-dacron tank liner which was susceptible to operational damage and was flamable (as was the insulating material) contrary to specifications. It also appeared that the position of the leak could not be ascertained due to instrumentation malfunctions and the FPC was critical for the continued use of the tank with an unlocated liner leak. Computations showed that enough heavy hydrocarbons could have accumulated in the tank lining to combust and create an overpressure sufficient to "float" the tank dome and cause it to collapse into the tank structure (*Id.* 258-61, FPC Staff findings). The New York Fire Department during the investigation found no evidence of sabotage (*Id.* at 782) so the tragedy was effectively caused by the design calling for materials which are no longer used in LNG tanks and by human error in violating rules concerning maintenance procedures.

As with the prior tragedy, construction and engineering techniques were thereafter improved and a better understanding of the hazards was gained. Meanwhile, abroad, Gazocean was designing and building LNG carriers for trans-Mediterranean carriage of LNG from Algeria to Europe. The vessels were small at first and employed quite a variety of tank designs (*see* Chapter 1, Specific Technology of Liquified Natural Gas, *Ocean Carriage, infra*). Liquefied propane gas with its much higher boiling point)-42.07° C. at atmospheric pressure) had been carried in pressurized or refrigerated tanks for some years. Some LPG carriers were used to carry LNG when properly refrigerated. As larger quantities were transported, however, the designs that emerged stressed insulated tanks which neither pressurized nor refrigerated the cargo, but simply tried to minimize heat gain (and consequent vaporization) to the already liquefied cargo which was loaded at cryogenic temperatures.

SPECIFIC TECHNOLOGY OF LIQUEFIED NATURAL GAS

This section will discuss in a non-technical manner the engineering or construction principles involved in each of the major steps in the LNG cycle and will give selective descriptions of specific installations as background for more technical discussions later in this paper.

LIQUEFACTION

Although natural gas is compressed during the liquefaction it is stored and transported at pressures equal to or only slightly greater than normal atmospheric pressure thus eliminating an additional source of stress on storage tanks or ships' cargo tanks. The boiling point (liquefaction temperature) of natural gas at atmospheric pressure is approximately -260° Farenheit. The gas dynamics process by which this temperature and pressure reduction is achieved is referred to as "throttling". This process employs a "Joule-Thomson" expansion. In this process, if the temperature and pressures are properly adjusted, energetic gas is caused to speed up through a narrowed aperature thus lowering its pressure. Its kinetic energy is eventually dissipated in the turbulent flow on the downstream side of the constriction but at lower velocities the gas has expanded without doing any significant work (friction heat buildup and gas compression can be ignored in a pipeline expansion process). As a result of this dissipation of energy the temperature of the gas is reduced on the downstream side of the valve. If the gas is initially cool enough, the expansion will reduce it below the boiling point and cause it to condense into a liquid. If the condensation is not complete and a vapor phase exists it can be recycled through successive compression-expansion cycles until it is all liquefied.

The more sophisticated process used in liquefaction plants is referred to as the auto-refrigerated cascade cycle. In this process natural gas is introduced after compression to 560 lbs. per square inch atmospheric at approximately 68° Farenheit. It flows directly through a heat exchange tower which is cooled by a refrigerant and emerges at the far end of the tower to a Joule-Thompson valve. It arrives at the valve in a pre-cooled condition and after expansion, emerges for transfer to storage tanks at 14.7 PSIA and a temperature of -258.5° Farenheit. The refrigerant employed may be methane or may be other refrigerants such as ethylene. In any event, this refrigerant is run through a bank of parallel compressors and then is cooled through Joule-Thompson expansion valves and through the heat exchanger four different times before it is finally withdrawn in pure vapor form and sent back to the compressors. Although the ratio of work input to the compressors to the mass of liquefied fluid extracted is somewhat worse than alternative systems, factors of flexibility, maintenance efficiency, control simplification and materials costs make the auto-refrigerated process the most attractive (Trident Engineering Associates, Inc., Maritime LNG Manual (National Maritime Research Center July 1974)).

OCEAN CARRIAGE

As of 1974 there were some 327 liquefied gas carriers of under 20,000 cubic meter capacity. All of these vessels utilized pressurized or refrigerated tanks. The cargoes of most of these vessels was propane. This gas with a liquid density of .6 compared to LNG's density of .49 can be more economically transported in small volumes. Also its much higher boiling point makes it economical to refrigerate during transit. Moreover Coast Guard requirements preclude using propane boil-off as boiler fuel. Finally, the smaller tank size allows greater assurance of tank integrity under pressurization. By January of 1974 there were five LNG carriers of the insulated tank design between 60,000 and 100,000 cubic meters with five more on order and thirty-three such vessels on order with capacities in excess of 100,000 cubic meters (Liquid Gas Carrier Register for 1974 (H. Clarkson & Co. Ltd. London) reprinted in Review of Marine Transport, 1974 (UNCTAD TD/B/C.4/125/supp.1)). As late as 1972 there were only eight LNG carriers of over 40,000 cubic meter capacity. (Latham, "Liquified Natural Gas--A Survey", Table 1, reprinted from Swenson, "LNG--A Road to Progress" (API 1972) *see* Appendix, Exh. 1). In 1974 twenty-four LNG carriers were completed, the largest of which was an 87,000 cubic meter ship built in Norway. The leading countries in terms of tons built were France and Norway (Lloyds Register of Shipping, Statistical Tables 1974). In terms of registration, the United Kingdom had thirty liquefied gas carriers under its flag totalling nearly 703,000 gross tons. Japan had 145 such vessels totalling 583,450 gross tons. Liberia, a flag of convenience, showed thirty registrations totalling 433,958 gross tons. Norway had forty-five vessels of 359,668 gross tons and Panama, another flag of convenience, had twenty vessels with 215,665 gross tons. Not all of these ships are suitable for LNG, however. As of 1975, the United States had only one registered vessel designed for LNG (Lloyds Register of Shipping, Statistical Table No. 2, 1975). General Dynamics has twelve ships under contract, five of which are designed for the Algeria-to-United States trade and seven of which are for Indonesia-to-Japan trade routes. Avondale is building ships using the Conch tank design, while the ships designed and built by Newport News shipyards will utilize membrane tanks made of stainless nickel steel. Sun Shipbuilding is also negotiating to build three ships for trans-Pacific routes and there is a probability that at least seven ships for foreign-to-foreign (non-subsidized) trade routes will be built in U.S. yards.

The most distinctive part of the LNG carrier design is the cargo tank configuration. There are at least eight viable tank designs although not all of them have been utilized in actual construction. In general, these designs may be further divided into two categories; free-standing tanks and membrane tanks. The former, as the name implies, are not in direct contact with the ship's hull. The latter assume a configuration that follows a cross-section of the hull. Other designs, as yet untried in actual application, involve semi-membrane tanks and modular tube tanks.

The Chicago Bridge & Iron Co. of Oak Brook, Illinois, has designed a spherical tank using thirty-six columns for support. The columns are seated in resin-impregnated beechwood keyways positioned a few feet beneath the sphere's equator. The bases of the columns are connected to the hull by means of an insulated hold-down device. The columns are sprung outward at ambient temperatures. Thus when cargo causes the sphere to contract the columns return to vertical to ensure compression loading and to minimize bending moments. (Todd Research & Technical Div., LNG Tank Designs 3-29 through 3-31 (National Maritime Research Center 1972). See Appendix, Exh. 36 for a depiction of this design.) There are no shipboard applications of this design known to this investigator.

The Columbia Gas System Service Corp. of Wilmington, Delaware has developed an integral (with the ship's hull) tank. The design calls for closed-cell polyurethane insulation confined in hexagonal "honeycombs" made of phenolic-impregnated fibreglass. A polyurethane elastomer barrier applied to the inboard surface of the insulation provides the only liquid-vapor barrier required. Thermal contraction problems are minimal and the elasticity of the materials is felt to allow flexing under dynamic sea loading of the hull (*Id.* 3-43 through 3-46). There are no applications known to this investigator.

Martin-Marietta Corp. of Denver, Colorado has concentrated its design effort on the "bleed and vaporize" or "wet" insulation concept. A cellular mylar insulation is used without an internal barrier other than a thin stabilizing film which is permeable. The LNG seeps through the film, then vaporizes inside the cells to create a vapor insulator. The system is conceived for use on spherical as well as prismatic free-standing tanks. This design could be important in eliminating the need for the huge steel sea covers presently required for the above-deck protection of spherical tanks from wave damage since the insulation is internal rather than external (*See*, *Id.* 3-48, 3-50 and 3-51). But to the extent that aluminum tanks must be protected from fire, the tank covers may prove to be necessary in any event.

Free-standing tanks may be spherical such as the Kvaerner-Moss design employed on the Norman Lady and the Technigaz design. Free-standing tanks may also be of prismatic configuration such as the Conch design utilized on the Methane Princess (27,400 cubic meter capacity ship). Tanks in the shape of vertical cylinders were used under the Gaz de France design installed on the Jules Verne (25,500 cubic meters). The Exxon free-standing tank was utilized on the 40,000 cubic meter Esso fleet owned by Prora Transporti SPA (Latham, Table 1 *supra*). Sophisticated (Invar) (36% nickel-iron alloy) membrane tanks designed by Gaz-Transport were utilized on the Polar Alaska and the Arctic Tokyo, both 71,500 cubic meter vessels built in Norway. (*See generally*, Thomas, "LNG Vessel Design and Operating Experience",Conference Proceedings on LNG Importation and Safety (National Academy of Sciences June 13, 1972.)) *See* Appendix, Exh. 30 & 35.

The Bridgestone Liquefied Gas Co. of Japan utilizes a semi-membrane tank configuration wherein the membrane "floats" almost completely free from the insulation on the inner hull. The tank is attached to the hull only at the tank dome by a complex "hanger" device and maintains its shape by a constant positive pressure supplied from a rubber "breathing" reservoir. The tank (primary barrier) may be either stainless steel or a nickel steel and the insulation is faced with a phenolic resin-saturated plywood secondary barrier coated with epoxy. The design has been successfully used in relatively small liquid propane carriers and its application to LNG carriers is being considered (*see* LNG Tank Designs *supra* at 3-41 through 3-43).

All of the tanks, of course, must be insulated and polyvinyl chloride foam (Klegecell) and perlite are commonly used. Membrane tanks, because they are closer to the ship's hull, are more vulnerable to collisions, and maintaining the secondary vapor barrier is more difficult because of its inaccessibility. It is possible also that the dynamics of sloshing in membrane tanks present greater stress problems. Not only is the insulation crucial to maintain the cryogenic temperature necessary to prevent the cargo from boiling, but it is also vital to protect the steel used in the hull of the ship from becoming so cold that it becomes brittle and fractures under the operational stresses of the sea. Fiberglass and polyurethane foam in addition to Klegecell can be used for insulation and balsa wood has been used to cushion the tanks and allow for differential thermal expansion where secondary membranes surround the inner tank. Membrane ships are designed with a secondary barrier for protection in the event of failure or cracking of the inner tank. Most tanks are made of 5083 aluminum.

Independent tanks are thought to be economically more efficient than membrane tanks in the long run. Their insulation efficiency is superior and boil-off proceeds at a lower rate during the voyage. Of course, boil-off can be used in dual fuel power plants as a substitute for bunker C, but it is presently more profitable to deliver it as cargo so there is some economic loss for excessive boil-off. Membrane tanks on the other hand, using such a thin Invar layer, readily cool down whereas the massive metal primary barrier of the independent tanks must be cooled more slowly to avoid thermal stresses. Independent tank designs such as the Conch and the Moss-Rosenberg spherical carry a "heel" that is a residue of the LNG cargo in each tank to maintain temperatures at no higher than -240° Farenheit during the ballast voyage. Membrane tanks by comparison need only carry a heel in one tank and are able to use this to spray all the tanks for forty-eight hours before loading. Since most of the heel in independent tanks boils off in the course of the ballast voyage cooling process, this tends to be a cost of operation (some officials in the industry maintain that most of the heel is preserved and is thus a one-time cost). In any event, operators of spherical tank vessels must purchase an additional quantity of LNG which does in fact boil off to make the final reduction in temperature from -240° Farenheit to -255° Farenheit. Using a voyage from Arzew, Algeria to Cove Point, Maryland (3670 nautical miles each way) and assuming that bunker C costs $3 a barrel and that the price of energy from natural gas CIF is $.75 per million BTU's (per thousand cubic feet) it can be shown that a Conch independent tank vessel will net over $57,000 per year more than a membrane tank LNG carrier. (*See* R. Wooler, MARINE TRANSPORTATION OF LNG AND RELATED PRODUCTS 57-61 (1975)).

The spherical tanks in the Moss-Rosenberg system incorporated in Norwegian-built vessels, and being installed on the General Dynamics built ships in the United States do not require secondary membranes as their material strength can be more easily computed by engineering analysis and mathematical simulations. Spherical tanks can be computed to develop small cracks a substantial time in advance of tank rupture. Even these negligible cracks are not predicted to occur within the operational lifetime of the vessel. Spherical tanks are in the free-standing category and the tremendous weight of the tank and its enclosed cargo are transferred to the ship's hull by means of an equatorial "skirt". This skirt is forty feet high and has insulation over the upper twelve feet of its height. The weight is transferred from the tank to the skirt to the skirt table and hence widely throughout the hull. Spherical tanks extend far above the weather deck of the vessel and are typically enclosed by regular steel hemispheres to protect them from the battering of the seas and undue thermal radiation. The spherical tanks themselves are insulated by seven layers of one mil thick aluminum foil, four layers of two inch polyurethane foam and an outer layer of hypalon rubber 50-60 mils thick.

Improvements that may be forthcoming on third generation LNG carriers might include a telescoping or "stacking" of spheres in spherical tank design ships, the deletion or reduction in thickness of the mild steel tank covers (domes) on those designs (particularly spherical tanks) which protrude above the weatherdeck. (Booz-Allen *supra* at VIII-6 through VIII-7). Other concepts rated superior by the Booz-Allen panel of experts which may receive further design and development attention in the near future (but which so far have not established appeal in the market) are multiple vertical cylinders for tanks and internal polyurethane-based insulation. (*Id.* at IX-17). Since the peak demand for LNG ships will be in the 1980's, there is scarcely time for extended developmental programs. It seems likely that the ships will be ordered and built almost immediately in order to provide the necessary return on investment. The same concern would apply to the U.S. Maritime Administration's funding of developmental programs since the U.S.-flag fleet will not likely exceed forty-nine ships (with a few more ships used for foreign trade becoming incidental beneficiaries of government sponsored research). (*See Id.* at II-22).

The insulated catch basin underneath the spherical tank is capable of containing the amount of cargo that would leak from a crack in the spherical tank over a period of fifteen days (predicated on a hypothetical crack that would propogate to a length of three and one quarter inches after fifteen days). Leaks are channeled to the catch basin through splash barriers or spray shields which surround the tank. Drainage piping is made of stainless steel and the catch basin itself which is ordinary hull steel is covered with polyvinyl chloride closed-cell foam 1 1/2" thick bonded into a continuous blanket (Abstract Specification for 125,000 meter LNG Ship with Reliability and Safety Highlights, 20-21 (General Dynamics Quincy Ship Building Division Rev. July 1974)). The PVC foam is self extinguishing and will not contribute to flamability should an ignition source be close by.

Hull steel has varying properties but is designed to withstand brittle fracture at a steady state temperature distribution for ambient conditions of 0° Farenheit in the air and 32° Farenheit in the water with the air moving at 5 knots. All of this assumes of course that the spherical tanks contain LNG at cryogenic temperatures (-260° F.). (*Id.* at 11).

Using the General Dynamics spherical tank LNG carrier as an illustration (*See* Appendix, Exh. 2), some of the general specifications are worth noting. These 125,000 cubic meter ships are 936' long, have a beam of 143', have a height of 82' and when fully loaded are designed to draw 36' of water. The maximum continuous shaft horsepower is 43,000, the deadweight is 63,600 long tons, and the oil-burning cruising radius is approximately 10,000 nautical miles. The vessels are designed to cruise at twenty knots (*Id.* at 1). There are two submerged vertical cargo pumps in each tank and when operating simultaneously they could unload the entire ship in twelve hours. Each pump is powered by a 300 horsepower electric motor and has a capacity of over 4,600 gallons per minute. The ships are single screw and have a rudder ratio of 0.0174. Boilers are manufactured by Foster-Wheeler Corp. The propulsion turbine is manufactured by General Electric. A 2,200 horsepower Bird-Johnson bow thruster, with variable pitch is installed in the bow.

The ten centimeter radar is equipped with true motion display and early warning alarm for preset proximities. The three centimeter radar has a relative motion display. This ship is also equipped with a Raytheon Doppler log system which provides true speed and distance travelled determined by bottom tracking. In deep water, the system provides relative speed from water scatter. The vessels will be equipped with a Sperry Marine collision avoidance and satellite navigation system. This system is capable of providing very accurate positional data and can simulate course projections and track and plot up to 20 targets simultaneously. Passive U-tube stabilizing tanks are used to reduce amplitudes of roll. The cargo tanks were built to withstand sloshing stresses. Cargo piping is stainless steel outside the tanks and aluminum inside the tanks. The tanks themselves are made of 5083-0 aluminum and have been designed to safely withstand the most probable maximum load combination in a North Atlantic sea spectrum. In addition to bearing the weight of the enclosed cargo, the tanks must respond satisfactorily to stresses and dynamic bending moments generated by hull deformations while the vessel itself plows through the sea.

In terms of stability, the General Dynamics designers have computed that the vessels can survive damage at least to the extent that an open hole forty-six feet in length, twenty-nine feet in depth (*i.e.*, penetration) and running from baseline to main deck will not sink the ship. This survival capability is a Coast Guard requirement (*See* IMCO Gas Code, Ch. II *infra*). The vessels have a complete double hull and, using an analysis developed for setting safety factors involving collisions of nuclear powered ships, it is computed that a 38,000 ton tanker ramming the LNG carrier at right angles would have to have an average velocity of 8.3 knots in order to penetrate to the tank boundary. If the right angle impact were to be at the center line of the tank, the velocity would only need to be 4.2 knots, but if it were the furthest from the tank, that is, in the location of the transverse bulk head between tanks, it would have to be 18.5 knots. It is felt that the spherical tanks can withstand rupture better than the prismatic or membrane tanks (*Id.* at 12).

LNG carriers presently being built are of double hull construction. While this offers increased protection against cargo tank rupture from rammings, strandings and collisions, the double hull should not be confused with the double bottoms which have been the subject of an extensive debate in the Intergovernmental Maritime Consultative Organization (IMCO) with regard to crude oil tankers. In the latter case, the double bottom spaces are to be used for sea water ballast *only* and thus represent an anti-pollution measure. The purpose in LNG carriers, on the other hand, is a combination of safety and functional need. The inter-hull spaces may be filled with sea water ballast in part, but they may also house fuel tanks for the ship's engines. In short, they are not designed to comply with or for the same purpose as the proposed IMCO requirement of double bottoms on oil tankers.

With regard to propulsion the ship can burn both bunker C and boil-off vapors from the cargo tanks. This is the so-called dual fuel system that is employed on all LNG carriers currently being constructed. If excess vapors are being generated for any reason, provision is made to dump steam to the main condenser rather than vent the vapor to the air. If the vapor cannot be used as fuel in the boilers, tanks may be isolated and the pressure may be allowed to increase for the course of a voyage. Atmospheric venting is also possible in an emergency at locations safely remote from ignition sources. During the course of a typical voyage some 7% of the LNG cargo boils off. Third generation ships may have on-board reliquefaction plants utilizing on-board production of liquid nitrogen as a refrigerant. The saving in LNG, with the ability to sell up to an additional 7% of the BTU value of the cargo could, in certain gas-oil price structures, make this system economically attractive for large ships (Trident Engineering Associates, Inc., Maritime LNG manual 103-108 (National Maritime Research Center, July 1974)). A General Dynamics official contends that the boil-off rate used in this projection is higher than can be expected on the typical voyage. (Telephone interview with Bennett Holt, Nov. 5, 1976.) There is redundancy in the sense that either boiler is capable of single operation. All major main propulsion systems have machinery backup and there are three ship service electrical generators, any one of which can supply all normal loads while at sea. One of the three generators is an automatically starting diesel which can load-share in parallel in the event that the other generators become 80% loaded. There is also an emergency generator (250 kilowatt) which is capable of handling the navigation, communication, emergency lighting, fire pump and personnel elevator power needs. This is located outside of the engine room. (*Id.* at 17).

In terms of control of gaseous cargo and leaks of LNG, each tank has three capacitance probes and one float gauge to determine the LNG level within the tank. Each tank contains two safety relief valves to vent to the atmosphere. The buildup of gaseous methane atmospheres on the ship is prevented by maintaining positive pressures between cargo tanks and the atmosphere by use of the gas compressor control system. Similarly a hold-to-atmosphere positive pressure differential is maintained by the nitrogen makeup system (essentially an inert atmosphere in the non-tank hold spaces). Each tank is provided with pressure transducers with low and high level alarm triggers. Similar transducers are provided in each hold area. All valves can be remotely controlled from the cargo control room on cargo and vapor lines. Emergency quick closing valves operate automatically on signals from the cargo control room, the wheelhouse, and stations forward and aft of the cargo tank area. On shore-connection valves and the gas-to-engine-room valve there are fusable elements which will cause the valves to close in case of fire. A methane detection system based on the infra-red absorption technique analyzes samples taken from twenty-seven locations on the ship. The analysis is repeated for each station every thirty minutes. Alarms will sound when the analysis shows methane concentrations of 20% or more of the lower flamable limit. Tank temperatures are measured top and bottom by resistance temperature detectors. Nitrogen (for inerting or purging) is carried on board in a liquid nitrogen storage tank and can also be produced by a 4,500 cubic feet per minute gas generator (*Id.* at 3, 20-23).

Fire supression is accomplished by three independent systems. A sea-water fire main system utilizes two 1,100 gallon per minute centrifugal pumps located at opposite ends of the ship and draws through separate sea chests. The second system is a CO^2 system for the engine room, the ballast pump room, the emergency diesel generator, the paint room and the forward pump room. For LNG fires, the third system is a dry powder system using potassium bicarbonate as the extinguishing agent and propelled through hoses and nozzles by pressurized nitrogen. A combination of hose stations and fixed monitors (capable of remote control) can reach any area on the cargo deck. The monitor nozzle has a range of 100' and a sufficient discharge rate to extinguish a 60' diameter LNG fire within 10 seconds (*Id.* at 14). The ship design also calls for a water spray system to cover the fore and aft cargo piping, crossover piping, the deckhouse, compressor room and cargo control room to prevent overheating. The spray system utilizes 355 variously sized and located nozzles to accomplish the required coverage. A water curtain system operating off the main fire fighting system directs spray over the deck and side of the vessel in the vicinity of the cargo loading-unloading area to protect the ship's hull during loading or discharge operations from any LNG which might be spilled.

The 125,000 cubic meter General Dynamics ships have a crash stop distance of 7,000 feet and a turning diameter of 2,300 feet. Estimates for projected 165,000 meter LNG carriers indicate a crash stop distance of 10,270 feet and a turning diameter of 2,500 feet.

SHORESIDE STORAGE AND DISCHARGE OF SHIP

LNG terminals will necessarily have to be on or near the waterfront with minimum water depths at the pier ranging from thirty-eight to fifty feet at mean low-low water (deeper depths are of course acceptable). Fifty feet is considered a minimum depth for the third generation 165,000 cubic meter vessels, especially if the berthing area is exposed to wave action. Ships discharge via cryogenically insulated pipelines to shoreside storage tanks which contain the LNG until it is transferred out. *See* Appendix, Exh. 37 for a listing of LNG receiving terminals.

Piping from the pier is typically stainless steel inside, with aluminum outer shielding, covered in turn by at least two inches of fiberglass insulation. Pipes may vary in diameter and length according to the volumes to be transferred and the distances covered. Because of the temperature extremes, special allowances must be made for contraction at cryogenic temperatures. Hand tools used for work in a terminal facility are usually made of berylium, bronze, aluminum or some other spark proof alloy, although, if the lines are purged, conventional tools are acceptable. All electrical tools must be grounded.

The majority of the LNG will be vaporized and introduced into high pressure pipeline distribution systems. Such systems will often be owned by entities other than the entity owning and operating the terminal. Thoughput for the tanks may take place within a matter of days, or at most weeks. The tanks themselves are double walled, and in most cases are constructed out of 9% nickel steel (one notable exception is the Phillips/Marathon Oil tank in Kenai, Alaska, which is constructed of aluminum and has a 675,000 barrel capacity). There is a resilient blanket on the side of the inner wall facing the anular insulated space. This blanket is typically made of fiberglass. The remainder of the three foot wide anular space is filled with loosely packed perlite as an insulating material. The outer walls are constructed of mild steel and the tank structure is in turn surrounded by a dike sufficient to contain the entire contents of the tanks if spilled. In addition to input pipes for delivering LNG there are vapor withdrawal pipes and relief valves for emergency relief of overpressure. *See* Appendix, Exh. 3 and 4.

Precautions built into the design of the terminal for Distrigas of Massachusetts Corp. located in Everett, Massachusetts, include a depressed area for loading tank trucks sufficient in volume to contain the entire volume of a 12,000 gallon tank truck. Crude dikes also border the pipeway running from storage tanks to pier. The large dikes surrounding the storage tanks (capacities of 374,000 barrels and 600,000 barrels respectively) and a vapor barrier fence serve to constrain any heavier-than-air vapor clouds that might be generated in the course of a spill. Fire fighting equipment (mobile and fixed powder projectors and a Halon system) is located at strategic points throughout the property. Automatically activated high expansion foam systems will protect pipeways at Northwest Natural Gas' proposed LNG facility at Newport, Oregon. (Witt, Wicks & Olleman, "Evaluation of LNG Transport and Storage Hazards" 7 (Ore.St.Univ. unpublished 1974)).

Some of the vapor which boils off from the LNG inside the storage tanks is withdrawn and used to power the compressor (which requires about 8% of the total boil-off). Of the remainder, about half is sent into the distribution system in gaseous form and the other half is reliquefied and returned to the tank. Typically the boil-off gas which is sold to the pipeline is nitrogen rich and therefore too "lean" in methane to be acceptable so it is enriched by vaporized LNG drawn from the bottom of the tank.

The Staten Island LNG facility formerly owned by Distrigas and presently co-owned and operated by Eastcogas consists of two 900,000 barrel tanks. Each tank is built of carbon steel and pre-stressed concrete, compression being by circumferential wrapping with solid strand wire covered with gunnite cement. The double floor uses stainless steel and 9% nickel steel with insulation in between. The anular space between the inner and the outer tank is filled with perlite. An eight and one-half foot thick reinforced concrete berm rises to the full height of the tank and is concentric inside the outer concrete wall (Conference on LNG *supra* at 198-199). Thus the berm not only acts as a device for capturing LNG that leaks from the tank, but also serves as a radiation barrier in the case of fire, as a de facto third shell to the tank for crash worthiness as to external impacts, and serves to drastically limit the surface area of any pool of escaped LNG compared to more conventional diking.

At Distrigas' Everett facility specified procedures must be carefully followed in discharging cargo. First, the unloading manifolds on the ship and unloading arms to the shore must be inerted with nitrogen gas and cooled down to prevent flash vaporization of the LNG as it enters the unloading lines. "Geyser" boiling in the vertical risers feeding LNG storage tanks and "bubble" formation and collapse in LNG transfer pipes must be guarded against to avoid atmospheric venting and fluid hammer respectively. (Grobe, "Characteristics and Operational Aspects of LNG Terminals" 22 (unpublished 1975)). All monitoring devices should be checked for safe operation. During the discharging process it is necessary to send vapor from the storage tank to the ship's cargo tanks. *See* Appendix, Exh. 14. In part this is necessary because the volume of LNG introduced into the tank will displace an equal volume of vapor which must then be sent somewhere. More importantly, it is necessary to prevent a low pressure situation from arising in the ship's cargo tank. Carried to extreme, it could cause atmospheric pressure to collapse the tank inward. But even short of that, it creates a suction effect tending to retain the LNG in the tank and causing the pumps to overwork or partially cavitate.

Even before the ship's manifold valves are open, a pump should be started up to maximum pressure to enable a leak inspection to be effective. Assuming no leaks are found in the piping or manifold and that the terminal operator confirms the terminal is ready to receive cargo, pumping can commence. For the first twenty minutes there may not be any vapor coming from the terminal and pumps will be operating at reduced power during this cooldown period. With two pumps per tank it is unlikely that there will be a total pump failure, but if such did occur, spherical tanks can be emptied by pressurizing the tank with inert gas and literally forcing out the LNG cargo (LNG Manual *supra* at 137). If the ship's tanks are equipped with an eductor system, the vessel can leave the dock and transfer cargo from the tank with the disabled pumps to one with operable pumps and then return to the pier to complete its discharge.

Approximately 5% of the cargo is left in each tank and this is referred to as the "heel". It remains on the ship during the ballast voyage in order to maintain the tanks at near cryogenic temperatures. The heel is often circulated by means of a pumping system which takes it up to a spray jet near the top of the tank and lets it spray out and run to the bottom. One reason the on-board reliquefaction plants are attractive in the third generation LNG carriers is that sufficient nitrogen would be manufactured by this process to use it for tank cooling to eliminate the need for any heel and all of the cargo could be sold. This saving must not be misconstrued, however, as much of it is a one time cost to the importer (providing it has a long term carriage contract with the owner of the LNG carrier). That is to say, the heel is purchased one time and thereafter remains in the ship and at the end of the contract could be claimed by the importer. Moreover, vapors boiling off of the heel can be used in the dual fuel system so when the heel is eliminated fuel oil costs will increase commensurately. For a more detailed discussion of tank cooling costs *see* Chapter I, Specific Technology of Liquefied Natural Gas, *Ocean Carriage*, *supra*.

VAPORIZATION

Vaporizers are essentially devices to boil the liquid natural gas by introducing heat and then to superheat the vapor to acceptable pipeline temperatures. Compressors are also utilized to achieve the necessary pipeline input pressure. There are four categories of vaporizors presently employed at LNG terminals. Integral heated vaporizers, sometimes called direct flame vaporizers, have a combustion source directly in the vaporizer, operating on the pipes of LNG. The second category is remotely heated vaporizers which use a heat exchanger and a circulating intermediate fluid to transfer heat from the primary heat source to the LNG via the heat exchanger. The third category are called ambient vaporizers and typically use sea water as a bath through which the pipes of LNG flow. The fourth type are process heated vaporizers which derive heat from LNG processes themselves (Anderson and Daniels, *LNG Terminals: Existing and Proposed Systems Compared*, Pipeline and Gas Journal 44, 66 (Sept. 1975)).

PENDING PROJECTS

Existing LNG trade routes primarily involve Algeria and Libya exporting to European countries, Brunei and Alaska exporting to Japan and one relatively low volume contract from Algeria to Distrigas of Massachusetts. All of these trades are predicated on long term contracts ranging from fifteen to twenty years. (Anderson and Daniels, *LNG: A Key Energy Supply Source with Big Problems*, Pipeline Industry 35 (May, 1976)). Other LNG transactions which are the subject of executory contracts involve Indonesia (Pertamina) and Japan, a twenty year contract starting in 1977 and calling for delivery of one million cubic feet per day (gaseous volume); Algeria (Sonatrach) and the United States, delivery to El Paso Natural Gas consortium operated by Columbia LNG Corp. at Cove Pt., Maryland with twenty year duration at a delivery rate of 1 BCF per day; Algeria (Sonatrach) and United States, delivery to Eascogas LNG Inc. at Staten Island, New York, and Providence, Rhode Island starting in 1977 for twenty-two year term eventually reaching a rate of 600 million cubic feet per day; Sonatrach to Spain starting in 1979 for 436 BCF per day; and Sonatrach to Distrigas in Boston starting in 1977 for twenty years at 61 BCF per day (*Id.* at 36).

It is reported that LNG imports accounted for 78% of Japan's natural gas supply in 1975, and less than 2/100ths of 1% of the United States' supply and only 4.7% of western Europe's supply (*Id.*). If the high range of projections for forecasted imports to the United States materializes in the year 1985, the percentage would be between 7% and 8% of the total natural gas supplies in that year (*Id.*). *See generally*, Appendix, Exh. 5.

Projected LNG trades based on negotiations currently under way indicate the possibilities of large contracts calling for delivery beginning in the late 70's or early 80's from Algeria to the United States (Cove Pt., Maryland, Lake Charles, Louisiana); from Algeria to Canada (with 2/3 to 3/4 being delivered to the U.S. by gaseous pipeline after vaporization) for one BCF per day for twenty years starting in 1981 (Wall Street Journal, Oct. 5, 1976, p.9, col. 1); from Indonesia to the United States for twenty years at 550 million cubic feet per day (between Pertamina and Pacific Lighting International); from Nigeria to the United States calling for 650 million cubic feet per day under a twenty year contract beginning sometime in the 1980's; from Malaysia and Sarawak to Japan with an estimated daily rate of 750 million cubic feet per day. The Pacific Lighting International trade route from Indonesia projects a need for a fleet of nine 125,000 cubic meter LNG carriers. Three to be built by Newport News Shipyards, three to be built by Avondale Shipyards and three to be built by Gazocean and Gas Transco in Euripe (Pacific Indonesia Project DEIS 6 (FPC, May 1976)). These tankers would be operational 345 days per year and would require eighteen days to make the trans-Pacific voyage of 8,300 nautical miles (*Id.*).

Other possible trade routes would involve natural gas produced in the Cook Inlet area and exported from the Kenai Peninsula in Alaska to southern California and to Oregon. Pacific Alaska LNG Co. proposes to purchase and carry 400 million cubic feet per day to a terminal in Los Angeles (operated by Western LNG Terminal Co.) with possible initial delivery in mid-1979. Marathon Oil-Phillips, who are already exporting to Japan, had proposed to sell LNG to Northwest Natural Gas Co. of Oregon but the assertion of FPC jurisdiction caused the sellers to withdraw from the arrangement (*see* Chapter VII, § 7 Certification and § 4 Approval of Rates, *Jurisdictional Issues, infra*). It is possible that interest in this project will be rekindled in the future.

Other nations which could possibly begin exporting LNG are Iran, Quitar and Russia. Additional exports could be forthcoming from Abu-Dhabi to Japan and from Nigeria to and Algeria to the United States. In several of these cases future negotiations will be in abeyance pending the proving of adequate reserves to justify the contract.

Additionally, there are the proposals for delivering the natural gas produced on the North Slope of Alaska to the lower forty-eight states. There are two competing proposals for transporting this gas. Under one proposal it would travel by pipeline in gaseous form through Canada and would enter the United States at two points in Idaho and Montana as branch pipelines carried it to the west and east coast respectively. This is the so-called Arctic Gas Transmission System. The alternative proposal would pipe the gas roughly parallel to the trans-Alaska pipeline route through a liquefaction plant at Pt. Gravina and hence by LNG carrier to one of three terminal sites in southern California (Pt. Conception, Oxnard or Los Angeles). This route would involve eleven 165,000 cubic meter LNG carriers. *See* Appendix, Exh. 6.

LNG CARRIER FLEET PROJECTION

A synthesis of energy demand projections using 1973 and 1972 studies and combining them for an objective estimate indicated a peak natural gas demand of 34.29 quads (quadrillion BTU's) in 1985 tapering off to 27 quads in 1990 as nuclear power came on line. This projection was developed by using the Department of Interior's study for total energy demand, subtracting the National Petroleum Council's estimates of energy from coal, the Atomic Energy Commission's estimates of energy supplied by nuclear power and Interior's own estimates of the contributions from hydroelectric generation and oil-fired generators and steam turbines. (Booz-Allen Applied Research 1 ANALYSIS OF LNG MARINE TRANSPORTATION III-19 (MARAD November 1973)).

Various scenarios were considered by the Institute of Gas Technology, a Stanford Research Institute study and the National Petroleum Council with regard to the effect of potential off-shore gas field discoveries and the impact of deregulation of domestic wellhead prices insofar as increased supply was concerned. Deregulation turned out to be the determinative parameter. In the event total deregulation occurs, the two studies that dealt with this scenario projected increased discovery rates (NPC and SRI studies cited *Id.* at III-23). It is interesting to note that to maintain the existing reserve-to-production ratios much more new gas must be discovered and proven than is included in new production in any given year. At the present production rates approximately 22 TCF must be discovered (which is double the current rate of exploration) if gas production were to grow at a rate of 4.5% a year. It must be understood that most additional gas sales are "dedicated" under long-term supply contracts with an average duration of thirteen years which requires an addition of 13 TCF to reserves for every TCF of increased or additional sales in the immediate present. For any sort of reasonable growth projection exploration effort must be quadrupled over present efforts. There seems wide agreement that this is not likely to occur absent extensive deregulation (*Id.* at III-25 through III-27).

Given the fact that demand and production estimates (especially when production from the lower forty-eight states alone is considered) indicate there will be a shortfall, the question remains from where will the additional supplies come? Since most studies seem to agree that the peak demand for natural gas will be in the period 1985 to 1900 (*see* Booz-Allen, *supra*, at III-19 and III-28) Alaskan north slope gas is the most likely addition. The Booz-Allen study concluded that synthetic gas produced from coal with an average twenty-year selling price in 1972 dollars of from $.75 to $1.45 per million BTU at the plant gate is the next most likely source in the 1980's. Before 1980, LNG imported from abroad appears to be the most likely candidate. The difficulty with this, of course, is that LNG projects typically have a twenty-year duration. This factor could deter development of such projects altogether (*Id.* IV-4 through IV-10).

With regard to the demand for LNG carriers (assumed to be 125,000 cubic meter vessels)** high, medium and low estimates were developed by Booz-Allen from studies projecting demand, domestic production, and supplemental supply for the years 1975 through 1990. A modified Delphi approach was used to assign probabilities to high, medium and low projections for each of these components (*Id.* at IV-13). These in turn were matched against four possible import scenarios ranging from projects already underway or approved at one extreme through all projects including those which are purely speculative at the other extreme. Matching net demand to potential import scenarios a probabilistic projection of the number of ships required can be generated. Booz-Allen concluded that there was a 27% probability that no ships would be required but a 49% probability that 112 ships would be required. However, it also concluded that the demand projections were unrealistically high because of the assumption that natural gas would completely penetrate the boiler fuel market and supplant distillate and residual oil for that use, and because of the assumption that no efforts would be used to curb total national energy production. (*Id.* at IV-12 through IV-17). Again assigning subjective probabilities to the impact of regulatory restrictions through a Delphi procedure, it was felt that there was a 50% probability of eliminating gas as a boiler fuel, a 25% probability that an energy conservation program could achieve 10%-20% cutbacks, and a 15% probability of enforcing some national policy of energy independence (*Id.* at IV-24). Adjusting for these factors, Booz-Allen concluded that the probable fleet size would be bounded by a minimum of twenty-six and a maximum of forty-nine ships (*Id.* at IV-26).

In the three years since the Booz-Allen study was released, minimal progress has been made in firming up cost estimates on synthetic gas from coal. The price of petroleum distillate feedstocks such as naptha for syngas from oil have risen as a result of OPEC policies. Meanwhile, more and more LNG import proposals are being negotiated and submitted for FPC approval. Energy conservation efforts which reached their peak during the OPEC boycott appear to have been relaxed or disregarded by the consuming

** *See* p. 22 *infra*.

public. Shipyards are vigorously pressing marketing programs to build LNG carriers and the qualified compromise of the Booz-Allen projection appears realistic.*

THE PRESIDENT'S MESSAGE OF FEBRUARY 26, 1976 AND THE ENERGY RESOURCES COUNCIL TASK FORCE

In the President's February speech on energy he attempted to lay the groundwork for intensive study toward resolution of the possible conflicts in achieving two important goals: combating the energy shortage and implementing Project Independence. The key passages of his speech were as follows:

> "We expect imports of liquefied natural gas to grow in the next several years to supplement our declining domestic supply of natural gas. We must balance these supply needs against the risk of becoming overly dependent on any particular source of supply.
>
> "Recognizing these concerns, I have directed the Energy Resources Council to establish procedures for reviewing proposed contracts within the Executive Branch, balancing the need for supplies with the need to avoid excessive dependence, and encouraging new imports where this is appropriate. By 1985 we should be able to import one trillion cubic feet of LNG to help meet our needs without becoming overly dependent on foreign sources."

These comments caused great alarm in the natural gas industry, the shipbuilding industry and among the public utilities producing electrical power or distributing natural gas. It was generally felt in these industries that three to four TCF of annual LNG imports would be more appropriate to meet the projected demand. However, officials at the Institute of Gas Technology indicate that even high level forecasts for the year 1985 only exceed the Presidential target by about 20% rather than 300%. (Anderson & Daniels, *LNG: A Key Energy Supply Source with Big Problems*, Pipeline Industry (May, 1976)).

As a consequence of the Presidential directive, a Task Force established by the ERC has been intensively reviewing the various import proposals. To enable it to integrate its findings and reach conclusions, the Task Force has three main charges. First, it is to review present or pending projects. Second, it must look at the socio-political aspects of the exporting countries, including those countries with whom negotiations are underway, or those who have gas reserves who are potential gas exporters of the future. Third, it must study regional distribution patterns within the United States and the impact of LNG importations to coastal states coupled with the interconnection of interstate pipelines. Included in this would be a study of how curtailment and supply disruptions would impact on the various consumer classifications. Although working drafts of the Task Force's report are presently circulating, these are not releasable to the public or available to investigators and researchers. An interesting caveat to the Presidential statement can be found in the accompanying fact sheet where it is stated that the Task Force "will establish procedures for . . . possible reassessment of the target if deregulation is not achieved." Thus an apparent assumption of the Executive Branch is that further or complete deregulation of natural gas prices will be forthcoming in the near future. (For further discussion of this issue *see* Chapter VIII, Deregulation of Domestic Natural Gas *infra*.) Although the White House has subsequently attempted to downplay the suggestion that the one TCF figure was a "target", it appears at the least to be a policy guideline. Ignoring or overriding such a guideline will require either changed circumstances or well-documented justifications.

* A follow-up study done by MARAD's Office of Policy and Plans (N. Harllee, *U.S. Market for Liquid Natural Gas and LNG Tanker Fleet* (March 1975)) treated the Booz-Allen projections as possibly skewed toward lower figures since both domestic exploration and alternative fuel technology has lagged behind projections indicating less-than-anticipated substitution in supplies (compared to LNG). (*See generally*, Marcus, Offshore Liquefied Natural Gas Terminals, Progress Report #1 1-20 and 1-21 (MIT Center for Transportation Studies 1976) [hereinafter cited as "Marcus, *Offshore LNG*"]).

** Modeling done by Professor Marcus' group indicates that, at a 16% annual rate of return, a 282,000 m^3 ship could generate present worth capital savings of $340 million compared to a 125,000 m^3 ship. (Marcus, *supra* at 2-6, 2-12). Of course ship scale is only one parameter for overall logistical econometric modeling. (*See, e.g.*, Marcus, *supra* at 2-16 through 2-24). Larger ships with drafts of approximately fifty feet, even though more economical to build and operate, will require more dredging or offshore berthing arrangements, more storage capacity, greater costs for cryogenic piping, etc. Thus the progression toward larger ships is by no means assured.

structural and operational safety of LNG carriers

Although LNG presents a minimal environmental threat as a pollutant, it does have small but finite risks associated with its transport and storage. The chief hazard is fire. Property in the exact vicinity of a sustained LNG fire would either be consumed or damaged beyond repair. More distant structures could be ignited through heat radiation to the point where they would fuel themselves and spread as a conventional fire. Similarly, human beings and animals could suffer radiation burns which might or might not be lethal. Personnel who came in direct contact with LNG would suffer localized freezing which could be fatal. This is sometimes referred to as a cryogenic burn. Localized spills of LNG on conventional steel, such as might be used in the hull of a ship, can cause a drastic loss of ductility and strength and can result in brittle fractures if the metal is in any way stressed. This could lead to the disabling or breaking up of an LNG carrier. There is also the possibility that a dense, cold, heavier-than-air methane vapor cloud could displace enough oxygen to cause asphyxiation of anyone attempting to breath in the atmosphere. Asphyxiation can occur when the oxygen content is less than 10 mole %. (Maritime LNG Manual *supra* at 231.)

HISTORY OF THE DEVELOPMENT OF DESIGN AND OPERATIONAL STANDARDS

Although the United States Coast Guard has long been involved in operational safety standards, *e.g.*, hazardous cargo anchorages, petroleum discharge regulations, and crew testing and certification, for many years it was not directly involved with creating standards or structural requirements for ships. To the extent that structural requirements could be found in Coast Guard regulations, they generally required compliance with the construction standards of the non-governmental ship surveying organizations. Thus, American Bureau of Shipping for the United States vessels and foreign surveyors such as Lloyds or Norske Veritas for foreign vessels, tended to set construction standards. By the 1950's, substantial quantities of dangerous chemicals were moving in bulk over U.S. waterways and the Coast

Guard in 1957 published some tentative regulations concerning refrigerated gas carriers (Dickey & Luckritz, "U.S. Coast Guard Regulations and IMCO Recommendations for LNG Tankers" I. (U.S. Coast Guard 1974)). In 1961 a chlorine barge sunk in the Mississippi River with great potential for harm to the surrounding population if the tanks ruptured. In 1964 NASA requested the Coast Guard to certify the barges it was using to transport cryogenic cargoes of liquid oxygen and liquid hydrogen from New Orleans to Huntsville, Alabama in connection with its rocket program. (Liquefied Natural Gas, Views and Practices, Policy and Safety I-4 (U.S.C.G.-478, 1976)). In 1965 the Coast Guard instituted the first Letter of Compliance Program (46 CFR § 154) for vessels carrying hazardous cargoes. Under this program, any bulk chemical carrier, regardless of its flag of registry or country of construction was required to apply in advance for a letter of compliance before visiting U.S. ports (Dickey & Luckritz, *supra* at 7). (*See also* Appendix, Exh. 8.) In January of 1967, the United States requested the Intergovernmental Maritime Consultative Organization (IMCO) to assign a committee to prepare a set of international regulations controlling the construction of chemical bulk carriers. (C.G.-478 *supra* at I-2 through I-3). As a result of this request, the Maritime Safety Committee of IMCO established a Subcommittee on Ship Design and Equipment. This subcommittee did in fact produce the Code for the Construction and Equipment of Ships Carrying Dangerous Chemicals in Bulk which was adopted by the IMCO Assembly in October of 1971. The IMCO Bulk Chemical Carrier Code is in close harmony with the previously developed U.S. Coast Guard regulations on the same subject (U.S.C.G. -478 *supra* at I-4). At the same time, the Subcommittee was further charged with development of a separate code to cover carriage of hazardous gases compressed or liquefied in bulk. (IMCO Assembly Resolution A.212 (VII) October 12, 1971).

In the early 70's as concern increased over maritime pollution, the Coast Guard was given powers under the Water Quality Improvement Act of 1970 to board and inspect vessels, including foreign vessels, in U.S. navigable waters or the contiguous zone in the interest of the prevention of oil pollution (33 USCA § 1321(m) (1975 Supp.)). Under the same legislation, the President and the Secretary of Transportation delegated their powers to the Commandant of the Coast Guard to promulgate regulations governing the inspection of tankers in order to reduce the likelihood of discharges of oil (33 USCA § 1321(1) (1975 Supp.)). In the same legislation the Coast Guard was charged with producing a study on the control of hazardous polluting substances to be delivered to Congress. A study was in fact delivered via the President on March 16, 1971 (U.S.C.G. -478 *supra* at I-4). The Coast Guard had long been requiring various life saving, communications, and navigation equipment pursuant to statutory authority or the provisions of the Safety of Life at Sea Convention to which the United States is a Contracting State. *See, e.g.*, The Vessel Bridge to Bridge Communication Act, 33 USCA § 1201 *et seq.* (1975 Supp.). In 1972 the Ports and Waterways Safety Act (46 USCA § 391 (1975 Supp.)) authorized the Coast Guard to study the need for and to design and implement vessel traffic systems, to conduct shipboard inspections of maneuvering capabilities and to set minimum requirements for navigational equipment. (*See generally*, Swan, "An Analysis of Vessel Traffic Systems in Three West Coast Ports" (Ore.St.Univ. Sea Grant Prog. 1976)).

The Chemical Transportation Industry Advisory Committee (CTIAC) has assisted the Coast Guard in redrafting Part 38 (liquefied flamable gases) of Title 46 of the Code of Federal Regulations. Membership on CTIAC includes representatives of the Shipbuilders Council of America, the American Bureau of Shipping (a prominent hull surveying organization), the Society of Naval Architects and Marine Engineers (SNAME) and the American Gas Association to name only a few. Specific corporations such as Arco, Exxon, and J.J. Henry (ship design) also have representatives on CTIAC. (Dickey & Lucritz, *supra* at 4). Some may argue that having entities in the regulated industry participate in framing the regulations is inherently suspect and will lead to compromises on costly safety features. Nevertheless the practical experience of the Committee members is extremely valuable in identifying hazards and articulating feasible ways to eliminate or minimize them. Moreover it should be noted that (a) the Coast Guard retains the ultimate control over the content of the regulations as CTIAC is advisory only; (b) opportunities for public input exist through the hearing procedure; (c) the industry has extremely large investments to protect and is likely to be safety conscious simply from enlightened self-interest; (d) the IMCO Gas Code is quite stringent in its own right so American vessels and operators will have less reason to fear rate undercutting by operators with less expensive (less safe) vessels.

A further word about the letter of compliance program is deserved. The interim regulations for the issuance of letters of compliance are found in 46 CFR § 154 (1975). Initially, it is clear that LNG carriers are subject to the letter of compliance procedure

(36 CFR § 154.3(b)(1)(ii), (v) (1975)). The Coast Guard will be specifically interested in methane detectors and other alarms as well as the design and arrangement of cargo tanks, piping, and vent systems, and the suitability of electrical equipment (*Id.* at § 154.3(c)(1), (3),(6)). Before the vessel arrives in port a review is required of the ship's plans and specifications. At least two weeks prior to the actual arrival, the Coast Guard must be notified of the first American port to be entered. If the vessel passes the review to the satisfaction of the Coast Guard, she will be allowed to arrive at the port where she will be boarded before berthing for an on-board inspection. (*Id.* at § 154.4(b), (c)). The on-board inspection entails an examination of tanks, piping, machinery, alarms, fire fighting capability and a general assessment of vessel condition and personnel performance. (*Id.* at § 154.4(d)). The regulations state:

> "serious discrepancies such as those involving inoperative safety equipment, leaking cargo piping or non-explosion proof electrical installations may require immediate correction prior to cargo transfer operations. Minor discrepancies may not preclude permission to transfer cargo, but may require correction prior to a second call in a U.S. port, either on the initial voyage or on a subsequent voyage."

(*Id.* at § 154.4(d)(iv)). For subsequent visits of the vessel, it may be boarded at the harbor entrance and while en route to berth, underway tests and examinations of the fire fighting equipment, leak detectors, quick closing valves and other safety equipment may be conducted to assure that the vessel is being maintained close to the original standards upon which the letter of compliance was granted (*Id.* at § 154.4(d)(3)). Every two years the vessel will be reinspected for a renewal of the letter of compliance (*Id.* at § 154.4(d)(2)). Change of owner or registry will invalidate letters of compliance and must be reported to the Commandant of the Coast Guard to be followed by reinspection if a revised letter of compliance is desired. (*Id.* at § 154.4(f)).

If the foreign LNG carrier has been issued an IMCO certificate under the 1971 Bulk Chemical Code a full fledged review by U.S. Coast Guard officials may be avoided. The certificate must be issued by the country of registration or by a recognized classification society duly authorized by that country. If an LNG carrier has a valid certificate of fitness issued under the new IMCO Gas Code by the country of registration or by a recognized classification society duly authorized by that country, presentation of a copy of the certificate will obviate the need for full review (a detailed discussion of the new IMCO Gas Code and the areas in which U.S. structual requirements may differ follows in the next section). However, in anticipation of a possible emergency involving the ship in a U.S. port, certain plans and information in English must be submitted during the on-board examination. These include specifications for the cargo containment system, the general arrangement plan, a plan of the liquid and vapor cargo piping, a section plan midships, and the fire fighting and safety plan. Additionally, the vessel must carry on board in English (without necessarily surrendering it) a description and schematic arrangement for inerting cargo tanks, hold spaces, or intra barrier spaces; a description of tank gauging equipment; a description and instruction manual for calibration of the leak detecting equipment; a schematic plan showing the location of leak detectors and their sampling points; and a description of the provisions for cargo temperature and pressure control in compliance with Article 7.1 of the IMCO Gas Code. For a list of other safety regulations with which LNG activities must comply, *see* Appendix, Exh. 7.

Just how effective the letter of compliance on-board examination can be is open to some doubt. It is reported that on one of the early visits of the French LNG carrier *Descartes* to Boston, crew members had disguised leaks in the cargo tank membranes by purging the surrounding area with inert gas so that no alarms sounded on the monitors during the period they were being tested by the Coast Guard inspectors. (Ingram, "Peril of the Month: Gas Super-tankers," The Washington Monthly, 7, 11 (February 1973)). Another incident is reported concerning a small Norwegian LPG carrier in which gauges on the gas detector system were out of calibration and sounded alarms all the time, with the result that they had simply been turned off and ignored. (*Id.* at 12). Thus, short of requiring space-technology reliability, there will always be the human factor in maintaining safety equipment and in heeding its warnings and reacting properly when they are given.

In questioning the responsibility of foreign flying vessels and their crews, Weinberg says, "'flags of convenience' have led to much of the world's oil tonnage being carried on Liberian and Panamanian vessels--a pattern which LNG tankers continue to follow. In 1970 one-quarter of the entire world's tanker tonnage, and an even greater proportion of tankers under construction, were of Liberian registry."

(Weinberg, *Cargo of Fire: A Call for Stricter Regulation of LNG Shipment and Storage*, 4 FORDHAM URBAN L.J. 495 (1976)). While the statement about oil tankers is accurate as of 1975 only 13 1/2% of the LNG tonnage was registered Liberian with another 7% registered Panamanian. Although the trend still persists it does not reach the proportions applicable to crude oil carriers. Liberia is second in terms of gross registration and Panama is fifth behind Japan, Liberia, Norway, and France (Lloyd's Registry of Shipping, 1975 World Fleets).

In the same vein Weinberg suggests that "foreign flag vessels are always subject to inspection the first time they enter United States waters, and not afterwards." While it is true that plan review (in those instances where a certificate of fitness from IMCO is not available) is only undertaken at the initial visit, reexaminations are conducted bi-ennially. Alterations or modifications are required to be resubmitted for review and all vessels are subject to boardings and usually are boarded at the harbor entrance for underway tests and examinations of the fire-fighting equipment, leak detectors, quick-closing valves and language proficiency (*see* 46 CFR §154.4(a) - 4(d)(2)(i), and 154.4 (d)(3)).

IMCO STRUCTURAL REQUIREMENTS

In November of 1975 the Ninth Assembly of IMCO adopted the Code for the Construction of Equipment of Ships Carrying Liquefied Gases in Bulk [hereinafter Gas Code] (A.328 (IX)). This code applies to newly constructed vessels which are defined as those for which the building contract is placed after October 31, 1976 or the delivery of which is after June 30, 1980 and those which have undergone a major conversion with the same two triggering dates (IMCO Gas Code 1.2.2 (a)).

SALIENT FEATURES OF THE NEW CONSTRUCTION IMCO GAS CODE

An initial survey is required before new ships are put into service in order for the certificate of fitness to be issued. The surveyors must be satisfied that the structure, equipment, fittings, arrangements and materials comply with the Code. Subsequent to the initial survey, intermediate surveys, at intervals not to exceed thirty months, should ensure that safety equipment and pump and piping systems continue to comply with the Code and are in good working order. At longer intervals, not to exceed five years, periodic surveys must be held to ensure that structure, equipment, fittings, arrangements and materials remain in compliance with the Code. A certificate may be in the official language of the issuing country, but at least one copy of the certificate has to be translated into either English or French. Once issued, a certificate of fitness is to be "accepted" by other signatory countries "for all purposes" and "should be regarded as having the same force" as their own certificates. Significant alterations to the vessel can cause a certificate to become invalid as will a transfer of registration of the vessel (Gas Code §§ 1.1.5, 1.6.1, 1.6.6, 1.6.9 and 1.6.10). A specimen certificate is found in Appendix, Exh. 9.

Hull Configuration and Arrangements, Stability, and Survival Capability

The LNG carrier's heel at any stage of flooding shall not exceed 30°, and in the final stage of flooding the vessel must be capable of rolling 20° beyond its equilibrium position. The emergency power supply must be capable of operating at the final stage of flooding and the life saving devices must be capable of being operated from the lower side of the vessel at that time. (Gas Code 2.4.1). The waterline during such flooding should never be such as to permit downflooding to occur (*Id.*).

For purposes of these computations side damages are assumed to be inboard at right angles to the keel 1/5 of the beam or eleven and one-half meters whichever is less. The longitudinal extent of the damage is assumed to be 1/3 of the length of the vessel to the 2/3 power or fourteen and one-half meters, whichever is less. And the vertical extent is to be from the baseline of the damage upwards without limit. With regard to bottom damage, longitudinal damage is the same in the forward part of the ship, transverse damage is the beam of the ship divided by six, or ten meters, whichever is less in the forward part of the ship (or five meters in other parts) and the vertical extent of the damage is to be 1/15 of the beam or two meters, whichever is less (Gas Code 2.3.2).

The cargo tanks must be positioned in such a way that they will not be penetrated by the assumed bottom damage referred to above. The Code does permit the tank to be within 760 millimeters of the shell plating at other locations (Gas Code 2.6.1(b), 2.6.2) (*see* diagram in Appendix, Exh. 10). The Code requires that hold spaces be segregated from machinery and boiler spaces, from accomodation areas, from service and control spaces, and from water tanks, stores and chain lockers. For LNG ships with membrane tanks, double hulls are required (Gas Code 3.1.4). Piping may not penetrate accomodation, machinery, pump room, compressor or control station spaces, but may penetrate transverse coffer dams in the hold space (Gas Code 3.1.5). Gas-safe and gas-dangerous spaces are defined and entraces, ventilators, openings, etc., may not face the cargo area. In pump rooms and compressor rooms, through-bulkhead or through-deck fittings must have gas tight seals. Cargo control rooms must be gas-safe spaces above the weatherdeck and instrumentation should be by indirect reading systems if possible (Gas Code 3.3 and 3.4). Access to gas-dangerous zones in the cargo tank or hold area shall be through air locks and all access ways shall be of sufficient dimension to allow the evacuation of unconscious personnel by other personnel wearing breathing apparatus (Gas Code 3.5.3 and 3.6). Detailed provisions for the types of materials used in hull and tank construction depending on location, function and operating temperature are found in Chapter 6 of the Gas Code along with procedures for testing welds, material quality and production competency. *See* Appendix, Exh. 11.

Cargo Tanks

The Code classifies cargo tanks as either integral or membrane or semi-membrane or independent. Independent tanks are further divided into types A, B and C. Type A tanks are designed by classical ship structural procedures and are constructed of plane surfaces. Type B tanks are designed using refined analytical tools and methods. The Moss-Rosenburg spherical tanks are type B independent tanks. Type C tanks are designed according to pressure vessel criteria. (Gas Code 4.21 - 4.24). All tanks and their supports and fixtures should be designed to withstand the expectable combinations of loading from internal pressure, external pressure, ship motion (dynamic loads), thermal loads, sloshing loads, hull deflection stresses and gravity loads. It is unlikely that LNG carriers would employ integral tanks since these are generally limited to temperatures more than -10° Centigrade. Independent type C and type B tanks are generally restricted to a maximum design vapor pressure of 0.25 kp/cm^2 (Lakey, New IMCO Code, reprint of a paper given at the 63d Annual Meeting of Compressed Gas Association in Houston, Tex., 25-27 Jan. 1976). Dynamic loading from ship operation is based on the full range of ship motions over the ship's operating life, normally taken to correspond to 10^8 wave encounters (Gas Code 4.3.4). Sloshing loads are to be considered when "partial filling is contemplated" (Gas Code 4.3.5). It is unclear whether this section would refer to ships returning "in heel". Such ships are certainly in a partially loaded condition, even though they typically are carrying only 5% of tank capacity.

Structural analysis on independent tanks type B must include classic deformation, buckling, fatigue failure, and crack propagation. Also, a three-dimensional analysis as to stress levels contributed to by the ships hull must be undertaken. The Administration in the country of registration may require model tests of such tank designs as well (Gas Code 4.4.5). Formulae are provided for analysis of independent tank types C (Gas Code 4.4.6). Factors for computing allowable stress concentrations in independent tanks are provided in the Code (Gas Code 4.5). Tank supports should be designed to allow for thermal expansion and contraction to prevent movement of the tank under hull loads and deflections without undue stress to the tank. Designs should provide support even at the maximum heel of 30° (Gas Code 4.6.1 and 4.6.2). Provision must also be made to withstand upward forces caused by an empty (bouyant) tank in a hull space flooded to the summer load line draft without deformation of the hull structure (Gas Code 4.6.7). One section of the Code requires supports sufficient to withstand a collision force from forward to aft without deformation likely to endanger the tank structure. The measurement of the collision force appears to be in static terms rather than dynamic terms (Gas Code 4.6.4). Secondary barriers are required on membrane, semi-membrane and independent type A tanks and should be designed to contain cargo leakage for a period of fifteen days under operating conditions without lowering the temperature of the ship's structure to cause brittleness. The partial secondary barrier (catch basin) required for type B independent tanks may allow for liquid evaporation, rate of leakage, and pumping capacity.

Insulation considerations are important not only to stop heat leaking into the cargo and thus causing boil-off, but also to prevent brittleness of the carbon steel in the hull. IMCO standards require that the hull metal does not fall below minimum allowable service temperature for the relevant grade of steel (as defined in Chapter VI of the Gas Code) with the cargo tanks at operating cryogenic temperature for LNG and ambient temperatures of 5° Centigrade for air and 0° Centigrade for the sea water (Gas Code 4.8.1). The Code does, however, permit the fixing of lesser values for ambient temperatures by the country of registration for ships which may trade in low temperature latitudes (*Id.*). If heating devices are used for transverse structural members of the hull, a power plant for the heating system must be considered as an essential auxiliary. Insulation materials must be resistent to fire and flame spread (Gas Code 4.9.7). Precise requirements for welding of independent tanks are spelled out (Gas Code 4.10.1). For independent tanks type C, 100% of the butt welds must be radiographically inspected (Gas Code 4.10.7(b)). Provisions are spelled out for the hydrostatic or hydropneumatic testing of independent tank designs (Gas Code 4.10.8).

Valves and Pumps

Materials having a melting point below 925° Centigrade are prohibited from general use in piping outside the cargo tanks and a complete stress analysis is required for LNG piping including not only the weight of the pipes and thermal contraction, but also loads induced by the hogging or sagging of the ship (Gas Code 5.2.7 and 5.2.8). Expansion joints and expansion bellows must be pressure tested at two to five times the design pressure and must be subjected to a cyclic fatigue test of at least two million cycles for piping in the way of deformation loading due to ship dynamics. These tests may be waived by the authorities of the country of registration if complete documentation (presumably prototype testing) is supplied to establish the suitability of expansion joints (Gas Code 5.2.9). Various procedures and tests are spelled out for pipe fabrication, welding, flange coupling, etc.

Every piping system to a cargo tank must be provided with shut-off valves located as close to the tank as practicable. A quick closing remotely controlled shut-off valve must be provided for ship-to-shore liquid and vapor connections. For tanks with a maximum allowable relief valve setting (MARVS) in excess of 0.7 kp/cm^2, remote control quick closing valves are required on all valves except for safety relief valves. Integrated circuitry is required to automatically shut down cargo pumps and compressors once the quick closing valves are actuated. The control system for all quick closing shut-off valves must be designed to be operated at a single control panel which is duplicated in at least two remote locations on the ship, one of which has to be the cargo control room. Fire-sensitive fusable elements (set between 98° Centigrade and 104° Centigrade) must be included in the quick closing shut-off valves. The valves must be designed to fail in the closed position in case of loss of power, and also be capable of local manual closing (Gas Code 5.3). To the extent flexible cargo hoses are used, they must be designed for a bursting pressure five times greater than the maximum pressure to which they would be subjected in normal operation (Gas Code 5.4.2). Redundance in cargo pumps is required in situations where the pumps are of the immersible type. (Gas Code 5.5.1).

Ventilation, Venting, and Use of Boil-off in Dual Fuel Power Plants

Cargo compressor rooms, pump rooms and gas-dangerous cargo control rooms must be fitted with fixed mechanical ventilation systems of the negative pressure type (Gas Code 12.1.5). Exhaust ducts from such ventilation systems must discharge upwards and be located at least ten meters from ventilation intakes and openings to gas-safe spaces (Gas Code 12.16). Electric motors driving ventilation fans must be located outside all ducting designed to exhaust flamable products and fans themselves must be made of non-ferrous materials or austenetic steel to obviate sparking (Gas Code 12.1.9). Hold void spaces, coffer dams and piping alleyways must be capable of being ventilated (with portable fans if fixed installation is not feasible) when entry into such areas by humans is necessary (Gas Code 12.2).

Each cargo tank must be equipped with at least two pressure relief valves of equal capacity. They must be designed and installed to prevent their becoming inoperative due to ice formation. The setting of the relief valves may not be higher than the maximum pressure for which the cargo tank is designed and the valves must be set and sealed by authorities appointed by the country of registration. The values of the pressure so set must be recorded and retained aboard the ship (Gas Code 8.2.1 through 8.2.5). Vents from the relief valves shall be not less than a height equal to 1/3 of the beam of the vessel (or six meters whichever is greater) above the weatherdeck (Gas Code 8.2.9). Such vents should be no less than seventy-five feet from the nearest air intake or opening to the accomodation, service, or control spaces (Gas Code 8.2.10). The valves must be positioned in the cargo tanks so that they will remain in the vapor phase (*i.e.*, in the space above the liquid cargo level) under conditions of 15° of list (Gas Code 8.2.17). If a shipboard fire could produce overpressures within the tank requiring a compensating venting greater than the capacity of the required relieve valves, additional relief valves must be installed with fusable override systems designed to preclude their opening during normal operation (Gas Code 8.3). Cargo tanks not designed to withstand an external pressure differential in excess of 0.25 kp/cm^2, and tanks not capable of withstanding the maximum external pressure developed under maximum discharge rates with no vapor return to the cargo tank, must be equipped with vacuum protection systems. Such systems must either shut down discharge or should admit inert gas, cargo vapor, or air to the tank (Gas Code 8.4). Pressure relief valves must be sized in such a manner to withstand whichever is greater between the maximum attainable working pressure of the cargo tank inerting system or the calculated vapor pressure generated under external fire exposure of the tank while not permitting more than a 20% rise in the cargo tank pressure above the MARVS (Gas Code 8.5).

If a dual fuel propulsion system is utilized, as it is in virtually all second generation LNG carriers, the gas fuel line must be a double-walled pipe with inert gas in the anular space surrounding the inner pipe. Mechanical ventilation must be provided for the pipeway and gas detection devices should be provided to indicate leaks. Automatic shutdown of the gas fuel supply in the event of failure of the exhaust ventilation fan must be provided (Gas Code 16.2). Ventilation hoods must be provided at all valves, flanges, and places where the gas is consumed such as boiler feeds, gas turbine inputs, etc. Forced air ventilation should sweep across the gas utilization unit and be exhausted at the top of the hood or casing (Gas Code 16.5). In the event that the ventilation draft is lost, the flame on the boiler burners is extinguished, or there is abnormal pressure in the gas fuel supply line or failure of the remote valve control system two valves in the supply system will automatically close and the contents of the pipe between the two valves will be vented to the atmosphere automatically. Alarms on the detection system should be set to shut down the fuel supply before the gas concentration reaches 60% of the lower flamable limit (Gas Code 16.6 and 16.10).

Environmental Control Problems

Piping within the cargo tanks must be provided to permit purging from operational condition to gas-safe condition via the intermediate medium of inert gas and to purge out the oxygen with cargo vapor prior to cooling and loading (Gas Code 9.1). For ships with tanks other than independent type C tanks, inter barrier spaces, *i.e.*, spaces between the outer membrane or cargo containment barrier and the inner tank, must be filled with inert gas or, subject to approval of the country of registry, with dry air, subject to immediate displacement by inert gas (Gas Code 9.2).* Valving and piping must be designed to preclude backflow of cargo vapor into the inert gas system (Gas Code 9.4.4). Inert gas sufficient to meet these requirements may be either carried in compressed or liquefied form on board, or may be generated on board, providing its oxygen content is at no time greater than 5% by volume. Inert gas generating plants and inert gas piping must not be located in accomodation, service or control station spaces (Gas Code 9.5).

Cargo tanks may not be filled to more than 98% of capacity without specific authorization by the officials of the country of registration taking into account the configuration and equipment of the tank. Procedures for coordinating the reference temperature at which such volume measurement is to be made with the settings on the pressure relief valves is spelled out (Gas Code 15.1).

Leak Detection Devices and Gauging Instrumentation

Pressure and temperature indicators should be installed in or on tanks, piping and inert gas generating systems and at least one level indicator must be installed in each tank. Such devices must be installed so as to preclude the dangerous escape of cargo at any time (Gas Code 13.1 and 13.2). Unless the cargo tank has a MARVS higher than the maximum possible pressure during loading, all tanks must be equipped with a high liquid level alarm (Gas Code 13.3).

In membrane tanks (and in other tanks requiring secondary barriers) carrying cargoes at cryogenic temperatures colder than -55° Centigrade, temperature indicating devices must be installed in the tank insulation or on the hull structure adjacent to the containment system. Such devices must give readings at regular intervals and give audible warnings when temperatures approach the embrittlement range for the hull steel. Additionally, temperature indicators are to be affixed to the tank boundaries to warn of unsatisfactory temperature gradients (Gas Code 13.5.2 and 13.5.3).

Gas detection equipment for flamable gases is required for LNG carriers and the audible and visual alarms from such equipment are to be located on the bridge, in the cargo control position, and at the gas detector readout location. If the equipment itself is located in a gas-safe area, gas sampling lines must have shutoff valves to prevent cross communication with gas-dangerous spaces and arrangements must be made to exhaust the gas from the detector equipment to the atmosphere in a safe location (Gas Code 13.6.4 and 13.6.5). Permanently installed gas detection sampling heads connected to audible and visual alarms must be provided for cargo pump rooms,

Only for tanks requiring full secondary barriers. Catch basins under spherical tanks are not included.

cargo compressor rooms, non gas-safe cargo control rooms, hold spaces in the cargo area, ventilation hoods in the engine room and air locks (Gas Code 13.6.7). The detection equipment must be capable of sampling and analyzing each sampling head location sequentially at intervals not exceeding thirty minutes with continuous sampling of gas ventilation hoods and dual fuel pipe ducts (Gas Code 13.6.8). The alarms should be set to activate when vapor concentration reaches 30% of the lower flammable limit (LFL) (Gas Code 13.6.10). In vessels utilizing membrane tanks the gas detection sampling heads must be located in the hold spaces and/or inter barrier spaces (Gas Code 13.6.11). Each ship must be equipped with a suitable instrument for determining oxygen levels in inert atmospheres (Gas Code 13.6.14).

Spark Proofing

Intrinsically safe electrical equipment may be fitted in gas-dangerous spaces. Cargo pumps may be electrically powered and submerged but the motors should be capable of being isolated from their electrical supply during gas-freeing operations (Gas Code 10.2.1 and 10.2.2). In vessels whose cargo tanks do not require a secondary barrier, hull spaces may contain explosion-proof lights, flame-proof valve motors, cathodic corrosion protection and fathometer transducers in gas-tight enclosures, and through runs of cables (Gas Code 10.2.4). Electric motors driving cargo pumps or cargo compressors must be separated from the space in which the pumps or compressors are located by a gas-tight bulk head (Gas Code 10.2.5(b)). In addition to these requirements, the electrical requirements of part C of Chapter 2 of the 1974 Safety of Life at Sea [SOLAS] Convention must be followed (Gas Code 10.1). There are also limitations to the type of electric equipment which can be used in various areas of the deck, particularly those over the cargo area and enclosed or semi-enclosed spaces containing cargo piping (Gas Code 10.2.6 and 10.2.7). IMCO worked closely with the International Electro-technical Commission and incorporated many of its recommendations, which appear in Chapter 20 (tankers) of its publication 92-5. (Lakey, New IMCO Code, reprint of a paper given at the 63d Annual Meeting of Compressed Gas Association in Houston, Tex., 25-27 Jan. 1976.)

Fire Prevention Equipment

This chapter of the Gas Code begins by stating that regulations 56 through 59 of Chapter II-2 of the 1974 Safety of Life at Sea Convention apply to all ships, including LNG carriers. Regulations 43 and 52 of the SOLAS convention are generally applicable as well. Hydrants and nozzles should be arranged in such a way that at least two jets of water can reach any part of the deck or tank covers in the cargo area with hose lengths not exceeding thirty-three meters (Gas Code 11.2.2). Stop valves should be installed in the fire mains at intervals of not more than forty meters between hydrants in the cargo area in order to isolate loss of pressure through collision damage (Gas Code 11.2.3). In ships having automated fire rooms, as will be the case with most of the LNG carriers, provision must be made for remote actuation of at least one fire pump to the fire main from the bridge or from a control station outside the cargo area (Gas Code 11.2.5). A water spray system must be provided to cover exposed tank domes, ondeck storage vessels for flammable products, cargo manifolds, deck houses and superstructure walls facing the cargo area with a spray of at least ten liters per square meter per minute on horizontal surfaces (Gas Code 11.3.1 and 11.3.2). Dry powder extinguishing systems must be arranged so as to deliver powder from two hoses or a combination of hose and monitor to any part of the above-deck cargo area. The system should be propelled by inert gas dedicated solely for this purpose and stored in pressure vessels (Gas Code 11.4.2). A monitor nozzle, capable of remote control must be located so as to protect the cargo loading and discharge manifold areas. All monitors should have capacities not under ten kilograms per second and all hose lines should be non-kinkable and of a capacity of not less than 3.5 kilograms per second (Gas Code 11.4.3 and 11.4.5). Each powder reservoir should contain enough powder to provide a minimum forty-five second discharge time for all attached monitors and nozzles. If monitors are expected to cover an area further than ten meters away, the capacity must be increased: *e.g.*, at 40 meters the capacity must be forty-five kilograms per second (Gas Code 11.4.6).

Gas-dangerous spaces such as compressor and pump rooms are to be provided with a fixed inerting fire smothering installation. Carbon dioxide and steam are not recommended for the inerting medium (Gas Code 11.5.1).

Operations and Personnel

In addition to the personal gear required by the 1974 SOLAS Convention, a minimum of three complete sets of safety equipment must be provided to permit personnel to enter and work inside gas-filled spaces. Such equipment must include a self-contained air breathing aparatus not using previously stored oxygen and having a capacity of 1200 liters of free air, protective clothing, boots, gloves, and goggles, a steel cord rescue line attached to a belt and an explosion proof lamp (Gas Code 14.4). Personnel are prohibited from entering cargo tanks, hold spaces, or cargo-handling spaces that are gas-dangerous unless fixed or portable equipment has revealed a sufficient oxygen content in the atmosphere and the absence of toxic elements, or unless they are wearing breathing aparatus and the operation is under the close supervision of a responsible officer (Gas Code 18.4.1). Needless to say, unless the gas dangerous area has been certified as gas-free, personnel are not permitted to introduce any potential source of ignition (Gas Code 18.4.2).

Cargo emergency shutdown and alarm systems should be tested and/or checked before cargo operations begin. Information should be available on board pertaining to the cargo and it should include, *inter alia*: a sufficient description of the physical and chemical properties of the cargo for safe containment; what action is to be taken in the event of spills or leaks; fire fighting procedures; detailed procedures for cargo transfer, gas freeing, tank cleaning, and changing to different cargoes; and minimum inner hull steel temperatures (Gas Code 18.1.1).

PROBABLE UNITED STATES VARIATIONS ON THE IMCO GAS CODE

United States Coast Guard in its on-going letter of compliance program has requirements that deviate in four aspects from the IMCO Gas Code. The Coast Guard has substituted higher stress sustaining requirements for independent tank types B and C than are provided in the Gas Code 4.5. It is requiring crack arresting steels (grade E) to be used in the deck stringer, the shearstrake, and the turn of the bilge (where grade D is also acceptable). Another important variation is that the insulation on the tanks is required to be designed with differing ambient temperatures than are specified in the IMCO code. The latter requires 5° Centigrade for the air and 0° Centigrade for sea water. The Coast Guard is requiring, for service to the lower forty-eight states, an ambient temperature (in air with a five knot wind chill factor) of -18° Centigrade. For vessels serving Alaska, the ambient air temperature at 5 knots is set a -29° Centigrade (compare Gas Code 4.8.1). Vessels designed pursuant to the IMCO ambient temperature requirements may be allowed entry on restricted service depending on the location and the season. The Coast Guard is also requiring that the cargo tank pressure system be designed to maintain the cargo without venting to the atmosphere for a period of twenty-one days while the vessel is in port under ambient temperatures of 45° Centigrade for air and 32° Centigrade for sea water. Since there are proscriptions against maneuvering with total gas fueling, and since for prolonged stays in port a vessel would most likely be moored or anchored in any event, this means that the gas must be combusted to heat steam which may be dumped through the condenser and/or the tanks must be designed to sustain higher-than-normal vapor pressures due to the unrelieved boil-off.

The Coast Guard advises that any ship that has applied for a letter of compliance after March 11, 1975 has been required to meet the IMCO Gas Code in full, subject to the aforementioned United States modifications. (Henn & Dickey, "New Regulations for Liquefied Gas Carriers" 17 (a paper presented at GASTECH 75 at Paris, France, October 1975). *See generally*, Coast Guard publication U.S.C.G. -478 *supra* at III-7 through III-12).

EXISTING CONSTRUCTION

The IMCO Code, dealing as it does primarily with requirements for construction, can be very effective as to ships which are presently being designed or which will be designed and built in the future. With regard to ships that are already partially or completely constructed or had been contracted for and fully designed when the Code was promulgated, the problem is much more difficult. The IMCO Sub-committee on Bulk Chemicals has been assigned to take over the function of the Sub-committee on Ship Design and Equipment with respect to bulk chemicals and liquefied gases. It has been given a charge to develop, as a priority matter, a code for existing vessels designed to carry liquefied gases. Work is now proceeding on this code and working drafts are being circulated. In the meantime the IMCO Assembly has urged governments to apply the standards of the new ship construction Gas Code, insofar as it is reasonable and practicable, to those ships which are presently under construction.

OPERATIONAL REQUIREMENTS

AT SEA

Although the U.S. Coast Guard has no jurisdiction over foreign flag vessels on the high seas in terms of their operational procedures, good practice on LNG carriers would call for routine monitoring of the various alarm systems. IMCO requirements call for sampling no less often than every half hour for the gas detectors in the hold spaces and intra barrier spaces. Provision is generally made for hard copy printouts of the readings and good practice would be to procure and review a hard copy printout at least every third watch (*i.e.*, twice in every twenty-four hours at approximately twelve hour intervals) even though no alarms have sounded.

On ballast voyages while the ship is in heel, cool down procedures must be undertaken to insure that overly large temperature gradients do not exist between the top and the bottom of the tanks. Generally 30° Centigrade is about the maximum tolerable gradient and if that is approached or exceeded, a cool down procedure must be initiated. This consists of spraying the LNG heel, from the top towards the shell of the tank to produce a cooling effect (Maritime LNG Manual *supra* at 142). On voyages where the carrier is laden with LNG the primary cargo handling problem, besides leak detection, is boil-off which normally occurs at a rate between 0.2% and 0.25% per day by volume. Generally a maximum vapor pressure of one p.s.i.g. is permitted. When pressures reach or exceed that maximum, the boil-off must be withdrawn for use in the dual fuel system, venting to the atmosphere (not permitted in port), or for dumping to the condensers (*Id.* at 144). For a list of alarms and corrective measures *see* Appendix, Exh. 12.

When the vessel begins maneuvering in constricted waters as it enters a harbor and approaches a terminal, specialized requirements are imposed upon it and upon the terminal by the Coast Guard Captain of the Port. These are developed and authorized under 50 U.S.C. § 191 with approval of the Coast Guard Commandant. § 191 empowers the Secretary of the Treasury (the department under which the Coast Guard used to operate before its control was transferred to the Department of Transportation), subject to the approval of the President, to make rules and regulations governing the "anchorage and movement of any vessel foreign or domestic in territorial waters of the United States" following a Presidential proclamation or executive order declaring a "national emergency to exist by reason of natural or threatened disturbance of the international relations of the United States". Such rules and regulations were for the purposes, among others, of preventing "damage or injury to any harbor . . . of the United States . . . (and) to safe-guard against destruction, loss or injury from sabotage or other subversive acts, accidents, or other causes of similar nature, to vessels, harbors, ports and waterfront facilities . . . ." Executive Order No. 10173 (15 Fed. Reg. 7005, October 20, 1950 amended by E.O. No. 10277 on July 31, 1951) made the necessary finding of the threat to national security and it has never been withdrawn or rescinded. Until the passage of the Ports and Waterways Safety Act of 1974, (46 U.S.C.A. § 391 (1975)) this was the tenuous authority upon which the Coast Guard Port Captains formulated their regulations.

Only a few ports have LNG terminals. Thus only a few extant port regulations pertain specifically to LNG carriers and even these are not entirely standardized. *See* Appendix, Exh. No. 13 for excerpts from the Port of Boston's LNG-LPG operations/emergency plan. Certain general requirements appear to be basic in most of the plans and they are as follows: Like all sea-going vessels, the LNG ships are required to monitor the bridge-to-bridge radiotelephone frequency (channel 13) and must guard the emergency channel (16). Vessels are to be boarded by Coast Guard authorities, typically in the roadstead or anchorage prior to berthing (in Boston for example, the boardings usually take place in Broad Sound). During times of anchorage a live bridge watch is required to be maintained with frequent (usually hourly) taking of bearings. An anchorage report must be sent to the Captain of the Port on channel 16 at intervals ranging from one to four hours. No cargo may be transferred while vessels are at anchorage. New York, Boston and Tokyo all restrict LNG carrier movement inside the harbor to daylight hours. Prior to entering the harbor, Coast Guard form 4260 (permit to handle dangerous cargo) must have been issued to the vessel.

If the vessel does not already have a letter of compliance, or has one that is due for renewal or revalidation, plan review procedures, or verification of a current certificate of fitness under IMCO, must precede the ship's visit and in some cases, boarding by Coast Guard officials must occur no less than seventy-two hours before a proposed discharge. Most ports require a pre-arrival offshore boarding for vessels making their initial entry into the port in any event. The vessel's agent must notify the Coast Guard in advance of the arrival of the vessel and a security broadcast is usually made and repeated at least 24 hours before the ETA of the vessel. Most ports require the master, in advance of the vessel's actual arrival, to send a message to the Captain of the Port stating in effect:

> "to the best of my knowledge and belief there are no known casualties to this vessel or its machinery which might affect its seaworthiness. I further state that all cryogenic handling and

detection equipment is in proper operating condition and has been operating for the duration of this passage." (*See, e.g.,* Port of Boston, LNG-LPG Operations Emergency Plan 2).

For transiting the harbor typical requirements include a Coast Guard escort vessel (at least while inbound laden), a maximum speed limitation (in Tokyo twelve knots in the Bay, and three and one-half knots in the port area; eight knots in Boston Harbor), and restrictions on movement under minimum visibility, and a moving envelope of no-traffic. On the visibility issue, Long Beach and New York limit navigation to places where visibility is one mile or greater in the ahead direction. Boston requires minimum visibility of at least two miles and provides detailed alternatives for vessels who have already entered the harbor when visibility closes down (*See* Appendix, Exh. No. 13). Vessels transiting Dorchester Bay in Boston (*e.g.*, heading for the LNG facilities at Commercial Point) may do so only within two hours of high water. Virtually all ports are prohibiting venting of boil-off vapors to the atmosphere while in the port area. The no-traffic envelope requires that no other vessel be allowed to be underway in an area that moves with the LNG carrier. Typically the area is two miles ahead and one mile astern. This is designed to avoid potential close quarters maneuvering situations with the attendant risk of collision. Implicit in this is the fact that the escort vessel provided by the Coast Guard will be several hundred yards ahead of the LNG carrier and will be repeatedly broadcasting a security alert and will be using an amplified bull horn if necessary to prohibit traffic within the no-traffic envelope. The moving no-traffic envelope has been criticized by some as being capable of "shutting the port down" every time an LNG carrier enters (which in some high volume projections might be as often as once every fifteen and one-half hours (*see e.g.*, Pacific Indonesia Project DEIS, *supra* Table 2 at 300)) (*see* Weinberg, *supra* at 505). There are several answers to this argument. First, if the greatest risk can be shown to be collision with another vessel, then the no-traffic envelope is indeed a good way to minimize that risk. Second, for most ports only a small segment of the relevant waterways would be "shut down" at any given time. Third, to the extent that the criticism may be valid in congested ports, this is an argument for locating LNG terminals in more remote areas of the Coast where conventional traffic will not be effected.

Once the vessel reaches her berth, additional requirements are imposed. If a pre-arrival boarding has not occurred, Coast Guard inspectors will at that time board, verify that drip pans are underneath the cargo discharge manifold, that fire fighting systems are operable, that fusible links are installed in cargo discharge valves, that the maximum allowable relief settings are appropriate, and that all lighting fixtures in the cargo area are explosion proof. Vessels are typically required to moor bow outward and to maintain quick departure capability in the engine room. New York and Los Angeles require live tugs standing by at all times while the vessel is transferring cargo and steel towing pendants are required to be located fore and aft on the off-pier side with the bight of the cable at water level for emergency make-up should the vessel have to be removed from the pier (Los Angeles-Long Beach USCG Draft Regulation for Transport of Hazardous Cargo Reqt. II-14) (*see e.g.*, C.G. -478, IV, 3, Item (17)). Welding and torch work are uniformly prohibited during cargo handling operations as is bunkering (the latter presumably for fear of static electricity build-up and/or of conventional flammability hazards). Cargo operations are to cease if electrical storms occur. Continuous communications must be established between the terminal operators and the vessel with responsible parties at either end being fully fluent in the English language.

The Los Angeles Port Safety Council requires vessels maneuvering within the harbor to maintain an anchor watch, to have anchors clear of the hawse pipe and to have an officer forward to direct emergency dropping of the anchor. Additionally, it requires the ship's steering engine room to be manned with personnel competent to shift from conventional to emergency steering with an open line of communication to the ship's bridge while maneuvering to and from berth (Vessel Rqts. 15-16). Typically ports will require large signs indicating that people must keep clear and that flammable cargo is being handled. New York and Los Angeles require security zones in the immediate vicinity of the vessel's berth at the terminal facility. Presumably this means vessel traffic is prohibited within the area and vehicular traffic is prohibited on land within the area.

Boston does not require standby tugs while the vessel is handling cargo at the berth, but local tugs are available on fifteen minute call. Although the Boston fire department is notified in advance of the vessel's arrival and again when it begins working cargo, no fire boats are required to stand by. Assisting tugs sometimes make up at the anchorage near Deer Island at President Roads in the Boston Harbor with additional tugs used solely for the berthing operation joining the vessel at the Mystic River bridge. After an LNG vessel has discharged in Boston it is allowed to depart without adherence to the transit regulations outlined above providing it is fully discharged. In this case, "fully discharged" does not require that the heel be discharged, although the volume of cargo carried is reduced by at least 95% in contrast with the inbound voyage. During times when the LNG barge Massachusetts was operational, it would depart the outer terminal without a Coast Guard escort craft, but security broadcasts were made indicating its departure. Boston Coast Guard officials would not permit an LNG vessel to enter port with inoperative leak detectors or inoperative fire fighting equipment if these had been reported or discovered (Boston LNG-LPG Operations Emergency Plan 13). On the other hand, small maintenance problems which are not inherent in the design can often be fixed on board while the vessel is detained in Broad Sound. Boston officials stated that if the lower temperature gauge in a cargo tank were out of order they would probably let the vessel come in anyway. Presumably in such a situation the letter of compliance would be endorsed so that the defect would have to be corrected before the vessel next visits a U.S. port.

SURVEILLANCE OF THE DISCHARGE OR LOADING OPERATION

After the LNG carrier has moored the Coast Guard continues to assert jurisdiction over her loading or discharging activities. Insofar as the concern is with operations on board the vessel, there can be little doubt of its jurisdiction. At the other extreme, the Office of Pipeline Safety (or the State Public Utilities Commission) seems to have jurisdiction once the vaporized gas leaves the terminal's compressor and enters a high-pressure gas pipeline. It is less clear which agency has jurisdiction over the terminal's shoreside equipment and personnel during the unloading of the vessel.

The Regulations state that the Coast Guard Captain of the Port

> ". . . may prescribe such conditions and restrictions relating to the safety of waterfront facilities and vessels in port as he finds to be necessary under existing circumstances. Such conditions and restrictions may extend, but shall not be limited to, the inspection, operation, maintenance, guarding, and manning of, and fire-prevention measures for, such vessels and waterfront facilities.
>
> ". . .Whenever the captain of the port finds that the mooring of any vessel to a wharf, dock, pier, or other waterfront structure would endanger such vessel or any other vessel, or the harbor or any facility therein by reason of conditions existing on or about such waterfront structure, including, but not limited to, inadequate guard service. insufficient lighting, fire hazards, inadequate fire protection, unsafe machinery, internal disturbance, or unsatisfactory operation, the captain of the port may prevent the mooring of any vessel to such wharf, dock, pier, or other waterfront structure until the unsatisfactory condition or conditions so found are corrected. . .." (33 CFR § 6.14-1, -2 (1975))

In Executive Order 11249 (Oct. 10, 1965) (modifying E.O. 10173 & 10277) the Coast Guard was given authority to establish security areas during cargo handling operations and such areas could extend to land "in immediate proximity" or "contiguous" to piers. (*Id.* at § 2 amending 33 CFR 6.01-4) Additionally, the Coast Guard was authorized to control access to the area. (*Id.* at §§ 4 and 5 amending 33 CFR § 6.04-5 and -6) Although such control could conceivably be asserted so broadly as to present conflicts with local fire marshalls or to cause planning uncertainty for terminal executives, this is not likely to occur if early patterns of cooperation are indicative. Terminals whose storage tanks are remote from the pier (utilizing easements to locate cryogenic transfer pipelines) might strain the "contiguous" language, but common sense indicates that, in order to meaningfully oversee an integrated flow process such as LNG discharge and vapor return, authority must extend (physically) as far as the storage tank.

The Coast Guard typically will have at least one officer at the terminal throughout the discharging (or loading) operation. Such on-the-scenes supervision when contientiously pursued could achieve at least three objectives: The discharge inspections could help assure fundamental safety precautions were not overlooked. (*See* Appendix, Exh. 8, Captain of the Port of Boston, Safety Inspection for Foreign Vessels Carrying Bulk Cargo of Unusual Risk, Liquefied, Flammable Gases, Items 6, 7, 9 and 12). Such pre-discharge checks might include verifying the cool down of the terminal lines running from tank to ship. Differential rates of cooling between the bottom and top of large diameter pipes can cause bowing and deflection between supports which may produce stresses in excess of design limits. (*See* Anderson & Daniels, *LNG Terminals:*

Existing and Proposed Systems Compared, Pipeline & Gas Journal 44, 48 (Sept. 1975)). The second objective would be to monitor personnel access to the piers, violations of the smoking prohibition and the prohibition against spark producing equipment. (*See* E.O. No. 11249, Oct. 10, 1965). The third objective would be to give immediate warning to Coast Guard headquarters and local fire officials in the event of a malfunction, leak or other failure of the cargo transfer system. The foregoing comments are not meant to imply that terminal operators are not energetically committed to the same objectives. Indeed, most terminals have or contemplate personnel training programs, discharge procedures and checklists which parallel those of the Coast Guard.

The Coast Guard's draft requirements for Los Angeles-Long Beach LNG terminals require, *inter alia*, "combustible gas indicators to detect leaks and possible accumulations of an ignitable mixture," loading platforms equipped with wind velocity and direction indicators, and waterscreen systems to separate "vessel and facility in case of emergencies." (Rqts. V-11, 13 and 14).

siting of terminals; shoreside and underway risks

THE ROLE OF THE FEDERAL POWER COMMISSION

The present administrative practice is to have a would-be LNG terminal operator apply to the Federal Power Commission for a § 7 (of the Natural Gas Act) certification of public convenience and necessity. Although no one is seriously challenging the appropriateness of that forum for hearings on the application and issuance of the certificate, there is rather sharp disagreement as to whether or not the FPC should promulgate rules relating to the safety of such a facility. During the hearings on the Tetco disaster, the Department of Transportation took the position that its Office of Pipeline Safety had exclusive jurisdiction to promulgate such regulations by virtue of the Natural Gas Pipeline Safety Act of 1968 (49 U.S.C. §§ 1671 et. seq. (1970)). Sec. 3a of that Act empowers the Secretary of Transportation to establish safety standards for "pipeline facilities" and "the transportation of gas." Sec. 2(4) defines "pipeline facilities" to include "without limitation . . . any equipment, facility or building used in the transportation of gas". Previously in § 2(3) "transportation of gas" had been defined as "the gathering, transmission, or distribution of gas by pipeline, or its storage in, or affecting interstate or foreign commerce." Although the word "liquefied" is not used in the Act, the Department of Transportation takes the position that the phrase "any . . . facility" would extend to LNG tanks and piping. It points to testimony by the then Secretary of Transportation Boyd at the hearings on the bill which eventually became the Pipeline Safety Act, where the Secretary contended that "the term 'a pertinent facility' . . . would include without limitation storage facilities . . . including those for liquid natural gas. . . ." (*Hearings on S. 1166 before the Senate Committee On Commerce*, 90th Cong., 1st sess. (1967) at 21.) As the legislation finally emerged the modifier "pipeline" was substituted for the modifier "a pertinent" immediately preceding the word "facilities". Although there is other legislative history, indicating it was Congress' intent to provide safety standards for "pipeline facilities" and not just the naked pipelines, it is not entirely clear that Congress envisioned massive LNG terminals and storage tanks as opposed to an occasional compressor station or dehumidifier. On the other hand, the phrase in the Act pertaining to the "storage of gas. . . affecting . . . foreign commerce" could have contemplated just such a terminal since foreign commerce in natural gas (other than that with Canada or Mexico) does require cryogenic storage of LNG. In any event, the Office of Pipeline Safety (OPS) has asserted the right to establish safety regulations for LNG terminals but due to understaffing has been unable to act in furtherance of this asserted jurisdiction.

The Pipeline Safety Act itself recognizes that FPC certification (under § 7 of the Natural Gas Act) can only procede upon a certification by the applicant that it will "design, install, inspect, test, construct, operate, replace, and maintain the pipeline facilities in accordance with federal safety standards. . ." Thus the OPS argues that while the FPC issues a certificate and must take safety into consideration on an ad hoc basis with each particular applicant, the FPC should not be in the safety regulation business but should rely on standards and regulations promulgated by Transportation through OPS and should confine its overt safety regulation to questions of pipeline routing through populated or ecologically fragile areas. The FPC on the other hand, takes the position that while the OPS may set minimum standards, the FPC is not bound by compliance of an applicant with such standards, but may insist on higher standards in particular cases. (*See* Report on Legislative Issues Relating to the Safety of Liquefied Natural Gas Storage by the Special Subcommittee on Investigations of the House Committee on Interstate and Foreign Commerce, 16-17, 93rd Cong., 2d sess. (1974)). In 1974, a House Committee on Interstate and Foreign Commerce issued a report critical of FPC management of LNG safety. It asserted that the agency had "no bureau or division devoted exclusively to safety", and that a "handfull of administrative personnel . . . who have other principal functions handle LNG safety part-time. . . ." (*Id.* at 19) (This may have been a reference to the FPC's Bureau of Natural Gas or its Office of Energy Systems.) The report was also critical of the OPS's lack of progress in formulating safety regulations for LNG facilities. In recent months the FPC has apparently conceded the formulation of safety regulations including pipelines between tanker and fixed facilities on shore to the OPS. (Paper given by Joseph Kasputys and Joseph Gustafero of the Department of Commerce before the Cryogenic Society of America, 8-9 (May 1976)).

The statutory authority for the Federal Power Commission to become involved with LNG terminals in the first instance is found in § 3 of the Natural Gas Act (15 U.S.C. § 717b (1970)). Relevant portions of this statute say that:

> ". . . no person shall . . . import any natural gas from a foreign country without first having secured an order of the Commission authorizing it to do so. The Commission shall issue such order upon application unless, after opportunity for hearing, it finds that the proposed. . . importation will not be consistent with the public interest. The Commission may by its order grant such application in whole or in part, with such modification and upon such terms and conditions as the Commission may find necessary or appropriate . . .."

Of interest also are the provisions of § 7 of the Natural Gas Act which read in pertinent part as follows:

> ". . . no natural gas company . . . shall . . . undertake the construction or extension of any facilities . . . [for the 'transportation or sale of natural gas subject to the jurisdiction of the Commission'] unless there is in force with respect to such natural gas company a certification of public convenience and necessity issued by the Commission, authorizing such acts or operations. . .." (15 U.S.C. § 717f (c)).

Elsewhere the same section states that:

> ". . .a certificate shall be issued to any qualified applicant therefore, authorizing the whole or any part of the operation, sale, service, construction, extension, or acquisition covered by the application if it is found that the applicant is able and willing properly to do the acts and to perform the service proposed and to conform to . . . [the terms of the Natural Gas Act] and the requirements, rules and regulations of the Commission thereunder and that the proposed service, sale, operation, construction, extension or acquisition, to the extent authorized by the certificate, is or will be required by the present or future public convenience and necessity. . .." (15 U.S.C. § 717f (e) (1970)).

While it is clear that the FPC can grant, deny or condition any orders allowing the importation of natural gas regardless of whether it is in a gaseous or liquid state at the moment of importation, it is less clear whether it can insist upon a certification of public convenience and necessity. In the celebrated *Distrigas* case (*Distrigas Corp v. FPC*, 495 F.2d 1057 (D.C. Cir. 1974)) the court held that importers not selling in interstate commerce did not fall under the § 7 jurisdiction of the FPC, reaffirming the decision in *Border Pipeline Co. v. FPC*, 171 F.2d 149 (D.C. Cir. 1948) (discussed in Chapter VII, § 3 Approval of Imports, *infra*). The court did suggest, however, that under its § 3 order granting power the FPC could impose the equivalent of the arguably more exacting § 7 certification requirements on the construction or acquisition of import facilities or on the subsequent intrastate sale of the gas. The court referred to the FPC's § 3 authority as "plenary and elastic" (*Id.* at 1064) and went on to say:

> "While imports of natural gas are a useful source of supply, the potentially detrimental effect on domestic commerce can be avoided and the interest of consumers protected only if they are subject to comprehensive regulation; such regulation cannot or will not, as a practical matter, be imposed by the states; such imports will, therefore, be in the public interest only if the Commission exercises with respect to them the same detailed regulatory authority that it exercises with respect to interstate commerce in natural gas. In short, we find it fully within the Commission's power . . . to impose on importers of natural gas the equivalent of § 7 certification requirements . . . ." (*Id.*)

On the interesting issue of whether or not Distrigas was co-mingling LNG for intrastate sale with LNG for interstate sale (it was admitted that a small fraction of the imports would be sold in interstate commerce) the court noted that the Commission had withdrawn this basis for its assertion of jurisdiction and that therefore it was not an issue on appeal. The court did suggest, however, that the approval of the construction of an importation facility such as an LNG terminal could be greatly complicated if co-mingling were present, especially if the operations "were largely or entirely intrastate at the outset and only later became interstate" after the terminal was "already constructed and in operation, making the traditional test for § 7 certification--economic feasibility, adequacy of supply, financing, costs, etc.--much more difficult to apply" (*Id.* at 1061-1062, n. 24).

There has been some pressure to let the Coast Guard expand its LNG jurisdiction to include site approval for LNG terminals. Representative John Murphy of New York introduced a bill (H.R. 4440) on March 6, 1975, to require the Secretary of Transportation to certify sites adjacent to the navigable waters of the United States suitable for the location of liquefied natural gas storage terminals. If such legislation were passed, questions might arise as to whether a terminal operating on non-adjacent property which simply had an easement over waterfront property for its pipelines and its pier foundation could be covered under the legislation. (*Compare* 33 CFR § 6.04-1 (1975)). Similarly, there may be some doubt whether the Secretary (or the Coast Guard, under delegated powers) could actually select a particular site for a particular applicant or could only certify an inventory of suitable sites to limit the applicant's choice. In any event, the bill did not emerge from the House Committee on Merchant Marine and Fisheries.

INPUTS FROM OTHER AGENCIES

Many LNG terminals will require either long finger piers reaching out into water of adequate depth or the dredging of new channels, or both. The permits for this type of construction or dredging activity are issued by the Army Corps of Engineers under its authority from §§ 401, 403 of the Rivers and Harbors Act (33 U.S.C. §§ 401,403 (1970)).

The Environmental Protection Agency oversees the preparation and circulation of environmental impact statements and other agencies such as the Department of Interior's Bureau of Fish and Wildlife Service or the National Marine Fisheries Service may review applications or intervene pursuant to their powers under the Fish and Wildlife Coordination Act (16 U.S.C. §§ 661 et. seq.). To the extent that precautionary areas or traffic separation schemes or other elements of a vessel traffic system may be required for navigational safety of the LNG carriers as they approach or depart the berth, the U.S. Coast Guard will necessarily be involved as well.

STATE AND LOCAL CONTROL

ENVIRONMENTAL CONCERNS

In the area of environmental legislation state control often turns on whether or not there is preemptive federal legislation.

(*Compare*, *Askew v. the American Waterways Operators*, 411 U.S. 325 (1973) (licensing requirements and strict liability for marine oil terminal operators) *with City of Burbank v. Lockheed Air Terminal*, 411 U.S. 624 (1973) (local attempt to curfew airport to minimize noise preempted.)) In some areas such as shoreside effluent pollution of water, Congress has intended the states to take a major regulatory role. *See, e.g.*, 33 U.S.C. § 1251 (Federal Water Pollution Control Act Amendments of 1972) where it is stated "It is the policy of the Congress to recognize, preserve, and protect the primary responsibilities and rights of the states to prevent, reduce and eliminate pollution . . . ." Although the word "primary" is missing, similar language is found in the Estuarine Areas Act of 1968 with regard to the state's role in "protecting, conserving and restoring" estuaries (16 U.S.C. § 1221 (1970)). Even though the Coast Guard has been given extensive powers under the Ports and Waterways Safety Act of 1972 (33 U.S.C.A. § 1221 *et. seq.* (1975)), federal legislation specifically permits states to require and enforce even higher (but not lower) standards in regards to "structures." (33 U.S.C.A. § 1222(b) (1975)). Certainly an LNG terminal would be such a structure. *See generally*, Swan, *American Waterways: Florida Oil Pollution Legislation Makes it Over First Hurdle*, 5 J. Maritime Law & Commerce 77, 95-97 (1973).

As a practical matter the environmental impacts of constructing and operating LNG terminals are relatively minimal. If dredging is required there is a need to consider the impact of disposing of the berm and of instrusion on indigenous crustaceans. Filling of estuarine areas might be involved but is not innevitable. Sewage and effluents, other than warmed water are minimal or nonexistent. For discussion on water warming through ambient vaporizers, *see* Chapter III, Preparation of Environmental Impact Statement, *infra*. Even spilled LNG has no lasting environmental effect. It may temporarily freeze earth or the surface of water but even large spills evaporate in less than an hour with little or no impact on marine biota or water purity.

ZONING CONSIDERATIONS

Local zoning ordinances may preclude locating LNG terminals in certain areas. Such zoning has long been held constitutional, *see, e.g.*, *Village of Euclid v. Ambler Realty Co.*, 272 U.S. 365 (1926) and *State v. Jersey Central Power & Light Co.*, 262 A.2d 385 (1970). If a state attempted to totally zone out any LNG terminal anywhere on its coastline this would very likely have to be justified on safety or welfare, the so-called "police power" grounds, rather than on notions of an orderly allocation of function to assure the highest and best use of land. In the broader context of coastal zone management, Congress has sought to encourage the states to exercise their full authority in developing and implementing management programs to "achieve wise use of the land and water resources of the coastal zone giving full consideration to ecological, cultural, historic and aesthetic values as well as to needs for economic development." (16 U.S.C.A. § 1452(a) (1975 supp.). As a result of this 1972 legislation, responsibility for general zoning plans has been passed to the states, subject to federal approval.

In California the policy guidelines of the Coastal Management and Development Agency specify that only one LNG terminal shall be permitted in the California coastal zone until "engineering and operational practices can eliminate any undue risk." Initially the policy requires that LNG terminals shall be built "only on sites remote from human population concentrations." Construction of LNG port facilities "shall not involve dredging or filling of land areas unless there is no less environmentally damaging alternative." Special consideration shall be given to the impact of cool water discharges into sea water. (Policy No. 95). Various general requirements such as diking, tank structure integrity, earthquake and fire protection, and auxiliary power supplies are developed in Policy No. 97.

STATE PUBLIC UTILITIES COMMISSIONS

To the extent LNG terminal operators are making intrastate sales, rates and tariffs may be regulated, scrutinized and approved by state Public Utilities Commissions. *See* Chapter VII, § 7 Certification and § 4 Approval of Rates, *Jurisdictional Issues, displacement sales, infra*, for the federal jurisdictional impact of "displacement sales." Distrigas of Massachusetts sought and obtained the approval of seventeen different state regulatory agencies before building the LNG tanks on Staten Island in New York (now owned by Eascogas) (*see* Conference on LNG Importation, *supra* at 179-184 and 194).

SAFETY CONSIDERATIONS

Even if Congress has legislated in an area extensively but has not explicitly preempted state safety regulations a state may usually proceed under its police powers for the safety and welfare of its residents. *See, e.g.*, *Quinn v. New York Bd. of Standards & Appeals*, 357 N.Y.S.2d 762 (1974) holding the decision in *Distrigas supra* did not prevent state courts from considering LNG terminal safety issues raised by residents of the surrounding area.

In maritime law there is also some precedent for this type of regulation. The maritime-but-local doctrine as enunciated in *Cooley v. Board of Port Wardens*, 53 U.S. 299 (1851) upholds local establishment of pilotage and quarantine requirements. Similarly, in *Kelly v. Washington*, 302 U.S. 1 (1937), a state was permitted to require safety inspections pertaining to the hull integrity of small craft but the scope of such regulation was expressly limited to that which was "plainly essential to safety and seaworthiness" (*Id.* at 15). Important litigation is now pending on appeal from the district court for the Western District of Washington (*Atlantic Richfield Company v. Evans*, Docket No. C 75-648) in which a tanker operating company is challenging the State of Washington's prohibition of tankers in excess of 125,000 deadweight tons from Puget Sound and its requiring (in the absence of tug-assisted transit) special hull construction and configuration for oil tankers between 40,00 and 125,000 deadweight tons (Chapter 125, Laws of Washington 1975, 1st Extraordinary Session). (*See generally*, Swan, *American Waterways . . ., supra* at 86-93). In practice, the question of whether a state's attempt to promulgate and enforce safety requirements for LNG terminals was preempted by the Natural Gas Act and the Natural Gas Pipeline Safety Act would be difficult to resolve. *Compare, Northern States Power Co. v. Minnesota*, 320 F.Supp. 172 (D. Minn. 1970) *aff'd*, 447 F.2d 1143 (8th Cir. 1971), *aff'd Mem.*, 405 U.S. 1035 (1972) (more stringent state standards for nuclear power reactor designs struck down in view of utility's compliance with Atomic Energy Commission standards), *and First Iowa Hydroelectric Cooperative v. FPC*, 328 U.S. 152 (1946) (state engineering requirements related to water diversion on interstate power dam held not binding in federal licensing proceeding), *with California v. Zook*, 336 U.S. 725 (1949) (enforcement of state law upheld where "ride bureaus" use of non-licensed carriers violated both state and federal law), *and Chrysler Corp. v. Tofany*, 419 F.2d 499 (2d Cir. 1969) (national uniformity under federal law subordinated to state regulation designed to accomplish the same end of reducing accidents on highways).

The New York legislature recently enacted legislation covering the certification and siting of LNG terminals and conversion (vaporization) facilities. The Department of Environmental Conservation is charged with establishing criteria for the siting of LNG facilities as well as issuing certificates of environmental compatibility and public necessity to applicants desiring to construct or operate such a facility. (Chapter 892 Laws of New York of 1976). The siting regulations are to take account of population density adjacent to and along the delivery route, transportation risks, and projections of LNG plume dispersion in the event of a casualty. (*Id.* § 23-1709). Applications must be filed by any person desiring to construct, enlarge, or put into use any presently unused facility. The State Department of Transportation is to establish criteria for safe transportation and if overland routes are employed, the Department of Environmental Conservation must approve the delivery route (*Id.* § 23-1713). Special provision is made for the training and qualification of municipal fire department personnel in risk-exposed areas for coping with LNG fires. The cost of this training is to be assessed against the facility owner "to be included as part of the expense related to the furnishing of this form of energy" . . . presumably as a permissible addition to expenses in formulating rates (*Id.* § 23-1715). Grandfather rights are given to facilities already in operation by September 1, 1976, but if, after a special review, upon a showing of "alternate means of meeting the service needs currently satisfied . . . [by the facility] or upon a showing that the service needs . . . are not sufficient to outweigh the public interest in safety" the facility may be ordered discontinued. In such event the agency may allow a phase-out period not to exceed three years from the date of determination (*Id.* § 23-1705(5) and 23-1719(3)). It is not clear from the statutory language whether "phase-out" refers to the gradual stepping down of throughput or is simply a grace period during which the facility may be operated in the normal way. Facilities completed, but not in use for any reason (this might well be the situation at the Eascogas tanks on Staten Island) may not be activated until such time as the Department of Environmental Conservation has adopted and filed regulations (which must be done within one year of the effective date of the legislation). There is a procedure set out for petitioning a hardship case to permit the activity to continue during the moratorium period just referred to (*Id.* § 23-1721(3)). As to the civil liability aspects of the New York legislation, *see* Chapter V, Terminal Owners Liability, *Strict Liability by Statute*, *infra*.

PREPARATION OF ENVIRONMENTAL IMPACT STATEMENT

The Federal Power Commission is the leading agency in drafting the environmental impact statement required under NEPA for the approval of LNG terminals. *See* Appendix, Exh. 15 for FPC Order 415-C and the FPC's rules and procedures with regard to intervention.

There has been considerable pressure from industry to force the FPC into developing site selection criteria and facility operation standards for LNG terminals. The pressure for this has arisen mainly because the certification hearings, especially when the FPC carries the concurrent burden of preparing the Environmental Impact Statement, tended to be very long and protracted. Moreover, many issues are argued redundantly and massive records are compiled as subsequent applicants and interveners develop the same issues. (*See, In the Matter of the Need for Site Selection and Facility Operation Criteria for LNG Importation and Storage Terminals*, FPC Docket No. RM 76-13). Petitioners argue that recent cases have firmly established a requirement for federal agencies to issue a programatic environmental impact statement when long-range, multiphase projects with heretofore unexperienced impacts on the environment are involved. *See, Scientists' Institute for Public Information Inc. v. AEC,* 481 F.2d 1079 (D.C. Cir. 1973) ("irretrievable commitment of resources" to liquified metal fast breeder reactor program). A year earlier the D.C. Circuit Court of Appeals had been critical of policy in the environmental area as being "established by default" and of "inaction and environmental decisions [which] continue to be made in small but steady increments that perpetuate the mistakes of the past without being dealt with until they reach crisis proportions," *Natural Resources Defense Council v. Morton,* 458 F.2d 827, 836 (D.C. Cir. 1972) (sale of oil and gas leases). In *Sierra Club v. Morton*, 514 F.2d 956 (D.C. Cir. 1975) *cert. granted sub. nom., Kleppe v. Sierra Club,* ___U.S.___, 96 S.Ct. 772 (1976) the court stated that programatic EIS's can be required even if the agency is granting approval in a series of actions which it does not overtly define as a "program."

PROCEDURE FOR APPLICANTS AND INTERVENORS

On occasion, the various agencies concerned with developing policies, granting approvals, and evaluating proposals have cooperated in the preparation of environmental impact statements. For example, the Department of Interior and the Federal Power Commission entered into a memorandum of understanding to jointly prepare the Alaska Natural Gas Transportation Systems EIS (Statement of John S. Smith, *supra* at 40-41, and n.2). Jurisdictional problems caused the agreement to be recinded subsequently, but the two agencies' staffs continued to work cooperatively.

With regard to the preparation of environmental reports and the documents submitted by an applicant for § 7 certification (which are de facto utilized in conjunction with applicants for a § 3 order approving imports) the Commission has issued Order No. 85 (June 7, 1973). Requirements of this Order particularly relevant to LNG terminals include: an identification of equipment and the submission of working drawings (*Id.* at 33); a description of land uses and a listing of the locations of major transportation corridors nearby such as ship channels and aviation traffic patterns (*Id.* at 35); a description and analysis of impacts resulting from accidents and natural catastrophes and the capability of the facility to absorb the predicted impacts (*Id.* at 40); a discussion of alternatives to the proposed action showing the systematic procedure used to arrive at the final proposal including a balancing of environmental costs and benefits (*Id.* at 47). "All realistic alternatives must be discussed even though they may not be within the jurisdiction of the Commission or the responsibilities and capabilities of the applicant." (*Id.*) This last requirement drew criticism at the hearings but the Commission declined to modify it. It did say, however, that it would apply a rule of reasonableness as articulated in *Natural Resources Defense Council v. Morton*, 458 F.2d 827 (D.C. Cir. 1972) where it was said that "NEPA was not meant to require detailed discussion of the environmental effects of single 'alternatives' put forth in comments when these effects cannot be readily ascertained and the alternatives are deemed only remote and speculative possibilities." (*Id.* at 837,838) (Quoted in FPC Order No. 485 at 6.)

The timing of the issuance of the final environmental impact statement has recently been before the United States Supreme Court, *Aberdeen and Rockfish RR v. S.C.R.A.P.*, 442 U.S. 289, 95 S.Ct. 2336, 2355-56 (1975). The court said that the final EIS must accompany the agency's proposal through the agency review process where the agency is initiating the action. On the other hand, where the agency is responding to proposals from the regulated parties the final EIS need not be prepared until the agency "reports". However, if an agency has failed to give written consideration to environmental issues, this failure is reviewable whether or not the agency's order or rule making is otherwise ripe for review (*Id.* at 2355). Thus, in the case of the application for an importation permit by a single applicant it would seem that the issuance of the FEIS could be contemporaneous with the Commission's order. On the other hand, if the FPC were to formulate site suitability criteria or were to promulgate regulations concerning terminal construction or methods for computing allowable or tolerable levels of risk this would be more on the order of a programatic EIS initiated by the agency and the FEIS would have to be available at the time the proposal was made public and prior to the public hearings. (*Id.* at 2356). In any case the agency must not abdicate its responsibility to consider, evaluate, and articulate environmental impacts by passively accepting the applicant's draft EIS. It must formulate the FEIS. (*See*, *Green County Planning Bd. v. FPC*, 455 F.2d 412 (2d Cir. 1972).)

To the extent that the FPC treats § 3 importation orders de facto like "public convenience and necessity" certification proceedings under § 7 of the Natural Gas Act, the procedural sequence would normally proceed in the following order: the applicant would file his application and supporting exhibits; the proceedings would be duly noticed in the Federal Register with third parties having thirty days to intervene; the FPC staff would study the proposal and prepare its own "workup"; if a public hearing were requested by intervenors or the FPC, it would be held before an administrative law judge and typically the direct testimony of the applicant, FPC staff and intervenors (if any) is filed ahead of time in written form and the oral portion of the hearing is confined to cross-examination of witnesses and experts; after the completion of the evidentiary hearing, the administrative law judge will issue his or her initial decision as to which parties may take exceptions before the record is presented to the Commission. These in turn may be reviewed by the five member Federal Power Commission and if any party is dissatisfied with the Commission's decision it can petition for a rehearing within thirty days; if the petition for rehearing is denied or if the third party is still dissatisfied, a judicial review may be had in the Circuit Court of Appeals, either in the District of Columbia or in the District where the principal facilities involved in the application will be or are located. The format of the application and the required exhibits are specified in 18 C.F.R. § 157.

STREAMLINING FOR SIMULTANEOUS CONSIDERATION OF ALTERNATIVES

Applications of entities wishing to sell, transfer, or receive natural gas (either in gaseous or liquid form) from Alaska's north slope and its associated continental shelf to other states of the United States will be expedited under Public Law No. 94-586 which was signed into law on October 22, 1976.

In this legislation the FPC is directed to review all applications pending concerning such natural gas as well as "other reasonable alternatives" for the transportation of such gas and to deliver its recommendation for a single system by May 1, 1977 (S. 3521, § 5(b)). *See* Appendix, Exh. 6.

The Commission must consider and discuss in its reports the following factors: (1) projected energy supply and demand for the United States in each region including alternative fuel supplies and deliverability of natural gas; (2) the impact upon competition; (3) transportation costs and delivered prices for each region of the country over the economic life of the natural gas transportation equipment; (4) the extent to which, if at all, the system could be used for other natural resources in addition to Prudhoe Bay gas; (5) environmental impacts; (6) safety, efficiency and potential for interruption; (7) construction timetables; (8) feasibility of financing; (9) supporting reserves, both proven and probable; (10) cost to consumers; (11) capability and cost of expanding the system to transport additional volumes in excess of initial system capacity; (12) estimates of capital and operating costs. (*Id.* § 5(c)). The Commission's report is to be a matter of public record. Other agencies and interested parties would have until July 1, 1977 to submit reports to the President commenting on the recommendation of the FPC with regard to their own expertise in areas of environmental impact, safety, international relations, national security, financing, impact on the national economy and relationship to other aspects of national energy policy (*Id.* § 6(a)). By September 1, 1977, the President shall decide and issue his decision as to which Alaskan gas transportation system, if any, shall be approved (the President may defer his decision up to ninety days). He shall decide this on all the information provided him as to which system, if any, best serves the national interest and, additionally, shall consider specifically the impact toward reducing the dependency of New England and the middle

Atlantic states on imported oil. The President's decision shall be transmitted immediately to the Senate and House of Representatives on the first day that both are in session, accompanied by a detailed report (*Id.* § 7(a)(1) and 7(b)). If public financing is foreseen in whole or in part, the President's report shall make a recommendation concerning the use of federal financing authority (*Id.* § 7(c)). Within twenty days of the President's decision being delivered to Congress the FPC shall issue a public report commenting on that decision (*Id.* § 5(g)). The President's decision shall become final upon enactment of a joint resolution of the House and Senate in the first period of sixty calendar days of continuous session after the receipt of the decision. If Congress has not so acted within the sixty days the President has thirty days in which to propose a new or modified decision and deliver it to Congress (*Id.* § 8(a)(b)). Procedures are built into the bill whereby debate is limited and filibustering is prohibited in order to expedite Congressional review. Additionally, the Council on Environmental Quality, within twenty days of the transmittal of the President's decision to Congress, shall provide an opportunity for any interested person to present oral or written data, views or arguments on the legal and factual sufficiency of the environmental impact statements prepared in connection with the President's decision. It shall submit its report and summary of testimony to the appropriate committees in Congress (*Id.* § 8(f)).

Actions of federal officials or federal agencies under the act shall not be open to judicial review although claims contesting the validity of the act itself may be brought within sixty days of the enactment of the joint resolution by Congress. Similar review is afforded claims alleging infringement of Constitutional rights or actions beyond the scope of the authority conferred by the act. Exclusive jurisdiction is laid in the District of Columbia Circuit Court of Appeals acting as a special court and assigning such challenges docket preference "to the greatest extent practicable." The court must render its decision within ninety days unless a longer time is found to be required to "satisfy requirements of the United States Constitution." Further judicial review is limited to a petition for certiorari with the United States Supreme Court to be filed within fifteen days after the decision of the Court of Appeals (*Id.* § 10).

Other features of the bill of interest include making exports of Alaskan north slope natural gas in excess of one million cubic feet per day are contingent upon a Presidential finding that "such exports will not diminish the total quantity of quality or increase the total price of energy available to the United States and are in the national interest" (*Id.* § 12). It is unclear whether the daily quantity limitation is for individual projects or is cumulative for all exports having their origin in north slope production. Also any recommended system must include plans for direct delivery of Alaskan gas to states both east and west of the Rocky Mountains.

Finally there is a provision requiring equal access to Alaska natural gas transportation systems. This effectively would prohibit the practice of giving priority to equity users. Exactly what the implications of this would be with regard to LNG carriers is hard to foresee. At the very least, it seems difficult to convert what is a classic case of dedicated private carriage to a situation of common carriage, especially when receiving and vaporization plants may be sized in reliance upon the size of the LNG carrier fleet which would serve them.

In addition to expediting otherwise protracted administrative proceedings and judicial review, the proposed legislation requires the simultaneous evaluation of and selection among (or rejection of all) competing proposals for getting the north slope gas to United States markets. Centralized planning seems desirable in this regard, not only from the environmental standpoint but in terms of the public interest and from the demands on the capital financing market. Second, the legislation will inject an overtly political body, Congress, as well as the Executive Branch, into the decision making process. Although reasonableness of the decision and the definition of the public interest are not open to judicial review, the provisions for abbreviated administrative review and for hearings both by the Council of Environmental Quality and by the Congressional committees, and the public nature of the various reports, should ameliorate that shortcoming to a large degree. Moreover, the traditional scope-of-authority inquiry and constitional issues are open to judicial review.

The concept of having procedures to determine which delivery systems will be utilized when there are competing sytems is not only logical and efficient, but is virtually necessary in order to attract investors to the respective projects. In most cases economies of scale require large volumes of gas to be transported before there is a reasonable return on the investment. In the case of North slope gas, virtually the total production would have to be dedicated to a system to make it attractive to investors. Thus the competing routes and methods of transport are virtually mutually exclusive.

In *Ashbacker Radio Corp. v. FCC*, 326 U.S. 327 (1945), the Supreme Court held it to be a mockery to delay the hearing on one of the applicant's request for a broadcast frequency when the FCC had already awarded the frequency to another applicant. Professor Davis has said of *Ashbacker* "the effect of the holding seems to be that an applicant is entitled to a comparative hearing . . . whenever an allegation is made that two or more applications are mutually exclusive" (K. DAVIS, ADMINISTRATIVE LAW TREATISE 575 (1958)).*

TECHNOLOGICAL ALTERNATIVES

There are of course a very large number of alternatives which might conceivably be considered, but three examples will suffice to show the types of things which may usefully be considered. Columbia Gas, operator of the facility at Cove Pt., Maryland, decided that cryogenic pipes could be encased in an underwater trench to reach from an offshore island pier, where there was suitable depth of water for the LNG carrier, to the terminal facility ashore. Environmentalists had raised objections to the long trestle or causeway supporting the pipes, and the alternative solution proved to be technologically feasible. (*See* Anderson & Daniels, *LNG Terminals: Existing and Proposed Systems Compared*, Pipeline & Gas Journal 44, 47 (September, 1975)). Another source of environmental concern has been the cooling of sea water used in ambient vaporizers. While studies of cooling water used by nuclear power plants have generally shown that a few degrees warming has not been harmful to aquatic life or has been harmful only for a very limited radius around the outflow pipe, it is relevant to compute the volume of water effected and the temperature gradient involved. Western LNG Terminal Co. which is proposing to build an LNG terminal at Oxnard, California, plans to use seawater exchange vaporizers for its base-load vaporization needs. At ultimate project development there would be thirty-six such seawater vaporizers using a total of 450,000 gallons per minute. The return seawater would be 12° Farenheit cooler than the water when it entered the vaporizers. At the Oxnard facility, the water would be supplied from the Southern California Edison Co.'s Ormond Beach electricity generating station. When that power plant is operating at full load the cooling water used by it is raised 30° Farenheit above ambinet ocean temperatures, thus a 12° drop in temperature would not leave the water below ambient temperature, but would actually help cool it back toward that temperature from the heating it received in the power generating plant. (*See*, Pacific Indonesia Project, DEIS 11-12 (FPC May 1976)). Studies by Dames & Moore of the Ormond Beach generating station effluent have shown no measurable negative biotic impacts have occurred in the outfall area as a result of thermal discharges exceeding the ambient seawater temperature by as much as 30° Farenheit. (Pacific Indonesida Project DEIS 110 (FPC May 1976)).

Finally, seawater exchange vaporizers often require biocides to be added to the water to keep the exchanger tubes free of marine encrustation. Obviously if these biocides are added in large quantities, and if they are not subsequently neutralized, they might have an adverse effect on marine life back in the ocean when the water is returned. (*See*, Findings of the California Coastal Agency in conjunction with issuance of its "Policies on LNG Facility Siting"; Anderson & Daniels, *LNG Terminals . . .*, *supra* at 66).

Some innovative symbiotic relationships have been envisioned for the potential LNG terminal in Newport, Oregon in that a refrigerant might be shared between an adjacent ice plant and the vaporization equipment at the LNG terminal to accomplish the heat transfer needs of both facilities at a reduced cost.

RISK ANALYSIS

In order to better assess the safety of proposed LNG transport and terminal operations, sophisticated risk analyses using logic trees, mathematical simulations, and drawing on the disciplines of physics, fluid dynamics, gas dynamics, metallurgy, statistics and higher mathematics have been developed. Essentially the inquiries proceed as follows: The probability of a leak-producing event (ship collision, tank or pipe rupture, tank penetration by missle or aircraft, or externally caused rupture, *e.g.*, earthquake, hurricane or tsunami) is computed. This computation in itself is really a two-part computation involving the probability of the event occuring and also a determination of the conditional probability that having occurred, sufficient forces and energy will be involved to cause a

**See* chapter end *infra* for Alaskan gas developments.

rupture. These probabilities are then multiplied together and are usually annualized to fit the concept of annual risk of an LNG spill. The second step is to compute the LNG outflow and from this, to postulate pool size and location. Instantaneous outflows are assumed in most of the models. The third step involves heat transfer computations to establish a rate of vaporization. The following step introduces gas dynamics to determine the configuration of the plume, its gravity flow, its wind transport, the entrainment of water vapor, and turbulent mixing. The next step determines the probability of ignition and the radiant heat flux falling upon given targets from plume and/or pool fires. The penultimate step is to make assumptions about the number, location and vulnerability of human targets. Then the product of these probabilities is obtained to assess the ultimate risk of mortality which is site-dependent for any given terminal location and environs. Some of the commonly accepted measures of risk are fatalities, fatalities per year, and fatalities per person exposed per year.

There are several research organizations engaged in generating risk assessments in this area or in related areas. A detailed description of the technqiues of each of these organizations and their conclusions with regard to various proposals will not be attempted. Instead, the principal techniques used will be identified and described in general terms. Sources of basic data will be identified and illustrative outcomes for at least one terminal proposal will be reviewed. Ambiguities or dubious assumptions will be noted when there is a possibility of producing a material bias in the ultimate assessment.

LNG CARRIER CASUALTIES

Science Applications Inc. developed a sophisticated risk assessment for the Western LNG Terminal Co. Its model postulates that ships get into collisions because of random movements, not in accordance with navigation rules or prior plans. The expression "random movements" does not necessarily relate to capricious or involuntary rudder positions. Rather it refers to the "collective ensemble" of human error in judgments and oversights and mechanical failures which cause ships' maneuvers to deviate from the prescribed or anticipated safe patterns. (Letter from Lawrence Gratt and Eugene Chen of SAI to author dated October 26, 1976). The method defines an area of interest called a "transit zone" which is roughly square in configuration. Using specified velocities, the time it will take a ship to transit the zone moving parallel to one of its edges can be computed. Base data statistics are used to compute the probability of encountering another ship in the transit zone. Knowing the number of transits in the general vicinity per year, that number can be divided into the number of seconds in a year to find the probability of a ship being within the zone during the number of seconds it takes the LNG carrier to complete its transit. The more difficult feat is computing the probability per unit time of a collision given that both of them are in the same zone and on a random course. For this it is important to know the size and relative motion of the two ships. Since the relative bearings of ships will remain constant if they are on a collision course, SAI has constructed an expression for the flux of colliding ships at specific angles. Since the ships are not non-dimentional points, but in fact have vast length and substantial width, a "target cross section" is computed for use in the formula. Using the target cross-section of each ship and relative velocity of closing it is possible by trigonometric manipulation to determine the flux. This flux can then be integrated over all possible collision angles. Finally, a collision parameter is introduced to take account of the fact that not all ships will be maneuvering into collision at all times within the area under study. SAI developed a weighted parameter by comparing the totally stochastic prediction of accidents against the history of actual collisions in the ports of Los Angeles, Long Beach, Boston, New York, Tampa, Galveston and Mississippi River delta. A specific parameter for each port area was derived. The individual parameters were then combined after being given a weight proportional to the square of the traffic transiting the zone to which they refer. (Science Applications Inc., LNG Terminal Risk Assessment Study for Oxnard, Calfironia, Appendix 5.A and p. 5-19). Even lacking empirical collision data, it is felt that a collision parameter can be approximated from "fundamental information on general human behavior, equipment reliability, etc." (Chen, "Analysis of Ship Collision Probabilities" in Papers Presented at Fourth International Symposium on Transport of Hazardous Cargoes by Sea 237, 246 (USCG/NAS 1975)).

Base data for the SAI study and for most of the other collision risk assessment models are derived from the Waterborne Commerce Statistics compiled annually by the Corps of Engineers and from Accident Statistics of the U.S. Coast Guard. These statistics were studied by SAI for the seven traffic areas previously mentioned. The Army Engineers statistics are compiled by vessel draft while the Coast Guard statistics are compiled by displacement tons. Therefore further postulations concerning the relationship of draft to displacement must be made to convert the data. Coast Guard statistics differentiate between tankers, passenger/cargo ships, barges and tugs so tanker data is used as tankers most closely resemble LNG carriers. Tankers were assumed to proceed at an average speed of 8.9 knots through the areas in question with tugs being slightly slower and cargo vessels being slightly faster. SAI projected 3,000 transits of ships with displacements over 1,000 tons in a year's time for purposes of this study. In the vicinity of Oxnard, California, this appears to be a realistic projection.

The square area used in the SAI study lies between the north-bound coastwise traffic lane and the coastline. Inbound LNG vessels from Alaska would have to turn to port and cross in front of the northbound traffic lane. Vessels arriving from Indonesia would probably cut across both northbound and southbound lanes. Coastwise traffic in the lanes would be presumably much higher than in the traffic area SAI has modeled. While each lane is fairly narrow and transit time would be relatively short, this could prove a deficiency in the application of their model. On the other hand, the northbound (closest) lane is at least four miles offshore so that any collision that took place in the lane would require that the LNG vapor plume travel at least four miles to reach inhabited mainland. (*Id.* 5-2).

The FPC staff in preparing the draft environmental impact statement for the Pacific Indonesia Project, which was also to use the Oxnard Terminal facility, determined that tanker casualties were related to tanker transits with a probability of 4.4×10^{-3} casualties per trip. Staff applied this probability which had been generated by the Oceanographic Institute of Washington in its "Offshore Petroleum Transfer System for Washington State, a Feasibility Study" (1974) which was based upon screening of empirical records for seven traffic areas: Chesapeak Bay; Delaware Bay; the Gulf Coast; Los Angeles and Long Beach; New York; Puget Sound; and San Francisco. This accident rate includes collisions, rammings and groundings. Using the well-known study by Porricelli, Keith & Storch ("Tankers and the Ecology" 67 (SNAME Transactions 1971)), FPC staff factored the total casualties into the three categories mentioned above. Then, using casualty reduction factors derived from the Coast Guard's "Vessel Traffic Systems: An Analysis of Port Needs" (1973) the staff had the capability of determining whether a vessel traffic system could further reduce various types of casualties. However, there is no VTS proposed for Oxnard so these factors were disregarded in this particular study. Using the casualty weighting factors, 32% of the cascualties were assumed to be collisions, 29% rammings, and 39% groundings. (Pacific Indonesia Project DEIS 310 (FPC May 1976)).

Having thus predicted the number of collisions, rammings and groundings, the staff proceeded to estimate how many of these would cause the release of LNG cargo. Relying on statistics collected by Porricelli, Keith and Storch in their article "Tankers and the Ecology", *supra* which showed what percentage of casualties lead to a spill of oil when oil tankers were involved and which indicated spill location using the categories piers, harbors, entrances, coastal and sea. Staff considered in this statistical breakdown only those spills in which the discharge was in excess of 1000 tons (a 1000 ton spill of LNG would be approximately 2000 cubic meters or 8% of the capacity of one of the cargo tanks on a 125,000 cubic meter LNG carrier).

Relying on recent studies of grounding incidents involving forty-three cases, the staff found that only 15% resulted in penetrations exceeding a height equal to the beam of the ship divided by fifteen. Designs for the present second generation and the proposed third generation LNG carriers indicate that cargo tanks would be further from the outer bottom plating than the distance derived from this ratio and thus a "reduction factor" of 0.15 (100% less 85%) was applied to the grounding projections. (Pacific Indonesia Project DEIS (FPC May 1976) at 311-313, citing, on bottom penetration, J.C. Card, "Effectiveness of Double Bottoms in Preventing Oil Outflow from Tanker Bottom Damage Incidents", *Marine Technology* 60-64 (Jan. 1975)). It would appear that there is a possibility of including this factor twice since a similar reduction factor was used to generate the pollution-causing-incident factor mentioned earlier. Insofar as groundings are concerned, it is entirely possible that the reason less than 20% of the vessels grounding spilled oil was that some of them already had double-bottomed tanks. It is true that most vessels at the time of the Porricelli study did not have double bottoms, but at least in theory this seems to make the reduction factor somewhat suspect.

Staff applied a similar reduction factor to collisions based on a 1973 Coast Guard study (Bovet, *Preliminary Analysis of Tanker Grounding and Collisions* (U.S.C.G., Jan. 1973)), in which fifty-two collisions studied showed the median depth of penetration was 5.2 meters. A somewhat earlier study analyzing sixty-seven collisions found a median penetration depth of 4.8 meters (Comstock & Robertson, *Survival of Collision Damage Versus the 1960 Convention on Safety of Life at Sea,* 69 SNAME Transactions (1969)). These same two studies indicated that in 75% of the collisions studied the penetration depths exceeded the depth of the inner hull of an LNG tanker. As a result, the staff uses a 0.75 factor for collisions. It should be pointed out that if spherical tanks are used, this reduction factor may be conservative since only at the point of tangency will the tank be as close to the outer hull as the distance between the inner hull and the outer hull.

With regard to ramming, it was felt that the use of bow thrusters (especially helpful in docking procedures) and the large mass of metal forward of the forwardmost tank would both tend to mitigate tank rupture from this type of incident. There is approximately 110 feet of hull structure forward of the number one tank. (Pacific Indonesia Project DEIS 317 (FPC May 1976)). Computations have indicated that speeds in excess of thirty knots would be necessary for rupture of the forward tank in a head-on collision with an elastic object, *i.e.* another ship. FPC staff takes the position that this is greater than the speed of which LNG carriers are capable, but this may mask the fact that in a head-on collision (as opposed to ramming an anchored ship) where both ships had forward motion, their velocities would be additive. On the other hand, if an inelastic collision occurs (say with a bridge pier), any speed above 10 knots could cause rupture (*Id.*). The staff finally decided upon a 0.15 factor. The pollution-causing incident statistics showed that only 11% of the 222 ramming incidents studied caused an outflow giving credence to the staff's choice.

A somewhat similar methodology was used by the FPC in its Final Environmental Impact Statement on Alaska Natural Gas Transportation Systems. The analysis there took its original probabilities for a tanker incident from historic Coast Guard records of Cook Inlet and Price William Sound. There seem at least two serious objections to this method. It ignores the fact that traffic would increase from roughly sixty-three tanker trips per year in 1974 to a much higher number of trips when the LNG project reaches its ultimate capacity. Four hundred twenty-five "deliveries" per year are projected for the Gravina Point facility. Since the LNG carrier must enter in ballast and depart laden, this figure should be doubled for 850 transits. This would be a more than fourteen-fold increase in the traffic. Presumably traffic density has some correlation to collisions (the only reported casualties involving tankers in the past have been groundings). Second, the size of the tankers serving Prine William Sound ports (principally Valdez) in the past have been small utility tankers with smaller momentum and greater maneuverability than the massive LNG carriers. The FPC report may also be questioned on one of its "reduction factors". The staff uses a collision factor of 0.25 based on the fact that the LNG carriers will have double hulls. As a support theory for this, the staff cites a 1973 study which showed a 73% reduction in oil spills from *groundings*. (El Paso-Algeria Corp., "Report on Environmental Factors for the Marine Transportation of LNG in the Delaware Estuary" FPC Docket No. CP 73-258 (Sept. 1973) cited at Alaska Natural Gas Transportation Systems, FEIS III-409 and II-582 (FPC April 1976)). While the double hulls are indeed useful in protecting the cargo tanks from grounding damage, they are substantially less effective in diverting penetrations through collision (*see* discussion of Pacific Indonesia Project *supra*).

Assuming a casualty has occured and the penetration is deep enough to reach a cargo tank, it is obvious that not every portion of the hull is used to enclose cargo tanks. Moreover, analysis may be relevant to determine whether more than one cargo tank is ruptured in a casualty. Most LNG carriers designs have approximately 66% of the vessel's length devoted to cargo tanks. The various studies of cargo tank vulnerability have indicated the probability of striking a vulnerable area between 66% and 82%. (*Compare*, Comstock & Robertson, *supra*, *and* 4 U.S. Coast Guard Commandant's International Technical Series 55 (April 1974) cited in Pacific Indonesia Project DEIS at 322 *with* Minorsky, *An Analysis of Ship Collisions with Reference to Protection of Nuclear Power Plants*, Journal of Ship Research (Oct. 1959) cited in Alaska Natural Gas Transportation Systems, FEIS at III-410). Admittedly the rupture of a single cargo tank in a severe collision is more likely than multiple ruptures. However, in membrane type tanks, a collision at the transverse bulkhead could rupture two adjacent tanks. It can be shown from Comstock & Robertson's data that the median collision damage length was twenty-six feet and that 30% of the collisions occurred at a location within twenty-six feet of a transverse bulkhead. Staff approximated the probability of a collision being in a position to damage a transverse bulkhead within the cargo tank portion of the hull to be 0.365 (Pacific Indonesia Project DEIS 321 (FPC May 1976)) (arguably this figure is too high due to a computational error (division instead of multiplication) and should only be 0.246) and the rupture of more than two tanks by means of a collision was not considered a credible accident. A possible deficiency in this analysis seems to be that although the reasoning is sound enough as to impact penetration, it may possibly disregard the effects of radiant heat from an LNG fire on or immediately about the ship (spilled from the tanks that did rupture) on the remaining tanks. Although groundings have resulted in the complete rupturing of all cargo tanks in oil tankers, it seems correct that this would not occur with regard to LNG carriers for the purposes of the "worst case" incident since the breakup of a ship due to wave action usually takes place over a period of days and would not produce an *instantaneous* spillage of the LNG. (*Id.* at 321). Instantaneous spills are usually modeled as the "worst case" because of the large volumes released. In actuality non-instantaneous spills (say those lasting twelve to fifteen hours) could also present hazards if a favorable wind direction shifted over time to a direction that blew the plume to a more populated area.

In its September 1976 hazard analysis (Cook Inlet-California DEIS) the FPC staff used some different assumptions which it feels are more realistic. Only those casualties involving tankers of 5000 deadweight tons or more oil escaped were treated as pollution causing incidents. Then the data was examined as to frequency of cases where 20% of the cargo was spilled (*Id.* at II-196). This figure was used because the FPC staff abandoned its previous position that a two-tank spill was the worst credible accident and now feels that a one-tank spill is the worst credible accident (*Id.*). Previous studies by FPC staff had included all spills where 1000 tons or more of cargo had been spilled. The effect of these three changes--(a) counting only larger spills, (b) factoring down to the probability of a 20% (or greater) volume spill, and (c) assuming smaller (*i.e.*, one tank) outflows--was to substantially reduce the computed probability of a spill (from 2.57×10^{-3} to 5.59×10^{-4}) and of a plume reaching land (from 1.18×10^{-4} to 2.90×10^{-5}). (*Compare* Pacific Indonesia DEIS 329 (FPC May 1976) *with* Cook Inlet-California DEIS II-216 *both* for Oxnard, California although the former is based upon 50% more arrivals.)

For ship-related casualties, *e.g.*, collisions, groundings or rammings while maneuvering offshore or moored to an extended offshore pier, these modifications are probably realistic since usually only maximum outflows are capable of producing plumes which could reach populated areas ashore. However, if such maneuvers are close ashore (*e.g.*, in rivers or canals) or the piers are shoreside (*e.g.*, Distrigas' pier in Everett, Massachusetts) they will underestimate the risk. That is, smaller outflows could *still* produce plumes that could endanger those ashore but the probabilities of such lesser spills have *not* been cumulated in the overall risk assessment.

Another, less substantial, change in the FPC staff's model resulted from a broader data base (two additional years) for allocating casualties into the collision-ramming-grounding categories. The casualty rating factors were adjusted for collisions from .32 to .38, for rammings from .29 to .27, and for groundings from .39 to .35 (*compare* Pacific Indonesia DEIS 310 (FPC May 1976) *with* Cook Inlet-California DEIS II-181, 191 (FPC Sept. 1976)).

The FPC has used a vessel traffic system reduction factor of 0.25 for LNG traffic approaching or departing a liquefaction terminal on Price William Sound. This is on the assumption that the Valdez VTS will extend out into the Sound which appears consistent with current planning. While it is true that some studies have predicted accident avoidance through vessel traffic systems will reduce probability of rammings by 85% (*see* Computer Sciences Corporation, "Final Report of Vessel Traffic Systems Issue Study, "Appendix G. at 11 (March 1973)), these efficiencies apply more to stationary targets, *i.e.*, anchored or moored ships, or aids to navigation, sunken wrecks, etc., than to the situation where two or more ships are actively maneuvering. The FPC staff cited Coast Guard evaluations of vessel traffic systems in the Saint Lawrence Seaway and in the Port of Rotterdam showing a four fold reduction in ship collision (Alaska Natural Gas Transportation Systems FEIS at III-410 (April 1976)).

Science Applications, Inc. computed its risk probabilities on the basis of scenarios involving a 37,500 cubic meter spill from an LNG carrier. This would represent the entire capacity of the largest single tank on a third-generation carrier (Science Applications, Inc., "LNG Terminal Risk Assessment Study for Oxnard, California", 8-78 (Dec. 1975)). The FPC staff has computed potential outflows based on a 740 cubic meter spill which is one standard deviation above the mean observed outflow of 435 cubic meters for oil tankers in the vicinity of harbor entrances. The exponential formula for computing this potential in probabilistic terms was derived from Oceanographic Institute of Washington's study of "Offshore Petroleum Transfer Systems for Washington State" (December 1974). Using this formula FPC staff concluded that the chance of a spill size exceeding 3300 cubic meters was only slightly better than one chance in 100. (Alaska Natural Gas Transportation Systems FEIS III-410-413 (FPC April 1976). Although it is not entirely clear, it appears that this is derived from a data base of tanker casualties in which oil spills of some size actually occurred. It might be questioned whether additional factors implicated in the rupture of an LNG tank, such as the potential for fire and cryogenic embrittlement of hull metal resulting in greater dynamic stresses on the tanks themselves might cause this reduction factor to be overstated. This component of the hazard analysis (which led to a "negligible" probability of a spill size large enough for the plume to reach shore at Oxnard) has not been utilized in subsequent studies and was only one of two apparently parallel analyses in the Alaska Natural Gas Transportation Systems FEIS (*compare* Vol. I Appendix A *with* Vol. III Appendix C).

Science Applications Inc. has extended its collision computations to include rammings of a moored LNG ship or of the 6000 foot trestle pipeway for the Oxnard terminal. Here it used the 3 chances in a 1000 probability derived from the nuclear reactor report attributing such collisions to human error e.g misreading radar or misconstruing nighttime shorelights while heading for Port Heuneme some two miles away. (Science Applications, Inc., "LNG Terminal Risk Assessment Study for Oxnard, California," (Western LNG Terminal Co.)(December, 1975) citing "Reactor Safety Study and Assessment . . ." WASH-1400 (Oct- 1975)). Nikiski LNG terminal in Alaska's Kenai Peninsula has relatively strong tides and these have proven to create some hazards involving vessels colliding with LNG vessels loading at the pier. In one near-incident the Chevron oil tanker, MV Tuttle, was attempting to dock near the end of a flood tide but her crew were unable to secure the vessel before the ebb tide had started. After trying for an hour to berth itself, the Tuttle aborted its attempt but because of its proximity to the SS Polar Alaska at the LNG pier there was a danger of the ship drifting out of control into collision with the LNG carrier. Although the velocity involved would have been small and it is likely that collision would have been more of a glancing or scraping impact than a perpendicular impact, such local navigational problems must be taken into account (*see* Alaska Natural Gas Transportation Systems FEIS, II 6-25 (FPC 1976)).

SAI's model also includes a more sophisticated derivation of the tank rupture probability based on the Minorsky method (Science Applications, Inc., "LNG Terminal Risk Assessment Study for Oxnard, California 5-25 through 5-30 (December 1975) citing Minorsky, *An Analysis of Ship Collisions with Reference to Protection of Nuclear Power Plants*, SNAME Journal of Ship Research (October 1959)). For these purposes the struck ship is considered as having no forward motion since such motion contributes only to the length of the gash rather than its depth of penetration (*Id.* at 5-26). Collision energy is a function of the mass of the striking ship, the hydrodynamic mass of the struck ship, the velocity of the striking ship and the angle of collision (*Id.*). The "structural resistance to deformation" can be computed as a function of penetration depth and, by setting depth at seven feet (felt to be the closest a cargo tank would be to the outer hull), a minimum speed for the striking ship at any given angle can be computed. Using the data base of Coast Guard and the Waterborne Commerce Statistics and analogizing LNG carriers to tankers, the probability of an LNG carrier being the struck ship in a collision can be derived. This is factored by an 0.82 probability that it will be hit within one of the vulnerable "cargo tank" areas and in turn factored by the probability of the striking ship having the necessary velocity in excess of the minimum for penetration. For collisions the angle of impact is twice as likely to be in the range of 70° to 110° than in the areas from 0° to 69° and 111° to 180° combined. This is not true where the LNG ship is rammed while at dock since then it is not a maneuvering vessel. In that instance, the disperion of angles of impact seems to be uniform throughout the range (*Id.* 5-27 through 5-30).

Booz-Allen's 1973 study for MARAD utilized a simplified risk analysis based upon U.S. Coast Guard Casualty Incidents Data and Army Engineers' Waterborne Commerce Statistics (essentially the same data base used by most of the collision risk analysis studies as a starting point). Booz-Allen focused on the ports (Boston, Providence, New York, Delaware River, Chesapeake Bay, Savanna, Galveston and Los Angeles) thought to be likely sites of import terminals. Adjusting for ships over 1000 gross tons and looking only at incidents where monetary damage to the vessel exceeded $100,000 or losses to vessel and cargo combined exceeded $150,000, probabilities of serious incidents per transit for each of the eight ports were readily developed. Determining from operator proposals how many ships would be dedicated to each port, knowing their average speed, and the distance of the trade route in question, the number of transits in loaded condition per port was derived. Applying this number of transits to the probability-of-casualty-per-transit factor, a major incident risk per year for each port was developed (Booz-Allen, *supra* VII-6 through 7-9).

Several nontechnical observations can be made at this time with regard to casualties to LNG carriers. LNG carriers are designed with superstructures aft; thus the bridge is at least 700 feet astern of the bow. For personnel on the bridge this creates a sizeable blind spot in the water dead ahead of the vessel. The blind spot is enlarged in vessels utilizing spherical tanks since the upper hemispheres of these tanks rise high above the weatherdeck. An elevated bridge is being employed on the General Dynamics design to partially alleviate this problem. However, in constricted waters one would expect a lookout forward either in the crow's nest in the foremast forward of the No. 1 tank or in the eyes of the ship both of which are provided with telephonic communications with the bridge. On the General Dynamics design the 3 cm. radar antenna is on the foremast providing a completely unobstructed picture forward of the vessel. A 10 cm. radar antenna is located on the top of the pilot house resulting in a two-ship length blind spot dead ahead for surface echoes (*i.e.*, small craft). The overall radar coverage of these combined systems more than satisfies the 5 1/2° deflection rule (Abstract Specification for 125,00 cubic meter LNG ship by General Dynamics at 18).

The various ventilation systems and gas detectors required of ships built in compliance with the IMCO Gas Code along with the correlative temperature and pressure indicators should greatly minimize the possibility of operational fires or explosion on board the ship or of tanks bursting through overpressure or underpressure. However, it must be noted that the best designed ship may be poorly maintained and the most foresighted alarm system may be disregarded. Thus training and indoctrination of personnel in maintaining the systems, heeding their warnings and obeying standard operating procedures cannot be over-emphasized.

Fatigue failures and brittleness failures of hull material and tank structures should be virtually eliminated by adherence to IMCO Gas Code requirements which are predicated upon North Atlantic sea stresses. Since some of the proposed LNG trade routes involve Alaskan and Russian seaports, air and water requirements may have to be more restrictive than permitted by the general provisions of the IMCO Gas Code. This is particularly true since LNG vessels are designed as shallow draft vessels not requiring deepwater ports. With cargo capacity roughly equivalent to 160,000 deadweight ton displacement tankers and lengths approximately the same as such vessels, it is apparent that the LNG carriers have much greater freeboard. Moreover, spherical tanks designs will have an even higher sail area. Under such circumstances and allowing for wind chill, the atmospheric ambient temperature will be controlling over the seawater temperature.

LOADING AND DISCHARGE

Science Applications, Inc. has employed a fault tree analysis in assessing the risks and probabilities inherent in the loading or discharge operation. In this context, the fault tree schematically depicts component failure modes, external events and human acts or omissions capable of producing systems failures. For many of the initiating events at the "bottom" of the tree actual probabilities are unknown because there is no data base available (either from want of recordkeeping or because the system is new and unique) or because no one has yet attemped to mathematically model the occurrence of such an event. In such cases, probabilities are assigned "guesstimates" usually derived through the use of the Delphi method of group discussion featuring independent appraisal, statistical manipulation of the individual inputs, and feedback to the group for further discussion of appraisal, etc. This iterative technique is believed to produce reasonably accurate "ballpark" estimates providing the members of the group have specialized knowledge in at least one area relevant to the event under appraisal.

Such schematics are not only invaluable in troubleshooting or in trying to anticipate failure modes but also serve as a graphic and easily understood way of cumulating probabilities in a complex system. Two types of logic "gate" are used. The "and" gate depicts the situation where the co-existence of all input events is required to produce the output event. The "or" gate depicts a condition under which the output event will exist if any one or more of the input events exists. Thus, working upwards through the fault tree one first assigns probabilities to the nonreducible basic events. If two or more of these events feed into an "or" gate the probabilities are summed. If two or more of these basic events feed into the "and" gate the probabilities are multiplied. The resulting sum or product then becomes a probability of the next higher level on the fault tree and so on until the probability of the ultimate occurrence under study is defined. *See* Appendix, Exhs. 16-19 for illustrative fault trees.

Using fault tree methodology SAI developed probabilities for leak of a ship tank not undergoing transfer, leak of a ship tank during transfer, leak in a ship-to-shore transfer system during unloading, leak in a pipeline with transfer not in process, leak in a transfer arm, leaks in storage tanks, and leaks in secondary pump areas (LNG Risk Assessment for Oxnard, *supra* 3-12 through 3-34). Probabilities input to the lowest levels of the fault tree were assigned on the basis of engineering judgment drawing upon the experience (both informal and recorded) of the petrochemical and aerospace industries, upon the probabilities utilized in the AEC's Reactor Safety Study (WASH-1400) (which in turn were partially supplied by the Delphi process), and upon the fourteen year experience of the cryogenic industry. To the extent probabilities were borrowed from the petrochemical and aerospace industries, they were felt to be conservative since the high pressures and temperatures, corrosive mediums, and cyclic temperature variations typical of those applications are not present in LNG operations. (Interview with Gerald Kopecek of SAI on Nov. 1, 1976). On the other hand, cryogenic temperatures would seem to present at least as much potential for failure as high temperatures. The fault trees pertain to a single tank so the probability derived therefrom must be multiplied by the number of tanks per ship and some feeling for the continuous presence of a ship at the terminal area must be developed. At the Western LNG Terminal, for example, 565 ship dockings per year are projected with an average berth-vicinity time of eighteen hours per ship. From this, it can be computed that at any given time there will be an average of 1.15 ship transfers under way. SAI computes that the probability of internal failure of the ship's tanks is only 1.13×10^{-11} per year (*Id.* at 3-15). One thing demonstrated by the fault trees is that in general redundancy pays off since the probabilities of independently actuated fail-safe systems all failing simultaneously is the product of the independent probabilities.

SAI also computed that the probability of a rupture of the ship-to-tanks transfer system which could not be isolated was only 3.6×10^{-9} and felt that this would not appreciably increase the larger risk of ship tank rupture in the vicinity of the pier which was computed as 8.7×10^{-6}. The principal components of that probability were having the LNG carriers struck by either a ship (3.4×10^{-6}) or by a crashing aircraft (4.0×10^{-6}) from a nearby airbase.

SHORESIDE STORAGE

Stratification and Rollover Problems

Shoreside storage tanks are not refrigerated and are not significantly pressurized. Their contents are maintained in liquid form by means of thick insulation which minimizes the inflow of heat which in turn leads to vaporization. Above the liquid within the confines of the tank is natural gas in the vapor form which is allowed to build up to a pressure slightly in excess of atmospheric pressure. This "positive pressure" approach minimizes contamination and ensures that oxygen in the atmosphere will not enter the tank to permit the creation of a combustible mixture. In LNG import terminals there is typically a fairly high rate of throughput and because the terminals are usually supplied by a single source, the density and molecular composition of the gas (given equal temperature) are equal. However, some terminals will be receiving gas from more than one source. For example, Western LNG Terminal may be receiving Indonesian gas and Alaskan gas and may receive gas produced in both the Cook Inlet area and the North Slope of Alaska. Moreover peak shaving LNG facilities which liquefy gas during the summer for revaporization and sale during the winter months have little or no throughput for several months at a time. Even when all the LNG came from the same source field, there is a possibility of differing densities within a tank due to the thermal stratification.

The tendency to stratify has serious implications because of the phenomenon known as "rollover". If a layer of a ship's cargo is fed into the bottom of a tank with an existing heel there is a possibility of a sudden buoyant inversion. This could occur if the upper layer through heat transfer processes vaporizes enough of its light fractions to become of equal density. Similarly, if the under layer, absorbing heat through the tank bottom, becomes relatively more bouyant, inversion could occur. If the under layer should now suddenly rise to the top it will be superheated, vis-a-vis the vapor pressure (or, put another way, in the absense of so great a static head) and can flash vaporize. Once this occurs the gas pressure on the containment vessel is dramatically and rapidly increased. Hopefully the emergency release vents will function before the tank bursts.

A rollover incident did occur in La Spezia, Italy in 1971 while the terminal was receiving cargo from the LNG carrier Esso Brega. In that case it could be shown that the Esso Brega had remained at anchorage in the bay for nearly a month while the lighter components of its LNG boiled off, leaving a dense liquid methane cargo behind. This cargo was warmer and heavier than the heel in the shoreside tank, yet it was loaded under heel. This did result in a rollover, the vapor from which vented through the relief valves for seventy-five minutes (Conference Proceedings on LNG Importation and Terminal Safety 27-30 (NAS, Boston, Mass., June, 1972)). Since that incident terminal operators have developed more sophisticated procedures with regard to tank loading and maintenance. Great efforts are made to equalize pressures. If the transfer pressure of the loading system is adequate for high-velocity flows and the level of the heel in the tank is low enough, stratification can be broken up and mixing can be achieved by the use of an inlet jet nozzel directed in a horizontal plane. Temperature differences are held to a minimum or equalized if possible. Denser feed should be introduced to the top of the tank and lighter feed on the bottom of the tank to facilitate self-mixing, which will delay rollover or will inhibit it entirely. (Grobe, "Characteristics and Operational Aspects of the LNG Terminal" 21 (unpublished, 1975)). Recirculating pumps can also be used in smaller tanks to physically destratify the liquid by pumping the bottom liquid up to the top (Anderson & Daniels, *LNG Terminals . . .*, *supra* at 64; Conference Proceedings, *supra* at 439). Varying the vapor withdrawal rate over an hour can also change the temperature of the top layer (*Id.* at 150). The Columbia Gas terminal at Cove Point, Maryland is designed to allow a complete shutdown of the send-out facilities for two and one-half days without venting any of the normal boil-off in the storage tanks. This is accomplished by packing the boil-off in the first ten miles of terminal-owned pipeline at a pressure of 1250 lbs per square inch (*Id.* at 214).

Elaborate maintenance and operations procedures have been formulated and written out by the Distrigas Corporation of Massachusetts. These procedures not only specify sequentially, step-by-step how various operations are to be performed, but also are punctuated with warnings and explanations of the significance of certain procedures (*see, e.g.*, Purging, Cool-down, and Maintenance Procedures described in Distrigas Corporation's submission to the Federal Power Commission of May 16, 1963, response to question 10, Docket No. CP73-135). For a listing of various safety detectors for a terminal and the sequence of responses to their activation *see* Appendix, Exh. 20. *See also*, description of fire detection and supressing equipment for proposed Western LNG Terminal in Pacific Indonesia Project FEIS 18, 159 (FPC May 1975). The flow control system at Northwest Natural Gas' Portland, Oregon peak-supply LNG plant utilizes permissive logic hardware (designed by Chicago Bridge & Iron and using Square-D solid state devices) to prevent the effectuation of an operation called for by the human operator which might prove to be unsafe in view of system pressures and temperatures.

SAI Penetration Energy Model

Science Applications, Inc. has developed an energy penetration model for objects crashing into the shoreside storage tanks at the proposed Oxnard facility. The Oxnard terminal is within three miles of a naval air station, and is within five miles of the Ventura County Airport. In addition to aircraft traffic, the Pacific Missile Test Center launches missiles from the naval air station property. The mathematical model was developed to take into account air and missile traffic and the probability of crashes. Using the data base maintained by the National Transportation Safety Board in its automated system for on-line analysis and retrieval of accident data (SOLARAD), accident statistics were classified by locality, weight of aircraft, type of crash, and type of flight (Science Applications, Inc., LNG Terminal Risk Assessments Study for Oxnard, California, 6-6 through 6-8 (December 1975)). A 35% growth factor based on FAA estimates for Ventura County Airport forecasted to the year 1985 was employed (*Id.* at 6-25). Using glide-angle computations and trigonometry, the probability of impact is a function of height of tank structure. It was felt that a region of impact on the ground three times as big as the base area of the tank would be a reasonable crash area to consider in the computation. For crashes within five miles of airfields a constant can be developed which represents the proportion of the number of crashes divided by the impact area times the number of operations. For the probability of crashes from aircraft not jetting to and from airfields in the vicinity, commercial airway accident statistics were used for adjacent airways on an in-flight-crash-rate-per-mile basis multiplied by the number of flights per year and again multiplied by the effective (adjusted) area of the facility divided by the ten mile width of the jet route plus twice the distance from the facility to the center of the route (*Id.* at 6-29).

After having developed the probability for a crash into the tank the next step was to develop the kinetic energy computations to find out what penetration will occur. SAI assumed that the crashing aircraft would be nondeforming. This is a conservative assumption since in actuality there would be considerable deformation which would absorb a certain amount of energy (*Id.* at 6-45). SAI developed a computer program, LNGTP, with the input parameters of impact area, tank wall thickness, impact obliquity angle, impact velocity, wall type and tensile strength. Hagg-Sankey formulas and the BRL concrete formula were used (*Id.* at 6-A-1, 6-A-7).

The Western LNG Terminal design calls for the storage tanks to be individually surrounded by concrete dikes eighteen inches thick and seventy-nine feet high (*Id.* at 2-7). Using trigonometry it can be shown that for a tank of the proportions proposed at the Western LNG facility (*i.e.*, 239' outer diameter and 81' side wall), it can be shown that the tank roof will be hit 70% of the time that the structure is hit. In the computer program penetration energy formulas are placed in a subroutine which sequentially runs computations for the outer tank, the perlite insulation in the annular space, and inner tank using the Hagg-Sankey formulas (*see*, Hagg & Sankey, *The Containment of Disc Burst Fragments by Cylindrical Shells*, Transactions of the ASME, Paper No. 73-WA-Pwr2). If exit velocity of the crashing aircraft is zero, the assumption is that the wall was barely penetrated and the aircraft sticks in the wall as a plug or stopper in the Hagg-Sankey computations. If, using the BRL concrete formula the thickness of the wall that can be penetrated exceeds the actual design thickness of the dike, penetration is deemed to have occurred (SAI, LNG Terminal Risk Assessment Study for Oxnard, California 6-44 (December 1975)). The computations show that planes as large as a Grumman Gulfstream II and larger can penetrate the sidewall of a tank above the dike level and can penetrate the roof. Only a plane as massive as a Boeing 747 or 727 however, could penetrate through the concrete dike and through the outer and inner steel tank shells (*Id.* at 6-48 and 6-49). Having earlier computed the probabilities of the aircraft striking the structure and allocating the strikes between roof and sidewall and finally computing the mass of the aircraft and its velocity necessary to penetrate the walls, a penetration probability can be established (*Id.* at 6-50) on an annualized basis. SAI computes that the probability of penetrating the tank and breaching the dike is 9.6×10^{-7} (*Id.*). The significance of the breach of the dike for the evaporation of the escaped LNG and for vapor plume formation will be discussed, *infra*.

SAI performed similar computations with regard to missiles from the test range which might abort their missions and crash into a storage tank or which might collide with their targets in mid-air and disintegrate (or which might be deliberately detonated) sending fragments earthward to impact upon the tank. Similar trigonometry and energy penetration formulas were used as for the aircraft crash study. Specific velocities and masses could be computed since this information is available from the missile test center. The resultant probability of rupture of the tank wall and cement dike was computed to be 8.3×10^{-10} (SAI Oxnard *supra* at 8-163).

In terms of protection from natural hazards, the typical LNG storage tanks have mild steel walls which are positively grounded and afford adequate protection from lightning stikes. Pipelines are similarly grounded. The Distrigas tanks at Everett, Massachusetts are designed to withstand a wind pressure of fifty-five pounds per square foot, which is computed to be the equivalent of a wind velocity of 124 miles per hour (Distrigas Corporation submission of May 16, 1973 to the Federal Power Commission in Docket CP73-135, response to Question 12). The tanks designed for the Oxnard Western LNG Terminal facility are designed to withstand instantaneous wind gusts up to 104 miles per hour (Pacific Indonesia Project FEIS *supra* at 11).

Tornadoes although smaller in size than hurricanes can have extremely high wind velocities and also can create substantial atmosphere under-pressures (in the "eye"). ERDA's predecessor agency, the Atomic Energy Commission, established tornado design criteria for nuclear reactor containment vessels based on internal (rotational) wind velocities of 30 mph, translational velocities of 60 mph and maximum pressure differentials of 3 psi in 3 seconds (Reactor Safety Study, WASH-1400, AEC). Arthur D. Little, Inc. using Thorn's predictive model found an average probability of a tornado striking an LNG facility in Boston to be 5.64×10^{-4} (an order of magnitude less than the probability at a midwest location). A tank manufacturer has opined that double-walled tanks would withstand winds up to 200 mph and 3 psi internal overpressures due to safety factors used in design. If failure were to occur it would probably be at the wall-roof seam which would allow venting of gas but not necessarily spillage of LNG. (Arthur D. Little, Inc., Technology and Current Practices for Processing, Transferring and Storing Liquefied Natural Gas 177-179 (DOT Dc. 1974)).

Earthquake risks can be successfully taken into account by geo-design investigations and the resulting design safeguards. However, the Arthur D. Little study indicated that dynamic loading from sloshing of LNG during earthquake tremors may be an overlooked risk in land-based tank designs (*Id.* at 180-181).*

In addition to impact ruptures, earthquakes and sabotage, two additional problems ought to be considered. First, there is a possibility of a fire inside one of several standing terminal storage tanks (*e.g.*, following an explosion which blew up the tank dome but did not rupture the walls). The effects of the thermal radiation from the first fire on the structural integrity on the adjoining tank walls must be considered. One may assume that the separation or interspacing requirements of the National Fire Protection Association Standards No. 59A must be observed. *See generally*, Appendix, Exh. 29. One set of calculations has been done positing a fire in a topless vertical cylindrical tank of 184' diameter with a liquid level of 128' with an interspacing tank wall to tank wall of 102'. Assuming a sixty mile per hour wind during wintertime at Boston, Massachusetts, it was computed that 14,500 BTU per hour per square foot would be received by the neighboring tank which would heat locally to an equilibrium temperature of 670° Farenheit. Convection cooling from the wind was allowed for in the computations, but inductive cooling along the circumference of the tank shell was disregarded. It was shown that the allowable stress for carbon steel would be within 98% of its stress level for normal temperatures and thus no structural problems should be presented for the outer shell (presumably insulation in the annular space would prevent the inner shell from approaching those temperatures . . . this further assumes non-flammable installation). The same study posited the entire shell to be at the hot local temperature of 670° and found that the boil-off rate would at most be increased by a factor of 2.8 which was close to, although in excess of, the vaporization and compressing plant design load of 2.4 times normal boil-off. (Distrigas Corporation letter to FPC of May 16, 1973, response to question 11, Docket No. CP73-135).

The second complication involves explosions from nearby non-LNG facilities and the effect this would have on structural integrity of the LNG storage tanks. The controlling facts are felt to be the air-blast overpressure and flying fragments. The latter can be analyzed under the impact penetration models discussed earlier. The Booz-Allen study analyzed explosion sources from refineries, petroleum terminals, oil pipelines and petrochemical processing plants and computed minimum separation distances to insure overpressures of less than 1.2 pounds per square inch. (The 1.2 psi figure is conservative since nonreinforced concrete structures will be destroyed at higher pressures but presumably the tanks and dikes could withstand greater pressures.) The distances are a function of the quantity of the material which explodes so a range of distances is presented. Minimum distances range from a quarter of a mile for a pipeline to 4.3 miles for a refinery with 5 and 2/3 million barrels at risk and 7 miles for an oil tank farm or tanker terminal with 25 million barrels at risk. (Booz-Allen *supra* VII-19 through VII-21.)

Sabotage

Chicago Bridge & Iron conducted a study to see if the storage tanks could withstand small arms fire. Using a 30.06 hunting rifle with high velocity bullets and armor-piercing ammunition, its researchers fired at close range at wall thicknesses which were the thinnest used, *i.e.*, were at the top of the tank, with a bullet trajectory that was normal to the plating. Armor piercing ammunition fired from weapons with a muzzle energy greater than 2,000 foot-lbs did succeed in penetrating the outer wall but were spent and were found imbedded in the perlite insulation and none reached the inner shell, let alone penetrated it (*Id.*). The tests were felt to be conservative since the closest non-secured boundary to most tanks is 200 feet and the thinnest sections of the tank are at the top requiring an angle shot from the ground which would further reduce the chance of penetration. On the other hand, a serious sabateur would not likely limit him or herself to relatively innocuous small arms fire.

FLAME MECHANICS AND CHEMISTRY

Pool Development and Configuration

There are at least four types of pools that

**See* Chapter end *infra* for discussion of seismic risks.

can develop from an LNG spill. It is possible that a tank will be breached on land and the dike will not be penetrated so the spill, depending on the shape of the dike, will form a deep or shallow pond with the spill volume equal to the volume in the tank from its original fill level down to the height of the breach. A second possibility is for a ruptured tank or ruptured pipeline to produce a leak which would drain either by static head or by being under pressure until it could be isolated and would form a elevation-contoured pool over the terrain. This could occur when the dike was breached or, in the case of a pipeline, when there was no dike. The third case would involve the formation of the LNG pool on top of water when a ship's tank was ruptured and the LNG spilled onto the water's surface. The fourth case might result from an underwater rupture which released the LNG underwater. Since the LNG is lighter than water it would rise to the surface. For a discussion of the possible explosive nature of such a release *see* subsection *Flameless Explosions, infra.* In all cases the LNG will immediately absorb heat from the underlying seawater or ground and will begin to evaporate. Some theoreticians in modeling LNG spills on water assume that the surface of the water will freeze and thus partially insulate the overlaying LNG pool, but experiments do not support the assumption. If an instantaneous spill is postulated at a point source, the action of the force of gravity on the volume of liquid will cause it to spread out and thus the size of the pool will increase over time to some finite dimension before it is totally evaporated. The thermodynamic formulas and mathematical models are very sophisticated in this area, but some general description may be useful.

The relevant information to be derived is typically the maximum pool radius (for spills on water) and the time for complete evaporation. The FPC staff has adopted the Raj/Kalelkar formula which predicts a 37,500 cubic meter spill (representing the entire contents of the largest tank on a third generation LNG carrier) would spread to have a maximum pool radius of 446 meters and would completely evaporate in five minutes (Pacific Indonesia Project, *supra* at 339). Naturally, the maximum heat transfer would occur when the radius is at the maximum and the thickness is at a minimum and this will produce the greatest evaporation rate. If attenuated spills are postulated instead of instantaneous spills, ongoing evaporation results in smaller maximum pool diameter but no appreciable difference occurs until the spill duration exceeds twelve minutes (Science Applications, Inc., *LNG Terminal Risk Assessment for Oxnard, California* 8-23 (1975)). At some finite pool diameter the LNG pool is so shallow that it begins to break up into small "puddles." SAI used an evaporation rate of 0.04 lbs per foot^2-second, which is in close agreement with research results produced by the U.S. Bureau of Mines and the Esso Company (*Id.* at 8-22, 8-26). Pool diameters and pool configuration are more complex on land primarily because the soil freezes, inhibiting heat flow and causing a decrease in the evaporation rate with time. This phenomenon is a function of the water content of the underlying soil which permits the ice to form. To the extent that the spill is trapped in a dike there will be heat flow from the diking material, which will have a different heat flux than natural soil. Since many dikes are lined with insulating materials the heat transfer equations become even more complex. Land spill experiments have been conducted by Gaz de France, Thompson Ramo Woolridge, Arthur D. Little, and the American Gas Association. Additional sophistication can be added by hypothesizing the breach in a shoreside storage tank with varying hole diameters and static heads and using conventional fluid dynamics formulas to compute the discharge rates. The configuration of the pool and its diameter is necessary to calculate the vapor source rate (weight of vapor generated per unit of area per unit of time).

Since the throughput of most import terminal tanks is high (as opposed to peak shaving tanks) and their primary purpose is to facilitate tanker unloading and to provide a buffer for the vaporization equipment, a substantial amount of the time they are empty (Western LNG Terminal estimates this will be the case 40% of the time for any given tank). (SAI, Oxnard *supra* at8-165). Thus even if the tanks were penetrated, the analysis can exclude 40% of the penetrations as not resulting in any outflow. The SAI analysis of 88,000 cubic meter spill from a land storage tank postulated a rupture at the bottom of the tank when the tank was full. They did a parallel analysis for a 44,000 cubic meter spill which postulated the rupture half way up the tank wall with a full tank (*Id.*).

Plume Dispersion, Air Entrainment and Mixing

Freshly vaporized methane is much colder and is approximately 40% denser than the ambient air (*Id.* at 8-48). Gravity causes the cloud to spread outwards with decreasing height to form a pancake-shaped cloud over the pool. Heat flows into the cloud from the surface of the water not already covered by LNG, from the surrounding air, and from the freezing of water vapor entrained in the cloud itself (*Id.*). As heat is added, the cloud becomes less dense and may actually become neutrally buoyant. If there is wind present, this will serve to elongate and displace the cloud in the downwind direction. The FPC staff has computed the radius of an LNG cloud of neutral buoyancy at 746 meters following an instantaneous source spill of 37,000 cubic meters of LNG (Pacific Indonesia Project, *supra* at 339-344). This computation assumed no mixing of methane and air. To the extent that mixing occurs there will be a concommitant enlargement of the radius.

Science Applications, Inc. has developed a complex computer model called SLICE, which it describes as including "hydrodynamic equations expressing the conservation of mass, momentum and energy together with a Boussinesq approximation for the atmosphere . . . [and] written in rectangular coodinates." (SAI, Oxnard *supra* at 8-50) The SLICE computations are augmented with a different computer model in those situations where the spills are so large that the gravity induced spread velocities are larger than the average atmospheric wind speed. This program is called SIGMET. An underlying assumption of this program is that the vapor cloud adjusts rapidly in the vertical direction to a hydrostatic balance of forces. For this reason differential equations dealing with vertical momentum do not include the acceleration for diffusion terms. Additionally, the vertical coordinate is altered by replacing the altitude with a scaled pressure coordinate comprised of two terms, the gradient of geopotential height, and the gradient of surface pressure. (*Id.* at 8-57 through 8-59). Both SLICE and SIGMET contain a factor for modeling the air-methane mixing which ensues from turbulent flux and eddies (*Id.* at 8-60). Recent theories suggest variations of three or fourfold in the turbulence factor but since air entrainment appears to be (approximately) a function of the square root of the turbulence, the difference in computed values should not be large. SAI is proposing sensitivity studies focusing on this factor. (Interview with Dr. Walter England of SAI on Nov. 1, 1976). The programs are designed for numerical integration over time intervals (SIGMET) or over downwind distance intervals (SLICE). The computer produces three-dimensional concentration, temperature and velocity predictions. Turbulent dispersion coefficients are utilized in the program for expressing local diffusivity based on empirically observed data concerning local wind velocities and directional variations and atmospheric stability classes (A through G). Backcasting using small scale plume dispersion experiments by the American Gas Association has shown that the SLICE and SIGMET programs (although SIGMET was at variance with respect to the leading edge velocity) are effective in modeling vapor plume dispersion and concentration.

Since the primary danger from an LNG plume is deflagration (burning) rather than freezing or suffocation, it is relevant to ascertain the configuration of the cloud within the flammable limits of 5-15% methane by volume in air. Thus the computer programs output numbers defining concentration isopleths enabling actual depiction of the cloud configuration and also output the downwind range from the spill source of the furthermost lower flammable limit (LFL or 5% concentration) of the cloud. *See* Appendix, Exh. 21. The model can be run with varying inputs of wind speed, size of spill source, and spill locale (in a dike, on land, or over water). The program will also compute the lapsed time from spill to attainment of maximum downwind distance. *See* Appendix, Exh. 22. This is relevant since ignition probabilities discussed in the next section are a function of elapsed time. The SAI computations show a six kilometer distance to the outer LFL under a fifteen meter per second wind moving the cloud for about 700 seconds following a 37,500 cubic meter spill. (*Id.* at 8-83). *See*, Appendix, Exh. 34 for vapor concentration isopleths developed by SAI's computer plotting.

The FPC staff, utilizing formulas and computer routines developed by Bruce Turner of the Environmental Protection Agency (Workbook of Atmospheric Dispersion Estimates, EPA Pub. No. AP-26 (1972)), has developed an approximation procedure whereby area sources such as LNG spill pools are converted to the equivalent of a point source. Dispersions in the vertical and cross-wind directions are then modeled on the basis of standard deviations about such a median point. Factors are introduced to account for differing stability classes of the atmosphere and the formulas are simplified to produce ground-level concentrations along the center line of the plume. (Pacific Indonesia Project, *supra* at 344-347). The FPC used the "D" stability condition (considered neutral) but felt that condition C might be even more typical as the gas cloud shifts towards positive bouyancy. It now appears that positive bouyancy is predicated on a study by Hoult (LNG Conference *supra* 87-99 (NAS 1972)). Hoult's assumption of sequential warming and mixing appears to have been empirically refuted. (*See* FPC Docket CP73-47, Testimony (direct) of Dr. David Burgess, U.S. Bureau of Mines pp. 2-5, 7-8). Computing a 37,500 cubic meter spill on water with a D stability condition and a five mile per hour wind, the solution revealed a downwind distance to LFL of 1.53 kilometers which is in reasonably good agreement with the similar computation by SAI. (*Id.* at 351; Alaska Natural Gas Transporation Systems, *supra* at Vol. I, Appendix A p. 34; Cook Inlet, California DEIS II-239 (FPC Sept. 1976)). The FPC's previous application of Turner's virtual point-source, Gaussian method to an ultra-large (1.8 mile pool diameter) spill was characterized as "preposterous" and said to introduce "significant error". (Burgess testimony *supra* at 8-10 where Dr. Burgess contends that the basically valid Turner method cannot be applied to exaggeratedly large pools derived from the faulty ice-formation-insulation model of Hoult.)

Other researchers have developed rather wide variations in the maximum distance to the lower flammable limit under "D" atmospheric conditions. Professor James Fay of MIT is reported to have computed a distance of 300,000 feet. Dr. David Burgess of the Bureau of Mines is reported to have calculated 200,000 feet and 37,000 feet was the predicted distance in a study by the American Petroleum Institute. (Pacific Indonesia Project *supra* at 150). Dr. Walter May of the Esso Research and Engineering Center is reported to suggest a distance of eight to twelve miles with an eight knot wind (Peril of the Month: Gas Supertankers, *supra* at 9). A prediction of 5280 feet for the outer reach of the LFL was made by Professors Witt, Wicks and Olleman at Oregon State University in 1974 (Evaluation of LNG Transport and Storage Hazards 5). Dr. R.O. Parker from New York University's chemical and nuclear engineering department, uses a ventilation model to represent wind drift of a plume evaporating from an LNG pool. He has computed that if a two foot diameter hole were instantaneously cut into the bottom of the side wall of a cylindrical tank 132' high, 184' in diameter, filled with LNG and surrounded with a dike 17' high enclosing an area of 350,000 square feet and if stable weather conditions with a two meter per second wind prevailed, the negatively bouyant vapor cloud would travel less than 100 feet before it became positively bouyant. (*See* materials submitted by Distribas Corporation on May 15, 1973 to Federal Power Commission, response to Question 13, Docket No. CP73-135). (For difficulties with a positive bouyancy model, *see* Burgess testimony *supra*.) A study a the Naval Weapons Center at China Lake has predicted a 10,000 cubic meter spill with a 5 mph wind will produce a plume with a LFL 3500 meters from the spill source after thirty-five minutes. (Lind, "Explosion Hazards Associated with Spills of Large Quantities of Hazardous Materials, Phase I" at 30 (U.S.C.G. 1974)). Relying on the atmospheric dispersion formulas and pool-size formulas developed by Esso in its 1972 experiments in Texas with small man-made spills (Feldbauer et. al., "Spills of LNG on Water-Vaporization and Downwind Drift of Combustible Mixtures" (Esso Research & Engineering Co. Report No. EE61E-72, May and November 1972)). Booz-Allen predicts downwind vapor dispersion using a five mile per hour wind and a stable weather condition. The distance to the lower flammable limit for a 20,000 cubic meter spill was computed to be 41,000 feet and the distance for a 125,000 cubic meter spill was calculated at 90,300 feet. (Booz-Allen, *supra* VII-24 through VII-27).

Obviously, it is difficult to compare such predictions when different atmospheric stability classes, different wind velocities and different source configurations are used by different investigators. In many cases the models used by the various researchers appear to be similar but differing inputs or assumptions produce large variances in the results. For example, an LNG plume may be a collection of vapor trails with non-uniform concentrations. An average concentration below the LFL could nevertheless contain pockets or cloudlets of sufficient concentration to make the vapor ignitable. In this regard assumptions about peak-to-mean ratios become significant in predicting deflagration. Dr. Fay reputedly used a 50:1 ratio and an F stability condition. Thus a mean concentration of 0.1% methane in air would support deflagration in his computations since the pockets of peak concentration would be at the LFL of 5%. Dr. Burgess' experimental data showed a peak-to-mean ration of 10:1 and this apparently reflected variations for mixing turbulence and for meandering due to wind shifts (Burgess testimony *supra* at 10-13). For computational purposes he recommends a safety factor of 2, making the adjusted ration 20:1 (*Id.* at 15). SAI's SIGMET model predicts variations from mean concentration on the order of 10% to 20% in clouds from large (88,000 cubic meters) spills and as high as 2:1 or 3:1 in smaller, less stable vapor clouds. SAI believes it has demonstrated mathematically that peak-to-mean ratios explainable by meander of small plumes are not applicable to computations relevant to predicting flamefront propagation in the interior of vapor clouds homogenous (*i.e.*, continuous) in the horizontal direction (unpublished memorandum by L.E. Hauser of SAI 5-11 (April 30, 1976)).

The SAI computations also introduced differences in humidity of the air and discovered that the more moist air with greater water vapor content caused shorter plume ranges and quicker dispersions as more heat flux was involved. (SAI *supra* at 8-100). SAI also modeled a spill of 88,000 cubic meters representing the rupture of a storage tank at ground level. To be conservative they used formulas as if the spill occurred over water instead of over land. This will produce a larger plume because of the greater heat flux. In a thirty-five mile an hour wind (approximately fifteen meters per second) such a spill would achieve a maximum distance to LFL of six kilometers in an elapsed time of about 800 seconds. (*Id.* at 8-90). Another interesting scenario computed by SAI postulated an internal failure of the tank resulting in a fifty square foot hole in the bottom of the tank without a rupture of the dike. The escaping LNG is thus contained completely within the dike. Boiling will occur, but the vapor generation rate is relatively small and the maximum distance to LFL is only fifty meters at an elevation of about ten meters. (*Id.* at 8-94).

Ignition, Deflagration and Flame Front Dynamics

In order for ignition to occur, there must be a high enough ignition temperature, a long enough total heating time, a large enough quantity of energy transferred and a flammable mixture layer thicker than a nonflammable layer which might otherwise quench the flame in a time shorter than the ignition delay time. (*Id.* at 8-106). All risk assessment models assume that there is a very high probability of ignition at the site of the spill when it is caused by a casualty involving impacts or penetration such as collision by aircraft, missiles, or ships. Fatigue failures, vacuum pressure collapses and overpressure tank burstings are not so likely to provide ignition sources. If the vapors are not immediately ignited at the source of the spill, a flamable cloud may disperse as discussed in the preceeding section. Although there may be an occasional vessel at sea in the path of the plume, it may be safely assumed that probability of ignition while the plume is over water is effectively zero. On the other hand, when the plume reaches land, ignition sources would include pilot flames on stoves and water heaters, fires for steam boilers, welding torches, hot exhaust gas from some engines, and electrical arcs and sparks from motors, circuit breakers, relays, shorted wires, and even static electricity.

Most studies conservatively assume an ignition probability of 90% at the source of the spill, *e.g.*, sparks from rupture of metallic tanks. The FPC staff assumed that there were 500 ignition sources per square kilometer of populated regions on land and that each such source produces ignition only 1% of the time (Pacific Indonesia DEIS *supra* at 151). Probability statistics will show that by the time a flamable plume has encountered 458 ignition sources (slightly less than the number in one squre kilometer) there is a 99% probability that it will have ignited. By the time it has covered 2 square kilometers, the probability is in excess of 99.99%. (SAI Oxnard *supra* at 8-112 and 8-113). Where there are low population concentrations such as those adjacent to liquefaction terminals in Alaska, it may well be that the only human lives that could possibly be endangered even if the plume reaches all the way to shore would be those of employees at the facility itself.

Assuming an ignition source is encountered, the flame will propogate back through the areas of the plume that are within the flammable limits (assuming the plume is still whole and has not started to break up into small cloudlets) until it reaches the source. If ignition should occur after evaporation is completed at the source, the rear end of the cloud would have left the vicinity of the LNG ship or the LNG facility. Propogation through the "rich" portions of this mixture has been estimated to be at a speed no greater than one mile per hour (Witt, Wicks & Olleman, *supra* at 6). At fuel concentrations above the upper flammable limit, the rate of flammability is determined by and limited to the rate of mixing of fresh air with fuel and partially burned combustion products. In regions of the cloud where concentrations are between the lower flammability limit and the stochiametric mixture ratio, flame will travel through the unburned gas at a rate controlled by the chemical properties of the mixture and the level of locally generated turbulence (SAI Oxnard *supra* at 8-116). Not surprisingly, the total thermal output per unit of surface area of a flame sheet is greater in areas of stochiametric balance than in lean areas of the plume. Thermal energy output per unit of time increases with flame velocity which is a function of wind speed (*Id.* at 8-121 and 8-124).

With regard to stationary fires at LNG

pools, formulas allow the calculation of the radiation flux incident on a target outside the area of the fire itself. Relevent inputs to the computations are flame diameter at base, mass burning rate of fuel, ambient air density, acceleration of gravity, and the wind velocity. Additionally, a "view factor" must be utilized for any particular target. The latter relates the plane of the exposed surface of the target and its orientation to the flame front through trigonometric relationships to quantify the time integrated radiation flux received by the target (*Id.* at 8-130 through 8-140).

Using empirically developed standards, SAI has estimated that humans exposed to a thermal flux level of 5700 BTU per square foot per hour, will become fatalities after five seconds (*Id.* at 8-141). FPC staff utilized different empirical findings and found that a ten second exposure to a flux of 5300 BTU per square foot per hour would be fatal (Pacific Indonesia Project, *supra* at 355). Neither estimate allowed for reflection from light clothing or convective cooling by wind and are thus felt to be conservative. Staff computations have revealed that radiative heat emission decreases rapidly with time as the flame front passes by and they conclude that surroundings are exposed to dangerous heat radiation for only a short time with regard to plume fires, but exposure from pool fires may have a duration of over fifty times that of the fatal radiation period of a moving cloud front (*Id.* at 357). Using Esso Research & Engineering Co. studies, Booz-Allen developed safe distances from the fire for non-ignition of wooden materials (where heat flux is less than 3200 BTU per square foot per hour) and computed safe distances for a 25,000 cubic meter instantaneous spill as 0.4 mile from the center of the spill. This radius would be doubled for a spill of 125,000 cubic meters (Booz-Allen *supra* VII-30 through VII-31).

SAI computations determined that the flame cannot be supported in the lean regions between flammable cloudlets and the main cloud, at least when the interstices are greater than expansion radius (eight-fold) of the flammable cloudlet due to burning (SAI *supra* 8-151 and 8-152). (Burgess does not deny this but assumes that "ignition of any part of the cloud will produce a general conflagration of all portions of the cloud above the lower flammable limit" (Burgess testimony *supra* at 15)). Computations reveal that any human outdoors within a frontal distance less than five times the radius of the circle whose center is the center of the flame front and whose perimeter is the lower flammable limit boundary will receive a fatal heat flux. Similarly, a person whose offset distance from the fire front is less than twice that radius will receive enough flux to be killed. (*Id.* at 8-139 and 8-140). These formulas are simplifications of more sophisticated analyses utilizing two lateral flame front motions: downwind and crosswind. (Interview with Dr. Walter England of SAI on Nov. 1, 1976).

For pillars of flame, especially from pool fires or fires consuming LNG impounded within a dike, prevailing winds can cause a fire pillar to "overhang". In strong winds, large fires might conceivably tilt by as much as 45°. If the wind shifted through 360°, it has been predicted that anyone within a 1000 foot radius of the center of the pool would be killed by radiation flux. (Burgess & Zabetakis, "Miscellaneous Notes on Catastrophic Tank Failure", incorporated in appendix to Congressional hearings investigating TETCO disaster at p. 133 (1974)). An estimate of skin blistering within a radius of 900 feet of a pool fire was made by Professors Witt, Wicks and Olleman (Evaluation of LNG Transport and Storage Hazards (Oregon State University)).

Generally speaking, LNG plumes are not expected to explode. Of course, if the vapor, within flammable limits, were to be advected into a closed space and then became ignited, it is a possibility that the escaping gases could have an explosion-like impact. This is in part what happened in the TETCO disaster where the combustion gases "floated" the tank dome, which then collapsed downard into the tank. Experiments at the government's facilities at China Lake California, have so far been unsuccessful in detonating vapor plumes. A detonation, as opposed to a deflagration, has a supersonic flame propogation rate which in turn prevents pressure equalization from occurring at the speed of sound or less. In deflagration, pressure gradients across the flame front will seldom exceed eight to one, but in detonation, they may be forty to one or greater (R. WOOLER, MARINE TRANSPORTATION OF LNG AND RELATED PRODUCTS 159 (1975)). German scientists are reported to have set off open air gas (not necessarily natural gas) explosions using TNT as an igniter ("Peril of the Month . . ." *supra* at 10). For a discussion of so-called "flameless explosions, see subsection *Flameless Explosions infra*.

A researcher at the Naval Weapons Center at China Lake, California has postualted LNG plume detonations killing half the people within 200 meters of the cloud's edge. (Lind, "Explosion Hazards Associated with Spills of Large Quantities of Hazardous Materials: Phase I" at 4 (U.S.C.G. 1974)). The fatal radiation flux calculations of SAI appear to indicate that all victims caught outdoors as the flame front passes can be considered as fatalities if they are so close as 200 meters from the cloud's edge. (Interview with Dr. Walter England, Nov. 1, 1976) Thus the concussion affect of such a detonation might actually be less than and masked by the radiation affects. However, *if* an open air detonation could occur, a "fireball" or "firestorm" scenario is possible (*See* Burgess testimony *supra* at 20). This could elevate the flame and result in much larger view factors to those below with a corresponding increase in radiation flux. (Interview with Dr. Walter England of SAI on Nov. 1, 1976).

In an effort to empirically test the possibility of an explosion, experiments were run at China Lake in which quantities of methane and air in a steel tube were detonated by an explosive booster. (Lind, *supra* at 5). With a relatively large booster a non-ideal detonation was observed. The investigator concluded that affects are weak at distances greater than ten times cloud height and that damaging detonation does "not appear likely" in clouds of expected sizes. (*Id.* at 9, 49). Elsewhere in his study he characterizes propogation of the flame into a "confined space" as a "viable mechanism" for an explosion which would in turn detonate the open-air vapor plume. (*Id.* at 48). Dr. Burgess has also stated that "it must be assumed [based on detonations of propane] that ignition of an unconfined methane cloud can cause . . . overpressures [causing serious damage]." (Burgess testimony *supra* at 19-20).

Damage Scenarios

There are basically three ways by which escaped LNG can harm human beings. The LNG can vaporize and ignite and a fire can produce injuries or fatalities. Those actually within the pool and plume fires are killed. Some persons not inside the fire area may also become fatalities from exposure to the fire's heat (radiation damage). Second, persons coming in contact with the LNG can suffer freeze burns and frostbite of sufficient severity to be fatal by contacting the extremely cold liquid. This is generally referred to as cryogenic damage. Third, if a person were in the midst of a LNG vapor cloud that was sufficiently "rich", that is, had displaced more than 50% of the oxygen normally in the atmosphere, he or she might suffocate. With the exception of ship's crew who might be thrown in the water after a collision or terminal plant workers who might be trapped in the dike area, the probability of cryogenic damage would seem to be minimal since most of the LNG pools will either be on the sea or on the terminal premises.

Science Applications, Inc feels that fatalities through suffocation should not be anticipated for persons trapped for as long as ten minutes in an unignited vapor cloud since its computer program shows that average methane concentration will never exceed 50% beyond the boundaries of the LNG pool. However, the computer employs zones 200 meters square so that it is possible peak concentrations near the pool boundary could exceed 50%. The plume itself will of course be very cold, but will be warming rapidly over time. Although SAI's risk analysis tends to discount any fatalities from merely being surrounded by the vapor cloud, it would seem that, if nothing else, sever frostbite would be inflicted upon the exposed parts of the body such as face and hands and on the respiratory tract.

The radiation damage computations are more complex. Obviously, one of the first things to be considered for any particular terminal site is population density of the surrounding area. Another important parameter is the direction of prevailing winds. STAR data are historic statistical summaries prepared by the National Climatic Center at Ashville, North Carolina for use in air pollution studies. The data is divided into atmospheric stability groupings and is tabulated in a bivariate frequency distribution for sixteen wind directions and six wind velocity categories. The data is also available to show relative frequency of wind direction (SAI, Oxnard *supra* at 8-5 and 8-6). The FPC staff applies a reduction factor to the probability of the vapor plume reaching or spreading over a populated area ashore to reflect the fact that wind direction, wind stability and wind velocity will vary over time. Thus the undiscounted probability assumes "worst case" conditions, whereas the reduced probability is felt to produce a time-averaged depiction that is more realistic. If LNG carriers were expected to always or almost always arrive at approximately the same time of day, the factor would have to be adjusted accordingly.

Population density projections usually must be projected to some point (often the midpoint) of the future projected life of the facility. SAI assumes evacuation will be impossible for persons caught inside the plume area, or within its lethal radiation range. On the other hand, no fatalities are charged against secondary fires which may be ignited in wooden structures, etc. as a result of the initial radiation. All persons endangered by such fires are assumed to be able to evacuate. Immediate and presumably total avoidance action is assumed in the case of the spills where the LFL is within the terminal facility boundaries and ignition has not occurred (*Id.* at 8-158). SAI feels that the assumption that all population enveloped by the burning plume would be fatalities is conservative since they feel "fatalities would not be heavy in sheltered locations even though directly covered by the passage of a flame through a vapor plume, in fact they would not be expected to be 100% in non-sheltered locations so covered." (*Id.*) In industrial areas, where most terminals will be located, the eight-to-five population will be much greater than the population during the remainder of the day. Similarly, weekdays will have greater population densities than weekends. SAI's conservative calcuations use weekday density figures for all hours and days. Tidal changes and collective bargaining contracts may cause LNG carrier discharge operations or loading operations to be concentrated during certain times of the day. However, for purposes of tank ruptures, and outflow studies, the tanks are always assumed to be full (*Id.* at 8-159). To the extent that residential areas are within the hazard area of the projected heat flux, nighttime populations are used which again would be conservative (*Id.* at 8-160). SAI states that recent aerial surveys of southern California indicate that 80% of the people are inside shelter at any one time during the day. At night this percentage should increase. Based on this estimate, SAI postulates that 20% of the population within the regions that are exposed to fatal amounts of heat flux would be fatalities. SAI feels this to be conservative since it ignores sheltering or "heat shadowing" for those outdoors and counts them all as fatalities (*Id.* at 8-158). This 80% reduction factor assumes that all persons can safely evacuate themselves from the area of secondary fires. If persons are only treated as safe while inside and the structure that surrounds them catches fire, then they must successfully evacuate, and must avoid a fatal flux of radiation. Of course, the ignition of the structure would take a certain amount of time and during that time, the flamefront will have moved. If it is moving away from the subject, it is quite possible that safe evacuation will be possible without fatal burns since the flamefront will be receding at ten meters per second and flux varies inversly with the square of the distance. If the flame front is moving toward (or at least closer to) the subject, the timing of the escape may be crucial to its success. The FPC staff has estimated that only 10% of people not enveloped by the cloud but within the fatal heat flux radiation area will become fatalities. This estimate is apparently predicated upon some facts, some estimates, and some non-specific information concerning the 1944 East Ohio Gas Co. LNG fire. (Alaska Natural Gas Transportation Systems FEIS III-424 and 425 (FPC April 1976)).

Pursuing the methodology for different inputs it is possible to increase the fatality surface area by hypothesizing larger and larger LNG outflows. SAI's computer program shows that if unusually fast winds are blowing this does not necessarily increase the area (population) exposed. The higher wind simply attenuates the plume into a long streamer instead of an elipse or elongated pancake and the total area is not appreciably greater between a three meter per second wind and a thirty-five meter per second wind. (*Id.* at 8-160). As greater volume spills are postulated or as spills from the terminal (as opposed to a ship several thousand feet offshore at the end of an extended pier) are postulated, more and more fatalities can be projected. On the other hand, larger spills are less probable. A fatality probability per year table can be generated (*see* Appendix, Exh. 23). Another interesting output is an estimate of the life threat to any one person per year at various distances from the LNG facility. Using constant probability contours an interesting geographic plot can be developed (*see* Appendix, Exh. 24).

Most risk analyses conclude with a comparison of the risks projected from LNG terminal operation with other commonly experienced death-producing incidents. When reduced to a probability per person per year basis, comparators include transportation accidents, home accidents, homicide, occupational accidents, and burns, among others. *See* Appendix, Exh. 25. In general, the probability per person per year of dying from an LNG spill at the Oxnard terminal is two orders of magnitude less likely than the least likely of the above-mentioned causes (SAI, Oxnard *supra* at 9-2 and 9-3). The FPC staff, in approving the Oxnard terminal location vis-a-vis Alaskan shipments in its Final Environmental Impact Statement felt that the risk per person per year was negligible especially when compared to the finite risks of death from electrocution, firearms, fires, falls, and motor vehicles. The FPC staff thought that the LNG terminal risk was at least as slight as that from the operation of nuclear power plants (Alaska Natural Gas Transportation Systems, FEIS III-425c and 425d (FPC April 1976)).

Flameless Explosions

Flameless explosions have been proven to be heat conversion reactions rather than chemical reactions. They are actually nothing more than the almost instantaneous formation of vapor bubbles which expand rapidly due to superheating. If enough of these bubbles are produced at once and if their vapor cannot be released quickly enough due to the LNG pool layer, pressurization and shock waves may form. This phenomena will only occur when LNG lies on top of water and when the methane content of the LNG is less than forty mole percent (Conference Proceedings on LNG *supra* at 5). If there is more methane than this in the LNG it will simply film boil on the water. For weathering or boil-off to achieve such a low mole percent the total LNG liquid volume would be reduced by 90% (*Id.*). The enormous increase in the steady state rate of nucleation (*i.e.*, the formation of individual bubbles) at the maximum superheat temperature produces an explosion-like phenomenon. Small ice crystals may accellerate the nucleation process. The heavier fractions of the natural gas (propane and n-butane) appear to be involved in these vapor explosions. The explosions can either be within one second of the spillage on water or can be "delayed" some tens of seconds. (*Id.* at 11).

At a conservative boil-off rate of 0.3% per day it would take stored LNG nearly 800 days to reach the proper mole percent to permit this phenomenon to occur. Research has shown that the explosions cannot occur if the mole ratio of propane to ethane in the LNG is 1.3 or greater (*Id.* at 16). In spills on open water large explosions cannot occur although near-simultaneous popping may occur at various places in the spill pool (*Id.*). The mechanical energy released in one of these explosions is calculated to be only 0.5 calories per square centimeter of LNG/water interface area which is felt to be negligible (*Id.*).

Some theorizing has occurred as to the consequences of release of LNG beneath the air-water interface, *e.g.*, from a beneath-the-waterline puncture of an LNG carriers' cargo tank. Two consequences are possible. The less likely one is that the "bubble" of LNG would rise to the surface with substantial amount of the liquid unevaporated and would then form a pool on the surface and evaporate according to conventional evaporation models. The more likely consequence would be an atomization or mixing of the LNG with the water before it reached the surface. As the liquid bubble rose, the static head pressure would be less and the bubble would expand. The critical diameter of such an isolated bubble has been computed to be 3.6 centimeters. After this size is attained, the bubble would break up to create smaller bubbles (Distrigas Corporation, materials transmitted to FPC on May 16, 1973, response to Question 6, Docket No. CP73-135). The velocity of acendency in the water can be computed for bubbles with diameters of more than 0.2 centimeters and the heat transfer from water to LNG bubble that would occur during the transit time can be computed. General turbulence among a constellation of such bubbles would be expected to reduce the maximum stable diameter (*Id.*). It is predicted that no real explosion would occur although a series of pops might be caused as the individual droplets desuperheated (*Id.*). Analysis of Bureau of Mines data and experimental results by Baumeister, Hamill and Schoessow ("A Generalized Correlation of Vaporization Times of Drops in Film Boiling on a Flat Plate", Proceedings of Third International Heat Transfer Conference 66-73 (AIChE/ASME, August 1966)) suggests that for droplets of less than 0.75 centimeters in diameter, liquid bubbles released thirty feet below the surface would have evaporated by the time they reached the surface. This would place the vapor and the surrounding water close to thermal equilibrium and would facilitate the dispersion of the gas upon reaching the surface as the gas would be positively bouyant (*Id.*).

For a relatively complete bibliography of risk assessment research studies see the Arthur D. Little study *supra* at 139-141 reprinted herein as Appendix, Exh. 38.

On December 7, 1976 as this manuscript was in the publication process, the FPC staff filed a "position brief" in the Alaska Natural Gas Transportation Systems proceeding (*El Paso Alaska Co., et al.* Docket No. CP75-96). The staff compared the Arctic Gas Project (McKenzie Valley gas-state pipeline) with the Alcan Project (Prudhoe Bay-Yukon Territory-British Columbia gas-state pipeline) and the El Paso Alaska system (gas-state pipeline to Gravina Pt. Alaska and then LNG ships to California).

The staff concluded that assuming Canadian diplomatic cooperation the record "overwhelmingly" supported the Arctic Gas alternative (as modified by the deletion of the westward "leg") (FPC brief 37).

The relative disadvantages of the LNG proposal as seen by FPC staff included "thermal pollution problems, the safety questions raised by LNG terminals and ships, the facility reliability uncertainty, and the passage through high-risk seismic activity areas in Alaska and California . . .." (*Id.* at 13). Review of the competing applicants' economic analyses of their own and their opponents' proposals persuaded the staff that capital costs of LNG tankers and terminals might be subject to greater-than-projected overruns because of the new technology involved (*Id.* at 19). Comparing the modified Arctic Gas project with the LNG system in terms of incremental delivery unit cost in the fifth year of operation at specified throughputs and to specified delivery points, the staff concluded that the McKenzie Valley alternative was less costly. (*Id.* at 19-23). Locating the required high pressure, large diameter pipe in the "Fairbanks Corridor" (the route proposed for the low pressure Alcan alternative) would be environmentally optimal, but the staff determined that the additional costs (over the Arctic Gas-McKenzie Valley route) would exceed the benefits (*Id.* at 27).

Environmentally, the major disadvantage seen by the staff in the El Paso LNG system was that it transported "gas through a rugged mountain area to a geologically dangerous Alaskan shoreline for further [ocean] transportation to an earthquake region in California . . ." a route with "the least desirable geotechnical alignment . . .." (*Id.* at 31). The staff observed that "El Paso has not conducted the necessary work to establish a proper seismic design for its terminal at Point Gravina, nor has it surveyed and studied the adjacent offshore region. . ." (*Id.*). The staff also contends that the California "receiving terminal . . . has likewise not been designed adequately to assure that it would withstand the maximum credible earthquake expected at such site." (*Id.*) It is probable that El Paso will file a countering brief in due course.

The staff did feel that the "all American" El Paso LNG project would be more attractive to investors in terms of capital costs. (*Id.* at 34).

financing of liquified natural gas carriers

Because of the extreme cost of producing an LNG carrier, a variety of financing devices are used by potential owners. This section will primarily discuss legal aids to financing new construction of LNG vessels for U.S. registry. It will conclude with a short discussion of financing of liquefaction facilities in foreign countries.

CONSTRUCTION DIFFERENTIAL SUBSIDY

ELIGIBILITY AND AMOUNT

As of May, 1976 the Maritime Administration of the Department of Commerce (MARAD) had committed $198 million in construction differential subsidies for the construction of fourteen [actually, only nine appear to be under CDS] LNG carriers (Kasputys & Gustaferro speech to Cryogenic Society of America, Inc. 11 (Dept. of Commerce, May 1976)). The Maritime Administration grants these subsidies through the Maritime Subsidy Board (MSB) under authority conferred on it (via the Secretary of Commerce) by Title V of the Merchant Marine Act 1936. Only vessels built for use in the foreign commerce of the United States, *i.e.*, from U.S. ports to foreign ports and back, are eligible for the construction differential subsidy (CDS). The ship must be built in the United States or Puerto Rico and owned by a citizen of the United States (including corporations). In order for a corporation to qualify as an American citizen, the controlling interest therein must be owned by citizens of the United States and its president or other chief executive officer and the chairmer of its board must be citizens of the United States and no more of its directors than a minority of the number necessary to constitute a quorum may be non-citizens and the corporation itself must be organized under the laws of the United States or one of the states or territories (46 U.S.C. §§ 802, 1152 (1970). The prospective purchaser of the vessel must possess the "ability, experience, financial resources and other qualifications necessary for the operation and maintenance for the proposed new vessel." (*Id.*)

All members of the crew of the subsidized vessel must be U.S. citizens and the ship must continue to be documented under U.S. registry for twenty years. (46 U.S.C.A. §§ 1274(b)(3), 1132(a) (Supp. 1975)). Under the Merchant Marine Act of 1970, LNG carriers built with CDS money may engage in outport (foreign-to-foreign) trade in accordance with normal commercial practice (*see* 46 U.S.C.A. § 1121(c) and 46 C.F.R. § 278, General Order 111). MARAD may consent to temporary transfer of a subsidized vessel to domestic trade upon the condition that the owner will rebate annually that proportion of 1/20th of the CDS paid for such vessel as the gross revenue derived from the domestic trade bears to the gross revenue derived from all the voyages completed during the preceeding year. (46 U.S.C. § 1156 (1970)).

In contracts entered into in fiscal year 1977 through June 30, 1979, the CDS is limited to a maximum 50% of the construction cost of the vessel (46 U.S.C. § 1152). Some shipbuilding officials predict that CDS payments on LNG carriers will not exceed 20%-30% of the total price since American builders are inherently more cost competitive in high-technology construction. The purpose of the construction differential subsidy is to subsidize construction in U.S. shipyards which promotes employment of the U.S. labor force and preserves technological knowhow and induces purchase of the capital equipment necessary to construct and repair a U.S. fleet. The Secretary of Commerce is required to ascertain the fair and reasonable cost of building a similar type vessel (less the required U.S. National Defense features) in a representative foreign shipyard. The subsidy is to cover the excess in costs over that amount incurred by the owner's contracting for it to be built in a U.S. shipyard at an approved price. The subsidy thus places the owner on an equal footing with its foreign counterparts, thereby increasing the likelihood that the vessel will be built and documented in the United States.

CONTRACTING POSTURE

Originally the subsidy-built vessels were required to be put out for competitive bidding and the MSB essentially offered a "bid-on-it-or-forget-it" proposition to the shipyards. In 1970 amendments to the Merchant Marine Act permitted negotiated contracts between shipowner and shipyard, however, and at the same time reduced the maximum amount of subsidies on the theory that American yards were becoming more productive and thus more cost-competitive. Under the present program, there are likely to be three bilateral contracts: MSB-shipyard; shipyard-shipowner; shipowner-MSB. The long-run purpose of the Merchant Marine Act is to modernize and improve the efficiency both in construction and operation of the U.S. Merchant Marine and MARAD favors financing ships in series. In this way, many vessels may be constructed from the same basic design providing a broader base over which to amortize research and development costs. When a departure from existing design is proposed, it must be justified against the economics of group, standardized construction. However, technology in constructing LNG carriers is so new and changes so rapidly that some industry officials are dubious that "learning curves" will necessarily improve (reduce) labor costs in successive ships. New designs which optimize mechanization and labor saving equipment and thus reduce the cost of the *operating* differential subsidy (ODS) are looked upon favorably (46 C.F.R. § 251.1, Appendix No. 1 (1975)). The requirements listed as national defense features include the prohibition of the use of grey cast iron (which would be prohibited in any event by the IMCO Gas Code).

CHANGES AND VALUE ENGINEERING

A change will only be subsidized if it is determined that the net effect of the change will, with reasonable certainty, decrease the projected ODS payments over the life of the ship or produce a rate of return on the incremental investment to the owner of at least 10% per annum after taxes or correct a design deficiency (referred to as an "essential change") or comply with a change in the requirements of a regulatory body which became effective later than thirty days preceeding the bid opening or became effective after the contract was executed. (46 C.F.R. § 251.1, Appendix No. 1 (1975)).

MSB contracts have typically included a value engineering clause (*see, e.g.,* MSB Contract No. 257, article 33). Under such a clause, the builder has the right to propose to the purchaser and the Board, a change in the plans and specifications upon the basis that the changed work or material will produce substantially as satisfactory a vessel as the work or material originally specified. The proposal must be supported by an estimate of the decrease in cost resulting from the switch, the probable delay in the delivery date of the vessel caused by the switch, and the latest date by which a change order must be adopted. If the purchaser desires to adopt the proposal it may authorize a change in the plans and specifications. The contractor then estimates the reduction in cost applicable to such change and the contract price is reduced by an amount equal to 50% thereof. The full value of the reduction resulting from an MSB-approved value engineering change is for the benefit of the purchaser and the MSB pays its original share of the contract price. In other words, the cost savings are shared by the owner--as it would have incurred the cost had there not been the change--and the builder who is allowed to keep the subsidized portion of the cost, presumably as a reward for discovering economies of alternative design. It should be noted that if the proposal has previously been set out in a MARAD value engineering informational letter, the yard is not entitled to 50% of the savings. In short, as to future contracts, it becomes either a new contract condition or a non-essential change.

RESEARCH AND DEVELOPMENT: PROPRIETARY RIGHTS

There are at least five possible ways that research, design, and engineering data can be generated and ultimately utilized in the construction of a ship. The builder can be obliged by the construction contract to do the design work and can accomplish the research and design in the fulfillment of its obligations. Second, the builder may have done research on its own, without any contracts. This is particularly true with regard to LNG carriers, where competing yards are perfecting designs and building up know how in anticipation of entering the market in search of construction contracts. Third, the purchaser can have undertaken the research on its own and without subsidization. Fourth, the purchaser can have enjoyed a partial government subsidy for the research which it did on its own. Finally, it is possible that the government has generated the research (*e.g.*, through the Office of Naval Research).

Typical MSB contracts (*see, e.g.*, Contract No. MA/MSB-369 article 9 (containership contract)) establish the following property rights: (1) design and engineering data furnished to the builder by the purchaser or the Board shall reamin the property of the purchaser or the Board as their interests appear and reuse by the builder shall be subject to the approval of the owner of the data. (2) Plans developed by the builder as part of his contract shall become, upon delivery, the property of the purchaser and the MSB as their interests shall appear although the builder is permitted to retain a copy of the plans, designs and data for its own official records. In such case, the builder shall have the right to use or transfer such plans with the approval of the MSB, but neither the builder nor the purchaser shall be entitled to any fees or royalties (other than reproduction cost plus 10%). Obviously the theory here is that since the design was paid for by the subsidized construction contract, the MSB should have the right to decide if it is open to use by other purchasers or by the yard in furtherance of its policy of standardized production and cost saving. (3) Designs, data and research generated by the purchaser without subsidy aid will be the purchaser's property and treated as in (1) above. (4) Designs and data developed by the purchaser with subsidy help shall be made available by the purchaser to any designee of the MSB for use in the construction of similar vessels under other contracts. If this information is made available the purchaser is entitled to a fee in an amount per vessel equal to the quotient of a purchaser's non-subsidized share of the design expense divided by the total number of vessels in the group or series which first utilized the design feature. (5) Research and designs generated by the builder while not under contract obligation to do so, remain the property of the builder, but it must make such data available to the MSB or its designee upon request in return for the payment of a reasonable royalty, license fee, or commission. Builders using or employing data or designs or plans disclosed to them and not owned by them shall maintain such information in confidence except as necessary to disclose such material to their subcontractors upon whom a similar obligation of confidentiality shall be imposed. Whether the spirit of these provisions will be adhered to is unclear to this investigator. The provisions pertaining to items (3) and (4) above are not explicitly included in LNG contracts (*See, e.g.*, MSB Contract No. -257, art. 5).

Owners of ships already subsidized who are participating in the capital construction fund (established under the Merchant Marine Act of 1936, § 607(b)) may withdraw funds for "research, development and design expenses incident to new and advanced ship design and machinery and equipment . . ." (46 C.F.R. § 255.21 (1975)). "Research" is defined as the process of investigation which leads to the discovery and establishment of new scientific facts, physical laws, or techniques. "Development" means the experimental application of science or technology to create novel systems, equipment, or techniques resulting in a workable, practical end product or process. "Design" is defined as the conversion of basic engineering data into a proposed item for production. Ships embodying "novel and unique concepts and techniques so as to provide improved functional or economical capabilities . . ." meet the definition of "New and advanced ship design". (*Id.* at § 255.22). A further discussion of the capital construction fund *see* Chapter IV, Private Financing, *Tax Benefits; internal financing, capital construction fund, infra.*

TERMINATION CONSEQUENCES

Termination and MSB Option

The MSB may terminate payments under the contract upon a determination that termination is in the best interests of the United States. Upon receipt of a notice of termination, a builder must stop work on the date and to the extent specified in the notice, must place no further subcontracts or orders for materials or services for the terminated work, must assign to the MSB, if so directed, all of its rights under subcontracts so terminated or must settle outstanding liabilities on such subcontracts with the approval of the MSB. The builder must also deliver all the fabricated or unfabricated parts, work in process, completed work, and material pertaining to the terminated work or must use its best efforts to sell such items if so directed by the Board. (If a sale is ordered the builder is allowed to bid on such property itself.) The builder must also inventory and hold securely all items not disposed of and may request their removal or may enter into a storage agreement with the MSB covering the holding period.

The builder must then submit a termination claim to the MSB identifying the amount due the builder, within one year after the effective date of termination. The claim may include the contract price for work done and not theretofor compensated. The builder is also entitled, among other things, to the cost of settling and paying claims of subcontractors and vendors arising out of the terimation and a profit on unfinished work not exceeding 10% determined pursuant to § 8.303 of the Armed Services Procurement Regulations, 32 C.F.R., Parts 1-39, Vol. II. If it appears that the builder would have sustained a loss on the entire contract had it been completed, no allowance for profit shall be made and an adjustment reducing the amount of settlement to reflect the loss not sustained shall be made. Storage and transportation costs attributable to material and assemblies held or disposed of may also be a basis for compensation. The amount of shortages (lost, stolen, or damaged) and claims by the purchaser or Board against the builder under the contract may be offset against the builder's termination claim. (*See, e.g.*, Containership Contract No. MA/MSB-369, Art. 15). If the termination order were to occur at an advanced stage of construction of the vessel (a rather unlikely possibility), the termination claim by the builder could include a detention claim for loss of use of his construction or assembly basins or graving yards until such time as it could find a purchaser to assume the contract and thus enable it to continue construction or until enough additional work on the assemblies could be accomplished to enable them to be floated out and towed to a non-essential location.

Default of Purchaser in Making Payments

If the purchaser defaults, builder may give the MSB and the purchaser written notice of such default. If the default remains unremedied fifteen days after receipt of such notice a further notice of default must be sent by the builder to the purchaser and the Board. The MSB, within fifteen days after receipt of the second notice, may elect to take over the purchaser's payments or to have the builder complete only one vessel under the contract, or may exercise its termination option. Meanwhile the builder is free to pursue his contract remedies against the purchaser.

Default of Builder

The builder's failure to proceed with the work in such a manner as to enable the delivery schedule specified in the contract to be met may be a default if such delay is not excused by other provisions of the construction contract. If such a lack of diligence is detected, the purchaser shall give notice of such failure to builder. If the builder has not, within fifteen days after receiving such notice, demonstrated to the satisfaction of the MSB that it has taken steps sufficient to remedy the failure, or that there is no such failure and that it will meet the schedule, there is no default. Otherwise, its behavior shall be deemed a default. Although the purchaser's rights to contractually specified (liquidated) damages for delay beyond the delivery date are not prejudiced, a special proviso states that delivery up to seventy-five days late shall not be a default if the builder has been performing with "due diligence." (MA/MSB Contract No. 257, Art. XX(a)). Delivery dates may be extended when the delay was caused by something beyond the control of the builder. This has been defined in construction contracts to include intervention of the U.S. Government, Acts of God, strikes, fires or vandalism which are the result of causes reasonably beyond the builder's control, by late delivery of necessary machinery or supplies (assuming the builder's attempt to procure such machinery or supplies was expeditious and prudent, and equivalent substitutes were sought). (*See, e.g.,* Contract No. MA/MSB-257, Art. VI). Similar default provisions come into play upon failure to make prompt payment for labor, materials and services which are provided to and required to be purchased by the builder. Dissolution or bankruptcy of the builder, or the appointment of a receiver, or the filing of a petition for reorganization under the Bankruptcy Act by the builder, shall also be deemed a default (*Id.* Art. XX).

In the event of such a default, the MSB may decide with the purchaser to have the vessel completed and may take possession of and use and occupy the builder's yard and equipment (without payment of rental or other charges to the builder) to achieve that purpose. The builder is also obliged to assign all contracts, orders and subcontracts to the purchaser and the MSB and to pay any excess costs (over contract costs) incurred in having the work completed. The purchaser and the MSB may also elect to leave the vessel in an incomplete condition and attempt to sell it (*see, e.g.,* Contract No. MA/MSB-257, Art. XXI). The contract rights of the purchaser and the MSB are without prejudice to any other rights they have under law or equity in the event of a default by the builder.

OPERATING DIFFERENTIAL SUBSIDY

ELIGIBILITY

Eligibility for the operating differential subsidy (ODS) is restricted to American flag vessels owned and controlled by citizens of the United States, manned by U.S. citizen crews and not engaging directly or indirectly in domestic trade. LNG carriers are deemed to be in "essential service in the foreign commerce" and conceivably could be important for national defense in time of a fuel shortage. (*See* 46 U.S.C. §§ 1171 and 1121(b) (1970)). To be eligible for ODS, the operator must operate each subsidized vessel for a minimum of 335 days each year in the carriage of bulk cargo in foreign commerce or outport trade. (46 C.F.R. § 252.20(a) (1975)). Payment is based on voyage-days and during periods of layup or reduced crew, some or all costs may not be subsidized. The "essential service" requirement is satisfied for a given period if the ship carries at least 30% of its total cargo in the U.S. foreign commerce. The percent of the subsidy payable increases from 40% (when U.S. foreign commerce cargo is between 30 and 40%) to 70% (when the U.S. foreign commerce cargo is between 40 and 50%) to 100% (above 50%). The above percentages are computed by determining the larger quotient between ton-miles of cargo carried in U.S. foreign commerce divided by all ton-miles of cargo carried or gross revenue earned from U.S. foreign commerce divided by total gross revenue earned. The period shall be thirty-six successive calendar months of operation. The subsidy contracts may be for as long as twenty years (*Id.* § 252.21).

An owner/operator applicant for an ODS must demonstrate that it has a minimum working capital in an amount equal to 50% of the average annual voyage expenses for each of the ships to be covered by the ODS contract. A shipowner must also show net worth in an amount equal to 25% of the owner's share of the costs (*i.e.,* the non-subsidized portion) of all ships to which the ODS will be applied.

The objective of the subsidy is to make the American merchant marine competitive against foreign shipping companies who employ foreign crews at lesser wages and therefore are able to operate with lower costs. Since foreign-flag vessels are disqualified from operating in U.S. coastwide or domestic trade, there is no need for a subsidy for U.S. ships operating in such trades. Moreover, if there is another U.S. flag operator in the service for which the applicant proposes to begin operations under subsidy, the application cannot be approved without a hearing and a finding by the MSB that the existing service by U.S. flag ships is inadequate and that additional ships such as the applicant's should be added to the service. (46 U.S.C. § 1175(c) (1970)). The "buy-American" policy is applied to require stores, supplies, and permanent repairs to be purchased in the United States or Puerto Rico except in emergencies. (46 U.S.C. § 1176 (1970)). Fresh food and fuel are not included in that requirement. Limited domestic trade calls are permitted without loss of the ODS (*e.g.,* San Francisco to Honolulu en route to Japan) if the Secretary of Commerce finds that such domestic service "will not result in a substantial deviation from the service route or line for which the operating differential subsidy is paid and will not adversely effect service on such . . . route or line." (46 U.S.C. § 1183(c) (1970)). Shipowners operating their vessels under charters in excess of five years duration must submit the charters to the Assistant Secretary of Commerce for approval prior to execution if the charters involve foreign-to-foreign trade. Generally approval is granted if it may reasonably be expected that the vessel will be employed to a "significant extent" during the charter in the U.S. foreign commerce. Vessels under charter of five years or less which do not have options to renew, may engage in out-port trade without the prior approval of the Assistant Secretary (46 C.F.R. §§ 278.2 and .4 (1975)).

COMPONENTS AND MEASUREMENT OF THE SUBSIDY

The ODS is defined as "the excess of the cost of subsidizable items of expense incurred in the operation under United States registry of a vessel over the estimated fair and reasonable cost of the same items of expense, . . if such vessel were operated under the registry of a foreign country whose vessels are substantial competitors of the vessel . . ." (46 C.F.R. § 252.3(l) (1975)). The cost items in which comparisons are made as the basis for measuring the subsidy payment are base wages, repairs and maintenance expense, and insurance premuims. Competing operations are developed out of data for comparable type vessels (*e.g.*, chemical bulk carriers). The principal competitive foreign flags would be those whose aggregate registered tonnage equals at least 60% of the total tonnage of all competative vessels, not to exceed the five foreign flag fleets with the greatest total tonnage. Finally, a competition weight factor is developed by taking a ratio or percentage, the numerator of which is the total deadweight tonnage of the vessels of the particular foreign flag and the denominator of which is the total deadweight tonnage of the vessels of all principal competitive foreign flags as defined above. (*Id.* § 252.22).

The subsidy payable for wages is equal to the number of voyage-days in the fiscal year (other than days of "reduced crew") multiplied by the wage subsidy per diem rate effective for that fiscal year plus the sum of unpredictably timed costs multiplied by the wage subsidy percentage rate for that year (*Id.* § 252.31(a)). The wage subsidy per diem rate equals the difference between the subsidizable wage costs and the composite foreign wage costs divided by the subsidizable wage costs for a particular fiscal year. Determination of subsizidable wage costs requires the allocation of collective bargaining costs on a per diem basis. These include fixed costs, such as base wages, vacation pay, and fringe benefits, and variable costs such as overtime and penalty pay, transportation expenses, and payments to relief officers (*Id.* § 252.31(c-3)).

U.S. wage costs are derived from the actual negotiated crew complement in effect on January 1st of the fiscal year in question and are computed on a daily basis. Foreign wage costs and crew complements are to be ascertained from Alien Crew Declaration Statistics. If all the competing vessels have not actually called at U.S. ports, they will be determined from responses of the managing operators of such vessels as do call at U.S. ports. Disclosure of this information to the U.S. Government is required under authority conferred by the Shipping Act of 1916 (46 U.S.C. § 820 (1970)). Insofar as possible, functional matchups will be made when precise nomenclature is not the same for crew job descriptions. Conversion from foreign currencies to U.S. currency equivalents shall be done at the average of the monthly foreign exchange rates for the year if the foreign crew is paid in foreign money (*Id.* § 252.31(f)). For the fiscal years other than the base period year, appropriate adjustments are made by comparing January 1st costs under the Index of the Bureau of Labor Statistics for changes in wages and benefits for employees under collective bargaining agreements in transportation and non-agricultural industrial activities (*Id.* § 252.31(b)). Variable costs are added to fixed costs on the basis of the preceding year's experience (as the ratio of the preceding year's variable costs to that year's base wage costs). The unweighted percentage of foreign costs to U.S. wage costs is then obtained for the principal competitors and the weighting factors are applied to get a single composite weighted percentage. This factor is then applied to the total U.S. wage costs to arrive at the "composite foreign wage cost". This in turn is subtracted from the subsidizable wage costs (all in daily units) to obtain the wage subsidy per diem rate (*See* Appendix, Exh. 25 for illustrations).

The same policies underlie the maintenance and repair element of the ODS. The idea being to enforce the "buy-American" aspects of the shipyard aspects of operations by equalizing the costs with the costs of repairs and maintenance performed in foreign yards. Repairs must be done in shipyards in the United States or Puerto Rico to be eligible. Average price quotations of U.S. repair yards are established by MARAD for each of the four coastal areas: East, West, Gulf and Great Lakes. Repairs are divided into categories such as underwater repairs, electrical, and boiler, etc. (*Id.* § 252.32(b)). Every three to five years

MARAD requests reliable ship repairers in selected U.S. and foreign ports to provide price quotations for representative samples of work described in a standard set of specifications representative of the types of work in each principal category. Between responses to these requests, the costs so obtained are adjusted by indexing using the respective country's wage index (in the United States the Monthly Index of Wages (hourly earnings in manufacturing) published by Bureau of Labor Statistics). (*Id.* § 252.32(c)). The principal foreign competitors maintenance and repair cost data are factored by category of repair work and by percentage done in any particular country (derived from responses to questionnaires to foreign lines or by assuming that repairs followed the repair survey and noting the country in which the repair survey was made as reported by Lloyd's of London). Finally, this weighted figure for any particular country of foreign flag competition is multiplied by such flag's "competition weight factor" (*Id.* § 235.32(b)). As with wages, the methodology enables MARAD to assess the approximate impact of a U.S.-flag operator making its repairs in American yards as opposed to its principal competitors making their repairs wherever they see fit to make them, based on historic records and adjusted over time for inflation or deflation in the wage rate and for changes in foreign exchange. The final subsidy rate is then applied to the eligible expenses as reported by the subsidized U.S. operator. For an example of these computations, *see* Appendix, Exh. 26.

The third element of the ODS is the subsidy based upon differences in hull and machinery, and protection and indemnity insurance premiums. The hull and machinery insurance subsidy rate computations will be discussed first. The subsidy rate is the difference of the eligible premium costs less the composite foreign premium costs divided by the eligible premium costs, expressed as a percentage (*Id.* § 252.33(a)). "Eligible premium costs" are defined to mean the premium costs actually incurred by the operator during the calendar year in question for hull and machinery, increased value, excess general average, salvage and collision liability insurance. The "composite foreign premium cost" is the foreign premium cost less the general average portion plus an adjusted (substitute) particular average portion. Particular average in this context means losses *not* involved in the general average relationship between ship (carrier) and cargo as allocated under the York-Antwerp rules by general average adjustors and arbitrators. Since payouts under hull insurance primarily go for repair costs which may be less for repairs effected in foreign yards by competing owners not under a "buy-American" constraint, the particular average cost is multiplied by a factor which reflects the common costs of such repairs, *i.e.*, 100% less the repair subsidy rate (described in the preceding section). The particular average portion is defined as "the difference of the hull and machinery portion of the foreign premium cost less the estimated total loss premium included therein multiplied by the particular average factor". This in turn requires two further explanations. The particular average factor for the particular operator applying for the subsidy is computed in fractional form where the numerator is the total insurance payout of repair claims in particular average over the last ten years and the denominator is the payout of all claims under the hull and machinery insurance for the same period. Second, it should be noted that total loss payouts are excluded from the denominator of that fraction just as the premium attributable to total loss coverage is excluded in defining the "particular average portion." In short, when a vessel is a total loss or a constructive total loss, restoration of value is accomplished by a cash payment which the insured is free to re-invest toward the cost of a replacement ship or invest elsewhere as it sees fit. There are no repairs as such to be made to the lost vessel and therefore it is a distinct and different kind of risk with a different premium pricing structure. The Maritime Subsidy Board, in estimating the composite foreign premium cost of each vessel of each principal competitive foreign flag, makes the following assumptions for computational purposes: (1) each such vessel has the same types and amounts of insurance coverage and deductible averages as the subsidized vessel; (2) each vessel is insured in the British insurance market at a market rate that is the same as that for the subsidized vessel; (3) the fraction of particular average repair claims for each vessel is the same as that of the subsidized vessel; (4) insurable repairs for each vessel are performed in the same countries and in the same proportion in each of such countries as non-insurable repairs (*Id.* § 252.33(c)). For a sample calculation of the hull and machinery subsidy rate *see* Appendix, Exh. 27.

The second component fo the insurance subsidy is the subsidy to reflect the difference in premium costs (calls) paid (assessed) for protection and indemnity insurance (liability insurance). Once again, the purpose is to pay a subsidy which has the net effect of equalizing the operating costs for such premium expense. To the extent American flag lines may use higher deductibles, and to that extent become self-insurers, the formula makes allowance for such payouts. Included in this premium subsidy in addition to protection and indemnity (P & I) coverage is excess insurance, cargo insurance, pollution liability insurance. In P & I insurance, because awards to crew members for injuries and deaths can vary so drastically according to the standard of living and the compensation systems utilized in the various countries in which suits are brought, the total premium cost is factored into the crew liability portion and the "all other liabilities portion" with "excess" insurance (which tends to be an option which insureds may or may not elect to have) and pollution liability excluded altogether. The crew liability factor is determined by the subsidy applicant's five-year experience ratio and is a fraction, the numerator of which is the crew injury or death claims paid during that period and the denominator of which is the total of all claims paid during the same period. Where payouts have not yet been made for a past year's liability-generating incidents, an estimated payout is used. Crew liability premium costs for foreign flags are to be determined by the MSB based on data available to MARAD if there is a coincidence between crew nationality and flag. If the vessel is registered under a flag of convenience then MARAD data pertaining to premium costs for similar vessels under the same nationality as the crew shall be used (*Id.* § 252.34 (b)). Cost differentials are assumed to be attributable only to the crew liability portion of the total premium cost (*Id.* § 252.34(d)). Using the foreign flag cost and applying a crew liability factor derived from the applicant's history and adding in a constant portion for the "all other liabilities portion" to arrive at a built-up estimated foreign premium cost, an unweighted differential is developed by subtracting from the applicant's total premium costs the estimated foreign premium cost and using the difference as the numerator of a fraction, the denominator of which is the applicant's total premium cost. This in turn is weighted by the competition weight factor for each of the principal competing flags. The protection and indemnity subsidy rate is then the sum of the several weighted differentials (46 C.F.R. § 252.34(b) (c)). *See* Appendix, Exh. 28 for an illustrative computation of the protection and indemnity insurance subsidy rate.

It should be noted that the competiton weight factors always add up to 100%. For subsidy applicants who have not been operating for five or ten years in the past in those cases where five or ten year historic records are required to develop some factor, special procedures are spelled out in the regulations for synthesizing these factors (*see, e.g., Id.* § 252.33(c)(2)).

TITLE XI MORTGAGE INSURANCE

By the spring of 1976, MARAD had committed nearly one billion dollars in Title XI insurance guarantees for the construction of fourteen LNG carriers (Kasputys & Gustaferro speeches to Cryogenic Society of America, Inc. (May 1976, MARAD)). Title XI is a form of government guarantee to the lender in the case of a loan, to the mortgagee in the case of a chattel mortgage or a preferred ship mortgage, or to the trustee in case of government-issued debentures sold to investors and payable by the registered owner. The effect of this guarantee is to reduce substantially the risk involved and to give lenders an added incentive to make loans at attractive rates.

ELIGIBILITY

The guaranteed loan must be for the purpose of constructing, reconstructing or reconditioning vessels which will be documented under the laws of the United States, which will be entitled to the highest classification and rating for vessels of that type by the American Bureau of Shipping, which are built in American shipyards, and which satisfy the requirements of the Safety of Life at Sea Convention (SOLAS) and the United States Coast Guard. If it is a mortgage to be guaranteed, the terms of the mortgage will not exceed twenty years for new construction. The borrower and lender and other secured parties must be citizens of the United States. Corporate citizens are defined as those corporations (1) with a controlling interest owned by citizens of the United States and (2) with presidents and chairers of the board of directors who are citizens of the United States and (3) with no more of their directors than a minority of the number to constitute a quorum as non-citizens, and (4) which are organized under the laws of the United States or one of its states or territories. (46 U.S.C. §§ 802, 1103 (1970)). Similarly, the trustee designated in a trust indenture shall be approved pursuant to Public Law 89-346 (requiring that it be a citizen of and incorporated in the United States, that it be a bank or trust company with trust authority and subject to state or federal government supervision, and that it have a combined capital and surplus of at least $3 million.)

The cost of the vessel's construction is to be determined by competitive bid unless done pursuant to a negotiated contract by the Secretary of Commerce or the Maritime Administrator on a finding that the construction differential exceeds 35% (*see* 46 U.S.C.A. § 1152 (1975)). The applicant for such mortgage insurance must demonstrate that is has working capital in "an amount equal to the difference between the total estimated capitalizable cost of the vessel to the applicant . . . and the amount of the insured loan commitment." In addition to this, working capital is required to be equal to the sum of 8% of the capitalizable cost of the ship to the applicant plus one year's premium on all marine insurance plus the first year's premium for the Title XI insurance. The applicant must also demonstrate net worth (not less than 50% of which is represented by common stock equity) in an amount at least equal to the sum of the difference between the capitalizable costs of the vessel to the applicant . . . and the amount of the insured mortgage plus 4% of the estimated capitalizable costs of the vessel to the applicant. Applicants who are parties to operating differential subsidy agreements need not meet these minimum financial requirements.

The insurance is available to finance vessels used in coastwise or intercoastal trade, on the Great Lakes, in the fishing industry, or in the foreign trade of the United States (46 U.S.C. § 1104(a)(1)). Thus, shipowner borrowers who are not eligible for CDS or ODS may still benefit from TITLE XI insurance (46 C.F.R. § 298.4 (1975)). The maximum insurance payable is limited to 75% of the actual cost paid (above subsidy) for the construction of the vessel excluding legal fees, accounting fees, loan commissions, title documentation fees, and pre-delivery operating expenses. (46 U.S.C. § 1244(b)(2) (1970) (domestic trade high-seas ships are covered up to 87 1/2%); 46 C.F.R. § 298.7 (1975)). However, such maximum payout limitation applies to unpaid principal and does not refer to accured interest. (46 C.F.R. § 298.2(k)-(o)). A borrower must pay cash for at least 25% of the actual cost but this may be done in two installments: a first payment of 12.5% followed by a second equal payment after 50% of the total actual costs to the borrower are paid (*Id.* § 298.8(e)).

RESERVE FUND, OPERATIONAL COVENANTS

The reserve fund concept requires that the shipowner-borrower transfer a predetermined portion of the ship's net earnings to what is essentially an escrow account maintained by the reserve fund depository. Assets in such a reserve fund may be invested and may generate returns and there are provisions for withdrawal of these profits. The fund is built up to provide a source of cash collateral or very liquid assets should the Secretary of Commerce have to take over the payments in the event of a default. Within 120 days of the end of each fiscal year the borrower [hereinafter "the Company"] computes its net reserve fund income. Gross income includes investment income from assets already in the reserve fund and, of course, includes operating revenues from the vessel whose mortgage is insured. The net is arrived at after deducting the voyage operating expenses, charter hire, if any, allocation of administrative overhead and taxes paid. After thus determining the net income, the Company may annually deduct the amount of the principal actually paid or redeemed by the Company during the fiscal year and an amount equal to 10% of the Company's aggregate original equity investment in said vessel. (MARAD Title XI Reserve Fund and Financial Agreement--Special Provisions, exhibit 1, § 2(b) hereinafter cited as Reserve Fund Agreement.) After the second set of deductions the Company is required to deposit in the fund an amount equal to 50% of the balance. These contributions must continue until such time as the insured obligations have been satisfied and discharged or the MARAD insurance guarantees have been terminated or the value of the reserve fund is equal to or in excess of 50% of the principal amount of the outstanding insured obligations (Reserve Fund Agreement § 2(b)(2)(D)). There are also provisions, conditioned on certain demonstrations of solvency, that the Company may be governed solely by operational covenants and not have to contribute further to the reserve fund. (*Id.*).

Withdrawals from the reserve fund may be made from time to time upon approval of the Secretary of Commerce for the purposes of redeeming Title XI bonds, paying charter hire, reimbursing the Company for capital gains taxes resulting from gains in capital transactions of the reserve fund, payment to the Company's general treasury of the interest and dividends earned on fund investment, or transfer back to the Company of that portion of the reserve fund in excess of 50% of the principal amount of the insured bonds or obligations (an event which will occur after the debt is paid down over time) (*Id.* § 3). In addition to terminating when the obligations are paid off, the fund may terminate and be paid over to the Secretary of Commerce in the event that there has been an event of default which has triggered a payment of the insurance to the indenture trustee for the insured bonds. Resort to the collateral in the fund in no way prejudices any other remedies that any of the parties may have (*Id.* § 4). Sec. 5 of the Special Provisions of the Agreement specifies the eligible investments which may be made by the fund depository and further states that, in lieu of cash, the Company may deposit in the reserve fund "negotiable certificates of deposit, short term commercial paper or securities which are eligible investments. . ." of appropriate value (*Id.* § 5). The Company retains the right to vote any securities deposited in or obtained by the reserve fund and to exercise any other rights common to such security holders (*Id.* § 6). If the Company has elected to establish a capital construction fund (*see* Chapter IV, Private Financing, *Tax Benefits, Internal Financing, construction reserve fund infra*) with respect to vessels as to which loans are insured under Title XI, the Company and the Secretary of Commerce are required to enter into an agreement that the capital construction fund and all assets therein shall be security for the United States Government in lieu of the reserve fund (*Id.* § 9).

In addition to commiting itself to establish and contribute to the reserve fund, a borrower whose obligations are insured under Title XI makes certain operational covenants to the United States. The following transactions are forbidden without prior written consent of the Secretary of Commerce unless, after such transaction in any fiscal year, the working capital and net worth of the Company will exceed certain minimum amounts incorporated in each individual reserve fund agreement: withdrawal of capital; redemption of shares or conversion of shares into debt; payment of cash dividends or in kind dividends or stock dividends in stock other than the stock of the Company (operators receiving ODS are exempt from this prohibition); making of loans or advances to stockholders, directors, officers, employees or affiliates; investing in the securities of any affiliate; increasing any direct employee compensation beyond $50,000 per year; giving raises to any employee earning in excess of $50,000 per year; initially employing or reemploying any person at a direct compensation rate in excess of $50,000 per year; acquiring any fixed assets other than those required for normal operation and maintenance of Company vessels. Additionally, there are restrictions that the Company may not, without the prior written consent of the Secretary: create encumbrances other than liens incurred in the ordinary course of business; enter into any operating agreement for the vessel; sell or demise charter of the vessel; guarantee the obligations of any other corporation (other than endorsement of checks and negotiable instruments acquired in the ordinary course of business); embark upon any new business not connected with shipping; merge, consolidate or sell off assets (whose aggregate worth exceeds 10% of the Company's total assets); assume or incur further indebtedness (other than customary current liabilities); make investments other than in United States Government bonds or notes and eligible investments as defined in the reserve fund agreement; pay subordinated indebtednesses; enter into below-market-value sale and lease back agreements (*Id.* § 12).

In the alternative under § 13 of the Reserve Fund Agreement, the Company need not contribute to the fund and need not be bound by the foregoing covenants if the companies working capital is greater than half of the annual charter hire and lease obligations not counted as current liabilities on the balance sheet, and if its long term debt does not exceed two times its net worth, and its net worth is at least as much as an amount specified in the particular agreement. If this option is elected, the Company binds itself to an alternative set of covenants which are nearly identical and which involve similar activities which are prohibited unless after the transaction the status of working capital and long term debt ratios is as specified immediately above. The salary limits of these alternative covenants are somewhat more generous than are allowed for companies not electing the § 13 option (*see also*, 46 C.F.R. § 298.4(k) and 298.8(k)).

THE SECURITY AGREEMENT

Under the security agreement the shipowner is obligated to keep the vessel covered with hull insurance to a value at least equal to 110% of the unpaid principal amount of the outstanding obligations (or for a greater value if required by the Secretary of Commerce up to the "full commercial value of the vessel"). (General Provisions of MARAD Security Agreement, § 2.07(b)). Such insurance must include war risk insurance. In the event that the vessel is laid up (a not uncommon phenomena for LNG carriers as they await completion of foreign liquefaction facilities or domestic import terminal facilities) port risk insurance may be substituted. (*Id.*) The Secretary of Commerce is to be made a loss payee as his or her interest may appear on the policies. (*Id.*) The Secretary may pay directly for repairs or may consent that underwriters reimburse the shipowner if it has paid for repairs so long as there is no existing default under the mortgage or bond obligation (*Id.* § 207(c)). Builder's risk insurance and protection and indemnity (both marine and war risks) policies must be taken out by the shipowner without expense to the Secretary of Commerce or the shipyard (*Id.* § 207(a) and 2.07(e)). There shall be no recourse against the United States for nonpayment of premiums or calls and at least ten days written notice of cancellation for nonpayment must be given to the Secretary of Commerce (*Id.* § 2.07(i)).

A salient feature in this financing scheme is that the borrower executes a so-called "Secretary's Note". Principal and interest on this note is payable by payment of the interest on the obligations and repayment of the principal of the loan or redemption of the bonds as the case may be. In short, performance under the note is fulfilled when the borrower's obligations to the lender are made good. Additional provisions of the agreement pertain to payments out of the escrow fund or the construction fund in the form of progress payments to the yard as the vessel is being built (*Id.* § 4 and 5).

The interest of the Secretary of Commerce in this security equals but does not exceed the guarantee fee due and payable, administrative expenses, accrued interest upon the Secretary's Note, and an amount equal to the unpaid balance of principal upon the Secretary's Note. (*Id.* § 7.01). Residual interests are essentially in the shipowner (*Id.* § 7.02).

The concept of the Secretary's Note with collateral running directly to the Secretary is the result of 1972 amendments designed to streamline the security, eliminate the need for cumbersome assignments, and reduce the number of documents and parties involved should a foreclosure become necessary (*see* Cook, *Government Assistance in Financing Title XI Federal Guarantees*, 47 TULANE L.REV. 653, 659-660 (1973)). These same amendments gave the Secretary of Commerce greater flexibility in waiving acts of default which are curable or as to which there are more efficient remedies than foreclosure. Previously the Secretary had to obtain the consent of the mortagee or bondholders and the indenture trustee (*Id.* at 662). Similarly, the Secretary is permitted to guarantee obligations having a maturity date based on the newest vessel to be covered by the guarantee. If several vessels of differing ages are being financed, presumably the Secretary can require premature retirement of the bonds in quantities applicable to each vessel as it reaches the end of its economic life (*Id.* at 663).

With the recent popularity of sale-and-leaseback arrangements, the Secretary of Commerce has on occasion permitted biannual mortgage payments to be made on a level-debt basis rather than equal-payments-on-principal with decreasing interest as the balance declines. This enables the repayment to be geared to match lease payments (*Id.* at 668).

CALCULATION OF PREMIUM

The Secretary of Commerce has the power to set the fee for the Title XI mortgage insurance within the statutory limits which are 1/2% to 1% of the amount of the obligations for a delivered ship and between 1/4% and 1/2% of the obligations for a ship under construction (46 U.S.C. § 1104(d) (1970)). The amount of the obligation in fact will be reduced over time and as the premium is for an annual period, the average principal amount outstanding is used (46 C.F.R. § 298.10(b) (1975)). The borrower pays the money to the lender for the premium costs at least sixty days before it is due and the premiums are in fact paid to the Maritime Administration by the lender. Current contracts scale the premium rate from 1/2% to 5/8% to 3/4% to 1% as the ratio of net worth to long term debt of the borrower decreases (General Provisions of Security Agreement § 3.02(d)). The net worth and long term debt figures used are those reported on Maritime Administration Form 172 or computed in accordance with General Order 22 (*see* 46 C.F.R. § 282) if no Form 172 has been filed (*Id.* § 3.02(b)).

PRIVATE FINANCING

INTERNAL FINANCING, TAX BENEFITS

Construction Reserve Fund

A citizen (corporations included) of the United States owning a vessel operating in either the foreign or domestic commerce of the United States upon the sale of the vessel or upon an actual or constructive total loss of the vessel may deposit the net proceeds of the sale or the loss indemnity in a Construction Reserve Fund. This law is much like the section of the Internal Revenue Code which permits a homeowner to reinvest the proceeds of the sale of a dwelling in the building or acquisition of a replacement dwelling, without recognition of gain on the first sale. If a shipowner deposits the proceeds within sixty days of receipt and makes the appropriate election on its income tax return for the year in which the gain was realized, both ordinary income and capital gains taxes are deferred. Net proceeds are defined as the adjusted basis of the ships sold or lost plus the amount of gain which would otherwise be recognized (46 U.S.C. § 1161(c)-(d)). In order to assure deferral of the taxes, within three years after depositing the funds the taxpayer must expend or obligate for expenditure funds for the construction or acquisition of a new vessel or for the liquidation of existing or subsequently incurred purchase money indebtedness on a new vessel (*Id.* § 1161(g)). In the case of purchases or construction contracts, at least 12 1/2% of the price must be paid or irrevocably committed before the deadline and for non-subsidized vessels, the ship must be 5% completed before the deadline (*Id.*). With regard to the "new" vessel acquired, reconstructed, or constructed, the basis will be adjusted downward by the amount of tax-deferred gain funds expended for its purchase (*Id.* § 1161 (d)). American citizens operating vessels in the U.S. foreign or domestic commerce obtain a further benefit by this legislation in that money in the fund will not be charged against the tax payers for purposes of computing an accumulated earnings tax under § 531 of the Internal Revenue Code (*Id.* § 1161(f)). As to those vessels obtained by acquisition, they must be generally less than five years old to qualify as a "new" vessel.

Capital Construction Fund

Whereas the Construction Reserve Fund only applied to monies generated by the sale or indemnity for total loss of a vessel, the Capital Construction Fund allows U.S.-citizen shipowners operating in the U.S. foreign or domestic trade to deposit the earnings of their existing vessels in a fund for the purposes of deferring income and capital gains taxes (46 U.S.C. § 1177(a)). Not only are the ordinary income earnings and capital gains in the operation of an eligible vessel in such trade tax deferred, to the extent deposited in the fund, but the earnings and returns on investments of the fund are also tax deferred (*Id.* § 1177(d)). Similarly, such funds are exempt from the accumulated earnings tax (*Id.*).

The fund should be divided into three sub-accounts known as the capital account, the capital gain account and the ordinary income account, depending on the source of the transaction which produced the funds which were deposited. As in the case of the Construction Reserve Fund, withdrawals from this fund may be used to acquire, construct, reconstruct or reduce indebtness incurred in connection with the acquisition or construction of a qualified vessel or barge or container which is part of the compliment of a qualified vessel (*Id.* § 1177(e) and (f)). Withdrawals from the fund shall be treated as made first from the capital account, second from the capital gain account and third from the ordinary income account. If withdrawals are made from the capital gain account, the basis of the acquired vessel shall be reduced by an amount equal to 5/8's of such amount for corporate taxpayers. If withdrawal is from an ordinary income account, the basis of the acquired vessel will be reduced by the amount of the withdrawal (*Id.* § 1177(g)). Non-qualified withdrawals from the fund are treated as being withdrawn in the reverse order and in general are accounted for on a first-in, first-out basis (*Id.* § 1177(h)).

The acquired vessels, to be eligible and qualified, must be built or reconstructed in the United States, documented under the laws of the United States, and operated in the United States foreign commerce, the Great Lakes trade, or the non-contiguous domestic trade (*Id.* § 1177(k)). There are ceilings imposed by the law on the amount of deposits to the fund. In any taxable year, such deposits must not exceed the sum of the portion of the taxpayer's taxable net income attributable to the operation of the agreement vessels without regard to loss carrybacks, plus depreciation claimed for such year with respect to the agreement vessels, plus the net proceeds of sale or insurance indemnity (to that extent, deposits in this fund resemble those in the Construction Reserve Fund), plus returns on investment of the fund itself (*Id.* § 1177(b)).

The benefits of the capital construction fund are particularly attractive to owners thinking of acquiring LNG carriers since vessels in "liquid. . . bulk cargo carrying services trading between the foreign ports in accordance with normal commercial bulk shipping practices. . ." are now eligible. The definition of foreign commerce is thus broadened to include outport trade making the benefits of the fund available to the would-be purchaser of an American flag LNG carrier to be operated, *e.g.*, from Indonesia to Tokyo, on relatively short term charters or in a spot market (46 U.S.C.A. § 1244 (1975)).

Investment Tax Credit

§ 38 of the Internal Revenue Code provides for an investment tax credit equal to 7% of the basis of new tangible property (*see*, *Id.* §§ 46(a), (c), and 48(a)). This would include U.S.-documented LNG carriers operated in the foreign or domestic commerce of the United States (*Id.* § 48(a)(2)(iii)). The Internal Revenue Service has ruled that subsidized operators must reduce their bases to reflect what they actually paid to acquire or construct the vessel and that if purchase-money mortgages were paid off with tax deferred funds, the investment tax credit will be recaptured. (*See* Kominers, *Federal Government Aids to Merchant Shipping*, 47 TULANE L.REV. 691, 722 (1973)). Pending litigation and joint regulations of the Departments of Commerce and Treasury will hopefully clarify the impact of these rulings.

COLLATERALIZATION OF LOANS

Beside the traditional security device of a preferred ship mortgage, which is available as soon as the vessel is documented (46 U.S.C §§ 911-961 (1970)), lenders usually endeavor to take an assignment of the charter hire. If the vessel is to be bareboat chartered or leased to a large oil company or natural gas company, this is relatively good security. Similarly, long-term time charters, if they are provided with escalation clauses to cover increased operating expenses due to inflation, are considered adequate security. It should be added added that to preclude the risk of unforeseen downtime or layups, the lenders usually require time charterers to agree to the so-called "hell or high water" clause which insures that hire will be paid during the term of the charter regardless of the condition or utilization of the vessel.

Because there are instances where a casualty can occur to the vessel and the owner will be ineligible to claim hull insurance benefits, English and American underwriters have recently changed their insurance policies to assert that the mortgagee has no better rights than the assured. In such instances, lenders may insist that the borrower take out mortagee's interest insurance. (*See* Mahla, *Some Problems in Vessel Financing--A Lender's Lawyer's View*, 47 TULANE L.REV. 629, 644 (1973)). There are related problems concerning the insurance coverage of an owner under his P & I entry if the vessel is mortgaged and the mortgagee has not guaranteed payment of the calls to the P & I Association. (*See, e.g.*, *Rules of the United Kingdom Mutual Steamship Assurance Association (Bermuda)*, Rule 20(B)(ii) (1976)). Such guarantees are usually not offered and the P & I clubs generally waive the requirement, but lenders must be careful to have a written understanding so that insurance coverage may not later be voided at the insurer's election (*see* Mahla, *supra* at 645).

For domestic LNG trade routes, lenders might desire project-wide security, including liquefaction plants and terminals to the extent that they were owned by the same entity. But even in the United States, the terminals and vessels are often owned by different companies. American banks are somewhat chary about lending to companies investing in foreign countries for liquefaction facilities at the present time, although as credibility is established in the stability of foreign supply, these investments may become more attractive. To the extent that the tanker owner is trading for its own account and is selling the cargo to importers or public utilities in the United States, assignments of the proceeds under the long-term supply contracts also might be exceptable collateral.

The leveraged demise charter is a type of lease that is currently popular in that it facilitates various tax advantages. In this type of financing, the ship user contacts a leasing agent to arrange, in effect, what amounts to 100% financing for the construction of an LNG carrier. The leasing agent finds an investor with a cash flow and tax rate such that the advantages of the investment tax credit, accelerated depreciation and the capital construction fund deferrals can be utilized fully and efficiently. This investor usually puts up 25% and is the equity partner. The remaining 75% is borrowed from an institutional lender. The charter contains a "hell or high water" clause. Generally with this combination of financing the effective interest rate is considerably lower than that at which the potential ship user could borrow if it were to become the shipowner. Under certain assumptions, it can be shown that savings as high as 3.9% per annum can be achieved in the early years over the user's going directly to the money market and becoming a purchaser. (*See* Kalaidjian, *Government Chartering and the Charter in Modern Finance*, 49 TULANE L.REV. 1021, 1029-1034 (1975)). *See generally*, speech of Stanley Powell, Director of United States Leasing International Inc. "Financing Through Leasing".

UNIFORM COMMERCIAL CODE FINANCING STATEMENTS FOR BUILDERS

Prior to the delivery of a ship, the shipyard retains title to the components and the assemblies, hull and superstructure. Since progress payments have been made by the purchaser or by the purchaser and the MSB, the practice at some shipyards has been to file an Article 9 financing statement on behalf of the purchaser. In effect, this treats the progress payments as loans towards the construction costs and confers upon the purchaser (lender) a non-maritime lien on the vessel under construction. Prior to documentation of the vessel, institutional lenders and the MSB are left to their chattel mortgages and contract rights. If default did occur, it seems very probable that they would contest both the shipyard's title and the purchaser's security interest.

INTERNATIONAL FINANCING OF FOREIGN LIQUEFACTION FACILITIES

The Export-Import Bank (EXIM) has committed $390 million for LNG or LNG related projects in Algeria (Kasputys & Gustaferro speech, *supra* at 12). The Export-Import Bank operates under the authority of 12 U.S.C. § 635 as amended (1976 Supp. to U.S.C.A.). The Bank is required to provide Congress for each loan involving the export of any "product or service related to the production, refining or transportation of any type of energy, or the development of any energy resources with a statement assessing the impact if any, on the availability of such . . . energy supplies thus developed for use within the United States." (12 U.S.C.A. § 635(b)(1)(A) (1976 Supp.)). The recent amendments limiting loans to Communist countries have implications for the development of Russian LNG trade routes to the United States and are discussed in Chapter VIII, Reliability of Foreign Suppliers, *Economic Factors, infra*. The Export-Import Bank is also in a position to finance foreign-flag LNG carriers. Such loans would be possible even if the foreign owner were a wholly-owned subsidiary of a United States parent corporation. EXIM could advance 90% of the purchase price and would probably split that 90% two or three ways. In a two-way split, private banks would take 45% with or without guarantees from EXIM and would be repaid from early maturing notes or bonds. In a three way split, the Private Export Funding Corporation (PEFCO), a syndicate formed recently by some fifty private banks interested in financing exports, would take 30%, a private bank would take 30% and EXIM would take 30%, with the private bank being paid from the earliest maturities, and EXIM from the latest maturities. EXIM maintains a fixed lending rate at 6% and the PEFCO also utilizes a fixed rate. As to LNG vessels, EXIM would be willing to allow repayment terms of twelve years after construction with interest-only paid during the construction period. Although this term is longer than terms afforded by other governmental lenders, it may be significant that EXIM feels that still longer terms are not justified. (*See generally*, Statement of John E. Corette, General Counsel for Export-Import Bank "Financing of LNG Tankers.")

The Overseas Private Investment Corporation (OPIC) is precluded by its charter from making lonas "to finance operations for mining or other extraction of any deposit of ore, oil, gas, or other minerals." (22 U.S.C.A. § 2194(c) (Supp. 1976)). However, OPIC is empowered to issue insurance against currency inconvertability and expropriation through the end of 1979 (*Id.* § 2194(a)). "Eligible investors" for the purpose of such investment insurance are "limited to U.S. citizens, U.S. corporations which are substantially beneficially owned by U.S. citizens, and foreign corporations and partnerships owned by U.S. citizens or U.S. corporations to the extent of at least 95% of the share capital."(22 U.S.C.A. § 2198(c) (1976 Supp.)).

liability and liability limits

BUILDER'S LIABILITY

CONTRACTUAL PROVISIONS

Under the typical contract approved by the Maritime Subsidy Board between the yard and the purchaser, the builder is obliged to correct at its expense any weakness, deficiency, failure, breaking down or deterioration, in workmanship or material or any failure of vessel or of any equipment, machinery of material to function as prescribed and as intended by the plans and specifications if these pertain to the conventional aspects of the vessel and manifest themselves within one year after the actual delivery of the vessel. For cryogenic aspects, the guarantee period is within twelve months after tests of such aspects or fifteen months after delivery whichever period is shorter (but in no event less than twelve months after delivery). (*See, e.g.,* Contract No. MA/MSB-257, art. XVIII (a)). The builder is not responsible for consequential damages or damage to the vessel caused by the defective equipment, for ordinary wear and tear, or for deficiencies to the extent that they are aggrevated by the negligence of the purchaser or operator of the vessel (*Id.*). However, if a piece of equipment damages itself due to some defect, the entire piece of equipment must be restored or replaced at the builder's expense. The purchaser must notify the contractor of such deficiencies within thirty days after the end of the one-year period and provisions are made for a guarantee survey of the vessel at or near the expiration of the one-year period (*Id.* art. XVIII (b) and (c)). To the extent that a deficient part is supplied by a subcontractor or vendor and carries a longer warranty or guarantee, the builder agrees to assign its rights against the supplier to the purchaser (*Id.* art. XVIII (e)).

Many shipyard contracts covering non-subsidized ships contain clauses which purport to limit or exclude the yard's liability. For convenience of discussion, these may be subdivided into five categories: (1) exculpatory clauses regarding negligence; (2) disclaimers of expressed and implied warranties; (3) contractural waivers of consequential damages; (4) indemnification agreements; (5) contractual limitations on liability.

Exculpatory clauses in contracts have generally been upheld, at least where the parties were of roughly equal bargaining power. One would assume such equality to be present in the shipbuilding context. However, if *all* yards insist on identical clauses, the purchaser's threat to take its business elsewhere is less meaningful. Conceptually exculpatory clauses are difficult because they span contract and tort law. The consequences of agreeing to such a clause are of course, anticipatory, but that in itself is not fatal since many of the other rights and liabilities created in contractual arrangements can be said to pertain to future events. It does indicate, however, that the clause must be well drafted and must make an express delineation of the situations in which exculpation will be allowed. If the clause is upheld, it will serve as a defense to claims in tort as well as claims in contract so long as such claims arise out of the circumstances contemplated by the agreement of the parties to the contract. (*See, e.g., Hall-Scott Motor Car Co v. Universal Ins. Co.*, 122 F.2d 531 (9th Cir.) *cert. den.*, 62 S.Ct. 360 (1941).) On the other hand, it is clear that such exculpatory clauses, even when valid, cannot bind third parties, who are not parties to the contract.

When such clauses have been invalidated, it is either on grounds of overreaching in the contract (*e.g.*, a contract of adhesion) or on grounds of public policy. For example, common carriers are held to owe their passengers an especially high standard of care. This duty arises out of the carrier-passenger relationship. Thus it has been held against public policy to allow them to contract so as to escape fulfillment of this duty. (*See, e.g., New York Central RR v. Moliney*, 252 U.S. 152 (1920) (alternative holding); *Virginia Beach Bus Line v. Campbell*, 73 F.2d 97 (4th Cir. 1934).) The United States Supreme Court has held that there is no public policy against pilots exculpating themselves for their negligent decisions while on the bridge of the piloted vessel so long as the shipowner has a choice of pilots and there is no local monopoly. (*Sun Oil v. Dalzell Towing*, 287 U.S. 291 (1932).) On the other hand, in *Bisso v. Inland Waterways Corp.*, 349 U.S. 85 (1955) the court struck down exculpatory clauses in towage contracts. Sometimes public policy may even favor exculpation. *See* for example, the recent legislation providing for statutory exculpation of pharmaceutical manufacturers producin swine flu vaccine. Pub.L.No. 94-380 (1976).

In any event, exculpatory clauses are strictly construed against the party benefite and can be avoided if there is a finding of gross negligence. The courts have not been altogether successful in articulating a line of demarcation between ordinary and gross negligence, but the latter is usually on a level of culpability close to recklessness.

> "If the facts show wilful conduct from which injurious results may be reasonably anticipated, though not intended, it has been held that defendant must respond in damages as for wanton and wilful negligence. These words do not signify degrees of negligence, but have reference to the intent with which the act complained of was done. There is an intention to do the wrongful act, but not to inflict the resulting injuries and against that liability, therefore, the wrongdoer cannot shield himself by contract."

(*Westre v. Chicago M & St. P. Ry.*, 2 F.2d 227, 229 (8th Cir. 1924) (dictum)). As an example of a case striking down an exculpatory clause, where gross negligence was involved, *see Fairfax Gas & Supply Co. v. Hadary*, 151 F.2d 939, 942 (4th Cir. 1945) where the court said:

> "Even then, if it be the rule that a private contractor, may by contract generally relieve himself of liability for mere negligence such a rule . . . should have no application to the facts of the instant case . . . [where] the conduct of . . . [the defendent] may certainly be called gross negligence . . . if . . . not wantonness. Our social conscience is shocked that . . . [the defendent] should be here permitted to hide behind the beneficient shield of contract."

For the general rule that it takes gross negligence to invalidate an exculpatory clause, *see Maryland Casualty Co. v. Owens-Illinois Glass Co.*, 116 F.Supp. 122, 124 (S.D.W. Va. 1953) (dictum)).

If the yard were doing repair work on an LNG carrier as opposed to constructing it, and while in its custody the ship suffered damage due to its negligence, the interesting question would arise whether it could sue for repairing not only the original work, but also for repairing the consequences of its negligence. In situations where there was no exculpatory clause in the repair contract, the yard would be defeated in its claim. *See, e.g., The William Rockefeller,* 57 F.2d 897 (E.D.N.Y. 1932) and *Pan American Transportation Co. v. Ralims Dry Dock and Repair Co.,* 281 Fed. 97 (2d Cir. 1922). With an exculpatory clause, and if the yard were asked to do the additional repair work, the yard would probably prevail assuming gross negligence or overreaching were not found.

Disclaimers of expressed or implied warranties or limited warranties have been litigated frequently under common law and under the Uniform Commercial Code. In order to disclaim the implied warranty of merchantability the disclaimer must specifically mention the word "merchantability" and must do so in bold-face type. Other implied warranties may be disclaimed by a general (non-specific) disclaimer, but to the extent the disclaimer contradicts express warranties made by the same party, the express warranties will control. Again, disclaimers are only defective between the vendor and the vendee and do not bind third parties to whom they were not communicated. Where personal injuries are incurred, such disclaimers have been declared to be prima facie unconscionable (Uniform Commercial Code § 2-719(3)). Limited warranties such as appear in the MARAD approved construction contract are sometimes known as "give-and-take" warranties. That is they "guarantee" workmanship and materials and yet commit the warrantor only to replace the defective part without exposing it to liability for the consequences of the part's failure or malfunction. Where personal injury is involved, this type of limitation upon the warranty has been struck down. *See, e.g., Henningsen v. Bloomfield Motors Inc.,* 32 N.J. 358, 161 A.2d 69 (1960) (steering failure on automobile). For more on the implied warranty of workmanlike service by shipyards in new construction *see* Chapter V, Builder's Liability, *Manufacturers Liability in Tort, infra.*

Even where it may be against public policy to uphold an exculpatory clause, courts have approved contractual requirements that the potential injured party take out insurance and cause the insurer to waive its subrogation rights. *See, e.g., Twenty Grand Offshore Inc. v. West Indian Carriers Inc.,* 492 F.2d 679 (5th Cir. 1974) and *Fluor Western Inc. v. G. & H. Offshore Towing Co.,* 447 F.2d 35 (5th Cir. 1971). The theory here is that the victim will get the benefit of the insurance and thus will not be out of pocket (other than the insurance premium). That still leaves open the question of whether it is good public policy to remove the threat of legal liability as a deterrant to careless operations. For a case holding that parties at arm's length can agree to a limitation of remedy, (limited to the replacement of defective parts), which would be valid even against a claim based on strict liability, *see K-Lines v. Roberts Motor Co.,* 75 Or.Adv. 3343, 541 P.2d 1378 (1975) (property damage claim by vendee).

Indemnification clauses, like exculpatory clauses, are construed narrowly against the indemnitee. Clauses holding an actor free from the consequences of its own negligence, must be particularly explicit and unambiguous. *See, e.g., Chicago & N.W. Ry. v. Chicago Packaged Fuel Co.,* 195 F.2d 467 (7th Cir. 1952). Even where such an indemnity or hold-harmless agreement might successfully exculpate a negligent actor from liability to the indemnitor or to entitle it to indemnity for payment of third-party claims, it may not become a basis for affirmative recovery of the indemnitee's own property damage. *Cf. U.S. v. Nielson,* 349 U.S. 129 (1955) ("borrowed employee" clause ineffective to support claim for property damage sustained by real employer).

To the extent that LNG carriers must enter shipyards for repair, repair contracts may include so-called "red letter" clauses, limiting liability for negligence to a finite dollar amount. Assuming damages exceed that amount, the validity of such clauses will be in issue. The courts have upheld such limitations as against challenges that they were contrary to sound public policy. *See Alcoa Steamship Co. V. Charles Ferran & Co.,* 383 F.2d 46 (5th Cir. 1967). Nor do such limitation clauses have to meet the requirements for liquidated damage clauses, namely that the amount set is reasonable and that the precise measurement of damages would be difficult or impossible to ascertain. (*See* Restatement, Contracts § 339, Comment g.)

If such a clause were included in a new construction contract, it might well be argued that damage to a not-yet completed vessel was not suffered by the purchaser but was rather an injury to the interest of the shipyard (since it had an obligation under contract to deliver a sound vessel) therefore rendering the clause inefficacious. Recent MSB contracts for subsidized LNG carriers have included limitations on the builder's liabilities in both contract and tort to the purchaser for certain subsystems. MA/MSB Contract No.-257 specifies a $5 million limit on claims guaranteed by a license from Conch on the design or performance of the cryogenic system. Similarly there is a $23 million limit on claims based on construction or installation of the cryogenic system by Avondale Shipyard's subcontractor, Kaiser Aluminum and Chemical Sales, Inc. (*Id.* art. XVIII (h)).

Another possibility which may arise is that the vessel would already have a fixture or a starting date for a "hell or high water" time charter but negligence of the yard in constructing the vessel caused delay in its delivery which either triggered the charter's cancelling clause or else deferred the start of hire. Even if financing arrangements call for interest only during the construction period, deferral of the income-producing utilization of the vessel can be very costly. Similarly, if the damage occurs between progress payments the escrow agent may not have to release the next construction payment but often the lender treats these funds as committed and as part of the principal owing nevertheless. In any event, the cancellation or deferral of the charter represents a loss or deferral of revenue to the purchaser. Generally the courts have not allowed the shipowner (purchaser) to recover for a loss of revenue under a contract with a third party (*see Robins Dry Dock v. Flint*, 275 U.S. 303 (1927). *But see J. Ray McDermott & Co. v. S.S. Egero*, 453 F.2d 1202 (5th Cir. 1972)). For a further discussion of cutting off liability for remote consequential damages *see* Chapter V, Shipowner or Operators' Liability, *Common Law Damage Cut-offs, infra.*

MANUFACTURERS' LIABILITY IN TORT

Design Defects

The design of a vessel will obviously influence the way it performs and how safe it is. Failure to use reasonable care in engineering strength of materials computations or in doing scale-model testing, or overlooking a safety feature when a reasonable designer would have foreseen the risks involved in omitting the feature, could constitute negligent design. *See, e.g., Trojan Boat Co. v. Lutz*, 358 F.2d 299 (5th Cir. 1966) (design of yacht which did not call for bilge ventilating ducts held to be negligent when vapors accumulated and exploded causing injury). For some products the standard of reasonable care and design is pegged to the general safety consciousness of the industry and consumers at the time the product was designed even if subsequent awareness would call for more or better safety features. *See, e.g., Ward v. Hobart Manufacturing Co.*, 450 F.2d 1176 (5th Cir. 1971).* It seems unlikely that builders of LNG carriers could fail to be aware of the need for safety in view of the intensive controversy over the safety of these vessels and over LNG in general. Recent cases have established that the designer has a duty to design against unduly injurious consequences from a collision or casualty using the product, even though such activity would obviously not be its "intended use." *See Larsen v. General Motors Corp.*, 391 F.2d 495 (8th Cir. 1968) (design of steering wheel assembly to minimize "second collision" injuries in auto).

A design defect may be actionable under strict liability in tort (*see* Restatement (2d), Torts § 402A). *See, e.g., Jamieson v. Woodward & Lothrop*, 247 F.2d 23 (D.C. Cir. 1957) (5-4) (defective design of elastic exercise device). *See generally, Noel, Manufacturers' Negligence of Design or Direction for Use of Product*, 71 Yale L.J. 816 (1962). Design defects have been described as inadvertent and advertent. A recent Oregon Supreme Court case has formulated a test for determining whether an inadvertent design is defective so as to impose strict liability on the manufacturer. In a jury case, the jury is instructed to *assume* that the manufacturer knew of the possibility of exposure to harm (*i.e.*, the risk) inherent in the design it used, and then the jury must decide whether a reasonable manufacturer would have gone ahead and marketed the product with that knowledge. *See Phillips v. Kimwood Machine Co.*, 269 Or. 485, 525 P.2d 1033 (1974). An implicit limitation on imputing the knowledge of risk to the manufacturer under this method is that the risk be "knowable" under modern methods of scientific investigation. Advertent design defects are those where the designers foresaw the risk but for reasons of efficiency, economy, low probability of harm, or technological impossibility of achieving a superior design, may have chosen to use the design notwithstanding the risk. It has been suggested that this problem is so polycentric that commonlaw courts are unsuited for determining liability and that standards would be more appropriately set by administrative agencies. *See Henderson, Judicial Review of Manufacturers' Conscious Design Choices: the Limits of Adjudication*, 73 Colum. L.Rev. 1531 (1973).

**See also, Bruce v. Martin-Marietta Corp.*, 544 F.2d 442 (10th Cir. 1976).

owners' design

It is possible that LNG ships will be manufactured according to plans or specifications developed by either the shipbuilder or the Maritime Administration. In such a case, if the manufacturer is in complete compliance with the plans and the harm occurred solely because of the poor design incorporated in the plans, the shipyard would not be liable. *See U.S. v. Spiran*, 248 U.S. 132 (1918) (drydock design); *Turkish State Railway v. Vulcan Ironworks*, 153 F.2d 616 (D.Pa. 1957) (dictum) (no liability when manufacturer followed purchaser's specifications for locomotive boilers). However, if the purchaser merely indicates the special purposes to which the product is to be put or prescribes functional features, this will not protect the manufacturer from implied warranty liability. *Cf. Alcoa v. Electro-Flo Corp.*, 451 F.2d 1115 (10th Cir.1971) (portable "dodge-'en car" floor).

compliance with regulations

Even if Coast Guard officials had made a complete plan review or had made a shipyard visitation for a crucial step in the fabrication, their approval would not release the shipyard from liability. *See, e.g., Boylston v. Armour & Co.*, 196 S.C. 1, 12 S.E.2d 34 (1940) (tainted ham duly approved by U.S.D.A. inspectors). Of course, if the shipyard's foreperson was expressly countermanded by a government official and, as a result of doing it as ordered by the official the product became defective, the shipyard would have a right of indemnity against the government.

Since many of the design parameters are set by Coast Guard regulations, the yard may successfully plead that it had no discretion in design and simply complied with what the regulation required. If this compliance can be shown to be the sole cause of the casualty this should serve as a defense for the shipyard. In *In re The Marine Sulphur Queen*, 450 F.2d 89, 98 (2d Cir. 1972), the court held that a vessel which had been specially reconstructed to carry molten sulphur in bulk was not negligently designed making its owners liable per se. Plaintiffs had alleged that the vessel, which was lost with all hands on board, broke up because an American Bureau of Shipping rule pertaining to transverse bulkheads had been violated. The court found that there was a provision in the ABS rule for approval by the Coast Guard where special arrangements are necessary. In fact, the Coast Guard had approved the design which deviated from the ABS specification so per se liability was denied although the owners were held to be liable on other grounds. In *Martin Oil Service v. St. Louis Shipbuilding & Steel Co.*, 1965 AMC 1899 (Ed. Mo.) a shipbuilder was held not negligent in the design of a gasoline barge which subsequently exploded because it had followed the Coast Guard regulations in its design, the plans had been reviewed and approved by the Coast Guard, and the Coast Guard had made a pre-launch inspection of the vessel. *See also, Southwestern Gas & Electric Co. v. Deshazo*, 199 Ark. 1078, 138 S.2d 397 (1940) (power company's lines laid out in accordance with Utility Commission rules thus no liability when fallen tree caused electrocution). Another court, however, has held that compliance with labeling requirements in the Department of Agriculture's regulations pertaining to the marketing of a pesticide known as Peratheon did not automatically preclude liability for negligent design, defective labeling, or negligent failure to warn. The court felt this was a jury question and upheld a verdict for the plaintiff. *Hubbard-Hall Chemical Co. v. Silverman*, 340 F.2d 402 (1st Cir. 1965).

the unavoidable defect and state of the art defenses

Restatement (2d) Torts, § 402A, Comment k says "products which, in the present state of human knowledge, are quite incapable of being made safe for their intended and ordinary use" are not unreasonably dangerous if "such experience as there is justifies the marketing and use of the . . . [product] nothwithstanding a . . . recognizable risk" and the product is "accompanied by proper directions and warning." *Compare Reys v. Wyeth Laboratories*, 498 F.2d 1264 (5th Cir. 1974) *with Cunningham v. Pfizer*, 532 P.2d 1377 (Okla. 1974) on the issue of adequate warnings with regard to unavoidably unsafe drugs. In *Cunningham v. McNeal Memorial Hospital*, 47 Ill.2d 443, 266 N.E.2d 897 (1970) the court held a hospital strictly liable for supplying whole blood infected with serum hepatitis. The defendant hospital in that case argued that there was no way to detect the hepatitis in the blood and that therefore the exemption of Comment k applied. The court stated that it was "of absolutely no moment" that the defendant was unable to detect the bad blood since it felt that the blood was "adulterated" with hepatitis. Cigarette and drug manufacturers have generally succeeded in avoiding liability for side effects which were unknown and unknowable at the time their products were manufactured. *See, e.g., Basco v. Sterling Drug*, 416 F.2d 417

(2d Cir. 1969) and *Green v. American Tobacco Co.*, 391 F.2d 97 (5th Cir. 1968) (8-4 on Rehearing en banc).

Although it might seem that most of the hazards of LNG carriage by sea have by now been foreseen by marine engineers and architects, it is possible that there are some hazards which are not yet known to today's designers. The mere fact that they are not yet known, however, is probably not sufficient for the unavoidable defect defense or the state of the art defense since, if they are "knowable" by diligent research and experimentation given our present scientific equipment and methodology, it may be no excuse that the designer had not bothered to discover them.

Manufacturing Flaws

workmanship

Workmanship which is not up to the standard of a reasonable journeyperson worker and materials which fail because of their inadequacy and which a reasonable inspection program would have detected and rejected, will lead to liability based on negligence. Even where the shipyard can demonstrate that it hired only the most skilled workers, provided only the best tools, had a reasonable ratio of supervisors to workers, and inspected the work produced in a reasonable manner, it may still be liable under the strict liability principles of Restatement (2d) Torts § 402A if its product turns out to be unreasonably dangerous. In some cases where an exact reconstruction of the failure made is not possible because the product has disintegrated or been lost, admiralty courts have applied strict liability on a "non-specific defect" theory. *See, e.g., Lindsay v. McDonnell Douglas Aircraft Corp.*, 460 F.2d 631 (8th Cir. 1972). (In California a showing of "unreasonable dangerousness" is not required once a "defect" can be identified. *See Cronin v. J.B.E. Olson Corp.*, 104 Cal.Rptr. 433 (1972)).

However, as to the purchaser of the vessel, the yard might attempt to raise an assumption of risk or estoppel defense under certain circumstances. If the owner's representative or surveyor were present in the yard when the allegedly faulty workmanship was going on, it might be argued that the shipowner had "approved" the work. In the rare case where some deviation from plans and specifications was proposed to and agreed to by the owner's representative and it was that deviation which lead to the casualty, this argument might be justified.

In general the argument seems weak, however. Shipyards are very large areas and a single human being certainly cannot approve everything that is done in the entire yard (even supposing he or she is on the premises twenty-four hours a day). Moreover, such a person's presence is usually for the purpose of checking gross progress on the vessel for purposes of releasing progress payments, or to perform statistical sampling rather than for individual approval and ratification of every item of work done. Finally, there would be a serious question as to the authority of such a person to waive an owner's claim. Usually a surveyor's authority is limited to protecting the owners interest, stopping incorrect work that he or she happens to observe, and making suggestions. Even where the purchaser makes specific efforts to test the product prior to acceptance and fails to discover the defect, the manufacturer is still liable for the defective product. *See Boeing Airplane Co. v. Brown*, 291 F.2d 310 (9th Cir. 1961). There is some dictum, however, in charter cases which suggest that a person employing a marine surveyor may be estopped from asserting a claim based on condition of the vessel which was observed by the surveyor. *See Hampton Roads Carriers Inc. v. Allied Chemical Corp.*, 329 F.2d 392 (4th Cir. 1964). *See also, In re Marine Sulphur Queen*, 460 F.2d 89, 104-105 (2d Cir. 1972). In any event, strict liability has been extended by the courts to plaintiffs who are bystanders and not parties to the purchase transaction (*see, e.g., Codling v. Paglia*, 345 N.Y.S.2d 461 (1973)), and such bystander plaintiffs could not be bound by any supposed assumption of the risk by the purchaser.

materials and subassemblies

In shipbuilding all of the steel is produced by a steel supplier and many pieces of equipment and small components and subassemblies are supplied by sub-contractors or vendors. Thus, the prime assembler (the shipyard) would have an obligation to test (in a manner reasonably calculated to discover potential hazards) the materials and components incorporated into an LNG carrier. *See, e.g., Westric Battery Co. v. Standard Electric Co.*, 482 F.2d 1307 (10th Cir. 1973); *Nicklaus v. Hughes Tool Co.*, 417 F.2d 983 (8th Cir. 1969). Moreover, the duty to test is non-delegable and cannot be contracted out to the supplier as a means of avoiding liability. *See, e.g., Boeing Airplane Co. v. Brown*, 219 F.2d 310 (9th Cir. 1961). This appears equally true when component parts are involved. In *Watz v. Zapata Offshore Co.*, 431 F.2d 100 (5th Cir. 1970), a manufacturer of marine hoists incorporated in its product chains manufactured by another comapny. Despite the fact that the hoist manufacturer performed a number of tests, it failed to catch a faulty link which fractured causing an injury. The court held the hoist manufacturer to a duty to perform additional tests. In *McKee v. Brunswick Corp.*, 354 F.2d 577 (7th Cir. 1965), the court held the manufacturer of a pleasure yacht whose engine exploded because of a faulty ignition coil supplied by a component manufacturer to a duty to test both the coil and the assembled engine. In *Sieracki v. Seas Shipping Co.*, 149 F.2d 98 (3d Cir. 1945) *aff'd* 328 U.S. 85 (1946) a shipbuilder was held liable to an injured longshoreman for a defective shackle which it had purchased from another company. The court held that the shackle should have been X-rayed by the shipyard to detect the flaw before it was installed in the vessel. A few cases dealing with contractor's liability that have considered the matter have held that the builder is not responsible for the insufficiency of the building resulting from a latent defect in construction materials it purchased from someone else without knowledge of the defect if the contractor exercised reasonable care in selecting its supplier. However, the latest case to consider this has rejected this rule and expressly disapproved of earlier precedents. *See Clarke v. Campbell*, 492 S.W.2d 7 (Mo. app. 1973).

Not only must a manufacturer test the raw materials and lesser components but it also has a duty to test the assembled whole to establish its reliability as a system. *Cf., e.g., Barnhart v. Freeman Equipment Co.*, 441 P.2d 993 (Okla. 1968) (manufacturer of tie rods for trucks had to determine compatibility with entire front end assembly).

In addition to testing against design specifications manufacturers have been held to a duty to functionally test the finished products. Particularly appropriate in this context is the case of *Foley v. Pittsburg Desmoines Co.*, 363 Pa. 1, 68 A.2d 517 (1949) which involved the manufacturer of the LNG storage tank that collapsed in Cleveland, Ohio. The manufacturer tested the tank hydrostatically but the court found this to have been an insufficient test since when it was actually functioning it would have been filled with LNG and the critical need was to determine how the steel would function in response to cryogenic temperatures. Also of interest is *Ebers v. General Chemical Co.*, 310 Mich. 261, 17 N.W. 2d, 176 (1944) where an insecticide manufacturer was held liable for damage to peach trees in Michigan where the insecticide was applied by a farmer. The manufacturer had field-tested the chemical on peach trees but not trees growing in the climate and soil of Michigan. Of further interest is the fact that the defendant contended that he had relied upon U.S. Department of Agriculture recommendations in conducting his test, but the court held this was a jury question and would not be an automatic defense.

component suppliers

Under New York law, neither the shipowner nor the injured bystanders can sue component suppliers in strict liability as they are felt to have an adequate remedy against the shipyard. *See Goldberg v. Kolsman Instrument Corp.*, 12 N.Y.2d 432, 191 N.E.2 81 (1963) (faculty altimeter cause commercial passenger plane to crash). *But see, Suvada v. White Motor Co.*, 32 Ill.2d 612, 210 N.E.2d 182 (1965) (air brakes).

Builder's Duties Regarding Product Information

There is little chance that a modern shipyard would neglect any of its duties in this regard but it is clear that it must provide tactical data on the vessel, operating manuals, and probably suggested maintenance schedules. In *Reddick v. White Consolidated Industries*, 295 F. Supp. 243 (D. Ga. 1968) the court held the manufacturer of a gas heater strictly liable for inadequate instructions concerning the venting of the heater. The plaintiff had improperly installed the exhaust vents and as a result was asphyxiated. Although the heater itself performed properly, the court held the defective "product" was the inadequate instruction manual. The complaint was held to state a cause of action in implied warranty. Restatement (2d) Torts, § 402, Comment j says that "In order to prevent the product from being unreasonably dangerous, the seller may be required to give directions or warning . . . as to its use. . . if he has knowledge, or by the application of reasonable, developed human skill and foresight, should have knowledge of the . . . danger."

SHIPOWNER OR OPERATORS' LIABILITY

GENERAL MARITIME LAW

If a fire is caused through the fault or neglect of an LNG ship operator and it spreads to the pier and thus damages the pier and other things on shore, the shipowner will be responsible. Originally damage to shore structures was not remediable in admiralty court. *See The Plymouth*, 70 U.S. (3 Wall) 20 (1866). This was changed in 1948 when Congress passed the Admiralty Extension Act (46 U.S.C. § 740 (1970)). In many ports shallow harbors will require long finger piers out to adequate depth to berth LNG carriers, thus any fire on the pier can be controlled before it reaches other structures on dry land. However, the pier itself would be considered a portion of the land so long as it was built on piles (which all LNG piers and trestles would be) rather than floating. Even if the ship were not yet moored when the LNG spill occurred but the pool spread to shore and then ignited, or vaporized and the plume reached shore and then ignited, jurisdiction would lie in the federal courts under the Admiralty Extension Act. Moreover, if the LNG carrier was at fault either through operational errors or navigational errors for the spillage, there is authority under the general maritime law to make them responsible for the consequences of the spill. *See Petition of New Jersey Barging Corp.*, 168 F.Supp. 925 (S.D.N.Y. 1958) and *Salaki v. Atlas Tank Processing Corp.*, 120 F.Supp. 225 (E.D.N.Y. 1953). It should be remembered in passing that with pier lengths typical of most LNG terminals, mathematical simulations indicate that for many spills neither the pool nor the plume would actually reach shore. This would be all the more true if the prevailing winds happened to be shore-to-sea at the time. Of course, if the ship were berthed and the automatic fuseable links in LNG pipes to shore failed to automatically close the valves (an extremely low probability occurrence) flame could conceivably move through and explode the pipeline. A more likely scenario is simply that the flammable portions of the pier would catch fire. Since many of the piers would be made of reinforced concrete, however, even this pathway for ship-to-shore transmission of a flame front seems unlikely.

Besides liability to owners of damaged property on land, the vessel operator would have liability to the cargo owner and crew members to the extent of losses or injuries resulting from an onboard LNG ship fire. In cases where vessels have mysteriously broken up at sea with all hands lost the courts generally have found the ships to be unseaworthy. If the plaintiff can prove that there was some element of unseaworthiness in the vessel, the trier of fact is permitted to infer that the element of unseaworthiness was the cause of the loss. (*See In re Marine Sulphur Queen, supra*, at 99). This is true even where several instances of unseaworthiness are demonstrated but no one can say with any certainty which or how many of them contributed to the loss. A court has said that "when an unseaworthy vessel disappears at sea in expectable weather but otherwise unknown circumstances . . . the burden of production, but not the burden of persuasion . . . [is shifted] to the owners to demonstrate that the inference . . . [of causation] is unreasonable." *Id.* at 100. In the *Marine Sulphur Queen* a hot sulphur carrier lacked three dimensional thermal expansion capability without stressing the hull unduly and was overloaded so that some hot sulphur spilled into the void space between the tank and the skin of the ship.

In *The Pennsylvania*, 259 F.2d 458, 1958 A.M.C. 1775 (9th Cir.) a cargo ship went down with all hands on board in a January crossing of the North Pacific in the Gulf of Alaska. The last radio messages indicated that a crack had opened in the hull and that she was taking water in the engine room. Presumably she broke in half and rapidly sank. The court not only held the vessel to be unseaworthy but held that the managing agent had not used due diligence to make her seaworthy before the ship sailed and therefore the shipowner was not entitled to limitation of liability as against cargo and death claims. The salient finding of the trial court upon which the Ninth Circuit based its decision was the fact that the vessel was unseaworthy by reason of its crack sensitivity while plying the stormy seas and cold ambient temperatures of the Gulf of Alaska. The relevance of such a decision to operators of LNG carriers is obvious should small spills be allowed to embrittle hull metal or should poorly maintained insulation allow a lessening of the temperature gradient between cargo tanks and hull plating. In *The Pennsylvania* a twenty-two foot crack had opened in the deck on a previous voyage and this had been repaired to the knowledge of the company's port engineer. It is improbable that cracks will develop and propagate in cargo tanks, but small local spills could cause outer hull embrittlement. Although the logic of the findings by the trial court in *The Pennsylvania* seems at best attenuated, it might be argued with some justification that LNG carriers are inherently susceptible to cracks. Thus alert crew members and prompt, thorough corrective action must necessarily be standard procedure in the operation of these vessels.

Despite the folklore (no doubt aggravated by media and attorneys) that *every* casualty is redressible, there is a possibility that a shipowner could defend on the theory of inevitable accident. However, a true accident is somewhat like an Act of God, that is, it cannot be ascribed to the *antecedent* negligence of the operators, nor a defect in design or manufacture traceable back to the builder. It has been said that to successfully defend on an unavoidable theory the defendant:

> "Either must show what was the cause of the accident and that the result of the cause was inevitable; or must show all the possible causes, one or the other of which produced the effect; and must further show with regard to every one of these possible causes that the result could not have been avoided. . . The test of inevitable accident is met when, first, the cause of the accident is disclosed within the limits of the most reliable expert knowledge peculiar to the given art, and, second, when it is conclusively shown that with the exercise of reasonable care, based upon such knowledge, the accident did, nevertheless, in fact occur."

The Beacon, 6 F.Supp. 779, 780-781 (D. Md. 1934). The opinion in a more recent case involving loss of steering of a tug when a hydraulic line failed said:

> "Where, as here the defendant asserts the accident was inevitable due to a latent defect in the vessel's machinery something more than a mere failure in the machinery must be shown . . . the Defendant must show proof of the . . . (equipment's) age, history, and strength, and must show that it had not been used so long as to impair the strength of the metal."

Ernest Construction Co. v. Mobile Towing Co., (TUG COMMODORE) 294 F.Supp. 15, 1968 A.M.C. 2541, 2543 (S.D. Ala.). In short, the defendants must sustain the burden of showing adequate maintenance and inspection procedures including preventative maintenance.

INAPPLICABILITY OF STATUTORY LIABILITY SCHEMES

The 1969 IMCO Civil Liability Convention (reprinted in 9 INT'L LEGAL MATERIALS 45 (1970)) embodies strict liability for the escape of oil insofar as it may damage property or resources ashore or afloat through contamination. However, cargoes such as LNG would be excluded since the Convention is very specific that persistent oil is the only cargo within the scope of its coverage (*Id.* Article I (5)). Similarly, the 1971 IMCO Supplemental Fund convention designed to fund excess recoveries for liabilities under the Civil Liability Convention is only triggered by the spill of persistent oil (reprinted in 10 INT'L LEGAL MATERIALS 137 (1971)). IMCO has had under consideration other marine bulk cargoes containing pollutants. (*See* Resolution of the International Legal Conference on Marine Pollution Damage and International Cooperation Concerning Pollutants other than Oil, G.A. Res. 2566, 24 U.N. GAOR Supp. 30 at 38, U.N. Doc. A/7854 (1970) reprinted in 9 INT'L LEGAL MATERIALS 424 (1970)). As a result of this on-going study the IMCO drafters and diplomats produced the 1973 Ship Pollution Convention (12 INT'L LEGAL MATERIALS 1319 (1973)) but this treaty is directed at the intentional discharge of pollutants from tankships in the course of bilge pumping, tank washing, bunkering and cargo transfer. The Convention does contain an Annex for the "control of pollution by noxious liquid substances in bulk". LNG carriers do not wash tanks. Indeed, they usually keep them chilled with a heel left on board even when in ballast and they would only be drained and purged at long intervals when necessary repairs or surveys had to take place. Thus the proscriptions in this treaty pertain, if at all, only peripherally (for bunkering, bilge pumping) to LNG carriers.

The 1972 Amendments to the Federal Water Pollution Control Act (33 U.S.C.A. §§ 1321 et. seq. (Supp. 1975)) do provide for strict liability for the discharge of "hazardous substances" into or upon the navigable waters of the United States or the waters of the contiguous zone (up to twelve miles offshore of mean low low water). This strict liability runs in favor of the U.S. Government for actual costs incurred in clean up and removal with liability limits running up to $14 million. (*Id.* § 1321(f)). The Water Quality Administrator has promulgated regulations designating certain materials as "hazardous substances." (49 C.F.R. §§ 170 et. seq. (1975)). Since the legislation was primarily designed to combat and provide a remedy for pollution of water and shoreline, the Administrator's statutory guidelines limit the hazardous substance designation to those "elements and compounds when discharged in any quantity into . . . waters . . . or adjoining shorelines. . . present an imminent and substantial danger to the public health or welfare. . . ." LNG of course, would satisfy this definition, but its hazard lies not in its pollution capability, but in its ignitability. Thus to speak of strict liability for costs of removing the substance does not really address the issue. The LNG will evaporate, even from a large spill, in twenty minutes or less. An LNG cloud, if not ignited, will entrain enough water vapor and absorb enough heat from land, air and water to become positively buoyant and rise to be naturally dispersed in the upper atmosphere within a few minutes so this legislation is not particularly appropriate to liability exposures of LNG carriers.

Similarly, the Deepwater Port Act of 1974 (33 U.S.C.A. §§ 1501 et. seq. (1975 Supp.), Pub.L.No. 93-627) is designed to provide remedies for oil spills from crude oil tankers and product tankers using deepwater terminals such as monobuoys or artificial islands offshore. The operative language of § 18 of the Act speaks repeatedly of the "discharge of oil". In any event, LNG carriers are being designed with drafts in the range of thirty-six to forty-two feet and it is anticipated that they will discharge and load at shoreside terminals rather than deepwater ports. Not only would exposure to offshore winds and seas be more dangerous in the case of an LNG carrier, but the additional problem of undersea piping capable of maintaining cryogenic temperatures would be both formidible and expensive.

INAPPLICABILITY OF VOLUNTARY COMPENSATION SCHEMES

Neither the Tanker Owners' Voluntary Agreement Concerning Liability for Oil Pollution (TOVALOP) nor its excess recovery fund compliment, the Contract Regarding Interim Supplement to Tanker Liability for Oil Pollution (CRISTAL) pertain to LNG pollution damages as they expressly exclude LNG carriers and LPG carriers from the definition of "tanker".

LIMITATION OF LIABILITY

Even where recovery is possible due to fault or strict liability under certain circumstances the shipowner or demise charterer may be entitled to limit its liability to a finite monetary amount. At the international level most maritime nations, with the conspicuous exception of the United States, are signatories to the 1957 Brussels Limitation of Liability Convention (Reprinted in 6 A BENEDICT ADMIRALTY, 634 (Rev. 7th Ed. 1969)). The limits defined by that convention are based on monetary units (standard gold francs) multiplied by the adjusted net tonnage of the vessel. Thus if the ship owner is found entitled to limit its liability, the limit is set at a finite amount, regardless of the post-collision value of the vessel.

Under American law, hull insurance payable in the event of a partial or total loss need not be surrendered into the limitation fund (*see The City of Norwich*, 118 U.S. 468 (1886)). The American limitation statute (46 U.S.C. § 183 (1970)) limits the size of the limitation fund for property damage claims to the post-casualty value of the vessel plus pending freight if any. If personal injury or deaths are involved, such claimants are entitled to a possible total recovery in the aggregate of $60 U.S. per gross ton. (*Id.* § 183(b)-(f)). In view of the extreme value of LNG carriers this might seem an ample upper limit. However, if damage to the vessel were serious enough to produce a major spill and consequential third party damages, it probably means there would be a pool fire or a shipboard fire in addition to structural damage and the post-casualty value might be drastically reduced. Moreover, if wind conditions were right and proximity to shore were such that a vapor plume could reach a populated urban area and then ignite, claims could be enormous. For example 300,000 people reside on Staten Island in New York (site of Eastcogas' LNG terminal), not to mention a multitude of industrial facilities.

In the past when activities deemed essential to the American economy have been undertaken, special federal statutory limits on liability have been enacted (*see, e.g.*, 42 U.S.C. § 2210 (maximum liability of slightly over $500 million for operator of nuclear power reactor) and 43 U.S.C.A. § 1653 (1976 Supp.) (strict liability of $50 million for holder of right of way for Alaska Oil Pipeline (Prudhoe Bay to Valdez) and $14 million individual responsibility for tanker owners carrying trans-Alaska pipeline oil)).

COMMON LAW DAMAGE CUT-OFFS

There is commonlaw precedent for cutting off recovery of damages which are remote or causally attenuated from the activity upon which liability is predicated. Unfortunately, a variety of theories are used to justify this result, including proximate cause, unforeseeable consequences, supervening cause, and culpable activity which as "come to rest". In fact most of this judicial legerdemain is bottomed on a policy notion that to impose additional losses would simply be catastrophic for the defendant and that a broader fiscal base (*e.g.*, federal disaster aid money or various forms of direct and indirect public relief) must be used to absorb the loss. Since the ability to insure against liability (another form of risk spreading) or to spread the cost through pricing policies as a form of self-insurance are predicated in part on the ability to predict, anticipate, or foresee the occurrence of such losses, notions of foreseeability necessarily play a part in such damage cutoffs. In the celebrated English cases involving the Waggonmound, the English courts rejected a retrospective test of liability for unusual damages and adopted the foresight test (*see Overseas Tank Ship (U.K.) Ltd. v. Miller Steamship Co.*, 2 All England Reports, 709 (1966)). In *The Waggonmound* the chief engineer of a vessel in Sidney Harbor countenanced the discharge of some bunker oil from his ship. By a fairly rare combination of events, local winds carried the oil slick across the harbor where it collected under the pilings of a ship repair company. The repairer was conducting "hot work" (*i.e.*, using acetylene cutting torches). Meanwhile the ship operator, who had spilled the oil, made no effort to collect or disperse it. Some hot sparks in the repair yard ignited some cotton waste which in turn fell off the repairer's dock into the waters beneath. Conditions were just right for the oil to ignite and a large fire started, damaging plaintiff's vessel which was moored nearby. The Privey Council stated that so long as the risk was a real one and not farfetched, a reasonable person with the experience of the chief engineer should have taken the modest action required to stop the spillage at an early stage, even though he might have realized that the risk would only come to fruition "in very exceptional circumstances." (*Id.* 719).

An even more bizarre case was decided by the Second Circuit Court of Appeals in 1964 (*Petition of Kinsman Transit Co.*, 338 F.2d 708 (2d Cir.)). Defendant's vessel was moored at a river wharf three miles upstream from Buffalo, New York. The Buffalo River at that time of year contained small chunks of ice and debris. Some of this accumulated between the ship's bow and the river bank and caused her mooring lines to part. As a result, the ship broke loose and careened stern first down the winding river where it collided with another moored ship, breaking that ship's mooring lines and thus adding a second powerless ship drifting stern first down the river. A drawbridge in Buffalo was not raised in time and the two vessels wedged between the bridge and the shore, creating a partial dam of the river. This caused water and ice to back up and flood shore facilities as far as two miles upstream. Negligence could be found on the part of the ship's crew in handling the mooring lines and anchors and on the part of the drawbrwdge operators in delaying the raising of the span (which, had it been raised, might have allowed the vessels to pass safely through). Using a zone of peril type of analysis, the court reasoned that improperly moored ships or improperly maintained mooring facilities could result in ships breaking away and damaging themselves or property into which they might drift. Thus so long as the time, place, and general type of harm was similar to that which could be foreseen, the particular sequence in which it occurred or the particular factors which additionally may have contributed to the magnitude of the harm, would not preclude liability. Strictly speaking it would seem that flooding is not quite the same as damage from a collision impact, especially for a shore structure, but nevertheless the majority of the court concluded "where the damages resulted from the same physical forces whose existence required the exercise of greater care than was displayed and were of the same general sort that was expectable, unforeseeability of the exact developments and of the extent of the loss will not limit liability." (*Id.* p. 726). Four years later the sequelae of this incident were still being litigated and in *Kinsman Transit No. 2*, 388 F.2d 821 (2d Cir. 1968), the appeal was by the owner of one of the downstream vessels which was struck and broken loose from its moorings by the first ship. The issue on appeal did not go to property damage to the ship, but rather economic loss to the shipowner who was in the midst of discharging cargo when its ship was struck and consequently had to rent special equipment to continue the discharge from the new location of its ship (by then firmly embedded in the ice jam). The court denied liability and said, "under all the circumstances of this case, we hold that the connection between the defendant's negligence and the claimant's damages is too tenuous and remote to permit recovery." (*Id.* p. 825). Thus, there may be some point where attenuated losses, especially economic losses, may not be rederessable against an LNG carrier whose negligence has been a substantial cause of an LNG fire.

TERMINAL OWNER'S LIABILITY

Of course, terminal owners will be responsible for their ordinary negligence in the operation of the terminal. Indeed, as in the firearm cases (*see, e.g., Jensen v. Minard*, 44 Cal.2d 325, 228 P.2d 7 (1955)) the "reasonable person" standard of care will impose an obligation on the terminal operator to use great care. This may be in part because a terminal operator is saddled with special duties in its status as a quasi public utility. But even apart from that, it is simply because the "reasonable person" *does* use great care when performing activities that have the potential for great harm such as handling firearms or storing LNG. The balance of the discussion in this section will be devoted to specialized applications of commonlaw and statutory rules to terminal operators' liability.

ULTRA-HAZARDOUS ACTIVITY

Commonlaw courts have imposed strict liability on defendants who carry on "abnormally dangerous" activities, notwithstanding that the defendant has used the utmost care. Liability is limited, however, to the kind of harm which is expected to result from the carrying on of the activity if it miscarries. (*See* Restatement (2d) Torts § 519 (tent. Draft No. 10, 1964)). The American Law Institute summarizes the cases by saying that an activity will be found to be abnormally dangerous depending on the following factors: (a) whether it involves a high degree of risk of harm to others; (b) whether the gravity of the harm which may result from the activity is likely to be great; (c) whether the risk cannot be eliminated by the exercise of reasonable care (if it cannot, this is a reason for terming the activity abnormally dangerous); (d) whether the activity is a matter of common usage (if it is, it is not likely to be termed abnormally dangerous); (e) whether the activity is inappropriate to the place where it is carried on (if it is, then it may be abnormally dangerous); and (f) the value of the activity to the community (if it has high value, it cannot be prohibited so it is a candidate for strict liability). (*Id.* § 520). High-pressure water mains have been held not to be abnormally dangerous activities in *Pacific Northwest Bell Co. v. Port of Seattle*, 81 Wash.2d 59, 491 P.2d 1037 (1971) and *McDaid v. City of Pendleton*, 4 Or.App. 380, 478 P.2d 642 (App. 1970).

On the other hand, in *Siegler v. Kuhlman*, 81 Wash.2d 448, 502 P.2d 1181 (1972), the Washington Supreme Court held the transportation of gasoline by a trailer tank truck on a freeway to be an abnormally dangerous activity and imposed strict liability. The court emphasized the large quantity of the gas, "the great dangers inherent in the volatile and explosive nature of the substance", and the hazards of high speed traffic as a source of collision and ignition in rendering its decision. The quantity and flammability criteria are certainly met by the storage of LNG although the traffic impact problem is much less than transportation on a public freeway. However, some terminals are located close to airport glide paths and may be exposed to some slightly enhanced risk of impact by large commercial aircraft.

POSSIBLE NON-DELEGABILITY OF DUTY OF SAFE DESIGN

If the terminal storage tanks or piping or valves or vaporizers were improperly designed, the independent contractor retained for the design would be liable on negligence principles for the design alone and on strict liability principles if the designer also manufactured or installed the faulty element. A more interesting question is whether the terminal operator also may be responsible on the theory that it could not delegate the design work to the independent contractor. The American Law Institute indicates that such would be the case (*see* Restatement (2d) Torts § 442, Comment d). However, most of the existing cases seem to imply that if the owner had used due diligence in selecting a competent architect it is entitled to rely on the architect's plans. (*Burk v. Ireland*, 166 N.Y. 305, 59 N.E. 914 (1901)). However, a more recent case allowed recovery against the owner and then gave him a right over (for indemnity) against the architect and builder. (*See Inman v. Binghampton Housing Authority*, 152 N.Y.S.2d 79 (1956)). Although there seems to be a paucity of decided cases and theoretical literature on this issue, this writer feels that the imposition of a non-delegable duty is fairly probable in future years. In such cases, the terminal operators should be able to implead the manufacturer and thereby be indemnified. *See, e.g.*, *Noto v. Pico Peak Corp.*, 469 F.2d 358 (2d Cir. 1972) (negligent manufacturer of ski lift).

FIRE SPREAD CASES

The so-called New York rule on the spread of fire is that a defendant who has negligently caused a fire to originate on its property is responsible to the first adjacent property owner for fire damage to that plaintiff's property but is not liable to more removed property owners. *See Ryan v. New York Central RR*, 35 N.Y. 210 (1866). It has been suggested that this minority rule is based on the policy that property owners can best evaluate their own fire losses anticipatorily and that first-party fire insurance is therefore more efficient than third-party liability insurance. Moreover, the rule may be a reaction against the catastrophically large liability exposures that would otherwise be suffered by defendants in densely populated areas. Contrast the New York rule with the Kansas rule which cuts off liability in terms of distance from the original fire measured in miles. Again, local policies may be at play as large wheat farms (uneconomic or impossible to insure) might be the most vulnerable victims of fire, expecially decades ago when old locomotives showered sparks on trackside wheat fields. (*See, e.g.*, *Atchison, T. & S.F.R. Co. v. Stanford*, 12 Kan. 354, 15 Am. Rep. 362 (1874)). It is uncertain whether a terminal operator would benefit from such damage cutoff rules under modern jurisprudence, but very large exposures should be anticipated.

VIOLATIONS OF CRIMINAL OR SAFETY STATUTES AND REGULATIONS

Even if liability were based on a fault (*e.g.*, negligence) standard, injured parties might be able to prevail on the issue of breach of the duty of due care by pointing to violations of criminal statutes or safety and welfare statutes. Although few jurisdictions any longer adhere to a strict "per se" doctrine of negligence through statutory violation, many jurisdictions treat such a violation either as a rebuttable presumption of negligence (where the defendant must show that under the circumstances its conduct was excusable or otherwise reasonable) or as a permissible inference of negligence where the jury would be free to find for the plaintiff on the breach issue solely on evidence of violation of statute, but would not be compelled to do so. (*See, e.g.*, *Freund v. DeBuse*, 264 Or. 447, 506 P.2d 491 (1973) (automobile brake maintenance statute)). In any event three threshold demonstrations must be made before any advantage can accrue to the plaintiff. It must be shown that there was a clear violation of the statute; it must be shown that the statute was designed to protect the class of persons of which the plaintiff is a member; and it must be shown that the statute was designed to prevent or minimize the same type of harm by which the plaintiff was injured. (*See Arthur v. Flota Mercante Gran Centro Americana*, 487 F.2d 561 (5th Cir. 1973) (Coast Guard regulations re securing gangway on vessel)).

Although Coast Guard regulations implementing IMCO treaties such as the Safety of Life at Sea Convention and the Gas Code are not criminal statutes as such, they are unmistakeably health and welfare (safety) regulations duly promulgated with the force of statutory law. In general there is a requirement that the statutory violation be shown to have *caused* the injury complained of. This is to some extent subsumed in the threshold showing with regard to the type of harm. But in many cases a demonstration of cause-in-fact is required as part of the plaintiff's case. *Compare Stachniewicz v. Mar-Cum Corp.*, 259 Or. 583, 488 P.2d 436 (1971) (requiring proof of cause in violation of liquor regulation) *with Haft v. Lone Palm Motel*, 3 Cal.3d 756, 91 Cal.Rptr. 745, 478 P.2d 465 (1970) (no independent proof of cause required for violation of swimming pool warning sign statute).

There are some statutes which although enacted for preventative safety purposes, also contain express provisions creating or relating to civil liability after an accident has occurred as the result of a violation (*see, e.g.*, Federal Consumer Products Safety Act, 15 U.S.C.A. § 2573 (1975 Supp.) (civil liability for "knowing violation" of rule or order of Federal Product Safety Commission)). The majority of such statutory regulation schemes, however, do not address themselves to civil remedies but leave that the the extant tort law (*see, e.g.*, Natural Gas Pipeline Safety Act of 1968, 49 U.S.C. § 1677(b) (1970)). Moreover, compliance with a safety regulation does not necessarily mean that the defendant will not be found negligent in its conduct as the railroad cases readily show. *See, e.g.*, *Southern Pacific RR Co. v. Mitchell*, 80 Ariz. 50, 292 P.2d 827 (1956).

STRICT LIABILITY BY STATUTE

This investigator is aware of only one statute which specifically calls for strict liability in conjunction with the handling and storage of liquefied natural gas. In June of 1976 the New York legislature enacted the Liquefied Natural and Petroleum Gas Act. Besides establishing a fairly comprehensive set of siting criteria and a permit procedure, the Act creates strict liability for entities storing, transporting, or converting (vaporizing) LNG within the state.

> "Neither compliance with the requirements of this . . . [Act], nor the exercise of due care, shall excuse any such person from liability for personal or property damage determined to be caused by the accidental release of liquefied natural or petroleum gas within the state, and neither proof of means of

ignition nor distinctions between direct and consequential damage shall relieve such person of absolute liability without regard to intent or negligence for any personal or property damage thereby caused. (New York Laws of 1976, Chapter 892, Section 23-1717 (8)).

Not only is strict liability involved, but the Act expressly eschews any limits on consequential damage. Thus, even owners of areas that are burned by secondary fires ignited by the radiation flux of the burning LNG could bring actions against the terminal operator or LNG carrier. If a conventional vessel rammed an LNG carrier while at the berth at Staten Island causing the rupture of a tank and the formation of an LNG plume which eventually ignited causing damage ashore, the LNG carrier owner (or demise charterer) would be strictly liable, but would have an action over for indemnification against the culpable ramming vessel and its owner. In such a case third-party claimants could not utilize strict liability in claims against the ramming vessel, but would have to rely on conventional fault-based theories. Whether such risks are insurable against open-ended liability remains to be seen, and, if they are not, whether LNG transportation and storage inside of New York will be economically feasible remains an open question.

IMPLICATIONS OF CERTIFICATION PROGRAMS OR SAFETY RULE PROMULGATION

In view of the care taken in formulating regulations and in conducting plan review of new vessel designs, it is quite unlikely that design error could be introduced through this process. Nevertheless, it is possible to conceive of a situation where it could be shown that a casualty would not have occurred but for the incorporation of a design element required by the regulations or by a plan review board. In such a situation, could the Coast Guard or the Office of Pipeline Safety possibly be liable for damages to the shipowner, the facility operator, or injured third parties? The Coast Guard exercises its authority to review plans of American flag vessels to be constructed, as well as plans of foreign flag vessels already built and desiring to trade in U.S. waters. (46 C.F.R. § 91.20 and .55 (1975); 49 U.S.C. § 1672(b) (1970) (OPS)).

If in fact the risk pathway was beyond the state of knowledge at the time the regulations were promulgated, or the plan was reviewed, it is hard to see how the Coast Guard or the OPS could be faulted. On the other hand, if it was not beyond the state of the art, and thus was knowable even if not presently known, it may be that an agency with specialized responsibility to promulgate the regulations should do the necessary research (or contract to have it done). In any event, if there were not an objection by the shipbuilder or facility owner on record, it would seem that the engineers and architects of the latter entity would be at least equally negligent. A more plausible scenario might simply involve an error in reviewing the plans or in publishing the requirement. Negligence liability has been predicated upon failure to maintain aids to navigation once the government undertook that function (*see, e.g., Indian Towing Co. v. United States*, 350 U.S. 61 (1955)). It might be argued similarly that although the government was not obliged to promulgate hull-structure or cargo-handling requirements or operational requirements, once it did so, it was obliged to draft the regulations and to carry out the plan reviews and on-board inspections with due care. *Cf. Hoffman v. United States*, 398 F.Supp. 530 (E.D. Mich. 1975) (failure to match facts against clear regulatory requirements for issuance of license to air taxi service). For a case where a product certifier was held liable for negligent certification of a faulty design for a fire extinguisher, *see Hempstad v. General Fire Extinguisher Corp.*, 269 F.Supp. 109 (D. Del. 1967). (*See generally*, Restatement (2d) Torts § 324A).

The issue of sovereign immunity is also present here. This has been waived in various statutes, including the Federal Tort Claims Act and the Suits in Admiralty Act. In *Bardelaben Marine Corp. v. United States*, 451 F.2d 140 (5th Cir. 1971), the court held that a suit for a stranding alleged to have resulted from an inaccurate chart could be brought under the Suits in Admiralty Act (46 U.S.C. § 741). Similarly, in *Tankrederiet Gefion v. United States*, 241 F.Supp. 83 (E.D. Mich. 1964), the court held that jurisdiction and consent to suit were found under the Suits in Admiralty Act for a claim alleging that a grain ship had caught fire due to improper inspection procedures by government grain inspectors. If distinctions are to be made between updating marine charts and inspecting the way grain is loaded on ships on the one hand, and performing plan reviews and on-board inspections on the other, it would be a fine distinction indeed. It seems that in both cases, the allegations would be that government officials charged with a job have failed to use due care in carrying out that job, with the result that their errors contributed to a casualty. Of course, it could be argued that in the respective situations the shipowner was jointly responsible for failure to use on-board navigation equipment, or for failure to have the chief officer inspect the cargo, or for failure to have its own marine architect discover the flawed design. But joint tortfeasers can be held jointly responsible to third parties (*see The Alabama v. The Gamecock*, 92 U.S. 695 (1876)). Even as to claims by the vessel owner against the government, the contributory negligence of the vessel owner would merely diminish its recovery proportionately rather than bar the claim altogether.

More fundamental errors, either in not doing sufficient research, or in making choices and tradeoffs between safety features, or in making probabilisitic assessments or risks for cost-benefit type analyses, would seem to be "judgmental" and should be protected under both the Federal Tort Claims Act and the Suits in Admiralty Act as "discretionary" acts. (*See, e.g.,* 28 U.S.C. § 2680(a) (1970) and *Dalehite v. United States,* 346 U.S. 15 (1953) (acts of administrators establishing plans, specifications or schedules of operations held "discretionary"). *See also United States v. Washington,* 351 F.2d 913 (9th Cir. 1965) (decision where to place transmission lines spanning canyon was assumed to be discretionary but failure to warn pilot was not); *United Air Lines, Inc. v. Wiener,* 335 F.2d 379, 397-398 (9th Cir. 1964) *cert. den. sub nom., United Air Lines, Inc. v. United States,* 379 U.S. 951 (decision to conduct military training flights was discretionary but failure to warn commercial airline was not); *United States v. White,* 211 F.2d 79 (9th Cir. 1954) (decision not to "dedud" army firing range assumed to be discretionary but failure to warn person about to go onto range of unsafe condition was not).

marine insurance

Not only will LNG carriers be very large capital investments, but they also have the potential, however remote, of inflicting losses upon thousands of potential claimants. Additionally, the carriers are the vital link between the exporting country and the importing country without which the tremendously costly LNG facilities cannot function. Thus, any downtime for the vessels must be held to a minimum and repairs must be made on an expedited basis. Because of the specialized construction of the ships and the specialized materials involved and their very large size, it is likely that only a few shipyards around the world will be capable of effecting repairs. Some of these same shipyards may have their bays and drydocks engaged for the production of new LNG carriers. Thus repair costs will be high and expedited repairs will be even more expensive. All of this means that besides making every effort to design reliability into the systems initially, the availability of insurance to cover the various risks is of paramount importance.

BUILDER'S RISK INSURANCE

The premiums for builder's risk insurance will either be treated as part of the shipyard's overhead and priced out accordingly, or will be paid directly by the purchaser of the ship or ships being built (*see* Chapter IV, *Construction Differential Subsidy* and *Title XI Mortgage Insurance supra*). Essentially this type of insurance covers risks that arise while the vessel is still in the custody of the shipyard. These can range all the way from conventional hull and protection and indemnity risks while the vessel is on builder's trials, shakedown cruises, or afloat being fitted to losses of equipment and materials that have been allocated to the ship but may not yet be physically installed in the hull. The Institute clauses Builder's Risks cover three types of property: the hull and machinery while under construction in the yard of the builder, machinery while being constructed or manufactured by subcontractors, and machinery bought from suppliers or vendors after delivery to the builder. Coverage for hull and machinery constructed by the builder extends while the property is at the builder's yard or "at builder's premises elsewhere within the port or place of construction at which the builder's yard is situated and whilst in transit between such locations." The "elsewhere within the port or place" phraseology would seem to contemplate that all subassembly operations are within the same community, port or harbor. To the extent that some manufacturers such as General Dynamics have their aluminum tank or stainless steel tank manufacturing operations in a separate locality, special endorsements would be necessary to extend coverage (Institutee Clause 2). In no event will the coverage extend beyond thirty days from the completion of builder's trials (*Id.* Clause 3).

One unique provision covers the cost of replacing defective parts discovered to contain latent defects during the period of the insurance (*i.e.*, before delivery) (*Id.* Clause 5). Design defects on the other hand, are treated somewhat differently in that damage to the vessel or components thereof which occurs during the coverage period due to a faulty design is insured, but the cost and expense of redesigning or renewing parts improperly designed is not covered (*Id.* Clause 6). Builder's trials coverage is included up to 250 nautical miles by water from the shipyard and can be "held covered" at an additional premium in the event trials need to go futher to sea (*Id.* Clause 7).

The basic policy contains a Running Down Clause similar to the 4/4ths RDC found in conventional hull and machinery policies. It also has a protection and indemnity clause with liability coverage for cargo on the other vessel in a collision, general property damage, wreck removal, loss of life and personal injury as well as any general liabilities recoverable under the P & I rules of the United Kingdom Mutual Steamship Assurance Association (Burmuda) Ltd. (*Id.* Clause 15). There is apparently no limit on the liability (similar to an open entry in a P & I Club) so long as each participating underwriter pays no more than its proportionate share of the coverage with regard to the insured value of the vessel under construction (*Id.* Clause 17).

Employee injuries to the assured's employees or subcontractors covered directly or indirectly by worker's compensation schemes are excluded as are claims arising from strikes, lockouts, labor distrubances, riots and civil commotions (*Id.* Clause 19). the basic policy has the usual war risk exclusion (free from capture and seizure (FFCS) restraint of princes, sabotage, nuclear radiation and nuclear weapons) (*Id.* Clauses 21-24). It also excludes damages caused by earthquakes and tidal waves (*Id.* Clause 25). An endorsement identified as "Clause 139" appears to limit the amount recoverable under the protection and indemnity clause for any one accident to the "sum . . . insured." This is elsewhere defined as the final contract price or the total building cost plus a designated percent. Another endorsement identified as "Clause 118" extends coverage to the builder's employees and claims arising out of strikes or labor disturbances. An extra premium is required to obtain this endorsement. Negotiable deductibles are included, but as of July, 1976, these are expected to reach minimum amounts of $5,000. A rider may be obtained by extra premium to gain more risk coverage and overcome the FFCS exclusions of the basic policy. Coverage extends to items which are on the vessel at the time of its launch or which are later added to the vessel in a launched condition, but only from and after the time they are emplaced on the vessel (Clause 117, lines 1-36). Even this endorsement, however, excludes damage arising from hostile detonations of nuclear weapons, seizure for customs violations, or arising out of an outbreak of war between England, United States, France, Russia or China or any of them (Clause 117, lines 39-53). Moreover, the war risk coverage on the rider automatically cancels in the event of the use of atomic weapons, a major war, or in the event of the vessel being requisitioned (*Id.* lines 63-84).

There has been some concern as to whether the insurance market could issue policies satisfactory to cover the yard's exposure considering the enormous value of LNG carriers. This is particularly true where yards are building vessels sequentially with the resulting multiple vessel exposure. It has been suggested that prelaunch risks might be absorbed by non-marine underwriters such as fire insurers in amounts up to $200 million or more. Stringent yard surveys and minimum separation distances for non-installed components etc., may be required by these underwriters. To the present date, it appears that the post-launch risks have been successfully covered in their totality by the American Hull Insurance Syndicate and the Lloyds and English insurance companies (*see generally*, speech of Richard Mittnacht, Vice-President of Johnson & Higgins, "Insurance of LNG Vessels During Construction").

WAR RISKS

At certain times the commercial insurance market has been unable or unwilling to offer coverage on war risks and for this reason the federal government has a program for interim coverage until adequate coverage can be obtained from private sources (*see* 46 C.F.R. Subchapter G (1975)). In fact, the government uses an underwriting agency to perform the administrative functions of issuing and adjusting the insurance. War risk coverage provides coverage to fill the gaps left by the war risk exclusions in the hull insurance, the protection and indemnity insurance and the builder's risk insurance (*see* 46 U.S.C. § 1282 (1970)).

U.S.-documented vessels are eligible for this insurance. Vessels under flags of convenience in the Panlibhon countries (Panama, Honduras, or Liberia) which are over 1500 gross tons and not over twenty years of age and which are subject to an unqualified contractual commitment to the United States and are either owned by U.S. corporations or by foreign corporations in which a majority of the stock is owned and controlled by U.S. citizens are also eligible. A third eligibility category would include vessels similar to those in the second category except that they are owned by foreign corporations which are not directly controlled by U.S. citizens or corporations, but nevertheless are under long-term charters or contracts which MARAD deems to subject them to U.S. control in the event of an emergency. The charterer in such case must be either a U.S. citizen or a U.S.-controlled corporation. (46 C.F.R. § 308.1 (1975)). An applicant for interim war risk insurance in either of the last two categories must further warrant that the vessel will maintain its eligibility and will be made available to the United States government upon request in the event of national emergency pursuant to the terms of the contract of commitment (*Id.*).

Such insurance will only cover the owner's interest in a vessel which was built with a construction differential subsidy in the event of an actual or constructive total loss. The Secretary of Commerce is empowered to set the total loss value at a figure not to exceed the amount that would be payable if the vessel had been requisitioned for government use (*Id.* § 308.103). The war risk hull insurance attaches automatically and simultaneously upon the outbreak of war between any of the following countries: United States, England, France, Russia or China and terminates thirty days thereafter. The policy underlying this termination provision is apparently that conventional coverage might terminate in the event of such an incident and that thirty days would give operators time to complete their voyage commitments and obtain special risk endorsements through conventional private insurance channels. Coverage under the war risk hull clause includes "the risks of hostilities or warlike operations, piracy, civil war, revolution, rebellion or insurrection or civil strife arising therefrom, floating and/or stationary mines and/or torpedoes whether derelict or not, weapons of war employing atomic or nuclear fission and/or fusion or other like reaction or radioactive force or matter and the application of sanctions under international agreements whether before or after declaration of war and whether by a beligerent or otherwise. . .." (MARAD Form 240-A).

Coverages for war risks, builder's risk insurance are divided into the pre-launch period coverage, the post-launch period primary coverage, and the post-launch period excess coverage. The excess coverage is utilized when there is some war risk coverage available from the private market and the primary coverage is utilized when no war risk coverage is obtainable from companies doing business in the United States. It should be noted that the protection and indemnity coverage in the builder's risk attaches only from the moment the vessel becomes waterborne.

HULL AND MACHINERY INSURANCE

In a general sense, the perils to which LNG carriers are exposed are of the same general nature as those to which all seagoing cargo-carrying vessels, especially bulk carriers, are exposed. One would expect the hull policies therefore to be identical except possibly for negotiated riders, deductibles, and possibly higher premium rates to reflect a greater or less knowable risk.

The Running Down Clause or RDC is that portion of the hull insurance which affords protection against liability arising out of the insured's vessel colliding with another vessel and damaging it or its cargo. Although earlier versions of the hull policy employed a 3/4ths RDC with the idea of leaving 1/4 of the responsibility on the insured as an incentive for safe navigation, modern RDC's recongize that the entire risk will be insured anyway and are written on a 4/4ths basis. Since the real hazard of LNG carriers is fire from ignition of their spilled cargo, the value of this particular clause to the LNG industry is somewhat greater than it would be to any conventional shipowner. It could happen that a low-impact collision was enough to rupture a tank and ignite the spilling LNG causing a pool fire which engulfed the other vessel before the two colliding vessels could be separated. In such a situation, impact damage might be relatively slight whereas radiation and oxidation damage from being in the center of a pool fire could cause the other vessel to be a total loss.

Some hull policies are now using a so-called "liner negligence" clause in place of the additional perils clause. This clause essentially extends coverage to errors of judgment, incompetence and negligence of any person, latent defects in the machinery or hull, and accidents on shipboard or elsewhere. This extends the coverage considerably beyond the original concept of insuring the ship against the perils of the sea, fire, pirates, etc. An important further broadening is accomplished by the liner negligence clause over the additional perils clause in that negligence is now that of "any person" instead of just that of charterers, repairers, masters, officer, crew or pilots. Similarly, the coverage for accidents used to be limited to dry docks and now is simply left at "shipboard or elsewhere." Thus for an LNG carrier, this would extend to damages during loading or discharge attributable to accidents ashore, or the mistakes and errors of terminal personnel. One additional peril, that of contact with aircraft, or rockets, does not explicitly appear in the liner negligence clause, but is apparently subsumed under the concept of an accident on shipboard. (Letter from Philip E. Smith of Frank B. Hall & Co. dated Oct. 21, 1976.) To the extent that the proposed LNG terminal at Oxnard, California is close to the missile test range at Point Hueneme, and that the Staten Island terminal is not far from major airports, this might represent an important narrowing of coverage.

It has been speculated by a senior marine insurance official that the world insurance market will not resist extending coverage to LNG carriers, but will rate them approximately 40% higher for premium purposes than even VLCC's and ULCC's carrying crude oil. This was felt to be basically due to the lack of experience with the new technology involved, so this same person felt that evidence of proper and continuing training of the crew might result in an eventual lowering of the premium. He also speculated that underwriters might resist the inclusion of the liner negligence clause in the early years of insuring LNG carriers.

As discussed in Chapter IV, *Title XI Mortgage Insurance, The Security Agreement, supra*, when vessel financing is insured under Title XI, the shipowner is obliged to keep the vessel covered with hull insurance and, at the Secretary's request, with war risk hull insurance. The security agreement specifies how the insurance proceeds are to be disbursed in the event of a partial loss or an actual or constructive total loss. (MSB Security Agreement, § 2.07) Marine and war risk protection and indemnity insurance is also required. The right to self insure or have a special deductible is negotiable with each insured. The United States is to be a named assured on all policies of builder's risk, hull insurance and P & I coverage. Unless the requirement is waived by the Secretary of Commerce, the policy shall have no recourse against the United States for payment of premiums or calls and at least ten days prior written notice of cancellation for non-payment of premiums shall be given to the Secretary by the underwriters (*Id.* § 2.07(i)).

With regard to vessels constructed with the help of a construction differential subsidy, the contract between the MSB and the shipowner places similar obligations upon the shipowner. If requested by the MSB, the owner must insure the interest of the government in the vessel against the risk of total loss for a period of twenty-five years, or so long as the board pays the ower an operating differential subsidy in connection with that vessel, whichever period is longer. (Contract MA/MSB-370, Art. 5(a)). The interest of the government is essentially that proportion of the value attributable to the CDS payments and payments for the cost of national defense features. The difference in premium cost between insuring the owner's interest only and the owner's interest plus the MSB interest is reimbursed to the owner by the Board. (*Id.* Art. 5(d)). (*See generally*, 46 C.F.R. §§ 289.1-.3 (1975)).

PROTECTION AND INDEMNITY INSURANCE

It has sometimes been said that hull insurance and P & I insurance are to ships as collision coverage and liability coverage to automobiles. Protection and indemnity insurance covers risks that are excluded by the hull policy including the RDC. Thus, personal injury and death claims, claims of cargo carried on board the insured vessel, claims of property owners ashore, and other lesser claims are included in P & I coverage.

The insurance is typically underwritten by mutual assurance associations, often referred to as P & I "Clubs". Like any mutual insurance company, the owners insure themselves. Thus, in this context, the club members are shipowners. The association commonly hires a professional management entity to administer the insurance program. Club dues or "calls" are made periodically. At each renewal, the club attempts to adjust the premium rating for each of its members so that the size of the call is commensurate with the risk to the association created by the member. Changes in the nature of the trade engaged in by the ship, the flag of registry, the quality of crew and management are used to weight the premium further between members. Of course, high deductibles or restricted coverage will result in a lower premium rating. Catastrophic losses are shared among P & I associations around the world under a stabilizing arrangement known as the "pool". Even larger losses that might cause wide fluctuations in size of calls from year to year are reinsured beyond the pool of P & I clubs. (*See* U.K. P & I Club, MUTUALITY 13-18 (1972)). The loss history of any individual club member is also relevant as it is reflected in its actual loss ratio and may call for a higher call at the next renewal. Clubs typically put out an "advance call" at the beginning of the year and, if the income so generated is insufficient to pay reinsurance premiums, contributions to the pool, administrative costs, and losses payable by the club, a supplementary call is assessed shortly after the close of the year (*Id.* at 25).

Entries in the associations may be either unlimited or special, with the former having open-ended liability coverage (*Id.* at 27). Insofar as LNG carrier operators are concerned, the key coverages would probably be "excess" coverage above the coverage of the RDC and the hull insurance, and coverage for damage to fixed and floating objects other than a vessel in collision with the insured vessel. (*See, e.g.*, 1976 Rules of United Kingdom Mutual Steamship Assurance Association (Bermuda) Ltd., Rules (14)(A) and 34(13) and Rules of the West of England Shipowners Mutual Protection and Indemnity Association (Luxembourg), Rules 15d, 15e and 21.) Since even a 4/4ths RDC usually limits the hull underwriters to a payout no greater than the insured value of the vessel, there used to be some doubt as to whether this "excess" liability (assuming the shipowner were not entitled to limit its liability to the insured value of the vessel or less) was recoverable under the P & I policy. In *Landry v. Steamship Mutual Underwriting Assn.*, 177 F.Supp. 142 (D.Mass. 1959) *aff'd.*, 281 F.2d 482 (1st Cir. 1960), it was held that the P & I policy did pick up this excess. Many P & I Clubs then amended their policy conditions to exclude this type of exposure. The result was that in many circumstances there was a need to acquire a rider (usually to the hull policy) to provide so-called "excess" coverage. (*See generally*, Hecht, *The Hull Policy: Inter-relationship of Hull and P & I*, 41 TULANE L.REV. 389, 392-395 (1967)). Currently however, the major P & I Clubs routinely include "excess" coverage if the vessel is fully (a minimum of U.S. $82 per gross ton) insured under her hull policy. (*See, e.g.*, West of England Rules 15(1)D and 21).

TOVALOP and CRISTAL, as discussed in Chapter V, *Shipowner or Operators Liability, Inapplicability of Voluntary Compensation Schemes supra*, pertain only to pollution from the spillage of oil and are not of special importance to LNG carrier operators. Obligations under the TOVALOP agreement are insured by P & I clubs. But even ships with open entries have finite limits for oil pollution liability (*see* West of England, Rule 15E(2) (maximum exposure of $10 million as of 1975) and United Kingdom Rule 14B (maximum limits of $30 million as of 1976).

A special endorsement known as the Pollution Buy-Back Endorsement is coming into common usage in the American insurance market to override the exlusions in the P & I Club rules for pollution liabilities. Essentially, the endorsement covers the insured for "any loss, damages, costs, liability or expense. . . (it) shall become liabile to pay and shall pay in consequence of the actual or potential discharge, emission, spillage or leakage upon or into the seas, waters, land or air of oil, petroleum products, chemicals or other substances of any kind or nature whatsoever. . . "where the spill was "proximately caused by fault on the part of the assured". However, even this endorsement excludes liability under federal, state or local legislation regulating or controlling the discharge. It also excludes coverage for fines or penalties and has a 3% deductible feature. Although the endorsement's exclusion for liability under state law would apparently exclude liability under New York's new strict liability law for LNG accidents, in general the endorsement would seem to afford coverage for an LNG spill followed by ignition and fire damage to structures and objects not on the insured vessel. Whether this is in fact any broader or more extensive than the coverage under the normal rules for damage to fixed and floating objects is problematical. The West of England P & I Club, on the other hand, includes pollution liability in its basic coverage (*See* Rules 15(1)E and 20(e)).

PORT RISK INSURANCE

To the extent that vessels are not in navigation, but are laid up with no crews or only a skeleton crew or a shipkeeper, it becomes expensive to pay for hull and P & I insurance. If the lapse is of long enough duration, most owners will cancel their hull policies and withdraw their entry in their P & I Club and substitute port risk insurance. Mortgagees and other secured parties have an interest in making sure they are included in this coverage and that it is adequate to protect their interest in the security. There have been several instances already where LNG carriers have been completed but either the liquefaction facility or the receiving terminal was not functional. Since they are special purpose ships and there was no appreciable spot market for LNG, these vessels were idled. Circumstances like this will usually dictate switching to port risk insurance.

AMERICAN WATER QUALITY INSURANCE SYNDICATE

Prior to June 1, 1976, the Water Quality Insurance Syndicate (WQIS) which was designed to insure liability of shipowners and operators under the U.S. Federal Water Pollution Control Act as amended by the 1970 and 1972 amendments, extended its coverage only to the cost of cleaning up or removing spills of oil or hazardous polluting substances. This cost was either incurred by the ship operator directly or was paid as an indemnity to the federal government for its costs of clean up. As of June 1, 1976, the WQIS expanded its coverage to include liability to third parties for damage to property arising from pollution. (Letter from R.S. Lagattolla, Manager, WQIS, to author dated July 22, 1976). Since LNG has not been designated by the Water Quality Administrator as a hazardous substance, the Federal Water Pollution Control Act does not apply to such a spill. On the other hand, a spill of LNG certainly could produce property damage for third parties. Strictly speaking, however, it does not seem that LNG is a pollutant as its damaging characteristics result from its flammability, not from its polluting character (which is virtually non-existent). Thus, it seems unlikely that the expanded coverage would extend to damage or injuries caused by ignition of an LNG plume or pool.

regulation by the Federal Power Commission

The Federal Power Commission is a legislatively created agency deriving its authority from the Natural Gas Act of 1938. (15 U.S.C. §§ 717 et. seq. (1970)). Its general purpose is to oversee the rates charged for interstate sales of natural gas, to prevent abuses in rate structure and in accessability for interstate pipelines used for the transportation of natural gas, and to exercise some control over the export and import of natural gas. Since liquefied natural gas transportation was not envisioned by Congress when it enacted this legislation, the potentially burgeoning importation of LNG from Alaska and abroad raises some interesting questions of statutory construction. § 1 of the Natural Gas Act defines the Commission's jurisdiction and creates exceptions thereto, to be discussed hereinafter. § 4 (*Id.* § 717(c)) deals with the rates charged which are required to be "just and reasonable". § 7 (*Id.* § 717(f)) is the so-called certification section. The key phrases of this section provide that no one:

> "shall engage in the transportation or sale of natural gas, subject to the jurisdiction of the Commission, or undertake the construction or extension of any facilities therefore, or acquire or operate any such facilities . . . unless there is in force with respect to such natural gas company a certificate of public convenience and necessity issued by the Commission authorizing such acts or operations. . . ." (*Id.* § 717f(c)).

Elsewhere in the section it is provided that such a certificate shall be issued:

> "if it is found that the applicant is able and willing properly to do acts and to perform the service proposed and to conform to the provisions of this chapter and the requirements, rules, and regulations of the Commission thereunder, and that the proposed service, sale, operation, construction, extension, or acquisition,

> to the extent authorized by the certificate, is or will be required by the present or future public convenience and necessity. . . ." (*Id.* § 717f(e)).

§ 3 of the Act speaks to the exportation or importation of natural gas from a foreign country and makes such activity subject to the Commission's authorizing it to do so in a formal Commission order. The statute provides that the Commission:

> "shall issue such order upon application unless, after opportunity for hearing, it finds that the proposed exportation or importation will not be consistent with the public interest. The Commission may by its order grant such application, in whole or in part, with such modification and upon such terms and conditions as the Commission may find necessary or appropriate . . . ." (*Id.* § 717b).

While it is true that some volume of natural gas is liquefied and exported as LNG from Cook Inlet (Kenai Peninsula) area of Alaska to Japan and that miniscule amounts of natural gas are piped into Mexico from the United States, future projections indicate that LNG will be entering the United States as an import and the implications of § 3 approval must be considered in that context.

§ 3 APPROVAL OF IMPORTS

In the oft-cited decision of *Border Pipeline Co. v. FPC*, 171 F.2d 149 (D.C. Cir. 1948), the issue was whether the FPC had § 7 certification jurisdiction over a gas pipeline in Texas which sold gas at its terminus to an industrial consumer who in turn transportated it to Mexico by pipeline. The Texas pipeline utilized gas produced in Texas which had not been comingled with gas from any other state and the consumer transported the gas directly from Texas to Mexico. The court felt that foreign commerce was not to be confused with interstate commerce and that foreign export was only mentioned in § 3 which merely required a Commission order authorizing the export. Border Pipeline Company already had such authorization and it was held that it could not additionally be forced to go through a § 7 certification procedure.

In *Distrigas Corp. v. FPC*, 495 F.2d 1057 (D.C. Cir. 1974), discussed in Chapter III, The Role of the FPC, *supra*, the same court had occasion to reconsider the role of the FPC with regard to an LNG import terminal. Although the court declined to overrule the Border Pipeline decision, and confined FPC jurisdiction over such an operation to that conferred by § 3 of the Act, it did substantially broaden the FPC's powers. In effect, § 3 orders as they may be conditioned, are now tantamount to a plenary investigation under § 7. The operative words have remained "consistency with the public interest" instead of the § 7 language of "public convenience and necessity", but extensive documentation and protracted hearings can be expected. In addition to the environmental impact concerns and safety features discussed in Chapter III *supra*, there appear to be at least four and possibly five other factors the Commission will scrutinize.

High on the list, of course, will be the need for the gas. Any system of projections of demand versus supply must be treated with economic objectivity. Will the perceived future demand be generated from new consumers? Will it be due either to a growth or redistribution of population or through industrial growth? Will the projected future demand be caused by a shift toward "cleaner" or possibly cheaper energy sources? Can additions to proven reserves be demonstrated to be large enough to justify long-term contracts and the capital costs involved in high pressure pipelines, storage facilities, etc.? What impact will exhortations to conserve energy have? A correlative concern is how the applicant LNG terminal or its immediate customer, the natural gas wholesaler or pipeline company, plans to allocate the gas vaporized from the LNG received at the terminal. Will it be strictly intrastate or will it service interstate customers or some combination of the two? Will its impact be relatively localized (*e.g.*, two or three coastal states) or will it have regional impact (*e.g.*, the southeastern United States), or will it have national impact through displacement sales, long distance transmission lines, etc.? Specific plans for allocating the imported LNG and some measure of the impact of the allocation plan must be produced and evaluated.

In addition to allocation generally, the question of priorities must be investigated, particularly with regard to interruptable service and curtailments. That the Federal Power Commission has jurisdiction over curtailments has now been established, even when curtailments involves direct sales to users rather than sales for resale. *See FPC v. Louisiana Power & Light Co.*, 406 U.S. 621 (1972) *commented on* Note 61 GEO.L.J. 833 (1973).

Since LNG terminals are so expensive, they are sometimes owned as joint ventures between two or more corporations. Frequently the corporations are pipeline companies or natural gas distribution companies. Thus it is possible that there would be antitrust implications both from the standpoint of acquisition of assets under § 7 of the Clayton Act and, possibly, conspiratorial agreements in restraint of trade in violation of § 1 of the Sherman Act. The Supreme Court in *Gulf States Utilities Co. v. FPC*, 411 U.S. 747 (1973) (6-3) held that the Commission must consider the potential anticompetitive consequences of a proposed bond issue under § 204 of the Federal Power Act. (16 US.C.A. § 824c(a)). The FPC had earlier denied some municipalities' (intervenors) requests for a hearing on the grounds that the bond issue revenue would be used to finance anti-competitive activities. Thus the FPC is charged with "considering" the anti-competitive implications of proposals, requests for orders and applications for certification. (*See also, Gainesville Utilities Dept. v. Florida Power Corp.*, 40 FPC 1227 (Docket No. 68/550)). The earlier case of *California v. FPC*, 369 U.S. 482 (1962) (5-2) is somewhat difficult to reconcile with *Gulf States*. In the former case, the Department of Justice commenced an antitrust action against two pipeline companies, alleging violations of Clayton § 7. Meanwhile, there was a certification proceeding pending before the FPC under § 7 of the Natural Gas Act for the acquisition of jurisdictional assets. A stay in the federal court action based on primary jurisdiction was obtained and the FPC eventually authorized the merger. The Court of Appeals then approved the FPC's authorization and the case went before the U.S. Supreme Court. The Court held that the FPC should not have proceeded in the fact of the pending antitrust suit and, even though the Clayton Act by its own terms excludes "transactions duly consumated pursuant to authority given by the Federal Power Commission . . ." (15 U.S.C. § 18), the Commission could not preemptively determine antitrust issues. (*California v. FPC, supra* at 489-490). Thus it would seem that while the FPC may not ignore antitrust issues on the one hand, it may not proceed to determine them in the face of a pending antitrust action in the federal courts. This may be nothing more than a common sense resolution of the problem. It ensures that antitrust issues will be considered and that if the Department of Justice or a private litigant feels that specific violations are occurring or will occur, it need not intervene in the agency proceeding, but may institute a statutory antitrust action.

Another factor considered by the Commission is the economic feasibility of the proposed operation. Does the applicant have the capital resources to finance the proposed activity? Or can it successfully enter the money market to obtain them? To some extent, the longevity of the company, its experience in the same or related operations, its solvency, its debt structure, its projected amortization of the LNG facilities are all relevant to this determination. Ultimately aspects of these issues will also crop up in approval of tariffs. The FPC recently turned down a request by Distrigas of Massachusetts to exclude its depreciation reserves that had accrued up to December 31, 1975. The corporation had been in a loss position since its inception. No depreciation expense had been recouped from the rate payers. The FPC felt that past losses ought not to be made up in present or future rates. (*See* Gas Industries, June 1976.)

Finally, there is the touchy question of whether the FPC can consider non-jurisdictional alternatives to the proposed energy import (*see* discussion with regard to environmental impact statement in Chapter III, Preparation of Environmental Impact Statement, *supra*). Examples of this would be synthetic gas, generated from coal, and gas from the methane-methanol-methane converson process. The importation and conversion of such fuels as methanol is outside the jurisdiction of the FPC. (Statement of Richard L. Dunham, Chairman FPC, before the *Joint Hearing of the Senate Committees on Interior and Insular Affairs and Commerce pursuant to S.Res. 45* (The National Fuels and Energy Policy Study) 94th Cong., 2d sess. Ser. 94-29, Pt. 1 at 11 (1976). *See Joint Hearings before Senate Committees on Commerce and Interior and Insular Affairs on S. 2510, 2778, 2950, and 3167*, 94th Cong., 2d sess., ser. 94-72 (Commerce) Pt. 3 at 1835 (1976).

The methanol alternative has been the subject of an economic cross-comparison study by Booz-Allen Applied Research (*see* "An Analysis of LNG Marine Transportation" (COM-74-11684, Nov. 1973)). The study proceeded by comparing the cost at each step of the way from the producing foreign well to the U.S. import terminal or conversion station. There are variables which make the comparison difficult such as the length of pipeline from well to seaport (natural gas pipeline for LNG is more expensive per mile than a methanol pipeline), and the cost of natural gas at the wellhead. The idea of the methanol conversion is to convert the natural gas to methanol close to where it is produced, then pipe it to a port and load it on a conventional bulk liquid tanker for transport to the United States, then reconvert it to a form of natural gas. The cost of the marine leg of the transportation cycle varies with distance with the methanol tankers being substantially cheaper than LNG carriers. Although for short distances methanol carriers with restricted drafts (LNG carriers are being designed with drafts of thirty-six to forty feet) would be less economical, over the long distances (more representative of sources in Iran and Indonesia) the methanol carriers are cheaper (*Id.* at VIII-18 to VIII-25). However, the Booz-Allen study concedes that cost estimates are not entirely credible for methanol since the conversion technology lags considerably behind the LNG technology and there is uncertainty whether data from pilot plant runs can be extrapolated to the large scale required of such projects. Moreover, the foreign capital investment is higher for methanol land-based facilities than for LNG (where a relatively more substantial proportion of the cost is in the ocean transportation link). Moreover, methanol plants require between 1 and 2 1/2 billion gallons of water per year compared to LNG liquefaction which requires virtually no fresh water and this could be a serious problem in middle eastern countries (*Id.* at VIII-26). Whether and to what extent then, it is possible to make valid comparisons remains in doubt.

§ 7 CERTIFICATION AND § 4 APPROVAL OF RATES

JURISDICTIONAL ISSUES

Production and Gathering

The Alaska natural gas production creates a situation which raises several interesting jurisdictional issues. To the extent that the gas is sold and sent to the lower forty-eight states, the sale by an Alaskan producer would be a "sale for resale" in interstate commerce. (15 U.S.C. § 717(b) (1970)). § 1(b) of the Natural Gas Act has an exemption, however, for the "production or gathering" of natural gas. (*Id.* § 717(b)). Marathon and Phillips Oil Co. have producing fields in Alaska's Kenai Peninsula. They jointly own a twenty inch-diameter eighteen mile-long line from Marathon's field. Phillips uses a combination undersea-overland line that runs for forty-five miles from its Cook Inlet offshore field. Both lines eventually arrive at a liquefaction plant owned by Kenai LNG Corporation, which is jointly owned by Marathon, Phillips and Phillips' retirement income plan trustee. (FPC Opinion No. 735 dated June 23, 1975 in Docket Nos. CI74-537 and 538 at 4-5). Certain sales are made to industrial users in the vicinity of the LNG plant and Marathon delivers a small volume of gas to the city of Kenai and the Alaska Pipeline Co. for resale. Phillips also makes one sale upstream of the liquefaction plant. The gas from both producing fields is of pipeline quality after passing through dehydrators at the fields. Sufficient field pressure exists that no compression is needed for transmission to the liquefaction plant. The vast bulk of the gas then arrives at the liquefaction plant and is eventually transported in LNG tankers (Initial Decision Docket Nos. CI74-537 and 538 at 17-18).

Marathon and Phillips contended that they were entitled to the production and gathering exemption for their pipelines behind the liquefaction facility. The FPC on the other hand, took the position that the pipeline was a transmission facility since the gas was already of pipeline quality as evidenced by the fact of the sales to Alaska customers. The producers countered that these sales were incidental and were not the "primary purpose" of the pipeline and that they were analogous to "tailgate sales" behind the plant which could be disregarded. They contended, with considerable credibility that the local market could not begin to absorb the production and since no pipelines were in existence to the lower forty-eight states where the demand was, the liquefaction plant was tantamount to a production facility (*see Southern Union Gathering Co.*, 47 FPC 1177 (1972) discussing the "primary function" test when interpreting the "production and gathering" exemption of 15 U.S.C. § 717(b) (1970); *see also, United Gas Improvement Co. v. Continental Oil Co.*, 381 U.S. 392, 402 (1965)). In *Phillips Petroleum Company*, 10 FPC 246 (1951) *rev.d on other grounds, sub. nom. Phillips Petroleum Co. v. Wisconsin*, 347 U.S. 672 (1954) the Commission said "processing may include operations undertaken to make the gas salable. . ." (*Id.* at 277). It certainly can be argued that gas that cannot be delivered to a user has no market and therefore is not salable. If the gas can only be transported by sea and therefore must be liquefied, the liquefaction plant would seem to be a "processing" facility within the production exemption. The Federal Power Commission in its decision on Phase 1 of the Marathon Oil/Phillips Petroleum Co. hearing concerning the transport of LNG to Newport, Oregon, from Nikiski, Alaska rejected this contention and held that the pipelines required § 7 certification. The Commissioners took the position that the gas was of "pipeline quality" once dehydrated in the field and that the large diameter lines were not for gathering (*i.e.*, for most of their length, no tributary lines joined them) and took the position that liquefaction was not "traditional processing".* The Commission did say that certification for the LNG plant and the field-to-plant line would not taint the companies respective eligibilities for independent producer status. (Docket Nos. CI-74-537 and 538 Opinion No. 735 at 12-13).

The Commission went on to hold, understandably, that sale by the producers at the LNG terminal was a sale in interstate commerce and was therefore subject to regulation (*Id.* at 10-14). The Commission recognized that it would have jurisdiction over the wellhead prices of the gas, but since no wellhead sale was contemplated in the LNG transactions, it was content with approving the FOB Nikiski prices of the LNG under § 4. The Commission made it clear however, that the cost of production at the wellhead would be an element which would have to be documented and which would be an influential factor in the Commission's appraisal of the LNG price.

The ocean transportation leg of the cycle is an area where the Commission declined jurisdiction. Although the LNG carriers would briefly be transiting state waters and would do their loading and discharging in state waters, the Natural Gas Act provides that interstate commerce is jurisdictional "only insofar as such commerce takes place within the United States" (15 U.S.C. § 717(a)7 (1970)). It was felt that the overwhelming portion of the trip was on the high seas and the Commission held that mere entrance into a port would not alter the non-jurisdictional nature of the vessels' operations. (*Id.* at 31). *Cf. Seatrain Lines v. United States*, 152 F.Supp. 619 (D. Del.) *aff'd* 355 U.S. 181 (1957) (exemption of oil tanker from regulation under Interstate Commerce Act § 303(e)).

* In certain mid-west gas fields there is a relatively high content of entrained helium. Since federal law requires the conservation and extraction of helium (50 U.S.C. §§ 167-167n (1970)) and since it can only be extracted by a distillation process, the "traditional" processing in such fields *does* involve liquefaction.

The "Hinshaw" Exemption

This exemption is found in § 1(c) of the Act (*Id.* § 717(c)) which exempts persons and facilities which receive natural gas "within or at the boundary of a state if all the natural gas so received is ultimately consumed within such state. . . ." provided that the rates and service are subject to state regulation. Again referring to the proposed Alaska/Oregon trade route, the purchaser of the LNG, Northwest Natural Gas, was planning on buying it FOB Alaska and transporting it on its LNG carrier to its terminal at Newport, Oregon. The Commission held that this would not satisfy the receipt-within-the-state requirement of the Hinshaw exemption. It rejected arguments that the gas would not be physically in the company's storage until it reached Oregon and that the LNG would not be returned to "natural" gas form until it was revaporized. The Commission was impressed by the fact that risk of loss and title to the gas passed in Alaska, far beyond the Oregon boundaries. The Commission suggested, however, that if another entity owned the tanker and purchased the gas for resale and delivery to Northwest Natural Gas in Oregon the exemption would remain intact. The Commission was not concerned that the "other person" which would purchase the gas in Alaska, transport it and resell it to Northwest in Oregon might be a subsidiary of Northwest Natural Gas (Commission Opinion No. 735 in Docket Nos. CI-74-537 and 538 issued June 23, 1975 at 17). Of course, the subsidiary would have to have its sale price approved since it would be selling for resale in interstate commerce, but § 7 certification of the subsidiary's LNG carrier and Northwest Natural's storage and vaporization plant would not be required (*Id.*).

Displacement Sales

There are several ways in which an ostensibly intrastate sale may have the effect of selling in interstate commerce and therefore cause an import terminal's facilities to become jurisdictional. If a long-distance transmission pipeline which transports gas in interstate commerce were to terminate in the same state as an import terminal and the import terminal, after vaporizing its gas, piped it to the interstate pipeline, this would be deemed a "displacement" sale. This would be so even though the gas would be input and eventually delivered and consumed in the same state. It is argued that as a result of supplying gas to satisfy the contractual commitments of the pipeline to customers in that state, the pipeline has to deliver less gas to the end of the pipeline and can in fact sell more to customers in other states upstream of the LNG terminal's input pipe. So long as the interstate pipeline connection exists, input to the pipeline has the advantage of spreading the benefits of LNG imports beyond the immediate coastal area. Since displacement sales are deemed to affect interstate commerce they will invoke § 7 jurisdiction.

Another possible way to have a displacement sale would be for the import terminal to sell directly to an in-state customer who is under contract to buy its supply from an interstate pipeline. The customer could pay the pipeline and the pipeline would pay the terminal. Since its obligation to its customers was fulfilled by the terminal, the pipeline operator would have an equivalent amount of excess gas which it could deliver to existing customers (or sell to new customers) in other states. Although the high cost of duplicating pipeline routes and the complexity of the payment scheme make this type of displacement sale less likely, there seems no reason why it should not similarly invoke the Commission's jurisdiction. Still another possibility is if a terminal's intrastate customer were located close to an interstate pipeline as was the terminal, but the customer and the terminal were not close to each other, the customer might buy its gas from the terminal and pay the terminal, but actually take delivery from an interstate pipeline. Then, the terminal would have to "repay" the pipeline by inputing an equivalent amount of gas into the interstate pipeline so the latter could service its downstream customers.

Finally the terminal could deliver vaporized gas in-state to an entity, A, a customer of an interstate pipeline. As a result of this delivery, say of quantity x, the pipeline would be able to sell the contract amount (b) plus x to another of its customers, B, and would not deliver x to A. Then B would pay the terminal the price of x and A would pay the pipeline its normal charges for x.

Contents of § 7 Application

The Code of Federal Regulations (18 C.F.R. § 157.13 and .14 (1975)) specifies the exhibits which are required to be attached to an application for § 7 certification. Environmental factors are required to be analyzed in terms of impacts, alternatives, and irreversible and irretrievable commitments of resources. Flow diagrams, data and technical specifications for proposed machinery and equipment must be disclosed. Lists and breakdowns of projected customers by name, locality and type of service (firm industrial, interruptable industrial, residential space heating, commercial space heating, etc.) is required along with a designation of whether they will be served at retail or wholesale. Total past and expected curtailments of service by the applicant, and each customer receiving new or additional supplies must be identified.

As might be expected, various documents disclosing the corporate and financial status of the applicant are required, as is a geographic location and identification of the prospective facility. Financial considerations require detailed support including a "detailed description of applicant's outstanding and proposed securities and liabilities. . . interest or dividend rate, dates of issue and maturity, loading privileges and principal terms and conditions. . . ." The method of marketing securities must also be described, along with a statement of anticipated cash flow, including cash flow during the construction period and the schedule for retirement of outstanding debt security. A proposed tariff showing changes over the present tariff with supporting data showing system cost-of-service for the first year of operation, and allocation of cost to each service classification and the basis therefore, the proposed rate base and rate of return, operating expenses segregated by functional accounts, depreciation and depletion allowances and taxes estimated must also be submitted. At hearings on the application direct testimony is usually submitted in written form and then the witnesses are made available for cross-examination.

"JUST AND REASONABLE" RATES

It would avail the Commission little to stop at fixing a profit rate for a distributing company or for a sale-for-resale-in-interstate-commerce company, because consumer prices could still rise if the "raw materials" cost increased due to increases in wellhead price. Thus the Commission will examine wellhead prices where the sale is at the wellhead or at least will examine wellhead costs where that becomes a component of the eventual price of first sale in interstate commerce. There are three pricing schemes which have been under extensive discussion and debate for regulated or partially regulated natural gas prices. Since gas produced from vaporized LNG will be substantially more expensive than existing regulated gas, the most important discussions center around incremental pricing versus "rolled-in" pricing.

As the name implies, incremental pricing would allow a price structure for each separate source of gas and if gas produced from LNG was much more expensive, it would carry a "price tag" that would reflect the total costs in its delivery to the customer. Under a rolled-in price scheme, on the other hand, if 25% of the gas consumed in the country were from LNG imports, a single pricing structure could be employed and spread over all gas consumed. Thus while the price would go up, it would be borne by all customers equally and users would not be conscious of more than a modest price increase because the true cost would be rolled-in or diluted with the lower cost regulated gas.

Persons concerned with energy conservation and persons skeptical of capital-intensive investments tied to foreign resources would argue that incremental pricing should be used so that only those new customers or customers desiring additional gas who were willing to pay the full costs, would use the LNG-derived gas. When the true costs were perceived, it is felt that fewer customers would demand the extra increment of gas consumption. Thus LNG projects would either die aborning or be more limited in extent. Those who argue for rolled-in pricing say that if it were not for the artificial supression of price due to regulatory edict, the prices of domestic gas would be higher anyway. They also contend that the overall demand can be met in a more palatable way if a single price can be set for gas regardless of its source. Proponents of rolled-in pricing argue that in times of shortage or inadequate supply, fair allocation would require a lower rather than a higher price for additional increments so that those most in need of gas could afford it and it would not become an exclusive perogative of affluent persons or persons who could pass the cost along to their customers. (*See* Statement of Robert Nathan made during FEA hearing reported in Gas Industries (June, 1976)). Of course, using such words as "need" and "inadequate" to some extent begs the issue. It also ignores the fact that non-curtailment policies for residential consumers to a very large degree protect those who are already enjoying gas service.

In order for incremental pricing to have an impact as an incentive to conserve fuel, the pricing structure must be carried through consistently, "down to the burner tip." If someone in the distributional chain ahead of the ultimate consumer is able to employ rolled-in pricing, the impact will be greatly diminished. Moreover, if users are willing to pay more to get an enlarged supply, many economists feel that this "economic rent" should be captured by U.S. producers as a means of capitalizing more intensive exploration costs and thus furthering the principles of national energy independence. Incremental pricing or deregulation of "new" domestic natural gas would have this effect, but allowing rolled-in pricing of LNG imports at presently projected quantities would not materially alter the present situation. In short, such arguments contend that LNG import pricing policies could lead to dependence on foreign gas as a relatively painless crutch and capital would not be attracted to gas exploration in the United States above the present, inadequate, levels.

A third method of pricing (not necessarily mutually exclusive) is the so-called "peak load" pricing. This too is a conservation oriented scheme, but it could equally well be described as paying-the-true-cost-of-variable-demand. In point of fact, much energy consumption is concentrated at certain times of the day or certain seasons of the year. In order to supply the needs of these peak times, generation capacity and fuel supply facilities must be so large that they stand idle in times of lesser demand. Since overcapacity is expensive and is to some extent an inefficient allocation of resources and capital, peak load pricing would apply premium or surcharge rates to users who wished to have their supply arrive during "peak" times. The feeling is that industrial operations would either reschedule their needs for periods during the middle of the night or other times of lower demand in order to qualify for a lower price per BTU, or else would pay a premium and pass the prices along to their customers thus more accurately allocating the costs of having the reserve capacity.

There are numerous difficulties in developing a workable peak-load pricing theory. One problem is that the "peak" may be price-sensitive and thus will shift in a responsive fashion and thus no longer lend itself to deterministic analysis. Joint cost problems become quite sophisticated as heterogeneous production capability (*e.g.*, base load on hydro, intermediate load on coal, and peak loads on natural gas) is introduced. Curtailment or rationing costs (an aspect of capacity cost) add further complexity. Identifications of the actual timing and duration of peak demand has not been adequately incorporated in most theories. Finally, the practical aspects of metering to support variable price tariffs suggest that hardware costs may exceed benefits. (*See*

Symposium on Peak Load Pricing, 7 BELL J. ECON. 197-248 (1976)).

Some utilities in investigating the most appropriate allocation of overhead and stand-by capacity costs for developing cost-of-service tariffs have found that residential customers may have been subsidized by industrial customers. (Interview with Harold Grobe, Superintendent Gas Supply & Communications, Northwest Natural Gas Co., October 18, 1976).

On the other hand, it has been argued that allocating fixed (capital) costs equally between variable demand (peak load) city-gate (buying for resale to residential users) customers and high volume, level demand customers (sub-pipelines and industrial users) subsidizes industrial consumption in times of chronic curtailment. (*See Consolidated Gas Supply Corp. v. FPC*, 520 F.2d 1176, 1180, 1186 (D.C. Cir. 1975). The FPC has, as a result of such an argument reallocated fixed costs 75% to commodity (volumetric) use and only 25% to demand (peak capacity) use. (50 F.P.C. 1348 (1973)). This reallocation was affirmed on appeal (*Consolidated Gas, supra*). Intervenors had argued that setting rates to jurisdictional customers ought not to involve efforts to discourage industrial users from using natural gas. Although this argument impressed the administrative law judge, the Commission rejected it, saying in "the exigencies of present circumstances . . . [such a purpose and result would be] in the national interest." (50 F.P.C. at 1355-56). Since the District of Columbia Circuit court found independent support in the record for the Commission's reallocation, it did not rule on the validity of the intervenors' arguments or the FPC's response thereto.

Some intervenor-purchasers had built storage facilities to handle *their* customers peak demand while still presenting a level demand to their supplier. They urged that their construction of these expensive facilities (some of which could have been LNG plants) estopped the FPC from allocating more costs to them. The court, using the not-arbitrary-or-unreasonable test of the end results of the Commission's order (*FPC v. Hope Natural Gas Co.*, 320 U.S. 591 (1944)) rejected this argument and found the reallocation reasonable. (*Consolidated Gas, supra* at 1188).

While peak loads would not be directly effected by LNG imports, LNG storage tanks have played a role in "peak shaving" especially when needs are seasonal. It is possible in times of low consumer demand to liquefy natural gas, store it locally and revaporize it in the winter when residential heating needs increase. With a level demand on the gas supplier, this could result in a smaller supply facility capacity than would otherwise be required and would be a factor in keeping prices down.

Applicants for certification to develop the natural gas on the north slope of Alaska have proposed an "all events" tariff for selling their gas. A similar tariff was approved in Docket CP71-68 on behalf of Columbia LNG Corporation. Essentially such cost-of-service tariffs allow investors to be assured that unforseen construction costs and guaranteed debt service (interest in sinking fund obligations) will be covered by some guaranteed margin. Thus for example, a tariff might be set at a floating factor of 1.25 times these costs. Another possible financing device might be to use a customer surcharge to generate money ahead of time for the construction costs. To the extent that existing users could avoid curtailment or could expect to be entitled to increased usage, the savings in capital costs (whether they be debt or equity) ultimately reflected in future sales prices might be sufficiently great to make the additional advance cost to the customers attractive. (Testimony of Anthony Jiorle, Docket No. CP75-96 (El Paso Alaska Co., et al) appended to statement of Richard L. Dunham, Chairman FPC, before the Committee on Commerce and the Committee on Interior and Insular Affairs of the U.S. Senate, February 17, 1976, at 113-119 and 156-158).

political, national security and diplomatic problems

"PROJECT INDEPENDENCE"

Presently the head of the Federal Energy Amdinistration is also the Chairperson of the Energy Resources Council. The Council is charged with producing a task force report evaluating the various proposals to import LNG (*see* Chapter I, The Presidents Message of February 26, 1976 and the Energy Resources Council Task Force *supra*). The FEA apparently uses a 30:1 ratio between proven recoverable reserves and gas production. This assumes 85% convertability. "Convertability" is a measure of the ability to extract the gas compared to the total amount of gas in the ground. After ten or more years, the inherent pressure of a gas field begins to drop and extracting the last portion of the gas from the gas field is often economically unfeasible. Moreover, exploration and development costs frequently have to be amortized over at least twenty years. For these reasons the 30:1 ratio, although higher than used by some forecasters, appears to be justifiable. As the result of this ratio, among other factors, it is reported that the FEA thinks it is not totally unlikely that five TCF of natural gas may be demanded from foreign imports by the year 1985.

The notion of national independence of energy supply, which arose out of the OPEC boycott and the program name "Project Independence" are directed at making the United States more self-sufficient in terms of its energy resources. This objective can be accomplished by efforts in at least four areas. Producers can be encouraged through economic incentives such as deregulation of natural gas prices to devote greater effort to exploration and thus to find more energy resources which are economically feasible to extract. Second, research can continue on alternative fuels and synthetic fuels. Third, existing energy-using equipment can be refined in the engineering sense to make it more efficient and alternative ways of performing the work presently done by fossil fuels can be found, *e.g.*, solar energy for space heating and for heating hot water. Finally, wide-spread campaigns can be undertaken to encourage and accomplish energy conservation.

The Federal Energy Administration produced a comprehensive economic model, as part of its Project Independence Report, to evaluate current and projected energy situations over the period of 1973-1985 in the United States. The report projects that the United States will continue to be heavily dependent on foreign imports of oil in the year 1985. An elastic supply curve was postulated and projections were based on prices of $4, $7, and $11 per barrel of crude oil stated in 1973 dollars. The FEA model has been criticized for assuming nonassociated natural gas production is sensitive to foreign oil prices. Oil prices and gas prices in turn are related to projected drilling rates. These were input as exogenous factors independent of price. Drilling rates used were essentially those given by the National Petroleum Council. One critic contends this leads to a clear downward bias in the projected production of nonassociated gas. (Hausman, *Project Independence Report: An Appriasal of U.S. Energy Needs up to 1985*, 6 BELL J.ECON. 517, 530 (1975)). He points out that since the report assumes that drilling will increase at the rate of 5% a year this has to be independent of price. In 1973 and 1974 the average increase in drilling was around 25% indicating a strong price correlation (*Id.* at 531).

Professor Hausman is also critical of the FEA's model which suggests that in the household and commercial sector natural gas and coal are complements of residual and distillate fuels rather than substitutes for them. He attributes error in part to the gaps in the data base resulting from nonequilibrium markets (due to shortages induced by FPC price regulation) and to distortions in data resulting from the general nonavailability of gas followed by a sudden increase in supply attributable to completion of a new interstate pipeline (*Id.* at 543). He is also critical of the model's failure to achieve "BTU equilibrium", that is under a deregulation assumption (phased deregulation is assumed in the project Independence Report) prices of alternative energy sources should be close enough to parity that each would be a perfect substitute for the other. Even allowing for complications, Hausman contends the large disparities between projected fuel prices suggest the model may be unreliable (*Id.* at 545). Presumably the elements of the FEA study will be refined and improved in the course of the Energy Resources Council's Task Force Report on importation of LNG (*See* Chapter I, LNG Carrier Fleet Projection *supra*).

The reasons for seeking energy independence are multi-faceted. Obviously, military vulnerability and national defense are important factors. Foreign exchange drains and balance of payments considerations certainly are a substantial factor. Policies of foreign aid and development of less developed countries are factors and politically triggered acts of foreign countries such as nationalization, expropriation, and boycotts by producer cartels are also of major importance.

The Federal Power Commission routinely routes proposals for LNG imports to the Department of Defense and the Department of State. This is done pursuant to Executive Order 10,485 (Sept. 3, 1953, 18 Fed. Reg. 5397) issued pursuant to the Defense Production Act of 1950 (50 U.S.C. § 2061 et. seq. (1970)). This order requires that the Secretary of State and Secretary of Defense make favorable recommendations on any application pending before the FPC for such an import or export. In the case of disagreement between the FPC and the two Secretaries, the application must be submitted to the President for approval or disapproval (*Id.*). The Department of Commerce, The Maritime Administration and the Federal Energy Administration are also advised of such applications. The following sections will review two aspects of the political debate over the importation of LNG from foreign countries: the risks inherent in foreign supply, and the impact of deregulation of domestic gas prices.

RELIABILITY OF FOREIGN SUPPLIERS

TECHNICAL ASPECTS

Technical competency of the exporting country's personnel and the availability of maintenance equipment and spare parts are major concerns when entering into long-term supply contracts, and making investments in capital-intensive systems. It is reported that SONATRACH's fourth train compressor was "blown" due to an operational error. "Trains" in liquefaction plants represent one complete throughput process. In a typical large plant there are multiple trains operating in parallel. In the case of SONATRACH's plant at Skikda, Algeria the fourth train would have produced approximately 7,000,000 cubic meters of LNG per year. The compressor, a massive and expensive piece of equipment, was designed and built in France and was being "broken-in" by Algerian operators. Apparently the operators turned off the lubricating pump at the same time they turned off the power producing torque on the shaft of the compressor.

Being a well-balanced machine with a good deal of inertia it normally would have coasted to a stop, but without circulating oil and with precision tolerances, metal-to-metal contact occurred. The resulting thermal expansion ruined the journal bearings reportedly causing the compressor to destroy itself within two minutes. Being a very expensive item, there was no "spare" on the premises.

Distrigas had originally entered into a supply contract with SONATRACH for the output of the fourth train and had contracted with French importers for any surplus the French did not require from the third train. As a result of this breakdown, deliveries were stopped for well over a year. Subsequently Distrigas renegotiated its contract to acquire rights in 25% of the combined output of trains one through four, regardless of which ones were running (interview with Rod Twedell, Assistant Terminal Manager, Distrigas of Massachusetts on June 15, 1976).

Notions of preventative maintenance, a well-catalogued and readily accessible inventory of spare parts, and the ability to "contain" small malfunctions and breakdowns before they jeopardize an entire complex system, are obviously attitudes and skills that cannot be instantaneously acquired. This is especially true when a plant is delivered on a "turnkey" basis. Despite painstaking operations manuals by the manufacturers of the equipment and on-site checkouts, some sort of ongoing training program is obviously a necessity for technical and supervisory personnel. This is especially so if the exporting nation is determined to staff the operation with nationals of no previous experience in the LNG industry. An additional concern arises out of the fact that some natural gas contains mercury and other corrosive contaminants. Considerable technical know-how is needed to determine the exact constituents and to operate the equipment to successfully strain out undesirable contaminants in the liquefaction process. If they are not removed and the gas is ultimately used as boiler fuel they can have damaging effects. Other start up problems encountered at Skikda included clogging of seawater intake by beach sand, improper venting of lines leading to the flare stack, high pressure casing damage due to faulty operation of the load control turbine blades, and leaks in heat exchangers due to excessive gas velocities. (*See generally*, J. Dolle & D. Gilbourne, "LNG: Start Up of the Skikda LNG Plant", Chemical Engineering Progress p. 39-43 (Jan. 1976)).

POLITICAL UNCERTAINTIES

The behavior of the OPEC (Organization of Petroleum Exporting Countries) group during the recent crude oil boycott must be foremost in the fears of planners in the State Department, Department of Defense and the Federal Energy Administration. The OPEC countries do not presently make any effort to control liquefied natural gas production or export. This may be because not every OPEC member has natural gas fields. On the other hand, it would not be surprising to see the formation of a cartel among the countries which can produce natural gas (OGEC?). Among the Arab nations the ones who do have natural gas, particularly Libya and Algeria, seem to have more in common than the OPEC countries generally. Also there would be somewhat fewer members to such a cartel and thus it would be theoretically easier to police.

Iran has enormous reserves of associated gas which it is presently flaring. As an alternative it could reinject it into the oil fields to maintain production pressure and to "bank it" against the day when gas prices may be higher and transportation technology more advanced. It could also liquefy it and ship it as LNG, or it could develop overland pipelines for sales to Europe or Russia. China appears to have an extensive gas field offshore in the Gulf of Pohai on its northern coast. Tentative negotiations are underway to develop this field with the ultimate goal of exporting it for consumption in Japan. Iran's exporting consortium, known as KALINGAS, uses gas from the Kangan field.

Possible destinations of waterborn LNG presently appear to be Japan, the United States, and Belgium (Anderson & Daniels, *Cross-Currents Buffet World LNG Trade*, Chemical Engineering 87, 90 (March 1976)). Nigeria is discussing construction of two LNG liquefaction complexes. Nigeria will own 60% of the liquefaction facilities and the necessary LNG tankers, with foreign investors owning the remaining 40% and paying Nigerian taxes on revenues attributable to the liquefaction facilities. Nigeria has the advantage of being relatively close to the east coast of the United States and it did not participate in the OPEC crude oil embargo of the United States. Further, while there has been political unstability in Nigeria, successive governments have conspicuously left management in the oil industry and the governmental bureaucracy overseeing the oil industry intact (Interview with Glen Rase, economist for State Department's Office of Fuels and Energy on

June 17, 1976).

Indonesia, which exports through its state trading company "Pertamina" is regarded as a relatively stable country and has a reputation of not interferring with technical operations staffed by foreigners or foreign trained technicians. Pertamina itself, however, is believed to be having financial difficulties. Japan is reputed to be negotiating for an LNG project with Malaysia and the state of Sarawak as a result of the recent proving of reserves in that area (Anderson & Daniels, *supra* at 90).

The USSR has substantial proven reserves of natural gas and LNG projects with the United States would no doubt further detente, at least so long as delivery schedules and pricing remain mutually agreeable. One such export project, the North Star International, would require a 1600 mile gaseous-state pipeline across permafrost. Economic studies show that the break-even point for a natural gas pipeline (not requiring the LNG cycle) is approximately 1200 miles (Rase, interview, *supra*).

The current political situation in Libya and its poor performance in export projects involving Italy and Spain make it an improbable trading partner (Booz-Allen, *supra* Vol. 1 at VIII-30). Australia and Chile have gas reserves but present indications are that they will keep their production for internal consumption as will England and Norway with their North Sea fields. Venezuela officially terminated its LNG export project in mid-1974 and at least three factors make it improbable as a future source of LNG: there is a feeling that production will be reserved for domestic consumption (Anderson & Daniels, *supra* at 91); tendencies towards nationalization have effectively dried up foreign investments; and it was a member of OPEC although it did not participate in the boycott.

Ecuador is reported to have recent gas finds and its need for foreign exchange and relative proximity to the United States Gulf coast make it a possible exporter although its extreme political instability might retard the necessary inflow of capital for liquefaction facilities (Booz-Allen, *supra* at Vol. 1, VII-32).

ECONOMIC FACTORS

Although the supply contracts are typically of a twenty to twenty-five year duration, the price clauses have more flexibility. Some employ escalator clauses with an objective index. Others provide for re-opening on price every four years. It is reported that Algeria will negotiate all future contracts with a combination "floor" and index system. The floor is to be $1 per million BTU's FOB Algeria. FOB price will excalate above the floor in relation to the price of fuel oil (the index). A hardship clause will permit a re-negotiation if fuel oil prices fall significantly under the floor. The floor price itself would be tied to presently unspecified economic indicators which would reflect inflationary trends (Anderson & Daniels, *supra* in Chemical Engineering at 88).

Pertamina uses a floating pricing formula to calculate an FOB price expressed in U.S. dollars per million BTU. The price is recalculated at the start at each quarter. The formula it uses to derive the price uses $1.25 as the base price and factors this by an equally weighted sum of the domestic (Indonesian) crude oil price and the applicable value of the initial Index for Fuel and Related Products in Power which is defined in the contract (*Id.*). If LNG prices are not "pegged" relative to crude oil they are often pegged to fuel oil prices. This may be in part because Venezuelian fuel oil is said to "overhang" the market. It could presumably be "dumped" at prices competitive with other ready-to-burn petroleum products. It may also be because number two fuel oil is widely used for residential home heating and would thus be competitive where natural gas is available to homeowner consumers.

There is obvious concern on the part of government planners that the United States importers may expend billions of dollars on LNG carrier fleets and reception terminals and thus get themselves financially locked into long-term contracts only to find the FOB price inexorably moved upwards by international politics including reduced output of crude oil and higher prices on crude oil distillates. So long as the importer's long run average costs are less than its marginal revenue in reselling the imports it would continue importation even with the prospect of short-term losses. If price increases were allowed to be passed on through rolled-in pricing considerable price increases might be tolerated. Moreover, since importers are usually obliged to take certain minimum quantities in a period of time, repudiation of the contract could well bring legal retaliation for breach.

Although it can be argued that the

exporting countries need the importing countries as much as the importing countries need them, many economists fear that cartel arrangements will enable exporting countries to progressively step up the price. Support for this position may be found in the fact that conversion of both home heating and industrial applications from one fuel to another is typically expensive and unless multiple systems already exist, *e.g.*, as in some electric utilities for peak-load periods, new customers may not be inclined to withdraw from the market just because of price increases. Second, the typical liquefaction facility in a foreign country is highly leveraged. The exporting country may have as little as 10% of its own money in the project, with the rest on loan from European banks or the United States' Export-Import Bank. As it depletes more and more of its reserves and as its domestic needs increase, the value of the gas to the exporting country climbs. This might motivate price escalations or supply disruptions. However, as equity in the project builds up, there would seem an ever greater incentive for the exporter to act in a stable, responsible fashion to ensure the economic health of its trading partners. Moreover, on the basis of rate of return on invested capital, the opportunity costs of foregoing sales for political purposes are large indeed.

Unlike domestic crude oil where various "spot" markets operate to siphon off temporary excess capacity and where small traders not vertically integrated or not committed to long term contracts can buy, LNG markets tend to be enduring and bilateral. The importer is (usually) desirous of all it can get and the expensive facilities required at either end tend to eliminate the probability of casual deliveries. Moreover, LNG carriers are typically dedicated to a specified trade route, although multiple loading and discharge ports are not inconceivable. For the same reasons it is unlikely that LNG carriers would operate as "tramps" on short-term charters. Instead, the typical arrangement would be that the importer owns the vessel or that the transportation company owns the vessel and dedicates it through a long-term charter to servicing a particular importer (*e.g.*, Gazocean has a transportation contract with Distrigas of Massachusetts to deliver Algerian LNG). (Twedell interview, *supra.*) If, as has happened to the ships designed to deliver gas to Columbia Gas-El Paso's Cove Point facility from Algeria, the carriers are constructed before the liquefaction facility is completed, there would be a possibility that vessels could be temporarily employed carrying other LNG during peak demand periods or when vessels normally dedicated to a given route were unexpectedly down for repairs, etc.

The great cost of LNG carriers and terminals is a further reason why utilization factors must be kept high and downtime must be minimized. Moreover, when comparing LNG carriers to conventional crude oil tankers by capital cost per ton of capacity ratio is nearly 4:1. Even on a thermal basis the ratio of capital cost to BTU's of capacity is nearly 3:1. (*See* R.G. Wooler, Marine Transportation of LNG 71 (1975)). Unused excess capacity would seem unduly expensive and would in the long run reduce the rate of return. On the other hand, to the extent that the vessels suffer from unexpected downtime (say, *e.g.*, downtime in excess of twenty days per year) ship capacity must either be increased or better systems reliability must be built into the ships in the first instance. If a breakdown occurs while the ship is laden, boil-off will continue nevertheless resulting in waste. Hell-or-highwater charters may mitigate the risk of off-hire periods insofar as the owner's capital investment is concerned, but if the ship were an importer-owned asset, downtime on the vessel would be money out of the importer's pocket.

Another important consideration in importing LNG from abroad is the impact this will have on United States balance of payments. If one assumes an average FOB price of 90¢ per thousand cubic feet and assumes imports of three TCF per year we would have an annual cash outflow of $2.7 billion excluding transportation charges (U.S. Comptroller General, REPORT TO CONGRESS ON NATURAL GAS SHORTAGE: THE ROLE OF IMPORTED LNG 32 (Oct. 1975)). Transportation costs would add to this amount depending on the mix of foreign-flag and U.S. -flag vessels.** Russia and Algeria are reported to have requirements that 50% of their LNG imports must be carried on their ships (*Id.* at 33). Russia has one-third of the world's natural gas reserve (*Id.* at 41) and is in need of U.S. capital and know-how to develop its production and liquefaction facilities. Purchases from Russia might to some extent be offset by sale of equipment and know-how to Russia.

A final complication, which has potential impact on the development of an LNG trade with Russia (which was considering trade routes from Pechamo to the east coast of the United States and from Vladivastok to

** *See* p. 116 *infra*.

to the U.S. west coast) are the 1975 amendments to the Foreign Trade Act. In the Jackson Amendment (sponsored by Senator Jackson of Washington) any "nonmarket economy country" (Russia) may not participate in "any program of the government . . . which extends credits or credit guarantees or investment guarantees. . ." during any period in which the President determines such country "denies its citizens the right or opportunity to emigrate." In Russia the issue would presumably turn on the freedom of Russia's Jewish population to emigrate. A Presidential determination showing no such abuse must be delivered to Congress. During the first eighteen months the amendment is in force, the President may waive the prohbiitions of the Act by Executive Order if he reports to Congress that "such waiver will substantially promote the objectives. . . [preserving fundamental human rights] and that the President has received assurances that the emigration practices of that country will henceforth lead substantially to the achievement of . . . [this] objective . . . ." The waiver authority may be continued for an additional twelve month period pursuant to a concurrent resolution of Congress. An elaborate contingency procedure is specified in the statute for further extensions of the waiver authority (*see* 88 Stat. 2056-2060 amending 19 U.S.C. § 2432).

The 1974 amendments to the Statute of the Export-Import Bank similarly restrict development of Russian LNG facilities with United States money. These amendments state in pertinent part that:

> "no loan or financial guarantee or combination thereof which equals or exceeds $25 million for the export of goods or services involving research, exploration, or production of fossil fuel energy resources in the Union of Soviet Socialists Republic shall be finally approved . . . unless in each case the Bank has submitted to the Congress with respect to such . . . [transaction] a detailed statement describing and explaining the transaction at least twenty-five days of continuous session of the Congress prior to the date of final approval." (88 Stat. 2355 Amending 12 U.S.C. § 635).

Elsewhere the amendements state that no:

> "loan or financial guarantee or combination thereof shall be for the purchase, lease or procurement [by Russia] of any product or service for production [including processing and distribution] of fossil fuel energy resources. Not more than $40 million . . . [of aggregate loans to Russia] shall be for the purchase, lease or procurement of any product or service which involves research or exploration of fossil fuel energy resources." (88 Stat. 2336 Amending 12 U.S.C. § 635e).

Congress, by concurrent resolution acting upon a Presidential recommendation, may approve larger loan or guarantee amounts (*Id.*). These amendments would appear to minimize or block Export-Import Bank participation in capital development of Russia's nascent LNG industry, at least until such time as Congress acts to specifically approve such funding.

DEREGULATION OF DOMESTIC NATURAL GAS

To the extent natural gas is associated with deposits of crude oil a joint cost problem exists and in the early days of gas production gas could be treated almost as a byproduct. Consequently, the exploration and production costs were allocated to the crude oil. Only the ascertainable separate costs such as dehumidification and compression were viewed as a separate cost of the gas. With greater demand for gas and the technical advancements in high-pressure interestate pipelines, unassociated gas fields were sought and tapped (*see* Bryer & MacIvoy, *The Natural Gas Shortage and the Regulation of Natural Gas Producers*, 86 Harv.L.Rev. 941, 954-55 and n. 52 (1973)).

In simplest form the arguments over degregulation turn on two issues: the performance of the regulators in achieving the asserted goals of controlling abuses of market power manifested by excessively high prices and, implicitly, perhaps accomplishing an income transfer in favor of the consumer; and the impact of artificially depressed prices on the development of natural gas reserves and correlative production rates. Additional complications are introduced by notions of flexible cost-of-service tariffs, "most favored nation" clauses in pipeline contracts, and rolled-in pricing for new production.

PURPOSES OF REGULATION

Bryer and MacIvoy contend that natural gas production is not a concentrated industry, citing *Southern Louisiana Area Rate Cases*, 428 F.2d 407, 416 n. 10 (5th Cir.) *cert.*

denied, 400 U.S. 950 (1970). Even on a regional basis there is no evidence of alarming concentration (*see*, Bryer and MacIvoy, *supra* at 946). They reject the argument that the key to pricing is the ownership of reserves (particularly when most-favored-nation clauses allow the producer to alter the price under existing contracts to the price being paid by its customer under its newest and most expensive contract) by attacking its factual premise that there was excessive concentration in the holding of reserves (*Id.* at 946-47). Moreover, there is some evidence that at a time of rapid rise in the field price (1950-1958) pipelines enjoyed monopsony status and actually depressed prices.

Bryer and MacIvoy also suggest that in order to stop windfall profits through most-favored-nation clauses and to preserve the prices of "old" more cheaply discovered and produced intramarginal supplies, a multi-tiered type of regulation would be required. They contend this requires a knowledge of the location and shape of the supply curves for production and new reserves. Such information is presumably difficult or impossible to acquire. Additionally, they contend that lower prices for intra-marginal gas stimulate further demand requiring some sort of rationing and prioritization, not to mention restrictions against arbitrage. Restrictions based on moral deservingness are politically sensitive to administer and may run counter to the more objective allocations achievable in an open market (*Id.* at 951).

DIFFICULTIES ENCOUNTERED BY THE FPC

The Commission originally set ceiling prices on new gas and used a survey over base years in the recent past to determine the cost of finding and producing new gas. Bryer and MacIvoy reason that such a method of setting ceiling prices invariably induced shortages because exploration and development costs were increasing and historical averages necessarily lagged behind future costs. Additional problems may have been created by the fact that extraction of the last portions of a wasting resource is invariably more expensive than extraction of the first portions (*Id.* at 962).

If costs increase and prices are fixed only the most likely potential gas fields will be explored and only the cheapest wells will be in production. Meanwhile the costs of alternative fuels have risen due to short supply, petroleum boycotts, increased consumer demand, and general inflation. With ceiling prices below market clearing prices "demand" for natural gas has naturally increased, even more than would be the case with open-market pricing. Thus the controlled price has actually contributed to and in large part been responsible for the perceived increase in demand.

An important effect of the regulated price has been to divert new supplies, not under contractual commitment, to intrastate (unregulated) markets. This has caused considerable relocation of industrial customers which have moved to states with domestic gas supplies. It has also caused a proportionate decrease in the supplies available to interstate pipelines whose principal customers are local gas utilities who in turn resell to residential consumers (*Id.* at 977). In addition to intrastate distributers, many producers are selling directly to industrial customers in the state of production (*Id.*).

Floating multi-tiered classification systems have been suggested where what is now "new" gas would eventually be reclassified as "old" gas after the passage of a certain number of years. Bryer and MacIvoy argue that this would nevertheless deter exploration and development since producers would understand that eventually newly discovered supplies would be subject to ceilings. The accuracy of this prediction no doubt depends on the amortization period and the rate of escalation of future exploration costs. Bryer and MacIvoy favor an unregulated price and would accomplish income transfers by means of taxes on producers. It is felt this might fall on the more successful producers and those enjoying economic rent for their good luck or skill in making early, cheap discoveries while falling less harshly on marginal producers (*Id.* at 985).

Theoretically the benefits from regulation can be quantified as the difference between the controlled price and the market price times the quantity of gas which producers are willing to supply at the controlled price. The detriment to consumers is the loss of consumer surplus which is a measure of the price consumers would be willing to pay if they were the only customers and were incrementally adding to the quantity of their purchases in an open market summed over all such customers. Since price in the open market is fixed at the margin, such purchasers purchase whatever they require at the marginal price and in that sense get their additional units at a price less than that which they would have been willing to pay if they were negotiating incremental unit by incremental unit. *See* Appendix, Exh. 33 for a schematic illustration (reproduced from Bryer & MacIvoy, *supra* at 981-982 n. 127).

MODELING OF REGULATORY ALTERNATIVES

In recent years several econometric models have been developed to predict price impacts upon exploration and discovery of natural gas. In a recent article the co-author of one of the models compares his model and two others by "backcasting". That is, he uses historic data for past periods to see how well the model correlates with the actual facts. He also compares them in the forecasting mode looking ahead in the years 1975 through 1980 (Pindyck, *The Regulatory Implications of Three Alternative Econometrics Supply Models of Natural Gas*, 5 BELL J. ECON. & MGT. SCIENCE 633 (1974)). The MacIvoy-Pindyck model was found to predict new discoveries best for the historical periods. For future forecasting the MacIvoy-Pindyck model showed an excess demand of ten TCF in 1980 under "cost of service" regulation (this represents an historical average cost pricing which implied wellhead prices increases of 1¢ per thousand cubic feet per annum on new contracts.) Under a deregulation policy, the MacIvoy-Pindyck model predicted elimination of excess demand by the year 1979 (*Id.* at 643-644).* The Kazoom model developed for the FPC appeared lacking in price sensitivity and even under a deregulation policy showed excess demand of seven TCF in the year 1980. A model developed by Erickson and Spann proved to be extremely price sensitive and predicted eighteen TCF of surplus supplies (suggesting exportation) by 1980. In the MacIvoy-Pindyck model "deregulation" was in fact continued regulation but with allowed price increases of 15¢ per thousand cubic feet immediately and thereafter further price increases of 4¢ per thousand cubic feet each year. The author concludes that since the models do not show a consensus, more investigation into the dynamic response of exploration to price incentive is crucial (*Id.* at 645). (For a detailed articulation of the MacIvoy-Pindyck model *see* 4 BELL J. & MGT. SCIENCE 454 (1973)).

CURRENT STATUS OF DEREGULATION

On July 27, 1976 the Federal Power Commission allowed a 90¢ per thousand cubic foot gas price increase at the wellhead for interstate gas. This increase was applicable to gas brought into production in 1975 or later. Gas produced in 1973 and 1974 enjoyed a 49¢ per thousand cubic feet price increase. This action by the FPC is presently challenged by pending litigation brought by a coalition of consumer, labor and government groups. While it is technically not a deregulation, it clearly represents an effort by the FPC to bring gas prices into parity with competing sources of energy. On November 5, 1976 the FPC reconsidered the July increases but reduced them by only pennies.

* Professor Marcus and his associates feel that the post-boycott price increase of oil from the modeled price of $6.50/bbl. to $13.00/bbl. may once again make LNG importation attractive as an alternative to oil importation. (Marcus, *Offshore LNG* 1-24 and 1-25).

** It appears that the only shipyard presently capable of building 300,000 m^3 LNG carriers is located in Spain. So long as this is the case, the construction differential subsidy will not have any effect in inducing U.S. owners to order their ships from U.S. yards. Thus there would be a balance of payments outflow for the shipbuilding assembly labor, materials and overhead and for such components as were not exported from the U.S.

appendices

Exhibit 1	(Liquified Natural Gas - A Survey, P. 60, P.R. Latham) Existing LNG Carriers
Exhibit 2	(General Dynamics Abstract, March 1975) Ship Diagrams
Exhibit 3	Cutaway depiction of Chicago Bridge & Iron shore based LNG tank
Exhibit 4	(Science Applications, Inc. Dec 1975, LNG Terminal Risk Assessment Study for Oxnard, CA., p.2-8) LNG Tank Profile
Exhibit 5	(LNG Trade, P.J. Anderson and E.J. Daniels, Pipe Line Industry, May 1976, p. 35) Existing LNG Trades
Exhibit 6	(Proposed Alaska-Lower 48 Pipeline Systems, Statement FPC Vice Chairman Don S. Smith, 9 Oct 1975, p. 23)
Exhibit 7	(List of Safety Codes and Regulations, Statement of FPC Chairman R.L. Dunham, 17 Feb 1976, pp. 78-82)
Exhibit 8	(LNG-LPG Operation/Emergency Plan, Port of Boston, USCG, Feb 1976) Safety Inspection Form
Exhibit 9	(IMCO Model Fitness Certification, Annex VII of MSC XXXII/19, pp. 146-150) Model Form of Certificate of Fitness
Exhibit 10	(IMCO Tank Location Requirements, Annex VII to MSC XXXII/19, p. 24)
Exhibit 11	(New Regulations for Liquefied Gas Carriers, A.E. Henn and T.R. Dickey, Oct 1975, p. 10) Location of Enhanced Grades of Steel
Exhibit 12	(List of Illustrative Alarm Systems, LNG Manual, National Maritime Research Center, July 1974, pp. 237-240)
Exhibit 13	(LNG-LPG Operation-Emergency Plan, Port of Boston, USCG, Feb 1976, pp. 1-5) LNG/LPG Event Chart - Normal Operation
Exhibit 14	(Loading/Unloading Schematic, LNG Manual, National Maritime Research Center, July 1974, p. 99)
Exhibit 15	(FPC Implementation Procedures)
Exhibits 16 through 19	(SAI Fault Tree for leak in ship's tank during transfer - symbolism, p. 3-10)
Exhibit 20	(Table 25, Pacific-Indonesia Project DEIS, FPC, Bureau of Natural Gas, May 1976, p. 158) Sequence of Responses to Detector Activation
Exhibit 21	(SAI LNG spill cloud configuration/concentration isopleths, Dec 1975, p. 8-82)
Exhibit 22	(SAI Time/Distance plot for LNG spill vapor plume, Dec 1975, p. 8-83)
Exhibit 23	(SAI Table - Fatalities/Year Probability, p. 8-169)
Exhibit 24	(SAI Contour Map.Estimate Fatalities, p. 8-168)
Exhibit 25	(Sample Calculations of "Wage subsidy per diem rate", 46 C.F.R. § 252.31(j), 1 Oct 1975)
Exhibit 26	(Sample Calculations leading to "maintenance and repair subsidy rate", 46 C.F.R. § 252.32(e), 1 Oct 1975)
Exhibit 27	(Sample Calculations "hull and machinery insurance subsidy rate", 46 C.F.R. § 252.33(e), 1 Oct 1975)
Exhibit 28	(Protection and Indemnity insurance subsidy rate, 46 C.F.R. § 252.34(g), 1 Oct 1975)
Exhibit 29	(National Fire Protection Assn., Requirement No. 59-A, excerpts)
Exhibit 30	(Booz-Allen Applied Research, Inc., Analysis of LNG Marine Transportation, Listing of First Generation LNG carrier particulars, Nov 1973, pp. VII-2 to VII-5)

Exhibit 31 (Booz-Allen Analysis data file, Nov 1973, Appendix D(21))

Exhibit 32 (Booz-Allen Analysis Technical Specifications, Nov 1973, Appendix D(32))

Exhibit 33 (Impacts of Regulation of Natural Gas Rates, S. Breyer and P.W. MacAvoy, 86 Harv. L. Rev. 941, 981-82 n. 127 (1973))

Exhibit 34 (Pac-Indo Project DEIS, FPC, May 1976, p. 332) Comparison of Risks

Exhibit 35 (Gaz-Transport Membrane Tank, LNG Tank Designs, National Maritime Research Center, Dec 1972, p. 3-35)

Exhibit 36 (Chicago Bridge & Iron Free-Standing Tank, LNG Tank Designs, NMRC, Dec 1972, p. 3-30)

Exhibit 37 (LNG Receiving Terminals, Draft paper, H.S. Marcus and J.H. Larson, p. 27 and p. 29)

Exhibit 38 (D. Allan, et al, Arthur D. Little, Inc., Technology and Current Practices for Processing, Transferring and Storing Liquefied Natural Gas, Dec 1974) Major LNG Safety Research References

TABLE 1: EXISTING LNG CARRIERS

Name	Year Comp.	Cap. C.M.	Length LBP	Owner	Builder	Cargo Cont. Sys.	Class
ARISTOTLE ex METHANE PIONEER	1958	5126	321'	Antarctic Gas Inc.	Rebuilt at Alabama DD&SB	Conch Aluminum Self Supporting	*ABS
METHANE PROGRESS	1964	27400	575'	Methane Tanker Finance	Harland & Wolf	Same	ABS
METHANE PRINCESS	1964	27400	575'	Conch Methane Tankers	Vickers-Armstrong	Same	ABS
PYTHAGORE	1964	630	174'	Gazocean Armement	Duchesne & Bossiere	Technigaz Stainless Steel Membrane	BV
JULES VERNE	1964	25500	617'	Gaz Marine	AT. & Ch. de la Seine	Gaz Transport 9% Nickel-Steel Vertical Cylinder	BV
POLAR ALASKA	1969	71500	754'	Polar LNG Shipping Corp.	Kockums MV A/B	Gaz Transport Inver Membrane	ABS
ARCTIC TOKYO	1969	71500	754'	Arctic-LNG Transportation Co.	Kockums MV A/B	Same	ABS
ESSO BREGA	1969	40000	640'	Prora Transporti S.p.A.	Italcantieri Genoa	Double Wall Aluminum Self Supporting	ABS
ESSO PORTOVENERE	1970	40000	640'	Prora Transporti S.p.A.	Italcantieri Genoa	Same	ABS
ESSO LIGURIA	1970	40000	640'	Prora Transporti S.p.A.	Italcantieri Genoa	Double Wall Aluminum Self Supporting	ABS,RI
LAIETA	1970	40000	640'	Naviera de Productos Licuados	Astano-El Ferrol	Double Wall Aluminum Self Supporting	ABS
EUCLIDES	1971	4000	315'	Antarctic Gas Inc.	At.&Ch. du Havre	Technigaz 9% Nickel-Steel Spherical	BV,RI
DESCARTES	1971	50000	695'	Gazocean, Paris	Chantiers de l'Atlantique	Stainless Steel Membrane Conch Ocean	ABS,BV
HASSI R'MEL	1971	40000	606'	SONATRACH	C.N.I.M.	Gaz Transport	**ABS,BV

*ABS classification under 6/68
**Pending completion of required service tests of containment system

SOURCE: Swenson, E.D., "LNG-A Road to Progress," American Petroleum Institute, 1972

Exhibit 1. (Liquified Natural Gas - A Survey, P. 60, P.R. Latham) Existing LNG Carriers

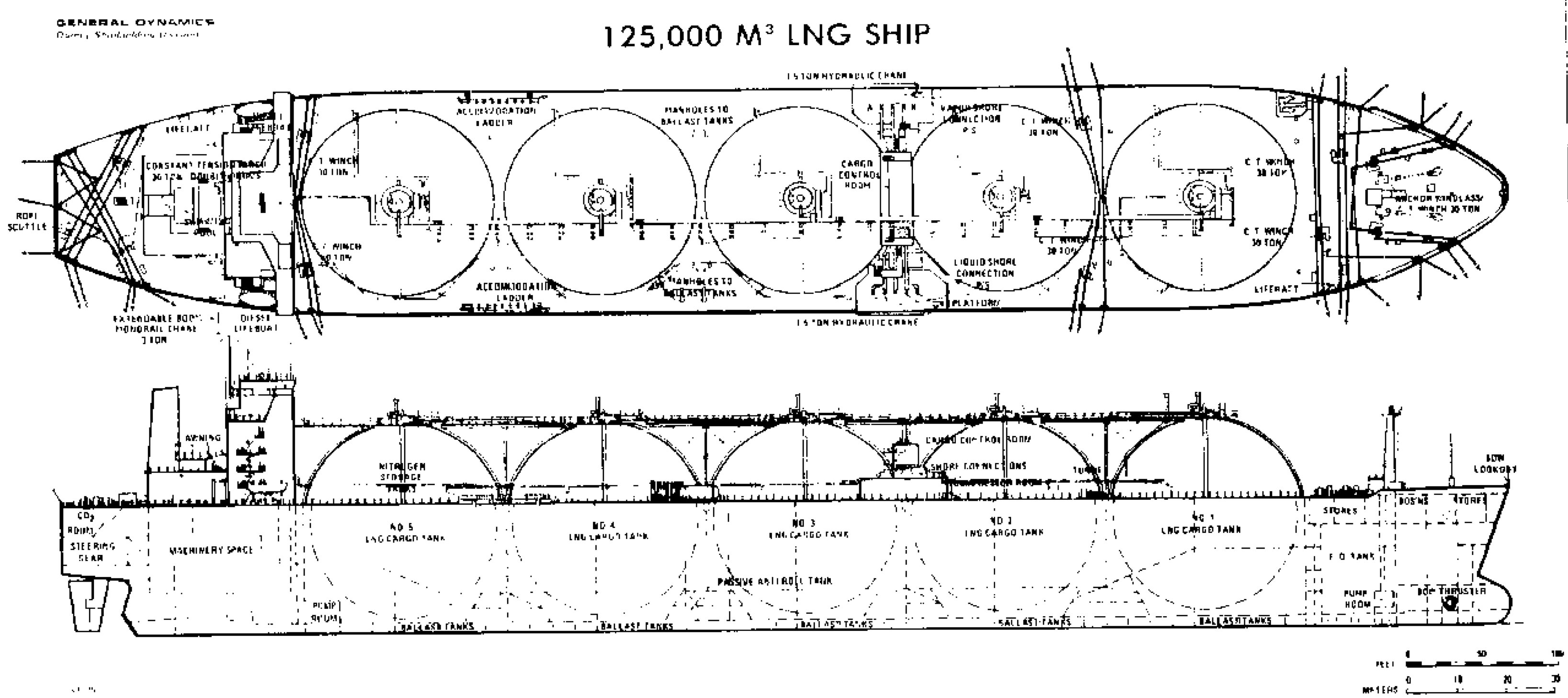
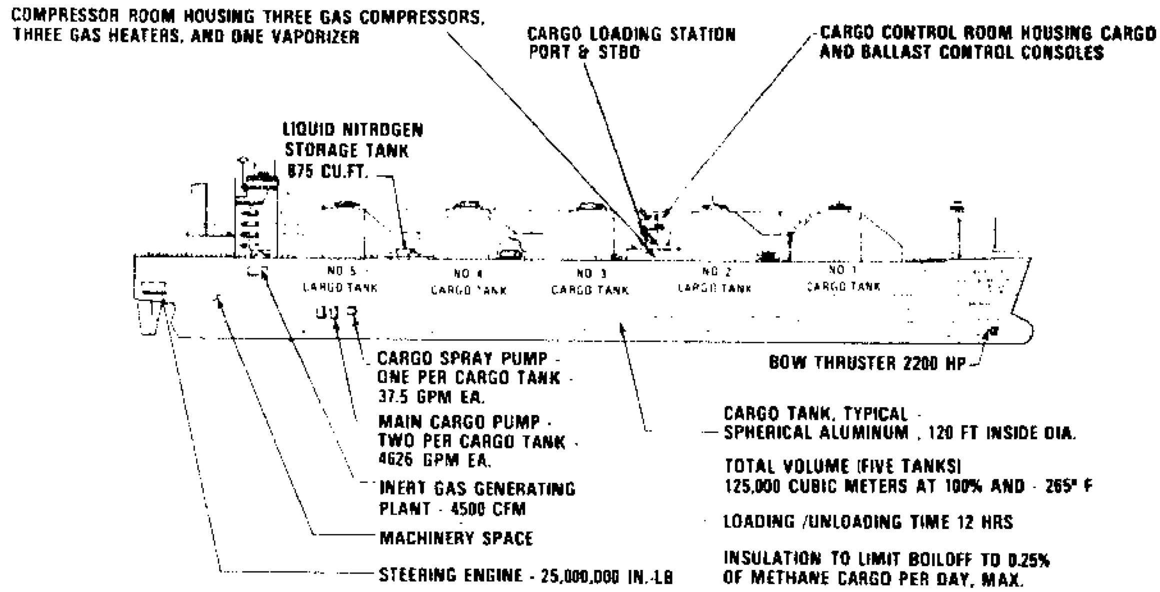


Exhibit 2. (General Dynamics Abstracts, March 1975) Ship Diagrams

MAJOR CARGO HANDLING MACHINERY AND MANEUVERING MACHINERY



MAIN PROPULSION COMPONENTS

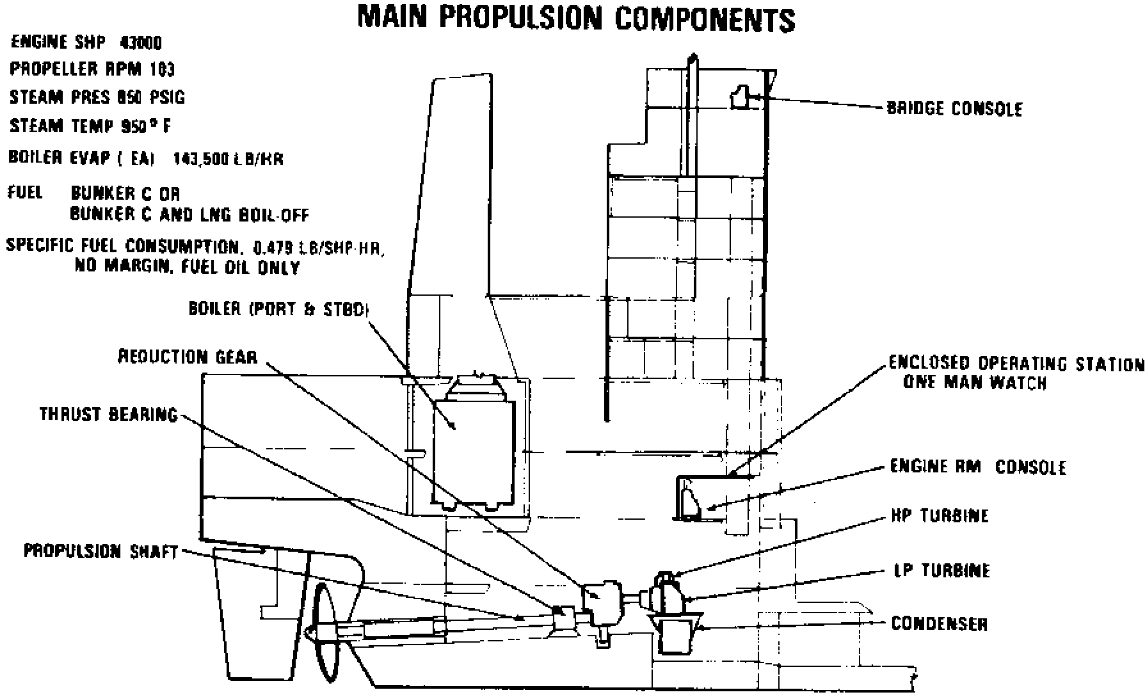
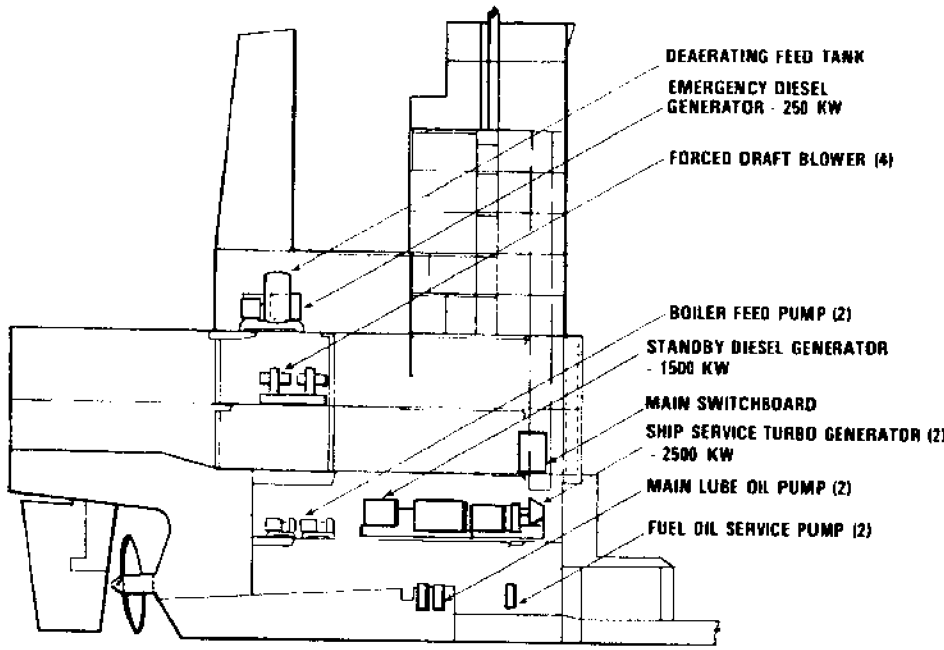


Exhibit 2. continued

MAJOR PROPULSION AUXILIARIES AND ELECTRICAL EQUIPMENT



MAJOR SHIP AUXILIARIES

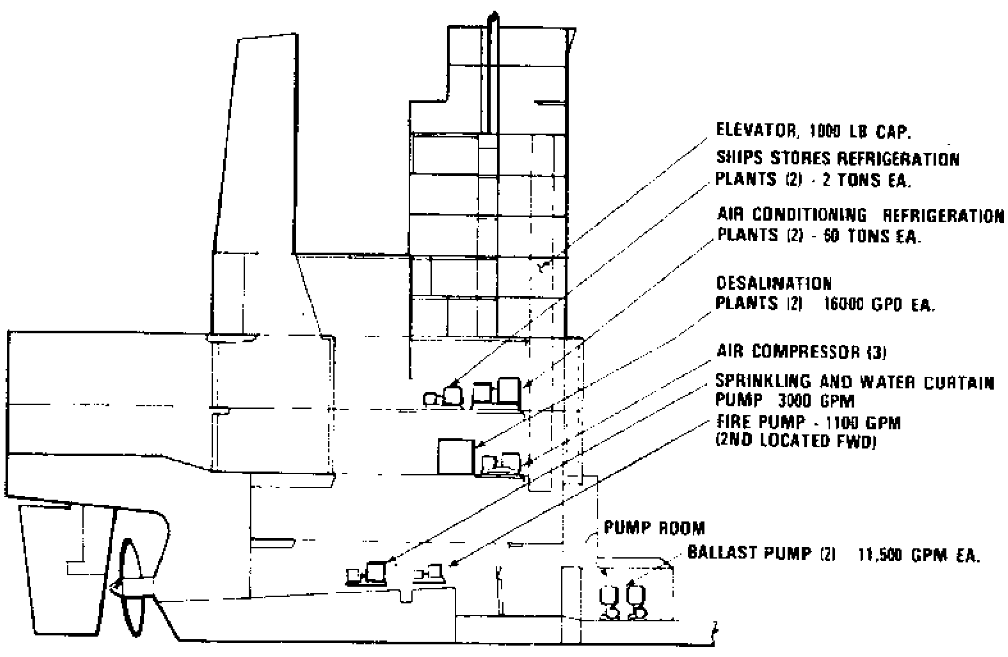


Exhibit 2. continued

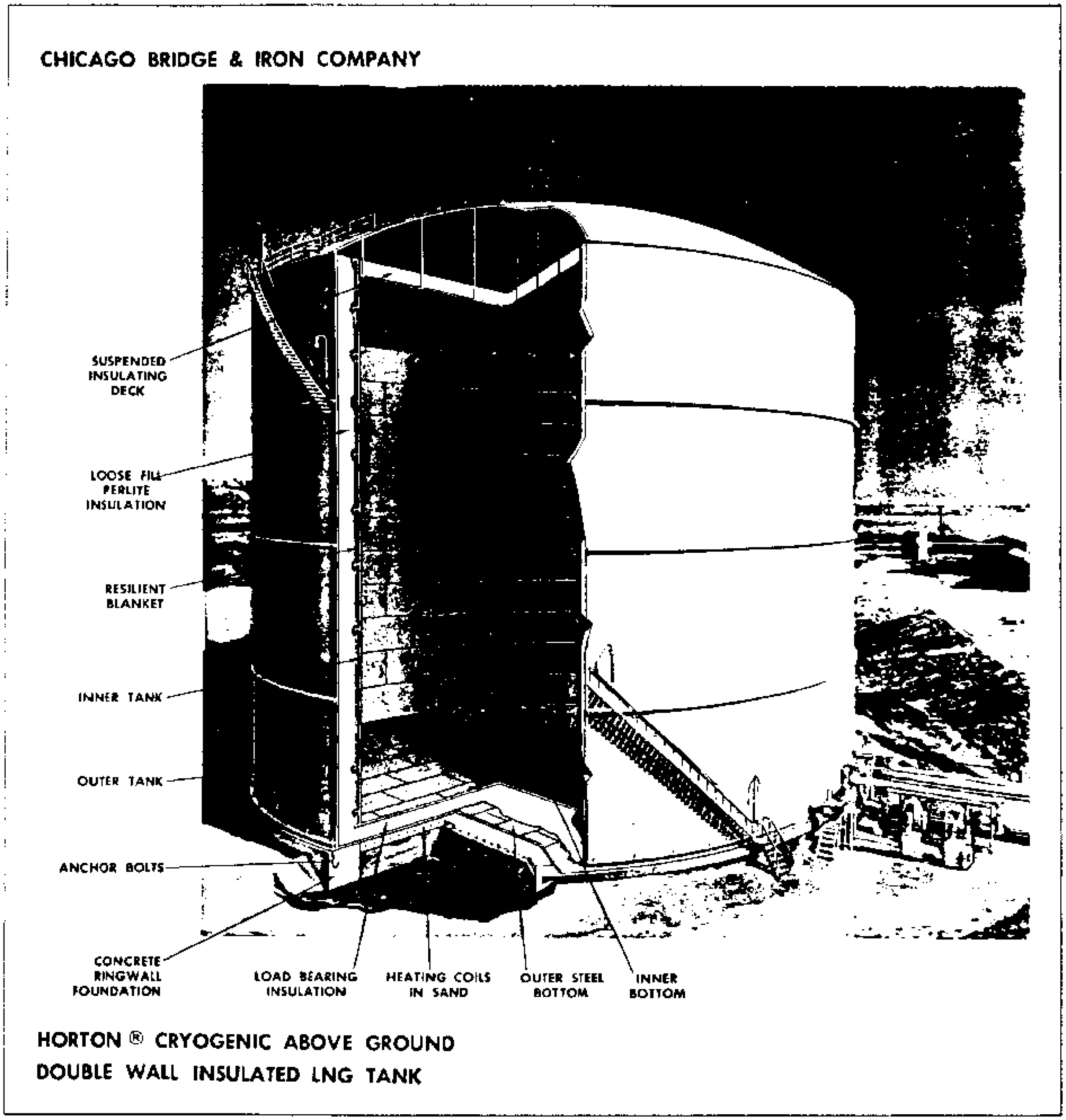


Exhibit 3. Cutaway depiction of Chicago Bridge & Iron shore based LNG tank

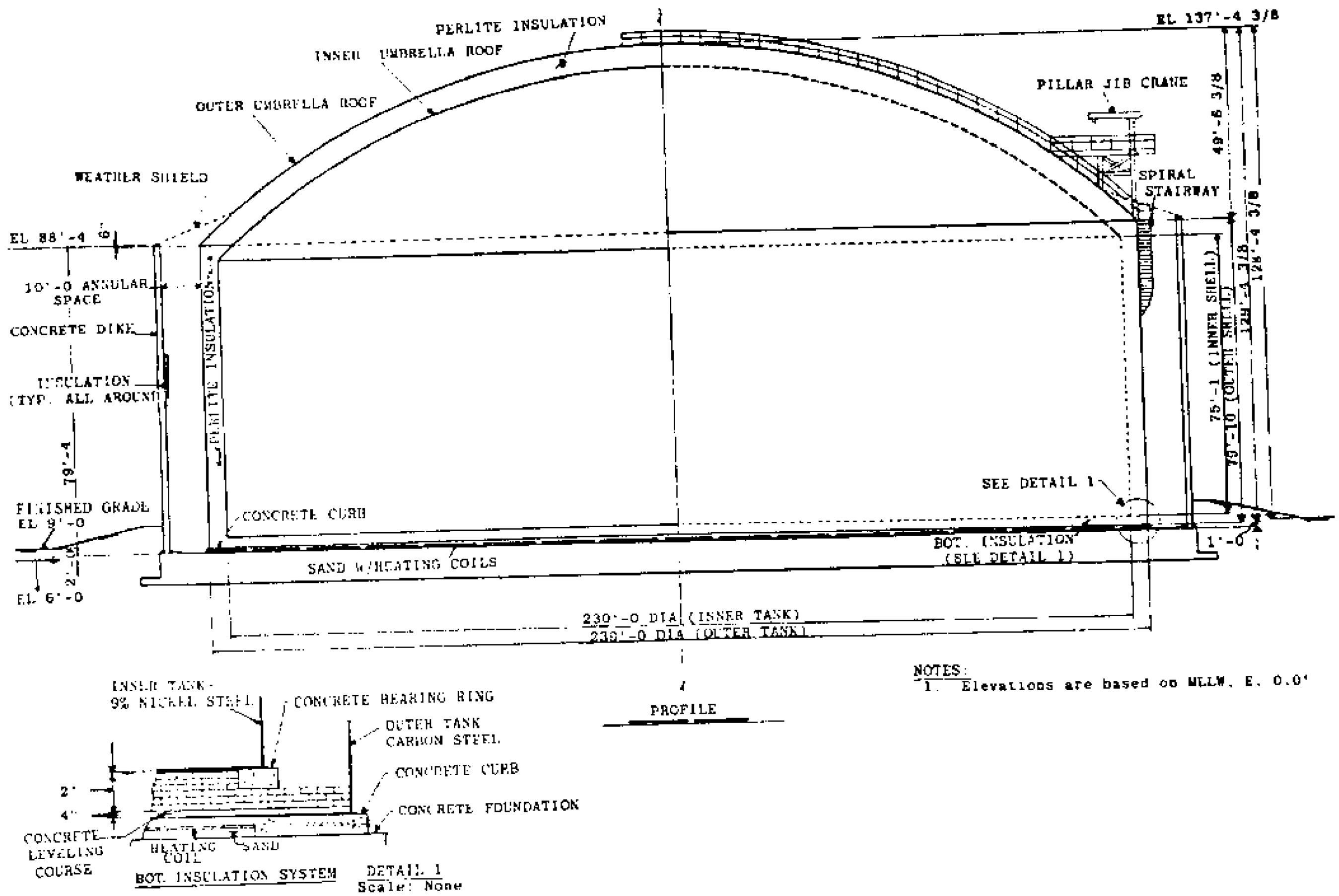


Exhibit 4. (Science Applications, Inc. Dec 1975, LNG Terminal Risk Assessment Study for Oxnard, CA., p.2-8) LNG Tank Profile

TABLE 1—Existing LNG trades

Trade	Companies Involved	Initial delivery date	Contract term, years	Volume, MMcfd
Algeria-United Kingdom Arzew-Canvey Island	CAMEL British Gas Corp. Conch International	1964	15	100
Algeria-France Arzew-Le Havre	CAMEL Gaz de France	1964	15	50
Algeria-France Skikda-Fos	SONATRACH Gaz de France	1972	15	350
Libya-Italy Marsa El Brega-La Spezia	Esso Standard Libya SNAM Progetti S.p.A.	1969	20	235
Libya-Spain Marsa El Brega-Barcelona	Esso Standard Libya Empresa Nacional del Gas, S.A.	1971	15	110
Algeria-Spain Arzew-Barcelona	CAMEL Empresa Nacional del Gas, S.A.	1974	15	40
Alaska-Japan Kenai-Negishi	Phillips Petroleum Co. Marathon Oil Co. Tokyo Electric Power Co. Tokyo Gas Co., Ltd.	1969	15	180
Brunei-Japan Lumut-Sodegaura, Negishi, Semboku	Brunei LNG, Ltd. Coldgas Trading Power Co. Osaka Gas Co., Ltd. Tokyo Gas Co., Ltd. Tokyo Electric Power Co.	1972 1975 (Expansion)	20 20	524 217 741
Algeria-U.S. Arzew, Skikda-Everett	SONATRACH Alocean Ltd. Distrigas Corp.	1972	20	43.6

TABLE 2—Firm commitment LNG trades

Trade	Companies Involved	Initial delivery date	Contract term, years	Volume, MMcfd
Abu Dhabi-Japan Das Island-Tokyo	Abu Dhabi Liquefaction Co. Tokyo Electric Power Co.	1976	20	450
Indonesia-Japan North Sumatra, East Kalimantan-Japan	Pertamina Osaka Gas Co., Ltd. Kansai Electric Power Co. Chubu Electric Power Co. Kyushu Electric Power Co. Nippon Steel Corp.	1977	20	1,050
Algeria-U.S. Arzew-Cove Point, Md Savannah, Ga	SONATRACH El Paso LNG Co. (Algerian Subsidiary) Columbia LNG Corp. Consolidated System LNG Co. Southern Energy Co.	1977	20	1,000
Algeria-U.S. Skikda Staten Island, N.Y.; Providence, R.I.	SONATRACH EASCOGAS LNG, Inc.	1977 (Full delivery, 1980)	22	600
Algeria-Spain Skikda-Barcelona	SONATRACH Empresa Nacional del Gas, S.A.	1978	20	436
Algeria-U.S. Skikda-Everett, Mass.	SONATRACH Alocean Ltd. Distrigas Corp.	1977	20	61.4

TABLE 5—Projected probable LNG trades

Trade	Companies Involved	Initial delivery date	Contract term, years	Daily volume, MMcfd
Malaysia-Japan Sarawak-Japan	Petronas Mitsubishi Corp. Tokyo Gas Co., Ltd. Osaka Gas Co., Ltd. Tokyo Electric Power Co.	1979	20	750
Algeria-U.S.	SONATRACH El Paso LNG Co. (Algerian Subsidiary) El Paso Eastern Co. Consolidated System LNG Co. Southern Energy Co. Transco Energy Co.	1981-82	25	1,000
Algeria-U.S. Algeria-Lake Charles	SONATRACH Trunkline LNG Co.	1979	20	445
Indonesia-U.S. North Sumatra-Calif.	Pertamina-Mobil Pacific Lighting International Pacific Indonesia LNG Co. Western LNG Terminal Co.	1979	20	550
Alaska-U.S. Kenai-Calif.	Pacific Alaska LNG Co. Western Terminal LNG Co.	1979-80	20	Initial 200 Total 400
Chile* Cabo Negro-Quintero Tocopilla	ENAP	1978	NA†	220
Nigeria-U.S.	Ministry of Mines and Power Shell British Petroleum Development Co. of Nigeria	1980-85	20	650
Algeria-Belgium	SONATRACH S.A. Distrigaz	1979	20	340

*Only project outside major importing areas
†NA = not available

Exhibit 5. (LNG Trade, P.J. Anderson and E.J. Daniels, Pipe Line Industry May 1976, p. 35) Existing LNG Trades

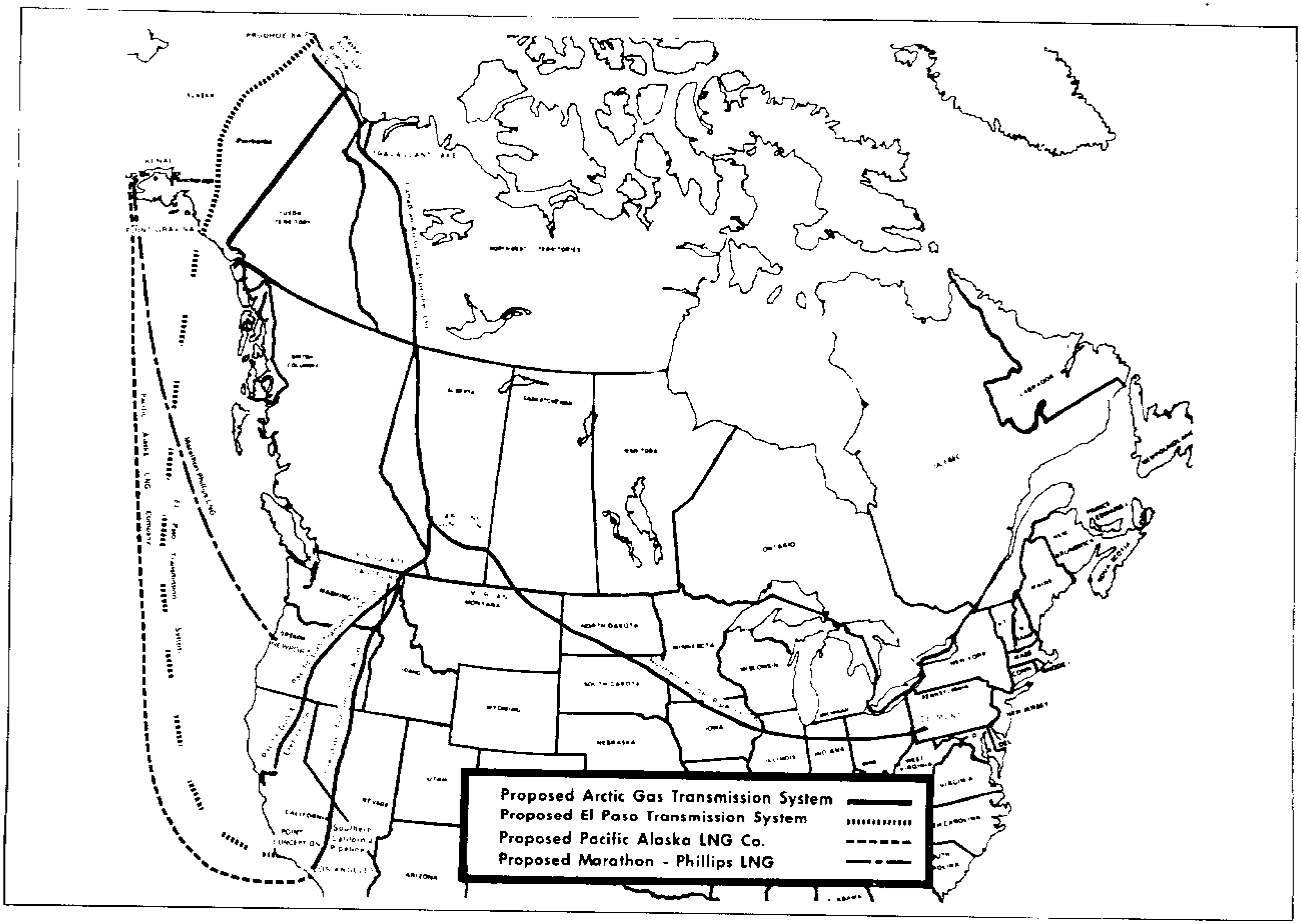


Exhibit 6. (Proposed Alaska-Lower 48 Pipeline Systems, Statement FPC Vice Chairman Don S. Smith, 9 Oct 1975, p. 23)

Federal Regulations

1. National Pipeline Safety Act, 49 CFR Part 192 and amendment 192-10.

2. Occupational Safety and Health Act, 29 CFR Parts 1910, 1910.23 and 1926.

3. Clean Air Act - Amended (Public Law 91-6041).

4. National Environmental Policy Act of 1969 (Public Law 91-190).

5. Water Pollution Control Act (Public Law 92-504).

6. Natural Gas Act.

7. Federal Water Pollution Control Act 1973, 40 CFR Part 125.

8. Noise Control Act 29 CFR Parts 1910.95 and 1926.52.

9. Federal Aviation Act of 1958, 49 USC Part 1350.

10. The Fish and Wildlife Coordination Act, 15 USC Part 661.

11. The Rivers and Harbors Act 1899, 33 USC Part 401, Transportation Act of 1966 49 USC Part 1665.

12. LISCG Regulation - 33 CFR Security of Vessels and Waterfront Facilities.

Alaska Regulations and Codes

1. As 18.70.050 Regulations of the Department of Public Safety.

2. Alaska Administrative Code 19.000.

Exhibit 7. (List of Safety Codes and Regulations, Statement of FPC Chairman R.L. Dunham, 17 Feb 1976, pp. 78-82)

STANDARDS APPLICABLE TO THE CONSTRUCTION AND OPERATION OF THE PROPOSED LNG PLANT AND MARINE TERMINAL

LNG Terminal

1. Title 49 CFR, Part 192 - Amendment 192-10, Liquefied Natural Gas Systems and Part 192, Safety Standards for Transport of Natural Gas by Pipeline.

2. American Association of State Highway Officials (AASHO)

3. American Society of Mechanical Engineers - Pressure Vessels.

4. American Society of Civil Engineers - Wind Forces.

5. American National Standards Institute; various standards in the areas of Civil Engineering, Lighting, Instrumentation, Mechanical Engineering, Noise, Sanitation, Materials Handling.

6. American Concrete Institute (ACI), Specifications for Structural and reinforced concrete construction.

7. American Institute of Steel Construction (AISC).

8. American Petroleum Institute (API); API std. 620, Appendix Q 1973 and others.

9. American Waterworks Association.

10. American Society for Testing and Materials (ASTM): Concrete and Structural Steel Standards.

11. Diesel Engine Manufacturers Association.

12. Hydraulic Institute Standards (HIS); Pump Standards 1969.

13. American Gas Association; AGA Gas Engineers Handbook - Purging.

14. American Welding Society - Structural Welding Code.

15. USCG Regulation - CFR Title 33 Security of Vessels and Waterfront facilities.

16. National Board of Firefighting Underwriters.

17. National Fire Protection Association (NFPA); NFPA No. 10 (1972), Installation of Portable Fire Extinguishers.

Exhibit 7. continued

18. NFPA No. 30 - Flammable and Combustible Liquids Code.

19. NFPA No. 59A-1972; Storage and Handling of LNG.

20. NFPA No. 70-1971; National Electrical Code.

21. NFPA No. 77-1972; Static Electricity.

22. NFPA No. 78; Lightning Protection Code.

23. NFPA No. 87-1971; Piers and Wharves.

24. NFPA No. 90A-1972; Air Conditioning and Ventilating Systems.

25. NFPA No. 194-1968; Screw Threads for Fire Hose Couplings.

26. NFPA No. 196-1972; Fire Hose.

27. Occupational Safety and Health Act - Title 29 CFR, Parts 1910, 1910.23 and 1926.

28. Uniform Building Code - Zone 3.

OTHER INDUSTRY AND UNDERWRITER HEALTH AND SAFETY CODES

Pipeline

1. American National Standards Institute (ANSI) B31.8 Gas Transmission and Distribution Piping.

2. American Petroleum Institute (API).

3. American Society for Testing Materials.

4. Manufacturer's Standardization Society of the Valve and Fittings Industry (MSS).

5. American Waterworks Association.

LNG Terminal

1. American Association of State Highway Officials (AASHO).

2. American Society of Mechanical Engineers - Pressure Vessels.

3. American Society of Civil Engineers - Wind Forces.

Exhibit 7. continued

4. American National Standards Institute; various standards in the areas of Civil Engineering, Lighting, Instrumentation, Mechanical Engineering, Noise, Sanitation, Materials Handling.

5. American Concrete Institute (ACI) Specifications for Structural and Reinforced Concrete Construction.

6. American Institute of Timber Construction Manual.

7. American Institute of Steel Construction (AISC).

8. American Petroleum Institute (API); API std. 620 1973 and others.

9. American Waterworks Association.

10. American Society for Testing and Materials ASTM: Concrete and Structural Steel Standards.

11. Diesel Engine Manufacturers Association.

12. Hydraulic Institute Standards (HIS); Pump Standards 1969.

13. American Gas Association; AGA Gas Engineers Handbook - Purging.

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22. NFPA No. 87-1971; Piers and Wharves.

23. NFPA No. 90A-1972; Air Conditioning and Ventilating Systems.

24. NFPA No. 194-1968; Screw Threads for Fire Hose Couplings.

25. NFPA No. 196-1972; Fire Hose.

26. Uniform Building Code - Zone 3.

Exhibit 7. continued

MIO BOSTON

SAFETY INSPECTION FOR FOREIGN VESSELS CARRYING BULK CARGO OF UNUSUAL RISK

LIQUIFIED FLAMMABLE GASSES

VESSEL NAME ______________________ NATIONALITY ______________

GROSS TONS ______________ DATE OF INSPECTION ________________

EXPIRATION DATE: CARGO SAFETY EQUIPMENT CERTIFICATE ______________

EXPIRATION DATE: CARGO SHIP SAFETY CONSTRUCTION CERT. ______________

CERTIFICATE OF FINANCIAL RESPONSIBLITY FROM FED. MARITIME COMM __________

DATE: LOAD LINE ______________

OWNER: NAME ____________________ ADDRESS ____________________

AGENT: NAME ____________________ ADDRESS ____________________

CARGO: ____

1. LETTER OF COMPLIANCE: DATED ____________________(SEE COMDT NOTE 5923)

2. CARGO TANKS AND CARGO PIPING RELIEF VALVES SET AND SEALED BY CLASSIFICATION SOCIETY OR SAFETY ADMINISTRATION WITH CERTIFICATION OF SET POINT ABOARD ______________
   IF VALVES NOT SEALED SUITABLE OFFICIAL RECORDS AVAILABLE TO DETERMINE NO CHANGE BY SHIP OF SET PRESSURE ________________________

3. CHECK OF CARGO LEAK DETECTION SYSTEM (READOUTS MADE, ALL SENSING POINTS) INSTRUMENT SCALE ______________

PRODUCT CARRIED: LNG (5.0%) LPG (2.4%) LEL __________ LNG (15%) LPG (9.5%) UEL __________

UNUSUAL READINGS NOTED: AMOUNT ____________ LOCATIONS ____________

DO ALARMS (AUDIBLE AND VISUAL) FUNCTION ______________
SET POINT FOR ALARM ______________________________
FREQUENCY OF READINGS PRIOR TO U.S. PORT ENTRY ______________

4. CARGO AND SECONDARY BARRIER (IF INSTALLED) AND VOID SPACE TEMPERATURE SENSING SYSTEM FREQUENCY OF READINGS WITH CARGO ON BOARD PRIOR TO ENTRY TO U.S. PORT ____________________

   CHECK MADE OF ALL SENSING POINT UNUSUAL TEMPERATURES NOTED: __________

5. REMOTE SHUTDOWN OF AUTOMATIC CARGO VALVES (30 sec)
   REMOTE SHUTDOWN OF CARGO PUMPS
   TESTED FROM ALL CONTROL STATIONS ______________
   FUSABLE LINKS ______________

6. VESSEL ELECTRICALLY BONDED TO SHORE CARGO SYSTEM ______________

7. DRIP PANS OR OTHER HULL PROTECTION IN PLACE UNDER CONNECTION OF VESSEL CARGO SYSTEM TO SHORE ________________________

Exhibit 8. (LNG-LPG Operation/Emergency Plan, Port of Boston, USCG, Feb 1976) Safety Inspection Form

8. ELECTRICAL EQUIPMENT AND LIGHTING IN HAZARDOUS LOCATIONS CHECKED. FIXTURES INTACT, EXPLOSION PROOF ______________________

9. FIRE FIGHTING EQUIPMENT EXAMINATION AND IN PLACE READY FOR USE ______________________

   DECK DRY CHEMICAL SYSTEM ______________________
   DECK WASH SYSTEM ______________________

10. INTERNATIONAL SHORE CONNECTION ______________________

11. PURGE RATE ______________________

12. CARGO PIPING SYSTEM, EXPANSION JOINTS ______________________

13. VESSEL MANNING (ATTACH COPY OF CREW LIST) ______________________

14. DETECTION & SHUTDOWNS, BOIL OFF SYSTEM (METHANE ONLY) ______________________

15. POLLUTION PREVENTION EXAMINATION ______________________

16. WARNING SIGNS IN PLACE ______________________

17. COMMUNICATIONS ESTABLISHED ______________________
    (SHIP TO SHORE) ______________________

18. CONTROL OF OPERATIONS ESTABLISHED ______________________

19. CARGO LINE COOL DOWN CARRIED OUT PROPERLY ______________________

20. VESSEL PERSONNEL HAVE ADEQUATE KNOWLEDGE OF ENGLISH AND APPEAR KNOWLEAGABLE IN SHIP CARGO OPERATIONS ______________________

21. GENERAL CONDITION OF VESSEL ______________________

REMARKS:

____
MARINE INSPECTOR

Exhibit 8. continued

Model Form of Certificate of Fitness for the Carriage of Liquefied Gases in Bulk

CERTIFICATE OF FITNESS FOR THE CARRIAGE OF LIQUEFIED GASES IN BULK

(Official Seal)

Issued in pursuance of the

IMCO CODE FOR THE CONSTRUCTION AND EQUIPMENT OF SHIPS CARRYING LIQUEFIED GASES IN BULK

Under the authority of the Government of

....
(full official designation of the country)

by ....
(full official designation of the competent person or organization authorized by the Administration)

Name of Ship	Distinctive Number or Letter	Port of Registry	Cargo Capacity (m^3)	Ship Type (Section 2.5 of the Code) 1]

Date of building or major conversion contract ....

Date on which keel was laid or ship was at a similar stage of construction or on which major conversion was commenced ....

The certificate should be drawn up in the official language of the issuing country. If the language used is neither English nor French, the text should include a translation into one of these languages.

Exhibit 9. (IMCO Model Fitness Certification, Annex VII of MSC XXXII/19, pp. 146-150) Model Form of Certificate of Fitness

THIS IS TO CERTIFY:

1. That the above mentioned ship is

   * (i) a ship as defined in 1.2.2(a) of the Code;

   [* (ii) a ship as defined in 1.2.2(b) of the Code;]

   * (iii) a ship as defined in 1.2.3 of the Code.

2. (i) that the ship has been surveyed in accordance with the provisions of section 1.6 of the Code;

   (ii) that the survey showed that the structure, equipment, fittings, arrangements and materials of the ship and the conditions thereof are in all respects satisfactory and that the ship:

   * (a) complies with the relevant provisions of the Code;

   * [(b) complies with the provisions of the Code referred to in paragraph 1.2.2(b)2/]

3. That the following design criteria have been used:

   (a) Ambient air temperature .....°C3/

   (b) Ambient water temperature .....°C3/

   (c)

Tank type and number**	Stress Factors4/				Material4/	MARVS
	A	B	C	D		
Cargo piping						

** Tank numbers referred to in this list are identified on the annexed, signed and dated tank plan numbered 2..

   (d) Mechanical properties of the cargo tank material were determined at ......°C.5/

* Delete as appropriate

Exhibit 9. continued

4. That the ship is suitable for the carriage in bulk of the following products, provided that all relevant operational provisions of the Code are observed 6/:

Products	Conditions of Carriage (tank numbers, min. temperature, max. pressure, max. density, tank loading conditions)

* Continued on the annexed signed and dated sheet(s) No.1A

* Tank numbers referred to in this list are identified on the annexed, signed and dated tank plan numbered 2A.

5. That in accordance with sections 1.5/2.7* the provisions of the Code are modified in respect of the ship in the following manner:

This certificate is valid until the .... day of .... 19....

Issued at ....
(place of issue of certificate)

.... 19....

The undersigned declares that he is duly authorized by the said Government to issue this certificate.

....
(signature of official issuing the certificate and/or seal of issuing authority)

(seal or stamp of the issuing authority, as appropriate)

* Delete as appropriate

Exhibit 9. continued

Surveys

This is to certify that at a survey required by section 1.6 of the Code, this ship was found to comply with the relevant provisions of the Code.

Intermediate survey

Place ....
Signature and Seal of issuing authority   Date ....

Place ....
Signature and Seal of issuing authority   Date ....

Place ....
Signature and Seal of issuing authority   Date ....

Place ....
Signature and Seal of issuing authority   Date ....

Notes on completion of Certificate:

1/ "Ship Type": Any entry under this column must relate to all relevant recommendations, e.g. an entry "Type IIG" should mean Type IIG in all respects prescribed by the Code. This column would not usually apply in the case of an existing ship and in such a case should be noted "See paragraph 2(ii)(b)".

[2/ Paragraph 2(ii)(b): Insert the appropriate sub-paragraph of [1.2.2(b)] according to the status of the ship in relation to the provisions of this paragraph.]

3/ Paragraph 3(a) and 3(b): The ambient temperatures accepted or required by the Administration for the purposes of 4.8.1 of the Code to be inserted.

4/ Paragraph 3(c): Stress factors and materials as accepted or required by the Administration for the purposes of 4.5.1(d)(i) and 4.5.1(e) of the Code to be inserted.

5/ Paragraph 3(d): Room temperature or other temperature accepted by the Administration for the purposes of 4.5.1(f) to be inserted.

6/ Paragraph 4: Only products listed in Chapter XIX of the Code, or which have been evaluated by the Administration in accordance with paragraph 1.7.3 of the Code, should be listed. In respect of the latter "new" products, any Special Requirements provisionally prescribed should be noted.

Exhibit 9. continued

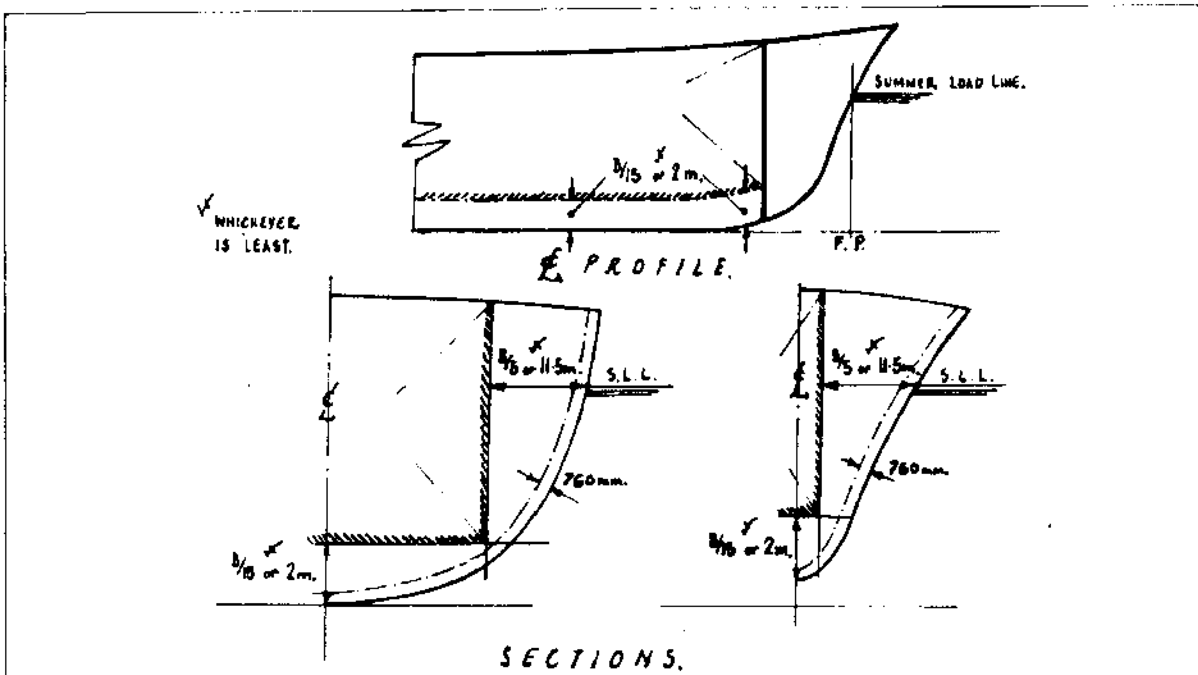


Figure 2.1 - Tank Location Requirements as set out in 2.6.

Exhibit 10. (IMCO Tank Location Requirements, Annex VII of MSC XXXII/19, p. 24)

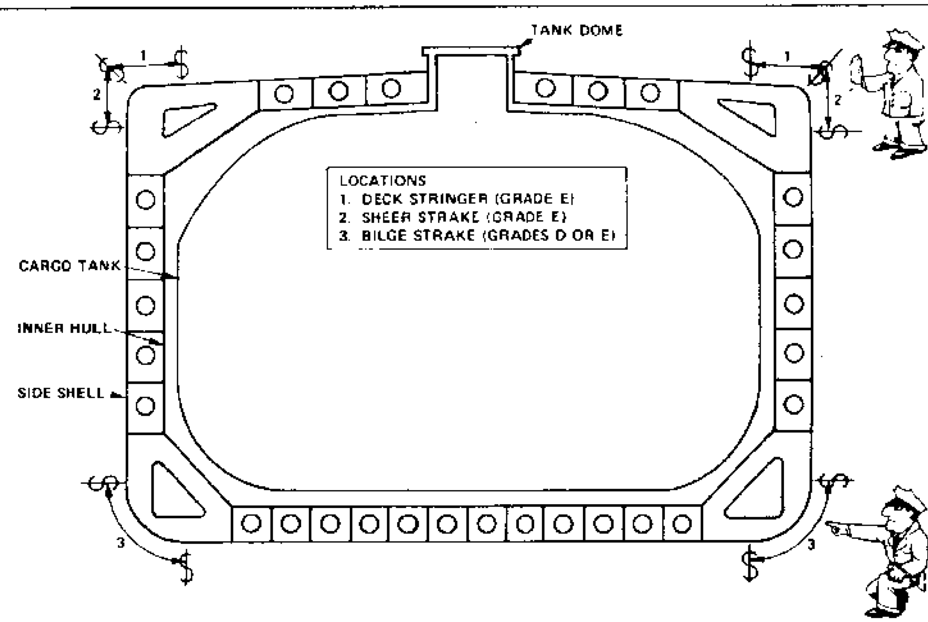


FIGURE 3. LOCATION OF ENHANCED GRADES OF STEEL AS CRACK ARRESTORS

Exhibit 11. (New Regulations for Liquefied Gas Carriers, A.E. Henn and T.R. Dickey, Oct 1975, p. 10) Location of Enhanced Grades of Steel

The following is a brief description of some of the alarm points included in the alarm system of one type of LNG tanker. It is included to provide the reader with a clearer understanding of the functions of such a system.

This particular system is a 100 point alarm panel which gives a visual and audio signal when certain measurements of operational or functional conditions exceed a predetermined value. When an alarm condition is reached on any reading, a flashing red light will come on, and a siren will sound in the gas control room where the panel is located, and also in the electric motor room. Provided on the panel are switches for changing the flashing light to a steady light; for blocking certain alarms which are only used for special functions, such as loading or unloading operations; and reset buttons used to turn off alarms on points which may give an alarm when not actually in an alarm condition. The panel also has a "test" button which is used to test the light and logic circuits of the panel. When the "test" button is pushed, a test is made of all alarm points except the ones which have been temporarily blocked. Certain critical alarm points are repeated in the wheelhouse, but the light stays on until these alarm conditions are corrected.

The following is a description of some of the alarm points including, in some cases, what they indicate and general corrective measures.

1. Low Differential Pressure Between Tank and Primary Insulated Space - An indication that the pressures between the cargo tank and the primary insulated space have been equalized - accompanied by automatic emergency shut-down of the cargo handling system - 6 alarm points.

2. Low Differential Pressure Between Tank and Secondary Space - An indication that the pressure between the secondary insulated space and the cargo tank has equalized - accompanied by automatic emergency shut-down of the cargo handling system - 6 alarm points.

3. Cargo Pumps Stopped - Indicates that the cargo pumps have stopped - these may be planned stops or due to emergency shut-down, low liquid level, low power, low LNG vapor header pressure, or pump failure - 12 alarm points.

4. Secondary Barrier Low Temperature - Indicates secondary barrier temperature has dropped from normal temperature of (typically) -70°C to -110°C. This indication may be caused by either a leak in the primary barrier or water in the insulated spaces. If a leak is detected, steps must be taken to isolate the barrier and tank - 6 alarm points activated from a number of thermocouples and temperature switches.

5. Water in Insulated Space - An indication of water in the secondary barrier insulated space - results from a leak in the inner hull, and alarm is activated by a water detector. The ballast tanks surrounding the affected cargo tanks should be deballasted and a dewatering pump installed - 6 alarm points.

Exhibit 12. (List of Illustrative Alarm Systems, LNG Manual, National Maritime Research Center, July 1974, pp. 237-240)

6. <u>Very High Level</u> - Caused by overfill of cargo tank and occurs when LNG liquid level reaches 99.2% of tank capacity. Activated by high level probe and accompanied by automatic emergency shut-down of the cargo system - 6 alarm points.

High Level - Indicates liquid level 98.1% of tank capacity - 6 alarm points.

7. <u>Desired Remaining Liquid Level</u> - Indicates tank has been pumped out to the volume to be left in the tanks for spraying the other tanks to keep them cool and to provide boiler fuel on the ballast trip - 1 alarm point.

8. <u>Forward Pumproom Bilge Alarm</u> - Excessive accumulation of bilge water in the forward pump room - requires inspection and pumping out - 1 alarm point.

9. <u>Deck Winches, Hydraulic Oil - Low Level</u> - Indicates low oil level in either the forward or aft gravity tanks of the hydraulic deck machinery - 1 alarm point.

10. <u>Ballast Valves, Hydraulic Oil - Low Level</u> - Indicates low level in a sump tank of ballast valve hydraulic oil actuating system.

11. <u>Fire in Electric Motor Room or Gas Compressor Room</u> - Alarm actuated by thermocouples in the electric motor room or the smoke detector system from the gas compressor room. When alarm is activated, alarms sound in affected compartments, as well as in gas control room and engine room, the ventilating fans in the midship house will automatically be stopped and, after a short delay, five bottles of CO_2 will be automatically released into the affected room. Action which ensues includes actuating the emergency shut-down system and the general fire alarm, cutting off electrical power to the gas control switchboard, starting of fire pumps, personnel evacuation of gas control room, isolation of certain LNG vapor valves, activation of the water curtain systems, and the carrying out of general fire fighting instructions.

12. <u>Tank Pressure Below 5 gm/cm²</u> - Activated by a drop in vapor header pressure.

13. <u>High Differential Temperature, Gas Compressor</u>

14. <u>High Suction Temperature to Compressor</u>

15. <u>Low Suction Temperature to Compressor</u>

16. <u>High Compressor Discharge Temperature</u>

17. <u>Compressor Stopped</u>

18. <u>Gas Pipe Duct Fan or Engine Room Vent Fan Stopped</u>

Exhibit 12. continued

19. Inert Gas System Failure

20. Methane Exhaust Heater Low Drain Temperature

21. Nitrogen Excess Flow

22. Low Flow Gas Analyzer

23. Vaporizer Starts

24. Vaporizer Outlet High-Low Temperature

25. Nitrogen High-Low Pressure

26. High-Low Level, Nitrogen Tanks

27. N_2 from Methane Vaporizer, High-Low Temperatures
These alarms monitor the temperature of the nitrogen gas from the LNG vaporizer.

28. Fresh Water Pumps Stopped - Indication of mechanical or electrical failure in pumps.

29. High Temperature Methane Heater Outlet

30. Vacuum Pumps, Sealing Water Tank - Low Level

31. Gas Alarm - Actuated by analyzers which monitor the insulated spaces with alarm given when LNG vapor concentration reaches 36%. The analyzers which monitor the various rooms and passageways will sound an alarm at 1.8% concentration. After the alarm sounds, it is necessary to check the gas analyzer panel to determine which sample point gave the alarm.

32. 20 psig Control - Low Air Pressure

33. Venting Methane to Mast

34. Low N_2 Header Pressure

35. Atmospheric Nitrogen Heater Outlet Low Temperature

36. Odorizing Pump Stopped

37. Low Temperature Methane Heater Outlet

38. Fresh Water Pumps, High Suction Temperature

39. Gas Detector Failure - Indicates power failure to the gas detector.

40. Impulse Air Low Pressure

Exhibit 12. continued

LNG/LPG EVENT CHART - NORMAL OPERATION

Phase I

72 Hour Advance Notice of Arrival (Page 2)

Appropriate Personnel and Organizations Notified (Page 2)

Message from Vessel's Master to COTP stating integrity of vessel and cargo handling equipment (Page 2)

Phase II

Arrival of vessel at Broad Sound (Page 2)

Joint COTP/MIO boarding and inspection (Page 2)

Permission to enter harbor denied based on results of inspection.

Problems encountered during inspection corrected.

Permission granted by COTP to enter harbor.

Appropriate agencies notified (Page 2)

Security Broadcast (Page 2)

Vessel enters harbor escorted by CG craft (Page 4)

Vessel moors at facility (page 4)

Secure Security Broadcast

Phase III

Hook up monitored (Page 4)

Transfer operations commence

Transfer operations monitored (Page 5)

Transfer operations completed

Phase IV

Vessel has cargo aboard

Appropriate agencies notitied (Page 5)

Security Broadcast

Vessel leaves harbor under Coast Guard escort.

Vessel has no cargo aboard

Vessel departs harbor

Exhibit 13. (LNG-LPG Operation-Emergency Plan, Port of Boston, USCG, Feb 1976, pp. 1-5) LNG/LPG Event Chart - Normal Operation

PHASE I: <u>Notification and Arrival</u>

1. The facility and/or the vessel's agents must notify the Captain of the Port of Boston at least 72 hours in advance of the vessel's arrival and again immediately prior to the arrival of the vessel.

2. Upon notification of arrival the vessel movement officer, Marine Safety Office, Boston shall:

a. Insure that the vessel has a letter of compliance*

b. Notify appropriate Coast Guard personnel and keep them informed of all developments.

c. Maintain a daily update of vessel's estimated time of arrival.

d. Pass any unusual or additional information to interested parties.

e. Arrange Coast Guard Boarding parties, escort detail and monitoring detail.

3. The day prior to arrival of the vessel, the vessel movement officer shall:

a. Prepare a security broadcast*

b. Notify pilots, Boston towboats, appropriate fire departments and all major port facilities of the estimated time of harbor transit and any special requirements affecting harbor transit.

4. Prior to the vessel's arrival, the master shall send a message to the Captain of the Port, Boston stating that:

"To the best of my knowledge and belief there are no known casualties to this vessel or its machinery which might affect the sea worthiness. I further state that all cryogenic* handling and detection equipment is in proper operating condition, and has been operating for the duration of this passage."

PHASE II: <u>Transit</u>

5. LNG/LPG vessels arriving at the Port of Boston shall maintain a radio guard on Channel 13 (156.65MHZ) and Channel 16 (156.8MHZ).

6. The vessel will normally be requested to anchor in Broad Sound pending an inspection by Coast Guard personnel. LNG/LPG vessels having a current letter of compliance and satisfying the requirements of this plan, may be authorized to anchor at

Exhibit 13. continued

Anchorage 2 in the northeast quadrant if the weather and sea conditions preclude a boarding and inspection in Broad Sound. Permission to use Anchorage 2 will be granted by the Captain of the Port of Boston on a case by case basis.

7. While the LNG/LPG vessel is at anchorage, a live bridge watch shall be maintained. A round of bearings fixing the vessel's position shall be taken and recorded hourly followed by a report every four hours to Group Boston on Channel 16FM stating that the anchor is holding and operations are normal. An immediate report shall be made to Group Boston if there is a significant change in position or problem aboard the vessel.

8. The vessel may enter the harbor only after an inspection by Coast Guard personnel representing the Captain of the Port of Boston has been held and a transfer permit has been issued (CG Form 4260). This inspection will normally take place while the vessel is anchored in Broad Sound. Should sea conditions preclude a safe boarding, the LNG/LPG vessel may be required to maintain maneuverability and provide a lee for the boarding party.

9. An LNG/LPG vessel must have its cryogenic sensing and indicating instrumentation in operation while the vessel is in U.S. waters. The master of the ship must be prepared to demonstrate to the CG boarding team that the cryogenic handling equipment is in proper working order. A copy of the check list used by the Coast Guard boarding team during their inspection is included as enclosure (4).

10. The vessel shall have on board a cylinder of properly certified span gas* for testing the gas detection system*.

11. The vessel may enter the harbor only during daylight hours.

12. The vessel may enter the harbor only during periods of good visibility. If the visibility is less than two miles, the vessel shall:

a. If at sea or in Broad Sound, not enter the port.

b. If underway in the harbor, the following applies:

(1) If entering the harbor inbound for the Mystic River and not yet past the Fort Point Channel, notify Coast Guard Group Boston on 16FM and proceed with caution back to Anchorage 2 or Broad Sound if Anchorage 2 is occupied.

(2) If entering the harbor inbound for the Mystic River and at a point east of the Fort Point Channel notify CG Group Boston on 16FM and continue to the ship's berth.

(3) If outbound from the Mystic River, notify CG Group Boston on 16FM and continue outbound.

Exhibit 13. continued

(4) If inbound for Commercial Point Dorchester and not yet to a point opposite buoy number 3, notify CG Group Boston on 16FM and proceed with caution to anchorage 2 or Broad Sound if anchorage 2 is occupied.

(5) If inbound for Commercial Point Dorchester and past buoy number 3, notify CG Group Boston on 16FM and continue with caution to the ship's berth.

(6) If outbound from Commercial Point Dorchester notify CG Group Boston on 16FM and continue outbound.

(7) When notified on 16FM that the vessel is turning around and returning to anchorage (either anchorage 2 or Broad Sound), CG Group Boston will make an immediate security broadcast on 16FM.

13. Vessels transitting Dorchester Bay may do so only within two hours of high water.

14. The vessel will not begin transit of the harbor until the U.S. Coast Guard escort vessel arrives on scene.

15. The vessel will transit the harbor within a moving safe area. This concept has been developed in order to avoid crossing situations involving the LNG/LPG ship and other vessels in the harbor.

16. All vessels in the harbor are required to obey certain rules while a vessel transporting LNG/LPG is underway in the harbor. A detailed description of these rules is contained in Appendix III.

17. The vessel must moor bow to seaward and be prepared to get underway on short notice should an emergency occur. They shall also have two cable mooring lines at the water's edge on the outboard side of vessel for emergency hook-up if the need should arise.

PHASE III: <u>Discharge</u>

18. No cargo will be off loaded prior to the satisfactory completion of the Coast Guard arrival safety inspection*.

19. Venting gas to the atmosphere is not permitted in port; however, nothing in this instruction should be implied to require or authorize elimination of installed ship safety equipment.

20. All cargo operations must cease if electrical storms are present. However, cargo transfer connections should be maintained.

21. If interpreters are not available, all ship's personnel directly involved in the transfer operation shall readily speak

Exhibit 13. continued

the English language.

22. The U.S. Coast Guard will have personnel on scene to monitor the transfer operation. Upon completion of the transfer operation and when all hoses are disconnected, on scene monitoring will terminate. Detailed instructions to the Coast Guard monitoring detail are contained in Appendix II.

23. The vessel or agents will provide the estimated time of departure to the CG Group Boston OOD* and inform him of any changes in this time of departure.

PHASE IV: Departure

24. LNG/LPG vessels departing with full or partial cargoes will follow the procedures set forth under Phase II - "Transit". LNG/LPG vessels departing with no cargo aboard are exempt from these regulations.

Exhibit 13. continued

Figure 4-14 A Typical Loading/Unloading Arrangement

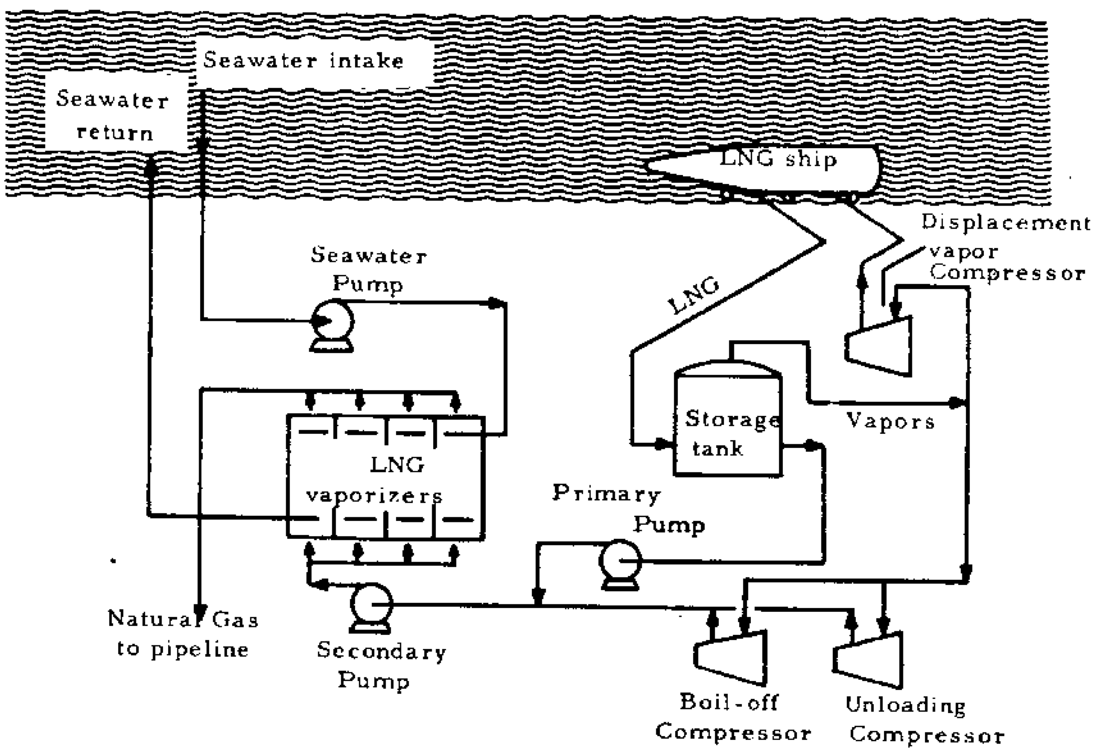


Exhibit 14. (Loading/Unloading Schematic, LNG Manual, National Maritime Research Center, July 1974, p. 99)

FEDERAL POWER COMMISSION-ORDER 415-C
(Issued December 18, 1972)
STATEMENT OF GENERAL POLICY TO IMPLEMENT PROCEDURES FOR COMPLIANCE WITH THE NATIONAL ENVIRONMENTAL POLICY ACT OF 1969

§ 2.80 Detailed Environmental Statement.

(a) It shall be the general policy of the Federal Power Commission to adopt and to adhere to the objectives and aims of the National Environmental Policy Act of 1969 (Act) in its regulation under the Federal Power Act and the Natural Gas Act. The National Environmental Policy Act of 1969 requires, among other things, all Federal agencies to include a detailed environmental statement in every recommendation or report on proposals for legislation and other major Federal actions significantly affecting the quality of the human environment.

(b) Therefore, in compliance with the National Environmental Policy Act of 1969 the Commission staff shall make a detailed environmental statement when the regulatory action taken by us under the Federal Power Act and Natural Gas Act will have a significant environmental impact. A "detailed statement" prepared in compliance with the requirements of §§ 2.81 through 2.82 of this Part shall fully develop the five factors listed hereinafter in the context of such considerations as the proposed activity's direct and indirect effect on the air and water environment of the project or natural gas pipeline facility: on the land, air, and water biota; on established park and recreational areas; and on sites of natural, historic, and scenic values and resources of the area. The statement shall discuss the extent of the conformity of the proposed activity with all applicable environmental standards. The statement shall also fully deal with alternative courses of action to the proposal and, to the maximum extent practicable, the environmental effects of each alternative. Further, it shall specifically discuss plans for future development related to the application under consideration.

The above factors are listed to merely illustrate the kinds of values that must be considered in the statement. In no respect is this listing to be construed as covering all relevant factors.

The five factors which must be specifically discussed in the detailed statement are:

(1) the environmental impact of the proposed action,
(2) any adverse environmental effects which cannot be avoided should the proposal be implemented;
(3) alternatives to the proposed action,
(4) the relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity, and
(5) any irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented.

(c) (i) To the maximum extent practicable no final administrative action is to be taken sooner than ninety days after a draft environmental statement has been circulated for comment or thirty days after the final text of an environmental statement has been made available to the Council on Environmental Quality and the public.

(c) (ii) Upon a finding that it is necessary and appropriate in the public interest, the Commission may dispense with any time period specified in §§ 2.80-2.82.

§ 2.81 Compliance with the National Environmental Policy Act of 1969 under Part I of the Federal Power Act

(a) All applications for major projects (those in excess of 2,000 horsepower) or for reservoirs only providing regulatory flows to downstream (major) hydroelectric projects under Part I of the Federal Power Act for license or relicense, shall be accompanied by Exhibit W, the applicant's detailed report of the environmental factors specified in § 2.80 and 4.41. All applications for surrender or amendment of a license proposing construction, or operating change of a project shall be accompanied by the applicant's detailed report of the environmental factors specified in § 2.80. Notice of all such applications shall continue to be made as prescribed by law.

(b) The staff shall make an initial review of the applicant's report and, if necessary, require applicant to correct deficiencies in the report. If the proposed action is determined to be a major Federal action significantly affecting the quality of the human environment, the staff shall conduct a detailed independent analysis of the action and prepare a draft environmental impact statement which shall be made available to the Council on Environmental Quality, the Environmental Protection Agency, other appropriate governmental bodies, and to the public, for comment. The statement shall also be served on all parties to the proceeding. The Secretary of the Federal Power Commission shall cause prompt publication in the Federal Register of notice of the availability of the staff's draft environmental statement. Written comments shall be made within 45 days of the date the notice of availability appears in the Federal Register. If any governmental entity, Federal, state, or local, or any member of the public, fails to comment within the time provided, it shall be assumed, absent a request for a specific extension of time, that such entity or person has no comment to make. Extensions of time shall be granted only for good cause shown. All entities filing comments with the Commission will submit ten copies of such comments to the Council on Environmental Quality. Upon expiration of the time for comment the staff shall consider all comments received and revise as necessary and finalize its environmental impact statement which, together with the comments received, shall accompany the proposal through the agency review and decision-making process and shall be made available to the parties to the proceeding, the Council on Environmental Quality, and the public. In the event the proposal is the subject of a hearing the staff's environmental statement will be placed in evidence at that hearing.

(c) Any person may file a petition to intervene on the basis of the staff draft environmental statement. All interveners taking a position on environmental matters shall file timely comments, in accordance with paragraph (b) of this section, on the draft statement with the Commission including, but not limited to, an analysis of their environmental position in the context of the factors enumerated in 2.80, and specifying any differences with staff's position upon which intervener wishes to be heard. Nothing herein shall preclude an intervener from filing a detailed environmental impact statement.

(d) In the case of each contested application, the applicant, staff, and all interveners taking a position on environmental matters shall offer evidence for the record in support of their environmental position. The applicant and all such interveners shall specify any differences with the staff's position, and shall include, among other relevant factors, a discussion of their position in the context of the factors enumerated in § 2.80.

(e) In the case of each contested application, the initial and reply briefs filed by the applicant, the staff and all interveners taking a position on environmental matters must specifically analyze and evaluate the evidence in the light of the environmental criteria enumerated in § 2.80. Furthermore, the Initial Decision of the Presiding Administrative Law Judge in such cases, and the final order of the Commission dealing with the application on the merits in all cases, shall include an evaluation of the environmental factors enumerated in § 2.80 and the views and comments expressed in conjunction therewith by the applicant and all those making formal comment pursuant to the provisions of this section.

Exhibit 15. (FPC Implementation Procedures)

§ 2.82 Compliance with the National Environmental Policy Act of 1969 Under the Natural Gas Act.

(a) All certificate applications filed under Section 7(c) of the Natural Gas Act (15 U.S.C. 717f(c)) for the construction of pipeline facilities, except abbreviated applications filed pursuant to Sections 157.7(b), (c) and (d) of Commission Regulations and producer applications for the sale of gas filed pursuant to Sections 157.23-29 of Commission Regulations, shall be accompanied by the applicant's detailed report of the environmental factors specified in § 2.80. Notice of all such applications shall continue to be made as prescribed by law.

(b) The staff shall make an initial review of the applicant's report and, if necessary, require applicant to correct deficiencies in the report. If the proposed action is determined to be a major Federal action significantly affecting the quality of the human environment, the staff shall conduct a detailed independent analysis of the action and prepare a draft environmental impact statement which shall be made available to the Council on Environmental Quality, the Environmental Protection Agency, other appropriate governmental bodies, and to the public, for comment. The statement shall also be served on all parties to the proceeding. The Secretary of the Federal Power Commission shall cause prompt publication in the Federal Register of notice of the availability of the staff's draft environmental statement. Written comments shall be made within 45 days of the date the notice of availability appears in the Federal Register. If any governmental entity, Federal, state, or local, or any member of the public, fails to comment within the time provided, it shall be assumed, absent a request for a specific extension of time, that such entity or person has no comment to make. Extensions of time shall be granted only for good cause shown. All entities filing comments with the Commission shall submit ten copies of such comments to the Council on Environmental Quality. Upon expiration of the time for comment the staff shall consider all comments received and revise as necessary and finalize its environmental impact statement which, together with the comments received, shall accompany the proposal through the agency review and decision-making process and shall be made available to the parties to the proceeding, the Council on Environmental Quality, and the public. In the event the proposal is the subject of a hearing, the staff's environmental statement will be placed in evidence at that hearing.

(c) Any person may file a petition to intervene on the basis of the staff draft environmental statement. All interveners taking a position on environmental matters shall file timely comments, in accordance with paragraph (b) of this section, on the draft statement with the Commission including, but not limited to, an analysis of their environmental position in the context of the factors enumerated in § 2.80, and specifying any differences with staff's position upon which intervener wishes to be heard. Nothing herein shall preclude an intervener from filing a detailed environmental impact statement.

(d) In the case of each contested application, the applicant, staff, and all interveners taking a position on environmental matters shall offer evidence for the record in support of their environmental position. The applicant and all such interveners shall specify any differences with the staff's position, and shall include, among other relevant factors, a discussion of their position in the context of the factors enumerated in § 2.80.

(e) In the case of each contested application, the initial and reply briefs filed by the applicant, the staff, and all interveners taking a position on environmental matters must specifically analyze and evaluate the evidence in the light of the environmental criteria enumerated in § 2.80. Furthermore, the Initial Decision of the Presiding Administrative Law Judge in such cases, and the final order of the Commission dealing with the application on the merits in all cases, shall include an evaluation of the environmental factors enumerated in § 2.80 and the views and comments expressed in conjunction therewith by the applicant and all those making formal comment pursuant to the provisions of this section.

FEDERAL POWER COMMISSION

RULES OF PRACTICE AND PROCEDURE

18 CFR 1.8 Intervention

"(a) Initiation of intervention. Participation in a proceeding as an intervener may be initiated as follows:

(1) By the filing of a notice of intervention by a State Commission, including any regulatory body of the State or municipality having jurisdiction to regulate rates and charges for the sale of electric energy, or natural gas, as the case may be, to consumers within the intervening State or municipality.

(2) By order of the Commission upon petition to intervene.

(b) Who may petition. A petition to intervene may be filed by any person claiming a right to intervene or an interest of such nature that intervention is necessary or appropriate to the administration of the statute under which the proceeding is brought. Such right or interest may be:

(1) A right conferred by statute of the United States;

(2) An interest which may be directly affected and which is not adequately represented by existing parties and as to which petitioners may be bound by the Commission's action in the proceeding (the following may have such an interest: consumers served by the applicant, defendant, or respondent; holders of securities of the applicant, defendant, or respondent; and competitors of the applicant, defendant, or respondent).

(3) Any other interest of such nature that petitioner's participation may be in the public interest.

(c) Form and contents of petitions. Petitions to intervene shall set out clearly and concisely the facts from which the nature of the petitioner's alleged right or interest can be determined, the grounds of the proposed intervention, and the position of the petitioner in the proceeding, so as fully and completely to advise the parties and the Commission as to the specific issues of fact or law to be raised or controverted, by admitting, denying or otherwise answering specifically and in detail, each material allegation of fact or law asserted in the proceeding, and citing by appropriate reference the statutory provisions or other authority relied on: Provided, that where the purpose of the proposed intervention is to obtain an allocation of natural gas for sale and distribution by a person or municipality engaged or legally authorized to engage in the local distribution of natural or artificial gas to the public, the petition shall comply with the requirements of Part 156 of this chapter (i.e., Regulations Under the Natural Gas Act). Such petitions shall in other respects comply with the requirements of §§ 1.15 to 1.17, inclusive.

(d) Filing and service of petitions. Petitions to intervene and notices of intervention may be filed at any time following the filing of a notice of rate or tariff change, or of an application, petition, complaint, or other document seeking Commission action, but in no event later than the date fixed for the filing of petitions to intervene in any order or notice with respect to the proceedings issued by the Commission or its Secretary, unless, in extraordinary circumstances for good cause shown, the Commission authorizes a late filing. Service shall be made as provided in § 1.17. Where a person has been permitted to intervene notwithstanding his failure to file his petition within the time prescribed in this paragraph, the Commission or officer designated to preside may where the circumstances warrant, permit the waiver of the requirements of § 1.26(c)(5) with respect to copies of exhibits for such intervener.

(e) Answers to petitions. Any party to the proceeding or staff counsel may file an answer to a petition to intervene, and in default thereof, may be deemed to have waived any objection to the granting of such petition. If made, answers

Exhibit 15. continued

shall be filed within 10 days after the date of service of the petition, but not later than 5 days prior to the date set for the commencement of the hearing, if any, unless for cause the Commission with or without motion shall perscribe a different time. They shall in all other respects conform to the requirements of §§1.15 to 1.17, inclusive.

(f) Notice and action on petitions

(1) Notice and service. Petitions to intervene, when tendered to the Commission for filing, shall show service thereof upon all participants to the proceeding in conformity with §1.17(b).

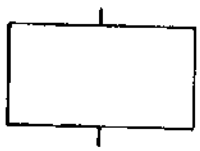
(2) Action on petitions. As soon as practicable after the expiration of the time for filing answers to such petitions or default thereof, as provided in paragraph (e) of this section, the Commission will grant or deny such petition in whole or in part or may, if found to be appropriate, authorize limited participation. No petitions to intervene may be filed or will be acted upon during a hearing unless permitted by the Commission after opportunity for all parties to object thereto. Only to avoid detriment to the public interest will any presiding officer tentatively permit participation in a hearing in advance of, and then only subject to, the granting by the Commission of a petition to intervene.

(g) Limitation in hearings. Where there are two or more interveners having substantially like interests and positions, the Commission or presiding officer may, in order to expedite the hearing, arrange appropriate limitations on the number of attorneys who will be permitted to cross-examine and make and argue motions and objections on behalf of such interveners."

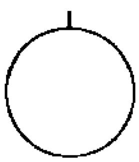
Exhibit 15. continued

EVENT REPRESENTATIONS

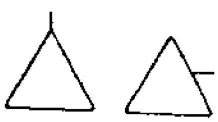
The rectangle identifies an event that results from the combination of fault events through the input logic gate.



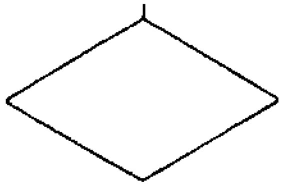
The circle describes a basic fault event that requires no further development. Frequency and mode of failure of items so identified are derived from empirical data.



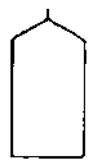
The triangles are used as transfer symbols. A line from the apex of the triangle indicates a transfer in and a line from the side denotes a transfer out.



The diamond describes a fault event that is considered basic in a given fault tree. The possible causes of the event are not developed whether because the event is of insufficient consequence or the necessary information is unavailable.

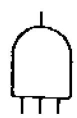


The house is used as a switch to include or eliminate parts of the fault tree as those parts may or may not apply to certain situations.



LOGIC OPERATIONS

AND gate describes the logical operation whereby the coexistance of all input events is required to produce the output event.



OR gate defines the situation whereby the output event will exist if one or more of the input events exists.

INHIBIT gates describe a causal relationship between one fault and another. The input event directly produces the output event if the indicated condition is satisfied. The conditional input defines a state of the system that permits the fault sequence to occur, and may be either normal to the system or result from failures.

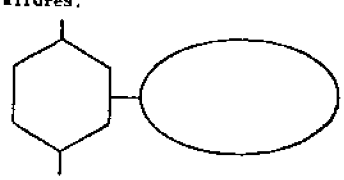


Figure 3.1 Fault Tree Symbolism

Exhibits 16-19 (SAI Fault Tree for leak in ship's tank during transfer - symbolism, p. 3-10)

Figure 3.5 Fault Tree for Leak in a Ship Tank During Transfer

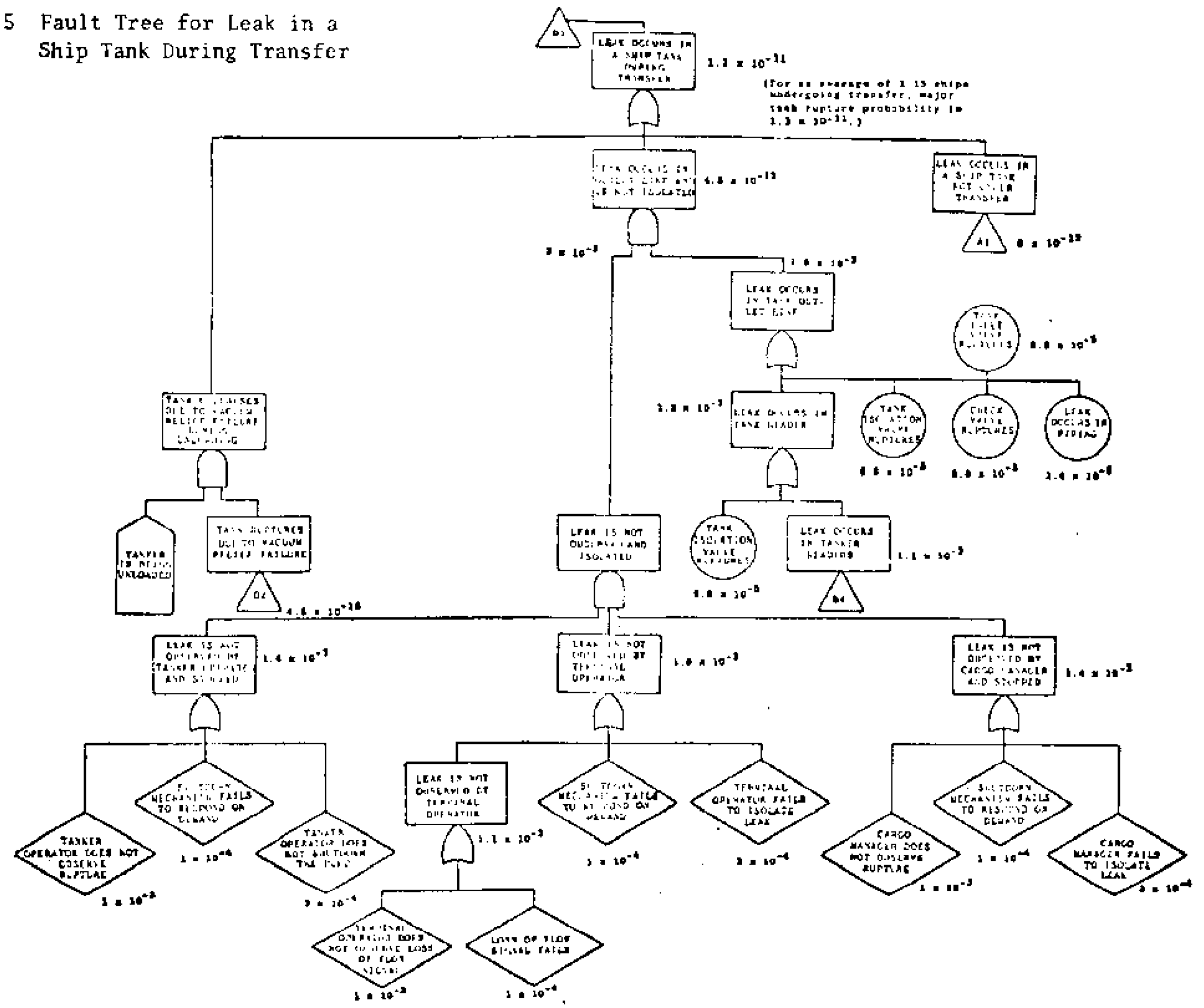


Exhibit 17. Fault Tree for Tank Leak

Figure 3.6 Fault Tree for Tank Rupture During Transfer due to Vacuum Relief Failure

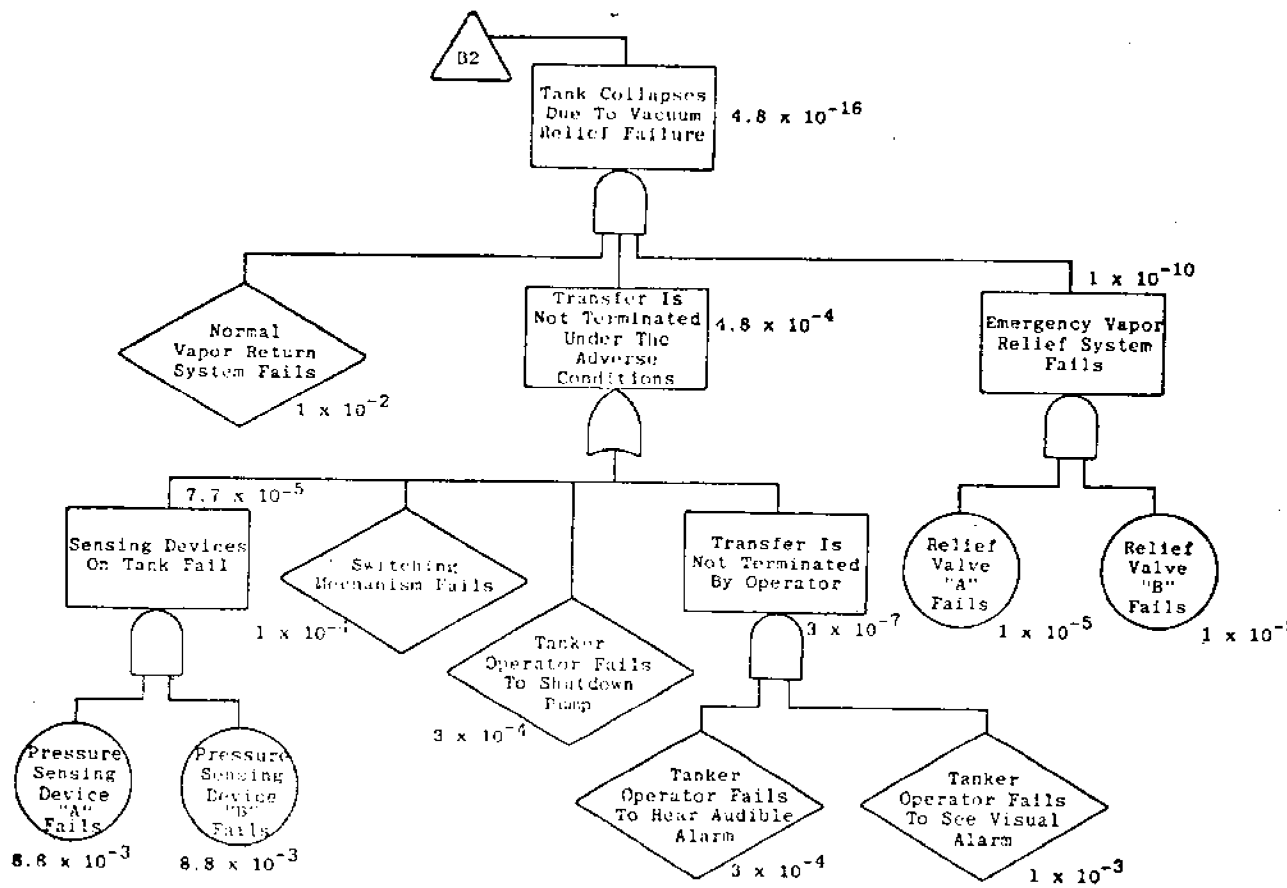


Exhibit 18. Fault Tree for Tank Rupture

Figure 3.7 Fault Tree for Tanker Headers During Transfer

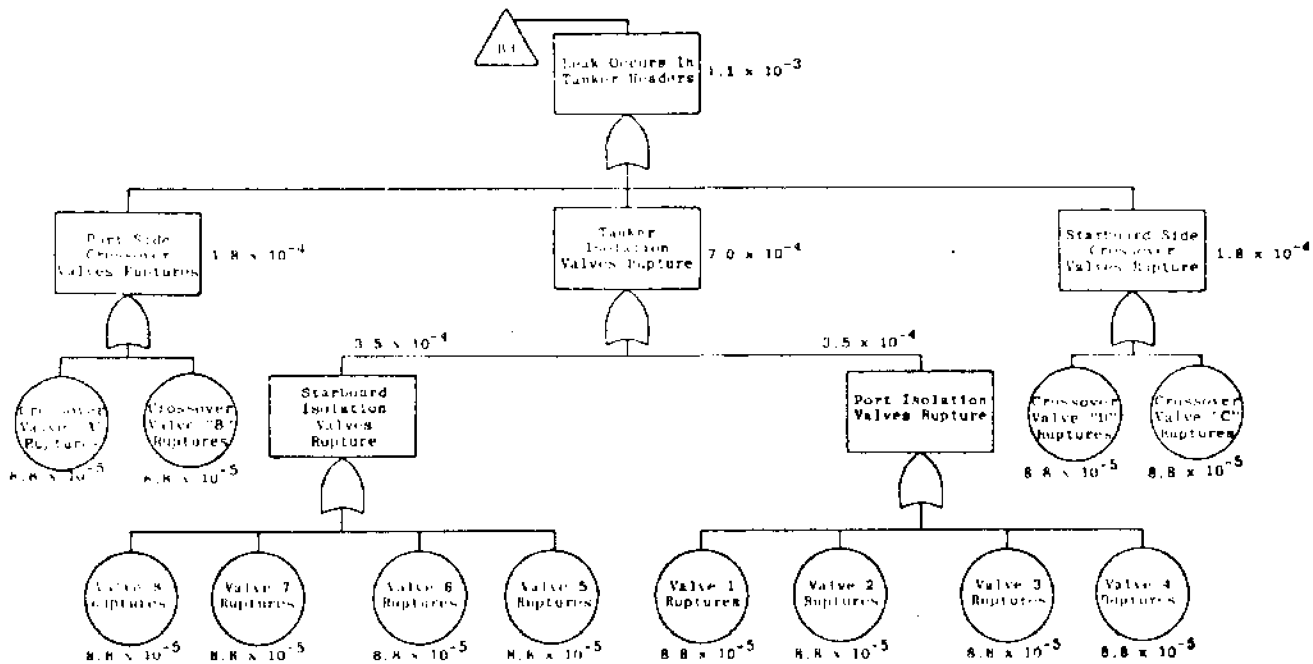


Exhibit 19. Fault Tree for Tanker Headers

SEQUENCE OF RESPONSES TO DETECTOR ACTIVATION

TERMINAL LOCATION	SENSOR TYPE	RESPONSE AT EACH LEVEL OF ALARM
I. Vaporizer Area	Gas detectors	1. 35% of LFL, alarm. 2. 65% of LFL, alarm. Remote and local manual shutdown of vaporizer
	Low Temperature Detector (Grade Level)	1. Alarm. Remote shutdown of vaporizer. Remote and local manual actuation of expansion foam system.
	UV Fire Detectors	1. Alarm. Automatic actuation of dry chemical and/or expansion foam system with manual overrides. Remote and local manual shutdown of vaporizer and associated equipment.
II. Pump Area	Gas Detectors	1. 35% of LFL, alarm. 2. 65% of LFL, alarm. Remote and local manual shutdown of pump.
	Low Temperature Detector (Grade Level)	1. Alarm. Remote and local manual shut-down of pump. Remote and local manual activation of high expansion foam system.
	UV Fire Detectors	1. Alarm. Automatic actuation of dry chemical and/or expansion foam systems with manual override. Remote shutdown and local manual of pump and associated equipment.
III. Unloading Dock Area	Gas Detector	1. 35% of LFL, alarm. 2. 65% of LFL, alarm. Remote and local manual shutdown of unloading system.
	Low Temperature Detectors	1. Alarm. Remote and local manual shut-down of unloading system.
	UV Fire Detectors	1. Alarm. Remote and local manual actua-tion of dry chemical and/or expansion foam systems, shutdown of unloading system.
IV. Compressor Area	Gas Detectors	1. 35% of LFL, alarm. 2. 65% of LFL, alarm. Remote and local manual shutdown of compressors.
	UV Fire Alarm	1. Alarm. Manual operation of dry chemi-cal unit, remote and local manual shutdown of compressors.
V. Tank Relief Vents	Temperature Rise Sensor	1. Alarm. Automatic operation of dry chemical fire extinguishing system.
VI. Bellows in LNG Transfer line from Dock to Tanks	Low Temperature Detectors	1. Alarm. Remote manual operation of shutdown sequence for unloading line.

Exhibit 20. (Table 25, Pacific-Indonesian Project DEIS, FPC, Bureau of Natural Gas, May 1976, p. 158) Sequence of Responses to Detector Activation

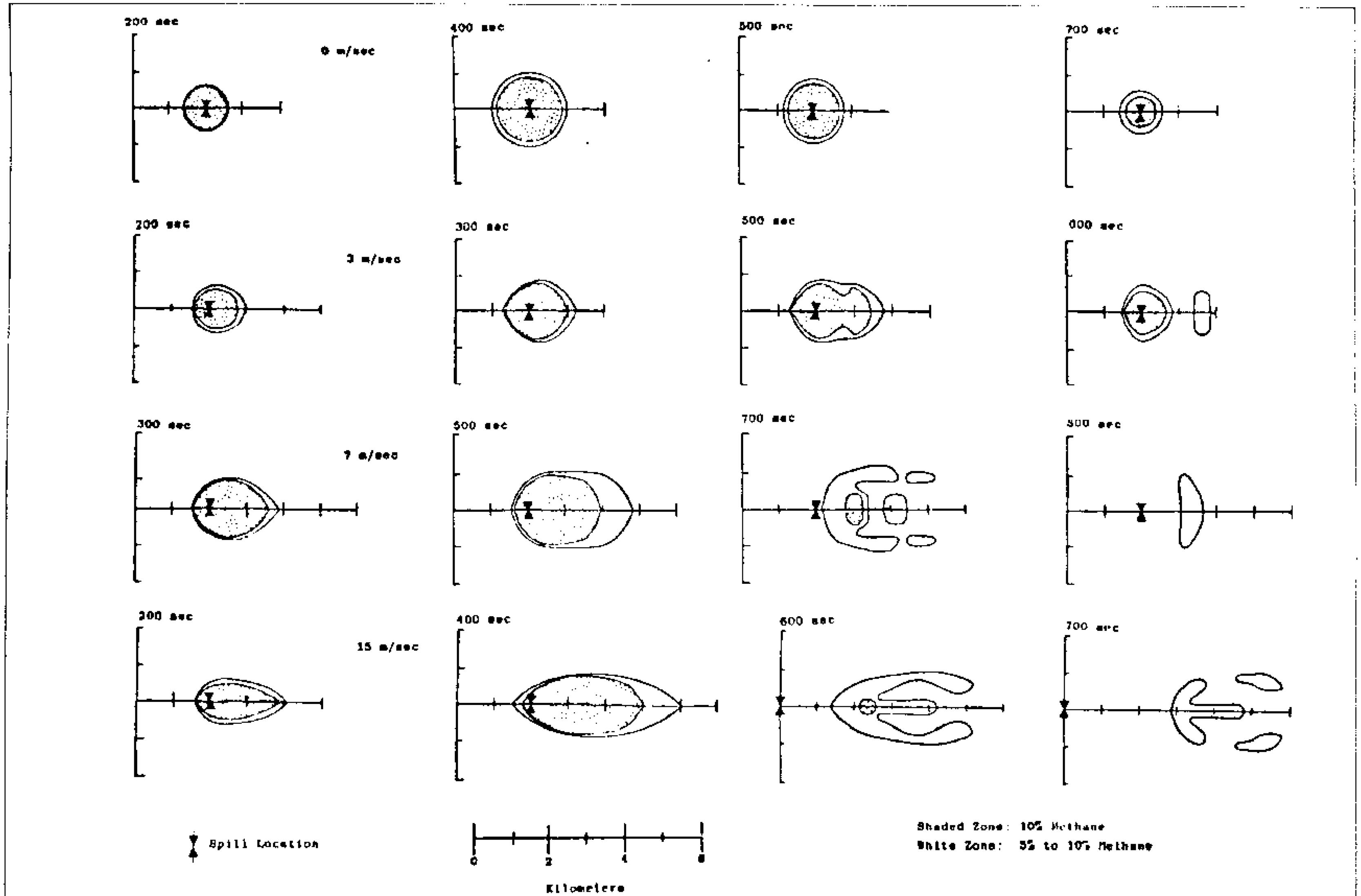


Figure 8.3.4.2. Concentration Isopleths for Instantaneous Spills of 37,500 m^3 of LNG on Water for Various Wind Speeds

Exhibit 21. (SAI LNG spill cloud configuration/concentration isopleths, Dec 1975, p. 8-82)

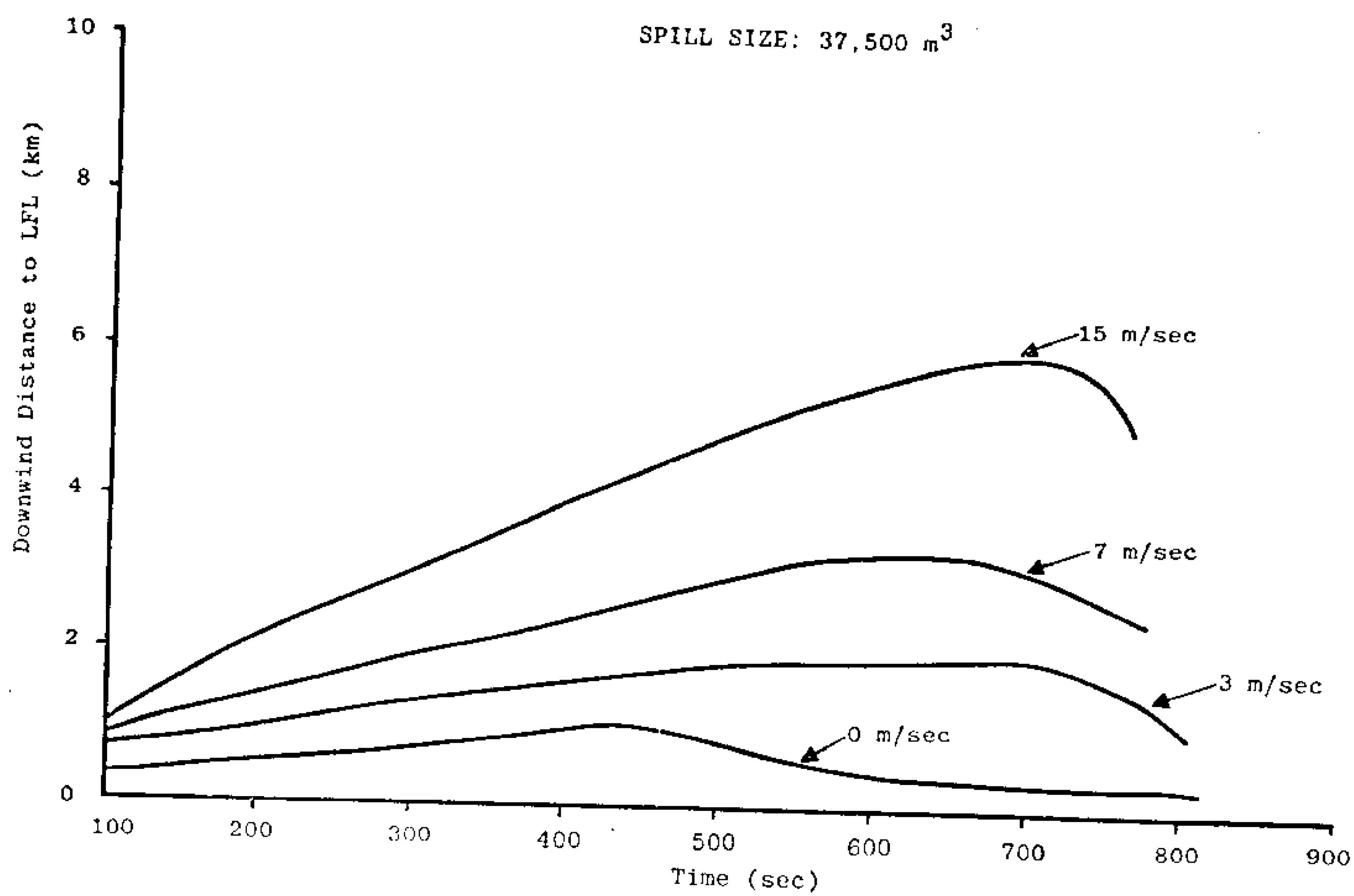


Figure 8.3.4.3 Downwind Distance to the LFL at Ground Level Resulting from an LNG Spill of 37,500 m^3 at Various Wind Speeds

Exhibit 22. (SAI Time/Distance plot for LNG spill vapor plume, Dec 1975, p. 8-83)

Table 8.6.6 Probability of Occurrence of Calculated Fatality Levels

Fatalities	Probability of Occurrence Per Year, All Cases
1 - 100	5.7×10^{-13}
100 - 1,000	3.8×10^{-7}
1,000 - 2,000	2.2×10^{-7}
2,000 - 10,000	9.9×10^{-9}
10,000 - 20,000	1.9×10^{-11}
20,000 - 30,000	6.1×10^{-14}
30,000 - 40,000	6.8×10^{-19}
40,000 - 50,000	5.4×10^{-23}
50,000 - 60,000	2.0×10^{-30}
60,000 - 70,000	8.9×10^{-36}
70,000 - 80,000	3.5×10^{-40}
80,000 - 90,000	2.9×10^{-41}
90,000 - 100,000	3.2×10^{-49}
100,000 - 110,000	7.4×10^{-57}
110,000 - 120,000	7.7×10^{-57}
Maximum 113,000	1.4×10^{-57}

Because the population distribution increases significantly beyond the first kilometer from the land-based site; and because conservative assumptions have been used for radiation exposure, there are few postulated accidents that would result in fewer than 100 fatalities (these result primarily from the relatively distant shipping accidents). Thus, the calculated probability of 1-100 fatalities is much lower than the probability of 100-1000 fatalities.

Exhibit 23. (SAI Table - Fatalities/Year Probability, p. 8-169)

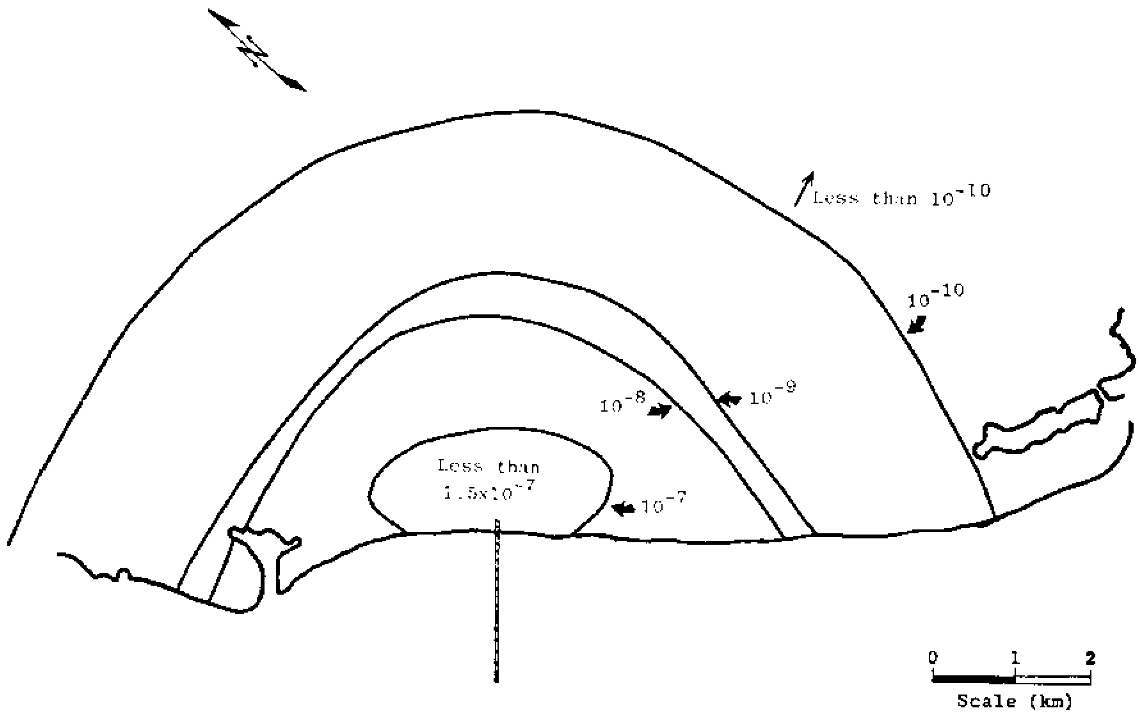


Figure 8.6.1 Contour Map: Estimated Fatalities Per Person Per Year, All Spill Locations Combined

Exhibit 24. (SAI Conour Map. Estimate Fatalities, p. 8-168)

(3) Example calculation of the wage subsidy per diem rate and wage subsidy percentage rate

ABC Steamship Co., T8-S-101c—Worldwide Services

[Calculation of wage subsidy rates [1]]

Base period	Interim period	U.S. wage costs	Collective bargaining costs	Application of BLS index to base period cost	Averaging in base periods (4)+(5)÷2	Appropriate limits	Base period cost	Subsidizable wage costs	Composite foreign wage cost	Wage subsidy per diem rate	Wage subsidy percentage rate (11)÷(9)
1973		2,729.78	2,644.20								
	1974	2,943.37	2,634.07	2,644.20×107.8=2,850.45		90 pct (4)=2,550.66	2,644.20	2,644.20	793.42	1,850.78	69.99
1975 [2]		3,143.40	3,077.08	2,644.20×116.3=3,075.20	3,051.14	110 pct (4)=3,117.48; 97.5 pct (4)=2,974.40		2,850.45	835.33	2,015.12	70.69
						102.5 pct (4)=3,127.70	3,051.14	3,051.14	883.29	2,167.85	71.05

[1] This computation is based on a new vessel entering subsidized service in July 1972.
[2] Base period for example purposes only

Exhibit 25. (Sample Calculation of "Wage subsidy per diem rate", 46 C.F.R. § 252.31 (j), 1 Oct 1975)

(3) Example calculation of maintenance and repair subsidy rate.

ABC Steamship Co., Inc., T8-S-101c Vessel—Worldwide Services

[Determination of maintenance (upkeep and repairs) subsidy rate calendar year 1974]

Principal competitors	Distribution of repairs: Country	Distribution of repairs: Percent	Percentage cost differential	Proportionate cost differential (percent)	Competitive weight factor (percent)	Weighted differential (percent)
Japan	Japan	85	36.2	30.8		
	United States	15	0	0		
	Total	100		30.8	23.4	7.207
Norway	Norway	15	14.7	2.2		
	Netherlands	20	43.2	8.6		
	Japan	45	36.2	16.3		
	United States	20	0	0		
	Total	100		31.6	31.1	9.828
United Kingdom	United Kingdom	80	49.2	39.4		
	Hong Kong	15	50.3	7.5		
	United States	5	0	0		
	Total	100		46.9	45.5	21.340
	Total					38.375
	Subsidy rate					38.37

Exhibit 26. (Sample Calculations leading to "maintenance and repair subsidy rate", 46 C.F.R. § 252.32(e), 1 Oct 1975)

(e) *Example calculation.* The following is an example calculation of the hull and machinery insurance rate for an operator who insures his vessels partially in the British market:

ABC STEAMSHIP COMPANY, INC., T8-S-101c

VESSEL—WORLDWIDE SERVICES

Calendar Year 1974

1. *Eligible premium costs*	$200,000
2. *Composite foreign premium cost:*	
(i) Foreign premium cost:	
A. Hull and machinery coverage:	
Amount of total coverage	$8,000,000
Average premium rate in British market	2.25%
Premium cost in British market	$180,000
B. Increased value coverage:	
Amount of total coverage	$2,000,000
Average premium rate in British market	.625%
Premium cost in British market	$12,500
C. Excess liability coverage:	
Amount of total coverage	$3,000,000
Average premium rate in British market	.15%
Premium cost in British market	$4,500
D. Foreign premium cost	$197,000
(ii) Adjusted particular average portion:	
A. Particular average portion:	
Hull and machinery portion $180,000 less estimated total loss premium of $40,000 (8,000,000x 50%) times particular average factor of 70%	$98,000
B. Adjustment factor:	
100% less maintenance and repair subsidy rate of 38.37%	61.63%
C. Adjusted particular average portion	$60,397
(iii) Foreign premium cost ($197,000) less particular average portion ($98,000)	$99,000
(iv) Composite foreign premium cost	$159,397
3. *Subsidy rate*	20.30%

$$\frac{\$200{,}000 - \$159{,}397}{\$200{,}000}$$

Exhibit 27. (Sample Calculations "hull and machinery insurance subsidy rate", 46 C.F.R. § 252.33(e), 1 Oct 1975)

(g) Example calculation of protection and indemnity subsidy rate:

ABC Steamship Co., Inc., T8-8-101c Vessel—Worldwide Services

[Determination of protection and indemnity insurance subsidy rate, 1974]

	United States	Japan	Norway	United Kingdom
Crew liability	[1] $1.44	[2] $0.03	[2] $0.48	[2] $0.64
All other liabilities	.25	.25	.25	.25
Total premium cost	1.69	.28	.73	.89
Cost differential (excess of U.S. cost over foreign cost)				
Unweighted differential		1.41	.96	.80
Competition weight factor		83.43	56.80	47.34
Weighted differential		23.4	31.1	45.5
		19.523	17.665	21.540
Sum of weighted differentials			58.728	
Subsidy rate			58.72	

[1] Determined by applying 85 pct to total net premium cost per g.r.t. of $1.69, reported on form MA-122.
[2] Crew liability data obtained by Maritime Administration.

Exhibit 28 (Protection and Indemnity insurance subsidy rate, 46 C.F.R. § 252.34(g), 1 Oct 1975)

72. Relief Devices Between Shutoff Valves

720. A relief valve shall be installed between each pair of shutoff valves on liquid piping and other equipment such as heat exchangers or process drums which may contain liquid.

708. The requirement of 707 may be reduced by the rate of vaporization which results from minimum normal heat gain (on the coldest day and with low liquid level) to the container contents. A gas repressuring line with suitable control and source of gas shall be provided when required to avoid drawing air into the container. The use of a gas repressuring system shall not obviate the use of vacuum valves to admit atmospheric air in an emergency.

31. Aboveground LNG Containers

310. The minimum clear distance between aboveground LNG containers shall be one-fourth of the sum of the diameters of adjacent containers.

311. Buildings shall not be located within a diked area surrounding an LNG container or nearer than 50 feet to a container (see 301). This does not apply to noncombustible valve, pump or meter enclosures or similar structures.

312. The minimum clear distance from the edge of an aboveground LNG container to the nearest important building or group of buildings not associated with the LNG plant or to the owner's property line or public way shall be 200 feet and in no case shall the clear distance from the dike surrounding the aboveground LNG container be less than 100 feet from the nearest important building or group of buildings or the owner's property line or public way.

461. LNG storage containers do not require lightning protection (see Lightning Protection Code, NFPA No. 78).

462. Electrical grounding and/or bonding shall be provided as required by 540 and 6130, Static Electricity, NFPA No. 77, and National Electrical Code, NFPA No. 70.

4641. In the case of undiked aboveground containers, fired equipment shall be located at least 100 feet from such containers and at least 100 feet from any probable path of liquid flow to a topographical enclosure and from any such enclosure.

465. Fired equipment, excluding vaporizers (see 614 and 622) located in a building, shall be separated from all compartments or rooms containing process equipment handling LNG or high pressure gas by a wall of substantially noncombustible material and vaportight construction.

61. Indirect-Fired Vaporizers

610. The heating medium lines entering and leaving the LNG vaporizing heat exchanger shall be provided with suitable means for minimizing the flow of vaporized gas into the heat transfer system in the event of tube rupture in the vaporizer.

621. Direct-fired vaporizers and direct-fired process heaters shall be located in accordance with 461 and 4641 and at least 100 feet from a property line which can be built upon.

701. At least one relief valve on an LNG container shall be set to open at a pressure not in excess of the container design pressure.

7011. The valve or valves shall have a capacity capable of preventing an overpressure greater than 10 per cent above the design gage pressure while discharging the maximum flow that can originate from:

(a) normal heat gain from ambient conditions through the insulation and container fittings,

(b) flash vaporization of an incoming stream,

(c) operational upset such as the failure of a control device which would permit the uncontrolled flow of a liquid, vapor or gas into the container,

(d) normal drop of barometric pressure. (This can cause flash vaporization and expansion due to a drop of the absolute pressure.)

Exhibit 29. (National Fire Protection Assn., Requirement No. 59-A, excerpts)

702. If additional relief valves are required for fire exposure, they shall be set to open at a pressure no greater than 10 per cent above the design gage pressure. The rate of discharge for fire exposure is given in Appendix A. The total relief valve capacity shall be sufficient to release the efflux of gas that may result from an exposure fire at an overpressure no greater than 20 per cent above the design gage pressure.

705. All discharge vents from the safety relief valves or common discharge headers shall be installed in such a manner as to:

7051. Lead to the open air.

7052. Be protected against mechanical damage.

7053. Exclude or remove moisture and condensate. This may be done by the use of loose-fitting rain caps and drains. Drains shall be so installed as to prevent possible flame impingement on the containers, piping, equipment, and structures.

7054. Discharge in an area which:

(a) Will prevent possible flame impingement on containers, piping, equipment, and structures.

(b) Will prevent possible vapor entry into enclosed spaces.

(c) Will be above the heads of personnel who may be on the container or adjacent containers, stairs, platforms, or ground.

(d) Will be above the possible water level, if from underground containers where there is a possibility of flooding.

7055. Prevent malfunction due to freezing or icing.

706. A full area stop valve may be used between the container and the relief valve for inspection and repair purposes only when more than one relief valve is provided.

7061. When a stop valve is provided it shall be locked or sealed open and it shall not be closed except by an authorized person who shall remain stationed there while the valve is closed and who shall again lock or seal the valve in the open position before leaving the station. This valve(s) shall not be closed when reliquefaction or other operating systems which prevent overpressure are shut down.

7062. Only one stop valve shall be closed at a time.

707. A vacuum relief valve or valves shall be provided to protect the container against an excessive partial vacuum. This valve or valves shall be sized, except as provided in 708, to accommodate a flow which may result from:

7071. Withdrawal of stored liquid at the maximum rate.

7072. Withdrawal of vapor from the container at the maximum blower or compressor suction rate.

7073. Rise of barometric pressure. (This can cause contraction of the gas or vapor due to an increase of absolute pressure in the container.)

Exhibit 29. continued

2. RISKS TO LNG PROJECTS RESULTING FROM LNG TANKER OPERATIONS

(1) Experience With LNG Tankers

A 125,000 cubic meter LNG ship carries about 2 trillion Btu of energy when fully loaded. This energy represents a hazard to the LNG facilities themselves when the ship is at dock, to other shoreside facilities when the ship is in the channel or harbor, and to other ships when at sea. If an accident occurs which does not involve damage to the LNG facilities, the temporary or permanent loss of the ship itself to the trade will have an effect on deliveries and, hence, the project.

Since the LNG tanker trade is both recent in origin (1964) and small in numbers of vessels (approximately 16), insufficient operating statistics are available for predicting accidents involving the forecast LNG tanker fleet of between 26 and 49 vessels in 1980. Before estimating the potential of a tanker incident, it is appropriate to examine the experiences of existing LNG ships.

Exhibit 30. (Booz-Allen Applied Research, Inc. Analysis of LNG Marine Transportation, Listing of First Generation LNG carrier particulars, Nov 1973, pp. VII-2 to VII-5)

To date, the operating experience with LNG tankers has been remarkably good. There have only been minor difficulties in maneuvering of the ships with one reported accident. Some minor difficulties have developed with the cargo holds themselves. No major accidents (such as collisions or groundings) have occurred, and there have been no releases of liquid other than the one reported below. The operational histories of the individual tankers, where available, are given below.

The METHANE PRINCESS and the METHANE PROGRESS, the first commercial LNG tankers, were delivered to their owners in April and June 1964, respectively. The ships are equipped with free-standing, prismatic, aluminum cargo tanks. In their 9 years of service, no LNG leak has occurred in any of the cargo tanks. After initial operation, fractures were observed at the weld connection of a vertical bracket to a bottom stiffener in the METHANE PRINCESS. The connections were reinforced on all nine tanks of the ship. Cold spots have been observed on the inner hull and water leakage into the insulation space from the ballast space has occurred at fractures. The cold spots resulted from improper fitting of the insulation. Fractures in the steelwork were repaired and heating coils provided in the cofferdam spaces to provide additional heat for the traverse bulkheads where slightly lower than anticipated temperatures were observed.

The JULES VERNE, developed by Gaz-Transport, has 9-percent nickel steel cylindrical tanks and has made over 200 voyages from Arzew to Le Havre, with a few spot cargoes to Canvey Island. The only significant occurrence that has been reported on the JULES VERNE has been a serious deck fracture caused by a cargo spill during the ship's second loading. The spill occurred as a result of overfilling when the operating crew "lost" the liquid level in the number 2 tank. The liquid-level gauge in that tank was not functioning correctly, as the result of a foreign body having lodged in way of the vertical track of the float. Other means of determining liquid level, if available, were not correctly used and the resulting overfill caused LNG to spill from the vent riser, fracturing the cover over the tank and the deck stringer plate. Temporary repairs were made to deck and dome to allow the ship to continue operation until the annual drydocking, at which time the affected structure was renewed.

The POLAR ALASKA and the ARCTIC TOKYO, which employ the Gaz-Transport Invar membrane system, have encountered several interesting operational problems, but on balance have been successful. On the first ballast voyage of the POLAR ALASKA, a cable tray on the pump support column

Exhibit 30. continued

in the number 1 tank broke loose and perforated the primary barrier in several locations. This damage was discovered during the second loading, when a drop in temperature on the secondary barrier and an increase in temperature between primary and secondary barriers were noted. No gas was detected behind the primary barrier during the ballast voyage. The cargo in the tank was transferred to others and the ship departed for Japan with the number 1 tank empty. During the gas-freeing operation in Japan, the space between the barriers was inadvertently pressurized. The primary barrier was distorted during this incident and repairs were made in less than 3 weeks during drydocking following the ship's seventh voyage. Reinforcement of the cable trays in the remaining tanks had been carried out earlier.

On subsequent voyages, all tanks were stripped at discharge and allowed to warm up naturally during the ballast voyage, to remove altogether the possibility of damage from liquid sloshing, which was felt to be a major contributing factor to the cable tray failure.

The ARCTIC TOKYO also experienced some minor difficulties caused by sloshing of liquid. During one voyage, gas was detected behind the primary barrier in number 1 tank. Examination of the tank was postponed until the next regular drydocking, recently completed, during which the secondary barrier and insulation were found to be in excellent condition. The primary barrier showed one small area, apparently in or near a corner at which the leak referred to above occurred. This ship also has recently operated with tanks stripped during ballast voyages.

The ESSO BREGA class ships are equipped with double-wall freestanding aluminum tanks. Operation of these ships thus far has proven highly successful. No abnormalities in tanks on insulation systems have been observed.

The EUCLIDES is the first ship equipped with spherical tanks capable of carrying LNG. The system employed on this ship, which can transport 4000 cubic meters of cargo, is that of Technigaz, using 9-percent nickel steel tanks insulated with plastic foam. The EUCLIDES has carried about six cargoes of LNG, mainly from Arzew to Boston. At other times, she has carried other cryogenic cargoes (such as ethylene and butadiene) in the Mediterranean. Operation has been highly successful. The first two discharges at Boston were carried out by pressurization of the cargo tanks and without benefit of cargo pumps, which at that time had not been installed on the ship.

Exhibit 30. continued

The DESCARTES is the first ship to use the current Technigaz (ex-CONCH OCEAN) stainless steel membrane tank system. She has made two voyages carrying LNG from Arzew to Boston and has carried one cargo of LPG from Venezuela to Europe. The ship has operated eminently satisfactorily. During the second voyage to Boston, a gas concentration was observed in the space surrounding the membrane on the aftermost tank. An examination in the shipyard disclosed a minor fault at the connection of the membrane to the tank dome. This fault was repaired without difficulty and the ship returned to service.

The HASSI R'MEL completes the list of ships from which operating experience can be learned. This ship employs the Gaz-Transport Invar membrane system. The limited service experience thus far gained has been entirely satisfactory.

Exhibit 30. continued

TABLE D-1 MISCELLANEOUS DATA FILE

	Data Item	Responsible Organization
1.	Intercept, entry/exit costs	Manalytics
2.	Coefficient, power term, entry/exit costs	Manalytics
3.	Exponent, power term, entry/exit costs	Manalytics
4.	Scaling factor, foreign entry/exit costs	Manalytics
5.	Intercept, daily port costs	Manalytics
6.	Coefficient, power term, daily port costs	Manalytics
7.	Exponent, power term, daily port costs	Manalytics
8.	Scaling factor, foreign daily port costs	Manalytics
9.	Vessel amortization period, years	Manalytics
10.	Vessel salvage value, fraction	Manalytics
11.	Vessel ROI after tax required, fraction	Manalytics
12.	Vessel tax rate, fraction	Manalytics
13.	Fgn. facility amortization period, years	Manalytics
14.	Fgn. facility salvage value, fraction	Manalytics
15.	Fgn. facility ROI after tax req'd, fraction	Manalytics
16.	Fgn. facility tax rate, fraction	Manalytics
17.	U.S. facility amortization period, years	Manalytics
18.	U.S. facility salvage value, fraction	Manalytics
19.	U.S. facility ROI after tax req'd, fraction	Manalytics
20.	U.S. facility tax rate, fraction	Manalytics
21.	LNG source cost, \$/cu. m. of LNG	Manalytics
22.	Bunker fuel cost, \$/long ton	Booz, Allen
23.	LNG density, lbs/cu. m.	Booz, Allen
24.	Bunker density, lbs/cu. ft.	Booz, Allen
25.	LNG heat content, Btu's/cu. m. of LNG	Booz, Allen
26.	Bunker heat content, Btu's/long ton	Booz, Allen
27.	Blank	Booz, Allen
28.	Maximum port delay, days	Booz, Allen
29.	Burn boil-off, at sea: 1 yes; 2 no	Manalytics
30.	Burn boil-off, maneuvering: 1 yes; 2 no	Booz, Allen
31.	Fleet A&G rate, fraction	Booz, Allen
		Manalytics

Exhibit 31. (Booz-Allen Analysis data file, Nov 1973, Appendix D(21))

TABLE D-4 TECHNICAL SPECIFICATIONS FILE

	Data Item	Responsible Organization
1.	LBP, feet	J. J. Henry
2.	Beam, feet	J. J. Henry
3.	Depth, feet	J. J. Henry
4.	Draft, feet, loaded, arrival	J. J. Henry
5.	Draft, feet, ballast	J. J. Henry
6.	Block coefficient, loaded	J. J. Henry
7.	Block coefficient, ballast	J. J. Henry
8.	Displacement, long tons, loaded	J. J. Henry
9.	Displacement, long tons, ballast	J. J. Henry
10.	Fuel reserve, long tons	J. J. Henry
11.	Miscellaneous and stores, long tons	J. J. Henry
12.	LNG capacity, cu. m.	J. J. Henry
13.	Cryogenic volume (excl. cargo), cu. m.	J. J. Henry
14.	Cargo box cubic, cu. m.	J. J. Henry
15.	Fuel capacity, long tons	J. J. Henry
16.	Ballast capacity, long tons	J. J. Henry
17.	Comb. fuel and ballast capacity, long tons	J. J. Henry
18.	Shaft horsepower, rated	J. J. Henry
19.	Shaft horsepower, utilized	J. J. Henry
20.	Speed, knots, loaded	J. J. Henry
21.	Speed, knots, ballast	J. J. Henry
22.	Gross tonnage	Manalytics
23.	Boil-off rate, loaded, cu. meters LNG/day	J. J. Henry
24.	Boil-off rate, ballast, cu. meters LNG/day	J. J. Henry
25.	LNG, minimum in tanks, cu. meters (arrival)	J. J. Henry
26.	Fuel use rate, at sea, Btu's/shp-hr	J. J. Henry
27.	Fuel use rate, disch., Btu's/hr	J. J. Henry
28.	Fuel use rate, other, Btu's/hr	J. J. Henry
29.	Annual lay-up time, days	J. J. Henry
30.	Loading rate, cu. m. LNG/day	J. J. Henry
31.	Discharging rate, cu. m. LNG/day	Manalytics
32.	Preparation time, loading, days	Booz, Allen
33.	Preparation time, discharge, days	Booz, Allen
34.	Crew size	J. J. Henry
35.	Lightship weight, long tons	J. J. Henry
36.	First ship cost, $	J. J. Henry
37.	Direct labor hours	J. J. Henry
38.	Direct labor cost, $	J. J. Henry
39.	Direct material cost, $	J. J. Henry
40.	Composite overhead rate, fraction	J. J. Henry

Exhibit 32. (Booz-Allen Analysis Technical Specifications, Nov 1973, Appendix D(32))

At the level of production supplied under price ceilings (Q_{fpc}), consumers, as represented by the pipelines, were willing to pay a price for gas not only above the FPC ceiling (P_{fpc}), but considerably above the market-clearing price (P_{market}) as well. Moreover, for each unit of additional production up to market-clearing levels (Q_{market}), consumers were willing to pay more than the market-clearing price. Thus, the area of the triangle ABF is equal to the difference between what consumers doing without gas were willing to pay for additional production ($Q_{market} - Q_{fpc}$) and what they would have actually had to pay for it under market-clearing conditions (equivalent to the rectangle BFHG). This surplus which consumers who actually did without gas would have obtained under hypothesized market-clearing conditions represents the losses to them from FPC price ceilings.

These losses to consumers doing without gas can be compared to the gains by consumers who obtained new gas production. These gains are represented by the area of the rectangle CBED. This area is the difference between the market-clearing and FPC price ($P_{market} - P_{fpc}$) multiplied by the quantity of new gas production they received (Q_{fpc}). Thus, if the area of triangle ABF is at least equal to the area of rectangle CBED, then the gains to those who received gas were offset by the losses by those who had to do without.

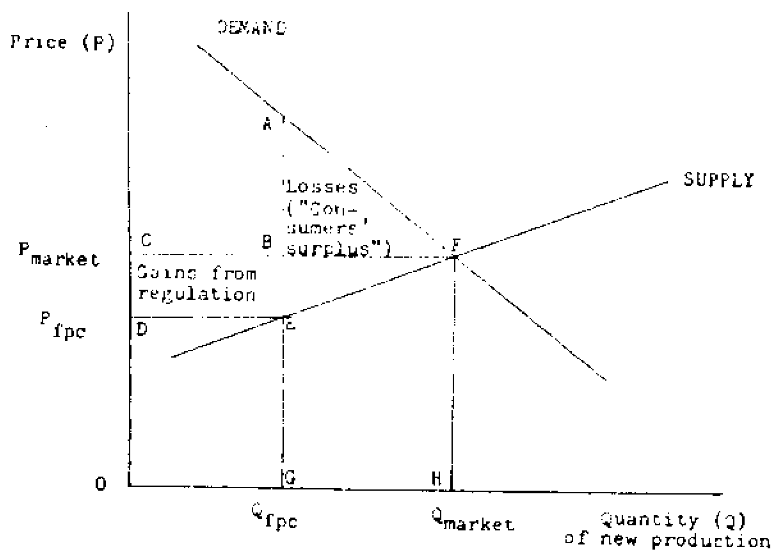


Exhibit 33. (Impacts of Regulation of Natural Gas Rates, S. Breyer and P.W. MacAvoy, 86 Harv. L. Rev. 941, 981-82 n. 127 (1973))

TABLE 17

COMPARISON OF RISKS

Accident Type	Total Fatalities	Probability Per Person Per Year
Motor Vehicle	55,791	2.5×10^{-4}
Falls	17,827	1.0×10^{-4}
Fires & Hot Substances	7,451	4.0×10^{-5}
Drownings	6,181	3.3×10^{-5}
Firearms	2,309	1.0×10^{-5}
Air Travel	1,778	1.0×10^{-5}
Falling Objects	1,271	6.2×10^{-6}
Electrocution	1,148	6.2×10^{-6}
Lightning	160	5.0×10^{-7}
Tornadoes	91	4.0×10^{-7}
Hurricanes	93	4.0×10^{-7}
All Accidents	111,992	6.2×10^{-4}
100 Nuclear Power Plants	-	2×10^{-10}
Transportation of LNG - Proposed Projects		
Point Conception 2/	0.013	-
Oxnard 2/	0.040	-
Los Angeles 2/	0.197	-
Transportation of LNG - Ultimate Projects		
Point Conception 2/	0.024	-
Oxnard 2/	0.301	-
Los Angeles 2/	2.173	-

1/ Reactor Safety Study, U.S. Nuclear Regulatory Commission, Wash 1400; October 1975.

2/ Staff's estimated fatalities per year.

Exhibit 34. (Pac-Indo Project DEIS, FPC, May 1976, p. 332) Comparison of Risks

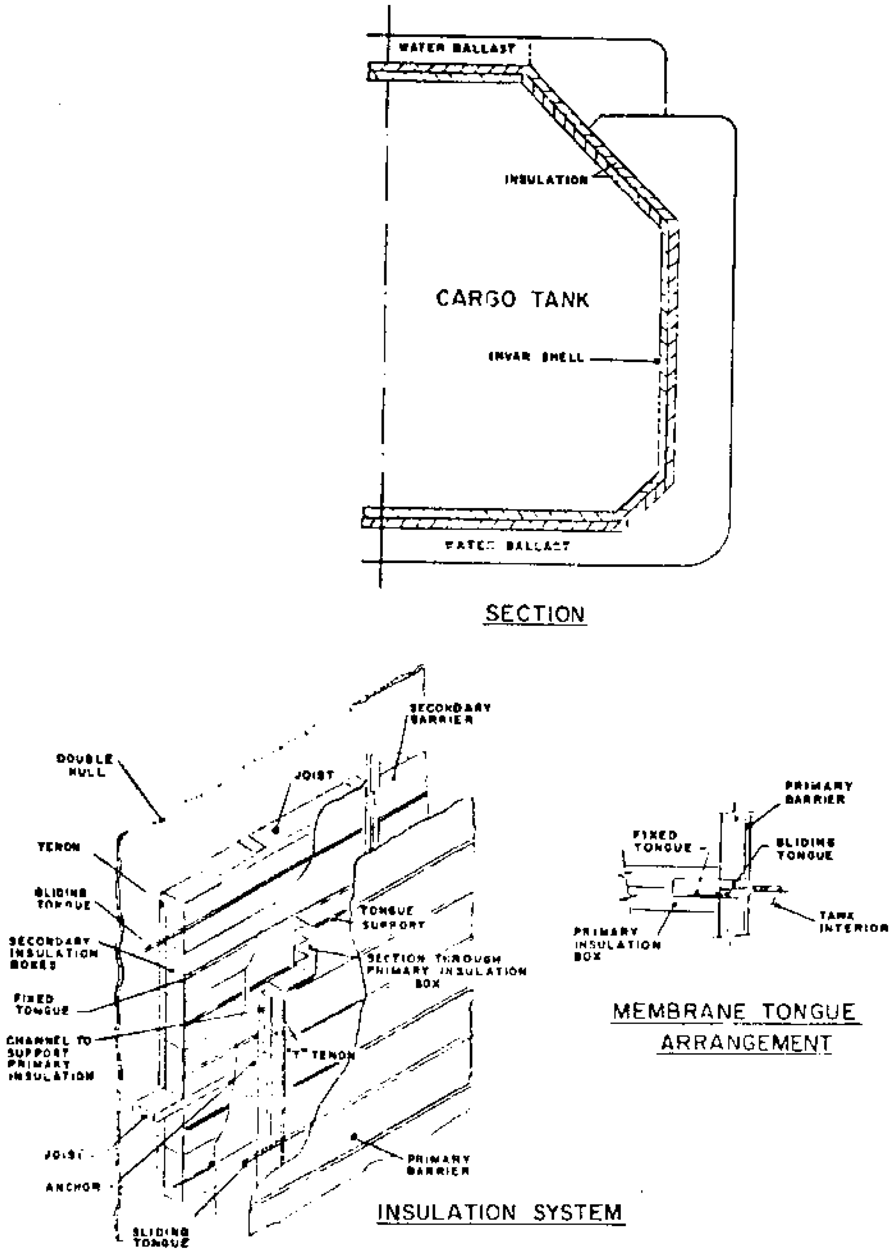


FIG. 3.11
GAZ-TRANSPORT MEMBRANE TANK

Exhibit 35. (Gaz-Transport Membrane Tank, LNG Tank Designs, National Maritime Research Center, Dec 1972, p. 3-35)

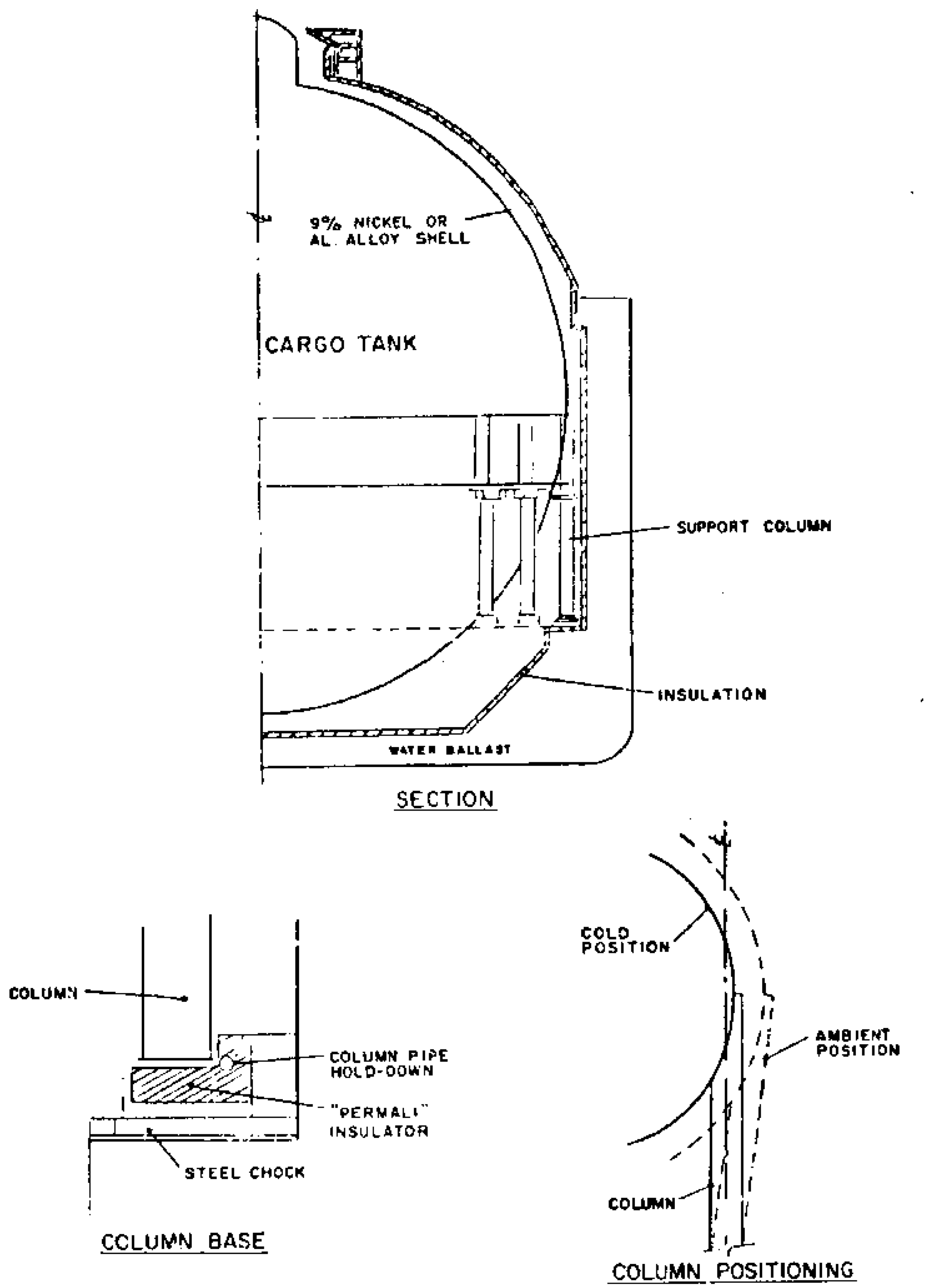


FIG. 3.10

CHICAGO BRIDGE AND IRON FREE-STANDING TANK

Exhibit 36. (Chicago Bridge & Iron Free-Standing Tank, LNG Tank Designs, NMRC, Dec 1972, p. 3-30)

B. RECEIVING TERMINALS

Terminal	Dock Facilities	Storage: Number of Tanks	Storage: Total Capacity Mbbl[a]	Storage: Type
Distrigas Corp. Everett, MA	Berth and wharf; one ship	2	900	Aboveground, 9% nickel
Distrigas Corp. Staten Island, NY	Berth and wharf; one ship	2	1,800	Aboveground, prestressed concrete
Algonquin LNG, Inc. Providence, RI	Berth and wharf; one ship	1 2	600 1,200	Aboveground, 9% nickel Aboveground, 9% nickel
Columbia LNG Corp. Consolidated System LNG Co. Cove Point, MD	"T"-head unloading pier (2,500 ft pier connected with 5,280 ft underwater tunnel--6,400 ft total length); two ships	4	1,500	Aboveground, aluminum
Southern Energy Co. Elba Island, GA	Berth and wharf; one ship	3	1,200	Aboveground, aluminum
Gas Natural S.A. Barcelona, Spain	Berth and wharf; one ship	2 1	500 500	Aboveground, concrete Aboveground, 9% nickel
SNAM (ENI) La Spezia, Italy	Finger pier; pier length 1,640 ft; two ships	2	630	Aboveground, 9% nickel
British Gas Corp. Canvey Island, England	"T"-head unloading pier; trestle length, 750 ft	6 4	360 1,200	Aboveground, aluminum Cryogenic, in-ground
Gaz de France	"T"-head finger	3	226	Aboveground, 9% nickel

Exhibit 37. (LNG Receiving Terminals, Draft paper, H.S. Marcus and J.H. Larson, p. 27 and p. 29)

		Storage		
Terminal	Dock Facilities	Number of Tanks	Total Capacity Mbbl[a]	Type
Gaz de France Fos sur Mer, France	Finger pier; pier length, 13,124 ft; one ship	2	400	Aboveground, aluminum
Tokyo Gas Co. Ltd. Tokyo Electric Power Co., Inc. Negishi Works Yokohama, Japan	Berth and wharf; one ship	4 2	1,006 440	Aboveground, 9% nickel In-ground composite shell
Tokyo Gas Co. Ltd. Tokyo Electric Power Co., Inc. Sedegaura, Japan	Finger pier; one ship	5 6	1,510 2,265	Aboveground, aluminum In-ground composite shell
Osaka Gas Co. Ltd. Semboku, Japan	Berth and wharf	2 1	566 283	Aboveground, 9% nickel Aboveground, aluminum
Western LNG Terminal Co. Los Angeles, CA	Berth and dock; one ship (165,000 m^3)	2	1,100	Aboveground, 9% nickel
Western LNG Terminal Co. Oxnard, CA	Offshore unloading platform and trestle; trestle length, 6,000 ft; one ship (165,000 m^3)	2	1,100	Aboveground, 9% nickel
Western LNG Terminal Co. Point Conception, CA	"T"-head unloading pier and trestle; total length, 4,600 ft; two ships (165,000 m^3)	4	2,200	Aboveground, 9% nickel

[a]Thousands of barrels; 1 barrel =

Source: Phillip J. Anderson and Edward J. Daniels, "LNG Terminals: Existing and Proposed Systems Compared." Pipeline and Gas Journal, September 1975, p. 54-55.

Exhibit 37. continued

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Exhibit 38. continued