UNITED STATES OF AMERICA

Before the

FEDERAL POWER COMMISSION

Volume III of V

Application of El Paso Alaska Company at Docket No. CP75-___ for a Certificate of Public Convenience and Necessity

Pursuant to § 7(c) of the
Natural Gas Act

Respecting the
Proposed
Trans-Alaska Gas Project

Dated: September 23, 1974

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EXHIBIT F-I, F-II, F-III, F-IV

ENVIRONMENTAL REPORT

Application of

EL PASO ALASKA COMPANY

Introduction

INTRODUCTION

This Environmental Report describes the environmental aspects of Applicant's proposed Trans-Alaska Gas Project (referred to herein as the "Alaskan Project").

The Alaskan Project constitutes a transportation system for the movement of natural gas from the Alaskan North Slope to markets in Alaska and the Lower 48 States. Its principal components are:

1. An 809-mile, 42" O.D. buried, chilled gas pipeline, designed to transport some 3.5 bcf/sd from Prudhoe Bay on the North Slope of Alaska to Gravina Point on the Alaskan South Coast (referred to herein as the "Alaskan Gas Pipeline");

2. A liquefaction plant near Gravina Point, with an annual average day design capacity of 2863 MMcf/d LNG equivalent loaded on board the LNG carriers, and necessary LNG storage and handling facilities (referred to herein as the "LNG Plant");

3. A marine terminal near Gravina Point with berthing for two LNG carriers and LNG loading facilities to transfer some 58,000 gpm of LNG from storage to each of the two ships (referred to herein as the "Alaskan Marine Terminal");

4. Eleven 165,000 cubic meter LNG carriers operating between Gravina Point, Alaska, and Point Conception, California (referred to herein as the "LNG Carrier Fleet");

5. Terminalling, regasification and storage at Point Conception, California, and pipeline facilities within the State of California. Such facilities are a vital link in the movement of Prudhoe Bay natural gas, either directly or by displacement, to consumers in the Lower 48 States. They and their potential impacts have been described in the application recently filed by Western LNG Terminal Company. In such application, Point Conception is one of three LNG receiving points proposed;

6. Existing transmission facilities owned and operated by El Paso Natural Gas Company ("El Paso Natural") between the Arizona-California border

and the Permian Basin of West Texas. Such facilities presently transport natural gas in a westerly direction from major production areas in West Texas and northwestern New Mexico. As a principal component of the Alaskan Project, El Paso Natural's existing system will be modified to accommodate both direct easterly flow of gas across the Arizona-California border and the delivery, through displacement, of Alaskan gas into major natural gas transmission systems extending from Texas and Oklahoma to the East and Midwest. Because the required modifications to El Paso's system will be minor in nature (taking place principally within existing compressor stations), their potential impacts are judged to be minimal and are not addressed in this Report; and

7. Major, existing natural gas transmission pipelines extending from West Texas and the Texas-Oklahoma Panhandle to natural gas markets in the East and Midwest. It is contemplated that such systems will have sufficient excess transmission capacity to accommodate the portion of Alaskan gas destined for non-Western markets. Thus, only minor modifications of such systems are expected and they are not within the scope of this Report.

Applicant's environmental assessment was conducted on the basis of information derived from current, published literature, supplemented by appropriate field investigations. This Report describes the scope of such assessment and the conclusions drawn therefrom. It has been prepared pursuant to the provisions of FPC Order No. 483, Docket No. R-473 (June, 1973), "Guidelines for the Preparation of Applicant's Environmental Reports." In some of the 11 sections, however, the format necessarily departs from that suggested in the Guidelines in order to provide increased clarity and continuity.

This Report comprises Volumes III, IV and V of the total FPC Application, as follows:

VOLUME III

Introduction

The Introduction provides a brief description of the Alaskan Project, along with an overview of the organization and scope of this Environmental Report.

Section 1 - Description of the Proposed Action

Section 1 presents a summary of the national energy picture, as well as a detailed description of the proposed facilities, their location, land requirements, construction plans and schedules, operation and maintenance procedures, and future plans.

VOLUME IV

Section 2 - Environmental Baseline

Section 2 describes existing abiotic, biotic and socioeconomic conditions in the area of the proposed Alaskan Project. Section 2A presents such information for the State of Alaska in terms of the three geographic areas constituting the principal climatic, physiographic and biologic divisions in the state. Section 2F describes baseline conditions in the North Pacific Ocean.

VOLUME V

Section 3 - Environmental Impact of the Proposed Action

Section 3 describes both certain and threatened impacts upon the existing environment which will result from construction, operation and ultimate termination of the proposed Alaskan Project. As in the case of Section 2, Section 3 is comprised of Sections 3A and 3F, which treat the State of Alaska and the North Pacific, respectively.

Section 4 - Measures to Enhance the Environment or to Avoid or Mitigate Adverse Environmental Effects

Section 4 comprises a discussion of those necessary measures taken or to be taken by Applicant to eliminate or lessen the effects of potentially undesirable impacts of the Alaskan Project.

Section 5 - Unavoidable Adverse Environmental Effects

Section 5 lists those impacts of the Alaskan Project which are judged by Applicant to be both unfavorable and not susceptable to effective mitigation. They are presented in subjective terms, such as once-occuring, repetitive, continuous, short-term and long-term. Most of such impacts are incremental to similar impacts of the Alyeska oil pipeline project.

Section 6 - Relationship Between Local Short-term Uses of Man's Environment and the Maintenance and Enhancement of Long-term Productivity

Section 6 describes the proposed Alaskan Project in terms of the benefits it will provide, as compared to its effects on the long-term productivity of the Project area.

Section 7 - Irreversible and Irretrievable Commitments of Resources

Section 7 consists of a compilation of both abiotic and biotic resources which will be irreversibly consumed due to implementation of the Project.

Section 8 - Alternatives

Section 8 describes those alternatives to (and within) the Project which are considered by Applicant to constitute realistic and reasonable options. They are discussed in terms of economic, environmental and engineering factors.

Section 9 - Permits and Compliance with Other Regulations and Codes

Section 9 contains all known governmental and industrial regulations and codes which may apply to the Alaskan Project, and all permits and other approvals which Applicant may be required to secure.

Section 10 - Sources of Information

Section 10 lists major information-gathering contacts made by Applicant with various governmental agencies and other entities, as well as Project-related studies undertaken, and participating consultants.

Section 11 - LNG Safety

Section 11 provides an analysis of potential hazards of LNG. It includes studies of the exposure of LNG carriers to collision while underway, and of the dispersion characteristics of an LNG vapor plume resulting from a "maximum credible spill," occuring either on land or on water. The analysis considers LNG where it may exist in any component of the Project, from the plant at Gravina Point, Alaska, through the carriers' approach to Point Conception, California.

Using the substantial data base accumulated in Alaska in recent years (largely due to the implementation of the Trans-Alaska Oil Pipeline Project), Applicant has described the baseline environment for the areas to be affected by the Project from the standpoint of a "functional dynamic system."

Such approach allows interpretation of the function of each animal in its environment, and its specific and multiple interactions, regardless of population size. This is a markedly more advanced and useful tool than a static, natural history cataloging of biota, and is one which allows reasonably accurate predictions of potential impacts from one or more dislocative actions. Furthermore, to more accurately describe the environmental setting at the time when construction of the Alaskan Project is to commence, Applicant has relied heavily on the Final Environmental Impact Statement, Proposed Trans-Alaska [Oil] Pipeline, and most, if not all, impacts of the gas pipeline will be incremental or additive to those of Alyeska. Furthermore, the timing of the Alaskan Project, if realized, will provide for certain mitigative effects to impacts of the oil pipeline, principally in the socioeconomic sector (see Section 3).

For the reader's convenience, a glossary of scientific and technical terms used in this Report is presented in the following pages. Additionally, a copy of a large scale map of the State of Alaska is included in the map pocket on the back cover of this book.

GLOSSARY OF TERMS

Ablation - the combined processes by which a glacier wastes

Alluvium - clay, silt, sand, gravel or similar material deposited by running water

Anadromous - migrating up rivers from the sea to breed in fresh water

Anticline - a fold in the earth's strata that is convex upward

Arcuate - curved or bowed

Aufeis (icing) - a sheet of ice formed on a river flood plain in winter when shoals in the river freeze solid or are otherwise dammed so that water spreads over the flood plain and freezes.

Autotrophy - fixation of light energy from sun and/or use of inorganic compounds for food by plants and bacteria (cf Heterotrophy)

Batholith - a body of intrusive rock, with the general characteristics of a stock, but of much larger size

Beaded stream - a stream in permafrost soil along which are dispersed pools or "beads" created by melting of large bodies of ground ice

Bedrock - solid rock underlying unconsolidated surface materials

Benthic - referring to the bottom of a body of water or to organisms living in the bottom

Biome - an ecosystem or series of ecosystems distinguished by the structure or stature of the dominant primary producers (e.g., tundra biome dominated by grass-like species, moss, and lichens)

Biota - flora and fauna together; organisms

Carnivore - animal that consumes other animals; carnivores may eat herbivores, saprovores, or other carnivores

Climax vegetation - final assemblage of plant species at the end of successional series; may or may not be stable community

Community - an association of interacting populations variously delimited, but often by spatial occurrence or by their interactions

Cryopedogenic - refers to cold soil processes or conditions

Detritovore - aquatic organism that consumes dead organic material (cf Saprovore)

Ecosystem - the assemblage of biotic communities and abiotic parameters into an interactive system

GLOSSARY OF TERMS
(Continued)

Ecotone - a habitat created by juxtaposition of distinctly different habitats--an edge habitat

Eolian - deposits arranged by the wind. Applied to the erosive action of the wind and to deposits which are due to the transporting action of the wind

Eutrophication - gradual depletion of dissolved oxygen in a body of water, resulting in a system favoring plant over animal life

Fluvial - of, or pertaining to, rivers; growing or living in streams or ponds; produced by river action, as a fluvial plain

Glacial Flour - fine-grained soil formed by glacial erosion of rock

Gleization - process of forming gley soils (sticky gray, organically rich layer in frequently saturated ground)

Gneiss - a coarse-grained rock in which bands rich in granular mineral alternate with bands in which schistose minerals predominate

Graywacke - a type of sandstone, generally tough and well indurated with a dark color

Habitat - where an organism is found in space, often characterized by dominant plant species or physical characteristic; "address" (cf Niche)

Herbaceous - non-woody (plants)

Herbivore - animal that consumes living plant tissues

Heterotrophy - obligatory use of organic materials for food, as by consumers (cf Autotrophy)

Ice Lense - thin layer of ground ice generally in lenticular form

Interstitial Ice - strands or lenses of ice within a soil mass

Kame - a conical hill or short irregular ridge of gravel or sand deposited in contact with glacier ice

Layering - in plants, spread from parent organism by secondary vertical structures growing from long lateral stems

Lithosols - shallow soil largely composed of incompletely weathered rock fragments

Loess - a homogenous, nonstratified, unindurated deposit consisting predominately of silt, deposited primarily by the wind

Mafic Intrusion - basic igneous intrusive rock

Nappes - a large body of rocks that has moved forward more than 1 mile from its original position either by overthrusting or by recumbent folding

Niche - organism's functional role in the ecosystem; "occupation," e.g., herbivore, saprovore (cf Habitat)

Oligotrophic - low in productivity; particularly in reference to fresh water lakes, connoting clear water with high oxygen content

Oriented Thaw Lakes - water-filled surface depression: formed by subsidence of thawed permafrost and displaying a preferred compass orientation of their long axes

Permafrost - permanently frozen subsoil

Phagotrophy - feeding by engulfing and digesting food; refers in text to algal cells which are normally autotrophic

Photosynthate - chemical products of photosynthesis

Phyto- - having to do with plants

Pingo - a hill cored with ice

Polygonal Ground - polygonal soil patterns produced by alternate freeze and thaw of the surface soil, or by contraction of frozen soil

Potentiometric Surface - the surface to which water in an aquifer would rise by hydrostatic pressure

Primary production - accumulation of energy and nutrients by green plants and other autotrophs--a quantity (cf Primary productivity)

Primary productivity - rate of energy and nutrient accumulation by plants and autotrophs; secondary productivity is rate of accumulation by consumer organisms through growth and reproduction

Regosols - soils consisting chiefly of imperfectly consolidated material and having no clear-cut and specific morphology

Riparian - referring to the banks of a lake or river

Saprovore - organism that consumes dead organic material and decomposer organisms associated therewith, primarily in terrestrial soils

Scarp - an escarpment, cliff, or steep slope of some extent along the margin of a plateau, mesa, terrace or fault trace

Schistosity - that variety of foliation that occurs in the coarser grained metamorphic rocks

Seiches - periodic oscillations of a body of water whose period is determined by the resonant characteristics of the containing basin as controlled by its physical dimensions. These periods range from a few minutes to an hour or more

Sera - stages in succession particular to a given region or habitat (cf Succession)

Solifluction - downward creep of soil and vegetative mat on slopes, most often associated with pronounced freeze-thaw cycle

Solum - upper part of soil profile, in which active soil formation occurs

Species diversity - used here informally, as numbers of species within a functional unit of the ecosystem; i.e., the more species operating as herbivores, the greater the species diversity

Subnivean - under or in the snow, as in subnivean habitats

Succession - successive replacements through time of species populations by other species populations, following initial biotic colonization, or disturbance to a region

Syncline - a fold in rocks in which the strata dip inward from both sides toward the axis

Talus - a collection of fallen disintegrated material which has formed a slope at the foot of a steeper slope or cliff

Thermokarst - settling or caving of the ground due to melting of ground ice

Tsunami - a sea wave produced by a submarine earthquake or volcanic eruption. Commonly misnamed tidal wave

Turnover rate - informally: the rate at which energy, nutrients, or individuals are cycled through the ecosystem; formally: the ratio of productivity to biomass

Vascular - possessing true conductive tissue; applied in text to plants, to distinguish grasses, shrubs, trees, and flowering plants from mosses, ferns, lichens, and algae

Vivipary - in plants, refers to method of reproduction in which fully formed (already-green and photosynthesizing) young plants are broadcast by the parent plant

Section 1
Description of Proposed Action

SECTION 1 - DESCRIPTION OF PROPOSED ACTION

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Section 1.0
Introduction

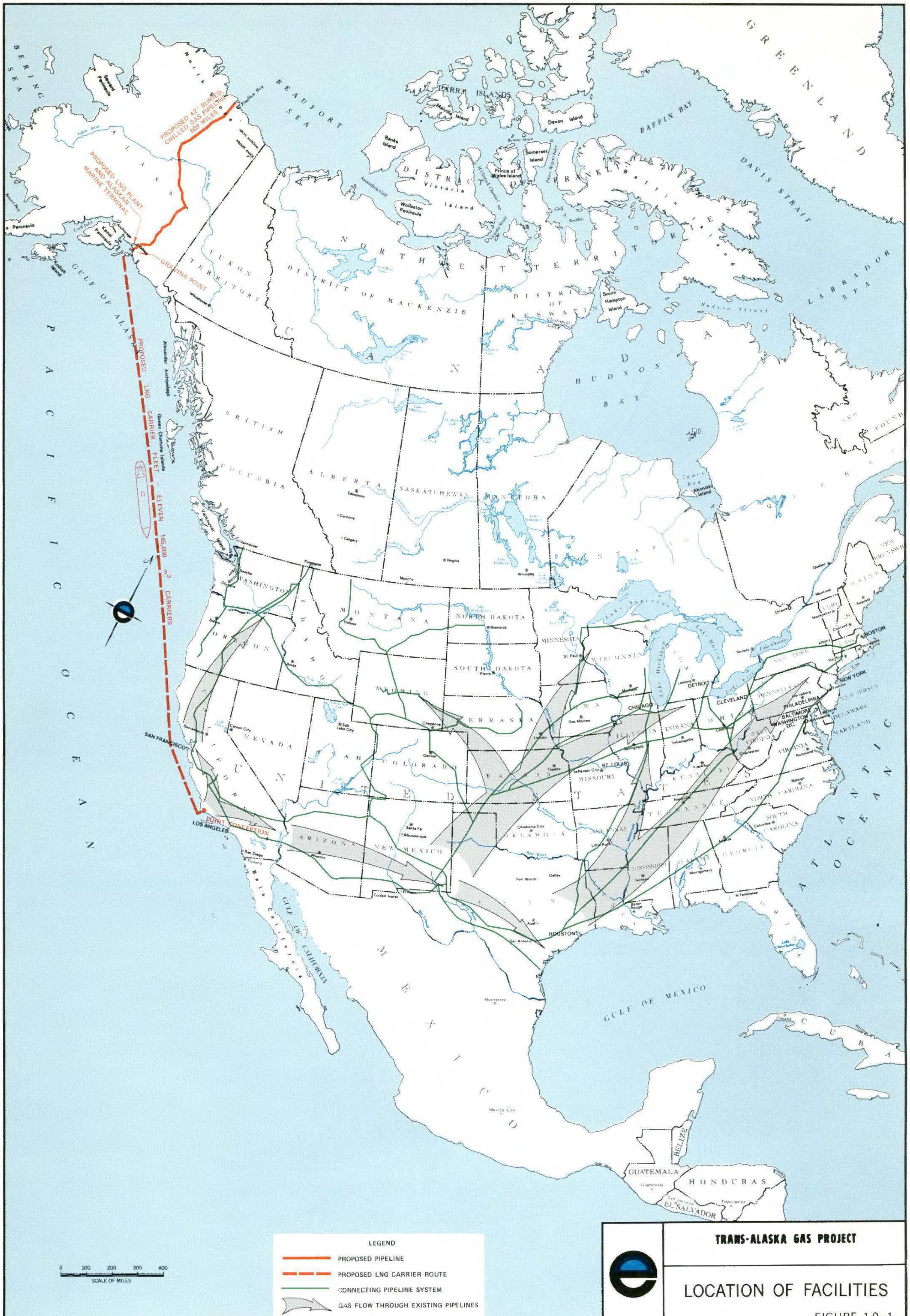
1 DESCRIPTION OF PROPOSED ACTION

1.0 INTRODUCTION

Applicant proposes the Alaskan Project for the purpose of delivering substantial quantities of natural gas supplies to consumers located throughout the continental United States.

The proposed action contemplates the transportation of Prudhoe Bay gas by means of a large-diameter pipeline to the southern coast of Alaska, where it will be liquefied and shipped by a fleet of special cryogenic tankers to the West Coast of the United States. At Point Conception, California, the liquefied natural gas (LNG) will be off-loaded and regasified, and then delivered into pipeline systems in California for ultimate distribution to markets in the contiguous United States (see Figure 1.0-1).

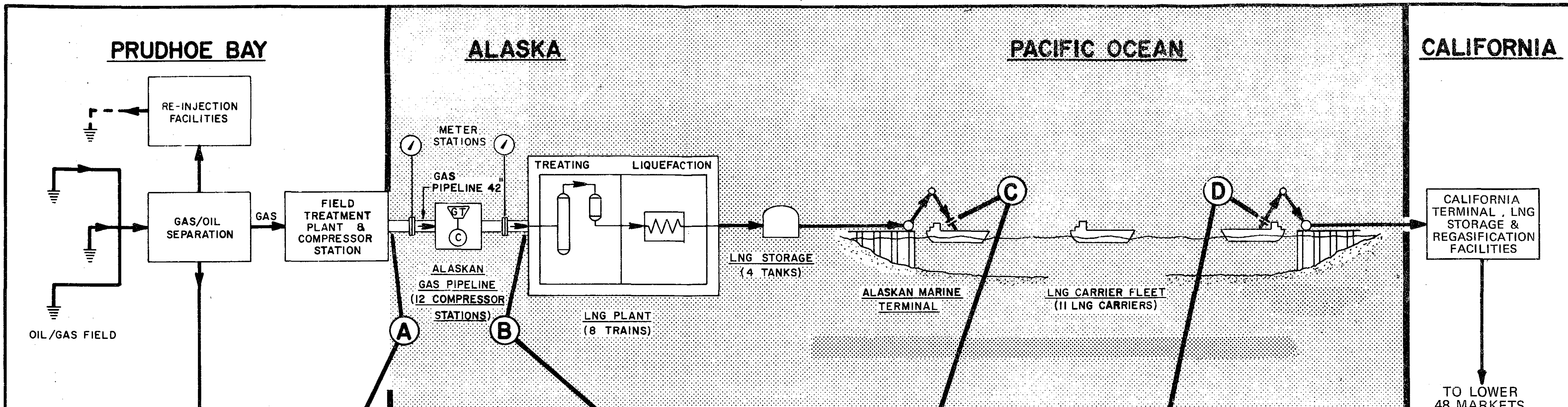
For ease of reader reference, the Overall Project Material Balance and the Overall Project Summary Construction Schedule are presented in Figures 1.0-2 and 1.0-3, respectively.



TRANS-ALASKA GAS PROJECT

LOCATION OF FACILITIES

FIGURE 1.0–1



(A) PIPELINE GAS FROM FIELD TREATMENT PLANT

COMPONENT	MOL %
N_2	0.75
CO_2	1.02
C_1	85.91
C_2	7.77
C_3	3.93
iC_4	0.26
nC_4	0.30
iC_5	0.03
nC_5	0.02
C_6+	0.01
TOTAL FLOW MMCF/CD	3283.30
HHV. BTU/SCF	1130.13
GROSS HEAT. BILLION BTU/CD	3710.56
GROSS HEAT. % OF STREAM (A)	100.00

(B) FEED GAS TO LNG PLANT

COMPONENT	MOL %
N_2	0.75
CO_2	1.02
C_1	85.91
C_2	7.77
C_3	3.93
iC_4	0.26
nC_4	0.30
iC_5	0.03
nC_5	0.02
C_6+	0.01
TOTAL FLOW MMCF/CD	3190.07
HHV. BTU/SCF	1130.13
GROSS HEAT. BILLION BTU/CD	3605.20
GROSS HEAT. % OF STREAM (A)	97.16

(C) LNG TO CARRIER

COMPONENT	MOL %
N_2	0.06
CO_2	
C_1	86.66
C_2	8.37
C_3	4.25
iC_4	0.28
nC_4	0.32
iC_5	0.03
nC_5	0.02
C_6+	0.01
TOTAL FLOW MMCF/CD	2864.01
HHV. BTU/SCF	1157.80
GROSS HEAT. BILLION BTU/CD	3315.95
GROSS HEAT. % OF STREAM (A)	89.37

(D) LNG TO REGASIFICATION PLANT

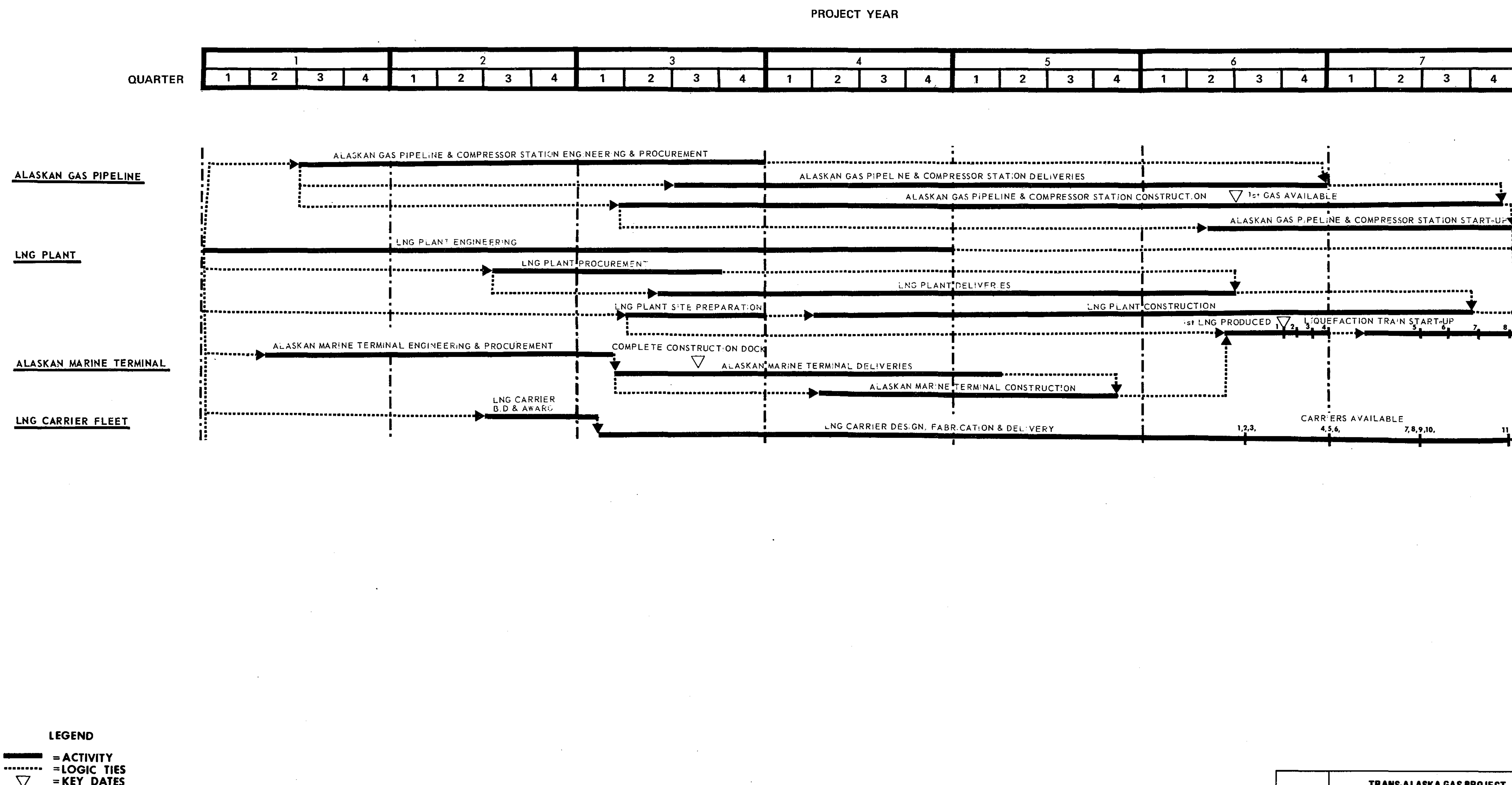
COMPONENT	MOL %
N_2	0.05
CO_2	
C_1	86.47
C_2	8.49
C_3	4.32
iC_4	0.28
nC_4	0.33
iC_5	0.03
nC_5	0.02
C_6+	0.01
TOTAL FLOW MMCF/CD	2809.50
HHV. BTU/SCF	1160.20
GROSS HEAT. BILLION BTU/CD	3259.58
GROSS HEAT. % OF STREAM (A)	87.85

NOTES:
- STANDARD CONDITIONS 14.73 PSIA AND 60° F
- VOLUMES SHOWN ARE AVERAGE DAY RATES OVER A PERIOD OF 365 DAYS

TRANS-ALASKA GAS PROJECT

OVERALL PROJECT MATERIAL BALANCE (ANNUAL AVERAGE DAY)

FIGURE 1.0–2



TRANS-ALASKA GAS PROJECT

OVERALL PROJECT SUMMARY CONSTRUCTION SCHEDULE

FIGURE 1.0–3

1.1 PURPOSE

1.1.1 Purpose of Facilities

The proposed Alaskan Project will provide for the utilization of one of this nation's great untapped natural resources--the vast natural gas reserves of Prudhoe Bay, Alaska--at a time when demands for total energy and for natural gas will far exceed the available supply. The Energy Overview presented in Section 1.1.2 following, discusses energy supply and demand and the contribution of the "All American" Alaskan Project toward alleviating the energy crisis and promoting United States energy self-sufficiency.

Figure 1.0-1 illustrates the following four major components of the Alaskan Project:

(1) Alaskan Gas Pipeline,
(2) LNG Plant,
(3) Alaskan Marine Terminal, and
(4) LNG Carrier Fleet.

The Alaskan Gas Pipeline will transport natural gas from Prudhoe Bay to the Gravina Peninsula on the southern coast of Alaska. There the gas will be liquefied at the LNG Plant and transferred via the Alaskan Marine Terminal to the LNG Carrier Fleet, for shipment to the southern coast of California and subsequent regasification and distribution in the Lower 48 States.

1.1.2 Energy Overview

The proposed action is essential to help satisfy future energy demand. The following sections discuss future supply and demand for both total energy and natural gas for the nation.

1.1.2.1 Supply and Demand for Total Energy

The National Petroleum Council (NPC) is an officially established industry advisory board to the Secretary of the Interior. In December, 1972, the NPC published the "U.S. Energy Outlook: A Report of the National Petroleum Council's Committee on U.S. Energy Outlook", referred to as the Full Report. The groundwork for the Full Report was an interim report entitled, "U.S. Energy Outlook: An Initial Appraisal 1971-1985", which was published in July, 1971, and which will be referred to as the Initial Appraisal, or Intermediate case.

The single case projections of the energy supply and demand balance made by the NPC Initial Appraisal were expanded in the Full Report to include three demand cases and four supply cases. The Full Report utilized for the intermediate demand case the same 4.2% annual average growth rate as was used in the Initial Appraisal for the 1971-1985 period. Further, it adopted high and low ranges of 4.4% and 3.4% to include the probable differences that might occur under various assumptions concerned with economic activity, cost of energy, population and environmental controls, as more fully described in the Full Report and in a subsequent NPC task group report entitled, "U.S. Energy Outlook: Energy Demand". The four sets of supply assumptions are explained in detail throughout the Full Report and are discussed briefly in the following excerpt from page 5 thereof:

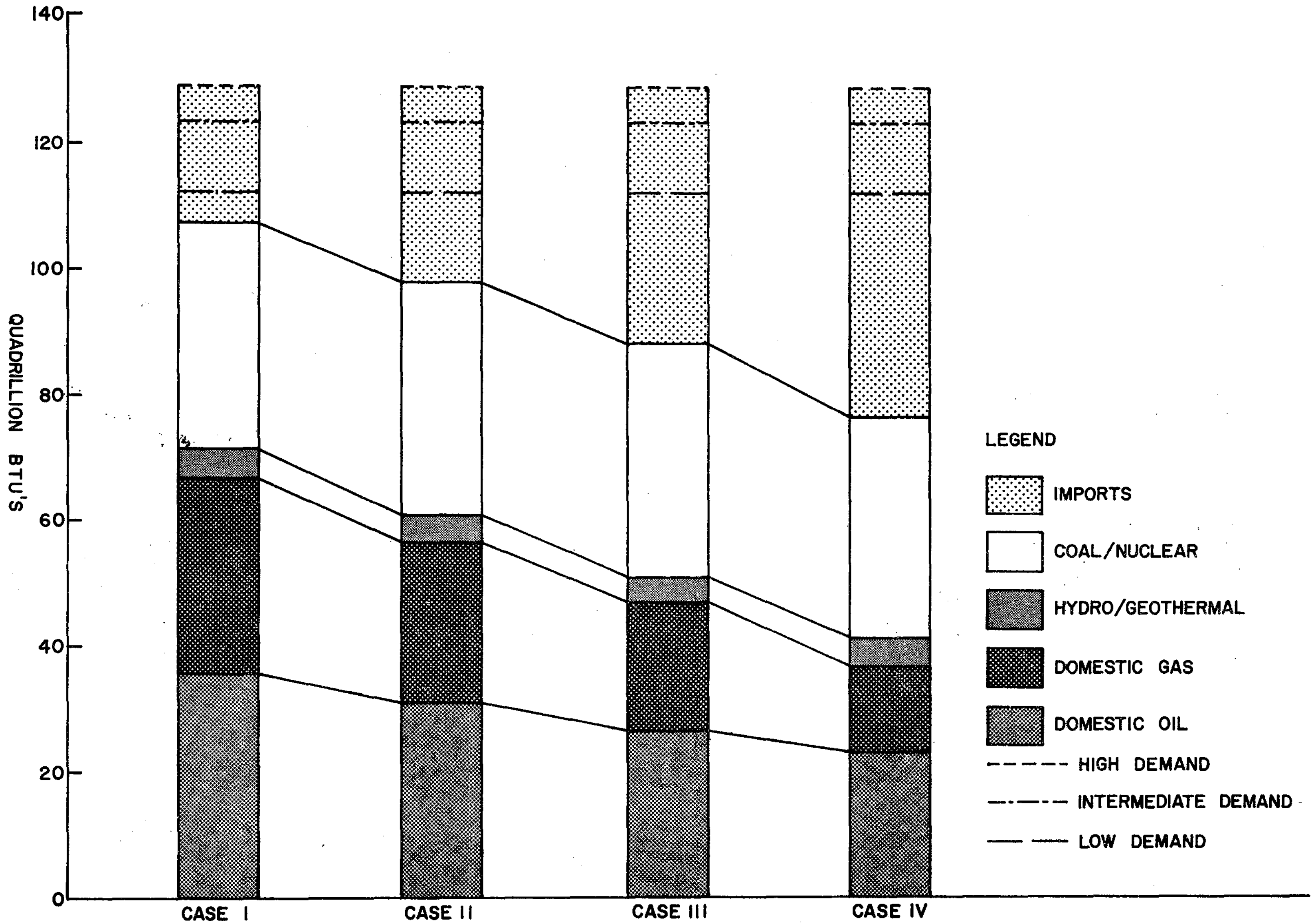
> "The high end of the calculated supply range (Case I) would be difficult to attain because it requires a vigorous effort fostered by early resolution of controversies about environmental issues, ready availability of government land for energy resource development, adequate economic incentives, and a higher degree of success in locating currently undiscovered resources than has been the case in the past decade. The low end of the range of supply availability (Case IV) represents a likely outcome if disputes over environmental issues continue to constrain the growth in output of all fuels, if government policies prove to be inhibiting, and if oil and gas exploratory success does not improve over recent results. Two intermediate appraisals (Cases II and III) were also developed, with the higher supply Case II assuming improvement in finding rates for oil and gas, and a quicker solution to problems in fabricating and installing nuclear power plants."

Figure 1.1-1 illustrates the NPC Full Report projection of the energy supply and demand balance in 1985. Assuming ultimate realization of the NPC's most optimistic supply case and the most conservative demand case, demand will be 5.5%, or six quadrillion Btu, higher than domestic supply. At the other extreme, the highest NPC demand case is projected to be 70%, or 54 quadrillion Btu, more than the lowest supply estimate of 77 quadrillion Btu. The NPC assumed that the supply deficiencies would be satisfied by oil imports, since gas imports were included in the estimate of domestic gas supply.

The intermediate supply cases II and III are shown in relation to demand in Figure 1.1-2 for the years 1975, 1980 and 1985. The domestic supply deficiency is projected to increase with time in each case.

An energy report was published in December, 1972, by the U.S. Department of the Interior entitled, "United States Energy Through the Year 2000", and will be referred to herein as the USDI Report. Supply and Demand were not forecasted separately by the USDI Report; all supply limitations on all fuels were considered, resulting in a forecast of consumption rather than of demand. Also considered were the Gross

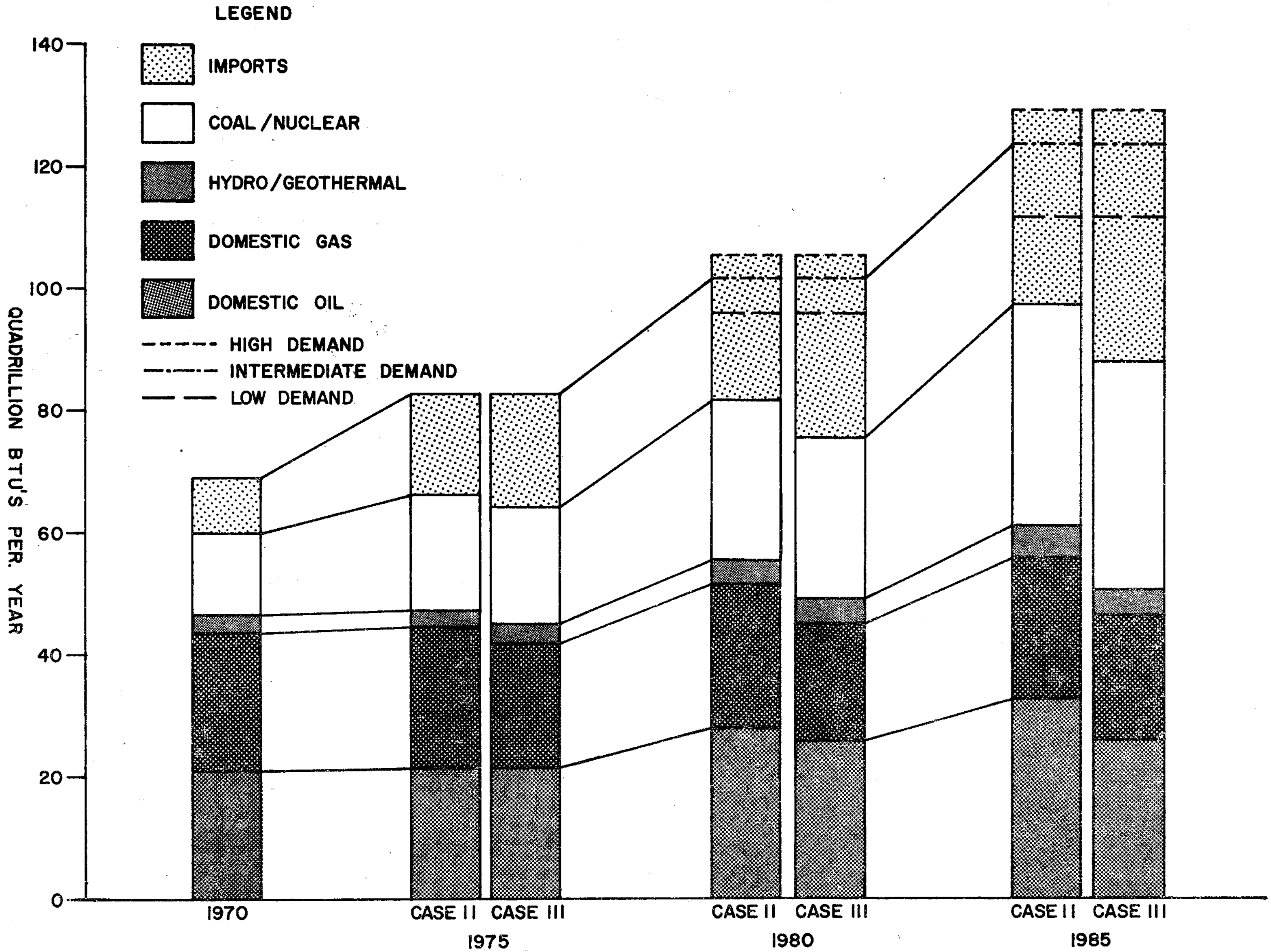
REFERENCE:
NATIONAL PETROLEUM COUNCIL, 1972



TRANS-ALASKA GAS PROJECT

UNITED STATES ENERGY SUPPLY AND CONSUMPTION IN 1985

FIGURE 1.1 – 1



REFERENCE:
NATIONAL PETROLEUM COUNCIL, 1972

TRANS-ALASKA GAS PROJECT

ENERGY SUPPLY AND CONSUMPTION CASES II AND III

FIGURE 1.1 – 2

National Product (GNP), population, industrial production, prices, technology, and life-style. The results of the USDI Report, presented in Figure 1.1-3, generally agree with the NPC low demand case for 1980 and 1985 shown in Figure 1.1-2. The USDI Report's estimate of the distribution of energy by consuming sector is shown in Figure 1.1-4.

A visual energy model capable of displaying the size and complexity of the national energy situation in a readily comprehensible manner has been developed by the Congressional Joint Committee on Atomic Energy (JCAE). Such model is explained in detail in the Committee's report entitled, "Understanding the National Energy Dilemma", published in September, 1973, by The Center for Strategic and International Studies.

The JCAE Report simply illustrates a new method of data presentation and contains no new information. Among the references cited by the JCAE Report were: the information and interpretation of the Lawrence Livermore Laboratory based primarily on information released by the Department of the Interior and the National Petroleum Council (Lawrence Livermore Laboratory, 1972); the NPC Initial Appraisal; the NPC Full Report; and the USDI Report, "United States Energy through the Year 2000". The JCAE Report included the Supply/Demand chart shown as Figure 1.1-5 (with a gas equivalency scale added). This chart illustrates the expected magnitude of domestic supply deficiency, and the enormous increase in imports that will be necessary to prevent shortages.

The Pace Company Consultants and Engineers published a report containing energy forecasts which take into consideration the recent Arab oil embargo (The Pace Company, 1974). Figures 1.1-6 and 1.1-7 illustrate the Pace projections of U.S. energy consumption by fuel type and by consuming sectors. Pace considered the Arab oil embargo to be the most significant influence on 1974 energy balance, and therefore included only low and median cases in the projection of 1974 consumption:

Median - Highest consumption pattern attainable within present process capacity limits.

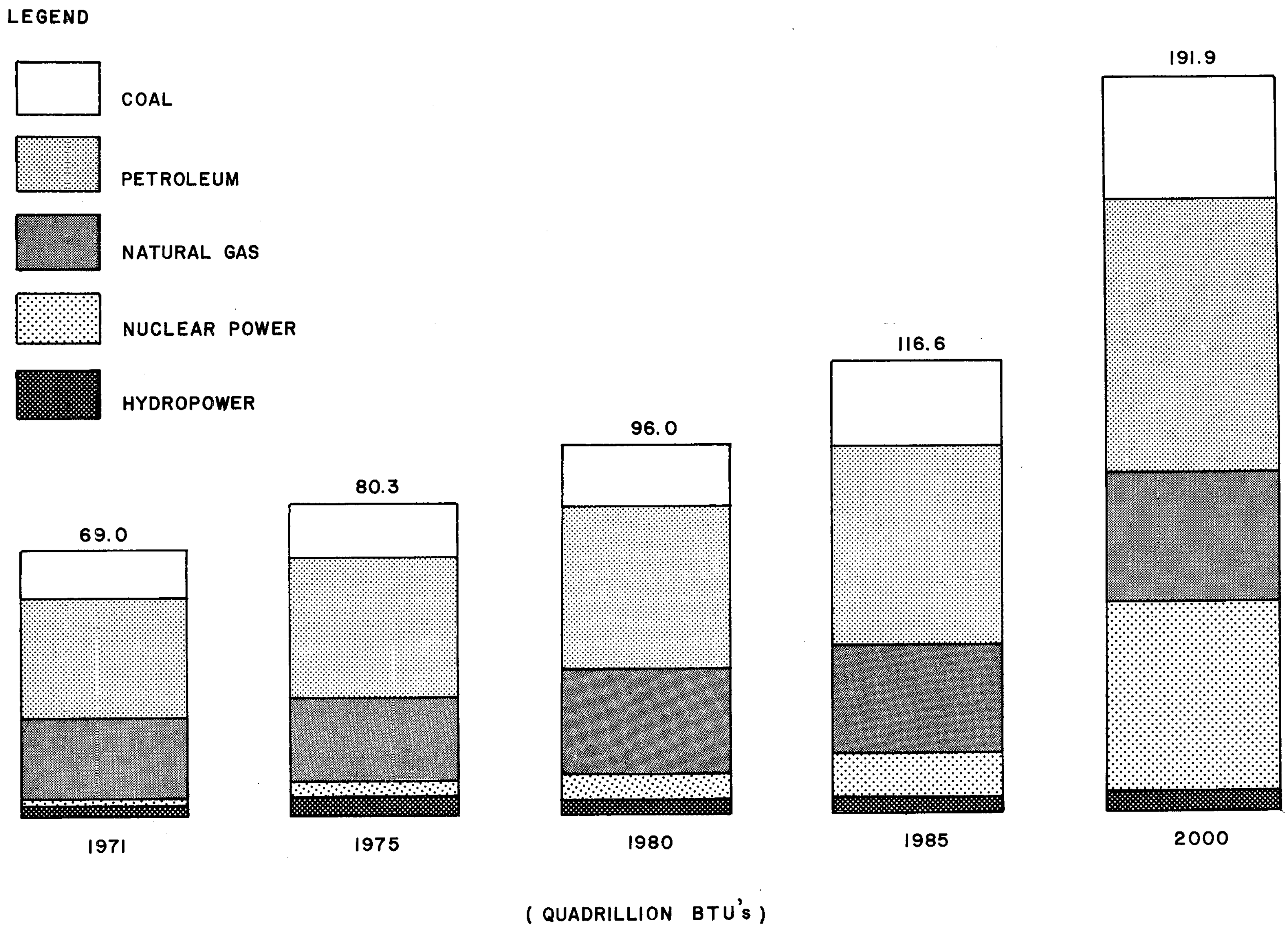
Low - Average 1974 pattern with the Arab oil embargo effective.

For the years 1977, 1980, and 1985, three possible cases were forecast: Median or "most probable" bracketed by a Low and High Sequence which Pace considered practical extremes. General conditions assumed for each sequence are summarized by Pace as follows:

Median - Requires early solution of the Arab oil embargo and government price control policy permitting timely initiation and completion of refinery projects.

Low - Will apply if the Arab oil embargo or uncertainties in government policy continue beyond mid-1974. Delays in refinery projects caused by uncertainties will have a serious negative effect continuing long after lifting of the embargo.

High - Probably not realistically attainable, but illustrates consumption levels which would prevail under optimum circumstances.

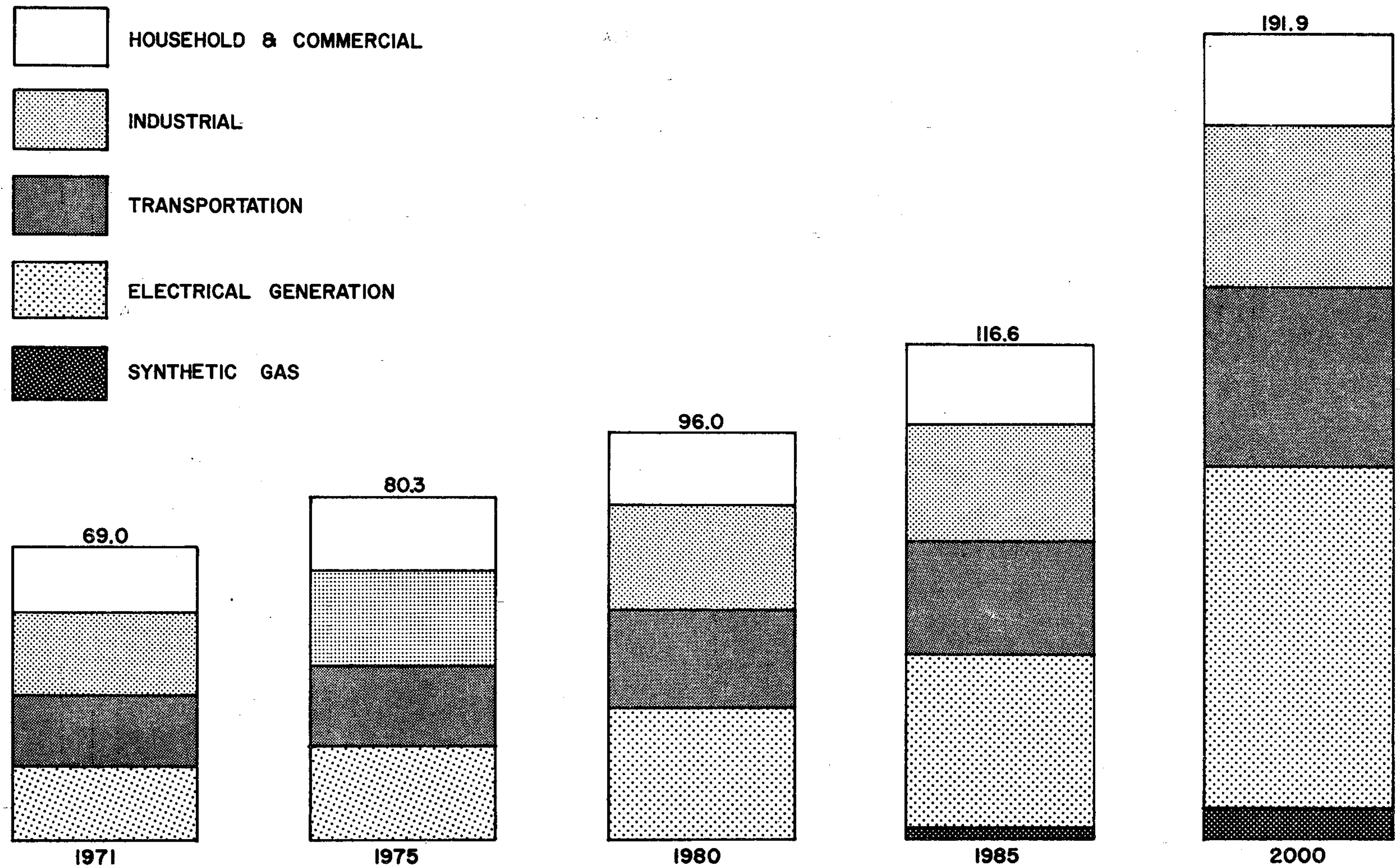


REFERENCE :
U.S. DEPARTMENT OF INTERIOR, 1972

TRANS-ALASKA GAS PROJECT

UNITED STATES
ENERGY CONSUMPTION
BY SOURCE. 1971–2000
FIGURE 1.1 – 3

REFERENCE:
UNITED STATES DEPARTMENT OF
INTERIOR, 1972



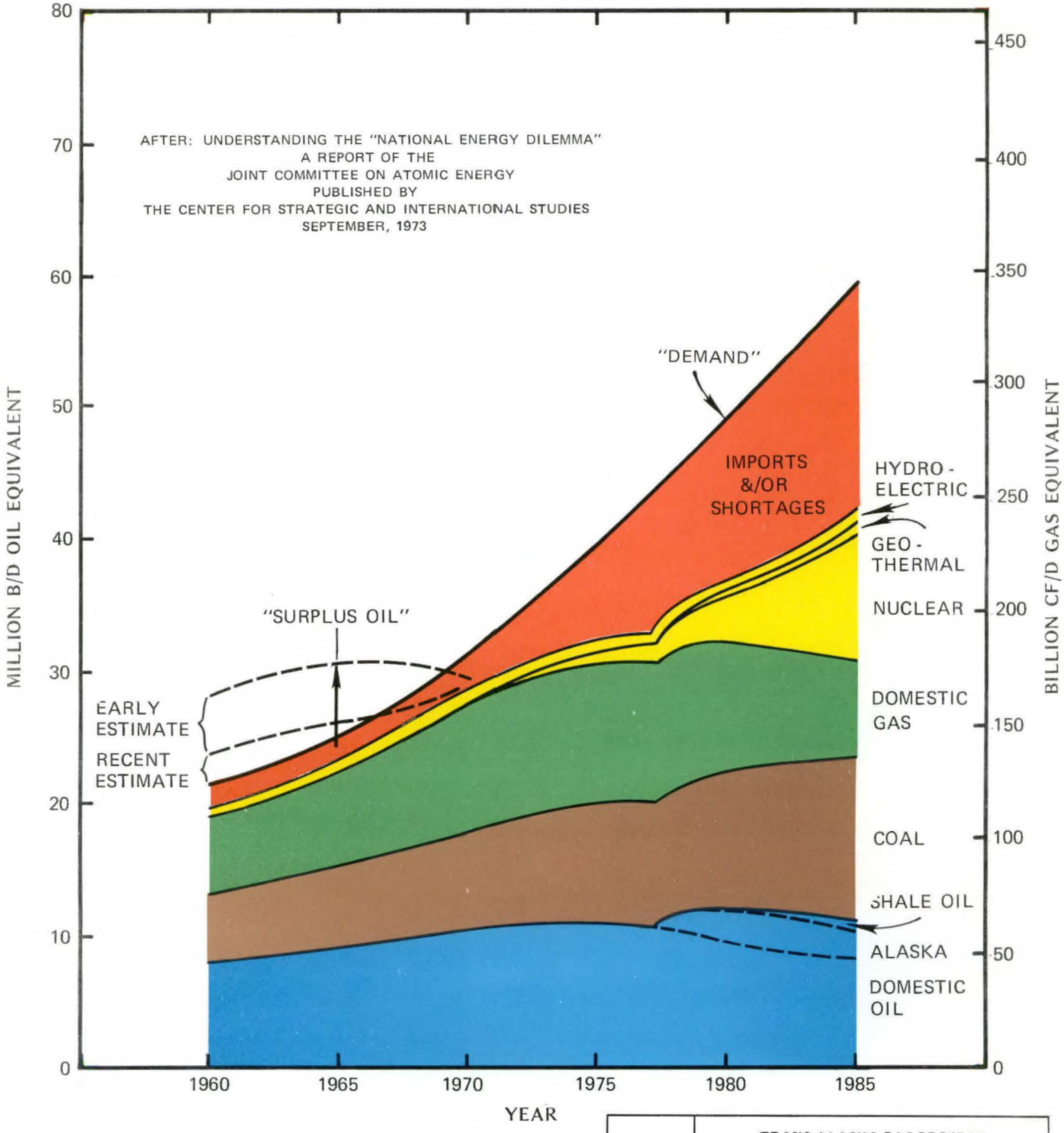
(QUADRILLION BTU'S)

TRANS-ALASKA GAS PROJECT

UNITED STATES
ENERGY CONSUMPTION
BY SECTOR. 1971–2000

FIGURE 1.1 – 4

BARRELS/DAY OIL EQUIVALENT vs YEARS
CUBIC FEET/DAY GAS EQUIVALENT vs YEARS



NOTES

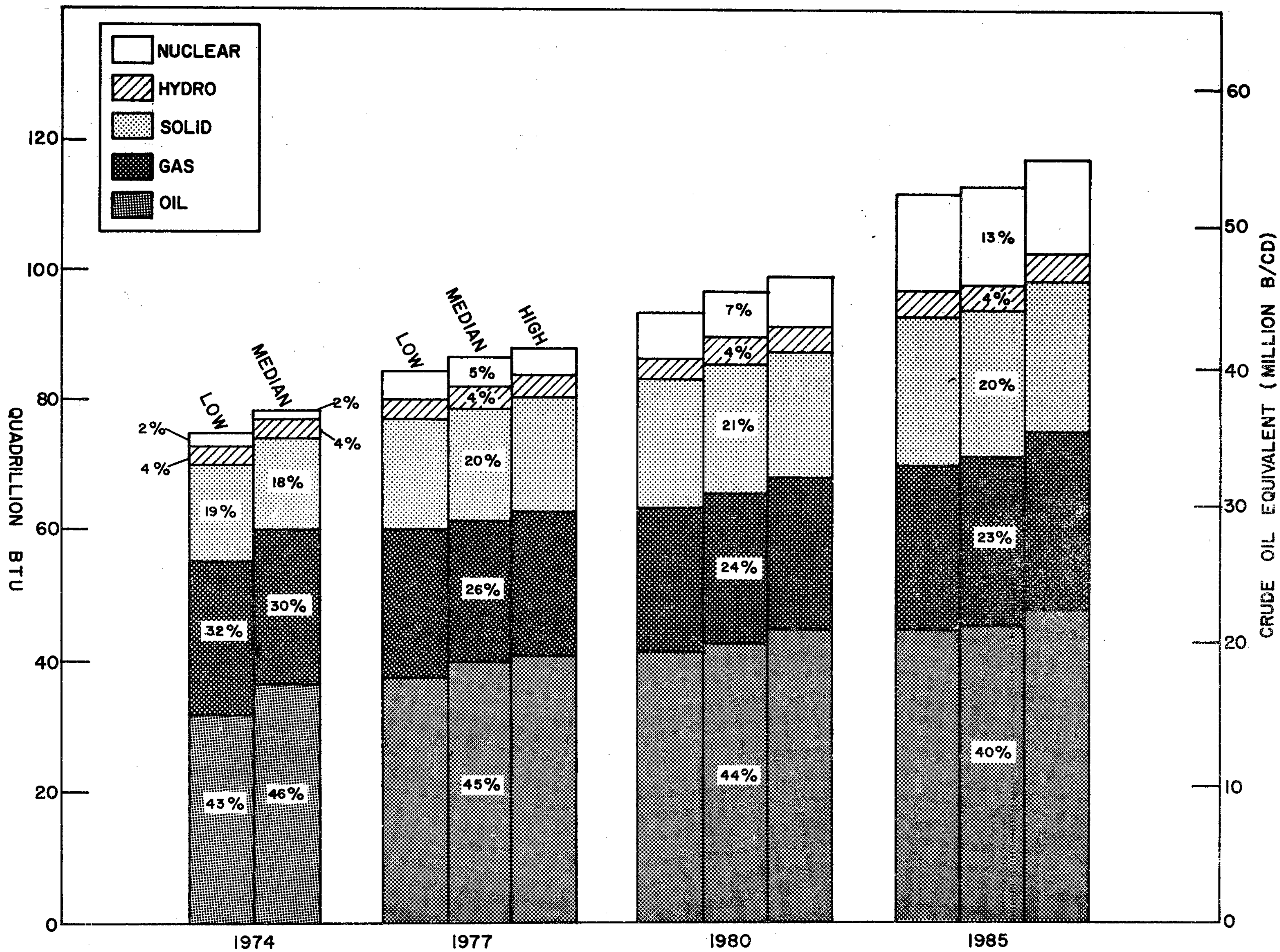
1 BARREL (BBL. OR B) CRUDE OIL = 5,800,000 BTU
1 CUBIC FOOT (CF) NATURAL GAS (CH_4) = 1,000 BTU

TRANS-ALASKA GAS PROJECT

"SUPPLY/DEMAND"
(1960–1985)

FIGURE 1.1–5

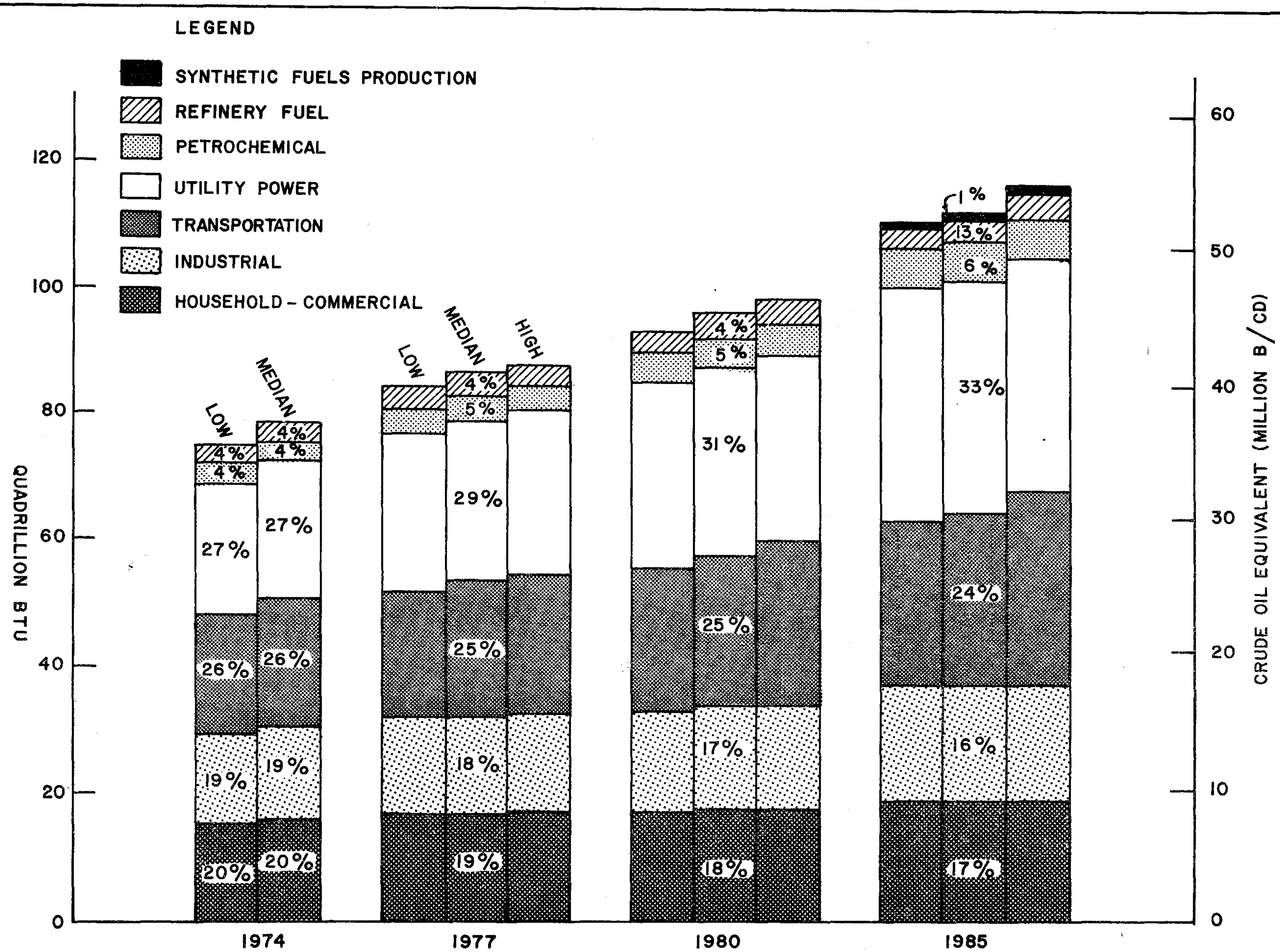
REFERENCE:
THE PAGE COMPANY, 1974



TRANS-ALASKA GAS PROJECT

UNITED STATES ENERGY
CONSUMPTION BY FUEL TYPE

FIGURE 1.1 – 6



REFERENCE:
THE PACE COMPANY, 1974

TRANS-ALASKA GAS PROJECT

UNITED STATES ENERGY CONSUMPTION BY SECTOR

FIGURE 1.1 – 7

The Pace Report stated that energy consumption has historically been demand limited, but that future consumption will be limited by supply. The consumption growth rates used by Pace are:

	Average Annual Growth Rate, %		
	Sequences		
	Low	Median	High
1960 to 1965	-	-	3.9
1965 to 1972	-	-	4.4
1972 to 1974	1.8	4.5	-
1974 to 1977	3.1	3.7	4.0
1977 to 1980	3.6	3.8	4.0
1980 to 1985	3.7	3.3	3.6

Pace assumed that the substantial difference between future domestic supply and consumption would be satisfied by imports.

1.1.2.2 Supply and Demand for Natural Gas

In June, 1974, the Staff of the Federal Power Commission (FPC) released (in advance of Commission approval) a preliminary draft of Chapter 9 (Future Domestic Natural Gas Supplies) of the National Gas Survey. Drastic changes are necessary, according to the draft report, if natural gas or substitutes for it is to meet its projected share of the nation's future energy requirements.

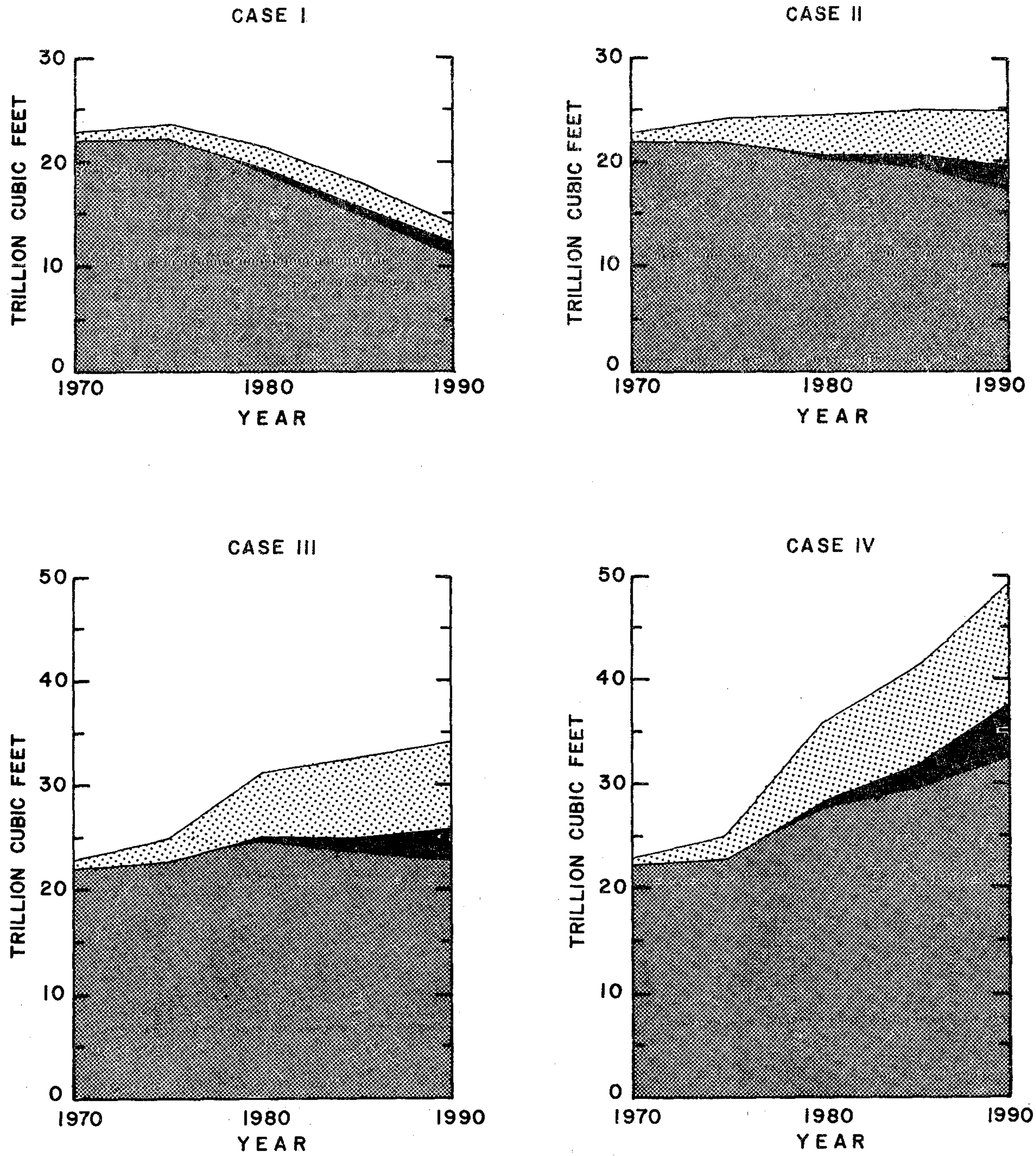
In order to present a perspective of the possible future gas supplies, the report included four projections for the 1970-1990 period, which are listed in Figure 1.1-8 and Table 1.1-1. The projections were based on assumptions ranging from continuation of current trends for Case I, to maximum possible supply conditions for Case IV, with Case II and III assuming intermediate conditions, as described below (Foster Associates Reports, 1974):

Case I (Continuation of Current Trends)

Onshore, non-associated gas forecasts based on projections of the Supply-Technical Advisory Task Force-Natural Gas Supply using current average wellhead prices inflated at 4% annually until 1975 and then held at this level (25¢-27¢/Mcf) through 1990; onshore associated-dissolved gas supplies projected by FPC Staff based on National Petroleum Council forecasts of crude oil reserve additions and historical gas-oil ratio trend data; no offshore development[1/] except to a limited extent in the Gulf of Mexico and Pacific offshore region; no gas from Alaska; pipe-

---

1/ A basic offshore supply projection was developed by the FPC Staff using information provided by the U. S. Geological Survey for the Outer Continental Shelf, together with Staff-prepared forecasts for state offshore areas. In view of the change in the domestic oil and gas situation resulting from the oil embargo of 1973-1974, Staff adjusted
(continued on page 1.1-14)



LEGEND

GAS FROM FOREIGN SOURCES

SUBSTITUTE NATURAL GAS FROM DOMESTIC SOURCES

NATURAL GAS FROM DOMESTIC SOURCES

REFERENCE:
FPC STAFF 1974

TRANS-ALASKA GAS PROJECT

FUTURE AVAILABLE GAS SUPPLIES

FIGURE 1.1 – 8

TABLE 1.1-1

FUTURE AVAILABLE GAS SUPPLY
(TRILLION CUBIC FEET)

	Actual 1970	Case I 1975	Case I 1980	Case I 1985	Case I 1990	Case I Total 1971-1990	Case II 1975	Case II 1980	Case II 1985	Case II 1990	Case II Total 1971-1990
NATURAL GAS FROM DOMESTIC SOURCES	22.0	22.2	19.1	15.1	11.2	359	22.5	20.6	20.0	17.9	408
Gas From Conventional Sources **	22.0	22.2	19.1	15.1	11.2	359	22.5	20.5	19.5	16.9	403
Lower 48 States	21.8	22.0	18.9	14.8	10.9	355	22.3	20.3	17.6	14.3	387
Onshore	18.6	17.7	14.1	11.0	8.3	275	17.9	14.7	12.0	9.6	288
Offshore	3.2	4.3	4.7	3.8	2.6	80	4.4	5.6	5.6	4.7	99
Alaska	.1	.2	.2	.3	.3	4	.2	.2	1.9	2.7	16
Gas From Stimulation Of Low-Permeability Reservoirs ***	.0	.0	.0	.0	.0	0	.0	.1	.5	1.0	5
SUBSTITUTE NATURAL GAS FROM DOMESTIC SOURCES	.0	.0	.2	.7	1.2	8	.0	.3	1.1	2.2	12
Gas From Coal	.0	.0	.2	.7	1.2	8	.0	.3	1.1	2.2	12
Gas From Oil Shale	.0	-	-	-	-	-	-	-	-	-	-
Gas From Organic Waste	*	-	-	-	-	-	-	-	-	-	-
Hydrogen	*	-	-	-	-	-	-	-	-	-	-
TOTAL SUPPLY FROM DOMESTIC SOURCES	22.0	22.2	19.3	15.8	12.4	367	22.5	20.9	21.1	20.1	420
GAS FROM FOREIGN SOURCES	.8	1.4	2.1	2.2	1.7	35	1.8	3.8	4.2	5.1	67
Pipeline Imports ****	.8	1.0	1.0	.9	.2	17	1.2	1.3	1.4	2.1	28
Liquefied Natural Gas	*	*	.4	.4	.4	5	.1	1.5	1.5	1.5	20
Gas From Liquid Hydrocarbons *****	*	.4	.7	.9	1.1	13	.5	1.0	1.3	1.5	19
Gas From Methanol	*	-	-	-	-	-	-	-	-	-	-
TOTAL SUPPLY	22.8	23.6	21.4	18.0	14.1	402	24.3	24.7	25.3	25.2	487

	Case III 1975	Case III 1980	Case III 1985	Case III 1990	Case III Total 1971-1990	Case IV 1975	Case IV 1980	Case IV 1985	Case IV 1990	Case IV Total 1971-1990
NATURAL GAS FROM DOMESTIC SOURCES	22.6	24.7	23.6	22.8	465	22.6	27.7	29.6	32.5	542
Gas From Conventional Sources **	22.6	24.2	22.6	21.3	453	22.6	26.5	26.6	27.9	508
Lower 48 States	22.4	22.3	20.2	17.6	420	22.5	24.3	23.5	22.2	462
Onshore	18.0	15.3	13.3	11.3	303	18.0	15.6	14.1	12.5	312
Offshore	4.4	7.0	6.9	6.3	117	4.5	8.7	9.4	9.7	150
Alaska	.2	1.9	2.5	3.8	33	0.2	2.2	3.1	5.7	47
Gas From Stimulation Of Low-Permeability Reservoirs ***	.0	.5	1.0	1.5	12	.0	1.2	3.0	4.6	34
SUBSTITUTE NATURAL GAS FROM DOMESTIC SOURCES	.0	.4	1.3	3.0	16	.0	.6	1.9	5.1	26
Gas From Coal	.0	.4	1.3	3.0	16	.0	.6	1.9	5.1	26
Gas From Oil Shale	-	-	-	-	-	-	-	-	-	-
Gas From Organic Waste	-	-	-	-	-	-	-	-	-	-
Hydrogen	-	-	-	-	-	-	-	-	-	-
TOTAL SUPPLY FROM DOMESTIC SOURCES	22.6	25.1	24.9	25.8	481	22.6	28.3	31.5	37.6	568
GAS FROM FOREIGN SOURCES	2.2	6.1	7.7	8.4	110	2.4	7.5	9.5	11.6	136
Pipeline Imports ****	1.2	1.9	2.2	2.6	40	1.2	2.0	2.9	3.7	50
Liquefied Natural Gas	.4	2.7	3.8	3.8	45	.4	3.2	3.8	4.7	51
Gas From Liquid Hydrocarbons *****	.6	1.5	1.7	2.0	25	.8	2.3	2.8	3.2	35
Gas From Methanol	-	-	-	-	-	-	-	-	-	-
TOTAL SUPPLY	24.8	31.2	32.6	34.2	591	25.0	35.8	41.0	49.2	704

Note: Totals may not add due to rounding.

* Less than 0.05 trillion cubic feet.
** Includes all gas projected to be produced from domestic oil and gas wells.
*** Includes those low-permeability reservoirs which contain gas that is not commercially producible under current prices and technology.
**** Primarily from Canada. Imports from Mexico in 1972 were about 0.008 trillion cubic feet.
***** Classified as gas from foreign sources because incremental supplies of liquid hydrocarbons must be imported.
\- No estimate made.

Source: FPC, 1974

line imports under currently authorized projects only; LNG imports under presently authorized projects only; no gas available from stimulation of low-permeability reservoirs; SNG from coal assuming completion of three coal gasification plants by 1980 and 15 plants by 1990; and gas from liquid hydrocarbons assuming completion of all naphtha plants under construction and construction of one-fourth of all currently proposed crude oil plants by 1980 (plus one additional crude oil plant every third year beginning in 1981).

Case II ("Conservative Realistic" Situation)

Onshore, non-associated gas forecasts based on Task Force projections assuming wellhead prices increasing from 34¢ in 1975 to 58¢/Mcf in 1990 (adjusted for inflation); associated-dissolved gas projections as in Case I; offshore development in all areas according to the proposed USGS leasing program but with each sale five years later than scheduled and with discovered reserves only half as large as projected in Case IV; completion of a pipeline from the North Slope of Alaska to the Lower 48 by 1984; some increase in pipeline imports from Canada's traditional supply areas plus some imports from the Mackenzie Delta and the Arctic Islands through large diameter pipelines constructed to Lower 48 markets by 1984 and 1989; LNG imports assuming implementation of all projects currently filed with the FPC; gas from low-permeability reservoirs based on an average of low production estimates by the Technology Task Force for nuclear and hydraulic fracturing, but with a projection delay of five years in the schedule used by the Task Force; SNG from coal assuming four coal gasification plants in operation by 1980, increasing to 27 by 1990; and gas from liquid hydrocarbons assuming completion of all naphtha plants currently under construction plus 50% of proposed "probable" plants, and construction of one-third of the proposed crude oil plants by 1980 plus one additional plant constructed every second year beginning in 1981.

Case III ("Optimistic Realistic" Situation)

Onshore, non-associated gas forecasts based on Task Force projections assuming hypothetical wellhead gas prices increasing from 42¢ in 1975 to 89¢/Mcf in 1990 (adjusted for inflation); projection of associated-dissolved gas as in Case I; offshore leasing under the USGS proposed schedule but with discovered reserves only half as large as projected in Case IV; completion of a pipeline from the Alaskan North Slope to Lower 48 market by 1979; pipeline imports the same as in Case II, except for completion of pipelines from the Mackenzie Delta and Arctic Islands frontier areas by 1979 and 1984 and construction of a pipeline from Canada's Atlantic Offshore area by 1980; LNG imports the same as in Case II except for assumption of more optimistic deliveries

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the USGS estimates to show more optimistic projections for the OCS during the 1980-1990 period than originally forecast by the USGS. These adjusted projections, plus the state offshore projections prepared by Staff, constitute the most optimistic (Case IV) projections for the offshore area. Projections of offshore supply in Cases I, II and III differed from Case IV in assuming reduced or delayed leasing activity and lower levels of discoveries.

by 1975 and implementation of nine prospective projects; stimulation of low-permeability reservoirs the same as in Case II except for elimination of the five-year time lag; SNG from domestic coal based on the Coal Gasification Task Force's "best guess situation"; and gas from liquid hydrocarbons assuming completion of all naphtha plants currently under construction plus all proposed "probable" plants, and construction of half the proposed crude oil plants by 1980 plus one additional plant every other year after 1980.

Case IV (Maximum Future Supply)

Onshore, non-associated gas forecasts based on Task Force projections assuming hypothetical wellhead gas prices rising from 50¢ in 1975 to $1.21/Mcf in 1990 (adjusted for inflation); projection of associated-dissolved gas as in Case I; offshore projections derived from USGS forecasts based on inferred discoveries from USGS' proposed leasing schedule, assuming new gas prices rising from 50¢ in 1975 to $1.21/Mcf in 1990 (adjusted for inflation or from 50¢ to 76¢/Mcf (unadjusted for inflation); completion of the North Slope pipeline through USGS with the resulting gas supplies available to the Lower 48 States as LNG by 1978; pipeline imports essentially the same as in Case III but with completion of the Mackenzie Delta pipeline by 1978 and the Arctic Islands pipeline by 1979 and with substantial capacity increases installed on each line earlier than in the three other cases; LNG imports the same as in Case III except for the inclusion of three additional highly prospective projects; stimulation of low-permeability reservoirs based on an average of the Technology Task Force's high production cases for both nuclear and massive hydraulic fracturing; SNG from coal gasification the same as for Case III, except for assumption of a 6% growth rate after 1980; and gas from liquid hydrocarbons assuming completion of all naphtha plants now under construction plus all proposed "probable" plants and half of the "doubtful" plants, and completion of three-fourths of the proposed crude oil plants by 1980 plus one additional plant each year until 1990.

The report considers Case II to be reasonably assured, and Case III to be attainable.

The FPC Staff projected future gas demand in Chapter 7 of the National Gas Survey (also issued prior to Commission approval in June, 1974, as a preliminary report). At the time of the Demand Task Force study, the most detailed and comprehensive gas requirements forecast available was Volume IV of the report prepared by the Future Requirements Committee (FRC, 1971). (FRC Volume V has subsequently been released, and will be discussed in a following section). The FRC utilized a "grass roots" information gathering approach by asking every company or organization which could be identified as a final supplier of gas to forecast their individual gas requirements based on certain assumptions, including the continuation of the 1970 price relationship of gas to competing fuels, which may prove susceptible to exception in view of pricing trends since 1971.

The Demand Task Force decided to make its own projection which would be responsive to the recent volatility of energy prices, and surveyed a number of companies which estimated gas requirements for the FRC study. The results of the projections of gas demand under various price conditions (summarized on Table 1.1-2) indicate that price may be an important determinant of the future gas market.

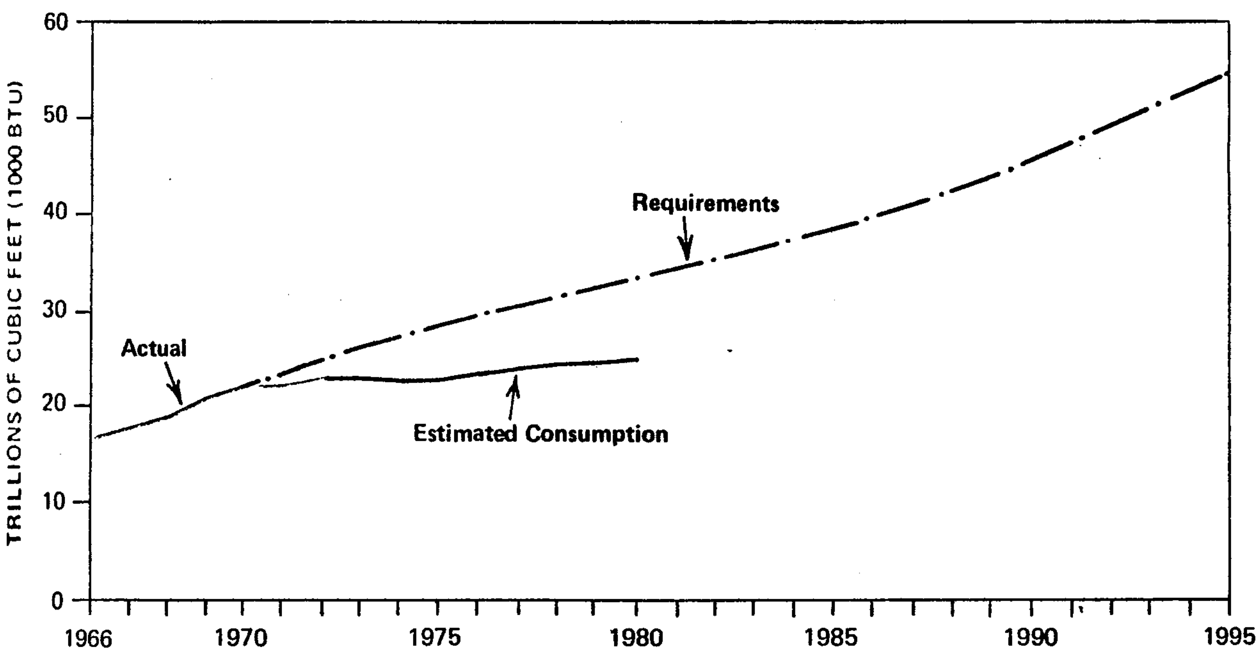
It can be seen from a comparison of Tables 1.1-1 and 1.1-2 that demand will exceed supply in all combinations of the various cases, except for the highest supply projection, which is probably unattainable.

The most recent report (Volume V) of the Future Requirements Committee (FRC, 1973) presents not only estimates of the market need for gas under conditions of adequate supply as past reports have covered, but also estimates of consumption based on expected available supply. The FRC forecasts of national gas requirements by state and class of service for 1980 and 1985 are listed in Tables 1.1-3 and 1.1-4, while a similar consumption forecast, which is tantamount to allocation of limited supplies, is listed in Table 1.1-5 for 1980 (consumption was not projected past 1980).

A comparison of the FRC estimates of total consumption and total requirements is illustrated below:

FIGURE 1.1-9

UNITED STATES GAS CONSUMPTION AND REQUIREMENTS, 1966-1995*



*Excluding field use.

Source: FRC, 1973

TABLE 1.1-2

DISTRIBUTION-TECHNICAL ADVISORY TASK FORCE-GENERAL FORECAST OF U.S. GAS DEMAND 1/
(Trillion Cubic Feet)

	Price Assumptions 2/	1975	1980	1985	1990
Case I	Most Likely Pattern Of Future Percentage Price Changes 3/ in Gas and Other Fuels 4/	29.4	34.6	39.8	43.9
Case II	Gas: 125% of Case I Other Fuels: Case I	28.6	31.5	34.7	36.2
Case III	Gas: 75% of Case I Other Fuels: Case I	30.3	36.8	44.0	52.2
Case IV	Gas: Case I Other Fuels: 125% of Case I	29.7	35.4	41.2	46.7
Case V	Gas: Case I Other Fuels: 75% of Case I	29.0	33.8	38.3	41.1
FRC Base Case 4/					

1/Excluding Alaska and Hawaii.

2/See pp. 100-101 of Volume IV of FPC National Gas Survey.

3/For example, if the Case I residential gas price increase from 1970 to 1980 is 30%, then the Case II residential gas price increase from 1970 to 1980 is 37.5 percent (125% of 30% = 37.5%); therefore, if 1970 gas price was $1.00/Mcf, gas price would be $1.30 for Case I 1980 and $1.375 for Case II 1980. Other fuel prices would remain unchanged from Case I to Case II.

4/Cases I through V; "Natural Gas Demand Forecasts, "Report of the Distribution-Technical Advisory Task Force-General, April 1973, Volume IV National Gas Survey. FRC Base Case; "Future Gas Requirements of the United States, "Volume No. 4, Denver Research Institute, University of Denver, October 1971.

Source: FPC National Gas Survey, Chapter 7, June, 1974.

TABLE 1.1-3

UNITED STATES GAS REQUIREMENTS BY STATE AND CLASS OF SERVICE, 1980
(Millions of Cubic Feet at 1000 Btu Per Cubic Foot at 14.73 psia)

	Firm			Utility Power Generation				
	Residential	Commercial	Industrial	Firm	Interruptible	Interruptible[1]	Other	Total
UNITED STATES TOTAL	6,769,231	3,200,398	9,755,466	3,436,876	3,329,550	4,893,608	2,117,820	35,811,949
FIELD USE								2,309,000
TOTAL EXCLUDING FIELD USE								33,502,949
1. NEW ENGLAND	201,434	84,043	60,189	711	10,853	29,850	17,090	404,170
Connecticut	47,455	22,913	29,056	–	21	7,369	6,060	112,874
Maine	983	522	834	–	–	–	130	2,469
Massachusetts	129,916	49,889	25,472	711	6,096	16,285	9,127	237,496
New Hampshire	5,039	2,224	408	–	–	998	483	9,152
Rhode Island	16,360	7,483	4,359	–	4,136	3,748	1,141	37,227
Vermont	1,681	1,012	60	–	600	1,450	149	4,952
2. APPALACHIAN	2,024,593	945,438	1,836,928	11,312	207,369	623,366	375,768	6,024,774
Delaware	12,939	7,637	11,864	69	1	5,150	1,545	39,205
District of Columbia	16,544	17,578	–	–		7,238	1,551	42,911
Kentucky	104,521	55,979	93,850	824	–	54,435	71,010	380,619
Maryland	110,092	37,248	50,022	4,311	38	88,891	17,007	307,609
New Jersey	216,934	126,368	87,667	258	64,169	111,702	27,717	634,815
New York	448,764	186,678	152,727	390	116,082	111,139	54,460	1,070,240
Ohio	573,985	261,017	728,706	3,090	8,520	85,603	49,646	1,710,567
Pennsylvania	397,105	173,380	473,503	2,318	10,300	102,307	73,015	1,231,928
Virginia	81,921	46,727	74,879	–	8,258	54,223	26,100	292,108
West Virginia	61,788	32,826	163,710	52	–	2,678	53,717	314,771
3. SOUTHEAST	411,665	232,634	507,346	130,432	302,037	1,033,246	197,427	2,814,787
Alabama	76,045	37,612	133,412	133	20,506	144,947	38,128	450,783
Florida	31,437	28,215	102,587	130,296	140,652	281,304	15,053	729,544
Georgia	132,803	51,007	65,782	–	84,312	166,362	37,914	538,180
North Carolina	58,648	40,322	57,806	3	12,625	160,798	26,282	356,484
South Carolina	47,239	16,735	29,130	–	11,276	124,288	12,747	250,415
Tennessee	65,493	58,743	118,629	–	32,666	155,547	58,303	489,381
4. GREAT LAKES	1,543,154	793,452	1,472,800	218,057	369,760	797,332	197,513	5,392,068
Illinois	651,137	358,973	633,823	139,520	39,943	128,085	82,569	2,034,050
Indiana	225,843	119,958	384,709	32,700	69,026	121,160	42,150	995,546
Michigan	502,989	246,895	374,302	40,759	200,329	314,597	62,216	1,742,087
Wisconsin	163,185	67,626	79,966	5,078	60,462	233,490	10,578	620,385
5. NORTHERN PLAINS	349,193	179,262	210,207	7,019	178,944	243,822	89,849	1,258,296
Iowa	124,873	64,214	112,943	304	74,908	98,791	44,104	520,137
Minnesota	133,092	54,506	59,922	6,715	60,959	92,213	21,039	428,446
Nebraska	65,203	41,909	35,687	–	41,390	41,465	23,632	249,286
North Dakota	11,276	10,030	975	–	187	2,303	695	25,466
South Dakota	14,749	8,603	680	–	1,500	9,050	379	34,961
6. MID-CONTINENT	416,726	193,359	268,635	463,766	331,607	471,320	255,467	2,400,880
Kansas	115,914	48,086	64,787	9,320	203,499	142,068	151,404	735,078
Missouri	207,434	96,934	114,875	36	106,983	132,019	28,601	686,882
Oklahoma	93,378	48,339	88,973	454,410	21,125	197,233	75,462	978,920
7. GULF COAST	612,855	229,472	4,966,917	2,460,266	433,185	408,628	663,461	9,774,784
Arkansas	60,468	32,982	204,170	123,407	14,658	23,503	58,171	517,359
Louisiana	112,155	35,261	1,783,581	510,702	114,215	42,257	178,125	2,776,296
Mississippi	50,870	26,233	151,461	171,957	18,626	29,610	91,277	540,034
Texas	389,362	134,996	2,827,705	1,654,200	285,686	313,258	335,888	5,941,095
8. ROCKY MOUNTAIN	238,226	146,445	59,186	43,945	27,670	217,461	26,401	759,334
Colorado	138,778	97,626	36,770	43,739	27,330	68,173	9,003	421,419
Montana	26,981	19,493	2,457	206	73	39,879	5,214	94,303
Utah	56,189	19,008	8,292	–	267	65,066	4,602	153,424
Wyoming	16,278	10,318	11,667	–	–	44,343	7,582	90,188
9. PACIFIC SOUTHWEST	851,151	335,580	188,637	101,368	1,468,125	862,645	188,700	3,996,206
Arizona	55,558	49,989	45,845	36,720	37,194	56,360	42,958	324,624
California	743,152	255,191	101,396	1,679	1,376,987	778,740	79,220	3,336,365
Nevada	18,882	15,924	10,040	25,320	16,880	8,167	2,287	97,500
New Mexico	33,559	14,476	31,356	37,649	37,064	19,378	64,235	237,717
10. PACIFIC NORTHWEST	120,234	60,713	184,621	–	–	205,938	15,869	587,375
Idaho	15,649	9,457	29,125	–	–	15,094	2,975	72,300
Oregon	34,691	19,348	78,916	–	–	59,390	3,490	195,835
Washington	69,894	31,908	76,580	–	–	131,454	9,404	319,240
11. PACIFIC[2]	–	–	–	–	–	–	90,275	90,275
Alaska		–		–	–	–	85,188	85,188
Hawaii		–		–	–	–	5,087	5,087

[1] Other than utility power generation.

[2] Alaska and Hawaii's data and category of use statistics cannot be shown separately without revealing confidential data.

Source: FRC, 1973

TABLE 1.1-4

UNITED STATES GAS REQUIREMENTS BY STATE AND CLASS OF SERVICE, 1985
(Millions of Cubic Feet at 1000 Btu Per Cubic Foot at 14.73 psia)

	Firm			Utility Power Generation				
	Residential	Commercial	Industrial	Firm	Interruptible	Interruptible[1]	Other	Total
UNITED STATES TOTAL	7,724,357	3,939,779	11,234,358	4,261,563	3,147,473	5,829,840	2,389,748	41,159,118
FIELD USE								2,632,000
TOTAL EXCLUDING FIELD USE								38,527,118
1. NEW ENGLAND	241,556	106,905	80,981	812	10,058	33,437	19,691	493,440
Connecticut	57,855	32,425	42,929	–	22	9,840	7,396	150,467
Maine	1,170	621	993	–	-	–	130	2,914
Massachusetts	155,664	60,858	31,513	812	5,300	17,193	9,989	281,329
New Hampshire	6,144	2,547	509	–	–	1,200	660	11,060
Rhode Island	18,772	9,320	4,957	–	4,136	3,754	1,354	42,293
Vermont	1,951	1,134	80	–	600	1,450	162	5,377
2. APPALACHIAN	2,273,571	1,153,801	2,250,105	11,440	213,161	736,908	424,637	7,063,623
Delaware	14,979	9,696	13,924	69	1	5,665	1,854	46,188
District of Columbia	17,578	21,714	–	–	–	11,374	1,861	52,527
Kentucky	115,104	67,225	111,903	1,030	–	66,729	82,450	444,441
Maryland	131,854	48,156	61,848	3,693	38	107,188	20,026	372,803
New Jersey	257,215	167,535	116,967	283	64,169	131,628	33,920	771,717
New York	492,347	218,857	190,147	390	116,545	135,875	62,683	1,216,844
Ohio	631,509	309,540	921,433	3,090	9,780	94,403	56,525	2,026,280
Pennsylvania	446,441	212,964	562,005	2,833	13,339	112,482	79,812	1,429,876
Virginia	100,559	59,407	79,618	–	9,288	68,680	31,733	349,285
West Virginia	65,985	38,707	192,260	52	–	2,884	53,773	353,661
3. SOUTHEAST	490,717	283,518	606,960	130,432	389,978	1,354,265	235,689	3,491,559
Alabama	83,915	42,898	145,782	133	18,567	163,450	43,508	498,253
Florida	42,978	38,575	146,593	130,296	220,826	441,652	21,509	1,042,429
Georgia	154,692	59,476	77,213	–	95,321	190,592	44,381	621,675
North Carolina	75,274	51,381	64,926	3	11,580	210,019	31,715	444,898
South Carolina	58,073	21,540	34,618	–	11,018	166,011	27,306	318,566
Tennessee	75,785	69,648	137,828	–	32,666	182,541	67,270	565,738
4. GREAT LAKES	1,797,043	1,038,207	1,853,882	228,069	433,736	931,527	226,604	6,509,068
Illinois	761,408	484,202	774,315	131,380	37,469	134,471	95,553	2,418,798
Indiana	260,877	151,336	502,049	32,700	69,126	146,630	48,697	1,211,415
Michigan	583,577	322,144	471,545	59,011	266,510	375,470	70,968	2,149,225
Wisconsin	191,181	80,525	105,973	4,978	60,631	274,956	11,386	729,630
5. NORTHERN PLAINS	390,537	208,671	230,604	7,680	187,880	262,280	103,276	1,390,928
Iowa	139,598	76,022	128,617	365	78,953	113,042	52,339	588,936
Minnesota	149,763	65,041	62,350	7,315	64,236	95,041	21,929	465,675
Nebraska	72,251	46,496	37,727		43,004	42,734	27,837	270,049
North Dakota	12,363	11,023	1,075	-	187	2,034	736	27,418
South Dakota	16,562	10,089	835	–	1,500	9,429	435	38,850
6. MID-CONTINENT	468,691	225,061	269,214	477,420	360,495	563,930	281,747	2,646,558
Kansas	127,552	55,684	70,139	9,628	219,340	158,054	162,010	802,407
Missouri	238.269	115,057	94,073	36	120,374	157,636	33,047	758,492
Oklahoma	102.870	54,320	105,002	467.756	20,781	248,240	86,690	1,085,659
7. GULF COAST	696,908	290,389	5,446,281	3,253,960	467,988	517,678	738,329	11,411,533
Arkansas	68,236	37,074	210,742	148,540	20,521	24,536	67,492	577,141
Louisiana	127,651	40,055	1,917,499	664,194	192,709	63,007	190,846	3,195,961
Mississippi	58,854	29,829	159,749	240,739	20,790	34,757	105,527	650,245
Texas	442.167	183,431	3,158,291	2,200,487	233,968	395.378	374,464	6,988,186
8. ROCKY MOUNTAIN	258,179	165,726	70,746	57,820	36,621	253,292	29,432	871,816
Colorado	144,967	108,730	41,726	57,820	35,571	81,191	10,455	480,460
Montana	28,915	23,043	3,418	–	73	46,611	4,178	106,238
Utah	67,005	22,541	10,733	-	977	75,541	5,594	182,391
Wyoming	17,292	11,412	14,869	–	–	49,949	9,205	102,727
9. PACIFIC SOUTHWEST	955,764	394,125	215,054	93,930	1,047,556	949,702	214,083	3,870,214
Arizona	69.172	64,649	53,486	26,008	38,701	63,169	49,948	365,133
California	825,560	294,025	116,183	687	945,432	854,016	85,296	3,121,199
Nevada	22.782	18,924	10,040	27,430	18,990	8,167	2,561	108,894
New Mexico	38.250	16,527	35,345	39,805	44,433	24.350	76,278	274,988
10. PACIFIC NORTHWEST	151,391	73,376	210,531	–	–	226,821	18,051	680,170
Idaho	19,089	11,054	32,351	–	–	17,406	3,080	82,980
Oregon	42,785	23,870	93,985	–	–	60,546	4,141	225,327
Washington	89,517	38,452	84,195	–	–	148,869	10,830	371,863
11. PACIFIC[2]	-	–	–	–	–	–	98,209	98,209
Alaska		–	-	–	–	–	92,020	92,020
Hawaii		–	–	–	–	-	6,189	6,189

[1] Other than utility power generation.

[2] Alaska and Hawaii's data and category of use statistics cannot be shown separately without revealing confidential data.

Source: FRC, 1973

TABLE 1.1-5

ESTIMATED GAS CONSUMPTION BY STATE AND CLASS OF SERVICE, 1980
(Millions of Cubic Feet at 1000 Btu Per Cubic Foot at 14.73 psia)

	Firm			Utility Power Generation				
	Residential	Commercial	Industrial	Firm	Interruptible	Interruptible[1]	Other	Total
UNITED STATES TOTAL	6,470,502	3,064,961	6,845,459	2,773,406	980,664	2,938,292	1,754,441	27,136,725
FIELD USE								2,309,000
TOTAL EXCLUDING FIELD USE								24,827,725
1. NEW ENGLAND	196,070	87,066	47,940	–	6,744	29,773	21,823	389,416
Connecticut	43,209	19,613	17,285	–	–	5,567	6,140	91,814
Maine	949	852	678	–	–	84	241	2,804
Massachusetts	123,009	55,592	24,452	–	6,006	18,312	11,899	239,270
New Hampshire	5,478	3,229	679	–	138	1,800	470	11,794
Rhode Island	20,355	6,162	4,736	–	–	2,560	2,853	36,666
Vermont	3,070	1,618	110	–	600	1,450	220	7,068
2. APPALACHIAN	1,885,875	799,667	1,234,156	8,084	137,361	306,070	294,385	4,665,598
Delaware	11,380	4,901	12,333	68	511	2,321	775	32,289
District of Columbia	15,985	12,205	–	–	–	2,555	1,163	31,908
Kentucky	97,809	45,378	57,644	459	4,913	34,534	51,420	292,157
Maryland	108,515	24,550	34,970	4,310	38	37,684	12,454	222,521
New Jersey	196,834	112,757	67,278	–	41,389	59,429	20,513	498,200
New York	434,939	156,214	96,700	173	79,511	69,849	44,281	881,667
Ohio	530,306	223,664	465,112	2,004	1,467	34,684	39,474	1,296,711
Pennsylvania	357,386	157,342	370,703	1,019	5,102	38,564	62,622	992,738
Virginia	71,342	32,994	35,585	–	4,430	25,257	9,681	179,289
West Virginia	61,379	29,662	93,831	51	–	1,193	52,002	238,118
3. SOUTHEAST	381,641	242,017	307,612	124,206	37,643	547,883	139,138	1,780,140
Alabama	68,359	32,717	68,312	103	4,487	92,535	24,248	290,761
Florida	36,355	37,299	4,945	124,100	23,412	62,142	9,882	298,135
Georgia	124,458	54,447	59,360	–	208	158,319	27,823	424,615
North Carolina	47,743	29,842	47,230	3	–	33,119	14,832	172,769
South Carolina	44,589	38,163	27,310	–	–	78,667	18,219	213,334
Tennessee	60,137	49,549	100,455	–	3,150	123,101	44,134	380,526
4. GREAT LAKES	1,407,726	807,154	1,080,159	34,266	14,315	319,605	161,742	3,824,967
Illinois	590,416	337,440	434,099	5,613	4,156	66,681	71,491	1,509,896
Indiana	213,100	104,836	257,901	9,336	510	36,732	33,130	655,545
Michigan	442,224	297,954	288,258	16,460	8,037	112,014	46,118	1,211,065
Wisconsin	161,986	66,924	99,901	2,857	1,612	104,178	11,003	448,461
5. NORTHERN PLAINS	345,888	170,793	168,669	4,690	75,530	173,708	132,748	1,072,026
Iowa	122,414	54,626	78,710	190	26,542	53,889	95,391	431,762
Minnesota	132,556	56,006	56,996	4,500	26,140	70,101	19,675	365,974
Nebraska	64,978	41,618	32,254	–	22,261	38,858	16,657	216,626
North Dakota	11,257	9,725	42	–	187	3,690	701	25,602
South Dakota	14,683	8,818	667	–	400	7,170	324	32,062
6. MID-CONTINENT	377,049	169,350	155,823	317,783	190,298	376,690	170,919	1,757,912
Kansas	103,038	47,634	40,542	8,419	113,238	114,633	105,656	533,160
Missouri	184,245	78,725	48,117	36	56,600	75,412	20,477	463,612
Oklahoma	89,766	42,991	67,164	309,328	20,460	186,645	44,786	761,140
7. GULF COAST	671,127	244,622	3,485,239	2,243,391	420,449	361,778	540,177	7,966,823
Arkansas	49,862	28,307	182,211	108,100	10	13,095	68,363	449,948
Louisiana	148,137	28,507	1,541,219	381,794	74,360	27,999	107,798	2,309,814
Mississippi	37,903	25,018	112,020	–	–	33,210	68,445	276,596
Texas	435,225	162,830	1,649,789	1,753,497	346,079	287,474	295,571	4,930,465
8. ROCKY MOUNTAIN	238,226	146,045	34,280	4,134	9,957	134,833	24,025	591,500
Colorado	138,778	97,226	11,864	3,928	9,617	35,196	6,627	303,236
Montana	26,981	19,493	2,457	206	73	39,879	5,214	94,303
Utah	56,189	19,008	8,292	–	267	28,995	4,602	117,353
Wyoming	16,278	10,318	11,667	–	–	30,763	7,582	76,608
9. PACIFIC SOUTHWEST	849,985	332,587	171,542	36,852	88,367	573,870	167,083	2,220,286
Arizona	53,327	45,910	39,460	12,426	–	642	28,986	180,751
California	743,476	255,080	101,553	1,824	88,367	563,612	85,677	1,839,589
Nevada	18,882	15,924	4,903	11,802	–	8,167	1,790	61,468
New Mexico	34,300	15,673	25,626	10,800	–	1,449	50,630	138,478
10. PACIFIC NORTHWEST	116,915	65,660	160,039	–	–	114,082	12,126	468,822
Idaho	18,624	13,560	35,383	–	–	9,270	2,582	79,419
Oregon	35,795	20,305	75,171	–	–	22,489	2,625	156,385
Washington	62,496	31,795	49,485	–	–	82,323	6,919	233,018
11. PACIFIC[2]	–	–	–	–	–	–	90,275	90,275
Alaska	–	–	–	–	–	–	85,188	85,188
Hawaii	–	–	–	–	–	–	5,087	5,087

[1] Other than utility power generation.

[2] Alaska and Hawaii's data and category of use statistics cannot be shown separately without revealing confidential data.

Source: FRC, 1973

Supply-limited consumption will be less than three-fourths of total requirements by 1980, according to these estimates. The FRC emphasizes the seriousness of the situation in stating:

> The importance of these data to the gas industry is that they show gas consumption growing at 1.6 percent compound annual growth rate compared to a potential growth in the markets for gas of 3.6 percent. For the nation this means that in the short-term gas will be carrying a somewhat smaller proportion of the total energy requirements than in the past placing a heavier demand on other energy forms if total energy consumption is to grow at a near historical or projected growth rate.

Since there will apparently be a large deficiency in the supply which will be available to meet future demand for natural gas, it is informative to examine the degree to which such supply deficiency will affect service to various classes of gas customers. The FRC's 1980 and 1985 gas requirements by class of service are summarized in Table 1.1-6, along with the FRC projection of how the available supply will be allocated to the various classes of service in 1980 (1985 consumption was not forecasted). For comparison the FPC "Conservative Realistic" Case II supply projection is also shown. The available supply will likely be no greater than that forecast by Case II, since the assumptions of Case II as listed previously include deliveries of gas to Lower 48 markets from the North Slope of Alaska (for which Applicant is seeking authorization), and further include gas from such unpredictable sources as low-permeability reservoirs, increased pipeline imports from Canada[2/], and proposed liquid hydrocarbon reforming plants (from which plants gas production is unpredictable due to the current worldwide uncertainties in price and availability of liquid hydrocarbons as evidenced by the recent Arab Oil Embargo).

It can be seen from Table 1.1-6 that field use gas and firm requirements in 1980 are only 1.6 tcf less than total consumption forecasted by the FRC (25.5 tcf vs. 27.1), and that almost one half of interruptible requirements will not be satisfied.

[2/] The chairman of the Canadian National Energy Board, M. A. Croewe, recently said that there will be no more export approvals for the Western Canadian gas until Canada's total fuel supply-demand picture has been determined (The Oil Daily, 1974).

TABLE 1.1-6

DEMAND BY CLASS OF SERVICE COMPARED WITH SUPPLY

FRC Forecasts (tcf)

	Requirements		Consumption	Deficiency	%Deficient
Firm	1980	1985	1980	1980	1980
Residential	6.8	7.7	6.5	0.3	
Commercial	3.2	3.9	3.0	0.2	
Industrial	9.8	11.2	6.8	3.0	
Utility Power	3.4	4.3	2.8	0.6	
Field Uses 1/	2.3	2.6	2.3	0.0	
Subtotal	25.5	29.7	21.4	4.1	16%
Interruptible					
Utility Power Generation*	3.3	3.2	1.0	2.3	
Other	4.9	5.8	2.9	2.0	
Other	2.1	2.4	1.8	0.3	
Subtotal	10.3	11.4	5.7	4.6	45%
Total	35.8	41.1	27.1	8.7	24%

FPC CASE II SUPPLY ESTIMATE (tcf)

	1980	1985
Domestic Natural Gas 2/	20.6	20.0
SNG from Domestic Coal 3/	0.3	1.1
Gas from Foreign Sources 4/	3.8	4.2
TOTAL	24.7	25.3

Sources: FRC, 1973
FPC, 1974

1/ Gas used in field operations performed in producing, treating and delivering gas and oil to transmission systems.

2/ Includes Lower 48 onshore and offshore, Alaska and low-permeability reservoirs. (Alaska = 0.2 tcf in 1980 and 1.9 tcf in 1985).

3/ Production from four plants in 1980, increasing to 27 by 1990.

4/ Includes pipeline imports, LNG and SNG from liquid hydrocarbons.

Comparing FRC demand estimates to FPC supply estimates[3], it can be seen that field use and firm requirements exceed the total supply by 0.8 tcf in 1980 and by 4.4 tcf by 1985. Total requirements of 35.8 tcf in 1980 will exceed total supply of 24.7 tcf by an astounding 11.1 tcf, while the deficiency in 1985 will be 15.8 tcf, more than the total consumption of natural gas in the United States in 1964 (USDI, 1972).

It should be apparent from the previous discussion that the United States cannot afford to be "optimistic" in its efforts to meet the gas shortage, because if the future supply is not as great as that estimated by the FPC Case II, the potentially disasterous result will be increased curtailment of service to firm customers, including residential and commercial customers not having the capability to switch to other fuels and thereby effect a natural gas demand reduction.

1.1.2.3 Contribution of the Alaskan Project Toward Alleviating the Total Energy and Natural Gas Shortages

The proposed Project will deliver an annual average of 1.03 trillion cubic feet of gas (equivalent to 1.2 quadrillion Btu) to Lower 48 markets. This represents 20% of the total energy supply deficiency in 1985 assuming simultaneous realization of the NPC's most optimistic supply case and most conservative demand case (see Figure 1.1-1). However, the supply/demand situation will probably be closer to that portrayed by Figure 1.1-5, in which case the impact of 1.03 tcf of Alaskan gas would be in the range of 4% of the projected total supply deficiency in 1980, and 3% of the expected higher total energy deficiency in 1985.

In terms of natural gas supply and demand, as summarized in Table 1.1-6, full Project implementation by 1980 would provide a volume of gas equal to one-fourth of the FRC forecasted national firm requirement deficiency. Moreover, the volume of gas to be delivered to the Lower 48 is greater than the total supply deficiency projected in residential and commercial classes of service in 1980.

Annual deliveries of one tcf of Alaskan gas would also eliminate in 1980 the 0.8 tcf deficiency of total supply (FPC Case II) below FRC firm requirements, and would eliminate 20% of the corresponding 4.4 tcf deficiency in 1985.

The proposed Alaskan Project would supply 4% of the FPC Case II estimate of the total national gas supply in 1980 (24.7 tcf) and 1985 (25.3 tcf). Because of the large national impact of the proposed action resulting from Applicant's proposal to distribute Alaskan Gas to major markets by utilization of displacement capability and excess capacity

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[3] The FPC did not forecast demand on the basis of class of service; however, the FPC estimates of total demand (Table 1.1-2) for the most likely pattern (Case I) of interfuel price relationships are very similar to the FRC estimates--34.6 and 35.8 in 1980 and 39.8 and 41.1 in 1985.

in existing pipelines, a separate analysis of the energy situation by state and region (other than the FRC projections of gas requirements and consumption listed by state and region) has not been developed at this time; its development would ultimately turn on the manner in which the Alaskan supply is allocated throughout the Lower 48 States.

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1.2 LOCATION

1.2.1 Alaskan Gas Pipeline

1.2.1.1 Pipeline

The Alaskan Gas Pipeline will consist of 809.2 miles of 42-inch outside diameter (O.D.) pipe connecting the gas producers' facilities located near Prudhoe Bay on the Alaskan North Slope, to the proposed LNG Plant located near Gravina Point in Southern Alaska, as shown in Figure 1.2-1. The gas pipeline will be located within the Transportation and Utility Corridor designated by the U.S. Department of the Interior, and will follow the route of the Alyeska oil pipeline for most of its distance. Topographic alignment sheets showing the pipeline route in detail are included in the Appendix to Section 2A.2 of this Report.

Commencing in the southeast quarter of Section 11, Township 11 North, Range 14 East, the pipeline will proceed south from the Prudhoe Bay facilities across the treeless plain of the North Slope of Alaska and into the Brooks Range at Galbraith Lake. The pipeline will cross the Continental Divide in the Brooks Range through Atigun Pass and follow the valleys of the North Fork Chandalar, Middle Fork Koyukuk, and Dietrich Rivers. As the rivers turn westward, the route will continue south across the drainage pattern and through uplands to the Yukon River. The course will then change to southeast, passing east of Fairbanks, and continue up the Tanana River Valley to the Delta River. In this area, the route will turn again southward up the Delta River and cross the Alaska Range through Isabel Pass. The route will advance south through the highlands between the Gulkana and Gakona Rivers, across the Gulkana River, down the Copper River drainage to Tonsina, and into the Chugach Mountains. The pipeline will follow the Richardson Highway through Thompson Pass and Keystone Canyon to a point near the head of Valdez Arm, where it will turn and cross the Chugach Mountain crest to a point of termination at the proposed LNG Plant in the southeast quarter of Section 17, Township 14 South, Range 5 West, Cordova (C-6 Quadrangle), Alaska.

1.2.1.2 Compressor Stations

There will be twelve compressor stations spaced at various intervals over the 809-mile route to be followed by the Alaskan Gas Pipeline. The general locations of stations are shown on the Map of Alaska, Figure 1.2-1.

Specific station locations are plotted on the Topographic Alignment Sheets in Section 2A.2, and are listed by milepost in Table 1.2-1.

LOCATION OF FACILITIES IN ALASKA

FIGURE 1.2–1

TABLE 1.2-1

LOCATION OF COMPRESSOR STATIONS

Station Number	Mile-post	Reference Figure in Section 2A.2 Appendix	Length of Access Road Miles
1	58.7	4	4.0
2	106.6	5	1.0
3	154.2	7	0.5
4	235.9	11	2.6
5	294.1	14	0.1
6	357.8	17	1.0
7	415.3	19	1.0
8	481.4	21	6.0
9	539.4	23	0
10	590.5	25	0.3
11	658.2	28	2.5
12	721.0	31	3.0

Short access roads will be constructed to 11 stations from existing state roads or from the proposed State-Alyeska Haul Road.

1.2.1.3 Other Facilities

Maintenance Bases

As shown in Figure 1.2-1, four maintenance bases will be located along the pipeline route as follows:

Maintenance Base	Milepost	Location Reference
A	106.6	Compressor Station No. 2
B	294.2	Compressor Station No. 5
C	481.4	Compressor Station No. 8
D	-	City of Valdez

Meter Stations

A meter station will be located at each end of the proposed pipeline. The Prudhoe Bay Meter Station will be situated on the discharge side of the producers' compressor station in the southwest quarter of Section 11, Township 11 North, Range 14 East. The meter station at the southern terminus of the pipeline will be located at the inlet of the LNG Plant in the southeast quarter of Section 17, Township 14 South, Range 5 West.

Dispatching and Control Center

The Dispatching and Control Center will be located at the LNG Plant.

Communications Facilities

A microwave communication station will be located at each compressor station and at both meter stations. Fifteen repeater stations will be located on higher elevations near the pipeline right-of-way to provide the continuous line-of-sight path required for microwave transmission.

Block Valves

There will be a total of 62 mainline block valves located singly or in pairs at compressor stations, at meter stations, and at points on the pipeline between stations so that the maximum distance between any two adjacent valve locations is less than the maximum separation specified by the Department of Transportation, minimum Federal Safety Standards contained in Part 192, Title 49, Code of Federal Regulations.

1.2.1.4 Population Centers Along Pipeline Route

Table 1.2-2 presents a list of communities located within five miles of the proposed pipeline route, which will not actually pass through any urban areas. In addition to the places listed below, the pipeline will pass within 14 miles of Valdez, and will be over 160 miles from Anchorage. Its southern terminus will be approximately 14 miles northwest of Cordova.

TABLE 1.2-2

COMMUNITIES WITHIN FIVE MILES
OF THE PROPOSED ALASKAN GAS PIPELINE

Place	1970 Population
Wiseman	Less than 100
Livengood	Less than 100
Fairbanks (including North Star Borough)	45,864
Delta Junction	709
Fort Greely	1,820
Gulkana	53
Glennallen	363
Gakona	88
Copper Center	206

The above tabulation does not include temporary construction camps of Alyeska Pipeline Service Company.

1.2.1.5 Scenic, Historic, Recreational, and Wildlife Areas

A general description of the character and distribution of scenic, historic, recreational, and wildlife resources along the route of the Alaskan Gas Pipeline and near the LNG Plant site is provided in Section 2A of this Report.

The entire area has high to very high values in terms of wildlife, aesthetic values, and recreational potential. For this reason, individual points and sites have not been identified. Comprehensive inventories of historical and archeological resources have been compiled by the Alaska State Division of Parks (1974) and the Joint Federal-State Land Use Planning Commission (JLUPC, 1973). Wildlife and recreational resources are also detailed in JLUPC (1973).

1.2.1.6 Crossings of Waterways, Highways, Railroads and Pipelines

The proposed natural gas pipeline will cross 29 natural waterways with drainage areas of over 100 square miles each. In addition, 43 lesser streams (see Table 1.2-3), and scores of minor drainages will be crossed. These crossings will present no stability problem for the pipeline; however, 17 waterway crossings are classified as major, and will require special design considerations.

The pipeline route crosses highways or primary roads 44 times, as listed in Table 1.2-4.

The pipeline will not intersect any railroads or power lines.

The route of the proposed gas pipeline will cross the Alyeska oil pipeline a total of 25 times, and that of two other pipelines once each. A tabulation of these crossings by milepost is presented in Table 1.2-5.

1.2.2 LNG Plant

The proposed LNG Plant will be located at the southern terminus of the Alaskan Gas Pipeline on Gravina Peninsula, which is located in south central Alaska on the northeastern shore of Prince William Sound. The peninsula is bounded by Port Gravina to the northwest and by Orca Bay and Sheep Bay to the south and east, respectively.

The LNG Plant site will be located on the southeastern shore of Gravina Peninsula, approximately 14 miles northwest of Cordova, 35 miles south of Valdez, and four miles northeast of Gravina Point, in portions of Sections 16, 17, 20 and 21, Township 14 South, Range 5 West.

Figures 1.0-1, 1.2-1, and 1.2-2 show the orientation of the LNG Plant with respect to the overall project, the State of Alaska, and the area surrounding the Gravina Peninsula, while Figure 1.2-3 is a plot plan showing the relative locations of the various plant facilities as well as the adjacent marine terminal.

TABLE 1.2-3

ALASKAN GAS PIPELINE
LIST OF WATERWAY CROSSINGS

	Stream	Milepost	Minimum Depth of Cover	Concrete Coating	Crossing Length
*1.	Putuligayuk River	3.4	8'	520'	600'
2.	Glacier Fork Atigun River	152.0	5'	1,000'	1,080'
3.	Nutirwik Creek	180.0	5'	800'	880'
4.	Snowden Creek	194.2	5'	600'	680'
*5.	Beetles River	201.8	8'	1,000'	1,080'
6.	Minnie Creek	221.0	5'	520'	600'
7.	Marion Creek	228.2	5'	520'	600'
8.	Slate Creek	232.8	5'	1,000'	1,080'
*9.	South Fork Koyukuk River	248.0	8'	1,120'	1,200'
10.	Jim River	261.2	5'	520'	600'
11.	Prospect Creek	270.0	5'	520'	600'
12.	North Fork Bonanza Creek	277.1	5'	320'	400'
13.	Bonanza Creek	278.8	5'	320'	400'
14.	Fish Creek	287.0	5'	200'	280'
*15.	Kanuti River	294.9	5'	200'	280'
*16.	Yukon River	343.0	Elevated - on Highway Bridge		2,295'
17.	Isom Creek	353.6	5'	200'	280'
18.	Hess Creek	368.6	5'	200'	280'
19.	Erickson Creek	371.9	5'	120'	200'
20.	Lost Creek	381.2	5'	120'	200'
21.	Tolovana River	387.7	5'	320'	400'
22.	Slate Creek	397.4	5'	200'	280'
23.	Tatalina River	401.2	5'	800'	880'
24.	Globe Creek	405.7	5'	520'	600'

*Major River Crossings

ALASKAN GAS PIPELINE
LIST OF WATERWAY CROSSINGS
(Continued)

	Stream	Milepost	Minimum Depth of Cover	Concrete Coating	Crossing Length
25.	Aggie Creek	411.8	5'	120'	120'
26.	Washington Creek	419.9	5'	320'	400'
27.	Chatanika River	426.0	5'	1,000'	1,080'
28.	Treasure Creek	429.9	5'	320'	400'
29.	Goldstream Creek	435.5	5'	200'	280'
*30.	Chena River	446.0	9'	600'	680'
31.	Moose Creek	455.3	5'	5,300'	5,380'
32.	French Creek	All between (439.6 & 468.3) = (6 crossings)	5'	520'	600'
33.	Little Salcha River	475.9	5'	1,000'	1,080'
*34.	Salcha River	480.8	10'	720'	800'
35.	Redmond Creek	484.8	5'	320'	400'
36.	Shaw Creek	504.8	5'	320'	400'
*37.	Tanana River	516.3	14'	1,000'	1,080'
38.	Jarvis Creek	531.2	5'	1,200'	1,280'
39.	Ruby Creek	555.5	5'	320'	400'
40.	Bear Creek	556.7	5'	1,520'	1,600'
41.	Darling Creek	558.9	5'	800'	880'
42.	One Mile Creek	562.1	5'	320'	400'
43.	Gunnysack Creek	563.0	5'	520'	600'
44.	Camp Terry Creek	563.4	5'	320'	400'
45.	Falls Creek	564.2	5'	200'	280'
46.	Suzy Q Creek	565.0	5'	280'	360'
47.	Lower Suzy Q Creek	565.5	5'	320'	400'
48.	Boulder Creek	566.0	5'	520'	600'

*Major River Crossings

ALASKAN GAS PIPELINE
LIST OF WATERWAY CROSSINGS
(Continued)

	Stream	Milepost	Minimum Depth of Cover	Concrete Coating	Crossing Length
49.	Whistler Creek	566.8	5'	400'	480'
50.	Flood Creek	569.2	5'	320'	400'
51.	Michael Creek	570.4	5'	320'	400'
52.	Trims Creek	571.5	5'	520'	600'
53.	Castner Creek	573.1	5'	4,000'	4,080'
54.	Lower Miller Creek	573.4	5'		
55.	Miller Creek	575.1	5'	1,000'	1,080'
*56.	Phelan Creek No. 1	578.5	5'	1,520'	1,600'
*57.	Phelan Creek No. 2	584.5	5'	2,320'	2,400'
58.	McCallum Creek	587.2	5'	800'	880'
59.	Phelan Creek No. 3	588.4	5'	920'	1,000'
60.	Gulkana River	592.6	5'	720'	800'
61.	Fish Creek	598.0	5'	200'	280'
*62.	Gulkana River	639.3	10'	600'	680'
*63.	Tazlina River	671.4	Aerial Crossing		800'
*64.	Klutina River	682.0	5'	1,000'	1,080'
*65.	Tonsina River	706.9	5'	760'	840'
66.	Tiekel River No. 1	729.7	5'	320'	400'
67.	Tiekel River No. 2	734.1	5'	4,000'	4,080'
*68.	Tsina River	740.2	5'	320'	400'
*69.	Sheep Creek	757.4	7'	400'	480'
*70.	Lowe River	764.2	7'	4,000'	4,080'
71.	Dead Creek	788.4	5'	320'	400'
72.	Gravina River	790.3	5'	320'	400'

*Major River Crossings

TABLE 1.2-4

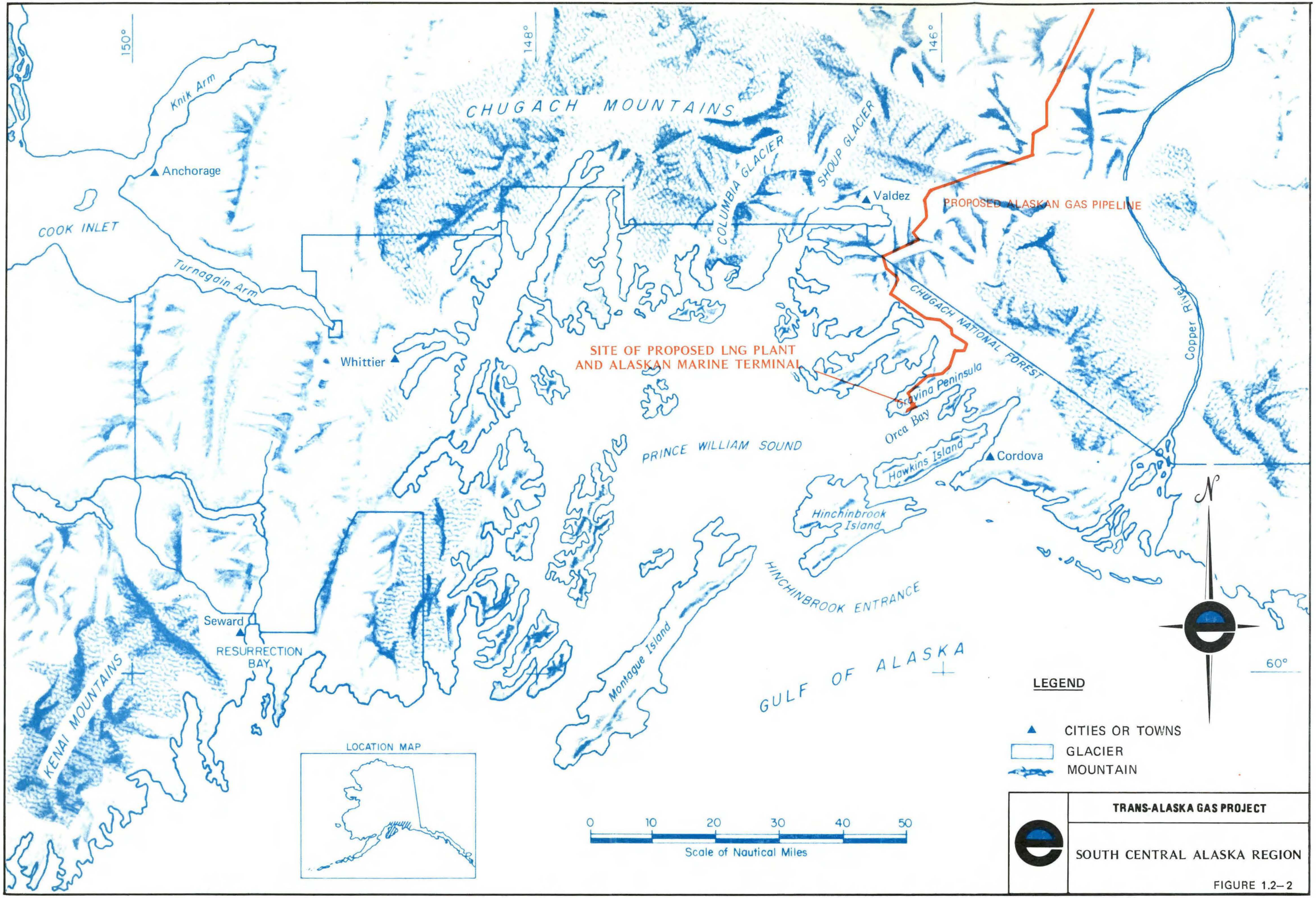
ALASKAN GAS PIPELINE
LIST OF ROAD CROSSINGS

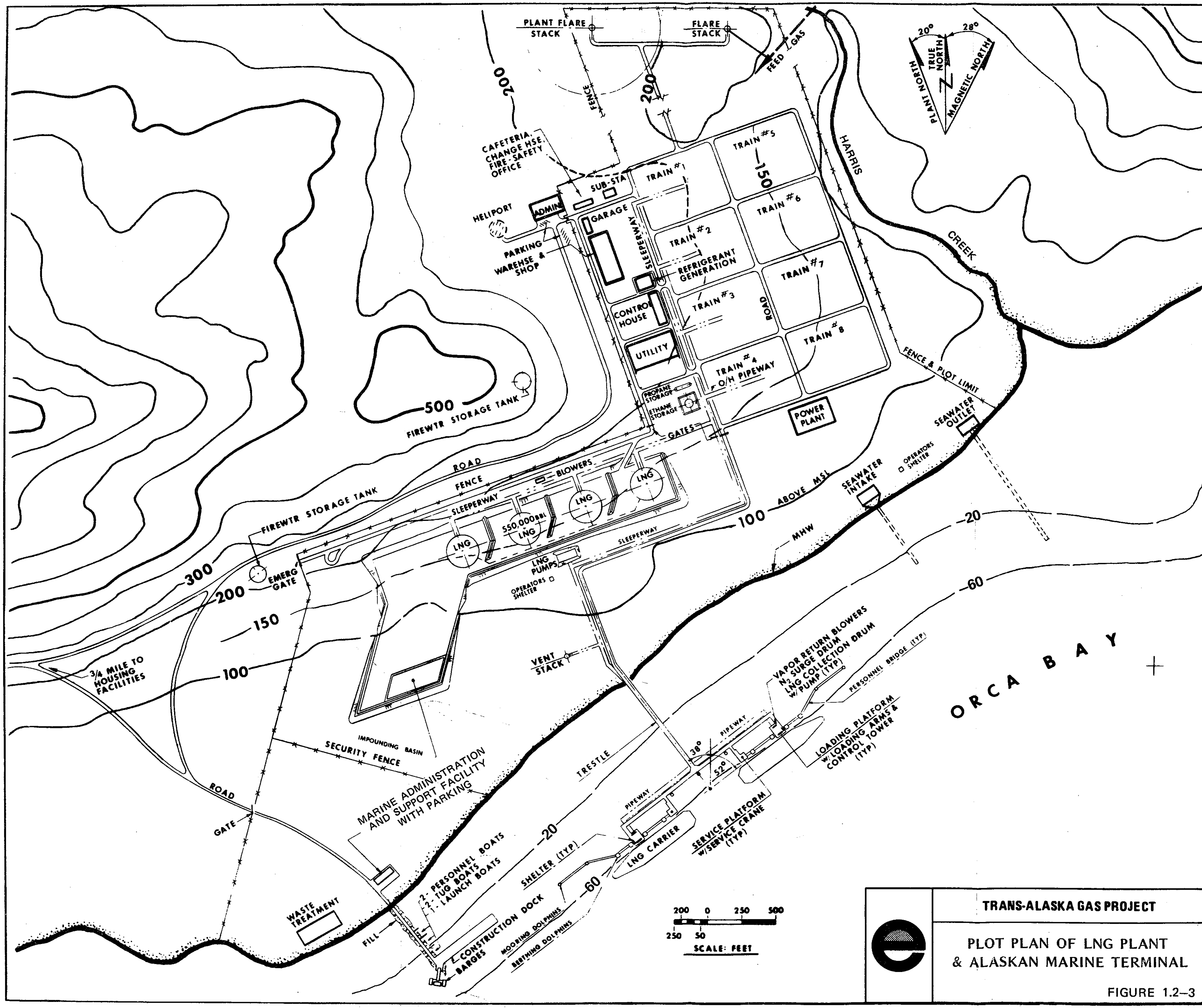
Milepost	Description
4.8	All Weather Road (local)
27.8	Proposed State Highway (Alyeska)
31.5	Proposed State Highway (Alyeska)
118.2	Proposed State Highway (Alyeska)
132.0	Proposed State Highway (Alyeska)
135.6	Proposed State Highway (Alyeska)
139.8	Proposed State Highway (Alyeska)
161.8	Proposed State Highway (Alyeska)
292.3	Proposed State Highway (Alyeska)
293.1	Proposed State Highway (Alyeska)
341.7	Proposed State Highway (Alyeska)
343.3	Proposed State Highway (Alyeska)
349.6	Alaska State Highway
353.7	Alaska State Highway
384.0	Alaska State Highway
386.2	Alaska State Highway
431.8	Murphy Dome Road
434.2	Elliott Highway
435.3	Steese Highway
442.1	Chena-Hot Springs Road
446.5	Nordale Road
448.8	Peede Road
452.5	Plack Road
454.2	Nelson Road
527.0	Alaska Highway
537.8	Richardson Highway
547.1	Richardson Highway
555.9	Richardson Highway
558.9	Richardson Highway
571.7	Richardson Highway
575.6	Richardson Highway
578.4	Richardson Highway
585.0	Richardson Highway
588.5	Richardson Highway
592.7	Richardson Highway
632.4	Richardson Highway
668.8	Glenn Highway
729.7	Richardson Highway
734.6	Richardson Highway
740.1	Richardson Highway
746.8	Richardson Highway
747.5	Richardson Highway
754.0	Richardson Highway
763.6	Richardson Highway

TABLE 1.2-5

ALASKAN GAS PIPELINE
LIST OF PIPELINE CROSSINGS

Milepost	Description
0.9	Local Pipeline (small diameter)
117.4	Proposed Alyeska Oil Pipeline (48")
131.8	Proposed Alyeska Oil Pipeline (48")
162.5	Proposed Alyeska Oil Pipeline (48")
341.7	Proposed Alyeska Oil Pipeline (48")
343.9	Proposed Alyeska Oil Pipeline (48")
387.2	Proposed Alyeska Oil Pipeline (48")
433.0	Proposed Alyeska Oil Pipeline (48")
463.0	Proposed Alyeska Oil Pipeline (48")
475.6	Proposed Alyeska Oil Pipeline (48")
481.2	Proposed Alyeska Oil Pipeline (48")
498.5	Proposed Alyeska Oil Pipeline (48")
526.7	Military Products Pipeline (8")
572.0	Proposed Alyeska Oil Pipeline (48")
575.5	Proposed Alyeska Oil Pipeline (48")
579.4	Proposed Alyeska Oil Pipeline (48")
580.6	Proposed Alyeska Oil Pipeline (48")
588.6	Proposed Alyeska Oil Pipeline (48")
596.1	Proposed Alyeska Oil Pipeline (48")
673.6	Proposed Alyeska Oil Pipeline (48")
729.0	Proposed Alyeska Oil Pipeline (48")
732.2	Proposed Alyeska Oil Pipeline (48")
736.6	Proposed Alyeska Oil Pipeline (48")
738.1	Proposed Alyeska Oil Pipeline (48")
740.6	Proposed Alyeska Oil Pipeline (48")
755.3	Proposed Alyeska Oil Pipeline (48")
764.7	Proposed Alyeska Oil Pipeline (48")


150°
148°
146°
60°
CHUGACH MOUNTAINS
Knik Arm
Anchorage
COOK INLET
Turnagain Arm
Whittier
COLUMBIA GLACIER
SHOUP GLACIER
Valdez
PROPOSED ALASKAN GAS PIPELINE
CHUGACH NATIONAL FOREST
Copper River
SITE OF PROPOSED LNG PLANT
AND ALASKAN MARINE TERMINAL
Gravina Peninsula
Orca Bay
Hawkins Island
Cordova
PRINCE WILLIAM SOUND
Hinchinbrook Island
HINCHINBROOK ENTRANCE
Montague Island
GULF OF ALASKA
Seward
RESURRECTION BAY
KENAI MOUNTAINS
LOCATION MAP
0 10 20 30 40 50
Scale of Nautical Miles
LEGEND
CITIES OR TOWNS
GLACIER
MOUNTAIN
TRANS-ALASKA GAS PROJECT
SOUTH CENTRAL ALASKA REGION
FIGURE 1.2-2



TRANS-ALASKA GAS PROJECT

PLOT PLAN OF LNG PLANT & ALASKAN MARINE TERMINAL

FIGURE 1.2–3

1.2.3 Alaskan Marine Terminal

The proposed Alaskan Marine Terminal will be located in Orca Bay, in water with a depth of 51 feet at mean lower low water (MLLW), 1200 feet offshore from the proposed LNG Plant, which is sited on the southeastern shore of Gravina Peninsula at coordinates 60° 38' N. Latitude, 146° 08' W. Longitude. Orca Bay, the primary body of water in the southeastern region of Prince William Sound (see Figure 1.2-2), is oriented in an east-west direction and has an average water depth in excess of 300 feet. At the location of the proposed marine terminal, Orca Bay is approximately six miles wide.

Sheep Bay is an eight mile long northeastern extension of Orca Bay. The entrance to Sheep Bay is about four miles wide and is situated between Gravina Point to the west and Sheep Point to the east. The area in the vicinity of the entrance has water depths ranging from 60 to 300 feet. Near the head of Sheep Bay, the average depth is less than 60 feet and there are several small islands and shoal areas.

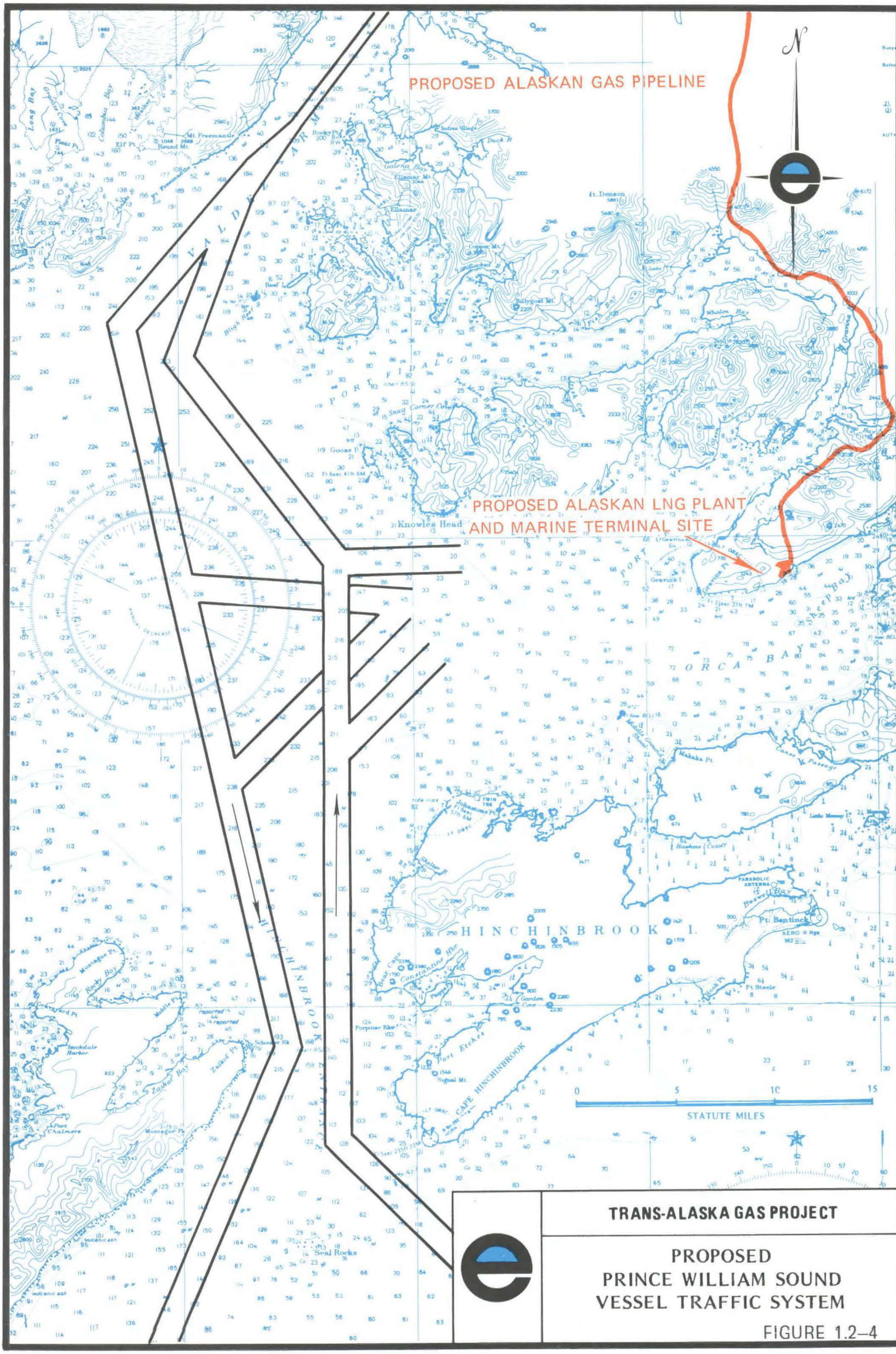
The waters in the immediate vicinity of the site range from 50 to 300 feet deep. There are no underwater obstructions indicated on navigation charts for the area. Because the waters are deep and open, there will be no need for turning basins in the vicinity.

A small boat harbor will be located adjacent to the marine terminal and will extend out from shore approximately 600 feet to a water depth of approximately 25 feet below MLLW. Figure 1.2-3 shows the plant and terminal facilities, including the carrier berths, the small boat harbor and the location on the plant site of buildings which will provide office space and related services in support of the marine terminal and LNG Carrier Fleet.

1.2.4 LNG Carrier Fleet

The marine transportation trade route extends from the Alaskan Marine Terminal serving the LNG Plant on the Gravina Peninsula to Point Conception, California, approximately 120 miles north of Los Angeles. The trade route, illustrated in Figure 1.0-1, consists of three sections; the Alaskan Coastal Route, the Ocean Route, and California Coastal Route.

After departing from the terminal waters of Orca Bay, an outbound LNG carrier will traverse the western extremity of the bay for approximately ten nautical miles to Prince William Sound proper. Passage through the Hinchinbrook Entrance will be in the proposed outbound ship traffic safety lane. Present U.S. Coast Guard plans (Figure 1.2-4) envisage an outbound traffic safety lane on the western side of Hinchinbrook Entrance extending southwesterly beyond Seal Rocks. The corresponding traffic inbound lane will be east of the outbound lane. Seal Rocks, Wessels Reef and Middleton Island will serve as points of reference for vessels approaching or departing Alaskan waters.



TRANS-ALASKA GAS PROJECT

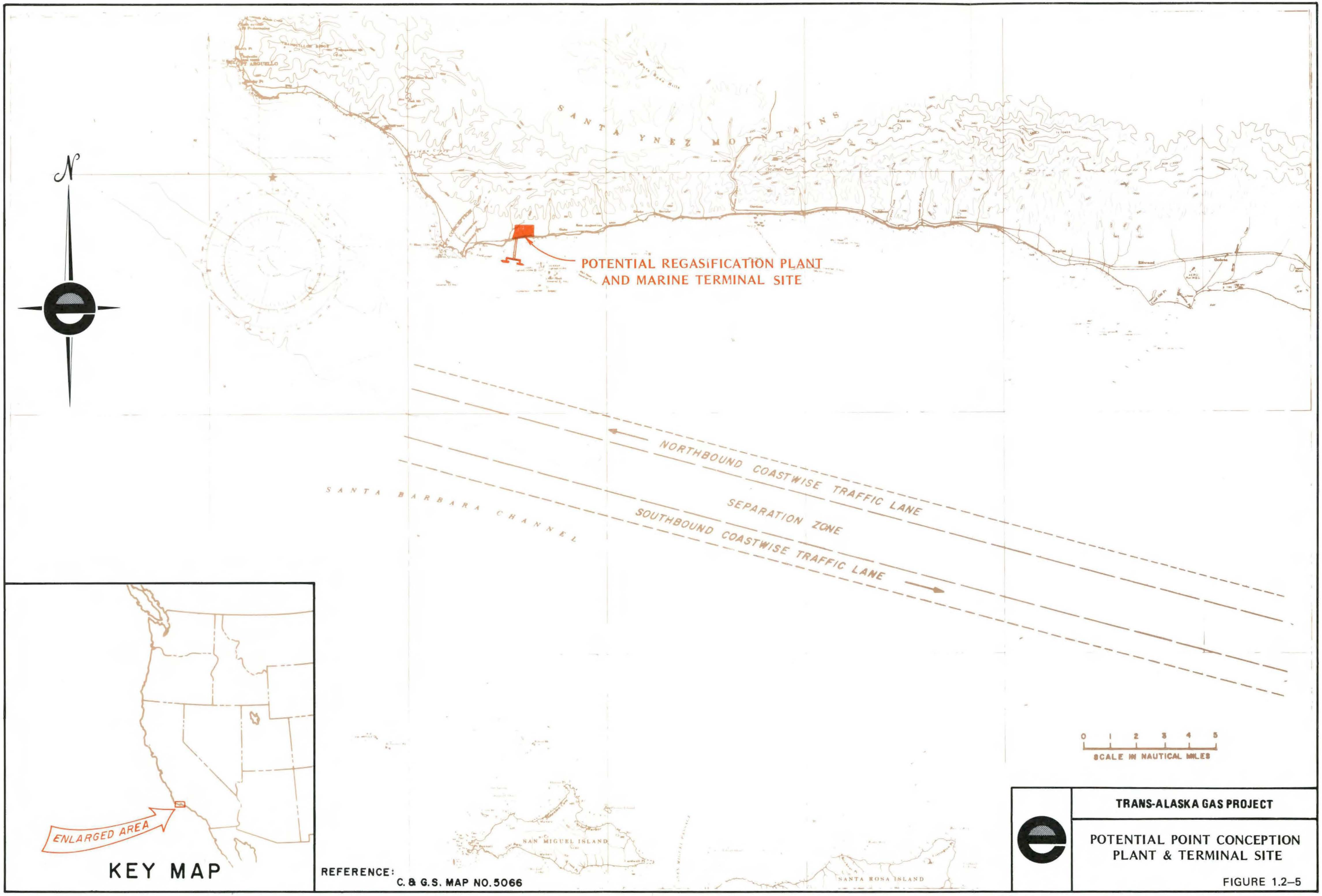
PROPOSED
PRINCE WILLIAM SOUND
VESSEL TRAFFIC SYSTEM

FIGURE 1.2–4

The 1902-mile voyage between the Gravina Peninsula and Point Conception will normally require four and one-half days. The transit of the Gulf of Alaska and the Northeast Pacific Ocean will involve relatively light traffic densities and no navigational obstructions. Normal celestial navigation will be supplemented by the navigational systems on board the ships.

The LNG Carrier Fleet navigation of waters off California will be well west of the Farallon Islands, which are located approximately 25 nautical miles west of San Francisco, to avoid coastal traffic. Transit along the California coast will continue well offshore to avoid the coastwise traffic associated with ports south of the San Francisco area.

The approach to the Point Conception terminal will begin south of Point Arguello (see Figure 1.2-5). The LNG carriers will maintain a safe and prudent course along the Point Conception coastline. Once clear of Point Conception and Government Point, the vessels will make a direct transit to the terminal site. No submerged obstacles are known to exist along the proposed course.



REFERENCE:
C. & G.S. MAP NO. 5066

TRANS-ALASKA GAS PROJECT

POTENTIAL POINT CONCEPTION PLANT & TERMINAL SITE

FIGURE 1.2–5

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Section 1.3
Land Requirements

1.3 LAND REQUIREMENTS

1.3.1 Alaskan Gas Pipeline

1.3.1.1 Permanent Land Requirements

The land area which will be utilized on a permanent basis is estimated to be the following:

Twelve compressor station sites,		216 acres
Pipeline right-of-way (809.2 miles long and 53.5 feet wide),		5,247 acres
Fifty sites for helicopter pads		10 acres
Fifteen sites for communication facilities,		8 acres
Sites for four maintenance bases and two meter stations,		26 acres
Sites for permanent storage of spoil from tunnel construction,		100 acres
Roads providing continuous access to compressor stations (22 miles long and 50 feet wide),	133 acres	
Roads providing access to construction camps and pipe storage yards (50 feet wide and 2 miles in length)	12 acres	
Total permanent road area		145 acres
Total area permanently removed from present land uses		5,752 acres

Additional land will be required to provide greenbelts for the 12 compressor stations (approximately 504 acres), the 15 sites for communication facilities (approximately 7 acres), and the 4 maintenance bases and 2 meter stations (approximately 9 acres). Such acreage will be utilized to provide additional work space during construction. On a permanent basis, the only maintenance to be performed will consist of minor vegetation control.

1.3.1.2 Temporary Land Requirements

Only 53.5 feet of the proposed 150-foot wide pipeline right-of-way will be kept clear of tall shrubs and brush after construction is completed. The total additional right-of-way width required for construction will be 96.5 feet, or 9,465 acres which will be returned to present uses after construction.

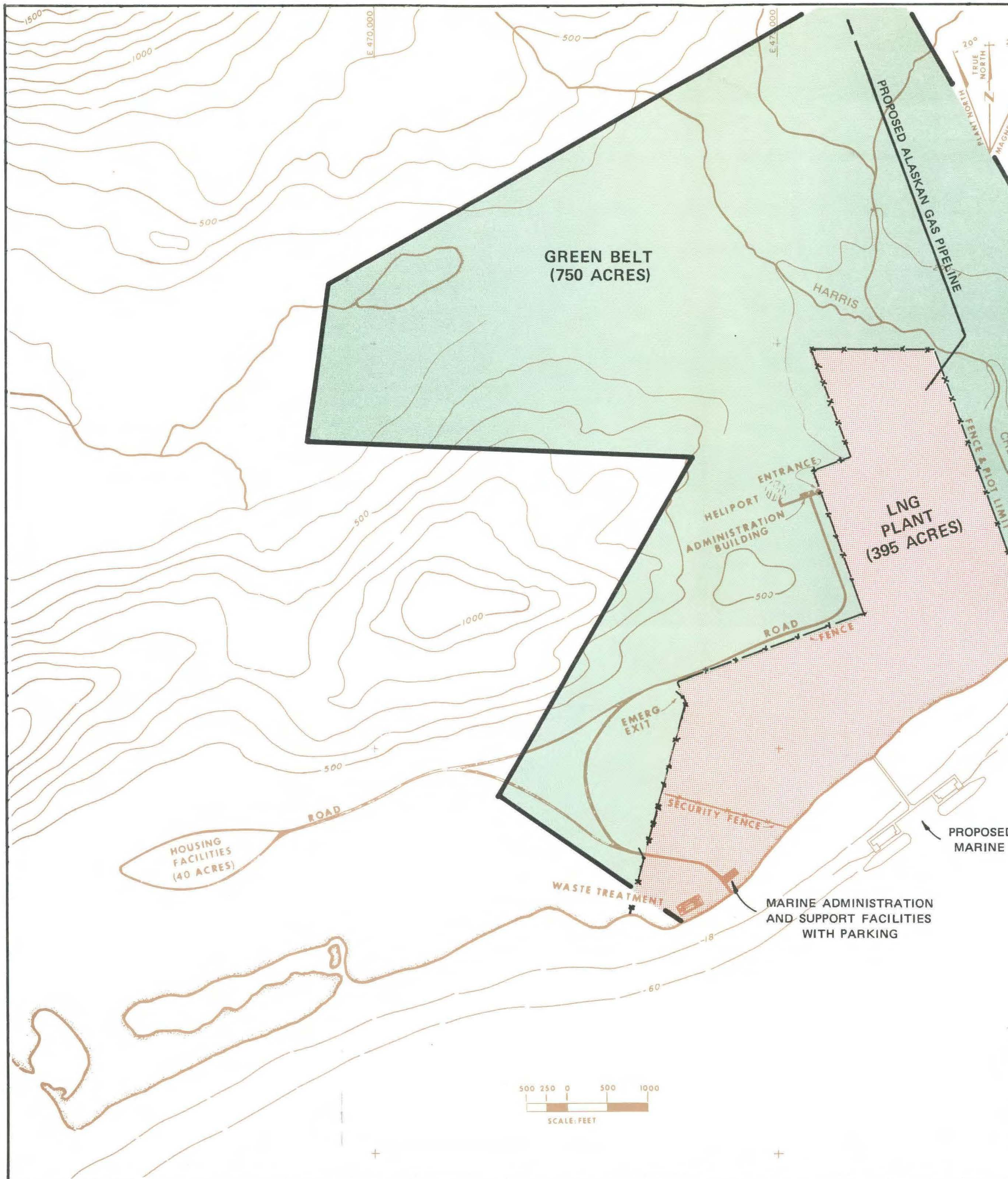
Requirements for additional temporary land use during construction are estimated to be the following:

Additional construction right-of-way on pipeline 96.5 feet wide by 809.2 miles long,		9,465 acres
Additional work space required at major river crossings,		36 acres
Six construction camps at 22 acres each,		132 acres
Borrow pits, quarries and other sources of construction materials,		60 acres
Roads providing access to borrow pits, quarries and other sources of construction materials (50 feet wide and 226 miles in length)		1,370 acres
Major pipe storage and double-jointing yards at four locations		
Prudhoe Bay	20 acres	
Pipeline Milepost 718	20 acres	
Fairbanks	50 acres	
Valdez	23 acres	
Thirty six intermediate pipe storage yards spaced at 20-mile intervals along the route	72 acres	
Total pipe yard area	185 acres	185 acres
Total temporary land area		11,248 acres

1.3.2 LNG Plant

The LNG Plant land requirement will be 395 acres, as outlined on Figure 1.3-1 by the fence at the plot limit. Essentially all of the land area within the plot limit will be utilized during construction of the plant.

Construction of auxiliary facilities outside of the plant limits will take place adjacent to the proposed plant site. These facilities



TRANS-ALASKA GAS PROJECT

LNG PLANT
LAND REQUIREMENTS

FIGURE 1.3–1

include housing facilities, marine administration and warehouse buildings, wastewater treatment facility, LNG Plant administration building, a heliport and roads connecting such facilities to the LNG Plant. The land requirement for these auxiliary facilities is estimated to be 55 acres.

A 750-acre greenbelt (which will not be cleared or otherwise removed from present land uses) will effectively insulate the LNG Plant and auxiliary facilities from future developments on adjacent land. The area required for the greenbelt plus the 450 acres required for the fenced plant area and auxiliary facilities brings the total LNG Plant land requirement to 1200 acres.

1.3.3 Alaskan Marine Terminal

1.3.3.1 Terminal Area Required by Onshore Facilities

It will be necessary to construct a 10,100-square-foot building onshore to provide space for offices and various services related to the marine terminal and the LNG Carrier Fleet. The building will be located within the 450-acre site required for the LNG Plant, and will occupy only a small fraction of the total plant site.

1.3.3.2 Terminal Area Required by Offshore Facilities

The two carrier berths will be positioned approximately 1200 feet offshore in water 51 feet deep at mean lower low water. The overall length of the two berths will be approximately 2600 feet, measured parallel to the shoreline.

The offshore area required for the marine terminal is approximately 115 acres, which includes sufficient area offshore from the mean high water level to accommodate the terminal with two carriers at berth. The liquefaction plant will occupy land area inland from the mean high water level.

The area required by the construction dock and small boat harbor is about 12 acres and is included in the 115-acre total for the marine terminal.

1.3.3.3 Terminal Area Required for Carrier Maneuverability

The LNG vessels utilizing the marine terminal will require an area free from obstructions and submerged hazards in which they can maneuver safely when traveling to and from the marine terminal. The southern region of Prince William Sound, in which the ships will travel prior to their arrival at the marine terminal, does not present any foreseeable difficulties from a navagational standpoint.

The proposed LNG carriers will require a turning area roughly in the shape of a square measuring approximately 2,000 feet on a side. At the proposed location of the marine terminal, the bay is approximately six miles wide. Navigable water extends approximately three miles to the east of the marine terminal, while to the west, there exists an unlimited area in which the ship can navigate. The offshore area adjacent to the marine terminal is considered to be more than adequate for safe maneuvering of the proposed LNG carrier, and there is no need for turning basins in the vacinity.

1.3.4 LNG Carrier Fleet

The land requirements of the LNG Carrier Fleet administrative support facility are included in the land requirements for the Alaskan Marine Terminal.

Section 1.4
Proposed Facilities

1.4 PROPOSED FACILITIES

1.4.1 Alaskan Gas Pipeline

1.4.1.1 Pipeline

The Alaskan Gas Pipeline will be approximately 809.2 miles long. The outside diameter of the welded steel pipe will be 42 inches, and the pipe wall thickness will be primarily 0.75 inches. Pipeline appurtenances will include block valves and cathodic protection facilities. There are no looping, lateral or gathering pipelines proposed.

Except at isolated locations, such as compressor stations and aerial river crossings, the pipe will be buried. Degradation of permafrost adjacent to the buried line will be minimized by chilling the gas.

A summary of the mainline 42-inch O.D. pipe required is:

Wall Thickness Inches	Length Feet	Length Miles
0.750	4,253,278	805.6
0.900	54,845	10.4
1.080	56,308	10.7
Total	4,364,431	826.7

The above includes a 1% terrain roughness factor, a 1% wastage of pipe with a 0.750" wall thickness, a 5% wastage of pipe with wall thicknesses of 0.900" and 1.080", and 2,000 feet of additional pipe to tie-in at the LNG Plant and at the producers' facilities.

1.4.1.2 Compressor Stations

Gas compression will be provided at each station by two 23,400 H.P. ISO-rated gas turbine-driven centrifugal compressor units.

Discharge gas cooling will be accomplished by a propane refrigeration plant consisting of a gas turbine-driven centrifugal multi-stage compressor unit(s), air-cooled condensers and evaporators. Station 12 will not require a refrigeration plant, since permafrost is not characteristic of the area south of this station. The refrigeration requirements under summer flow conditions are presented in Table 1.4-1.

TABLE 1.4-1

ALASKAN GAS PIPELINE/REFRIGERATION REQUIREMENTS

Station Number	Number of units	Installed ISO HP	Refrigerant Compressor Operating BHP	Fan Condenser Operating BHP
1	1	4130	3919	1018
2	2	8260	3972	970
3	2	8260	3918	905
4	2	8260	5955	1202
5	2	8260	6783	1352
6	2	8260	7166	1411
7	2	8260	6866	1332
8	2	8260	7427	1443
9	2	8260	6932	1363
10	2	8260	7096	1416
11	2	8260	4269	870
12	0	0	0	0
Total	21	86730	64303	13282

Electric power at each compressor station will be provided by gas-fired, turbine-driven generators. Each station will also have a heating system, automation control and instrumentation systems, fuel and starting gas systems, a blowdown system, and an instrument air system. Other facilities provided will be station piping, a gas scrubber, and storage tanks for water, oil and propane, emergency power generation systems, living quarters, fire detection and control systems, and waste disposal systems.

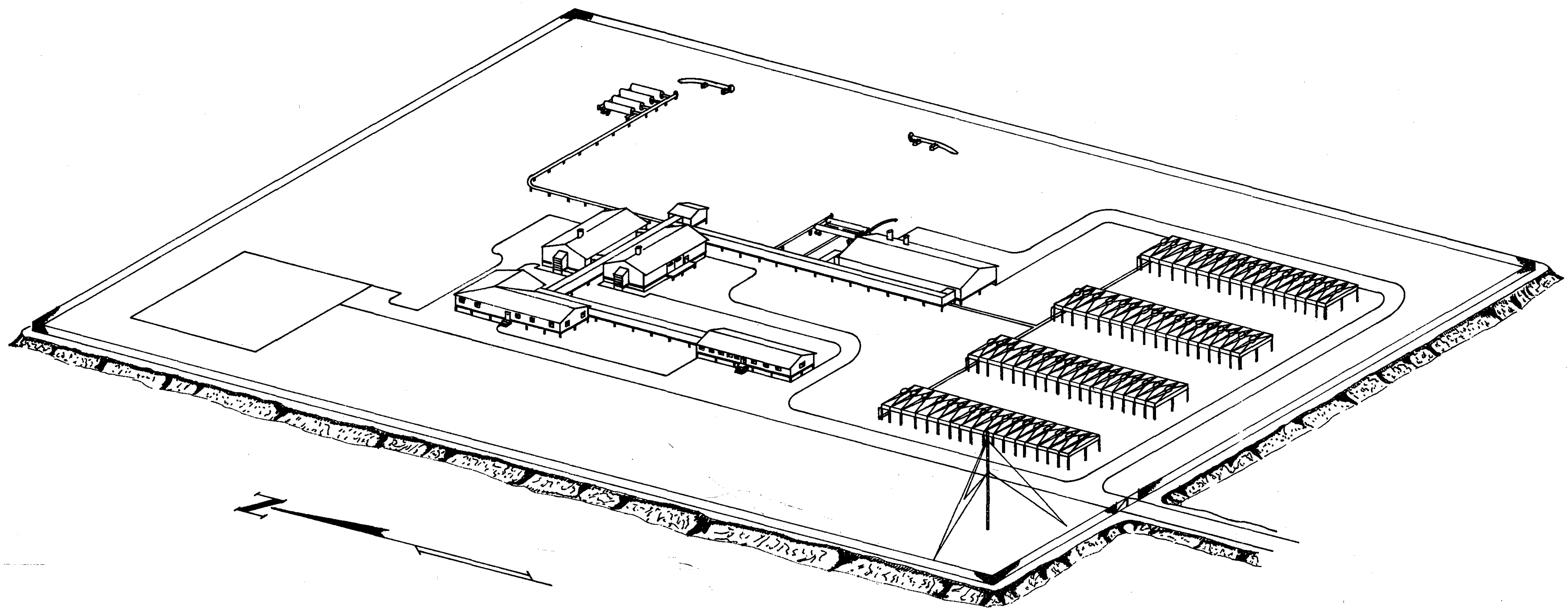
Transportation facilities generally provided for each station will be a heliport and an access road. Station 9 will not require an access road, and no road to any station will exceed six miles in length (see Table 1.2-1).

Figures 1.4-1, 1.4-2 and 1.4-3 provide perspective, plan and elevation views of a typical compressor station.

1.4.1.3 Other Facilities

Maintenance Bases

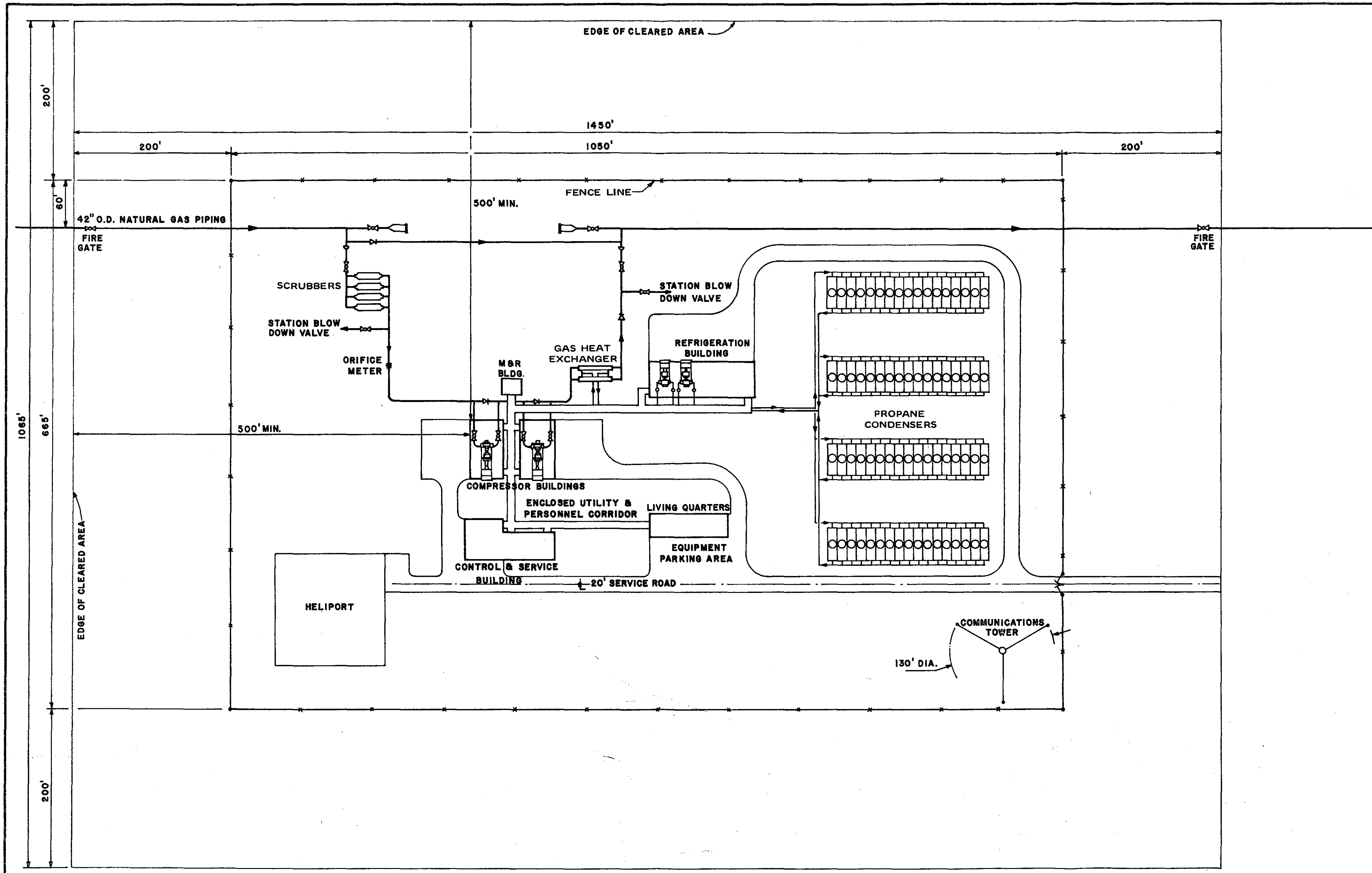
Maintenance bases will be required at Compressor Stations 2, 5, and 8, and at Valdez. Each base will consist of living quarters for



TRANS-ALASKA GAS PROJECT

TYPICAL COMPRESSOR
STATION PERSPECTIVE VIEW

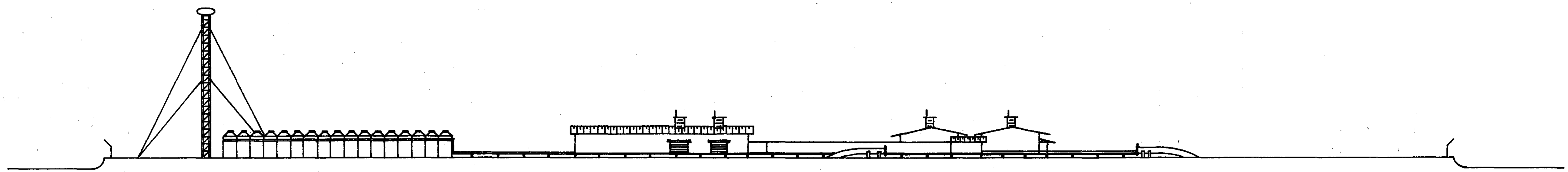
FIGURE 1.4 – 1



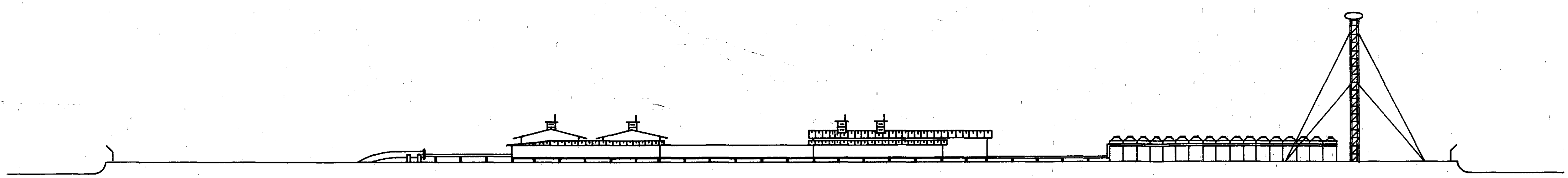
TRANS-ALASKA GAS PROJECT

TYPICAL COMPRESSOR STATION
PLOT PLANT

FIGURE 1.4 – 2



VIEW FROM EAST SIDE OF STATION



VIEW FROM WEST SIDE OF STATION

TRANS-ALASKA GAS PROJECT

TYPICAL COMPRESSOR STATION
PROFILE VIEW

FIGURE 1.4 – 3

30 men, a recreation hall and first aid station, a kitchen, a utility building, and a warehouse/workshop building. The buildings will be connected with fully enclosed corridors for personnel and utility lines. A communications tower and outside storage area will also be provided. The bases will be connected to the State Highway system by permanent gravel roads, and will utilize the helicopter pads at the compressor stations and the Valdez airport.

Meter Stations

One meter station will be located at the inlet to the pipeline, and another at the inlet to the LNG Plant. Both will be of the differential orifice-type, designed to handle the maximum anticipated volume with an orifice beta ratio of approximately 0.6 and a maximum differential pressure range of 100 inches of water.

The 20-inch, three-section standard orifice-type meter runs with a senior orifice fitting will be interchangeable between the two stations. The Prudhoe Bay station will be equipped with eight operating meter runs plus one spare. Fourteen operating meter runs plus one spare will be utilized at the LNG Plant Meter Station.

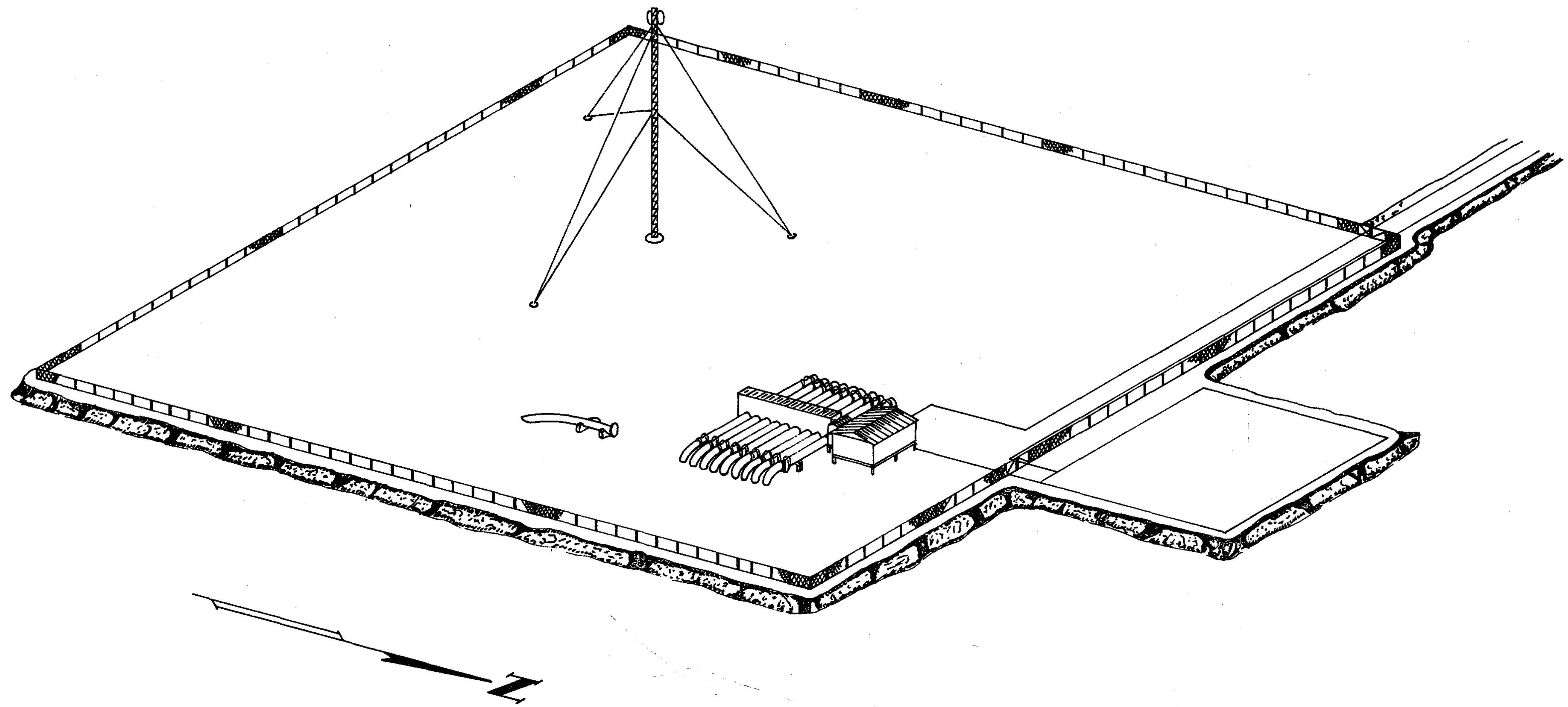
Each station will have an 8-foot high cyclone fence surrounding the metering facilities and communications tower, and a helicopter pad will be adjacent to the station. Figure 1.4-4 is a perspective view of the Prudhoe Bay facility, which is identical to the meter station at the LNG Plant except for the number of meter runs.

Communications Facilities

Communications for the pipeline system will be provided by a line-of-sight microwave system (operating in the 6 GHz band), which will consist of a facility at each pipeline terminal and compressor site and fifteen repeater sites along the pipeline route. This system will provide 600 Baud data channels for the supervisory control system as well as channels for voice communications. "Hot standby" equipment capabilities are included.

Dispatching and Control Center

The Dispatching and Control Center will be located within the LNG Plant, and will consist of one office building for the General Superintendent, Engineering Department, dispatching specialist, and general system personnel. Facilities will include the supervisory "master" station used to control and monitor the entire pipeline system, a direct communications link with the LNG Plant, and an external communications link.



TRANS-ALASKA GAS PROJECT

PRUDHOE BAY METER STATION
PERSPECTIVE VIEW

FIGURE 1.4 – 4

1.4.2 LNG Plant

Figure 1.2-3 is a plot plan showing the relative location of the LNG Plant facilities. An artist's conceptual drawing of the LNG Plant is presented in Figure 1.4-5. Other details of equipment functions and operations are included in Section 1.6.2, "Operational and Maintenance Procedures." The LNG Plant will be comprised of:

Process facilities for treating, dehydration and liquefaction of the gas,

Support facilities to supply the energy and materials necessary for the operation of the process facilities, and

Buildings for housing administration personnel, process control personnel, maintenance facilities, fire and safety facilities, and warehousing.

The drivers which will provide mechanical horsepower in the LNG Plant include gas turbines, steam turbines, electric motors, diesel engines, and hydraulic turbines. Installed horsepower required will total approximately 1.33 million horsepower. To avoid duplication, driver horsepower for the electric generators, 276,260 horsepower, is not included in the total, since most of the electricity generated will be used to power the electric motor drivers.

1.4.2.1 Process Facilities

The process facilities will be provided in eight parallel trains, each designed to deliver a net equivalent of 378.81 million cubic feet per stream day (MMcf/sd) to the LNG Carrier Fleet from LNG storage. Each train is composed of three unit operations:

Diglycolamine (DGA) gas treating for removal of CO_2,

Molecular sieve dehydration for removal of water, and

Refrigeration and compression for liquefaction of LNG.

LNG Product storage and handling equipment is also provided as required.

The DGA gas treating unit will reduce the carbon dioxide (CO_2) content of the gas to 50 ppm CO_2 to prevent its deposition in downstream processing facilities. Major equipment provided in each DGA unit will be:

A CO_2 contactor for removal of CO_2 by contacting the gas with a lean DGA solution,

A DGA regenerator column where the CO_2 is removed from the DGA solution and expelled to the atmosphere,

A DGA reclaimer unit for processing contaminated DGA,

Heat exchangers for heat recovery, heat rejection, solution regeneration temperature control, and

Centrifugal pumps for circulation of liquids throughout the unit.

Molecular Sieve Gas Dehydration

Gas drying to 1 ppm will be required to prevent moisture in the gas from freezing and plugging cryogenic equipment in the liquefaction plant. Major equipment facilities to be provided in each molecular seive dehydration unit are:

Vessels for containment of the molecular sieve desiccant which removes water vapor from the treated natural gas,

A regeneration gas heater to provide hot gases which heat the desiccant bed to drive off the water vapor during the regeneration cycle,

A regeneration gas compressor which recycles the regeneration gas back to the main stream,

Heat exchangers for heat recovery and heat rejection to the atmosphere,

Filters for removal of desiccant dust from the gas stream before liquefaction, and

Gas/liquid separators for removing liquid water from the regeneration gas.

Liquefaction

The liquefaction process selected is the Phillips Petroleum Company's "Optimized Cascade Cycle", which utilizes propane, ethane and methane refrigerants in series. Major facilities provided in each liquefaction unit will be:

A propane compressor and refrigeration system which furnishes highest temperature level refrigerant cooling requirements,

An ethane compressor and refrigeration system which furnishes intermediate temperature level refrigerant cooling requirements,

A methane compressor and refrigeration system which furnishes low temperature level refrigerant cooling requirements,

Gas/liquid separators for disassociating liquefied natural gas from the vaporous natural gas as the feed stream passes through the various steps of refrigeration, Gas/liquid separators for separating the liquid and vapor refrigerant streams,

Heat exchangers for heat rejection and refrigeration recovery,

Centrifugal pumps for transfer of liquefied natural gas to storage,

Demethanizer, deethanizer, and depropanizer columns and reboilers for production of the propane and ethane refrigerant makeup, and

Storage vessels for ethane and propane refrigerants.

LNG Product Storage and Handling

The LNG Product will be stored in four aboveground storage tanks at a pressure of 15.2 psia and the corresponding equilibrium temperature of approximately minus 256°F. The four 550,000 barrel tanks will be located at an elevation of 150 feet above sea level and will be within a diked area to contain spills. Finger dikes will direct flow from the individual tank dikes to a common impounding basin located away from adjacent tanks.

A schematic diagram of a typical LNG storage tank is shown in Figure 1.4-6. Each tank will be of conventional LNG design with flat bottom, insulated suspended deck and double walls consisting of an insulated 9% nickel steel inner tank and a killed carbon steel outer shell.

A complete ring-walled base will be electrically heated to prevent frost heaving. Ground temperatures will be continuously monitored in the central control room. Each tank will be individually controlled on absolute pressure with gage pressure override to minimize pressure fluctuations during carrier loading. Duplicate monitoring, automatic shutdown and pre-alarming devices will be installed in order to prevent potentially dangerous conditions from evolving into full scale emergencies.

The LNG carrier loading facility will include the capability of recovering all LNG vapors from such sources as tanks and carrier cooldown, loading, and storage boil-off.

LNG Product Storage and Handling Facilities will be:

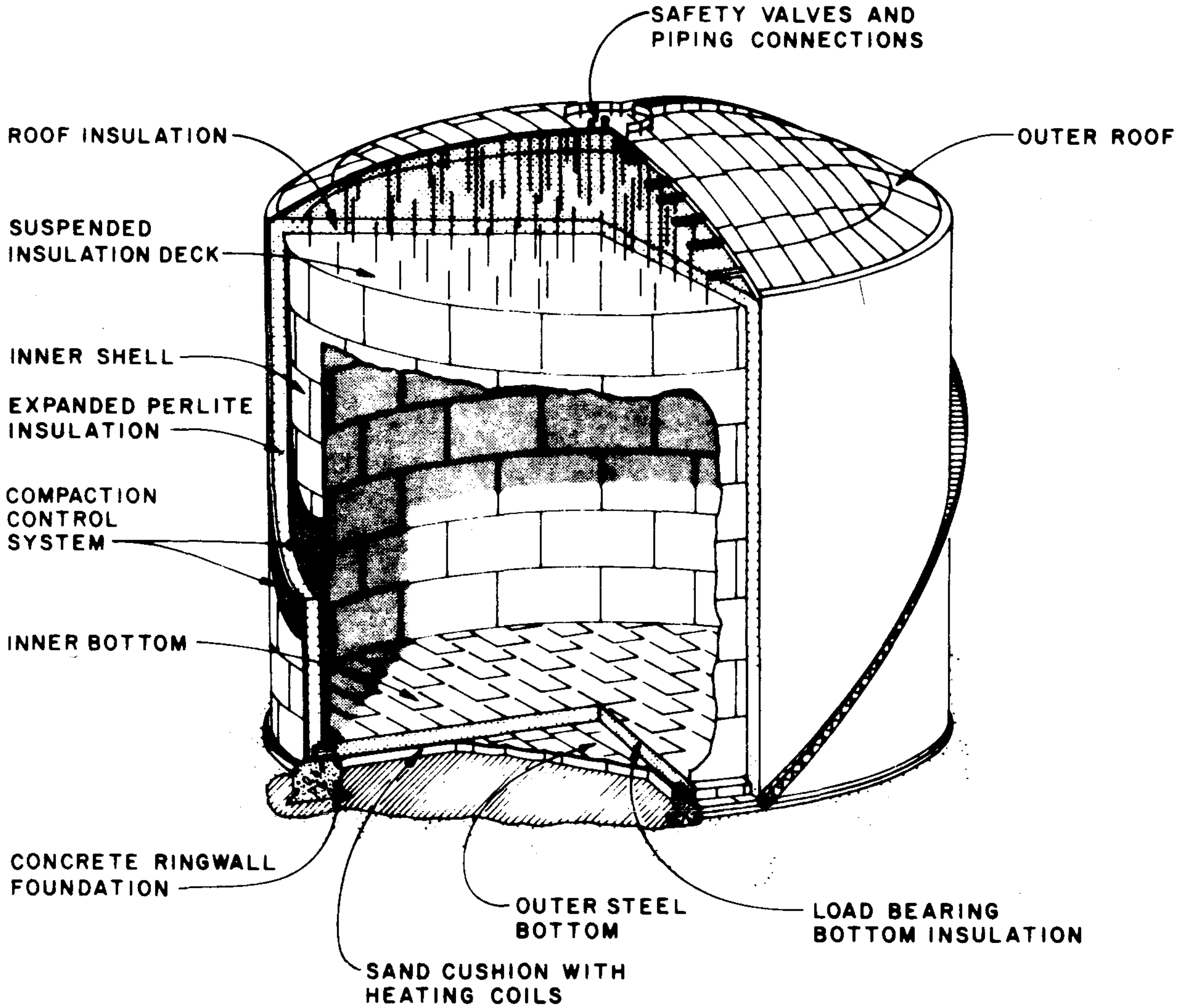
LNG tanks for storing LNG in preparation for shipment,

LNG pumps to transfer LNG from storage to the LNG carrier,

Blowers for recovery of vapors from LNG storage, piping, and for vapors generated during ship loading operations,

Accumulators for collection of LNG from drains and pumps for returning the LNG to storage, and

Nitrogen surge drum for purging of drained LNG loading arms.



TRANS-ALASKA GAS PROJECT

SCHEMATIC DIAGRAM OF
TYPICAL LNG STORAGE TANK

FIGURE 1.4–6

1.4.2.2 Process Support Facilities

Support equipment necessary for the operation of the process facilities are:

Electric power generators driven by regenerative gas turbines for normal operating power requirements,

A diesel-driven electric power generator to provide emergency power,

Centrifugal air compressors and desiccant driers for supplying instrument and utility air to the complex,

Nitrogen generation facilities consisting of compressors, exchangers, a nitrogen separation column, liquid nitrogen storage tanks and a nitrogen vaporizer to supply nitrogen for purging and gas blanketing,

Flares and vents to provide safe disposal of vapors generated during emergency conditions,

A fire protection system including two elevated fire water storage tanks, diesel-driven fire water pumps, fire hydrants, dry chemical fire extinguishing units and a portable foam generating truck,

A desalting water system of the multiple flash-type to provide fresh water makeup requirements,

A potable water system serving the process units, support facilities and buildings, including a storage tank, a hypochlorinator and carbon filters,

Cooling water systems including a once-through sea water system for coolers in clean service and a closed-loop fresh water cooling system for those areas in which there is a chance of contamination. Equipment will include cooling water pumps, pump suction basins, moving screens, coolers, and a chlorine injection system,

A boiler feedwater system to furnish water to the steam generating units. Equipment includes storage tanks, deaerators, a mixed bed polishing type demineralizer and pumps for transferring the water throughout the unit,

A steam generation system consisting of supplementary fired gas turbine waste heat boilers and a gas fired conventional boiler, and

Waste product and disposal systems.

1.4.2.3 Buildings and Personnel Boats

The various buildings required for plant administration and operation and for operator housing are described in the following paragraphs.

Administration Building

A single story building of approximately 30,000 square feet in area will house administrative and technical offices and conference rooms. A laboratory, pipeline Dispatching and Control Center and a communication room will also be included as a part of this building.

Maintenance Shop and Warehouse Building

A 55,000-square foot building will be provided for warehousing plant supplies, spare parts, and maintenance materials. Maintenance shops for the various crafts will be provided in a portion of this building.

Control Building

The control building will contain main control panels for all process trains and utility plants. Its size will be approximately 18,000 square feet, and it will include operating offices, kitchen, locker room, bathroom, control laboratory for use by operators, a supply room and a mechanical equipment room.

Cafeteria, Change House, Fire and Safety Building

A single, 6,000-square foot building is planned near the main plant entrance to provide a dressing room area equipped with 270 lockers, a cafeteria seating 50 people, offices for fire and safety personnel, fire and safety equipment storage, first aid facilities and offices for the security personnel.

Garage

A garage will be provided for servicing maintenance vehicles and other plant rolling stock, with space for heated parking of the fire truck and ambulance. Facilities will include hydraulic lifts, a dynamometer, and fueling facilities for diesel and gasoline. Approximately 4,500 square feet of area is required for this building.

Compressor Buildings

Each of the eight LNG process trains will contain a group of compressors and drivers which are housed in a compressor building equipped with bridge cranes for maintenance use. Each building will contain 25,000 square feet of area.

Utility Building

A single utility building will house utility facilities such as demineralizer and desalting equipment, instrument air compressor and the operating faces of boilers. A switchgear room will be included in the 5,000 square feet of space.

DGA Sump Building

A 600-square foot building will be provided to enclose one end of the DGA mixing sump, and to store 25 drums of DGA. The sump will be 17' x 17' square and 10' deep, and will hold sufficient DGA for a single train.

Switchgear Buildings

A 1,000-square foot switchgear building will be provided for each liquefaction train to house motor controls and switchgear.

Power Plant Building

A two-level power plant building of 60,000 square feet area is planned to house the power generators and drivers, switchgear, the stand-by generator, a control room, lavatory, battery room, and supply room. A bridge crane will be included over the turbine generator.

Personnel Housing

Sixty-five permanent homes, each containing 2,500-square feet and located on a 1/4 acre site, will be included in the housing complex located 3/4 mile west of the plant to provide residences for key operating personnel. Other personnel will reside in the Cordova area.

Guest House

A 7,500 square foot guest house will accomodate 15 people. Included are a kitchen and dining room, and a recreational room.

Recreational Building

A recreational building of 12,000 square feet area will be provided at the housing complex and will include a small store, kitchen and dining facilities, billiard room, auditorium, bowling alley, swimming pool and sauna.

Operator Shelter Buildings

Two shelter buildings will be constructed--one each at the LNG loading pumps and the seawater intake structure. Each will have an area of 200 square feet, and will contain a small desk, toilet and lavatory.

Personnel Boats

Two personnel boats will provide the primary means of travel between the LNG Plant and the City of Cordova. The boats will provide the necessary flexibility to support the plant and to serve plant personnel residing near the plant.

Each personnel boat will be capable of carrying approximately 40 passengers at speeds of approximately 25 miles per hour and will have a deck cargo-carrying capacity of 20,000 pounds. The boats will be licensed and certified by the U.S. Coast Guard and will be equipped with navigation and life saving equipment.

1.4.3 Alaskan Marine Terminal

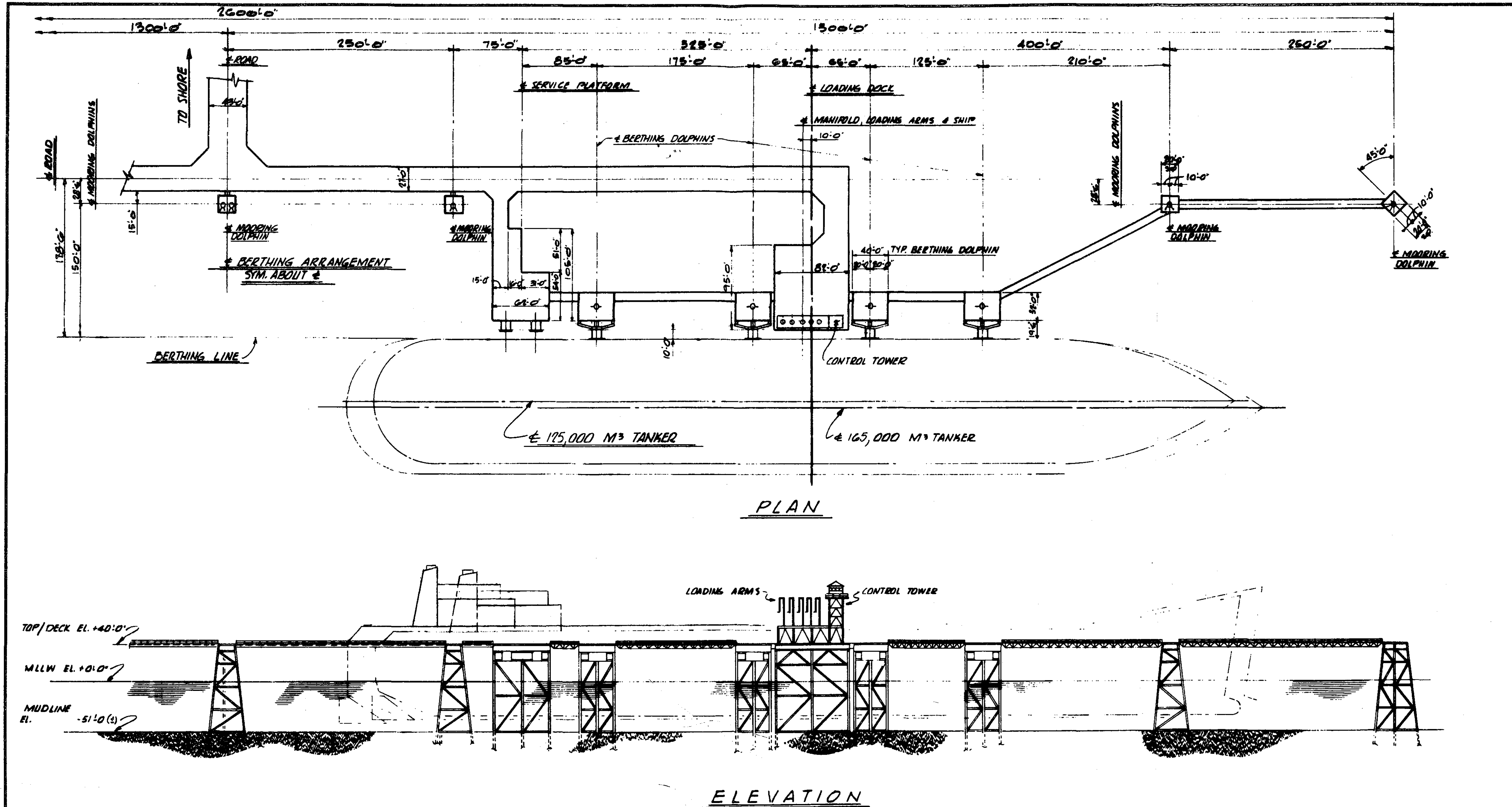
The Alaskan Marine Terminal is designed to provide berthing and simultaneous loading facilities for two 165,000 cubic meter (m^3) LNG carriers. The primary components of the marine terminal (Figure 1.4-7) will be one loading platform and one service platform for each berth, four berthing dolphins and three mooring dolphins per berth, an additional mooring dolphin common to both berths, personnel bridges providing access to the various dolphins from each loading platform, and one trestle which connects the loading and service platforms to shore. Loading arms and a control tower will be located on each LNG loading platform. The two berths are aligned almost parallel to the shoreline approximately 1200 feet offshore at a water depth of 51 feet below mean lower low water.

Support facilities for the marine terminal will include several buildings located ashore and a small boat harbor, which will accommodate the tug boats, personnel boats and mooring launch.

1.4.3.1 Loading and Service Platforms and Trestle

Loading Platform

The loading platform at each berth will be used to support the cryogenic loading arms and related service facilities comprising the LNG loading system. Each platform will support a control tower, four 16-inch diameter LNG loading arms, one 16-inch diameter vapor arm with a 3-inch diameter nitrogen line connection, one 2-1/2-inch diameter hydrant for potable water, several hydrants and monitors for firewater, one pneumatic connection tying the shipboard emergency shut-down system to the plant emergency shut-down station, one four-line telephone cable, one control cable for pressure control of the vapor return system, and one gangway.



NOTE: ROADWAY JACKETS OMITTED FOR CLARITY

TRANS-ALASKA GAS PROJECT

ALASKAN MARINE TERMINAL
PLAN AND ELEV. SINGLE BERTH

FIGURE 1.4–7

The loading platform, as well as the service platform, trestle, and berthing and mooring dolphins, will consist of a deck section (a bridge in the case of the trestle) which will be elevated 40 feet above mean lower low water by a "jacket" section. A jacket section is a supporting structure consisting of a set of vertically driven or slightly battered (angled) pilings which are braced horizontally and diagonally with tubular crossbeams. Each piling (leg) is protected by an outer tubular covering, or "jacket". The loading platform deck section will be 82 feet by 95 feet. The jacket section will have three bays (rows) of three legs each with center-to-center spacing of 35 feet parallel and 42 feet perpendicular to the shoreline.

The control tower will be 15 feet by 10 feet in cross-section and approximately 60 feet high and will support a control house. The base of the control house will be 90 feet above mean higher high water.

Each 16-inch diameter loading arm will consist of a base and riser, an inboard arm section and an outboard arm section, and related equipment necessary for operation and storage of the unit.

The riser will be a vertical pipe connecting the platform piping with the loading arm and acting as a support column for the loading arm assembly. The inboard section of the arm will be connected to the riser and to the outboard section of the arm by swivel joints. The offshore end of the arm will terminate in a combination swivel unit connected to the carrier's manifold and will be equipped with a butterfly valve used primarily to avoid small product spills when the arm is disconnected.

The loading arms, spaced 9 feet apart, center-to-center, will be hydraulically operated. Movement of the entire arm in the horizontal plane, as well as individual movement of either section of the arm in the vertical plane will be accomplished using hydraulic cylinders positioned on the arm. Once the arm has been connected to the carrier's manifold, the hydraulic unit will be bypassed, thereby allowing the entire loading arm to move freely with the ship's motion at the dock. The hydraulic unit can be operated locally or from the control tower. The loading arms will be fitted with limit switches to sound an alarm or initiate shutdown of the cargo transfer operation in case the arms exceed their motion envelope.

Service Platform

The service platform at each berth will consist of a deck section and a ten-legged jacket section. The main deck area will be L-shaped with a 62-foot by 54-foot section and a kick-out area of 31 feet by 54 feet. Each service platform will be equipped with a crane used primarily for transferring stores containers between the service platform and a carrier at berth.

Trestle

Access from shore to the loading platforms for piping, personnel and vehicular traffic will be provided by a trestle, which will consist of jacket structures, pipe support bridges and a roadway bridge. Four-pile jacket structures will be alternated with two-pile jacket structures and will be spaced 100-feet on center to support the elevated roadway and piping from shore to the berths.

The pipe support bridge will consist of two laterally braced wide flange girders. The roadway will be 12 feet wide with a reinforced concrete slab with curbs and will be supported by three 36-inch girder beams laterally braced at 20-foot intervals with 12-inch beams.

1.4.3.2 Berthing and Mooring Dolphins

Berthing Dolphin

Each berthing dolphin will consist of three sections: a deck, a fender system, and a jacket structure. The jacket structure for each berthing dolphin will have three seaward legs vertical and the three shoreward legs battered at 1 to 8 (H:V) toward the shore.

The four berthing dolphins at each berth will have a flexible fender system consisting of a wale face and one marine fender used to absorb the impact energy of the carrier's contact during berthing. The wale face is the contact surface of the fender which bears against the carrier's hull. The face will be made of 1-3/4-inch thick high density polyethylene wear pads. The wear pads will be supported by a steel frame bolted to the fenders. The fenders will be supported by a gridwork of steel box beams welded to the jacket structure. The fender system will also absorb the impact of carrier motion due to wind or wind-generated wave forces.

Each berthing dolphin will be equipped with a powered capstan and one set of two quick-release hooks to accommodate spring lines. These lines maintain the longitudinal position of the carrier relative to the loading platform.

The powered capstan will be mounted on the dolphin directly behind the set of quick-release hooks and will be used to haul in a spring line from the carrier. The capstan consists of a vertical, cylindrical drum driven by an explosion-proof electric motor.

The two quick-release hooks will be located in the center of the dolphin and mounted on a common circular base secured to the deck of the dolphin. Each hook will have a rated load capacity of 60 tons and will be free to rotate in the horizontal plane.

Mooring Dolphin

The seven mooring dolphins will secure a berthed LNG carrier and allow a minimum of movement due to wind, waves and currents, or a combination of the three. These dolphins will be located shoreward of the berthing dolphins and will support the mooring lines led out from the carrier. Three mooring dolphins will be used for each berth and an additional mooring dolphin will be common to both berths.

A 20-foot square deck and a jacket structure will be the primary components of each mooring dolphin. The deck will be covered by a metal grating supported by deck beams. Each of the four legs of the jacket structure will be battered toward the center of the dolphin on a 1 to 8 slope.

Each mooring dolphin will be equipped with a powered capstan and one set of quick-release hooks similar to those used on the berthing dolphins. The two quick-release hooks on each mooring dolphin are oriented side by side on a common base and are positioned perpendicular to the offshore edge of the dolphin.

Personnel Bridges

Access from the loading platform to the berthing and mooring dolphins will be provided by personnel bridges, each consisting of a truss and a walkway. The truss will be composed of heavy chord members interconnected with bracing members to form a triangular configuration. The walkway will consist of grating and handrails.

1.4.3.3 Support Facilities

Small Boat Harbor

The small boat harbor, composed of a construction dock, roadway and ferry landing, will be used as a shelter for the tugboats, personnel boats and morring launch stationed at the Alaskan Marine Terminal. During construction, it will serve as an unloading area and access way for materials and equipment used to build the terminal and LNG Plant.

The construction dock and roadway will form a breakwater located on the southwestern end of the marine terminal. Walkways will be constructed on the shoreward side of the breakwater for protection from large waves. The harbor will be located to permit water to circulate so as to prevent ice formation in the winter.

Support Building

Office space and accomodations will be provided at the LNG Plant in a single 10,100-square-foot building (see Figure 1.2-3) for administrative and operating staff in support of the marine terminal and the LNG Carrier Fleet. The space requirements will be distributed among administrative offices, laboratories, and warehousing and workshops.

1.4.4 LNG Carrier Fleet

The LNG Carrier Fleet will consist of eleven 165,000 m^3 ships. The operational characteristics will be similar for all the ships, although there may be differences in cargo containment systems and in design details, which are dependent on the particular shipyard in which each ship will be constructed.

The shore-based facilities will include space for administration, shop and warehousing, and facilities for storage and transfer of provision containers and liquid nitrogen.

1.4.4.1 General Carrier Description

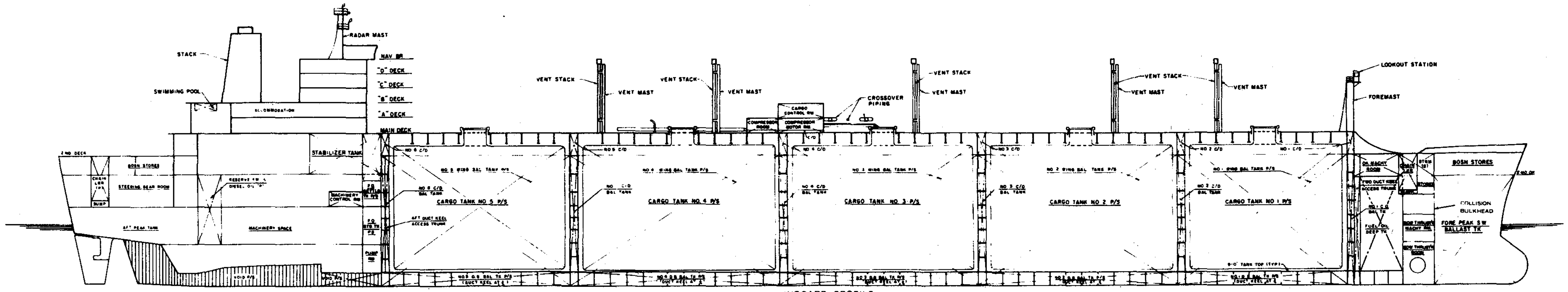
Each 165,000 m^3 LNG tanker (see Figure 1.4-8) will be 1002 feet in overall length, 150 feet in beam, and 101 feet in hull depth, with a displacement of approximately 122,000 long tons, a loaded draft of 40 feet, and a loaded freeboard of 61 feet. The ship will have a general configuration similar to modern bulk commodity carriers, with the propulsion machinery and deckhouse aft. The cargo control room will be located amidship, near the cargo loading system.

The LNG tanker's hull structure will be a double hull design, consisting of a second reinforced steel hull (inner hull) approximately 10 feet above the bottom of the ship (outer hull). The double hull design will also be used for the sides of the vessel and, in some cases, the decks. The space between the inner and outer hull of the ship will be used, among other things, for shipboard services, inspection access, and clean ballast water when the ship is empty of cargo.

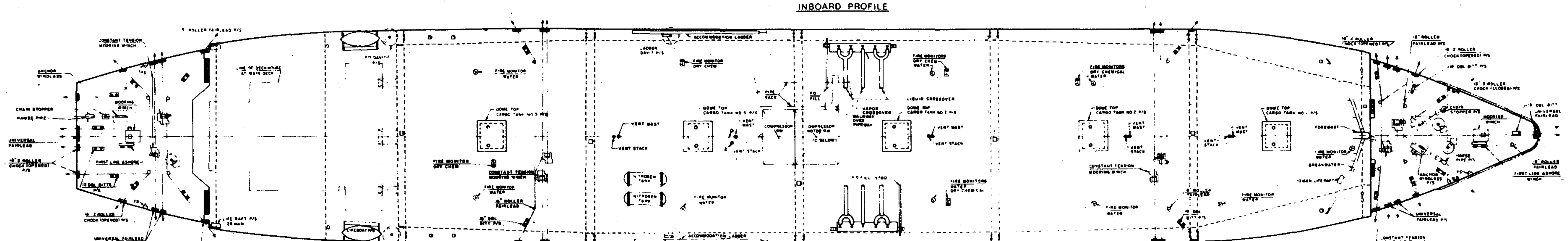
Propulsion machinery onboard the ships will be 55,000-shaft horsepower transmitted through twin propellers. An average service speed of 18.5 knots will be attained under most open sea conditions. The primary fuel will be LNG boiloff vapors supplemented by Bunker "C" fuel oil.

To assure high maneuverability, the carriers will have an unusually large rudder angle of 45 degrees (rather than the normal 35 degrees) and a 2500-horsepower bow thruster. The bow thruster will consist of a propeller located in a transverse tunnel through the ship's forward underwater area to produce a lateral force which causes the ship to rotate around its vertical axis.

The effectiveness of the rudder, being directly proportional to the square of the propeller race velocity, is greater at higher speeds. The effectiveness of the bow thruster is greatest at speeds below one to two knots. Together, the rudder and bow thruster will provide positive steering control at all speeds.

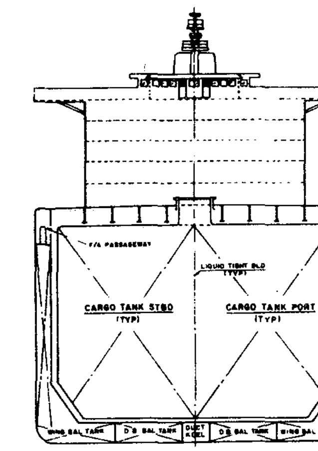


INBOARD PROFILE



MAIN DECK

GENERAL ARRANGEMENT



MIDSHIP SECTION

TYPICAL PRINCIPAL CHARACTERISTICS

LENGTH OVERALL	1002 FEET
LENGTH BETWEEN PERPENDICULARS	952 FEET
BEAM	150 FEET
DEPTH OF HULL	101 FEET
DRAFT	40 FEET
BLOCK COEFFICIENT	0.75
DISPLACEMENT	122,000 LONG TONS

CLASSIFICATION

AMERICAN BUREAU OF SHIPPING ✠ A1 Ⓔ

LIQUEFIED GAS CARRIER ✠AMS ✠ACC

LEGEND

P/S - PORT AND STARBOARD
S.W. - SALTWATER
F.W. - FRESH WATER
F.O. - FUEL OIL
DBL - DOUBLE
C/D - COFFERDAM
F/A - FORE AND AFT
D.B. - DOUBLE BOTTOM

TRANS-ALASKA GAS PROJECT

TYPICAL 165,000 M^3 LNG TANKER
CONCH CARGO SYSTEM

FIGURE 1.4–8

1.4.4.2 Cargo Containment Systems

The most often used cargo containment systems for LNG tankers (see Figure 1.4-9) are divided into two categories: 1) "free standing" or "self supported" tanks which have sufficient strength to stand by themselves and to support the weight and dynamic forces of the cargo; and 2) "integral" or "membrane" tanks in which a thin metal barrier supported by insulation contains the liquid cargo. The membrane tank insulation in turn transmits the weight and dynamic forces of the cargo to the inner hull structure of the ship itself.

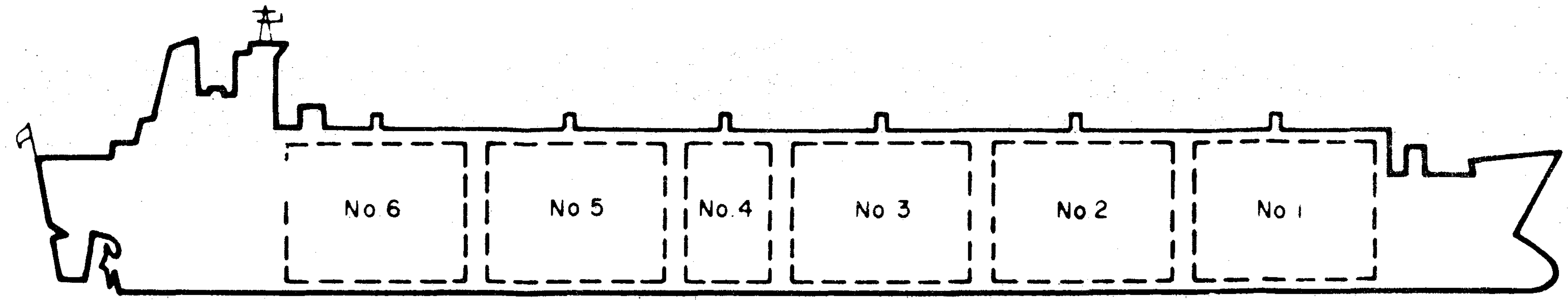
Five cargo containment systems are regarded as acceptable for use in the LNG Carrier Fleet: the Kvaerner-Moss spherical tank and the Chicago Bridge and Iron spherical tank (both free standing), the Conch free standing prismatic tank, the Gaz Transport membrane tank and the Technigaz membrane tank. All are described in a paper presented to the Society of Naval Architects and Marine Engineers in November, 1971 by the J. J. Henry Company, Inc.

The Kvaerner-Moss tank (see Figure 1.4-10) consists of a sphere of nine percent nickel steel or aluminum supported solely by a cylindrical skirt. The skirt is attached to the sphere by welding to a specially shaped forged or extruded section at the equator of the tank and to the ship structure by means of a conventional welded connection. Insulation consists of polyurethane foam applied to the entire outer surface of the sphere, and to a portion of the skirt to control thermal stresses and to limit heat leak into the tank through this plating.

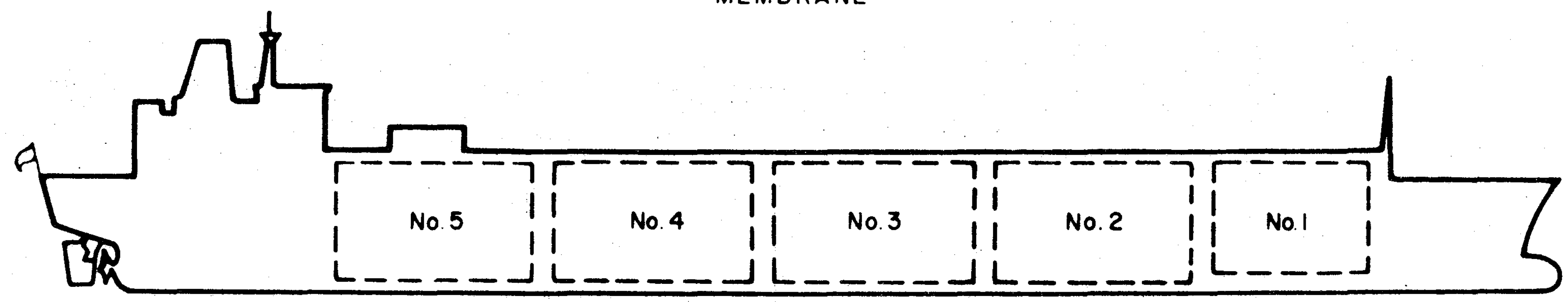
The Chicago Bridge and Iron ("CB&I") system is similar to the Kvaerner-Moss system. CB&I's is a spherical design utilizing the same tank material and similar insulation. The unique aspect of this system compared to Kvaener-Moss is column support of the tank rather than the cylindrical skirt and the use of a keyway system to anchor the tank to the support structure of the ship's hull.

The system offered by Conch International Methane, Ltd., (see Figure 1.4-10) features structurally self-supporting aluminum tanks of prismatic shape. The corners and upper boundaries of the insulated hold are fitted with balsa panels, forming a "picture frame" type of arrangement. The entire area surrounded by these boundary panels is covered with sprayed polyurethane, which bonds to the ship's structure and the tapered edges of the panels. Several layers of nylon mesh are embedded in the polyurethane, making the entire mass fracture-resistant during thermal cycling and also enabling the foam to serve as a liquid-tight secondary barrier.

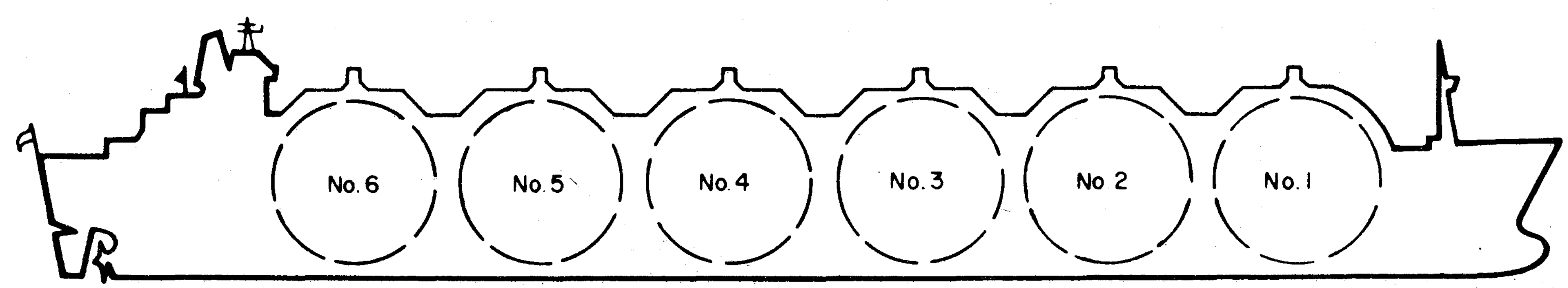
The membrane tank containment system as developed by Gaztransport is shown in Figure 1.4-11. It consists (from the ship's structure inward toward the cargo) of secondary insulation, a secondary barrier,



MEMBRANE



PRISMATIC FREE STANDING

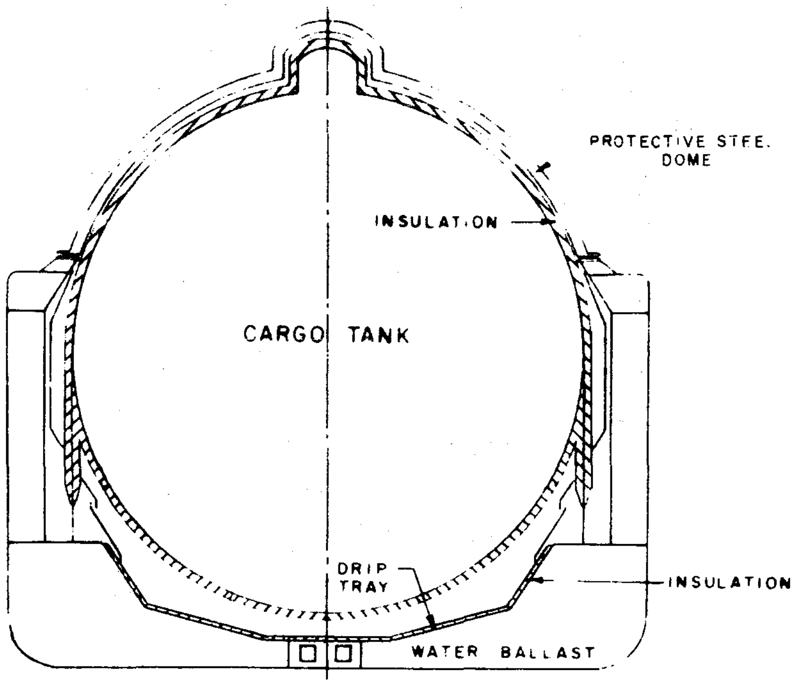


SPHERICAL FREE STANDING

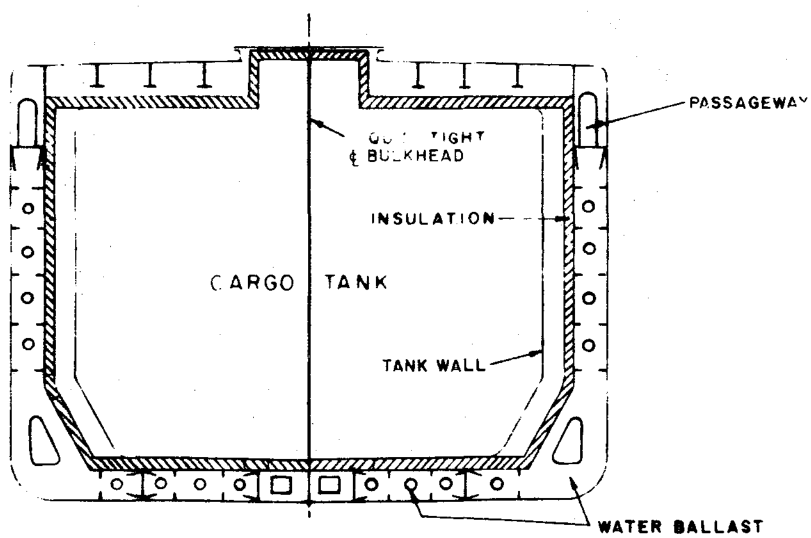
TRANS-ALASKA GAS PROJECT

LNG CARRIER FLEET
COMMON CARGO TANK
CONFIGURATIONS

FIGURE 1.4–9



TYPICAL SECTION OF KVAERNER-
MOSS SPHERICAL TANK DESIGN

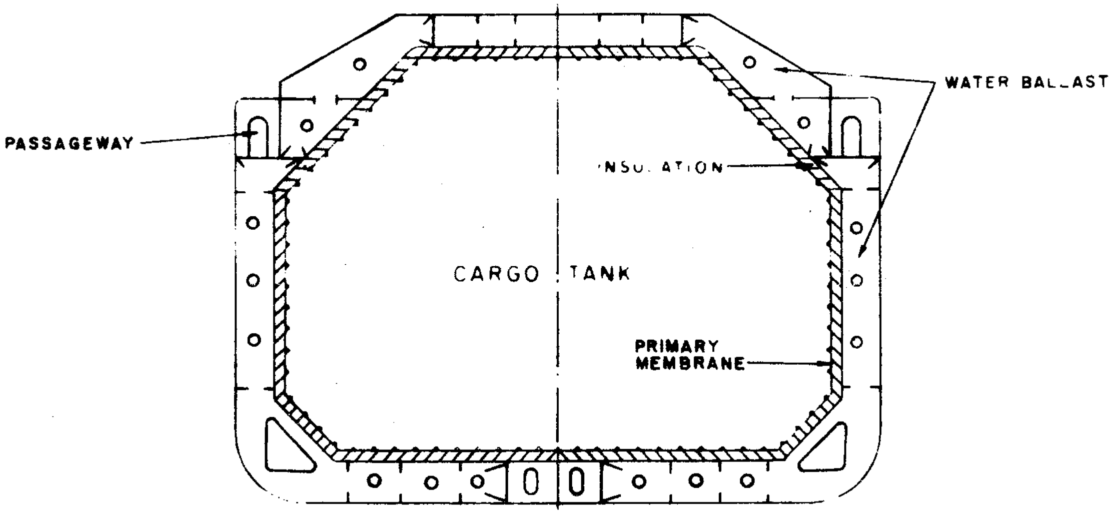


TYPICAL SECTION OF CONCH
FREE STANDING TANK DESIGN

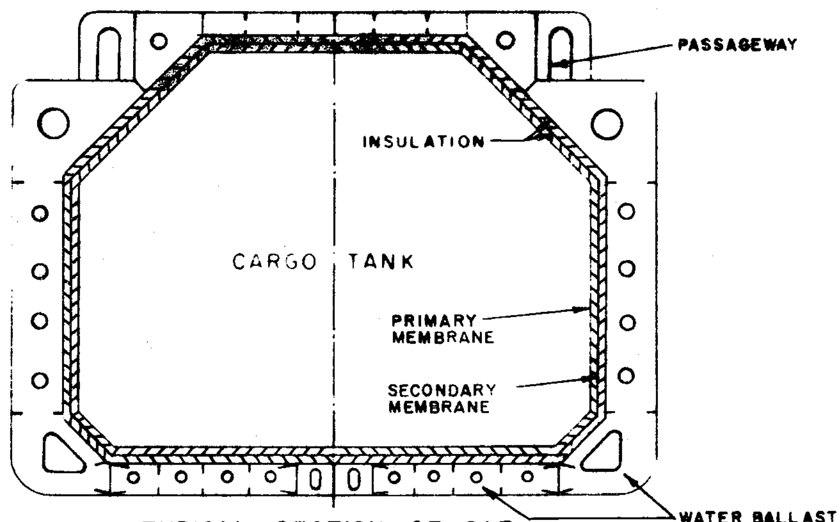
TRANS-ALASKA GAS PROJECT

LNG CARRIER FLEET
SELF-SUPPORTING CARGO
CONTAINMENT SYSTEMS

FIGURE 1.4–10



TYPICAL SECTION OF TECHNIGAZ MEMBRANE TANK DESIGN



TYPICAL SECTION OF GAZ TRANSPORT MEMBRANE TANK DESIGN

TRANS-ALASKA GAS PROJECT

LNG CARRIER FLEET
MEMBRANE CARGO
CONTAINMENT SYSTEMS

FIGURE 1.4–11

primary insulation and a primary barrier. The two insulation layers are virtually identical, as are the two barriers, with the exception of the arrangements for anchoring the primary insulation to the secondary barrier. Each barrier is made up of 16-inch wide, 0.5 millimeter thick Invar (36 percent nickel-iron alloy) sheets with upturned edges. The primary and secondary insulation consists of a multitude of plywood boxes filled with perlite. Invar was chosen for the barriers because of its very low coefficient of thermal expansion, making expansion joints or corrugations in the barriers unnecessary.

The Technigaz membrane system, detailed in Figure 1.4-11, is similar in structural concept to the Gaz Transport system. The ship's cargo hold structure provides the support for tank, insulation and LNG. The arrangement of insulation and barriers is also similar to the Gaz Transport concept. The system consists (proceeding inward from the double hull) of mineral wool insulation, plywood supporting balso wood insulation, a sealed-plywood secondary barrier, a thin balso wood pad and the corrugated (waffled) stainless steel primary barrier.

1.4.4.3 LNG Carrier Operational Systems

The carrier support systems, which will be located in the ship's accommodations and in the engine room, include: control equipment for operating boilers and propulsion machinery; navigation and communications systems; equipment for operating cargo and ballast control systems; inert gas systems; a custody transfer system; an emergency shutdown system; and a fire protection system.

(1) Operational Control Equipment for Boilers and Propulsion Machinery

Control equipment for monitoring and operating boilers and propulsion machinery are located both in the engine room and on the navigation bridge. The equipment is designed for single watch-stander operation.

(2) Operational Equipment for Cargo and Ballast Control Systems

The central control room for ballast and cargo handling will be located amidship where all cargo systems will be controlled and alarm systems monitored. Cargo handling and ballast valves will be equipped with valve operators controlled from the central cargo control room.

(3) Custody Transfer

This system will measure the level, temperature and density of the LNG in the tanks. The liquid level in the tank will be measured by two different devices. The primary measuring device will be a "capacitance" type liquid level measuring instrument. The secondary measuring device will be a nitrogen "bubbler" type instrument. The density of the LNG will be measured by a magnetic suspension device.

(4) Navigation and Communication Systems

The LNG tankers will be equipped with three and ten centimeter radars with separate displays. Either radar may be connected to the computerized collision avoidance system to be installed in each tanker. The collision avoidance system will provide the LNG tanker captain with all-weather capability to determine the location, speed and course of all other vessels within potential collision range. If the location, speed and direction of travel of the LNG tanker and another vessel indicates a collision course, advance warning will be immediately displayed on the system's screen. The system allows the ship's officer to test different possible corrective actions by immediately displaying the results of the corrective action before executing a course change. Additional navigational capability includes a satellite navigation system with an Loran backup system, a gyrocompass with a standby compass, a depth sounder indicator and a radio direction finder.

Primary communication requirements are supplied with a radio telegraph, single-side and double-side band radio telephone transmitters, and a 1000-watt, high frequency voice transmitter with a high frequency backup telegraph. A 52-channel VHF radio telephone will be provided in addition to the mandatory bridge-to-bridge channels.

(5) Inert Gas Systems

A reliable supply of inert gas will be required to maintain an inert atmosphere and to minimize the moisture content in the space between the inner hull and the cargo tanks. The normal practice for most LNG tankers has been to provide liquid nitrogen storage tanks and a vaporization system for day-to-day usage.

Since it will be impractical to carry sufficient quantities of liquid nitrogen onboard to inert all of the LNG cargo tanks simultaneously, it will be necessary to produce additional quantities of inert gas from a special, independently-fired inert gas generator.

(6) Emergency Shut-down System

An emergency shut-down system will be provided to stop cargo pumps and compressors and to activate all quick-close valves. The emergency shut-down system is automatically activated by fire, low cargo tank pressure, or excessive movement of the ship at the dock beyond the limits of the loading arms. In addition, there will be five manually-activated emergency shut-down stations located throughout the ship. The maximum time required to shut down the system will be approximately 15 seconds.

(7) Fire Protection System

The basic fire protection system designed for the LNG tankers will include dry powder units, water turrets and water spray systems. The entire cargo deck area is covered by the fire protection system, which is located so that all important areas are overlapped to insure maximum protection. A system of spray nozzles will be installed along the longitudinal and crossover cargo piping so that the piping and the deck beneath can be constantly sprayed with water.

Section 1.5
Construction Procedures

1.5 CONSTRUCTION PROCEDURES

1.5.1 Alaskan Gas Pipeline

1.5.1.1 Initial Procedures

Pre-Job Preparation

By the end of the third project year (see Figure 1.5-1), initial site preparation will begin on all construction sections: specific sites will have been selected for the pipe storage yards, double jointing yards, and construction camps. Sources of gravel will be located and the overburden will be removed to permit thawing. Gravel will be hauled and spread on the work sites to form a gravel pad with a thickness of from 1 foot to 6 feet as required for the protection of the permafrost. The pads will then be allowed to weather until just before they are to receive their load. At that time, the pads will receive additional gravel, if needed, and grading, leveling, and compacting will be completed.

Gravel access roads will be constructed from the Alaska State Highway to the pipeline right-of-way and to the pipe storage yards.

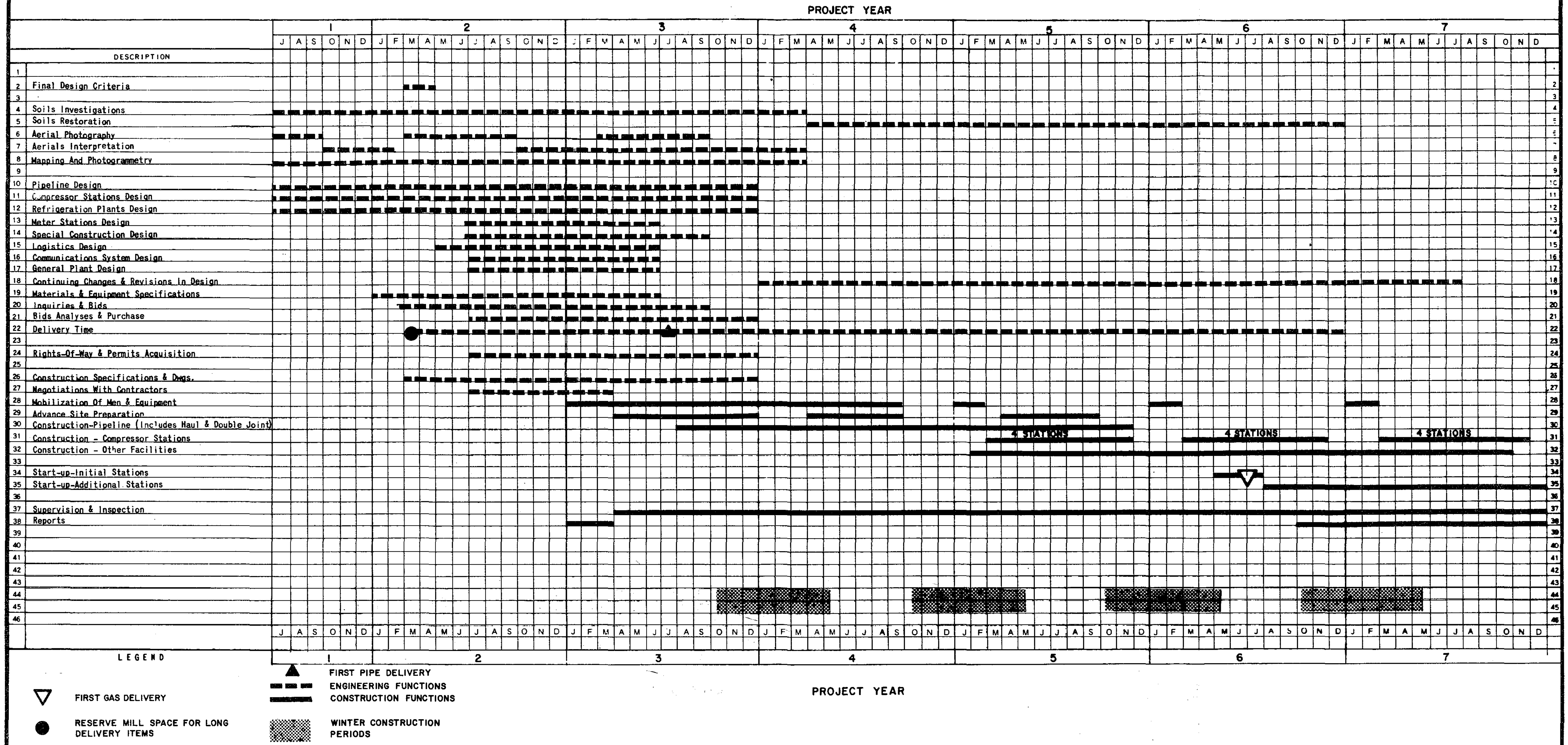
During this same period, site preparation work for the compressor stations and maintenance camps will also be started. This will consist of clearing, leveling, and preparing gravel pads.

Pipe will start arriving in Fairbanks in July of the third project year and in Valdez in September of the same year. Double jointing and hauling of pipe will start immediately thereafter.

Construction camps will be erected in the third project year. Additional men and equipment will start arriving during the third quarter of that year for the winter construction season.

The equipment will be winterized with low temperature oils and greases and by installing cabs or wind screens. All equipment will be fully assembled and tested for proper operation.

Each construction spread will have two ambulances in attendance with trained personnel for emergencies. Each separate crew of each spread will be equipped with a heated personnel carrier, shelter and survival gear on the job at all times to provide protection and emergency supplies in the event of unexpected blizzards.



TRANS-ALASKA GAS PROJECT

ALASKAN GAS PIPELINE
CONSTRUCTION SCHEDULE

FIGURE 1.5–1

Right-of-Way Preparation

In terrain having only organic covering, the right-of-way preparation will consist of, first, preparing the work pad and spoil pad on the sides of the ditch line by moving snow over these areas and compacting it to the required thickness; second, removing the snow from over the ditch line and compacting it on the workpads; and third, removing the one to two feet thickness of organic material from over the ditch line and storing it on the right-of-way, out of the way of other operations, spoil or debris. In areas where right-of-way leveling is necessary for construction purposes, the snow will be removed, the organic surface layer removed and stockpiled and the area levelled by ripping and blading.

In areas with a cover of brush and trees, right-of-way preparation will be preceded by the hand clearing of this vegetation.

Trees will be trimmed, cut into specified lengths, and stockpiled. Brush and slash will be spread uniformly over the right-of-way during clean up and restoration to provide soil insulation and enhance nutrient recycling.

It is estimated that approximately 80% of the total right-of-way required will be on Federal Lands, 10% on State of Alaska Lands, and 10% on native and privately owned lands. Right-of-way permits may be required from at least twelve additional agencies, as detailed in Section 9 of this report.

1.5.1.2 Construction Schedule

The Alaskan Gas Pipeline project schedule (Figure 1.5-1) is presented in terms of project years. It shows an estimated 6-1/2 years from the date of initiation to the date the system is capable of operating at full capacity. The first two years will consist primarily of engineering, data accumulation, materials procurement, and preparations for construction. Construction of the pipeline itself will require three years, and construction of compressor stations will continue for an additional 1-1/2 years.

Specifications will be prepared, and contract negotiations completed so that the first contractor would start work in March of the third project year on advance site preparation. This work will consist of stripping overburden from material sites to allow controlled thawing; mining and stockpiling gravel; filling, grading, and leveling work sites; building roads; and preparing station sites. This work will continue through the fifth project year.

Pipeline construction is estimated to start in August of the third project year. Six pipeline construction spreads will be required, with construction sections as illustrated in Figure 1.2-1, and as described below:

Section No. 1: MP 0 to 137, Prudhoe Bay to Galbraith Lake
Section No. 2: MP 137 to 270, Galbraith Lake to Prospect Creek
Section No. 3: MP 270 to 413, Prospect Creek to Wickersham Dome
Section No. 4: MP 413 to 560, Wickersham Dome to Darling Creek
Section No. 5: MP 560 to 718, Darling Creek to Mosquito Creek
Section No. 6: MP 718 to 809, Mosquito Creek to the LNG Plant site

Section Nos. 1, 3, 4 and 5 are planned for winter construction, Section No. 6 is summertime construction, and Section No. 2 is a combination of winter and summer construction. Parts of Section Nos. 4 and 5 may also be summer construction.

Compressor station construction is scheduled to start in January of the fifth project year commencing with mobilization. Piling will be installed so as to provide freeze-back prior to loading. Concrete foundations will be set during early summer of the fifth year. The installation of equipment, piping, and buildings will start immediately after the foundations are tested and ready for loading. Additional stations will be constructed according to the schedule shown in Figure 1.5-1.

The installation of meter stations, communication systems, instrumentation, and other associated facilities will be scheduled concurrently with the pipeline and compressor stations.

Engineering and Design

Engineering and design work will be completed during the first, second, and third project years, and will be scheduled to take advantage of the seasons. Primarily, this work will consist of final investigations into definitive designs, methods, and locations; accumulation of detailed engineering data on soils, climate, hydrology, archaeology and groundwater; and special studies such as thermal simulation, optimization studies, and coordinative studies with Alyeska. Final specifications for materials, equipment, and construction will be prepared.

Final design criteria will be established as soon as possible, primarily by incorporating recommendations, if any, of federal and state agencies. Two and one-half years have been allowed for data accumulation, and mapping will be completed along with a detailed design of the entire system during the fourth project year.

Soils investigations will continue throughout construction to verify the validity of the construction plans and to develop a soils restoration program that will preserve the permafrost and thus maintain pipeline stability.

Minor route changes--normal procedure during any pipeline construction--may be required to prevent excessive degradation of the environment, to provide greater pipeline stability, to facilitate ditching or other construction activities, and to improve the economics of the pipeline.

Purchasing Schedule

It is anticipated that long deliveries may be experienced on many major items for this project, and it is further anticipated that these delivery times may worsen if other large construction projects are started in the United States during the next few years.

Therefore, it is planned that purchase orders will be issued very early in the third project year and that mill space will be reserved for long delivery items in the second project year.

Purchasing of a majority of the normal delivery items will also be accomplished during the third project year using standard inquiry and bid procedures. It will probably be necessary to continue the purchasing function during construction. Expediters will be used throughout the project to insure timely deliveries.

Rights-of-Way and Permits Acquisition

It will be necessary to accomplish a majority of the surveying and mapping work in the first and second project years. Acquisition of required rights-of-way and permits is to be completed during the third project year.

Construction of the Pipeline

Pipeline Construction Section Number 1 (MP 0-137)

Winter construction is scheduled throughout this section, with the work season extending from October to May, or approximately 210 days per year. In the 2-year construction program, these 420 days will be reduced by the equivalent of 60 days because of total darkness and 96 days because of severe cold and wind. It is estimated that the average rate of progress for 264 work days will be 2,740 feet per day.

Pipe will arrive by barge during the short period of the summer that ice pack is not present in Prudhoe Bay. In the event that the coast is not clear of ice pack in the year selected for pipe delivery, the contingency plan will be to haul the pipe to the job site by truck from Fairbanks. Approximately 23,000 joints of pipe will be delivered, and approximately 80% (18,000 joints) will be double jointed. At the rate of 150 double joints per day, 61 days will be required during August to October to complete the double jointing work for Section No. 1 plus a portion from MP 137 to MP 164.

Transporting pipe along the proposed State-Alyeska Haul Road to pipe storage areas, including a portion for construction in Section 2, will start about the first of September using trucks and steering trailers, and will continue into the construction period.

Pipeline Construction Section Number 2 (MP 137-270)

Winter construction is scheduled throughout this section except for approximately three miles of special construction in rock through Atigun Pass. It will be necessary to build this three miles of pipeline in summertime because severe snow and wind conditions preclude winter construction. There will also be close coordination with Alyeska because of the narrow confines of the pass.

The work season is also shortened to approximately 180 days per winter from late October to late April primarily because the seasonal thaw is estimated to occur earlier than on the North Slope. During the two year program, this equates to 360 days of winter season. Approximately 40 net days are estimated to be lost because of total darkness and 61 net days lost because of severe cold and wind. The rate of progress for 259 working days is estimated to be 2,650 feet (approximately one-half mile) per day.

Pipe for the portion of this section north of Atigun Pass will come in by barge to Prudhoe Bay with the pipe for Section No. 1. Pipe for the portion of the route south of Atigun Pass will be hauled by truck from storage in Fairbanks.

Pipeline Construction Section Number 3 (MP 270-413)

Winter construction is scheduled throughout this section. The work season contains approximately 170 days from late October to early April. In two years, this amounts to 340 days, of which approximately 30 net days will be lost because of darkness and 50 net days lost because of weather. The average rate of progress for 260 working days is estimated to be 2,900 feet per day. Pipe for Section No. 3 will be hauled from storage in Fairbanks.

Pipeline Construction Section Number 4 (MP 413-560)

Winter construction is scheduled throughout this section. The work season contains approximately 150 days from November to March. In two years, this equals 300 days, of which 30 net days will be lost as a result of darkness and 50 net days lost because of weather. The rate of progress for 220 working days will be 3,538 feet per day. Pipe for Section No. 4 will be hauled from storage in Fairbanks.

Pipeline Construction Section Number 5 (MP 560-718)

Winter construction is scheduled throughout this section except for 40 miles from MP 560 to MP 600 in the Alaska Range that will be built during summer months. The winter season consists of approximately 140 days from November to March. This equals 280 days in two years from which 30 net days will be lost as a result of darkness and 40 net days will be lost because of weather. The rate of progress for the 118 miles of winter construction in 210 days is 2,970 feet per day. Pipe for Section No. 5 will be hauled from Valdez pipe storage.

Pipeline Construction Section Number 6 (MP 718-809)

Summer construction is scheduled throughout this section because of heavy snowfall in the mountains which makes winter construction difficult. River crossings and pipeline across lowlands adjacent to the rivers will be installed in the winter to avoid conflict with seasonal fish migration. Pipeline across scattered muskeg areas will be installed after seasonal frost has penetrated. This section is all extremely difficult mountain construction complicated by heavy rainfall. Special construction is required through the Keystone Canyon. With an estimated 318 net working days for the rest of Section No. 6, the average rate of progress will be 1,378 feet per day.

Pipe for Section No. 6 will be hauled from Valdez and from the LNG Plant site. Double jointing is not feasible for this section because of the rough terrain and the numerous bends required.

1.5.1.3 Logistics

The logistics of the Project were developed on the basis of obtaining all permanent equipment for the pipeline system and all construction equipment in the Lower 48 States, and moving this equipment to the job site via existing systems of rail, barge, and truck transportation.

Materials and supplies will also be moved by existing transportation systems. The sources for these items will be local Alaskan suppliers to the extent of their capabilities, and the remainder will be supplied from the Lower 48 States.

Lead time and delivery time for all items are based on 1973 estimates by manufacturers.

Mainline Pipe

Pipe will likely be obtained in equal amounts from three major pipe mills in the United States. Total production time to complete the 826 miles of pipe (including station piping) is expected to be 16 months, with deliveries keeping pace with production to avoid stockpiling at any intermediate points. Pipe will be loaded directly onto rail cars at the mills (9 joints per car) and transported in trainload lots to Seattle. From Seattle the pipe will be transported by either barge-train or charter barge, depending upon destination.

Pipe destined for the North Slope (166 miles) can be most economically conveyed by large 400' x 100' special barges, each capable of holding 15-1/2 miles of 42" pipe. The disadvantage of this method is that it allows no flexibility since the route to Prudhoe Bay is only open for six weeks in the summer (early August to mid-September) with the added risk of the Beaufort Sea being icebound all summer, as happens occasionally. In the event Beaufort is icebound, the contingency plan is to haul this pipe overland via the proposed State Highway from Fairbanks to the job site. The barges would be diverted to Anchorage and the pipe transferred to rail cars for shipment to Fairbanks.

Pipe for the central sector of 407 miles will be shipped by barge-train. By this method, pipe will remain on the original rail cars from the mills to Fairbanks from where they will be transported by truck the short distance to the double jointing yard.

The 253 miles of pipe destined for the most southerly portion of the line will be transported by charter barge from Seattle, 218 miles of pipe being shipped to Valdez and 35 miles of pipe to the LNG Plant site at Gravina. Subsequent transport to the stockpiles will be by truck.

It should be noted that the special pipe barges referred to above are presently scattered around the world, and their availability at the time of construction has not been established. Should it be necessary to construct new barges, 18 months lead time will be required. Concerning the barge-train capabilities, the operators have indicated willingness to expand the system, should there be concurrent demands upon the system by other parties.

<u>Construction Equipment</u>

No sea shipments of equipment directly in Prudhoe Bay are anticipated because of the slightly higher cost and the element of risk compared with the rail and/or road route from the south (as distinct from pipe where the direct barge method is considerably cheaper).

All self-powered wheeled equipment will be shipped from the plants or contractors yards to Seattle by rail. Trucks and trailers will be driven from the rail cars onto the charter barges at Seattle and driven off upon arrival in Alaska directly to the Sections. Smaller trucks such as pickups will be loaded onto trailers or larger trucks in order to conserve space on the barges and reduce driving in Alaska. It will be necessary to establish a marshalling area in or near Seattle in order to assure maximum loadings and minimum delays.

Heavy equipment for Section Nos. 1 to 4 will be shipped from factories or contractors yards via barge-train to Fairbanks and thence by road to job sites. For Section Nos. 5 and 6, the equipment will be shipped by charter barge to Valdez or Gravina from where it will be transported by road to job sites.

<u>Permanent Equipment</u>

All permanent equipment, other than pipe, will be shipped direct from factory by rail to Seattle. From Seattle, all material destined for points north of approximately milepost 560 will remain aboard the rail cars for shipment through to Fairbanks and thence by road to the site. Equipment for the southern portion of the line will be shipped from Seattle to Valdez or Gravina by charter barge.

Consumables, Including Tape & Primer

Lumber, fuels and lubricants, skids, survival equipment, propane, cement, arctic clothing and some miscellaneous items will be obtainable from Alaskan suppliers.

All tape and primer and most spare parts, food, welding rod, explosives, steels and bits, etc., will be imported from the lower 48 in container lots. Containers will be loaded aboard container ships at Seattle and unloaded onto rail cars or trucks at southern Alaskan ports for transportation to destinations.

The supply of fuel to contractors' storage from Alaskan refineries will require a fleet of approximately 24 tanker trucks operating continuously in peak periods when each contractor is expected to consume 15,000 gallons of diesel oil per day. In addition, 8 rail tank cars will be required to transport fuel as far as Fairbanks during these periods.

General Statistics

Total tonnage, all permanent and temporary equipment, materials, consumables, camps, etc., (excluding sand, gravel and selected backfill)	1,079,202 Tons
Rail car loads, excluding container cars	15,091
Container rail cars	1,176
Charter barge loads	42
Barge-train barge loads	138
Container ship loads	3

Purchasing

All equipment and materials necessary to construct the pipeline and compressor stations can be produced within two years from the date of order placement. Manufacturers contacted have stressed, however, that ability to fill orders so far in the future will depend upon commitments undertaken in the meantime, which may be considerable. The world-wide demand for heavy construction equipment, for example, is expected to be very high, and permanent equipment constructed of special cryogenic steel (scraper traps, check valves, etc.) will require long lead time.

Peak Transportation Requirements

The demand for rail cars will be highest when a pipe mill is producing for the Fairbanks stockpile (barge-train route). A production rate of 77 miles per month will require 1,189 pipe cars (gondolas) per month. Allowing 35 days for a round trip from the mill to Fairbanks, the total number of cars required to keep pace with mill production will be 1,386. At the same time, 4 rail cars per day will be required to haul construction equipment to the same destination, thus requiring an additional 140 cars. Total rail cars in service at the peak period will therefore be 1,526.

To transport the rail cars to Alaska, which will be arriving at Seattle at an average rate of 44 per day, a tug with its two barges will be required at Seattle at all times. Allowing 10 days at sea for each tow, 4 tugs and 8 barges will be required. The maximum number of charter barges in service at any one time will be 17, 13 of which will be transporting pipe to Prudhoe Bay, 2 with pipe to Valdez, and 2 hauling trucks and equipment into south Alaska ports.

General

Barging into south Alaska ports can be carried out year-round, and sufficient unloading facilities exist at Anchorage, Valdez and Whittier. Pipe and materials for the last 35 miles of the pipeline (MP 774 to MP 809) will be unloaded at the ferry dock at the LNG Plant site. The pipe destined for Prudhoe Bay will be off-loaded onto lighter barges for transportation to shore, due to the shallowness of the water.

A great deal of material will be transported over Alaskan roads, and it is assumed that the proposed State-Alyeska Haul Road from the Yukon River to Prudhoe Bay will be completed and available for use. For heavy loads such as bulldozers and compressors, special haulage permits will be obtained as required.

1.5.1.4 General Pipeline Construction Method

In the construction of the Alaskan Gas Pipeline, the "lay method", as specifically adapted to the arctic environment, will be employed except where there is a requirement for other special construction techniques. The lay method is discussed below; special construction is the subject of subsection 1.5.1.5.

Snow Pad

Winter construction makes it feasible to provide a compacted snow pad as a working surface on the pipeline right-of-way. Snow fences will be erected along the right-of-way to capture snow for this purpose. In the event of an early snowfall, the snow will be cleared off the work pad area to accelerate the freezing of the active layer using special, light-weight, rubber-tired snow plow equipment. After the active layer freezes, the accumulated snow will be spread over the working area and compacted for strength. In the event of an insufficient amount of snow, brush, slash, and wood chips cleared from the right-of-way will be mixed with snow for added strength and volume of material. Also, the snow can be supplemented by spraying water over these filler materials and allowing it to freeze, or artificial snow can be provided using snow machines.

Stringing

Double jointed pipe will be used where the contours of the ditch permit the use of 80 foot joints with very little bending and where access roads permit the hauling of 80 foot joints. The pipe will be hauled and stockpiled at 20-mile intervals near the haul road on previously constructed gravel pads. During construction, pipe will be hauled from the storage yards and strung, on skids, along the pipeline right-of-way. Conventional stringing trucks and self steering trailers will haul three double joints or four single joints at a time.

Bending

Field bending will be done on the right-of-way following stripping and before welding. Areas requiring bends will be staked in advance and single joints used at those locations. Bends will not exceed 10° per 40-foot joint of pipe. The bending machine will have an internal mandril to prevent wrinkles, buckles, or flattening of the pipe.

Welding

The rate of welding progress and the consequent number of welders and the amount of welding equipment required will be governed by the speed of the ditching operations, the time available for construction on each spread and the proportion of pipes which can be double-jointed in advance.

Basically, the mainline will be welded by the manual shielded metal arc process. The weld will be deposited downhill, which is customary for "big-inch" cross-country pipelines having special cold weather provisions. After the pipe ends are prepared for welding by a buffing crew, pipes will be lined up by means of hydraulically powered line-up clamp. Multiple passes will be applied to complete the welds, with interpass cleaning and cooling carefully controlled.

Considerations taken into account in planning welding activities on this particular project are cold weather operations and techniques for welding of high yield strength pipe.

Apart from the problems encountered in the welding of high yield strength pipe, the fact that much of the welding will be carried out in sub-zero conditions necessitates the use of welding enclosures or tents and insulation blankets. In addition, pipe ends may need to be preheated immediately prior to welding. The use of welding tents will enable the welding to proceed under adverse snow and wind conditions which otherwise would cause a shutdown of operations. The insulating blankets will be used to control the cool down rate of the welds between passes and to eliminate or minimize preheating between passes.

While the use of the high yield strength pipe permits higher working stresses and thinner wall pipe, the metallurgy dictates much greater care in the specification of welding procedures. The main difficulty in welding such steel in low ambient temperatures is a tendency for cracks to form adjacent to the weld when rapid cool-down of the weld occurs. The degree of preheating required to prevent cracking (and possibly some porosity) is dependent upon the composition of the steel. The composition of the steel under certain low temperatures may require a preheat temperature of up to 200°F for cross country pipe and 380°F for heavy wall pipe.

The normal method of preheating pipe ends is by use of hand operated propane heaters, but for this project, mainly for logistical reasons, electric heating is being considered. Electric heating is carried out by means of flat ceramic pad heating elements wrapped around the pipe ends immediately in advance of the welding. Current is supplied by a small diesel-operated generator.

The type of electrodes to be used will be determined by procedure tests on samples of the pipe. Such procedure tests will include destructive and nondestructive testing and analysis. Also, to be determined from these tests is the release time for the internal line-up clamps. It is anticipated that the clamps will be held in position until the stringer bead pass is at least 75% completed.

Conventional diesel engine-driven welding machines will be used throughout to minimize the problem of fuel logistics and cold weather operating problems.

Pipe bevel preparation will be carried out in advance of all welding. The welding area will be cleaned to bright basic metal. Immediately upon reaching preheat temperature the root pass will be started and continued to completion. Within 5 minutes of the root pass completion, the second, or "hot" pass will be started and completed without delay. After the hot pass, the weld area will be protected to prevent the temperature from falling below the preheat temperature. In the event the interpass temperature does fall below the limit no welding will be allowed until the weld has been reheated. Upon completion, the weld will be blanketed to control the cool down rate. An internal line-up clamp will be used to remove any ovality from the pipe for pipeline alignment purposes, and the clamp will not be removed until at least 75% of the root pass has been completed. The remaining 25% of the root pass will be completed in no more than three increments evenly spaced around the weld circumference. Heated shelters will be provided for the protection of the workers.

Ditching

Normally, a ditch at least 7 feet deep and 5-1/2 feet wide at the bottom will be excavated. The sides and bottom of the ditch will be cleaned of all rock, clods and other debris that could cause damage to the pipe or its protective coating. Ditching by blasting in rock will produce a ditch 5-1/2 feet deep and 5-1/2 feet wide at the bottom.

Ditching in frozen soils will be accomplished by blasting and excavating with backhoes. During winter operations, the ditch will be cut behind the welding crews if possible to minimize the time that the ditch will be open and subject to thaw or snow fill.

"Super ditchers" have already been built that are capable of digging ditches in certain frozen soils. Because teeth currently available for these large machines do not last long enough to provide for their economical operation, they will be used only under selected conditions.

Blasting

Blasting in frozen soils for the pipeline ditch will require only slight modification of conventional techniques. Ditch blasting within 15 feet of pipe or other equipment on the right-of-way will be covered by blasting mats to restrain fragments.

Rock blasting will be accomplished by drilling, loading and shooting. Permafrost blasting will follow the same general procedure except the ditch will be 7 feet deep. The conventional pipeline ditch blasting technique of using milli-second delays in the shot line will be used. Shot tests will be run to determine the most effective load and pattern for the particular terrain being blasted.

Coating, Wrapping

Coating and wrapping will be applied by line travel methods. The pipe will be cleaned to basic metal, and will be preheated to the tape manufacturer's specification and primer applied. After the primer has dried, the polyethylene tape coating will be applied using the line travel spiral wrap method, with overlap of the wrap of 1/2" to 1". The tape and primer will be stored along the right-of-way in heated vans until the time of application to insure that the application temperature is within specifications.

Lower-in

Before lowering-in the pipe, the ditch will be checked to insure that it is free of all rock, clods, or other objects that could be harmful to the coating or pipe. If immovable harmful objects are present, suitable padding material will be placed in the bottom of the ditch to provide a smooth, continuous surface to support the pipe. Before the pipe is lowered in, the coating will be checked for holidays by using an approved holiday detector.

Backfill

Care will be taken during the backfilling of the pipeline ditch to eliminate voids in the backfill. Where the ditch spoil contains lumps or clods, it will be pulverized to control particle size of the backfill. After the pulverized backfill is placed in the ditch, it will be compacted to the maximum density that soil conditions and pipeline strength will allow.

After the backfilling operation is complete, the organic material which was originally removed from the ground surface and stockpiled will be spread evenly over the disturbed surface and lightly compacted.

Testing

After lowering in or backfilling, the pipe will be tested with compressed air.

Clean-up

Surface restoration and revegetation will complete the construction of the pipeline phase of the project. Snow fences and other temporary construction facilities will be removed. Organic debris, such as trees and brush will be mulched and scattered along the right-of-way. Combustible debris, such as paper and plastics, will be hauled to an approved site and incinerated. Debris that will not burn will be removed from the right-of-way and disposed of in an approved manner.

Disturbed areas will be restored, within practicability, to their condition prior to construction. Areas susceptible to erosion will be contoured and reinforced as required, and previously stripped and stockpiled tundra will be replaced. Disturbed areas will be revegetated with native grasses suitable to the particular climatic regime. Fertilizer will be applied in such a manner as to minimize leaching into surface drainage systems. Mulched slash, spread along the right-of-way and over other disturbed sites, will be a further source of nutrient supply.

Typical Crossings

Illustrations of a typical water crossing, an uncased road crossing, and a dike crossing are presented in Figures 1.5-2, 1.5-3, and 1.5-4 respectively. Difficult crossings which require special consideration are discussed in subsection 1.6.1.1.

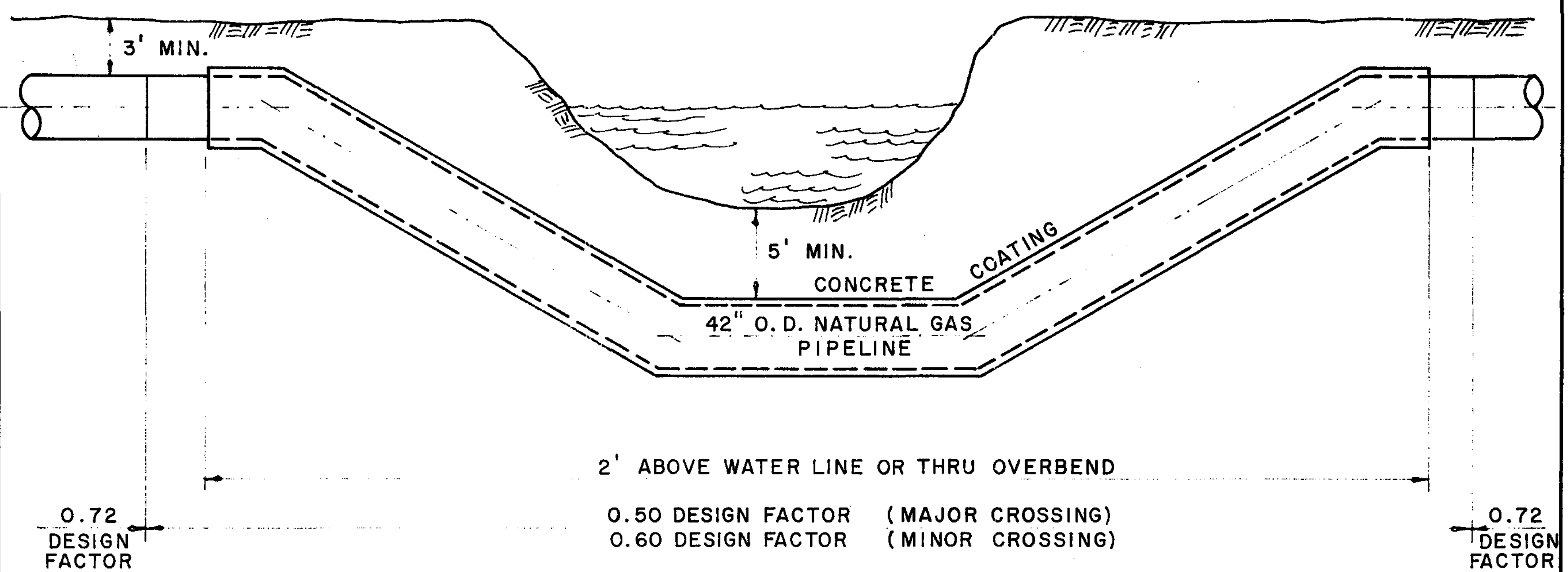
At typical stream crossings, the pipeline will be buried a minimum of five feet below the stream bed. Concrete coating on the pipe is specified for all river crossings, not only to supply the additional weight necessary to prevent flotation, but also to provide protection during construction and later from abrasion should scour ever expose a portion of the buried line. The use of heavy concrete coated pipe, therefore, reduces the depth of bury necessary. Concrete coated pipe is specified between the stream crossings overbends or two feet above design flood stage. Stream crossings are listed in Table 1.2-3.

The pipeline stream crossing limits are taken to extend one pipe joint (40 feet) beyond the concrete coating.

River control structure and training works may be necessary at selected locations. In certain areas it will be desirable to extend Alyeska control structures to protect the gas line. Training works can also be used effectively to reduce the length pipe required when crossing alluvial fans. The use of stream control structures will be minimized to avoid undesirable disturbances on the particular stream.

River crossing construction will be scheduled in winter to minimize direct disturbance to aquatic biota and to avoid siltation. It is also possible to build ice bridges across the streams to effectuate equip-

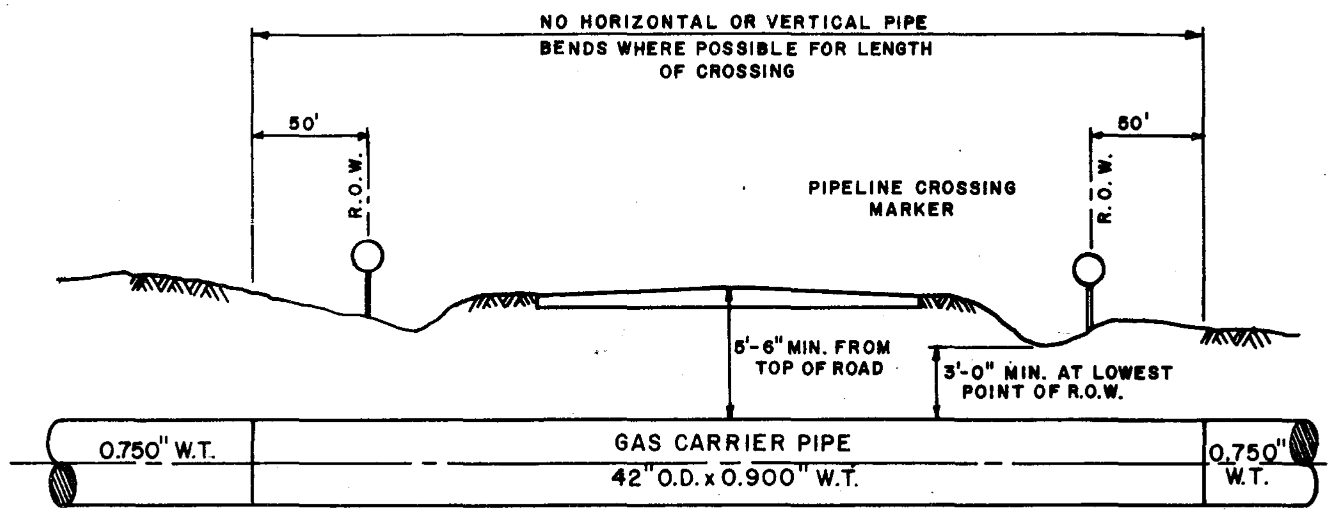
CONCRETE COATING	150 LBS. /C. F.	190 LBS. /C. F.
0.60 DESIGN FACTOR	5 IN.	3 1/2 IN.
0.50 DESIGN FACTOR	4 IN.	2 3/4 IN.



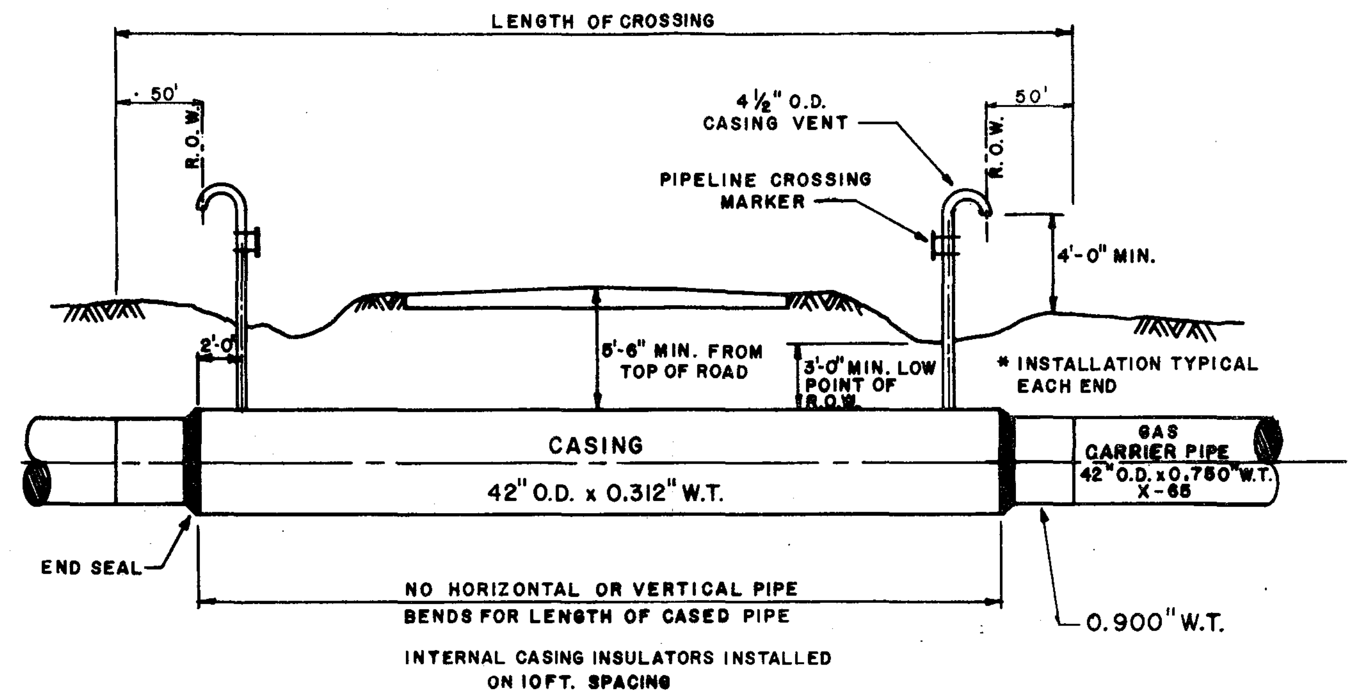
TRANS-ALASKA GAS PROJECT

TYPICAL WATER CROSSING

FIGURE 1.5–2



TYPICAL UNCASED CROSSING

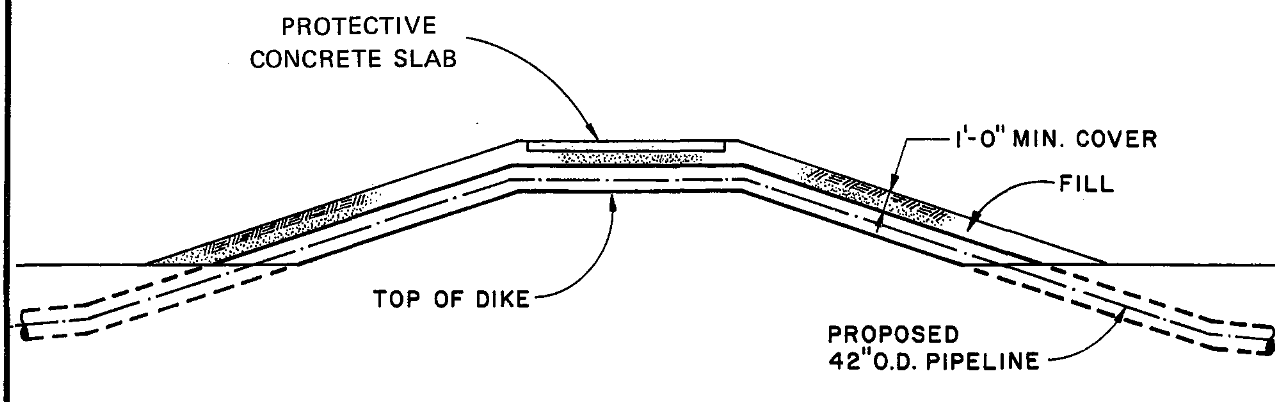


TYPICAL CASED CROSSING

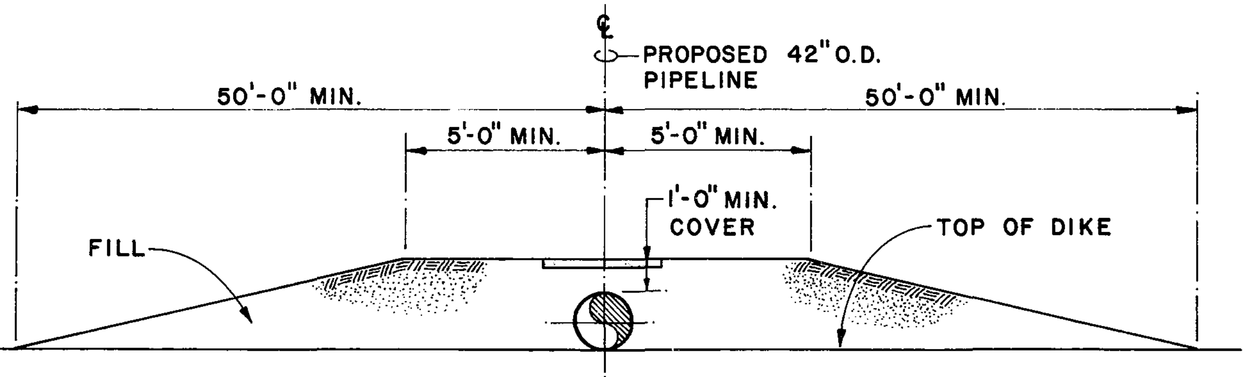
TRANS-ALASKA GAS PROJECT

TYPICAL CASED OR UNCASED ROAD CROSSING

FIGURE 1.5–3



ELEVATION



SECTION

TRANS-ALASKA GAS PROJECT

TYPICAL DIKE
CROSSING

FIGURE 1.5–4

ment crossings. Settling ponds will be employed downstream of the crossing on the few streams to be crossed during summer in order to minimize turbidity in the water.

Road Crossings

The pipeline route will cross highways or primary roads 44 times, as shown in Table 1.2-4. Some of these crossings will be installed with, and some without casings, as shown in Figure 1.5-3. It will be necessary to acquire crossing permits from the Alaskan Department of Highways, and, in some cases, from the military and local authorities.

Pipeline Crossings

The route of the proposed natural gas pipeline will cross the route of the proposed Alyeska oil pipeline a total of 25 times and that of two other pipelines once each. A tabulation of these crossings by mileposts are shown in Table 1.2-5.

It will likely be necessary to coordinate the design and construction of the gas pipeline with that of the oil pipeline at these crossing points. Generally, the gas pipeline will cross under the oil pipeline because the latter will be built first, and a large portion of the oil line will be built aboveground. If the crossing occurs in a rock area, and the oil line is buried, special construction will be required for the gas line to cross over the top of the oil line.

Access Roads

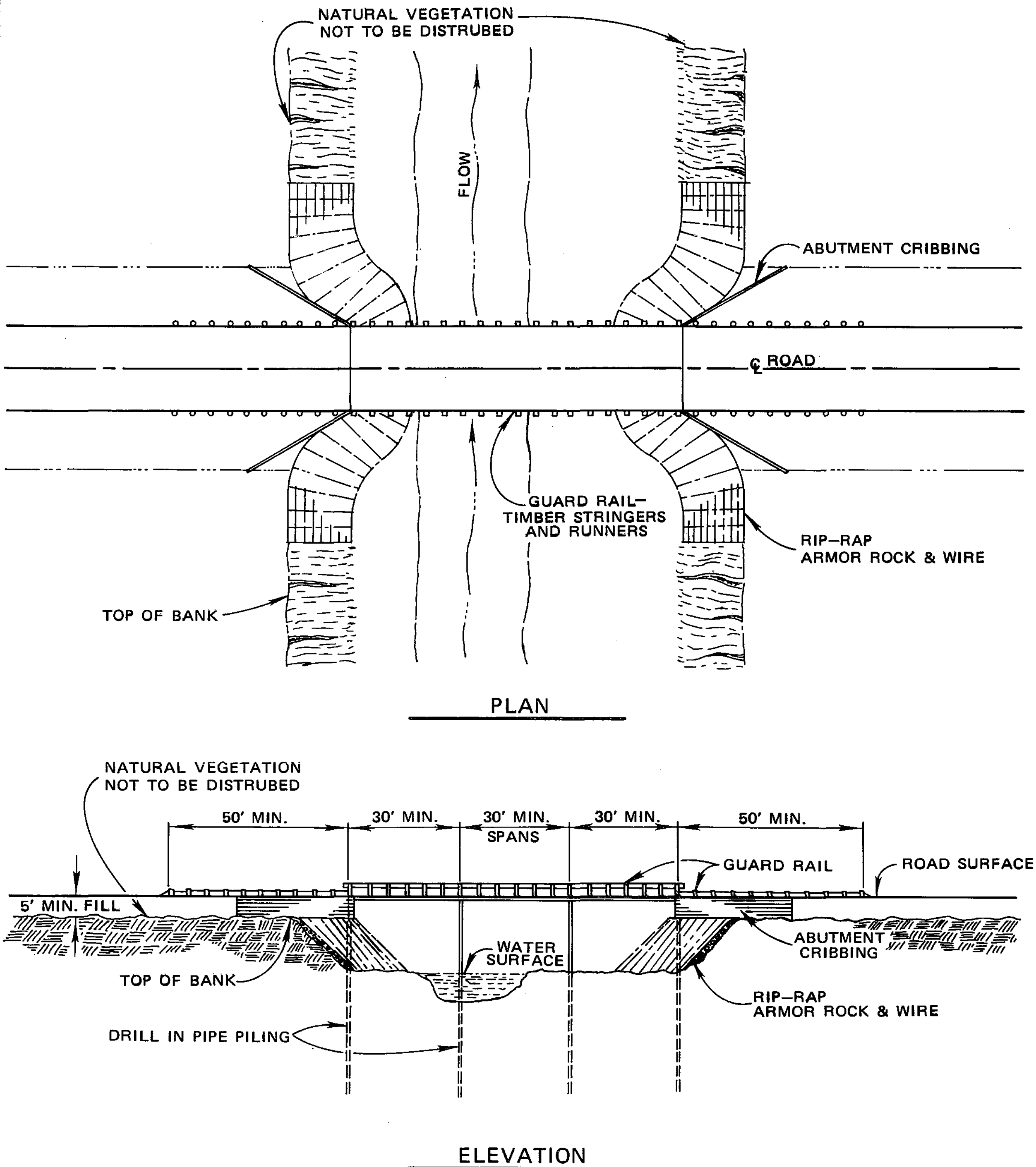
Roads will be required to provide access to eleven compressor stations during construction as shown in Table 1.2-1. A total of 22 miles of compressor station access roads will be constructed, all of which will remain in use after construction to provide permanent access.

Other access roads will be required during the construction phase of the project. Approximately two miles of roads will be necessary to provide access to construction camps and temporary pipe storage yards. A total of approximately 226 miles of roads will provide access to borrow pits, quarries and other sources of construction materials.

In the event that access roads must cross a waterway, the method of crossing to be utilized is illustrated in Figure 1.5-5. Typical access roads will be constructed over various types of terrain as shown by the cross sections in Figure 1.5-6.

1.5.1.5 Special Pipeline Construction

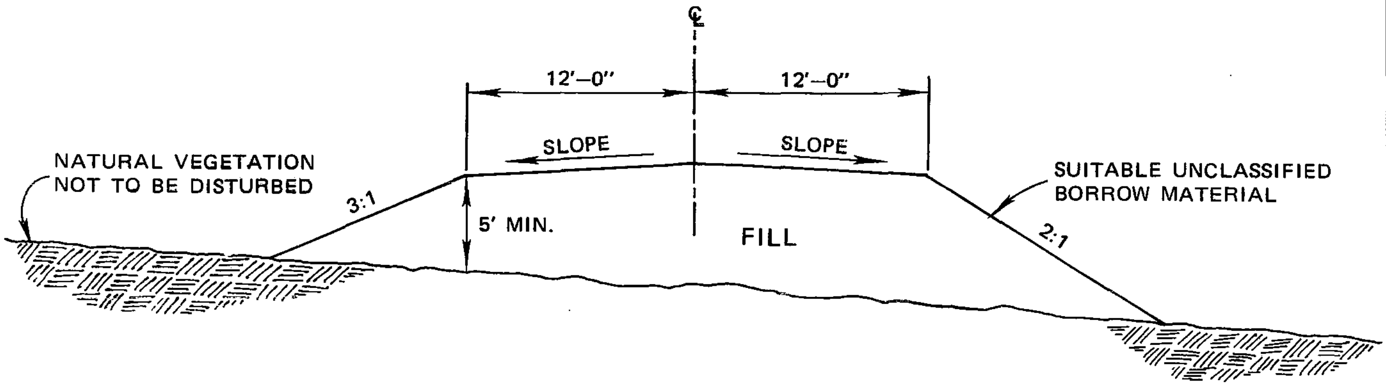
Certain areas cannot be negotiated using the standard arctic-modified lay method discussed in the previous section. Special construction techniques to be employed in these areas are presented below.



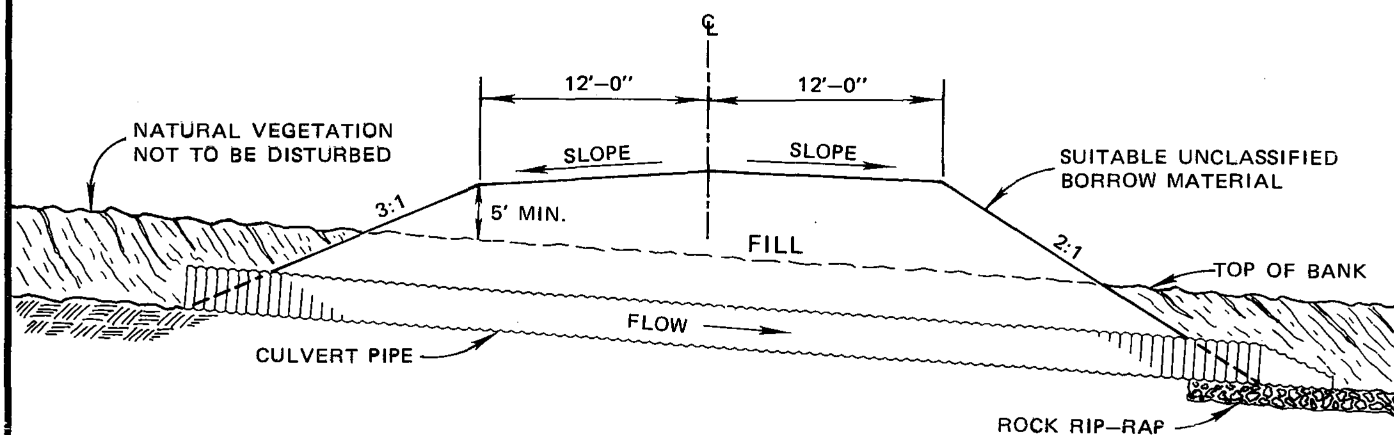
TRANS-ALASKA GAS PROJECT

TYPICAL TEMPORARY
PILE BENT BRIDGE

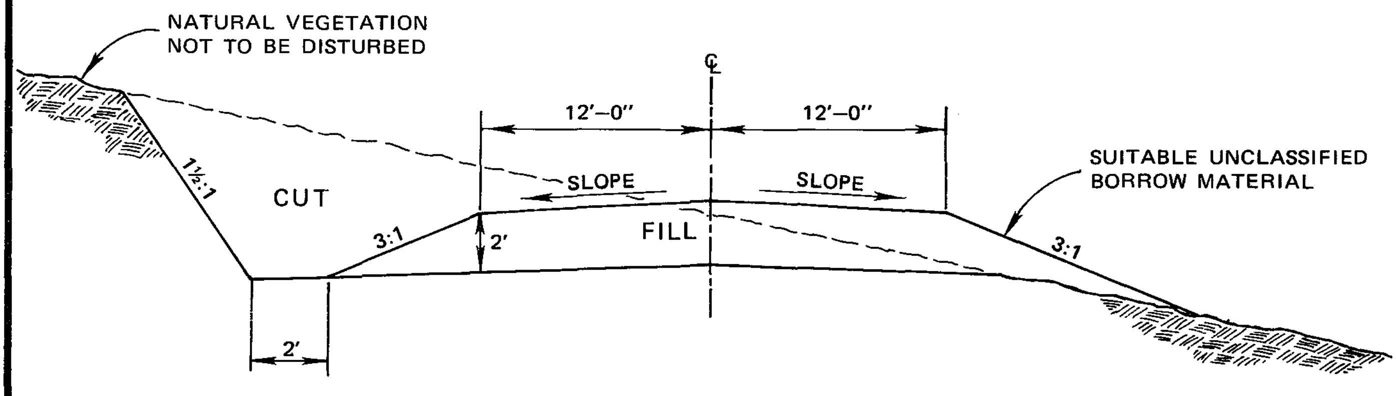
FIGURE 1.5–5



TYPICAL FILL SECTION



TYPICAL FILL SECTION
CULVERT INSTALLATION



TYPICAL CUT–FILL SECTION

TRANS-ALASKA GAS PROJECT

TYPICAL
ACCESS ROADS

FIGURE 1.5–6

Atigun Pass Area (MP 163) (See Figure 8 in Section 2A.2 Appendix)

Pipeline construction through the Atigun Pass Area (sometimes called Dietrich Pass) will be difficult due to the narrow confines and the presence of the State-Alyeska Haul Road and the Alyeska oil pipeline. It should be feasible to construct the gas pipeline through this pass adjacent to the Alyeska Line; however, it the oil line is in operation, construction will be contingent on receiving permission from Alyeska, and from appropriate government agencies. Major rock work in close proximity to the oil line is complex and must be undertaken with caution to avoid danger to the oil line.

Design for this portion must be coordinated with the construction of the State road and Alyeska oil line. Certain portions of the route on the south side of the pass must be blasted, benched, and ditched up-slope of the Alyeska line. The gas line must cross over the oil line in rock on the north side of the pass.

Construction through the Atigun Pass will be almost exclusively in rock. The pipeline will not be buried within the talus slopes because of the instability of these features. The planned route circumscribes all major talus cones, although shattered, weathered bedrock on very steep slopes will be encountered. The most difficult area appears to be on the south side of the pass at about milepost 163, where approximately 800 feet of very steep slope must be benched in rock prior to ditching. The season for pipeline construction in Atigun Pass must be summer, because snow and wind conditions are too severe in the winter.

Yukon River (MP 343) (See Figure 16 in Section 2A.2 Appendix)

The Alaskan Gas Pipeline will cross the Yukon River on the State of Alaska Department of Highways bridge. The bridge, to be constructed prior to pipeline construction, is designed to accommodate large diameter pipelines on either side of a 30-foot roadway. The Alyeska oil pipeline will be supported on one side of the bridge and the proposed natural gas pipeline on the opposite side.

Pipeline supports will be welded at intervals to the box girders on the bridge. The gas pipeline will be anchored firmly to the bridge at the approximate center point. Guides will be provided at intervals to maintain the alignment, and expansion loops will be constructed on each end of the bridge, with anchors constructed outside of the expansion loops. This configuration will allow expansion and contraction of the suspended portion of the pipeline without affecting the buried line on either side of the river.

The total length of the bridge will be 2,295 feet, and it will be constructed at a grade of minus 6% to the north.

The bridge is designed to accommodate a 50 year flood estimated to be 1,018,000 cfs. Pipeline Design Flood for the Yukon River is 1,600,000 cfs. A flood of Pipeline Design Flood magnitude might inundate the north approach to the bridge, but it is unlikely that major damage would occur, due to low overbank velocities.

Moose Creek Dam Crossing (MP 455.3) (See Figure 20 in Section 2A.2 Appendix)

At milepost 455, the proposed natural gas pipeline will cross the Corps of Engineers' proposed Moose Creek Flood Control Dike. The Corps of Engineers requires that all crossings of dikes be over and not through such structures. It will be necessary to construct ramps on either side of the proposed dike to provide support for the gas pipeline. Heavy wall concrete-coated pipe will be used for the portion of the line south of the dike, which may be periodically inundated.

Whistler Creek to Trims Creek (MP 567-572) (See Figure 25 in Section 2A.2 Appendix)

The terrain between Whistler Creek and Trims Creek along the Delta River offers very difficult pipeline construction. It is characterized by steep valley walls rising directly from a braided, glacial-fed stream floodplain. The section is further complicated by the presence of the Richardson Highway between the east valley wall and the Delta River floodplain. Alyeska has chosen to bury the crude oil pipeline within the river floodplain. Their design entails the use of a buried concrete coated pipe protected from river erosion by a series of "T" head spur dikes extending outward from the highway embankment. To follow the same route with the natural gas pipeline would require extension of the protective dikes to a sufficient distance beyond the Alyeska line necessary to gain a sufficient separation.

To bury the gas pipeline within the river floodplain beyond the oil pipeline without the protective spur dikes would require deep burial, and probably frequent maintenance. A main river channel may develop just off the end of the Alyeska dikes, and scour will be excessive, thereby requiring the location of the pipeline off the floodplain.

The route chosen for this study is along the east valley slope above the highway and is out of the floodplain. The valley slope between Whistler Creek and Trims Creek is interrupted by several deep canyons, the crossing of which would be very difficult and costly. Therefore, the route has been designed to descend the valley slopes to the easier construction across the alluvial fans and then re-ascend the slope to avoid the floodplain. Construction along the valley slope will be in rock and will require that a right-of-way be excavated prior to ditching. Spans may be utilized across the narrow drainage features provided snowslide conditions do not preclude their use. Winter reconnaissance will be required to determine this, and meanwhile, a fully buried line is proposed. Special construction is considered necessary throughout this section.

Denali Fault (MP 573-575) (See Figure 25 in Section 2A.2 Appendix)

Between mileposts 573 and 575, the pipeline route crosses the Denali Fault. The Denali Fault is one of the largest known faults in Alaska, and has been traced for 870 miles across the interior of Alaska and Canada. It is described as a right-lateral strike slip fault; that is, its relative movement has been approximately horizontal. Field evidence indicates a long geological history of movement, although none has actually been observed. The area is classified as seismically active and movement along the fault zone must be considered a possibility.

Throughout this zone the gas pipeline route will follow a line roughly parallel to the Delta River traversing alluvial fans formed by Lower Miller and Castner Creek. Although there is only a slight possibility of significant movement along the fault during the design lifetime of this system (about 25 years), it is advisable that some special precautions be taken in this area, including implacement of heavy wall pipe, concrete coated pipe (specific gravity of 1.25) across the two creeks, and excavation of a ditch with gently sloping sidewalls, backfilled with select granular material. Such design assures that any lateral shifting of the soil along the fault line will tend to displace the pipeline upward rather than create a shearing force across the buried line. In addition, mainline block valves located at highway crossings on either side of the zone at mileposts 572 and 576 will enable the area to be isolated readily in case of upset.

<u>Tazlina River Crossing (MP 671.4)</u> (See Figure 29 in Section 2A.2 Appendix)

Special construction will be required at milepost 671 for the Tazlina River Crossing, which is unique in that it will be subject to inevitable stream bed degradation. A large meander loop located approximately two miles downstream of the proposed crossing is on the verge of becoming cut off. The neck of land where the cut off will take place is approximately 400 feet wide at low water and less than 50 feet across at flood stage. Elevation of the low point in the neck is only 7 or 8 feet above flood stage and the neck could easily fail during an extreme flood. The possibility for this happening is further enhanced by the fact that the Tazlina River drainage basin contains four glacial impounded lakes which periodically drain, resulting in large flood discharges. These glacial outburst floods have occurred every 3 or 4 years since 1950, when they were first recorded.

Should flood water further erode the narrow meander neck, and then break across, erosion would be rapid and a river chute would develop.

The water surface elevation difference across the neck is greater than 15.3 feet. After cut off, river bed degradation would immediately begin, and progress upstream until ultimately the entire stream bed is incised to a depth of approximately 15 feet below its present depth.

Obviously, a pipeline buried within the stream bed at a depth of less than 15 feet (plus scour depth) would ultimately be endangered.

Calculated scour depth at the pipeline crossing site is 9-1/2 feet; therefore, a minimum depth of cover of 25 feet (9.5 feet scour, 15.3 feet erosion) would be required for a secure buried river crossing.

It is estimated that the cost of such a crossing would exceed that of an aerial crossing. Therefore, an aerial crossing consisting of a suspension bridge with a main span of 650 feet will be employed. Expansion loops in the pipeline will be provided on either side of the bridge.

Tsina River (MP 746.9-747.6) (See Figure 33 in Section 2A.2 Appendix)

This section of the proposed pipeline route will be within the Tsina River floodplain. Two road crossings will be required, and the intervening pipeline section must be protected from river erosion by special methods.

The pipeline will be installed near the toe of the Richardson Highway and buried with a depth of cover of five feet. A thirty-foot wide rock apron extending from the toe of the highway embankment and over the buried line will be provided. On the outboard side of this apron, an additional rock apron will be constructed on a slope of 2:1 toward the river to a distance sufficient to provide a depth of cover equal to the depth of scour (approximately 10 feet).

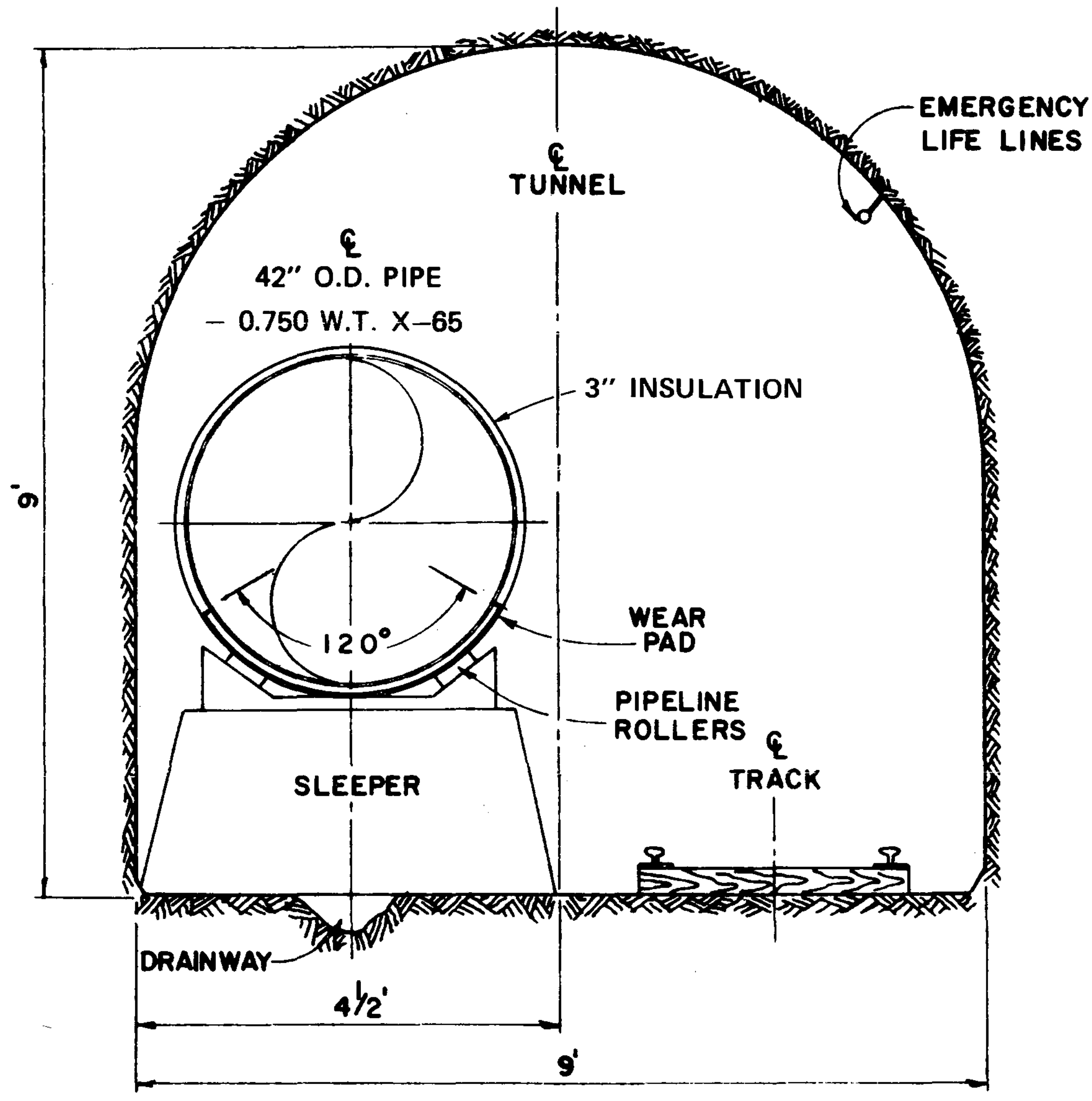
The Corps of Engineers' Class 3 riprap will be required for these aprons. This class of riprap must have a median size ranging between 210 and 300 pounds.

Keystone Canyon Special Construction (MP 760-762) (See Figure 1.5-7 following and Figure 38 in Section 2A.2 Appendix)

Two 9-foot x 9-foot tunnels with a connecting natural bench will be used to minimize rock work and provide the route for the gas pipeline in the Keystone Canyon area. A cross-sectional view of such tunnels is presented in Figure 1.5-7. Tunnel Number One (on the north end of Keystone Canyon) will connect the natural bench to the old Richardson Trail (which was the access road to the interior of Alaska during the late 1890's and early 1900's). Tunnel Number Two (on the south) will carry the pipeline from the bench to the high ground at the south end of the canyon. Tunnel Number One will be about 2,300 feet in length and will be portalled in at a point near the Old Richardson Trail to allow space for expansion offsets. It will be driven at +0.5% grade and will exit at an elevation above the old trail. Tunnel Number Two will be approximately 1800 feet in length and will be portalled in above the old trail. The tunnel will be driven at a slight incline upward to the southwest. The north tunnel will be driven first in order to provide access to the north portal site of Tunnel Number Two.

It is anticipated that standard drilling, blasting, and mucking techniques will be used. Hauling will be by rail and electric locomotive to approved spoil dumps near the east end of each tunnel.

Roof support will be primarily through the use of a natural arch supplemented by rock bolts with plates. At each portal and each section of unstable material that may be encountered, timber will be used for roof support. Portions of the tunnels where rock spalling and small rock falls are likely to occur will be lined with galvanized chain link fencing rock-bolted to the back and ribs.



TRANS-ALASKA GAS PROJECT

TYPICAL SECTION THROUGH TUNNEL

FIGURE 1.5–7

A vent line, air line, water line, electric line and blasting line will be carried forward continuously while driving the tunnels.

A "dry" building for changing clothes and showering will be provided as closely as possible to the north tunnel portal, as will an electric shop, "chippy shop" (for repairing air tools), timber framing shop, mechanic shop, and compressor-generator building.

Pipeline construction through the tunnels will be accomplished by normal "pull" methods. Permanent concrete sleepers will be poured in place every 50 feet and pipeline rollers will be permanently installed on each sleeper (see Figure 1.5-7). Bare pipe will be welded continuously at a welding station near each tunnel portal. A winch will be used to pull the pipeline through the tunnel. When the pipeline is in place, it will be jacked up and wear pads bolted in place on the pipe across those areas making contact with the rollers. After installing, the pipe will be primed, painted and insulated. Special measures must be taken to insure that priming and painting are completed on the portion of the perimeter resting on the supports.

Pipe laying work will progress from the south end of each tunnel and proceed northward, with the pipe storage yard located at some point north of tunnel number one. The sequence of construction must be as follows:

(1) Drive north tunnel from north portal,
(2) Excavate where necessary and grade section between tunnels,
(3) Drive south tunnel from north portal,
(4) Lay pipeline through south tunnel.
(5) Ditch and lay pipeline between tunnels,
(6) Lay pipeline through north tunnel, and
(7) Tie-in pipeline on each end.

Each portal will be provided with doors to prevent unauthorized entrance. A permanent ventilation fan will be installed at one end of each tunnel. The railroad track will remain intact to allow for transport of inspection and maintenance personnel and equipment.

Snowslide protection will be provided at all portals, and in particular at the north portal of tunnel number one. The pipeline will cross the small stream channel and continue through an offset in an underground mode, then emerge to enter the tunnel. An offset will be necessary in the pipeline at each end of each tunnel entrance.

Pipeline Buoyancy

In areas where pipeline buoyancy may be a problem, corrective measures will be taken during construction. The principal method to prevent flotation is with backfill. In most sections, the backfill material will be the same material that was excavated from the ditch. Where this material is frozen, it will be necessary to crush it prior to its use; otherwise, a high void ratio would result and water accumulations in these voids could cause pipe flotation. Excessively ice-rich materials will not be used for backfill. If the excavated materials are not suitable, granular backfill will be hauled and placed in the ditch to a depth of at least three feet over the pipeline. Sections of the route presently known to require granular backfill materials are shown on the Topographic Alignment Sheets in Section 2.A.2 Appendix.

In other areas, pipeline anchors, frost anchors, and similar devices will be used. The conditions encountered in the soil will dictate the type of anchor weight or other supplemental system.

Continuous concrete coating on the pipe will be required at all river crossings, and in areas where backfill, anchors, or weights are inadequate. The thickness of the concrete will be designed to provide the coated pipe system with a specific gravity of 1.25 at river crossings, and 1.15 in areas which are intermittently inundated.

Corrosion Control Facilities

The pipeline will be protected from corrosion by 100 percent external coating, and by installing cathodic protection stations along the line. Test leads will be attached to the pipeline at intervals of approximately one mile, at all road crossings, and at all pipeline crossings.

Upon completion of the pipeline, an electric potential survey will be conducted to provide data for designing the cathodic protection station. It is estimated that stations will be required every 20 miles along the pipeline. It is planned to use "deep well" anode ground beds with DC power generated at each station.

1.5.1.6 Methods of Construction of Compressor Stations

Site preparation for the initial four compressor stations is scheduled for summer of the third project year. It will consist of clearing, grading, and preparation of the gravel pad over the station site, and will be carried out in conjunction with site preparation work for the construction camps, maintenance bases, and the construction of access roads. The gravel pads will be allowed to weather until the fifth year. Site preparation for the remaining eight compressor stations is scheduled for the fourth and fifth project years.

In early spring (when permafrost temperatures are the lowest) of the fifth construction year, piling foundations for four stations will be installed. Four more stations will be started in the sixth year, and the last four stations in the seventh year. During the remainder of each construction year, buildings and equipment will be installed. These items will be pre-fabricated in the manufacturers' shops to minimize the amount of field work required.

Instrumentation, controls, and communications will be installed during the same years.

Foundations will be of two general types. In permafrost areas facilities will be supported on adfreeze piles projecting several feet above the ground surface. In non-permafrost areas, conventional concrete footings or poured-in-place caissons may be used if the presence of favorable soil foundation materials is confirmed by soils investigations. The foundations for major structures will include insulated floor decks, upon which the superstructure of the buildings will be placed. Smaller buildings, such as living quarters and covered walkways, will arrive at the site as pre-fabricated sectional units with insulated floors, and will be placed directly on pile caps or concrete foundations.

Pile emplacement in permafrost areas will be accomplished by placing piles in pre-drilled holes of a greater diameter than the pile and backfilling with a sand slurry that freezes the pile into position. Pile installations will be accomplished in late winter and spring when permafrost temperatures are the coldest.

At stations where bedrock exists at depths of five to eight feet, the foundation type will depend on actual soil conditions. If sound, ice-free bedrock occurs at a relatively shallow depth, concrete foundations keyed into bedrock will be used. This method would require stripping the existing overburden to bedrock and backfilling with non-frost-susceptible material after concrete work has been completed. In the event bedrock is located at a greater depth, concrete caissons drilled and anchored into bedrock will be more economical.

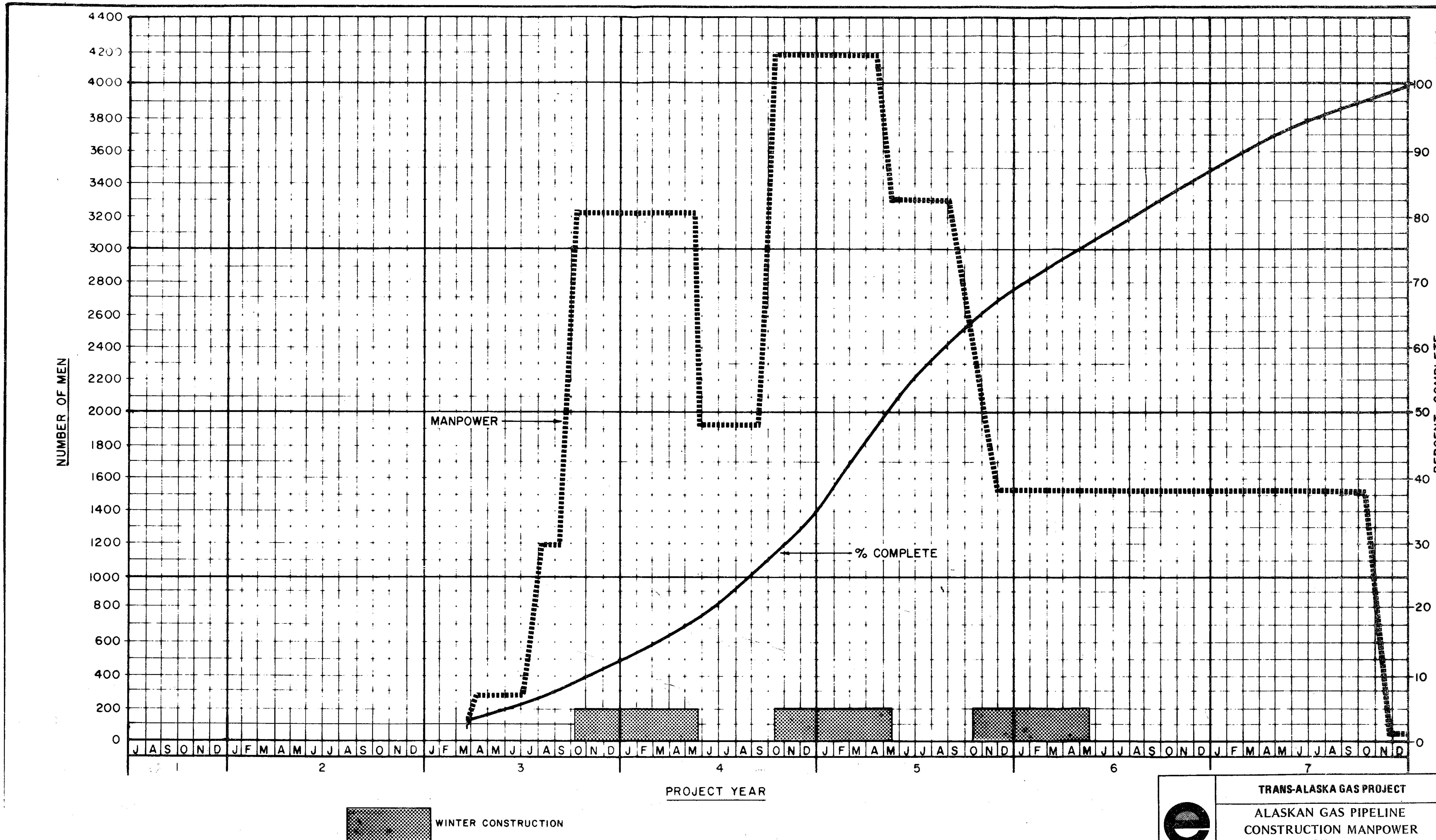
Regardless of which type of foundation is used, frost susceptible material in the active zone will be removed and replaced with a free-draining non-frost susceptible material to reduce tangential heave forces on vertical structural surfaces. Buildings will also have a 4-foot air space below the floor systems to control thaw penetration due to heat flow from buildings and equipment.

1.5.1.7 Labor Considerations

A schedule of manpower required during construction is shown in Figure 1.5-8. The labor force will peak at 4,200 men during the winter between the 4th and 5th project years. Total man hours for construction are estimated to be 21,700,000.

Housing for the work force will be provided at six work camps--one for each construction spread.

Construction workers previously employed by Alyeska will be utilized to the maximum extent possible. Another source of work forces will be local labor pools, including native labor; the balance of the construction work forces will be imported from the Lower 48.



TRANS-ALASKA GAS PROJECT

ALASKAN GAS PIPELINE
CONSTRUCTION MANPOWER
CURVE

FIGURE 1.5–8

1.5.2 LNG Plant

1.5.2.1 Initial Procedures

Pre-construction Investigations

Contractor mobilization and site preparation will be prefaced by detailed site investigations, including topographic mapping, soils sampling and testing, and climatological and hydrologic studies. Offshore, marine biological studies will be conducted to support final design of the waste heat disposal system.

Site Development

A significant amount of stripping and clearing will be necessary to prepare the site for construction. Trees, the vegetative mat, and the underlying peat (in some locations) will be removed from construction areas. Excavation of considerable bedrock will be necessary for site leveling.

Overburden soils 10 to 25 feet deep are present over most of the site and may be 50 feet deep on the eastern third of the site. This soil is expected to be suitable as fill and will be graded and used where possible. Disposal areas for waste materials, such as non-burnable organic soils, will be in approved locations onshore.

Suitable aggregate is expected to be available from sources near the site area. If necessary, additional sources will be developed at the mough of either Simpson Creek or the Rude River.

Quarry rock for road construction and similar uses, as well as rip-rap, will be obtained by excavating within or adjacent to the site.

Foundation Preparation

Overburden will be excavated to sound bedrock for foundation of large structures such as LNG storage tanks, compressors and other major equipment. This equipment will be founded on concrete mats placed directly on bedrock. Where excavation to bedrock is not practical because of overburden thickness, such equipment will be constructed on caissons founded in bedrock. Smaller structures will be placed on shallow spread footings, providing suitable soil conditions occur.

Groundwater inflow may be a problem during construction, and some dewatering may be required. A bed of clean, granular fill placed over existing soils should provide a practical alternative to dewatering for roadways and plant areas.

Where bedrock is fractured, slopes in rock cuts will be limited to less than 1 to 4. Alternatively, an artificial protection (such as rock bolting) will be provided to stabilize excavated rock slopes.

1.5.2.2 Construction Schedule

The planned construction schedule for the LNG Plant is presented in Figure 1.5-9 as a bar graph, listing the major work items. A logic diagram is included as Figure 1.5-10, and shows in greater detail the tasks performed during the lengthy construction period.

Construction work will continue year-round, but will be reduced during winter months to those tasks which can be accomplished during inclement weather, and will be accelerated during summer work periods to take advantage of better weather and longer days.

The scheduled delivery of equipment and materials and fabrication durations are based on the market conditions for the last quarter of 1973. Two months are allowed for shipping time to the sob site. It is assumed that a 60-hour work week will be used, and that sufficient skilled labor will be available to support the construction program as planned. Field move-in is dependent on the timely construction of the ferry and barge docks that are required to move materials, equipment and personnel to the job site. Field move-in for site preparation is scheduled for April of project year 3.

Construction of LNG storage tank #1 will commence on April 1 of project year 3, and tank #4 erection will end in June of project year 6. Each storage tank erection will take 17 months, of which 4 months is allocated for testing and insulation.

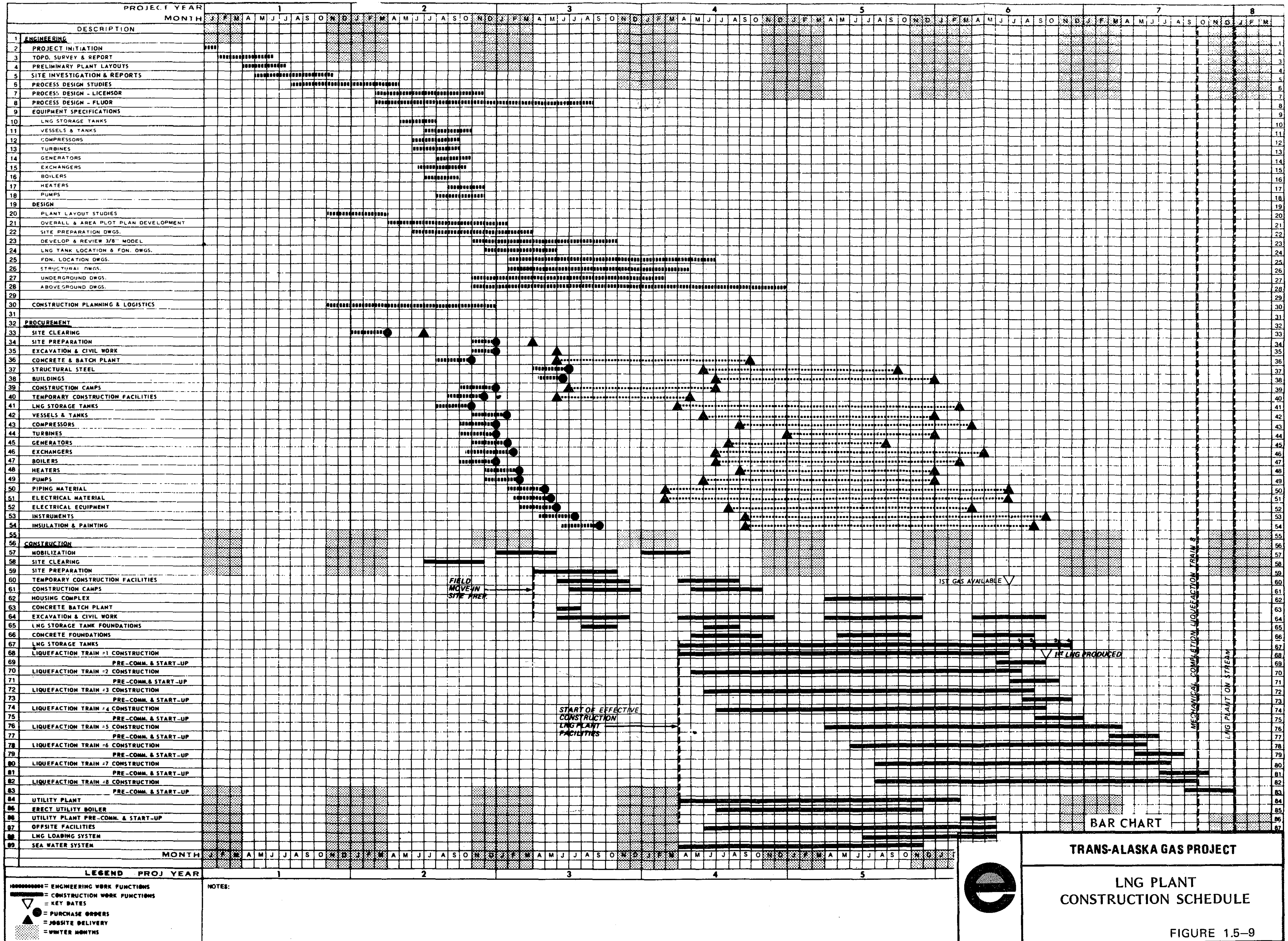
The logic diagram, which is shown in Figure 1.5-10, is the basis for the critical path scheduling system. It illustrates the activities, sequence and dependencies of activities required to execute the construction plan for the LNG Plant.

The following terms are used when referring to logic diagrams:

Activity - A time and resource consuming effort required to complete a specific segment of a project, and which is sufficiently self-contained to permit scheduling as a unit.

Node - The distinct point in time which represents the beginning or ending of an activity, usually indicated by some geometrical shape.

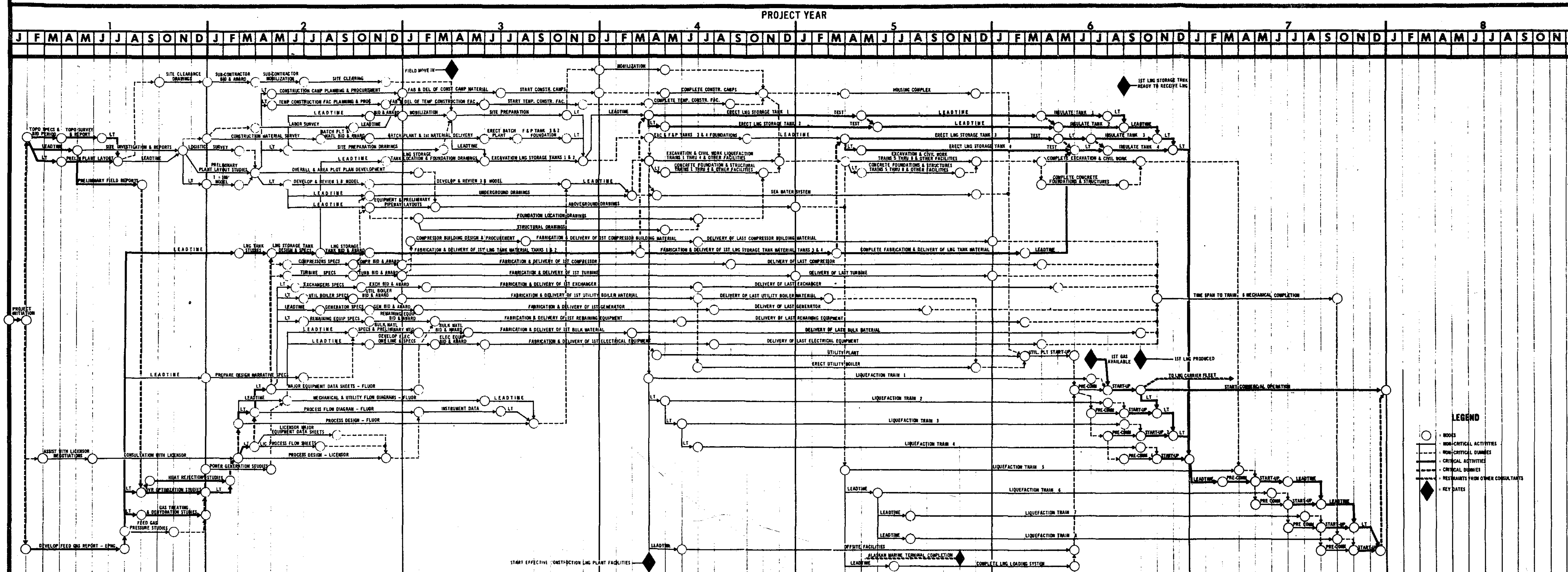
Dummy - An activity which does not consume resources or time; it is used only to show logical ties within a network (also called a restraint).



TRANS-ALASKA GAS PROJECT

LNG PLANT CONSTRUCTION SCHEDULE

FIGURE 1.5–9



TRANS-ALASKA GAS PROJECT

LNG PLANT
LOGIC DIAGRAM

FIGURE 1.5–10

Critical path - The longest chain of activities in a network. The activities on the critical path will determine the project duration.

Lead time - The time existing between the end of one project and the start of another. Lead time expends time but no resources.

The construction time required for the LNG Plant is determined by the critical path shown below:

Project Mobilization
Site Data Gathering and Reports
Process Design Studies
LNG Storage Tank Design and Specifications
Procurement of LNG Storage Tank Material
Fabrication and Delivery of LNG Storage Tank Material
LNG Storage Tank Erections
Insulation of LNG Storage Tanks
LNG Tank #1 Ready to Receive LNG
Liquefaction Train #1 Start-up
First LNG Available (October of Year 6)
Liquefaction Train #8 Start-up

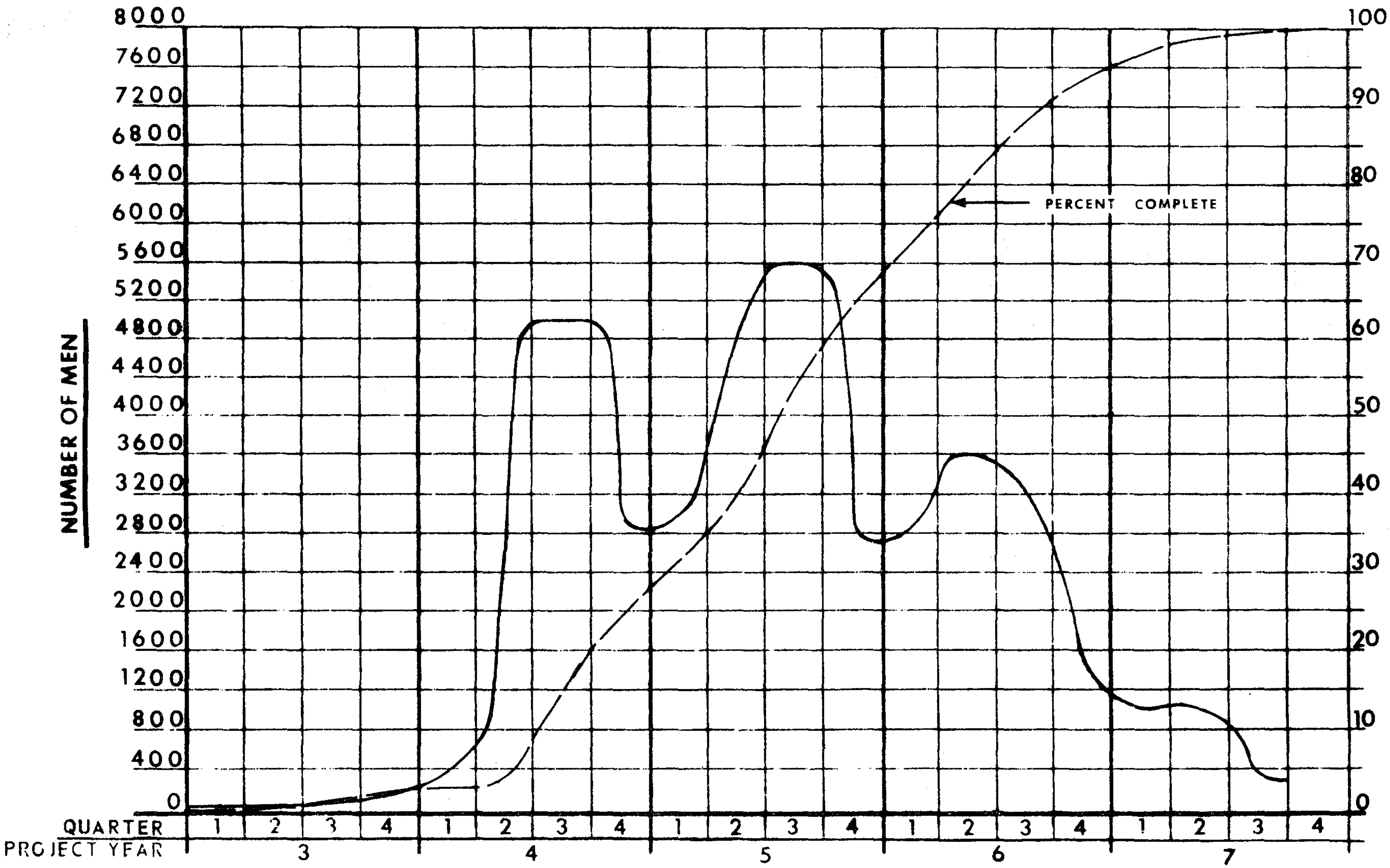
1.5.2.3 Labor Considerations

Figure 1.5-11 shows the manpower curve for construction of the LNG Plant. The total work force is expected to peak at approximately 5600 personnel during the summer of the fifth project year.

Personnel for the various crafts will be recruited through a project office established in Anchorage. It is planned to use the current Alaska work force to a maximum to staff this project. Available craft and administrative personnel attracted to Alaska during construction of the Alyeska oil pipeline will also be utilized. The remaining craftsmen will come from the Lower 48 states. Work will be assigned preferentially to local contractors for construction and related services, when skills are equivalent.

Commercial carriers will be used to transport new employees to Cordova. Crew boats and a ferry system will be utilized to transport personnel from Cordova to the LNG Plant site.

A construction work camp will be provided to house supervisors and their families and craft personnel. Location of the camp is approximately one mile west of the proposed LNG Plant site. Two-man rooms will be provided for the craft personnel, while mobile homes will be furnished for supervisors and their families. The construction camp facility for the craft workmen will include living quarters, kitchen and dining halls, recreational facilities, a medical and first aid dispensary, and a camp store.



TRANS-ALASKA GAS PROJECT

LNG PLANT
CONSTRUCTION MANPOWER CURVE

FIGURE 1.5–11

1.5.2.4 Construction Facilities and Logistics

Buildings

Temporary construction buildings which will be required during the construction of the LNG Plant are listed below:

- Administration Office
- Equipment Maintenance Shop
- Warehouse
- Carpenter Shop
- Iron Worker's Shop
- Electrical and Instrument Shop
- Pipe Fabrication Shop

As required, area superintendent offices and craft change houses will be located within the plant area.

Upon completion of construction, the temporary buildings will be either removed or converted to permanent facilities.

As construction progresses, permanent plant buildings will replace temporary facilities for use by construction forces.

Utilities

A brief description of the utilities which will be required for construction of the LNG Plant follows:

(1) Water -- Water required for personnel, fire protection and construction use will be supplied from wells or a creek near the site location. The potable water will be treated to meet U.S. Department of Health drinking water standards.

(2) Fire Protection -- Fire protection will be provided during construction phases at all work areas and in all buildings. The permanent plant fire water system will be constructed and activated very early in the project, to serve both as a source of fire protection and as wash down water. Supplemental dry chemical systems will be provided, and will be located for easy access by workmen in all areas. A plant fire truck and temporary firewater stations will be available for use at the start of construction.

Fire protection in buildings at the construction camp will include automatic sprinkler systems and fire stations (water hose and dry chemical extinguishers) at strategic locations in all buildings, fuel facilities and furnace rooms.

(3) Sanitary Sewage -- A sanitary sewage system will be provided to collect, treat and appropriately dispose of the liquid wastes from the work camp housing complex, in accordance with applicable federal, state and local regulations.

(4) Electric Power -- An electric power generation system will be installed to provide construction requirements and housing needs.

(5) Fuels -- A fuel oil and gasoline system will be provided to serve construction equipment and housing needs.

(6) Concrete Batch Plant -- A batch plant will produce concrete for equipment foundations, tanks, and other construction needs as required.

(7) Chemicals -- Few chemicals will be required during the construction phase. Chemicals used will be subsequently flushed to a retention area, neutralized, and released if compatible with accepting waters. In the event that further treatment is required, a portable processing unit may be used.

Logistics

Logistics planning will commence upon initiation of the project. Directions for packaging and shipping materials will be issued to suppliers to assure receipt of materials and equipment compatible with shipping facilities. Logistic plans include marshalling materials in the Pacific Northwest for barge shipment direct to the LNG Plant site, and for rail shipment to Alaska via marine rail car carriers, with trans-shipment to the jobsite by barge.

Construction equipment and material will be received by barge and moved to the plant area by truck. A construction dock will be installed following initial move-in for use throughout the project. A "laydown and storage" area near the plant will be utilized for all equipment and materials which can be stored outdoors. Equipment will be installed on its foundation as received whenever possible. A temporary warehouse will provide storage for all materials and equipment requiring indoor protection. All plant equipment as received will be segregated by unit for ready identification.

1.5.3 Alaskan Marine Terminal

1.5.3.1 Initial Procedures

Pre-Construction Investigation

Oceanographic conditions, natural hazards, weather availability of materials, construction problems, and other possible difficulties were considered in determining the design and layout of the Alaskan Marine Terminal. Further investigations will be conducted during the planning stage preceding construction, including:

(1) Detailed soil borings to determine the thickness of the overburden and to determine the properties of the underlying strata,

(2) A hydrographic survey to provide information on surface contours of the sea floor and also data on the winds, waves, and currents in the construction area,

(3) Material source site surveys to determine environmentally acceptable locations of suitable quantities of raw materials for construction, and

(4) Tests to verify pin pile specifications and the bond strength of grout to pile and bedrock formations.

Site Preparation

Based on information obtained from offshore surveys, extensive site preparation prior to construction will not be necessary. Such surveys indicated no boulders, ridges or deep holes in the offshore area in which the marine terminal will be located. The absence of these obstructions precludes the need for dredging or blasting.

Onshore earthwork may require the removal of some large boulders to get drilling equipment to locations where pilings are required. Additional onshore earthwork may be needed at the point where the approachway intersects the beach bluff. If it is necessary to excavate the bluff, the amount of earthwork required should not be substantial, since the approachway will be elevated at the point where it will intersect the bluff.

1.5.3.2 Construction Schedule

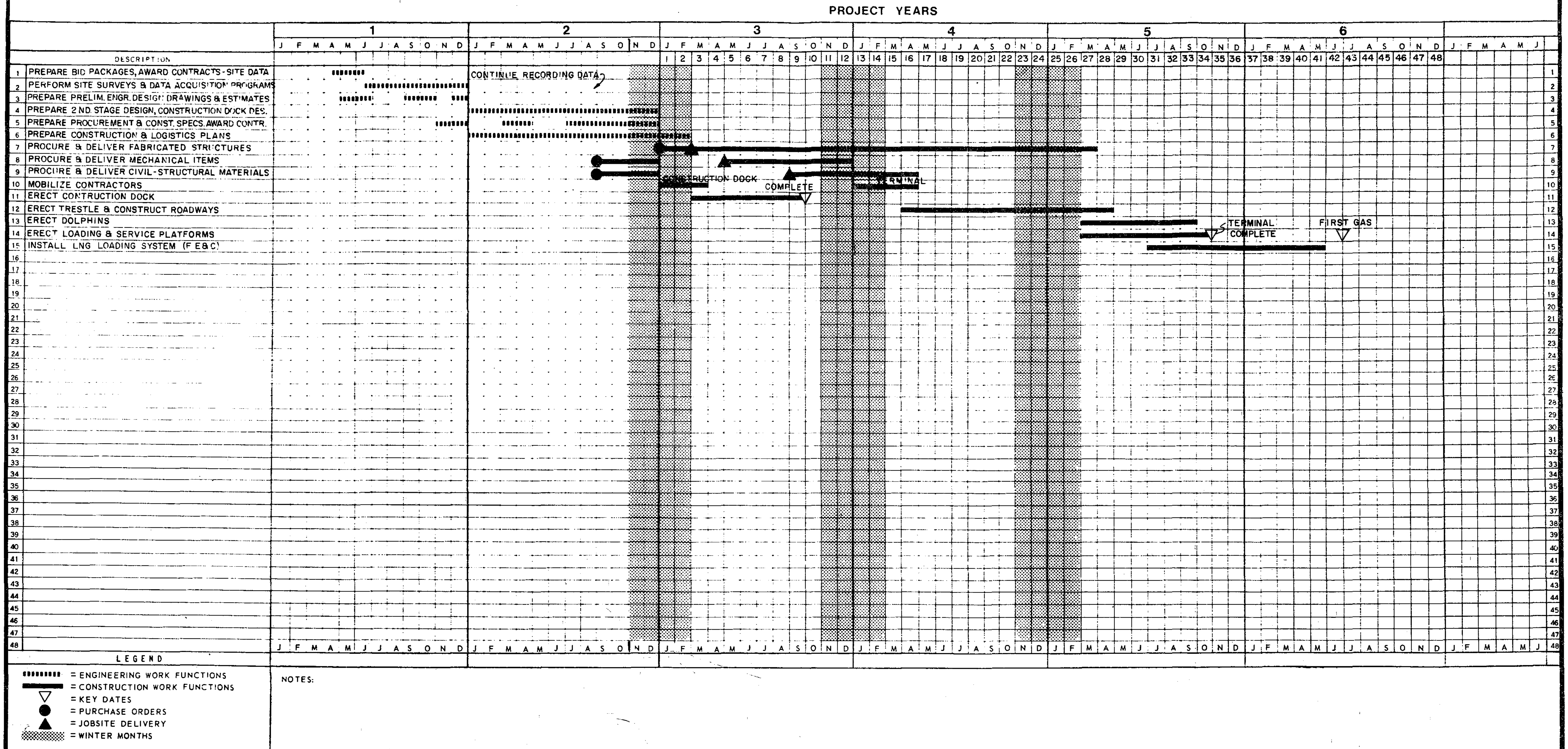
Figure 1.5-12 is a bar graph of the construction schedule for the Alaskan Marine Terminal showing major work functions, time durations, milestone dates, project parameters and resource requirements.

Start of construction is set conditionally for January of the third year. Construction of the marine terminal is estimated to require a total of 54 months, of which 20 months are required for the "front-end" site work, design and planning.

The "front-end" engineering work activities include development of the design criteria, final design of the facilities, preparation of detailed drawings and specifications, procurement of material and equipment, the preparation of bids and contractor selection.

Construction work activities include mobilization of the contractor and erection of the construction dock, to be followed by the erection of the marine terminal; fabrication and delivery of structures and other materials and equipment are included in these activities.

The construction dock will be completed nine months after the initiation of contractor mobilization. Mobilization for the main terminal construction will commence the first month of the 4th project year.



TRANS-ALASKA GAS PROJECT

ALASKAN MARINE TERMINAL
CONSTRUCTION SCHEDULE

FIGURE 1.5–12

Erection of the terminal will proceed until completion in the 11th month of the 5th project year. This completion schedule will allow sufficient time for installation of cryogenic piping well in advance of first gas deliveries to the LNG Plant.

The schedule spans three winter construction periods. Aside from contractor's mobilization, the only winter construction activity occurs in the period from November through February of the 4th and 5th project years.

1.5.3.3 Construction Methods

Although the functions of the loading platform, service platform, berthing dolphin, mooring dolphin, and trestle are different, the field installation of the jacket structure is similar for each.

The jacket structures will be fabricated and placed on barges for towing to the site. Jacket structures will be either launched or lifted from the barges and placed in position with a derrick barge crane. Piles will then be placed inside the jacket legs and driven through the overburden material into the bedrock for a distance equal to the diameter of the pile. The driven pile will be welded to the top of the jacket. The material inside the driven pile will be removed and a hole drilled into the bedrock to secure the pin pile. The pin pile will be required for lateral, compressive, and tensile support.

After the pin pile is inserted into the drilled hole, grout will be pumped into the pin pile under pressure and will be circulated outside of the pin pile to provide a bond with the bedrock. The grout will also circulate in the annular space between the pin pile and driven pile. Flat or circular bars will be welded to the outside circumference of the driven pile to assure a good bond.

Pin piles will be used to anchor the structures into the bedrock formation. The use of pin piles is an accepted procedure where hard foundation material exists and drilling is required for pile installation.

The deck section will be installed following the pile installation. The legs of the upper deck section will be stabbed into the piling and welded in place. Provisions will be made for adjusting the deck elevation by approximately two feet to assure that the final deck elevation for the structures will be over 40 feet above MLLW.

The loading arm structure and control tower will be installed following completion of the loading platform deck.

The fender system for the berthing dolphins will be installed last. Alignment columns will be used to provide proper horizontal alignment for the wale faces of the four berthing dolphins, to provide for tolerance. The six alignment columns can be adjusted in length to permit horizontal alignment of the fender. The fender assembly consisting of box beams, horizontal and vertical intermediate beams, cell fenders, and wale face, will then be installed.

1.5.3.4 Labor Considerations

Construction manpower requirements for the Alaskan Marine Terminal are shown on Figure 1.5-13. This curve presents the variation in total labor force required at the job site during the construction period. The curve indicates that the manpower will peak at a level of 120 during the fourth and fifth project years.

All site preparation work will be conducted by crews living on barges or in temporary structures located ashore. Once construction begins, operations will be based on land at the site. Housing will be provided for personnel who will be supervising offshore work during the construction of the marine terminal.

1.5.3.5 Construction Facilities

Among the facilities and equipment required during construction will be several onshore buildings and various support vessels and docks.

A temporary onshore field office with approximately 1,800 square feet of space will be constructed. This office will be removed after construction is completed.

An onshore storage yard and warehouse also will be required for construction. Although present plans are to receive materials as needed with no rehandling, some minor items of material and equipment will have to be stored in a temporary, 3/4 acre storage yard.

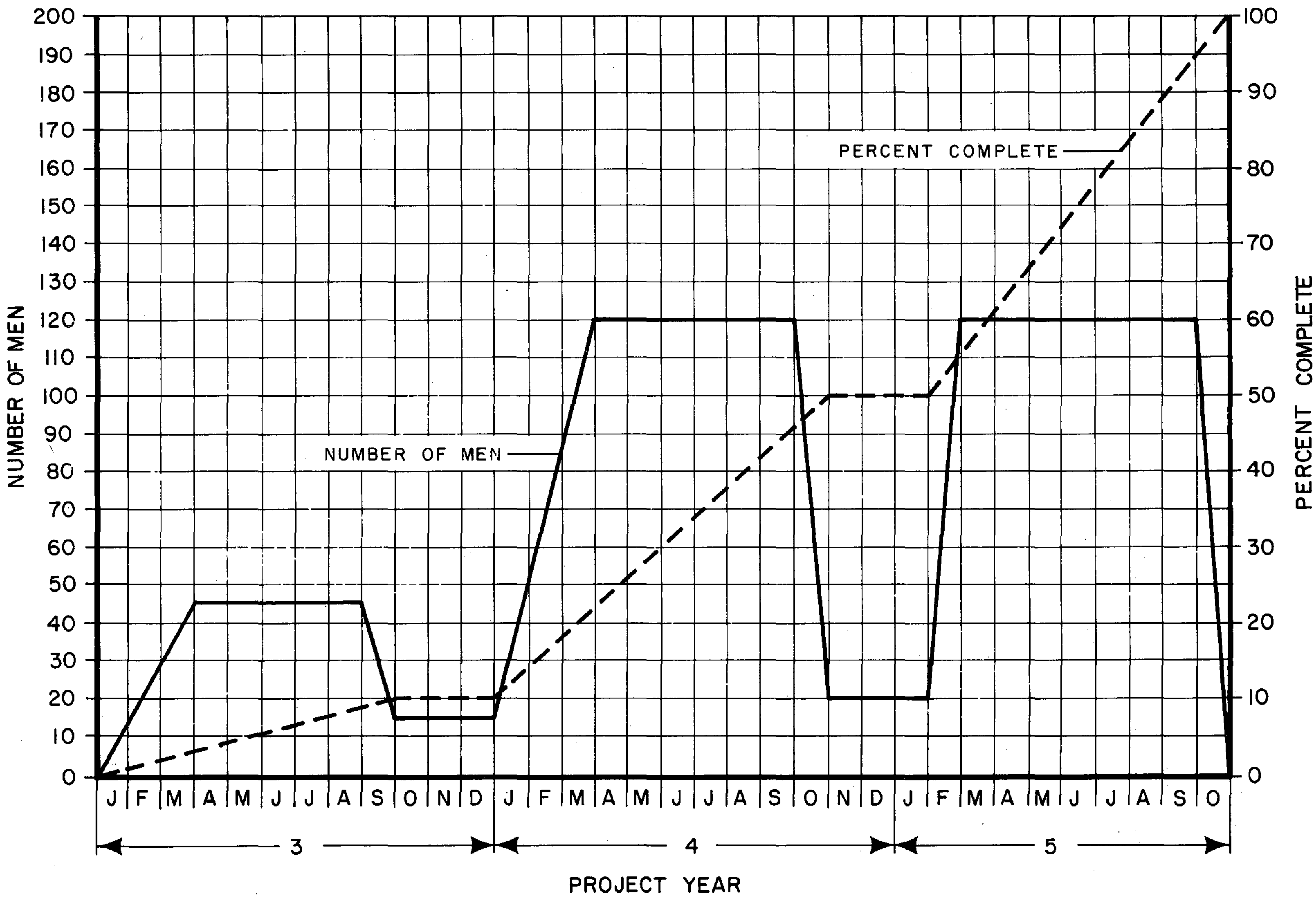
A temporary warehouse, with approximately 800 square feet of space, will be installed to store small items, requiring protection from the weather. In addition, the warehouse will serve as a garage for minor repair and maintenance of construction equipment.

An onshore fuel oil storage facility will be installed to store fuel needed during construction.

The small boat harbor will be protected by a breakwater, and will be located on the southwestern end of the marine terminal. The exposed side of the breakwater will be used as a barge dock; a ferry dock will also be incorporated into the breakwater design.

The construction dock will be designed to support a crawler crane capable of lifting a 100 ton load. After construction is completed, the construction dock will continue to operate as the small boat harbor in support of the marine terminal.

The dock will have a surface dimension of 70 feet by 532 feet, and will consist of three concrete caissons floated to the proposed location and sunk by filling with granular materials. The top surface of the dock will be crushed gravel compacted to provide a level surface. Concrete caissons will also provide breakwater protection on the shoreward side of the dock for the tugs, crewboats, and mooring launch.



TRANS-ALASKA GAS PROJECT

ALASKAN MARINE TERMINAL
CONSTRUCTION MANPOWER
CURVE

FIGURE 1.5–13

A roadway 13.5 feet wide will slope uniformly from the end of the construction dock to the shoreline. The roadway will be constructed on a rubble mound structure surfaced with crushed rock and gravel.

The ferry dock will consist of two 10-foot by 30-foot floats flexibly connected to a 20-foot by 20-foot landing float. The landing float will be connected to the roadway by a bridge which will be pinned at each end. Along with the flexible float connections, this pinning will allow the float assembly to adjust for changes in water level. Two mooring dolphins will be installed to secure the float assembly and provide mooring for the ferry. Construction and support vessels will include a derrick barge, drilling barge, cement barge, two cargo barges, harbor tugs, two crewboats and a launch.

1.5.4 <u>LNG Carrier Fleet Construction</u>

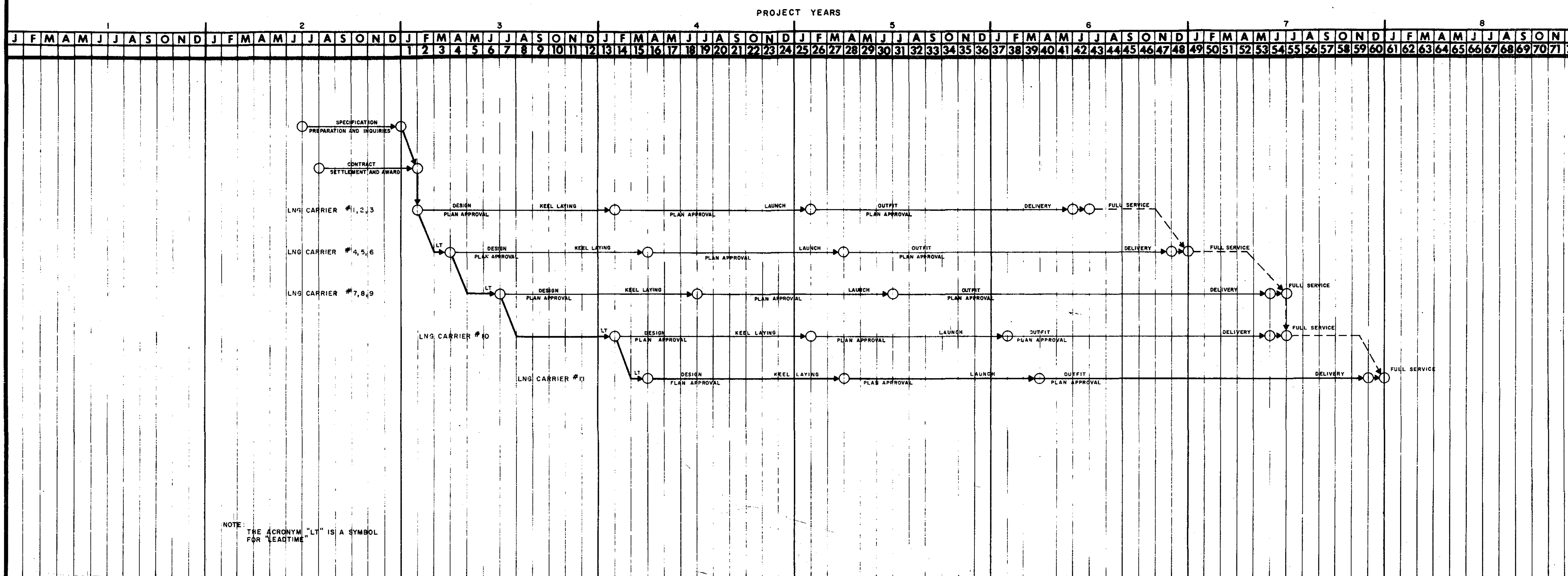
The construction and delivery schedule for the LNG carriers is one which best interfaces the fleet buildup with the construction and start-up schedules for the LNG and Regasification Plants, storage and terminal facilities. Each of the four U.S. shipyards presently constructing LNG tankers has the capability to construct and deliver three sister ships within 54 months after the contracts are awarded. Normally, ships can be delivered at six-month intervals, thereby providing a 12-month buildup schedule. Because the LNG Plant will be at full capacity fifteen months after the first train goes on stream, a twelve-month buildup schedule for the fleet is satisfactory.

The logic diagram construction schedule illustrated by Figure 1.5-14 has been prepared on the basis of using four shipyards. Three yards will build three ships each, and one will build two ships. The selection of the shipyards which will construct the LNG tankers will be based on several factors: cost of construction, terms and conditions of the construction contract, acceptability of containment systems and capability of meeting schedules.

The major events which take place during the construction are signing of the contract, laying the keel, launching, sea and gas trials, and ultimately delivery. The design, fabrication and delivery schedules are shown in Figure 1.5-14.

The shipyard will complete most of the design work and some of the hull steel fabrication work before laying the keel. Once the steel arrives at the yard, it will be sandblasted and primed before the prefabrication of hull subassemblies begins. The piping, fittings and foundations will be under fabrication simultaneously with the hull subassemblies. After the keel is in place, the main hull subassemblies and foundations will be erected.

Between the laying of the keel and launching the vessel, the yard will begin installing fittings, electrical cable, sheet metal hardware, major and minor machinery, cargo tank insulation, main shafting and propellers. After the ship is launched, it will be taken to the



TRANS-ALASKA GAS PROJECT

LNG CARRIER FLEET
LOGIC DIAGRAM

FIGURE 1.5-14

outfitting dock, where prefabrication procedures already underway will be completed along with the joiner and outfitting work. Normally, membrane tanks are installed early in the construction schedule, while free standing tanks will generally be installed last.

Prior to delivery, the ship's cargo system, machinery and equipment will be tested both at dockside and at sea under operating conditions. Tests will be conducted under the supervision of the representatives for the yard, the owners and the responsible regulatory agencies. The sea trials will assure that the ship is fit for service and will perform according to the contract specifications regarding fuel consumption, vibration, speed, etc.

Once the sea trials are completed, the LNG cargo system performance will be tested by gas trials. During gas trials, which are expected to require an average of eight days, the cargo tanks will be cooled down and partially loaded with LNG from an existing source. All cargo system equipment will be tested under operating conditions, and the United States Coast Guard will verify that its regulations are satisfied. The gas trials and the correction of deficiencies will be the last events to occur before delivery of the vessel.

Since all the U. S. shipyards which presently have the capability to construct LNG tankers are located on the East Coast or Gulf Coast, 30 days have been allowed between vessel delivery and the in-service date to sail the vessel from the shipyard to the Alaskan Marine Terminal. The key dates corresponding to the major construction events are shown in Table 1.5-1.

TABLE 1.5-1

KEY TANKER CONSTRUCTION DATES

Ship #	Yard #	Contract	Keel	Launch	Gas Trials	Delivery	In-Service
1	1	February 1 (Year 3)	February 1 (Year 4)	February 1 (Year 5)	May 1 (Year 6)	May 31 (Year 6)	June 30 (Year 6)
2	2	February 1 (Year 3)	February 1 (Year 4)	February 1 (Year 5)	May 1 (Year 6)	May 31 (Year 6)	June 30 (Year 6)
3	3	February 1 (Year 3)	February 1 (Year 4)	February 1 (Year 5)	May 1 (Year 6)	May 31 (Year 6)	June 30 (Year 6)
4	1	February 1 (Year 3)	April 1 (Year 4)	April 1 (Year 5)	November 1 (Year 6)	November 30 (Year 6)	December 31 (Year 6)
5	2	February 1 (Year 3)	April 1 (Year 4)	April 1 (Year 5)	November 1 (Year 6)	November 30 (Year 6)	December 31 (Year 6)
6	3	February 1 (Year 3)	April 1 (Year 4)	April 1 (Year 5)	November 1 (Year 6)	November 30 (Year 6)	December 31 (Year 6)
7	1	February 1 (Year 3)	July 1 (Year 4)	July 1 (Year 5)	May 1 (Year 7)	May 31 (Year 7)	June 30 (Year 7)
8	2	February 1 (Year 3)	July 1 (Year 4)	July 1 (Year 5)	May 1 (Year 7)	May 31 (Year 7)	June 30 (Year 7)
9	3	February 1 (Year 3)	July 1 (Year 4)	July 1 (Year 5)	May 1 (Year 7)	May 31 (Year 7)	June 30 (Year 7)
10	4	February 1 (Year 3)	February 1 (Year 5)	February 1 (Year 6)	May 1 (Year 7)	May 31 (Year 7)	June 30 (Year 7)
11	4	February 1 (Year 3)	April 1 (Year 5)	April 1 (Year 6)	November 1 (Year 7)	November 30 (Year 7)	December 31 (Year 7)

Section 1.6
O & M Procedures

1.6 OPERATIONAL AND MAINTENANCE PROCEDURES

1.6.1 Alaskan Gas Pipeline

1.6.1.1 Design Considerations and Calculation Methods

The Alyeska Pipeline Service Company Project Description filed with the USDI was used extensively in the accumulation of soils, climatological, seismic, ice and permafrost data used for the conceptual design of the proposed gas pipeline.

The Alaskan Gas Pipeline is designed to receive approximately 3500 MMcf/sd of natural gas at Prudhoe Bay and deliver it, less fuel, to the LNG Plant. Such design requires twelve compressor stations, each consisting of two compressor units rated at 23,400 (ISO) horsepower each. Gas measurement will be based on 14.73 psia pressure and 60°F temperature. Design and flow calculations have been based on the composition of the gas as set forth in the Overall Material Balance, Figure 1.0-2.

Refrigeration Unit

The pipeline is designed to operate as a chilled pipeline in order to mitigate degradation of permafrost. The objective is to control the temperature of the gas so that it is at all times lower than 32°F and higher than the dew point of the gas. Refrigeration provides for the stability of the pipeline, since degradation of the permafrost would result in undesirable conditions, such as differential settlement and slope failure.

The refrigeration plant design is based on the maximum refrigeration load required at the individual stations and on the operating conditions encountered at the particular locations.

Pipe Specifications

The mainline pipe will be manufactured by the double submerged arc, longitudinal seam or spiral welded seam processes, (with a 65,000 psi minimum yield strength) to the minimum requirements of the American Petroleum Institute's Specification for High Test Line Pipe 5LX or Spiral Weld Line Pipe 5LS to Grade X-65 and as further specified by Applicant. The steel used in the pipe will have a low carbon content (0.14 to 0.15%) with specially formulated chemistry, and will be specially tested for use in low temperature applications. The maximum allowable operating pressure will be 1670 psig. Additional pipe data are presented in Table 1.6-1.

TABLE 1.6-1

ALASKAN GAS PIPELINE PIPE DATA
42" O.D. - API 5LX-65, 1670 Psig DESIGN PRESSURE

Location Class	1	2	3	4
Design Factor (% of Specified Minimum Yield Strength)	72%	60%	50%	40%
Wall Thickness, In	.750	.900	1.080	1.350
Pipe Weight				
Lbs/Ft	330.4	395.1	472.0	586.1
Tons/Mile	872.3	1043.0	1246.1	1547.3
Wt. Fresh H_2O, I.D. Lbs/Ft	558.4	550.2	540.4	525.8
Displaced Fresh H_2O, O.D. Lbs/Ft	600.6	600.6	600.6	600.6
Surface Area/Ft Pipe, Sq Ft	10.996	10.996	10.996	10.996
Metal Area, Sq In	97.2	116.2	138.8	172.4
Flow Area, Sq In	1288.3	1269.2	1246.6	1213.0
Moment of Inertia, In^4	20685	24555	29087	35659
Section Modulus, In^3	985.0	1169.3	1385.1	1698.0
Radius of Gyration, In	14.59	14.54	14.48	14.38
Flexibility Factor, K*	.5455	.4512	.3727	.2942
Stress Intensification Factor, i*	.4301	.3790	.3336	.2850
Concrete Coating for Negative Buoyancy, In				
1.25 S.G.				
190 lb/Cu Ft	3.76	3.22	2.56	1.55
150 lb/Cu Ft	5.62	4.84	3.87	2.36
1.15 S.G.				
190 lb/Cu Ft	3.10	2.57	1.93	0.95
150 lb/Cu Ft	4.54	3.79	2.86	1.41

* = For curved pipe only

Meter Stations

The meter stations will be the differential orifice type designed to handle the maximum anticipated volume with an orifice beta ratio of approximately 0.6 and a maximum differential pressure range of 100 inches of water.

Calculation Methods

Various calculation methods were utilized in the project design to determine such factors as gas properties, thermal regime conditions and river scour. The methods and their sources are listed below. An equation which is given without a complete explanation of symbols is included only to identify a specific calculation method. For a definition of symbols used in equations and for a discussion of the methods, the reader is urged to consult the specific references cited.

Gas Properties

Certain gas properties, used for pressure and temperature gradient and station power requirement calculations, were obtained using the "COPE" System developed by Chem-Share, Inc., and distributed by the NGPA. This system uses an adaptation of the corresponding states method (Fisher and Leland, 1970; Starling, *et al.*), and is based on an equation of state developed by A. J. Vennix, and correction factors for component reduced properties developed by T. W. Leland (both of Rice University, Houston, Texas). Properties obtained from this system, or from subroutines coupled to the system, are compressibility factor, viscosity, enthalpy, and entropy. The values of these properties are generated as a function of pressure, temperature and gas composition.

Pressure and Temperature Gradients

The pressure and temperature gradients for steady-flow conditions in the pipeline are calculated using the following differential equations representing the momentum and heat balance, respectively, at any given location on the line (Katz, 1959; Uhl, *et al.*, Dodge, 1944).

$$(1) \quad \frac{1}{\rho}\frac{dP}{dx} + \frac{V}{g}\frac{dV}{dx} + \frac{2fV^2}{gD} + \frac{dE}{dx} = 0,$$

$$(2) \quad \frac{dH}{dx} + \frac{1}{J}\frac{dE}{dx} + \frac{V}{Jg}\frac{dV}{dx} + \frac{q_T}{W} = 0, \text{ where,}$$

P = absolute pressure (lbs/ft^2)
T = bulk fluid temperature (°F)
V = bulk fluid velocity (ft/sec)
x = distance along pipeline (ft)
ρ = bulk fluid density (lbs/ft^3)
H = specific enthalpy (Btu/lb)
D = line inside diameter (ft)
E = line elevation (ft)
W = mass flow rate (lbs/sec)
q_T = total heat transfer through wall of pipe (Btu/lineal foot of pipe/sec)
g = acceleration due to gravity (ft/sec^2)
f = friction factor (dimensionless)
J = mechanical equivalent of thermal energy (=778.3 ft-lbs/Btu)

Equation (1) can be transformed into the AGA steady state flow equation for gas transmission lines. The pressure and temperature gradients are computed simultaneously using equation (2) and the AGA steady state equation. The Joule-Thompson effect is computed implicitly in equation (2) through the term dH/dx, which gives the change in temperature with expansion at constant enthalpy.

The rate of conductive heat transfer, q, through the pipe wall is calculated using the equation (Beale, et al., 1938):

$$(3) \quad q = \frac{2\pi ks \quad (T - T_A)}{log_e \quad (4h/D)} \quad ,$$

where T_A is the soil temperature (°F) at pipe centerline depth and a distance from the pipe great enough that that the thermal influence of the pipe is insignificant, h is the depth (feet) of the pipe centerline below the soil surface, and ks the effective thermal conductivity (Btu/ft/sec/°F) of the soil in the vicinity of the pipe; D is inside diameter of pipe in feet.

The friction factor, f, is calculated using the method recommended by the Institute of Gas Technology for both "fully turbulent flow" and for "partially turbulent flow." The transition from "partially" to "fully" turbulent flow, for purposes of evaluating the friction factor, occurs at the Transitional Reynolds Number.

Compression and Cooling Power

The brake horsepower required for gas compression was calculated using the gas enthalpy difference across the compressor, based on given compressor suction pressure, suction temperature, and discharge pressure (Katy, 1959). Single-stage adiabatic compression was assumed. The brake horsepower is given by $P = (H_d - H_s) / (2545 \times e_m)$, where H_s and H_d are gas enthalpy (btu/hr) at the compressor suction and discharge conditions, respectively. The suction enthalpy, H_s, is calculated directly using the given compressor suction pressure and temperature. The discharge enthalpy is calculated according to

$$H_d = H_s + \frac{H_i - H_s}{e_a},$$

where H_i is the gas enthalpy at given compressor discharge pressure and an entropy equal to the entropy at suction conditions, e_m is the compressor mechanical efficiency, e_a is the compressor adiabatic efficiency, and the overall efficiency $e_o = e_m \times e_a$.

The compressor discharge temperature is calculated as the temperature for which gas enthalpy is equal to H_d, above, and pressure equal to the given compressor discharge pressure. The discharge cooling load (*Tons*), if any, is equal to $(H_d - H_c)/12000$, where H_d is as defined above, H_c is the gas enthalpy (Btu/hr) at the cooling system discharge pressure and given maximum station discharge temperature. The horsepower required for cooling is calculated based on its load, using the methods described in the refrigeration horsepower section following.

Refrigeration Horsepower

The refrigeration horsepower required to chill the gas at the compressor stations is developed in two parts: the horsepower of the refrigerant compressor, plus the fan horsepower for the vapor condenser in the refrigeration cycle. The compressor horsepower is calculated in terms of the coefficient of performance (COP) and the efficiency (E) by the equation (4): $Comp.\ HP/Ton = 4.71/(COP \times E)$. The fan horsepower is given in terms of the maximum differential pressure by

$$(5)\quad Fan\ HP/Ton = \left(\frac{cfm}{Ton} \times \Delta P\right) / \left(6350 \times E\right).$$

The design temperatures used for these calculations are:

- Condensing refrigerant = ambient air + 15°F
- Discharge gas = 25°F minimum
- Refrigerant at evaporator outlet = desired discharge gas temperature less 10°F
- Ambient air temperatures are interpolated from the mean averages of the nearest weather stations.

Thermal Regime

The Thermal Regime Prediction Model was developed to predict the behavior in soils around the pipeline and to analyze corrective measures. The model solves the general equation for heat transfer by conduction:

$$(6) \quad \frac{\partial q}{\partial r} - \frac{\partial h}{\partial r} = pc\frac{\partial T}{\partial t} \, .$$

The following equation of state is incorporated:

$$(7) \quad \frac{\partial q}{\partial r} = -k\frac{\partial T}{\partial r} \, .$$

Initial and boundary conditions must be satisfied. The initial condition states that at time t=0, an initial temperature must be assigned througout the region of interest. Temperature boundary conditions require that on any prescribed boundary a temperature can be imposed which must be satisfied over any time interval. Heat transfer boundary conditions state that on any prescribed boundary a heat flux can be imposed which must be satisfied over any time interval. Surface heat transfer boundary conditions require that at any boundary, conductive heat transfer can be imposed which must be satisfied over any time interval.

The calculus of variations replaces the partial differential equation (6) and the boundary conditions with a set of linear equations where the unknown dependent variables are evaluated at a set of discrete points in both space and time. The solution used here follows the convolution approach described by Wilson and Nickell (1966) and Hwang, Murray, and Brooker (1972). The potential function is stated as

$$(8) \quad X = 1/2 \int_V T_i k_{ij} * T_j dV - \int_V \rho c (T_0 - \tfrac{T}{2}) * T dV - \int_V g * h * T dV - \int_{S_2} g * Q_2 * T dS - \int_{S_3} C_S (T_3 - \tfrac{T}{2}) * T dS.$$

Redefinition of the potential function for special discretization and time discretization leads to the derivation of the following discrete time variational equation:

$$(9) \quad [K_1] \; \{T\}_n = [K_2] \; \{T\}_{n-1} + \{R\}_n$$

Pipe Wall Thickness

The Barlow Formula was used to calculate the wall thickness of the pipe for a maximum allowable operating pressure (design pressure) of 1670 psig and for the Class 1, 2, 3, and 4 locations as specified in Part 192, Title 49, Code of Federal Regulations, Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards. The Barlow Formula (and variations):

$$S = \frac{pD}{2t} \text{, where}$$

$$p = \frac{2St}{D} \times F \times E \times T \text{, and}$$

$$t = \frac{pD}{2S \times F \times E \times T} \text{, and where}$$

S = minimum specified yield strength, psi
p = design pressure, psig
D = outside diameter of pipe, inches,
t = wall thickness of pipe, inches,
F = design factor,
  F = 0.72 in Class 1 locations,
  F = 0.60 in Class 2 locations,
  F = 0.50 in Class 3 locations,
  F = 0.40 in Class 4 location,
    and variations as provided by code,
E = longitudinal joint factor as provided by code for various pipe specifications,
T = temperature derating factor as provided by code.

Stresses in a Buried Pipeline

The initial determination of pipe grade and wall thickness is made according to the Barlow formula. Additional factors that must be taken into account are temperature, bending stresses and seismic stresses. In calculating stresses, a buried pipeline is considered as being fully restrained. For such a restrained line, the effects of the pipe temperature from installation temperature to operating temperature, tension due to internal pressure, seismic force and (in some instances) bending must be included. When these stresses are high, combined stresses rather than principal stresses determine the maximum allowable design conditions of the pipeline. Beam bending stresses are included in the longitudinal stress for those portions of the restrained line which are supported above ground. Stresses considered in this study are:

Hoop Stress

(10) $S_h = \frac{pD}{2t}$ (Variation of Barlow Formula)

S_h = hoop stress, psi (allowable),
p = internal pressure, psig,
D = outside diameter, in,
t = wall thickness, in.

Longitudinal Pressure Stress (Tension)(Kent and Kent, 1938):

(11) $S_p = \gamma S_h$, where
S_p = longitudinal pressure stress, psi,
γ = Poisson ratio = 0.3,
S_h = hoop stress, psi.

Longitudinal Stress due to temperature difference (Kent and Kent, 1938)

(12) $S_L = E\alpha\ (T_2 - T_1)$
S_L = longitudinal stress (Compression or tensile) psi,
E = modulus of elasticity, psi. = 29×10^6,
α = coefficient of thermal expansion, in/in/°F=6.5×10^{-6}

T_1 = installation temperature, °F
T_2 = operation temperature, °F.

During an earthquake the ground is distorted by traveling seismic waves. These waves will induce stresses in a buried pipeline as it moves with the ground. The pipe is flexible in bending for the large radii of curvature which the ground movements will produce. Bending stresses will therefore be quite small. However, compressive and tensile stresses can be produced by direct ground strains during the earthquake since the pipe is rigid with respect to longitudinal strains.

Seismic Stress (Alyeska Pipeline Service Company, 1972):

(13) $$S_{SE} = RE\frac{V}{2c}$$, where

S_{SE} = seismic stress, psi,
R = reduction factor for slippage between ground and pipe,
V = ground motion velocity, ft/sec,
c = wave propagation velocity, ft/sec.

A buried pipeline in a confining ditch and in good soils is fully supported and no bending stresses occur. However, bending stresses occur in free spans and in zones of soil subsidence (Kent and Kent, 1938):

(14) $$S_B = \frac{1}{12}\,\frac{wL^2}{Z}$$, where

S_B = bending stress, psi,
w = pipe weight, lbs/inch,
L = span length, in,
Z = section modulus, in^3.

The stresses enumerated above interact to add to or offset each other. For the purpose of the design of this pipeline, all of the sustained forces in the pipeline will be included in the total combined stresses:

(15) $$Sc = S_h + (\pm E\alpha\,(T_2 - T_1) - \gamma S_h \pm S_{SE} \pm S_B),$$

Sc = combined stresses
max. Sc = 90% of specified minimum yield strength.

Forces must be considered at transition points from below ground to aboveground piping and at bends. The forces at transition points, such as at compressor stations where block valves are located, must also include the longitudinal fluid pressure force. The Force at transition is:

(16) $$F = A[E\alpha\,(T_2 - T_1) + 0.5\,S_h - \gamma S_h],$$ where

F = force, lbs,
A = pipe metal area, sq in.

The force at bend is:

(17) $$F_\theta = 2A\,[E\alpha\,(T_2 - T_1) + 0.5\,S_h - \gamma Sh]\,Sin\,\frac{\theta}{2},$$

where θ is the angle of the pipe bend deflection. The calculation of these forces will provide the basis for the design of anchors and restraints.

River Scour

The method used to determine the depth of scour of a stream at a crossing site, and therefore the depth necessary for burial of a pipeline, is outlined by Blench (1969). The basic formula for this computation is derived from the regime theory of canals:

$$(18) \qquad d = \sqrt[3]{\frac{q^2}{F_b}}, \text{ where}$$

d is the regime depth or the average depth of a river or canal when in equilibrium,
q is the discharge intensity,
F_b is the bedload factor

This computed depth is multiplied by a factor Z to determine the maximum depth of scour that may occur, depending on channel conditions to be expected at the crossing. Z factors will vary from 1.4 for a free eroding bend in a meandering stream to 4 or more for a forced rigid bend.

The discharge intensity q is computed from the flow in cubic feet per second for a main channel divided by the average breadth of that channel. It is expressed in cubic feet per second per foot of breadth.

In determining scour depths for a braided river a bankfull stage of the major channels is considered to be the condition leading to the maximum scour. Discharges beyond bankfull stage may result in decreasing scour depths. The Z factors used in determining scour depths will vary in braided streams up to Z=4 when the point of scour is at the location of confluence of two major channels. Flow intensity is computed by determining, through the use of the Manning equation (Chow, 1959), a main channel discharge and dividing by the average channel breadth.

In analyzing a stream to determine if regime conditions have been reached or if some other control is responsible for the channel depth, breadth, and stream characteristics, one of several slope formulas given by Blench are applied. If the theoretical slope approximates the actual slope as measured it can be assumed that normal regime conditions are satisfied and the river is neither degrading or aggrading and will continue in its present character. The most common formula for the theoretical slope of rivers is

$$(19) \qquad S = k \frac{F_{b_o}^{11/12}}{Kb^{1/6}\,Q^{1/2}} f'''(c)$$

$f'''(c)$ a bed load function of "c" as given by Blench, and k a constant applied to define the character of the stream. Values of k given by Blench are:

k = 1.25 River that looks straight in an air photo,
k = 2.0 River of conspicuous well-developed meandering without braiding,
k = 3.0 Braided river,
k = 4.0 River of extreme braiding.

River Hydraulics

Hydraulic calculations must be made for each river crossing to determine water surface profiles during pipeline design flood discharges. The most common method to determine stage at individual cross sections is through the use of Manning's flow equation (Chow, 1959). For streams of uniform cross sectional area along a specific reach, this method gives satisfactory results, but where a reach is complicated by cross sections of varying geometry a back-water method is necessary to correctly define the water surface profile. The U. S. Corps of Engineers computer program HEC 2 provides a satisfactory method for this determination.

Gravel Pads

Gravel pad thicknesses north of the Brooks Range have been calculated by the use of the degree-day concept for heat conduction in soils, after Frederick J. Sanger, Cold Regions Research and Engineering Laboratory (CRREL), to mitigate the degradation of permafrost. The above method makes use of the Modified Bergrenn equation, which is based on a temperature step change at the surface of a semi-infinite slab. The equation with parameters converted to English units for soils is

(20) $$X = \lambda\left(\frac{48nKI}{L}\right)^{\frac{1}{2}},$$ where

X = depth of thaw (ft),
K = coefficient of thermal conductivity for frozen and unfrozen soils (Btu/ft-hr-°F)
L_s = latent heat of fusion for H_2O (Btu/lb),
L = volumetric latent heat of soil-water mixture (Btu/cf),
I = air thawing index (degree-days),
λ = lambda coefficient (Sanger, 1969) based on soil and air conditions,
γ_d = dry unit weight of soil (lb/cf),
w = moisture content of soil (%)
t = length of thawing season (days),
T_o = reference temperature (32°F),
T_d = mean daily air temperature,
n = conversion of air thawing index to surface thawing index.

The air thawing index is evaluated as follows (Alyeska Pipeline Service, 1971):

$$I = \int_o^t (T_d - T_o)\, dt \qquad for\ (T_d - T_o) > 0,$$

$$and\ L = \gamma_d \frac{w}{100} L_s.$$

Adfreeze Pile Embedment

Adfreeze pile embedment lengths have been calculated using temperature dependent ultimate adfreeze bond stress in creep for saturated soils, after F. J. Sanger (1969) based on CRREL experience in Alaska. The following loading conditions must be satisfied.

Summer Loading:

$$P + P_n < P_p ,$$

(21) $$P + \pi d \; \Sigma \tau_{n_i} \, L_{a_i} < \pi d \; \Sigma \tau_{p_i} \, L_{p_i} ,$$ where

τ_n = soil-pile friction (tons/ft^2),
d = outside diameter of pile (ft),
τ_p = adfreeze bond stress in permafrost,
τ_a = adfreeze bond stress in shallow surface soils which may develop heave forces during winter freezing.

Winter Loading:

$$P_a < P + P_p ,$$

(22) $$\pi d \; \Sigma \tau_{a_i} \, L_{a_i} < P + \pi d \; \Sigma \tau_{p_i} \, L_{p_i} .$$

Friction Pile Capacities

The pile embedment lengths in thawed soils have been calculated using the Vierendeel static method of estimating friction pile capacity as published by Bowles (1968). The following force equation must be satisfied:

$$P_u = P_f - P_n ,$$

(23) $$P_u = 1/2 fP \; \Sigma \; \gamma_i L_{f_i}^2 \; tan^2(45° + \frac{\phi_i}{2}) - (1/2) P \gamma_n K f L_n^2 ,$$ where

L_f = embeded length in residual soil (ft),
L_n = depth of granular fill (ft),
γ_f = unit weight of residual soil (lb/cf),
γ_n = unit weight of granular fill material (lb/cf)
P = perimeter of pile (ft),
f = coefficient of friction based on pile surface roughness,
ϕ = angle of internal friction of soil,
K = pressure coefficient based on soil properties.

The allowable pile capacity is then given in terms of the factor of safety (F.S.):

(24) $$P_a = \frac{Pu}{F.S.} .$$

1.6.1.2 Operational Procedures

The pipeline system will be controlled from the Dispatching and Control Center at the LNG Plant site, where a dispatcher will be on duty 24 hours per day. Normal change in operating conditions of the compressor station will be effected from the control center by means of the telecommunication system. The pipeline system annual average day flow-diagram and material balance is shown in Figure 1.6-1, and the maximum daily design capacity and material balance is shown in Figure 1.6-2.

Compressor Stations

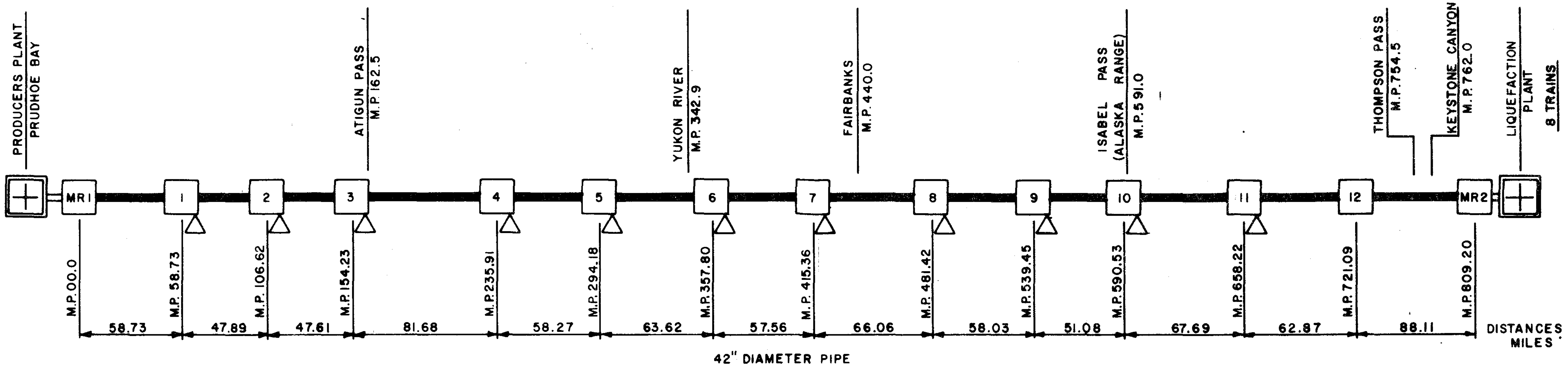
Although the compressor stations will normally be operated remotely, two men trained in manual station operation will be assigned to each station 24 hours per day in case of an emergency.

The automatic control system for each unit provides for local and remote automatic start-up, operation and shut-down. The basic system is electronic. Control is accomplished by means of sequential programming with appropriate checks in the sequence. The variables indicative of the unit performance are measured and regulated according to the demand of the system or unit performance limitations. Auxiliary systems will be monitored and annunciators will provide a warning of improper conditions as well as an indication of the trouble area. The start-stop sequence control permits the operator to start the turbine compressor by pushing a single button. The stop sequence is designed to unload the compressor safely and shut down the machine either as a command stop or as an emergency stop.

The typical compressor station particulate emission level will be less than one pound per thousand pounds of fuel used. Peak exhaust stack SO_2 emissions will be below 0.5 ppm. Oxides of nitrogen are expected to be present, but exact quantities are not known. Similar operations have oxides of nitrogen emissions 11 to 12 pounds per thousand pounds of fuel consumed at maximum power level.

Sanitary wastes will be disposed of by approved methods. Sewage and liquid industrial wastes will be treated in a processing plant operated on a physical-chemical cycle, and activated carbon filters and chlorination will provide secondary treatment prior to discharge during thaw periods. Tertiary treatment, if necessary, will consist of dewatering and disposing of sludge by approved incineration or deposition methods. Solid wastes will be burned in an approved incinerator or will be processed and buried in approved locations.

All gas turbine exhausts, relief and vent valves will be constructed in such a manner as to restrict noise levels to 90 dBA or less, at a minimum of twenty-five feet from the source. In addition, all personnel will be required to wear approved "safe-sound" ear protectors when working in the vicinity of this equipment.



ITEM NO.	ITEM	METER STA. MR 1	COMPRESSOR STA. NO. 1	COMPRESSOR STA. NO. 2	COMPRESSOR STA. NO. 3	COMPRESSOR STA. NO. 4	COMPRESSOR STA. NO. 5	COMPRESSOR STA. NO. 6	COMPRESSOR STA. NO. 7	COMPRESSOR STA. NO. 8	COMPRESSOR STA. NO. 9	COMPRESSOR STA. NO. 10	COMPRESSOR STA. NO. 11	COMPRESSOR STA. NO. 12	METER STA. MR 2
1	STATION INLET FLOW RATE MMCF/CD		3283.3	3275.3	3267.5	3260.1	3252.9	3244.7	3236.6	3228.4	3220.3	3212.0	3203.9	3197.4	
2	STATION OUTLET FLOW RATE MMCF/CD	3283.3	3275.3	3267.5	3260.1	3252.9	3244.7	3236.6	3228.4	3220.3	3212.0	3203.9	3197.4	3190.0	3190.0
3	STATION FUEL MMCF/CD		7.976	7.792	7.408	7.184	8.178	8.155	8.180	8.137	8.223	8.109	6.577	7.355	
4	COMPRESSOR INSTALLED HP (ISO)		46.800	46 800	46.800	46.800	46.800	46.800	46 800	46.800	46,800	46,800	46,800	46,800	
5	NO. COMPRESSOR UNITS INSTALLED		2/23 400	2/23 400	2/23 400	2/23 400	2/23,400	2/23 400	2/23 400	2/23,400	2/23,400	2/23.400	2/23,400	2/23,400	
6	NO. REFRIGERATION UNITS INSTALLED		1/4.130	2/4.130	2/4.130	2/4.130	2/4.130	2/4.130	2/4.130	2/4.130	2/4.130	2/4.130	2/4,130	0	

FUEL CALCULATION

TIME OF YEAR	FLOW MMCF/CD	FUEL.MMCF/CD
1. WINTER	3.375 0	96 192
2. SEPTEMBER	3.375.0	114 839
3 WINTER	2 953.0	65.636
4. SEPTEMBER	2.953.0	76 259
5. SUMMER	2 953.0	83 351
AVE. 1 & 2 FOR 205 DAYS	691 875.0	21 630.68
AVE. 3 & 4 FOR 40 DAYS	118 120.0	2 837.90
AVE. 4 & 5 FOR 120 DAYS	354 360.00	9 576 60
TOTAL PER YEAR MMCF	1,164 355.0	34.045.18
DAILY AVERAGE MMCF/CD	3 190.0	93.274

LEGEND:

MR1 METER STATION

PIPELINE

12 COMPRESSOR STATION

REFRIGERATION PLANT

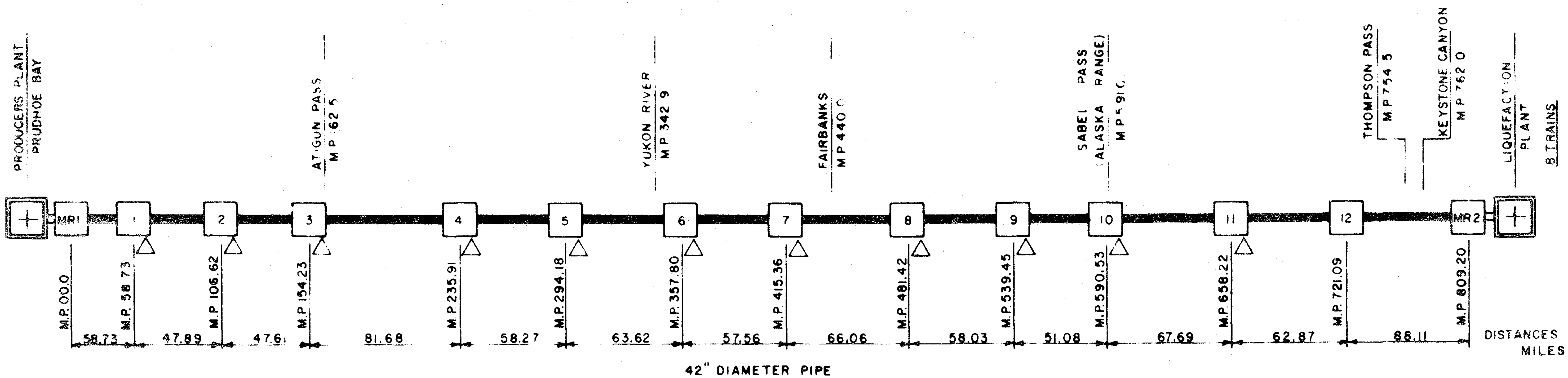
NOTES:

TEMPERATURE BASE	60°F
PRESSURE BASE	14.73 PSIA
GAS SPECIFIC GRAVITY	0.6518
HIGH HEATING VALUE	1130.13 BTU/CF
M.A.O.P.	1685.0 PSIA
TOTAL FUEL	93.274 MMCF/CD

TRANS-ALASKA GAS PROJECT

FLOW DIAGRAM
3190 MMCF/CD FLOW
MATERIAL BALANCE

FIGURE 1.6–1



ITEM NO.	ITEM	METER STA. MR 1	COMPRESSOR STA. NO. 1	COMPRESSOR STA. NO. 2	COMPRESSOR STA. NO. 3	COMPRESSOR STA. NO. 4	COMPRESSOR STA. NO. 5	COMPRESSOR STA. NO. 6	COMPRESSOR STA. NO. 7	COMPRESSOR STA. NO. 8	COMPRESSOR STA. NO. 9	COMPRESSOR STA. NO. 10	COMPRESSOR STA. NO. 11	COMPRESSOR STA. NO. 12	METER STA. MR 2
1	STATION INLET FLOW RATE MMCF/SD		3489.8	3480.2	3471.1	3462.4	3452.8	3442.8	3432.7	3422.7	[illegible]	3402.5	3392.8	3383.6	
2	STATION OUTLET FLOW RATE MMCF/SD	3489.8	3480.2	3471.1	3462.4	3452.8	3442.8	3432.7	3422.7	[illegible]	3402.5	3392.8	3383.6	3375.0	[illegible]
3	STATION FUEL MMCF/SD		9.615	9.[illegible]21	8.655	9.624	9.999	10.106	9.966	10.293	9.931	9.668	9.256	8.605	
4	STATION INLET PRESSURE PSIA		1188.7	1197.4	1220.2	1233.2	1202.1	1206.5	1207.8	1201.8	1204.7	1217.7	1229.2	1133.2	
5	STATION INLET TEMPERATURE °F		1.3	.4	2.3	7.[illegible]	4.4	5.4	5.0	5.5	4.4	5.7	10.0	3.3	-2.6
6	COMPRESSOR INLET PRESSURE PSIA		1183.7	1192.4	1215.2	1238.2	1197.1	1201.5	1202.8	1196.8	1199.7	1212.7	1224.2	1128.2	
7	COMPRESSOR OUTLET PRESSURE PSIA		1695.0	1695.0	1695.0	1695.0	1695.0	1695.0	1695.0	1695.0	1695.0	1695.0	[illegible]	[illegible]	
8	COMPRESSOR OUTLET TEMPERATURE °F		45.9	43.8	43.2	48.4	47.9	48.6	47.9	49.3	47.6	47.7	48.[illegible]	52.6	
9	STATION OUTLET PRESSURE PSIA	1685.0	1685.0	1685.0	1685.0	1685.0	1685.0	1685.0	1685.0	1685.0	1685.0	1685.0	1640.0	1654.2	765.6
10	STATION OUTLET TEMPERATURE °F	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	52.6	
11	AMBIENT AIR TEMPERATURE °F (MEAN AVG.)	35.0	31.3	31.6	32.0	38.2	40.2	41.8	42.8	44.0	43.9	43.6	42.9	39.7	41.0
12	COMPRESSOR OPERATING BHP		43,170	41,689	39,346	39,407	41,960	41,611	41,194	[illegible],907	41,146	39,900	36,300	46,649	
13	COMPRESSOR INSTALLED HP (ISO)		46,800	46,800	46,800	46,800	46,800	46,800	46,800	46,800	46,800	46,800	46,800	46,800	
14	COMPRESSOR RATIO		1.4319	1.4215	1.3949	1.3800	1.4159	1.4108	1.4092	1.4163	1.4128	1.3978	1.3479	1.4689	
15	NO. COMPRESSOR UNITS INSTALLED-BHP		2/23,400	2/23,400	2/23,400	2/23,400	2/23,400	2/23,400	2/23,400	2/23,400	2/23,400	2/23,400	2/23,400	2/23,400	
16	REFRIGERATION LOAD (TONS)		8,796	7,639	7,302	10,124	9,817	10,163	9,761	10,449	9,528	9,532	9,645	0	
17	REFRIGERATION H.P. REQUIRED COMPR.		4,199	3,695	3,598	6,308	6,510	7,036	6,939	7,648	6,956	6,907	6,877	0	
18	NO. REFRIGERATION COMPR. INSTALLED		1/4,130	2/4,130	2/4,130	[illegible]	[illegible]	[illegible]	2/4,130	2/4,130	2/4,130	2/4,130	[illegible]	0	
19	REFRIGERATION H.P. REQUIRED-COND.		[illegible]	[illegible]	1,256	1,304	1,769	1,848	1,785	1,923	1,752	1,750	1,765	0	

LEGEND

MR1 METER STATION

PIPELINE

12 COMPRESSOR STATION

REFRIGERATION PLANT

NOTES:

TEMPERATURE BASE	60°F
PRESSURE BASE	14.73 PSIA
GAS SPECIFIC GRAVITY	0.5518
HIGH HEATING VALUE	1130.13 BTU/CF
M.A.O.P.	1685.0 PSIA
TOTAL FUEL	114.839 MMCF/SD

TRANS-ALASKA GAS PROJECT

FLOW DIAGRAM
3375 MMCF/SD FLOW
SEPTEMBER CONDITIONS

FIGURE 1.6-2

All compressor buildings will be equipped with the following: fire detection and alarm system, hazardous gas detection devices, automatic fire extinguishing system, and portable fire extinguishers.

Refrigeration will be provided at Compressor Stations No. 1 through No. 11 to maintain the desired gas temperature. This discharge temperature will be both locally and remotely adjustable depending upon pipeline conditions. Station No. 12 will not require refrigeration as permafrost is not characteristic of the area south of this station.

Multiple centrifugal multistage refrigeration compressors with gas turbine drivers will be housed in the refrigeration building. Compressed propane gas will flow from the compressor discharge through aboveground piping to the air cooled condensers. Liquid propane will flow from condensers through aboveground piping to the gas evaporators. Propane gas will flow from the gas evaporator through aboveground piping to the propane compressors.

Dispatching and Control Center

The control of the pipeline system will be based on a pressure set point on the discharge side of each compressor station. A computer will be located at the Dispatching and Control Center within the LNG Plant administration building to monitor the system, to accumulate data, and to execute the operational commands issued by the dispatcher. The pressure control set points can be adjusted remotely from the Dispatching and Control Center or locally at the stations.

Metering Facilities

The meter tubes will have automatic meter switching to maintain a desirable differential regardless of changes in the load.

The flow will be calculated at both meter stations by a digital gas flow computer which has a readout of totalized flow and flow rate. These readouts will be transmitted, along with line pressure, to the Dispatch and Control Center, where personnel will monitor meter station operation 24 hours per day. In addition, alarms will be transmitted from the Prudhoe Bay Meter Station to the control center to indicate high hydrogen sulfide, carbon dioxide or water content, or high temperature or low pressure.

Communications

Supervisory control of the pipeline system will be provided by equipment at each terminal and compressor site with interconnection provided by the 600 Baud data circuit. The supervisory "master" station (located at the Dispatching and Control Center) will provide control, monitoring, and data acquisition functions for the system operator. "Remote" units (located at terminal and compressor sites) will provide the capability for remote control, status monitoring, and data acquisition from the master station.

1.6.1.3 Maintenance Procedures

Maintenance of the pipeline system will be performed by company maintenance personnel who will operate from four proposed maintenance bases located along the pipeline. Maintenance equipment and spare parts will be stored at each base including main unit replacement modules.

Pipeline

The pipeline will be regularly patrolled by air to insure that the system is in good condition and to detect possible leaks or other areas requiring maintenance. The pipeline maintenance crews will keep all erosion control structures in good condition and will install additional structures as necessary along the right-of-way, at road crossings or at stream crossings.

The gravel pads at all heliports and stations in permafrost areas will be checked regularly, and additional gravel will be provided to ensure the integrity of the pad.

Compressor Stations

Normal maintenance will include periodic filter changes, equipment cleaning, lubrication, calibration of instruments, and painting. Periodic shut-downs will be scheduled for internal inspection of major components.

Communications Facilities

Regularly scheduled on-site inspection of all communications equipment will be performed by maintenance personnel holding FCC licenses for such work. All towers will also be inspected at regularly scheduled intervals.

1.6.1.4 Possible Accidents

The most serious accident that can happen to a gas pipeline system is the rupture of piping or vessels under pressure. The results of such a rupture pose a threat to the safety of people and property in the immediate vicinity and create a source of fuel for a fire. Since gas is lighter than air, any spillage will be dissipated to the atmosphere.

Automatic shut-down devices are included in the design so that a sudden decrease in pressure (such as caused by a pipe rupture) will close appropriate automatic block valves. Leaks will be detected by monitoring the gas volumes obtained from the two meter stations and the meters at each compressor station.

When a leak is detected an alarm will be transmitted to the Dispatching and Control Center. The District Superintendent will locate and inspect the trouble spot, assess the situation and immediately initiate the action necessary. The dispatchers will also immediately notify the LNG Plant, the producers' field facilities, governmental agencies, local emergency agencies and nearby airports, as necessary.

Emergencies can occur as a result of damage by graders, bulldozers or other equipment; gunshots; fires of outside origins, or other man-instigated actions. The proposed pipeline will be constructed in a buried mode to avoid as many of these man-made incidents as possible. The compressor stations will be equipped with elaborate fire fighting equipment to protect people and aboveground equipment in the event of fire inside the facilities. Wildfires are also a potential hazard to the pipeline system; however, control of vegetation from the pipeline rights-of-way and the areas around the stations will provide a buffer zone around these facilities.

1.6.1.5 Manpower Requirements

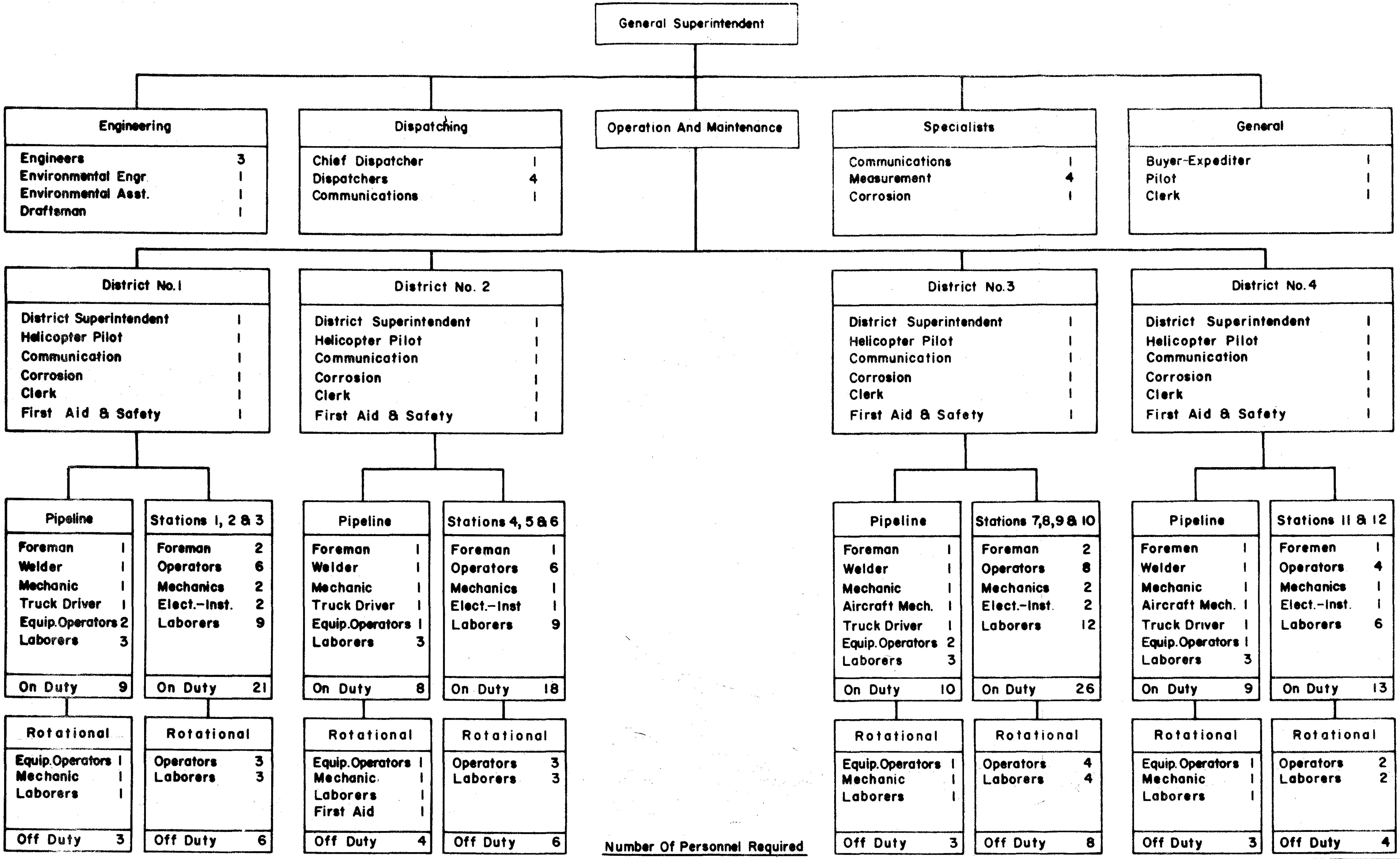
Total manpower required for operation and maintenance will be 268, although 71 of these will be employed by contract support services as follows:

catering and housekeeping	36
aircraft fuel and maintenance	5
station supplies and hauling	30
Total	71

The pipeline organization excluding support services will require 197 men, as shown in the chart of personnel assignments in Figure 1.6-3. The work schedule will be set up on a rotational basis so that each man assigned duties at the compressor stations or maintenance bases in remote locations will be available for an "active" 10 days and will be at home for an "inactive" 5 days. Transportation to and from stations will be furnished by the operating company.

The compressor stations will be manned on an 8 hour day basis by 2 operators who will remain in housing accomodations at the stations during the off-hours of their "active" 10 days.

A dispatcher will be on duty 24 hours per day at the Dispatching and Control Center located at LNG Plant site.



Number Of Personnel Required

Supervisory And Technical	22
Operation And Maintenance	
On Duty	138
Off Duty	37
Total	197

Support Personnel For Catering, Services And Supplies Are Shown In Table 9, And Total 71 People.

Grand Total 268 People.

TRANS-ALASKA GAS PROJECT

ALASKAN GAS PIPELINE ORGANIZATION CHART

FIGURE 1.6–3

1.6.2 LNG Plant

1.6.2.1 Design Considerations

Process Type

The Phillips Optimized Cascade Process has been selected for the LNG Plant. Phillips Petroleum Company supplied the process design data for the liquefaction unit; overall plant design and sizing of utilities and off-sites are by Fluor Engineers & Constructors. Gas supply and composition were specified by Applicant.

Feed Gas

Feed gas to the LNG Plant will be natural gas piped from the Alaskan North Slope fields. Design basis for the LNG Plant is 3375.0 MMscf/sd inlet from the Alaskan Gas Pipeline, which will provide an LNG equivalent of 3030.44 MMscf/sd to the fleet. The normal and range of feed gas compositions and conditions considered are shown in the following table:

TABLE 1.6-2

LNG PLANT FEED GAS

Component	Normal (Mol %)	Range (Mol %)
Nitrogen	0.75	0.50-2.00
CO_2	1.02	0.50-2.00
C_1	85.91	83.76-87.00
C_2	7.77	7.58-7.80
C_3	3.93	3.79-3.93
iC_4	0.26	0.19-0.36
nC_4	0.30	0.18-0.36
iC_5	0.03	0.02-0.05
nC_5	0.02	0.02-0.04
C_6+	0.01	Nil-0.01
Total Sulfur	Less than 1 grain/100 Scf	
H_2S	Less than 1/4 grain/100 Scf	
Temperature	-2.6°F (September conditions)	
Pressure	650 psig minimum, 750 psig maximum	

Design Parameters

Plant facilities will include the capability for recovering all vapors resulting from tanker cool-down, loading, and storage boil-off.

Design ambient conditions are:

Minimum dry bulb temperature	-25°F
Mean dry bulb temperature	40°F
Design dry bulb temperature	60°F
Maximum dry bulb temperature	82°F
Mean wet bulb temperature	38°F
Design wet bulb temperature	56°F
Maximum wet bulb temperature	68°F
Elevation above sea level	150 ft.
Seawater temperature	52°F & 63°F

The DGA Gas Treating Unit design parameters afford the following flexibility in meeting the allowable product specifications with variations in inlet gas flow rate, pressure, or CO_2 content:

Normal residual CO_2 content of the treated gas is 50 ppm, based on a CO_2 concentration of 1.02 Mol% in the feed gas. The maximum CO_2 concentration of 2.0 Mol% in the feed gas will be reduced to a residual CO_2 content of 100 ppm in the treated gas. This will meet the liquefaction unit design limit.

The DGA Gas Treating Unit has an overdesign capacity of approximately 7 percent. For design, a conservative DGA/CO_2 mol ratio of 4.0 has been used, providing additional reserve capacity in the DGA System.

Contactor operating pressure may vary from 665 to 730 psig. The design is based on a minimum pressure of 665 psig. Any pressure increase above 665 psig increases the CO_2 removal efficiency.

The plant will be self-sufficient for energy when supplied with feed gas. The only process inputs will be gas and minor quantities of catalysts and chemicals. Refrigerants will be produced from the feed gas stream. Fresh water, nitrogen and electricity will be generated within the plant.

Seismic

Design of the facility to withstand seismic forces requires consideration of the direct and indirect effects of earthquakes, and must also consider local geology and soils conditions. The direct effect is vibratory ground motion, while indirect effects include landslide, subsidence, soil liquefaction, and tsunami wave generation.

The preliminary seismic design is based on an effective bedrock acceleration of 0.60g for the maximum ground motion to which the most important equipment in the facility can be exposed without loss of fluids from storage tanks or processing equipment. Equipment designed on this basis (using dynamic analysis techniques) is capable of withstanding an earthquake of magnitude 8.4-8.6 on the Richter Scale (such as the 1964 Prince William Sound earthquake). A factor of 0.30g applies to other facilities. The above seismic design criteria are tentative, selected with the purpose of supporting preliminary design and cost estimates.

Careful location of the facility and adequate site preparation will minimize the risks of vibratory ground motion, landslide, subsidence and soil liquefaction. Location of the onshore facility at a 150-foot elevation will eliminate the risk of tsunami damage.

Equipment

All major drivers and compressors, with one exception, are of proven design with greater than one year's successful commercial operation. The GE Frame 7, two-shaft, gas turbine is the only exception to this one-year criterion. This model gas turbine is currently in production and will have had several years of commercial operation before being placed in service at the LNG plant.

Four 550,000 bbl LNG storage tanks will provide storage equal to about 2 tanker loads. Tanker loading facilities are designed for an average loading rate of 58,000 gpm to each of two carriers simultaneously. LNG will be delivered at 40 psig pressure at the ship's rail.

1.6.2.2 Process Operations

Each of the eight trains of the LNG Plant will have the following process sequence:

(1) Purification to remove carbon dioxide.
(2) Dehydration to remove water vapor.
(3) Liquefaction to condense the feed gas into a liquefied natural gas (LNG) product.
(4) LNG product storage and handling to accumulate and transfer the LNG product to tankers.

(1) DGA Gas Treating

The diglycolamine (DGA) gas treating unit will reduce the carbon dioxide (CO_2) content of the pipeline feed gas from 1.02 Mol% to 50 ppm. High CO_2 content would result in solid CO_2 deposition in the LNG tanks, and perhaps in the cryogenic exchangers; the CO_2 concentration must therefore be reduced to assure successful plant operation. The removal of CO_2 to low concentrations will be accomplished by contacting the gas with aqueous 65% DGA solution as the reactant. The rich DGA solution (that is, high in CO_2 content) will be continuously regenerated and reused in a cyclic process.

The design treating capacity is 450 MMcf per stream day for each of eight trains.

Process Flow Description

The following narrative description is graphically presented in Process Flow Diagram in Figure 1.6-4.

Natural gas from the trans-Alaskan Gas Pipeline will enter the battery limits at a design temperature of -2.6°F and will be heated in a preheat exchanger to 40°F by dry gas from the dehydration unit. The feed gas will then enter the DGA Unit under pressure control and will flow up through the CO_2 contactor column counter-current to the lean DGA solution. The lean DGA solution will enter the top of the contactor at a temperature of 90°F and at a rate of four mols of DGA per mol CO_2. The treated gas stream, partially saturated with water (15°F dew point depression) will be warmed to 98°F from the heat of reaction. The treated gas will leave the top of the contactor and will be cooled before it enters the dehydrators.

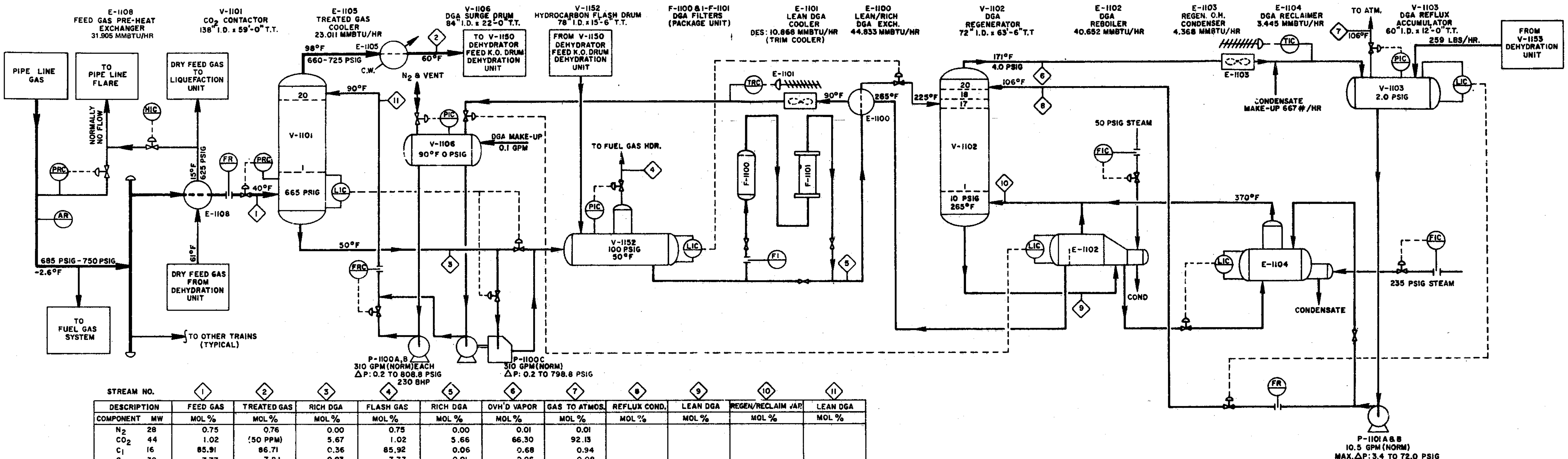
The DGA solution leaving the bottom of the contactor will be rich in CO_2 and must be regenerated by steam stripping before reuse. This solution will leave the contactor at a relatively high pressure (665-730 psig) and will flow through a hydraulic turbine and into a flash drum, reducing the pressure to 100 psig. Energy extracted from the hydraulic turbine will be used to drive one of three 50% capacity DGA circulation pumps - 2 operating, 1 standby. The flashed gas will be routed under pressure control to the fuel gas system.

The cool rich solution will be preheated in a shell-and-tube exchanger by the hot lean solution before entering the DGA regenerator. The rich solution entering the regenerator at 225°F will flow downward and will contact hot vapors at 265°F flowing upward. The CO_2 will thereby be stripped from the solution and leave the regenerator as overhead vapor. A shell-and-tube, kettle-type steam heated reboiler will be utilized to produce the stripping vapor. The hot lean solution will be withdrawn from the reboiler, heat exchanged with the rich solution stream, air trim cooled (if necessary), accumulated in a surge drum and pumped back to the contactor to complete the cycle.

Foaming will affect plant throughput, increase DGA losses, prevent adequate regeneration, and adversely affect the sweetening efficiency. An anti-foaming agent will therefore be added batch-wise through a pressure flow chemical solution tank.

(2) Molecular Sieve Gas Dehydration

The gas stream from the DGA gas treating unit in each train will be fed to a molecular sieve gas dehydration unit to reduce the gas moisture content from 0.03 Mol% H_2O to less than 1 ppm in order to prevent the moisture from freezing and plugging cryogenic equipment in the liquefaction plant. Three separate beds of 4-Angstrom molecular sieve adsorbent will be utilized in each train to dry the feed stream before



NOTE:
1. ONLY ONE TRAIN SHOWN

STREAM NO.		1	2	3	4	5	6	7	8	9	10	11
DESCRIPTION		FEED GAS	TREATED GAS	RICH DGA	FLASH GAS	RICH DGA	OVH'D VAPOR	GAS TO ATMOS.	REFLUX COND.	LEAN DGA	REGEN/RECLAIM VAP.	LEAN DGA
COMPONENT	MW	MOL %	MOL %	MOL %	MOL %	MOL %	MOL %	MOL %	MOL %	MOL %	MOL %	MOL %
N_2	28	0.75	0.76	0.00	0.75	0.00	0.01	0.01				
CO_2	44	1.02	(50 PPM)	5.67	1.02	5.66	66.30	92.13				
C_1	16	85.91	86.71	0.36	85.92	0.06	0.68	0.94				
C_2	30	7.77	7.84	0.03	7.77	0.01	0.06	0.08				
C_3	44	3.93	3.97	0.02	3.93	0.00	0.03	0.04				
iC_4	58	0.26	0.26	0.00	0.26	0.00	0.00	0.00				
nC_4	58	0.30	0.30	0.00	0.30	0.00	0.00	0.00				
iC_5	72	0.03	0.03	0.00	0.03	0.00	0.00	0.00				
nC_5	72	0.02	0.02	0.00	0.02	0.00	0.0C	0.00				
C_6+	86	0.01	0.01	0.00	0.00	0.00	0.00	0.00				
DGA	105			22.79		22.78	0.00	0.00		19.68	1.95	24.12
H_2O	18		0.10	71.13		71.49	32.92	6.80	100.00	80.32	98.05	75.88
TOTAL		100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
LBS/HR		931,352	909,447	348,261	595	348,278	26,665	22,849	4,647	367,789	41,529	326,355
MOL. WT.		18.834	18.575	39.333	18.823	39.324	35.243	41.957	18.000	35.152	19.702	39.022
GPM				621		621			9.3	754		620
MMSCF/SD		450.000	445.543		0.288		6.887	4.956			19.181	

TRANS-ALASKA GAS PROJECT

LNG PLANT
DGA GAS TREATING UNIT
PROCESS FLOW DIAGRAM

FIGURE 1.6-4

liquefaction. The molecular sieves selectively adsorb water molecules while letting gas molecules pass through.

Each dehydration unit is designed to supply processed gas at a rate of 445 MMcf/stream day/train to the liquefaction unit. This rate is 5 MMcf/stream day less than the design feed to the DGA gas treating unit essentially because of the CO_2 removed in the DGA unit.

Process Flow Description

Cooled, treated gas containing water vapor and some entrained DGA solution will enter the dehydrator feed knockout drum where liquids are separated from the gas. Liquid will return to the hydrocarbon flash drum in the DGA plant.

A total of three dehydrators per train will be operated cyclically. At any given time, two dehydrators will be in parallel drying service while the third is undergoing regeneration. Each dehydrator will automatically be regenerated every 12 hours by recycled, hot-dried feed gas at 500°F and 235 psig. A staggered, 18-hour overall cycle will be employed with each dehydrator so that a fresh dehydrator is placed in service every six hours.

All operating conditions relative to proper performance of the dehydrators will be transmitted to a central control room for monitoring by operating personnel. Thus, mechanical malfunctions or abnormal conditions may be promptly detected and corrected with a minimum of interruption to normal operations.

Moisture analyzers will be provided at the outlet of each dehydrator to continuously monitor the moisture content of the dehydrated stream. Thus, loss of desiccant adsorptive capacity and impending breakthrough will be detected in the early stages and corrected before the bed allows more than the design limit of moisture to pass through with the gas stream.

A vent valve on the gas header leading to the liquefaction system will allow diversion of the treated gas to the flare system during abnormal conditions.

Since regeneration gas heaters are important for both dehydration and liquefaction plant operations, a spare heater will be provided.

A provision for routing regeneration gas to the liquefaction plant will provide a means of deriming (removing frost and ice from) the cryogenic section of the plant.

(3) Liquefaction

Phillips Petroleum Company's "Optimized Cascade Cycle" liquefaction process utilizes propane, ethane and methane refrigerants in series. The propane and ethane are conventional closed systems with two and three stages respectively. The methane system is an open-cycle utilizing methane-rich gases flashed at a total of four pressure levels from the liquefied natural gas. Hence, there will be a total of nine refrigerant levels in the plant.

The feed gas will be almost totally condensed against propane, ethane and methane refrigerants sequentially, and then flashed to remove nitrogen. A secondary benefit of such flash is to provide most of the plant fuel requirements. After the final flash, the LNG will be pumped to storage. Vapors generated in storage or during LNG carrier loading will be returned to the liquefaction unit for product and refrigeration recovery. The design liquefaction capacity is 378.81 MMcf/stream day/train net equivalent delivered to the LNG Carrier Fleet, on an operating basis of 345 stream days/calendar year.

Process Flow Description

The Liquefaction Unit Schematic Flow Diagram in Figure 1.6-5 depicts the major components of the liquefaction and refrigeration systems; Figure 1.6-6 shows the Refrigerant Production System.

The plant description follows in three sections:

Natural Gas Liquefaction
Refrigeration Systems
Refrigerant Production

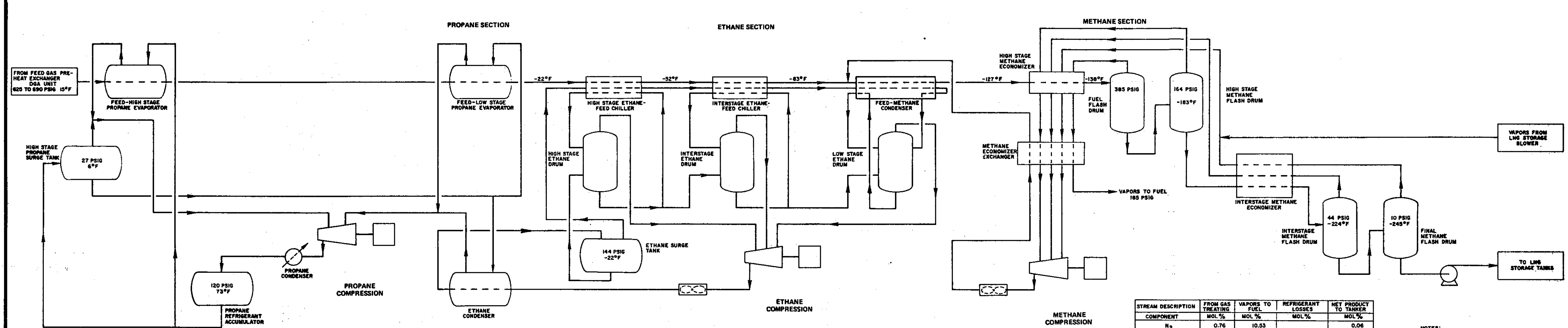
Natural Gas Liquefaction

The flow of the feed gas stream, from entry into the liquefaction units through the LNG product pump to storage, is described in this section, along with the fuel gas draw stream.

Feed gas from the gas treating and dehydration units will enter the liquefaction unit at approximately 15°F and at a pressure which can range from 625 psig to a regulated maximum of 650 psig as the gas enters the propane section.

The feed gas will first be cooled by high and low stage propane refrigerant to -22°F. Partial condensation will occur in each exchanger as the feed is progressively cooled below this temperature. Upon leaving the propane section evaporators, feed gas will be cooled by high stage and interstage ethane refrigerant. The natural gas stream will then be joined by the open-cycle methane compressor discharge stream and will enter the feed-methane condenser, which will be refrigerated by low stage boiling ethane, which is not a pure refrigerant, and which contains some methane.

The process stream will be further cooled in exchange with cold methane vapors and then flashed to approximately 385 psig. The flashed vapors will become a fuel stream containing most of the nitrogen in the feed gas. This stream will then be reduced to fuel gas pressure and will flow through the high stage methane economizer and the methane economizer exchanger before entering the fuel system at 185 psig.



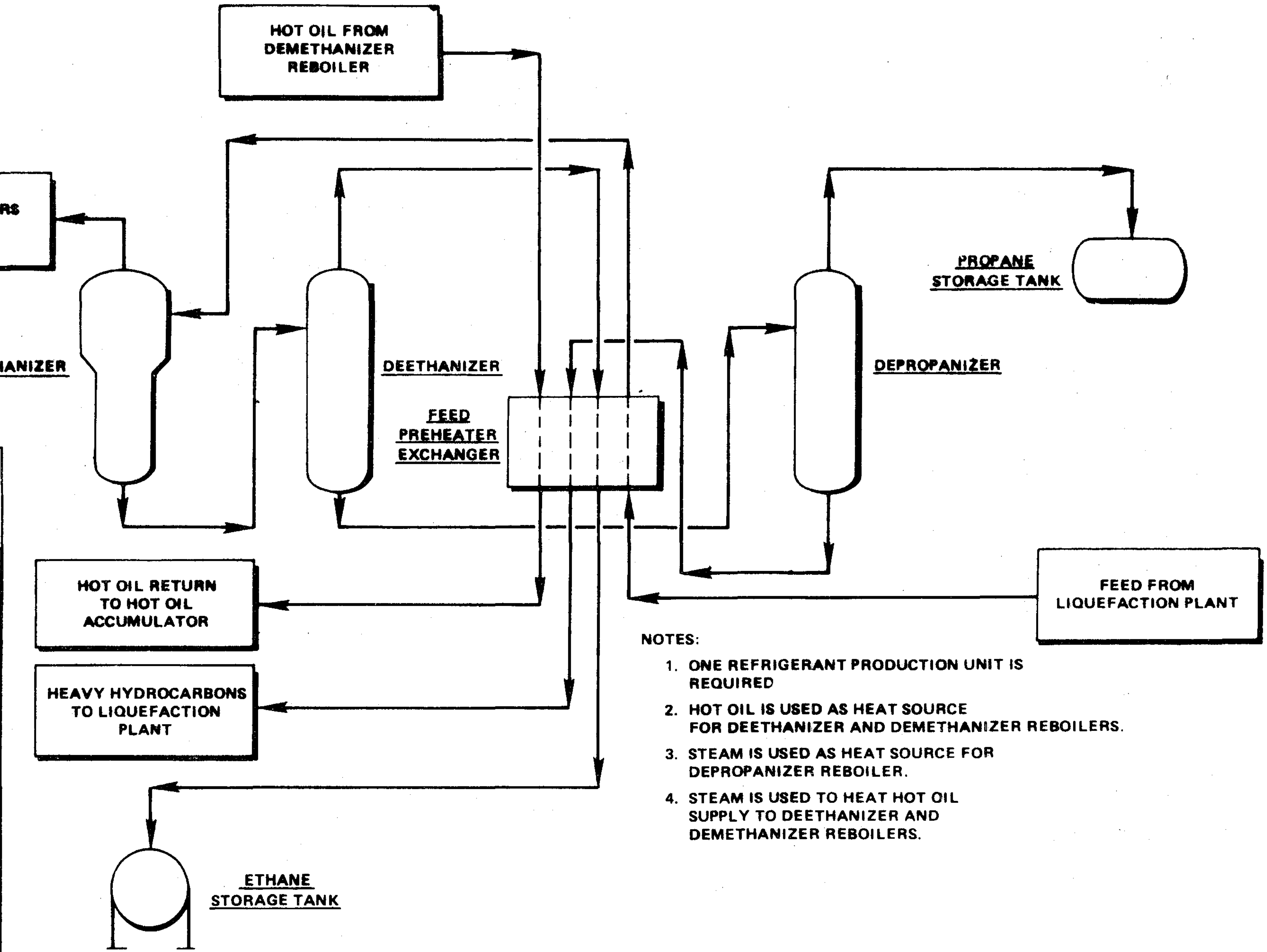
STREAM DESCRIPTION	FROM GAS TREATING	VAPORS TO FUEL	REFRIGERANT LOSSES	NET PRODUCT TO TANKER
COMPONENT	MOL %	MOL %	MOL %	MOL %
N_2	0.76	10.53		0.06
C_1	86.80	89.03	42.86	86.66
C_2	7.85	0.43	32.65	8.37
C_3	3.97	0.01	24.49	4.25
iC_4	0.26			0.28
nC_4	0.30			0.32
iC_5	0.03			0.03
nC_5	0.02			0.02
C_6+	0.01			0.01
TOTAL FLOW MMSCF/STREAM DAY	406.00	27.05	0.14	378.81
HHV, BTU/SCF	1141.59	912.01	1630.72	1157.80
GROSS HEAT VALUE, MMMBTU/STREAM DAY	463.48	24.67	0.23	438.58

NOTES:

1. TOTAL BRAKE HORSEPOWER REQUIREMENTS FOR PROPANE, ETHANE AND METHANE COMPRESSORS IS 137,324 BHP/TRAIN.
2. ONLY ONE LIQUEFACTION TRAIN SHOWN.

TRANS-ALASKA GAS PROJECT

LNG PLANT
LIQUEFACTION UNIT
SCHEMATIC FLOW DIAGRAM
FIGURE 1.6-5



NOTES:

1. ONE REFRIGERANT PRODUCTION UNIT IS REQUIRED
2. HOT OIL IS USED AS HEAT SOURCE FOR DEETHANIZER AND DEMETHANIZER REBOILERS.
3. STEAM IS USED AS HEAT SOURCE FOR DEPROPANIZER REBOILER.
4. STEAM IS USED TO HEAT HOT OIL SUPPLY TO DEETHANIZER AND DEMETHANIZER REBOILERS.

TRANS-ALASKA GAS PROJECT

LNG PLANT
REFRIGERANT PRODUCTION
SCHEMATIC FLOW DIAGRAM

FIGURE 1.6–6

Liquid from the fuel flash drum will be flashed in the high-stage methane flash drum to about 164 psig and the vapors will become the high-stage methane refrigerant. The liquid will be further cooled by heat exchange with inter-stage and low-stage methane flash vapors, and then flashed to 44 psig. The liquid will be flashed a final time to 10 psig into the final methane flash drum. The vapor streams from the interstage and final methane flash drums will be passed through the three economizing heat exchangers to recover the refrigeration. With the exception of the fuel gas stream, all vapors will be recompressed to approximately 635 psig by the methane compressor.

The methane compressor discharge will be cooled by an air cooler, will flow through the methane economizer exchanger and will join the feed gas stream ahead of the feed-methane condenser, as described above.

Liquid from the final flash drum will be pumped to LNG storage. Vapors produced in the LNG storage tanks will be boosted by the vapor blowers and returned to the liquefaction unit to join with the low stage methane refrigerant vapors.

Refrigeration Systems - Propane

The propane refrigeration system will produce two levels of refrigeration. Part of the condensed propane at 120 psig in the propane refrigerant accumulator will be reduced to the high stage pressure, approximately 27 psig, and used to first cool the feed gas. The remaining propane refrigerant will be flashed into the high-stage propane surge tank. Propane from the high-stage surge tank will then be reduced to the low-stage pressure of 5 psig and is used to cool the feed gas further and to condense the ethane refrigerant.

Propane vapor from each of the two stages will be sent independently to the propane compressor at their respective temperatures and pressures, and will be compressed to 125 psig and condensed against sea water. Since the proposed compressor is a centrifugal unit, a minimum flow through the unit must be maintained to avoid surging. This is accomplished by a recycle system which permits surge-free operation of the liquefaction unit from zero to one hundred per cent of capacity.

Automatic valves will close between the compressor and the liquefaction section whenever the compressor stops. This feature will retain the propane in the liquefaction unit because the equipment design pressure is high enough to prevent venting.

The driver for the propane compressor will be a General Electric two-shaft Frame 7 gas turbine. Exhaust gases from the turbine will be used in a supplementary fired waste heat boiler to produce 1200 psig, 900°F steam for driving turbines on the ethane and methane compressors.

Refrigeration Systems - Ethane

The ethane refrigeration system will employ three levels of refrigeration. The refrigerant vapor from the compressor will be desuperheated in an air cooler and then condensed by low stage propane refrigerant in the ethane condenser. Liquid from the ethane surge tank will be flashed in series down to the high stage, interstage, and low stage ethane drums. Liquids produced in the flashes will be used to cool and condense the feed gas and the methane compressor discharge. The ethane refrigerant will contain some methane. An ethane-rich methane-ethane mix will be drawn from the surge tank, then condensed and subcooled through three stages of ethane refrigeration before being flashed and evaporated to complete the total condensing of the feed-methane stream.

The ethane compressor will receive vapors at three pressures. The ethane refrigeration compressor will be a centrifugal unit. Automatic recycle is provided in the event flow to the compressor is reduced to near the surge point. This will permit the liquefaction unit to be operated from zero to one hundred percent of capacity. As with the propane compressor, whenever the compressor stops, automatic valves will close between the compressor and the liquefaction section.

The ethane compressor driver will be an extraction turbine using steam produced by the waste heat boiler at 1200 psig and 900°F. Approximately 50% of the steam will be extracted at 250 psig to power boiler fans and feed-water pumps. The remaining steam will be condensed by sea water at 4 inches of mercury absolute pressure. The condensate is pumped to the deaerator in the boiler feedwater system.

Refrigeration Systems - Methane

The four streams utilized as refrigerants in the open-cycle methane systems are discussed above under "Natural Gas Liquefaction". Three of these streams enter the suctions of the methane compressor at their respective pressure levels, and the fourth stream is depressured to the plant fuel gas system.

The methane compressor system will be similar to that of the ethane compressor previously described. The compressor discharge will be cooled first by air coolers and then in the methane economizer exchanger before re-entering the main process stream upstream of the feed-methane condenser.

Like the propane and ethane compressors, the methane compressor will be a centrifugal machine and will be equipped with a recycle system to permit flow through the compressor to prevent surge. This arrangement will permit operation of the liquefaction train from zero to one hundred percent of capacity. As with the other compressors, a shutdown will automatically block-in the compressor system.

The steam turbine driver will be similar to that for the ethane system, except that only 16% of the steam will be extracted from the turbine at 65 psig to supply part of the low pressure process steam requirements, such as deaerators, gas treating plant, and desalination units. The remaining 84% will be condensed against seawater at 4 inches of mercury absolute pressure.

Refrigerant Production

A refrigerant production unit will provide refrigerant makeup for all of the liquefaction trains. This unit will consist of a demethanizer, deethanizer, and depropanizer system. The system will operate as follows:

Feed to the refrigerant production unit will be taken as a liquid from upstream of the feed-methane condenser in any of the liquefaction trains. It will be preheated and flashed to remove most of the methane. The remaining methane will be stripped out in the demethanizer and sent to fuel.

Demethanizer bottoms will flow to the deethanizer. The deethanizer overhead product will be the ethane refrigerant.

The deethanizer bottoms will flow to the depropanizer column. The depropanizer overhead product will be the propane refrigerant. The depropanizer bottoms will be chilled by the methane feed stream and reinjected to the LNG.

The propane will be stored in a conventional ambient temperature LNG storage tank. The ethane will be stored in a refrigerated storage tank designed for -80°F and a pressure rating of 85 psig. Propane and ethane refrigerant storage capacity will be sufficient to charge one liquefaction train.

(4) LNG Product Storage and Handling

The LNG Product will be stored in four aboveground storage tanks at a pressure of 15.2 psia and the corresponding equilibrium temperature of approximately minus 256°F. The LNG carrier loading facility will be capable of delivering an average LNG flow rate of 58,000 gpm to each of two LNG carriers simultaneously.

Storage

LNG product will be pumped from the final flash drum in each train through a common header to the LNG tankage area. The four storage tanks will be designed to handle the plant rundown (production) through a top-fill connection with an internal line extended to near the tank bottom to provide adequate mixing. Vapor flash and normal tank boil-off will be returned under tank pressure control through the vapor blower to the low stage methane compressor suction in the liquefaction plant. Normal boil-off from the tanks will be less than 0.1% per day.

To minimize pressure fluctuations caused by ship loading operations, the tanks will be individually pressure controlled. These controls will be maintained on an absolute pressure scale to avoid boil-off fluctuations with changing atmospheric conditions. However, gage pressure control will override the absolute pressure at the upper and lower pressure limits, for tank protection.

Safety pressure and vacuum valves, sized to handle the full emergency requirements will protect the tanks under extreme conditions. Redundant monitoring, automatic shut down and pre-alarming devices are installed to prevent emergency conditions from occurring.

Tank level monitoring will be accomplished by two float-type level transmitters (one operating, one spare) and one differential pressure type level transmitter, all with recording read-out in the central control room. In addition, a multi-point temperature probe with incremental and read-out capability will be provided. This multiple read-out capability allows early detection of stratification of tank contents. The tank rundown line and the LNG carrier loading line shut down systems can be manually or automatically activated in case of abnormal operating conditions.

Handling

Two fully equipped and independent LNG loading berths will be provided. The loading capacity of the system will be designed to handle the simultaneous loading of two LNG carriers.

Cooldown of the loading arms and the LNG ship tanks will be accomplished by two 50% capacity cooldown pumps. These pumps are designed to deliver a combined flow of 1051 gpm at a pressure of 60 psig measured at the ship's flange. An automatic minimum flow bypass control around the pumps will allow a turndown from 100% to 0%, to accommodate all foreseeable cooldown rates. This system will also be used to purge the ship's tanks of inert gas following return from dry-dock.

The loading operation will be started at low rates by gravity flow through the pump bypass valve. After the initially heavy boil-off vapor release has stabilized, the loading pumps will be started sequentially to satisfy the flow demand.

The LNG loading pumps will take suction from the bottom of the LNG storage tanks and supply the product at a nominal average rate of 58,000 gpm for each of two LNG carriers at a pressure of 40 psig measured at the vessel's flange. Eight parallel seal-less suction pot-mounted LNG pumps will be provided to handle the full loading rate; these eight pumps will serve all four storage tanks. These pumps will be locally started but can be stopped from each berth control panel in the control tower, the carrier, the central control room, the emergency shut down system, or locally. An automatic pressure control system on the pump discharge header will open a return valve to protect the LNG loading pump at low carrier loading rates. This will allow the loading operator to throttle the valves to the ship tanks without tripping the pump. Automatic shut down controls will be provided for additional pump protection.

The loading operation at each berth will utilize five 16-inch articulated loading arms--four liquid-handling and one vapor-handling. Each arm will be provided with an automatic shut-off valve to prevent LNG spillage during emergency conditions. The loading operation will be controlled from a fully instrumented control panel in a loading control tower overlooking the berth. All vital control instruments will be duplicated in the central control room. Product samples will be taken during the loading operation and analyzed for composition.

Displacement and boil-off vapors will be returned to the tankage system by two motor-driven centrifugal blowers. Vapor flash caused by pump energy input and pipeline heat leak will be minimized during the normal loading process by controlling the carrier tank pressure 0.4 psi higher than the storage tank pressure. Though only one blower will be used under normal loading operation, a second parallel blower is required during the cooldown operation.

The vapors will be returned to the storage tanks during loading operation on demand control. The returned vapors will replace liquid piped out of the tank. Excess vapors will be returned via the storage blowers to the liquefaction plant.

An emergency vent stack will be provided and sized to handle the maximum possible capacity during an unexpected emergency and an unexpected trip-out of the tankage vapor blower. This stack will also be used to vent the inert gas from the carrier tanks after return from dry dock.

After completion of the loading operation, the loading arms will be isolated and drained into the LNG drain collecting drum. The LNG will then be pumped back to the storage tanks. The LNG loading line will not be drained during interim periods; vapors caused by heat leakage will be returned to the LNG Plant, where they will be reliquified.

An emergency shut-down system will be provided, activated manually or automatically, to stop the loading operation and close the liquid arm isolotion valves. Automatic shut-down will be initiated by: ship movement at the pier beyond the limits of the loading arms; fires within or near the loading system; excessively high or low pressure in the ship cargo tanks; loss of air supply; and, in some tank designs, a low differential pressure between the cargo tanks and the insulation spaces.

1.6.2.3 Support Operations

The LNG Plant will be self-sufficient with respect to utilities. Operating supplies which must be brought in are shown in Table 1.6-3. Additionally, the plant will require spare parts and lubricants for the mechanical equipment.

DGA will be delivered in barrels to the plant and stored in a heated building adjacent to the DGA sump. For startup, propane will be shipped to the plant and stored in conventional LNG storage vessels. Catalyst and chemicals will be delivered to the plant by ship and barge and stored in the warehouse.

Natural gas from the feed stream will be used as required for fuel to generate the required electric power and steam. The plant will produce liquid and vapor nitrogen requirements. For startup, additional nitrogen required for purging will be purchased in liquid form.

Diesel fuel will be required for the operation of the personnel boats, plant rolling stock, and intermittently for various in-plant stand by equipment. The arctic grade diesel fuel will be delivered by barge and stored near the small boat harbor.

The utility systems for the LNG plant are described in the following sections.

Desalinated Water

Five packaged multiple-flash type desalination units will be used to meet the fresh water makeup requirements of the plant, since an adequate quantity of fresh water has not been identified. One unit will be spare. Each unit will produce 345 gpm of desalinated water (with a maximum salinity of 5 ppmw and total dissolved solids content of 15 ppmw) from 3,035 gpm of seawater taken from the discharge of the sea cooling water supply pumps. The remaining 2,690 gpm brine from each operating unit is returned to the sea through the sea cooling water discharge canal. The desalinated water is stored in an epoxy-lined cone roof tank (43,000 barrels capacity) and pumped to the systems shown in Table 1.6-4.

TABLE 1.6-3

CATALYSTS, CHEMICALS AND UTILITY REQUIREMENTS

Initial Charge

Molecular Sieve	1,008,000 lbs
Inert Support (1/4" - 3/4")	8,800 cu ft
Alumina	2,880 cu ft
DGA (100%)	66,900 gal.
Propane	600,000 gal.1/
Corrosion Inhibitor (e.g., Drewgard 100)	360 gal.
Fire Chemicals:	
Mechanical Foam Concentrate	10,000 gal.
Sodium or Potassium Bicarbonate	25,000 lbs
Fresh water2/	7,770,000 gal.
Nitrogen3/	3,210,000 lbs

Consumption4/

Molecular Sieves	336,000 lbs/yr5/
DGA (100%)	261,400 gal./yr
Corrosion Inhibitor	1,250 gal./yr
Anti-Foaming Agent	4,200 lbs/yr
Trisodium Polyphosphate	29,800 lbs/yr
Hydrazine (35 wt %)	1,970 lbs/yr
Sodium Hydroxide (25 wt %)	89,840 lbs/yr
Sulfuric Acid (93.2 wt %)	270,550 lbs/yr
Chlorine	4,746,470 lbs/yr
Arctic Diesel	460,000 gal./yr
Fire Fighting Chemicals:	
Mechanical Foam Concentrate	If needed
Sodium or Potassium Bicarbonate	If needed

1/Estimate eight - 75,000 gallon shipments.

2/Fresh water required to fill up the two fire water storage tanks. This will be made by the desalination plant.

3/Nitrogen required for three volume displacements of the four LNG Storage tanks and the process equipment prior to the initial start-up.

4/Based on a 345-day on-stream factor for each train.

5/Based on three year life.

TABLE 1.6-4

DESALINATED WATER MAKE-UP SUMMARY

SYSTEMS	DESIGN FLOW, GPM
Demineralizer Feed 1/	1,040
Fresh Cooling Water Make-up	80
Potable Water	125
TOTAL (for 8 trains)	1,245

1/ Demineralizer product water is used as boiler feedwater makeup.

Steam and Condensate

Three nominal steam pressure levels will be used:

High pressure steam at 1200 psig (900°F)
Intermediate pressure steam at 235 psig (saturated)
Low pressure steam at 50 psig (saturated)

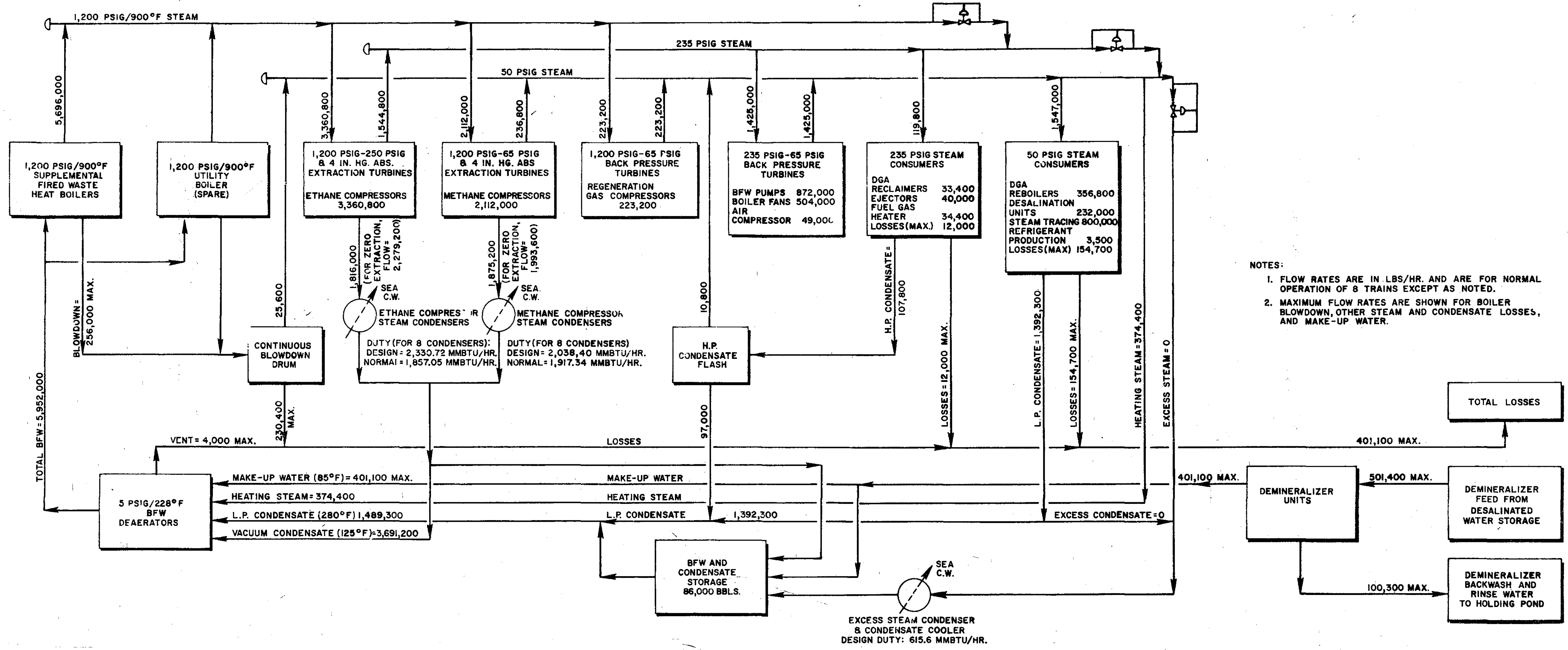
A supplementary gas-fired waste heat boiler for each train will generate a maximum of 800,000 lbs/hr of high pressure steam. An additional gas-fired utility boiler of the same capacity is provided as a spare and for start-up purposes. Exhaust gas from the propane compressor gas turbine driver will supply hot gas as a heat source to the waste heat boilers.

The block flow diagram in Figure 1.6-7 shows the steam and condensate distribution for the entire complex during normal operation. At design conditions, the quantity of steam generated in eight boilers will be 5,696,000 lbs/hr at 1200 psig and 900°F.

High pressure steam will be used to drive the eight ethane compressors and eight methane compressor extraction turbines. The exhaust steam from these turbines will be condensed at 4 inches of mercury absolute pressure against seawater and returned to the boiler feedwater deaerators.

Some ethane compressor turbine steam will be extracted at 250 psig to drive back pressure turbines for the boiler feedwater pumps, the boiler fans, and one air compressor. Steam will be exhausted from the back pressure turbines at a nominal 65 psig level to supply most of the heat required for the deaerators, DGA gas treating units, desalination units, and steam tracing.

Some methane compressor turbine steam will be extracted at a nominal 65 psig to balance low pressure steam requirements; low pressure steam will also be produced through condensate flashing and boiler blowdown flashing.



TRANS-ALASKA GAS PROJECT

LNG PLANT
STEAM & CONDENSATE SYSTEM

FIGURE 1.6-7

Boiler Feedwater

Condensate will be recovered for reuse as boiler feedwater. Makeup water will be supplied from the desalinated water storage tank and demineralized and then fed to the deaerators. Four boiler feedwater deaerators at 1,600,000 lbs/hr capacity each and two mixed bed polishing type demineralizer units at 830 gpm capacity each will be provided.

Each demineralizer is designed to produce a net of 830 gpm of demineralized water with a total dissolved solids content of 0.5 ppmw from 1040 gpm of desalinated feedwater; 210 gpm will be used for backwashing and rinsing one unit and then will be discharged to a waste water holding pond. The demineralizers will be designed to handle water containing 50 ppmw solids from the desalination unit; normal feedwater to the demineralizers will contain 15 ppmw total dissolved solids. The resin mixture in each demineralizer unit will consist of a strong acid cation resin which can be regenerated with sulfuric acid and a strong base anion resin which can be regenerated with sodium hydroxide. One unit will be operating while the other is being regenerated. During normal operation the feed streams to each deaerator will include the following:

Condensate from low pressure steam consumers and high pressure condensate flash drum,

Vacuum condensate pumped from the ethane and methane compressor turbine steam condensers,

Heating steam from low pressure steam header, and

Make-up water from the demineralizer.

A boiler feedwater and condensate storage tank will be provided to collect low pressure and vacuum condensate, and demineralized water not fed directly to the deaerators.

Seawater Cooling

Once-through seawater cooling will be provided as the main cooling media. Seawater will flow through an intake pipe to trash racks and moving screens in the pumping basins, and will then be filtered through automatic strainers at the pump discharges. Fourteen operating pumps and two stand-by pumps will be provided, each consisting of an individual suction basin, permitting maintenance shutdown of the basin, the moving screen, and the pump. These pumps are designed to supply the total sea cooling water, screen wash water, and desalination unit feed water requirements.

A chlorine system, consisting of a booster pump, chlorinators, vaporizers, and liquid storage cylinders, will inject chlorine into the seawater at the seawater intake, the pump suction, and the automatic strainers at a rate regulated so that the chlorine concentration of the effluent stream does not exceed 1 ppm.

Cooling water will be piped and distributed to the eight liquefaction units and the utility plant (see Figure 1.6-8). A shutoff valve will be installed on the seawater supply header to each liquefaction unit. Each seawater exchanger will be equipped with a mussel trap. The major sea cooling water users will be the propane condensers and the methane and ethane compressor turbine steam condensers. Seawater from the exchangers and brine from the desalination units will be returned to the ocean through a discharge canal and a dispersion header system. The total design flow for the seawater cooling system is 1,147,370 gpm. Table 1.6-5 is a summary of the cooling water requirements.

TABLE 1.6-5

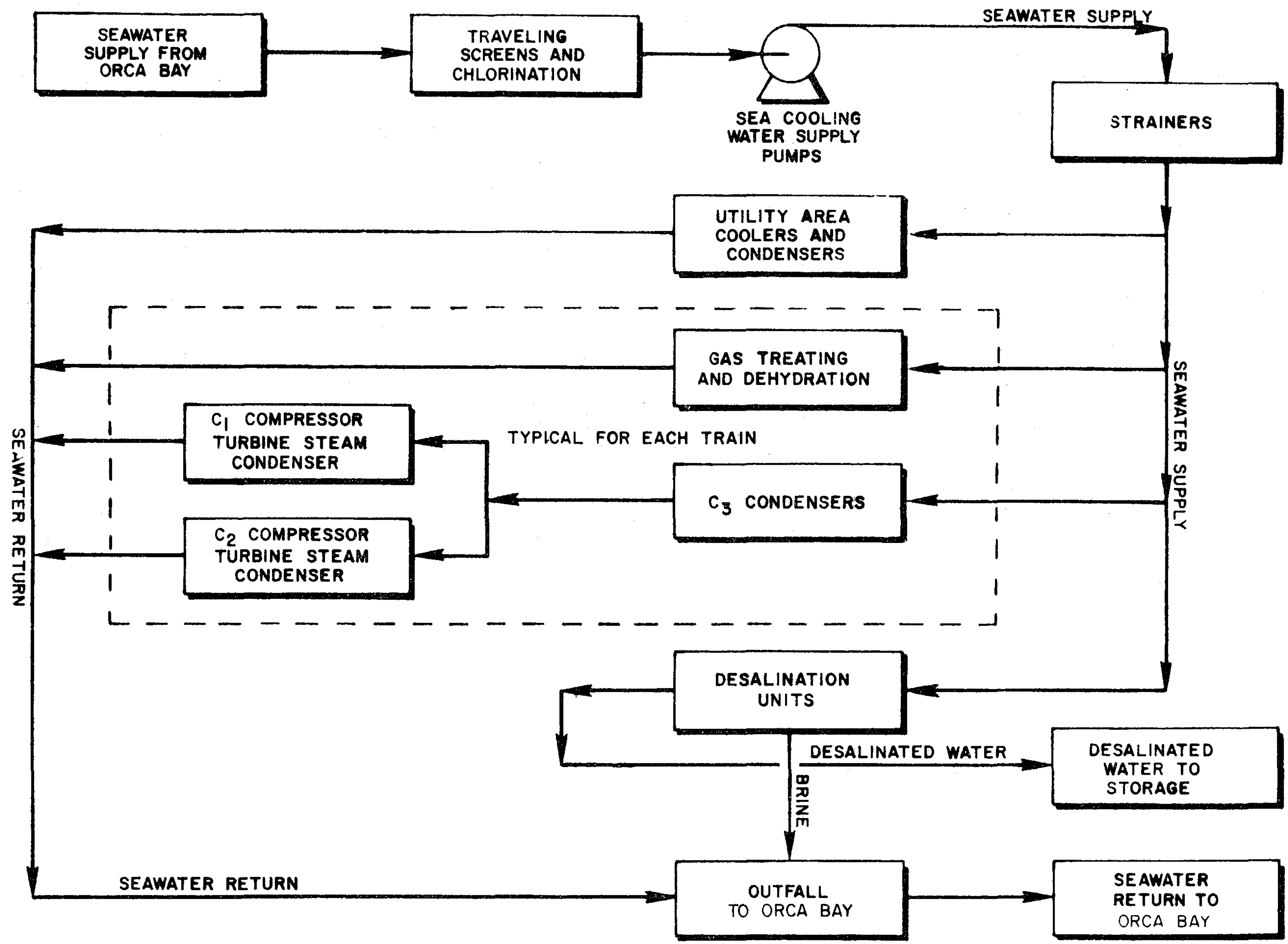
SEAWATER COOLING SUMMARY

Service	Design Flow, GPM	Cooling Water Temperature Rise, °F
Propane Condensers1/	1,048,700	7
Turbine Steam Condensers for Methane and Ethane Compressors1/	1,048,700	8.3
DGA Treating Coolers & Condensers	18,780	20
Utilities Coolers & Condensers	79,890	20
TOTAL (for 8 trains)	1,147,3702/	15.73/

1/Series flow through propane condensers and turbine steam condensers.

2/The sea cooling water pumps are designed to supply an additional 23,620 gpm for the total screen wash and desalination feed requirements.

3/The total average temperature rise including the brine discharged from the desalination units to the seawater discharge canal will be 16.1°F.



TRANS-ALASKA GAS PROJECT

LNG PLANT
SEAWATER COOLING
BLOCK FLOW DIAGRAM

FIGURE 1.6–8

Fresh Water Cooling

A closed fresh cooling water system will be required for the lube oil coolers of the propane, ethane, and methane compressors and compressor drivers. Make-up water will be supplied from the desalinated water storage tank.

Fresh cooling water at 100°F will be pumped to the users from the fresh cooling water storage tank (5,200 barrels capacity). The hot return water at 120°F maximum is cooled to 100°F using sea water in the fresh water/sea water exchanger. The corrosion inhibitors required will be added to the fresh cooling water storage tank. A summary of flows and temperatures is shown in the following table:

TABLE 1.6-6

FRESH COOLING WATER SUMMARY

Area	Design Flow, GPM	Cooling Water Temperature Rise, °F
Propane, Ethane, and Methane Compression (Lube Oil Cooling)	14,200	20
Utilities	2,000	20
TOTAL (for 8 trains)	16,200	20

Potable Water

Potable water for the plant process units, offsites, and administration building will be supplied from the desalinated water storage tank and pumped through carbon filters and an automatic hypochlorinator to the drinking water surge drum which will be pressured with clean plant air.

Electric Power

Eight electric power generators at 23.7 megawatt capacity each will be provided, including one spare. Each generator will be driven by a Frame 5 size regenerative cycle gas turbine to provide power at 13.8 Kv, 3 phase, 60 Hz.

One emergency diesel engine-driven power generator with 600 kw capacity will be provided. The emergency power generator will start automatically on total power failure in the plant and will supply power for emergency lighting, battery chargers (instruments), and electric motor-operated emergency shut-down valves.

Control systems and shut-down/interlock systems will operate on direct current and are therefore insensitive to power fluctuations.

The primary distribution voltage is 13.8 kv, with secondary distribution at 4160 volts and 480 volts. All substations supplying process or critical loads are double-ended to achieve the highest degree of power reliability and continuity.

Electric power requirements are listed in Table 1.6-7.

Fuel Gas

Fuel gas will be required as boiler and heater fuel and as the sole energy source to drive the gas turbines for the propane compressors and electric power generators. The exhaust gases from the propane compressor turbine drivers will be sent to the waste heat boilers to provide part of the boiler heat requirements. The remaining heat will be provided by supplementary gas-firing.

Approximately 65 percent of the average fuel gas requirements will be produced in the flash drums in the liquefaction trains. Flash gas from the DGA gas treating units will furnish less than 1% of fuel gas used, while pipeline gas will provide the remaining fuel requirements.

The difference between the average fuel gas consumption as shown in the fuel gas summary (Table 1.6-8) and conditions shown on the overall material balance (Figure 1.0-2) is due to refrigerant losses and losses in the DGA regeneration section.

TABLE 1.6-7

ELECTRIC POWER SUMMARY 1/

Area	Connected Load kw	Normal Operating Load kw	Operating Load When Loading Tanker kw
Gas Treating	4,570	2,500	2,500
Liquefaction	14,120	7,980	7,980
Refrigerant Production, LNG Storage, and Handling	12,440	1,720	8,980
Utilities and Off-sites 2/	114,080	93,740	93,740
Lighting	1,000	1,000	1,000
TOTAL kw (for 8 trains)	146,210	106,940	114,200
Average kw (8 trains)		109,840 3/	

1/ Motor efficiency = 92%

2/ Seawater cooling supply pumps are the major electric power users in the utilities and offsites area. Total connected load for these pumps is 104,960 kw, and normal operating load is 91,840 kw.

3/ Average = 0.6 (normal) + 0.4 (Tanker Loading).

TABLE 1.6-8

FUEL GAS SUMMARY[1/]

User	Fuel Gas Required For Average Operations Billion Btu/d (HHV)
Propane Compressor Gas Turbine Drivers	106.854
Supplemental Fired Waste Heat Boilers	139.281
Electric Power Generator Gas Turbine Drivers	29.943
Miscellaneous	10.538
TOTAL (all trains)	286.616

[1/] Fuel gas requirements are on an average calendar day basis. All eight trains will be operating simultaneously only 205 days of the year on the average; of the remaining 160 days, only seven trains will be in service.

Instrument and Utility Air

Two centrifugal air compressors will provide 100% of the required instrument and utility air. Each compressor will have a capacity of 3000 cfm at a discharge pressure of 140 psia. The operating compressor will be steam turbine-driven, and the spare compressor will be electric motor-driven.

Atmospheric air will be filtered before being compressed. Each compressor will have individual fresh water inter- and after-coolers. The two compressors will have a common air receiver with a hold-up time of two minutes at 3000 cfm. The compressed instrument and utility air will be prefiltered and dried in a dual column desiccant type dryer to a dew point of -45°F at 100 psig.

After-filters will be provided to prevent any powered desiccant from carrying over into the instrument and utility air header. Normal header pressure is 100 psig.

Nitrogen

Two packaged nitrogen generation units will be provided; one is a spare. Each unit will include a compressor, exchangers, a nitrogen separation column, a 5 metric ton liquid nitrogen storage tank, and a nitrogen vaporizer. Each nitrogen unit can produce 30,000 cf/h of nitrogen vapor at 150 psig and 120 lbs/hr of liquid nitrogen. The liquid nitrogen will be stored and used to provide for short duration peak demands of nitrogen.

A liquid nitrogen line will connect this facility with the LNG loading berths to allow transfer of up to 5 metric tons of liquid N_2 to the LNG carriers. Transfer of liquid nitrogen to the carrier is required only under abnormal conditions and is not a part of normal operations.

During normal operations, the plant will use an estimated average of 12,630 cf/h of nitrogen vapor, including 11,100 cf/h for the liquefaction facilities, and 1,530 cf/h for LNG storage and handling. Nitrogen will be used for purging of liquefaction cold boxes, the stem seals of electric motor operators for control valves and emergency shutdown valves, and miscellaneous electrical equipment.

After the loading of an LNG carrier, nitrogen vapor will be required to purge the loading arms. Nitrogen vapor for use in purging the loading arms and other berth facilities will be stored in a nitrogen surge drum.

Additional nitrogen storage tank trucks and vaporization facilities will be rented to provide nitrogen vapor for purging process equipment and LNG storage tanks during the initial plant start-up and during scheduled plant shut-downs.

Fire Fighting System

Primary water supply will be furnished by either of two fresh water gravity tanks with elevation sufficient to provide a minimum of 100 psig at the most remote hydrant. One fire water storage tank can provide a 12-hour supply of fresh water to the LNG storage and process areas at a flow rate of 7500 gpm. Another tank can provide a 6-hour supply of fresh water to the LNG loading berths and marine fire water system at a flow rate of 3000 gpm. A back-up fire water system will consist of three diesel engine-driven vertical fire water pumps which supply seawater to the fire water system. Each pump will have a capacity of 2500 gpm at 150 psig discharge pressure. The pumps will be located in a separate suction basin at the seawater pump station. Fire water will be distributed to strategically located hydrants and monitor nozzles by a looped, underground system of fire mains.

The pressure will be maintained in the system by static head from the elevated fire water storage tank. If the water level in the tank drops below 5 feet from the bottom, an alarm will sound in the central control room. The diesel engine-driven pumps will then be manually started to supply seawater to the fire water piping system. After each use of the back-up seawater supply system, the pipes will be drained of seawater and flushed and pressurized with fresh water. The seawater pumps will be tested using a bypass around the fire water piping system to avoid unnecessarily contaminating the piping with seawater.

The water spray systems will include monitor nozzles and fire hydrants located throughout the processing berthing and storage facilities. Automatic sprinklers will be provided in offices, warehouses, and other buildings. The water spray will extinguish non-hydrocarbon fires and provides a cooling medium for exposed equipment. Monitor nozzles at the loading berth will be also used to provide a water spray for promoting the dispersion of vapors in the event of an LNG spill. The fire water system on the loading platform will be compatible with the system on the LNG carrier to provide mutual assistance in case of failure of one system.

Dry chemical or Halon fire extinguishing equipment will be contained in five portable trailer units: two for the LNG loading area, one for the pumping station, one for the process area, and one for the LNG storage area. Fixed-nozzle, self-contained dry chemical or Halon extinguishing systems will be located at each LNG loading platform and each building containing gas compressors or LNG pumps.

In addition to fire hydrants, monitor nozzles, and dry chemical or Halon systems, a mechanical foam application system will be provided to blanket the LNG storage tanks for fire protection. The mechanical foam system will thus provide protection to tanks exposed to radiated heat from a nearby fire. The foam system will consist of one portable foam generating truck and fixed piping and foam distribution nozzles for each LNG storage tank. To utilize the foam system on any one tank, the foam generating truck will proportion an appropriate amount of foam concentrate into the firewater system branch line serving that tank. The solution will then flow through the fixed piping and exit as foam at the tank top through foam distribution nozzles. The foam proportioning and injection point for each tank will be located at a safe distance from the LNG tanks to ensure operator safety. The capacity of the system is designed to cover one LNG tank top with a 3% foam solution at a density of 0.10 gpm per square foot for one hour.

Numerous hand-operated CO_2 extinguishers and breathing apparatus are located throughout the plant. Additional fire prevention systems are discussed in Section 1.6.2.7.

Other Supporting Systems

Relief System

Pressure relief gases will be burned in an elevated smokeless flare stack. Two separate flare stacks will be provided, one for relief of high pressure pipeline gases, and one for relief of process plant gases.

The process plant pressure relief header will collect gas from the sub headers from all trains and will be sloped toward a common knockout drum to facilitate draining of condensate from the header. Cold gases such as refrigerants will pass through a cold knockout drum and will be heated prior to entering the common knockout drum. Gases from the common knockout drum will pass on to the flare stack.

The waste gases (consisting primarily of CO_2) from the DGA gas treating units will be discharged to the atmosphere through a vent stack.

An emergency vent stack will be provided at the storage area and designed to handle low pressure (slightly above atmospheric) emergency venting requirements from the LNG tankage and loading facility.

DGA Storage

Aqueous 65% DGA solution for all of the trains will be pumped from the 8,000 gallon DGA solution make-up tank to the DGA surge tank in each train. A 12,000 gallon DGA sump will be provided with a capacity to hold the DGA solution content of one complete train.

DGA will be added to the sump by gravity flow from individual drums in a heated building adjacent to the sump. Solution concentrations will be manually monitored. The DGA solution will be filtered before being sent to the DGA makeup tank to remove any particulates picked up in the sump.

Diesel Fuel Storage

Arctic grade diesel fuel shipped in by barge for the use of personnel and work boats will be stored in a tank at the small boat harbor. Fueling facilities at the plant garage and other miscellaneous requirements will be served by a tank truck from the small boat harbor.

Small arctic diesel fuel containers will be included as an integral part of emergency equipment, such as the emergency diesel-driven firewater pump and the emergency power generator. All storage containers will be equipped with level indicating and low level alarming devices and will be protected by relief valves against over-pressure.

Instrumentation and Controls

The natural gas liquefaction facility is designed for remote control from one centrally located control building. The control panel in the control building will be of the free standing "post office box" type. A removable graphic process display will be provided for the compressors, utilities, and loading berth stations. Essential control information on the local panels will be duplicated on the central main panel.

The control instrumentation will be standard miniature electronic type with signal ranges of either 4-20 ma or 10-50 ma direct current. A complete battery powered DC back-up system will be provided in case of failure of the main power supply systems.

Continuous analytical instruments will be used where necessary, for stream analysis, moisture and carbon dioxide measurement to provide process monitoring. Compressors and turbine drivers will be equipped with electronic vibration, axial position and bearing temperature monitoring equipment.

Control valves will be pneumatically operated. Bypass and block valves will be supplied for control valves in severe and critical service. Valves in services experiencing low pressure drop and freedom from corrosion and erosion potential will not be supplied with a full block and bypass station. Wafer type butterfly valves with tight shut-off sets will be used for cryogenic lines in the storage and loading areas.

Emergency shut-off valves of all sizes, and operating valves in cryogenic service sizes 8 inches and above will be equipped with power operators, while maintenance-type block valves will be manually operated. All emergency shut-off valves and some vital normal operating valves can be remotely operated from the central control room and from local push-button stations. Valve position lights in the control room indicate the closed, open or in-transit condition. Power operators for all emergency shut-down valves will be connected to the emergency power supply system as back-up. In addition, a handwheel will be supplied for all motor operated valves to stroke the valves manually in case of total power outage.

Electronic interlock relays, shut-down systems, solenoid valves and other systems vital to safe and uninterrupted plan of operation will be powered from a reliable 48 V DC battery system to withstand any possible power dip or power outage.

Field mounted instruments and control components will be protected against the weather. In general, electric heat tracing will be used when required.

1.6.2.4 Maintenance Procedures

The LNG Plant is designed to produce LNG 365 days per year. Project basis is for each of the eight trains to operate 345 days per year to deliver the supply of 2864 MMcf/cd of LNG equivalent net to the tanker. Equipment essential to production will be spared. The design stresses reliability of operation for continuity of LNG deliveries. This includes an allowance of 20 days per year per train for downtime. Scheduled downtime is assumed to be 15 days. The remaining 5 days are allowed for unscheduled downtime. Since each of the trains can operate independently, scheduled maintenance will be performed on one train at a time.

Instrument readings will be monitored and performance estimates made to determine which equipment is losing efficeincy or showing signs of wear; this equipment will then be scheduled for maintenance. Equipment which is spared or not required for continuous operation will be shutdown and maintained while the plant is in operation.

No unusual maintenance problems are anticipated for the liquefaction unit. The cryogenic equipment will operate under clean and corrosion-free conditions at the low operating temperatures involved. Provisions will be included for deriming (thawing) of cryogenic equipment if required.

The equipment items expected to require the most maintenance are the steam turbines, steam supply system, and the hot section of the gas turbines. The equipment manufacturers recommended inspection intervals will be followed to avoid unscheduled interruption of liquefaction plant operation. Scheduled maintenance on these items will be performed during the annual shut-down period.

Corrosion can create a maintenance problem if adequate allowance is not made in the design. The parts of the plant which might experience corrosion are the DGA gas treating facilities and the sea water cooling system. This corrosion will be minimized by the use of proper materials and linings where required. Corrosion inhibitors will be added to the DGA system.

Maintenance of the marine LNG loading equipment, such as the LNG loading pumps and the loading and vapor return arms will be performed between scheduled periods of operation.

The LNG storage tanks will be relatively free from maintenance because the contents are essentially non-corrosive. Maintenance on associated equipment, such as testing of relief valves and foundation heater adjustments, will be accomplished without taking the tanks out of service.

Proper maintenance procedures are important for the protection of plant personnel. Maintenance and inspection will be carried out only by authorized personnel who are adequately trained and fully aware of the safety hazards of the operations to be conducted. Ignition sources, such as gas or electric welding equipment will not be used in maintenance operations until the surrounding atmosphere has been checked and found safe. If welding or cutting operations are to be done on vessels or piping which have contained flammable or toxic gases, they will be purged with nitrogen to a safe condition. Vents and drains will be provided on all equipment to facilitate this purging. Care will be exercised to ensure that sparks or molten metal do not drop or spatter into adjacent, unsafe areas when welding or cutting is being done. Whenever practical, equipment will be removed and maintained in shop areas.

Accessibility to equipment is an important consideration in the design of an easily maintained plant. All equipment will be designed, constructed and installed in such a way that it will be readily accessible for maintenance or can easily be removed to the maintenance shop.

To insure against extended downtime for maintenance, long delivery spare parts for machinery will be warehoused at the facility.

Maintenance is a consideration in the design and procurement of all equipment. Interchangeability of parts between equipment, specification of common sizes of exchanger tubes, interchangeability of instrumentation components etc., are all considerations which minimize the quantity of spare parts stocked and the corresponding investment in inventories, while providing an adequate supply to keep the plant operating.

A well-trained plant maintenance force and well-equipped shops will be provided for conducting maintenance on plant equipment consistent with operating requirements.

1.6.2.5 Waste Products and Disposal Systems

Waste Water System

The waste water streams will be collected in a holding pond (60 ft. wide x 320 ft. long x 10 ft. deep) and analyzed and discharged to the bay if in compliance with regulations. The waste water streams collected in the pond will include treated sewage effluent water and non-oily effluent water. The proposed waste water system is shown in Figure 1.6-9. A summary of waste water flows, compositions, and temperatures is presented in Table 1.6-9 for average conditions unless otherwise stated.

Raw sewage will be collected in an equalization tank to smooth out surges in flow, and will then be sent to an activated sludge unit to reduce biological oxygen demand (BOD). Activated sludge treatment will be followed by chlorination for disinfection. The biological oxygen demand, suspended solids, and chlorine concentrations in the treated effluent will comply with Federal and State of Alaska regulations before the treated effluent is discharged to the holding pond. Off-specification material will be recycled back through the activated sludge unit or the chlorination unit, according to the treatment level required. The equalization tank and activated sludge unit are included in the block labeled "Sanitary Effluent Treating" on the waste water system diagram. Compressor house drainage systems will collect oily drips and drains from the normal operation and maintenance of the compressors. The drainage system effluent will be routed through a coalescing medium for oil removal before being blended with the raw sewage upstream of the sewage treating facilities. A storage sump immediately downstream of the coalescer will provide hold-up of the effluent for oil content testing. In the event there is a break-through of oil, off-specification material will be recycled back through the oil removal system.

Good housekeeping and proper operation of oily water drainage systems will ensure that water drained to the holding pond is not contaminated with oil. Oil skimmers will be provided at the pond as an additional safeguard, but they are not expected to be used during normal operation.

In addition to the combined effluent stream from the sewage treating facilities, the following non-oily effluent water streams will be discharged directly to the holding pond: boiler blowdown, process area and tank farm storm sewer effluent water (mostly rainfall run-off), fresh cooling water losses, and demineralizer backwash and rinse effluent water.

The holding pond will serve as an equalization basin to smooth out surges in effluent water flows and composition and to allow settling of suspended solids. The pond will be designed to provide a retention time of approximately 2-1/2 hours at the maximum design waste water flow rate of 8,867 gpm. Ninety percent of this design flow is rainfall run-off from tank farm and process area storm sewers during the maximum expected rainfall rate of one inch in one hour. At other times the effluent retention time in the holding pond will be much longer than 2-1/2 hours.

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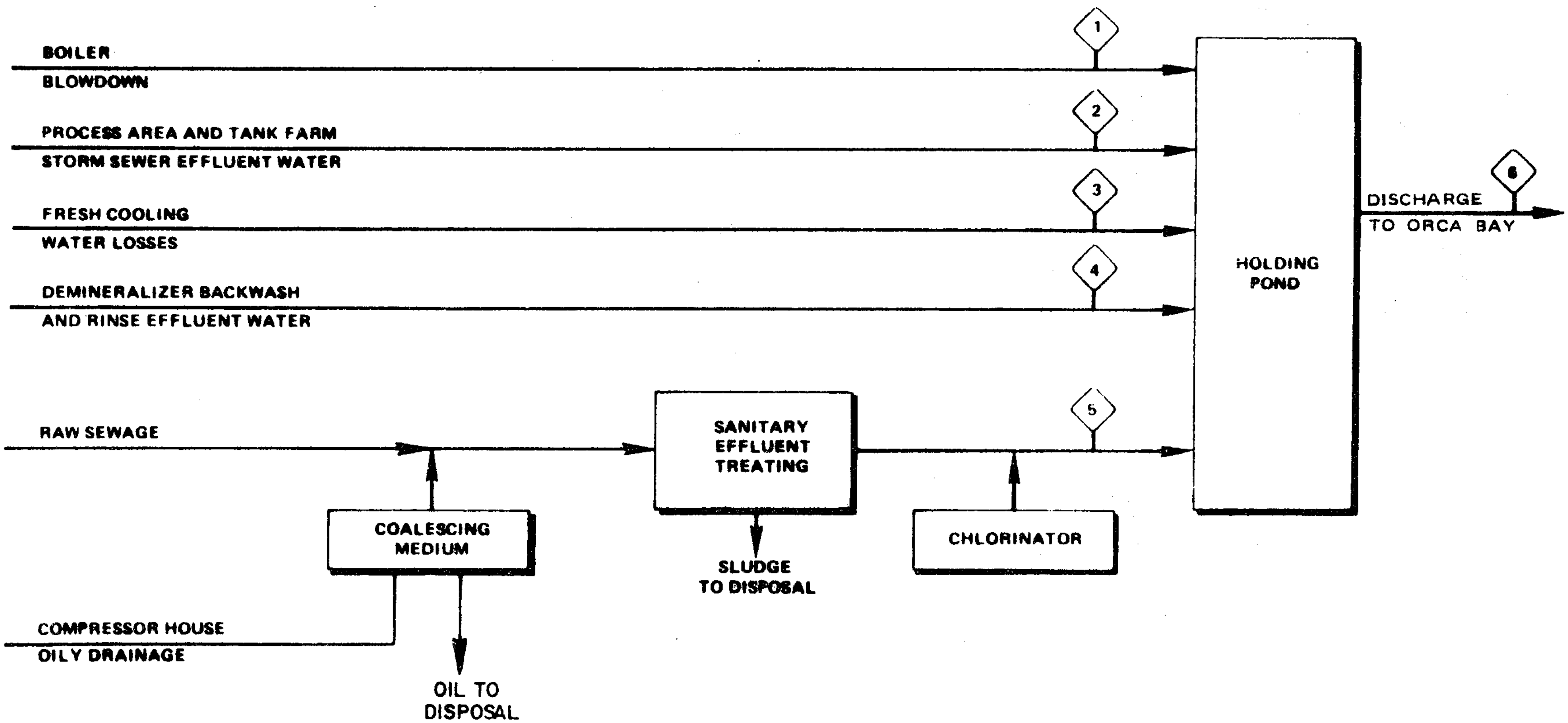


LNG PLANT
WASTE WATER SYSTEM

FIGURE 1.6-9

TABLE 1.6-9

WASTE WATER SUMMARY [1/]

Component	Stream Number[2/] 1	2[3/]	3	4	5	6
Flow, gpm						
Average	120	1000	0	30	19.5	1169.5
Normal	100	600	0	25	13	738
Design	512	8000	80	210	65	8867
Temperature, °F	100	50		70	70	56
pH	7.0	7.0		7.0	7.0	7.0
BOD, ppmw					25	0.4
Phosphate ($PO_4^{\equiv}$), ppmw	15					1.5
Chloride (Cl^-), ppmw	20	10		25	25	12
Oil and grease, ppmw		<1				<1
Suspended Solids, ppmw	15	100			20	5 [4/]
Total Dissolved Solids, ppmw	200	25		100	450	52

[1/]Values given are for average conditions unless otherwise stated.

[2/]See Waste Water System flow diagram on preceding page for stream identification.

[3/]This stream is made up primarily of rainfall runoff drained to storm sewers in the process area and tank farm.

[4/]Most of the suspended solids settle out in the holding pond.

The holding pond will be provided with an automatic pH recorder-controller to maintain the pH of the pond effluent water between 6.8 and 7.2. This water will be further analyzed for other parameters, including BOD, dissolved oxygen, oil and grease, suspended solids, color, and odor, and will then be discharged to the bay. The quality of the water discharged from the holding pond will comply with Federal and State of Alaska regulations.

Storm water runoff from areas outside the tank farm and process areas will be discharged directly to the bay through concrete-lined channels.

Air Quality

Clean burning fuel gas from the LNG Plant and the pipeline will be used as the sole energy source to drive the gas turbines for the propane compressors and electric power generators. The exhaust gases from the propane compressor turbine drivers will be discharged to the waste heat boilers to provide part of the boiler heat requirement. The remaining heat will be provided by supplementary gas-firing. Fuel gas will also be used for all fired process heaters. The electric power generator turbine exhaust gases and the waste heat boiler and process heater flue gases will be discharged to the atmosphere from elevated stacks.

There will be five sources of emissions from the plant to the atmosphere (including non-polluting emissions):

Particulates, nitrogen oxides and sulfur dioxide in the flue gases from the gas-fired equipment,

Hydrocarbon vapors (mostly methane) from the LNG tankage area emergency vent stack,

Waste gases (mostly carbon dioxide) from vent stacks in the DGA units,

Burned process and pipeline relief gases from the elevated smokeless flare stacks, and

Oxygen-enriched waste gas from the nitrogen production facilities.

Particulates, Nitrogen Oxides, and Sulfur Dioxide

Continuously operating equipment will be fired by fuel gas, for which particulate emissions are essentially zero. Diesel fuel, which will be used for certain minor functions such as operating the emergency generator, the emergency fire pump, and the personnel boats, will provide only minor contributions of particulates to the atmosphere.

The only significant nitrogen oxides (NO_x) emissions will be in the flue gases from the process heaters, boilers, and power generator gas turbines. The best available emission reduction techniques are used in the design of this equipment to minimize NO_x emissions.

The fuel gas to be burned has a sulfur content of less than 1.0 grain per 100 SCF and SO_2 emmissions will therefore be minimal.

A summary of stack emissions from the gas-fired equipment is shown in Table 1.6-10.

Hydrocarbons

The process units will be designed to avoid emissions of hydrocarbon vapors to the atmosphere. During upsets, however, hydrocarbon vapors may be discharged through the process plant pressure relief header to an elevated smokeless flare stack for burning. A separate flare stack is provided for burning of pipeline relief gases.

The tank farm is a potential source of hydrocarbon emissions. However, the storage facilities for propane, ethane, LNG, and for aqueous DGA solution are designed according to EPA guidelines to minimize these emissions.

LNG will be stored in aboveground, double wall storage tanks. Vapors (mostly methane) from LNG storage vessels will normally be compressed and returned to the suctions of the methane compressors in the liquefaction trains. During an upset such as the shutdown of the methane compressors, the vapors may be vented to the atmosphere through the emergency vent stack at the LNG tank farm.

The low vapor pressure DGA solution (less than 0.5 psia at storage conditions) is stored in a cone roof nitrogen-blanketed tank. The DGA system will include a closed sewer system for collecting drips and drains to minimize DGA emissions to the atmosphere; however, small quantities of hydrocarbons will be emitted from the DGA unit.

Mechanical seals will be used on pumps and compressors, and valve packing and gasketing materials will be carefully selected to minimize or eliminate hydrocarbon leakage to the atmosphere. In addition, LNG pumps will consist of the submerged, seal-less suction pot mounted type.

Waste Gases

The primary source of carbon dioxide emissions, other than from the stacks of gas-fired equipment, will be the DGA units. Waste gases from the regenerator overhead accumulators in these units will be vented directly to the atmosphere and will have a composition of 92.12

TABLE 1.6-10

STACK EMISSION SUMMARY FOR
AVERAGE OPERATION1/

Service	Total Units Operating	Excess Air % wt.	Stack Height, ft.	Total Heat Release, MMBtu/hr (HHV)	Total Flue gas Rate, MM lb/hr	NO_x (as NO_2)2/	
						lb/hr (Total)	lb/MMBtu
Gas Turbines for Propane Compressors	8	287				3/	3/
Supplemental Fired Waste Heat Boilers	8	120	150	10850 4/	13.76	2170	0.20
Gas Turbines for Electric Power Generators5/	6	287	100	1304.1	3.738	900	0.69
Regeneration Gas Heaters	8	20	100	111.3	0.106	22.4	0.20

1/Stream-day basis (345-day on-stream factor for each train). Operations when loading an LNG tanker will make up 40% of the operating time. Average fuel gas composition will be: 7.29% mol N_2, 0.46% CO_2, 87.83% C_1, 2.89% C_2, 1.32% C_3, 0.21% C_4+, and total sulfur content less than 1.0 grain/ 100 SCF.

2/Based on waste heat boilers and process heater manufacturers meeting the EPA "New Source Performance Guidelines" of 0.20 lb. NO_x/MMBtu for gaseous fuel burning equipment for steam generators of 250 MMBtu/hr heat input or larger.

3/Propane compressor turbine exhaust gases will be discharged to the supplemental fired waste heat boilers.

4/The total heat release from supplemental gas firing in the waste heat boilers is 6140 MMBtu/hr. Waste heat from the propane compressor turbine exhaust gases will provide an additional 4710 MMBtu/hr to the boilers.

5/Gas turbine generators will be designed to meet Alaska or EPA emission standards.

volume percent carbon dioxide, 6.8 percent water vapor, and 1.08 percent hydrocarbons. The venting rate of these waste gases will be 182,800 lbs/hr for all DGA units.

Oxygen-Enriched Waste Gas

Oxygen-enriched waste gas will be vented to the atmosphere from the proposed nitrogen production units, in which nitrogen is separated from air to meet purge gas requirements. The normal venting rate will be approximately 1030 lbs/hr total.

Odors

Odor-producing materials, such as asphalt, aromatics, and phenols, will not be present in any of the streams processed in this plant. The hydrocarbon emissions previously discussed will all be essentially odor free.

Solid Wastes

Sludge from the DGA and the activated sludge treating units will be disposed of by approved methods. Since the amount of sludge involved is small, the minor land area required will be within the plant boundary.

Refuse from plant operating personnel will be disposed of in approved land fill sites or will be incinerated. Solids from packaging of materials required for plant operation will be either recycled or disposed of along with non-sewage refuse from the plant.

Spent desiccant will be disposed of in land fill areas on the plant site at three to five year intervals and will not be a significant disposal problem. Estimated quantities of solid effluents are shown in the following table.

TABLE 1.6-11

SOLID EFFLUENTS TO DISPOSAL

Material	Quantity, lbs/year
Sludge from DGA and activated sludge treating units	40,000
Solid refuse from plant operating personnel and materials packaging	338,000
Spent desiccant	336,000

Noise Control

Noise levels will be maintained within the limits required by the Federal Occupational Safety and Health Act (OSHA) of 1970 by means of engineering controls which will reduce the sound intensity either at the source of the noise or in work areas. Where this is not feasible, administrative controls will be developed to limit the worker's time of exposure to those specified by OSHA. Where neither engineering nor administrative controls can reduce noise levels to acceptable limits, personnel protective devices such as earmuffs or earplugs will be used.

When final equipment selections are made, the following additional steps to control noise will be incorporated: mufflers on vents, jets, compressor inlets and outlets, and control valves; reducing airfan noise by using more blades and lower speeds; using totally enclosed motors or insulated wraps on motor cases; inlet mufflers and/or insulated ducts for boiler burners; and sound-insulated operating stations for full time working exposure in areas above 90 dBA. During and after startup of the complex, noise levels will be monitored to determine if and where additional noise control is required. The following table outlines typical limits that are applied to noise level design:

TABLE 1.6-12

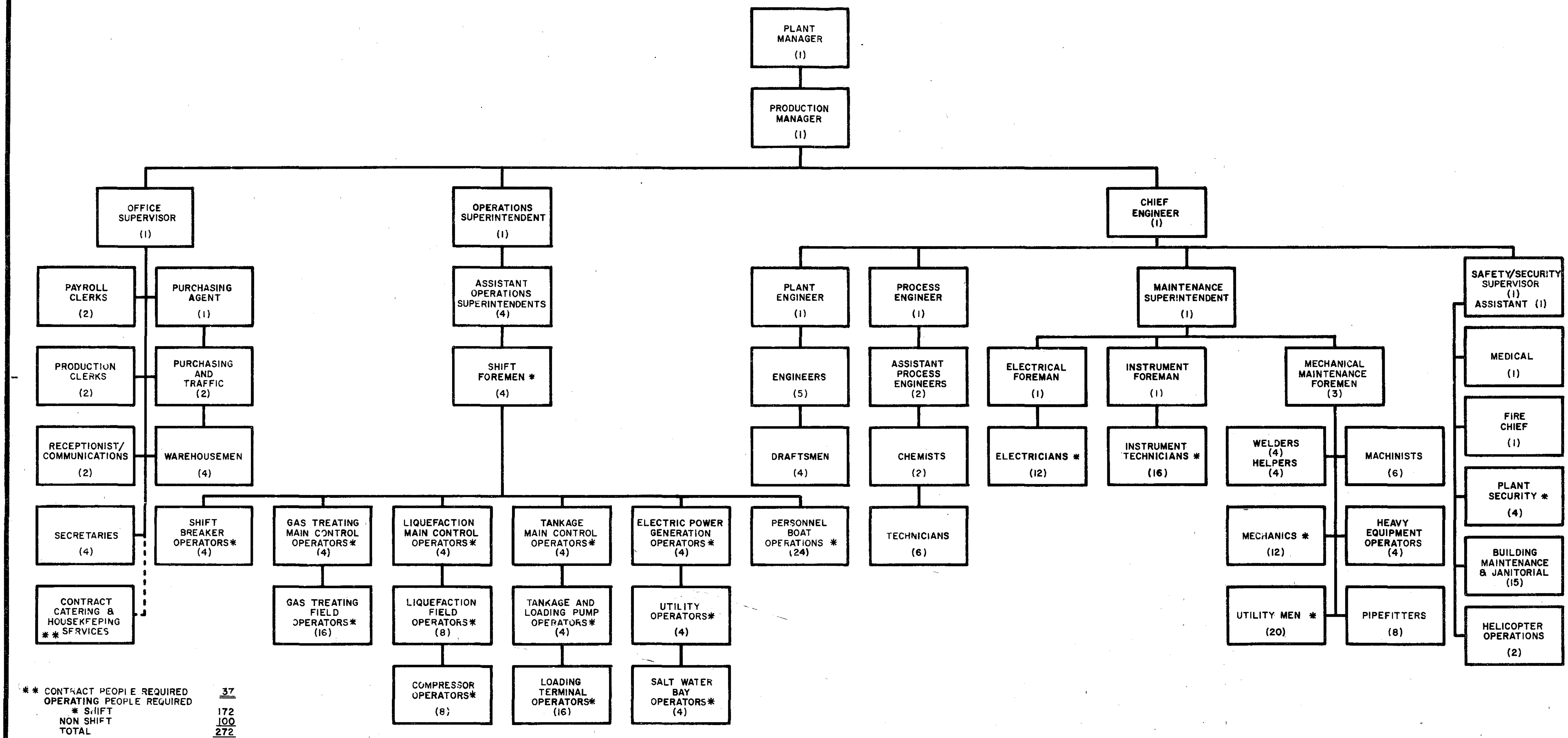
TYPICAL DESIGN NOISE LEVEL LIMITS

Facility	Continuous Noise Limit (in dBA)
Control rooms and offices	55
Boundary of complex	65
Within 5 feet of regular working area	85 - 90
Occasional working area	95
Infrequently occupied areas within plant	105

1.6.2.6 Manpower Requirements

The LNG Plant organization for operations and maintenance manpower is shown on Figure 1.6-10. A total of 272 operating employees will be required, while catering services will add 37 persons for a total of 309 assigned to the LNG Plant. This number does not include operating personnel for the marine facility (see Section 1.5.3) for ship handling, for operation of tugs and mooring launches, for marine service facilities, or for administrative personnel.

Sixty-five permanent homes will be provided for key operating personnel at the housing complex 3/4 miles west of the plant. Others will reside in the Cordova area.



TRANS-ALASKA GAS PROJECT

LNG PLANT
OPERATING MANPOWER

FIGURE 1.6–10

1.6.2.7 Capacity to Withstand Unusual but Possible Natural Phenomena and Accidents

Safety is a major consideration in the design of the entire LNG Plant. Safety elements considered in the design include detection of fire and/or presence of combustible vapors, high pressure relief and emergency venting, containment and control of LNG spillage and leaks, emergency shutdown systems, seismic considerations, noise control, adherence to applicable design codes, and personnel training. These safety considerations are discussed in more detail in the following paragraphs.

Fire Prevention

To protect the LNG Plant from fire, automatic ultraviolet flame detectors and combustible vapor detectors will be strategically located throughout the plant facilities. Detection of either fire or combustible vapors at any of these locations automatically will send an alarm to the central control room. These automatic detectors will be periodically checked for operability. Portable equipment will be used periodically to detect combustible vapors at less critical locations. In this manner, minor leaks will be detected and repaired before they can cause an emergency.

Fire control facilities in the LNG Plant site will consist of water spray, mechanical foam, dry chemical or Halon, and hand extinguishers. A detailed description of and control facilities is presented in Section 1.6.2.3, Support Operations.

All plant piping will be continuously grounded to protect against lightning and to prevent flowing LNG from building up static charges. Insulated flanges, bonding cables, and ground rods are used for tanks supported on non-conducting foundations. Piping, valves and fittings are of materials having required impact resistance at LNG temperatures. Provisions will also be made for thermal expansion and contraction by installation of bellows, expansion joints, and expansion loops. Block valves will be situated so that major areas of piping and equipment can be isolated in case of leaks. Relief valves will be provided between block valves to protect from possible over-pressure resulting from thermal expansion. Process fluid, high pressure steam, fire protection, and other critical piping will be identified by color coding, painting, or labeling.

Vehicles will operate only at low speeds and will be equipped with spark arrestors.

The control building will be constructed of fire resistant material, and will be kept under positive pressure which will be continuously monitored. No combustible process gases will be brought into the control room.

Venting

High pressure relief and emergency venting are important design considerations of the plant safety systems. During unusual or emergency situations, such as power failure or fire, it will be possible for the pressure of processing streams to increase above the normal working pressure. Accordingly, all pressure vessels will be provided with safety relief valves designed to operate at or below the maximum allowable working pressure of the vessel. In general, the hydrocarbon relief valves will exhaust to a closed relief header system and will be then discharged to an elevated flare stack, or they will be vented (without burning) at a safe height above the plant. The gases that are vented to the atmosphere without burning will originate primarily from the LNG storage and loading facilities, which will operate at a pressure too low for discharging vent gases to the flare stack. The vent stack diameter and height will be sized to ensure safe dispersion in the atmosphere. Lightning protection and location of the vent stack minimize the possibility of vapor ignition by lightning discharge. Nitrogen snuffing will be provided.

The LNG Plant design will incorporate a means of safely shutting down vital operations within the plant in the event of an emergency. The DGA gas treating facility will include automatic feed gas diversion to the flare system in the event that DGA circulation should cease. A flare header vent valve will be included in the dehydration facility on the gas header leading to the liquefaction section. The gas stream will be manually diverted to the flare header in the event that feed gas to the cryogenic section does not meet inlet specifications. Protection of the regeneration gas heaters in the dehydration facility during this venting operation, will be provided by monitoring equipment and control instruments to stop burner fuel flow in the event of high temperatures or low regeneration gas flow. Automatic shutdown will also occur at flame failure or low fuel gas pressure.

Spills and Leaks

Containment and control of LNG spillage and leaks is a major safety consideration in the design and operation of an LNG facility. Operational experience in existing LNG facilities has shown that no failures have occurred in large storage tanks containing LNG when they are constructed of proper materials to withstand cryogenic conditions. The tanks will be designed to withstand severe rain, snow, and earthquakes. Provisions will be made in the design for diked containment of the LNG. The bi-level diked area will contain more than the one tank volume. An LNG spill would flow through a trapezoidal channel from the diked area surrounding the tanks to the lower level diked area. This diked area will contain a low point sump designed to hold the LNG volume of a ten-minute duration spill from an assumed ruptured loading line at the tank. Spilled LNG within the dike will be dissipated by boil-off to the atmosphere. An automatic drainage valve will be used to keep the diked area free of rain water and snow melt.

LNG storage tank safety must also consider the possibility of stratification and subsequent "rollover", a term used to describe the sudden evolution of a large quantity of vapor within a storage tank. The phenomenon of rollover can occur in an LNG storage tank when two layers of LNG of different densities are not adequately mixed. To avoid stratification, the fill connection will be piped to the bottom in order to mix the tank contents. Operations will be monitored by comparing temperature and density of the LNG already in the tank with the LNG being sent to the tank.

To protect the storage tanks from possible overpressure caused by fire exposure or blocked discharge conditions, the tanks will be equipped with pressure relief valves set at the maximum allowable working pressure for the tank. These valves will discharge directly to the atmosphere. In addition, vacuum safety valves will be installed to protect the tank from a possible underpressure condition. Activation of these safety valves is extremely unlikely. An absolute pressure control system will maintain constant tank pressure even with changes in atmospheric pressure conditions. Gauge pressure instruments will be employed to override the absolute pressure instruments before the safety valves would be activated. Gauge pressure override could occur during periods of extremely sudden atmospheric pressure variation. High and low pressure switches will close the shut-off valves in the tank fill or emptying lines in case of failure of both pressure control systems, thus adding another dimension of safety to the pressure safety system.

Emergency Shutdown

An emergency shutdown system will be provided at the LNG product loading facilities to protect plant and personnel in the event of an LNG spill, fire or other emergency. All vital locations within the proposed LNG product storage and loading facilities can be isolated in emergency by means of remotely controlled valves. These valves will be located in the product line from each LNG storage tank, at each LNG loading pump, at each cool-down pump, at each vapor return blower, and on the loading line at the approach to both loading berths. To prevent potentially dangerous pressure surges during shutdowns, valves will be programmed for sequential closure at controlled rates. In the event of complete power failure, the normally motor operated valves could be operated by hand.

Emergency shutdown systems for both the ship and the loading facility can be manually activated from the carrier, the control building, or from the loading control tower at the berth. Automatic activation of the emergency shutdown system will be triggered by excessive LNG carrier movement during the loading operation or by high pressure in the LNG carrier tanks.

Automatic control systems will be provided with manual override so that control valves and process equipment can be manually operated from the control house and appropriate local control panels. Instrumentation will be designed so that in the event of a power or instrument air failure, the system goes into a fail safe condition that is maintained until operators take action. Electric interlock relays, shutdown systems, solenoid valves and other systems vital to safe and uninterrupted plant operation will be powered from a reliable 48V DC battery system to withstand any possible power reduction.

Communication to the control building by telephone or two-way radios will be provided throughout the plant to enable operators to activate fire fighting equipment, stop the flow of liquid gas and sound emergency alarms from within the plant without having to return to the control room. Communications will be provided from the LNG loading berth to the control building, pumping station, and carrier.

Seismic

Design of the facility to withstand seismic forces requires consideration of the direct and indirect effects of earthquakes, and must also consider local geology and soils conditions. The direct effect is vibratory ground motion, while indirect effects include landslide, subsidence, soil liquefaction and tsunami wave generation.

The preliminary seismic design is based on an effective bedrock acceleration of 0.60g for the maximum ground motion to which the most important equipment in the facility can be exposed without loss of fluids from storage tanks or processing equipment. Equipment designed on this basis (using dynamic analysis techniques) is capable of withstanding an earthquake of magnitude 8.4-8.6 on the Richter Scale (such as the 1964 Prince William Sound earthquake). A factor of 0.3g will be applied to other facilities. The above seismic design criteria are tentative, selected with the purpose of supporting preliminary design and cost estimates.

Careful location of the facility and adequate site preparation will minimize the risks of vibratory ground motion, landslide, subsidence and soil liquefaction. Location of the onshore facility at a high elevation will eliminate the risk of tsunami damage.

Training

All operating personnel will be fully instructed concerning any potentially dangerous situations associated with the LNG Plant and methods of handling such hazards. A formal training program will consist of both classroom and field training. Fundamentals such as properties of LNG, hazards, safety aspects and fire fighting techniques will be taught in the classroom, followed by practical drill application at the plant site. Manufacturer's representatives will conduct classes on specific pieces of equipment such as marine loading arms, control systems, LNG pumps, LNG storage tanks, fire fighting equipment, and the like.

Particular emphasis will be given to training in fire fighting techniques. All operators will be given drill ground training in the use of hose lines fitted with spray nozzles for use against small fires and LNG releases, and for protection of fire fighters when closing valves, making rescues, and similar activities. Refresher training will be given routinely and new employees will be oriented and trained with the regular crews and given special attention.

This training will be preceded by an analysis of classes of accidents to determine the best strategy and tactics for handling the various kinds of emergencies which could be expected.

1.6.3 Alaskan Marine Terminal

1.6.3.1 Design Considerations

The following criteria were established as a basis for the engineering design. The proposed marine terminal will consist of two berths with provisions for simultaneous occupancy and LNG loading. The LNG carrier design size is 165,000 cubic meters.

Carrier Dimensions

	Feet
Length Overall	1002.0
Beam	150.0
Draft	40.0
Freeboard	61.0
Displacement	122,000 long tons

Tide Range

	Feet
Storm Tide	1.8
Highest Astronomical Tide	15.2
Mean Higher High Water	11.9
Mean High Water	10.9
Mean Tide Level	6.2
Mean Low Water	1.4
Mean Lower Low Water (Datum-MLLW)	0.0
Lowest Astronomical Tide	-3.6

Wave Load

Wave load is defined as follows (design waves are assumed to act at maximum tide level):

With Berth Occupied:

Wave Height	4.0 Feet
Wave Period	6.0 Seconds

With Berth Unoccupied:

Wave Height	24.5 Feet
Wave Period	8.0 Seconds

Deck

Elevations for the superstructures of the marine terminal were selected on the basis of the maximum water elevation expected. At Gravina Point, the maximum tide level plus a twenty-foot tsunami will produce the maximum water elevation. This maximum level is computed as follows:

Highest Astronomical Tide	= 15.2 feet (MLLW)
Storm Surge	= 1.8 feet
Height of Tsunami Above Still Water (0.9) x (20)	= 18.0 feet
Maximum Wave Crest	= 35.0 feet (MLLW)

Since the maximum wave crest elevation above MLLW is expected to be 35 feet, the deck elevation of all structures was designed to be 40 feet above MLLW to prevent the LNG carrier from being lifted onto the deck superstructures.

Water Depth At The Marine Terminal

The berthing facilities are located about 1200 feet offshore in an area that has a water depth of 51 feet at MLLW to accommodate the 40-foot draft LNG carriers. Overburden at the site was assumed to be 40 feet thick for the purpose of engineering design.

Wind Condition Criteria

A carrier approach velocity of 1.0 foot per second perpendicular to the dock face was used as a criteria for calculating berthing energies. The conservative velocity of 1.0 foot per second was selected because of the frequency of moderate winds (10 to 30 knots) in the Gravina Point area and the large sail (broadside surface) area peculiar to LNG carriers In normal berthing the velocity will be considerably less than 1.0 foot per second.

The most severe weather conditions for operation of the terminal is established as a four foot significant wave height and a 30 mph wind. The maximum design wind speed with a carrier in berth is established as 60 mph. The maximum design wind speed for the fixed structures is 145 mph with a one minute duration for a 100 year storm.

The forces created by the 20-foot tsunami with the berth unoccupied were calculated using Solitary Wave Theory (Ippen, 1966), which is based on a single propagating wave and is used in predicting wave particle velocities and accelerations in shallow water breaking waves (the tsunami is classified as a shallow water wave for berth design purposes).

Seismic and Tsunami

No active fault zones are known to be located in the vicinity of the marine terminal site. In addition, there are no known offshore bathymetric features which would amplify a tsunami wave. The occurrence of subsidence, uplift or soil liquefaction due to earthquake activity has not been reported for the area in which the marine terminal site is located. Therefore, the earthquake design is based on the criteria outlined in the Uniform Building Code for a Zone 3 occurrence. The use of the Uniform Building Code for earthquake analysis is recognized by the American Petroleum Institute (1974). Final design will include detailed dynamic response analysis.

A 12-foot tsunami wave was selected as the design wave with carriers in berth. With the berths unoccupied a 20-foot tsunami wave was selected.

For the purpose of this design it was assumed that the 2,060 kip berthing load would be a larger load than that caused by a tsunami with the carrier at berth.

In the design and layout of the marine terminal the recommendations of Wilson in his work "The Tsunami of the Alaskan Earthquake, 1964: Engineering Evaluation" were followed. These include using elastic shock-absorbing fenders, a deck elevation that prevents the carrier from being lifted onto the dock structures by the tsunami, and constant tension mooring winches so that the carrier can ride up with the wave.

Design Loads

The loading conditions investigated in the design of the Alaskan Marine Terminal were made up of combinations of the following individual loads. These combinations were selected based on engineering judgment and experience gained from similar terminal designs.

Dead Load

Dead load is the total weight of all empty vessels and equipment, structures, fixed cranes, fireproofing, insulation, piping, electrical conduit, ducts and all materials forming a permanent part of the structure.

Operating Load

Operating load is the sum of the dead load plus the weight of any liquids or solids normally present within the vessels, equipment or piping during operation. Also included are the weights of all materials stored for operation and the operating loads of fixed cranes.

Live Load

Live load is the weight of all movable loads including personnel, temporarily stored material, maintenance equipment, etc. Live loads for the following structures are:

1) Loading Platform - a 250 psf load or a HS20-44 truck (36 ton truck), whichever is larger

2) Service Platform - a 250 psf load or a HS20-44 truck, whichever is larger

3) Trestle - a 200 psf load or a HS20-44 truck, whichever is larger

4) Berthing Dolphins - a 200 psf load

5) Mooring Dolphins - a 100 psf load

Wind Load

Wind load is the force resulting on a structure due to wind resistance. The design wind speed for the fixed structures is 145 miles per hour with a one minute duration, the maximum anticipated for a 100-year storm.

The structures are designed for this wind load in accordance with American Society of Civil Engineers Paper 3269, "Wind Forces on Structures" (Transactions Volume 126, Part II, 1961).

Earthquake Load

Earthquake load is the total horizontal static force equivalent, in design effect, to the dynamic loads created by ground motion during an earthquake.

For the purpose of this Report, the earthquake design is based on the criteria outlined in the Uniform Building Code for Zone 3 earthquake analysis and is recognized by the American Petroleum Institute Publication RP2A (January, 1974), "Planning, Designing and Constructing Fixed Offshore Platforms" as being acceptable.

Berthing Load

Berthing load is the load caused by the berthing of a 165,000 m^3 capacity LNG carrier with a maximum approach velocity, perpendicular to the dock face, of 1.0 foot per second and an approach angle of 0 to 10 degrees. The berthing load is calculated using the following equation:

$$E = (1/2)\ (M_v + M_h)\ (C_c)\ (C_s)\ (C_e)\ (V_n^{\ 2})$$

Where:

M_v = Mass of the Vessel in $\dfrac{(\text{kip - sec}^2)}{\text{ft.}}$

M_h - Hydrodynamic Mass in $\dfrac{(\text{kip - sec}^2)}{\text{ft.}}$

C_c = Configuration Coefficient

C_s = Softness Coefficient

C_e = Eccentricity Coefficient

V_n = Translational Velocity Normal to the Pier in ft./sec.

Based on the above formula, the design berthing energy is 3018 foot-kips.

The conservative approach velocity of 1.0 foot per second was selected because of the frequency of moderate winds (10 to 30 knots) in the Gravina Point area and the large sail area peculiar to LNG carriers. In normal berthing, the velocity will be less than 1.0 foot per second. Winds in the 10 to 30 knot range occur annually 55 percent of the time.

The berthing dolphin deck is designed for a 200 psf live load and a 120 kip spring line mooring load.

Mooring Load

Mooring loads result from reactions of the moored LNG carrier to a 60 mile-per-hour wind from any direction, with the carrier at light draft. A total load of 880 kips results during these conditions and the maximum load on any one dolphin is 352 kips.

The mooring hooks selected for these dolphins have a nominal capacity of 400 kips. The maximum design load for the mooring dolphins is based on this capacity.

Wave forces are not calculated for this study but the additional load due to four foot waves was assumed not to create forces greater than the 400 kip design load.

The mooring dolphin deck is designed for a 100 psf live load and a 400 kip mooring load. The common mooring dolphin deck is designed for a 100 psf live load and two 400 kip mooring loads.

Wave Load

Design waves are assumed to occur at maximum tide level. Wave loads are as follows:

1) With Berth Occupied

   Wave height of 4.0 feet with a period of 6.0 seconds.

2) With Berth Unoccupied

Wave height of 24.5 feet with a period of 8.0 seconds.

Tsunami Load

Tsunami waves are assumed to occur at maximum tide level. Tsunami loads are as follows:

1) With Berth Occupied

Wave height of 12.0 feet with a period of 19.0 minutes.

2) With Berth Unoccupied

Wave height of 20.0 feet with a period of 49.0 minutes.

For the purpose of this design, it was assumed that the berthing load would be a larger load than that caused by a tsunami with the carrier at berth. This assumption is made because of the complexity involved in calculating forces due to a tsunami on a carrier at dock.

The preliminary design and layout of the marine terminal follows the recommendations of Basil W. Wilson in his work "The Tsunami of the Alaskan Earthquake, 1964: Engineering Evaluation". This design includes elastic-shock-absorbing fenders, a deck of sufficient height to prevent the carrier from being lifted onto the dock structures by a tsunami and the use of constant tension mooring winches so that the carrier can ride up with the wave.

The calculations of forces created by the 20-foot tsunami with the berth unoccupied are based on Solitary Wave Theory. This theory is based on a single propagating wave and is used in predicting wave particle velocities and accelerations in shallow water breaking waves. For design purposes, the tsunami is classified as a shallow water wave, and its profile is most nearly approximated by the Solitary Wave Theory. The resulting calculated wave forces on the structures are based on this theory. A discussion of the Solitary Wave Theory is presented by Ippen, "Estuary and Coastline Hydrodynamics," 1966, McGraw-Hill, Inc.

1.6.3.2 Operational Procedures

The configuration of the proposed Alaskan Marine terminal and the broad expanse of water available offshore allows an LNG carrier to dock using one of two distinct methods. The primary difference between the two methods involves the initial approach of the LNG carrier relative to the offshore edge of the terminal. Both methods utilize tug assistance although the use of tugboats is not mandatory.

One method of docking involves positioning the LNG carrier parallel to the terminal at a distance of 100 to 300 feet away. This position is maintained with the aid of tugs while a mooring line is run out from each end of the LNG carrier. Each line is transferred to a mooring dolphin by a mooring launch. Once these lines are in position, the LNG carrier may commence heaving in on the lines, thereby pulling itself towards the terminal. The tugs will be used as necessary during this phase of the operation.

The second method of approach is more commonly used. In this operation, the LNG carrier makes a very slow approach towards the terminal at a slight angle to the offshore edge of the berthing dolphins. The LNG carrier may be stopped just before making contact with the fenders located on the berthing dolphins, or the approach might be continued until contact is made. In either case, the forward progress of the LNG carrier is stopped and the carrier is then pushed up flush against the fenders by the tugboats.

Regardless of the method utilized, two important factors must be considered during the docking operations. First the approach velocity should be less than 0.5 feet per second. During the periods in which high velocity winds occur, it may not be possible to maintain the velocity of the LNG carrier below an acceptable value. Therefore, the docking operation would have to be postponed until more moderate conditions prevail.

The second factor which must be considered is the angle of approach relative to the fender faces. The fenders are designed to compensate for an angular approach of up to 10 degrees. Through the first method of docking is ostensibly designed to pull the LNG carrier in parallel to the terminal, the carrier may be pulled in at a slight angle. In the second method of docking, the LNG carrier proceeds in the direction of the terminal at a slight angle relative to the fender faces. During the docking operation, it is a simple procedure to maintain the angular approach of the LNG carrier well within the 10 degree limit. However, the influence of winds and waves upon the motion of the LNG carrier must be taken into consideration during this phase of the docking operation.

Once the LNG carrier is alongside the terminal and has been positioned correctly with respect to the loading arms on the loading platform, it will be tied up in place. Mooring lines from the LNG carrier will be led out to quick-release hooks located on the berthing and mooring dolphins.

During the operation, the tugs will stand by to assist if needed in maintaining the LNG carrier's position alongside the marine terminal. When all the mooring lines are placed on the quick-release hooks, the tugs will no longer be required to stand by and cargo loading operations may be started.

Various systems will be interconnected between the marine terminal and the carrier (see Section 1.4.3) including cargo trawler facilities, communications, fire fighting and emergency shut-down systems, and resupply service facilities. Such systems will also be tied into the related systems of the LNG Plant.

The LNG will be transferred from the terminal loading dock to carrier by means of four 16-inch loading arms which will connect to the ship's manifold. Movement of the entire arm in the horizontal plane, as well as individual movement of either section of the arm in the vertical plane will be accomplished using hydraulic cylinders positioned on the arm. Once the arm has been connected to the carrier's manifold, the hydraulic unit will be by-passed, thereby allowing the entire loading arm to move freely with the ship's motion at the dock due to winds, waves and tides. The hydraulic unit can be operated locally or from the control tower.

The function of the emergency shut-down system is to stop the cargo loading operation in the event of an emergency. The system automatically stops the cargo transfer pumps and compressors and activates quick-closing valves to halt the flow of LNG from the liquefaction plant to the LNG carrier. In addition to various shut-down stations located throughout the plant, a connection into the system provides for use on the LNG carrier. The loading arms are provided with limit switches which also activates the shut-down system if excessive arm movement should occur during cargo loading operations.

The loading operations are discussed in detail in the operations of the LNG Plant transfer facilities in Section 1.6.2.2, under the heading "LNG Storage and Handling".

When the LNG carrier is ready to depart from the berth, the tugs will come alongside at the bow and stern. The mooring lines will let go from the quick-release hooks on the mooring dolphins and be retrieved by the LNG carrier.

As soon as all the mooring lines have been released the tugs will commence to pull the carrier away from the terminal. Once the LNG carrier is pulled clear of the pier, and any ship which may be in the adjacent berth, the carrier will begin to move forward under its own power. The tugs will then be released and the LNG carrier can depart.

1.6.3.3 Maintenance

Proper maintenance of the marine terminal is essential to prolong the life of the structure and to insure safe operation of the facilities. An inspection of all equipment and structures will be conducted on a regular basis and all damaged or worn parts replaced accordingly.

All structures and equipment above water will be subjected to a yearly maintenance inspection. Every five years a major survey should be conducted by professional divers to determine how underwater pilings and structure respond to the underwater environment. Underwater investigations will be conducted using ultrasonic and hammer tests.

Major maintenance areas include replacement of fenders and anodes.

The fender system for the marine terminal is designed to accommodate the berthing of LNG carriers ranging from 125,000 to 165,000 cubic meters. Since these fenders will be subject to frequent and abusive loadings, one fender per year may need replacing.

A cathodic protection system will be provided for each submerged structure in the form of a galvanic anode system which utilizes sacrificial alloy anodes. Each anode on the structure will be inspected on a yearly basis. If excessive deterioration occurs, the appropriate anode or head wire will be replaced to insure continued cathodic protection.

Snow and ice accumulations will be removed from all surfaces as necessary to insure that safe working conditions prevail on the marine terminal and all equipment remains accessible to terminal personnel. A snow blower will be used to remove accumulations of snow, and urea will be used to remove the ice.

Maintenance of the small boat harbor, the construction dock and the ferry landing will consist of periodic replacement of rubber fenders on the caissons, repairs to the surface of the dock and roadway, painting as required and sandblasting of the metal surfaces of the flexible floats which will be used for the ferry landing and walkways. A small amount of dredging and slope maintenance on the rubble mound structure will also be required.

The cryogenic loading arms will be designed for long periods of service with a minimum of routine maintenance. The component parts of each loading arm which require servicing on a periodic basis will be the swivel joints, counterbalance wires, the hydraulic control system, the overtravel alarm system and the tiedown latches. Visual inspection of these components will be conducted according to a regular schedule whenever the arms are in service.

The cryogenic swivel joints will be inspected closely to detect the presence of any gas leaking across the seals. If the presence of gas is detected around the outside seal, an inspection screw will be removed to facilitate examination of the primary seal. A small amount of gas will not necessarily indicate that the seals or the swivel joint is defective. However, the presence of any liquid escaping from the seals would warrant a replacement of the part in question.

The counterbalance wires will connect the outboard arm to a counterweight through a pantograph arrangement. The only periodic maintenance required for these wires will be lubrication. If individual strands of wire appear to be excessively worn or broken, the wires should be replaced.

The hydraulic control system will be used to position the inboard arms of the loading arm assembly. The system will consist of a hydraulic pump, reservoir, hydraulic fluid, hydraulic cylinders, and the necessary piping and flexible hoses. The primary area of concern is minor leaks within the hydraulic system. If leaks are detected, the faulty component should be repaired or replaced. Approximately every two to three years the hydraulic fluid must be changed and all seals in the system replaced. In locations subjected to extreme weather conditions, the flexible hoses may require replacement on a periodic basis.

The over-travel alarm system is designed to sound an alarm when the design motion envelope parameters for the loading arm are exceeded. The primary component of the alarm system is a set of microswitches mounted directly on the loading arms. These switches should be inspected periodically to insure that they are functioning properly and are not jammed or stuck in position.

The tie-down latches will be used to secure the loading arms in the stored position to prevent any movement due to high winds or storm conditions. Periodically, these latches should be lubricated to insure that they will operate easily with a minimum of force.

The support vessels stationed at the marine terminal will require periodic maintenance and inspection to insure that each vessel remains in good operating condition. The diesel engines of the tugs, crewboats, and the mooring launch will require overhauls at regular intervals. In cases of repairs, a work shop located ashore will be used. Replacement parts of frequently needed will be kept in storage. Commodities such as lube oil, filters, paint, grease and other materials of this nature will also be stocked in the warehouse.

The quick-release hooks and mooring capstans located on the mooring and berthing dolphins will require routine maintenance to insure their continued operation. Both the quick-release hooks and the capstans should be lubricated periodically. The releasing mechanism of the hooks will be inspected frequently to check for signs of wear or metal fatigue.

The electrical power leads of each capstan will be checked for frayed insulation or damaged connections.

1.6.3.4 Manpower Requirements

The total manpower requirement for the operational interface between the marine terminal and the tankers will be provided by the LNG Plant and the LNG Carrier Fleet. The manpower required to perform marine terminal maintenance will be provided by the LNG Plant.

1.6.4 LNG Carrier Fleet

1.6.4.1 Design Considerations

The LNG Carrier Fleet was designed to optimize the fleet configuration (i.e., fleet size, ship capacity and average ship service speed) so that operations of the fleet (a variable intermittent flow process) and the LNG Plant (a constant flow process) could be coordinated in a way that will assure a safe, efficient and uninterrupted flow within the system at a minimum cost. Factors influencing fleet configuration are characteristics of the trade route, operational and storage capacity of the LNG Plant, and inherent fleet requirements (see Table 1.6-13).

An additional fleet configuration control factor is the state of the art of LNG shipping. Currently, 19 ocean-going LNG tankers are in operation; their capacities range from 5,000 m^3 to 87,500 m^3. Fifty-four additional LNG tankers are under construction or on order from shipyards around the world with capacities ranging up to 130,000 m^3. Sixteen of these are on order from four U. S. shipyards, all with capacities of approximately 125,000 m^3.

All announced LNG projects which require marine transportation have the LNG storage and plant facilities located onshore. With existing technology, the insulated cryogenic lines from the plants to the LNG tanker berths must be located on an above-water pier or in an under-water tunnel where they will be accessible for maintenance. From a practical and economic standpoint, this requirement limits the distance from shore to the berths and often the water depth at the berths. Since the capacity of an LNG tanker is roughly proportional to the vessel's draft, the size of tanker available for any LNG project is, in many instances, limited by the water depth available at the marine terminals.

It was for this reason that the 125,000 m^3 tanker size was developed (by El Paso Natural Gas Company) for the 40-foot dredged water depth that exists on the U. S. East Coast. The Alaskan and West Coast terminal sites are not restricted to a 40-foot water depth; consequently, the LNG tankers studied for the Trans-Alaskan Gas Pipeline-LNG Project were larger ships with their attendant economic benefits.

While existing construction of LNG tankers is limited to approximately 125,000 m^3, primarily for trade route reasons, the technology for constructing larger LNG tankers safely is presently available (e.g., 200,000 m^3 LNG tankers have been designed). It has been derived directly from the experience of designing and constructing 125,000 m^3 vessels.

After 400 possible fleet configurations were analyzed, it was determined that a fleet of eleven 165,000 m^3 vessels with an average service speed of 18.5 knots would best serve the trade route between the LNG Plant and Point Conception.

TABLE 1.6-13

CERTAIN FLEET CONFIGURATION CONTROL FACTORS

LNG Plant Production	2864 MMcf/cd
Regasification Capacity Requirements at Point Conception	2809 MMcf/cd (Avg.) + 17% additional capacity for operating flexibility
Storage (both Alaska and California)	Four 550,000-barrel tanks
Trade Route	1902 miles
Alaska Coastal Waters	Reduced speed zone in vicinity of terminal
California Coastal Waters	Reduced speed zone in vicinity of terminal
Ocean Waters	Relatively constant speed under good conditions
Average Duration of Port Routines per Voyage	26 hours Alaska 25 hours California
Estimated Annual Ship Out-of Service Time	35 days

1.6.4.2 Operational and Maintenance Procedures

Trade Route

Once the vessels leave the vicinity waters of either terminal, they can steam straight through to the destination at a relatively constant speed, although weather, currents and other factors will affect the average transit time to some degree. In accordance with prudent navigational procedures, the ships will reduce their speed for the approaches to Gravina Point and Point Conception. The final maneuvering and berthing will be accomplished through the use of the ship's power, the bow thruster, tugboats and ship-board berthing systems.

The average round trip voyage will take approximately 11-1/2 days, with sailing time each way consuming almost 4-1/2 days and port events about 1 day each (see Table 1.6-14 for detailed port routines).

It is estimated that the total annual delays due to storms will be 59 days at the Alaskan Marine Terminal, and 47 days at Point Conception.

Cargo Handling

The minimum annual LNG lift volume will be 49,825,300 m^3 and will require 308 shiploads. For the loaded voyage, the cargo tanks of the ships can be filled to within 98 percent of rated capacity. For the ballast voyage, the tanks will be emptied to a small fraction of the cargo, which will be left onboard to cool the cargo tanks in preparation for immediate loading upon arrival at the Alaskan Marine Terminal.

For either the loaded or ballast voyage, the LNG in the tanks will experience an average daily boiloff rate of approximately 0.15 percent of the total cargo volume. The exact rate will depend on the influx of heat through the tank insulation. The resulting LNG vapor will be used as a major source of fuel to power the ship.

As a result of the boiloff process, the cargo delivered to Point Conception will experience a slight increase in heating value. This occurs because constituents with low heating values will comprise the highest percentage of the boiloff vapor. Constituents with higher heating values and lower vapor pressures will tend to remain in the delivered cargo.

The compositions and heating valves of the LNG cargo as loaded and delivered are shown in Figure 1.0-2, Overall Material Balance. The difference between the loaded and delivered compositions results from the boiloff. The material balance for the fleet is:

	MMBtu/yr
Lifted at LNG Plant	1,210,322,000
Boiloff	20,575,000
Delivered to Point Conception	1,189,747,000

TABLE 1.6-14

AVERAGE CARRIER EVENT DURATIONS

	Alaskan Marine Terminal	Point Conception
Tie-In Time (hours)		
Pick Up Pilot at Pilot Station	1.5	0.5
Delay in Pilotage Waters	1.0	1.0
Mooring	1.5	1.5
Connecting Lines and Cargo Gauging	2.0	2.0
Average Total	6.0	5.0
Pumping Time (hours)		
Average	14.6	14.6
Cast-Off Time (hours)		
Disconnect Lines and Cargo Gauging	2.0	2.0
Cast Off	1.5	1.5
Delay in Pilotage Waters	1.0	1.0
Drop Pilot	1.0	0.5
Average Total	5.5	5.0
Total Port Routine	26.1 hours 1.09 days	24.6 hours 1.03 days
Sailing Time to:	4.33 days	4.44 days
Average Round Trip Duration	---------11.5 days---------	

Storage and Transfer Facilities

Two carriers can be loaded simultaneously at the marine terminal by means of two cryogenic loading lines with multiple loading arms, as more fully explained in Section 1.6.3.

Facilities will be required at Point Conception to supply the ships with provisions, stores, supplies, Bunker "C" fuel, low sulfur diesel fuel and liquid nitrogen. Warehouse space will be necessary to store, maintain and replenish the portable provisioning containers which will be transported to and placed on the ship at regular intervals. Storage tanks, piping, pumps and loading arms to supply both Bunker "C" fuel, low sulfur diesel fuel and liquid nitrogen to the ships, will also be needed.

Low sulfur diesel fuel and liquid nitrogen storage and loading facilities will be provided at the Alaskan Marine Terminal. The diesel fuel facilities will be used primarily to provide fuel for the tugs and service boats.

Maintenance

It is planned that each ship will be in operation for 330 days a year. Drydocking for annual surveys and repairs is anticipated to require a total of 20 days, of which fourteen days will be required for the actual drydocking. Two days will be required to sail to the yard, and to evacuate gas, warm up, inert and aerate the tanks so they will be safe for entry. The four final days of the 20-day period will be required for the ship to return to its service route and to cool down its tanks at the LNG Plant in preparation for cargo loading.

To minimize scheduling problems, ship drydockings will be conducted coincident with major LNG Plant maintenance, usually during late spring, summer and early fall after the peak market demands of winter.

It was also assumed that unscheduled out-of-service time will equal 15 days, which would be used for repairs and maintenance not requiring drydocking and for other delays not scheduled.

The result is that fleet arrival times cannot be evenly spaced. There will be times when less than one day may elapse between arrivals, other times when a week or more could elapse. Nevertheless, the unscheduled interruptions will tend to average out over the 25-year lifetime of the fleet, and it was assumed that each ship will be able to maintain an average speed throughout its service.

Public Safety[1/]

The LNG carriers will be among the safest ships ever built, having design and operational features to reduce the probability of an

[1/] An extensive analysis of public safety considerations is presented in Section 11 of this Report.

accident caused by a breakdown, explosion, fire, ramming, grounding or collision. Design features in addition to equipment redundancy include an inert gas system, vapor detection system, extensive fire fighting systems, increased maneuverability, a sophisticated navigation/communication package including a collision avoidance radar system, and double hull design. The use of the LNG carrier's collision avoidance radar system will significantly improve navigation and reduce the probability of an accident. Extensive crew training programs will emphasize proper ship and cargo handling procedures in addition to emergency plans.

The United States Coast Guard is responsible for safety of shipping in United States port and contiguous waters. This regulatory agency will exercise close control to assure the protection of the environment and the safety of waterway and waterfront facilities before permitting the LNG tankers to enter any U.S. port or estuary.

1.6.4.3 Waste Product Disposal

Air Emission Control

Under normal operations, the ships will not vent LNG cargo boil-off to the atmosphere. Emergency venting of boil-off (primarily methane) would occur to maintain satisfactory cargo tank pressure only if the gas-burning equipment fails or if the steam condensing equipment fails when the ship's fuel requirement is low. If vented, the boil-off vapors would be heated to 50°F to ensure that they would be lighter than air and hence rise harmlessly into the atmosphere.

Minor quantities of combustion emissions will occur at sea because Bunker "C" will supplement the boil-off vapors as fuel, with major combustion emissions coming from spent natural gas.

While in port, the ship will burn Bunker "C" fuel oil at the rate of 920 gallons per hour. Fuel oil combustion emission rates obtained from the Environmental Protection Agency are shown below. The rates reflect the two percent by weight concentration of sulfur in the Bunker "C" that is representative of that which may actually be used.

Table 1.6-15

EPA COMBUSTION EMISSION RATES

Pollutant	Emission Rate (gm/sec)
Particulate	2.66
Sulfur Dioxide	36.28
Sulfur Trioxide	0.43
Carbon Monoxide	0.46
Hydrocarbons	0.35
Nitrogen Oxides	9.24
Aldehydes	0.11

LNG cargo will be loaded and unloaded through a closed system. No liquid or vapor will escape to the atmosphere. When LNG is transferred from shoreside tanks to vessel cargo tanks, the vapor will be returned by a separate line to fill the void created in the shoreside tanks.

Overboard Discharge Control

All overboard discharges will be carefully controlled to meet all applicable requirements at sea.

1) Ballast Water

The ships will take on a maximum of 66,000 long tons of ballast water at Point Conception and discharge it at the Alaskan Marine Terminal. This will not create a major environmental problem because the vessel's ballast tanks are segregated from the cargo and other miscellaneous tanks. They will be used only for the purpose of holding seawater to maintain the vessel in proper trim and draft. The ballast tanks will remain clean and will not contaminate the ballast water.

2) Bilge Water

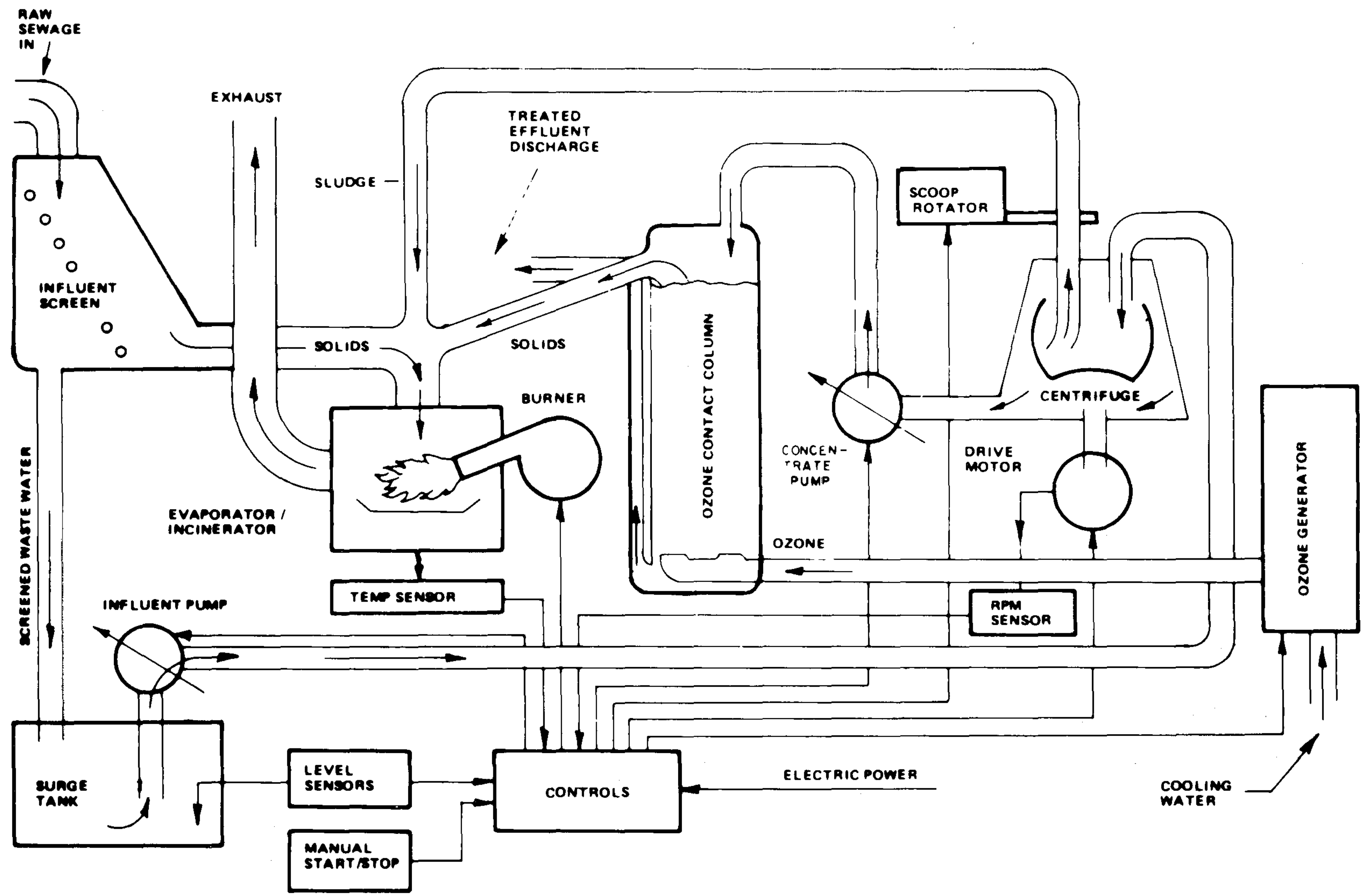
Minor bilge water accumulations will occur during normal engine room operation, and minor quantities of lubricants from the ship's machinery may accumulate in the bilge water. Bilge water accumulations at sea are processed by an oil/water separator before discharge to reduce the oil content to an acceptable level. The separator outlet will be equipped with an oily water detector which will stop the discharge of any effluent exceeding the appropriate regulatory standards. Effluent not meeting the discharge standards will be transferred to the holding tank for subsequent treatment. In port, all bilge water will be retained in a separate holding tank for discharge at sea.

3) Sanitary Wastes

The sanitary system for the LNG tankers will consist of a holding tank and an incinerator-type sewage treatment system. While the LNG tanker is in port, all shipboard sanitary wastes will be treated, and any effluent will be transferred to the holding tank for subsequent discharge at sea; none will be discharged in coastal waters.

Figure 1.6-11 is a schematic of the proposed sewage treatment system. This system will use waste screening and centrifugation to remove the majority of solids and associated biological oxygen demands, and will use ozonization for further disinfection. All solids and associated moisture will be eliminated by incineration and evaporation. The water effluent from the screening process will then be recycled for sanitary flushing or discharged overboard at sea.

Typically, the ship will generate 70 gallons per capita per day ("gpcd") of sewage containing human and domestic-type wastes.



TRANS-ALASKA GAS PROJECT

LNG CARRIER FLEET
TYPICAL SEWAGE
TREATMENT SYSTEM
FIGURE 1.6–11

4) Cooling Water

Cooling water will be required to remove the latent heat content of the exhaust steam in the condenser. Conditions may arise during the voyage when a ship's energy needs are less than that provided by cargo boil-off. The excess boil-off is burned in the boilers, and the surplus steam is condensed in the main condenser as a means of complying with the United States Coast Guard requirements for no venting of LNG vapor in United States waters. The shipboard condensers will discharge 60,000 g.p.m. of cooling water at $6^{o}F$ above intake conditions.

The cooling water from the condensers while the ship is at port will also be discharged at a rate of 60,000 gpm, although there will be only a $2^{o}F$ rise above the intake temperature.

5) Solid waste

Generally, the crew is expected to generate 1.85 pounds per capita per day of solid waste that is similar in type and quantity to residential waste accumulation. Solid wastes will be compacted and baled or ground before overboard disposal. These methods are acceptable on the open sea if the bales are properly weighted. However, there will be no dumping of solid waste into United States waters.

6) Liquid Nitrogen and Bunker "C" Provisioning

The ship will take on liquid nitrogen and Bunker "C" fuel oil at Point Conception. The transfer system will utilize articulated loading arms, a system which is much more reliable than the use of barges alongside the ship. This reliability results in a very low possibility of a liquid nitrogen or fuel oil spill.

7) Pierside LNG Spills (see Sections 3F and 11 of this Report)

Normal loading and unloading operations will utilize a closed system; hence no liquid or vapor will be released. The mooring system has been designed to prevent the ship from being pulled away from the berth, and the loading arms have been designed to allow for a substantial movement of the LNG tanker without equipment damage.

In the unlikely event a spill does occur, the ship's emergency shutdown system will close the cargo shutoff valves, and will shut down cargo pumps and compressors. The system will be automatically activated by conditions such as fire, low or high cargo tank pressures, or excessive movement of the ship at the dock. In addition, there will be five manually activated emergency shutdown stations. The maximum shutdown time is approximately 15 seconds.

Should a small quantity of LNG escape from manifold gaskets, it will be caught in heated drip pans beneath the shipboard manifold flanges. The manifold and deck piping will automatically drain into the cargo tanks when the cargo pumps stop, which will ensure that these lines empty rapidly in the event of an emergency shutdown or (un) loading arm disconnection.

Noise

The estimation of noise generated by the proposed LNG tankers is based on experience with similar sized ships. While in port, the power plant is required only to generate electricity and provide the various hotel requirements such as heat, refrigeration and air conditioning. The small amount of engine room noise generated for these needs is significantly attentuated by the ship's hull and water surrounding it.

Cargo discharge is accomplished using submerged electric-driven pumps. The ship's hull, cargo tank insulation and the cargo itself will substantially attentuate cargo pump noise. Noise from this operation will be in the same range of other ship-related sounds in this area.

1.6.4.4 Manpower Requirements

The total LNG Carrier Fleet Manpower Requirement will be 672 personnel who will perform operating and administrative functions. Each LNG carrier will be manned by 10 officers and 25 crew members who are fully trained to carry out safe and efficient operational procedures with special emphasis on emergency procedures.

The carrier personnel assignments are shown in Table 1.6-16. The full complement of fleet operating personnel will be 578 men, 50% higher than the number of crewmen (385) required to man all eleven ships at any one time. The additional personnel will allow operating flexibility for crew rotation, vacation or sick leave, and for personnel turnover.

There will be a total of 58 fleet administrative support personnel, including corporate executives, managers, accountants, technicians, clerks and secretaries. Home office personnel will include 6 executives and 41 managers and staff, while 11 managers and staff will be required for fleet support at the Alaskan Marine Terminal.

A fleet support operating staff of 36 personnel will be required at the marine terminal to perform the following tasks:

Dockmaster	1
Assistant Dockmaster	4
Foremen & Roustabouts	5
Operators and Utility Men	4
Tugboat Crewmen	22
Total	36

TABLE 1.6-16

LNG CARRIER CREW

RATING	NUMBER
Master	1
Chief Mate	1
2nd Mate	1
3rd Mate	1
Radio Officer	1
Bosun	1
Able Bodied Seaman	7
Ordinary Seaman	3
TOTAL DECK	16
Chief Engineer	1
1st Engineer	1
2nd Engineer	1
3rd Engineer	1
4th Engineer	1
Pumpman	3
Electrician	1
Repairer	1
Oiler	3
TOTAL ENGINEERING	13
Steward/Cook	1
Cook	1
Galleyboy	1
Messman	3
TOTAL STEWARDS	6
TOTAL SHIP'S CREW	35

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1.7 FUTURE PLANS

The proposed system has been designed to receive 3.5 bcf of natural gas per day at Prudhoe Bay, and to transport such gas to the southern coast of Alaska for liquefaction and shipment to the U. S. West Coast for distribution in the Lower 48 States.

If additional gas becomes available in the North Slope or other areas traversed by the pipeline, the proposed system can be expanded to move additional increments of gas to markets in the Lower 48. The capacity of the Alaskan Gas Pipeline can be increased by the normal procedure of adding pipeline loop and incremental compressor horsepower. The LNG Plant capacity can be increased incrementally by installing additional liquefaction trains and support facilities. The Alaskan Marine Terminal can be expanded by constructing additional berths to accommodate three or more LNG carriers simultaneously. The number of ships in the LNG Carrier Fleet can be increased to transport incremental volumes of LNG.

Discussions of future plans for the Lower 48 components of the overall Alaskan Project transportation system are presented in the various companion filings covering such components.


UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
ALASKA
MAP E
COMPILED FROM THE GEOLOGICAL SURVEY ALASKA RECONNAISSANCE TOPOGRAPHIC SERIES. SCALE 1:250 000. AND OTHER OFFICIAL SOURCES
SCALE 1:2 500 000
1 INCH APPROXIMATELY 40 MILES
WITH UTILITY AND TRANSPORTATION CORRIDOR,
ALYESKA OIL PIPELINE
AND PROPOSED TRANS–ALASKA GAS PROJECT FACILITIES
ADDED
DATUM IS MEAN SEA LEVEL
SPECIAL PRINTING FOR EL PASO ALASKA COMPANY
FAIRBANKS, ALASKA
FEDERAL CENTER, DENVER, COLORADO
WASHINGTON 25, D. C.
1954
ARCTIC OCEAN
BEAUFORT SEA
CHUKCHI SEA
BERING SEA
NORTON SOUND
BRISTOL BAY
PACIFIC OCEAN
GULF OF ALASKA
ALEUTIAN ISLANDS
FOX ISLANDS
PRIBILOF ISLANDS
BROOKS RANGE
ALASKA RANGE
PROPOSED 42" BURIED, CHILLED GAS PIPELINE
DESIGNATED UTILITY AND TRANSPORTATION CORRIDOR
ALYESKA OIL PIPELINE (UNDER CONSTRUCTION)
FAIRBANKS
ANCHORAGE
KODIAK
JUNEAU
UNITED STATES
CANADA
YUKON
ALASKA
NORTHWEST TERRITORIES
BRITISH COLUMBIA
DIXON ENTRANCE
HECATE STRAIT
BERING SEA
ALEUTIAN ISLANDS
ANDREANOF ISLANDS
PACIFIC OCEAN